Transportation Research Board
Special Report 311

Effects of Diluted Bitumen on Crude Oil Transmission Pipelines

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Special Report 311

Effects of Diluted Bitumen on Crude Oil Transmission Pipelines

Committee for a Study of Pipeline Transportation of Diluted Bitumen

Transportation Research Board

Board on Energy and Environmental Systems

Board on Chemical Sciences and Technology

NATIONAL RESEARCH COUNCIL
OF THE NATIONAL ACADEMIES

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This report has been reviewed by a group other than the authors according to the procedures approved by a Report Review Committee consisting of members of the National Academy of Sciences, the National Academy of Engineering, and the Institute of Medicine.

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Preface

This National Research Council (NRC) study was sponsored by the Pipeline and Hazardous Materials Safety Administration (PHMSA) of the U.S. Department of Transportation.[1] The study charge and origins are explained in Chapter 1. The contents and findings of the report represent the consensus effort of a committee of technical experts, who served uncompensated in the public interest. Drawn from multiple disciplines, the members brought expertise from chemistry and chemical engineering; corrosion and materials science; risk analysis; and pipeline operations, research, and safety regulation. Committee member biographical information is provided at the end of the report.

The study committee convened five times over 10 months, including a visit by several members to a pipeline terminal and energy research laboratory in the Edmonton and Fort McMurray areas of Alberta, Canada. Data-gathering activities during and between meetings were extensive. All but the final meeting contained sessions open to the public. During meetings, the committee heard from speakers from the oil and pipeline industries, environmental interest groups, research and standards organizations, oil testing companies, and government agencies from the United States and Canada. The committee also provided a forum for private individuals to contribute information relevant to the study. In sum, more than 40 people spoke before the committee during public meetings and site visits. To obtain additional information on the practice of transporting diluted bitumen by pipeline, the committee provided the Canadian Energy Pipeline Association with a questionnaire for distribution to pipeline operators with experience transporting diluted bitumen and other crude oils in North America. The questionnaire responses and agendas for the public meetings are provided in appendices to this report.

ACKNOWLEDGMENTS

The committee thanks the many individuals who contributed to its work.

During data-gathering sessions open to the public, the committee met with the following officials from PHMSA: Jeffrey Wiese, Associate Administrator; Linda Daugherty, Deputy Associate Administrator for Policy and Programs; Alan Mayberry, Deputy Associate Administrator for Field Operations; Blaine Keener, National Field Coordinator; and Jeffery Gilliam, Senior Engineer and Project Manager. The contributions of all were appreciated, especially those of Mr. Gilliam, who served as PHMSA's technical representative for the project.

Several officials and researchers from government agencies and laboratories in Canada briefed the committee during meetings: Iain Colquhoun, National Energy Board; John Zhou, Alberta Innovates Energy and Environment Solutions; Haralampos Tsaprailis and Michael Mosher, Alberta Innovates Technology Futures; and Parviz Rahimi, Heather Dettman, and Sankara Papavinasam, Natural Resources Canada. The committee thanks them all, especially Dr. Papavinasam, who twice briefed the committee, and Dr. Tsaprailis, who arranged a tour of the Alberta Innovates and Natural Resources Canada energy laboratory in Devon, Alberta.

[1] The contract was awarded on March 12, 2012.

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Early in its deliberations, the committee invited several nationally recognized experts to provide briefings on pipeline design, operations, and maintenance; corrosion evaluation and control; and developments in the North American petroleum market. The committee is indebted to Thomas O. Miesner, Pipeline Knowledge and Development; Arthur Diefenbach, Westpac Energy Group; Oliver Moghissi, DNV Columbus, Inc.; and Geoffrey Houlton, IHS. Their uncompensated briefings provided essential background for the committee's work.

The committee met with and received information from the following individuals representing the oil production and pipeline industries: Dale McIntyre, ConocoPhillips; Randy Segato, Suncor Energy, Inc.; Dennis Sutton, Marathon Petroleum Company; Bruce Dupuis, Jenny Been, and Bruce Wascherol, TransCanada Corporation; Colin Brown, Kinder Morgan Canada; Terri Funk and Shoaib Nasin, Inter Pipeline; and Trevor Place, Ashok Anand, Martin DiBlasi, and Scott Ironside, Enbridge Pipelines, Inc. The committee expresses its gratitude to all, especially to Mr. Ironside, who assisted in arranging presentations and the tour of a pipeline terminal in Alberta.

In seeking information on the properties of diluted bitumen and other crude oils, the committee received valuable information from the following individuals and organizations: Harry Giles, Crude Oil Quality Association; Bill Lywood, Crude Quality, Inc.; and Andre Lemieux, Canadian Crude Quality Technical Association. The information received on the chemical and physical properties of diluted bitumen and other crude oils was critical to many of the analyses in the study. The committee thanks each of them and their organizations for this assistance.

Finally, the committee thanks several individuals who briefed it or were otherwise helpful in identifying issues and providing relevant sources of data and other information. They are Anthony Swift, Natural Resources Defense Council; Peter Lidiak, American Petroleum Institute; Cheryl Trench, Allegro Energy Consulting; and Ziad Saad, Canadian Energy Pipeline Association. Mr. Saad was instrumental in distributing and collecting responses to the pipeline operator questionnaire.

Thomas R. Menzies and Douglas Friedman were the principal project staff. Menzies managed the study and drafted much of the report under the guidance of the committee and the supervision of Stephen R. Godwin, Director, Studies and Special Programs, Transportation Research Board (TRB). Additional technical assistance and oversight were provided by James Zucchetto, Director of the Board on Energy and Environmental Systems, and Dorothy Zolandz, Director of the Board on Chemical Sciences and Technology. Norman Solomon edited the report, and Jennifer J. Weeks prepared the edited manuscript for prepublication web posting, under the supervision of Javy Awan, Director of Publications, TRB. Claudia Sauls provided extensive support to the committee in arranging its meetings and managing documents.

The report has been reviewed in draft form by individuals chosen for their diverse perspectives and technical expertise in accordance with procedures approved by NRC's Report Review Committee. The purpose of this independent review is to provide candid and critical comments that will assist the institution in making the report as sound as possible and to ensure that the report meets institutional standards for objectivity, evidence, and responsiveness to the study charge. The review comments and draft manuscript remain confidential to protect the integrity of the deliberative process.

NRC thanks the following individuals for their review of this report: Khalid Aziz (NAE), Stanford University; John Beavers, DNV Columbus, Inc.; Jos Derksen, University of Alberta; Melvin F. Kanninen (NAE), MFK Consulting Services; John Kiefner, Kiefner & Associates,

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Inc.; Thomas Miesner, Pipeline Knowledge and Development; Gene Nemanich, Chevron Technology Ventures (retired); Stephen Pollock (NAE), University of Michigan; Massoud Tahamtani, Commonwealth of Virginia State Corporation Commission; and Patrick Vieth, Dynamic Risk USA, Inc. The review of this report was overseen by Elisabeth Drake (NAE), Massachusetts Institute of Technology, and Susan Hanson (NAS), Clark University. Appointed by NRC, they were responsible for making certain that an independent examination of this report was carried out in accordance with institutional procedures and that all review comments were carefully considered. Responsibility for the final content of the report rests solely with the authoring committee and the institution. Karen Febey managed the report review process under the supervision of Suzanne Schneider, Associate Executive Director, TRB.

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Executive Summary

Legislation enacted in January 2012 called on the Secretary of Transportation to determine whether any increase in the risk of a release exists for pipelines transporting diluted bitumen.[1] Bitumen is a dense and viscous form of petroleum that will flow in unheated pipelines only when it is diluted with lighter oils. The source of the diluted bitumen in North America is the oil sands region of Alberta, Canada. Diluted bitumen has been imported from Canada for more than 30 years and is currently transmitted through numerous pipelines in the United States. As imports of this and other Canadian crude oils have grown, new U.S. pipelines have been constructed, the flow directions of several existing pipelines have been reversed, and additional pipeline capacity is planned.

Determination of the risk of a pipeline release requires an assessment of both the likelihood and the consequences of a release. To inform its review of the former, the U.S. Department of Transportation asked the National Research Council to convene an expert committee to study whether shipments of diluted bitumen differ sufficiently from shipments of other crude oils in such a way as to increase the likelihood of releases from transmission pipelines. A finding of increased likelihood would lead the committee to conduct a follow-up review of the adequacy of federal pipeline safety regulations. In the absence of such a finding, the committee was tasked with issuing this final report, which documents the study approach and results.

STUDY APPROACH

The committee analyzed information in a variety of forms. Early in its deliberations, the committee provided a public forum for individuals to contribute information relevant to the study. The committee reviewed pipeline incident statistics and investigations; examined data on the chemical and physical properties of shipments of diluted bitumen and other crude oils; reviewed the technical literature; consulted experts in pipeline corrosion, cracking, and other causes of releases; and queried pipeline operators about their experience in transporting diluted bitumen.

The review of incident data revealed the ways in which transmission pipelines fail. Some failures can be affected by the properties of the transported crude oil, such as its water and sediment content, viscosity and density, and chemical composition. These properties were examined for diluted bitumen and a range of other crude oils to determine whether pipelines transporting diluted bitumen are more likely to experience releases. In addition, the committee considered whether pipeline operations and maintenance (O&M) practices, including internal and external corrosion control capabilities, are subject to changes that inadvertently increase the likelihood of release when pipelines transport diluted bitumen.

[1] Public Law 112-90, enacted January 3, 2012.

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RESULTS

Central Findings

The committee does not find any causes of pipeline failure unique to the transportation of diluted bitumen. Furthermore, the committee does not find evidence of chemical or physical properties of diluted bitumen that are outside the range of other crude oils or any other aspect of its transportation by transmission pipeline that would make diluted bitumen more likely than other crude oils to cause releases.

Specific Findings

Diluted bitumen does not have unique or extreme properties that make it more likely than other crude oils to cause internal damage to transmission pipelines from corrosion or erosion. Diluted bitumen has density and viscosity ranges that are comparable with those of other crude oils. It is moved through pipelines in a manner similar to other crude oils with respect to flow rate, pressure, and operating temperature. The amount and size of solid particles in diluted bitumen are within the range of other crude oils and do not create an increased propensity for deposition or erosion. Shipments of diluted bitumen do not contain higher concentrations of water, sediment, dissolved gases, or other agents that cause or exacerbate internal corrosion, including microbiologically influenced corrosion. The organic acids in diluted bitumen are not corrosive to steel at pipeline operating temperatures.

Diluted bitumen does not have properties that make it more likely than other crude oils to cause damage to transmission pipelines from external corrosion and cracking or from mechanical forces. The contents of a pipeline can contribute to external corrosion and cracking by causing or necessitating operations that raise the temperature of a pipeline, produce higher internal pressures, or bring about more fluctuation in pressure. There is no evidence that operating temperatures and pressures are higher or more likely to fluctuate when pipelines transport diluted bitumen than when they transport other crude oils of similar density and viscosity. Furthermore, the transportation of diluted bitumen does not differ from that of other crude oils in ways that can lead to conditions that cause mechanical damage to pipelines.

Pipeline O&M practices are the same for shipments of diluted bitumen as for shipments of other crude oils. O&M practices are designed to accommodate the range of crude oils in transportation. The study did not find evidence indicating that pipeline operators change or would be expected to change their O&M practices in transporting diluted bitumen.

In accordance with the study charge, these results focus on whether pipeline shipments of diluted bitumen have a likelihood of release greater than that of other crude oils. As indicated at the outset of this summary, the committee was not asked or constituted to study whether pipeline releases of diluted bitumen and other crude oils differ in consequences or to determine whether such a study is warranted. Accordingly, the report does not address these questions and should not be construed as having answered them.

Introduction

This chapter describes the study charge and scope, analytic approach, and report structure.

STUDY CHARGE

Section 16 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 calls for the Secretary of Transportation to "complete a comprehensive review of hazardous liquid pipeline facility regulations to determine whether the regulations are sufficient to regulate pipeline facilities used for the transportation of diluted bitumen. In conducting the review, the Secretary shall conduct an analysis of whether any increase in the risk of a release exists for pipeline facilities transporting diluted bitumen."[1]

Bitumen is a dense and viscous form of petroleum that will flow through unheated pipelines only when it is diluted with lighter oils. At present, the source of bitumen supplied to refineries in North America is the oil sands region of Alberta, Canada. Bitumen from Canada has been diluted for pipeline transportation to the United States for more than 30 years, primarily to refineries located along the Great Lakes and elsewhere in the Midwest. Bitumen production and imports from Canada have grown during the past decade, and this traditional U.S. oil-processing market no longer has the capacity to refine all of the supply. Meanwhile, refineries on the Gulf Coast, which have traditionally processed South American and Mexican crude oils with properties similar to bitumen, have sought access to the heavy crude oils from Canada. To accommodate the Canadian imports as well as the growth in domestic crude oil production, the flow directions of several existing pipelines have been reversed, new transmission pipelines have been constructed, and additional pipeline capacity is planned.

Within the U.S. Department of Transportation (USDOT), the regulation of pipeline safety resides with the Pipeline and Hazardous Materials Safety Administration (PHMSA). USDOT has thus delegated to PHMSA the responsibility of determining whether pipelines transporting diluted bitumen have an increased risk of release. A determination of risk requires an assessment of both the likelihood and the consequences of a release. To inform its assessment of the former, PHMSA contracted with the National Research Council (NRC) to conduct the study documented in this report. Specifically, PHMSA asked NRC to convene a committee of experts in pipeline operations; risk analysis; safety regulation; and chemical, materials, and corrosion engineering to "analyze whether transportation of diluted bitumen by transmission pipeline has an increased likelihood of release compared with pipeline transportation of other crude oils." PHMSA did not ask NRC to study the consequences of potential pipeline releases of diluted bitumen.

The full statement of task (SOT) for the study is contained in Box 1-1. The SOT calls for a two-phase study, with the conduct of the second phase contingent on the outcome of the first. In the first phase, the study committee is asked to examine whether shipments of diluted bitumen can affect transmission pipelines and their operations so as to increase the likelihood of release

[1] Public Law 112-90, enacted January 3, 2012.

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Box 1-1

Statement of Task

The committee will analyze whether transportation of diluted bitumen (dilbit) by transmission pipeline has an increased likelihood of release compared with pipeline transportation of other crude oils. Should the committee conclude that an increased likelihood of release exists, it will review the federal hazardous liquid pipeline facility regulations to determine whether they are sufficient to mitigate the increased likelihood of release.

In the first phase of the project, the committee will examine whether dilbit can affect transmission pipelines and their operations so as to create an increased likelihood of release when compared with other crude oils transported through pipelines. Should the committee conclude there is no increased likelihood of release or find there is insufficient information to reach such a conclusion, a second phase of the project will not be required and the committee will prepare a final report to the Office of Pipeline Safety (OPS) of the Pipeline and Hazardous Materials Safety Administration (PHMSA). This report may include recommendations for improving information to assess the likelihood of failure.

Should the committee conclude there is an increased likelihood of release on the basis of dilbit's effects on transmission pipelines and their operations, it will issue a brief Phase 1 report of its findings and then proceed to the second phase of the project to determine whether hazardous liquids pipeline regulations are sufficient to mitigate the increased likelihood of release. The committee's final report following completion of this second phase will contain the complete set of findings, conclusions, and recommendations of both project phases.

when compared with shipments of other crude oils transported by pipeline. In the potential second phase—to be undertaken only in case of a finding of increased likelihood—the committee is asked to review federal pipeline safety regulations to determine whether they are sufficient to mitigate an increased likelihood of release from diluted bitumen. If the committee does not find an increased likelihood of release or the information available is insufficient for a finding, the committee is expected to prepare a final report documenting the study approach and results.

STUDY SCOPE

The SOT makes reference to several terms that delineate the study scope and require explication. First, the SOT specifically requests an examination of "transmission" pipeline facilities. The pipelines in these facilities contain large-capacity pipe, usually 20 inches or more in diameter, and generally transport fluids over long distances under relatively high pressure (400 to 1,400 pounds per square inch). Transmission facilities also contain storage tanks, pumping equipment, and piping within terminals. Gathering pipelines used for collecting crude oil from production fields do not transport diluted bitumen in the United States and are not part of this study.

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As used in the SOT, the term "diluted bitumen" does not define a single product composition or specific set of product or shipment properties. Blending bitumen with lighter oils to lower viscosity is the common method of transporting this form of petroleum by pipeline. The volume of bitumen in a pipeline shipment will vary with the diluent, as will the chemical and physical properties of the shipment. The Canadian diluted bitumen transported in transmission pipelines to the United States generally contains 50 to 75 percent bitumen by volume, with light oils constituting the remainder. These bitumen blends are the subject of this study. It is recognized that the source and composition of bitumen shipments may change depending on technological advances, diluent supplies, refinery demands, and other technical and economic developments.

Finally, the SOT asks the committee to examine whether pipelines transporting diluted bitumen have a higher likelihood of release than pipelines transporting "other crude oils." Accordingly, the aim of this study is to determine whether shipments of diluted bitumen have a release history or specific properties associated with pipeline failures that lie outside the range of experience and properties represented by the full spectrum of crude oils transported by pipeline in the United States.

ANALYTIC APPROACH

An assessment of release likelihood requires information on the potential sources of pipeline failure. PHMSA mandates the reporting of releases from U.S. transmission pipelines and categorizes each according to its immediate, or proximate, cause. Historically, about one-third of reported releases have involved corrosion damage (Figure 1-1). Other causes include outside force damage, such as an excavator striking a buried pipe, and faulty equipment, operator error, and deficiencies in welds and materials used in pipeline manufacturing and installation.

The committee reviewed U.S. and Canadian data on reported pipeline releases. The review provided insight into the main causes of releases, but the incident statistics alone could not be used to determine whether pipelines are more likely to experience releases when they transport diluted bitumen than when they transport other crude oils. Few incident records contain information on the type of crude oil released in an incident or document the properties of the shipments moved through the pipeline over time. Causal details are also limited. Incidents categorized as corrosion damage, for example, do not specify whether the damage occurred as a result of the action of microorganisms, in combination with stress cracking, or at sites of previous mechanical damage. Such detailed information is important in determining the causative role of the crude oils being transported in the pipeline, particularly for failures arising from cumulative and time-dependent degradation mechanisms such as corrosion and cracking.

Having identified the main causes of pipeline releases, the committee assessed each cause with respect to its potential to be affected by the chemical and physical properties of the transported crude oil. Consideration was given to specific shipment properties that can contribute to internal degradation, external degradation, and mechanical damage in pipelines. While the committee did not perform its own testing of crude oil shipments, information on many of the chemical and physical properties of diluted bitumen and other crude oils was obtained from public websites and assay sheets. Additional information was obtained from a review of government reports and technical literature, queries of oil producers and pipeline

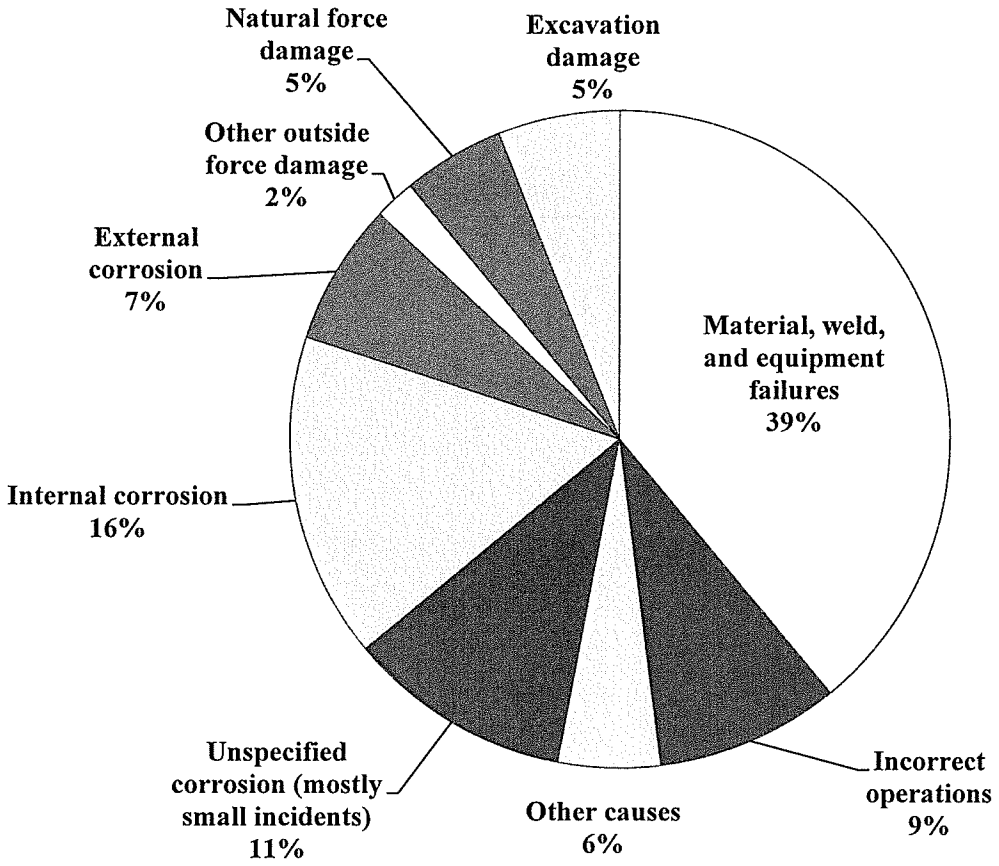

FIGURE 1-1 Causes of crude oil pipeline releases reported to PHMSA, 2002 to 2011. (Source: Incident data provided to committee by PHMSA Office of Pipeline Safety during presentations on October 23, 2012. http://onlinepubs.trb.org/onlinepubs/dilbit/Keener102312.pdf.)

operators, field visits, and inferences from secondary sources such as the maximum water and sediment content specified in pipeline tariffs. The committee then compared the relevant properties of diluted bitumen with the range of properties observed in other crude oils and looked for instances in which diluted bitumen fell outside or at an extreme end of the range.

Recognizing the possibility that some pipeline operators may modify their operating and maintenance practices when they transport diluted bitumen, the committee asked operators about their procedures in transporting diluted bitumen and other crude oils. The committee looked for evidence of changes in standard procedures, including corrosion monitoring and control practices, that could inadvertently make pipelines more susceptible to failure.

REPORT ORGANIZATION

The remainder of the report is organized into five chapters. Chapter 2 provides background on the transportation of crude oil by pipeline, including the main components of pipeline systems

and common aspects of their operations and maintenance. Chapter 3 describes the production, properties, and pipeline transportation of diluted bitumen. Chapter 4 reviews pipeline incident data from the United States and Canada. The analyses of how the comparative properties of diluted bitumen and other crude oils pertain to sources of pipeline failure are carried out in Chapter 5. Chapter 6 summarizes the main discussion points from the preceding chapters and presents the study results.

Appendix A contains the questionnaire developed for pipeline operators and the responses. A brief description of the federal hazardous liquid pipeline regulations and PHMSA safety oversight is provided in Appendix B. Agendas from the information-gathering sessions of committee meetings are provided in Appendix C.

2

Crude Oil Pipelines in the United States

This chapter provides background on the network of crude oil transmission pipelines in the United States; the main components of these systems; and common aspects of their operations, maintenance, and integrity management. The background was derived from several sources: National Petroleum Council 2011, Argonne National Laboratory 2008, Rabinow 2004, and a presentation to the committee by Thomas Miesner.[1]

NATIONAL PIPELINE NETWORK

Crude oil is transported, both onshore and offshore, in gathering systems and transmission pipelines. The gathering systems are made up of low-capacity pipelines—typically less than 8 inches in diameter—that move crude oil from wells to high-capacity transmission pipelines that are usually 8 to 48 inches in diameter. Before the crude oil leaves the production field, it is processed to remove excess water, gases, and sediments as necessary to meet the quality specifications of transmission pipelines and the refineries they access.

Most of the estimated 55,000 miles of crude oil transmission pipeline in the United States are interconnected to form a national network that links oil production regions, storage hubs, and refineries.[2] This extensive network accounts for more than 90 percent of the ton-mileage of crude oil transported within the United States.[3]

Transmission pipelines are critical in providing refineries with a steady supply of feedstock consisting of various types of crude oil. About 140 refineries operate nationwide. Some are vast complexes that can process more than 500,000 barrels of crude oil per day, while others serve relatively small and specialized markets and process less than 50,000 barrels per day.[4]

About 40 percent of U.S. refining capacity is located along the Gulf Coast, and the next largest center is in the Upper Midwest. Originally, the Gulf Coast refineries were supplied by domestic sources, primarily from Texas and Louisiana and from shallow waters in the Gulf of Mexico. As domestic production declined in the 1970s, the Gulf Coast refineries increasingly sourced their crude oil from Mexico, Venezuela, and the Middle East. Because the imports tended to be denser and higher in sulfur, refiners invested in facilities capable of processing such feedstock. In recent years, increased production from Canada, deep Gulf waters, and domestic shale fields has replaced waterborne imports. These supply shifts have had significant implications for the transmission pipelines that once moved crude oil from Gulf Coast ports to inland refineries as far north as Illinois and Ohio. Many of these systems have had their flow directions reversed and are now being used to transport Canadian crude oil to the Gulf Coast

[1] October 23, 2012 (http://onlinepubs.trb.org/onlinepubs/dilbit/Miesner102312.pdf).

[2] The Pipeline and Hazardous Materials Safety Administration (PHMSA) has estimated that the crude oil transmission pipeline network extended for 55,330 miles as of 2011.

[3] "Ton-mile" is a measure of the weight of a substance carried multiplied by the distance over which it is carried.

[4] One U.S. barrel of crude oil contains 42 gallons.

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refineries. The transition is under way, with major investments to add more north-to-south capacity by reversing more lines and building new ones.
For many decades, U.S. crude oil produced in the northern Rocky Mountains and Dakotas, as well as that produced in the western provinces of Canada, was transported to refining centers in Eastern Canada and the Upper Midwest. In recent years, as output from these oil-producing regions has grown significantly, crude oil supplies have exceeded refining capacity and are being transported south, where they are displacing crude oil traditionally sourced from Mexico, South America, and the Gulf of Mexico.

Both the East and West Coasts have remained largely independent markets for crude oil supplies. The eastern states have little oil production and no significant crude oil transmission pipelines. While the recent development of shale resources in New York and Pennsylvania is adding production capacity, truck and rail remain the dominant regional modes of crude oil transportation. The main East Coast refining centers in northern New Jersey, Philadelphia, and coastal Virginia receive most of their supplies from tanker vessels. In comparison, California has an extensive network of crude oil transmission pipelines because of significant in-state oil production. These pipeline systems, some of which consist of heated lines to move the native viscous crude oils, do not connect to pipeline systems in other states. Refineries in Washington State receive crude oil by tanker and from Western Canada by pipeline.

PIPELINE SYSTEM COMPONENTS

The individual pipeline systems that make up the U.S. crude oil transmission network vary in specific design features and components. Nevertheless, the systems have many common elements.

Line Pipe

Pipelines are made of sections of line pipe that are welded together and generally buried 3 or more feet below grade. Virtually all line pipe is made of mild carbon steel that is coated externally but not internally. Pipe sections are typically 40 feet long, manufactured with longitudinally welded seams and joined by circumferential girth welds during installation. Pipe wall thickness depends on many factors, including planned capacity and operating pressure. Most line pipe in crude oil transmission systems is operated at pressures between 400 and 1,400 pounds per square inch, is 20 or more inches in diameter, and has a nominal wall thickness ranging from 0.2 to 0.75 inches. Federal regulations in the United States require that pipeline operating pressures and other forces not generate stresses that exceed 72 percent of the specified minimum yield strength (SMYS) of the pipe, and therefore a higher operating pressure requires thicker pipe or pipe with higher yield strength.[5] Depending on pipeline design and routing factors, thicker-walled pipe may also be used where the pipeline crosses a body of water or in areas that are densely populated, environmentally sensitive, or prone to additional external forces such as seismic activity.

[5] Federal regulations concerning SMYS are contained in 49 CFR §195.406. The federal hazardous liquid pipeline safety regulations, as administered by PHMSA, are outlined in Box B-1, Appendix B. Some pipelines operate at 80 percent of SMYS with permission of PHMSA.

Inlet Stations and Tank Farms

Transmission pipelines originate at one or more inlet stations, or terminals, where custody of the shipment is transferred from the owner to the pipeline operator. Accordingly, inlet stations are access points for truck tankers, railroad tank cars, and tanker vessels as well as other pipelines, including gathering lines connecting production areas. Along with pumping stations, sampling and metering facilities are located at inlets to ensure that the crude oils injected into the pipeline meet the quality control requirements of the pipeline operator and intended recipients. Metering instruments usually include densitometers and may include viscometers, which are used to measure density and viscosity, respectively.

Tanks at inlet stations are used to consolidate shipments into batches sized for main-line movement, blend crude oils to meet quality specifications, and schedule shipments according to the needs of refiners. Tanks can vary in capacity from tens of thousands to hundreds of thousands of barrels.[6] All are made of steel and are unpressurized. They are usually designed with floating roofs that rise and fall with the liquid level to limit hydrocarbon loss from vaporization and minimize emissions of volatile organic compounds. Tanks usually have lined floors and are inspected and cleaned periodically to remove any water and sediment settling to the floor.

Pump Stations

To maintain desired flow rates, booster pumps are positioned at points along the pipeline at intervals of 20 to 100 miles depending on many factors, including topography, line configuration, pipe diameter, operating pressure, and the properties of the fluids being transported. Pump stations are often automated and are equipped with sensors, programmable logic controllers, switches, alarms, and other instrumentation allowing the continuous monitoring and control of the pipeline as well as its orderly shutdown if an alarm condition occurs or if established operating parameters are violated.

Valves

Shutoff valves are strategically located at pump stations, certain road and water crossings, and other points to facilitate the starting and stopping of flow and to minimize the impact of leaks. These valves, many of which can be controlled remotely, ensure that portions of the line can be isolated in the event of a leak or the need for repair or maintenance. In addition, check valves that prevent backflows may be located at elevation changes and other intermediate points. The opening and closing of valves, along with pumping station operations, are sequenced to prevent flow reversals and problems associated with over- and underpressurization. Bypass lines, safety valves (e.g., pressure and thermal relief), and surge tanks may be sited at stations to relieve pressure.

Intermediate and Terminal Facilities

Depending on the scope of operations, a transmission pipeline system may have intermediate points, in addition to terminal facilities, that connect to other pipelines, other modes of transport,

[6] Larger underground caverns are used for storage at some pipeline terminals.

and refineries. These stations usually contain tanks and crude oil sampling and metering facilities. Smaller "breakout" tanks at intermediate points may also be used to support maintenance and emergency activities; for example, to relieve pressure or to allow for temporary draining of a pipeline segment.

OPERATIONS AND CONTROL

Batch Operations

A transmission pipeline will rarely carry a single type of crude oil. At any given time, a large pipeline will usually be transporting dozens of shipments, typically in batches of at least 50,000 barrels and covering a variety of crude oil grades. Sometimes the batches are physically separated by plugs known as pigs, but most of the time they are not. To reduce undesirable mixing at interfaces, the batches are separated and sequenced according to characteristics such as density, viscosity, and sulfur content. Accordingly, batches are scheduled to permit the proper lineup of crude oils being moved into and out of storage tanks. Maintaining batch separation requires that operators closely monitor the flow characteristics of the pipeline, since reductions in flow velocity and loss of flow turbulence can lead to undesirable intermixing of batches.

Flow Regime

Most shipments flow through the pipeline at 1.5 to 3 meters per second (3 to 6 miles per hour), which equates to a delivery rate of 500,000 to 1,000,000 barrels of crude oil per day in a 36-inch transmission pipeline.[7] Flow conditions in the pipeline will remain turbulent within this range of flow velocities.[8] Pipeline operators strive to maintain turbulent flow, characterized by chaotic motion and the formation of eddies, to reduce intermixing of batches and to keep impurities such as water and sediment suspended in the crude oil stream. Choosing a desired flow regime requires the balancing of many technical and economic factors. Increasing operating pressure will increase pipeline throughput, which is generally desired by an operator to increase revenue capacity. Higher operating pressures, however, require a larger investment in pipe materials and pumping capacity and will increase energy use and operating costs.

The characteristics of the crude oil to be shipped are important considerations in establishing the flow regime. More energy is needed to pump dense, viscous crude oils than light crude oils with lower viscosity. Some crude oils are too viscous naturally to be pumped. The normal response when a highly viscous crude oil is transported is to dilute it with lighter oil. When a diluent is too costly or unavailable, an alternative approach is to transport the crude oil in a heated pipeline. However, heating a pipeline is an expensive option and presents construction

[7] http://www.aopl.org/aboutPipelines/?fa=faqs.

[8] Whether a flow is turbulent or nonturbulent (i.e., laminar) depends on the diameter of the pipeline, the velocity of the flow, and the viscosity of the crude oil. These parameters can be used to calculate the Reynolds number, which defines the flow regime as laminar to turbulent. As described later in Chapter 3, the kinematic viscosity of heavy crude oils can range up to about 250 centistokes (0.00025 square meter per second) at room temperature. These oils will need to be transported at about 2 meters per second (6.5 feet per second or 4.4 miles per hour) in a pipe with a diameter of 20 inches to achieve a Reynolds number higher than 4,000, which is at the transition from laminar to turbulent flow. In a larger pipe, lower velocities are required to maintain turbulence (e.g., 1 meter per second or 2 miles per hour for a 42-inch pipe). Further consideration is given to the beneficial effects of maintaining turbulent flow in Chapter 5.

and operating challenges that preclude its common use. Where the throughput capacity of a line needs to be increased without adding pumping capacity, an operator may inject drag-reducing agents to enhance flow. These chemicals, which consist of long-chain polymers, dampen turbulence at the interface between the crude oil and the pipe wall to reduce friction and enable increased flow velocity.

Pipeline flows are usually monitored and controlled by operators from one or more central control centers, where supervisory control and data acquisition systems collect and analyze data signals from sensors and transmitters positioned at pumps, valves, tanks, and other points en route. Parameters other than flow rate, such as line pressure, pump discharge pressures, and temperatures, are also monitored for routine operational and maintenance decisions and for leak detection.

Shipment Quality Control

In the United States, the Federal Energy Regulatory Commission (FERC) oversees the tariffs that interstate pipeline operators are required to publish as common carriers. For intrastate transmission pipelines, state authorities such as the Texas Railroad Commission and the California Energy Commission function much like FERC in overseeing tariffs for in-state movements.

Pipeline tariffs define the terms and conditions for the transportation service, including the quality specifications applicable to all shipments in the pipeline. The specifications are driven by both operational and commercial considerations. Measurements to ensure adherence to the specifications are usually taken at custody transfer points. It is common for these specifications to define the maximum allowable sediment and water content, viscosity, density, vapor pressure, and temperature of the shipment. Other shipment qualities, such as levels of sulfur, acid, and trace metals, are seldom delineated in published tariffs but may be specified in private agreements. Quality specifications are designed to protect the integrity of the pipeline and the ancillary facilities, ensure that the shipped crude oil meets the specifications of the refiner, and prevent valuable throughput capacity from being consumed by transporting sediment and water.

MAINTENANCE

Each operator tailors pipeline maintenance and integrity management practices within the parameters allowed by safety regulations and according to the demands of the specific system, including its age, construction materials, location, and stream of products transported. Nevertheless, many practices are standardized. Some of the most common cleaning, inspection, and mitigation practices are described below. Regulatory requirements that govern integrity management are outlined in Appendix B.

Cleaning

Periodic cleaning of crude oil pipelines and equipment is often performed to facilitate inspection as well as to maintain operational performance. Cleaning intervals, typically measured in weeks or months, will vary depending on operating conditions and crude oil properties. A variety of tools are used for cleaning the pipe and monitoring interior condition. Mechanical pigs equipped

with scrapers and brushes remove debris from the inner wall. The scraped deposits and scale are transported to clean-out traps. The scrapings may be tested for contaminants and corrosion by-products.

Inspection and Monitoring

A regular inspection regime that assesses the condition of rights-of-way, pipes, pumps, valves, tanks, and other components is important to maintaining pipeline operational integrity and preventing unplanned shutdowns. Rights-of-way are routinely monitored by aerial patrols looking for threatening activities and encroachments and by field inspectors conducting detailed surveillance of line and equipment conditions. While visual inspection of buried pipe is not possible, pipes exposed for repair are usually inspected for evidence of mechanical damage or signs of degradation that may be indicative of problems elsewhere on the line.

From time to time, instrumented, or "smart," pigs are run through the line to detect anomalies. The three primary instruments are geometry, metal loss, and crack tools. Geometry tools are normally equipped with mechanical arms that survey the pipe wall to detect dents and other geometry changes. Metal loss tools use either magnetic or ultrasonic technology. Crack tools are designed to detect cracks in the pipe body, especially those that are longitudinally oriented. The frequency of instrumented pig runs is determined by the risk management program of the operator, as influenced by government regulation. Some pipeline sections, mostly in older systems, are not configured to accept some instrumented pigs.

Other techniques for monitoring conditions inside the pipe include the use of corrosion coupons and electrical resistance probes. Coupons are steel samples inserted into the pipeline and periodically removed for examination. Because the coupons are weighed before and after the exposure, the amount of corrosion can be determined by weight loss. Electrical resistance probes inserted into the pipe provide information on the corrosivity of the stream. External corrosion is monitored primarily through the use of pipe-to-soil potential surveys, whereby the voltage is measured with respect to a reference electrode to determine whether adequate cathodic protection levels are present along the length of the pipeline. Techniques are also used to measure the voltage gradients in the soil above a protected pipeline to determine the size and location of coating defects. Coupons buried in the soil can supplement this external corrosion monitoring. In addition, coatings are inspected whenever portions of the pipeline are uncovered.

Corrosion Mitigation Practices

It is standard practice for buried transmission pipelines to be coated externally to provide a physical barrier between the steel and the surrounding corrosive environment. Desired coating characteristics include low permeability to water and salts, strong adhesion to steel, and good abrasion resistance (Beavers and Thompson 2006). The coating also needs to be durable and resist chemical and thermal degradation at pipeline operating temperatures.

Pipeline coatings have improved over the past several decades. Along with cold and hot applied tapes, field-applied coatings made from coal tar, asphalt, and grease were the dominant systems used through the 1950s (Michael Baker Jr., Inc. 2008; Beavers and Thompson 2006). Because of nonoptimal conditions for field applications, early coatings often had poor adhesion characteristics, with pinholes and other imperfections. Some also exhibited degradation of the

polymers. After time in service, the coatings tended to become porous or to detach from the pipe surface.

During the 1960s and 1970s, fusion bonded epoxy (FBE) coatings were introduced. Unlike other coatings, FBE coatings are formed by heating a powder on the surface of the metal. The components of the powder melt and flow to initiate a cross-linking process. These heat-cured coatings exhibit good mechanical and physical properties, including adhesive strength and resistance to degradation, and they are widely used today.

Even a well-coated pipe may have imperfections and develop small holes in the coating that can expose the pipe to corrosion attack. To counter this effect, pipelines are fitted with cathodic protection systems. In some systems, the electrochemical potential of the pipe is reduced by galvanically coupling to sacrificial anodes typically made of magnesium, aluminum, or zinc alloys that will preferentially corrode instead of the pipe. Other systems employ an impressed current applied to the pipeline with the use of a power supply to lower the pipeline potential. The cathodic protection system is designed to supply enough current to a pipe to prevent external corrosion at defects or holes that form in the coating where the external environment can come in contact with the steel surface. Defects in coatings are especially problematic when the disbonded coating shields distribution of the cathodic current to the defect site. This shielding is most often associated with the impermeable tapes and shrink sleeves used on some older pipelines. An advantage of modern FBE systems is that they are permeable to ionic flow and thus do not shield the exposed sites from cathodic protection.[9]

Preventing the internal corrosion of pipes starts with basic quality control and operational procedures that limit the entry and accumulation of water and other contaminants. As noted above, transmission pipelines are typically constructed of steel with no internal coatings, so the transported product is in contact with the steel. While oil is not corrosive, even small amounts of contaminants such as water and salts in the oil can be corrosive if they are allowed to accumulate on the steel surface. Certain gases dissolved in the product stream, especially oxygen, hydrogen sulfide, and carbon dioxide, can also increase the rate of corrosion. Actions to mitigate internal corrosion include controlling ingress of air at pumps and other entry points, limiting water and sediment content, and chemical treatment of the crude oil stream.

The chemicals injected into the crude oil stream usually consist of a mixture of additives that inhibit corrosion by various means. The most common mixtures contain surfactant chemicals that adsorb onto the steel surface and provide a barrier between the corrosive water and pipe steel. Many surfactants confer additional benefits by reducing the surface tension at the oil–water interface, which keeps the water entrained in the flow rather than depositing on the pipe wall. Chemical additives may also have properties that repel the water from the pipe wall, neutralize acids, and act as biocides to help inhibit microbiologically influenced corrosion. The rates of flow in transmission pipelines are normally sufficient to prevent the deposition of contaminants and to sweep away deposits that settle to the pipe bottom. Areas of low flow, such as steep angles of elevation and sections of isolated piping (called dead legs), are vulnerable to water and sediment accumulation and subsequent internal corrosion. Because the hydrodynamic and chemical processes of water and sediment accumulation are well understood, models for

[9] Inspections performed on gas gathering lines equipped with an early generation FBE coating (from the mid-1970s) revealed that less than 0.2 percent of pipeline sections exhibited blistering of the coating despite some operating in temperatures as high as 76°C (170°F). Removal of the blistered coating revealed no underlying corrosion because of the permeability of FBE to cathodic fields (Boerschel 2010; Batallas and Singh 2008).

analysis are available to guide pipeline construction and operating parameters to decrease the tendency for accumulations and to identify areas of greatest vulnerability to corrosion.

Additional details on the mechanisms of pipeline damage and factors that contribute to them are discussed in Chapter 5.

SUMMARY

The crude oil transmission network in the United States consists of an interconnected set of pipeline systems. Shipments traveling through the network often move from one pipeline system to another, sometimes being stored temporarily in holding tanks at terminals. Most operators of transmission systems are common carriers who do not own the crude oil they transport but provide transportation services for a fee. Few major transmission pipelines are dedicated to transporting specific grades or varieties of crude oil. They usually move multiple batches of crude oil, which are often provided by different shippers and include a range of chemical and physical properties. Crude oil shipments are treated to meet the quality requirements of the pipeline operator as well as the content and quality demands of the refinery customer.

Pipeline systems traverse different terrains and can vary in specific design features, components, and configurations. These differences require that each operator tailor operating and maintenance strategies to fit the circumstances of its systems in accordance with regulatory requirements. Nevertheless, the systems tend to share many of the same basic components and follow similar operating and maintenance procedures. Together, regulatory and industry standards, system connectivity, and economic demands compel both a commonality of practice and a shared capability of handling different crude oils.

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3

Bitumen Properties, Production, and Transportation by Pipeline

This chapter describes the chemical composition and physical properties of bitumen, the methods used to produce it, and the properties of the bitumen shipments that are diluted for pipeline transportation to the United States.

BITUMEN COMPOSITION AND PROPERTIES

Like all forms of petroleum, bitumen is a by-product of decomposed organic materials rich in hydrocarbons. According to the World Energy Council, bitumen deposits exist in about 20 countries, but the largest are in Canada, Kazakhstan, and Russia (WEC 2010, 123–150). Because only the Canadian bitumen is diluted for transportation by pipeline to the United States, it is the subject of the description in this chapter.[1]

Canadian bitumen deposits are concentrated in the Western Canadian Sedimentary Basin (WCSB), and particularly in the province of Alberta. Three regions in the WCSB have large reserves: the Athabasca, Peace River, and Cold Lake regions (Strausz and Lown 2003, 21). According to the government of Alberta, about two-thirds of the world reserves of recoverable bitumen are contained in the three regions, which total some 140,000 square kilometers (55,000 square miles) (ERCB 2012a). In some locations in Alberta, surface deposits are easy to spot, since the black bitumen is impregnated in sandstone along the sides of lakes and rivers. Most of the bitumen is not visible because it is deposited below the surface.

The bitumen-impregnated sands in the WCSB are referred to as bituminous sands, oil sands, and tar sands (Strausz and Lown 2003, 29). Canadians use the term oil sands, which is also used in this report. The typical composition of the WCSB oil sands is 85 percent sand and clay fines,[2] 10 percent bitumen, and 5 percent water by weight.[3] Oil sands also contain salts, trace gases, and small amounts of nonpetroleum organic matter.[4] These components exist together in a specific microstructure with a film of water that surrounds each sand and clay particle, and the bitumen surrounds the film, as shown in Figure 3-1. When freed from this microstructure, bitumen has a typical elemental composition of 81 to 84 percent carbon; 9 to 11 percent hydrogen; 1 to 2 percent oxygen, nitrogen, and other elements; and 4 to 6 percent sulfur, most of which is bound in the bitumen in stable (e.g., heterocyclic rings) hydrocarbon structures (Dettman 2012; Strausz et al. 2011; Gogoi and Bezbaruah 2002; Strausz and Lown 2003).

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[1] Canada contains the vast majority of the natural bitumen in North America. According to the U.S. Geological Survey, bitumen deposits exist in the United States in several states, mainly in Utah, California, and Alabama. While commercial mining operations are being planned in Utah, many technical and economic challenges remain to exploit this resource (USGS 2006).
[2] The solid particles consist of sand grain minerals, mostly of quartz but also feldspar, mica, and chert. The solid particles also consist of clay minerals, mostly kaolinite and illites (Strausz and Lown 2003, 31–32).
[3] Up to 18 percent of the ore can be made up of bitumen (Strausz and Lown 2003, 62).
[4] The organic matter consists of humin, humic acids, fulvic acids, and chemiabsorbed aliphatic carboxylic acids (Strausz and Lown 2003, 29–32).

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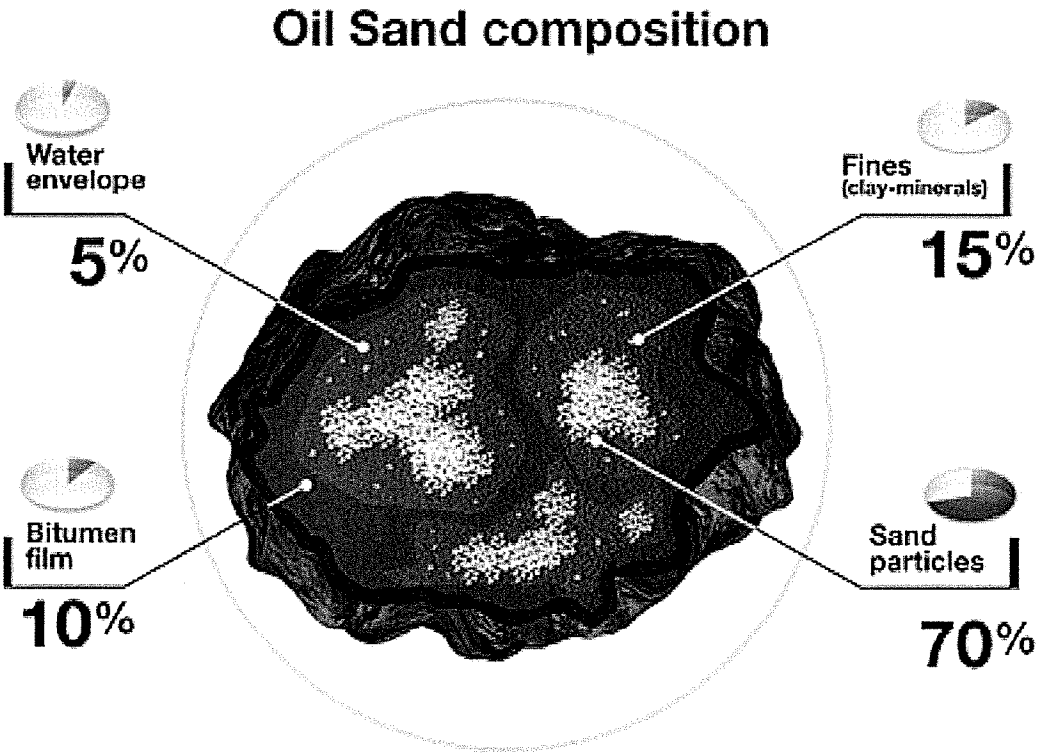

FIGURE 3-1 Composition of oil sands.

Hydrocarbon molecules account for 92 to 95 percent of the weight of bitumen.[5] These molecules range from light alkanes, such as ethane, to long-chain compounds with relatively high molecular weights and boiling points. The latter molecules are more common in bitumen than in the lighter, more paraffinic crude oils that have undergone less microbial degradation.[6] Bitumen contains relatively high concentrations of asphaltenes, which account for 14 to 17 percent of the total weight of the material (Strausz and Lown 2003, 95; Rahimi and Gentzis 2006, 151). Trace elements, such as vanadium and nickel, usually reside in the asphaltenes along with sulfur, nitrogen, and oxygen (Strausz and Lown 2003, 93–99, 495–498). The nitrogen in the bitumen is bonded with carbon in pyridinic structures, including quinolines and acridines (Rahimi and Gentzis 2006). The asphaltenes, as well as other nonparaffinic compounds such as naphthenes, give bitumen its high density and high viscosity (Strausz and Lown 2003, 99).

Bitumen is usually distinguished from other forms of petroleum on the basis of physical properties that derive in part from its relatively high asphaltene content. The U.S. Geological Survey (USGS) has used the following definition to distinguish bitumen from other heavy crude oils:

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[5] The ratio of hydrogen to carbon atoms is about 1.5 in bitumen, compared with 2.0 for very light oils (Strausz and Lown 2003, 95–96).

[6] Bitumen has undergone more biodegradation than have other petroleum oils. Because straight-chain paraffinic hydrocarbons are more readily metabolized by microorganisms, these hydrocarbons are depleted in bitumen (Strausz and Lown 2003, 90).

> Natural bitumen is defined as petroleum with a gas-free viscosity greater than 10,000 centipoises (cp) at original reservoir temperature. Petroleum with a gas-free viscosity between 10,000 and 100 cp is generally termed heavy crude oil. In the absence of viscosity data, oil with API gravity less than 10 degrees is generally considered natural bitumen, whereas oil with API gravity ranging from 10 degrees API to about 20 degrees API is considered heavy crude oil. The term extra-heavy crude oil is used for oil with a viscosity less than 10,000 cp but with API gravity less than 10 degrees. (USGS 2006)

The American Petroleum Institute (API) gravity scale referenced by USGS is an inverse measure of the density of a liquid relative to that of water at room temperature. A liquid with API gravity greater than 10 degrees will float on water; if the API gravity is lower than 10 degrees, it will sink.[7] Canadian bitumen (undiluted) typically has an API gravity between 7 and 13 degrees, whereas most heavy crude oils have values that are 5 to 15 degrees higher (Strausz and Lown 2003, 100). The viscosity of bitumen is also high compared with that of other crude oils across a range of temperatures. Figure 3-2 compares the effects of temperature on viscosity [in centipoise units (cp)] for bitumen derived from two WCSB reservoirs (Cold Lake and Athabasca), a Canadian heavy crude (Lloydminster), and typical light crude oils.[8] At most pipeline operating temperatures [0°C to 40°C (32°F to 100°F)], the lighter crude oils will behave as liquids, while the bitumen will remain in a semisolid state, having viscosities comparable with that of peanut butter. Although they are less viscous than bitumen, the heaviest conventionally drilled Canadian crude oils have relatively high viscosities as well.[9] Several Canadian crude oils, including the Lloydminster crude oils shown in Figure 3-2, are routinely diluted with lighter oils to improve their flow in transmission pipelines.[10]

BITUMEN PRODUCTION

The WCSB has long been a major oil-producing region of North America. Oil exploration commenced in the early 20th century, and by the 1960s hundreds of millions of barrels of Western Canadian crude oil were being exported each year through pipelines to the United States. Nearly all of this oil was produced with conventional drilling and well technology. By the 1990s, Western Canadian exports of conventionally produced oil were declining just as new technologies were being introduced to recover the vast deposits of bitumen contained in oil sands.

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[7] API gravity values are referred to as "degrees." Most crude oils have API gravities in the range of 20 to 40 degrees, but some range 10 degrees higher or lower.

[8] Centipoise is a measure of resistance to shear flow, or the dynamic viscosity of a fluid. A more common measure of resistance to flow by crude oils is the centistoke (cSt), which is the ratio of dynamic viscosity to fluid density, also known as kinematic viscosity. At room temperature, the kinematic viscosity of bitumen will exceed 100,000 cSt, compared with about 25 cSt for a medium-density crude oil. Kinematic viscosity is referenced more often in this report.

[9] This Canadian heavy crude oil is usually diluted with lighter oils for pipeline transportation.

[10] Lloydminster heavy crude oils have API gravities of 12 to 23 degrees (Strausz and Lown 2003, 26).

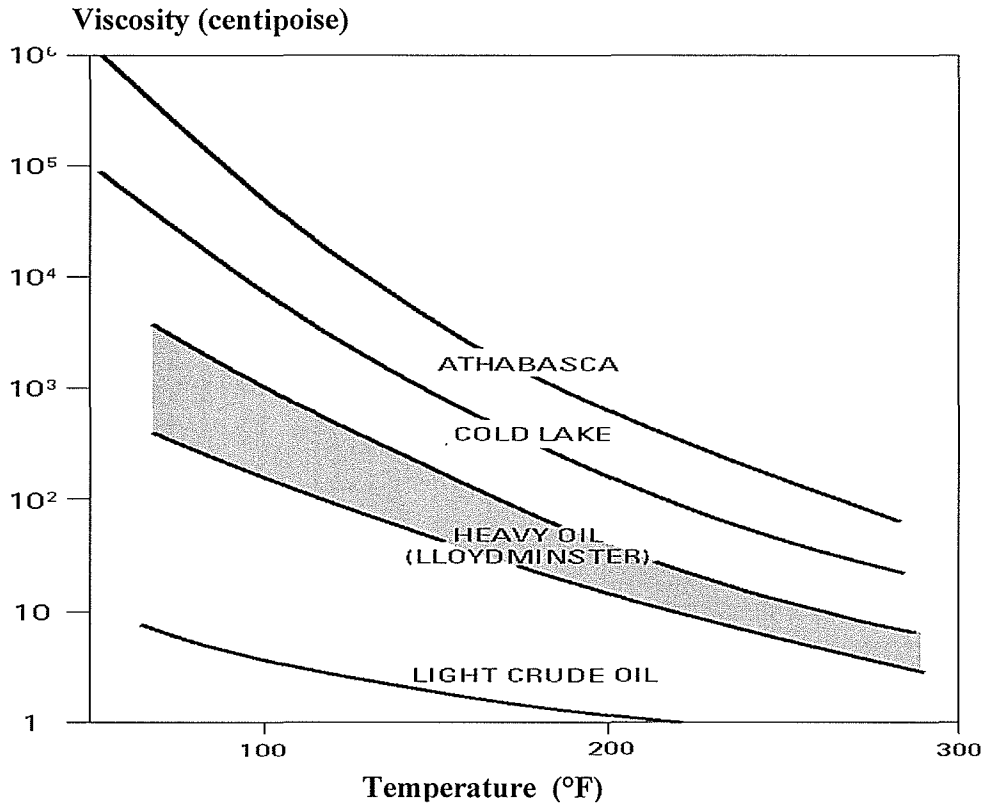

FIGURE 3-2 Response of crude oil viscosity to changes in temperature (Raicar and Procter 1984; WEC 2010, 126).

While natural bitumen had long been used as sealing material, Canadian entrepreneurs started mining deposits for refinery feed during the early 20th century. However, separating the bitumen from the mined ore required significant amounts of heated water, which made recovery expensive compared with the lighter crude oils that were less costly to drill elsewhere in Canada and the United States. Commercial ventures to mine bitumen began in the 1920s, but it took another 40 years of declining North American crude oil reserves, increasing consumer demand for gasoline and other refined petroleum, and advances in extraction and processing technologies to transform the mined bitumen into a commercially viable refinery feedstock.[11]

During the 1990s, thermally assisted in situ recovery methods were introduced in the WCSB to exploit the large reserves of bitumen located too deep for surface mining. After this development, the quantity of bitumen produced surpassed the quantity of conventionally produced oil from the basin. Today, bitumen accounts for more than 70 percent of the petroleum produced in Alberta, and in situ recovery methods account for nearly half of this bitumen production (ERCB 2012a).

[11] Oil Sands Discovery Centre. Facts About Alberta's Oil Sands and Its Industry. http://history.alberta.ca/oilsands/docs/facts_sheets09.pdf.

One in situ method in particular—steam-assisted gravity drainage (SAGD)—led to the recent growth in Canadian bitumen production for export to the United States. Indeed, no significant quantities of mined bitumen are diluted for pipeline transportation to the United States, the main market for bitumen recovered by using the SAGD process.[12]

Bitumen Mining and Upgrading to Synthetic Crude Oil

About 20 percent of the bitumen deposits in the WCSB are less than 60 meters (200 feet) deep and can be recovered by surface mining. Mining operations use diesel-powered shovels to excavate the ore, which is transported by truck to field facilities containing crushers. The crushed ore is mixed, or washed, with hot water to create a slurry that is piped a short distance, where it is agitated and filtered in separation vessels. The hot water heats and releases the water that surrounds the sand and clay particles. The agitation causes air bubbles to attach to bitumen droplets, which float in a froth to the top of the vessel. The froth is then deaerated with steam and diluted with a hydrocarbon solvent such as naphtha. The solvent coalesces and causes settlement of emulsified water and mineral solids. The suspended bitumen is then separated with a centrifuge and skimmer.

The extraction process for mined bitumen yields a product that typically contains 0.5 percent solids and 1 to 2 percent water by volume. This solid and water content is generally too high to be accepted by transmission pipelines. As a consequence, mined bitumen is nearly always upgraded, usually at nearby field plants, into synthetic crude oil. The field plants consist of refinery-type cokers that crack the bitumen into lighter products that are then processed in hydrotreating units to remove sulfur and nitrogen.[13] The processed streams are then mixed to produce a low-viscosity, low-sulfur synthetic crude oil that can be transported by transmission pipeline to refineries in Canada and the United States. The synthetic crude oils are also blended with other heavy Canadian crude oils, including in situ–produced bitumen, for pipeline transportation to the United States.

Nearly all of the bitumen mined in the WCSB is upgraded to synthetic crude oil.[14] This situation is subject to change as alternative methods are introduced to yield mined bitumen with reduced viscosity and water and sediment content comparable with that of the bitumen produced in situ and transported in diluted form through transmission pipelines. One alternative is to deasphalt the mined bitumen partially to produce synthetic crude oil that retains some of the heavier hydrocarbon fraction by substituting a paraffinic solvent for the aromatic-rich naphtha solvent traditionally used during removal of water and solids (Rahimi et al. 1998). Composed largely of pentanes and hexanes, a paraffinic solvent is more effective than naphtha in promoting aggregation and settlement of asphaltenes and suspended water and solids. Removal of asphaltenes through paraffinic treatment yields a processed bitumen that is less viscous and has lower levels of water and solids than mined bitumen that is processed with a traditional naphtha solvent.

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[12] The discussion focuses on surface mining and SAGD, which are the most common bitumen recovery methods. Other methods not discussed include cyclic steam stimulation, toe-to-heel air injection, vapor-assisted petroleum extraction, and cold heavy oil production with sand. More information on recovery methods can be found at http://www.oilsands.alberta.ca/.

[13] According to the Alberta Energy Ministry, the five upgraders operating in Alberta in 2011 had the capacity to process approximately 1.3 million barrels of bitumen per day (ERCB 2013).

[14] According to the Alberta Energy Ministry, in 2011 about 57 percent of oil sands bitumen production was upgraded to synthetic crude oil in Alberta. Most upgraders produce synthetic crude oil, but some also produce refined products such as diesel (ERCB 2013).

Mined bitumen processed with paraffinic solvent can be transported by transmission pipeline, usually by retaining some of the solvent as diluent.[15] Mined bitumen treated in this manner is being piped several hundred miles from oil sands production regions to large, centrally based upgraders elsewhere in Alberta, where it is processed into synthetic crude oil. The mined bitumen, however, is not transported through pipelines to the United States (except when upgraded to synthetic crude oil) because paraffinic solvents are too expensive to use as diluent for long-distance transportation. Instead, the solvent is recovered at the Canadian upgraders and piped back to bitumen production fields for reuse as a solvent.

In Situ Recovery

Because most Canadian bitumen is located deep underground, it can only be recovered in place. Although reaching the deposits is not difficult,[16] the challenge in recovering them is in separating and thinning the bitumen for pumping to the surface. A recovery method that is now common involves the injection of pressurized steam into the deposit. The steam thins the bitumen and separates it from the sand while the pressure helps to push the bitumen up the well.

A number of thermally assisted recovery methods are used in the WCSB. The two main methods are cyclic steam stimulation (CSS) and SAGD. CSS involves injecting steam into the bitumen deposit and letting it soak for several weeks. This process causes the bitumen to separate from the sand and become sufficiently fluid for pumping. Over the past decade, SAGD has surpassed CSS as the preferred thermal recovery method because a higher proportion of the bitumen is recovered. SAGD involves drilling two horizontal wells, one located a few feet above the other as shown in Figure 3-3. Steam is injected into the upper well, which heats the bitumen and causes it and steam condensate to drain into the lower well for pumping to the surface. At the surface, condensed water is separated from the recovered bitumen and recycled to produce steam for subsequent applications.

The high recovery ratio of SAGD is an important reason for the growth in Canadian bitumen production. SAGD now accounts for about half the bitumen recovered from the WCSB.[17] Compared with mining, SAGD has the advantage of eliminating the need to wash the ore with hot water because the bitumen is separated from the sand and clay underground. After further treatment (e.g., standard degassing, dewatering, and desalting), the recovered bitumen contains much lower levels of water and sediments (generally less than 0.5 percent by volume) than mined bitumen, and it is sufficiently stable for acceptance by long-distance pipelines. Whereas nearly all mined bitumen is upgraded into synthetic crude oil in Alberta, less than 10 percent of the SAGD-derived bitumen is processed into synthetic crude oil (NEB 2009). Most SAGD-derived bitumen is diluted with lighter oils for transportation by pipeline to U.S. refineries.

[15] While asphaltene concentrations have significant implications for bitumen viscosity, the removal of all asphaltenes would not reduce viscosity enough for undiluted bitumen to meet pipeline specifications (Rahimi and Gentzis 2006).

[16] The exploited deposits are generally less than 750 meters (2,500 feet) underground.

[17] In 2011, about 1.7 million barrels per day of bitumen were produced, with surface mining accounting for 51 percent and in situ processes accounting for 49 percent of the production (ERCB 2013).

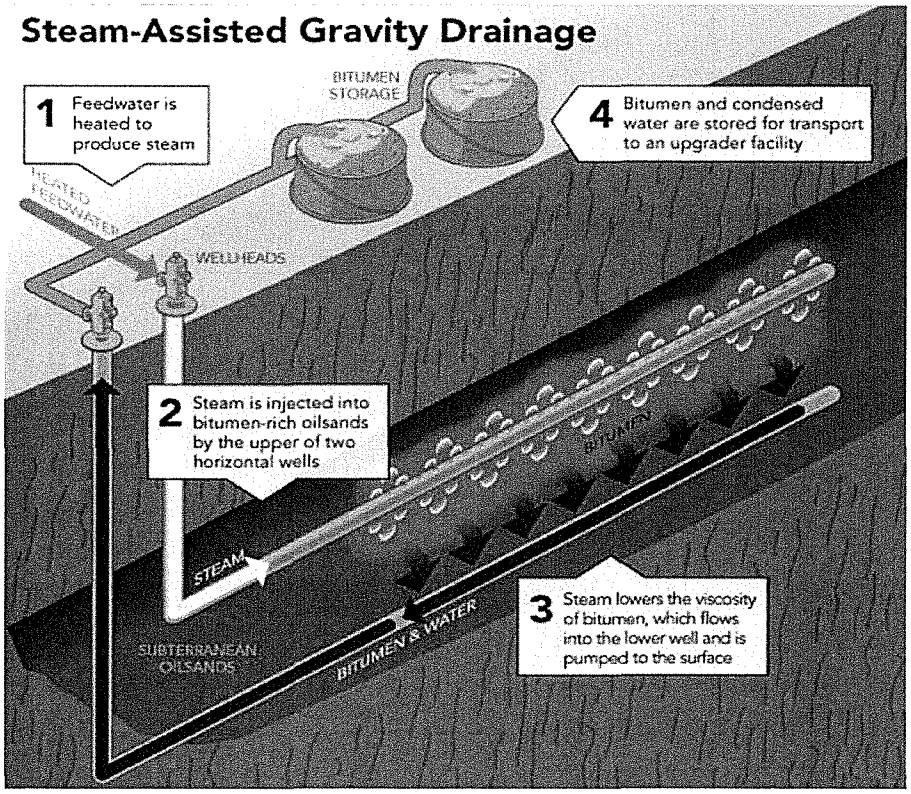

FIGURE 3-3 Bitumen recovered using SAGD (ERCB 2012b).

PIPELINE TRANSPORTATION OF DILUTED BITUMEN

According to the U.S. Department of Energy, imports of Canadian diluted bitumen and other crude oils have grown by more than one-third since 2000.[18] Partially as a result of Canadian supplies as well as newly exploited domestic oil shale, crude oil imports from other regions of the world are declining. In particular, the Canadian feedstock has supplanted heavy crude oils once imported in large volume from Venezuela and Mexico (Figure 3-4). While more than two-thirds of the Canadian crude oil is refined in the Midwest, refinery demand for this feedstock has been growing in other regions of the country, particularly at Gulf Coast refineries that are equipped to process heavy feed.

U.S. Pipelines Transporting Diluted Bitumen

Figure 3-5 shows U.S. refinery destinations for diluted bitumen and other Canadian crude oils, and Figure 3-6 shows the main pipeline corridors that access these refineries. Major export pipelines from Canada include the Enbridge Lakehead network, which serves several Great Lakes refineries; the TransCanada Keystone pipeline, which accesses the Cushing, Oklahoma, hub and refineries in southern and central Illinois; and the Kinder Morgan Express and Prairie

[18] http://www.eia.gov/countries/cab.cfm?fips=CA.

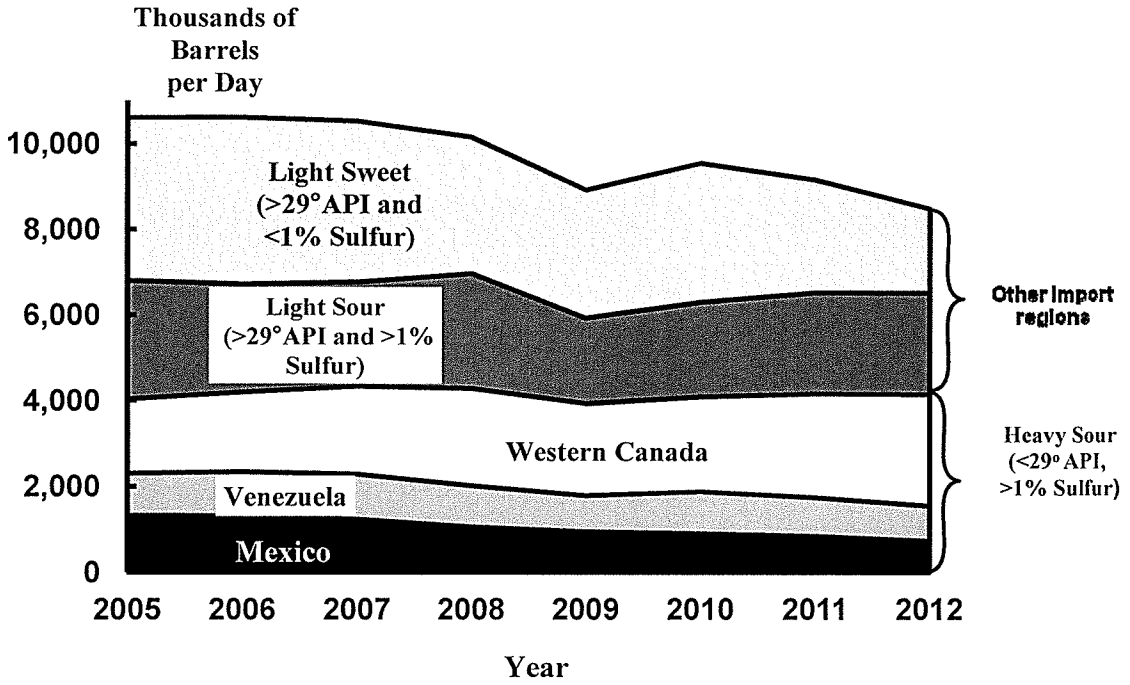

FIGURE 3-4 Annual U.S. crude oil imports by grade and origin. [Chart is derived from January 31, 2012, presentation to the committee by G. Houlton. Source data on crude oil imports were obtained from the Energy Information Administration, U.S. Department of Energy (http://www.eia.gov/countries/cab.cfm?fips=CA).]

pipelines, which transport Canadian crude oils to refineries in the Rocky Mountains and provide surplus to refineries farther east and south. These trunk lines are connected to pipelines that deliver feed to refineries as far east as Ohio and western Pennsylvania and as far south as the Texas Gulf Coast and New Mexico. Several connecting pipelines have recently undergone flow reversals, such as the 375-mile Occidental Centurion line, which now runs southwest from Cushing in the direction of El Paso, Texas; the 858-mile ExxonMobil Pegasus line, which runs south from Illinois to refineries on the Gulf Coast; and the 670-mile Enbridge Seaway line, which crosses East Texas and is expected to become fully operational during 2013.

Properties of Diluted Bitumen Shipped by Pipeline

In Canada, the National Energy Board (NEB) administers the tariffs, or terms and conditions, that govern the transportation of crude oil by transmission pipeline. For shipments entering the United States, pipeline operators must also file tariffs with the Federal Energy Regulatory Commission. As explained in Chapter 2, tariffs contain quality specifications for crude oil shipments that are intended to ensure compliance with the operational requirements of pipelines as well as possession of properties required by refiners. At custody transfer points, pipeline operators sample shipments to confirm compliance with tariff specifications.

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Density and Viscosity Levels

To ensure pipeline transportability, NEB tariffs specify that the density of crude oil shipments not exceed 940 kilograms per cubic meter (kg/m^3) (about 20 degrees API gravity) and that viscosity not exceed 350 cSt[19] when measured at the posted pipeline operating temperature.[20] To meet the specifications, Canadian bitumen is diluted into either "dilbit" or "synbit." The Canadian Association of Petroleum Producers describes dilbit as a bitumen blend consisting of diluent that has a density of less than 800 kg/m^3 (45 degrees API). If it has a density greater than or equal to 800 kg/m^3, the diluent is presumed to be synthetic crude oil, and the blend is called synbit (CAPP 2013).

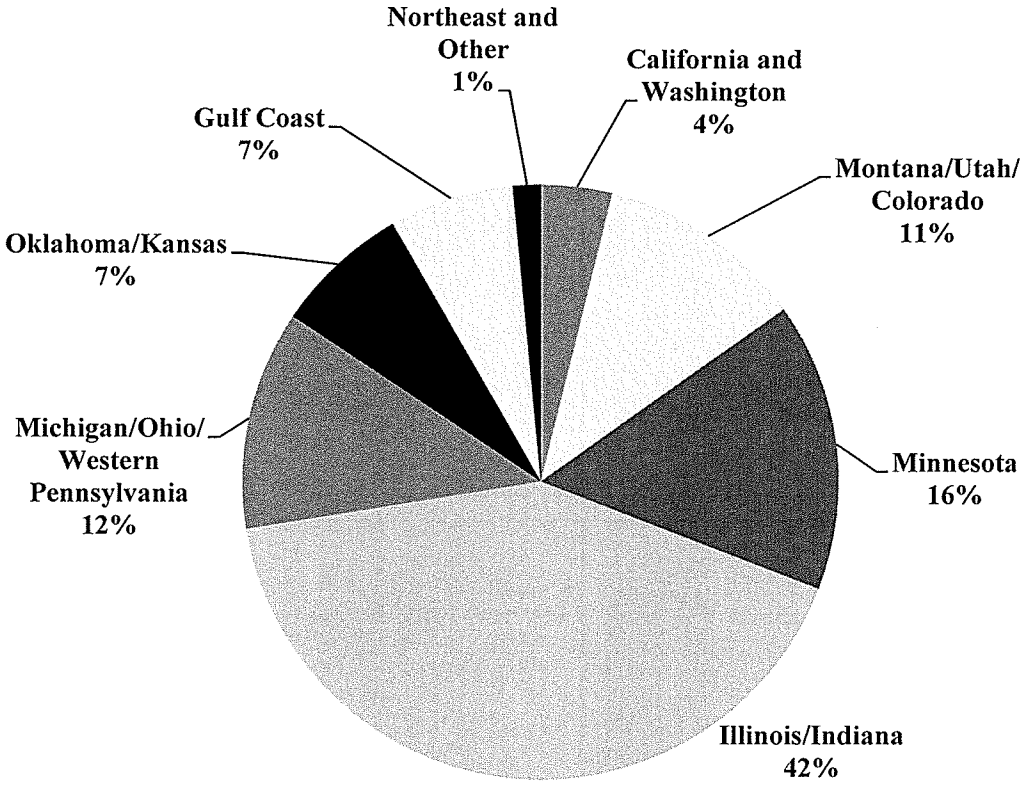

FIGURE 3-5 U.S. refinery destinations for Canadian heavy crude oil imports in 2011. [Source: National Energy Board fact sheet "Disposition of Heavy Crude Oil and Imports" (http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/sttstc/crdlndptrlmprdct/dspstnfdmstccrdlndmprts-eng.html#s1).]

[19] Kinematic viscosity and the centistoke (cSt) unit of viscosity measurement have been defined earlier in this chapter.

[20] For an example, see Article 1, page 3 (Definition for Heavy Crude) of NEB Tariff Number 4, Keystone Pipeline System Petroleum Tariff (http://www.transcanada.com/docs/Key_Projects/06_NEB_Tariff_No_4_Rules_and_Regs_CL.pdf).

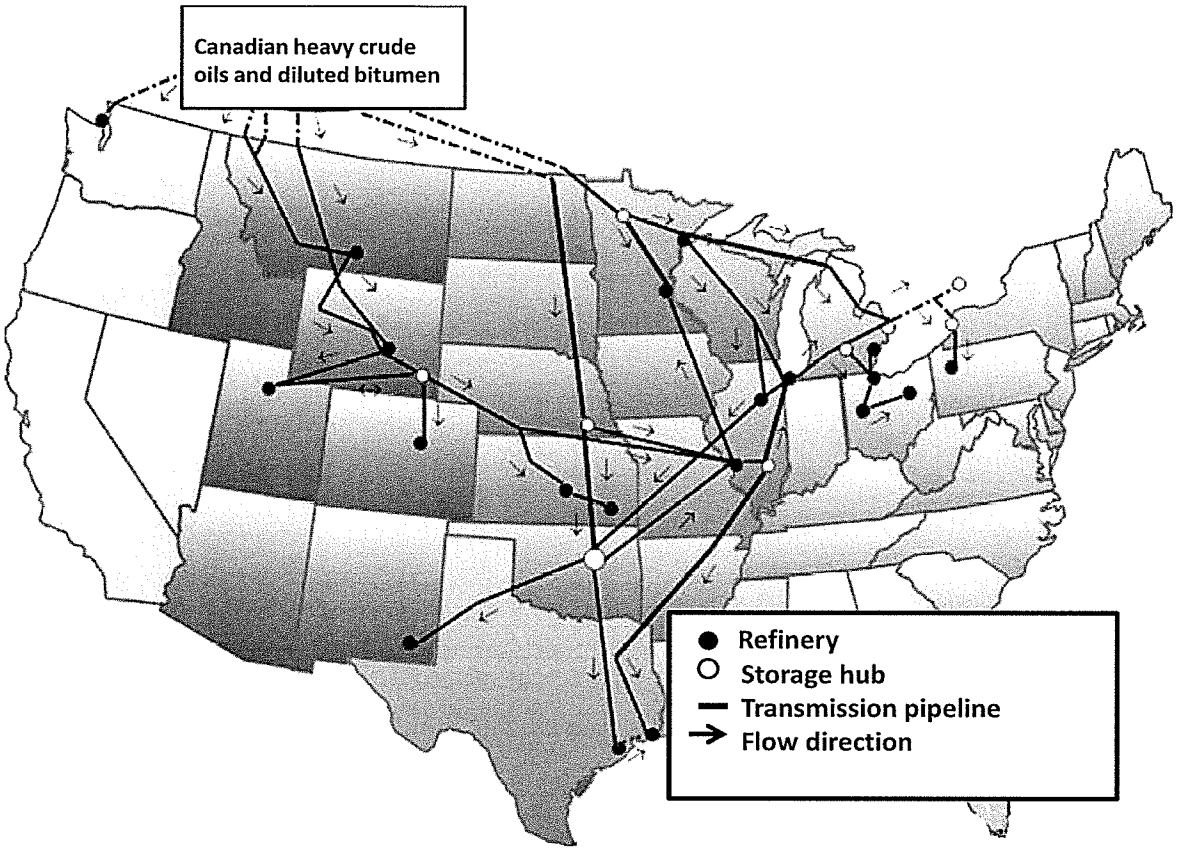

FIGURE 3-6 Main pipeline corridors moving Canadian crude oil to U.S. refineries.

In the case of dilbit, the most common diluents are naphtha-based oils, including natural gas condensate.[21] The light oils that are used have low densities (<750 kg/m^3), high API gravities (>60 degrees), and low viscosities (<1 cSt at room temperature). Compared with condensate, synthetic crude oils have higher densities (825 to 875 kg/m^3), lower API gravities (30 to 40 degrees), and higher viscosities (5 to 20 cSt). Some bitumen shipments are diluted with both condensate and synthetic crude oil to produce "dilsynbit."

Dilution and blending activity is common in the petroleum industry, as distillates and light oils are regularly mixed with heavier oils to alter shipment density and viscosity characteristics. The chemical compatibility of the oils and distillates must be considered before blending, particularly to avoid precipitation of asphaltenes. Thick deposits of these components can foul pipelines, pumps, and other equipment to create an increased need for pig cleaning to prevent flow assurance problems (Cimino et al. 1995; Saniere et al. 2004; Leontaritis and Mansoori 1988). Dilution with distillates containing high concentrations of light hydrocarbons such as pentanes and hexanes can cause asphaltenes to precipitate from oils if the distillate makes up a majority of the volume of the blend (Maqbool et al. 2009). The acceptable types and ratios of distillates blended with bitumen have therefore been analyzed to ensure chemical compatibility as well as a transportable product that does not deposit asphaltenes during postproduction storage and transportation (Schermer et al. 2004).

[21] Condensate liquid is produced from raw natural gas when the temperature is reduced below the boiling temperature of the gas.

As discussed earlier, distillates such as naphtha are usually mixed with bitumen at the production plant to facilitate water and sediment removal. Indeed, all or most of the diluent in diluted bitumen is blended during the processing stage before delivery of shipments for transmission by pipeline. In some cases, more diluent may be added after delivery to the transmission pipeline if further dilution is necessary to meet the density and viscosity levels required for long-distance transportation.[22] Like all crude oil blending, the mixing of diluent and bitumen is designed to make the shipped product miscible, or fully mixed in all proportions. As discussed in Chapter 2, once in the pipeline, batch shipments of diluted bitumen and other heavy crude oils are sequenced to avoid contact with lighter crude oil and condensate shipments. Meters along the pipelines track the batched stream to detect any changes in shipment density and viscosity.

After blending, diluted bitumen becomes a mixture of hydrocarbons with a range of molecular weights. As in the case of other crude oils, these hydrocarbons are separated by distillation at recipient refineries. Table 3-1 compares the distilled volume of light (low-molecular-weight) hydrocarbons in three diluted bitumen crude oils and five light, medium, and heavy crude oils imported from Canada. The light hydrocarbons in all crude oils are mainly

TABLE 3-1 Percentage (by Volume) of Low-Molecular-Weight Hydrocarbons in Selected Diluted Bitumen Blends and Other Canadian Crude Oils

	Access Western Blend (Diluted Bitumen)	Wabasca Heavy (Diluted Bitumen)	Borealis Heavy Blend (Diluted Bitumen)	Koch Alberta (Light Crude Oil)	Light Sour Blend (Light Crude Oil)	Sour High Edmonton (Medium Crude Oil)	Smiley–Coleville (Heavy Crude Oil)	Lloyd Kerrobert (Heavy Crude Oil)
Butanes	0.72	1.93	0.38	4.50	2.43	2.43	0.54	2.04
Pentanes	8.53	1.92	4.01	2.39	3.25	2.56	4.88	6.00
Hexanes	7.06	3.00	5.75	4.54	6.13	4.59	3.95	3.96
Heptanes	4.73	3.47	4.57	5.61	7.44	5.31	2.7	2.12
Octanes	2.74	3.53	5.28	6.09	8.72	5.58	2.12	1.38
Nonanes	1.43	2.64	4.04	4.97	7.18	4.60	2.05	1.36
Decanes	0.70	1.21	1.49	2.49	3.46	2.46	1.10	0.81
Total	25.91	17.7	25.52	30.59	38.61	27.53	17.34	17.67
Mass Recovered	**Distillation Temperature °C (°F)**							
5%	38 (101)	93 (200)	64 (147)	45 (114)	69 (156)	64 (147)	62 (144)	51 (123)
10%	70 (158)	152 (307)	93 (200)	92 (198)	87 (188)	93 (200)	114 (237)	136 (276)

SOURCE: Data obtained from CrudeMonitor.com by Crude Quality, Inc. (http://www.crudemonitor.ca/condensate.php?acr=SLD; http://www.crudemonitor.ca/crude.php?acr=SYN). Accessed March 1, 2013.

[22] Information on production processes was obtained from briefings by and interviews with bitumen producers and pipeline operators.

pentanes or heavier, with some measurable butanes and trace amounts of lighter molecules. Because of the diluent, the light fraction of diluted bitumen is comparable with that of medium and heavy crude oils and accounts for 17 to 27 percent of hydrocarbon volume.

The specific diluents used in blending are selected on the basis of many factors, including their availability in bitumen production regions. Table 3-2 shows the chemical and physical properties of the common diluent Southern Lights, a condensate produced in the United States and piped to Alberta. Because of its low viscosity, this condensate and others can be mixed with bitumen at a ratio of about 30:70 by volume.[23] Table 3-2 also shows the chemical and physical properties of a Suncor synthetic crude oil. Because it has a higher density than condensate, this and other synthetic crude oils are usually blended in even (50:50) ratios with bitumen. Illustrative blending ratios and resulting density and viscosity values for synbit and dilbit are given in Table 3-3.

TABLE 3-2 Selected Properties of Two Common Diluents

Property	Southern Lights Condensate Diluent	Suncor Synthetic Crude Oil Diluent
Density (kg/m^3)	675	861
API gravity (°)	78	33
Sulfur (weight percent)	0.03	0.17
Viscosity at 20°C (68°F) (cSt)	<0.5	6.3
Sediment (parts per million by weight)	16	0

SOURCE: Data obtained from CrudeMonitor.com by Crude Quality, Inc. (http://www.crudemonitor.ca/condensate.php?acr=SLD; http://www.crudemonitor.ca/crude.php?acr=SYN) and from Enbridge website (http://www.enbridge.com/DeliveringEnergy/Shippers/~/media/www/Site%20Documents/Delivering%20Energy/2012CrudeCharaceristics.ashx). Both accessed March 1, 2013.

TABLE 3-3 Example Blending Ratios and Density and Viscosity Levels for Synbit and Dilbit

Blend Component	Volume Percent	Density (kg/m^3)	Viscosity [cSt at 15°C (59°F)]
Synbit			
Bitumen	51.7	1,010	760,000
Synthetic crude oil	48.3	865	5.9
Total	100	940	128
Dilbit			
Bitumen	74.6	1,010	760,000
Condensate	25.4	720	0.6
Total	100	936	350

SOURCE: Illustrative blending ratios provided by R. Segato, Suncor Energy, October 23, 2012 (http://onlinepubs.trb.org/onlinepubs/dilbit/Segato102312.pdf).

[23] These blending ratios are nominal and will vary somewhat depending on seasonal temperatures and the flow regime of individual pipeline operators.

Once they are diluted for transportation, shipments of bitumen have physical properties comparable with those of other heavy crude oil shipments, and they can be stored and transported through the same pipeline facilities in a similar manner—that is, without a need to heat the crude oil to increase fluidity. API gravities for dilbit and synbit blends are generally in the low 20 degrees (a density of about 925 kg/m^3), and viscosities generally range between 75 and 200 cSt at pipeline operating temperatures.

Table 3-4 shows average density, API gravity, and viscosity values for six common diluted bitumen blends. The values are compared with those of six other heavy Canadian crude oils that are commonly piped to the United States. In some cases, these other heavy crude oils are also blended with lighter oils. As would be expected of commercial crude oils, the 12 sampled products have viscosities that conform to requisite pipeline tariff specifications.

According to API, shipments of diluted bitumen enter transmission pipelines at the same temperatures as other Canadian crude oils, generally in the range of 4°C to 25°C (40°F to 75°F) (API 2013). Temperatures will increase as a result of friction as the crude oil flows through the pipeline and because of high ambient temperatures during summer months. Because more pumping energy is needed for viscous crude oils, the temperature will be elevated in pipeline segments downstream from pumps. The temperature gain from pumping, however, will be the same for diluted bitumen as for other crude oils with similar densities and viscosities. Increasing pumping energy to boost the flow rate will raise the temperature further, but this effect will remain the same for all crude oils with corresponding levels of density and viscosity. Within the constraints of the design and safety factors of a pipeline, an operator may elect to increase the flow rate of any crude oil type as a means of adding throughput capacity, but this is strictly an economic decision.

TABLE 3-4 Comparison of Density, API Gravity, and Viscosity of Diluted Bitumen and Other Canadian Crude Oils

Canadian Heavy Crude Oils						
	Bow River	Fosterton	Lloydminster Blend	Lloydminster Kerrobert	Smiley–Coleville	Western Canadian Blend
Density (kg/m^3)	914	927	927	930	932	929
API gravity (°)	23	21	21	20	20	21
Viscosity at 20°C (68°F) (cSt)	100	96	145	146	144	145
Viscosity at 40°C (104°F) (cSt)	37	36	52	52	51	52
Diluted Bitumen						
	Access Western	Cold Lake	Peace River Heavy	Christina Lake	Wabasca Heavy	Surmount Heavy (Synbit)
Density (kg/m^3)	926	928	931	923	935	936
API gravity (°)	21	21	20	22	20	19
Viscosity at 20°C (68°F) (cSt)	150	153	113	178	134	131
Viscosity at 40°C (104°F) (cSt)	53	54	44	62	49	47

SOURCE: Data obtained from CrudeMonitor.com by Crude Quality, Inc. (http://www.crudemonitor.ca/tools/comp/crudecomparisons.php#results) and from Enbridge website (http://www.enbridge.com/DeliveringEnergy/Shippers/~/media/www/Site%20Documents/Delivering%20Energy/2012CrudeCharaceristics.ashx). Both websites accessed March 1, 2013.

Water and Sediment Content

Refiners dislike crude oil feed containing excess water and sediment that requires filtration and added treatment for effluent disposal. Furthermore, they do not want to pay for the transportation of these impurities in crude oil shipments. Water and sediment are also undesirable from the standpoint of pipeline operators because of the potential for internal corrosion, as discussed in Chapter 5. Canadian pipeline tariffs specify that basic sediment and water (BS&W) in crude oil shipments not exceed 0.5 percent by volume. While U.S. tariffs tend to allow higher BS&W limits (1 percent in most cases), the lower Canadian threshold becomes the constraining factor for diluted bitumen and other crude oils piped into the United States from Canada.

Data specifically on the water content of pipeline shipments are difficult to obtain (as distinguished from data on combined water and sediment volumes). Nevertheless, because the Canadian tariffs are generally more restrictive than those in the United States, it can be inferred that shipments of Canadian crude oils, including diluted bitumen, do not contain more water than other crude oils transported in U.S. transmission pipelines. In the case of sediment, any amounts measured in diluted bitumen are likely to derive from the bitumen, since the diluents are largely free of sediment (as shown in Table 3-2). Some sediment sampling data are available to compare diluted bitumen with other Canadian crude oils. Figure 3-7 shows the average sediment levels for

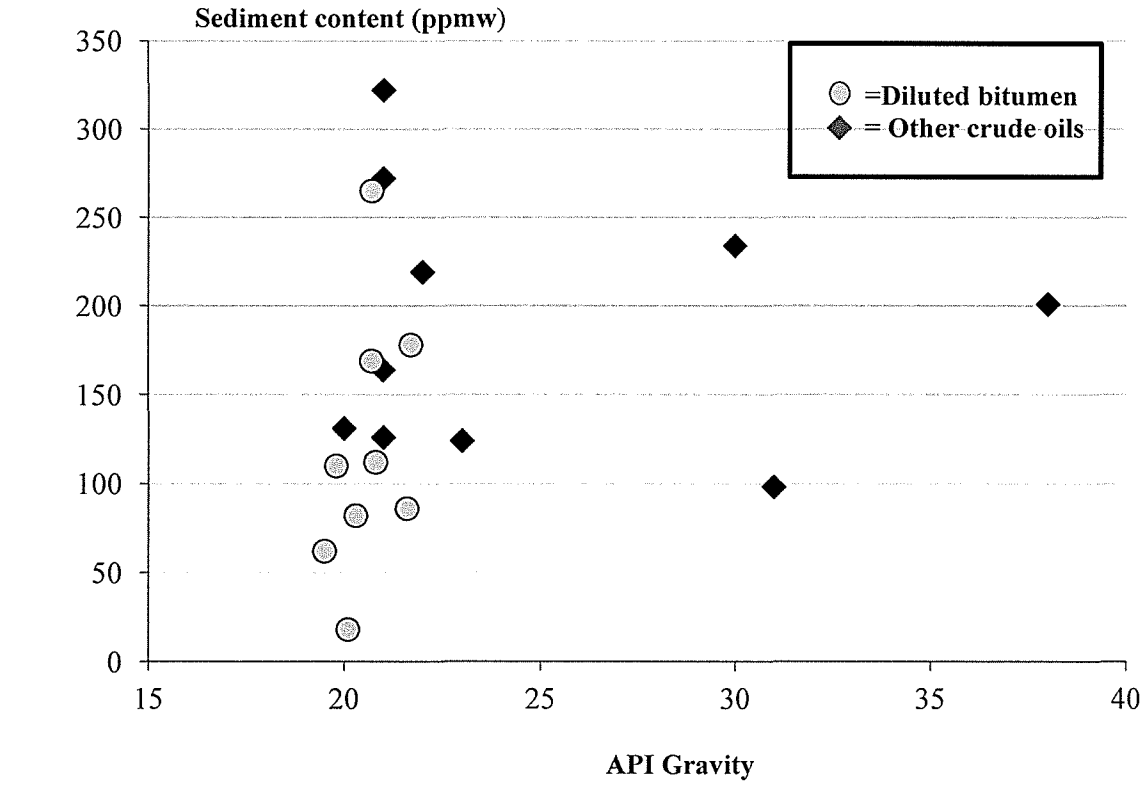

FIGURE 3-7 Average sediment content for nine diluted bitumen blends and 10 light, medium, and heavy Canadian crude oils. [Data obtained from CrudeMonitor.com by Crude Quality, Inc. (http://www.crudemonitor.ca/condensate.php?acr=SLD; http://www.crudemonitor.ca/crude.php?acr=SYN). Accessed March 1, 2013.]

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nine diluted bitumen blends and 10 light, medium, and heavy Canadian crude oils. Average sediment levels range from 18 to 265 parts per million by weight (ppmw) for the diluted bitumen and from 98 to 322 ppmw for the selection of Canadian crude oils.[24] Sediment quantities in this general range (<500 ppmw) will constitute less than 0.05 percent of the crude oil stream. The comparisons suggest that shipments of diluted bitumen contain sediment levels that are within the range of other crude oils piped into the United States.

Other characteristics of entrained sediments, such as the size, shape, mass, and hardness of solid particles, are seldom measured in pipeline shipments or reported in standard crude oil assays. Particle size is a potentially important factor in the tendency of sediments to clog pumps and other pipeline equipment and settle to the pipe bottom to form sludge. The shape, mass, and hardness of solid particles in sediment can also affect the potential for internal erosion.

While data on physical properties are limited, some values for particle size and other properties have been reported in laboratory studies of diluted bitumen and other crude oils. Figure 3-8 shows the particle size distribution of solids in diluted bitumen as measured by McIntyre et al. (2012). Median particle size was 0.1 micron (μm) and rarely exceeded 1 μm. Other data indicate that the distribution of particle size observed by McIntyre et al. (2012) is well within the range of other crude oils shipped by pipeline. The Canadian Crude Quality Technical Association (CCQTA) has spot sampled the desalter effluent from three refineries in Canada and the United States. The effluent was derived from crude oils other than diluted bitumen. The

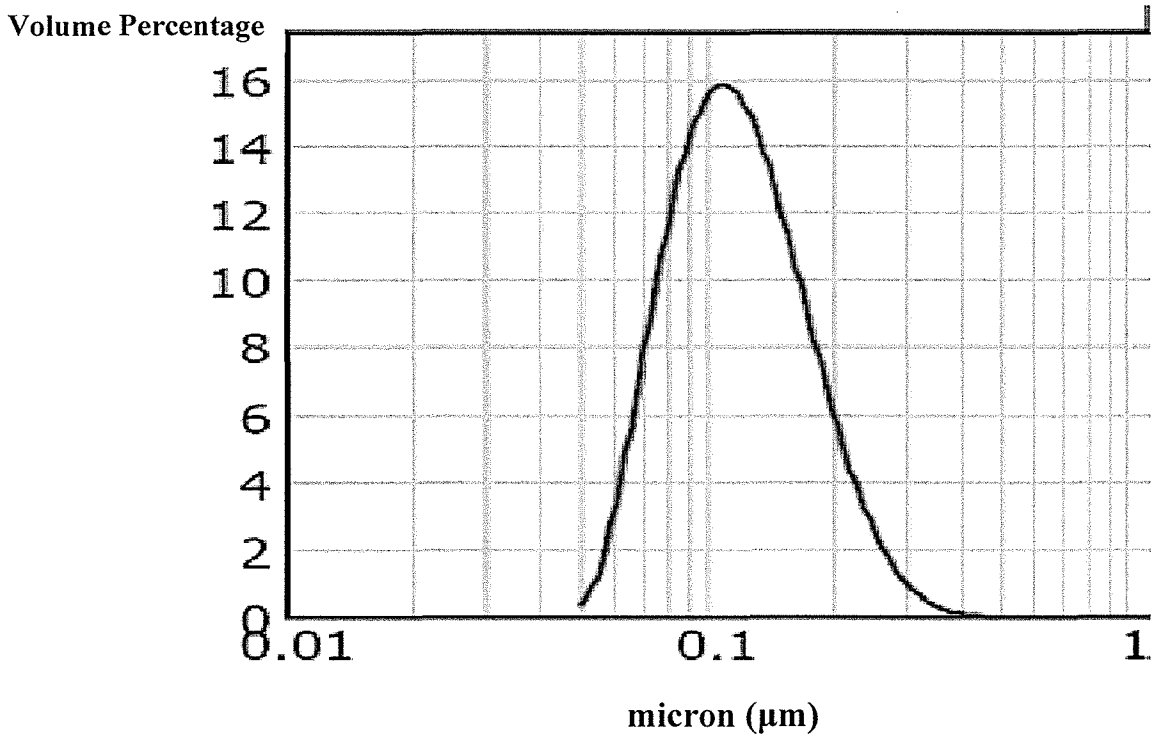

FIGURE 3-8 Particle size distribution of solids in diluted bitumen. (Source: McIntyre et al. 2012.)

[24] Most contaminants are expressed as parts per million (ppm), which is 1 milligram per kilogram for weight (noted as 1 ppmw) or 1 milligram per liter for volume (noted as 1 ppmv). 1,000 ppmw = 0.1 percent of weight.

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particle size distributions from these samples are shown in Table 3-5. The median particle sizes for the samples ranged from about 0.4 to 1.6 μm, higher than the median particle size reported for the diluted bitumen sampled by McIntyre et al. (2012).

CCQTA data on the nature of solids filtered from five diluted bitumen and two heavy crude oil samples show median particle sizes that are comparable across the samples, ranging from 1.0 to 2.4 microns for four of the five diluted bitumen samples and from 1.9 to 2.3 microns for the two heavy crude oil samples.[25] The fifth diluted bitumen sample had a median particle size of 5.6 microns. The maximum particle sizes in the five diluted bitumen samples ranged from 11 to 92 microns, while the maximum value for the two heavy crude oils was 33 microns. Data are more limited for characterizing the shape, mass, and hardness of solids in diluted bitumen and other crude oils. As noted earlier, the sand grains in unprocessed bitumen contain hard silicate minerals such as quartz, feldspar, and mica, in addition to the softer minerals found in clay fines (Strausz and Lown 2003, 31–32). However, the in situ–produced bitumen that is processed and diluted for pipeline transportation does not contain the same high levels of sand, clay fines, and other sediments found in bitumen in its native state. McIntyre et al. (2012) reported that about 1 percent of the solids in sampled diluted bitumen consisted of quartz, while clay materials (16 percent) and hydrocarbon and coke-like materials (83 percent) accounted for the remainder. X-ray diffraction analysis of the solids in the five diluted bitumen and two heavy oil samples taken by CCQTA indicate that silicate particles are more abundant in the solids of diluted bitumen (accounting for 13 to 45 percent of crystalline solids) than in the solids of other heavy crude oils sampled (accounting for 5 to 8 percent of crystalline solids).[26] However, the five diluted bitumen samples did not contain high levels of sediment, with none exceeding 350 ppmw (0.035 percent).

TABLE 3-5 Size Distribution of Solid Particles Obtained from Refinery Effluent for Crude Oils Other Than Diluted Bitumen

	Refinery A					Refinery B			Refinery C
Particle Size (μm)	Sample 1	Sample 2	Sample 3	Sample 4	Sample 5	Sample 1	Sample 2	Sample 3	Sample 1
Mean	0.85	1.1	1.13	0.74	1.14	2.67	1.23	0.82	0.98
Mode	0.32	0.31	0.28	0.33	0.39	2.33	0.26	0.53	0.54
Median	0.66	0.86	0.76	0.49	0.81	1.61	0.8	0.43	0.84
Minimum	0.13	0.17	0.13	0.06	0.13	0.06	0.1	0.07	0.15
Maximum	3.38	4.5	9.74	4.0	6.55	21.59	13.3	17.7	4.64
Standard deviation	0.55	0.76	1.05	0.67	0.9	3.09	1.3	1.36	0.6

SOURCE: Data provided by CCQTA and derived from Oil Sands Bitumen Processability Project. Presented to the committee on October 23, 2012 (http://onlinepubs.trb.org/onlinepubs/dilbit/SegatoLimieux102312.pdf).

[25] Data obtained from the CCQTA Oil Sands Bitumen Processability Project. Presented to the committee on October 23, 2012 (http://onlinepubs.trb.org/onlinepubs/dilbit/SegatoLimieux102312.pdf).

[26] Data obtained from the CCQTA Oil Sands Bitumen Processability Project. Presented to the committee on October 23, 2012 (http://onlinepubs.trb.org/onlinepubs/dilbit/SegatoLimieux102312.pdf). According to the CCQTA representative presenting the data, X-ray diffraction analysis does not measure the noncrystalline solids, which can account for 30 percent or more of the solids of sediment.

Other Properties

Pipeline tariffs in Canada and the United States generally do not contain specifications for shipment properties apart from those discussed above, although crude oil producers and refiners may have private agreements that specify qualities such as acidity and sulfur content. Table 3-6 shows the acidity and sulfur content for several sampled Canadian heavy crude oils and diluted bitumen blends.

The acidity of crude oil is generally referenced by using total acid number (TAN), a measure of the amount (in milligrams) of potassium hydroxide (KOH) needed to neutralize the acid in a gram of oil. TAN usually increases with the extent of oil biodegradation and generally is in the range of 0.5 to 3.0 for heavy oils (Strausz and Lown 2003, 430). Although it overlaps with the range of TANs found in heavy Canadian crude oils (as shown in Table 3-6), the range of acid content in diluted bitumen blends is generally higher than the range in other crude oils because of the greater biodegradation of the natural bitumen and resulting concentrations of high-molecular-weight organic acids.

The type of acid in diluted bitumen is more important to pipeline operators than total acid content. High-molecular-weight organic acids, such as naphthenic acids, are stable in the

TABLE 3-6 Sulfur and Total Acid Content in Sampled Canadian Heavy Crude Oils and Diluted Bitumen Blends

	Total Sulfur (percentage by weight)	TAN (mg KOH/g oil)
Canadian Heavy Crude Oils		
Fosterton	3.26	0.2
Lloydminster Blend	3.56	0.82
Lloydminster Kerrobert	3.12	0.92
Western Canadian Select	3.51	0.94
Diluted Bitumen Blends		
Albian Heavy Synthetic	2.5	0.57
Access Western Blend	3.93	1.72
Black Rock Seal Heavy	4.32	1.72
Cold Lake	3.75	0.99
Christina Lake	3.79	1.53
Peace River Heavy	5.02	2.5
Smiley–Coleville Heavy	2.97	0.98
Statoil Cheecham Blend	3.69	1.77
Surmount Heavy Blend Synbit	3.02	1.38
Western Canadian Blend	3.1	0.82

SOURCE: TAN data obtained from CrudeMonitor.com by Crude Quality, Inc. (http://www.crudemonitor.ca/condensate.php?acr=SLD; http://www.crudemonitor.ca/crude.php?acr=SYN). Sulfur data obtained from Enbridge (http://www.enbridge.com/DeliveringEnergy/Shippers/~/media/www/Site%20Documents/Delivering%20Energy/2012CrudeCharaceristics.ashx). Accessed March 1, 2013.

pipeline transportation environment. These acids have boiling points higher than water and do not react at pipeline operating temperatures. Although the organic acids can be corrosive to metals used in refineries processing crude oils at temperatures above 300°C (570°F), they are not corrosive to steels at pipeline temperatures (Nesic et al. 2012). This distinction is discussed further in Chapter 5.

The Canadian heavy crude oils and diluted bitumen contain 2.5 to 5 percent sulfur by weight. Whereas condensate and synthetic crude oils are largely free of sulfur (as shown in Table 3-2), natural bitumen contains 4 to 6 percent sulfur. As described earlier, most of the sulfur in bitumen is bound in stable hydrocarbon structures. Sulfur levels in the 2.5 to 5 percent range, as found in processed bitumen diluted for transportation, are high for light- and medium-density crude oils but not unusual for heavy crude oils. While high sulfur content in crude oil is generally undesirable for refining, it is problematic for transmission pipelines mainly if it exists in surface-active compounds and hydrogen sulfide (H_2S). H_2S is a weak acid that is corrosive to pipelines for reasons explained in Chapter 5. Available test data on the H_2S content in crude oil indicate lower levels in diluted bitumen (less than 25 ppmw in liquid phase) than in other crude oils of various densities (Figure 3-9).

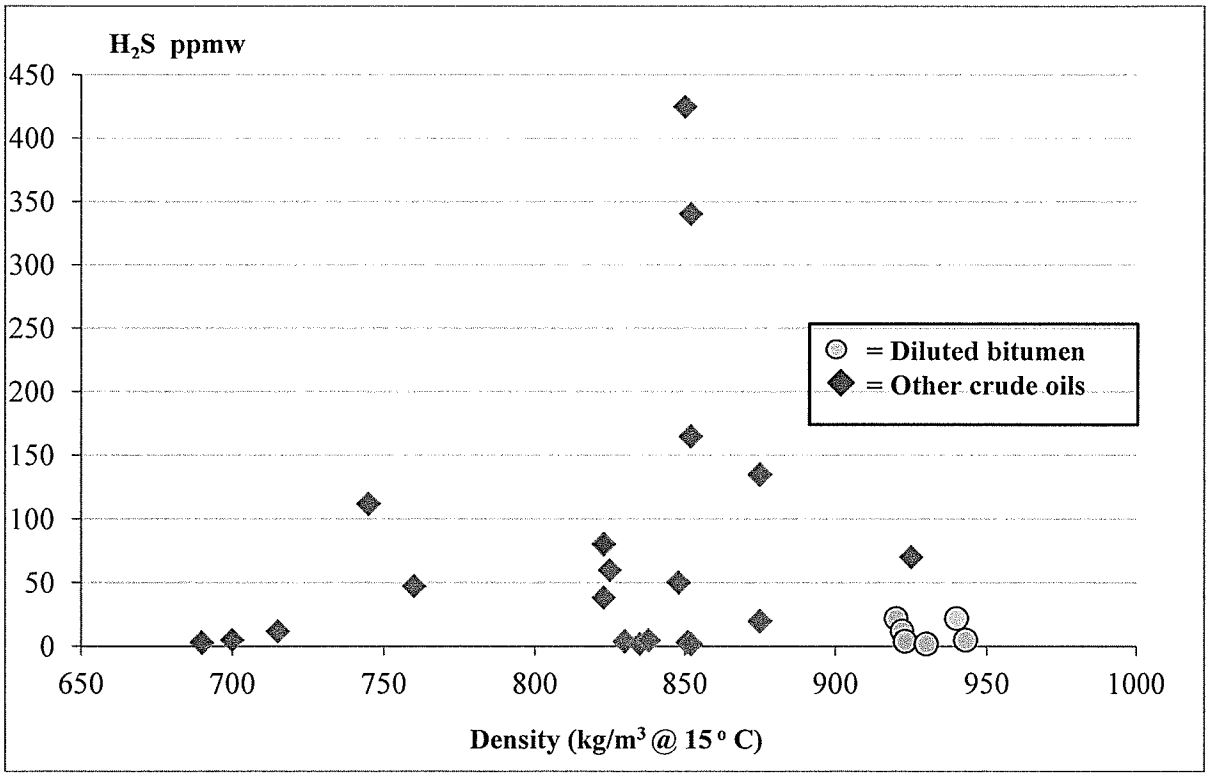

FIGURE 3-9 H_2S content of diluted bitumen and other crude oils. (H_2S is measured in liquid phase by using ASTM Test Method 5263. H_2S remains in a liquid state in pipelines because the partial pressures of operating pipelines are below the bubble point.) (Data submitted to the committee on November 13, 2012, by the Pipeline Sour Service Project Group of CCQTA.)

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Shipment Properties and Operating Parameters Reported by Operators

For additional data on the transport properties of diluted bitumen, the committee prepared a questionnaire for the Canadian Energy Pipeline Association (CEPA). CEPA distributed the questionnaire to member companies that regularly transport diluted bitumen by transmission pipeline. The questionnaire and responses from five Canadian operators are provided in Appendix A. A summary of the operator responses on the properties of diluted bitumen is provided in Table 3-7. All of the reported values for BS&W, H_2S, sulfur, density, TAN, and operating temperature are within the ranges provided in the preceding tables and figures.

With respect to the pipeline flow regime, the surveyed pipeline operators reported average flow velocities of 0.75 to 2.5 meters per second (2.5 to 6.7 feet per second) in transmission pipelines that mostly range in diameter from 20 to 42 inches but that include some mileage consisting of pipe having smaller (8 inches) and larger (up to 48 inches) diameters. Without knowledge of the pipe diameter associated with each reported flow velocity, the resulting flow cannot be verified as turbulent. In general, flow velocities ranging between 0.75 and 2.5 meters per second would be expected to maintain turbulent flow in pipelines ranging from 8 to 48 inches in diameter when they transport crude oils with the range of viscosities (113 to 153 cSt at 20°C) reported for the diluted bitumen and other heavy crude oils shown in Table 3-4.

The committee asked pipeline operators for information on the content of oxygen and carbon dioxide in shipments because these dissolved gases can be an important factor in the corrosion of pipe steel, for reasons explained in Chapter 5. Pipeline operators do not routinely measure oxygen and carbon dioxide concentrations in crude oil shipments because of the difficulty associated with sampling and detecting these gases. Nevertheless, the operators reported that because diluted bitumen and other crude oils enter the pipeline system deaerated, there should be no significant difference in the concentrations of oxygen and carbon dioxide gas in products transported in the same pipelines. Operators also reported that as a general matter they aggressively seek to limit avenues for air entry into the pipeline at all times, including periods of storage and blending and pumping operations.

TABLE 3-7 Properties and Operating Parameters of Diluted Bitumen Shipments Reported by Five Canadian Pipeline Operators

Property or Parameter	Unit	Range of Reported Averages	Lowest and Highest Values in Reported Normal Ranges	Highest Reported Extremes
BS&W	Volume percent	0.18 to 0.35	0.05 to 0.40	0.50
H_2S	ppmw	<0.50 to 6.77	<0.50 to 11.0	11.0
Sulfur	Weight percent	3.10 to 4.00	2.45 to 4.97	5.20
Density	API gravity	19.8 to 22.1	19.0 to 23.3	23.3
TAN	mg KOH/g	1.00 to 1.30	0.85 to 2.49	3.75
Operating temperature	°C (°F)	10 to 27 (50 to 81)	4 to 43 (39 to 109)	50 (122)
Flow rate	feet/second	2.5 to 6.7	0.5 to 8.2	8.2
Pressure	psi	430 to 930	43.5 to 1,440	1,440

NOTE: Operators reported that oxygen and carbon dioxide concentrations are not routinely measured in shipments of crude oil. See Appendix A for complete survey results.

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SUMMARY

The bitumen imported into the United States is produced from Canadian oil sands. The bitumen is both mined or recovered in situ by using thermally assisted techniques. Because a large share of the bitumen deposits is too deep for mining, in situ recovery accounts for an increasing percentage of production. Because mined bitumen does not generally have qualities suitable for pipeline transportation and refinery feed, it is processed in Canada into synthetic crude oil. Bitumen recovered through use of thermally assisted methods has water and sediment content that is sufficiently low for long-distance pipeline transportation. The bitumen imported for refinery feed in the United States is recovered through in situ methods rather than mining.

Like all forms of petroleum, Canadian bitumen is a by-product of decomposed organic materials and thus a mixture of many hydrocarbons. The bitumen contains a large concentration of asphaltenes and other complex hydrocarbons that give bitumen its high density and viscosity. At ambient temperatures, bitumen does not flow and must be diluted for transportation by unheated pipelines. The diluents consist of light oils, including natural gas condensate and light synthetic crude oils. Although the diluents consist of low-molecular-weight hydrocarbons, diluted bitumen does not contain a higher percentage of these light hydrocarbons than do other crude oils. The dilution process yields a stable and fully mixed product for shipping by pipeline with density and viscosity levels in the range of other crude oils transported by pipeline in the United States.

Shipments of diluted bitumen are transported at operating temperatures, flow rates, and pressure settings typical of crude oils with similar density and viscosity. Water and sediment content conforms to the Canadian tariff limits, which are more restrictive than those in U.S. pipeline tariffs. Solids in the sediment of diluted bitumen are comparable in quantity and size with solids in other crude oils transported by pipeline. While the sulfur in diluted bitumen is at the high end of the range for crude oils, it is bound in stable hydrocarbon compounds and is not a source of corrosive hydrogen sulfide. Diluted bitumen has higher total acid content than many other crude oils because of relatively high concentrations of high-molecular-weight organic acids that are not reactive at pipeline temperatures.

REFERENCES

Abbreviations

API	American Petroleum Institute
CAPP	Canadian Association of Petroleum Producers
ERCB	Energy Resources Conservation Board
NEB	National Energy Board
USGS	U.S. Geological Survey
WEC	World Energy Council

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4

Review of Pipeline Incident Data

This chapter reviews U.S. and Canadian pipeline incident statistics and investigations for insight into whether transmission pipelines experience more releases when they transport diluted bitumen than when they transport other crude oils.

U.S. AND CANADIAN INCIDENT DATA

The Pipeline and Hazardous Materials Safety Administration (PHMSA) requires that all regulated pipeline operators report unintended releases that meet certain thresholds of release quantities or impact severity. PHMSA tracks and analyzes these reports to inform its inspection, investigation, and enforcement activities.[1] PHMSA inspectors also conduct more in-depth investigations of selected incidents. Incidents involving especially severe consequences, such as deaths, injuries, evacuations, and environmental damage, may also be investigated by the National Transportation Safety Board (NTSB). Through field and forensic investigations, NTSB assesses both causal and contributing factors and recommends preventive and follow-up actions, including regulatory responses.[2] The National Energy Board (NEB) and Transportation Safety Board (TSB) serve similar functions, respectively, for incidents involving pipelines in Canada. PHMSA and NEB incident statistics and investigations, as well as relevant investigations by NTSB and TSB, are reviewed next.

PHMSA Incident Data and Investigations

PHMSA regulations require that operators of hazardous liquid pipelines, which include crude oil pipelines, report any incident that involves a release of 5 gallons or more or explosion, fire, serious injury, or significant property damage.[3] Incidents that involve any component of the pipeline facility, including line pipe, tanks, valves, manifolds, and pumps, must be reported. A short reporting form is required for notifying the agency of small releases, and a longer form is required for larger releases and any release into water exceeding 5 gallons. Before 2002 the threshold for reporting releases was 50 barrels. The reporting changes make comparisons of recent release data with historical performance difficult. A further complication of the reporting system is that while PHMSA reporting covers most crude oil pipelines, there are exceptions to coverage, such as some intrastate pipelines and gathering systems.

The number of incidents reported for regulated crude oil pipelines during 2002 to 2011 is shown in Figure 4-1. During the 10-year period, the number of large incidents fluctuated from about 80 to 120 per year. Total releases trended downward from about 190 to 150 per year, with small releases accounting for between one-third and one-half of the total. System components involved in the releases are shown in Figure 4-2. Main-line pipe and tanks were involved in

[1] More discussion of PHMSA safety oversight programs can be found in Appendix B.
[2] NTSB recommendations pertaining to PHMSA's pipeline safety authorities can be found at http://www.phmsa.dot.gov/pipeline/regs/ntsb.
[3] 49 CFR 195.50.

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about one-third of the incidents, while all other equipment, such as pumps, valves, and fittings, accounted for the rest. A generalization that can be made is that the larger releases tend to be associated with main-line pipe, and sometimes with tanks, whereas the other system components tend to experience smaller releases on average. For 2002 to 2012, the pattern of releases by system component and cause is shown in Figure 4-3 and Table 4-1. The causal distribution differed by component. For main-line pipe, internal corrosion was the cause of about one-third of releases, while external corrosion and outside force damage accounted for most of the remainder. For most other pipeline components, incorrect operation and malfunctioning equipment were the main causes of incidents. Most of the corrosion-related incidents reported to PHMSA occurred in pipes and pumps. Main-line pipe was the dominant location for external corrosion. Whereas main-line pipe also accounted for about one-third of incidents involving internal corrosion, more of these incidents occurred in pumps.

Each year, PHMSA inspectors select as many as two dozen pipeline incidents for more thorough investigation on the basis of the severity of the consequences, the nature of the suspected failure modes, and the incident and compliance history of the pipeline system involved. The investigations normally consist of site visits, forensic tests, interviews with operating personnel, and reviews of operator records. Since 2005, PHMSA has conducted 63 investigations of natural gas and hazardous liquid pipelines, including 14 incidents involving onshore crude oil transmission pipelines.[4] The latter incidents are referenced in Table 4-2. In the

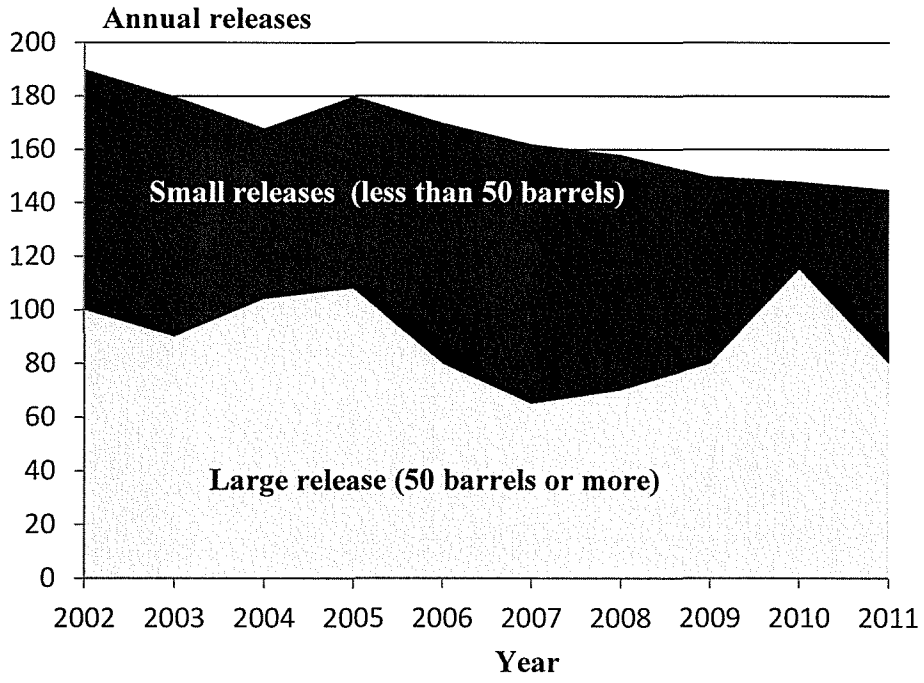

FIGURE 4-1 Crude oil pipeline incidents reported to PHMSA, 2002 to 2011. (Incident data were provided to the committee by PHMSA during the October 23, 2012, committee meeting.)

[4] http://phmsa.dot.gov/pipeline/library/failure-reports.

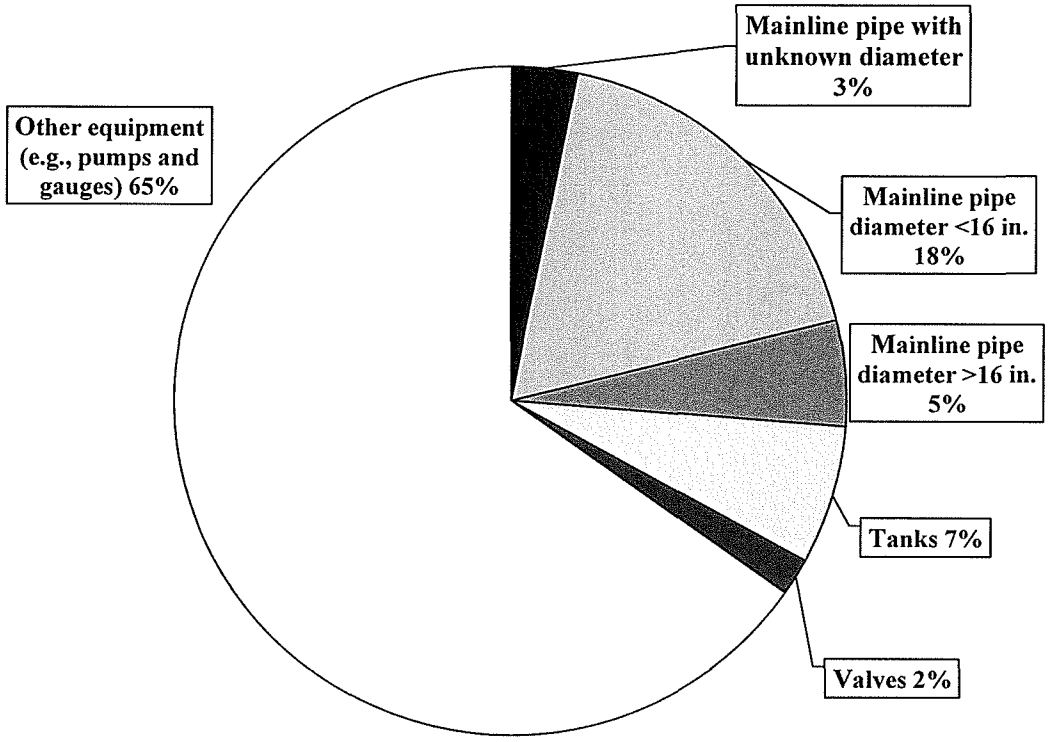

FIGURE 4-2 Crude oil pipeline incidents reported to PHMSA by system component involved, 2002 to 2012. [Data were obtained from analysis of PHMSA data from the Environmental Impact Statement of TransCanada XL permit application (U.S. Department of State 2013, Volume IV, Appendix K).]

two cases found to have involved internal corrosion, factors other than the properties of the crude oils transported were cited as causes. In three other cases, investigators reported that internal pressure cycles and associated stress loadings may have contributed to the formation and growth of cracks initiated at sites of external corrosion.

Apart from providing some examples of possible failures related to the transported product, the PHMSA investigations do not provide evidence that pipelines transporting diluted bitumen are more susceptible to release. In the next chapter, the chemical and physical properties of diluted bitumen are examined to deduce possible susceptibilities to pipeline damage.

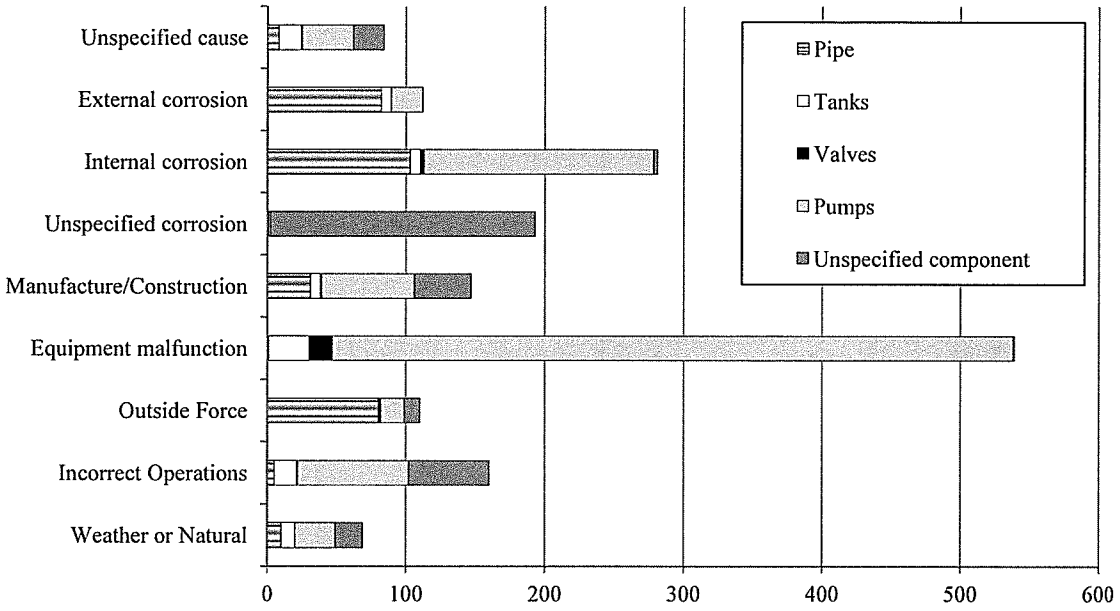

FIGURE 4-3 Crude oil pipeline incident reports to PHMSA by cause of release and system component involved, 2002 to 2012. (Source: U.S. Department of State 2013, Volume IV, Appendix K.)

TABLE 4-1 Crude Oil Pipeline Incident Reports to PHMSA by Cause of Release and System Component Involved, 2002 to 2012

Reports of Pipeline Releases to PHMSA, 2002–2012						
	Pipe	Tanks	Valves	Pumps	Unspecified Component	Total
Weather or natural force	10	10	0	29	20	69
Incorrect operations	5	16	1	80	58	160
Outside force	80	0	2	17	11	110
Equipment malfunction	1	29	17	491	1	539
Manufacture or construction	31	7	1	67	41	147
Unspecified corrosion	1	1	0	0	191	193
Internal corrosion	103	7	3	165	3	281
External corrosion	82	7	0	23	0	112
Unspecified cause	8	16	1	37	22	84
Total	321	93	25	909	347	1,695

SOURCE: U.S. Department of State 2013, Volume IV, Appendix K.

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TABLE 4-2 PHMSA Crude Oil Pipeline Incident Investigations, 2005 to 2012

Date of Failure	Operator	Location	Commodity Released	System Component	Attributed Cause	Summary
4/12/05	Jayhawk Pipeline	Stevens, Kansas	Crude oil	7-in. main-line pipe section	Internal corrosion	Sand and saltwater collected in a low point in the pipeline, resulting in corrosive conditions.
1/1/07	Enbridge Energy Partners	Clark County, Wisconsin	Crude oil from Canada	24-in. main-line pipe section	Defect in manufacture	Weld seams did not fuse during pipe manufacture. The defect grew to a critical size by fatigue from operating pressure cycles.
11/13/07	Enbridge Energy Partners	Clearbrook, Minnesota	Crude oil from Canada	34-in. main-line pipe section	Defect in manufacture	Pipe was transported to the construction site on rail cars, causing fatigue cracks from cyclical loading. Pressure cycling during operations may have caused the cracks to grow to failure.
2/18/09	Mid-Valley Pipeline	Cygnet, Ohio	Crude oil	12-in. branch connection to main line	Material failure	The combined loading of the branch connection, valve, and flanging caused the branch attachment to crack at the weld.
6/9/09	Enbridge Energy Partners	Gowan, Minnesota	Crude oil from Canada	26-in. main-line pipe section	Material failure	A sleeve installed 20 years earlier to repair a pipe split opened at a deficient weld.
12/23/09	Enterprise Products	Galveston, Texas	Crude oil from offshore	Meter station component	Material failure in a fitting	Cap screws on a stainless steel pressure switch failed because of hydrogen-assisted cracking promoted by galvanic corrosion.
3/1/10	Mid-Valley Pipeline	Gregg County, Texas	Crude oil	Tank farm manifold piping	Internal corrosion	Internal corrosion occurred in a dead-leg section of pipe with no flow during normal operations.
6/11/10	Chevron Pipe Line	Salt Lake County, Utah	Crude oil	10-in. main-line pipe section	Outside force damage	An electric charge jumped from a metal fence to the pipe, creating a 0.5-in. hole in the top of the pipe.
6/14/10	Suncor Energy Pipeline	Laramie, Wyoming	Crude oil	Breakout tank	Incorrect operation	Operating personnel did not respond to an alarm indicating tank capacity had been reached.

(*continued*)

TABLE 4-2 (*continued*) PHMSA Crude Oil Pipeline Incident Investigations, 2005 to 2012

Date of Failure	Operator	Location	Commodity Released	System Component	Attributed Cause	Summary
11/16/10	Shell Pipeline	Vinton, Louisiana	Crude oil from offshore	22-in. main-line pipe section	Material failure	The coating disbonded at a bend in the pipe allowing the onset of corrosion. Cyclical loading due to normal batch operations may have contributed to crack growth.
12/1/10	Chevron Pipe Line	Salt Lake County, Utah	Crude oil (condensate)	Valve used for water injection in main line	Incorrect operation	Water was not properly drained from the valve. Internal pressure brought on by freezing water caused the valve connection to leak.
1/26/11	Chevron Pipe Line	Plaquemines Parish, Louisiana	Crude oil from offshore	10-in. main-line pipe section at river crossing	Excavation damage	The pipeline was being lowered while in service. Stress concentrations from the procedure caused fracturing in an area with preexisting dents.
2/21/11	Enterprise Products	Cushing, Oklahoma	Crude oil	8-in. pipe within terminal area	Incorrect operation	Personnel purging a pipe failed to shut down the pump, which resulted in the delivery being pumped against a closed valve, causing a pipe with preexisting manufacturing defects to fail.
7/1/11	ExxonMobil Pipeline	Laurel, Montana	Crude oil	12-in. main-line pipe section	Outside force damage	River flooding caused debris to strike and rupture the line.

SOURCE: PHMSA's pipeline failure investigation reports can be found at http://phmsa.dot.gov/pipeline/library/failure-reports.

NEB Incident Statistics

NEB regulates interprovincial pipelines in Canada. The regulated network consists of 11,000 miles of crude oil pipeline, nearly all of which are in transmission systems. Regulated operators must file an "accident" record if a pipeline facility experiences a fatal or serious injury, fire, or explosion due to a release; any other damage to the pipeline that causes a release; and any form of outside force damage, even if it does not lead to a release. In addition, operators are required to file an "incident" report in the event of an uncontrolled release, operations that exceed design limits, an abnormality that reduces structural integrity, or a shutdown for safety reasons. These reported incidents do not necessarily involve releases.

From 2004 to 2011,[5] NEB received 12 accident reports and 292 incident reports involving crude oil transmission pipelines (TSB 2012, Table 5). Of the 292 incidents involving pipeline integrity issues—such as internal and external degradation—cracks accounted for the largest share, almost 30 percent (see Figure 4-4). Metal loss, mainly from corrosion, was reported in 16 percent of incidents. Of the 12 accident reports, one involved combined corrosion and cracking (stress corrosion cracking), as discussed in more detail below.

NTSB and TSB Investigations

The main transportation safety investigative bodies in the United States and Canada are NTSB and TSB, respectively. Although their pipeline investigations are thorough, they are infrequent and selective. For example, over the past decade NTSB has investigated fewer than a dozen

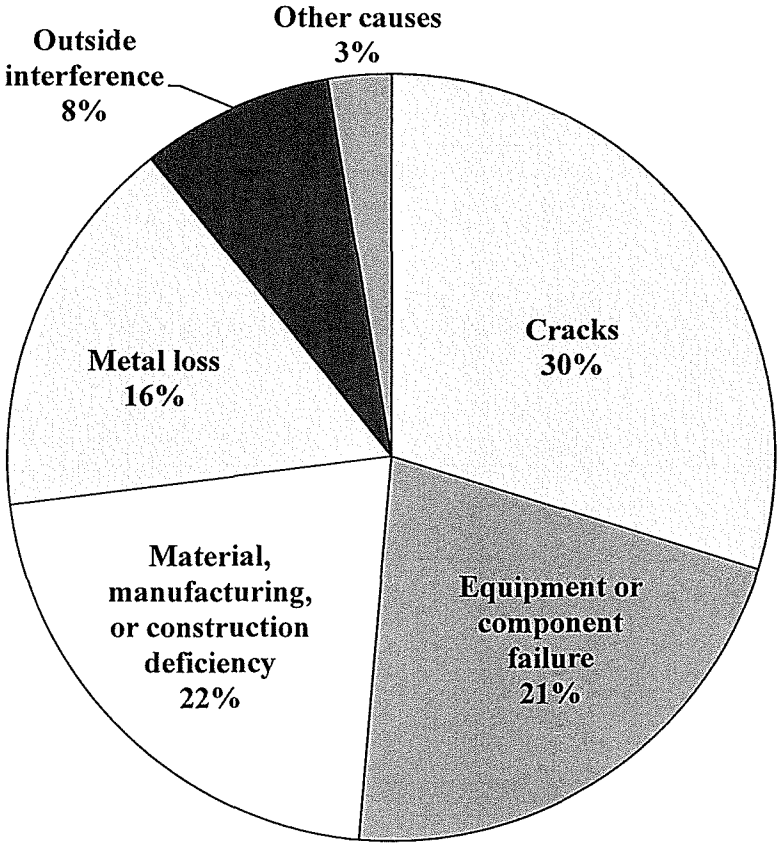

FIGURE 4-4 Causes of crude oil transmission pipeline incidents reported to NEB, 2004 to 2011. (Source: TSB 2012, Table 5.)

[5] Before 2004, the definition of reportable incident used by NEB was different from that used today. The reporting change makes longer-term trend analysis less meaningful.

pipeline incidents, most involving pipelines carrying volatile commodities such as natural gas and refined products.[6] The investigations are helpful in understanding factors that can interact to cause pipeline damage and failures, but they produce limited information useful in assessing the effect of specific crude oil types or crude oil properties on pipeline release probabilities.

In 2012, NTSB completed an investigation of a pipeline failure in which diluted bitumen was reported to have been released. The incident involved a 30-inch transmission pipeline that ruptured and released 20,000 barrels of product into a river near Marshall, Michigan (NTSB 2012). The investigators determined that the cause of the rupture was cracks that had formed in a corrosion pit on the outside of the pipe under a disbonded polyethylene tape coating. The cracks coalesced and grew as a result of stresses on the pipe, a process known as environmentally assisted cracking (EAC), which is described in more detail in Chapter 5. The Marshall release attracted considerable attention because of the consequences of the release and the actions of the operator. However, NTSB did not report that specific properties of the products transported through the pipeline at the time of the event or in the past had caused or contributed to the pipeline damage.

As noted above, one of the 12 crude oil pipeline accidents reported to NEB since 2004 involved a corroded and cracked pipeline. This release, which occurred in 2007, was investigated by TSB.[7] The release was from a 34-inch transmission pipeline originating in Alberta and transporting crude oil to the United States (TSB 2007). A forensic analysis of the ruptured pipe joint detected a shallow corrosion pit at a weld on the outside of the pipe that led to a stress corrosion crack, which eventually spread and fractured the pipe. TSB investigators determined that the polyethylene tape coating had tented over the weld, shielding the pipe from the beneficial effects of the cathodic protection current.[8] The corrosion pit that developed because of the tape failure became a stress concentration site where cracks formed and grew. TSB noted that 2 years earlier the operator had converted the pipeline to batch operations and surmised that this operational change may have contributed to crack growth as a result of more cyclic stress loadings from internal pressure fluctuations. Whether specific varieties of crude oil in the stream had properties that contributed to more severe pressure cycling was not reported by TSB.

A review of other NTSB and TSB investigations over the past decade did not indicate any cases in which specific crude oil types or shipment properties were associated with causes of pipeline damage or failure.

Assessment of Information from Incident Reports

The causes of pipeline incidents reported to PHMSA are proximate and broadly categorized. Incidents categorized as corrosion damage, for example, do not distinguish among those occurring as a result of the action of microorganisms, in combination with stress cracking, or at sites of preexisting mechanical damage. Some types of damage, such as EAC, may be categorized alternatively as caused by corrosion, a manufacturing defect, or a material failure. Whereas NTSB and TSB investigations provide detailed information on factors causing and

[6] NTSB pipeline investigation reports are available at http://www.ntsb.gov/investigations/reports_pipeline.html.

[7] NEB may conduct its own investigations of a reported incident to ensure that safety regulations are being followed and to determine the need for remedial actions.

[8] When the tape disbonds from the pipe steel, moisture can accumulate beneath the tape surface. Because the tape has fairly high electrical insulation properties, it can prevent cathodic protection current from reaching the exposed steel subject to corrosion.

contributing to pipeline releases, the investigations are too few in number to assess the causal effects of specific crude oil types and their properties.

Because of the potentially large number of factors associated with a given release, it is often difficult to isolate the role of any single causative factor, such as the effect of the specific crude oil being transported on time-dependent mechanisms such as corrosion and cracking. Sources of pipeline damage affected by the crude oils transported, either at the time of the release or in earlier shipments, are most pertinent to this study. Neither PHMSA nor NEB incident data contain informationon the types of crude oils transported or the properties of past shipments in the affected pipeline.

STATE AND PROVINCIAL INCIDENT DATA

Some U.S. states and Canadian provinces maintain reporting systems for incidents in intrastate and intraprovincial pipeline systems, including gathering lines. The Energy Resources Conservation Board (ERCB) holds this responsibility in Alberta. In the United States, several state regulators have authority over intrastate pipelines, including the state fire marshal of California. Pipeline incident data and analyses derived from both of these jurisdictions were considered.

Alberta ERCB Incident Data

The Alberta ERCB regulates and monitors the safe performance of oil pipelines in the province, with the exception of approximately 700 miles of NEB-regulated transmission pipeline crossing into other provinces and the United States.[9] ERCB mandates reporting of all pipeline incidents involving a release or damage from an outside force. In 2007, the agency reviewed the causes of 411 crude oil pipeline incidents reported from 1990 to 2005 (EUB 2007). The ERCB analysis showed that the largest single cause was internal corrosion, which the agency ascribed to the effects of the large percentage of gathering pipelines in the province. These small-diameter lines were described as susceptible to internal corrosion because of repeated low-flow conditions; frequent stopping and idling of movements; and the mixture of raw crude oil, gases, sediments, and waters carried from production fields (EUB 2007, 30). About 29 percent of the roughly 11,000 miles of ERCB-regulated pipeline mileage consisted of pipe with a diameter of 4 inches or less, and 73 percent had a diameter of 12 inches or less. Only about 1 percent of the mileage consisted of pipelines having a diameter of more than 22 inches.

Although ERCB release statistics have at times been cited as evidence of a corrosive effect of diluted bitumen on pipelines (Swift et al. 2011), the regulated systems represented by these incident statistics are not comparable with transmission pipelines in size, operations, or, most important, contents. As a result, the committee concluded that the ERCB data were not useful for the purposes of this study.

California Pipeline Safety Study

Pipeline operators in California have a long history of transporting crude oils with physical properties similar to those of Canadian crude oils and diluted bitumen. Most of the oil from the

[9] The Energy and Utilities Board regulated pipelines in Alberta until it was replaced in 2008 by ERCB.

San Joaquin Valley, for instance, has an American Petroleum Institute (API) gravity of 18 degrees or less, with the Kern River field producing especially dense crude oil with an API gravity of about 13 degrees (Sheridan 2006). Like bitumen producers, California oil producers commonly use thermal recovery techniques, such as injecting steam through the wellbore, to reduce crude oil viscosity and facilitate pumping to the surface. Heavier California crude oils are often transported undiluted through heated pipelines. This is not the case for Canadian bitumen, which is diluted for transportation.[10]

California has nearly 3,300 miles of transmission pipelines subject to federal safety regulation.[11] In addition, the state contains 3,000 to 4,000 miles of state-regulated pipeline, most of it in gathering systems. Responsibility for regulating the safety of hazardous liquid pipelines in California is shared by PHMSA and the California State Fire Marshal (CSFM).

In 1993, CSFM issued a report of the incident history of hazardous liquid pipelines in the state from 1981 to 1990 (CSFM 1993). The report examined releases from state and federally regulated lines, including those transporting refined petroleum products. Operators were required to submit records of releases during the period regardless of release quantity or consequences, along with information on pipeline diameter, length, age, operating temperature, and external coating type. Although the report is now 20 years old, its results have been cited as indicative of the potential effects of diluted bitumen on pipeline integrity (NRDC 2011).

The CSFM study documented 502 releases from hazardous liquid pipelines in California during the 10-year period. Analyses of the incident records indicated that external corrosion was the leading cause of releases, accounting for 59 percent, followed by third-party damage (20 percent), equipment malfunctions (5 percent), and weld failures (4 percent). Internal corrosion accounted for 3 percent, while operator error accounted for 2 percent.[12] Crude oil pipelines generated 62 percent of total releases, including 70 percent of the releases attributed to external corrosion.

While the CSFM study did not investigate each reported incident in depth, statistical analyses of the 502 records presented some patterns of interest. The age of the pipeline was correlated with a higher release rate. For example, 62 percent of the releases occurred in pipelines constructed before 1950, even though these lines accounted for only 18 percent of pipeline mileage. CSFM noted that many of the pipelines built in California during the first half of the 20th century lacked cathodic protection for most of their service lives, which suggests that the lack of cathodic protection, coupled with the absence of coatings or use of older coating materials, may have led to the high incidence of external corrosion relative to other failure causes.[13] The CSFM analysis revealed that 22 percent of the external corrosion incidents occurred in pipelines that were uncoated, and another 53 percent occurred in pipelines coated or wrapped with certain materials, most often asphalt and tar.

One finding that stood out among pipelines experiencing external corrosion was the disproportionate number of small-diameter pipelines that were operating at relatively high temperatures. Operating temperature was highly correlated with external corrosion—more than half the releases from external corrosion occurred in the 21 percent of pipeline mileage in which

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[10] As discussed in Chapter 2, California oil fields are served by transmission pipelines that connect to refineries elsewhere in the state. The transmission pipelines do not cross state borders.

[11] Pipeline mileage by state is available at the following PHMSA website: http://primis.phmsa.dot.gov/comm/reports/safety/CA_detail1.html?nocache=9253#_OuterPanel_tab_5.

[12] All other causes accounted for 7 percent of releases.

[13] As is discussed in Chapter 5, some older coating technologies shield cathodic protection currents.

the operating temperature regularly reached or exceeded 55°C (130°F). In addition, a large portion of the pipelines experiencing external corrosion consisted of small-diameter pipe. Although they accounted for only 13 percent of pipeline mileage, pipelines with diameters of less than 8 inches accounted for 21 percent of external corrosion incidents. Larger pipelines, with diameters of 16 inches or more, accounted for 23 percent of mileage but only 6 percent of the external corrosion incidents.

The preponderance of external corrosion incidents in smaller-diameter pipe and pipelines with high operating temperatures does not indicate that transmission pipelines contributed to the high rate of pipeline releases in California during the 1980s. Instead, the results suggest that older lines, many of which lacked modern coatings and cathodic protection for much of their operating history, were the main source of the releases. The high operating temperatures of many of these pipelines can be attributed to the thermal recovery methods used for California crude oil production. While the California experience illustrates the problems that can arise when pipelines are not properly protected against external corrosion, it is not indicative of the protections afforded crude oil transmission pipelines today.[14]

SUMMARY

A logical step in addressing the question of whether shipments of diluted have a greater propensity to causes pipeline releases than shipments of other crude oils is to examine historical release records. The incident statistics can be used to identify the general sources of pipeline failure. However, the information contained in the U.S. and Canadian incident records is insufficient to draw definitive conclusions. One reason is that the causal categories in the databases lack the specificity needed to assess the particular ways in which transporting diluted bitumen can affect the susceptibility of pipelines to failure. Another reason is that incident records do not contain information on the types of crude oil transported and the properties of past shipments in the affected pipeline. Because many pipeline releases involve cumulative and time-dependent damage, there is no practical way to trace the transportation history of a damaged pipeline to assess the role played by each type of crude oil and its properties in transport.

Incident reporting systems in Canada and the United States do not have uniform reporting criteria and coverage. Given the relatively small number of pipeline incidents, even minor variations in reporting criteria can lead to significant differences in incident frequencies and causal patterns. Some reporting systems combine incident reports from oil gathering and transmission systems, while others do not. Variation in reporting coverage is problematic because gathering pipelines are fundamentally different from transmission pipelines in design, maintenance, and operations and in the quality and quantity of the liquids they carry.

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Abbreviations

CSFM	California State Fire Marshal
EUB	Energy and Utilities Board
NRDC	Natural Resources Defense Council

[14] All hazardous liquid transmission pipelines are required by federal regulation to have cathodic protection.

NTSB	National Transportation Safety Board
TSB	Transportation Safety Board of Canada

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5

Assessing the Effects of Diluted Bitumen on Pipelines

This chapter examines the main causes of pipeline failure and the physical and chemical properties of the transported crude oils that can affect each. The relevant properties of diluted bitumen and other crude oil shipments are compared to make judgments about whether transporting diluted bitumen increases the likelihood that a pipeline will fail. Consideration is then given to whether pipeline operators, in transporting diluted bitumen, alter their operating and maintenance procedures in ways that can inadvertently make pipelines more prone to failure.

The following sections examine the potential sources of failure in pipelines from (*a*) internal degradation, (*b*) external degradation, and (*c*) mechanical forces. Because it is exposed to the shipped liquid, the inside of the pipe is the most obvious location to look for possible sources of damage from shipments. Corrosion is the main cause of internal degradation in crude oil transmission pipelines, followed to a lesser extent by erosion. Although the outside of the pipeline is not in contact with the shipped liquid, pipeline operating conditions associated with the shipment can affect the exterior of a transmission pipeline. Corrosion and cracking are the main sources of external degradation that can be affected by these conditions. Mechanical damage to the pipeline from overpressurization and outside forces also can be affected indirectly by the liquid in the pipeline.

SOURCES OF INTERNAL DEGRADATION

Pipelines sustain internal damage primarily as a result of progressive deterioration caused by corrosion and erosion of the mild steel used to manufacture line pipe. Internal corrosion is an electrochemical process that typically causes damage to the bottom of the pipe when water is present. Erosion is a mechanical process that causes metal loss along the interior wall of the pipe because of the repeated impact of solid particles, particularly at bends and other areas of flow disturbance. Both forms of attack reduce pipe wall thickness and can penetrate the wall fully to cause leaks or decrease the strength of the metal remaining in the wall to produce a rupture. Internal corrosion is more prevalent than erosion in crude oil transmission pipelines. Both sources of internal pipeline damage are reviewed next, and the potential for diluted bitumen to affect their occurrence in crude oil transmission pipelines is assessed.

Internal Corrosion

The electrochemical process that causes iron in steel to corrode involves anodic and cathodic reactions. The main anodic reaction is the oxidative dissolution of iron. The main cathodic reaction is reductive evolution of hydrogen. The main species that contribute to a higher rate of corrosion are dissolved acid gases such as carbon dioxide (CO_2) and hydrogen sulfide (H_2S) as well as organic acids. For the electrochemical reactions to occur, an ionizing solvent must be present, which in the pipeline environment is usually water. Salts, acids, and bases dissolved in the water create the necessary electrolyte.

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To prevent external corrosion, pipes are coated on the outside surface and cathodic protection is applied. In the case of internal corrosion, protecting the steel through the use of a coating or cathodic protection is impractical for various reasons. To prevent internal corrosion, therefore, pipeline operators try to keep water and other contaminants out of the crude oil stream and to design their systems so as to reduce places where any residual quantities can accumulate on the pipe bottom. They also use operational means to limit deposition, including maintenance of turbulent flow; periodic cleaning with pigs; and the injection of chemicals, called corrosion inhibitors, that disperse and suspend water in the crude oil and form a protective barrier on the pipe surface.

When crude oil is pumped from the ground, it is accompanied by some water and varying amounts of CO_2 and H_2S as well as certain organic acids. Crude oil producers try to minimize these impurities in delivering a stabilized product to the transmission pipeline, but eliminating them is prohibitively expensive. Transmission pipelines carrying crude oil therefore typically have some small amount of water and sediment (usually less than 1 percent by volume), and dissolved CO_2 and H_2S will exist in even smaller quantities. Of interest to this study is whether diluted bitumen contains any more of these corrosive contaminants than do other crude oils or whether these contaminants are more likely to settle and accumulate on the bottom surface of pipelines transporting diluted bitumen.

The various means by which water, sediment, dissolved gases, and other materials can cause internal corrosion of crude oil transmission pipelines are reviewed next.

Water Deposition and Wetting

Oil by itself is not corrosive to mild steel pipe in the temperature range in which transmission pipelines operate, which is typically well below 100°C. Water contact with the inside pipe wall is an essential precondition for internal corrosion. Pure water is not a significant source of corrosion when it acts alone. As discussed in more detail below, however, water in the presence of certain dissolved contaminants, such as CO_2, H_2S, and oxygen (O_2), will cause corrosion if the water is allowed to contact and wet the steel surface of the pipe. In theory, a pipeline carrying oil and a small amount of water will not experience internal corrosion if the water is dispersed and suspended in the oil rather than flowing as a separate phase in contact with the bottom of the pipe. The following factors can affect whether water falls out of the oil flow to cause water wetting of the steel surface:

- *Flow rate:* When oil and water move through a horizontal pipeline at low flow rates, gravitational force will dominate turbulent forces and cause the water to flow as a separate layer. As the rate of flow increases, the turbulence energy of the flow will increase, causing the water to become gradually more dispersed and entrained in the oil. The turbulence will cause water to break up into smaller droplets, and it will keep these finer droplets suspended.
- *Water content:* The more water present in the flow, the harder it becomes for the flowing oil to suspend all water droplets. Thus, water settles more readily when there is more of it in the pipeline stream.
- *Pipe diameter and inclination:* Water is more difficult to keep entrained as the diameter of the pipeline increases as long as other parameters remain the same, including the flow rate and physical properties of the crude oil. Pipe inclination has a comparatively small effect on the ability of oil to entrain water if the inclination is less than 45 degrees.

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- *Physical properties of the oil and water:* The density and viscosity of water and oil play an important role in water entrainment and settling. In general, oils that have high density and viscosity are better able to entrain water than are lighter oils, in part because the density of a heavy oil will be close to that of water. Another important physical property is the oil and water interfacial tension, or tendency of the water and oil to mix or separate. Interfacial tension is affected by the presence of surface-active substances naturally found in the crude oil as well as by surfactant chemicals that may be injected into the flow by the pipeline operator.
- *Chemical additives:* Chemicals injected into the flow stream can significantly influence water entrainment, primarily by affecting interfacial tension. As explained in Chapter 2, pipeline operators add corrosion-inhibiting chemicals to the oil stream to adsorb onto the steel surface and provide a protective layer against corrosion and water wetting. Another benefit of these additives is that they usually contain surface-active compounds that decrease oil and water interfacial tension so as to make it more difficult for water to separate from the oil flow. Conversely, chemical demulsifiers that are added to oil to remove water during processing before delivery to the pipeline can have the undesired effect of increasing the interfacial tension and thus causing easier separation of oil and water in the pipeline flow. Finally, the drag-reducing agents that are sometimes added by pipeline operators to enhance throughput can lower the ability of flowing oil to entrain water by dampening turbulence.

Solids Deposition

Solids in the crude oil stream settle to the pipe bottom for the same hydrodynamic reasons described above for water dropout. Typically the settled solids consist of a mix of inorganic and organic components. Sand, clay, detached scale, and corrosion products (such as carbonates and sulfides) are usually the main inorganic components of settled solids. Organic components commonly consist of asphaltenic and paraffinic compounds as well as other organic material formed by the action of microorganisms (Mosher et al. 2012; Friesen et al. 2012). The corrosive effect of microorganisms in pipeline deposits is discussed in more detail later in the section.

When the flow rate and associated turbulence are low, solids can settle and accumulate, particularly at the bottom of horizontal lines. When no water is present, the deposition of solids can impede flow to create a flow assurance problem. When the solids settle with water, the mix is often referred to as sludge. A porous layer of settled solids can retard corrosion by water containing aggressive species, because the solids will cover part of the steel surface and make it harder for those species to reach the surface. However, a porous layer of solids can also impede access to the steel surface by corrosion-inhibiting chemicals. In this case, the internal surface of the pipe that is covered by a layer of solids may corrode faster than the rest of the surface not covered by solids but protected by the chemical inhibitors. This adverse effect can be compounded by an unfavorable galvanic coupling between the unprotected area covered by the solids and the surrounding areas that are chemically inhibited.

The basic sediment and water (BS&W) content of a crude oil shipment, as described in the previous chapters, is a common measure of the amount of solids and water carried and can be used to predict the likelihood of deposit formation. Even when BS&W is very low (less than 0.5 percent by volume) and the fluid velocity is relatively high (>1 meter per second or >2 miles per hour), some accumulated solids and water may be found in low spots in the pipeline and in dead legs, where the flow rate is low or stagnant. Sludge deposits holding water containing the

dissolved gases, acids, and microorganisms discussed next are the source of a common form of localized internal corrosion commonly referred to as underdeposit corrosion.

Corrosive Effect of CO_2

CO_2 dissolved in water can have a particularly corrosive effect in pipelines, as evidenced by the series of reactions that ensue (DeWaard and Milliams 1975). Water containing dissolved CO_2 that forms carbonic acid (H_2CO_3) and wets the pipe surface leads to the dissolution of iron (Fe) from the pipe steel and the evolution of hydrogen (H_2) from the water. This weak acid partially dissociates in water to produce the bicarbonate ion (HCO_3^-) and protons (H); in water the protons are present as hydronium ions (H_3O^+). Bicarbonate ions dissociate further to produce more hydronium ions and carbonate ions (CO_3^{2-}). The hydronium ion is highly reactive as it seeks to obtain a missing electron from nearby species. In giving up electrons to hydronium ions, the iron atoms on the pipe surface are destabilized, and they dissolve in the water to form iron ions (Fe^{2+}). By obtaining the resulting electrons, the hydronium ions are converted to dissolved hydrogen gas (H_2). The corrosion by-product is iron carbonate ($FeCO_3$), which may deposit on the steel surface and be protective in some cases.

Keeping CO_2 out of the crude oil stream is particularly important because the ensuing corrosion process can occur rapidly. The reason is that as the hydronium ions are consumed by the corrosion reaction, the carbonic acid dissociates further to replenish the reactive ions, which allows the corrosion process to continue at a fast rate. As long as there is sufficient CO_2 to produce the carbonic acid, the iron in pipe steel that is water wet will continue to corrode. The full series of chemical reactions involved in CO_2 corrosion is detailed in Box 5-1.

Corrosive Effect of H_2S

H_2S is another gas that may be present in the crude oil stream to create corrosive conditions inside pipelines when it is dissolved in water. Crude oil is often extracted with some amount of H_2S. The concentrations in crude oil can be small [less than 100 parts per million (ppm) in the gas phase] or substantially larger. Other sulfur compounds in crude oil are less common, and they are typically soluble in oil rather than water, requiring high temperatures (>300°C) to become reactive (Nesic et al. 2012). Thus, their concentrations do not present a corrosion problem in transmission pipelines.

The reactions that cause H_2S to corrode pipe steel are generally similar to those described for CO_2. Like CO_2, H_2S gas is soluble in water. As a weak acid, the dissolved H_2S behaves in a manner similar to carbonic acid (H_2CO_3) by providing a reservoir of reactive hydronium ions. An important difference is that the layer of protective iron sulfide (FeS) always forms on the steel surface as a result of the reactions involving H_2S. Experimental evidence indicates that H_2S corrosion initially proceeds by adsorption of the H_2S to the steel surface. This adsorption is followed by a fast surface reaction at the steel and water interface to form a thin (about 1 micron) film of the iron sulfide mackinawite (Wikjord et al. 1980). The formation of mackinawite is an important factor governing the corrosion rate because the surface film can create a barrier that impedes the ability of other species to reach the steel. Accordingly, corrosion due to other contaminants such as CO_2 can be reduced when small amounts of H_2S (in the low ppm range in the gas phase) are present in crude oil.

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Box 5-1

CO_2 Corrosion of Mild Pipe Steel

CO_2 gas dissolved in water forms a weak carbonic acid (H_2CO_3):

$$CO_2 + H_2O \Leftrightarrow H_2CO_3$$

Carbonic acid partially dissociates in water to produce acidity [i.e., hydronium ions (H^+); water is omitted for simplicity]:

$$H_2CO_3 \Leftrightarrow H^+ + HCO_3^-$$

Further dissociation occurs in the bicarbonate ion (HCO_3^-) to produce more H^+ and form carbonate ions (CO_3^{2-}):

$$HCO_3^- \Leftrightarrow H^+ + CO_3^{2-}$$

The surface atoms of iron (Fe) in the steel will readily give up electrons to hydronium ions and dissolve into the water in the form of iron ions (Fe^{2+}):

$$Fe \rightarrow Fe^{2+} + 2e^-$$

In obtaining the additional electron, the hydronium ion will form hydrogen gas (H_2), and the reaction is complete.

$$2H^+ + 2e^- \rightarrow H_2$$

When the concentrations of the corrosion products in water (Fe^{2+} and CO_3^{2-} ions) exceed the solubility limit (typically at neutral and alkaline pH), they form solid iron carbonate on the surface of the steel:

$$Fe^{2+} + CO_3^{2-} \Leftrightarrow FeCO_3(s)$$

The layer of iron carbonate can become fairly protective and reduce the rate of underlying steel corrosion by blocking the surface and preventing the corrosive species from reaching it.

The rapid kinetics of mackinawite formation favor it as the initial product of H_2S reactions. However, with time, and as H_2S concentrations increase, mackinawite is less prevalent, and other forms of iron sulfide are seen, such as pyrrhotite. At high H_2S concentrations, pyrite and elemental sulfur are formed. While layers of any iron sulfide will offer some corrosion protection, there is no well-defined relationship between the type of iron sulfide layer and the ensuing rate of corrosion. It is well understood that high H_2S levels accompanied by elemental sulfur can lead to high rates of localized corrosion. However, elemental sulfur is usually associated with the production of natural gas with a high H_2S content. For a crude oil to have similarly high H_2S and elemental sulfur content would be unusual.

Corrosive Effect of Oxygen

Oxygen dissolved in water is undesirable in pipelines because it is highly reactive with iron. Corrosion generally becomes a problem when levels of dissolved oxygen reach those found in aerated surface water (typically about 8 ppm). Smaller amounts of oxygen (below 1 ppm) can become a problem when the oxygen reacts and impairs protective iron carbonate and iron sulfide

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layers. In general, the water associated with oil production does not contain oxygen, and therefore such high concentrations are seldom observed in shipments of stabilized crude oil transported in pressurized pipelines with controlled air entry points. Oxygen may become elevated when air is introduced into the pipeline inadvertently. Air may be introduced during shutdowns for inspections and repairs. Chronic sources of air ingress, such as during injection of chemicals and in storage tanks holding liquids at atmospheric pressure, are potentially more problematic. Nevertheless, how and why these air entry points would differ from one crude oil shipment to the next in the same pipeline facility are not evident.

Corrosive Effect of Organic Acids

Organic acids with low molecular weights are water soluble and thus present a significant corrosion threat when they are found in settled water that wets the steel surface of crude oil pipelines. A common representative of the family of water-soluble organic acids is acetic acid (CH_3COOH).[1] Other low-molecular-weight organic acids that can lead to corrosion of mild steel include propionic and formic acids. These weak acids create a corrosion scenario similar to the one described for CO_2 attack, with the organic acid taking the place of carbonic acid. Much like carbonic acid, organic acids provide a reservoir of hydronium ions. Their corrosive effect is particularly pronounced at low pH and higher temperatures, when their abundance can increase corrosion rates dramatically. At a higher pH (>6), the corrosive effect of organic acids on mild steel is negligible, regardless of concentrations.

Other organic acids found in crude oil—and notably in bitumen—are compounds with high molecular weight, which are often referred to as naphthenic acids. While these organic acids can be a significant corrosion threat at the high temperatures (>300°C) reached in refineries, they are not a threat to pipe steel because they are not soluble in water but are rather dissolved in the oil phase (Nesic et al. 2012). Accordingly, high-molecular-weight organic acids do not pose a corrosion threat to steel at pipeline temperatures. In some crude oils these acids may even have moderately inhibitive properties (Nesic et al. 2012).

Effect of Microbiologically Influenced Corrosion

The term microbiologically influenced corrosion (MIC) is used to designate the localized corrosion affected by the presence and actions of microorganisms (Little and Lee 2007). The types of damage that can be caused by these microorganisms are not unique, which means that MIC cannot be identified by visual inspection of the damage. Although MIC is discussed here with respect to internal corrosion, it can also contribute to corrosion on the outside of the pipe, as noted later.

Microorganisms that cause MIC are bacteria, archaea, and fungi. Some occur naturally in crude oils, while others may be introduced as contaminants from air, sediment, and water. The temperature range in which these organisms can grow is that in which liquid water can exist, approximately 0°C to 100°C (32°F to 212°F) (Little and Lee 2007). However, individual groups of microorganisms have temperature optima, including sometimes narrow ranges, for growth. The temperature range over which transmission pipelines operate will therefore select for specific microorganisms, but it will not prevent microbial growth.

[1] A household name for acetic acid is vinegar, which consists of 2 to 3 percent acetic acid dissolved in water.

For microorganisms to grow and proliferate, they require not only liquid water but also nutrients and electron acceptors for respiration. Accordingly, how microorganisms use water, nutrients, and electron acceptors to grow and how they influence corrosion is explained, and consideration is then given to whether levels of any of these essentials are likely to be affected by diluted bitumen.

Water Availability Microbial growth is limited by the availability of liquid water. Growth is therefore concentrated at oil–water interfaces and in the aqueous phase, including the water in deposits of sludge in pipelines. The volume of water required for microbial growth in hydrocarbon liquids is extremely small (Little and Lee 2007). Because water is a product of the microbial mineralization of organic substrates, microbial mineralization of hydrocarbon can generate the additional water needed for proliferation.

Nutrient Availability Microorganisms need suitable forms of carbon, nitrogen, phosphorus, and sulfur as nutrients (Little and Lee 2007).[2] In oil pipelines, hydrocarbons can be degraded by aerobic or anaerobic processes to yield assimilable carbon. Aerobic degradation of hydrocarbons is faster than anaerobic degradation, with the rate depending on the specific electron acceptors used in the process. In general, the susceptibility of hydrocarbon compounds to degradation can be ranked as follows: linear alkanes, branched alkanes, small aromatics, and cyclic alkanes (Atlas 1981; Das and Chandran 2011; Perry 1984). As the chain length of alkanes increases, bacteria show decreasing ability to degrade these compounds (Walker and Colwell 1975). Some high-molecular-weight polycyclic aromatics may not be degraded at all (Atlas 1981). As a practical matter, however, carbon availability is often not the main constraint for crude oil biodegradation. Both nitrogen and phosphorus are required for microbial growth. Low concentrations of assimilable forms of these elements can limit biodegradation.[3]

Electron Acceptors Microorganisms can use a variety of electron acceptors for respiration. In aerobic respiration, energy is derived when electrons are transferred to oxygen, which is the terminal electron acceptor. In anaerobic respiration, a variety of organic and inorganic compounds may be used as the terminal electron acceptor, including sulfate, nitrate, nitrite, iron (III), manganese (IV), and chromium (VI) (Little and Lee 2007). Anaerobic bacteria can therefore be grouped on the basis of the terminal electron acceptor, such as sulfate-, nitrate-, and metal-reducing bacteria.[4] In petroleum environments, the bacteria most often associated with MIC are sulfate reducers. In anaerobic environments, sulfate reducers produce H_2S when they use the sulfate as an electron acceptor.[5] In addition, many archaea can produce sulfides, and therefore the inclusive term for this group of anaerobes is sulfide-producing prokaryotes (SPP).

SPP-related corrosion of metals used in oil exploration and production has been reported around the world (Mora-Mendoza et al. 2001; Ciaraldi et al. 1999; El-Raghy et al. 1998; Jenneman et al. 1998). A main concern is that these microorganisms produce H_2S. As discussed

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[2] A representation of the major elements required for a typical microorganism composition is $C_{169}(H_{280}O_{80})N_{30}P_2S$.

[3] Atlas (1981) reported that when a major oil spill occurred in marine and freshwater environments, the supply of carbon was significantly increased and the availability of nitrogen and phosphorus generally became the limiting factor for oil degradation.

[4] There is specificity among anaerobes for particular electron acceptors. Facultative anaerobic bacteria can use oxygen or other electron acceptors. Obligate anaerobic microorganisms cannot tolerate oxygen for growth and survival. Obligate anaerobic bacteria are, however, routinely isolated from oxygenated environments associated with particles and crevices and, most important, are in association with other bacteria that effectively remove oxygen from the immediate vicinity of the anaerobe.

[5] Some anaerobes can also reduce nitrate, sulfite, thiosulfate, or fumarate (Little and Lee 2007).

earlier, H_2S reacts with the iron ions to form a thin layer of the iron sulfide mackinawite that adheres to the steel surface. In the absence of oxygen, and if the concentration of iron ions in the solution is low, this mineral layer will protect the iron in the steel pipe surface from dissolution (Wikjord et al. 1980). However, if oxygen is introduced, the iron sulfide can be converted to an iron oxide and elemental sulfur, which will cause the rate of corrosion to increase substantially for reasons already given.[6] Pipelines operators, therefore, seek to prevent the formation of colonies of SPP and other microorganisms in pipelines through design, operations, maintenance, and chemical means.

Internal Erosion

Solid particles flowing in the crude oil stream can cause erosion of pipe wall, particularly at flow disturbances such as pipe bends. The propensity for erosion is affected by the pipe material; angles of flow impact; flow velocity; and the amount, shape, mass, and hardness of solid particles in the stream. While pipeline erosion is common in the oil production industry, it occurs to a greater extent in production (field) pipelines that contain fluids with high levels of sand and minerals. For example, slurry flow in the pipelines used to move oil sands ore before bitumen extraction can be highly abrasive (Zhang et al. 2012). Because processed crude oils do not contain similarly high concentrations of solids, erosion is not observed to a significant degree in transmission pipelines. Of interest to this study is whether the diluted bitumen delivered to transmission pipelines contains significantly higher concentrations of abrasive solids than do other crude oils and whether it is transported at higher flow rates conducive to erosion.

Assessment of Effects of Diluted Bitumen on Sources of Internal Degradation

The properties of diluted bitumen as they pertain to the identified factors affecting susceptibility to internal degradation from corrosion and erosion are examined next.

Internal Corrosion

Water Wetting and Solids Deposition An important factor in water dropout and wetting is the total water content of the crude oil stream, which is measured by pipeline operators as part of shipment BS&W sampling. As reported earlier, Canadian transmission pipelines require that crude oil shipments not have a BS&W exceeding 0.5 percent. These levels are comparable with, and more often lower than, the levels commonly required by U.S. transmission pipelines. Accordingly, the level of water contained in shipments of diluted bitumen and other crude oils imported by pipeline from Canada will not be higher than that contained in shipments of other crude oils piped in the United States.

Even relatively small amounts of water in crude oil can settle to the pipe bottom. In considering the propensity of water to drop out of the oil stream, important factors include the viscosity, density, and surface tension of the oil and whether it is transported in a flow that is sufficiently turbulent to disperse and suspend water droplets. Shipments of diluted bitumen are

[6] The impact of oxygen on corrosion from anaerobic SPP was examined by Hardy and Bown (1984) by using mild steel and weight loss measurements. Successive aeration–deaeration shifts caused variations in the corrosion rate. The highest corrosion rates were observed during periods of aeration. Hamilton (2003) concluded that oxygen was the terminal electron acceptor in all MIC reactions. In laboratory seawater and fuel incubations, Aktas et al. (2013) demonstrated that there was no biodegradation of hydrocarbon fuels, little sulfate reduction, and no corrosion of carbon steel in the absence of oxygen.

transported at the same pressures and under the same turbulent flow regimes as shipments of other heavy crude oils. The report has demonstrated that diluted bitumen is more viscous than light and medium-density crude oils and is comparable in viscosity with heavy crude oils. A stream of diluted bitumen in turbulent flow should therefore confer the beneficial effect, relative to lighter crude oils, of dispersing and suspending any free water that may exist in the pipeline stream.

A low likelihood that a shipment of diluted bitumen contains water that will settle and wet the bottom of the pipeline will lead to a low likelihood of internal corrosion regardless of the corrosion mechanism or the presence of other contaminants that can contribute to corrosion. All crude oil shipments can carry particles consisting of sand, clay, organic materials, and hydrocarbons that have the potential to drop out of the stream at vulnerable locations in the pipelines. Given its high viscosity, diluted bitumen will suspend the very fine particles that may be contained in its sediment. The solids contained in diluted bitumen are not unusual in quantity or particle size but are within the range of other heavy crude oils, as established in the earlier comparisons. Whether any of the sediments that settle to the pipe bottom threaten underdeposit corrosion will depend critically on associated water, as well as the presence of corrosive gases, acids, and microorganisms.

Corrosive Gases (CO_2, H_2S, and Oxygen) If water does settle and wet the bottom of a pipeline carrying diluted bitumen, such as at low spots and dead legs, consideration of whether shipments of this type of crude oil contain comparatively high levels of dissolved gases that will increase the potential for corrosion is warranted. Data on the CO_2 contained in crude oil lines, including those carrying diluted bitumen, are not readily available. Nevertheless, concentrations can be inferred from the CO_2 levels present at the last point of gas–liquid separation upstream of delivery to the transmission pipeline. As is the case for shipments of other crude oils, various tanks will hold shipments of diluted bitumen before they are delivered to the transmission pipeline facility. This upstream storage, which occurs at atmospheric pressure, will provide the same opportunity for shipments of diluted bitumen as it does for shipments of other crude oils to degas CO_2 before entry to transmission pipelines. Such a comparable upstream environment will produce similarly low CO_2 concentrations and corrosion rates.

Likewise, the quantities of H_2S reported for diluted bitumen (>25 parts per million by weight in liquid phase), as reported in Chapter 3, are lower than in many other crude oils and do not pose a corrosion threat. Even if other corrosive agents are present, the small concentrations of H_2S would contribute little to the corrosive effect, except perhaps to provide a mildly mitigative impact because of the formation of protective iron sulfide layers. The conclusion is that concentrations of dissolved CO_2 and H_2S in diluted bitumen shipments are likely to be low and not greater than those found in other crude oil shipments that are stored and transported similarly.

Transmission pipeline operators restrict air entry points to prevent ingress of oxygen. There are no data on the oxygen content in crude oil pipelines to assess the effectiveness of these restrictions. However, diluted bitumen is transported in the same pipelines as other crude oils, and the number of air entry points can be assumed the same and purposefully restricted. Because crude oils are stored by pipeline operators in large atmospheric pressure tanks, the possibility of air ingress cannot be eliminated, but the ingress will be as low for shipments of diluted bitumen as it is for shipments of other crude oils stored similarly. Even if some free water is assumed to settle to the bottom of a pipeline carrying shipments of diluted bitumen, low levels of oxygen

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(e.g., below 1 ppm) will not constitute a serious corrosion threat or one that differs from that of a pipeline carrying shipments of other crude oils.

Acids In reviewing the chemistry of diluted bitumen in Chapter 3, no evidence emerged that it contains relatively high levels of low-molecular-weight organic acids such as acetic acid. The high total acid number of diluted bitumen derives from the presence of high-molecular-weight organic acids. These oil-soluble naphthenic acids do not pose an internal corrosion threat under pipeline conditions and may have mitigative effects on corrosion. The acid contained in diluted bitumen is therefore not a threat to internal corrosion of transmission pipelines.

Microbiologically Influenced Corrosion To understand whether diluted bitumen is more likely than other crude oils to cause MIC, it is helpful to examine whether this crude oil is more prone to providing the essential resources required for microbial growth. The water content of diluted bitumen shipments is comparable with that of other crude oil shipments, and diluted bitumen does not have constituents or operating requirements that make pipelines more prone to forming sludge that can harbor microorganisms. The other essential resources that deserve consideration are the availability of critical nutrients (especially carbon and nitrogen) and electron acceptors (especially oxidized sulfur compounds).

While microbial growth requires carbon, it may be limited more by the scarcity of nitrogen in petroleum. As reported earlier, most of the nitrogen in bitumen is bound in carbon structures and unavailable.[7] Lighter oils provide a more readily available source of degradable carbon than do heavy oils, including bitumen. The percentage of low-molecular-weight hydrocarbons is similar in diluted bitumen and other heavy crude oils and lower than the percentages in lighter crude oils. More of the carbon in diluted bitumen is contained in relatively high concentrations of asphaltenes. The molecular weight and structure of asphaltenes vary, but biodegradation of these compounds is an extremely slow process that does not provide a readily available source of carbon for microorganisms (Pineda-Flores and Mesta-Howard 2001).

With regard to the availability of electron acceptors, it was reported earlier that sulfur content is higher in diluted bitumen than in many other crude oils, but the sulfur is not in oxidized forms available for sustained sulfate reduction by SPP. Furthermore, the high sulfur content of bitumen is not correlated with high H_2S content. Most of the sulfur in bitumen is organic sulfur bonded to carbon in heterocyclic rings, which are not easily degraded by microorganisms and thus largely unavailable for metabolism.

In sum, the chemistry of diluted bitumen is not more favorable for microbial growth and activity than is that of other crude oils.

Erosion

The propensity for erosion is affected by the presence and physical properties of the solid particles in the stream, pipe material, angles of particle impact, and impact velocity. Pipe materials and impact angles are the same for diluted bitumen as for other crude oils transported through the same pipelines. Chapter 3 indicated that the velocity of diluted bitumen flowing through pipelines is not higher than the velocity of other crude oil flows. Furthermore, the diluted bitumen imported by pipeline into the United States is produced by using in situ methods that limit the amount of sand, minerals, and other solid particles recovered with the bitumen. The

[7] See Chapter 3.

extracted bitumen is processed to remove water and solids to achieve the requisite BS&W for pipeline transportation to yield solids levels that are similar to those of other crude oil shipments. While limited data are available on the specific physical properties of the solid particles in diluted bitumen, the generally low levels of solids (less than 0.05 percent) do not suggest that shipments of diluted bitumen increase the already low potential for erosion in crude oil transmission pipelines.

Summary of Effects on Sources of Internal Degradation

A review of product properties relevant to internal pipeline corrosion and erosion does not indicate that diluted bitumen is more likely than other crude oils to lead to these failure mechanisms. Shipments of diluted bitumen do not contain unusually high levels of water, sediment, dissolved gases, or other agents that can cause internal corrosion. The organic acids contained in diluted bitumen are not corrosive to steel at pipeline temperatures. Diluted bitumen has density and viscosity levels comparable with those of other crude oils, and it flows through pipelines with velocity and turbulence comparable with other crude oils so as to limit the accumulation of corrosive deposits. On the basis of an examination of the factors influencing microbial growth and activity, shipments of this crude oil do not have a higher likelihood than other crude oil shipments of causing MIC in pipelines. Because it has solids content and flow regimes comparable with those of other crude oils, diluted bitumen does not have a higher to propensity to cause erosion of transmission pipelines.

SOURCES OF EXTERNAL DEGRADATION

External Corrosion

External corrosion of pipelines is usually characterized by uneven metal loss over localized areas covering a few to several hundred square centimeters of the outside steel surface of the pipe (Beavers and Thompson 2006). The electrochemical reactions that are involved usually occur at physically separate locations on the surface. While the anodic reaction is primarily oxidation of iron, the cathodic reaction can be either the hydrogen evolution that occurs in the anaerobic electrolyte trapped under an impermeable pipe coating or the reduction of oxygen under a permeable coating. The water and soluble compounds needed to create the electrolyte can be present in the soil surrounding the buried pipe or in the atmosphere when a pipe is above grade. In addition, a portion of external corrosion incidents involve MIC (Koch et al. 2002; Beavers and Thompson 2006). As discussed later in the section, external corrosion pits can also be sites for the formation and growth of stress corrosion cracks.

External corrosion is thus affected by the pipe material, the corrosivity of the environment, and the performance of coatings and cathodic protection systems. For mild grades of carbon steel commonly used in transmission pipelines, the main concern is the corrosivity of the surrounding environment and the performance of coatings and cathodic protection systems. Although the transported product does not come in contact with either the coating or the environment surrounding the pipeline, it can influence both factors by affecting the operating pressure and temperature of the pipeline.

Because pipeline segments are located below and above ground, they can be exposed to corrosive conditions in the soil and atmosphere. Many factors affect soil corrosivity, including moisture and oxygen content, electrical resistivity, pH, temperature, porosity, microbial activity, and the presence of dissolved salts (Uhlig and Revie 1985; Escalante 1989; Beavers and Thompson 2006). For pipeline segments exposed to the atmosphere, the primary environmental factors influencing corrosion are relative humidity, salt deposition, pollution, and temperature. Operating pressure does not affect these corrosive conditions, but elevated pipeline temperatures and resulting heat flux to the air or soil medium can increase corrosion rates.

Pipeline temperature and pressure can both affect the condition and performance of coatings and cathodic protection systems. As discussed in Chapter 2, coatings provide a barrier between the pipe and the corrosive environment. Coatings can fail in a variety of ways including disbonding from the steel surface. In pipelines using some older coating technologies, such as asphalt mastic systems, elevated temperatures can cause the coating material to deform and potentially reduce surface coverage. Elevated pipeline temperatures can also result in degradation of adhesive properties and increase the diffusion of moisture through the coating in the direction of the steel surface. Moisture diffusion can cause swelling of the coating relative to the steel and bring about increased surface stresses that lead to disbondment. Fluctuating line pressures can cause interfacial strain between the coating and the pipe surface to produce mechanical disbondment of the coating.

An intact coating that prevents contact between the corrosive environment and the steel surface will generally prevent external corrosion. However, all coatings contain some defects that expose the steel. Accordingly, a critical defense against external corrosion is the application of cathodic protection. As discussed in Chapter 2, many cathodic protection systems use an electric current to prevent corrosion where coating coverage is imperfect. Temperature and pressure conditions that cause coating disbondment, therefore, can be more problematic if they impede, or shield, the distribution of cathodic current to sites where steel is exposed. An advantage of modern coating systems, such as fusion bonded epoxy, is that they are compatible with cathodic protection. Shielding is nevertheless a problem observed in some older pipelines wrapped with impermeable tapes and at girth welds treated with field applied shrink sleeves.

Cracking

The potential for transported products to affect the two main forms of cracking in pipelines is reviewed. Consideration is given to the mechanical process of fatigue cracking and forms of environmentally assisted cracking (EAC) that involve interactions of mechanical and corrosion processes.

Fatigue Cracking

Fatigue is characterized by the formation and growth of microscopic cracks on one or both sides of the pipe wall.[8] The first stage in the fatigue process is crack initiation, or nucleation. Nucleated cracks do not cause a fracture, but some may coalesce into a dominant crack as the variable amplitude loading continues. In the second stage, the dominant crack grows in a more stable manner and may eventually reach the thickness of the wall to produce a leak. Alternatively, the dominant crack may grow to a critical length and depth that the pipe steel can

[8] See Beavers and Thompson (2006) for additional description of stress cracking processes.

no longer endure, leading to a rupture. Pipeline internal and external surface conditions caused by factors other than fatigue can lead to initial cracks or enhance crack fatigue crack growth from stress concentration. These factors can include preexisting dents, weld defects, corrosion pits, manufacturing flaws, and damage incurred during pipe transportation to the installation site.

Fatigue cracking can ensue as a result of repetitive, or cyclic, stress loadings on a pipe. Cyclic stresses can be axial (parallel to the axis of pipeline), circumferential (stress in the tangential direction), or radial (perpendicular to the axis). Circumferential, or hoop, stress is usually the most important source of cyclic loadings because the stress created by internal pressure is normally the largest stress on the pipeline.

Because viscous crude oils create more friction, they will require a higher operating pressure than do less viscous crude oils to achieve the same flow rate. In practice, pipeline operators reduce the flow rate when they transport viscous crude oils rather than increase operating pressure. Operating pressure cannot be increased if the pipeline is at the stress limit prescribed in regulations. Thus, only when a pipeline is operating below its stress limit can operating pressure be raised to increase the flow rate of a viscous crude oil.

The pipe segments vulnerable to cracking are those with preexisting flaws or dents and other surface deformities caused by mechanical forces during installation or while in service. Stresses can concentrate at these damage sites, enabling cracks to form and grow after a relatively small number of load cycles, a phenomenon known as low-cycle fatigue.[9] Other locations on the pipe susceptible to stress concentrations include discontinuities at longitudinal and girth welds and at voids formed during pipe manufacturing (Zhang and Cheng 2009).

Pressure cycling is reported to have contributed to fatigue failures in crude oil transmission pipelines. An example is the July 2002 rupture of a 34-inch crude oil pipeline near Cohasset, Minnesota (NTSB 2004). In that incident, the originating crack formed at the seam of the longitudinal weld as a result of vibrations experienced during railroad transportation of the pipe to the installation site. According to the National Transportation Safety Board report, the preexisting crack grew to reach a critical size in response to pressure cycling stresses associated with normal in-service operations.

Environmentally Assisted Cracking

EAC results from the combined action of a corrosive environment and a cyclic or sustained stress loading. In general, EAC emerges in three basic forms: corrosion fatigue, stress corrosion cracking (SCC), and hydrogen-assisted cracking. EAC requires both a sufficient stress and a corrosive environment specific to the metal and thus is rare in crude oil transmission pipelines. However, when EAC failures do occur, they can be destructive; for example, the 2010 failure of a pipeline near Marshall, Michigan, was caused by EAC (NTSB 2012).

Corrosion fatigue cracking arises from a combination of corrosion and the same pressure-related cyclic stresses that produce fatigue cracking. In corrosion fatigue, the stresses sufficient to cause failure can be less severe because of the corrosion reaction and resulting damage. For example, corrosion pits can become stress concentrators that allow normal in-service pressure cycling to cause the formation and growth of cracks in the pit. In the case of pipeline SCC, the same corrosive factors may exist, but the main acting stress is the sustained hoop forces generated by the operating pressure as well as its cycling. The acting stress may also be residual

[9] Conversely, high-cycle fatigue occurs under a low-amplitude loading in which a large number of load cycles is required to produce failure.

in nature, introduced during bending and welding in manufacturing, or it may arise from external soil pressure or differential settlement. The same locations on the pipe that concentrate cyclic stresses, such as dents, scrapes, and other surface discontinuities, can concentrate static stresses. Furthermore, breaks in the surface film may occur at these discontinuities to make the area more prone to electrochemical corrosion.[10]

The factors that create corrosive environments enabling EAC, such as soil properties and the performance of coatings and cathodic protection, have already been discussed with respect to external corrosion. As with external corrosion, the maintenance of coating performance and cathodic protection is critical in controlling EAC (CEPA 2007). In the case of SCC, limiting the introduction of residual stresses during pipe manufacturing, transportation, and installation is also important in reducing susceptibility. Operating pressure is the major in-service source of static hoop stress. Lowering the operating pressure of a pipeline would be expected to reduce the potential for SCC. However, the specific relationship between SCC and hoop stress is not well established. For example, SCC failures have occurred in pipelines experiencing hoop stresses that have varied from 46 to 77 percent of the specified minimum yield strength of the pipeline.[11] Accordingly, adjusting operating pressures as a way to prevent SCC can be difficult.

EAC can be caused or exacerbated by hydrogen-assisted cracking. For example, when sources of hydrogen are present—such as from agents in the crude oil stream (e.g., H_2S) or from external sources (e.g., excessive cathodic protection voltage)—cracking potential may increase. Although hydrogen-assisted cracking is rare in crude oil transmission pipelines, it can occur as a result of the diffusion and concentration of atomic hydrogen at the crack tip or other microstructural trap site in a metal. The ingress of hydrogen into a metal is enhanced in the presence of sulfur species. The trapped hydrogen can cause internal stresses within the metallurgical structure favorable to enhanced cracking or act to reduce local roughness in the region of the crack tip. Hydrogen can also adsorb to the metal surface to reduce surface energy and migrate into the microstructure, thereby reducing interatomic bond strength and providing nucleation sites for cracks. Hydrogen-assisted cracking can occur on the inside or outside of the pipe, depending on the source of the hydrogen and its ability to reach the pipe surface.

Assessment of Effects of Diluted Bitumen on Sources of External Degradation

Because diluted bitumen only contacts the inside of a pipeline, it can contribute to external degradation only indirectly. In the case of external corrosion and EAC, one concern is that elevated operating temperatures can adversely affect the performance of the coating as a barrier to corrosion. The relevant question with respect to both external corrosion and EAC is whether diluted bitumen creates operating temperatures and pressures that are sufficiently different from those of other crude oils to increase coating disbondment. As has been reported, diluted bitumen and other heavy crude oils have similar densities and viscosities and flow through pipelines at the same rate and within comparable pressure and temperature ranges (see Chapter 3, Tables 3-4 and 3-7). For this reason, the likelihood of coating degradation and any associated external damage resulting from the operating parameters of diluted bitumen should be equivalent to that of other crude oils with comparable density and viscosity.

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[10] At sites of surface damage, such as dents and corrosion pits, stress levels in the circumferential and axial directions are higher than on undamaged portions of the pipe surface.

[11] National Energy Board, notes from January 12, 1996, meeting between National Energy Board SCC Inquiry Panel and Camrose Pipe Company Ltd., Exhibit No. A-58.

Pipelines transporting diluted bitumen and other heavy crude oils should not differ in the stress loadings generated by their transportation because operating pressures are comparable. Other sources of static stress, such as residual stresses from pipe fabrication and installation, would not be affected by the product in the pipeline. Transmission pipelines, therefore, should not experience more stress cracking from transporting diluted bitumen than from transporting other crude oils of similar density and viscosity.

Finally, if the exterior coating of the pipe disbonds, hydrogen may diffuse into the surface metal with a rate of uptake and subsequent potential for embrittlement that will depend on a number of factors, including pH and temperature. However, the operating parameters of diluted bitumen should not increase the potential for coating disbondment. With respect to the interior of the pipeline, the availability of H_2S and free sulfur to form hydrogen in diluted bitumen is relatively low. Thus, transporting diluted bitumen is not likely to increase the potential for hydrogen-assisted cracking.

SOURCES OF MECHANICAL DAMAGE

Mechanical damage to the pipeline and its components can occur as a result of overpressurization or outside forces. Mechanical forces can cause an immediate, and sometimes catastrophic, breach and release or make the pipeline more susceptible to releases by destabilizing support structures and damaging other components such as valves, joints, and other fittings. Damage from mechanical forces can also weaken the resistance of the pipeline to other failure mechanisms. Sites on the pipeline that sustain even light damage, such as scrapes, are vulnerable to corrosion attacks and stress-related cracking. Accordingly, consideration of whether the transportation of diluted bitumen creates an elevated potential for phenomena that can lead to mechanical damage is warranted.

Overpressurization

Various events can generate excessive pressure in a pipeline, including surges, thermal overpressure, column collapse, and human error. If the pipe is already weakened by corrosion, cracking, or deformities from earlier mechanical damage, overpressure events can increase the potential for damage and failure.

Pipeline operators prevent overpressure events through personnel training; standardized procedures; system design; and safety systems such as pressure relief valves, pressure switches, surge tanks, and bypass systems. Nevertheless, excessive pressure in a pipeline can occur as a result of operator error, thermal overpressure, and column separation. A transported fluid that increases the likelihood of any of these outcomes could increase the potential for mechanical damage.

Surge

Any action in a pipeline system that causes a rapid reduction in the velocity of the transported fluid could cause a pressure surge. Transient, high-amplitude pressure waves, or surges, are not normal and can cause mechanical damage to pipes, components (e.g., valves, seals, joints), instrumentation (e.g., meters and gauges), and support structures. Because all crude oils have

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relatively high bulk modulus (incompressibility), they have a comparable propensity for energy to be transferred in high-pressure waves when events trigger abrupt reductions in flow velocity.

Operator Error

Overpressurization can be caused by direct human error. Unintentional pumping of fluids against a closed valve with coincidental failure of pressure switches, pressure relief valves, and other protective devices is an example of a rare-event overpressurization scenario. Most pipelines are equipped with safeguards such as pressure switches and relief devices to avoid damage from these scenarios. If a transported liquid adds complexity to operational requirements, operator errors could increase.

Column Collapse

Pressure surges can arise from pressure differentials, or slack conditions, in the pipeline. A slack line can occur when the liquid being transported develops a vapor void at a point in the pipeline where line pressure drops below the vapor pressure of the liquid. The void will temporarily restrict the flow of liquid. When the void collapses, a pressure wave comparable with that of a rapid valve closure can be produced. The transformation of the liquid into a vapor phase is known as column separation. To prevent the occurrence of column separation, pipeline operators strive to maintain line pressure above the vapor pressure of the liquid. Locations vulnerable to pressure differentials are elevation peaks and the downstream side of slopes. A liquid that has certain properties, such as a relatively high fraction of hydrocarbons with high vapor pressure, can theoretically increase the potential for column separation.

Thermal Overpressure

A pipe segment that is full of liquid will experience a rapid pressure increase when it is exposed to a heat source and when volume expansion is restricted. Special procedures and thermal relief valves are used to prevent this occurrence in aboveground pipe segments where the flow may be impeded or blocked and the segment may be subsequently exposed to a heat source such as sunlight or fire. Because the chemistry of the trapped fluid determines the amount of pressure increase corresponding to an incremental increase in temperature, some transported liquids could have greater potential for thermal overpressure.

Outside Force Damage

Pipelines can sustain external mechanical damage from both natural forces and human activity. Natural forces include seismic movements and other ground shifts, such as those from landslides and subsidence. Examples of damage from human activity include accidental strikes from vehicles, earth moving activity, and surface loading by farm equipment. Intentional damage to a pipeline, or sabotage, is a potential source of mechanical damage, although it is rare.

There are ways in which the contents of a pipeline can affect or interact with an outside force failure mechanism. One possibility is that a denser, heavier fluid adds weight to a pipe that is free-spanning (i.e., unsupported) or traverses a terrain susceptible to inadequate support. Another possibility is that the heat flux from a fluid transported at an elevated operating

temperature reduces the stability of a pipeline in a frost zone. Similar interactions with the outside environment related to pipe vibrations, expansion, and contraction may be postulated as potential sources of mechanical damage.

Assessment of Effects of Diluted Bitumen on Sources of Mechanical Damage

Mechanical damage to the pipeline and its components can occur as a result of outside forces and overpressurization events. Several causes of outside force damage that could be affected to some degree by the properties of the transported liquid have been postulated. The most relevant properties of the transported liquid are density, viscosity, and operating temperatures. However, because these properties are the same for diluted bitumen as many other crude oils, there is no reason to believe their interactions with outside forces will differ. The same conclusion can be reached concerning the potential for mechanical damage due to chemical or physical properties that can affect the propensity for surge, column separation, or thermal expansion. The potential for these sources of mechanical damage should be indistinguishable from that of other crude oils. Diluted bitumen is blended like many other crude oils to remain fully mixed in the pipeline environment and it does not contain a high percentage of light (high vapor pressure) hydrocarbons.

EFFECTS ON OPERATIONS AND MAINTENANCE PROCEDURES

The preceding analysis has consistently found that the properties of diluted bitumen are within the range of other crude oils. These findings do not indicate a need for operations and maintenance (O&M) procedures that are customized to diluted bitumen, nor do they suggest that pipeline operators apply O&M procedures in transporting diluted bitumen that are different from those applied in transporting other crude oils with similar properties. Of course, if operators who traditionally carry only light crude oils do not make appropriate adjustments to line pressure and flow rates when they transport diluted bitumen or any other similarly dense and viscous crude oil, a greater potential for some of the failure mechanisms examined above could result.

Because most pipeline operators transport many varieties of crude oil, they routinely make adjustments to operational parameters to accommodate different crude oil grades. There is no reason to believe that operators fail to make these adjustments when they transport heavy crude oils generally or, more specifically, when they transport diluted bitumen. Nevertheless, to be comprehensive, a search was undertaken for evidence of O&M practices being altered in inadvertent ways that could be detrimental to pipeline integrity.

Operational Procedures

As discussed in Chapter 2, the operation of most pipelines is monitored and controlled by a combination of local and remote systems by using a centralized supervisory control and data acquisition system. Instrumentation at pump stations, tank farms, and other facilities includes sensors, programmable logic controllers, switches, and alarms. Remote systems allow for monitoring and coordination at centralized locations distant from the pipeline facilities. Together, these local and remote capabilities provide protection against abnormal operations—for example, by allowing for the orderly shutdown of pumps and cessation of flow if an alarm

condition occurs or if certain operating parameters are violated. Maintaining the integrity of control systems is essential in ensuring safe pipeline operations.

Therefore, whether there are any characteristics of diluted bitumen that could introduce more complexity into or otherwise compromise the satisfactory functioning of pipeline control systems and their components is worth investigating. As previously noted, none of the chemical and physical properties of diluted bitumen suggests that such an effect could be expected, because the properties fall within the range of other crude oils commonly transported by pipeline. Nevertheless, the committee undertook a search of any instances in which operators modified or were advised to modify their standard control and monitoring activities in transporting diluted bitumen. A search of published documents did not reveal any noteworthy reports, special standards, or guidance documentation. In consulting Canadian pipeline operators (see Appendix A), the committee asked whether the transportation of diluted bitumen required changes to set points for safety and control instrumentation. The response was as follows: "There are no differences. Standards and procedures are in place for control that are generic for all crude oil commodities shipped. The standards and procedures are structured to ensure safe operation regardless of the commodity." Likewise, all pipeline operators interviewed in public meetings convened by the committee stated that transporting diluted bitumen did not require different control or monitoring procedures.[12]

In its investigation of the July 25, 2010, EAC-related rupture near Marshall, Michigan, the National Transportation Safety Board found that the control center made repeated errors by increasing the delivery rate of the pipeline under the impression that low-pressure readings caused by the undetected rupture were indicative of slack line conditions caused by column separation (NTSB 2012). The product released in the incident, discussed in Chapter 4, was diluted bitumen. The phenomenon of column separation has already been reviewed, and no evidence that diluted bitumen has properties associated with it was found. Furthermore, the National Transportation Safety Board did not indicate that the shipment of diluted bitumen that was being delivered through the ruptured pipeline had actually experienced column separation or that any of the properties of the shipment had any other specific effect on the actions of the control center.

Maintenance Procedures

As described in Chapter 2, pipeline operators use various methods for preventing, detecting, and mitigating damage in pipelines. Methods for preventing external cracking and corrosion include use of coatings and cathodic protection. Methods for preventing internal corrosion include chemical treatments, flow maintenance, and in-line cleaning. Operators also monitor pipeline conditions by using various inspection tools, probes, and surveys. If transporting diluted bitumen compromises the ability of operators to carry out any of these activities, more adverse conditions could arise and persist and thereby increase the potential for failures.

[12] Representatives from Enbridge, Inc., and TransCanada Pipeline Company were invited to make presentations to the committee during its first meeting on July 23, 2012. During the public meeting, the representatives were asked to identify any special operational or maintenance demands associated with transporting diluted bitumen. None was identified. On October 9–10, 2012, committee members convened a public meeting in Edmonton, Alberta, in which representatives of several pipeline companies that transport diluted bitumen were interviewed. In conjunction with the meeting, committee members also visited a transmission pipeline terminal in Fort McMurray, Alberta, where representatives from the pipeline company explained operational and control procedures associated with diluted bitumen transportation. They also responded to questions from committee members. None of the interviews and information obtained from the site visit suggested that operators use different procedures for system control and monitoring when they transport diluted bitumen.

As with other potential issues, the absence of significant differences in the chemical and physical properties of diluted bitumen compared with other heavy crude oils suggests that no changes are required in pipeline maintenance and inspection regimes. Nevertheless, the committee searched for reports of operators experiencing difficulties in carrying out standard maintenance, mitigation, and inspection activities while transporting diluted bitumen. The committee also searched for standards and other guidance documentation alerting operators to issues associated with maintenance and inspection, such as advisories on the use of in-line inspection tools, chemical inhibitors, and coupons and probes for corrosion monitoring. The search did not uncover any issues or added complexities.

In addition, in its questionnaire to Canadian pipeline operators (see Appendix A), the committee asked whether the transportation of diluted bitumen required changes in pipeline cleaning intervals or predictive and preventive maintenance programs. No differences in cleaning intervals or predictive and preventive maintenance programs were reported. Pipeline operators who met with the committee during public meetings (as noted above) were asked similar questions, and all stated that no special maintenance and inspection issues arose in transporting diluted bitumen. They did not report any adverse affects on their ability to carry out their normal maintenance and inspection activities.

Assessment of Effects of Diluted Bitumen on O&M Procedures

As common carriers, operators of transmission pipelines generally have the ability to transport the wide range of crude oil varieties that are in the commercial stream. Accordingly, operations and maintenance procedures are designed to be robust, capable of ensuring operational reliability and safety without the need for significant procedural modifications from one crude oil shipment to the next. The chemical and physical properties of diluted bitumen do not suggest that transporting this product by pipeline requires O&M procedures that differ from those of other crude oils having similar properties. Likewise, inquiries with operators and searches of industry guidelines and advisories did not indicate any specific issues associated with transporting diluted bitumen that would negatively affect operators as they carry out their standard O&M programs, including their corrosion detection and control capabilities.

SUMMARY

The chemical and physical properties of diluted bitumen shipments have been examined to determine whether there are any differences from those of other crude oil shipments that increase the likelihood of pipeline failures from internal degradation, external degradation, or mechanical damage. Any differences that could affect either the frequency or the severity of a failure mechanism or the ability to mitigate it would suggest a difference in failure likelihood. The chemical and physical properties of diluted bitumen shipments were not found to differ in ways that would be expected to create a likelihood of release that is higher for a transmission pipeline transporting diluted bitumen than one transporting other crude oils. An assessment was also made with regard to whether pipeline operators transporting diluted bitumen alter their O&M procedures in ways that can inadvertently make pipelines more prone to the sources of failure. No differences were found in these procedures. The assessment results are summarized in the next chapter.

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Abbreviations

CEPA	Canadian Energy Pipeline Association
NTSB	National Transportation Safety Board

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6

Summary of Results

The study charge and approach and the main points from the preceding chapters are summarized in this chapter. The discussion summaries provide the basis for the findings presented at the end of the chapter.

RECAP OF STUDY CHARGE AND APPROACH

Section 16 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 calls for the Secretary of Transportation to "complete a comprehensive review of hazardous liquid pipeline facility regulations to determine whether the regulations are sufficient to regulate pipeline facilities used for the transportation of diluted bitumen. In conducting the review, the Secretary shall conduct an analysis of whether any increase in the risk of a release exists for pipeline facilities transporting diluted bitumen."[1] A determination of release risk requires an assessment of both the likelihood and the consequences of a release. To inform its assessment of the former, the U.S. Department of Transportation contracted with the National Research Council to convene an expert committee to "analyze whether transportation of diluted bitumen by transmission pipeline has an increased likelihood of release compared with pipeline transportation of other crude oils."

As detailed in Chapter 1, the project statement of task calls for a two-phase study, with the conduct of the second phase contingent on the outcome of the first. In the first phase, the study committee was asked to examine whether shipments of diluted bitumen can affect transmission pipelines and their operations so as to increase the likelihood of release when compared with shipments of other crude oils transported by pipeline. In the potential second phase—to be undertaken only if a finding of increased likelihood of release is made in the first—the committee was asked to review federal pipeline safety regulations to determine whether they are sufficient to mitigate an increased likelihood of release from diluted bitumen. If the committee did not find an increased likelihood of release, or the information available was insufficient to make a finding, the committee was expected to prepare a final report documenting the study approach and results.

The committee reviewed data on reported pipeline releases. The review provided insight into the general causes of pipeline failures, but the incident records alone could not be used to determine whether pipelines are more likely to fail when they transport diluted bitumen than when they transport other crude oils. Having examined the general causes of failures, the committee focused on the specific sources of pipeline damage that can be influenced by the transported crude oil. Specifically, it identified the chemical and physical properties of crude oil that can cause or contribute to sources of pipeline failure from damage sustained internally or externally or as a result of mechanical forces.

The committee did not perform its own testing of pipelines or crude oil shipments. Information on the properties of shipments of diluted bitumen and other crude oils was obtained from public websites and assay sheets. Additional information was obtained from a review of

[1] Public Law 112-90, enacted January 3, 2012.

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government reports and technical literature, queries of oil producers and pipeline operators, field visits, and inferences from secondary sources such as the maximum water and sediment content for pipeline shipments as specified in pipeline tariffs. The committee then compared the relevant properties of shipments of diluted bitumen with the range of properties observed in other crude oil shipments to identify instances in which diluted bitumen fell outside or at an extreme end of the range.

In view of the possibility that some pipeline operators may modify their operating and maintenance practices in transporting diluted bitumen, the committee first posited potential differences and then sought evidence. Operators were questioned about their practices. The committee looked for indications of changes in standard procedures, including corrosion control practices, that could inadvertently make pipelines more susceptible to sources of failure.

MAIN POINTS FROM CHAPTER DISCUSSIONS

Crude Oil Pipeline Transportation in the United States

As described in Chapter 2, the crude oil transmission network in the United States consists of an interconnected set of pipeline systems. Crude oil shipments traveling through the network often move from one pipeline system to another and are sometimes stored at terminals. Most operators of transmission systems are common carriers who do not own the crude oil they transport but provide transportation services for a fee. Few major transmission pipelines are dedicated to transporting specific grades or varieties of crude oil. They usually move multiple batches of crude oil, often provided by different shippers and encompassing a range of chemical and physical properties. Crude oil shipments are treated to meet the quality requirements of the pipeline operator as well as the content and quality demands of the refinery customer.

Pipeline systems traverse different terrains and can vary in specific design features, components, and configurations. The differences require that each operator tailor operating and maintenance strategies to fit the circumstances of its systems in accordance with the federal pipeline safety regulations. Nevertheless, the systems tend to share many of the same basic components and follow similar operating and maintenance procedures. Together, regulatory and industry standards, system connectivity, and economic demands compel both a commonality of practice and a shared capability of handling different crude oils.

Bitumen Properties, Production, and Pipeline Transportation

As discussed in Chapter 3, the bitumen imported into the United States is derived from Canadian oil sands. Canadian bitumen is both mined and recovered in situ using thermally assisted techniques. A large share of the bitumen deposits is too deep for mining, so in situ recovery accounts for an increasing percentage of bitumen production. Because mined bitumen does not generally have qualities suitable for pipeline transportation and refinery feed, it is processed into synthetic crude oil in Canada. Bitumen recovered in situ with thermally assisted methods has lower water and sediment content and is thus better suited to long-distance transportation by pipeline than is mined bitumen. Bitumen imported into the United States is produced in situ through thermally assisted methods rather than by mining.

Like all forms of petroleum, Canadian bitumen is a by-product of decomposed organic materials and thus a mixture of many hydrocarbons. The bitumen contains a relatively large

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concentration of asphaltenes that contribute to its high density and viscosity. At ambient temperatures, bitumen does not flow and must be diluted for transportation by unheated pipelines. Diluents consist of light oils, including natural gas condensate and light synthetic crude oils created from bitumen. Although the diluents consist of low-molecular-weight hydrocarbons, shipments of diluted bitumen do not contain a higher percentage of these light hydrocarbons than do other crude oil shipments. The dilution process yields a stable and fully mixed product for shipment by pipeline with density and viscosity levels in the range of other crude oils transported by pipeline in the United States.

Shipments of diluted bitumen are piped at operating temperatures, flow rates, and pressure settings typical of crude oils with similar density and viscosity levels. Shipment water and sediment content conforms to the Canadian tariff limits, which are more restrictive than those in U.S. pipeline tariffs. Solids in diluted bitumen shipments are comparable in quantity and size with solids in other crude oil shipments transported by pipeline. While the sulfur in diluted bitumen is at the high end of the range for crude oils, it is bound with hydrocarbons and not a source of corrosive hydrogen sulfide. Diluted bitumen has higher acid content than many other crude oils, but the stable organic acids that raise acidity levels are not corrosive at pipeline temperatures.

Review of Pipeline Incident Data

A logical step in addressing the question of whether shipments of diluted have a greater propensity to cause pipeline releases than shipments of other crude oils is to examine historical release records. The incident statistics can be used to identify the general sources of pipeline failure. However, the information contained in the U.S. and Canadian incident records is insufficient to draw definitive conclusions. As explained in Chapter 4, one reason is that the causal categories in the databases lack the specificity needed to assess the particular ways in which transporting diluted bitumen can affect the susceptibility of pipelines to failure. Another reason is that incident records do not contain information on the types of crude oil transported and the properties of past shipments in the affected pipeline. Because many pipeline releases involve cumulative and time-dependent damage, there is no practical way to trace the transportation history of a damaged pipeline to assess the role played by each type of crude oil and its properties in transport.

Incident reporting systems in Canada and the United States do not have uniform reporting criteria and coverage. Given the relatively small number of pipeline incidents, even minor variations in reporting criteria can lead to significant differences in incident frequencies and causal patterns. Some reporting systems combine incident reports from oil gathering and transmission systems, while others do not. Variation in reporting coverage is problematic because gathering pipelines are fundamentally different from transmission pipelines in design, maintenance, and operations and in the quality and quantity of the liquids they carry.

Effects of Diluted Bitumen on Sources of Pipeline Damage

The chemical and physical properties of diluted bitumen were examined in Chapter 5 to determine whether any differ sufficiently from those of other crude oils to increase the likelihood of pipeline failures from sources of damage internally or externally or from mechanical forces. Any differences that could affect either the frequency or severity of the failure mechanism or the ability to mitigate a potential failure mechanism would suggest a difference in failure likelihood.

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No properties were found to differ in any way that may change the likelihood of pipeline damage and failure. An assessment was also made with regard to whether pipeline operators transporting diluted bitumen alter their operating and maintenance procedures in ways that can make pipelines more prone to the causes of failure the procedures are intended to prevent. No differences were found in these procedures. Summaries of the assessments are presented in Box 6-1.

Box 6-1

Summary of Assessments of the Effects of Diluted Bitumen on Causes of Pipeline Damage

Internal Degradation
A review of product properties pertaining to internal pipeline corrosion and erosion did not find that shipments of diluted bitumen are any more likely than shipments of other crude oils to cause these failure mechanisms. Shipments of diluted bitumen do not contain unusually high levels of water, sediment, dissolved gases, or other agents that can cause internal corrosion. The organic acids contained in diluted bitumen are not corrosive to steel at pipeline temperatures. The densities and viscosities of diluted bitumen shipments are within the range of other crude oils, and the velocity and turbulence with which shipments flow through pipelines are comparable and limit the formation of corrosive deposits. On the basis of an examination of the factors that influence microbial growth, diluted bitumen does not have a higher likelihood than other crude oils of causing microbiologically influenced corrosion. Because shipments of diluted bitumen have solids content and flow regimes comparable with those of other crude oil shipments, they do not differ in their propensity to cause erosion of transmission pipelines.

External Degradation
Pipelines can sustain external damage from corrosion and cracking. Because diluted bitumen only contacts the inside of a pipeline, it can contribute to external degradation only as a result of changes in pipeline operational parameters, specifically pipeline temperature and pressure levels. Elevated operating temperatures can increase the likelihood of external corrosion and cracking by causing or contributing to the degradation of protective coatings and by accelerating rates of certain degradation mechanisms. Elevated operating pressures can cause stress loadings and concentrations that lead to stress-related cracking, particularly at sites of corrosion and preexisting damage. Because the densities and viscosities of diluted bitumen are comparable with those of other crude oils, it is transported at comparable operating pressures and temperatures. For this reason, the likelihood of temperature- and pressure-related effects is indistinguishable for diluted bitumen and other crude oils of similar density and viscosity. Consequently, diluted bitumen will not create a higher propensity for external corrosion and cracking in transmission pipelines.

(*continued*)

Box 6-1 (*continued*)

Mechanical Damage
Mechanical damage to the pipeline and its components can occur as a result of overpressurization or outside forces. Mechanical forces can cause an immediate release or make the pipeline more susceptible to release by destabilizing support structures; damaging other components such as valves and joints; and weakening resistance to other failure mechanisms, such as corrosion attack. The study examined several possible causes of an increased potential for mechanical damage due to the properties of the transported liquid, including the potential for shipments of diluted bitumen to cause pressure surges or to interact with outside forces that can cause damage in pipelines. None of the properties or operating parameters of diluted bitumen shipments was found to be sufficiently different from those of other crude oils to suggest a higher potential to cause or exacerbate mechanical damage in pipelines.

Effects on Operations and Maintenance Procedures
As common carriers, operators of transmission pipelines generally have the ability to transport the wide range of crude oil varieties that are in the commercial stream. Accordingly, operations and maintenance procedures are designed to be robust, capable of ensuring operational reliability and safety without the need for procedural modifications from one crude oil shipment to the next. The chemical and physical properties of diluted bitumen shipments do not suggest that transporting them by pipeline requires operations and maintenance procedures that differ from those of other crude oil shipments having similar properties. Likewise, inquiries with operators and searches of industry guidelines and advisories did not indicate any specific issues associated with transporting diluted bitumen that would negatively affect operators as they carry out their standard operations and maintenance programs, including their corrosion detection and control capabilities.

STUDY RESULTS

Central Findings

The committee does not find any causes of pipeline failure unique to the transportation of diluted bitumen. Furthermore, the committee does not find evidence of chemical or physical properties of diluted bitumen that are outside the range of other crude oils or any other aspect of its transportation by transmission pipeline that would make diluted bitumen more likely than other crude oils to cause releases.

Specific Findings

Diluted bitumen does not have unique or extreme properties that make it more likely than other crude oils to cause internal damage to transmission pipelines from corrosion or erosion. Diluted bitumen has density and viscosity ranges comparable with those of other crude oils. It is moved through pipelines in a manner similar to other crude oils with respect to flow rate, pressure, and

operating temperature. The amount and size of solid particles in diluted bitumen are within the range of other crude oils so as not to create an increased propensity for deposition or erosion. Shipments of diluted bitumen do not contain higher concentrations of water, sediment, dissolved gases, or other agents that cause or exacerbate internal corrosion, including microbiologically influenced corrosion. The organic acids in diluted bitumen are not corrosive to steel at pipeline operating temperatures.

Diluted bitumen does not have properties that make it more likely than other crude oils to cause damage to transmission pipelines from external corrosion and cracking or from mechanical forces. The contents of a pipeline can contribute to external corrosion and cracking by causing or necessitating operations that raise the temperature of a pipeline, produce higher internal pressures, or cause more fluctuation in pressure. There is no evidence that operating temperatures and pressures are higher or more likely to fluctuate when pipelines transport diluted bitumen than when they transport other crude oils of similar density and viscosity. Furthermore, the transportation of diluted bitumen does not differ from that of other crude oils in ways that can lead to conditions that cause mechanical damage to pipelines.

Pipeline operating and maintenance practices are the same for shipments of diluted bitumen and shipments of other crude oils. Operating and maintenance practices are designed to accommodate the range of crude oils in transportation. The study did not find evidence indicating that pipeline operators change or would be expected to change such practices while transporting diluted bitumen.

These study results do not suggest that diluted bitumen will experience pipeline releases at a rate that is higher than its proportion of the crude oil stream. Future pipeline releases can be expected to occur, and some will involve diluted bitumen. All pipeline releases can be consequential. As explained at the outset of this report, the committee was not asked or constituted to study whether pipeline releases of diluted bitumen and other crude oils differ in their consequences or to determine whether such a study is warranted. Accordingly, the report does not address these questions and should not be construed as having answered them.

APPENDIX A

Questionnaire to Pipeline Operators on Transporting Diluted Bitumen

The following questions were developed by the committee and given to the Canadian Energy Pipeline Association (CEPA) in January 2013. CEPA distributed the questionnaire to member pipeline companies and returned the results in March 2013. Operator responses are indicated in bold text.[1]

1. Please provide the following information:
   a. Total amount of transmission crude oil pipeline mileage: **Approximately 24,000**
   b. Mileage dedicated to dilbit service: **Approximately 890**
   c. Mileage in batch service: **Approximately 20,530**
   d. Percentage of barrels transported per day consisting of diluted bitumen:
      Operator A: 82 percent
      Operator B: 15 to 65 percent
      Operator C: 65 percent
      Operator D: 65 percent
      Operator E: 28 percent dilbit; 3 percent synbit

2. Please provide the following parameters on the properties of diluted bitumen measured at points of custody transfer or in-line (as appropriate and available):
   Table A-1 includes information gathered on a best-effort basis. One operator also reported some data for synbit, and these data were included for reference. In addition, H_2S data for a large number of crude oils are available from a study performed by Omnicon supported by several pipeline operators. These data were collected by using ASTM D5263 and have been included below for reference (see Figure A-1).

3. How often (e.g., percentage of barrels transported) is specified basic water and sediment (BS&W) exceeded at diluted bitumen initial custody transfer?
   For dilbit batches, between 0 and 0.6 percent of the barrels transported exceeded specified limits.

4. Is BS&W exceeded more often for diluted bitumen compared with other crude oils transported?
   Three operators reported no differences. In two cases, dilbit batches did exceed specified limits more often than other crude oils by a small margin of between 0.1 and 0.3 percent.

[1] API = American Petroleum Institute; CO_2 = carbon dioxide; H_2S = hydrogen sulfide; KOH = potassium hydroxide; O_2 = oxygen; ppm = parts per million; ppmw = parts per million by weight; psi = pounds per square inch; TAN = total acid number.

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TABLE A-1 Operator Responses to Question 2

Parameter	Operator	Average	Normal Range	Extreme High
Total BS&W (volume percentage)	A	0.35	0.25 to 0.40	0.5
	B	0.21	0.05 to 0.36	0.36
	C	0.18	0.11 to 0.25	0.5
	D	0.26	0.05 to 0.5	0.5
	E (dilbit)	0.28	0.1 to 0.38	0.5
	E (synbit)	0.31	0.28 to 0.34	0.5
Water share of BS&W	C	50 percent	40 to 60 percent	100 percent
Sediment share of BS&W	C	50 percent	40 to 60 percent	100 percent
Solid content (ppmw)	B		0 to 0.01	
Solids particle size (microns)	Not routinely measured in crude oil			
H_2S (ppmw)	B	6.77	0.1 to 11.1	11.1
	C	<0.5		10
	E	<0.5	<0.5	
Carbon dioxide (ppm)	Not routinely measured in crude oil			
Oxygen (ppm)	Not routinely measured in crude oil			
Sulfur (weight percentage)	A	3.8	3.62 to 3.85	
	B	3.3	2.45 to 4.76	4.8
	C	3.8	3.79 to 3.89	4.0
	D	3.7	3.0 to 4.1	4.1
	E (dilbit)	4.0	3.46 to 4.97	5.2
	E (synbit)	3.1	3.04 to 3.21	3.5
API gravity	A	21.5	19.0 to 23.1	
	B	20.6	19.3 to 21.3	
	C	22.1	21.4 to 22.2	
	D	21	19.0 to 23.3	
	E (dilbit)	21.5	20.3 t 21.9	
	E (synbit)	19.8	19.5 to 20.1	
Reid vapor pressure (psi)	B	5.1	2.54 to 7.58	7.58
	C	7		
	D	8	3 to 11.8	11.8
	E (dilbit)	7.3	5.85 to 7.79	14.9
	E (synbit)	3.1	2.4 to 3.0	14.9
TAN (mg KOH/g)	A	1	0.85 to 1.05	
	B	1.6	1.0 to 2.17	3.34
	C	1.6	1.52 to 1.64	1.82
	D	1.06	0.6 to 1.9	1.9
	E (dilbit)	1.3	0.92 to 2.49	3.75
	E (synbit)	1.6	1.4 to 2.22	2.5

(*continued*)

TABLE A-1 (*continued*) **Operator Responses to Question 2**

Parameter	Operator	Average	Normal Range	Extreme High
Transport temperature (°C), transmission pipelines	A	30	26 to 34	40
	B	10 (winter); 22 (summer)	4 to 29	32
	C	15	5 to 35	50
	D	27	13 to 43	43
	E	17	9.5 to 22.7	25.4
Flow rate (ft/s) in transmission pipelines	A	4	2.0 to 6.0	
	B	6.56	4.5 to 7.2	8.2
	C	2.5	0.5 to 4.7	5.0
	D	6.7	4.8 to 8.2	8.2
	E	3.63	3.63	4.04
Pressure (psi) in transmission pipelines	A	930	700 to 1,200	1,300
	B	600	43.5 to 1,160	1,440
	C	500	175 to 1,350	1,440
	D	430	50 to 1,440	1,440
	E	750	750	1,095

5. Do tank storage methods for diluted bitumen differ from those of other crudes to possibly affect level of O_2, CO_2, water, and other contaminants?
   No, the storage method is the same as for all crude oil commodities. Dilbits are generally stored in their own commodity group to reduce downgrading.

6. Note any differences in set points for safety and control instrumentation for pipelines in diluted bitumen service as opposed to lines in other service:
   There are no differences. Standards and procedures are in place for control that are generic for all crude oil commodities shipped. The standards and procedures are structured to ensure safe operation regardless of the commodity.

7. Note any differences in the frequency of shutdowns, low-flow, and non-turbulent flow conditions while in diluted bitumen service:
   There are typically no differences that are related to dilbit service. One operator reported a small increase of shutdown frequency due to BS&W exceedance.

8. Note any special surge control equipment and/or vibration monitors on pipelines that carry diluted bitumen:
   No special equipment has been installed specifically to accommodate dilbit.

9. Are drag reducing agents used for diluted bitumen transportation?
   If so, does their use differ (more or less?) compared with other crude types?
   Three of five operators are currently not using drag-reducing agents for dilbit transportation. The use of drag-reducing agents is not specific to dilbit transportation. Their use is based on the operational requirements of a particular pipeline segment and throughput required.

10. Do pipelines undergo more pressure cycling when in diluted bitumen service?
The operating philosophy and function of a pipeline drive pressure cycling, not the type of product transported. Batching between heavy and light products in the same pipeline may cause additional cycling; however, this is related to the switch in products rather than the products themselves. One operator reported that dilbit service lines cycle less frequently than those in conventional crude oil service.

11. Are pressure cycles measured and monitored for use in fatigue calculations?
Three of five operators currently monitor and use pressure cycles in fatigue calculations, and one operator is planning to complete this activity in the future. One operator does not currently complete this activity.

12. Are corrosion inhibitors, including biocides, used for diluted bitumen shipments?
If so, do quantities differ from those used for other crude types?
Three of the operators use chemical treatment for bacteria or corrosion control in at least some of their pipelines. Chemical treatment requirement is determined by the flow conditions and pipeline condition. When such treatments are required, the volume and quantities are the same as for other crude oil pipelines.

13. Is cleaning required at different intervals for pipelines in diluted bitumen service versus pipelines in other service?
The requirement for a cleaning program and cleaning intervals are primarily determined by consideration of flow conditions and the potential for water and sediment deposition for all crude oil types. No differences in cleaning intervals were reported by any operator.

14. Is the debris from pig cleaning analyzed?
If so, note any differences in composition for pipelines in diluted bitumen service?
Four of five operators complete testing of debris from pig cleaning, and no differences in composition have been reported for pipelines in dilbit service versus other heavy commodity pipelines. For pipelines in batch service with multiple products including dilbit, it is not possible to differentiate the sediment collected.

15. Is there any evidence from in-line inspection and/or other corrosion monitoring activities indicating unusual or unexpected corrosion locations for lines in diluted bitumen service?
Corrosion in heavy-oil pipelines can occur in areas where water or sediment accumulates—including low areas, critical inclines, and overbends. The latter location was unexpected when it was identified in 2005, but this does not appear to be unique to dilbit pipelines and is common to heavy commodities in general. No unusual or unexpected corrosion locations have been attributed to dilbit service.

16. Note any difference in clogging or wear of equipment, such as pumps, for lines in diluted bitumen service:
No clogging or unusual wear has been identified for lines in dilbit service.

17. Note any differences in predictive/preventive maintenance practices for lines in dilbit service:
No special predictive or preventive maintenance practices are required for dilbit pipelines.

18. More generally, do you have integrity management programs specific to lines in dilbit service?
No, dilbit lines are incorporated into overall integrity management programs. In more than 25 years of diluted bitumen service on some pipelines, no unique or more severe threats specific to diluted bitumen service have been observed.

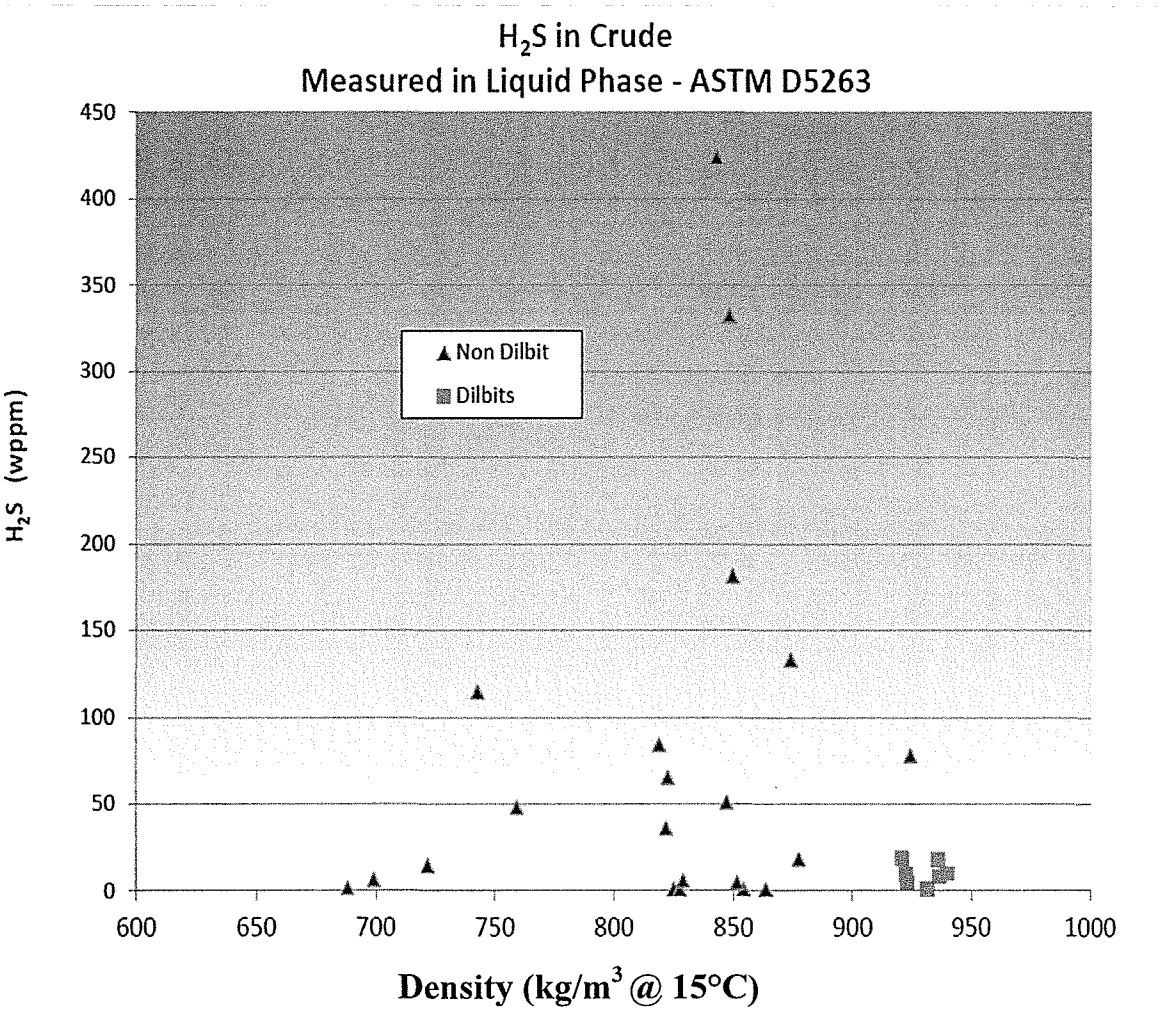

FIGURE A-1 Supplemental information on H_2S content.

APPENDIX B

Federal Pipeline Safety Regulatory Framework

ORIGINS OF HAZARDOUS LIQUIDS PIPELINE SAFETY REGULATION

The Hazardous Liquid Pipeline Safety Act (HLPSA) of 1979, as amended, provides the statutory authority for the U.S. Department of Transportation (USDOT) to establish regulatory standards for the transportation of hazardous liquid by pipelines, including those transporting crude oil.[1] Within the department, authority to carry out the act is delegated to the Pipeline and Hazardous Materials Safety Administration (PHMSA), which implements its authority through the Office of Pipeline Safety (OPS). OPS promulgates rules governing the design, construction, testing, inspection, maintenance, and operations of hazardous liquid pipelines. The regulations are intended to establish minimum safety standards applicable to all hazardous liquid pipeline facilities, thereby setting a safety floor that all operators must meet across the spectrum of pipeline systems. The regulations cover pipelines that transport crude as well as refined products.

A review of past OPS rulemaking notices reveals that as the regulatory program evolved and matured, USDOT and Congress began to question whether the regulatory program was having sufficient effect in reducing the risk of transporting hazardous liquid by pipeline. A central concern was that individual pipeline operators could be complying with each of the actions prescribed in the federal rules in a procedural, or "checklist," manner without really knowing whether these actions were collectively producing the desired safety assurance. Because pipeline facilities vary in their designs, construction, environments, and operating histories, specific safety assurance methods—including those not prescribed in federal rules—might be more suitable for one facility than for another. Moreover, OPS had long been concerned that it could not identify all facility-specific risks, which made a strictly prescriptive approach to safety regulation impractical. The changes made in response to these concerns have led to changes in the role of OPS and to new expectations for safety assurance by the pipeline industry.

PRESCRIPTIVE AND PERFORMANCE-BASED STANDARDS

After several major pipeline releases during the late 1980s and early 1990s, OPS started experimenting with other regulatory approaches to accompany its rules, which prescribed such specific actions as maintaining operating pressure at levels not to exceed 72 percent of specified minimum yield strength (SMYS).[2] The agency sponsored a series of demonstration projects that gave operators the incentive and flexibility to tailor their safety assurance methods to their specific circumstances. OPS reasoned that because pipeline operators have the most comprehensive and detailed knowledge of their systems, they are in the best position to devise their safety assurance programs, as long as they are given the motivation, tools, and regulatory flexibility to make effective choices.[3]

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[1] Rulemaking to begin implementation of HLPSA began in 1981 (*Federal Register*, Vol. 46, No. 143, July 27, 1981) and can be found at http://phmsa.dot.gov/staticfiles/PHMSA/hrmpdfs/1981%20hist%20rulemakings/46%20FR%2038357.pdf.

[2] §195.406.

[3] See *Federal Register*, Vol. 65, No. 237, Dec. 8, 2000.

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In 2000, OPS issued a landmark rulemaking titled Pipeline Integrity Management in High Consequence Areas.[4] Rather than prescribing specific operations and maintenance procedures, new rules laid out the key steps to be followed in developing and implementing a rationalized integrity management program based on principles of risk management. The regulations defined the core elements of the required program, such as the development of a written plan explaining how risks are to be identified; the logic used in choosing the tools, methods, and schedules employed for detecting and assessing risks; and the timetable for completing risk assessments and correcting deficiencies. The rules were written in performance-based language that does not tell operators exactly how they must conduct the risk assessments or precisely how they must act to mitigate identified risks. For example, if internal corrosion is identified as a threat in a particular pipeline segment, the operator is held responsible for selecting the best means to mitigate it—by using corrosion inhibitors, increasing the frequency of line cleaning, shortening inspection intervals, or selecting other defensible options.

Although performance-based rules have the advantage of allowing customized responses to specific circumstances, they can at times lack the clarity of a specific measure prescribed in rules applicable to all.[5] Accordingly, OPS has retained many of its prescriptive rules and continues to adopt new ones, depending on the safety concern. Box B-1 outlines the basic set of rules governing the transportation of hazardous liquids by pipeline, as contained in the Code of Federal Regulations, Title 49, Part 195. Examples of prescriptive rules, in addition to the aforementioned standard for maximum operating pressure, are those concerning pipeline design and construction features, such as the requirement for shutoff valves located at each side of a water crossing.[6] Nevertheless, in instances where alternatives to prescribed measures have safety merit, the operator can seek a waiver, or special permit, from OPS by demonstrating that the alternative measures will yield the same or higher levels of safety than the prescribed ones.[7]

An example of a special permit application is the original plan of TransCanada Corporation to construct the Keystone XL pipeline. When the pipeline was first proposed in 2008, the company petitioned OPS to allow for maximum operating pressures of 80 percent of SMYS. OPS agreed to the special permit conditioned on TransCanada Corporation implementing 57 measures not currently delineated in the regulations and on adding a degree of rigor not currently required. The conditions covered, among other things, quality control checks during the manufacture and coating of the pipe, tighter valve spacing, remote control valves, monitoring and control of operating temperatures, more frequent pig cleaning, and specific limits on the levels of water and sediment contained in the products transported. Although TransCanada Corporation eventually withdrew the special permit application, it agreed to comply with the 57 conditions as part of its separate presidential application to build and operate a pipeline that crosses a national border.[8]

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[4] See *Federal Register*, Vol. 65, No. 237, Dec. 8, 2000.

[5] For example, the National Transportation Safety Board recently urged PHMSA to revise the integrity management–high consequence area rule to better define when an assessment of environmental cracks must be performed, acceptable engineering methods for such assessments, and specific treatments that must be applied when cracks are found. http://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&SID=4c83a26cf5fcbaf90e350dddcff30166&rgn=div8&view=text&node=49:3.1.1.1.11.6.22.28&idno=49.

[6] §195.260.

[7] These are general regulations also pertaining to natural gas pipelines and are thus contained in 49 CFR Part 190.

[8] In 2008, TransCanada Corporation proposed the addition of a new hazardous liquid transmission pipeline, called the Keystone XL, which would originate in Alberta and terminate in Steele City, Nebraska. Because the pipeline crossed the U.S. border, it required presidential approval. Public Law 112-78 required the president to act on the application within 60 days of the law's enactment on December 23, 2011. In early 2012, President Barack Obama denied the application, citing a review by the U.S. Department of State that expressed the need for more information to consider relevant environmental issues and the

Finally, in addition to having special permit authority, OPS has broad authority in the name of public safety to demand that pipeline operators take certain actions not specifically called for in regulations. For example, if the agency discovers a hazardous condition, it can issue orders requiring operators to take certain responsive or precautionary measures.[9] On discovering a condition that may be of concern to multiple pipelines, OPS can issue advisory bulletins that notify operators about the condition and how it should be corrected.

SUPPORTIVE PROGRAMS

The emphasis on risk- and performance-based standards has not only affected OPS rulemaking activity but also changed other aspects of its safety oversight program. Where it does not prescribe specific safety actions or practices, OPS seeks to ensure that operators are in compliance with the performance-oriented demands outlined in the regulations. Aided by its inspection and enforcement capabilities, OPS will verify that pipeline operators are developing and implementing risk management programs that have a rigorous and technically sound basis. A checklist compliance inspection approach is not considered adequate. Inspecting for compliance under these circumstances requires an approach more akin to a quality assurance audit to ensure that operators are following a well-defined set of actions. In addition, the advent of performance-based regulations has meant that OPS safety researchers now have responsibility for providing technical guidance to aid operators in developing rigorous risk management programs, including development of the requisite analytic tools.

About half of the 200-person OPS staff is responsible for inspecting pipeline facilities, with assistance from more than 300 state inspectors. Inspectors are authorized to review the manual for operations and maintenance required of each operator. Inspectors also review records documenting the evaluations that have been performed to identify and prioritize risk factors, devise integrity management strategies, and prioritize the preventive and mitigative measures. If OPS has reason to believe that a specific risk factor is escaping the scrutiny of a pipeline operator, it can review company records to determine whether and how the risk is being treated. As described in Chapter 4, PHMSA also requires operators to report incidents involving releases from pipelines. The agency uses the reports to guide its regulatory, inspection, and enforcement priorities.

Through its research and engineering capacity, OPS can assist pipeline operators in complying with both prescriptive and performance-based rules. In 2012, the agency funded about $7 million in research, with most projects conducted in collaboration with industry through cooperative programs such as the Pipeline Research Council International, Inc. Much of the research is designed to help operators comply with regulatory demands; for example, by developing tools and methodologies to detect and map pipeline leaks, locate and diagnose faults in cathodic protection systems, inspect lines that cannot be pigged, and conduct risk analyses. Research projects are also designed to provide technical support for industry standard-setting activities; for example, by evaluating new test methods being considered by standards development committees.

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consequences of the project on energy security, the economy, and foreign policy (*Federal Register,* Vol. 77, No. 23, Feb. 3, 2012, p. 5614).

[9] 49 CFR §190.

Box B-1

Summary of Coverage of Federal Hazardous Liquid Pipeline Safety Regulations

Title 49, Part 195—Transportation of Hazardous Liquids by Pipeline

Subpart A—General	
§195.0 to §195.12	Regulation coverage, definitions, incorporations by reference of consensus standards, and compliance responsibility.
Subpart B—Reporting	
§195.48 to §195.64	Includes reporting requirements for accidents and safety-related conditions as well as requirements for operators to provide assistance during investigations.
Subpart C—Design	
§195.100 to §195.134	Includes pipe and component design requirements governing design temperature, internal design pressure, external pressure and loads, valves and fittings, closures and connections, and station pipe and breakout tanks.
Subpart D—Construction	
§195.200 to §195.266	Includes construction-related requirements governing material inspection, transportation of pipe, location of pipe, installation and coverage of pipe, welding procedures and welder qualifications, weld testing and inspection, valve location, pumping stations, and crossings of railroads and highways.
Subpart E—Pressure Testing	
§195.300 to §195.310	Includes requirements governing pressure testing of pipe, components, tie-ins, and breakout tanks. Also contains requirements for risk-based alternatives to pressure testing of older pipelines.
Subpart F—Operations and Maintenance	
§195.400 to §195.452	Includes requirements for an operations, maintenance, and emergency response manual; maximum operating pressure; inspections of breakout tanks and rights-of-way; valve maintenance; pipe repairs; line markers and signs; public awareness and damage prevention programs; leak detection and control room management; and integrity management in high-consequence areas.

(*continued*)

Box B-1 (*continued*)

Subpart G—Qualification of Pipeline Personnel

§195.501 to §195.509	Requirements for qualification programs and record keeping.

Subpart H—Corrosion Control

§195.551 to §195.589	Includes regulations on coatings for external corrosion control, coating inspection, cathodic protection and test leads, inspection of exposed pipe, protections from internal corrosion, protections against atmospheric corrosion, and assessment of corroded pipe.
Appendix A	Delineates federal and state jurisdiction.
Appendix B	Risk-based alternative to pressure testing older pipelines.
Appendix C	Guidance for integrity management program implementation.

APPENDIX C

Data-Gathering Sessions

Committee for a Study of Pipeline Transportation of Diluted Bitumen

First Meeting
July 23–24, 2012
Washington, D.C.

July 23

9:45 a.m. Briefing by study sponsor, Pipeline and Hazardous Materials Safety Administration (PHMSA)
Linda Daugherty, Deputy Associate Administrator for Policy and Programs
Alan Mayberry, Deputy Associate Administrator of Field Operations
Jeffery Gilliam, Senior Engineer and Project Manager
- Origins and scope of study
- Overview of PHMSA's regulatory program
- Agency data sources and technical reports
- Additional background

11:30 a.m. Overview of relevant industry consensus standards and state of the practice in detecting, preventing, and mitigating internal corrosion of oil pipelines
Oliver Moghissi, President, National Association of Corrosion Engineers (NACE), and Director, DNV Columbus, Inc

1:00 p.m. Alberta Innovates report, *Comparison of Corrosivity of Dilbit and Conventional Crude*
John Zhou, Alberta Innovates Energy and Environment Solutions
Harry Tsaprailis, Alberta Innovates Technology Futures

1:45 p.m. Industry associations
Peter Lidiak, Director, Pipelines, American Petroleum Institute

2:30 p.m. Operator experiences—Enbridge Pipelines, Inc.
Scott Ironside, Director, Integrity Programs

3:30 p.m. Operator experiences—TransCanada Corporation
Bruce Dupuis, Program Manager, Liquid Pipeline Integrity
Jenny Been, Corrosion Specialist, Pipe Integrity

4:15 p.m. Concerns raised in Natural Resources Defense Council (NRDC) report
Anthony Swift, Attorney, International Program, NRDC

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5:00 p.m.	General discussion
5:45	Adjournment

July 24

9:35 a.m.	National Energy Board (NEB)—Overview of Regulatory, Data, and Technical Activities Iain Colquhoun, Chief Engineer, NEB
10:15 a.m.	Standard and Non-Standard Methodologies to Evaluate Crude Oil Corrosivity Under Pipeline Operating Conditions Sankara Papavinasam, Senior Research Scientist, CanmetMATERIALS
11:00 a.m.	Public forum
12:15 p.m.	Adjournment

Subcommittee Meeting
October 9, 2012
Edmonton, Alberta

8:40 a.m.	Introductions: Enbridge Pipelines, Inc.; TransCanada; Inter Pipeline; Kinder Morgan; Crude Quality, Inc.
9:30 a.m.	Experience with diluted bitumen quality and cleanliness when entering the pipeline system
10:45 a.m.	Pipeline control and operations: diluted bitumen versus conventional crude oils
12:30 p.m.	Integrity knowledge of pipelines Findings from inspecting pipelines in high consequence areas for anomalies
1:30 p.m.	Other presentations
3:00 p.m.	Tour of Natural Resources Canada, CanmetENERGY laboratory

Second Committee Meeting
October 23, 2012
Washington, D.C.

10:50 a.m. Overview of pipeline equipment, field operations, control center, leak detection, maintenance, regulation, and economics
Thomas Miesner, Pipeline Knowledge and Development

1:30 p.m. Background on crude oils and diluted bitumen
Harry Giles, Executive Director, Crude Oil Quality Association
Randy Segato, Suncor Energy
Andre Lemieux, Canadian Crude Quality Technical Association

2:30 p.m. Diluted bitumen: chemical and physical properties
Heather Dettman, Natural Resources Canada, CanmetENERGY

3:30 p.m. Evidence from pipeline incident reporting systems
PHMSA data: Jeffery Gilliam and Blaine Keener, PHMSA
Pipeline Performance Tracking System: Peter Lidiak, American Petroleum Institute, and Cheryl Trench, Allegro Energy Consulting

4:30 p.m. Overview of PHMSA supplemental regulatory authorities to mitigate risk
Jeffery Gilliam, PHMSA

5:00 p.m. Adjournment

Third Committee Meeting
January 31, 2013
Washington, D.C.

10:30 a.m. Summary of NACE conference proceedings on heavy oil and corrosion
Sankara Papavinasam, Senior Research Scientist, Natural Resources Canada, CanmetMATERIALS

11:15 a.m. Operational experience transporting heavy crude oils by pipeline in California
Art Diefenbach, Vice President of Engineering, Westpac Energy

1:00 p.m. Overview of federal hazardous liquid pipeline regulatory approach
Jeffrey Wiese and Jeffery Gilliam, PHMSA

2:00 p.m. Changing patterns of crude oil supply and demand
Geoffrey Houlton, Senior Director, Global Crude Oil Market Analysis, IHS

3:00 p.m. Adjournment

Study Committee Biographical Information

Mark A. Barteau, *Chair*, is DTE Energy Professor of Advanced Energy Research, Professor of Chemical Engineering, and Director of the University of Michigan Energy Institute. Before accepting his appointments at the University of Michigan in 2012, he retired from the University of Delaware as Senior Vice Provost for Research and Strategic Initiatives and Robert L. Pigford Chair in Chemical Engineering. He was a National Science Foundation Postdoctoral Fellow at the Technische Universität München before joining the University of Delaware as Assistant Professor of Chemical Engineering and Associate Director of the Center for Catalytic Science and Technology in 1982. He became Director of the Center for Catalytic Science and Technology in 1996. He has held visiting appointments at the University of Pennsylvania and the University of Auckland, New Zealand. His research in surface chemistry and heterogeneous catalysis has been recognized with numerous awards, including the International Catalysis Award. He was the founding director of the University of Delaware Energy Institute. He is active in the National Research Council, serving as cochair of the Chemical Sciences Roundtable and as a member of the Chemical Engineering Peer Committee. He has also served on the Panel on Chemical Science and Technology, the Committee on the Review of Basic Energy Sciences Catalysis Program, and the Committee on Challenges for the Chemical Sciences in the 21st Century. He was elected to the National Academy of Engineering in 2006. He received a BS in chemical engineering from Washington University in St. Louis, Missouri, and an MS and a PhD in chemical engineering from Stanford University.

Y. Frank Cheng is Professor and Canada Research Chair in Pipeline Engineering in the Department of Mechanical and Manufacturing Engineering at the University of Calgary. His research has focused on pipeline corrosion, stress corrosion cracking, erosion–corrosion, coatings, metallurgical microelectrochemistry, and defect assessment. Before joining the faculty of the University of Calgary in 2005, he was a Natural Sciences and Engineering Research Council of Canada postdoctoral fellow at the Nova Research and Technology Center and a research scientist at the Center for Nuclear Energy Research at the University of New Brunswick. He is a member of the editorial board of *Corrosion Engineering, Science and Technology* and has published more than 120 articles in refereed journals on corrosion and pipeline engineering. He is the sole author of *Stress Corrosion Cracking of Pipelines*, published by Wiley. He is also Theme Editor of Pipeline Engineering for the *Encyclopedia of Life Support Systems* developed under the auspices of the United Nations Educational, Scientific, and Cultural Organization. He holds a BS in corrosion from Hunan University, an MS in materials engineering from the Institute of Metal Research from the Chinese Academy of Sciences, and a PhD in materials engineering from the University of Alberta.

James F. Dante is Manager of the Environmental Performance of Materials Section of the Southwest Research Institute. In this capacity, he supervises 15 staff engineers and technicians involved in basic and applied corrosion research for the energy industry and the U.S. Departments of Defense, Transportation, and Energy. Current programs include corrosion sensor research and implementation involving fluidized sensors, atmospheric corrosion sensors, and sensors for corrosion under insulation. His unit also conducts research on accelerated corrosion test methods and research to advance the mechanistic understanding of corrosion processes in

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various industries. Before joining Southwest Research Institute in 2009, he was Senior Research Scientist at Luna Innovations and leader of the University of Dayton Research Institute's group specializing in corrosion mechanisms, detection, and protection. He began his career as a materials research engineer at the National Institute of Standards and Technology. He holds a BA in physics from Johns Hopkins University and an MS in materials science and engineering from the University of Virginia.

H. Scott Fogler is Vennema Professor of Chemical Engineering and Arthur F. Thurnau Professor at the University of Michigan. He is internationally recognized for his research and teaching in chemical reaction engineering in petroleum engineering, including reaction in porous media, fused chemical relations, kinetics of wax deposition, gelation kinetics, asphaltene deposition kinetics, remediation colloidal phenomena, and catalyzed dissolution. The Chemical Manufacturers Association honored him with the National Catalyst Award in 1999. He has published more than 200 articles in peer-reviewed journals and books. He is author of *Elements of Chemical Reaction Engineering*, which is in its fourth edition and is estimated to be used by three-quarters of all chemical engineering programs in the United States. He has received numerous awards from the American Society for Engineering Education, including the Dow Outstanding Young Faculty Award in 1972, the Corcoran Award for Best Paper in Chemical Engineering Education in 1993, and the Lifetime Achievement Award from the Chemical Engineering Division in 2005. He earned a BS in chemical engineering from the University of Illinois and an MS and a PhD in chemical engineering from the University of Colorado.

O. B. Harris is President of O. B. Harris, LLC, an independent consultancy specializing in the regulation, engineering, and planning of petroleum liquids pipelines. From 1995 to 2009, he was Vice President of Longhorn Partners Pipeline, LP, which operates a 700-mile pipeline that carries gasoline and diesel fuel from Gulf Coast refineries to El Paso, Texas. In this position, he was responsible for engineering, design, construction, and operation of the system. From 1991 to 1995, he was President of ARCO Transportation Alaska, Inc., a company owning four pipeline systems, including the Alyeska Pipeline Service Company, which transports 25 percent of the crude oil from the North Slope of Alaska to the Port of Valdez. From 1977 to 1990, he held several supervisory and managerial positions at ARCO Pipeline Company, including District Manager for Houston and Midland, Texas; Manager of the Northern Area; and Manager of Products Business. At ARCO Transportation, he directed the efforts of a team of corrosion engineers advising Alyeska on making repairs to the Trans-Alaska Pipeline System. He is a past member of the Board of Directors of the Association of Oil Pipe Lines and the Pipeline and Hazardous Materials Safety Administration's Technical Hazardous Liquids Pipeline Safety Standards Committee. He holds a bachelor's degree in civil engineering from the University of Texas and an MBA from Texas Southern University.

Brenda J. Little is Senior Scientist for Marine Molecular Processes in the Naval Research Laboratory (NRL) at the Stennis Space Center. Earlier she was a Supervisory Research Chemist, Principal Investigator in the Biological and Chemical Oceanography Branch, Supervisory Oceanographer, and Head of the Biological and Chemical Oceanography Branch. During her 35-year career at NRL, she has made major contributions in identifying and understanding microbiologically influenced corrosion of marine materials, which has had a significant impact on a broad spectrum of Navy applications. Her research has been used to prevent and mitigate

corrosion problems in seawater piping systems, fire protection systems, weapon cooling systems, helicopter interiors, and nuclear waste storage. She participated in a special U.S. Department of Transportation investigation of corrosion mechanisms in the Alaska North Slope pipeline. She is Assistant Editor of *Biofouling,* the *Journal of Bioadhesion,* and *Biofilm Research*. She coauthored (with J. S. Lee) *Microbiologically Influenced Corrosion* (John Wiley and Sons, 2007). She has published more than 80 journal articles, more than 100 papers in symposium proceedings, and more than 20 book chapters. Her publications have earned her numerous NRL publication awards. She is a Fellow of the National Association of Corrosion Engineers (NACE) and a recipient of the Navy Meritorious Civilian Service Award and Women in Science and Engineering Award for Scientific Achievement. She holds a BS in biochemistry from Baylor University and a PhD in chemistry from Tulane University.

Mohammad Modarres is Minta Martin Professor of Engineering and Professor of Nuclear and Reliability Engineering and Director of the Reliability Engineering Program at the University of Maryland, College Park. His research centers on probabilistic risk assessment; uncertainty analysis; and the physics of failure mechanisms of mechanical components, systems, and structures. He has served as a consultant to several governmental agencies, private organizations, and national laboratories in areas related to probabilistic risk assessment, especially applications to complex systems such as nuclear power plants and pipelines. He has authored more than 300 papers in archival journals and proceedings of conferences and three books in various areas of risk and reliability engineering. He is a member of several journal editorial boards, including the *Reliability Engineering and System Safety Journal*, *Journal of Risk and Reliability,* and *International Journal of Reliability and Safety*. He is Associate Editor of the *International Journal on Performability Engineering*. He holds a master's degree in mechanical engineering and a PhD in nuclear engineering, both from the Massachusetts Institute of Technology.

W. Kent Muhlbauer is Founder and President of WKM Consultancy, which provides consulting services on all aspects of pipeline design, operations, and maintenance with an emphasis on risk management. Clients include major U.S. and international pipeline operators, federal and state regulatory agencies, engineering companies, and insurance companies. Pipeline risk assessment techniques developed by WKM are in use by pipeline operating companies worldwide. Before forming WKM in 1995, he designed, constructed, and maintained pipeline systems for Dow Chemical's Pipeline Division. He held a variety of engineering and management positions starting in 1982, including operations engineer, technology center specialist, pipeline and salt dome storage quality manager, control center supervisor, and regional operations and maintenance manager. He is author of the *Pipeline Risk Management Manual* (Elsevier 1992, 1996, 2004) and author of numerous articles and papers on pipeline risk management. He is a frequent speaker and instructor at conferences, workshops, training sessions, and seminars on pipeline risk management and integrity preservation. He holds a BS in civil engineering from the University of Missouri.

Srdjan Nešić is Professor of Chemical Engineering and Director of the Institute for Corrosion and Multiphase Flow Technology at Ohio University. Before joining the faculty of Ohio University in 2002, he was a Senior Lecturer in the Mechanical Engineering Department of the University of Queensland, Brisbane, Australia; Principal Research Scientist at the Institute for Energy Technology, Kjeller, Norway; and Research Scientist at Vincha Institute for Nuclear

Sciences, Belgrade, Hungary. His expertise is in flow effects and erosion of pipelines, electrochemical corrosion, computational and experimental fluid dynamics, and multiphase flow. He has authored more than 50 peer-reviewed journal articles on these subjects and more than 100 conference papers. He is a Fellow of NACE and has chaired numerous NACE technical sessions and conferences on internal pipeline corrosion and erosion. He is a member of the editorial board of the *Corrosion Journal*. He holds bachelor's and master's degrees in mechanical engineering from the University of Belgrade and a PhD in chemical engineering from the University of Saskatchewan.

Joe H. Payer is Chief Scientist at the National Center for Education and Research on Corrosion and Materials Performance and Research Professor of Corrosion and Reliability Engineering at the University of Akron. In this position he directed the University Corrosion Collaboration for the U.S. Defense Department's Office of Corrosion Policy and Oversight. Before joining the University of Akron in 2009, he was Professor of Materials Science at Case Western Reserve University, where he directed the U.S. Department of Energy's multiuniversity Corrosion and Materials Performance Cooperative for improved performance assessment for long-term disposal of spent nuclear fuel. His expertise is in materials selection, failure analysis, corrosion control methods, monitoring systems, and degradation mechanisms. His research has focused on localized corrosion of highly corrosion-resistant materials, gas and oil pipeline integrity, the effects of manufacturing processes on the performance and reliability of materials in service, coatings and surface treatments, and hydrogen and materials interactions. He is a Fellow of the American Society for Metals International; a Fellow and Past President of NACE; and a recipient of the American Society for Testing and Materials Sam Tour Award for Distinguished Contributions to Research, Development, and Evaluation of Corrosion Testing Methods. He earned a BS and a PhD in metallurgical engineering from Ohio State University.

Richard A. Rabinow is President of the Rabinow Consortium, LLC, which provides economic and business consulting services to the pipeline industry. He retired from ExxonMobil after a 34-year career with the corporation. At the time of his retirement in 2002, he was President of ExxonMobil Pipeline Company (EMPCo), a position he had held at EMPCo and its predecessor, Exxon Pipeline Company, since 1996. Before that, he was Vice President and Lower 48 Manager of Exxon Pipeline Company. He began his career at the Exxon Company in 1968, where he held several engineering and supervisory positions in refineries. He rose to Executive Assistant to the President of Exxon Company, Baytown Refinery Manager, Manager of Corporate Affairs, Manager of the Environmental and Safety Department. He is a past Chairman of the Association of Oil Pipe Lines and the Owners Committee of the Trans-Alaska Pipeline System. He has served on the Transportation Research Board's Committee for Pipelines and Public Safety and the Committee on Alaska's Oil and Gas Pipeline Infrastructure. He received a BS in engineering mechanics from Lehigh University and MS degrees in mechanical engineering and management, both from the Massachusetts Institute of Technology.

George W. Tenley, Jr., retired in 2010 as President of the Pipeline Research Council International (PRCI). PRCI is the collaborative research and development program for the energy pipeline industry. He joined PRCI in 1999 after working as an independent consultant on pipeline integrity planning and as a strategic advisor on pipeline risk management for Battelle Memorial Institute. From 1989 to 1995, he was Associate Administrator for Pipeline Safety in

the U.S. Department of Transportation. In this position, he was the senior federal official responsible for safety regulations governing the pipeline transportation of hazardous liquids and natural gases. From 1976 to 1989, he was a senior attorney and then Chief Counsel for the Research and Special Programs Administration. He began his career as an attorney for the Federal Aviation Administration and the Drug Enforcement Administration. He earned a BA in political science from the University of Maryland and a JD from the University of Maryland.

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Review Paper/

Crude Oil at the Bemidji Site: 25 Years of Monitoring, Modeling, and Understanding

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Abstract

The fate of hydrocarbons in the subsurface near Bemidji, Minnesota, has been investigated by a multidisciplinary group of scientists for over a quarter century. Research at Bemidji has involved extensive investigations of multiphase flow and transport, volatilization, dissolution, geochemical interactions, microbial populations, and biodegradation with the goal of providing an improved understanding of the natural processes limiting the extent of hydrocarbon contamination. A considerable volume of oil remains in the subsurface today despite 30 years of natural attenuation and 5 years of pump-and-skim remediation. Studies at Bemidji were among the first to document the importance of anaerobic biodegradation processes for hydrocarbon removal and remediation by natural attenuation. Spatial variability of hydraulic properties was observed to influence subsurface oil and water flow, vapor diffusion, and the progression of biodegradation. Pore-scale capillary pressure-saturation hysteresis and the presence of fine-grained sediments impeded oil flow, causing entrapment and relatively large residual oil saturations. Hydrocarbon attenuation and plume extent was a function of groundwater flow, compound-specific volatilization, dissolution and biodegradation rates, and availability of electron acceptors. Simulation of hydrocarbon fate and transport affirmed concepts developed from field observations, and provided estimates of field-scale reaction rates and hydrocarbon mass balance. Long-term field studies at Bemidji have illustrated that the fate of hydrocarbons evolves with time, and a snap-shot study of a hydrocarbon plume may not provide information that is of relevance to the long-term behavior of the plume during natural attenuation.

Introduction

It has long been recognized that spills of crude oil, gasoline, aviation fuel, diesel fuel, heating oil, and other petroleum hydrocarbon fuels all pose a risk of groundwater contamination by benzene, toluene, ethylbenzene, and xylenes (BTEX) (Council on Environmental Quality 1981). Significant research efforts initiated in the 1980s (summarized by Mercer and Cohen 1990; Chapelle 1999; Cozzarelli and Baehr 2003; Oostrom et al. 2006) were devoted to understanding the processes controlling the subsurface flow, dissolution, volatilization, and biodegradation of nonaqueous phase liquid (NAPL) hydrocarbon mixtures so that effective remediation strategies could be designed. These studies ranged from laboratory experiments to field studies, and involved the development and application of complex numerical models.

By the mid-1990s, considerable evidence suggested that the extent of subsurface hydrocarbon plumes was limited by natural attenuation processes, mainly biodegradation of hydrocarbons by naturally occurring bacteria (National Research Council 1993, 2000; Wiedemeier et al. 1999). The high costs of hydrocarbon source removal and groundwater cleanup, as well as recognition of the limited effectiveness of pump and treat systems (National Research Council 1994), led the Environmental Protection Agency (EPA) to adopt guidelines for risk-based site

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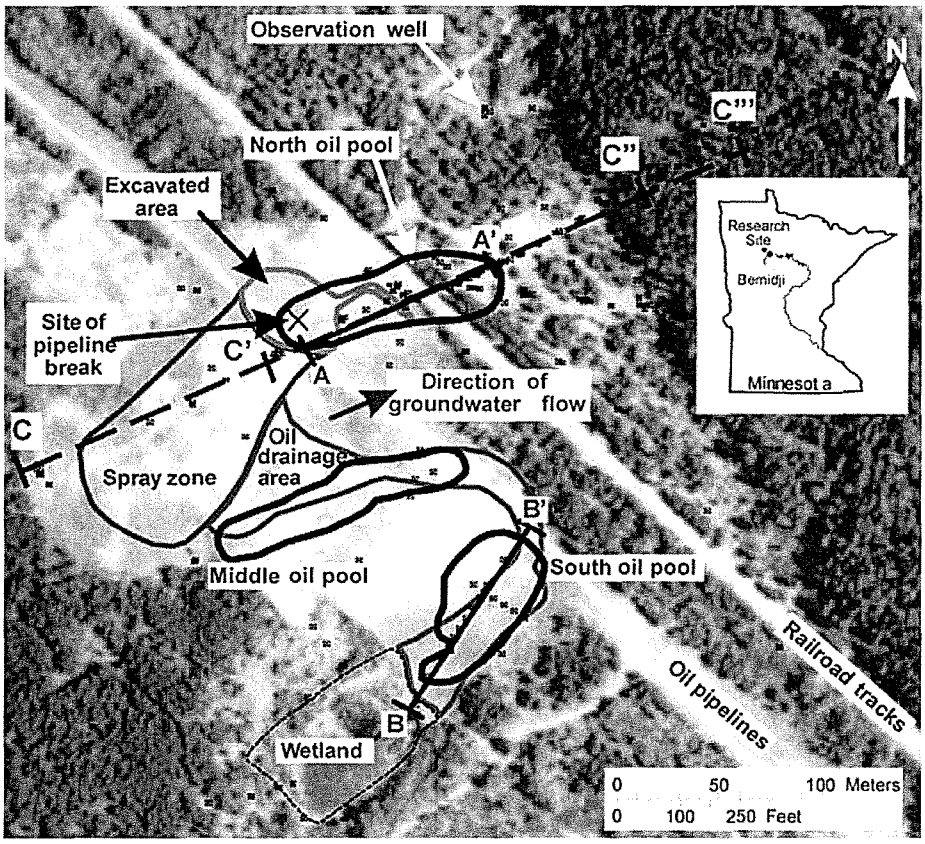

Figure 1. Aerial view of the Bemidji, Minnesota, crude-oil spill research site showing the site of the pipeline break, surface area impacted by oil spill, approximate extent of north, middle, and south oil pools floating on the water table, general direction of groundwater flow, and locations of cross sections shown in subsequent figures (modified from Delin et al. 1998; approximate extent of subsurface oil, August 1998, modified from Lakehead Pipe Line Co., written communication 1998).

assessments (EPA 1995) and the application of natural attenuation for petroleum hydrocarbons in groundwater (EPA 1997). In some cases, regulatory decisions of "no further action" (also known as site closure) were implemented at sites where groundwater benzene concentrations were dropping but did not yet meet state cleanup standards. The expectation was that natural attenuation would result in a continuing decrease in concentrations (Pelayo et al. 2008). However, a recent survey of 10 closed hydrocarbon contaminated sites in Wisconsin has shown that benzene concentrations exceed those measured at the time of site closure at five of the sites (Pelayo et al. 2008). The Wisconsin results indicate that natural attenuation of petroleum hydrocarbons can take longer than expected and that attenuation rates can change with time. Understanding the progression and evolution of natural attenuation processes, and determining the factors that control the spatial and temporal extent of a subsurface hydrocarbon plume, has been the subject of over 25 years of research at the crude-oil spill site near Bemidji, Minnesota.

On August 20, 1979, approximately 16 km northwest of Bemidji, an 86-cm diameter crude-oil pipeline burst along a seam weld, spilling about 1.7×10^6 L (10,700 barrels) of crude oil onto glacial outwash deposits (Figure 1) (Pfannkuch 1979; Hult 1984; Enbridge Energy 2008). The oil sprayed over an area of about 6500 m^2 (the spray zone) and collected in a wetland and topographic depressions where crude oil infiltrated through the unsaturated zone to the water table resulting in three subsurface oil bodies (termed the north, middle, and south oil pools, Figure 1). An estimated 1.1×10^6 L (6800 barrels) of the spilled oil was removed by pumping from surface pools and trenches, and an additional 0.2×10^6 L (1300 barrels) was removed by burning and excavation of soil. After cleanup efforts were completed in 1979 to 1980, about 0.4×10^6 L (2600 barrels) of crude oil remained in the subsurface. The NAPL oil trapped in the unsaturated zone and floating on the water table has provided a continuous source of hydrocarbon contamination. Hydrocarbon compounds have volatilized and dissolved from the oil at varying rates, changing the source composition and forming a soil vapor and groundwater plume within physically and chemically heterogeneous subsurface sediments (Figure 2). The compounds have been transported mainly by diffusion (with some advection) in the unsaturated zone, and by advection and dispersion in the saturated zone. Reactions and biodegradation have transformed the hydrocarbons to less toxic compounds,

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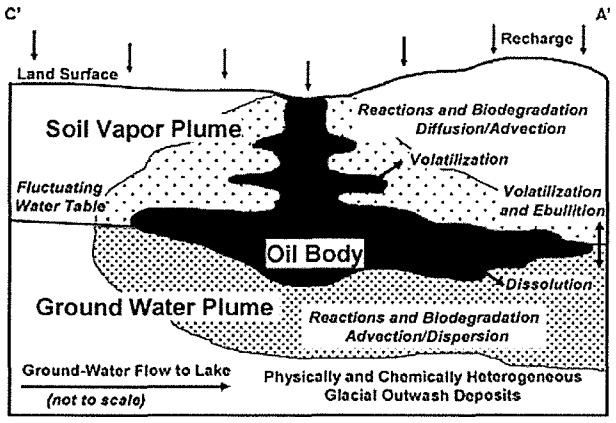

Figure 2. Generalized vertical cross section illustrating the fate and transport of spilled hydrocarbons in the subsurface (modified from Delin et al. 1998). Hydrocarbons infiltrate the subsurface as a separate oil phase, resulting in a residual oil source in the unsaturated zone and an oil body floating on the water table. Volatilization and dissolution of hydrocarbons from the oil phase produce vapor and groundwater plumes. The extent of these plumes is moderated by biodegradation and geochemical reactions that take place in a heterogeneous porous medium.

modified the subsurface redox conditions, and resulted in changes in mineral characteristics.

A long-term, interdisciplinary research project sponsored by the U.S. Geological Survey Toxic Substances Hydrology Program was established at the Bemidji site in 1983 in response to the research community's need for in situ field-scale studies of hydrocarbon fate to complement ongoing experimental and modeling efforts (Delin et al. 1998). An overview of the project with site maps and data is available at http://toxics.usgs.gov/sites/bemidji_page.html and http://mn.water.usgs.gov/projects/bemidji/. Research at this site has been oriented toward characterizing and quantifying the physical, chemical, and biological processes controlling the fate of hydrocarbons in the subsurface. From 1983 to 1999, scientists working at the site were able to study and document the extent and progression of hydrocarbon contamination under natural, undisturbed conditions. In 1999, a 5-year remediation effort focused on removing the NAPL oil source was initiated by the pipeline company in response to a mandate from the Minnesota Pollution Control Agency.

Twenty-five years of comprehensive, interdisciplinary research has made Bemidji one of the best characterized hydrocarbon spill sites in the world and has resulted in over 200 publications (complete list available at http://toxics.usgs.gov/bib/bib-bemidji.html). Research efforts at Bemidji have focused on developing and applying methods for measuring and investigating in situ properties and processes. Work at the site has ranged from characterization of microscopic-scale water-mineral interactions to plume-scale geochemical and microbial evolution, and has included testing of complex models of multiphase flow, reactive transport, and biodegradation. Investigations have involved the collection and analysis of more than 5000 samples of crude oil, water, soil, vapor, sediment, and microbes. The NAPL oil distribution and composition have been characterized and modeled to provide an understanding of the nature of the continuous hydrocarbon source. Monitoring and modeling of the geochemistry of the contaminated aquifer have elucidated the chemical and biological processes controlling the evolution and extent of the groundwater and soil vapor hydrocarbon plumes. Simulation has been used to test conceptual models, quantify properties and rates, and evaluate hydrocarbon mass balance. This paper presents an overview of Bemidji studies that have contributed to understanding the fate of hydrocarbons in the natural field setting. The approaches developed and processes studied at Bemidji are universal and can be adapted and used to evaluate other hydrocarbon spill sites.

Site Hydrogeology

The Bemidji oil spill is located in a pitted and dissected outwash plain comprised of moderately calcareous, moderately to poorly sorted sandy gravel, gravelly sand and sand with thin interbeds of silt (Franzi 1988). The average organic carbon content of these sediments was 0.09% (Baedecker et al. 1993), and the mean porosity was 0.38 (Dillard et al. 1997). At a depth of 18 to 27 m the outwash sediments are underlain by a low-permeability till layer. Local groundwater flow is to the northeast and discharges to an unnamed lake 300-m downgradient from the point of the pipeline rupture (Figure 1). Depth to the water table ranges between 0 (near the wetland) and 11 m, and water levels fluctuate as much as 0.5 m seasonally. The observed average water-table gradient was 0.0035 m/m (Essaid et al. 2003). Estimates of mean hydraulic conductivity at the north oil pool site ranged from 5.6×10^{-6} m/s (estimated from particle-size distributions, Dillard et al. 1997) to 7.0×10^{-5} m/s (calibrated model estimate, Essaid et al. 2003). Mean porosity, conductivity, and gradient estimates yield average velocity estimates that range between 0.004 and 0.056 m/day. A small-scale natural-gradient bromide tracer test conducted within the hydrocarbon plume, along a 1.6-m long flow path 57-m downgradient from the center of the oil body, yielded a mean flow velocity of 0.06 m/day and longitudinal dispersivity of 0.15 m (Essaid et al. 2003).

Mean annual temperature and precipitation at the site are 3°C and 0.58 m, respectively (National Oceanic and Atmospheric Administration 1983). Recharge rates at the site have been estimated using a water-table fluctuation method and an unsaturated zone water balance method based on time-domain-reflectometry measured soil moisture (Delin and Herkelrath 1999, 2005; Herkelrath and Delin 2001). Estimated values range from 0.1 to 0.3 m/year. The greatest recharge rates have been observed below areas of topographic lows, primarily as a result of accumulation of surface runoff in these depressions—the same depressions where spilled crude oil infiltrated to the water table.

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The Oil Phase Hydrocarbon Source

Crude oil is a complex mixture of hydrocarbon compounds that volatilize into the gas phase, dissolve in water, and biodegrade at different rates. The NAPL oil distribution in the subsurface affects its contact with the water and gas phases and consequently the rates of volatilization and dissolution of hydrocarbons. Increased oil in the pore space decreases the ease with which water and air can flow past the oil and reduces the oil surface area in contact with air and water phases, reducing the transfer of hydrocarbons. Furthermore, as mass transfer of hydrocarbon components from the oil to soil gas and water progresses, and biodegradation occurs, the composition of the hydrocarbon mixture in the oil changes. These processes can be individually isolated and studied in laboratory experiments, however, in the field they occur simultaneously with complex interactions.

Oil Phase Distribution

Characterizing the subsurface oil-phase distribution is a necessary step for understanding the influence of the NAPL oil source on the vapor and groundwater plumes. Often, the only information available at a field site is the thickness of oil floating on water in an observation well, a measurement that does not correlate well with the thickness of oil in the adjacent sediments (Kemblowski and Chiang 1990). Methods to determine the subsurface distribution of oil saturation, the fraction of the pore space occupied by oil (volume of oil/volume of pore space), were developed and applied at the Bemidji site. In 1989 and 1990, cores were collected at the south and north oil pools (Figure 3) using a sampling technique that could recover relatively undisturbed core samples from both the unsaturated and saturated zones while maintaining the in situ pore-fluid distribution (Hess et al. 1992). Cores were immediately frozen and cut into 78-mm long sections. Oil and water saturations, porosity, and particle-size distribution were determined for 146 core sections aligned along a 120-m transect at the south pool (Hess et al. 1992), and 269 core sections aligned along a 90-m transect at the north pool (Dillard et al. 1997). Both transects were approximately parallel to the direction of groundwater flow.

The observed south pool oil body (Figure 3A) was more than 70 m long with, the greatest oil saturation (0.62) measured near its center in a localized zone of high oil saturations. Outside this zone there was a large area with oil saturations less than 0.20. The oil body was asymmetric and it appeared that there may have been some downgradient lateral migration of oil below the water table, possibly through zones of high permeability. The thickness of oil measured in three wells at the time of core collection did not correspond to the oil-saturation distribution in the adjacent sediments (Hess et al. 1992), illustrating that accumulated thickness in wells is a poor indicator of the actual distribution of oil in the subsurface.

The distribution of oil at the north pool site was more complex than that at the south pool site (Figure 3B). A considerable amount of oil remained in the unsaturated

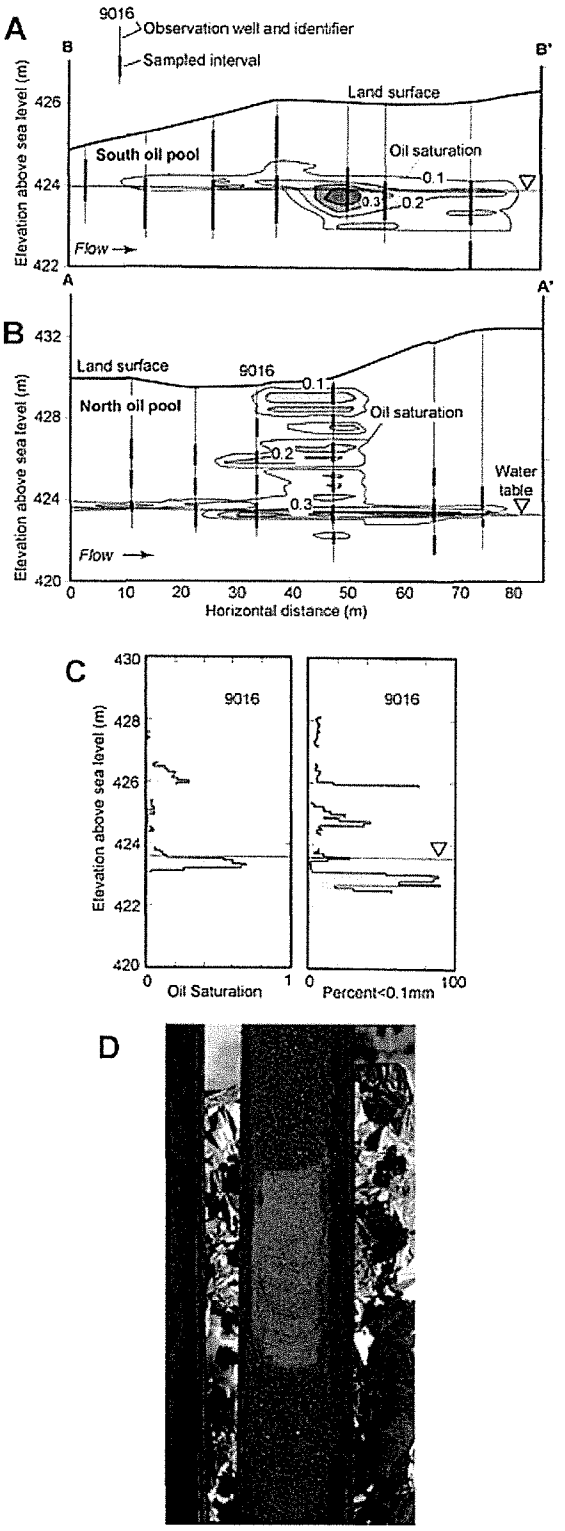

Figure 3. Oil-phase distribution at the Bemidji site (modified from Essaid et al. 1993; Dillard et al. 1997): (A) oil saturation (volume of oil/volume of pore space) distribution at the south pool; (B) oil-saturation distribution at the north pool; (C) oil saturation and percent grain size smaller than 0.1 mm at borehole 9016 showing the influence of heterogeneity on oil-phase distribution; (D) photograph of an oil core crossing the water table showing oil exclusion from a finer grained horizon.

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zone where oil infiltrated following the spill. The body of oil floating on the water table was not lens shaped, but rather consisted of zones of high and low oil saturation distributed along the general direction of groundwater flow. The maximum oil saturation of 0.74 was measured in the downgradient part of the oil body. Figure 3C shows profiles of oil saturation and particle size for borehole 9016 and illustrates the influence of fine-grained layers on oil-saturation distribution. A layer containing almost 80% fines occurred in the unsaturated zone at an elevation of about 426 m. Oil saturations above this layer were greater than 0.3, even though it was more than 2 m above the water table. Apparently the fine-grained layers impeded the infiltration and redistribution of oil. The peak oil saturation was below the water table within a zone that was lacking in fines, rather than at or above the water table as buoyancy would predict. Fine-grained layers occurred above and below the zone of high oil saturation, suggesting that migration of oil near the water table was controlled by heterogeneous layering. Figure 3D is a photograph of a core collected at the water table that illustrates the effect of grain size on oil saturation. The gray zone in the center is of slightly smaller grain size and is free of oil, whereas the coarser overlying and underlying zones are heavily saturated with oil. These field data illustrate the importance of heterogeneity and capillary effects on the distribution and movement of the oil phase.

By 1990, many modeling approaches had been developed to simulate the flow of NAPL oil, however, their field applicability was untested because of a lack of field-scale and site-specific knowledge of multiphase distributions and hydraulic properties (Mercer and Cohen 1990). Observed fluid saturation and particle-size distributions at Bemidji were used in conjunction with a multiphase cross-sectional flow model of the unsaturated and saturated zone to simulate the movement of oil and water at the spill site (Essaid et al. 1993; Dillard et al. 1997). Comparisons between observed and simulated oil-saturation distributions were used as indicators of the appropriateness of using prevalent multiphase flow modeling approaches, and the relative importance of factors controlling oil flow. Spatially variable sediment hydraulic properties and constitutive relations (capillary pressure-saturation and relative permeability-saturation) were estimated from particle-size data. At the south oil pool, the general asymmetrical shape of the observed oil body was reproduced only when hysteretic capillary pressure-saturation curves with oil entrapment and representations of spatial variability of hydraulic properties were incorporated into the model (Essaid et al. 1993). The small-scale details of the observed subsurface oil distribution were not reproduced in the simulations due to uncertainty in spatial correlations, hydraulic properties, and constitutive relations estimated from particle-size distributions.

Analysis of the permeability distribution estimated from particle-size data from the north oil pool site suggested that fine-grained layers were more predominant than at the south pool site. Permeability was distributed bimodal lognormally with two population distributions corresponding to two predominant lithologies: a coarse glacial outwash deposit and fine-grained interbedded lenses. A two-step geostatistical approach was used to generate a conditioned realization of permeability representing the observed bimodal heterogeneity (Dillard et al. 1997). This permeability distribution was used to simulate flow of oil and water in the presence of air along the north pool transect for the 1979 to 1990 period. Inclusion of bimodal aquifer heterogeneity was needed to reproduce the observed entrapment of oil in the unsaturated zone and the irregular shape of the oil body. When bimodal heterogeneity was included, pore-scale capillary pressure-saturation hysteresis did not have to be incorporated into the model because a large-scale hysteretic effect was produced by the presence of low-permeability fine-grained lenses that impeded oil flow.

The field observations and modeling indicate that subsurface oil-phase flow is very sensitive to porous media heterogeneity. Oil tends to occur at higher saturations and to be more mobile in the coarser-grained higher-permeability sediments. Pore-scale capillary pressure-saturation hysteresis and the presence of fine-grained sediments can impede oil flow, causing entrapment and relatively large residual oil saturations. Realistic simulated oil distributions were obtained only when the effects of heterogeneity on capillary pressure-saturation and relative permeability-saturation constitutive relations were represented. However, there is still considerable uncertainty in estimating these constitutive relations for NAPLs, especially in the case of three-phase oil relative permeability (Dillard et al. 1997). Inclusion of the observed 0.5-m water-table fluctuations in the south and north pool models did not significantly improve the correspondence between simulated and observed oil-saturation distributions, suggesting that spatial variability was a stronger influence on oil flow and/or there was limited oil-phase mobility.

Remediation at oil spill sites often targets removal of the NAPL oil phase in order to minimize the hydrocarbon source. The Bemidji remediation effort initiated in 1999 focused on removing sufficient NAPL oil so that it would only occur as a sheen on the water-table surface. Oil was recovered by inducing depressions in the water table by pumping from beneath the north, middle, and south oil pools, with removal of inflowing oil by skimming. Efficacy of oil removal by pump-and-skim remediation depends on oil mobility and flow to the pumped well. Herkelrath (1999) made a prediction of oil removal at the north pool based on oil saturations measured in cores. This analysis indicated that about 25% of the oil was recoverable assuming a residual oil saturation of 0.2 based on observed oil-saturation distributions (Figure 3). The remediation from 1999 to 2004 resulted in the removal of about 1.14×10^5 L of crude oil from the north, middle, and south oil pools (Enbridge Energy 2008), or about 27% of the oil that remained following the

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initial remediation in 1979 to 1980. Although the renewed remediation decreased oil thickness in the immediate vicinity of remediation wells, average oil thicknesses measured in wells at the north pool (0.6 m) and south pool (0.3 m) were unaffected. In one observation well located about 5 m from a remediation well at the north pool, oil thickness decreased twice briefly but rebounded to preremediation levels shortly thereafter. These results, together with ongoing analyses, suggest that oil-phase recovery is challenging, and that considerable volumes of mobile and entrapped oil may still remain in the subsurface at spill sites in spite of significant remediation efforts.

Oil Phase Composition

The composition of subsurface oil at the Bemidji site has changed over time due to volatilization, dissolution, and biodegradation. In 1987, Eganhouse et al. (1993) measured the molecular composition of oil samples obtained from the pipeline and locations spanning the length of the north pool oil body. The composition of the oil body samples was dominated by saturated hydrocarbons (58% to 61%), with aromatics representing most of the remainder (33% to 36% of total oil). The dominant hydrocarbons were normal alkanes (C_{6-32}). Eganhouse et al. (1996) showed that the oil near the upgradient edge of the oil body was depleted of the more soluble aromatic hydrocarbons such as benzene and toluene as compared with the downgradient edge of the oil body. Eganhouse et al. (1996) also observed that concentrations of hydrocarbons in groundwater flowing beneath the oil increased as the water flowed from the upgradient to the downgradient edge of the oil, approaching the effective solubility limit. These results suggested that the upgradient portion of the oil body had undergone more hydrocarbon dissolution than the downgradient portion because of the continuous inflow of groundwater with low hydrocarbon concentrations from the area upgradient of the oil body. As this water flowed past the oil body and hydrocarbon concentrations increased, the mass transfer of soluble components from the oil to the water phase decreased.

Landon and Hult (1996) collected 31 oil samples from wells at various locations within the oil body during 1988 to 1989. They characterized the physical and chemical characteristics of the oil samples, compared them to relatively unaltered oil (Landon 1993), and determined the mass loss from the oil phase. Changes in physical properties of the oil samples indicated that the rate of mass loss ranged from 0% to 1.25% per year. In the oil samples with the greatest mass loss, the alkanes accounted for about 80% of the loss and aromatic compounds accounted for the other 20%. In the less altered oil samples, aromatic compounds accounted for nearly all of the loss of mass. Landon and Hult (1996) concluded that oil mass was being lost primarily by volatilization of low chain-length alkanes in the highly altered oil samples, and dissolution of aromatics in the least altered samples.

Bekins et al. (2005a) examined the composition of the NAPL oil present in core samples 25 years after the spill. They observed that substantial biodegradation of the *n*-alkane fraction in the oil had occurred under methanogenic conditions and that methanogenic biodegradation first depleted the $\geq C_{18}$ *n*−alkanes (Figure 4A), the reverse of the aerobic biodegradation progression (Peters and Moldowan, 1993). The degree of alkane depletion (degradation state) varied with position in the oil body (Figure 4B). The least degraded oil occurred near the land surface, because of extremely low moisture conditions, and at the downgradient end of the oil body. Enhanced methanogenic biodegradation occurred where there was increased groundwater recharge. Recharge rates over twice the average value occur in a topographic low above the upgradient end of the oil body (Delin and Herkelrath 2005). The increased biodegradation below the high recharge zone could not be explained by recharge transport of favorable anaerobic electron acceptors because it was observed that all electron acceptors, except carbon dioxide (CO_2), were consumed in the vadose zone before the recharge reached the floating oil (Bekins et al. 2005a). Moreover, enhanced dissolution could not be the cause, because the degradation affected highly insoluble alkanes and was not correlated with oil saturation and water relative permeability. Bekins et al. (2005a) concluded that the most likely explanation for the variation in alkane degradation states was enhanced methanogenic biodegradation caused by recharge-facilitated transport of microbial growth nutrients from the land surface, in particular dissolved phosphate, believed to be the nutrient limiting microbial growth (Rogers et al. 1998).

These studies of the NAPL oil source at Bemidji have shown that the oil phase is slowly evolving with time as hydrocarbon components are lost through mass transfer to water and soil gas, and biodegradation. The oil-phase loss of relatively soluble components (e.g., BTEX) is sensitive to factors controlling dissolution, such as water concentrations and flow rates. Relatively volatile components (e.g., short chain-length alkanes) can be rapidly lost through volatilization under favorable conditions. Alkanes are also lost from the oil body by methanogenic degradation. Bekins et al. (2005a) pointed out that hydrologic conditions at a site can control oil degradation rates, and that techniques for dating a spill on the basis of the degree of degradation may yield very different results depending on where the sample was collected. In addition, techniques to identify spilled product based on fingerprinting may provide misleading results when methanogenic conditions are present, because the fingerprint of the degraded product in such cases differs from the expected pattern under aerobic conditions (Hostettler et al. 2007, 2008).

The Groundwater Hydrocarbon Plume

By the mid-1980s it was recognized that hydrocarbons could be effectively degraded by naturally occurring indigenous microbial populations (Wilson et al. 1986).

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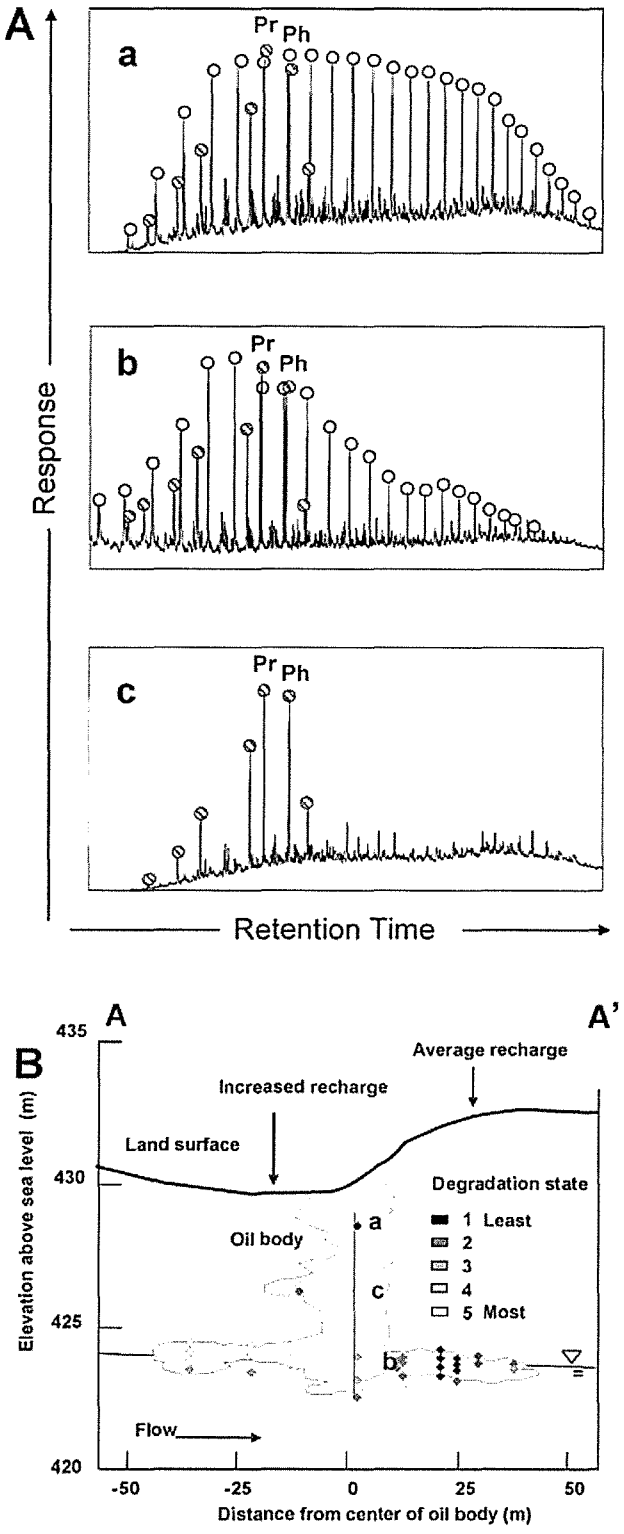

Figure 4. Evaluation of oil-phase degradation (from Bekins et al. 2005a): (A) ion chromatograms for oil samples with varying degrees of degradation (open circles are *n*-alkanes, black circles are isoprenoids) (a) relative undegraded sample with *n*-alkane concentrations greater than isoprenoids, (b) somewhat degraded sample showing selective removal of higher order *n*-alkanes and (c) highly degraded sample with *n*-alkanes completely degraded; (B) vertical cross section through north pool oil body showing relative degree of oil degradation for samples collected from 1999 to 2003.

Aerobic degradation of BTEX was accepted as an effective biodegradation process, and the potential of anaerobic degradation was just being documented (Wilson and Rees 1985). Studies initiated at Bemidji since 1984 have provided concrete evidence of the importance of anaerobic degradation for limiting the extent of hydrocarbon plumes, and significant insight into the succession of redox processes, microbial populations, and geochemical interactions. Hydrocarbon components dissolving from the oil phase have undergone different rates of transport and biodegradation. Within the plume, biologically mediated geochemical reactions have resulted in mineral alteration.

Geochemical Evolution of the Plume

Early characterization of the groundwater hydrocarbon plume (Baedecker et al. 1989, 1993; Bennett et al. 1993) identified five distinct geochemical zones below the water table (Figure 5). Zone 1 consisted of oxygenated uncontaminated native groundwater very low in nitrate, ammonia, and sulfate. Zone 2, below the spray zone, was characterized by reduced oxygen concentrations and the presence of refractory high-molecular-weight hydrocarbons transported from oil residues on the land surface. Zone 3, beneath and immediately downgradient from the separate phase oil body, was anoxic with high concentrations of hydrocarbons, dissolved manganese and iron, and methane. In addition, nitrate and ammonia concentrations were slightly higher than in background water possibly because of nitrogen-containing compounds in the oil and/or infiltration of fertilizer used at the land surface to promote tree growth following the spill. In Zone 4, there was a transition from anoxic conditions to fully oxygenated conditions, with a corresponding rapid decrease in hydrocarbon concentrations as a result of aerobic biodegradation. Zone 5 consisted of oxygenated water downgradient from the oil body with slightly elevated concentrations of dissolved inorganic and organic constituents. The relatively stable extent of the plume, when compared to groundwater flow rates, led to the conclusion that migration of the plume was being limited by natural attenuation processes, including both aerobic and anaerobic biodegradation.

Temporal changes in the plume were observed by measuring dissolved organic carbon (DOC), dissolved oxygen (DO), dissolved manganese (Mn^{2+}) and dissolved ferrous iron (Fe^{2+}), and methane (CH_4) concentrations in samples collected from water-table wells from 1986 to 1992 (Baedecker et al. 1993; Bennett et al. 1993; Eganhouse et al. 1993). DOC was split into two operationally defined fractions (Baedecker et al. 1993): volatile dissolved organic carbon (VDOC) and nonvolatile dissolved organic carbon (NVDOC). VDOC is composed primarily of benzene, alkylbenzenes, and low-molecular-weight alkanes and alicyclics, excluding methane. NVDOC is composed mainly of polysaccharides, humic and fulvic acids, low-molecular-weight organic acids, minor C_{15-28} alkanes, and polyaromatic hydrocarbons (Eganhouse et al. 1993). Figure 6 shows the temporal evolution of concentrations at a well located in the anoxic zone about 40-m

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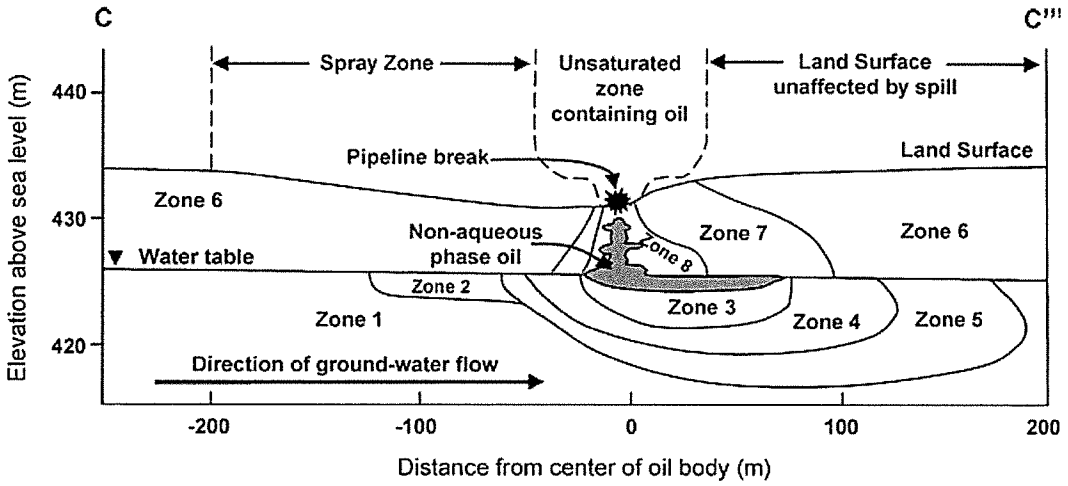

Figure 5. Subsurface geochemical zones identified at the north oil pool site (modified from Baedecker et al. 1993 and Delin et al. 1998). Zones are described in the accompanying text.

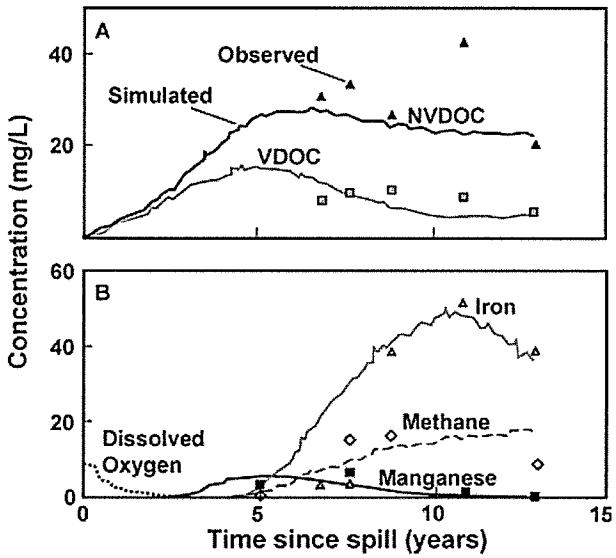

Figure 6. Observed (symbols) and simulated (lines) concentrations approximately 40-m downgradient from the center of the oil body, in the anoxic zone of the groundwater plume showing progression of terminal electron-accepting processes from aerobic degradation to manganese reduction, iron reduction, and methanogenesis: (A) volatile and nonvolatile dissolved organic carbon (VDOC and NVDOC, respectively); (B) dissolved oxygen, manganese (Mn^{2+}), iron (Fe^{2+}), and methane (modified from Essaid et al. 1995).

downgradient from the center of the oil body. VDOC and NVDOC concentrations reached relatively steady concentrations. Mn^{2+} increased, peaking in 1987, and then decreased, suggesting that the manganese available for reduction was being depleted. Fe^{2+} concentrations began to increase following the drop in Mn^{2+} and peaked in 1990. Methane concentration began to increase at about the same time as Fe^{2+} and leveled off in 1987. This sequence suggested that anaerobic (in addition to aerobic) biodegradation processes were limiting plume migration and expansion with sequential use of terminal electron acceptors that progressed from manganese reduction, to iron reduction, to methanogenesis. The trends in Fe^{2+}, Mn^{2+}, and CH_4 concentrations, and the isotopically heavier inorganic carbon, indicated that part of the plume became more reducing with time, and that the processes attenuating organic material were continuously evolving (Baedecker et al. 1993).

Further evidence of the importance of anaerobic biodegradation was obtained from anoxic laboratory microcosm experiments that showed benzene and alkylbenzene degradation concurrent with increased aqueous Fe^{2+} and Mn^{2+} concentrations indicating hydrocarbon biodegradation coupled with Fe and Mn reduction (Baedecker et al. 1993). In addition, Cozzarelli et al. (1994) investigated the geochemical evolution of low-molecular-weight organic acids in groundwater downgradient from the oil body over a 5-year period (1986 to 1990). Organic acids represent metabolic intermediates of crude-oil biodegradation and are structurally related to hydrocarbon precursors (Cozzarelli et al. 1990, 1994; Thorn and Aiken 1998). The concentrations of organic acids increased as microbial alteration of hydrocarbons progressed. The organic-acid pool changed in composition and concentration as biodegradation processes shifted from iron reduction to methanogenesis. Laboratory microcosm experiments conducted by Cozzarelli et al. (1994) supported the hypothesis that organic acids observed in the groundwater originated from microbial biodegradation of aromatic hydrocarbons under anoxic conditions.

Additional geochemical evidence of anaerobic biodegradation of hydrocarbons was provided by methane isotopic composition and sediment-associated iron. Revesz et al. (1995) found that carbon and hydrogen isotopic ratios of CH_4, and carbon isotopic fractionation between CH_4 and DOC, supported the hypothesis of CH_4 production by anaerobic breakdown of acetate (fermentation) as opposed to production by CO_2 reduction. Furthermore, there appeared to be minimal oxidation of dissolved CH_4

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along the flow path downgradient from the oil body. Tuccillo et al. (1999) found that the average HCl-extractable ferric iron (Fe^{3+})concentration in the sediments closest to the oil body was up to 30% less than background values as a result of Fe^{3+} reduction to Fe^{2+}. Fe^{2+} concentrations in sediments within the anoxic zone were as much as four times those in the background sediments, suggesting mineral incorporation of Fe^{2+}. This hypothesis was also supported by scanning electron microscopy (SEM) detection of authigenic ferroan calcite. At the transition zone from anoxic to oxic conditions there was a 70% increase in total extractable Fe, indicating reoxidation and precipitation of Fe mobilized from sediment in the anoxic plume. SEM confirmed abundant Fe^{3+} oxyhydroxides at the anoxic/oxic boundary. Zachara et al. (2004), however, identified significant ion-exchangeable Fe^{2+} in the sediments but relatively thin Fe-containing particle coatings on carbonate fragments suggesting minor precipitation of ferroan calcite in regions of the aquifer with elevated dissolved Fe^{2+} concentrations. Further work is needed to elucidate the processes causing the complex cycling of iron driven by biodegradation and redox conditions.

As anaerobic biodegradation of DOC in the Bemidji plume became well documented, researchers began to compare and contrast the behavior of individual hydrocarbon components in the anoxic zone. Eganhouse et al. (1996) compared concentrations of a range of monoaromatic hydrocarbons in oil and groundwater samples collected within the north pool anoxic zone. Immediately downgradient from the oil body, certain aromatic hydrocarbons (such as benzene) were at aqueous concentrations near those expected of an oil-water system at equilibrium, and these concentrations exhibited relatively little variation over a 9-month period (8% to 20%). Other compounds (such as toluene) had aqueous concentrations significantly below the equilibrium-predicted value, and their concentrations showed considerably more temporal variation (20% to 130%). As the dissolved hydrocarbons moved through the anoxic zone of the groundwater plume, concentrations of more persistent compounds, such as benzene, decreased slowly, whereas concentrations of readily biodegradable compounds such as toluene decreased rapidly (Figure 7). This suggested that the volatile hydrocarbon composition of anoxic groundwater near the oil body was controlled by a balance between dissolution and removal rates, with only the most persistent compounds reaching equilibrium with the oil phase. The extent of downgradient transport of individual dissolved hydrocarbons through the anoxic zone was not due to differences in sorption, but was controlled by structure-specific biodegradation rates. Compounds more resistant to anaerobic biodegradation extended farther downgradient from the oil body.

Early work at Bemidji (Baedecker et al. 1993) concluded that the hydrocarbon plume had reached a relatively steady state. However, continued monitoring has documented changes in the extent of the anoxic plume caused by evolving redox conditions. In the mid-1990s,

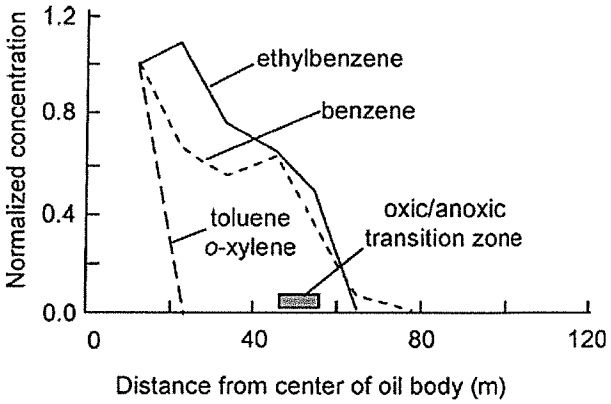

Figure 7. Groundwater concentrations of selected alkylbenzene compounds at the north pool, showing the effect of selective structure-dependent biodegradation of hydrocarbon compounds on persistence in the plume (modified from Eganhouse et al. 1996).

Murphy and Herkelrath (1996) developed a sample-freezing drive shoe designed to operate with a wire-line piston core barrel. This technique improved the ability to obtain cores with intact fluid and sediment distributions, facilitating centimeter-scale sampling of hydrocarbon concentrations (Cozzarelli et al. 2001) and microbial population distributions (Bekins et al. 2001). Cozzarelli et al. (2001) compared concentration distributions obtained from detailed sampling of porewater drained from aquifer cores with plume-scale concentrations determined by sampling from an observation well network along the centerline of the plume. The small-scale data showed that the hydrocarbon plume was growing slowly as sediment iron oxides were depleted and the aquifer evolved from iron reducing to methanogenic conditions. Some hydrocarbons, such as *ortho*-xylene, did not appear to be moving downgradient on the basis of observation well data, but actually were migrating in thin layers of the aquifer where iron oxides were depleted and methanogenic conditions existed. The plume-scale observation well data showed that the downgradient extent of the benzene plume did not change between 1992 and 1995 as shown by the location of the 0.05 mg/L BTEX concentration contours in Figure 8. However, during this period the zone of maximum concentrations of benzene spread within the anoxic plume. Thus, subtle concentration changes in the anoxic zone may indicate depletion of electron acceptors and the potential for future plume growth.

The slow growth of the Bemidji plume contrasts markedly with the rapid growth of another well-studied BTEX plume at Laurel Bay Exchange field site, Beaufort, South Carolina (Landmeyer et al. 1996). Chapelle et al. (2002) noted that the Laurel Bay aquifer sediments contained low concentrations of Fe^{3+} and that the redox state of the contaminated aquifer evolved rapidly to methanogenic conditions. At both the Bemidji and Laurel Bay sites, biodegradation of benzene and ethylbenzene under methanogenic conditions was limited, resulting in migration of those compounds once sediment Fe^{3+} was

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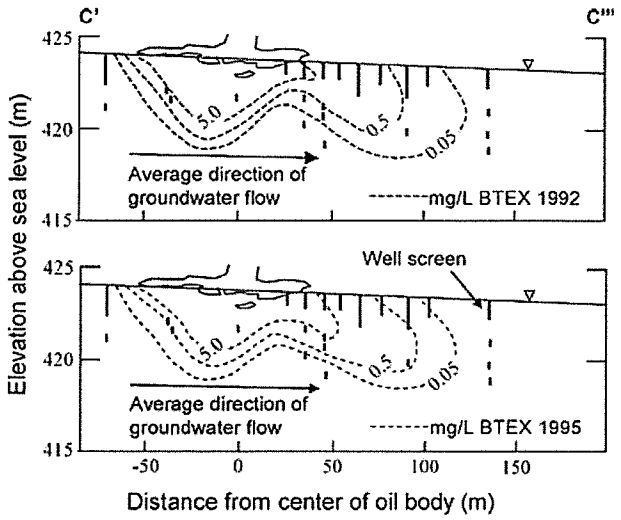

Figure 8. BTEX concentrations measured in wells (screened intervals shown as bars) in the groundwater plume for 1992 and 1995 showing that the extent of BTEX has remained relatively constant. However, the high concentration area in the core of the plume expanded as Fe^{3+} became depleted and conditions changed from iron reducing to methanogenic (from Cozzarelli et al. 2001).

depleted. However, the Bemidji benzene plume grew at only one sixth the rate of the Laurel Bay plume, due mainly to greater Fe^{3+} availability. Using data from the two sites, Bekins et al. (2005b) derived a method to relate expansion rates of benzene and ethylbenzene plumes to variations in sediment Fe^{3+} concentrations. Benzene front migration is retarded relative to groundwater velocity by a factor that depends on the concentrations of hydrocarbon and bioavailable sediment Fe^{3+}.

Long-term monitoring of plume-scale hydrocarbon concentrations and aqueous geochemistry has provided a well-documented field example of the evolution of natural attenuation processes. The Bemidji findings have influenced recommended approaches and protocols for evaluating natural attenuation at hydrocarbon spill sites (National Research Council 2000). Approaches developed at Bemidji for characterization of small-scale variations in chemistry have shown that shifts in biodegradation processes that impact the future extent of the plume may occur before changes can be detected in observation well concentrations.

Microbiology of the Plume

Concurrent with studies documenting geochemical evidence of biodegradation were efforts to characterize the microbial populations and processes responsible for aerobic and anaerobic biodegradation of hydrocarbons, as well as enhanced mineral-water interactions. Studies at Bemidji have documented bacterial colonization on rock surfaces resulting in enhanced quartz (SiO_2) dissolution, identified bacteria responsible for iron reduction, and characterized the spatial and temporal distributions of microbial populations.

Early studies of the inorganic geochemistry of the anoxic zone (Bennett and Siegel 1987; Bennett 1991; Hiebert and Bennett 1992; Bennett et al. 1993) observed SiO_2 concentrations that were an order of magnitude greater than expected equilibrium concentration with respect to quartz. This suggested that organic acid-SiO_2 complexes in the organic-rich anoxic zone were enhancing the dissolution of quartz and silicate minerals. SEM studies of sand grain surfaces in this zone showed etching of quartz and feldspar surfaces not observed on grain surfaces in the adjacent aerobic and uncontaminated zones. Hiebert and Bennett (1992) conducted in situ microcosm experiments in the anoxic plume to examine the effect of bacterial biodegradation processes on rock alteration. Their results suggested that the rate of dissolution of quartz and aluminosilicate minerals was greatly accelerated in the contaminated waters beneath the oil, probably due to the presence of surface-adhering bacteria and high concentrations of organic acids formed by the bacteria during hydrocarbon metabolism (Hiebert and Bennett 1992; Bennett et al. 1993). Expanded in situ microcosm studies of mineral surface colonization have shown that microorganisms tend to colonize surfaces that provide required electron acceptors and growth nutrients, such as iron present in goethite and phosphorous present in apatite (Bennett et al. 2000; Roberts 2004; Rogers and Bennett 2004; Mauck and Roberts 2007).

Studies at Bemidji were among the first field efforts that documented microbial evidence of anaerobic degradation of hydrocarbon compounds (Chapelle 1999; Cozzarelli and Baehr 2003). Lovley et al. (1989) demonstrated that Fe^{3+} could be an important electron acceptor for microbial oxidation of aromatic compounds in anaerobic groundwater by isolating a pure culture of the Fe^{3+}-reducing bacterium *Geobacter metallireducens* capable of obtaining energy for growth by oxidizing benzoate, toluene, phenol, or *p*-cresol, with Fe^{3+} as the sole electron acceptor. Culturing studies and molecular techniques for analyzing Fe^{3+}-reducing populations in the anaerobic groundwater plume have shown that *Geobacter* species were enriched in sediments where poorly crystalline Fe^{3+} was available and biodegradation was fastest (Anderson et al. 1998; Rooney-Varga et al. 1999; Anderson and Lovley 1999; Lovley and Anderson 2000). Anderson and Lovley (2000) also showed that the alkane hexadecane was degraded under methanogenic conditions in Bemidji sediments.

Bekins et al. (1999) used the most probable number (MPN) method to characterize the spatial distribution (in water and sediment) of six physiologic types in the anaerobic portion of the hydrocarbon plume: aerobes, denitrifiers, iron reducers, heterotrophic fermenters, sulfate-reducers, and methanogens (Figure 9A). Iron reducers formed the bulk of the microbial population in the anoxic zone of the plume. Areas evolving from iron reducing to methanogenic conditions were clearly delineated based on microbial populations, and generally occupied 25% to 50% of the plume thickness. Lower microbial numbers were observed below the water table than in the

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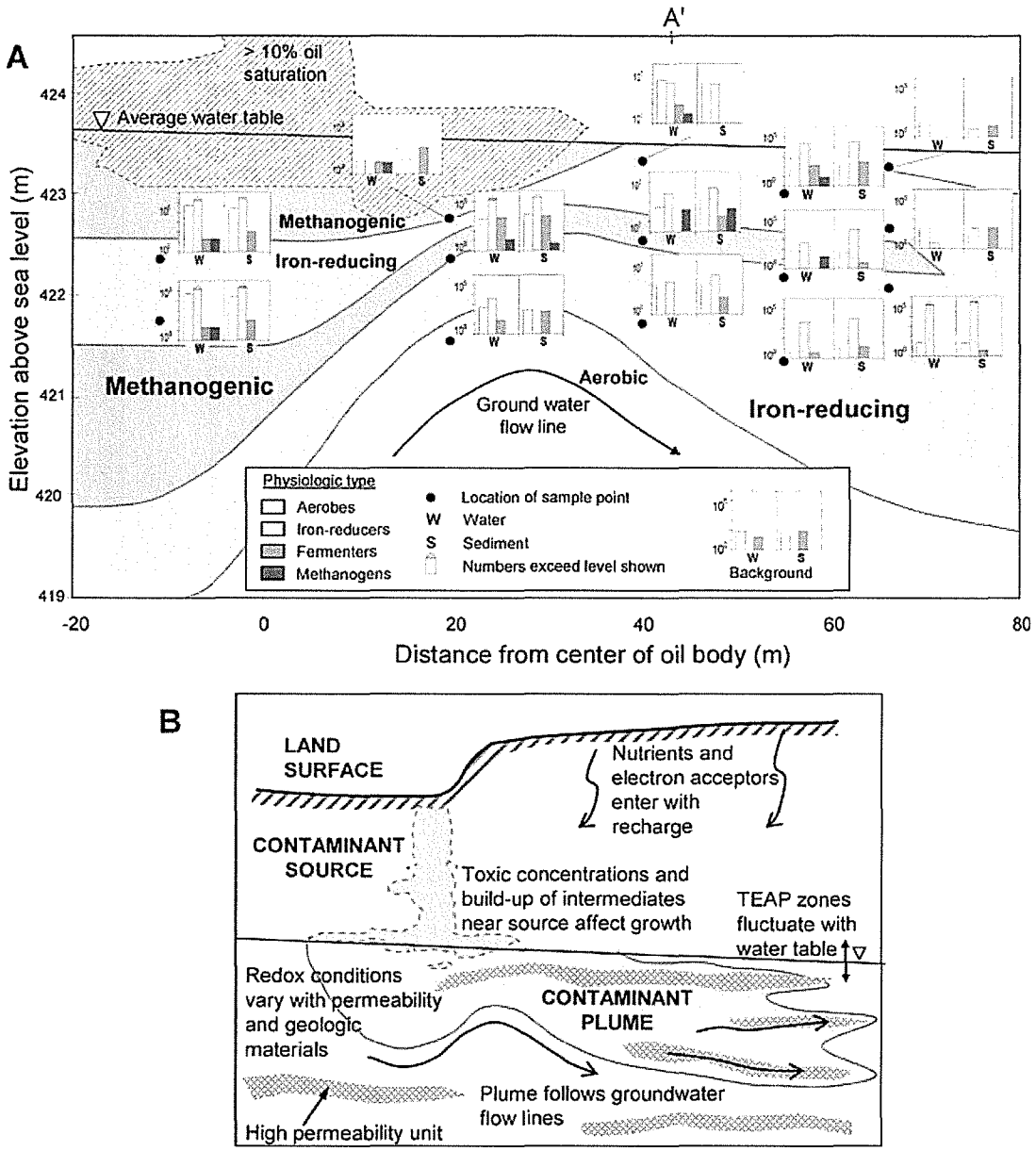

Figure 9. The influence of subsurface hydrologic and geochemical conditions on microbial populations in the hydrocarbon plume: (A) distributions of aerobes, iron reducers, methanogens, and heterotrophic fermenters in water and sediment within the north pool anaerobic plume (from Bekins et al. 1999); (B) conceptual model illustrating the complex interactions of recharge, water-table fluctuations, sediment heterogeneity, and geochemistry that influence microbial population growth (from Haack and Bekins 2000).

unsaturated zone, suggesting that nutrient limitations may be limiting growth in the saturated zone. Finally, the data indicated that an average of 15% of the total population was suspended, rather than attached to the solid substrate.

Haack and Bekins (2000) emphasized the importance of hydrogeological conditions on the evolution of terminal electron-accepting process (TEAP) zones and microbial populations (Figure 9B). Bekins et al. (2001) analyzed the microbial populations together with permeability, pore-water chemistry, NAPL oil content, and extractable sediment iron in the anoxic plume. Microbial data defined zones that had progressed from iron-reduction to methanogenesis as Fe^{3+} was depleted. These zones contained lower numbers of iron reducers, increased numbers of fermenters, and detectable methanogens. Methanogenic conditions existed both in the zone containing NAPL oil, and below the oil body in high permeability zones. High contaminant flux, either through local dissolution from the oil phase or increased advective transport through high permeability layers, played a key role in controlling first occurrence of methanogenic conditions. Other factors included the sediment iron content and proximity to the water table. Twenty years after the oil spill, a laterally continuous methanogenic zone had developed along a narrow horizon extending from the source area to 50 to 60 m downgradient of the oil body.

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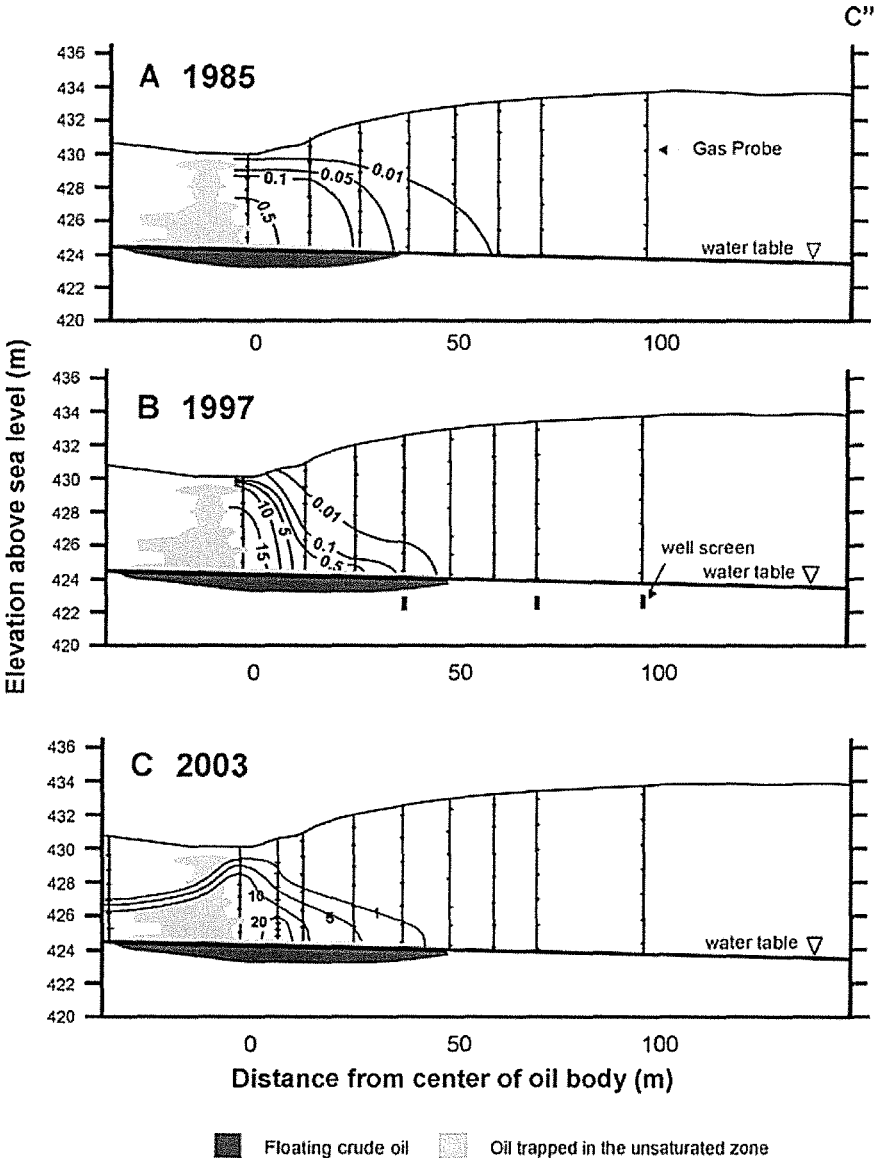

Figure 10. Unsaturated zone methane gas concentrations showing the increase with time as the plume became more methanogenic: (A) 1985 (modified from Hult and Grabbe 1988); (B) 1997 (from Chaplin et al. 2000); and (C) 2003 (modified from Amos et al. 2005).

The studies of microbial populations at Bemidji helped confirm that microbially mediated reactions and anaerobic biodegradation were responsible for the natural attenuation of hydrocarbons and observed plume geochemistry. The distribution and evolution of populations in a hydrocarbon plume are influenced by sediment properties, hydrologic conditions, and availability of electron acceptors and growth nutrients.

The Unsaturated Zone Vapor Plume

Volatile hydrocarbon compounds and biodegradation end-products are transferred from the NAPL oil and groundwater plume to the gas phase in the unsaturated zone. Understanding the factors controlling gas phase hydrocarbon transport is important for evaluating mass loss during natural attenuation and has relevance to the use of soil gas analysis as a field screening tool for NAPL contamination. Many techniques have been used to characterize unsaturated zone gas transport and biodegradation at the Bemidji site.

Mercer and Cohen (1990) cautioned that soil gas analysis could provide misleading results because unsaturated zone hydrocarbon gas concentrations were very sensitive to subsurface heterogeneity. Baehr and Hult (1991) documented the influence of heterogeneity when conducting pneumatic pump tests at Bemidji to estimate air-phase permeability, air-filled porosity and diffusion constants. They were able to characterize a thin silt horizon that separated the unsaturated zone into an upper and lower zone, with a sharp contrast in air permeability and moisture content above and below the silt lens. They illustrated

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that there was little air flow (and consequently little gas transport) across this interface.

Observation of unsaturated zone gas concentrations (hydrocarbon, oxygen [O_2], CO_2, and CH_4) at the north oil pool in 1997 was used to identify three geochemical zones shown in Figure 5 (Delin et al. 1998). The outer Zone 6 had near atmospheric concentrations of O_2. Zone 7, a transition zone, was defined by lower concentrations of O_2 (10% to 20%), hydrocarbon concentrations less than 1 part per million (ppm), and higher concentrations of CO_2 (0% to 10%) and CH_4 (0% to 10%). The inner Zone 8, immediately above the oil body, had the lowest concentrations of O_2 (0% to 2%) and contained the highest concentrations of CO_2 (>10%), CH_4 (>10%), and hydrocarbon (>1 ppm). Thus, the unsaturated zone vapor plume mirrored the saturated zone groundwater plume, suggesting a similar core of anaerobic degradation near the NAPL oil source. Hult and Grabbe (1988), Chaplin et al. (2002), and Amos et al. (2005) measured unsaturated zone CH_4, CO_2, and O_2 gas concentrations in 1985, 1997, and 2003, respectively. Their work showed that the vapor-phase plume above the oil body and adjacent to the oil trapped in the unsaturated zone has progressively become more anaerobic, with increasing methane concentrations (Figure 10), affirming the conceptual model of a vapor plume evolving from iron reducing to methanogenic conditions. In addition, Chaplin et al. (2002) observed that the hydrocarbon gases detected in the unsaturated zone in 1985 consisted mainly of C_{2-5} alkanes and smaller concentrations of aromatic compounds (benzene, cyclohexane, toluene, and methyl-cyclohexane). By 1997, hydrocarbon gas concentrations had decreased considerably and consisted mainly of C_{2-5} alkanes and methane with smaller concentrations of aromatic compounds (benzene, alylbenzenes, and toluene), suggesting that hydrocarbon loss by volatilization was decreasing with time, and that methanogenesis was increasing with time.

In addition to the volatilization of hydrocarbons from the oil phase, there is exchange of gases between the groundwater plume and the unsaturated zone. Revesz et al. (1995) observed that argon (Ar) and dissolved nitrogen (N_2) concentrations in the hydrocarbon plume were 25 times lower than background values and concluded that gas exsolution was removing dissolved CH_4 and gases from the groundwater. Isotopic evidence indicated that CH_4 was partly oxidized to CO_2 as it diffused upward through the unsaturated zone. Amos et al. (2005) used dissolved and vapor-phase gas data to study the processes controlling production, consumption and transport of methane in the subsurface. They found that regions of Ar and N_2 depletion and enrichment in the unsaturated zone were indicative of methanogenic and methanotrophic zones, respectively, and that reaction-induced advection, in addition to gas phase diffusion, was an important gas transport process at the site. In the saturated zone, the concentrations of dissolved Ar and N_2 were significantly lower in the methanogenic source region, implying that methane gas bubble formation and ebullition also removed the nonreactive Ar and N_2 gases. The Ar, N_2, and CH_4 gas concentrations returned to near background levels approximately 100-m downgradient of the oil source, significantly less than the distance predicted by advection rates, suggesting that the physical processes acting to attenuate the Ar and N_2 plumes must also be acting to attenuate the CH_4 plume. Finally, Amos et al. (2005) observed a slight depletion of N_2 relative to Ar near the oil body, suggesting nitrogen fixation by microbial activity.

Vapor concentrations in the unsaturated zone above the oil body have evolved with time due to volatile hydrocarbon depletion and TEAP progression to methanogenesis. Isotopes and inert gases have been shown to be useful markers for understanding the processes controlling gas transport and fate in the unsaturated zone.

Hydrocarbon Fate Modeling

Geochemical and transport models are effective tools for integrating field observations, testing hypotheses, determining the relative importance of simultaneously occurring processes, as well as quantifying reaction rates and system mass balance. The comprehensive, long-term field data set collected at Bemidji has provided an opportunity to test and refine modeling approaches. Efforts to model the fate of hydrocarbons in the Bemidji plume have become progressively more complex, providing increased insight into processes affecting the long-term fate of the groundwater and vapor plumes.

In the first modeling effort at the Bemidji site, Baedecker et al. (1993) used the geochemical mass-balance model NETPATH (Plummer et al. 1991) to deduce geochemical reactions occurring as groundwater flowed along a 40-m path in the anaerobic zone. The major reactions needed to reproduce the observed field geochemistry were dissolution of manganese and iron oxides, precipitation of siderite and a ferroan calcite, oxidation and reduction of total dissolved organic carbon (TDOC), and outgassing of CH_4 and CO_2. These results confirmed the conceptual model developed for the anaerobic Bemidji plume and described in the section above on geochemical evolution of the plume.

Essaid et al. (1995) modeled the evolution of the groundwater hydrocarbon plume and sequential use of terminal electron acceptors using the multispecies solute-transport and biodegradation model BIOMOC (Essaid and Bekins 1997). Relatively complex representations of sequential biodegradation processes, including aerobic biodegradation, manganese reduction, iron reduction, and methanogenesis with microbial growth and decay of three populations (aerobes, Mn/Fe reducers, and methanogens), were represented by multiple Monod kinetics with nutrient limitation. Simultaneous growth of Mn/Fe reducers and methanogens had to be allowed in the model to match observed concentrations. The source of hydrocarbon was represented by two operationally defined degradable dissolved fractions, VDOC and NVDOC, which entered the aquifer with recharge in the vicinity of the oil body. Model parameter estimates were constrained by published

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Monod kinetic parameters, theoretical cell yield estimates, and field biomass measurements and reaction stoichiometries. Despite considerable uncertainty in model parameter estimates, the simulations reproduced the general features of the observed groundwater concentrations (Figure 6) and the measured bacterial concentrations. Simulating the hydrocarbon plume made it possible to quantify the fate of the hydrocarbons. Model results indicated that 46% of the TDOC introduced into the aquifer was degraded: 66% of the VDOC and 39% of the NVDOC. Aerobic biodegradation accounted for 40% of the TDOC degraded and anaerobic processes accounted for the remaining 60%. Thus, the model results confirmed that anaerobic biodegradation was a very important process for natural attenuation of hydrocarbons.

In a subsequent modeling study, Essaid et al. (2003) considered dissolution from the oil body, transport, and biodegradation of BTEX compounds in the saturated zone. The studies of Eganhouse et al. (1993, 1996) had illustrated that individual hydrocarbon compounds dissolved and degraded at different rates (Figure 7). The goal of this modeling study was to estimate compound-specific BTEX field anaerobic biodegradation rates, the field-scale dissolution rate, BTEX removal from the oil body by dissolution, BTEX removal from the groundwater plume by aerobic and anaerobic biodegradation, and the influence of biodegradation on dissolution. The basic conceptual model included rate-controlled dissolution of BTEX from a stationary oil phase, first-order anaerobic degradation of dissolved BTEX, and a fixed rapid first-order rate of aerobic degradation of dissolved BTEX. Simplified representations of biodegradation and dissolution processes, involving as few parameters as possible, were used to facilitate inverse modeling. BIOMOC was used in conjunction with the universal inverse modeling code UCODE (Poeter and Hill 1998) to fit the extensive historical data from 1986 to 1997. BTEX concentrations in the oil and BTEX and DO concentrations in groundwater were simulated (Figure 11A). The estimated field-scale anaerobic biodegradation rates for toluene and *o*-xylene (0.2 and 0.03 d^{-1}, respectively) were greater than the dissolution rate coefficient (0.007 d^{-1}) resulting in limited plume extent. However, the estimated anaerobic biodegradation rates for benzene, ethylbenzene, and *m*, *p*-xylene (0.0007 d^{-1}, 0.0007 d^{-1}, and 0.002 d^{-1}, respectively) were less than the dissolution rate coefficient resulting in plumes that extended into the aerobic zone of the aquifer. The calibrated model was used to determine the BTEX mass balance in the groundwater plume (Figure 11B). Anaerobic biodegradation removed 77% of the total BTEX that dissolved into the water phase and aerobic biodegradation removed 17% (Figure 11B). However, estimated anaerobic biodegradation of individual dissolved hydrocarbon compounds ranged from a low of 51% for ethylbenzene to a high of 98% for toluene. Compounds that underwent less anaerobic degradation migrated downgradient to the oxic zone of the aquifer and consequently underwent greater aerobic degradation. These results were in good agreement with the mass-balance predictions of Essaid et al. (1995) confirming the importance of anaerobic biodegradation during natural attenuation, and illustrating that the relative importance of anaerobic processes was compound specific.

The model of Essaid et al. (2003) was also used to examine evolution of BTEX composition in the NAPL oil source. The degree of removal of BTEX from oil was influenced by oil saturation and rates of dissolution and biodegradation. BTEX removal was greatest in the low oil saturation fringes of the oil body where the interaction between flowing water and oil was the greatest (Figure 12). As expected, dissolution from the oil was greater for compounds with large effective solubility, such as benzene. However, toluene, with less than half of the effective solubility of benzene, experienced almost the same amount of dissolution from the oil (Figure 12). The rapid biodegradation of dissolved of toluene reduced water-phase toluene concentrations in contact with the oil, increasing the concentration gradient and enhancing dissolution. Loss from the oil body was minor for compounds having low solubility and small biodegradation rate (such as ethylbenzene). All BTEX compounds still had significant fractions remaining in the oil body after a simulation of 18 years of dissolution, potentially providing a long-term source of contamination.

Essaid et al. (2003) also explored an alternative iron-reduction conceptual model that modified the first-order anaerobic biodegradation process for benzene to be dependent on solid phase Fe^{3+} concentration, decreasing as ferric iron was depleted. The iron-reduction model produced plume behavior that was similar to that observed by Cozzarelli et al. (2001) and Bekins et al. (2001). The overall extent of the benzene plume was similar for both the basic (described above) and iron-reduction models (Figure 13). However, the simulated high concentration zone in the center of the plume (near the oil body) migrated downgradient in the iron-reduction case, as was observed in the groundwater plume (Figure 8), illustrating that depletion of Fe^{3+} in the anoxic zone could result in an increase in concentration with time.

Curtis (2003) developed a thermodynamically based reactive transport model with mineral dissolution and precipitation for geochemical conditions similar to those observed at Bemidji. He compared the common approach of simulating reactions of multiple TEAPs with an irreversible Monod rate law to reactive transport simulations where reactions were subject to the requirement that the Gibbs free energy of reaction (ΔG) be less than zero (or a threshold value). The order of preference of TEAPs is commonly assumed to be aerobic biodegradation, denitrification, Mn reduction, Fe reduction, sulfate reduction, and finally methanogenesis. This order of preference is based on standard geochemical conditions that may be very different from field conditions. The Monod method involves use of empirical inhibition constants to achieve sequential TEAPs and estimation of many parameters. Curtis (2003) performed simulations using a single

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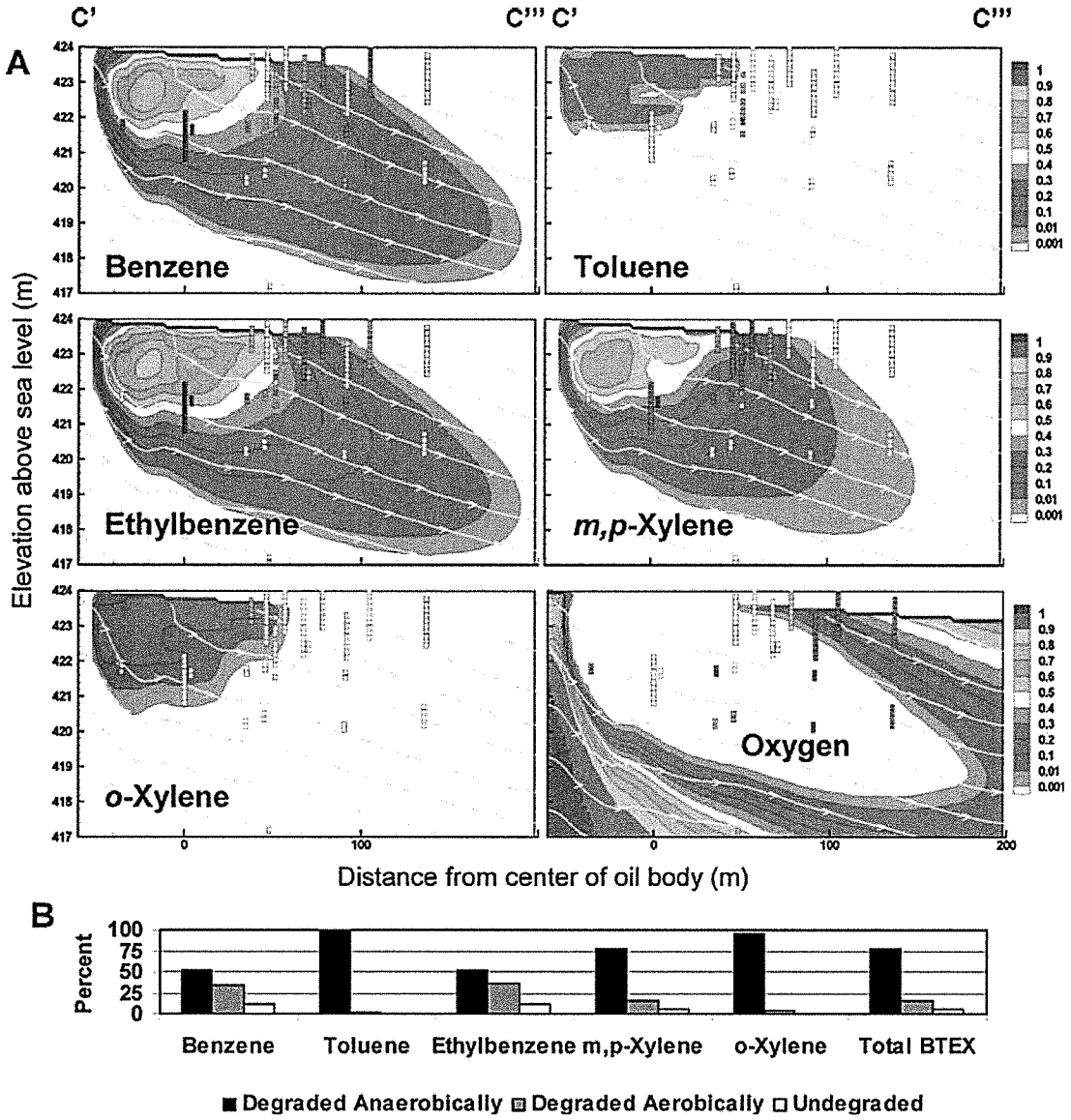

Figure 11. (A) The 1993 distribution of observed (boxes) and simulated (contours) BTEX and oxygen normalized concentrations showing that hydrocarbons with anaerobic degradation rates greater than their dissolution rate have limited plume extent (toluene and *o*-xylene), whereas compounds with anaerobic degradation rates less than their dissolution rate have plumes that extend to the aerobic zone (benzene and ethylbenzene); (B) model-predicted removal of dissolved BTEX by anaerobic and aerobic biodegradation (modified from Essaid et al. 2003).

organic substrate that was slowly and completely fermented to CO_2 and H_2. The hydrogen was then oxidized by the TEAPs with O_2, FeOOH, SO_4, and CO_2 as the terminal electron acceptors. Simulations using the Monod approach forced reduction of both FeOOH and CO_2 to proceed even when ΔG was positive, violating thermodynamics. This resulted in over prediction of FeOOH reduced to Fe^{2+} and large errors in pH. Curtis' (2003) alternate approach required a minimum number of reaction parameters and honored the governing thermodynamic constraints. Using H_2 as an intermediate was effective and efficient, allowing a fit to be obtained with only three reaction parameters. Applying this approach to Bemidji (Curtis et al. 1999) reproduced the observed pH buffering by methanogenesis, precipitation of authigenic mineral phases, parallel terminal electron acceptor use, and methane gas bubble formation.

Chaplin et al. (2002) determined unsaturated zone biodegradation mass removal rates by calibrating the gas transport model R-UNSAT (Lahvis and Bear 1997), using UCODE (Poeter and Hill 1998), to the observed O_2, CO_2, and CH_4 gas-concentration data. Reaction stoichiometry was used to convert O_2 and CO_2 gas-flux estimates to rates of aerobic biodegradation and convert CH_4 gas-flux estimates to rates of methanogenesis. Model results indicated that 3% of total volatile hydrocarbons diffusing upward from the floating oil were biodegraded in the bottom meter of the unsaturated zone in 1985. This increased to 52% by 1997, with methanogenesis responsible for approximately half of the removal. Chaplin et al. (2002)

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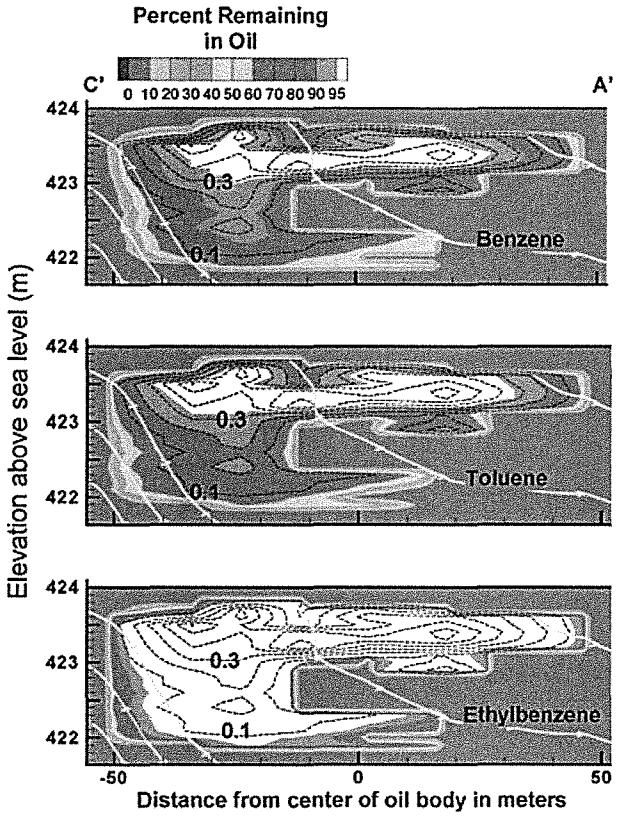

Figure 12. Simulated percent of benzene, toluene, and ethylbenzene remaining in the oil phase (relative to the initial amount in the oil body) after 18 years of dissolution and biodegradation. Dashed contours represent oil saturation and gray lines represent flow paths (from Essaid et al. 2003).

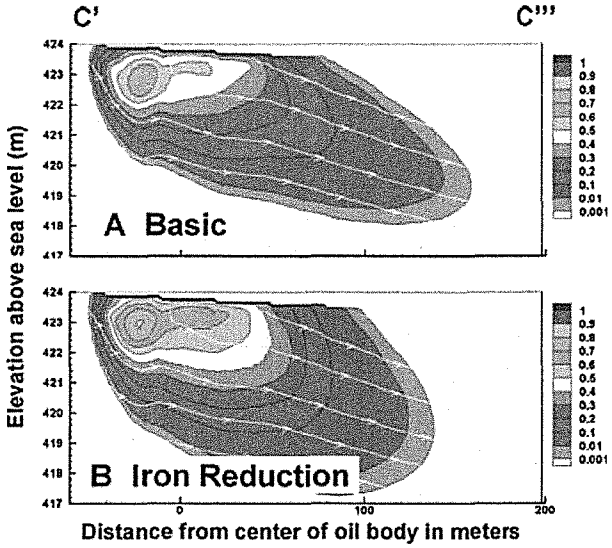

Figure 13. Predicted groundwater benzene concentration 50 years after the spill for the case of (A) a first-order anaerobic benzene biodegradation rate that is uniform in time and (B) a first-order anaerobic biodegradation rate that becomes zero when Fe^{3+} is depleted (from Essaid et al. 2003). The latter case reproduces the observed downgradient migration of the central high hydrocarbon concentration zone (see Figure 8).

concluded that volatilization was the primary mechanism for hydrocarbon removal in early stages of plume evolution, but that biodegradation became dominant in later stages as concentrations of volatile hydrocarbons in the oil decreased and microbial populations evolved.

Amos et al. (2005) provided field evidence that CH_4 and CO_2 production in the hydrocarbon plume formed gas bubbles, affecting groundwater chemistry and potentially solute transport. Amos and Mayer (2006) modified the unsaturated/saturated zone reactive transport code MIN3P (Mayer et al. 2002) to include the formation and collapse of gas bubbles in addition to kinetically controlled redox and mineral dissolution/precipitation reactions, equilibrium hydrolysis, aqueous complexation, ion exchange and surface complexation reactions. They examined processes related to gas bubbles and gas transport in the methanogenic hydrocarbon plume. Their simulations reproduced the observed depletion of the nonreactive gases N_2 and Ar where gas bubbles formed. They concluded that reduced permeability in the hydrocarbon source zone, caused by the formation of methane gas bubbles, and dissolution of low methane concentration bubbles entrapped during water-table fluctuations combine to reduce dissolved CH_4 concentrations in the anoxic plume.

Model development and application has been an important complement to the field analysis at Bemidji, affirming conceptual models developed from field and experimental observations. Models have progressively incorporated more complex processes and have provided a means to quantify mass removal and biodegradation rates. These modeling approaches have universal application to studies at other hydrocarbon contaminated sites.

Conclusions and Lessons Learned

In summarizing the status of NAPL knowledge at the end of the 1980s, Mercer and Cohen (1990) identified many limitations in the research community's understanding of subsurface NAPL behavior. Their recommendations for future research included: improved methods to measure in situ saturation; improved understanding of field constitutive relations (such as relative permeability functions); improved understanding of in situ volatilization and dissolution; studies of the influence of spatial variability on NAPL migration and recovery; and ongoing research at field sites to assess remediation strategies. They also pointed out that although many sophisticated models were available to simulate the flow of NAPL, they were mainly used in a conceptual mode because of the lack of chemical and site-specific data. Twenty-five years of study at the Bemidji crude-oil spill site has contributed significant knowledge in all of these areas.

Research at Bemidji has involved extensive investigations of multiphase flow and transport, volatilization, dissolution, geochemical interactions, microbial populations,

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and biodegradation. The challenge of understanding and predicting the fate of hydrocarbons in the field is that these processes occur simultaneously, interact with one another, and are influenced by subsurface flow rates. For example, oil present in the pore space reduces water flow and consequently reduces hydrocarbon dissolution. The feedback between groundwater flow, dissolution, and biodegradation influences the hydrocarbon plume extent. Also, the amount of nutrient rich recharge can impact biodegradation rates. Research at the Bemidji site has involved detailed monitoring and interpretation of field observations coupled with laboratory experiments and numerical process-oriented models of varying complexity. This combined approach has been used to synthesize and integrate field observations and develop a comprehensive understanding of the long-term fate of oil in the subsurface.

Early observations of groundwater geochemistry at Bemidji were among the first to document the importance of anaerobic processes for hydrocarbon removal and plume migration control (Baedecker et al. 1993; Eganhouse et al. 1993; Bennett et al. 1993). Aerobic biodegradation was known to be an effective hydrocarbon removal process. However, detailed characterization (Cozzarelli et al. 1990, 1994) and modeling (Essaid et al. 1995, 2003) of the Bemidji hydrocarbon plume illustrated that significant removal of hydrocarbons was also occurring in the central anaerobic core of the plume. Sequential use of terminal electron acceptors was observed (Baedecker et al. 1993; Bekins et al. 1999), coupled with selective structure-dependent biodegradation of hydrocarbon compounds (Eganhouse et al. 1996). Anaerobic biodegradation evolved from manganese reduction to iron reduction as manganese oxides were depleted. Iron reduction was shown to be very effective at hydrocarbon removal. When Fe^{+3} became depleted, methanogenesis became the predominant anaerobic biodegradation process. Methanogenic biodegradation was not as effective at removing hydrocarbon compounds as iron reduction, and consequent increases in hydrocarbon concentrations were observed in the core of the plume (Bekins et al. 2001; Cozzarelli et al. 2001). Certain BTEX compounds (such as toluene and *o*-xylene) were readily biodegraded and were not transported great distances in the plume. Benzene and ethylbenzene were more persistent. These findings illustrated that removal processes evolve with time, and estimates of removal rates made early in the life of a hydrocarbon plume may not be representative of future removal rates due to exhaustion of electron acceptors and/or nutrients. This must be kept in mind when evaluating the efficacy of natural attenuation as a remediation alternative at contaminated sites (Bekins et al. 2005b).

Spatial variability of hydraulic properties was found to be an important control on NAPL fate. The glacial outwash deposits at the Bemidji site consist primarily of moderately to poorly sorted sandy gravel, gravely sand, and sand with thin interbeds of fine sand and silt (Franzi 1988). The finer grained layers, although a small fraction of the subsurface deposits, have exerted an important influence on oil-phase flow. Observed and simulated oil-saturation distributions have illustrated that oil infiltration and redistribution are often controlled by grain-size heterogeneity due to its effect on pore size distributions and capillary phenomena (Hess et al. 1992; Essaid et al. 1993; Dillard et al. 1997). Where oil was entrapped above fine-grained layers that impeded downward movement, unsaturated zone oil saturations were still nearly 30% 20 years after the spill. Oil distributions in the saturated zone showed that the shape of the oil body floating on the water table was complex, and not lens shaped as would be expected in a uniform porous medium. Multiphase modeling studies showed that heterogeneity had to be included to reproduce this complexity (Essaid et al. 1993; Dillard et al. 1997). Modeling studies also showed that the oil flow was hysteretic, with infiltration and drainage following different characteristic curves. However, when the presence of the fine-grained layers was well characterized and explicitly represented in the multiphase flow model, hysteretic behavior could be reproduced simply through the effect of heterogeneity, without hysteretic characteristic curves.

Heterogeneity in hydraulic conductivity also influenced subsurface vapor diffusion, water flow, and the progression of biodegradation. Unsaturated zone air pump tests in an uncontaminated area showed that a thin low-permeability horizon could isolate air flow above and below it (Baehr and Hult 1991). Further studies of vapor-phase concentration above the oil body revealed a fine-grained horizon above which oxygen concentrations increased rapidly and below which there was a sharp gradient in methane concentrations (Amos et al. 2005). In the saturated zone, increased flow and mass transport rates in more conductive zones led to more rapid depletion of Fe^{2+} and more rapid evolution to methanogenic conditions (Haack and Bekins 2000; Bekins et al. 2001). Subsequently, BTEX compounds that degraded more slowly under methanogenic conditions were observed to increase in concentration and advance downgradient (Cozzarelli et al. 2001).

Considerable volumes of NAPL oil still remain in the subsurface despite 30 years of volatilization, dissolution, and biodegradation, and 5 years of pump-and-skim remediation (Herkelrath 1999; Enbridge Energy 2008). Concurrent with hydrocarbon plume evolution, the crude-oil source was evolving as hydrocarbon compounds degraded and dissolved at different rates (Landon 1993; Landon and Hult 1996; Eganhouse et al. 1996). Changes in the oil source are best described by examining two categories of hydrocarbon compounds: the relatively soluble aromatic fraction (including BTEX) and the relatively insoluble fraction (alkanes). For the soluble aromatic fraction, field data indicated that the upgradient part of the oil body underwent more dissolution than the downgradient end (Eganhouse et al. 1996). The inflow of relatively low hydrocarbon concentration groundwater created a concentration gradient across the oil-water interface driving dissolution of the soluble hydrocarbons. As water

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flowed downgradient past the oil body, hydrocarbon concentration increased and dissolution decreased. Modeling of dissolution and biodegradation processes has illustrated that dissolution is greatest where oil saturations are lower because of the greater flow of water through these zones (Essaid et al. 2003). Models results also have also shown that compounds with high effective solubilities (such as benzene) and/or large biodegradation rates (such as toluene) were depleted in the oil body more than other hydrocarbon compounds. Biodegradation in the water phase reduced hydrocarbon concentrations adjacent to the oil body, and consequently enhanced dissolution. The model results suggested that considerable BTEX still remained in the oil body 18 years after the spill.

The degree of depletion of the insoluble alkane fraction in the oil body (degradation state) did not depend on oil saturation, indicating that it was not caused by dissolution but instead was a result of methanogenic oil biodegradation (Bekins et al. 2005a). Alkane depletion was much higher in the area below a local topographic low where focused flow (Delin and Herkelrath 1999, 2005) has resulted in increased groundwater recharge and nutrient transport. Vastly different observed degradation states for the same starting oil composition from a single spill event invalidates use of degradation state to estimate the timing of a spill (Bekins et al. 2005a). Vapor-phase data indicate that methanogenic biodegradation was occurring in the oil body by 1987 and is the dominant degradation process today (Hult and Grabbe 1988; Revesz et al. 1995; Chaplin et al. 2002; Amos et al. 2005). Under methanogenic conditions the longer chain *n*-alkanes and alkyl side chains are depleted first, creating a fingerprint which can mimic a lighter fuel. This phenomenon was also observed at a diesel spill site in Mandan, North Dakota (Hostettler et al. 2007, 2008). Fingerprinting techniques used to identify the starting composition of spilled product must account for this degradation pattern and be based on other components of hydrocarbon fuels.

Detailed information from the Bemidji site has made it possible to develop increasingly complex models of the fate and transport of hydrocarbons in the groundwater plume. Geochemical mass-balance modeling (Baedecker et al. 1993) supported the hypothesis of anaerobic biodegradation of hydrocarbons in conjunction with dissolution of manganese and iron oxides, and outgassing of CH_4 and CO_2. Modeling of multispecies transport with sequential biodegradation represented by Monod kinetics showed that anaerobic processes removed more than half of the dissolved BTEX, and that iron reduction and methanogenesis had to occur concurrently to match observed plume concentrations (Essaid et al. 1995). Subsequent modeling based on thermodynamic constraints proved that this could be happening in the field (Curtis 2003). Inverse modeling with simple first-order biodegradation rates reproduced the general features of the plume, but failed to capture the subtle changes in the plume as it evolved from primarily iron reducing to methanogenic conditions (Essaid et al. 2003). Incorporating a switch from iron reducing to methanogenic conditions after the depletion of Fe^{3+} produced a simulated plume that reproduced the observed downgradient migration of the central high hydrocarbon concentration zone (Essaid et al. 2003). Reactive transport modeling including the effects of gas bubble formation and collapse has shown that outgassing and oxidation of methane has been an important process, and that bubble formation has impeded water flow (Amos and Mayer 2006).

Natural attenuation has been demonstrated to be an effective remediation strategy for many spills (Wiedemeier et al. 1999). However, transport and fate of hydrocarbons in the subsurface is a spatially and temporally complex problem. The persistent nature of the oil-phase hydrocarbon source and the long time frame for natural attenuation observed at Bemidji is not unique. Long-term field monitoring and process-oriented modeling at Bemidji has illustrated that hydrocarbon fate is compound specific and continually evolving with time. Thus, a snap-shot study of a hydrocarbon plume may not provide information that is of relevance to the long-term behavior of the plume under natural attenuation. Natural and induced changes in the oil source, redox conditions, microbial populations, recharge and flow rates will result in changes in plume extent. Ongoing research at the Bemidji crude-oil spill site continues to focus on providing insights and methods that will help us to understand and predict the evolution and fate of subsurface hydrocarbon plumes.

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Use of Long-Term Monitoring Data to Evaluate Benzene, MTBE, and TBA Plume Behavior in Groundwater at Retail Gasoline Sites

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Abstract: Long-term groundwater monitoring data for 48 retail gasoline sites were analyzed to define the characteristics of affected groundwater plumes containing benzene, methyl tert-butyl ether (MTBE), and tert-butyl alcohol (TBA). Results of this analysis were used to determine the observed range and statistical distribution of current plume lengths, plume stability conditions, constituent concentration trends and attenuation rates, and the remediation timeframe for this population of sites. The goal of this evaluation was to characterize plume behavior as observed across a variety of hydrogeologic settings, on the basis of detailed groundwater monitoring records, rather than to define the site-specific factors controlling plume behavior. The results indicate that MTBE plumes in groundwater underlying a majority of these underground storage tank sites that were monitored for five years or longer (1) have significantly diminished in concentration over time, (2) are comparable in length to benzene plumes, (3) are, like benzene plumes, principally stable or shrinking in size and concentration, and (4) are on track to achieve remedial goals within a timeframe comparable to or faster than that of benzene plumes. At these same sites, TBA plumes were found to be comparable to benzene and MTBE plumes in terms of plume length. However, whereas most TBA plumes are also stable or shrinking, the percentage of TBA plumes that are currently stable or shrinking (68%) is less than that for benzene plumes (95%) or MTBE plumes (90%), likely reflecting the temporary build-up of TBA concentrations in groundwater attributable to methyl tert-butyl ether (MTBE) biodegradation. Nevertheless, overall trends for TBA concentrations in groundwater indicate that TBA is attenuating at rates comparable to benzene and MTBE and can be expected to meet applicable remediation goals in a similar timeframe as the other gasoline constituents. **DOI: 10.1061/(ASCE)EE.1943-7870.0000488.** © *2012 American Society of Civil Engineers.*

CE Database subject headings: Groundwater pollution; Benzene; Plumes; Remediation; Gasoline.

Author keywords: MTBE; Benzene; TBA; Reformulated gasoline; RFG; UST; Groundwater plume behavior; Plume length; Attenuation rate decay rate; Remediation timeframe; Plume stability.

Introduction

In the 1990s, detections of methyl tert-butyl ether (MTBE) in the groundwater at petroleum storage tank sites and water supply wells generated considerable scientific and regulatory concern regarding the potential effect of this relatively new gasoline fuel additive on groundwater resources [USGS 1995; California Environmental Protection Agency (CEPA) 1999; USGS 2001]. In contrast to non-oxygenated gasoline fuel constituents, MTBE was known to be highly soluble in water, with low sorption coefficients, and was understood to be relatively recalcitrant to natural biological activity (Yeh and Novak 1991; Suflita and Mormile 1993; Hubbard et al. 1994; Mormile et al. 1994; Neilson 1994). As a result, some scientists predicted that, in comparison with non-MTBE gasoline, releases of MTBE-containing gasoline from underground storage tank (UST) sites would result in relatively long plumes of affected groundwater that would cause much longer-term effects on groundwater resources and drinking water supplies (Fogg et al. 1998; Odencrantz 1998; Weaver and Small 2002). These predictions were supported by the discovery of a few exceptionally long MTBE plumes extending thousands of feet down-gradient of the release point, such as in Long Island, New York (Weaver et al. 1996; Weaver et al. 1999).

However, studies evaluating actual field measurements of hundreds of MTBE plumes across the United States and abroad have found the true extent and duration of MTBE effects on groundwater to be much less than previously anticipated. Specifically, monitoring data for groundwater plumes at nearly 400 gasoline release sites in California (Happel et al. 1998; Shih et al. 2004), Texas (Mace and Choi 1998; Shorr and Rifai 2002; Rifai et al. 2003), South Carolina (Wilson et al. 2003), and Florida (Reid et al. 1999; Reisinger et al. 2000) show that MTBE plumes typically stabilize at relatively short lengths (< 200 ft), which are comparable to those of benzene plumes. Additionally, groundwater monitoring results from a total of 81 sites evaluated in Texas in 2002 (Shorr and Rifai 2002) and in Florida in 1999 (Reid et al. 1999) indicate that the majority of MTBE plumes (75%) are stable or decreasing in length. Furthermore, with regard to MTBE concentrations in individual monitoring wells, data from a total of 1628 monitoring wells in Texas (Rifai et al. 2003) and Connecticut (Stevens et al. 2006) indicate that MTBE concentrations in the groundwater are stable or decreasing over time in 74% of the wells evaluated. Research outside of the United States similarly reported the effects of MTBE

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on potable groundwater sources to be relatively limited on a regional scale. For example, in England and Wales, modeling analyses based on 3,000 groundwater samples from over 800 sites found that the potential plume dimensions for ether oxygenates, such as MTBE, did not pose a major threat to public water supplies (Environment Agency 2000). Additionally, a review of groundwater conditions at a number of sites with exceptionally large MTBE plumes discovered in the 1990s (Fogg et al. 1998; Odencrantz 1998; Weaver and Small 2002) indicate that the MTBE plume length and concentrations have diminished significantly over time [Environmental Assessment & Remediations (EAR) 2005; EAR 2011; New York State Department of Environmental Conservation (NYSDEC) 2011].

Nevertheless, some of these studies indicate that their conclusions may be of limited applicability or certainty owing to the short duration of groundwater monitoring history analyzed for individual sites (< 1 to 3 years) and/or insufficient evaluation of the plume stability condition (Happel et al. 1998; Shih et al. 2004). Employing short-term data to predict long-term plume trends can entail uncertainty because (1) short-term groundwater monitoring data are more vulnerable to seasonal fluctuations and sampling variability; and (2) employing short-term monitoring records could underestimate the true rate of attenuation of compounds, such as MTBE, that require longer acclimation periods to undergo biodegradation. Similarly, characterization of the plume stability condition is important for understanding whether the current plume length represents the maximum area of effect or if further plume expansion could occur.

In addition, recent reports on complex groundwater plumes (e.g., detached and/or diving plumes), such as those located in the Long Island, New York area (Weaver and Wilson 2000; Nichols and Roth 2006), in California (Wilson et al. 2004), in Illinois (Wilson et al. 2005), and in dual-porosity aquifers such as the Cretaceous Chalk in the United Kingdom (Thornton et al. 2006), note the importance of adequate monitoring networks to achieve detailed horizontal and vertical delineation of groundwater plumes at typical UST sites. In the absence of adequate horizontal and vertical delineation, failure to identify detached plumes or diving plume conditions could result in misinterpretation of the groundwater conditions at UST sites, such as underestimation of actual plume lengths. This study evaluates hydrogeologic conditions at each site to identify those sites at which diving plumes may be of concern because of elevated recharge rates, vertical flow gradients, and/or absence of stratigraphic features serving to impede downward plume migration.

The present study attempts to improve the understanding of MTBE plume behavior by (1) evaluating a database of geographically diverse sites with long-term groundwater monitoring records and (2) employing a comprehensive analytical approach that includes evaluation of current plume stability (including the potential for detached and diving plume conditions), current plume length, temporal concentration trends in groundwater, and attenuation rates for MTBE at these sites. In addition to MTBE, the behavior of benzene and tert-butyl alcohol (TBA) plumes in groundwater are evaluated and the long-term behavior of these three constituents in groundwater at these sites are compared. Benzene is used in this study as a representative component of non-MTBE fuel, for which the fate and transport characteristics in groundwater were well defined in prior studies, such as Weidemeier et al. 1999. TBA, an intermediate biodegradation product of MTBE, was shown to biodegrade in both aerobic and anaerobic environments (Zeeb and Weidemeier 2007). Evaluation of these three chemicals in groundwater at petroleum release sites is intended to characterize the behavior of MTBE relative to that of benzene, and the MTBE degradation product, TBA.

Methodology

This study was conducted using monitoring records from a database of 48 retail gasoline sites with historical detections of benzene and MTBE in groundwater. For this purpose, long-term monitoring records for UST sites, corresponding to sites with complete records for at least six monitoring wells for five years or more, were solicited from regulatory agencies, energy companies, and environmental consultants. Of an initial population of 54 sites, the number of sites found to meet the screening criteria was 48 for benzene, 48 for MTBE, and 38 for TBA. At each site meeting the minimum data requirements, plume behavior for each constituent was characterized by evaluating the current length, the current stability condition, the temporal concentration trends, the observed attenuation rates, and the timeframe necessary to achieve applicable remediation goals.

The groundwater remediation goals used to define the length of the affected groundwater plumes and evaluate the timeframe to achieve remediation endpoints are as follows: 5 μg/L for benzene, 10 μg/L for MTBE, and 12 μg/L for TBA. For benzene, the remediation goal corresponds to the federal maximum contaminant level (MCL) for drinking water (5 μg/L), (EPA 2009). For MTBE, the value corresponds to the New York State Department of Environmental Conservation (NYSDEC) groundwater standard for MTBE (10 μg/L), (NYSDEC 2008) and for TBA, the value corresponds to the California drinking water action goal (12 μg/L) (RWQCB 2004). The reported laboratory detection limits for groundwater analyses at the 48 sites evaluated in this study were rarely above the concentration limits (benzene = 6%; MTBE = 9%; TBA = 14%), providing an appropriate level of sensitivity to evaluate current compliance with remediation goals.

The following section describes the site database used in this study and the methodology used to evaluate plume behavior at each site.

Database of Long-Term Groundwater Monitoring Records for UST Sites

Key characteristics of the groundwater monitoring database for the 48 sites included in this study are as follows:

- Geographic location: The sites are located in various states in the United States with different histories of MTBE use; specifically, 63% of the sites are in California, 19% in New Jersey 10% in Alaska, 6% in Oregon, and 2% in Nevada. A majority of the sites (82%) are located in California and New Jersey, two states that together, represented 45% of the total MTBE consumption in the United States in 2001 (Lidderdale 2003).
- Current site use: Of the 48 UST sites, 30 are active service stations and 18 are inactive stations or vacant lots with no further potential for releases of gasoline.
- Release history: Available information indicates that underground fuel storage tanks and dispenser islands were principal sources of release of leaded and/or unleaded gasoline at the 48 sites evaluated. More than 70% of the 48 sites have records of releases occurring after 1992 or are active service stations that handled MTBE reformulated gasoline (RFG) after 1992.
- Environmental effects: Non-aqueous phase liquid (NAPL) or sheen was reported in monitoring wells at 34 of the 48 sites. Groundwater impacts were reported to be limited to a shallow aquifer unit at a majority of the sites, with only 6% of the sites reporting effects to more than one aquifer zone.

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- Groundwater monitoring program: For the 48 sites included in this study, the median number of groundwater monitoring wells per site is 17, with a median of four wells located in the source area ("source wells"), seven wells located within the plume downgradient of the source ("plume wells"), and six wells located outside of the affected groundwater plume ("delineation wells"). In this study, only wells designated as either source wells or plume wells were used to evaluate plume concentration trends. The median length of time that groundwater monitoring was underway at the 48 sites is 15 years for benzene, 11 years for MTBE, and eight years for TBA. Additionally, for the purpose of calculation of point attenuation rates, only those wells with more than eight years of monitoring data were used.
- Remediation history: For 44 of the 48 sites evaluated in this study, information was available regarding past or on going remedial actions for affected groundwater. In sum, seven sites (16%) were managed only by monitored natural attenuation (MNA); nine sites (20%) were addressed only with NAPL recovery; 13 sites (30%) received some form of active groundwater remediation (e.g., pump and treat, air sparging) without NAPL recovery; and 15 sites (34%) received some form of active groundwater remediation in combination with NAPL recovery.

As indicated by the relatively extensive monitoring well networks, the long groundwater monitoring periods, the past presence of NAPL, and the implementation of active remedies at a majority of the sites in this study, this database is more representative of sites with larger fuel releases and more extensive groundwater impacts as opposed to sites with only minor MTBE effects on groundwater (e.g., with a few monitoring wells showing low-μg/L concentrations of MTBE in groundwater). Consequently, the findings of this study should be understood to pertain to plumes at sites with relatively significant fuel releases and not to sites with de minimis releases of MTBE at which much shorter plume lengths and durations may be observed.

Evaluation of Groundwater Plume Behavior

For each of the 48 sites in this study, the behavior of the affected groundwater plume was evaluated as follows:

1. Plume stability: The current plume stability condition was characterized by two methods: (1) comparing the maximum spatial extent of the groundwater plume observed historically with the spatial extent observed during the most recent sampling event at the site and (2) evaluating long-term concentration trends in the wells located at the downgradient edge of the plume using the Mann-Kendall statistical method, as described in the MAROS software system [Air Force Center for Environmental Excellence (AFCEE) 2000]. For each constituent, the plumes were then classified as shrinking, stable, expanding, no trend, or detached. Plume concentration trends were characterized using the Mann-Kendall statistical method, as described in Aziz et al. (2003), as follows: (1) an increasing trend refers to a Mann-Kendall result of increasing with a significance level > 90%; (2) a decreasing trend refers to a Mann-Kendall result of decreasing with a significance level > 90%; (3) a stable condition refers to a Mann Kendall result of no trend at a significance level > 90% and with a coefficient of variation (COV) < 1 (indicating low degree of variability); and (4) no trend refers to a Mann-Kendall result of no trend but with a significance level < 90% and a high degree of variability ($COV > 1$). Using this approach, plume stability was evaluated for benzene at 42 sites, for MTBE at 41 sites, and for TBA at 34 sites.
2. Current measured and estimated plume length: Current plume lengths were determined either by (1) measuring the distance from the source location to the downgradient location meeting the remediation goal (i.e., a clean location), for those sites in which the existing monitoring well network included at least one clean downgradient well (designated as well-delineated plumes in this study); or (2) estimating the distance from the source to a clean downgradient location, using an empirical estimation method on the basis of the observed bulk attenuation rate (Newell et al. 2002), for those sites at which the current monitoring well network did not include a clean downgradient well. Plumes for which the lengths could not be either directly measured or estimated were designated as indeterminate.

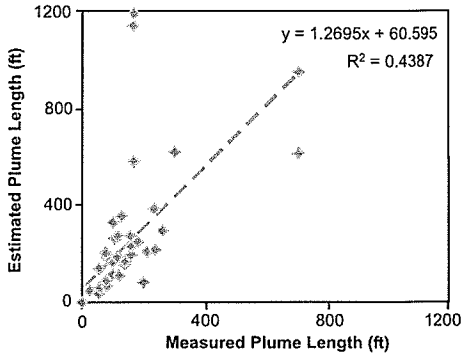

Fig. 1. Correlation between estimated ersus measured plume lengths at 30 UST sites with well-delineated MTBE, benzene, and TBA plumes

The available data were sufficient to provide measurements of plume length for 26 benzene plumes, 28 MTBE plumes, and 19 TBA plumes. These well-delineated plumes were considered the more reliable measure of plume length and were consequently used to check the plume length estimation method used for plumes with less complete delineation. As shown in Fig. 1, the estimated plume lengths for the well-delineated plumes, derived using the bulk attenuation rate, show a reasonable correlation to the true measured plume lengths at these sites (slope = 1.2, $R^2 = 0.43$), with the error tending toward overestimation of the true plume length in most cases. On this basis, this calculation method was considered a conservative method for estimating the plume length for those sites with less complete delineation. Using this methodology, estimated plume lengths were derived for an additional eight sites for benzene, seven sites for MTBE, and three sites for TBA.

Indeterminate plume lengths were found at 19% of the benzene sites, 15% of the MTBE sites, and 35% of the TBA sites in this study. To account for the effect of these indeterminate lengths on the plume population statistics (specifically, the median plume length), as a highly conservative measure the indeterminate plumes were assumed to be equal to or longer than the longest measured or estimated plume length determined for each constituent.

Additionally, to ensure that the available monitoring data provided a reliable measure of true plume dimensions, at each site and for each constituent the possible occurrence of a diving plume was evaluated on the basis of available data for vertical delineation of the plume. This entailed review of groundwater test results from the deeper monitoring wells on each site to confirm that the plume did not extend downward beyond the depth of the monitoring network, resulting in possible mischaracterization of the true plume length. Furthermore, each site was evaluated using the EPA plume dive calculator (Weaver and Wilson 2000) to determine whether site-specific hydrogeologic conditions could result in downward displacement of the plume

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sufficient to extend beyond the depth of the monitoring well network. Results of this analysis found none of the sites to pose a concern with regard to diving plumes. Stratigraphic features at each site may have played an important role in limiting plume dive in the groundwater underlying these sites (Wilson et al. 2005).

3. Current plume concentration trends: To evaluate the long-term temporal trends of constituent concentrations in groundwater at the 48 sites, monitoring data from individual wells that was sampled during eight or more sampling events, with detectable concentrations reported in four or more of these sampling events, were evaluated as follows:

   (1) Concentration trends in individual wells: To assess the trend of concentration versus time within each well, monitoring data from individual wells were statistically evaluated using the Mann-Kendall method, as described in the MAROS software system (AFCEE 2000). Additionally, to minimize the effect of analytical variability and data censoring attributable to the detection limit, only wells in which individual constituents had historically been detected above 20 μg/L were evaluated for concentration trends. Of the 589 source wells and plume wells installed at the 48 sites, 288 wells (43 sites), 306 wells (42 sites), and 241 wells (34 sites) met these minimum criteria for benzene, MTBE, and TBA, respectively.
   (2) Current versus historical compliance with applicable remediation goals: Monitoring data from individual wells that were sampled during at least one event after 2007 were evaluated for past and current compliance with the applicable remediation goals. In total, 218 wells (33 sites), 279 wells (34 sites), and 134 wells (22 sites) met these selection criteria for benzene, MTBE, and TBA, respectively.
   (3) Changes in maximum groundwater concentrations at individual sites over time: Additionally, as a simple measure of the change in plume concentrations over time on a site-wide basis, the maximum historical concentration of each gasoline constituent detected in any well during the initial 20% of the monitoring history at a site was compared with the maximum concentration reported at any well during the most recent sampling event conducted at the site after 2007. At the 48 sites, maximum concentrations of gasoline constituents measured in groundwater ranged between 45 μg/L and 120,000 μg/L for benzene, between 23 μg/L and 1,700,000 μg/L for MTBE, and between 68 μg/L and 700,000 μg/L for TBA. Reduction in maximum groundwater concentrations over time were evaluated at 42 sites for benzene, 41 sites for MTBE, and 34 sites for TBA.

4. Point attenuation rates in individual wells and at sites: A first-order rate of attenuation of chemical concentrations in the groundwater aquifer was calculated for each source well and plume well that exhibited a stable or decreasing concentration trend by estimating the slope of the lognormal plot of concentration versus time [lnC versus t; point attenuation rate, as defined in Newell et al. (2002)] for benzene, MTBE, and TBA at each well.
5. Additional and total remediation timeframe: For the purpose of this study, the additional remediation timeframe corresponds to the estimated future period required from the date of the last monitoring episode for each site (typically 2009) until the maximum constituent concentration measured at the site is reduced to the applicable remediation goal. This additional timeframe for each site was calculated using the site-specific average point attenuation rates (see point 4 above) and the most recent maximum concentration for each constituent (Newell et al. 2002). The total remediation timeframe for each compound was calculated as the sum of (1) the duration of groundwater monitoring period following the first detection of the constituent at the site and (2) the maximum estimated additional remediation timeframe necessary to meet the applicable remediation goal for that constituent. Using this approach, additional and total remediation timeframes were evaluated at 37 sites for benzene, 31 sites for MTBE, and 15 sites for TBA.

MTBE-degrading microbes are understood to require longer acclimation periods than the microbes that degrade benzene, toluene, ethylbenzene, and xylene (BTEX) constituents (Shah et al. 2009). Consequently, to avoid underestimating the true rate of biodegradation of MTBE in the groundwater, this evaluation included only those wells with long-term monitoring records (> 8 years) with detectable concentrations of gasoline constituents measured above the detection limit during four or more sampling events. Additionally, to ensure that the observed changes in the concentration were attributable to attenuation rather than an artifact of variable laboratory results or detection limits between sampling events, only those wells that exhibited concentrations above 200 μg/L for each gasoline constituent during the initial 20% of its monitoring history were used to calculate the point attenuation rate for that constituent. Using this approach, point attenuation rates were calculated for 187 wells (38 sites), 165 wells (30 sites), and 62 wells (16 sites) for benzene, MTBE, and TBA, respectively.

The "total remediation timeframe" for each compound was calculated as the sum of (1) the duration of groundwater monitoring period following the first detection of the constituent at the site and (2) the maximum estimated additional remediation timeframe necessary to meet the applicable remediation goal for that constituent. Using this approach, additional and total remediation timeframes were evaluated at 37 sites for benzene, 31 sites for MTBE, and 15 sites for TBA.

Results of Data Evaluation

Plume Stability

The results show that the vast majority of the benzene plumes (95%) and the MTBE plumes (90%) evaluated in this study are stable or diminishing in size (see Fig. 2). Less than 5% of benzene

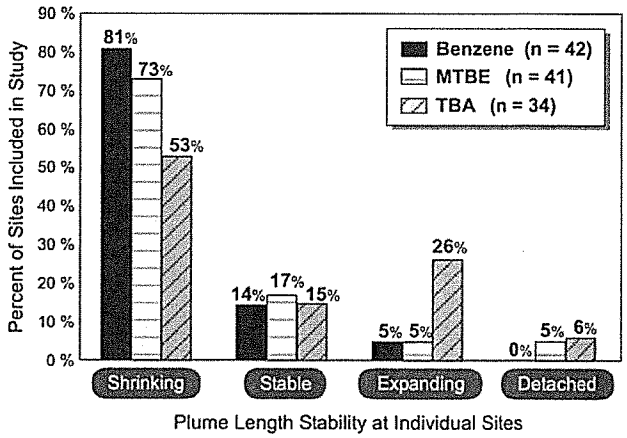

Fig. 2. Results of groundwater plume stability evaluation at individual sites

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plumes (2 of 42 sites) and MTBE plumes (2 of 41 sites) were observed to be expanding in size over time. MTBE plumes showed evidence of being detached from the original release area at a small number of sites (2 of 41 sites); however, comparison of the past and current dimensions of these detached MTBE plumes shows that the spatial extent of on-site and off-site groundwater impacts for these detached plumes is also diminishing in size. None of the 42 benzene plumes exhibited detached conditions.

For TBA, 68% of the plumes evaluated (23 of 34 sites) are currently stable or shrinking in size, whereas 26% (9 of 34 sites) were observed to be expanding in size over time. At the remaining two sites (6%), TBA was detected at higher concentrations in the plume wells than in the source wells, indicating a detached plume condition. The higher percentage of expanding TBA plumes (26%) compared with that of its parent compound MTBE (approx. 5%) suggests that, at some sites, biodegradation of MTBE has contributed to increased concentrations of TBA in the areas downgradient of the plume source area.

In summary, in terms of plume stability, MTBE plumes closely match the behavior of benzene plumes, with the vast majority of the MTBE plumes investigated (> 90%) being in a stable or diminishing condition. Additionally, preliminary evaluation of the MTBE footprint at the few sites with detached plumes shows that on-site and off-site groundwater impacts are now much smaller in size than in the past, thus suggesting that, similar to normal groundwater plumes, detached plumes also stabilize and attenuate over time and distance. Although a majority of the observed TBA plumes are also stable or diminishing (68%), the lower percentage relative to MTBE and benzene plumes likely reflects the temporary build-up of TBA concentrations in groundwater attributable to MTBE biodegradation. In general, TBA may persist within the portion of the plume where biodegradation of benzene, MTBE, and other gasoline constituents has depleted available electron acceptors, and then preferentially biodegrade in the downgradient portions of the plume, where higher concentrations of suitable electron acceptors are encountered.

Current Measured and Estimated Plume Lengths

For the purpose of this evaluation, plumes lengths were (1) measured directly for well-delineated plumes, (2) estimated using a conservative empirical relationship, or (3) characterized as indeterminate on the basis of available data (see the discussion in the Methodology section above). Results of the plume length evaluation for each category of plume are provided below and in Fig. 3.

(1) Measured plume lengths for well-delineated plumes: For sites with well-delineated plumes, the current median plume lengths, as measured by the monitoring well network, are 105 feet for benzene (26 sites), 75 feet for MTBE (28 sites), and 118 feet for TBA (19 sites) [see Fig. 3(a)]. The 90th percentile plume lengths for benzene, MTBE, and TBA at these same sites were 208 ft, 210 ft, and 226 ft, respectively. As a population, no statistically significant difference existed between MTBE plume lengths and benzene plume lengths at the same sites, as determined using the Student's t-test ($p = 0.69$). The two MTBE plumes found to be detached from the source area exhibited plume lengths of 550 ft (with a maximum downgradient extent 700 ft from the original source zone) and 510 ft (with a maximum downgradient extent 885 ft from the original source zone).

(2) Estimated plume lengths: For sites with stable or shrinking plumes at which the existing well network was not adequate to delineate the plume length but for which a bulk attenuation rate could be calculated (on the basis of a lnC versus distance plot), plume lengths were estimated using the method described in Newell et al. (2002) (see the discussion in the Methodology section above). For this population of sites, the current median estimated plume lengths are 354 feet for benzene (eight sites), 379 feet for MTBE (seven sites), and 371 feet for TBA (three sites) [see Fig. 3(b)].

(3) Measured and estimated plume lengths: In combination, the current median plume lengths were measured or were estimated to be 125 feet for benzene (34 of 42 sites), 110 feet for MTBE (35 of 41 sites), and 145 feet for TBA (22 of 34 sites) [see Fig. 3(c)]. For this data set, the 90th percentile plume lengths for benzene, MTBE, and TBA are 356 ft, 454 ft, and 366 ft, respectively [see Fig. 3(b)].

(4) Measured, estimated and indeterminate plume lengths: The plume length values presented above do not include indeterminate plumes, for which the plume lengths could not be measured or estimated on the basis of available data, corresponding to 19% of the benzene plumes (8 of 42), 15% of

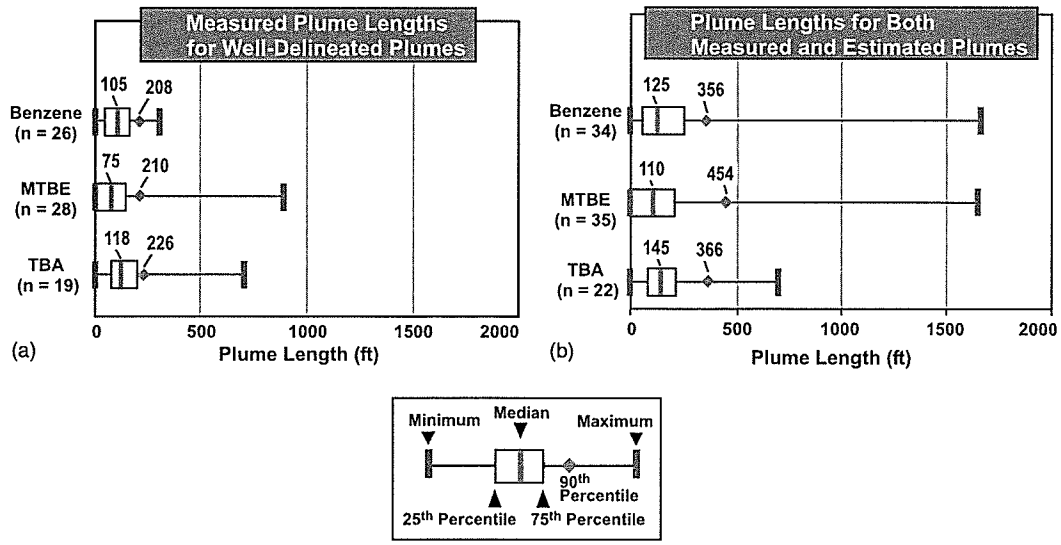

Fig. 3. Distribution of (a) measured plume lengths for well-delineated plumes; (b) measured and estimated plume lengths for all plumes

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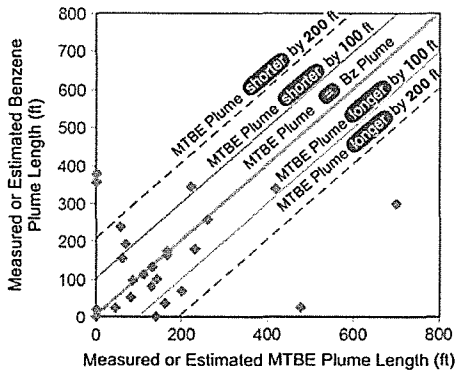

Fig. 4. Comparison of measured or estimated plume lengths for benzene versus MTBE

MTBE plumes (6 of 41), and 35% of TBA plumes (12 of 34) in our data set.

Given that these indeterminate plumes extended beyond the extent of the existing monitoring well networks, expecting that the average length of these plumes would exceed the average length of the plumes whose lengths were delineated or estimated is reasonable. Therefore, as a conservative measure, the median lengths of the full plume population, including the indeterminate plumes, were estimated using highly conservative assumption that all of the indeterminate plumes are equal to or longer than the longest measured or estimated plume length. Given this assumption, the adjusted median plume lengths for the full population of measured, estimated, and indeterminate plumes are 171 feet for benzene, 140 feet for MTBE, and 235 feet for TBA. These values correspond to a very conservative high-end estimate of median plume lengths and may significantly over estimate the true median plume length for this population.

(5) Comparison of MTBE and benzene plume lengths: On a site-by site basis, at the 33 sites at which both MTBE and benzene plumes were measured or estimated, the MTBE and benzene plumes are not statistically different on the basis of a Student's t-test analysis (assuming two-tail distribution and unequal variances between populations; p = 0.23). Fig. 4 provides a comparison of the MTBE and benzene plume lengths determined for these 33 sites. As shown, 70% of the MTBE and benzene plumes (23 of 33) are within +/ − 100 feet in length, whereas only 12% of sites (4 of 33) contained plumes that differed by more than 200 ft (see Fig. 4).

In summary, for the sites in this study, the lengths of MTBE plumes are comparable to those of benzene plumes (adjusted median values of 140 feet for MTBE versus 171 feet for benzene for all plumes, and unadjusted 90 percentile plume lengths of 454 feet for MTBE versus 356 feet for benzene for measured and estimated plumes). TBA plume lengths are also comparable to those of MTBE plumes (adjusted medians of 235 feet for TBA versus 140 feet for MTBE for all plumes, and unadjusted 90 percentile plume lengths of 366 feet for TBA versus 454 feet for MTBE for measured and estimated plumes).

Note that the applicable MTBE remediation goal employed in this study (i.e., 10 μg/L) is more stringent than groundwater standards applied in some states in the United States, including California (primary $MCL = 13$ μg/L) [California Department of Public Health (CDPH) 2009] and New Jersey ($MCL = 70$ μg/L) [New Jersey Department of Environmental Protection (NJDEP) 1997]. Consequently, the plume lengths presented in this paper represent a conservative overestimate of MTBE plume lengths subject to remedial action goals in those states.

Current Groundwater Concentrations and Concentration Trends

(1) Reductions in the maximum plume concentrations observed at each site: The monitoring records show that the maximum plume concentrations recorded within the initial 20% of the monitoring period decreased over time for 93, 90, and 74% of the benzene (40 sites), MTBE (38 sites), and TBA (26 sites) plumes evaluated in this study. Among these sites, the median reductions over time in the maximum historical groundwater concentration were 90%

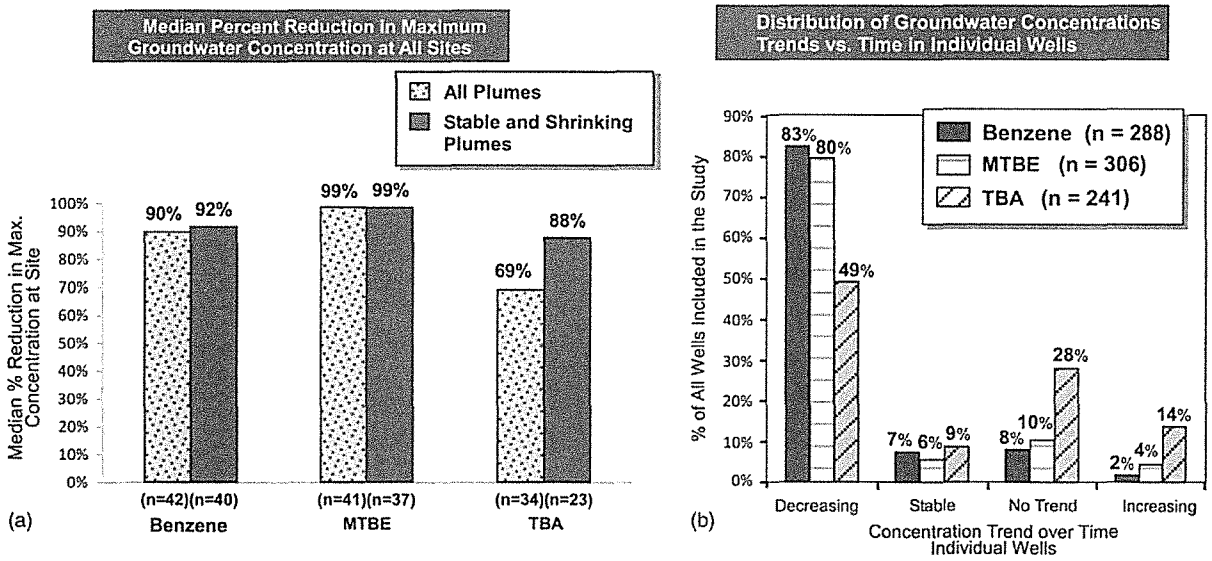

Fig. 5. Concentration Trends: (a) Median percent reduction in maximum groundwater concentration at all sites; (b) distribution of groundwater concentrations trends versus time in individual wells (Both stable plumes and no trend plumes have a Mann-Kendall result of "no trend." However, for our evaluation, consistent with the MAROS guidelines (Aziz et al. 2003), "stable" is used for "no trend" results for which the level of significance is > 90% and $COV < 1$, whereas no trend refers to no trend results with level of significance < 90% and/or COV > 1)

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for benzene, 99% for MTBE, and 69% for TBA [see Fig. 5(a). For those sites with shrinking or stable plumes, the percentage reductions in the maximum historical concentrations were slightly higher than for the full plume population, at 92% for benzene (40 sites), 99% for MTBE (37 sites), and 88% for TBA (23 sites). At sites with detached MTBE plumes (two sites) or TBA plumes (two sites), the concentration reduction was observed to be approximately 92% for MTBE and 81% for TBA.

(2) Concentration Trends in Individual Monitoring Wells: Evaluation of the concentration trends in individual monitoring wells found concentrations to be stable or diminishing over time for 90% of wells with detectable benzene and for 86% of wells with detectable MTBE [see Fig. 5(b)]. Less than 2% of the wells containing benzene and less than 4% of the wells containing MTBE exhibit increasing concentration trends. For TBA, 58% of individual wells show stable or diminishing concentration trends over time, whereas 13% of the wells exhibit increasing trends.

(3) Current versus historical compliance with applicable remediation goals:

All wells: The number of monitoring wells that meet the remediation goals for benzene and MTBE increased significantly over the monitoring periods [see Fig. 7(a)]. Specifically, the percentage of individual monitoring wells that meet the selected remediation goals (i.e., 5 μg/L for benzene and 10 μg/L for MTBE) increased from 10 to 48% for benzene and from 11 to 57% for MTBE, representing an approximate five-fold increase in compliance for each constituent. The percent of individual monitoring wells for which TBA meets the selected remediation goal (12 μg/L) also increased, but by a lesser margin than the other two constituents, increasing to 25% in the most recent sampling episodes compared with 16% historically, an approximate 60% increase. In general, the percentage of plume wells in compliance with the remediation goal is greater than those located in the source area, which is consistent with the commonly observed pattern of concentrations diminishing more rapidly in the downgradient portion of the plume, with measurable concentrations persisting for a longer period in the source area.

Site-wide evaluation: On a site-wide basis (i.e., in 100% of monitoring wells), 12% of the 43 sites affected by benzene, 24% of the 42 sites affected by MTBE, and 14% of the 35 sites affected with TBA presently meet the applicable remediation goal for all monitoring wells [see Fig. 6(b)]. Historically, none of these sites met the remediation goal on a site-wide basis for all monitoring wells.

In summary, during the monitoring period, the majority of sites investigated in this study experienced significant reductions in maximum plume concentrations for benzene, MTBE, and TBA (i.e., > 69% of sites for all three compounds). The median reduction observed in the maximum concentration in MTBE plumes (99%) exceeds that of benzene plumes (90%) for the full plume populations [see Fig. 5(a)]. Within individual monitoring wells, MTBE exhibits concentration trends comparable to those of benzene, with 86 to 90% of wells showing stable or diminishing concentrations over time. As a result, a much larger percentage of wells now comply with these remediation goals than was observed at the beginning of the monitoring period. Relative to benzene and MTBE plumes, a smaller percentage of TBA wells (58%) exhibit stable or diminishing concentrations, whereas a larger percentage indicate increasing concentrations (13%), which may reflect the temporary increase in TBA concentrations attributable to biodegradation of MTBE.

Detached MTBE and TBA plumes exhibit concentration reductions (MTBE: 85 to 99% reduction; TBA: 71 to 91% reduction) similar to those of non-detached plumes (MTBE: 29 to 100% reduction; TBA: 11 to 100% reduction). The median concentration reduction exhibited by all TBA plumes (69%) is less than that of MTBE (99%) and benzene plumes (90%), possibly reflecting the temporary build-up of TBA concentrations attributable to biodegradation of MTBE.

Point Attenuation Rates in Individual Wells

For wells exhibiting a trend of stable or diminishing concentrations over time, the data are amenable to calculation of a point attenuation rate (i.e., on the basis of C versus t) using the standard methods described in Newell et al. (2002). (Note that, in this paper, when concentrations are declining over time, the rate constant has a negative value; when concentrations are increasing over time, the rate constant is positive). The concentration attenuation rates observed in individual wells for the three gasoline constituents under study are as follows.

(1) Point attenuation rates in individual wells: First-order point attenuation rates estimated for benzene in 188 wells (39 sites)

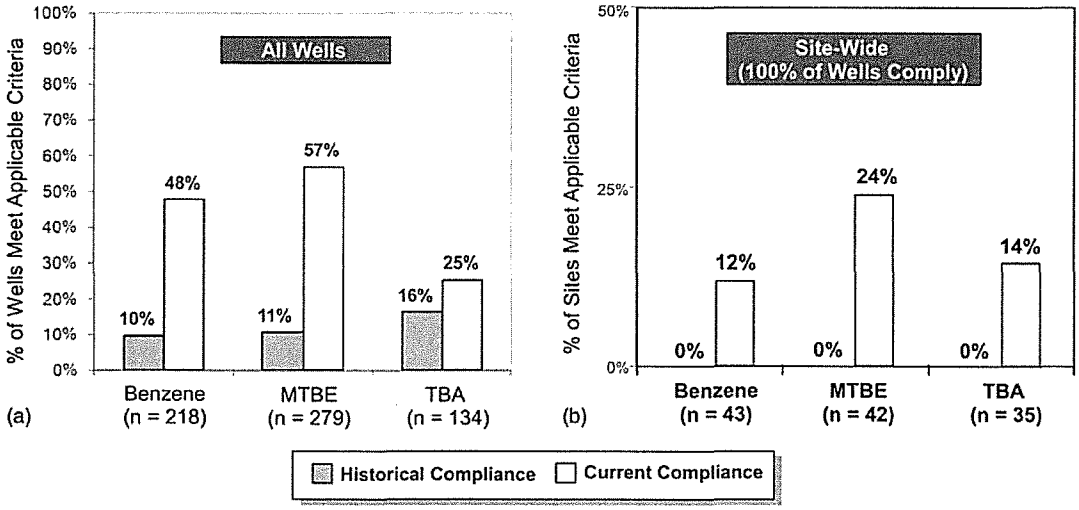

Fig. 6. Comparison of historical versus current compliance with remediation goals

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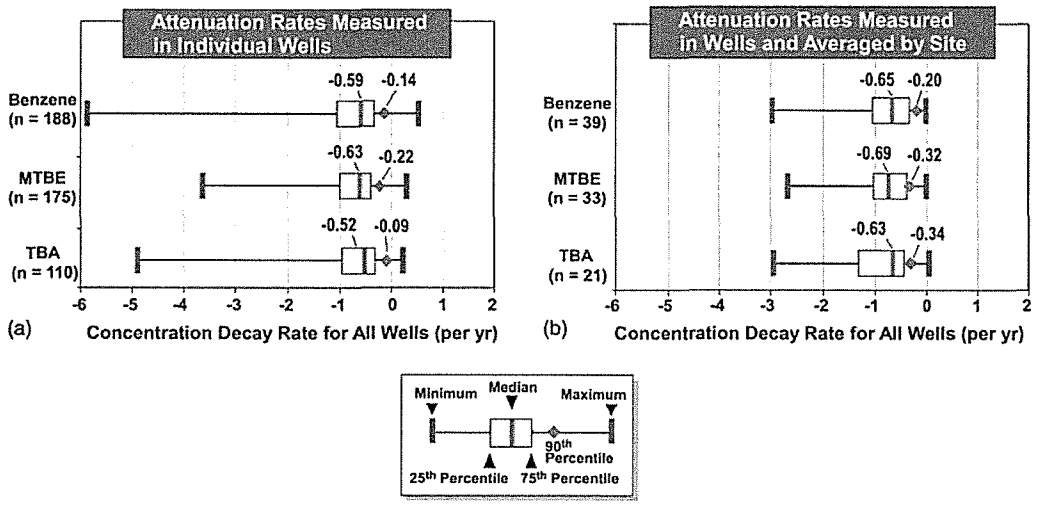

Fig. 7. Comparison of point attenuation rates for benzene, MTBE, and TBA at sites with stable or shrinking plumes

ranged from −5.8 per year to 0.52 per year, with a median value of −0.59 per year [see Fig. 7(a)]. For MTBE, first-order attenuation rates were estimated for 175 wells (33 sites) and were observed to range from −3.6 per year to 0.29 per year, with a median value of −0.63 per year. TBA degradation rates were estimated for 110 wells (21 sites) and ranged from −4.9 per year to 1.71 per year, with a median value of −0.52 per year.

(2) Median point attenuation rates in wells at each site: Site-wide attenuation rates obtained by calculating the median attenuation rate for individual wells at each site are shown in Fig. 8(b). Attenuation rates ranged between −0.12 and −2.9 per year (median = −0.65 per year) for benzene, −2.7 and 0.01 per year (median = −0.69 per year) for MTBE, and −2.94 and 0.025 per year (median = −0.63 per year) for TBA. These median attenuation values are comparable, but slightly faster (i.e., more negative), than the values determined for each chemical on the basis the full well population [see Fig. 7(a)].

In summary, concentration trends in individual wells and on a site-wide basis indicate that the point attenuation rates of benzene, MTBE, and TBA are similar

Overall Plume Attenuation Rates Based on Trend of Median and Maximum Concentrations among All Sites

As an alternative measure of the relative behavior of benzene, MTBE, and TBA in groundwater, the overall concentration trend for each constituent among the full population of sites was characterized as the change in the median and maximum concentrations versus time among all sites, as shown on Figs. 9(a) and 9(b) and discussed below.

(1) Reduction in overall median concentration versus time for full site population: The median concentrations of benzene, MTBE, and TBA in groundwater for the full site population all decreased significantly over the past 10 years. As indicated in Fig. 8(a), the overall attenuation rates (C versus t) exhibited by these median concentration values over the past 10 years are −0.20 per year, −0.47 per year, and −0.27 per year for benzene, MTBE, and TBA, respectively, corresponding to half lives of 3.4, 1.5, and 2.5 years.

(2) Reduction in maximum concentration versus time for full site population: Similar to the median values, the maximum concentrations of benzene, MTBE, and TBA in groundwater for this site population also decreased significantly over the past 10 years.

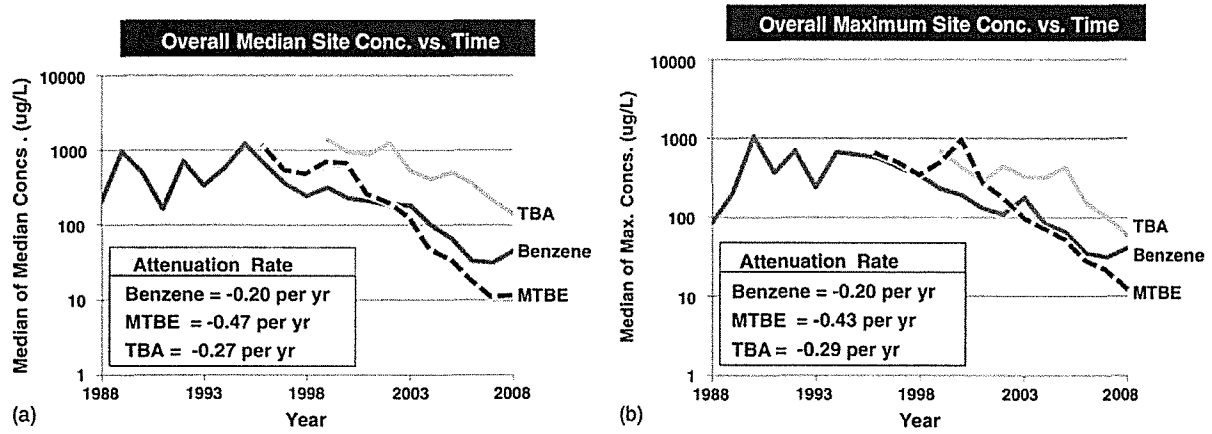

Fig. 8. Trend in site-wide median and maximum plume Concentrations versus time

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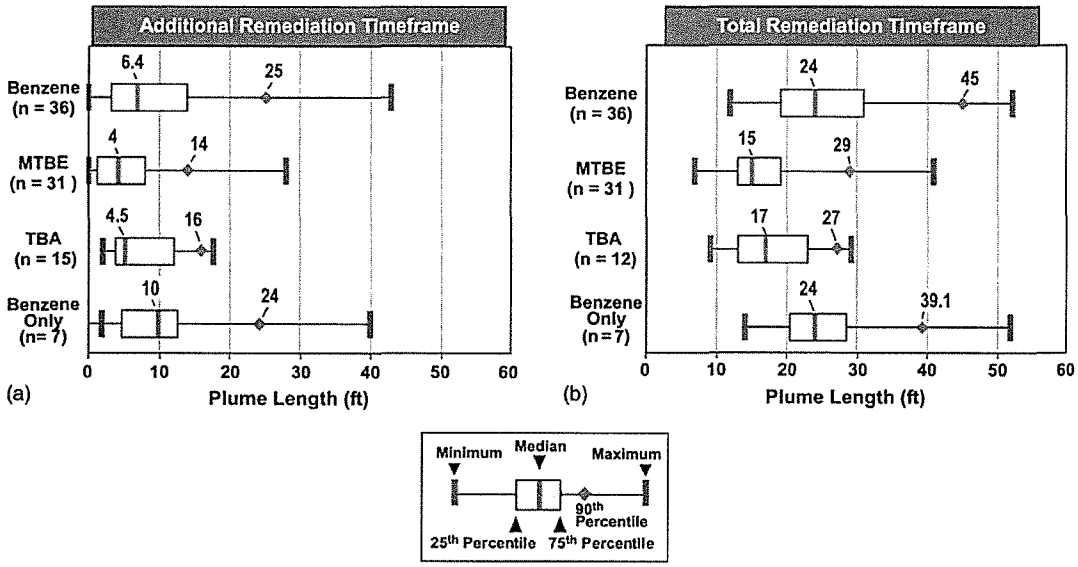

Fig. 9. Time to Remediation for Sites with Stable or Shrinking Plumes ("Benzene Only" refers to those sites where only benzene, not MTBE or TBA, exceeded the applicable remediation goal.)

As indicated in Fig. 8(b), the overall attenuation rates (C versus t) exhibited by these maximum concentration values over the past 10 years are −0.20 per year, −0.43 per year, and −0.29 per year for benzene, MTBE, and TBA, respectively, corresponding to half lives of 3.5, 1.6, and 2.4 years.

In summary, when evaluated on the basis of the full site population, both the median and maximum MTBE concentrations measured in groundwater are observed to decrease at a faster rate than the median and maximum concentrations of benzene. The faster attenuation rate observed for MTBE relative to benzene may reflect the effect of (1) the discontinued use of MTBE in the past decade, as a result of which unlike benzene, additional releases of MTBE cannot occur at active UST sites and/or (2) the much higher solubility of MTBE, compared with benzene, which can result in a more rapid rate of dissolution and depletion of MTBE from the source, eventually resulting in lower contributions of MTBE from the source to the plume, relative to benzene.

The median and maximum TBA concentrations observed for this site population are generally higher than either MTBE or benzene. In addition, TBA exhibits an overall average attenuation rate that is slower than MTBE. These observations are consistent with a temporary build-up of TBA, as a biodegradation product of MTBE, and limited biodegradation of TBA within the more concentrated portions of the plume in which electron acceptors were depleted by preferential biodegradation of BTEX and MTBE.

Effect of Active Groundwater Remediation on Plume Attenuation Rates

To evaluate the influence of active remediation on plume concentration trends, attenuation rates at sites at which active groundwater remediation and/or LNAPL recovery were conducted were compared with attenuation rates at those sites that were managed by MNA only. Table 1 summarizes the median attenuation rates determined for sites classified as: (1) MNA only, (2) NAPL recovery only, (3) groundwater remedy only, or (4) groundwater remedy plus NAPL recovery, on the basis of whether such actions were conducted for any period of time in the site history.

Student's t-tests (two-sided) comparing these four groups found that, for all three plume constituents, no statistically significant difference existed between the attenuation rates observed between (1) MNA-only sites versus groundwater remedy only sites (groups 1 and 3 in Table 1; p-value range for the three compounds = 0.10–0.43) or between (2) the combined population of MNA-only plus NAPL recovery only sites (groups 1 and 2 in Table 1) versus the combined population of groundwater remedy only and groundwater remedy with NAPL recovery sites (groups 3 and 4 in Table 1) (p-value range for the three compounds = 0.33–0.62). This analysis indicates that, for this set of sites, active groundwater remedies did not serve to measurably alter the rate of attenuation of plume concentrations versus time for the benzene, MTBE, or TBA. Rather, the fact that groundwater remedy only sites display attenuation rates comparable with those of MNA-only sites suggests that

Table 1. Comparison of Attenuation Rates of Median Plume Concentration versus Time for Different Remedial Action Conditions

	Benzene		MTBE		TBA	
Groundwater remediation method	No. of Sites	Median attenuation rate (1/yr)	No. of sites	Median attenuation rate (1/yr)	No. of sites	Median attenuation rate (1/yr)
1) MNA only	7	−0.20	6	−0.56	3	−0.23
2) NAPL recovery only	9	−0.13	9	−0.42	7	−0.18
3) Groundwater remedy only	13	−0.27	14	−0.47	12	−0.24
4) Groundwater remedy with NAPL recovery	13	−0.09	13	−0.46	11	−0.06

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natural attenuation is likely the dominant attenuation mechanism for this population of sites. This observation is supported by the overall trend of TBA and MTBE concentrations across the full population of sites (see point 5 above). The presence of TBA in groundwater at concentrations greater than MTBE similarly indicates that biodegradation of MTBE (i.e., conversion to TBA) is the dominant mass removal mechanism for MTBE and that this natural attenuation process is more significant than active remediation for this site population.

The finding that groundwater plumes at sites managed by MNA only versus sites managed by active groundwater remediation are comparable is consistent with prior investigations of large populations of BTEX plumes (benzene, ethylbenzene, toluene, and xylene), as reported in Newell and Connor (1998). Specifically, studies by Rice et al. (1995) of 208 BTEX plumes in California and by Mace et al. (1997) of 93 BTEX plumes in Texas found no statistical difference in plume lengths between active groundwater remediation sites and MNA only sites.

In summary, the attenuation rates of the median concentrations of the three plume constituents are equivalent for sites in which active groundwater remediation was conducted versus sites in which only MNA was applied. In the absence of more detailed information regarding the remediation activities at each of the sites in this study, particularly with regard to the mass of constituents removed or destroyed, and a comparison of plume conditions before and after the remedy, a degree of uncertainty in this analysis is recognized with respect to the effect of remediation on plume conditions. For example, remediation efforts that remove a significant portion of the source mass from the groundwater can certainly serve to reduce the maximum plume size and increase the rate of plume shrinkage. However, at face value, the similarity of the attenuation rates observed at actively remediated versus nonactively remediated sites suggests that natural attenuation of benzene, MTBE, and TBA may be the principal mechanism of mass removal for this population of plumes.

Additional and Total Remediation Timeframe

For sites with stable or shrinking plumes, which are amenable to calculation of point attenuation rates (C versus t), the average attenuation rates calculated for each site (see item 4b above) were used to calculate the additional time necessary for the site to meet the applicable groundwater remediation goal [see Fig. 9(a)]. The additional remediation timeframe was estimated to range from 0 to 43 years for benzene (median = 6.4 years for 36 sites), 0 to 28 years for MTBE (median = 4 years for 31 sites), and 2 to 18 years for TBA (median = 4.5 years for 15 sites).

For this same population of sites, the total remediation timeframe was determined as the sum of the additional remediation timeframe plus the number of years since monitoring first began on the site. The total remediation timeframe was estimated to range from 12 to 52 years for benzene (median = 24 years for 36 sites), 7 to 41 years for MTBE (median = 15 years for 31 sites), and 9 to 29 years for TBA [median = 17 years for 15 sites; see Fig. 9(b)]. For sites with MTBE and/or benzene plumes, the combined total timeframe to reach applicable remediation goals is within the range 16 to 53 years, with a median timeframe of 28 years. For sites at which only benzene ever exceeded the applicable remediation goal (i.e., no exceedance for either MTBE or TBA), the total remediation timeframe was estimated to be from 14 to 52 years (median = 24 years; 7 sites).

In summary, evaluation of the additional and total timeframe required to achieve remediation goals again shows benzene and MTBE plumes to exhibit similar behavior. Note that the total remediation timeframes for benzene and/or MTBE plumes combined (range of 16 to 53 years, with a median timeframe of 28 years) are comparable to the total remediation timeframes for sites at which groundwater impacts are limited to the presence of benzene only, with no MTBE effects above the applicable remediation goal (range of 14 to 52 years, with a median of 24 years). These results indicate that MTBE plumes are not recalcitrant in comparison to benzene plumes; in contrast, they can be expected to attenuate within the same general timeframe. Indeed, as suggested by the data in this study, at many sites, MTBE plumes may be observed to reach remediation goals more quickly than the benzene plume.

Comparison to Previous Studies

Earlier studies predicted that, in comparison to non-MTBE gasoline, releases of MTBE-containing gasoline from UST sites would result in relatively long plumes and much longer-term effects on groundwater resources (Fogg et al. 1998; Odencrantz 1998; Weaver and Small 2002). However, the results of the evaluation of gasoline plume behavior at 48 sites located in diverse hydrogeologic settings across the nation indicate that at a majority of UST sites that were monitored for five or more years: (1) the MTBE concentrations in groundwater significantly diminished over time, (2) MTBE plume lengths and stability conditions are comparable to benzene plumes, and (3) MTBE plume attenuation is on track to achieve remedial goals within a timeframe comparable to or less than that of benzene plumes. These findings are consistent with other studies that examined monitoring data for large populations of UST sites across the nation and found that the spatial extent and duration of MTBE effects on groundwater resources is much less than previously anticipated (Mace and Choi 1998; Reid et al. 1999; Shorr and Rifai 2002; Rifai et al. 2003; Wilson et al. 2003; Shih et al. 2004; Stevens et al. 2006). Review of our specific findings with regard to those of previous studies is summarized in Table 2 and discussed in further detail below.

1. Plume stability: The percentage of stable or shrinking MTBE plumes at the 41 sites evaluated in this study (90%) is toward the upper end of the range of values (50 to 96%) published in previous studies for a total of 81 sites evaluated in Texas in 2002 (Shorr and Rifai 2002) and in Florida in 1999 (Reid et al. 1999). These results suggest that, given the longer monitoring periods that were the focus of the current study and the greater passage of time since the release, a larger percentage of MTBE plumes will attenuate to a stable or shrinking condition.
2. Plume length: The median MTBE plume length determined in this study (adjusted upper-end median of 140 feet) is on the lower end of the range of median lengths (140 feet to 178 feet) reported in earlier studies (Mace and Choi 1998; Wilson et al. 2003; Reid et al. 1999). Again, this shorter median plume length may reflect the longer monitoring periods for the sites included in this study, which is consistent with continued attenuation of MTBE plume lengths over time.
3. Point attenuation rate: The median attenuation rate for MTBE in groundwater (–0.63 per year) reported for the sites include in this study is faster than the attenuation rate values published in previous studies (median of –0.35 per year) for MTBE-affected sites undergoing natural attenuation only (Schirmer et al. 1999; Wilson and Kolhatkar 2002; Hansen et al. 2003; Rifai et al. 2003; EPA 2005). The faster MTBE attenuation rates observed in this study may reflect the effect of the longer monitoring period, which may provide a more accurate estimate for attenuation rates for compounds, such as MTBE, that entail longer periods for acclimation of the in situ bacterial population.

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Table 2. MTBE Plume Characteristics Reported in the Current Study versus that Reported in Literature

MTBE plume characteristic	Results for MTBE plumes: Current study — No. of sites	Current study — Value	Prior studies of data for multiple plumes — No. of sites	Prior studies — Value	Reference	Comments
Percent of stable or shrinking plume	41	90%	81	50% to 96%	(Shorr and Rifai 2002; Reid et al. 1999)	Results fit within the range of previous findings, but indicate higher % of stable/shrinking plumes.
Plume length (feet)	35	Median = 140 ft[a]	356	Median = 140–178 ft	(Mace and Choi 1998; Wilson et al. 2003; Reid et al. 1999)	The study finds median MTBE plume length to be at lower end of range in prior studies.
Point attenuation rate (per year)	33	−3.6 to 0.29 (Median = −0.63)	100[b]	−1.2 to − 0.15 (Median = −0.35)	(Schirmer et al. 1999; Wilson and Kolhatkar 2002; Hansen et al. 2003; EPA 2005; Rifai et al. 2003)	The study finds MTBE attenuation rates to be faster than previous studies.

[a]Table shows the adjusted median plume length for sites at which plume lengths were either measured, estimated, or considered indeterminate.
[b]Results reported from MNA-only sites.

In addition, given the discontinued use of MTBE as a fuel additive, additional releases of MTBE can no longer occur at active UST sites; therefore, in the absence of such additional source contributions, faster attenuation rates are likely to be observed within the population of existing MTBE plumes (Stevens 2006). Furthermore, the higher solubility of MTBE compared with benzene may contribute to more rapid dissolution and depletion of MTBE from the source, resulting in larger reductions in source contributions of MTBE to the plume over the long term.

Conclusions

This study addresses the characteristics of benzene, MTBE, and TBA plumes in groundwater for a population of 48 retail service station sites, specifically in terms of plume length, plume stability condition, concentration reduction trends over time, attenuation rates, and the timeframe within which natural attenuation achieved remedial goals for each constituent. The goal of this evaluation was to characterize plume behavior as observed across a variety of hydrogeologic settings on the basis of detailed groundwater monitoring records, rather than to define the site-specific factors controlling plume behavior. The groundwater monitoring data analyzed in this study confirm that, over the long term for this site population, the behavior of MTBE plumes in groundwater is similar to that of benzene plumes with respect to current plume lengths and plume stability trends. However, overall MTBE concentrations are decreasing more quickly than benzene, and may, on average, reach the applicable remediation goals more quickly than benzene plumes. The faster attenuation of MTBE plumes compared with benzene is consistent with the discontinued use of MTBE as a fuel additive.

TBA plumes were also found to be comparable to benzene and MTBE plumes in terms of plume length. However, whereas most TBA plumes are stable or shrinking, the percentage of TBA plumes currently stable or shrinking (68%) is less than that for benzene plumes (95%) and MTBE plumes (90%), likely reflecting the temporary build-up of TBA concentrations in groundwater attributable to MTBE biodegradation. Nevertheless, overall trends for the median and maximum concentrations of TBA in groundwater at these sites indicate that TBA is attenuating at rates somewhat faster than benzene and can therefore be expected diminish to applicable remediation goals in a similar timeframe as the other gasoline constituents.

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Review of Quantitative Surveys of the Length and Stability of MTBE, TBA, and Benzene Plumes in Groundwater at UST Sites

by John A. Connor[1], Roopa Kamath[2], Kenneth L. Walker[2], and Thomas E. McHugh[2]

Abstract

Quantitative information regarding the length and stability condition of groundwater plumes of benzene, methyl tert-butyl ether (MTBE), and tert-butyl alcohol (TBA) has been compiled from thousands of underground storage tank (UST) sites in the United States where gasoline fuel releases have occurred. This paper presents a review and summary of 13 published scientific surveys, of which 10 address benzene and/or MTBE plumes only, and 3 address benzene, MTBE, and TBA plumes. These data show the observed lengths of benzene and MTBE plumes to be relatively consistent among various regions and hydrogeologic settings, with median lengths at a delineation limit of 10 μg/L falling into relatively narrow ranges from 101 to 185 feet for benzene and 110 to 178 feet for MTBE. The observed statistical distributions of MTBE and benzene plumes show the two plume types to be of comparable lengths, with 90th percentile MTBE plume lengths moderately exceeding benzene plume lengths by 16% at a 10-μg/L delineation limit (400 feet vs. 345 feet) and 25% at a 5-μg/L delineation limit (530 feet vs. 425 feet). Stability analyses for benzene and MTBE plumes found 94 and 93% of these plumes, respectively, to be in a nonexpanding condition, and over 91% of individual monitoring wells to exhibit nonincreasing concentration trends. Three published studies addressing TBA found TBA plumes to be of comparable length to MTBE and benzene plumes, with 86% of wells in one study showing nonincreasing concentration trends.

Introduction

Over the past two decades, thousands of underground storage tank (UST) sites across the United States have been investigated to assess the potential impacts of gasoline fuel leaks on the underlying soil and groundwater. This experience has generated extensive information regarding the nature and extent of groundwater plumes containing benzene, methyl tert-butyl ether (MTBE), and tert-butyl alcohol (TBA). In the 1990s, when regulations required that gasolines be blended with oxygenate additives like MTBE for more efficient combustion, some researchers predicted that, in the event of a gasoline release to groundwater, MTBE would form much longer groundwater plumes compared to benzene (Fogg et al. 1998; Odencrantz 1998; Weaver and Small 2002). These authors based their predictions upon considerations that (1) MTBE is more soluble and less sorptive than benzene and could therefore travel farther than benzene in groundwater, in the absence of other attenuation mechanisms; and (2) MTBE, unlike benzene, was suspected to be relatively resistant to biodegradation by native soil bacteria (Yeh and Novak 1991; Suflita and Mormile 1993; Mormile et al. 1994).

These predictions were initially supported by the discovery of a few exceptionally long MTBE plumes extending thousands of feet downgradient of the release

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point, such as in Long Island, New York (Weaver et al. 1996, 1999). In contrast to these few exceptionally long plumes, several studies conducted in the mid-1990s that compiled information from numerous UST sites found the measured lengths of benzene and MTBE plumes to be comparable (Happel et al. 1998; Mace and Choi 1998). However, some authors questioned whether these results were reliable, postulating that younger MTBE plumes could be continuing to expand while older benzene plumes might be stable or diminishing in size, and/or noting that proper delineation of plume lengths could be hampered by diving plume conditions or other limitations (Happel et al. 1998; Mace and Choi 1998; Shih et al. 2004).

Subsequent scientific studies have improved our understanding of the lifecycle of contaminant plumes and the behavior of gasoline additives in groundwater. Specifically, field and laboratory investigations have found MTBE to biodegrade in groundwater under both aerobic and anaerobic conditions (Mackay et al. 2001, 2007; Wilson et al. 2002; Gray et al. 2002; McKelvie et al. 2007a). Published studies conducted from 1995 to 2013 have compiled field data from thousands of UST sites across the country, providing information on the measured lengths of MTBE and benzene plumes in groundwater and/or the observed plume stability condition (Rice et al. 1995; Buscheck et al. 1996; Mace et al. 1997; Happel et al. 1998; Reid et al. 1999; Reisinger et al. 2000; Shorr and Rifai 2002; Wilson 2003; Rifai and Rixey 2004; Shih et al. 2004; Stevens et al. 2006; Tarr and Galonski 2007; Kamath et al. 2012). In addition, three studies have addressed the behavior of TBA plumes found in conjunction with MTBE gasoline releases (Shih et al. 2004; Kamath et al. 2012; McHugh et al. 2013).

Purpose of Review

In this paper, we have reviewed the results of 13 published studies of multiple plumes to characterize the statistical distribution of plume lengths, plume stability conditions, and concentration trends for benzene, MTBE, and TBA plumes at UST sites. These studies have applied a variety of technical criteria and methodologies to achieve a representative measurement of plume lengths and stability conditions at retail gasoline sites. In total, the studies provide quantitative data on over 550 MTBE plumes and over 1300 benzene plumes at retail gasoline sites in a variety of hydrogeologic settings.

This review paper updates prior publications that compiled information on large populations of benzene and MTBE plumes (Newell and Connor 1998) by incorporating the results of additional multi-plume studies conducted over the past 15 years. In addition, this study incorporates the results of three studies that have addressed TBA plume behavior in addition to benzene and MTBE (Shih et al. 2004; Kamath et al. 2012; McHugh et al. 2013). This paper describes the methodology employed to review and compile these data, presents statistical summaries of benzene, MTBE, and TBA plume characteristics, and addresses the significance and limitations of these data.

Compilation of the data from these 13 separate studies is intended to provide a more complete understanding of plume behavior across multiple regions, as well as summary statistics on the observed length and stability condition of these plumes. This review serves to compile information generated over two decades of scientific investigation so as to provide the reader the benefit of the accumulated knowledge and weight of evidence that could not be obtained from the individual studies on their own.

Compilation of Data from Published Studies

We have surveyed the published literature to identify prior studies that have compiled quantitative data on groundwater plume conditions at multiple UST sites in the United States. Table 1 lists 13 studies that provide quantitative information and statistical summaries regarding the lengths and/or stability conditions of benzene, MTBE, and/or TBA groundwater plumes. Appendix S1 includes summary data from each paper tabulated as the basis for this paper.

Technical Specifications of Quantitative Surveys of Plume Characteristics

Each of the studies compiled in this paper has employed one or more technical criteria to obtain a representative sampling of plume characteristics from among existing groundwater monitoring records at UST sites. Key considerations include the following:

1. *Nature of Release.* These studies provide information on plume conditions associated with gasoline fuel releases from UST systems, principally retail fuel marketing facilities. Plumes associated with other potential sources of release (pipelines, refineries, tank farms, truck spills, etc.) or materials (diesel fuel, bulk additives, etc.) were not included in these databases.
2. *Survey of Multiple Site Locations.* Each of the studies provides quantitative data on multiple benzene, MTBE, and/or TBA plumes. Individual studies on plume lengths include 22 to 289 sites per study. Studies on plume stability conditions include 34 to 271 sites per study, with one study addressing the overall plume concentration trends observed at over 4000 UST sites in California (McHugh et al. 2013).
3. *Duration of Groundwater Monitoring History.* A number of the studies selected sites with longer-term monitoring periods so as establish plume trends with less uncertainty associated with seasonal fluctuations, sampling variability, and attenuation rates for compounds, such as MTBE, which have been observed to require longer acclimation periods for biodegradation. For those studies that specified minimum monitoring periods, the minimum monitoring periods required exceeded one year in duration, with most of the studies requiring three or more years.
4. *Number of Groundwater Monitoring Points.* For most of the studies reviewed, plume characterization was based upon a minimum number of three to eight monitoring points per site to define the plume length or

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Table 1
Summary of Studies on Plume Length and Plume Stability Conditions Based upon Data from Multiple UST Sites

Study	State	No. of Sites Meeting Minimum Specifications	Minimum Specifications for Evaluation Sites	Plume Length Reported?	M, B in Same Wells?	Plume Stability Condition Evaluated?	
						Length Versus Time	GW Conc. Trend
1. Rice et al. (1995)	CA	271	8 events; 6 wells	B (271 sites)	—	B (271 sites)	B (271 sites)
2. Buscheck et al. (1996)	CA	119	NR	BTEX/Benzene (62 sites)[1]	—	—	BTEX (119 sites)
3. Mace et al. (1997)	TX	227	6 wells	B (217 sites)[2]	—	B (217 sites)	B (227 sites)
4. Happel et al. (1998)	CA	63	1 sampling event; 8 wells	M (50 sites), B (50 sites)[3]	Yes (43 sites)	—	—
5. Mace and Choi (1998)	TX	289	Three events (1995–1997)	M (89 sites[4]), B (289 sites)	—	M, B (20 sites)[5]	M (471 wells)
6. Reid et al. (1999), Reisinger et al. (2000)	FL	55	3 years; Minimum 3 wells with detections MTBE	M (55 sites), B (54 sites)	Yes	M (45 sites)	—
7. Shorr and Rifai (2002), Rifai et al. (2003), Rifai and Rixey (2004)	TX	36	3 years; Minimum 6 wells; Minimum 3 years MTBE data	M (36 sites), B (36 sites)	Yes	M (36 sites), B (36 sites)	M (1074 wells), B (1206 wells)[6]
8. Wilson (2003)	SC	212	NR	M (212 sites), BTEX (212 sites)	Yes	—	—
9. Shih et al. (2004)	CA	96	1 year; sufficient wells; proper lab QA/QC	M (96 sites), B (95 sites), TBA (86 sites)	Yes	M (96 sites), B (94 sites), TBA (86 sites)[7]	—
10. Stevens et al. (2006)	CT	22	4 years; active UST; no NAPL; consistent monitoring program; no active remediation	—	—	—	M (83 wells)
11. Tarr and Galonski (2007)	NH	25	M detections	—	—	—	M (78 wells)
12. Kamath et al. (2012)	CA, NJ, AK, OR, NV	48	Min. 6 wells	M (35 sites), B (34 sites), TBA (22 sites)	Yes, including TBA	M (41 sites), B (42 sites), TBA (34 sites)	M (42 sites, 306 wells), B (43 sites, 288 wells), TBA (34 sites, 241 wells)
13. McHugh et al. (2013)	CA	>4000	2001 to 2011	—	—	—	M (4190 sites) B (4404 sites), TBA (3675 sites)
Total	—	—	—	M (573 sites), B (1320 sites), TBA (108 sites)	474 sites	M (238 sites), B (680 sites), TBA (120 sites)	—

M = Methyl tert-butyl ether (MTBE); B = Benzene; BTEX = Benzene, toluene, ethylbenzene, and xylenes; TBA = tert-butyl alcohol; NR = not reported; — = not analyzed; NAPL = nonaqueous phase liquid; QA/QC = quality assurance/quality control; UST = underground storage tank.

[1] Buscheck et al. (1996) reported the percentage of sites with BTEX plume lengths less than 50 feet, between 50 and 100 feet, between 100 and 200 feet, and greater than 200 feet. The terms BTEX and benzene appear to be used interchangeably within this study.

[2] Mace and Choi (1998) also presented benzene plume length data, and these data were used to compare with MTBE; Mace et al. (1997) benzene plume length results are not presented in this paper to prevent double-counting the same dataset.

[3] Benzene plume lengths were estimated based on a 1-µg/L contour limit, inconsistent with the other studies, and therefore could not be used for weighted mean calculations in our paper.

[4] Mace and Choi (1998) estimated plume lengths at 99 sites, but 10 of these sites had plume lengths of 0 feet.

[5] Mace and Choi (1998) estimated plume behavior (i.e., plume stability) over time at 20 sites based on plume lengths measured at three different events but did not present the full results of their analysis, and their incomplete results are not analyzed in this paper.

[6] Shorr and Rifai (2002) only presented the number of wells with near zero or decreasing trends, and their plume stability results are not aggregated in this paper because relative percentages of wells in each trend category were not specified.

[7] Shih et al. (2004) aggregated the plume length dataset before statistical analysis of plume stability and concluded that while the plume length decreased for MTBE and increased for benzene and TBA, these results were not statistically significant at a 95% confidence interval.

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stability condition, with most of these studies requiring six or more monitoring points. The actual number of monitoring wells employed at most sites exceeded this minimum specification, with reported average numbers of monitoring points ranging from approximately 4 to 17 per site.

Methodologies for Characterization of Plume Length

The studies reviewed for this paper evaluated plume length based upon a site-by-site evaluation of groundwater monitoring data. Plume lengths were determined based upon measured site data by either of two methods: (1) hand-contouring of the measured concentrations on a scaled map of the sampling locations to the designated concentration limit, or (2) using an empirical or analytical method to estimate the plume length when the existing monitoring well network did not extend downgradient to the specified plume delineation limit. We refer the reader to the individual studies for method particulars.

The prior studies have employed a variety of concentration limits for the purpose of delineating plume length. In our review, based upon consideration of the action levels employed under many state regulatory programs in the United States, we have focused on MTBE and benzene plumes that have been delineated to a 5 or 10 µg/L (micrograms per liter) concentration limit. For benzene, many state agencies employ a 5 µg/L action level (corresponding to the Federal Primary Maximum Contaminant Level [MCL] for benzene in drinking water) for remediation of groundwater that is considered a potential drinking water source. MTBE action levels are generally higher and more variable among state agencies, with levels as low as 5 µg/L applied in California (Secondary MCL for MTBE; CDPH 2006). Evaluation of the plumes delineated to concentration limits of 5 or 10 µg/L provides a conservative basis for characterization of plumes subject to remedial action, as a number of states employ less stringent groundwater cleanup criteria, particularly for MTBE. TBA plumes were evaluated at a 10 µg/L (Shih et al. 2004) and 12 µg/L (Kamath et al. 2012) limit, consistent with California's drinking water notification level of 12 µg/L. Although these contour limits were not identical, the two datasets were combined in this study at an assumed level of 10 µg/L to increase the number of TBA sites, which have been evaluated in far fewer studies than either benzene or MTBE.

Methodologies for Classification of Plume Stability Conditions

As defined in prior publications (Rice et al. 1995; Newell and Connor 1998; ASTM 2010), the stability condition of an affected groundwater plume can be characterized according to the following stages (Figure 1):

1. *Expanding Plume*: The plume length and/or concentrations are increasing over time. Commonly observed immediately after the spill material reaches the groundwater and the dissolved chemicals are transported by moving groundwater.
2. *Stable/No Trend Plume*: The plume length and/or concentrations are not changing over time, indicating that the rate at which the dissolved chemical mass is entering the groundwater is balanced by natural attenuation mechanisms, such as dilution, dispersion, sorption, and biodegradation. "Stable" and "No Trend" were considered equivalent designations in a number of the studies. For those papers that distinguished between stable and no trend plumes, both designations indicate the plume concentration to be neither decreasing nor increasing with time; however, the "No Trend" designation entails a higher amplitude of variation (i.e., higher coefficient of variation) than the "Stable" designation.
3. *Shrinking Plume*: The plume length and/or concentrations are diminishing over time, indicating that the rate of mass release from the source area has reduced to the extent that the attenuation factors remove and disperse mass faster than it is entering the groundwater system.
4. *Non-Detect or Exhausted Plume*: In some cases, the affected groundwater zone may diminish to non-detectable levels in the groundwater, while at other sites, the process may slow or terminate in an "exhausted" condition, with trace concentrations of gasoline components remaining near the original source location.

At a given site, measurements can be conducted to determine if a plume is in an expanding, stable, shrinking, or exhausted condition (ASTM 2010). The plume stability condition can be characterized either on the *trend of the plume length* over time or the *trend of plume concentrations* over time in individual monitoring wells.

In the various studies identified on Table 1, the stability of the plume length over time was determined either by: (1) evaluating plume contour maps at different times to determine changes in the length of the plume, or (2) conducting statistical trend analyses on the concentrations measured at monitoring wells, typically located at the downgradient toe of the plume. For the purpose of analysis of plume concentration trends over time, various visual and statistical methods were employed to categorize trends as increasing, decreasing, or stable; we refer the reader to the individual studies for method particulars. While the reports used a variety of methods to characterize plume stability, the similarity of their results points to the consistency of MTBE, benzene, and TBA plume behavior across the various published studies and supports aggregating these results, as done in our study.

Statistical Review of Published Studies

To facilitate comparison of the typical lengths of MTBE, benzene, and TBA plumes at UST sites, overall median and 90th percentile plume lengths have been estimated as the weighted mean of the median and 90th percentile values reported in the individual studies. This calculation is based upon the understanding that, for sufficiently large datasets, order statistics, such as the median and 90th percentile values, are normally

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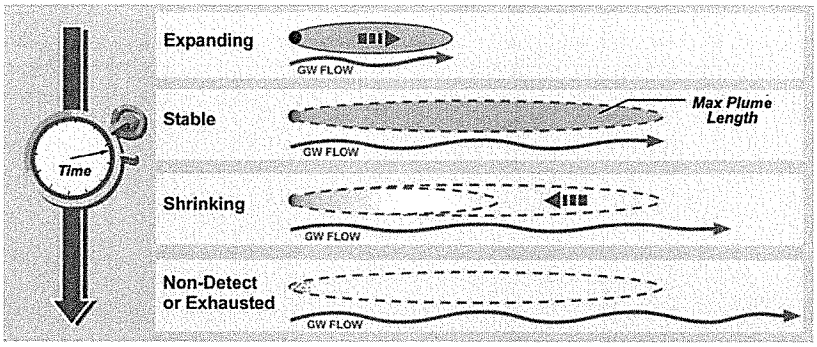

Figure 1. Schematic of groundwater plume stages at a typical UST site following termination of a spill or leak.

distributed, even if the underlying populations are not normally distributed. A weighted mean, based on the number of samples, has been employed to reduce the influence of smaller sample populations, which may exhibit greater variability in order statistics than larger sample populations. In other words, studies with more sites were weighted more heavily than studies with fewer sites. Similarly, the weighted mean approach was utilized to combine the results of the plume stability and concentration trend analyses.

The McHugh et al. (2013) study considered over 4000 UST sites to evaluate the overall trends of the maximum concentrations of MTBE, TBA, and benzene in groundwater over time. They did not address site-specific plume length or stability conditions, but provided important information regarding the net change in chemical concentrations over time in groundwater across these sites. Given the large number of sites they evaluated compared to the other published studies we reviewed, these results were not combined into the concentration trend summary statistics because they would overwhelm the weighted mean calculations; however, the results of McHugh et al. (2013) are compared with the summary statistics in this paper.

Limitations of These Studies

The authors of the various studies have identified possible limitations in their databases and, when feasible, have employed steps to mitigate the effects of these limitations on their findings. For example, a number of the studies note that, at many UST sites, the affected groundwater plumes are not fully delineated due to access restrictions or other limitations on the number and placement of groundwater sampling points. In addition, some authors note that, if the plume stability condition is not considered, comparison of older, stable plume lengths to younger, expanding plumes could be misleading, as the expanding plumes will not have achieved full length. Some authors also suggest that differences in MTBE and benzene plume lengths could reflect the effect of variable site conditions if the MTBE and benzene plumes are from different sites with distinctly different distributions of key attenuation parameters.

These limitations have been addressed by the authors of the 13 plume studies in a variety of manners. In some studies, plume lengths have been evaluated only for plumes with full delineation, based on a specified minimum number of monitoring points. In other studies, the maximum downgradient extent of the plume has been estimated based upon extrapolation of measured monitoring points, using the method described by Freeze and Cherry (1979) or Newell et al. (2002). Kamath et al. (2012) found this plume length estimation method to provide a reasonably conservative match to measured plume lengths on sites where both measurement and estimation methods were applied. Furthermore, six of the 10 studies that evaluate plume length compare benzene and MTBE plumes lengths from the same sites under the same hydrogeologic conditions.

In addition, 11 of the 13 studies have addressed the stability condition of the plumes, providing a basis for determining whether variations in plume age and associated stability condition (e.g., young expanding plume vs. older shrinking plume) could account for observed differences in the lengths of MTBE and benzene plumes. The vast majority of both benzene and MTBE plumes were found to be in a nonexpanding condition, showing that the concern of young versus old plumes is not a factor for plume length. The McHugh et al. (2013) study relied upon the maximum annual concentration of each plume constituent as a conservative basis to track plume concentration trends over time, based upon the consideration that the maximum concentration is likely near the source and therefore less likely to be affected by the extent of plume delineation or the change in the number of monitoring wells over time.

Findings of Previous Studies

Evaluation of Plume Lengths: MTBE, Benzene, and TBA

Statistical Distribution of MTBE, Benzene, and TBA Plume Lengths

As identified in Table 1, 10 of the 13 published studies address benzene and MTBE plume lengths, providing data on a total of 391 and 132 sites for MTBE plumes at 10

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and 5 µg/L delineation limits, respectively, and 826 and 165 sites for benzene plumes at 10 and 5 µg/L delineation limits, respectively. Two published studies also estimated plume lengths for TBA at a total of 108 sites (see Table S1 for tabulated values). Figure 2A and 2B provides side-by-side comparisons of the reported lengths of benzene and MTBE plumes from each of the 13 studies that evaluated plumes at a 5 and 10 µg/L plume delineation limit. Figure 3A and 3B summarize the weighted mean plume dimensions for MTBE, benzene, and TBA at delineation limits of 10 and 5 µg/L, respectively.

Consistency of MTBE and Benzene Plume Lengths Among Various Studies

The distributions of plume lengths shown in Figure 2 are relatively consistent among studies conducted in a variety of regions in the United States. For example, for plumes delineated to a 10 µg/L concentration limit (see Figure 2A), the median lengths of benzene plumes (826 sites) fall within the range of 101 to 185 feet, while the median lengths of MTBE plumes (391 sites) fall within a slightly narrower range of 110 to 178 feet (Table S1). Similarly, at this same delineation limit, the 90th percentile plume lengths range from 386 to 454 feet for MTBE (336 sites) and 261 to 480 feet for benzene (772 sites; Table S1).

The relatively narrow range of these plume length statistics across hundreds of UST sites suggests that plume lengths are consistent across a broad range of hydrogeologic settings and conditions. This observation is in agreement with prior studies that have found factors such as groundwater hydraulic conductivity and site lithology to be poor predictors of plume length among large numbers of plumes (Reid et al. 1999; Mace et al. 1997; Newell and Connor 1998; Shorr and Rifai 2002; Wilson 2003).

Comparable Lengths of MTBE and Benzene Plumes

The lengths of the benzene and MTBE plumes reported in the various studies are relatively comparable at both the median and 90th percentile levels, as illustrated by the weighted means of plume length statistics shown in Figure 3. The 90th percentile statistic is of particular interest in this regard as it incorporates the vast majority (90%) of gasoline plumes for which these data have been compiled. At a 10 µg/L delineation limit, the 90th percentile MTBE and benzene plume lengths are 400 feet (336 sites) and 345 feet (772 sites), respectively, showing MTBE plume lengths to be only 16% greater than those of benzene plumes (Figure 3A; Table S1).

At a delineation limit of 5 µg/L, the MTBE and benzene plume lengths are still found to be comparable, although with a moderately more pronounced difference; the 90th percentile MTBE (only evaluated in the Shih et al. 2004 study) and benzene plume lengths are 530 feet (96 sites) and 425 feet (165 sites), respectively, showing MTBE plumes to be 25% longer than benzene plumes (Figure 3B; Table S1). In general, the benzene plume lengths reported in the various studies are consistent with the study by Buscheck et al. (1996) that evaluated 62 UST sites in California and found that 85% of benzene plumes were less than 200 feet long. The Buscheck et al. (1996) study presented a range of plume lengths rather than a statistical distribution and thus could not be directly included in our statistical summary.

In absolute terms, the difference in these MTBE and benzene plume lengths ranges from only 55 to 105 feet (for 90th percentile plume lengths at the 10 and 5 µg/L delineation limits, respectively). The similar plume behavior of benzene and MBTE may reflect their biodegradation characteristics, as both compounds are biodegraded in aerobic groundwater and in most anaerobic geochemical settings.

Exceptionally Long Plumes

The maximum MTBE plume lengths identified in the studies addressed in this review paper generally fall in the range of 1000 to 1700 feet (see Figure 2). However, other publications have reported longer MTBE plumes (e.g., greater than 2000 feet) at individual UST sites (Weaver et al. 1996, 1999; ESTCP 2003; Thuma et al. 2001; McKelvie et al. 2007b). Consequently, while it is recognized that such exceptionally long MTBE plumes do exist, the small number of such plumes is consistent with the statistical distribution observed in the 13 studies, where MTBE plumes greater than 1400 feet in length correspond to less than 1% of the plume population. Incorporation of this small number of exceptionally long MTBE plumes into the data sets addressed in our review would not affect the weighted means of the median and 90th percentile plume lengths presented on Figure 3.

Lengths of TBA Plumes Compared to MTBE and Benzene Plumes

Two studies addressed the behavior of TBA plumes in addition to benzene and MTBE (Kamath et al. 2012; Shih et al. 2004) for a total of 108 sites. The weighted mean results from these studies (Figure 3A) indicate that the 90th percentile TBA plume length (420 feet at 10 µg/L; Table S1) is 5% greater than the 90th percentile MTBE plume determined from these and other studies. Similarly, the median TBA plume from the two studies at 10 µg/L is 15% longer than the median MTBE plume determined from a larger number of studies. However, the two studies that addressed TBA (Shih et al. 2004; Kamath et al. 2012) found TBA plume lengths to be comparable to benzene and MTBE plume lengths, with TBA plume lengths falling in between benzene and MTBE plume lengths. Shih et al. (2004) calculated 90th percentile values of the benzene, MTBE, and TBA plume lengths to be 341, 531, and 433 feet, respectively. Kamath et al. (2012) calculated the 90th percentile values of the measured and estimated plume lengths for benzene, MTBE, and TBA to be 356, 454, and 366 feet, respectively. Taken together, the aggregated results and individual studies suggest that TBA plume lengths are similar to MTBE and benzene plumes.

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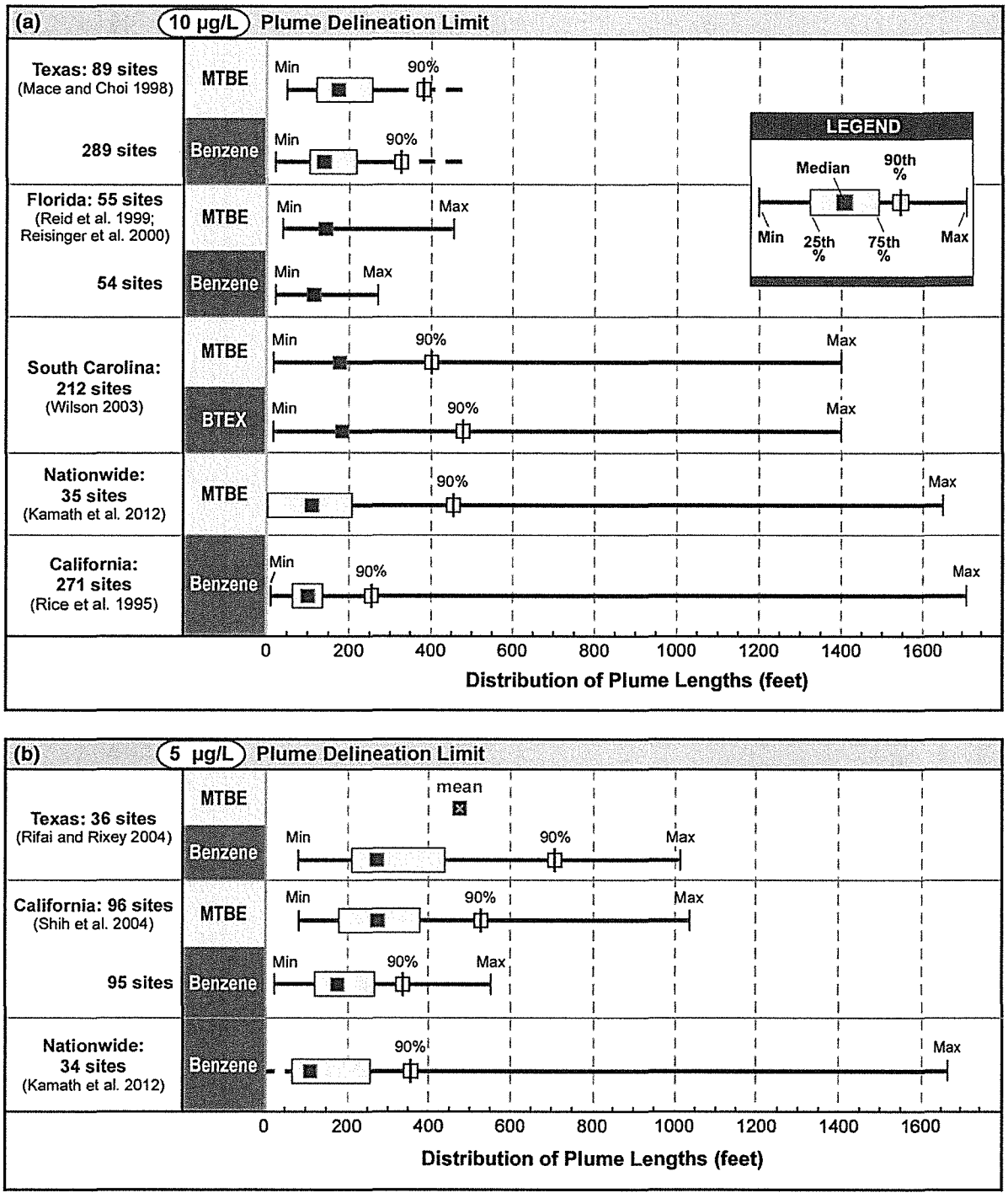

Figure 2. Summary of surveys of plume lengths in groundwater: MTBE versus benzene.

Evaluation of Plume Stability Conditions: MTBE, Benzene, and TBA

Stability Condition of Plume Lengths Over Time

Five studies have evaluated the stability of plume length over time for a combined 122 sites for MTBE plumes, 566 sites for benzene plumes, and 34 sites for TBA plumes (Reid et al. 1999; Reisinger et al. 2000; Kamath et al. 2012; Shorr and Rifai 2002; Rice et al. 1995; Mace et al. 1997). For each stability category, we have computed a weighted mean of the percentage of sites falling into that category. Table S2 reports these weighted mean values, as well as the values reported in each study, rounded to the nearest whole number for consistency.

Figure 4 compares the combined plume length trend distributions for MTBE, benzene, and TBA. These studies consistently found that the vast majority of both MTBE and benzene plume lengths are not increasing in length over time. For MTBE plumes, the percent of plume lengths found to be stable, no trend, decreasing, or

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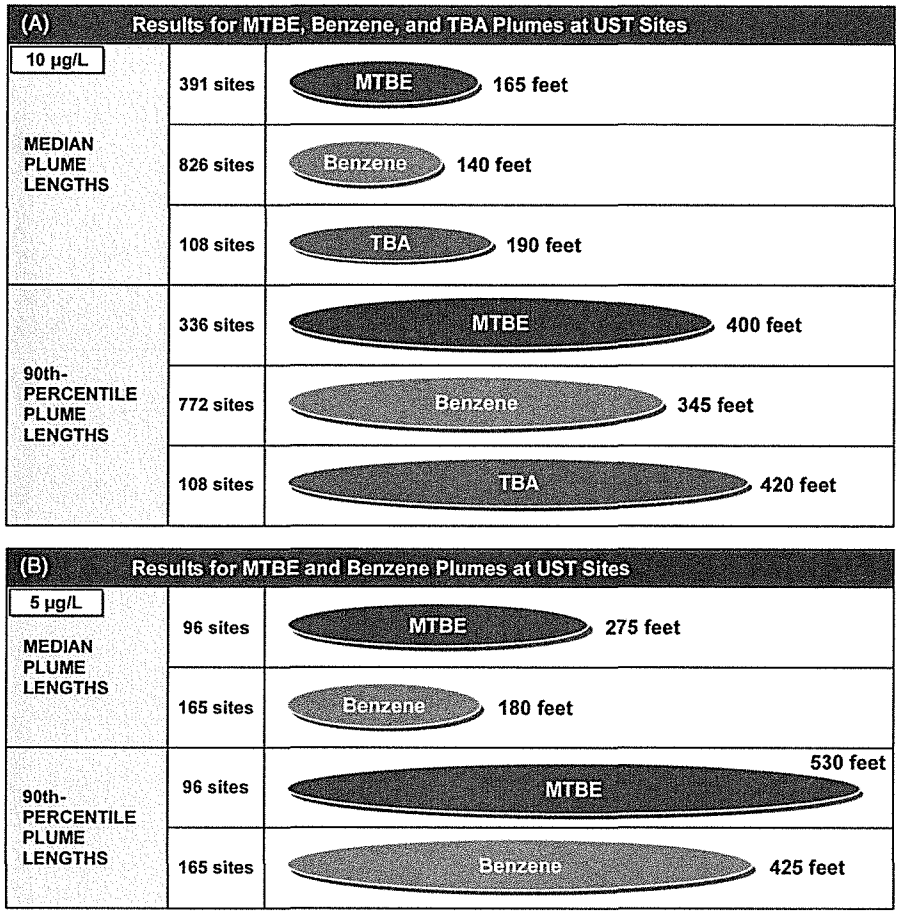

Figure 3. Weighted means of median lengths and 90th percentile lengths of MTBE, TBA, and benzene plumes. (A) Weighted means of plume lengths defined by 10 µg/L concentration limit. (B) Weighted means of plume lengths defined by 5 µg/L concentration limit. Lengths are estimated as the weighted mean of median and 90th percentile plume length values reported in various scientific surveys, rounded to the nearest 5 feet, for plumes delineated to a 10 µg/L concentration limit and 5 µg/L concentration limit. Data have been compiled for MTBE, benzene, and TBA plumes in groundwater underlying UST sites across the nation (see Table S1 for studies used to compile these summary lengths).

exhausted ranges from 90 to 96% among three studies, with the weighted mean percentage of plumes that are nonincreasing equal to 93%. Similarly, for benzene plumes, among four studies, the percent of plume lengths found to be stable, no trend, decreasing, or exhausted ranges from 92 to 97%, with the weighted mean percentage of plumes found to be nonincreasing equal to 94%. The overall percentages of plume lengths observed to be increasing over time is 6% for both MTBE plumes and benzene plumes.

The study by Kamath et al. (2012) specifically addressed the presence of detached MTBE plumes, that is, displacement of the plume mass downgradient from the original source point. They found this condition to occur at only 5% of MTBE sites (2 of 41 sites). Furthermore, these detached plumes were observed to be decreasing in area over time (Kamath et al. 2012). For the purposes of our analysis, the detached plumes were not considered as either increasing or nonincreasing.

Figure 4 also displays the trend distributions for TBA, as determined by Kamath et al. (2012). These data show that the majority of TBA plumes (68%) are stable or shrinking in length, while 26% are increasing. The percentage of nonincreasing plumes for TBA is lower than for benzene and MTBE (94 and 93%, respectively, are not increasing in length), which may reflect the temporary build-up of TBA concentrations in groundwater following biodegradation of MTBE (Kamath et al. 2012).

Concentration Trends in Individual Monitoring Wells Over Time

Seven studies have evaluated concentration trends of benzene and MTBE in individual wells over time (Mace and Choi 1998; Stevens et al. 2006; Tarr and Galonski 2007; Kamath et al. 2012; Buscheck et al. 1996; Rice et al. 1995; Mace et al. 1997), for a combined 938 wells for MTBE and 905 wells for benzene. Kamath et al. (2012) evaluated TBA concentration trends over time in 241 wells. Figure 5 shows the concentration trend distributions for MTBE, benzene, and TBA, with the percentage of plumes falling into each stability category calculated as weighted means among the seven

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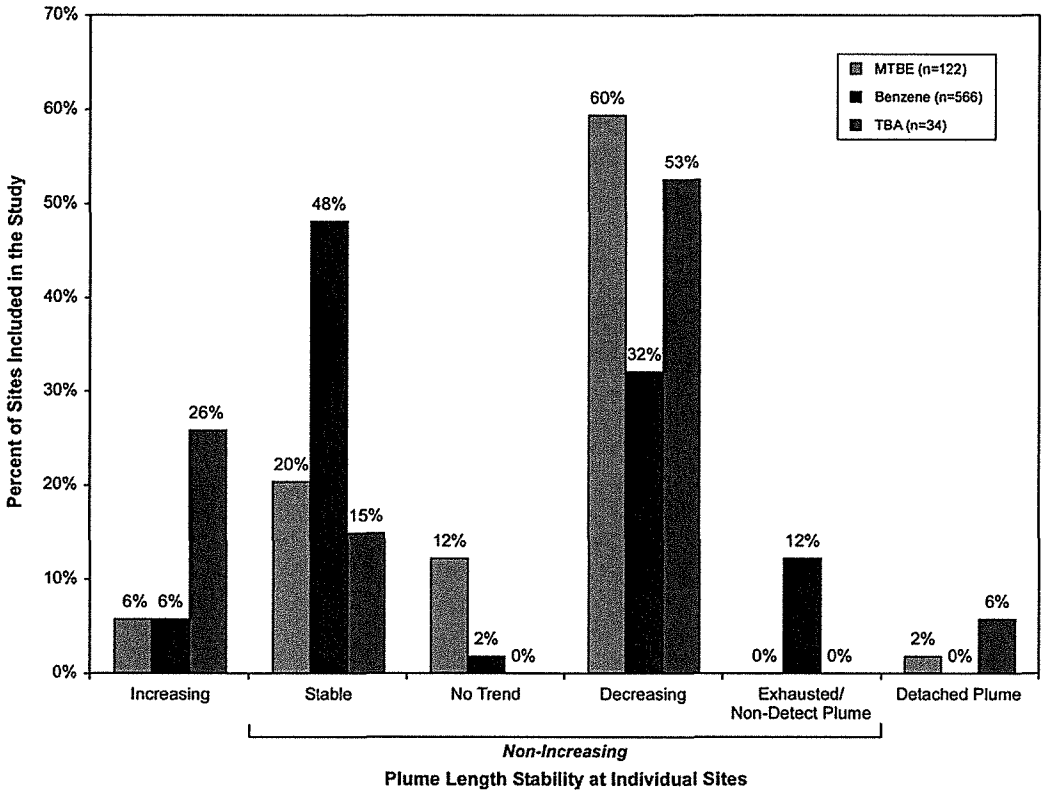

Figure 4. Comparison of plume length stability conditions for MTBE, benzene, and TBA plumes at UST sites. Data have been compiled for MTBE, benzene, and TBA plumes in groundwater underlying UST sites across the nation (see Table S2 for studies used to compile these stability percentages).

studies (see Table S3 for detailed data). In addition to these studies, McHugh et al. (2013) evaluated overall plume concentration trends for MTBE, benzene, and TBA for over 4000 sites in California. The McHugh study addressed the net change in the maximum plume concentrations at each site but did not characterize the plume stability condition per se in the same manner as the other studies; consequently, the weighted means shown on Figure 5 do not include the McHugh et al. (2013) results.

Figure 5 compares the combined distributions of well concentration trends for MTBE (938 wells), benzene (905 wells), and TBA (241 wells). As shown, MTBE and benzene again exhibit similar distributions, with the vast majority of wells showing nonincreasing concentrations over time for both MTBE (91%) and benzene (92%). However, unlike the plume length distribution, a higher percentage of wells exhibit decreasing concentrations for benzene (63%) than for MTBE (45%). Nevertheless, the combined percentage of stable, decreasing, or no trend wells is again comparable for the two compounds, corresponding to 80% of wells for MTBE and 84% of wells for benzene.

Evaluation of TBA concentration trends by Kamath et al. (2012) found stability condition distributions to be roughly comparable to those of benzene and MTBE, with 86% of the wells demonstrating nonincreasing trends. The moderately higher percentage of wells with increasing TBA concentration trends (14%, compared to 9% and 8% for MTBE and benzene, respectively) may reflect the production of TBA as a by-product of MTBE biodegradation, resulting in temporary replenishment of TBA concentrations until the MTBE source is depleted. Under this scenario, TBA concentrations in turn decrease as the MTBE source mass diminishes and the TBA itself is biodegraded.

Two studies specifically addressed MTBE plume conditions before and after the end of MTBE use as a gasoline additive in Connecticut (Stevens et al. 2006) and New Hampshire (Tarr and Galonski 2007). In both studies, in the 2 years following termination of MTBE use, the percentage of monitoring wells displaying a *decreasing* MTBE concentration trend was observed to increase. In Connecticut, Stevens et al. (2006) found that 93% of the 83 monitoring wells evaluated showed decreasing concentrations of MTBE 2 years after termination of MTBE use. By pooling the monitoring wells across 22 sites, they also determined that 55% of the sites showed a statistically significant decrease in MTBE concentrations between pre- and post-ban data (90th confidence level); only 5% (1 site) showed a statistically significant increase in MTBE concentrations. A similar study of 78 wells in New Hampshire (Tarr and Galonski 2007) reported that, after termination of MTBE use, 85% of monitoring wells exhibited decreasing concentrations, compared to decreasing concentrations at 68% of monitoring wells

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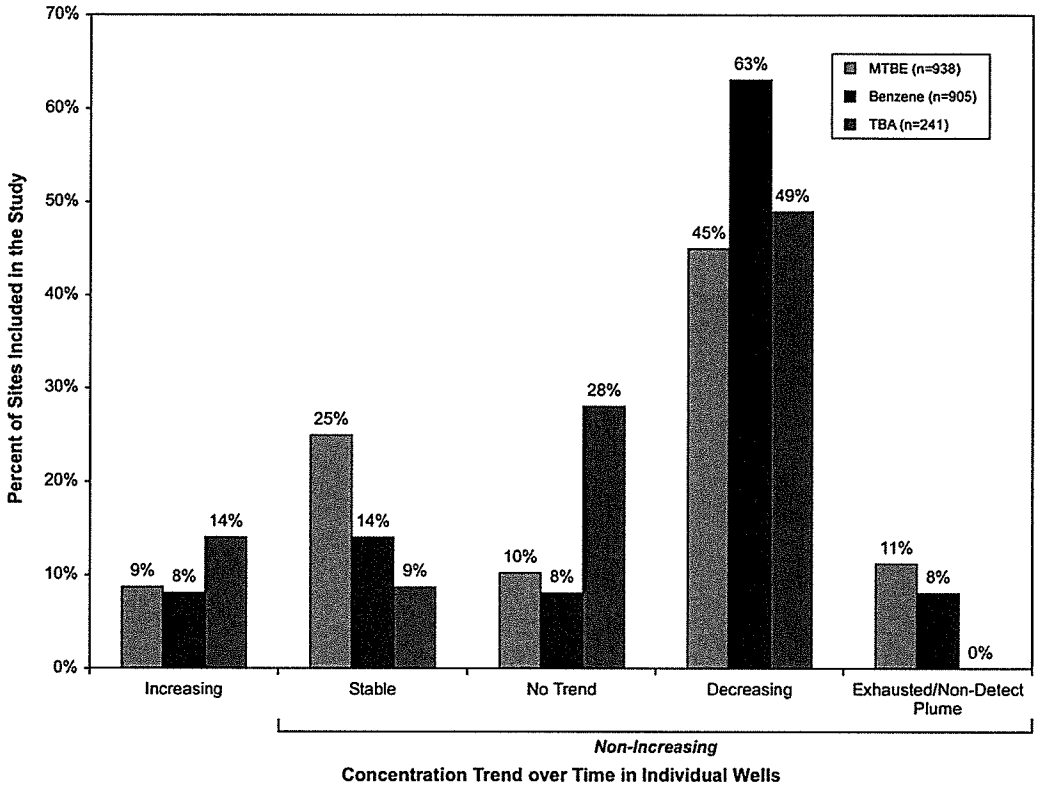

Figure 5. Comparison of concentration versus time trends for MTBE, benzene, and TBA in monitoring wells at UST sites. Data have been compiled for MTBE, benzene, and TBA concentration trends in groundwater underlying UST sites across the nation (see Table S3 for studies used to compile these concentration trends).

prior to the termination of MTBE use in gasoline. These studies demonstrated the decrease in MTBE concentrations with time following termination of MTBE use in these states.

McHugh et al. (2013) compiled data from over 4000 UST sites from the California GeoTracker database to evaluate the overall trends of benzene, MTBE, and TBA concentrations in groundwater over time. These monitoring data showed a large decrease in the groundwater concentrations of gasoline constituents over the period of 2001 to 2011 (85% decrease for benzene, 96% for MTBE, and 87% for TBA), measured as the change in the median of the maximum site concentrations over time. In addition, records of the sites for which continuous monitoring records were available for the full 10-year period (benzene: 1128 sites; MTBE: 1109 sites, TBA: 816 sites) showed benzene and MTBE levels to decrease continuously over this time period, while the maximum concentrations of TBA increased moderately over the period of 2001 to 2004 and then decreased from 2005 to 2011. The study found that the temporary build-up and subsequent decrease of TBA concentrations could be closely matched by a sequential first-order degradation model, which accounted for the generation of TBA as a product of MTBE degradation, followed by the biodegradation of the TBA itself (McHugh et al. 2013).

Conclusions

In this paper, we have combined the results of 13 previously published studies that surveyed the length and stability condition of affected groundwater plumes associated with releases of gasoline fuels from USTs at numerous service station facilities. These studies combined have addressed over 500 plumes for MTBE, over 1300 plumes for benzene, and 108 plumes for TBA, plus evaluation of concentration trends of all three gasoline constituents over a 10-year period for over 4000 UST sites in California. Employing a variety of approaches, these studies arrive at similar findings with regard to plume length and stability, which suggests that, in combination, these data and the related statistical parameters presented in this review paper provide a reliable characterization of benzene, MTBA, and TBA plume behavior at the majority of UST sites across the United States. Key findings regarding the statistical distribution of plume lengths and plume stability conditions at UST sites include the following:

1. *Comparison of MTBE and Benzene Plumes.* The plume delineation studies show MTBE and benzene plumes to be of comparable length at most sites. For example, at a 10 µg/L delineation limit, the 90th percentile MTBE and benzene plume lengths are 400 feet (336 sites) and 345 feet (772 sites), respectively, a relative difference of 16%. Similarly, at a 5 µg/L delineation limit, the 90th percentile MTBE and benzene plume lengths are

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530 feet (96 sites) and 425 feet (165 sites), respectively, a relative difference of 25%, although these values should be considered tentative due to smaller numbers of wells and only one study for MTBE. The vast majority of wells for both MTBE (91%) and benzene (92%) exhibit nonincreasing concentrations over time (i.e., stable, no trend, decreasing, or exhausted), and plume lengths also are predominantly nonincreasing over time for MTBE (93%) and benzene (94%). Consequently, reported plume lengths for benzene and MTBE are likely indicative of their maximum future lengths, as the plumes are generally not increasing in size and concentration.

2. *TBA Plumes Compared to MTBE and Benzene Plumes.* TBA plumes have been found to be of comparable length to benzene and MTBE plumes, with the majority of TBA plumes also nonexpanding (68%), although at a lower percentage than observed for MTBE or benzene plumes (Kamath et al. 2012). At over 4000 sites evaluated, TBA concentration trends over time showed an initial increase, followed by a decreasing concentration at rates comparable to those observed for MTBE and benzene (McHugh et al. 2013).
3. *Consistency Among Various Studies:* The various plume studies, conducted in different geographic regions and in a variety of hydrogeologic regimes, have found plume length statistics to fall into a relatively narrow range, suggesting that hydrogeologic conditions may be less important than other factors (such as the spill volume and biodegradation effects) in defining plume behavior, as has been observed in these and other studies (Reid et al. 1999; Mace et al. 1997; Newell and Connor 1998; Shorr and Rifai 2002; Wilson 2003). Rather, the similar biodegradation characteristics of MTBE and benzene, both of which are degradable in aerobic and most anaerobic geochemical settings, may be responsible for the comparable dimensions and stability conditions of these plumes.

Supporting Information

Additional Supporting Information may be found in the online version of this article:

Appendix S1. Review of Quantitative Surveys of the Length and Stability of MTBE, TBA, and Benzene Plumes in Groundwater at UST Sites.

Table S1. Statistical plume length data from the literature for MTBE, benzene, and TBA

Table S2. Plume stability results for MTBE, benzene, and TBA

Table S3. Concentration trend results for MTBE, benzene, and TBA

Table S4. Results from Stevens et al. (2006) analysis

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American Petroleum Institute

December 1998. Vers. 1.1

CHARACTERISTICS OF DISSOLVED PETROLEUM HYDROCARBON PLUMES

RESULTS FROM FOUR STUDIES

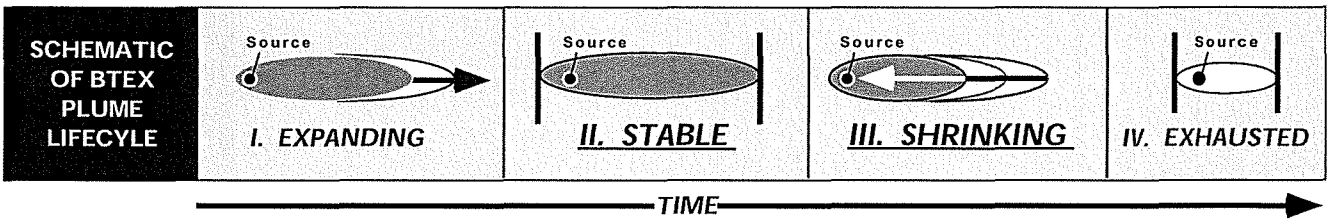
C.J. Newell and J.A. Connor, Groundwater Services, Inc.

API Soil / Groundwater Technical Task Force

EXECUTIVE SUMMARY

Recent studies of over 600 groundwater contamination sites throughout the U.S. provide important information regarding the fate and transport of petroleum hydrocarbons in the subsurface. This API research summary examines the findings of four independent research studies and addresses several key technical issues regarding the assessment and remediation of BTEX (benzene, toluene, ethylbenzene, xylene) plumes. On-going research regarding MTBE plume characteristics will be addressed in a future bulletin as data become available.

Key Finding: Most BTEX groundwater plumes are less than 200 ft in length and are in a STABLE or SHRINKING condition.



THE FOUR STUDIES

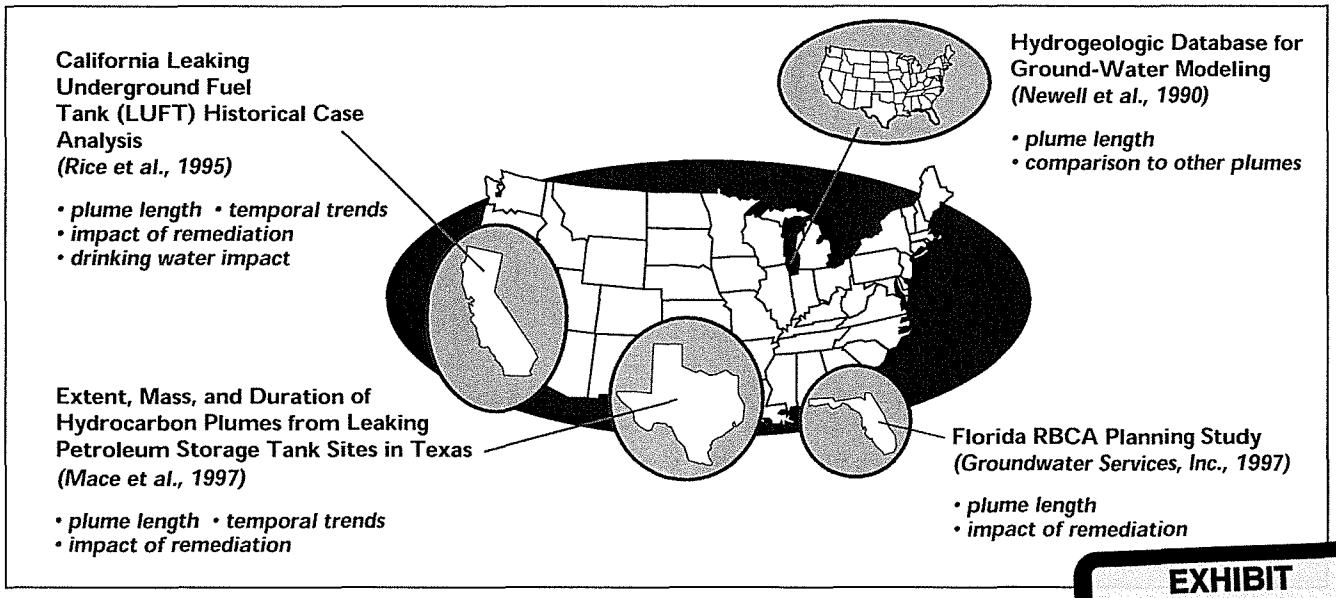
This bulletin summarizes information from four separate multi-site plume studies. Each study involved detailed analysis of data from a large number of sites (primarily underground storage tank facilities) to identify the key characteristics of groundwater contaminant plumes caused by petroleum hydrocarbon releases. Two comprehensive studies (California and Texas) evaluated how dissolved petroleum hydrocarbon plumes change over time.

In all four studies, detailed technical information regarding groundwater flow parameters and plume characteristics for each site were compiled from technical reports or questionnaires completed by site hydrogeologists or engineers. In combination, the four studies define the typical features of a dissolved hydrocarbon plume based on a cumulative database of 604 sites.

This API bulletin reviews the general methodology and principal conclusions of each study and uses these findings to answer several important questions related to the assessment and remediation of groundwater impacts associated with petroleum releases.

Technical Issues Regarding Dissolved BTEX in Groundwater:

- Typical plume length
- Persistence over time
- Effect of remediation
- Key factors in plume length
- Plume stability condition
- BTEX vs. other contaminants
- Drinking water impacts



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THE FOUR STUDIES (Cont'd)

California Leaking Underground Fuel Tank (LUFT) Historical Case Analysis

Rice, D.W., R.D. Grose, J.C. Michaelsen, B.P. Dooher, D.H. MacQueen, S.J. Cullen, W.E. Kastenberg, L.G. Everett, M.A. Marino. CA Environmental Protection Dept., Nov. 16, 1995.

APPROACH: This study, also referred to as the Lawrence Livermore National Laboratory (LLNL) Study, involved compilation and analysis of a detailed electronic database for 271 LUFT sites. Groundwater flow gradients and the average length and concentration of benzene plume were characterized on the basis of static water level data and groundwater time-series sampling records.

KEY RESULTS: Plume lengths "change slowly and stabilize at relatively short distances from the FHC (fuel hydrocarbon) release site" (90% of sites less than 255 ft). The median plume length was 101 ft for one of the two methods of calculation (see the following page). Plume lengths tend to change slowly with time, while average plume concentrations decline more rapidly. Hydrogeologic parameters (e.g., hydraulic conductivity, gradient) appear to have little relationship to plume length. Finally, "while active remediation may help reduce plume benzene concentrations, significant reductions in benzene concentrations can occur over time, even without active remediation."

Extent, Mass, and Duration of Hydrocarbon Plumes from Leaking Petroleum Storage Tank Sites in Texas

Mace, R.E., R.S. Fisher, D.M. Welch, and S.P. Parra. Bureau of Economic Geology, University of Texas at Austin, Austin, Texas. Geologic Circular 97-1, 1997.

APPROACH: The Texas Bureau of Economic Geology (BEG) evaluated groundwater impacts from fuel hydrocarbon releases at 217 sites in Texas. Groundwater plume lengths and concentration trends were analyzed in a manner similar to the California study (see Rice et al., above). In addition, hydraulic gradient and groundwater flow directions were characterized for various hydrogeologic and climatic regions of Texas.

KEY RESULTS: Most benzene plumes (75%) are less than 250 ft long and have either stabilized or are decreasing in length and concentration. The median plume length was 181 ft. Only 14% are increasing in concentration, and only 3% are increasing in length. The length of a benzene plume cannot be predicted on the basis of either site hydrogeology or previous remediation activities. Benzene plume characteristics are not statistically different between sites where groundwater remediation activities have or have not been implemented, although the authors state that these activities should "logically shorten the time required to decrease plume length and concentration."

Florida RBCA Planning Study

Groundwater Services, Inc. Prepared for Florida Partners in RBCA Implementation, Groundwater Services, Inc., Houston, Texas. 1997. www.GSI-net.com

APPROACH: The Florida RBCA (Risk-Based Corrective Action) Planning Study involved collection and analysis of groundwater data from 117 leaking underground storage tank (LUST) sites distributed throughout 33 counties in Florida. Using these data, the report addresses the cost significance of various policy decisions related to development of the Florida RBCA regulations. For use in this bulletin, the plume maps and detailed site questionnaires compiled for 74 sites were reanalyzed to define typical plume properties.

KEY RESULTS: The median plume length among these Florida LUST sites is 90 ft based on available benzene and BTEX data. The shorter plume lengths observed in this database may be related to the varying detection limits used for plume delineation. For plumes delineated to a 50 ppb benzene limit (51 sites), median plume length was 90 ft, compared to 120 ft for plumes delineated to 1 ppb benzene (21 sites). In addition, 51% of the Florida database sites are currently or had previously been subject to groundwater remediation efforts.

A Hydrogeologic Database for Ground-Water Modeling

Newell, C.J., L.P. Hopkins, and P.B. Bedient. Ground Water, Vol. 28, No. 5, Sept./Oct. 1990. pp. 703-714.
API, 1989. Hydrogeologic Data Base for Groundwater Modeling, API Publication No. 4476, Washington, D.C.

APPROACH: Hydrogeologic and chemical information from 400 site investigations across the U.S. was obtained in a national survey of National Ground Water Association members conducted in 1990. This 400-site database (available in spreadsheet form from the API Information Specialist, ehs@api.org) includes groundwater plume dimensions for a broad range of groundwater contaminants, including 42 service station BTEX sites, 40 non-service station BTEX sites, 78 chlorinated ethene sites, 25 non-ethene solvent sites, and 21 inorganic sites. For use in this bulletin, these data were reanalyzed to define typical plume properties for each chemical class.

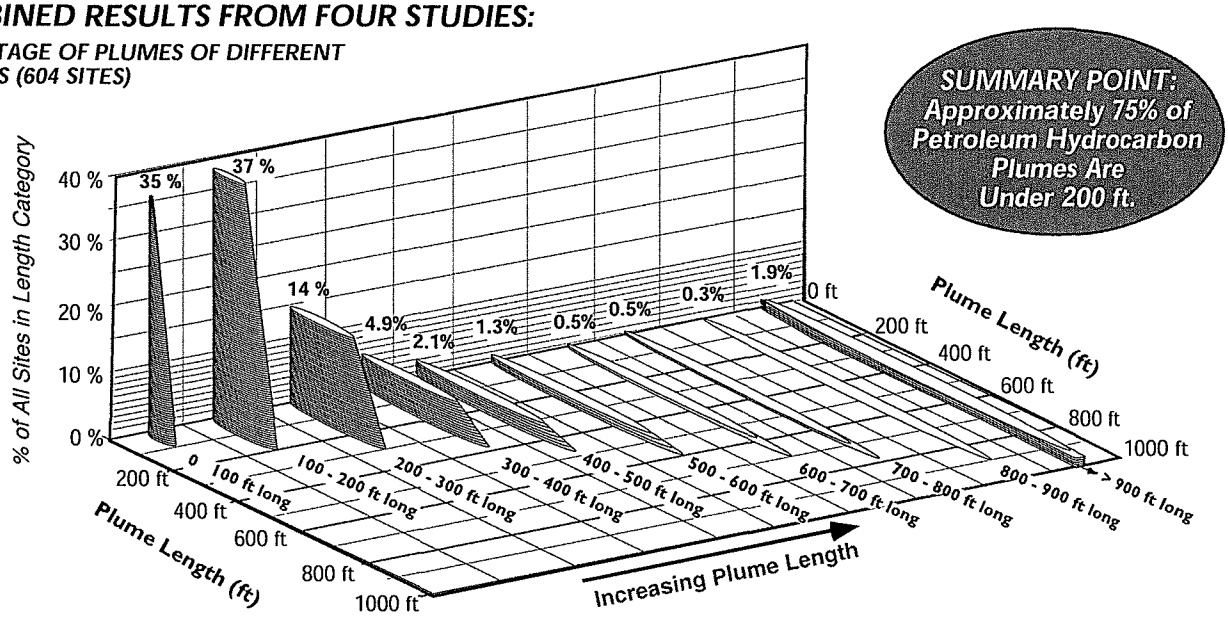
KEY RESULTS: The 42 service station sites show a median benzene/BTEX plume length of 213 ft. This database includes a higher percentage of longer plumes, with six BTEX plume lengths greater than 900 ft. On average, however, BTEX plumes are significantly smaller than the other chemical classes reported in this study, as discussed later in this Bulletin.

011798

WHAT IS THE LIMIT OF MIGRATION OF DISSOLVED PETROLEUM HYDROCARBON PLUMES?

COMBINED RESULTS FROM FOUR STUDIES:

PERCENTAGE OF PLUMES OF DIFFERENT LENGTHS (604 SITES)



SUMMARY POINT: Approximately 75% of Petroleum Hydrocarbon Plumes Are Under 200 ft.

INDIVIDUAL STUDY RESULTS:

ALL SITES	SUMMARY - ALL SITES
Maximum Length:	3020 ft
90th Percentile:	319 ft
75th Percentile:	203 ft
MEDIAN LENGTH: 132 ft	
25th Percentile:	80 ft
Minimum Length:	8 ft

CALIFORNIA (271 Sites)	Summary
Max	1713 ft
90th %	255 ft
75 %	146 ft
MEDIAN 101 ft	
25th %	66 ft
Min	8 ft

TEXAS (217 Sites)	Summary
Max	1619 ft
90th %	382 ft
75 %	250 ft
MEDIAN 181 ft	
25th %	137 ft
Min	54 ft

FLORIDA (74 Sites)	Summary
Max	600 ft
90th %	211 ft
75 %	158 ft
MEDIAN 90 ft	
25th %	60 ft
Min	12 ft

HGDB (42 Sites)	Summary
Max	3020 ft
90th %	945 ft
75 %	400 ft
MEDIAN 213 ft	
25th %	85 ft
Min	15 ft

• LOCATION OF SITES:	CALIFORNIA	TEXAS	FLORIDA	ENTIRE U.S.
• **Plume constituent(s):**	Benzene	Benzene	Benzene, BTEX	Mostly benzene, BTEX constituents
• **Plume Delineation Limit:**	10 ppb	10 ppb	1 - 50 ppb	Not reported; probably analytical detection limit.
• **Types of Sites:**	UST sites with affected groundwater. No fractured rock sites.	UST sites with affected groundwater. Includes limestone aquifers.	UST sites with affected groundwater.	UST sites at service stations located in various hydrogeologic settings.
• **Method For Determining Plume Length:**	***Modeled:*** Length extrapolated from 2-D transport models fit to site monitoring data. Reported results for exponential and error-function equations (summary stats above from error function).	***Modeled:*** Length extrapolated from 2-D GW transport model fit to site monitoring data. Used exponential equation only.	***Measured:*** Length derived from site plume maps. Data analyzed as part of this bulletin.	***Reported:*** Plume lengths reported by site consultants in survey questionnaires. Data analyzed as part of this bulletin.
• **Sites w/ Soil Vapor Extract.** • **Sites w/ GW Pump & Treat** • **Sites w/ GW Sparging**	— Not reported — 53 of 208 sites (26 %) — Not reported	—105 of 479 (22%) —92 of 479 sites (19 %) —22 of 479 sites (5 %)	— Not reported — 32 of 74 sites (43 %) — 6 of 74 sites (8 %)	—Not reported —Not reported —Not reported

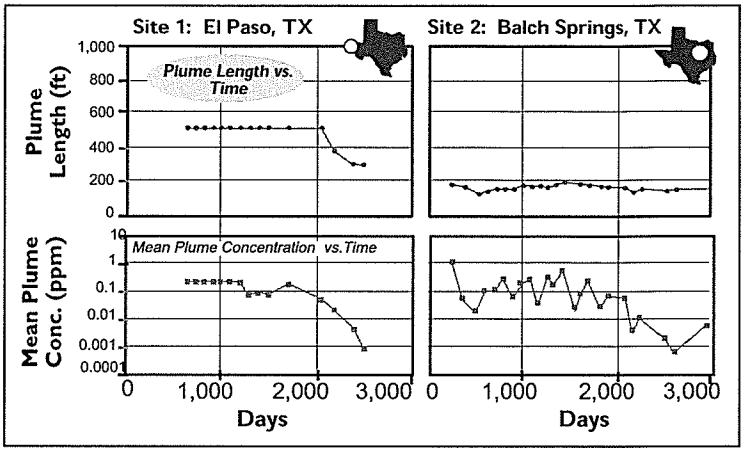
(note different #s of sites reported)

011799

HOW MANY PETROLEUM PLUMES ARE SHRINKING? STABLE? EXPANDING?

APPROACH

Both the California and the Texas studies (Rice et al., 1995; Mace et al., 1997) analyzed changes over time in the length and average concentration of dissolved hydrocarbon plumes. For the California study, these evaluations were conducted on a subset of sites having at least 6 wells and 8 sampling episodes extending over multiple years. Typical monitoring records for the Texas study ranged from 4 to 7 years as shown in data from two typical sites to the right.



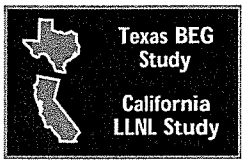
Plume stability trends were determined as follows:

Plume Length Trend: For each sampling episode, the plume length from the source to the 10 ppb concentration point was extrapolated using a 2-D groundwater transport model calibrated to the site monitoring data. Length vs. time was plotted for each site to define change over time.

Plume Concentration Trend: For each sampling episode, the average benzene concentration in the plume area was estimated using Delauney triangulation (Isaaks and Srivastava, 1989), an area-weighted averaging procedure involving subdivision of the plume area into triangular segments defined by adjacent wells. Average concentration vs. time was plotted for each site to define change over time.

These methods do not account for plume spreading beyond the area described by the monitoring well array. However, both studies found this approach to be sufficiently robust to accurately characterize plume trends over time.

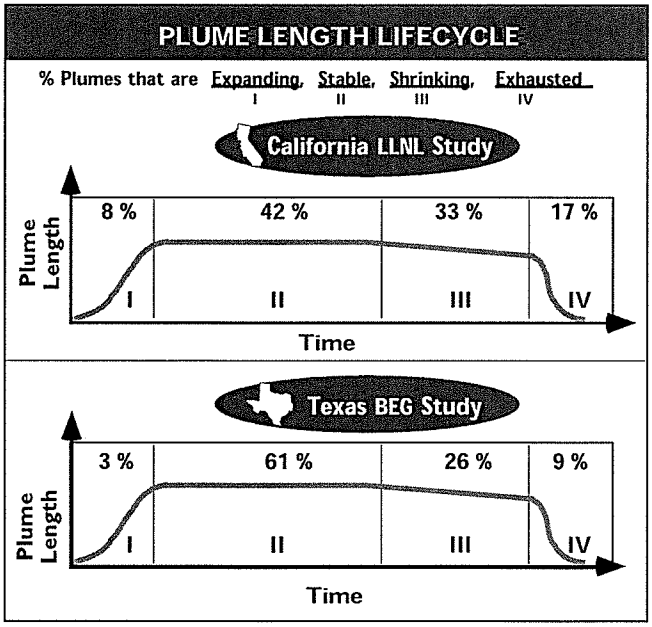
KEY RESULTS

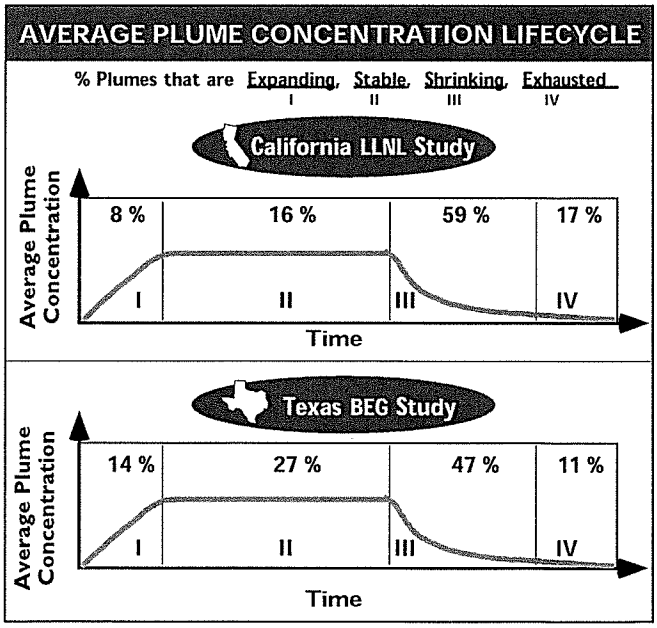


Based on the observed trends, the studies grouped the plumes into four categories:

- ***Expanding:*** Residual source present. Mass flux of contaminants exceeds assimilative capacity of aquifer.
- ***Stable:*** Insignificant changes. Active or passive remediation processes are controlling plume length.
- ***Shrinking:*** Residual source nearly exhausted, and active or passive remediation processes significantly reducing plume mass.
- ***Exhausted:*** Average plume concentration very low (e.g., 1 ppb) and unchanging over time. Final stages of source zone dissolution over a relatively small area at a site.

As shown in the conceptual plume lifecycle figures below, of the nearly 500 sites addressed by this analysis, nearly 75% were found to be in either a stable or shrinking condition, based on analyses of both plume length and concentration. Plume concentrations were predominantly shrinking (47 to 59%), whereas lengths were frequently stable (42 to 61%). These results suggest that dissolved hydrocarbon plumes tend to reduce more rapidly in concentration than in length. Similar results were observed in a plume study performed by Buscheck et al. (1996), where 67% of 119 plumes in northern California were found to be stable/shrinking in length, and 91% had stable/diminishing concentrations.





Figures adapted from Rice et al., 1996.

HOW LONG WILL BTEX PLUMES PERSIST?

CALIFORNIA & TEXAS STUDIES: *90% Attenuation of Average Concentration of Shrinking Plumes*

For those plumes characterized as **shrinking** (see page 4), both the California and Texas studies (Rice et al., 1995; Mace et al., 1997) included an evaluation of the time required for the average plume concentration to reduce by 90%. The rates of change calculated for each data set are shown in the table to the right.

Time Required for 90% Attenuation in Average Concentration for Shrinking Plumes:

161 SITES	MEDIAN SITE IN CALIFORNIA:	3.2 yrs
	10th Percentile:	1.5 yrs
	90th Percentile:	7 yrs
90 SITES	MEDIAN SITE IN TEXAS:	1.4 yrs
	10th Percentile:	0.7 yrs
	90th Percentile:	2.7 yrs

Note that, in these analyses, the ***average concentration*** term corresponds to an area-weighted average BTEX concentration derived using the Delauney triangulation method for each groundwater sampling episode. Consequently, trends in this concentration term should be representative of the total plume mass. Data from the California and Texas studies show that, once a dissolved BTEX plume begins to shrink (a condition observed at roughly 50 - 60% of the LUST sites in these studies), the rate of decline in plume mass is relatively rapid. Based on the median rate of mass reduction reported in these studies, *for a shrinking plume, only 5 to 10 years are required for the average plume BTEX concentration to drop from an initial level of 1 ppm down to 1 ppb.* (This assumes a first order decay model applies over three orders of magnitude of concentration reduction.) At this point, the plume reaches an ***exhausted*** condition, which may represent low levels of BTEX persisting in source-area wells for an extended time period thereafter.

WHAT IS THE EFFECT OF REMEDIATION ON BTEX PLUMES?

Three of the four studies evaluated the performance of remediation efforts in reducing or controlling petroleum hydrocarbon plumes. Based on a review of large site populations, the studies consistently draw a conclusion that runs counter to expectations: soil and groundwater remediation efforts did not result in smaller BTEX plumes.

QUOTES

CALIFORNIA

(Rice et. al, 1995)

"While active remediation may help reduce plume benzene concentrations, significant reductions in benzene concentrations can occur with time, even without active remediation." (pg. EX-2)

"At low concentration sites, pump and treat increases the probability of having a negative average benzene concentration trend by roughly a factor of two, while it has essentially no impact on probability at high concentration sites." (pg. 13)

"An analysis of plume length categories shows that none of the remediation treatment variables have a significant impact on the relative frequencies of the different categories." (pg. 13)

PROBABILITY (P) OF DECREASING CONCENTRATION TREND*

Pump & Treat Site?	Site Over-Excavated?	P
–	–	52 %
√	–	71 %
–	√	64 %
√	√	80 %

* 208 Sites > 1 ppb avg. conc.

TEXAS

(Mace et. al, 1997)

"The use of active ground-water remediation has not yet resulted in a lower median plume length at LPST sites throughout the state where corrective action is under way. This does not mean that remediation does not improve ground-water conditions at individual sites, but that when all LPST sites are reviewed, plume lengths at sites with remediation do not appear different from plume lengths at sites without remediation." (pg. 34)

"This probably means that significant spills occur before being detected and that most plumes are in place and in equilibrium before active remediation takes effect." (pg. 34)

	% OF PLUMES THAT ARE:		
	Stable	Shrinking	Exhaus.
67 Sites WITH Pump & Treat	35 %	61 %	4 %
117 WITHOUT Pump & Treat	38 %	52 %	10 %

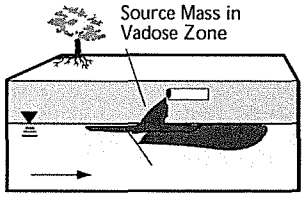
"We found no difference in plume length between different remediation techniques and sites with no remedial action." (pg. 33)

FLORIDA

(GSI, 1997)

"Of the 117 sites included in this study, affected soils have been previously removed at 28 sites. For these 28 sites, the estimated median groundwater source mass is approximately 34% lower than the median groundwater source mass where overlying soils have not yet been removed. These data suggest that, while the soil removal actions have served to reduce groundwater impacts, a significant percentage of the contaminant source (66%) remains in place in the saturated, water-bearing unit." (pg. 21)

"..soil removal would not significantly affect groundwater remediation requirements." (pg. 21)



011801

WHAT ARE THE FACTORS THAT CONTROL BTEX PLUME LENGTH?

TEXAS AND CALIFORNIA STUDIES

The California and Texas studies attempted to correlate plume length with various hydrogeologic factors. In both studies, plumes were segregated into two subsets (shallow vs. deep) and correlation coefficients were calculated for plume length vs. a range of site parameters. Results of these analyses are summarized below.

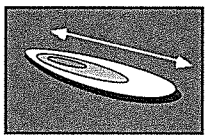
RESULTS: TEXAS STUDY

The Texas study (Mace et al., 1997) concluded that **plume length could not be predicted** by the following variables:

- *Depth to water*
- *Hydraulic gradient*
- *% Organic Carbon in water-bearing zone*
- *Thickness of sweep (smear) zone*
- *Hydrogeologic setting (in unconsolidated media)*
- *Previous remediation activities (see page 5)*

The authors concluded that "hydrogeologic site characteristics and site activities considered in this study do not explain the variation in average plume length or plume mass and concentration."

The report identifies other factors, such as the amount of spilled fuel and natural biodegradation rate, as having a greater influence than hydrogeology or previous remediation activities.



RESULTS: CALIFORNIA STUDY

The California study (Rice et al., 1995) concluded that **plume length was not correlated to:**

- *Groundwater depth*
- *Saturated thickness*
- *Free product thickness*
- *Hydraulic gradient*
- *Number of site layers*
- *Previous remediation activities (see page 5)*

The authors concluded that: "Individual or combinations of other hydrogeologic variables have little apparent relationship to plume characteristics. Correlations among a variety of hydrogeologic variables and plume length show no indications of interaction. Transport indices that in theory should affect plume length, such as groundwater flow velocity, show no correlation."

They attributed the lack of correlation to the presence of controlling but not measured variables (such as source mass and biodegradation rate), scatter in the hydrogeologic data, and cyclical change in hydrogeologic variables that causes a delayed effect on plume length, and general site complexity wherein each site has a unique set of controlling variables.

These studies suggest that the size of the release is probably one of the key variables that controls plume length. Larger sources (in terms of mass, width, and affected soil volume) mean that more dissolved-phase constituents are transferred to groundwater, creating longer dissolved phase plumes.

HOW MUCH GROUND WATER IS AFFECTED BY BTEX PLUMES?

An upper-range estimate of the total volume of groundwater resources impacted by releases from LUST sites can be obtained using a calculation method described in the California study (Rice et al., 1995). In this method, the 95th percentile BTEX plume volume observed in the California study (i.e., 0.7 acre ft. or 230,000 gallons) is multiplied by the total number of reported LUST sites to obtain a total affected groundwater volume. Dividing this value by the total groundwater basin storage capacity provides an estimate of the percentage of resources impacted by LUST sites. Results for both California and the U.S. are provided below. Note that LUST sites usually affect shallow water table aquifers not typically used for public supply.

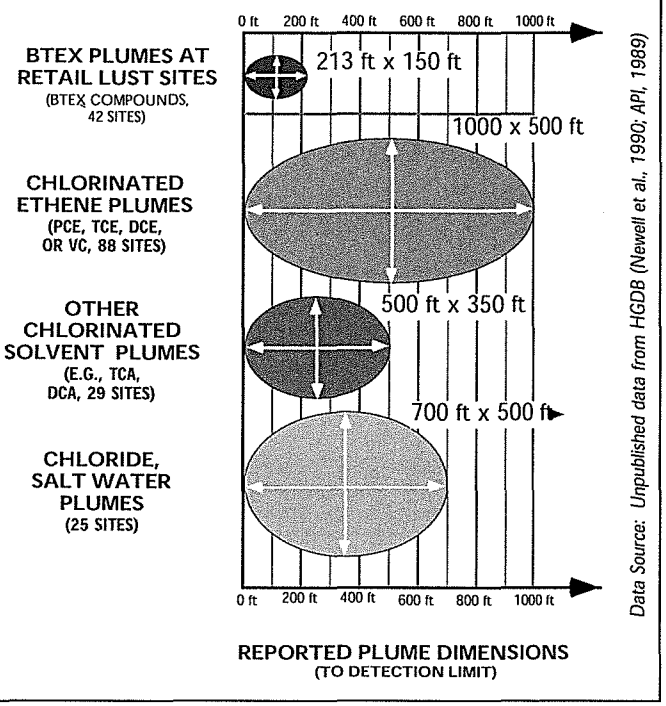
	BTEX Plume Volume (95%)	X	No. of LUST Sites	=	Total BTEX GW Volume	÷	Total GW Resource Volume	=	% Total GW Resource Impacted
	0.7 acre-ft		10,000		7000 acre-ft		1.3 billion acre-ft		**0.0005 %**
	0.7 acre-ft.		358,000 (U.S. EPA, 1998)		250,000 acre-ft		614.3 billion acre-ft (Lehr, 1985)		**0.00004 %**

011802

HOW ARE BTEX PLUMES DIFFERENT FROM OTHER PLUMES?

The HGDB Study (Newell et al., 1990) provides plume length data for a variety of contaminants, including BTEX, chlorinated solvents, and brine releases. This chart shows plume widths and lengths as reported by HGDB respondents. As shown, BTEX plumes are much smaller than other types of plumes. Likely causes for this difference include: i) the smaller source zone area associated with BTEX releases from LUST sites, and ii) the more bio-degradable nature of BTEX constituents relative to the other contaminants. Note that other studies are in progress to characterize other types of plumes (e.g., Happel et al., 1998; Mace, 1998; Newell et al., 1998).

BTEX VS. OTHER PLUME DIMENSIONS



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011803

API Soil & Groundwater Research Publications

Publ *4668*, Delineation and Characterization of the Borden MTBE Plume: An Evaluation of Eight Years of Natural Attenuation Processes, June 1998
In 1988, a natural gradient tracer test was performed in the shallow sand aquifer at Canada Forces Base (CFB) Borden to investigate the fate of a methyl-tertiary-butyl-ether (MTBE) plume introduced into the aquifer. Solutions of groundwater mixed with oxygenated gasoline were injected below the water table along with chloride (Cl^-), a conservative tracer. The migration of benzene, toluene, ethylbenzene, the xylenes (BTEX); MTBE; and Cl^- was monitored in detail for about 16 months. The mass of BTEX in the plume diminished significantly with time due to intrinsic biodegradation. MTBE, however, was not measurably attenuated. In 1995-96, a comprehensive groundwater sampling program was undertaken to define the mass of MTBE still present in the aquifer. Only about 3 percent of the initial MTBE mass was found, and it is hypothesized that biodegradation played an important role in its attenuation. Additional evidence is necessary to confirm this possibility. Pages: 88.
Order Number: I46680, Price: $30.00

Publ *4657*, Effects of Sampling and Analytical Procedures on the Measurement of Geochemical Indicators of Intrinsic Bioremediation: Laboratory and Field Studies, November 1997
This study evaluates the effects of various sampling and analytical methods of collecting groundwater geochemical data for intrinsic bioremediation studies. Sampling and analytical methods were tested in the laboratory and in the field. Several groundwater sampling and analytical methods may be appropriate for measuring geochemical indicators of intrinsic bioremediation. The methods vary in accuracy, level of effort, and cost. Pages: 86.
Order Number: I46570, Price: $30.00

Publ *4658*, Methods for Measuring Indicators of Intrinsic Bioremediation: Guidance Manual, November 1997
This guidance manual is intended to be a resource for practitioners of intrinsic bioremediation in allowing selection of sampling and analytical methods that meet project-specific and site-specific needs in scoping field investigations, provides procedures that will improve the representative quality of the collected data, and considers potential biases introduced into data through the sampling and analytical techniques employed in the site investigation. Pages: 96.
Order Number: I46580, Price: $35.00

Publ *4654*, Field Studies of BTEX and MTBE Intrinsic Bioremediation, October 1997
A gasoline release field site in the Coastal Plain of North Carolina was monitored for more than three years to allow calculation of in situ biodegradation rates. Laboratory microcosm experiments were performed to further characterize the biodegradation of BTEX and MTBE under ambient, in situ conditions. Finally, groundwater modeling studies were conducted to facilitate the interpretation of field data and to evaluate various approaches for predicting the fate and effects of these gasoline constituents in the subsurface. Pages: 244.
Order Number: I46540, Price: $40.00

Publ *4627*, *In Situ* and On-Site Biodegradation of Refined and Fuel Oils: A Review of Technical Literature 1988-1991, June 1995
This report reviews more than 200 technical articles published between 1988 and 1991 in the area of on-site and in situ bioremediation of petroleum hydrocarbons. It focuses specifically on current field and laboratory research related to petroleum hydrocarbon biodegradation including biodegradation of crude oil and solvents. Recent work in fate and transport modeling that can be applied to petroleum hydrocarbon contamination in groundwater is also covered. The review is designed to complement an earlier (pre-1988) review published by the U.S. Navy. Pages: 146.
Order Number: I46270, Price: $30.00

DR *200*, Modeling Aerobic Biodegradation of Dissolved Hydrocarbons in Groundwater, April 1995
This report describes a 3-D groundwater transport model that accurately characterizes the nature of aerobic biodegradation, i.e., the mixing of oxygen and dissolved hydrocarbons at plume edges of petroleum spills to the subsurface. The report also demonstrates the differences between spreading and mixing phenomena. The approaches in this report will be used to develop user-friendly biodegradation models which will be helpful in site-specific evaluations. The use of such models could lead to shorter and less expensive cleanups at some sites. Pages: 76.
Order Number: I00200, Price: $30.00

Publ *4593*, Transport and Fate of Non-BTEX Petroleum Chemicals in Soils and Groundwater, September 1994
Order Number: I45930, Price: $40.00

Publ *4601*, Transport and Fate of Dissolved Methanol, MTBE and Monoaromatic Hydrocarbons in a Shallow Sand Aquifer, April 1994
Order Number: I46010, Price: $65.00

Publ *4551*, Treatment of Gasoline-Contaminated Groundwater Through Surface Application: Laboratory Experiments, July 1994
Order Number: I45510, Price: $55.00

Publ *4552*, Treatment of Gasoline-Contaminated Groundwater through Surface Application: A Prototype Field Study, July 1994
Order Number: I45520, Price: $40.00

Publ *4415*, Literature Survey: Unassisted Natural Mechanisms to Reduce Concentrations of Soluble Gasoline Components, August 1985
Order Number: I44150, Price: $25.00

Publ *4476*, Hydrogeologic Data Base for Groundwater Modeling, February 1989
Order Number: I44760, Price: $25.00

NOTE: *Prices are subject to change.*

Copies of these publications are available from API's Publications Department, (202) 682-8375. For more information about the research, contact the Health, Environment, & Safety Information Specialist at the American Petroleum Institute by phone (202) 682-8319 or email ehs@api.org.

Ground Water Monitoring&Remediation

FORUM

A Comparison of Benzene and Toluene Plume Lengths for Sites Contaminated with Regular vs. Ethanol-Amended Gasoline

by G.M.L. Ruiz-Aguilar, K. O'Reilly, and P.J.J. Alvarez

Abstract

This article describes various statistical analyses of plume-length data to evaluate the hypothesis that the presence of ethanol in gasoline may hinder the natural attenuation of hydrocarbon releases. Plume dimensions were determined for gasoline-contaminated sites to evaluate the effect of ethanol on benzene and toluene plume lengths. Data from 217 sites in Iowa (without ethanol; set 1) were compared to data from 29 sites in Kansas that were contaminated by ethanol-amended gasoline (10% ethanol by volume; set 2). The data were log-normally distributed, with mean benzene plume lengths (± standard deviation) of 193 ± 135 feet for set 1 and 263 ± 103 feet for set 2 (36% longer). The median lengths were 156 feet and 263 feet (69% longer), respectively. Mean toluene plume lengths were 185 ± 131 feet for set 1 and 211 ± 99 feet for set 2 (14% longer), and the median lengths were 158 feet and 219 feet (39% longer), respectively. Thus, ethanol-containing BTEX plumes were significantly longer for benzene ($p < 0.05$), but not for toluene. A Wilcoxon signed rank test showed that toluene plumes were generally shorter than benzene plumes, which suggests that toluene was attenuated to a greater extent than benzene. This trend was more pronounced for set 2 (with ethanol), which may reflect that benzene attenuation is more sensitive to the depletion of electron acceptors caused by ethanol degradation. These results support the hypothesis that the presence of ethanol in gasoline can lead to longer benzene plumes. The importance of this effect, however, is probably site-specific, largely depending on the release scenario and the available electron acceptor pool.

Introduction

The use of ethanol as a gasoline additive is likely to increase in the near future as a substitute for the oxygenate MtBE (Powers et al. 2001a, 2001b). Regulatory renewable fuel requirements will also lead to additional ethanol use. Therefore, it is important to understand how ethanol affects the fate and transport of hydrocarbons in ground water. Previous laboratory studies have shown that the presence of ethanol could have undesirable effects on the biodegradation of BTEX (i.e., benzene, toluene, ethylbenzene, and *ortho-*, *para-*, and *meta-xylene*). Specifically, ethanol is often degraded preferentially and contributes to the depletion of nutrients and electron acceptors (e.g., O_2) that would otherwise be available to support BTEX biodegradation (Corseuil et al. 1998; da Silva and Alvarez 2002; Ruiz-Aguilar et al. 2002). In addition, high ethanol concentrations (>10%), which could occur initially at the source, could also enhance BTEX solubility and decrease sorption-related retardation, enhancing hydrocarbon migration (da Silva and Alvarez 2002; Powers et al. 2001b; Rao et al. 1990). These findings suggest that ethanol may hinder BTEX natural attenuation, which could result in longer BTEX plumes and a greater risk of exposure. Nevertheless, little is known about the magnitude and significance of this potential plume-elongation effect.

Plume dimensions and stability are important parameters to characterize for risk management because they determine the area of influence and the potential duration of exposure. Several investigators have developed mathematical models for predicting the effect of ethanol (added to gasoline at 10% by volume) on BTEX plume length (Table 1). These screening models predict that ethanol would increase the maximum BTEX plume length (i.e., when steady state is reached) by anywhere from ~10% to 150%. Whereas these models provide valuable insight into the potential ground water impacts of ethanol in gasoline, they are based on simplifying and influential assumptions and have not yet been validated with field data. Therefore, there is a need for empirical evaluations of the effect of ethanol on BTEX plume length.

This article describes statistical analyses of plume-length data to evaluate the general hypothesis that the presence of ethanol in gasoline hinders the natural attenuation of hydrocarbons, resulting in longer BTEX plumes compared to reg-

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Table 1
Modeling Efforts to Assess the Effect of Ethanol on Benzene Plume Length

Citation	Conceptual Model	Increase in Benzene Plume Length
Heermann and Powers (1996)	2-D transport from a pool of gasoline. Focus on cosolvency and interface mass transfer. Biodegradation not included.	≤ + 10% (for xylene not benzene)
Malcom Pirnie Inc. (1998)	Steady-State, 2-D transport from a gasoline pool. First-order decay of benzene when C_{EtOH}<3 mg l^{-1}. First-order decay of ethanol.	+ 17-34 %
McNab et al. (1999)	3-D aqueous transport. Continuous slow release of gasoline (up to 3 gpd) to a growing NAPL pool at the water table. First-order decay of ethanol and benzene. Benzene degradation rate constant defined by inverse correlation to BOD conc. at the source.	~ + 100 %
Molson et al. (2002)	3-D transport from a gasoline source at the water table at a residual saturation. Aerobic decay with O_2 as the sole electron acceptor quantified by Monod kinetics. Microbial growth incorporated.	+ 10–150 %

ular-gasoline releases. This article also addresses the likelihood that ethanol would hinder the natural attenuation of benzene to a greater extent than toluene due to differences in their biodegradability under the strictly anaerobic conditions induced by ethanol.

Methodology

Plume Data

Two sets of ground water data were collected from about 600 gasoline-contaminated sites. One of the data sets (set 1) was obtained from the Iowa Department of Natural Resources, Underground Storage Tanks Section (IDNR TIER-2 database). This database contained no information about the presence of ethanol; thus, the data were screened to exclude sites with suspected contamination by ethanol-amended gasoline. A review of site investigation reports and telephone surveys were conducted for this purpose. Many of the set 1 sites were also discarded because of insufficient data to plot the required plume contours (e.g., plumes not bracketed by downgradient wells) or because contamination resulted from multiple sources (e.g., overlapping plumes). Therefore, only 217 Iowa sites (contaminated with regular gasoline) were included in set 1. The other data set (set 2) was obtained from the Kansas Department of the Environment and Health (KDEH), and corresponded to 29 sites contaminated with gasohol (i.e., gasoline with 10% ethanol by volume). Site investigation reports did not show salient differences between the two data sets regarding release and response scenario (e.g., amount released, age of spill, or remedial activities). None of these sites reported MTBE contamination. In addition, MTBE is unlikely to affect BTEX or ethanol degradation in contaminated aquifers (da Silva and Alvarez 2002; Deeb et al. 2001; Ruiz-Aguilar et al. 2002). Thus, MTBE was not a factor in this study.

Determination of Plume Lengths

Benzene and toluene plume lengths were determined by contouring data from monitoring wells (which were typically separated by about 100 feet), using a computer algorithm based on Hardy's multiquadric method for plotting two-dimensional concentration contours (Saunderson 1994). This algorithm was incorporated into the Iowa RBCA TIER2 Interpolation Program version 2.17, which interfaces with the IDNR TIER-2 database. This approach eliminated subjectivity associated with drawing the plumes by hand. Selected computer-generated plumes were compared to the corresponding hand-drawn plumes for validation purposes. Plume lengths were then measured as the longest distance between the identified source and the 5 µg/L contour, which corresponds to the drinking water standard for benzene.

Statistical Analyses

Plume length data were imported into Minitab (version 13.1, State College, Pennsylvania), which was used to calculate population statistics for each data set. These statistics included the population mean, standard deviation, median, maximum, and minimum. Distribution analyses were performed using the Anderson-Darling test for log-normality at the 95% significance level (Freedman et al. 1998). A Kruskal-Wallis test was also performed to determine whether BTEX plumes were significantly longer in set 2 (with ethanol) than in set 1 (without ethanol). This nonparametric test, which ranks plume lengths from low to high and then analyzes the ranks (Lehmann 1975), is very robust to test differences in population medians (Johnson and Mizoguchi 1978). Two-sample

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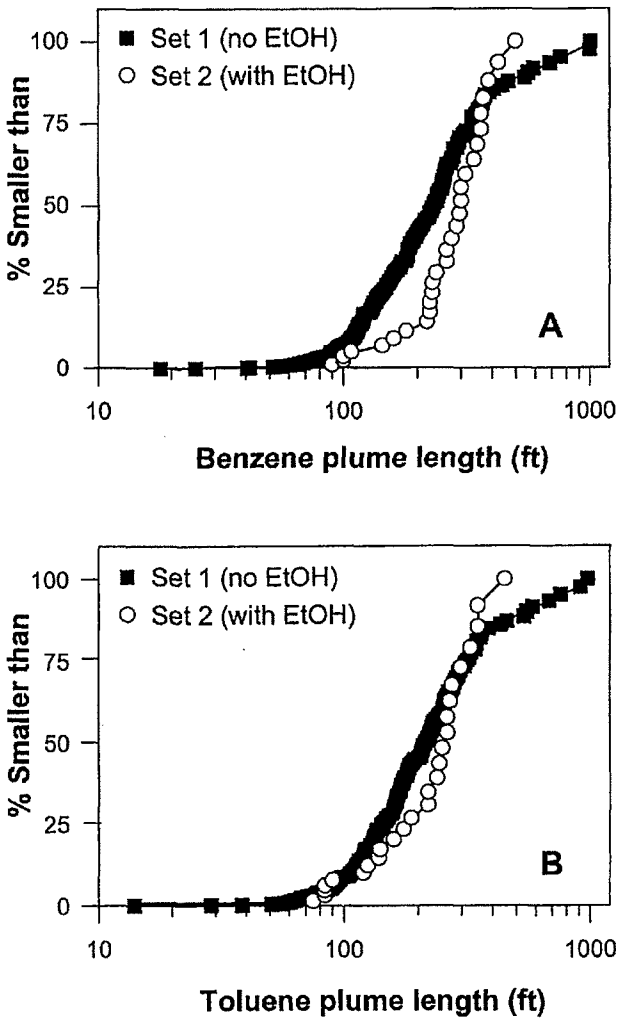

Figure 1. Cumulative distribution of (a) benzene and (b) toluene plume lengths for set 1 (Iowa data, without ethanol) and set 2 (Kansas data, with ethanol).

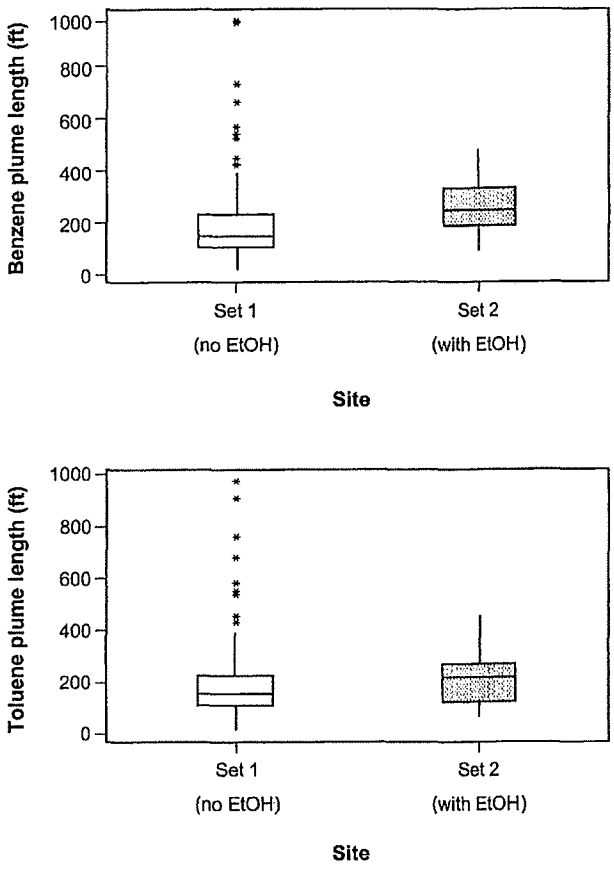

Figure 2. Box plots of the benzene and toluene plume length data. The line across the box represents the median. The bottom and top of the box represent the first and third quartiles (Q1 and Q3). The whiskers extend to the lowest and highest observations inside the region defined by Q1 −1.5(Q3-Q1) and Q3 +1.5(Q3-Q1). Individual points with values outside these limits (outliers) are plotted with asterisks.

Student's t-tests (Freedman et al. 1998) were also performed to determine if average benzene and toluene plume lengths were significantly different between the two data sets. Finally, a Wilcoxon signed-rank test was performed to test if benzene plumes were generally longer than toluene plumes, and to determine if this trend was statistically significant.

Results and Discussion

Plume length data were log-normally distributed ($p = 0.275$ for benzene and 0.394 for toluene) according to an Anderson-Darling test. The cumulative distribution of the plume lengths shows that benzene plumes were generally longer for set 2 (with ethanol) than for set 1 (without ethanol) (Figure 1a). For example, 92% of benzene plumes in set 2 were longer than 150 feet, compared to only 74% for set 1. The same trend was observed for plumes longer than 250 feet. In this case, 69% of benzene plumes in set 2 were longer than 250 feet, compared to 45% for set 1. However, none of the 29 plumes in set 2 was longer than 500 feet, compared to 12% of the 217 plumes in set 1. This trend reversal reflects that set 1 was a much larger data set and contained both the smallest and largest plumes. Note that these longer plumes are statistical outliers, as determined by the Tukey method (Tukey 1977; Figure 2). Similar results were observed for toluene, although the apparent elongation effect of ethanol was not as pronounced (Figure 1b).

Box plots corroborated that BTEX plumes with ethanol (set 2) were generally longer than those from set 1, without ethanol (Figure 2). A Kruskal-Wallis test showed that the median length of benzene plumes was significantly longer for set 2 than for set 1 (263 versus 156 ft $p < 0.001$; Figure 3). On the other hand, the difference for toluene plumes was not statistically significant (219 versus 158 feet, $p = 0.073$). Note that the median length for benzene and toluene plumes without ethanol is within 15% of that reported by Newell and Connor (1998) (i.e., 132 feet). This value was obtained from a compilation of four surveys (Groundwater Services 1997; Mace et al. 1997; Rice et al. 1995; Newell and Connor 1990), covering a total of 604 sites presumably contaminated with gasoline without ethanol.

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Table 2
Summary Statistics for Benzene and Toluene Plume Length Data

Parameters	Compound: Benzene Set 1 (no EtOH)	Benzene Set 2 (with EtOH)	Toluene Set 1 (no EtOH)	Toluene Set 2 (with EtOH)
Number of sites	217	29	211	26
Minimum (ft)	18	90	14	75
Median (ft)	156	263	158	219
Maximum (ft)	1005	500	973	450
Mean (ft) ± Std. deviation	193 ± 135	263 ± 103	185 ± 131	211 ± 99
p – value	0.002*		0.243	

*Data were significantly different ($p < 0.05$) as determined by a two-sample student's t-test.

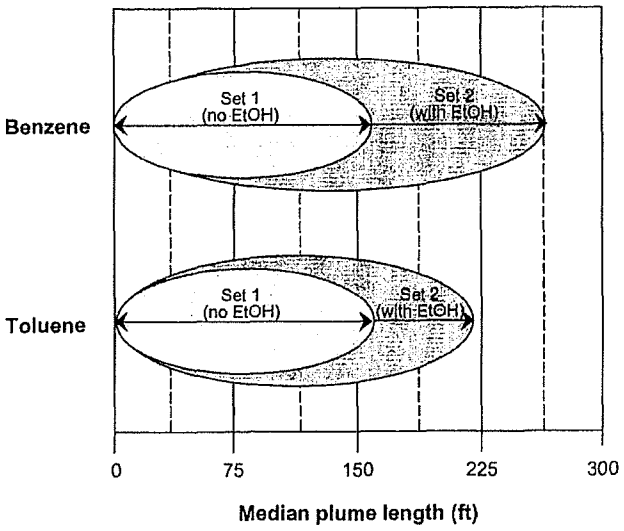

Figure 3. Median length of set 1 (Iowa data, without ethanol) versus set 2 plumes (Kansas data, with ethanol). The difference was significantly different for benzene ($p < 0.001$), but not for toluene ($p = 0.073$), as established by a Kruskal–Wallis test.

Table 2 summarizes the central tendencies of benzene and toluene plume lengths. The average length of BTEX plumes with ethanol was higher than the corresponding value without ethanol (by 36% or 70 feet for benzene, and by 17% or 26 feet for toluene). Similar to the Kruskal-Wallis test, two-sample student's t-tests showed that these differences were statistically significant for benzene ($p = 0.002$) but not for toluene ($p = 0.243$). Whereas an increase of 70 feet in the average length of benzene plumes is statistically significant, this does not imply that the corresponding increase in public health risk will also be significant.

Benzene plumes were generally longer than toluene plumes, and this difference was more pronounced for the data set with ethanol (set 2). Specifically, the average benzene plume was 20% longer than the average toluene plume for set 2, compared to a 4% difference for the data set without ethanol (set 1). A Wilcoxon signed rank test showed that both of these

Table 3
Predominant Lithologic Characteristics of the Sites Considered in This Study

Material	Percent of Sites Where Material was Dominant: Set 1 (no ethanol)	Set 2 (with ethanol)
Clay	40	31
Limestone	4	0
Mixed	28	34
Sand	15	23
Shale	0	3
No data available	13	9

Table 4
Benzene Plume Length Statistics, Segregated by Dominant Type of Aquifer Material*

Dominant Aquifer Material	Number of sites	Benzene Plume Length: Average (ft)	Standard Deviation (ft)
Set 1 (no ethanol, Iowa)			
Clay	85	184	107
Limestone	8	155	105
Mixed	59	172	84
Sand	35	249	215
No data available	31	199	164
Set 2 (with ethanol, Kansas)			
Clay	8	242	89
Mixed	9	283	105
Sand	8	250	92
Shale	1	288	0
No data available	3	292	201

*For a given set, differences between categories were not significantly different.

differences were statistically significant ($p < 0.05$), which suggests that the potential elongating effect of ethanol could be more pronounced for benzene than for toluene (Figure 3). Benzene, which is the most toxic of the BTEX compounds, is relatively recalcitrant under the anaerobic conditions exacerbated by an ethanol-driven consumption of electron acceptors (Corseuil et al. 1998; Heider et al. 1998). Toluene is more frequently reported to degrade under anaerobic conditions. The methyl group in toluene is electrophilic and facilitates nucleophilic attack by water (Alvarez and Vogel 1995) or by anaerobic catabolic enzymes such as benzyl succinate synthase (Heider et al. 1998). This facilitates the initiation of degradation without the action of an oxygen requiring oxygenase enzyme. The higher biodegradability of toluene and its higher tendency than benzene to be retarded by sorption (Alvarez et al. 1998) are conducive to shorter plumes.

As is commonly the case for many epidemiological studies, it should be pointed out that the inferences of our statistical analysis are constrained by other factors besides the presence of ethanol that could influence plume length. Although Iowa and Kansas have a similar geologic history, unaccounted confounding factors include hydrogeologic and geochemical characteristics that control the rates of advection,

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dilution, sorption, volatilization, and biodegradation, as well as site heterogeneity and the release and response scenarios. Unfortunately, logistical and cost constraints often preclude the quantification of these processes at gasoline-contaminated sites. Therefore, these factors could not be included in our statistical analysis, with the exception of considering borehole data that permitted the categorization of the sites according to the dominant type of aquifer material (Table 3). These data suggest that a slightly higher percentage of sites in set 1 were less permeable than in set 2 (i.e., 46% vs. 33% were clay-rich and 19% vs. 24% were sandy). Although plumes were generally longer in sandy than in clay-rich aquifers, the standard deviations for a given lithologic category were relatively large, as illustrated for benzene plumes (Table 4). Therefore, the dominant type of aquifer material did not have a statistically significant effect on plume length. This finding is consistent with previous plume studies (Rice et al. 1995; Mace et al. 1997). This does not mean that the type of aquifer material (and its associated permeability and sorption capacity) does not affect plume length. Rather, it implies that other factors that were not quantified could be more influential.

In spite of the many potentially confounding factors associated with field data, it should be recognized that (1) such confounding factors were likely randomized by the relatively large data set considered; (2) Kansas plumes were longer even though temperatures tend to be slightly warmer in Kansas than in Iowa, which is conducive to faster biodegradation; and (3) the results of the statistical analysis show a strong consistency of association with experimental and modeling results and with biologically plausible explanations discussed previously. Therefore, this work supports the hypothesis that the presence of ethanol in gasoline can lead to longer benzene plumes. These results should provide a basis for further field studies involving controlled gasohol releases to improve our gasohol-release risk assessment capabilities.

Conclusion

This study investigated the potential magnitude and significance of BTEX plume elongation by the presence of ethanol in gasoline. There was a statistically significant difference in mean benzene plume lengths between gasoline- versus gasohol-contaminated sites. The mean toluene plume lengths were not significantly different. Ethanol apparently hinders the biodegradation of benzene to a greater extent than toluene because benzene is less degradable under strictly anaerobic conditions that are exacerbated by the depletion of electron acceptors during ethanol degradation. The significance of this effect, however, is probably site-specific, largely depending on the release scenario and the available electron acceptor pool.

Acknowledgments

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Evaluation of the Impact of Fuel Hydrocarbons and Oxygenates on Groundwater Resources

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The environmental behavior of fuel oxygenates (other than methyl *tert*-butyl ether [MTBE]) is poorly understood because few data have been systematically collected and analyzed. This study evaluated the potential for groundwater resource contamination by fuel hydrocarbons (FHCs) and oxygenates (e.g., *tert*-butyl alcohol [TBA], *tert*-amyl methyl ether [TAME], diisopropyl ether [DIPE], ethyl *tert*-butyl ether [ETBE], and MTBE) by examining their occurrence, distribution, and spatial extent in groundwater beneath leaking underground fuel tank (LUFT) facilities, focusing on data collected from over 7200 monitoring wells in 868 LUFT sites from the greater Los Angeles, CA, region. Excluding the composite measure total petroleum hydrocarbons as gasoline (TPH_G), TBA has the greatest site maximum (geometric mean) groundwater concentration among the study analytes; therefore, its presence needs to be confirmed at LUFT sites so that specific cleanup strategies can be developed. The alternative ether oxygenates (DIPE, TAME, and ETBE) are less likely to be detected in groundwater beneath LUFT facilities in the area of California studied and when detected are present at lower dissolved concentrations than MTBE, benzene, or TBA. Groundwater plume length was used as an initial indicator of the threat of contamination to drinking water resources. Approximately 500 LUFT sites were randomly selected and analyzed. The results demonstrate MTBE to pose the greatest problem, followed by TBA and benzene. The alternative ether oxygenates were relatively localized and indicated lesser potential for groundwater resource contamination. However, all indications suggest the alternative ether oxygenates would pose groundwater contamination threats similar to MTBE if their scale of usage is expanded. Plume length data suggest that in the absence of a completely new design and construction of the underground storage tank (UST) system, an effective management strategy may involve placing greater emphasis on UST program for ensuring adequate enforcement and compliance with existing UST regulations.

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1. Introduction

The production and use of fuel oxygenates, particularly methyl *tert*-butyl ether (MTBE), have increased dramatically since the early 1990s as a consequence to federal and state regulations designed to improve air quality. The 1990 Federal Clean Air Act (CAA) Amendments mandated the use of winter oxyfuel or reformulated gasoline (RFG) to reduce carbon monoxide or ozone-forming hydrocarbon emissions in carbon monoxide and ozone nonattainment regions, respectively (*1*). In theory, the federal oxyfuel and RFG requirements do not specify a particular oxygenate, and gasoline refiners have several oxygenate options, including ethers (e.g., MTBE, diisopropyl ether [DIPE], ethyl *tert*-butyl ether [ETBE], *tert*-amyl methyl ether [TAME]) and alcohols (e.g., ethanol or *tert*-butyl alcohol [TBA]). In practice, however, MTBE has emerged as the dominant oxygenate in oxyfuel and RFG due to its lower cost and favorable transfer and blending characteristics (*2*). Currently, MTBE accounts for 85% of all oxygenates used in the United States or roughly 15 billion L $year^{-1}$ (*3*). While ethanol accounts for about 7% of the United States oxygenated fuel supply, ethanol is generally not used outside of the Midwest (*4*).

Fuel oxygenates can be accidentally introduced to subsurface environments during the refining, distribution, and storage of oxygenated fuels. Spills and leaks of oxygenate-containing gasoline pose a greater risk to groundwater resources as compared to that caused by other petroleum constituents (e.g., monoaromatics such as benzene, toluene, ethylbenzene, and total xylenes [BTEX]). Comparing to other petroleum constituents, fuel oxygenates are significantly more water soluble and are not adsorbed as readily to soil particles (see Table S1, Supporting Information), allowing them to travel farther and faster in groundwater (*4*−*6*). In addition, owing in part to their molecular structure, ether oxygenates including MTBE have been shown to resist biodegradation (*7*−*11*). The persistence and mobility of MTBE in subsurface environment, combined with its relative quantity in oxyfuel and RFG as compared to other gasoline constituents, have contributed to its dominant presence and frequent detection in groundwater plumes (*4*) and community water systems (CWS) (*12*). The relatively low odor threshold of MTBE renders many of these drinking water supplies with even low-level MTBE contamination to be unusable (*13*).

Concerns about potential groundwater contamination from MTBE have led several states to consider or enact MTBE bans (*4*). Unless the oxygenate requirements are removed through modification of the CAA, state- and federal-level bans of MTBE mean refiners must replace MTBE with another oxygenate. As a result, interest in the use and the environmental fate and transport of alternative oxygenates has increased significantly (*14*). However, to date, the state of knowledge is still quite limited for oxygenates DIPE, ETBE, TAME, and TBA (which together make up a total of up to 8% of United States oxygenates market). There are virtually no data on the environmental behavior of these other oxygenates (*15*), due primarily to difficulties in delineating their extent in the environment, lack of systematic analytical procedures for their determination as a group, and lack of regulatory requirement for their analysis. The extent and magnitude of

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oxygenate contamination (other than MTBE) in the United States remains unknown. It is imperative that the environmental impacts of alternative oxygenates be properly assessed, since limited evidence available suggests they would pose groundwater contamination threats similar to MTBE (*4*), if used in similar percent by volume amounts.

This paper characterizes the potential for groundwater contamination of fuel hydrocarbons (FHCs) and oxygenates by examining their occurrence, distribution, and extent at leaking underground fuel tank (LUFT) sites. Specifically, data on the frequency of detection, maximum concentration, and contaminant plume length in groundwater of FHCs and oxygenates at LUFT sites in the greater Los Angeles region are presented. Contaminant plume length is the primary measure in this research because it reflects the potential of the contaminant to impact receptors. Secondary analysis of the correlation among FHC and oxygenate plume lengths and concentrations and time series analysis of contaminant plume length are also presented. In addition, this paper addresses the role of fuel oxygenates in influencing the behavior of FHC plumes at LUFT sites. Analysis of these data provides information on the current extent/magnitude of impact to groundwater resources caused by fuel releases, addresses the fate and transport of released gasoline constituents, and provides a basis for making preliminary predictions on the implications of the expected shift to alternative oxygenates as MTBE is phased out, or reduced, in gasoline.

The approach utilized is to treat LUFT sites as statistical populations (*1*). LUFT sites are particularly important because they represent major point sources of gasoline constituents and the leading cause of FHC and oxygenate groundwater contamination. According to U.S. Environmental Protection Agency's (USEPA) Safe Drinking Water Information System, some 385 000 known releases of gasoline have already occurred at LUFT sites nationally (*5*) and approximately 35% of the CWS wells have one or more LUFT sites within a 1-km radius of the well (*5*). This paper focuses California, specifically the Los Angeles region, as California's large consumption of fuel oxygenates makes the state an important environmental indicator for the national impacts of oxygenates. In fact, California's consumption of MTBE accounts for approximately one-fourth of global MTBE consumption (*4*) and some 6700 MTBE LUFT sites are located within 0.8-km radius of CWS wells in the state (*16*). Los Angeles, which comprises about 28% of the population in California (*17*), exemplifies a typical RFG-program participating metropolitan area.

2. Experimental Section

2.1.1. Characterization of Contaminant Spatial Extent at LUFT Sites. Groundwater plume length for a given contaminant is defined as the distance from the source area to the farthest edge of the plume at a predetermined concentration contour. In this paper, the dissolved plume length in groundwater for FHC (benzene), oxygenates (MTBE, DIPE, ETBE, TAME, and TBA), and total petroleum hydrocarbons as gasoline (TPH_G) were investigated. TPH_G is a useful indicator of the presence and magnitude of gasoline contamination and includes C_4–C_{12} compounds. Dissolved concentration contours were defined to 5 $\mu g\ L^{-1}$ for benzene and ether oxygenates to 10 $\mu g\ L^{-1}$ for TBA, and to 100 $\mu g\ L^{-1}$ for TPH_G, taking into account both uniformity across different analytes as well as their method detection limits (MDLs). For each site, analytical data from groundwater monitoring wells, estimates of average groundwater gradient directions, and best professional judgment in extrapolating the most downgradient well contaminant concentrations to the respective predetermined concentration contours were used to contour the groundwater plume for estimating spatial extent. Other investigators (*1, 16, 18*) have applied similar methods for characterizing plume length.

Clearly, plume length as defined is two-dimensional. The lack of depth-specific data and other site-specific knowledge across the population of LUFT sites investigated in this paper preclude evaluation of plume transport in the vertical direction. In areas of significant recharge, this can bias the measurements toward shorter plumes, since a typical monitoring well screened across the water table may fail to detect the leading edge of the plume as it is deflected downward in response to the infiltration of recharge from above. Further, fluctuating flow directions as well as errors in their determination can result in monitoring well network configurations that create additional biases in plume length measurement. Despite these shortcomings, plume length remains an important indicator of the spatial extent of solute plumes and, in this paper, reflects the potential/relative potential of the FHCs and oxygenates to impact receptors.

2.1.2. Site Selection and Sampling Protocol for Contaminant Plume Length Study. From a list of over 1100 active LUFT facilities in the greater Los Angeles region, 500 facilities were randomly selected for site evaluation. Facilities qualified for inclusion in the plume length study if (a) sufficient groundwater monitoring data were available to define the contaminant plume lengths, (b) groundwater monitoring data covered at least the time period from 3rd quarter 2000 to 2nd quarter 2001, (c) at least one of the five fuel oxygenates of interest (MTBE, TBA, DIPE, ETBE, and TAME) was used or detected at the site, (d) at least one of the FHCs (TPH_G and benzene) was used or detected at the site, and (e) site analytical data met California Regional Water Quality Control Board–Los Angeles Region's (CRWQCB-LA) laboratory quality assurance testing requirements (*19*).

To investigate the influence of oxygenates on FHC plume length at LUFT sites, a distinct "FHC-only" population of LUFT facilities was identified for comparison. From the same list of LUFT facilities referenced above, 700 facilities were randomly selected for site evaluation. The "FHC-only" population was selected based on identical facility inclusion criteria as above, with the exception that none of the five oxygenates of interest was used or detected at the site (as demonstrated by soil and groundwater historical data). For TPH_G and benzene, only for 53 and 52 facilities, respectively, were plume lengths able to be estimated after examination of all 700 randomly selected sites.

2.2. Occurrence and Distribution of FHCs and Oxygenates at LUFT Sites. To investigate the occurrence/distribution of FHCs and oxygenates, data from LUFT sites were analyzed to determine the frequency of detection of FHCs and oxygenates at LUFT sites, their maximum site concentrations, and the correlation among these gasoline constituents. As part of the recent regulatory requirements adopted by the California State Water Resources Control Board, responsible parties for LUFT sites were required to submit laboratory analytical data and reports to the state Geotracker Internet Database in the Electronic Deliverable Format (EDF). From a list of over 1100 active LUFT facilities in the greater Los Angeles region, over 850 facilities had submitted their laboratory analytical data and reports in EDF, which ensured the data that were transmitted were of known quality and met all laboratory testing requirements specified by the regulatory agency (section 2.4). The resulting EDF from these facilities uniformly analyzed, at a minimum, FHC (BTEX), oxygenates (MTBE, DIPE, ETBE, TAME, and TBA) and TPH_G. An extensive data analysis was conducted of the electronic data and hardcopy reports from these facilities. For the time period between January and March of 2002, a total of over 7200 monitoring wells were sampled for these facilities.

2.3. Site Setting and Representativeness. To determine whether the LUFT sites selected for this study were repre-

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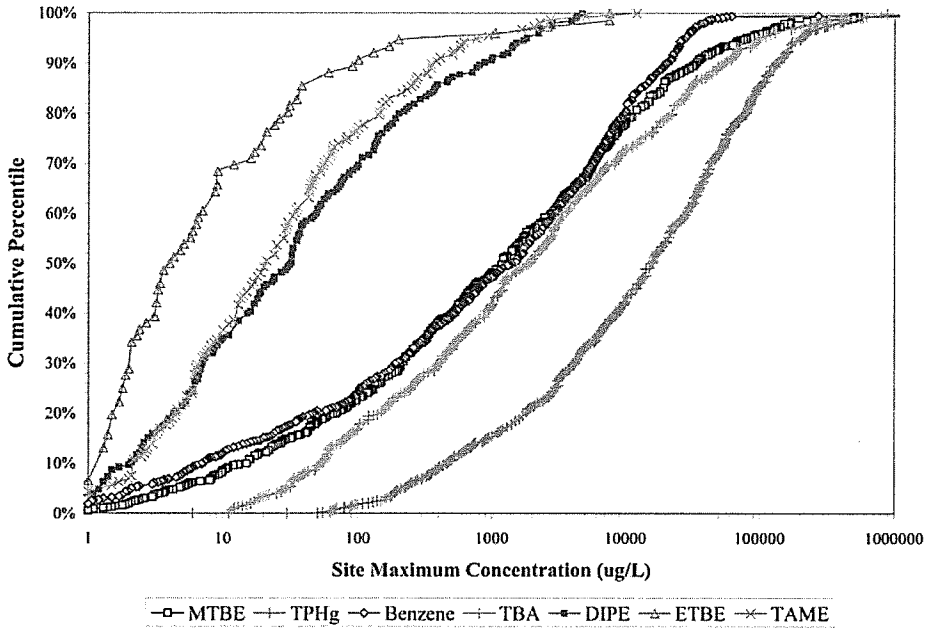

FIGURE 1. Plot of cumulative percentile of site maximum concentration for FHCs (TPH_G and benzene) and oxygenates (MTBE, TBA, DIPE, ETBE, and TAME).

TABLE 1. Summary Statistics on LUFT Site Maximum Analyte Concentrations and Site Analyte Detection Frequencies[a]

	MTBE	TPH_G	benzene	DIPE	ETBE	TAME	TBA
minimum ($\mu g\ L^{-1}$)	0.46	30	0.3	0.36	0.35	0.38	6
maximum ($\mu g\ L^{-1}$)	1.6×10^7	9.98×10^8	4.2×10^7	4 700	7 500	12 000	4.4×10^6
median ($\mu g\ L^{-1}$)	1 200	15 000	1 370	30	4	20	1 880
mean ($\mu g\ L^{-1}$)	44 840	3 783 500	83 750	290	260	240	30 120
g-mean ($\mu g\ L^{-1}$)	900	11 400	700	31	7	24	1 730
LUFT sites with detected analyte (*n*)	718	797	716	206	77	159	530
analyte site detection frequency (%)	82.7	91.8	82.5	23.7	8.9	18.3	61.1

[a] Note: *g*-mean denotes geometric mean.

sentative of the majority of LUFT sites in California, statistical analyses of site hydrogeology and contaminant impact were conducted in manner similar to Happel et al. (*1*) and reported in detail in text and figures in the Supporting Information.

2.4. Analytical Methods. The analysis of oxygenates as a group using conventional analytical procedures designed for petroleum hydrocarbons has been shown to be problematic (*1, 20*). USEPA Method 8020/21B, a protocol routinely employed for the analysis of LUFT samples, was unfit for monitoring of TBA and frequently yielded false-positive and inaccurate results when ether oxygenates were monitored in aqueous samples containing high TPH_G concentrations (>1000 $\mu g\ L^{-1}$). In contrast, Halden et al. (*20*) demonstrated that USEPA Method 8260B (gas chromatography/mass spectrometry) was a robust protocol for oxygenates over a wide range of TPH_G background concentrations. To ensure that appropriate protocols for the analysis of oxygenates were utilized, only those groundwater samples from LUFT sites that had been analyzed for BTEX and ether and alcohol oxygenates using USEPA Method 8260B were used for this study. TPH_G was analyzed using USEPA Method 8015 nonaromatic, nonhalogenated chromatograph procedure. Laboratory MDLs for TPH_G, BTEX, TBA, and ether oxygenates were set at 100, 1, 10, and 2 $\mu g\ L^{-1}$, respectively.

3. Results and Discussions

3.1. Occurrence and Distribution of FHCs and Oxygenates at LUFT Sites. To determine the frequency of detection of FHCs and oxygenates at LUFT sites, their maximum site concentrations, and the correlation among these gasoline constituents, groundwater monitoring data from over 7200 monitoring wells in EDF were analyzed from 868 LUFT sites in the greater Los Angeles region. At a reporting limit of 100, 1, 10, and 2 $\mu g\ L^{-1}$, for TPH_G, benzene, TBA, and ether oxygenates, respectively, 96% of the EDF-LUFT sites contained at least one FHC or oxygenate, 92% contained at least two analyzed compounds, 60% contained at least four compounds, and 1.5% contained all seven FHC and oxygenate compounds. TPH_G was the analyte most frequently detected at 91.8% of EDF-LUFT study sites, followed by MTBE and benzene at 82.7% and 82.5%, TBA at 61.1%, and the alternative ether oxygenates DIPE, TAME, and ETBE at 23.7%, 18.3%, and 8.9%, respectively.

The site maximum analyte concentration (SMAC) was a good indicator of the source analyte concentration or strength in groundwater. SMAC was determined for each of the seven FHCs and oxygenates at individual EDF-LUFT study sites. Figure 1 depicts a comparison of the SMAC cumulative distributions. The results indicate that, excluding the composite measure TPH_G, TBA has the greatest site maximum concentrations, followed by MTBE/benzene and DIPE, TAME, and ETBE. The mean, geometric mean, median, and other relevant measures are displayed in Table 1 for LUFT sites with detectable levels of analyte. The log-normality of the data sets, confirmed by graphical tools and more quantitative measures (e.g., coefficient of variation, the Shapiro–Wilk Test (*21*), and skewness), necessitated a natural log data transformation before computation of the *t*-test (*21*–

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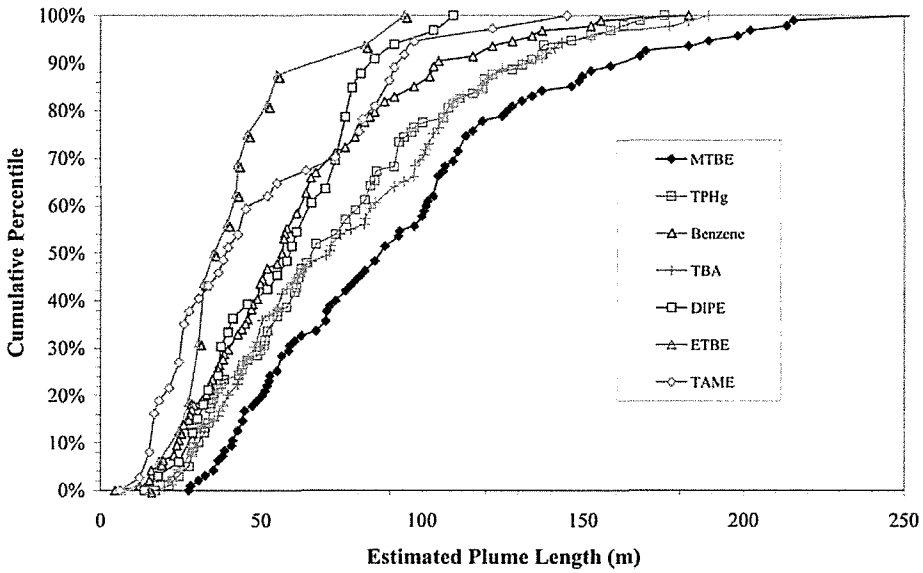

FIGURE 2. Plot of plume length cumulative percentile for FHCs (TPH_G and benzene) and oxygenates (MTBE, TBA, DIPE, ETBE, and TAME). Note: benzene, ether oxygenate, TBA, and TPH_G plume lengths were defined to 5, 5, 10, and 100 $\mu g\ L^{-1}$ dissolved concentration contours, respectively.

23) to examine the significance of variations in concentration observed among the FHC and oxygenate compounds. Bonferroni probability (*Bon. p*) was provided as protection for performing multiple *t*-tests simultaneously. Among the FHC and oxygenates, TPH_G has the greatest geometric mean site maximum concentration, followed by TBA, MTBE, benzene, and the ether oxygenates DIPE, TAME, and ETBE (Table 1), confirming what is observed in Figure 1. The student *t*-test verified statistically significant ($\alpha = 0.05$, *Bon.* $p < 0.05$) differences for 20 out of 21 possible pairwise comparisons among the seven FHC and oxygenate compounds.

The study observations indicate low concentrations of alternative ether oxygenates (DIPE, ETBE, and TAME) at LUFT sites (e.g., 50% of the detected maximum site concentrations for ETBE, TAME, and DIPE were less than 5, 20, and 30 $\mu g\ L^{-1}$, respectively (Figure 1)). Examinations of gasoline surveys provide definitive knowledge of which oxygenate and what volumes of that oxygenate are being used in a particular region of the country. As demonstrated by the 1995−1997 EPA Oxygenate Type Analysis and RFG Survey Data (*24*), the quantity of alternative ether oxygenates (DIPE, ETBE, and TAME) in Los Angeles area gasoline are near trace amounts ($\ll$1% by weight), which may explain their low soluble source concentrations observed.

In addition, high TBA source concentrations were observed. In fact, excluding the composite measure TPH_G, TBA has the greatest geometric mean site maximum groundwater concentration among our study analytes. This finding may be explained in terms of the solubility and sources of TBA. Even though TBA was added to gasoline in significantly lesser amounts than MTBE or benzene, its high miscibility meant that small quantities of TBA could translate into high groundwater concentrations. Further, different sources of TBA (as gasoline additive, impurity, or oxidation byproduct of MTBE) could by themselves, or in combination, result in the detected TBA in groundwater at LUFT sites.

3.2. Characterization of Contaminant Spatial Extent at LUFT Sites. Contaminant plume length was used as an initial indicator of the threat of contamination to drinking water sources by contaminants present in shallow groundwater at LUFT sites and was estimated according to procedures in section 2.1.1. Figure 2 presents FHC and oxygenate plume lengths in terms of cumulative percentile. The results indicate that among the FHCs and oxygenates, MTBE has the greatest plume length, followed by TBA/TPH_G, benzene, and the alternative oxygenates DIPE, TAME, and ETBE. The difference in plume length is clearly distinguishable, as in the case of MTBE versus FHC and MTBE versus other oxygenates. In contrast, pairwise comparisons between TBA/TPH_G, benzene/DIPE, and TAME/ETBE cumulative distributions indicate that for these pairs, the variation in plume length is difficult to distinguish as demonstrated by the overlapping cumulative percentile curves.

The statistical significance of the plume length differences among the FHC and oxygenate groups was examined using the two sample *t*-test (after log-transformation). The log-normality of the data sets indicates that the geometric mean and the median are better descriptors of the LUFT plume population. Table 2 summarizes the data. Among the FHC and oxygenates, MTBE has the greatest geometric mean plume length at 83 m, followed by TPH_G/TBA at 64 and 63 m, benzene/DIPE at 51 and 50 m, and TAME/ETBE at 36 and 34 m. The student *t*-test verified statistically significant ($\alpha = 0.05$, *Bon.* $p < 0.05$) differences for pairwise comparisons of MTBE and TBA to DIPE, ETBE, and TAME as well as comparisons between MTBE and TBA, MTBE and benzene, and TBA and benzene. In contrast, pairwise comparisons of DIPE, ETBE, and TAME to one another as well as benzene to DIPE or ETBE were not.

Contaminant groundwater plume length is influenced by factors such as hydrogeologic characteristics, matrix chemical interactions, source strength, biodegradation, and intrinsic properties of the chemical of interest. Under steady-state conditions, the differences in plume length among the FHCs and oxygenates at a particular site may be attributed primarily to differences in source strength and degradability of the contaminant. The lower source strengths of alternative ether oxygenates (DIPE, ETBE, and TAME) (Figure 1) as compared to MTBE, TBA, or FHCs may have contributed in large part to the observed localization of these plumes. In contrast, since the FHCs have source strengths of similar magnitudes as compared to MTBE and TBA (Figure 1), it is likely the significantly greater biodegradability of the FHCs (TPH_G and benzene) relative to TBA and ether oxygenates favored the more restricted plume migrations from the source areas as compared to MTBE and TBA plumes.

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TABLE 2. Summary Statistics on Estimated LUFT Site Analyte Plume Length in Groundwater[a]

	MTBE (5 $\mu g\ L^{-1}$)	TPH_G (100 $\mu g\ L^{-1}$)	benzene (5 $\mu g\ L^{-1}$)	DIPE (5 $\mu g\ L^{-1}$)	ETBE (5 $\mu g\ L^{-1}$)	TAME (5 $\mu g\ L^{-1}$)	TBA (10 $\mu g\ L^{-1}$)
facilities (*n*)	96	99	95	34	17	37	86
min (m)	26	11	7	14	15	6	15
max (m)	317	259	168	119	94	137	192
median (m)	84	66	51	58	35	40	61
mean (m)	96	75	60	55	39	47	73
g-mean (m)	83	64	51	50	34	36	63

[a] Note: *g*-mean denotes geometric mean.

TABLE 3. Change in Analyte Groundwater Plume Length over Time (1 year)[a]

	MTBE (5 $\mu g\ L^{-1}$)	TPH_G (100 $\mu g\ L^{-1}$)	benzene (5 $\mu g\ L^{-1}$)	DIPE (5 $\mu g\ L^{-1}$)	ETBE (5 $\mu g\ L^{-1}$)	TAME (5 $\mu g\ L^{-1}$)	TBA (10 $\mu g\ L^{-1}$)
case (*n*)	96	99	94	33	16	35	86
g-mean change (m)	−1.5	−0.3	0.6	0	1.5	1.2	3.7
g-mean (m)	83	64	51	50	34	36	63
% change	−1.8	−0.5	1.2	0	4.4	3.3	5.9
P value	0.28	0.89	0.61	0.94	0.58	0.19	0.06

[a] Note: negative *g*-mean change indicates that the plume length for the selected analyte decreased over time, while positive *g*-mean change indicates the opposite.

3.3. Time Series Analysis of Contaminant Spatial Extent at LUFT Sites. Contaminant plume lengths in groundwater were tracked for 1 year for a population of LUFT sites (section 2.1.2 for site selection). A total of 464 individual plumes were tracked resulting in a total of 1856 plume lengths estimated over four quarters (Figure S3, Supporting Information). Comparison of the cumulative percentile (CP) curves over four quarters indicate that for MTBE, TPH_G, and benzene, the overlapping CP curves suggest the changes in plume length over this time period are not discernible—either the plume lengths are stable or the time period examined is not sufficient for changes to develop and/or be detected. In contrast, comparison of the CP curves for the alternative oxygenates ETBE, TAME, and TBA indicates a somewhat discernible trend of increasing plume lengths over the 1-year period. This trend is most apparent in the case of TBA, where the plume length increase over 1 year is ~6%. Decreases in contaminant plume length beneath LUFT study sites over time are likely to be the result of decreasing source strength from ongoing source removal and cleanup as well as biodegradation. Increases in contaminant plume length over time, on the other hand, may be due to a variety of factors. The more recent release of gasoline formulations containing significantly greater quantities of oxygenates may not have afforded sufficient time for oxygenate plumes to reach maximum plume configurations. As for TBA, since it is also a degradation product of MTBE, it is possible that as the MTBE plume farther away from the source area continues to degrade into TBA at concentrations above detection limit; these changes in TBA concentration would be detected by the peripheral monitoring network and thus result in increases in plume length contour.

To assess whether the plume length differences that develop over time were statistically significant, paired *t*-tests were performed (after log-transformation) for each FHC and oxygenate compound. The results indicate that after 1 year, none of the plume length differences that occurred during this period was significant at $\alpha = 0.05$ (Table 3).

Rice et al. (*25*) conducted a trend analysis for benzene plume lengths with time and determined that approximately 60% of the sites studied contained no significant temporal trends, while 32% and 8% of the sites have decreasing and increasing temporal trends, respectively. While the vast majority of benzene and TPH_G plumes are apparently stable (*1, 25*), it remains to be seen whether oxygenate plumes have reached steady state. The different release histories of these compounds can be a factor in interpreting the plume length results. If the oxygenate plumes have not reached steady state, then the observed plume length results may not be indicative of future plume lengths. Time-series analysis of plume length data presented in this paper does lend some support to the stability of the plumes, FHC or oxygenate. However, substantially longer time-series analyses are needed to verify this assumption.

3.4. Impact of Fuel Oxygenates on FHC Plume Lengths. Several laboratory, modeling, and small-scale case studies have been conducted to investigate the impact of ethanol on FHC plumes (*26–28*). It has been demonstrated that high concentrations of ethanol have the potential to increase the spatial extent of FHC plumes primarily through (1) the reduction in the biotransformation rates of FHC attributed to a reduction of available electron-acceptor species that participate in biogeochemical oxidation/reduction reactions (*27*) and (2) increases in the solubility of FHCs through a cosolvency effect (*26*). To investigate whether the presence of fuel oxygenates other than ethanol can influence the mobility and spatial extents of FHC in a similar manner, two distinct populations of LUFT sites were identified. One population was composed of LUFT sites where oxygenates had been used or detected, versus another where none of the five oxygenates of interest had been used or detected (see section 2.1.2 for site selection/protocol). Figure 3 compares the FHC plume lengths at "FHCs only" versus at "FHCs and oxygenates" LUFT sites. A student *t*-test (after log-transformation) was used to test the significance of variations in TPH_G and benzene plume lengths between the two populations of LUFT sites. The results indicate that TPH_G and benzene plumes are significantly (at $\alpha = 0.1$) longer (+20–30%) in the presence of oxygenates.

By comparing FHC (TPH_G and benzene) plume lengths at LUFT sites that differ only in one respect (e.g., the presence or absence of oxygenates), an attempt was made to adjust for other differences between the population of LUFT sites. However, the presence or absence of oxygenates at LUFT sites may itself be indicative of the relative age of the spill. Not until the passage of 1990s CAA mandating the use of RFG or oxyfuel has the addition of oxygenate been so widespread and at such a dramatic scale. Consequently, LUFT

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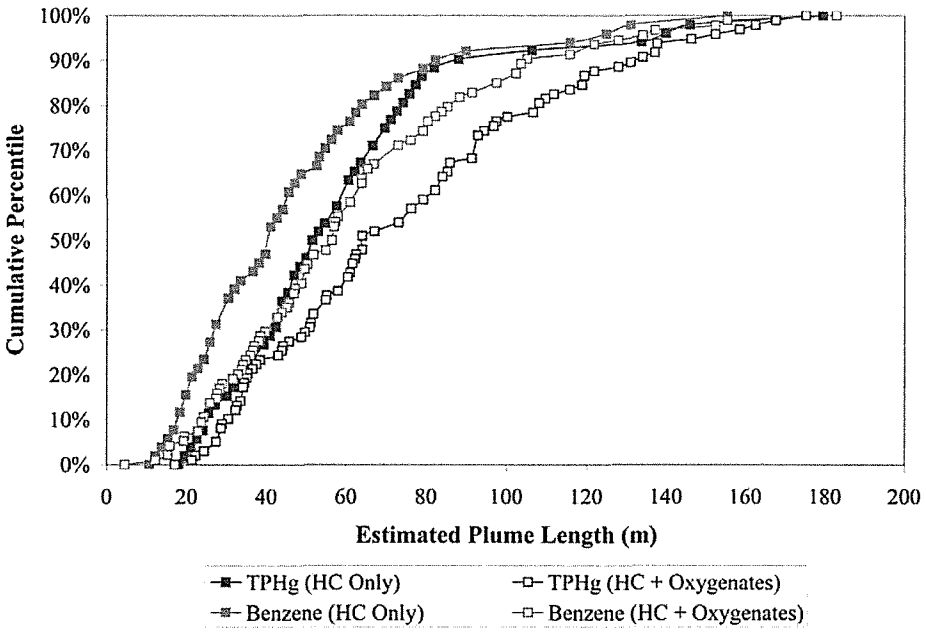

FIGURE 3. Comparison of TPH_G and benzene plume lengths at "hydrocarbons only" versus at "hydrocarbons and oxygenates" LUFT sites. TPH_G and benzene plume lengths were defined to 100 and 5 $\mu g\ L^{-1}$ dissolved concentration contours, respectively.

sites contaminated with both FHCs and oxygenates tend to have at least one or more recent fuel release(s). Conversely, LUFT sites impacted by only FHCs tend to have more aged source zones created by older spills from gasoline without oxygenate additives. Differences in the age of the spill can influence the length of FHC plumes since LUFT sites with more aged source zones also tend to have plumes that, relative to plumes at newer source zones, are stabilized or shrinking. Future work is needed to determine whether the increase in the FHC spatial extent is caused by the presence of oxygenates (e.g., through the mechanism of competition for electron acceptor species or the cosolvency effect) or is merely an artifact created by the inherent differences in the age of the spill resulting from the study design of separating LUFT sites into discrete populations ('FHCs-only' versus 'FHCs and oxygenates').

4. Implications

The site detection frequencies and maximum groundwater concentrations for TBA, MTBE, and benzene were elevated. While the groundwater samples beneath LUFT sites across the states frequently are analyzed for a suite of FHC (e.g., BTEX) and some oxygenate (e.g., MTBE) compounds, the analysis for other oxygenates in most states has seldom been performed. Site groundwater concentrations and plume length data indicate TBA contamination at a scale similar to MTBE. In addition, due to its physical/chemical properties, TBA is often the regulatory driver for treatment considerations at LUFT sites. Therefore, the presence of TBA needs to be confirmed at gasoline-impacted sites, and if confirmed, a specific cleanup strategy needs to be developed that accounts for its presence along with any other FHC or oxygenate compounds that are present. In contrast to benzene, MTBE, and TBA, the site detection frequencies and maximum groundwater concentrations for alternative ether oxygenate DIPE, ETBE, and TAME beneath LUFT facilities were low. Plume length comparisons also indicate these alternative ether oxygenates to be localized relative to MTBE, TBA, or FHCs. Even though data from this study suggests that current risk from the alternative ether oxygenates to groundwater resources at LUFT sites should be minimal, caution should be applied against over-interpretation of the data in anticipating the consequences of possible scale-up in usage of these compounds. An appropriate parallel may be found in the progression of the MTBE problem. Prior to the 1990s, when MTBE was used primarily as an octane booster, it made up only 1−3% by volume of some gasoline. It was only after the scale of MTBE usage escalated in response to the 1990s CAA Amendments that the environmental consequences associated with its use became apparent. All indications (e.g., physical/chemical characteristics such as high solubilities and low biodegradabilities (relative to FHCs)) suggest that the alternative ethers would pose groundwater contamination threats similar to MTBE if their scales of usage were expanded.

With the staggering number of LUFT facilities located in close proximity to community drinking water sources, LUFT sites represent major point sources of gasoline constituents and the leading cause of FHC and oxygenate groundwater contamination. There is little doubt that a large proportion of underground storage tank (UST) systems at gasoline stations leak, and that is apparently true even for upgraded, double-tank systems. The number of leaks indicates that the problem is primarily in the design of the system, which arises from real estate limitations, fire defense considerations, and a defense against accidents and vandalism (*29*). In the absence of completely new design and construction of the system that emphasizes detection, repair, and containment, an effective management strategy may involve placing greater emphasis on a UST program for ensuring adequate enforcement and compliance with existing UST regulations. In California, existing UST regulations require, specifically, the upgrading of USTs and the institution of leak detection systems. The plume lengths data indicate that under a well-managed UST program, with prompt detection and cleanup of source contaminants associated with failed UST systems, FHC and oxygenate plume lengths in the hundreds of meters were quite rare. The overwhelming majority of plumes associated with release(s) from LUFT facilities were relatively "localized". For instance, an examination of plume lengths of alternative ether oxygenate DIPE, ETBE, and TAME found 90% of the plumes were less than 100 m from the source area. Even in the case of MTBE, 90% of the MTBE plumes were observed to be less than 165 m. The adequate compliance with existing UST regulations may decrease the prob-

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ability of future leakage and allow for prompt response and cleanup of possible sources. This scenario could provide adequate safeguard against widespread and catastrophic impact of FHC and oxygenate plumes on groundwater sources since under these conditions the FHC and oxygenate plumes are likely to be localized.

Acknowledgments

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Supporting Information Available

Analyses of site setting and representativeness and correlation among SMAC and among contaminant plume lengths are reported in detail in text, tables, and figures in the Supporting Information. This material is available free of charge via the Internet at http://pubs.acs.org.

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Leukemia Risk Associated With Low-Level Benzene Exposure

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Background: Men who were part of an Australian petroleum industry cohort had previously been found to have an excess of lympho-hematopoietic cancer. Occupational benzene exposure is a possible cause of this excess.

Methods: We conducted a case-control study of lympho-hematopoietic cancer nested within the existing cohort study to examine the role of benzene exposure. Cases identified between 1981 and 1999 (N = 79) were age-matched to 5 control subjects from the cohort. We estimated each subject's benzene exposure using occupational histories, local site-specific information, and an algorithm using Australian petroleum industry monitoring data.

Results: Matched analyses showed that the risk of leukemia was increased at cumulative exposures above 2 ppm-years and with intensity of exposure of highest exposed job over 0.8 ppm. Risk increased with higher exposures; for the 13 case-sets with greater than 8 ppm-years cumulative exposure, the odds ratio was 11.3 (95% confidence interval = 2.85-45.1). The risk of leukemia was not associated with start date or duration of employment. The association with type of workplace was explained by cumulative exposure. There is limited evidence that short-term high exposures carry more risk than the same amount of exposure spread over a longer period. The risks for acute nonlymphocytic leukemia and chronic lymphocytic leukemia were raised for the highest exposed workers. No association was found between non-Hodgkin lymphoma or multiple myeloma and benzene exposure, nor between tobacco or alcohol consumption and any of the cancers.

Conclusions: We found an excess risk of leukemia associated with cumulative benzene exposures and benzene exposure intensities that were considerably lower than reported in previous studies. No evidence was found of a threshold cumulative exposure below which there was no risk.

Key Words: benzene, occupational exposure, leukemia, lymphoma, multiple myeloma, petroleum industry

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Benzene is present in crude oil, at most stages of petroleum production and distribution, and is a component of gasoline fuels, typically less than 3%. It is also a byproduct of combustion of fuels and other materials such as tobacco, wood, and coal. Benzene is present in indoor environments from activities such as cooking and heating, and it is ubiquitous in urban air at low concentrations. Nonsmokers living in an urban environment are typically exposed to average benzene concentrations in the order of 0.005 ppm.[1]

Benzene is classified as a group 1 human carcinogen by the International Agency for Research on Cancer,[2] and there is general agreement that benzene can cause leukemia in highly exposed individuals.[3] The extent of the risk of leukemia with exposure to low concentrations of benzene (less than 10 ppm) has been debated.[3-11] This debate has centered on 2 issues: whether the exposures were underestimated in previous epidemiologic studies and what model should be used to extrapolate the risk to lower concentrations of benzene, including whether there is a threshold exposure below which there is no risk.

In addition, there is debate about which subtypes of leukemia are associated with benzene exposure. Some but not all authorities consider that acute nonlymphocytic leukemias or, more specifically, acute myeloid leukemia, are the only subtypes clearly associated with benzene exposure.[3,8,9,12,13] Benzene has also been associated with increased risk of

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multiple myeloma,[3,14,15] although this too is disputed.[9,16] A review of 308,000 benzene-exposed workers from 26 cohorts in 5 countries found no increased rate of non-Hodgkin lymphoma.[17] In the U.K., the occupational exposure limit for benzene (maximum exposure limit) is 3 ppm as an 8-hour time-weighted average.[18] This was introduced in 2000 as the first part of a phased reduction to 1 ppm in 2003 in accordance with the Carcinogens Directive of the Council of the European Union.[19] The current American Conference of Governmental Industrial Hygienists' threshold limit value for benzene is 0.5 ppm.[20]

A prospective cohort study of all-cause mortality and cancer incidence in the Australian petroleum industry, known as Health Watch, was established in 1980 at the University of Melbourne for the Australian Institute of Petroleum. In 1999 the study was transferred to the University of Adelaide. The cohort consists of all employees except head office staff and those employed at Australian sites with fewer than 10 employees. Employees in the industry have been surveyed at approximately 5-year intervals using an interviewer-administered job and health questionnaire. This questionnaire obtained information on jobs and tasks, on possible confounding variables (including smoking and alcohol), and on specific health outcomes. The first survey was conducted from 1981-1983 and resulted in an original cohort of 10,979 men and 626 women. More subjects were recruited in the second and subsequent surveys. Approximately 95% of eligible employees in the industry have participated in Health Watch surveys. Employees were recruited into the Health Watch cohort after having served 5 years in the petroleum industry, and they remain in the cohort for life. Copies of death certificates are obtained and cancer incidence is validated through state cancer registries and the treating doctor. Cancer registration in Australia is a legal requirement of pathology laboratories and hospitals. In 1998 the cohort comprised 15,732 men and 1178 women.

Men in the cohort have been shown to have increases in the standardized incidence ratios for leukemia of 2.0 (95% confidence interval [CI] = 1.3-2.9) and for multiple myeloma of 1.9 (95% CI = 1.0-3.3).[21] We designed a case-control study to assess the association between lympho-hematopoietic cancers and occupational benzene exposure among men in the cohort. We report the exposure-response relationships for lympho-hematopoietic cancers, including the subtypes of leukemia, and benzene exposure based on matched analyses.

METHODS

This case-control study is nested within the Health Watch cohort. We estimated the occupational exposure to benzene of the cases and control subjects, drawing on the subject's entire job history and using measured exposures for a wide range of tasks in the petroleum industry.

Cases were defined as men in the Health Watch cohort who reported a newly diagnosed lympho-hematopoietic cancer to Health Watch (either by himself or by his family) that was confirmed by pathology report, cancer registration, letter from a medical practitioner, or death certificate. Registry cases who had not self-reported to Health Watch could be included under the terms of the ethics committee approval only if the man had been lost to follow up or had died.

Seventy-nine cohort members met the definition of lympho-hematopoietic cancer cases. They were identified by searching the cancer registries and through self-report to Health Watch. One man was found in the cancer registry, but under the terms of the ethics approval he could not be a case because he had not self-reported the disease and was not deceased or lost to contact.

All documentation on the cases was reviewed by the investigators and cases were assigned to International Classification of Diseases groupings according to the highest level of evidence (Table 1). For 9 cases with uncertain histology the documentation was reviewed by a hematologist who classified cases using the French-American-British system.[22]

We selected 5 male control subjects for each case. Control subjects were selected randomly from a list of all cohort members who were eligible at the time of diagnosis and matched by year of birth. As a result of the random selection, 5 workers were used as control subjects for more than 1 case, 4 of whom were used in 2 case-control sets and 1 in 3 sets. Thus, the total number of control subjects was 395. One worker selected as a control subject subsequently became a case; this subject was retained as a control subject because he was not diagnosed at the time of selection. As a control subject, his exposure was truncated at the time of the matched-case diagnosis (as with all control subjects). As a case his exposure was estimated up to the time of his diagnosis.

Each subject's smoking, alcohol, and job history had been collected as part of the Health Watch cohort surveillance.[21] For employees interviewed in either the first or second Health Watch surveys in 1981-1983 and 1986-1987, detailed information had been collected only on their current job and jobs held in the previous 5 years. During the third Health Watch survey in 1991-1993, full job histories were obtained for all current employees interviewed. For those Health Watch members no longer employed in the petroleum industry, lists of jobs held in the industry were obtained during the annual health check mail-out in 1994. The lists included job titles, company, site, area of work and dates, but no details of individual tasks or products handled. The job histories were cross-checked with company personnel records. In those instances in which discrepancies were found, the more detailed record (usually the subject's) was used.

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TABLE 1. Type of Cancer by Highest Level of Evidence for the Diagnosis

Type of Lympho-hematopoietic Cancer	ICD-9 Code	Highest Level of Evidence: Histology (N = 39)	Doctors' Letters (N = 17)	Cancer Registry Alone (N = 14)	Death Certificate (N = 9)	Total No. (N = 79)
Non-Hodgkin lymphoma	200, 202	14	6	5	6	31
Multiple myeloma	203	8	4	2	1	15
Leukemia	204–208	17	7	7	2	33
Chronic lymphocytic leukemia	204.1	5	5	0	1	11
Chronic myeloid leukemia	205.1	1	1	4	0	6
Acute lymphocytic leukemia	204.0	2	0	0	0	2
Acute nonlymphocytic leukemia*	205.0, 208.0	7	1	2	1	11
Other leukemia†	202.4, 204.9	2	0	1	0	3

*This group includes 9 acute myeloid leukemias and 2 acute undifferentiated leukemias.
†The 3 "other" leukemias were a hairy cell leukemia and 2 unspecified lymphocytic leukemias. ICD-9, World Health Organization International Classification of Diseases, 9th revision.

Cases were not themselves interviewed about their tasks, because this information might have been subject to recall bias. Instead, we interviewed contemporaries at the site who were familiar with the requirements of the job. These surrogate respondents provided information on the tasks that each subject would have performed for each job he had recorded in the job history, the technology used at that time, and products handled. Current and past employees were interviewed, and the interviews were structured using standard questionnaires for each job type based on those developed for previous petroleum industry epidemiologic studies.[23,24] The interviewers had no knowledge of the names and health status of the subjects.

We calculated the benzene exposure of each individual using a task-based algorithm involving the subject's occupational history; previously measured exposures for particular tasks in the Australian petroleum industry; and task-, site-, and period-specific data. This exposure model was similar to those used in some other petroleum industry epidemiologic studies[23,24] but more detailed in that it was task-based and applied to each individual's job history. This provided an estimate of cumulative exposure to benzene in parts per million-years (ppm-years) for each subject. The subjects were divided into geometric exposure groups. The exposure estimation process is described more fully elsewhere.[25,26]

We used the following additional exposure metrics to test the association with risk of leukemia, with and without adjustment for cumulative exposure:

1. Start date: Subjects were divided into 3 groups by their start date in the industry: pre-1965, 1965-1975, and post-1975.
2. Duration of employment: The duration of employment (in participating companies) was defined as the difference between the earliest start date and the latest finish date for each subject, truncated by date of diagnosis. We calculated quintiles of duration with cut-points approximately every 7 years.
3. Whether most of the career was spent as an office worker or as a blue collar worker.
4. Site of longest-held job and highest-exposed job: Each site where a subject worked was allocated to a site type. The period of time and associated exposure for each subject was then allocated to that site type. If a subject worked in the office at a refinery or a distribution terminal, he was included as an office worker rather than being assigned to a site type.
5. Intensity of exposure: We calculated the average exposure intensity (cumulative benzene exposure estimate divided by duration of employment) in ppm for each job. We divided the subjects into geometric exposure intensity groups based on their highest exposed job.
6. Subjects with exposure to benzene concentrate: We identified those subjects who had handled benzene concentrate that is 100% benzene or BTX (benzene-toluene-xylene, which is principally an aromatic fraction derived from coke oven operations, containing approximately 70% benzene).

All odds ratios and 95% confidence intervals are from matched analyses.

The study was carried out with the clearance of Monash University Standing Committee on Ethics in Research Involving Humans, and the Ethics Committees from Melbourne

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and Adelaide Universities. All subjects signed a consent form to allow access to their job histories, and cases consented to our contacting their treating doctor for diagnostic details.

RESULTS

The cases and control subjects were well matched demographically (Table 2). They were similar with regard to alcohol consumption and country of birth. Control subjects were slightly more likely than the cases to be exsmokers. The risk of leukemia was not associated with smoking; odds ratios (ORs) were 0.55 (95% CI = 0.18-1.32) for previous smokers and 1.28 (95% CI = 0.52-3.14) for current smokers compared with never-smokers. We estimated the OR for leukemia associated with smoking score (pack-years) and alcohol score (standard drink-years) both as continuous measures. The OR per 100 pack-years was 0.98 (95% CI = 0.80-1.19) and per 1000 drink-years was 0.78 (95% CI = 0.52-1.16).

The ages of the cases at the date of case diagnosis ranged from 26-79 years with a mean of 54 years (Table 2). The mean duration of employment, prior to diagnosis, was 20.4 years (standard deviation, 9.0 y), and ranged from 4.3-43 years. A control subject, employed for only 4.3 years at the time of diagnosis of the case to which he was matched, had satisfied the cohort criteria of being employed in the industry for 5 years or more.

Cases had, on average, a higher lifetime cumulative exposure than control subjects, and a greater proportion of cases were in higher exposure categories (Table 3). The subjects were grouped by cumulative exposure (ppm-years) into 6 geometric groups, and conditional logistic regression (case-matched) was used to calculate stratum-specific ORs (Table 4). No increase in risk for non-Hodgkin lymphoma/multiple myeloma was found with increasing exposure to benzene. However, the ORs for leukemia were found to be elevated for 3 of the 5 exposure groups compared with the lowest (≤1 ppm-years) as illustrated in Figure 1. The highest exposure group (>16 ppm-years) contained 7 of 33 leukemia cases, but only 3 of their 165 matched control subjects. For the 2 highest exposure categories combined (13 case-sets with >8 ppm-years cumulative exposure), the OR was 11.3 (95% CI = 2.85-45.1).

In a comparable study in the U.K. petroleum industry,[27] a cut-point of 4.79 ppm-years was used in the analysis. For comparison purposes we analyzed our data using the same cut-point and obtained an OR of 2.51 (95% CI = 1.1-5.7).

The OR associated with cumulative exposure as a continuous measure was 1.65 (95% CI = 1.25-2.17), which is consistent with an increase of 65% for each doubling of mean cumulative exposure.

There was no association between leukemia (with or without adjustment for cumulative benzene exposure) and date of starting work in industry or duration of employment (Table 5). Blue collar workers had a 3-fold risk of leukemia compared with office workers, but this risk disappeared when adjustment was made for cumulative benzene exposure (data not shown). Subjects who had worked longest at an airport had nearly 4 times the risk of leukemia compared with terminal workers but this result was based on small numbers. This finding did not change after adjustment for cumulative

TABLE 2. Lifestyle and Demographic Characteristics of the Cases and Control Subjects

Characteristic	Control Subjects (N = 395)	All Cases (N = 79)	Types of Cancer			
			Leukemia (N = 33)	NHL/MM (N = 46)	MM (N = 15)	NHL (N = 31)
Age in years; mean (range)	54 (26–76)	54 (26–79)	52 (34–71)	54 (26–75)	55 (39–75)	54 (26–70)
Tobacco; no. (%)*						
Never smoked	125 (32)	28 (35)	11 (33)	17 (37)	8 (53)	9 (29)
Previous smoker	166 (42)	21 (27)	8 (24)	13 (28)	6 (40)	7 (23)
Current smoker	103 (26)	30 (38)	14 (42)	16 (35)	1 (7)	15 (48)
Alcohol; no. (%)						
Never drank	79 (20)	16 (20)	7 (21)	9 (20)	1 (7)	8 (26)
Previous drinker	10 (3)	2 (3)	1 (3)	1 (2)	0	1 (3)
Current drinker	305 (77)	61 (77)	25 (76)	36 (78)	14 (93)	22 (71)
Country of birth; no. (%)						
Australia	259 (66)	56 (71)	25 (76)	31 (67)	10 (67)	21 (68)
UK	75 (19)	14 (18)	4 (12)	10 (22)	3 (20)	7 (23)
Other	60 (15)	9 (11)	4 (12)	5 (11)	2 (13)	3 (10)

*One control did not record smoking data.
NHL/MM, combined non-Hodgkin lymphoma and multiple myeloma; MM, multiple myeloma; NHL, non-Hodgkin lymphoma.

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TABLE 3. Cases and Control Subjects Grouped by Exposure to Benzene Expressed as Cumulative Exposure (ppm-years)

Characteristic	Control Subjects (N = 395)	All Cases (N = 79)	Types of Cancer			
			Leukemia (N = 33)	NHL/MM (N = 46)	MM (N = 15)	NHL (N = 31)
Mean and range of cumulative exposure (ppm-years)	4.7 (0.01–57.3)	7.27 (0.01–52.7)	10.63 (0.09–52.7)	4.85 (0.01–23.4)	4.73 (0.17–23.4)	4.91 (0.01–21.8)
Cumulative exposure (ppm-years); no. (%)						
≤1	138 (35)	18 (23)	3 (9)	15 (33)	4 (27)	11 (35)
>1–2	56 (14)	12 (15)	6 (18)	6 (13)	2 (13)	4 (13)
>2–4	67 (17)	16 (20)	8 (24)	8 (17)	5 (33)	3 (10)
>4–8	64 (16)	12 (18)	3 (9)	9 (20)	2 (13)	7 (23)
>8–16	53 (13)	11 (14)	6 (18)	5 (11)	1 (7)	4 (13)
>16	17 (4)	10 (13)	7 (21)	3 (7)	1 (7)	2 (6)

NHL/MM, combined non-Hodgkin lymphoma and multiple myeloma; MM, multiple myeloma; NHL, non-Hodgkin lymphoma.

benzene exposure. Similar results were found for those whose highest benzene-exposed job was at an airport.

There was a strong association between leukemia risk and exposure to benzene concentrate that was somewhat reduced when cumulative exposure was controlled for. That is, exposure to benzene concentrate resulted in a higher risk of leukemia than exposure to the same amount of benzene encountered in a more dilute form such as in gasoline.

The proportion of subjects whose highest exposed job was in high-intensity exposure categories was greater for cases than control subjects (Table 5). Exposure intensity in the highest exposed job was strongly related to leukemia risk, with the increase starting at around 0.8-1.6 ppm and with those in the highest exposure category being nearly 20 times more likely to develop leukemia than those who were unexposed. Adjusting for cumulative exposure removed the association between high-intensity exposure and leukemia. However, exposure intensity and cumulative exposure are highly correlated, and goodness-of-fit statistics and the stepwise conditional logistic regression algorithm did not provide unequivocal evidence that would distinguish between the relative contributions of cumulative exposure and exposure intensity to leukemia risk.

The ORs were also calculated by using conditional logistic regression for the leukemia subtypes acute nonlymphocytic leukemia, chronic lymphocytic leukemia, and chronic myeloid leukemia (Table 6); such calculations were not possible for acute

TABLE 4. Association of Leukemia and Non-Hodgkin Lymphoma/Multiple Myeloma by Benzene Exposure Group, From Conditional Logistic Regression Analysis

Cumulative Lifetime Benzene Exposure (ppm-years)	Leukemia OR (95% CI)	NHL/MM OR (95% CI)
≤1*	1.0	1.0
>1–2	3.9 (0.9–17.1)	1.1 (0.4–2.9)
>2–4	6.1 (1.4–26.0)	1.2 (0.5–3.0)
>4–8	2.4 (0.4–13.6)	1.3 (0.5–3.2)
>8–16	5.9 (1.3–27.0)	0.8 (0.3–2.6)
> 16	98.2 (8.8–1090)	1.1 (0.3–4.5)

* Reference category.

NHL/MM, combined non-Hodgkin lymphoma and multiple myeloma; OR, odds ratio; CI, confidence interval.

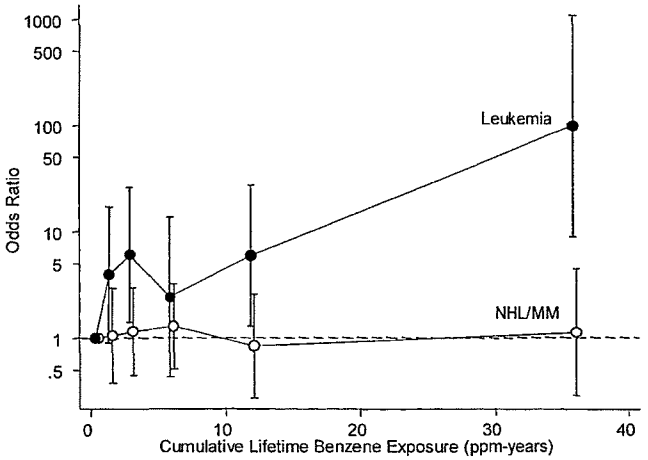

FIGURE 1. Leukemia and Non-Hodgkin Lymphoma/Multiple Myeloma (NHL/MM) odds ratios by geometric benzene exposure groups (ppm-years) displayed at the midpoint of the exposure group. (Circles indicate odds ratios; vertical lines depict confidence intervals).

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TABLE 5. Distribution of Exposure Variables for Leukemia Cases and Control Subjects and Results of Matched Analyses of the Risk of Leukemia Using These Variables

Exposure Characteristic	Cases (N = 33) No. (%)	Control Subjects (N = 165) No. (%)	Odds Ratio (95% CI)	Adjusted Odds Ratio* (95% CI)
Start date in industry				
Before 1965†	15 (45)	63 (38)	1.0	1.0
1965–1975	12 (36)	60 (36)	0.6 (0.2–1.9)	0.9 (0.3–3.2)
1975 or later	6 (18)	42 (25)	0.4 (0.1–1.6)	1.0 (0.2–4.8)
Duration of employment truncated at date of diagnosis (y)				
≤11†	15 (19)	77 (19)	1.0	1.0
>11–17	18 (23)	83 (21)	1.2 (0.4–4.0)	0.7 (0.2–2.5)
>17–22.5	12 (15)	81 (21)	1.6 (0.4–5.5)	1.2 (0.3–5.4)
>22.5–29	16 (20)	80 (20)	1.0 (0.2–4.2)	0.4 (0.1–1.9)
>29–43	18 (23)	74 (19)	1.6 (0.4–6.8)	0.4 (0.1–2.7)
Exposure to benzene concentrate				
No†	28 (84)	163 (99)	1.0	1.0
Yes	5 (16)	2 (1)	12.5 (2.4–64)	6.3 (1.1–36)
Exposure intensity group based on highest benzene-exposed job (ppm)				
≤0.1†	5 (15)	65 (39)	1.0	1.0
>0.1–0.2	9 (27)	26 (16)	3.9 (1.2–12.6)	1.2 (0.3–4.9)
>0.2–0.4	4 (12)	25 (15)	2.2 (0.5–9.4)	0.5 (0.1–3.2)
>0.4–0.8	4 (12)	11 (7)	6.6 (1.7–25.7)	0.6 (0.1–6.2)
>0.8–1.6	3 (9)	31 (19)	1.6 (0.4–6.7)	0.2 (0.0–2.0)
>1.6–3.2	6 (18)	6 (4)	5.6 (1.0–31.2)	0.4 (0.0–6.1)
>3.2	2 (6)	1 (1)	20.4 (1.6–270)	1.6 (0.1–38)

*Adjusted for cumulative benzene exposure.
†Reference category.
CI, confidence interval.

lymphocytic leukemia because there were only 2 cases. Because there were relatively few cases of the leukemia subtypes, it was necessary to combine the 3 lowest exposure groups and the 2 highest exposure groups. The ORs in the combined higher exposure group were raised relative to the combined lower exposure group for both chronic lymphocytic leukemia and acute nonlymphocytic leukemia.

DISCUSSION

These data provide strong evidence for an association between previous benzene exposure in the Australian petroleum industry and an increased risk of leukemia. However, we did not find an association of benzene with multiple myeloma or non-Hodgkin lymphoma, which is consistent with previous findings.[9,16,17]

In our data, leukemia seems to be associated with lower cumulative exposures than has been observed in other studies. The estimated cumulative exposures were generally similar to those reported for other petroleum industry studies, except that the most highly exposed subjects in our study had cumulative exposures of less than 60 ppm-years, whereas those in other studies were as high as 220 ppm-years.[27,28]

TABLE 6. Association of Leukemia Subtype With Cumulative Benzene Exposure From Conditional Logistic Regression Analysis

Cumulative Lifetime Benzene Exposure (ppm-years)	Leukemia Subtype ANLL (N = 11)	CLL (N = 11)	CML (N = 6)
≤4*	1.00	1.00	1.00
>4–8	0.52 (0.05–5.0)	2.76 (0.42–18.1)	-
>8	7.17 (1.27–40.4)	4.52 (0.89–22.9)	0.91 (0.08–9.8)

*Reference category.
ANLL, acute nonlymphocytic; CLL, chronic lymphocytic leukemia; CML, chronic myeloid leukemia.

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It has been suggested that there might be no increased risk at cumulative exposures below 200 ppm-years[9] or intensity of less than 20-60 ppm.[10] In a recent large cohort study of Chinese workers, the relative risk for all hematologic neoplasms was 2.2 (95% CI = 1.1-4.2) for workers exposed to benzene at estimated average levels of less than 10 ppm.[11] Over a working lifetime this could amount to a cumulative exposure of up to several hundred ppm-years. In our study, the risk of leukemia was increased at all cumulative exposures above 1 ppm-year, with a strong exposure–response relationship. There was no evidence of a threshold.

Leukemia risk in the highest exposure category was 98 (95% CI = 8.8-1090). Combining the 2 highest cumulative exposure groups resulted in an OR of 11.3 (95% CI = 2.85-45.1). This is considerably higher than that observed in a similar petroleum industry study,[28] which found an OR of 2.11 (95% CI = 0.01-138) for leukemia for those in the highest quartile of exposure (8-220 ppm-years). In a similar study,[27] the leukemia OR was 2.13 (95% CI = 0.90-5.03) for those in the highest quintile of exposure (>4.79 ppm-years). In our study, the matched OR for those exposed to greater than 4.79 ppm-years was similar at 2.51 (95% CI = 1.1-5.7).

We found a positive association of benzene exposure with both acute nonlymphocytic leukemia and chronic lymphocytic leukemia. An association between acute nonlymphocytic leukemia and benzene exposure has only been reported previously associated with exposures above 200 ppm-years.[9,16] In a U.K. petroleum industry study,[27] the risk of acute myeloid and monocytic leukemia did not increase with cumulative exposure when analyzed as a continuous variable. However, when categorized into discrete ranges, an odds ratio of 2.8 (95% CI = 0.8-9.4) was found for a cumulative exposure of 4.5-45 ppm-years.[27]

There are a number of possible confounders, including tobacco and alcohol consumption and exposure to other chemicals and radiation. Tobacco and alcohol were not confounding factors in our data. Workers in the petroleum industry are exposed to a wide range of aliphatic and aromatic hydrocarbons found in or derived from crude oil, ranging from natural gas (methane) to bitumen. Known carcinogenic exposures include sunlight, polycyclic aromatic hydrocarbons, asbestos, and possibly other insulating materials. A few, mainly older, workers have had exposure to paint, and some workers in the lubricating oils operations had exposure to white spirit (Stoddard Solvents), methyl ethyl ketone, and toluene. The subjects include some laboratory workers who have had exposure to a number of laboratory reagents.

In 1996, a comprehensive review of risk factors for leukemia concluded that the only confirmed occupational risk factors were exposure to benzene, radiation, and some retroviruses. There is some inconsistent evidence for leukemogenic potential from some pesticides, styrene and butadiene manufacturing, and ethylene oxide.[29] We consider it unlikely that subjects in this study were occupationally exposed to retroviruses or these other agents. Some workers employed in the petroleum extraction, refining, and distribution industries might have used x-ray machines in laboratories or pipe surveys, but the sources are thought to have been well shielded.

The present study has a number of strengths and weaknesses. The diagnoses of the cases were well established. However, the study was based on a relatively small number[79] of lympho-hematopoietic cancer cases, including 33 leukemias of which there were only 11 acute nonlymphocytic leukemias and only 11 chronic lymphocytic leukemias. This limits the power of the study to detect excess risks for leukemia subgroups, particularly when we stratified the subjects by exposure.

The cases were individually age-matched to control subjects, and both were drawn from the same prospective cohort of workers in the Australian petroleum industry. The cohort has been followed for 20 years with serial identification of jobs, smoking habits, and health status. Only 10 of the 474 subjects (2%) had incomplete job histories. Relatively few subjects in the cohort (6%) have been lost to follow up,[21] and vital status was confirmed every 5 years; thus we are confident that the control subjects were selected from an appropriate risk set.

We estimated the subjects' exposure to benzene quantitatively, on an individual basis, with an algorithm based on a substantial body of exposure data from the Australian petroleum industry.[25] The exposure assessment method was validated,[26] but there are always uncertainties and unknown sources of variation in retrospective exposure assessments. Between-worker variation in exposure measurements, resulting from personal factors such as individual work practice, was not included in the exposure assessment reported here. There was also uncertainty about exposures before 1975 because jobs have changed over the years, but the available exposure data used in the algorithm postdated this period. However, the Health Watch cohort is relatively recent compared with other similar studies in which jobs held before 1920 were assessed.[27,28] Most of the subjects in our case-control study started work after 1965; the earliest start date was 1941. This means that jobs have changed less in our study, and for most jobs we were able to identify changes by interviewing contemporary coworkers. These individuals did not have to recall far distant exposure conditions so their uncertainty was reduced.

For 33 cases, including 13 leukemia cases, the complete job history was obtained after lympho-hematopoietic cancer diagnosis. These cases provided information after diagnosis, about jobs held before 1975, thus introducing some potential for recall bias. These subjects' job histories were constructed from the information gathered during the Health Watch surveys and from company records. This was then sent to the

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subject for cross-checking. However, the high degree of agreement with the company records suggests that the self-reported job histories were reasonably accurate and that possible recall bias was low. For the remaining 46 cases, either the complete job history was obtained before diagnosis or only the company job history was used because, for example, the case died before the complete job history collection.

All smoking and drinking data were collected before individual diagnoses, thereby avoiding a potential cause of recall bias.

The benzene exposure assessments were carried out without any knowledge of the names and health status of the subjects to reduce observer bias. Detailed information on the circumstances of the exposure was provided, usually by contemporary work colleagues of the cases and control subjects. Some of the site interviewees might have been able to identify the subjects but were instructed not to reveal their names or health status to the interviewer. This could have given rise to some recall bias, because more effort might have been applied to recalling the tasks with benzene exposure for some of the cases because the connection between benzene exposure and lympho-hematopoietic cancer is widely known within the industry. However, it is unlikely that the employees would distinguish between the risk from benzene exposure of different cancers (leukemia compared with multiple myeloma or non-Hodgkin lymphoma). Our finding of increased risk specifically for leukemia but not for multiple myeloma or non-Hodgkin lymphoma suggests that recall and observer biases do not affect our main results.

It is unlikely that the baseline comparison group was incorrectly defined because this was a nested case-control study with the control subjects selected from the cohort matched by age. However, misclassification of only a few cases from the baseline group into higher exposure groups could markedly distort the exposure–response relation. Although the lowest exposed group contained many office workers, there is no strong socioeconomic gradient for risk of leukemia and the analysis of smoking suggested that this was not a confounding exposure. If there was a strong bias in the exposure estimates leading to differential misclassification, this should have affected the results for multiple myeloma and non-Hodgkin lymphoma as well; the questionnaire respondents would have been unlikely to draw a distinction between one form of hematopoietic cancer or another. The fact that no association was found between multiple myeloma/non-Hodgkin lymphoma and benzene exposure suggests that such bias, if present, was small. We cannot rule out the possibility that some bias was introduced in gathering the occupational histories, although such an effect would presumably be small. If such bias occurred, it could not explain the association between leukemia and benzene exposure that was found, but might have exaggerated the exposure–risk relationship and hidden a low-exposure threshold.

In summary, these data demonstrate a strong association between benzene exposure and the risk of acute and chronic leukemia. No association was found between benzene and non-Hodgkin lymphoma or multiple myeloma, or between any of the cancers and tobacco or alcohol consumption. The excess risk of leukemia was associated with lower cumulative exposures and lower exposure intensity than have been observed in other studies. We found no evidence of a threshold cumulative exposure below which there is no risk.

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United States Department of State 12.1

Reference: Keystone XL Project
Risk Analysis

Request:

DOS recently received a copy of a report that questions the validity of the risk analysis for the proposed Keystone XL Project that is summarized in the Section 3.13 of the supplemental draft EIS and included, in part, in Appendix P to the draft EIS. The undated report, ***Analysis of Frequency, Magnitude and Consequence of Worst-Case Spills From the Proposed Keystone XL Pipeline***, was prepared by John Stansbury, Ph.D., P.E. DOS requests that Keystone provide a response to that report, indicating whether or not the author has accurately portrayed the Keystone risk analysis, whether or not the author has made valid assumptions regarding the analysis of risk included in the report, and any other responses that would assist DOS in comparing the information in the report to the risk analysis submitted by Keystone. Please include in your response any clarification to the existing risk assessment that may be required to adequately address valid concerns (if any) raised in the Stansbury report.

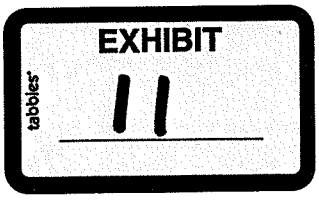
Response Part A:

An initial response to the Stansbury Report was previously provided to DOS. That response is repeated below. It is supplemented with the information in Response Part B.

The Stansbury/Friends of the Earth Report (Stansbury Report) attempts to build on a foundation of inaccurate assumptions that lead to greatly exaggerated estimates of releases of oil and consequences. This is simply the latest case of opportunistic fear-mongering, dressed up as an academic study.

The Keystone Pipeline system is subject to comprehensive pipeline safety regulation under the jurisdiction of the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA). As the recent State Department Supplemental Draft Environmental Impact Statement (SDEIS) recognizes, PHMSA is responsible for protecting the American public and the environment by ensuring the safe and secure movement of hazardous materials to industry and consumers by all transportation modes, including pipelines. To protect the public and environmental resources, Keystone is required to construct, operate, maintain, inspect, and monitor the pipeline in compliance with the PHMSA regulations at 49 CFR Part 195, as well as relevant industry standards and codes. These regulations specify pipeline material and qualification standards, minimum design requirements, required measures to protect the pipeline from internal, external corrosion, and many other aspects of safe operation.

Above and beyond the PHMSA regulations, Keystone has agreed to comply with 57 additional Special Conditions developed by PHMSA for the Keystone XL Project. Keystone has agreed to



incorporate these conditions into its design and construction, and its manual for operations, maintenance, and emergencies required by 49 CFR 195.402. These 57 Special Conditions are attached as Appendix C to the SDEIS.

PHMSA and the State Department took these 57 Special Conditions into account in the SDEIS. It is significant to note the finding in the SDEIS with respect to these conditions:

Incorporation of those conditions would result in a Project that would have a degree of safety over any other typically constructed domestic oil pipeline system under current code and a degree of safety along the entire length of the pipeline system similar to that which is required in High Consequence Areas (HCAs) as defined in 49 CFR 195.450. (SDEIS p. 2-9)

Based on an initial review, below are some of the major mistakes and misrepresentations in the Stansbury Report.

1. Stansbury Report Mistake: "River crossings are especially vulnerable," going on to describe "the pipeline is more susceptible to corrosion because it is below ground and pressures are relatively high."

The Facts: Keystone XL Pipeline is not vulnerable at river crossings; document referenced in report does not suggest it is.

Background: The Summary report states (p. 2) that that "River crossings are especially vulnerable," going on to describe that here "the pipeline is more susceptible to corrosion because it is below ground and pressures are relatively high."

In the corresponding section of Professor Stansbury's full report, headed "Most Likely Spill Locations" (p. 6), the author states that adjacent to rivers, "the pipeline is susceptible to high rates of corrosion because it is below ground (DNV, 2006)." (Note that there is no reference in this section of the report to the additional claim in the Summary that at river crossings "pressures are relatively high.")

Nowhere in the 2006 DNV document cited is there any suggestion that buried pipe at river crossings is more vulnerable to corrosion than any other portion of the buried pipeline. Nor is there any support for the statement in the summary about relative operating pressure at river crossings increasing susceptibility to corrosion.

The only statement in the DNV report remotely related to this unfounded assertion is this: "The Keystone Pipeline is being designed to consist entirely of below ground pipe except within Pump Station fence lines. Sections of the pipeline below ground were considered to be more likely to incur corrosion than above ground sections."

Further, the statement in the DNV report was made within a section that highlights special measures Keystone will employ to eliminate risk of external corrosion. Keystone employs an approach to corrosion protection that has virtually eliminated failure due to external corrosion in the 30-plus years it has been in use. It includes fusion bond epoxy coating (FBE) coupled with active cathodic protection, which places a small current on the pipe preventing loss of metal due to corrosion. Keystone also will be inspected more frequently than standard regulations require, to ensure the effectiveness of this system.

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Relative to other failure modes at river crossings, such as flooding or increased river flows scouring the river bottom or banks and exposing the pipe and making it vulnerable to damage or breakage, Keystone will utilize the horizontal directional drill (HDD) crossing method that places the pipe 25 feet or more below the river bottom at locations where scour is considered a potential threat. Other measures at river crossings further reduce the likelihood of failure. For instance, each of the river crossings mentioned in the report (Yellowstone, Missouri, Platte) will be installed using the HDD method and will utilize heavy-walled pipe with sacrificial abrasion-resistant coating applied over the FBE to further ensure the protective capability of the coating. These measures make these locations among the **least likely for a release** on the entire pipeline.

2. Stansbury Report Mistake: The report incorrectly asserts that TransCanada ignored 23% of statistical pipeline failures (pp. 1, 4).

The Facts: TransCanada's analysis accurately represents historical data and does not overlook 23% of incidents as claimed

Background: The report incorrectly asserts that TransCanada ignored 23% of statistical pipeline failures (pp. 1, 4). In part because the PHMSA data does not identify the cause for 23% of pipeline incidents, TransCanada used a more detailed assessment of causes of historical pipeline incidents, evaluating Keystone against each of these threats to establish an accurate risk profile. The applicable threats to the pipeline were determined using established pipeline industry standards ASME B31.8S and API 1160. This fact was noted within the DNV report itself:

> "It should be noted that the factors are similar but not identical to the U.S. Department of Transportation Office of Pipeline Safety (OPS) categories of failure (e.g., third party harm)." (DNV 2006, p. 3)

3. Stansbury Report Mistake: TransCanada "arbitrarily assigned a drain-down factor" for the pipeline

The Facts: TransCanada estimates of volume released – arbitrarily adjusted in the Stansbury Report – use results of a detailed study prepared by the California Fire Marshal

In calculating how much oil might be released from a pipeline after it is secured and isolated, the author claims TransCanada "arbitrarily assigned a drain-down factor" for the pipeline (p. 9). Not noted, however, is that TransCanada's methodology reflects not TransCanada's judgment but rather the results of an independent assessment by the California Fire Marshal in its role as a regulator in California. The report is well known and respected among pipeline regulators and risk assessors. After labeling use of the California Fire Marshal figure for retained volume "arbitrary," it is ironic that the author goes on to say the factor "is likely too high" and cuts it in half with no further justification.

4. Stansbury Report Mistake: TransCanada's adjustment to risk factors are arbitrary and improper

The Facts: TransCanada adjustments to risk factors are consistent with industry experience

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Background: The Summary report states that "TransCanada arbitrarily and improperly adjusted spill factors" (p. 1). The full report written by Professor Stansbury is less strident, suggesting the adjustments are "probably not appropriate" (p. 4).

The majority of pipeline infrastructure in North America was constructed many decades ago at a time when the materials, coating systems, and ongoing inspection capabilities that will be used for Keystone XL were not available. Studies show the benefits of these technologies in reducing pipeline incidents. For instance (as described in para. #1 above), the corrosion protection Keystone uses has virtually eliminated external corrosion as a cause of failure. Approximately two thirds of the pipelines in the US were constructed prior to 1970. It is therefore entirely appropriate to use an incident frequency for Keystone XL that is derived from pipelines of its class. To do otherwise would be like trying to estimate the gas mileage of a 2011 model car by using the average gas mileage of all cars built since the 1920s.

This is corroborated by observations included in the SDEIS, including:

> "It is likely that both incident frequency analyses tend to overestimate the likely spill frequency of the proposed Project since both analyses rely on data that include incidents on older pipelines that would not be operated under the Project-specific Special Conditions developed by PHMSA and incorporated into the design, construction, operations, and maintenance plans for the proposed Project." (SDEIS, p. 3-98)

Examples of measures taken by TransCanada to reduce risk on Keystone include:

- External corrosion – Keystone employs an approach to corrosion protection that has virtually eliminated failure due to external corrosion in the 30-plus years it has been in use. It includes fusion bond epoxy coating and active cathodic protection, which places a small current on the pipe preventing loss of metal due to corrosion. Keystone has agreed to a special regulatory condition requiring the pipeline to be internally inspected with an instrumented device that monitors the pipe wall for anomalies. Any wall degradation due to corrosion would be detected and addressed prior to failure. (These requirements are covered by several PHMSA Special Conditions, including #9, 10, 11, 33, 35-39, 42, 53.)
- External impact – Keystone will be buried at a deeper depth to minimize risk of external impact. In addition, pipe walls will exhibit greater puncture resistance and fracture control properties. Keystone will take additional steps to minimize risk of accidental excavation damage. (Required by PHMSA Special Conditions #7, 19, 40, 41, 48, 53, 54).
- Internal corrosion – Limit sediment and water content of oil shipped to 0.5%. Run cleaning tools twice per year in the first year and as necessary based on integrity analysis. Implement a crude oil monitoring and sampling program to ensure products transported meet specifications. Perform internal inspections at increased frequency. (Required by PHMSA Special Conditions #33, 34, 42, 53)
- Mechanical defect – enhanced material requirements and QA/QC program as described in PHMSA Special Conditions #1, 2, 4, 5, 6, 8, 12, 22.

5. Stansbury Report Mistake: The report erroneously relies on disproven assumptions on corrosivity of oil to be shipped.

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The Facts: Independent analysis of oil sands derived crude oils has conclusively demonstrated that, below 450 degrees Fahrenheit, these oils are not corrosive to steel.

Background: The Stansbury Report states Keystone is subject to higher failure rates due to corrosivity of oil to be shipped (p. 5). Independent analysis of oil sands derived crude oils has conclusively demonstrated that, below 450 degrees Fahrenheit, these oils are not corrosive to steel. The maximum operating temperature anywhere in the pipeline is 150 degrees. (Supplemental Draft EIS, Keystone XL, p. 3-112.) A recent independent assessment of crude oil quality by the firm Crude Quality Inc., including corrosion potential, has been completed and provided to the U.S. Department of State supporting these findings.

Keystone XL will ship a wide variety of crude oil types including conventional oil, shale oil, partially upgraded synthetic oil and oil sands derived bitumen blends. None of these crude types create a risk of destroying the pipeline from within and causing leaks. Furthermore these products have shipped and are currently being shipped across to the US via other cross-border pipelines from Canada. It would be an uneconomic business proposition to spend $13 billion dollars constructing a pipeline system that would be destroyed by the product it transported.

6. Stansbury Report Mistake: The erroneously states that abrasive sediment in the crude oil will cause higher failure rates

The Facts: The oil that will be shipped on Keystone XL "shall have no physical or chemical characteristics" that would damage or harm the pipeline.

Background: Report states Keystone is subject to higher failure rates due to abrasive sediment (p. 5). However, as clarified in the SDEIS, oil transported by Keystone must meet strict limits for sediment and water. (SDEIS, p. 3-116)

> Special Condition 34 (see Appendix C of this SDEIS) addresses the sediment and water content of the crude oil that would be transported by the proposed Project and states the following:
>
> "Internal Corrosion: Keystone shall limit basic sediment and water (BS&W) to 0.5% by volume and report BS&W testing results to PHMSA in the annual report."

The FERC-approved tariff for transport of oil on the Keystone Pipeline system also requires that all oil to be shipped:

> "shall have no physical or chemical characteristics that may render such Petroleum not readily transportable by Carrier or that may materially affect the quality of other Petroleum transported by Carrier or that may otherwise cause disadvantage or harm to Carrier or the Pipeline System, or otherwise impair Carrier's ability to provide service on the Pipeline System." (SDEIS, Pp. 3-116.)

7. Stansbury Report Mistake: The report erroneously states bitumen will sink, therefore "posing significant threat" to water resources.

The Facts: The gravity of crude oils that Keystone XL would transport are less than the specific gravity of water.

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Background: The report states bitumen will sink "posing significant threat" (p. 19). This issue was addressed in the SDEIS, which includes the following summary statement: "the specific gravity of the crude oils that would be transported on the proposed pipeline ranges from about 0.85 to about 0.93, less than the specific gravity of water. These crude oils, therefore, tend to float on water…" (SDEIS, p. 3-104)

8. Stansbury Report Mistake: The report suggests that TransCanada will cut back on monitoring and maintenance activities, causing increased risk in out years (p. 5).

The Facts: Contrary to a suggestion in the Stansbury Report, monitoring and maintenance activities are a required condition of operation.

Background: The report suggests that TransCanada will cut back on monitoring and maintenance activities, causing increased risk in out years (p. 5). However, the U.S. Code of Federal Regulations requires many of these monitoring and maintenance activities as a condition of operation. TransCanada has voluntarily committed to 57 additional safety conditions that include other enhanced monitoring and maintenance activities as additional conditions of continued operation. For instance, in order to continue to operate the pipeline, TransCanada must perform in-line inspection with a smart pig, conduct corrosion surveys, and perform valve inspections at specified frequencies – these are not discretionary. Additionally, TransCanada must meet requirements to patrol the pipeline every two weeks.

In addition to regulatory requirements, continuing to invest in the safety of the pipeline makes sense from a business perspective. Paying for increased maintenance is built into TransCanada's contracts with its shippers such that variable integrity spending costs are flowed through to the shippers. Additionally, the FERC rate allows the uncommitted toll to rise at a greater than inflation rate which allows for recovery of maintenance costs. There is therefore no financial incentive for TransCanada to cut back on monitoring and maintenance and a substantial financial penalty associated with leaks in the form of fines, cleanup costs, lawsuits and reputational damage. It is therefore not reasonable to suggest that TransCanada or another owner would increase their liability in order to reduce an expense that is flowed through to the customers.

9. Stansbury Report Mistake: The report tries to suggest that because shutdown on another pipeline took longer, that increased time should be the new assumption on shutdown time (pp. 7-8).

The Facts: Keystone time to shutdown has been accurately reflected in the risk analysis and is consistent with Keystone's record.

Background: The Stansbury Report tries to suggest that because shutdown on another pipeline took longer, that increased time should be the new assumption on shutdown time (pp. 7-8). However, the author does not address the differences in system design and operating characteristics (including single phase flow in Keystone) that make it unlikely that Keystone operators would experience difficulty detecting a leak. Nor does he address industry information sharing nor the workings of the regulatory regime, both of which serve to make it unlikely that operational errors are repeated.

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Additionally, Keystone has established its own operating record that demonstrates prompt reaction time to any indication of an operational abnormality. These response records align with the shut down times conveyed in Keystone's risk assessment report.

10. Stansbury Report Mistake: Report suggests that enough oil to fill a dozen Olympic-sized swimming pools would go unnoticed in Nebraska (pp. 8-9).

The Facts: The report's calculation of spill volume for "small" leak not credible because it ignores leak detection methodologies designed to detect low rate or seepage releases.

Background: In assessing worst-case "small" leak, the Stansbury Report suggests that enough oil to fill a dozen Olympic-sized swimming pools would go unnoticed in Nebraska (pp. 8-9). The estimate ignores leak detection methodologies designed to detect low rate or seepage releases.

As described below, Keystone will utilize a state-of-the-art integrated leak detection system. Real-time computerized systems can detect spills as low as 1.5 percent of throughput. In addition to surveillance and public reporting, Keystone will implement a non-real time mass balance procedure that can detect spills below 1.5 percent of throughput.

Data from actual pipeline spills demonstrate that substantial leaks do not go undetected for long periods of time. Further, those spills that are not detected within the first 48 hours are typically relatively small. PHMSA records (2001 through 2009) indicate that the majority of spills are 3 barrels or less, regardless of detection time. These data also indicate that the majority of spills are detected within 2 hours, with 99 percent of spills detected within 7 days. Of those spills not detected within the first 48 hours, the majority of spills were 15 barrels or less. In summary, large spills do not remain undetected for substantial periods of time.

The pipeline will be monitored 24 hours a day, 365 days a year from the Operations Control Center (OCC) using a sophisticated Supervisory Control and Data Acquisition (SCADA) system. Keystone will utilize multiple leak detection methods and systems that are overlapping in nature and progress through a series of leak detection thresholds. The leak detection methods are as follows:

- Remote monitoring performed by the OCC Operator 24/7, which consists of monitoring pressure and flow data received from pump stations and valve sites fed back to the OCC by the Keystone SCADA system. Remote monitoring is typically able to detect leaks down to approximately 25 to 30 percent of the pipeline flow rate.
- Software-based volume balance systems that monitor receipt and delivery volumes. These systems are typically able to detect leaks down to approximately 5 percent of the pipeline flow rate.
- Computational Pipeline Monitoring or model-based leak detection systems that break the pipeline into smaller segments and monitor each of these segments on a mass balance basis. These systems are typically capable of detecting leaks down to a level of approximately 1.5 to 2 percent of pipeline flow rate.
- Computer-based, non-real time accumulated gain/(loss) volume trending to assist in identifying low rate or seepage releases below the 1.5 to 2 percent by volume detection thresholds.

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- Direct observation methods, which include aerial patrols, ground patrols, and public and landowner awareness programs that are designed to encourage and facilitate the reporting of suspected leaks and events that may suggest a threat to the integrity of the pipeline.

The leak detection system will be configured in a manner capable of sending an alarm to the OCC operators through the SCADA system and also will provide the OCC operators with a comprehensive assortment of display screens for incident analysis and investigation. In addition, there will be a redundant, stand-by OCC to be used in case of emergency.

Keystone also will have an Emergency Response Program (ERP) in place to respond to incidents. The ERP contains comprehensive manuals, detailed training plans, equipment requirements, resources plans, auditing, change management and continuous improvement processes. The Integrity Management Program (IMP) (49 CFR Part 195) and ERP will ensure Keystone will operate the pipeline in an environmentally responsible manner.

11. Stansbury Report Mistake: The report relies on old claims that the emergency response plan for the Keystone pipeline is "woefully inadequate"

The Facts: Contrary to assumptions in the Stansbury Report, the Emergency Response capability for Keystone XL will meet or exceed requirements.

Background: The Stansbury Report relies on old claims that the emergency response plan for the Keystone pipeline is "woefully inadequate" (p. 3). This accusation was one of the items reviewed in detail in the SDEIS.

> "DOS and PHMSA have reviewed these hypothetical spill response scenarios prepared by Keystone and would also review a final ERP to be prepared by Keystone prior to startup of the proposed pipeline…Based on its review of the hypothetical spill response scenarios, ***DOS considers Keystone's response planning appropriate and consistent with accepted industry practice.***" (SDEIS, p. 3-122)

12. Stansbury Report Mistake: The report includes exaggerated descriptions of the physical extent of benzene.

The Facts: The exaggerated claims in the report do not match any oil-spill experience; furthermore, benzene concentration in heavy oils Keystone will ship will be comparable to other heavy oils shipped in the U.S. and will generally be lower than benzene concentrations in lighter crudes and in refined products such as gasoline.

Background: Benzene concentration in heavy oils Keystone will ship will be comparable to other heavy oils shipped in the U.S. and will generally be lower than benzene concentrations in lighter crudes and in refined products such as gasoline.

Exaggerated descriptions of the physical extent of benzene in the Stansbury Report do not match any oil-spill experience. The report does not account for emergency response containment and cleanup. Examination of field data collected from large spills into rivers typically finds that concentrations of petroleum products become undetectable in a relatively short distance. For example, following a 10,000 barrel release in 2007 from the Coffeeville Refinery in Kansas into

the Verdigris River, the EPA found no detectable concentrations of petroleum products 20 miles downstream at the closest municipal water intake.

13. Stansbury Report Mistake: The report claims TransCanada cut risk factors in half.

The Facts: TransCanada reflected the results of industry studies regarding failure rates of pipe-related equipment, reducing by half the anticipated number of failures caused by material defect.

Background: TransCanada assumed that its pipeline would be constructed so well that it would have only half as many spills as the other pipelines in service. Not true. Rather, TransCanada reflected the results of industry studies regarding failure rates of pipe-related equipment, reducing by half the anticipated number of failures caused by material defect. As discussed in item #4 above, measures that help achieve this performance are among the Special Conditions to which TransCanada has committed.

Here is the statement from the TransCanada report: "A 50% reduction in the DOT leak frequency was applied to the entire pipeline because the U.S. portion of Keystone will consist of entirely new materials and be constructed to meet current standards and requirements." [DNV section 4.1.13, page 13] The statement occurs in a section of the DNV report describing risk of mechanical defect. Other risk factors are adjusted differently for above-ground and below-ground pipe for instance.

14. Stansbury Report Mistake: The report suggests that releases at pump station sites means Keystone is using less reliable pipe.

The Facts: None of the pump stations releases involved pipeline.

Background: As of June 1, 2011 the Keystone pipeline has experienced fourteen (14) unplanned releases within pump/valve station facility sites, averaging 5-10 barrels each. None of these incidents have involved the pipeline itself. In two cases, nearby adjacent property was affected by spray. Otherwise, the incidents were contained within our pump station facility. Equipment has been replaced or repaired. In all cases, Keystone's operation personnel immediately isolate all releases and clean up and remediation efforts are employed to mitigate any effects to the environment.

TransCanada meets or exceeds all notification and reporting requirements to all state and federal agencies. In many of these cases, reporting to regulatory agencies was not required due to the very small volume of these spills. TransCanada has taken a transparent approach to proactively report all spills to federal and state regulatory agencies regardless of volume. Pipelines are the safest method of transporting the oil that must be moved throughout North America everyday.

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Response Part B:

Mr. Stansbury's document referenced above (the "Stansbury document") does not accurately portray the Keystone XL risk analysis nor has the author made valid assumptions regarding the analysis of the risk included in the report. The discussion below responds to a number of the points in the Stansbury document.

1. **The expected frequency of spills from the Keystone XL pipeline reported by TransCanada (DNV, 2006) was evaluated. (Stansbury document at p. 1)**

The DNV 2006 report is irrelevant to Keystone XL Pipeline Project. The Keystone XL pipeline project risk assessment is based on the Keystone XL Pipeline Project Risk and Consequence Analysis, April 2009 and Appendix A, Analysis of Incident Frequencies and Spill Volumes For Environmental Consequence Estimation for the Keystone XL Project, July 2009.

2. **The worst-case spill volume at the Hardisty Pumping Station was understated. (Stansbury document at pp. 1-2).**

The Hardisty Pump Station in Alberta Canada is irrelevant to the risk assessment for the US segments of the Keystone XL pipeline Project. Moreover, Stansbury's worst case spill estimates are based on incorrect assumptions, as discussed below.

3. **The primary difference between Stansbury's worst-case spill estimate and TransCanada's estimate is that TransCanada used 19 minutes as the expected time to shut down pumps and close valves (TransCanada states that it expects the time to be 11.5 minutes for the Keystone XL pipeline). Since a very similar pipeline recently experienced a spill (the Enbridge spill), and the time to finally shut down the pipeline was approximately 12 hours, and during those 12 hours the pipeline pumps were operated for at least 2 hours, the assumption of 19 minutes or 11.5 minutes is not appropriate for the shut-down time for the worst-case spill analysis. Therefore, worst-case spill volumes are likely to be significantly larger than those estimated by TransCanada. (Stansbury document at p. 2).**

Keystone has calculated the worst case discharge for the Keystone XL pipeline in accordance with 49 CFR §194.105. The Stansbury document suggests that, because shutdown on another pipeline took longer, that increased time should be used as the shut down time assumption for the Keystone XL Pipeline. Enbridge's pipeline was constructed in 1969, while Keystone XL Pipeline would be constructed in 2013 and would meet or exceed current regulatory standards. Stansbury does not take into account that the Keystone XL pipeline is instrumented at every mainline valve and has new, state-of-the-art leak detection and operator training systems that make it unlikely that Keystone operators would experience difficulty detecting a leak. Nor does he address industry information sharing or the workings of the regulatory regime, both of which serve to make it unlikely that alleged operational errors on one system are repeated on another system.

In addition, Stansbury does not take into account the fact that worst case discharge is determined using a large leak that would be instantaneously detected by the leak detection system resulting

in immediate initiation of shut down procedures. Nonetheless, in determining its worst case discharge, Keystone conservatively assumed a 10 minute leak confirmation period, plus nine minutes for pump shut down, plus a 3 minute valve closure time, for a total of 22 minutes. While detection of a smaller leak may require additional confirmation time, the small volumes released would not approach worst case discharge amounts. For example, Keystone has experienced small leaks at pumping stations on the Keystone system which resulted in releases that were a fraction of the estimated worst case discharge volumes. Despite being small, these leaks were identified by the sophisticated leak detection system employed on the pipeline and appropriate shut down and isolation measures were initiated. It is incorrect to assume that there could be a small leak that remained undetected for an extended period of time, as suggested by the Stansbury document (see item 15).

4. **The worst-case spill volumes from the Keystone XL pipeline for the Missouri, Yellowstone, and Platte River crossings were estimated by Stansbury to be 122,867 Bbl, 165,416 Bbl, and 140,950 Bbl, respectively. In addition, this analysis estimated the worst-case spill for a subsurface release to groundwater in the Sandhills region of Nebraska to be 189,000 Bbl (7.9 million gallons). (Stansbury document at p. 2)**

The results of the risk assessment for the Keystone XL pipeline are conservative as the largest spill on record from PHMSA records January 1986-May 2011 for large diameter hazardous liquid pipelines is 40,500 bbl of which 39,800 bbl was recovered. This occurred in 1991 on a 1967 vintage pipeline. Spills greater than 10,000 barrels are uncommon, occurring in less than 0.5 percent of all pipeline spills. Moreover, these estimates are based on incorrect assumptions regarding shut down times as outlined in response #3.

5. **The benzene released by the worst-case spill to groundwater in the Sandhills region of Nebraska would be sufficient to contaminate 4.9 billion gallons of water at concentrations exceeding the safe drinking water levels. This water could form a plume 40 feet thick by 500 feet wide by 15 miles long. (Stansbury document at p. 2).**

This claim is unsupported and disproven by field studies throughout the US. The groundwater study (Newell and Connor 1998) summarized the results of four nationwide studies looking at groundwater plumes from petroleum hydrocarbon contamination. The results show that movement of petroleum hydrocarbons is very limited, moving 312 feet or less in 90 percent of the cases. The longest plume was approximately 3,000 feet in length. Therefore, if groundwater became contaminated, any plume would be expected to result in highly localized effects. Importantly, these limits tend to be independent of the rate of groundwater flow. In contrast, chemicals used in some industries and in agriculture, such as commercial solvents, such as PCE and TCE (tetrachloroethylene and trichloroethylene) and pesticides, have much greater mobility and environmental persistence when compared to oil and its constituents.

6. **Among numerous toxic chemicals that would be released in a spill, the benzene (a human carcinogen) released from the worst-case spill into a major river (e.g., Missouri River) could contaminate enough water to form a plume that could extend more than 450 miles. (Stansbury document at p. 2).**

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This claim is unsubstantiated and unsupported by actual field data nor does it account for containment and cleanup efforts by the operator that limit downstream movement. For example, reference is made to a 2007 spill in Coffeeville, Kansas that released 10,000 barrels of crude oil that entered the flooded Verdigris River. EPA samples reported concentration of petroleum hydrocarbons to be below threshold limits at the first sampling point, located 12 downstream miles of the spill. In 2010, an Enbridge 30-inch pipeline ruptured, spilling 19,500 barrels of oil into the Kalamazoo River system. EPA reports that contamination has been documented in localized areas within 30 miles of the spill's origin. These case studies demonstrate that actual contamination is much less than implied by the Stansbury document.

7. **In estimating spill frequency, TransCanada ignored historical data for spills from "other causes," which represents 23 percent of historical pipeline spills (Stansbury document at pp. 1, 4).**

In its failure frequency analysis, Keystone determined the threats that are actually applicable to the Keystone XL Pipeline by using the combination of variables in the Time Dependant, Stable and Time Independent categories listed in API 1160[1] Section 8.7 and ASME B31.8S[2]. Keystone then used the PHMSA data for the categories of incidents that are associated with these applicable threats. The data for "other causes" was not used because it consists of offshore pipeline, offshore platform, tankage, tankage piping and terminal incidents data that are not applicable to the Keystone XL Pipeline. Keystone did however consider spills at pumping and metering facilities in its analysis of the PHMSA data.

8. **In estimating spill frequency, TransCanada assumed that its pipeline would be constructed so well that it would have only half as many spills as the other pipelines in service. The modification of historical pipeline incident data to account for modern pipeline materials and methods is "probably" overstated for this pipeline. (Stansbury document at pp. 1, 46)**

The modification for modern materials and methods is fully appropriate. Based on the PHMSA incident database January 1, 1986 through May 31, 2011, there are two (2) reported pipeline incidents on crude oil pipelines manufactured with high strength steel (grade X70 or higher) due to pipeline material and methods. This first incident was due to external corrosion and occurred in 1998 on a 1985 vintage pipeline. The second pipeline incident occurred on small diameter (24inch or less). This incident was due to electric flash resistance (ERW) pipe seam failure and occurred in 2007 on a 1998 vintage pipeline. As Keystone is a large diameter pipeline, its method of joining is double submerged arc welding (DSAW) and not ERW. Furthermore,

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[1] Section 8.7. In any risk assessment method, the likelihood is estimated using a combination of variables in categories such as the following: external corrosion, internal corrosion, third party damage, ground movement, design and materials, system operations

[2] ASME B31.8 S "*Managing System Integrity of Gas Pipelines*" classifies threats to pipelines in terms of "Time Dependant", "Stable" and "Time Independent" categories. Time Dependant Threats include: External Corrosion; Internal Corrosion; and, Stress Corrosion Cracking (SCC); Stable Threats include: Manufacturing Defects; Welding / Fabrication Related; and, Equipment Failure; and, Time Independent Threats include: Third Party / Mechanical Damage; Incorrect Operations, and Weather and Outside Force (Geotechnical)

Keystone will protect the pipeline from external corrosion using fusion bond epoxy (FBE) and a cathodic protection (CP) system. The combination of FBE and CP has proven effective over TransCanada's 30+ years of operation. Keystone implements 24 hour surveillance during pipe manufacturing and coating. Lastly, Keystone has implemented nine (9) specific material related conditions and will implement thirteen (13) construction method related conditions set forth in the PHMSA Special Condition Appendix C, over and above current regulations, which would ensure that Keystone is the safest pipeline built in North America, thereby minimizing any potential for spills resulting from materials and construction methods.

In order to establish the particular incident threats that would apply to the Keystone XL pipeline during its operational life, three key points were considered:

- Keystone XL is a new construction project, developed with the benefit of TransCanada's more than 50 years of pipeline construction and operating experience;
- The pipeline will be constructed and operated in accordance with comprehensive regulatory guidelines (49 CFR Part 195) and pipeline design standards (ASME B31.4), and;
- At the time the risk assessment was prepared, Keystone had applied to PHMSA for a Special Permit to allow it to design, construct and operate the pipeline up to 80% of the steel pipeline's specified minimum yield strength (SMYS). The Special Permit application provided that Keystone would comply with a number of pipeline integrity conditions over and above the applicable PHMSA regulations and industry standards. This included the 51 conditions from the Special Permit 2006-26617 issued by PHMSA to TransCanada for the Keystone Pipeline Project in April 2007. Keystone included these conditions in the base design of the Keystone XL Project and recognized their impact in modifying historic failure frequency data in preparing the Risk Assessment. Subsequent to the completion and submittal of the Keystone XL Project Pipeline Risk Assessment and Environmental Consequence Analysis in April 2009, Keystone withdrew the Special Permit Application. Nonetheless, PHMSA ultimately developed and recommend that Keystone adopt 57 conditions over and above the applicable regulations and industry standards and in some cases exceeding the requirements of the 51 conditions listed in the Keystone Special Permit 2006-26617. Keystone agreed to adopt these conditions, which are set forth in Appendix C of the Supplemental Draft EIS. Accordingly, the design assumptions underlying the failure frequency modifications remain conservative.

Taking these factors into consideration, the applicable threats were determined using both the American Society of Mechanical Engineers (ASME) B31.8S Managing System Integrity of Gas Pipelines and American Petroleum Institute (API) 1160 Managing System Integrity of Hazardous Liquid Pipelines as guidance. These standards outline processes for pipeline operators which can be used to assess risks and make decisions about risks in operating pipelines in order to reduce both the number of incidents and the adverse effects of errors and incidents. Moreover, in view of Keystone's adoption of additional conditions beyond those taken into account during preparation of the Risk Assessment, the modifications to historic failure frequency data reflected in the 2009 Risk Assessment are actually even more conservative.

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9. **Keystone will operate the pipeline at higher temperatures and pressures and the crude oil that will be transported through the Keystone XL pipeline will be more corrosive than the conventional crude oil transported in existing pipelines, which tends to increase failure frequency. The diluted bitumen to be transported through the Keystone XL Pipeline will be significantly more corrosive and abrasive than conventional crude oil. (Stansbury document at pp.1, 4-5).**

Keystone has withdrawn its application to operate up to 80% SMYS thereby reducing its throughput and operating pressure. PHMSA Special Condition 15 provides that "under no circumstances may the pump station discharge temperatures exceed 150° Fahrenheit (°F) without sufficient justification that Keystone's long-term operating tests show that the pipe coating will withstand the higher operating temperature for long term operations, and approval from the appropriate PHMSA region(s)."

The potential for internal corrosion (IC) to develop during transportation of oil sands derived crude oils due to sediment and solids is considered low. The following factors support the conclusion that the risk of corrosion from sediments and solids is low:

- Keystone's tariff specifications group sediments/solids with water content. The tariff contains a restriction of 0.5% solids and water by volume.
- "Solids and water" is comprised mostly of water, with solids typically at 5% of the solids/water content (reference www.crudemonitor.ca)
- Keystone will utilize a number of operating measures that will minimize solids in the pipeline:
    - periodic cleaning
    - turbulent flow operating regime
    - sediments are benign at the pipeline's proposed operating temperature (not to exceed 150°F per PHMSA Special Condition 15)

PHMSA Special Condition 34 requires Keystone to limit basic sediment and water (BS&W) to 0.5% by volume and report BS&W testing results to PHMSA annually. Keystone must run cleaning pigs twice in the first year and as necessary in succeeding years based on the analysis of oil constituents, liquid test results, and weight loss coupons in corrosion threat areas. At a minimum, in years after the first year, Keystone must run cleaning pigs once per year, at intervals not to exceed 15 months. Liquids collected during the pig runs, including BS&W, must be sampled, collected, and analyzed and internal corrosion plans must be developed, based on lab test results. This mitigation plan will be incorporated in the Keystone XL Integrity Management Plan and must be reviewed at least quarterly based upon crude oil quality. Keystone will also monitor and implement adjustments for the presence of deleterious crude oil stream constituents as per the PHMSA Special Conditions.

Furthermore, an independent analysis performed by Crude Quality Inc of oil sands derived crude oils has conclusively demonstrated that, below 450 degrees Fahrenheit, the oil sand crude oils are not corrosive to steel.[3]

In addition, the Energy Resources Conservation Board of Alberta issued a statement on February

[3] CAPP Response to US DOS re Keystone XL

16, 2011 stating "the ERCB can identify only three spills resulting from internal corrosion between 1990 and 2005 (and only eight from 1975 to 2010) [for Alberta pipelines]. The resulting average failure frequency for the grouping of crude oil pipelines from 1990 to 2005 is thus 0.03 per 1000 km per year. This is significantly lower than the U.S. rate quoted in [a recent Natural Resources Defense Council] study of 0.08 per 1000 km per year."[4] The ERCB stated further that:

> Analysis of pipeline failure statistics in Alberta has not identified any significant differences in failure frequency between pipelines handling conventional crude versus pipelines carrying crude bitumen, crude oil or synthetic crude oil. Diluent by nature is a lower viscosity, higher-vapour pressure solvent. It could then be considered to be more "volatile" in its natural state, as it consists of lighter end hydrocarbons. However, when blended with bitumen, the resulting blend is a "new" product consisting of thinned bitumen that more closely resembles conventional crude products. Once mixed with diluent, DilBit should behave in much the same manner as other crude oils of similar characteristics. In conventional oils sands processing, sulphur is removed during processing, as well as water (which is a primary concern in regards to corrosivity). The tariff specification for the Keystone XL project, for example, is virtually the same in regards to water content and solids contents as that specified for other heavy oil pipelines, thus there is no reason to expect this product to behave in any substantially different way than other oil pipelines. It should also be noted that pipelines in Alberta have never been safer. In 2009, Alberta posted a record-low pipeline failure rate of 1.7 pipeline failures per 1,000 km of pipeline (considering all substances), bettering the previous record-low of 2.1 set in both 2008 and 2007."[5]

10. Although pipeline technology has improved, new pipelines are subject to proportionately higher stress as companies use this improved technology to maximize pumping rates through increases in operational temperatures and pressures, rather than to increase safety margins. (Stansbury document at p.5)

Keystone XL pipeline is design in accordance with 49 CFR §195.106 and ASME B31.4. The federal regulation limits the pipeline's operating stress to no more than 72% of the pipeline steel material's specified minimum yield strength. Operating temperature is addressed in Item 9 above.

11. TransCanada relies on "soft" technological improvements which require an on-going commitment to monitoring and maintenance resources and which should not be assumed to be constant over the projected service life of the pipeline, and are

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[4] ERCB ADDRESSES STATEMENTS IN NATURAL RESOURCES DEFENSE COUNCIL PIPELINE SAFETY REPORT February 16, 2011

[5] ERCB ADDRESSES STATEMENTS IN NATURAL RESOURCES DEFENSE COUNCIL PIPELINE SAFETY REPORT February 16, 2011

subject to an ongoing risk of error in judgment during operations. (Stansbury document at p.5).

The PHMSA regulations at 49 CFR Part 195 require many of these monitoring and maintenance activities as a condition of operation. Keystone has voluntarily committed to 57 additional safety conditions that include other enhanced monitoring and maintenance activities as additional conditions of continued operation. For instance, in order to continue to operate the pipeline, Keystone must perform in-line inspections, conduct corrosion and depth of cover surveys, and perform valve inspections at specified frequencies – these are not discretionary. Additionally, Keystone must patrol the pipeline 26 times per year, at intervals not to exceed three weeks.

In addition to regulatory requirements, continuing to invest in the safety of the pipeline makes sense from a business perspective. Paying for increased maintenance is built into Keystone's contracts with its shippers such that variable integrity spending costs are flowed through to the shippers. Additionally, the FERC rate allows the uncommitted toll to rise at a greater than inflation rate which allows for recovery of maintenance costs. There is therefore no financial incentive for Keystone to cut back on monitoring and maintenance and a substantial financial penalty associated with leaks in the form of fines, cleanup costs, lawsuits and reputational damage. It is therefore not reasonable to suggest that Keystone or another owner would increase their liability in order to reduce an expense that is flowed through to the shippers.

12. **The TransCanada spill frequency estimation consistently stated the frequency of spills in terms of spills per year per mile. This is a misleading way to state the risk or frequency of pipeline spills. Spill frequency estimates averaged per mile can be useful; e.g., for extrapolating frequency data across varying pipeline lengths. However, stating the spill frequency averaged per mile obfuscates the proper value to consider; i.e., the frequency of a spill somewhere along the length of the pipeline. (Stansbury document at p. 5).**

Keystone was transparent in its use of statistics, including where and how they were derived, how they were applied, and by expressing the potential risk in a variety of ways to promote greater understanding and clarity to a broad audience. Spill frequencies are expressed several ways throughout the document to facilitate comparison with other pipelines and modes of transport, and to promote project-specific understanding. As suggested, spill frequencies expressed as an average per mile facilitates comparison with pipelines of various lengths and to national averages, which are also expressed in this normalize expression of risk. Within the same sentence of expressing the average risk value in terms of incidents/per mile*year (page 3-2), risk was immediately expressed in terms of risk for the whole pipeline over a 10-year period and as an occurrence interval for any single mile of pipe. This provides decision-makers multiple opportunities to understand spill risk and how it applies to the project as a whole as well as to an individual's piece of property. The risk assessment addresses risk specifically to the project as a whole and by pipeline segment (Table 3-1), providing an estimate of the number of spills that could occur over a ten-year period. The risk assessment also uses the spill frequency and historical spill volume data to estimate the potential frequency of different sizes of spills (Table 3-2). In Section 4 of the risk assessment, these same statistics are used to generate estimates of spill frequency and spill volumes in high consequence areas.

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13. **Likely failure points include welds, valve connections, and pumping stations. A vulnerable location of special interest along the pipeline system is near the side of a major stream where the pipeline is underground but at a relatively shallow depth. (Stansbury document at p. 6)**

Keystone is required to conduct non-destructive examination of 100% of the pipeline and pump station welds, in addition to a hydrostatic pressure test. (PHMSA Special Conditions 5, 8, 20, 22). Furthermore, below-ground mainline valve connections are welded, hydrostatically tested and capable of inspection by an in-line inspection tool. Pump station infrastructure undergoes regular maintenance and inspection, piping and equipment is contained within property boundaries which are contained by berms.

The Keystone XL pipeline is designed with a minimum depth of cover of 5 feet below the bottom of waterbodies including rivers, creeks, streams, ditches and drains for a depth normally maintained over a distance of 15 feet on each side of the waterbody measured from the top of the defined stream channel. The depth of cover may be modified by Keystone based on site specific conditions and in accordance with PHMSA Special Condition 19. The Project's depth of cover meets or exceeds the federal requirements noted in 49 CFR 195.248 of 48 inches for inland bodies of water with a width of at least 100 feet from high water mark to high water mark (for normal excavation, 18 inches for rock excavation) and PHMSA Special Condition 19 on depth of cover. Furthermore, major rivers will be crossed employing the horizontal directional drill (HDD) method, whereby the pipe is installed at a minimum of 25 feet below the river bottom there by eliminating the potential for scour to affect the pipeline's integrity. HDD crossings also utilize pipe with a wall thickness of 0.748 inch and abrasion resistant coating applied over top of the FBE coating.

14. **An independent assessment of TransCanada's emergency response plans for the previously built Keystone pipeline was done by Plains Justice (Blackburn, 2010). This document clearly shows that the emergency response plan for the Keystone pipeline is woefully inadequate. Considering that the proposed Keystone XL pipeline will cross much more remote areas (e.g., central Montana, Sandhills region of Nebraska) than was crossed by the Keystone pipeline, there is little reason to believe that the emergency response plan for Keystone XL will be adequate. (Stansbury document at p. 3).**

Keystone is required to submit its emergency response plan for the Keystone XL Pipeline to PHMSA prior to commencing operations for review and approval. As contrasted with Mr. Blackburn, a lawyer, PHMSA has the professional and technical expertise necessary to perform an independent and competent evaluation of the adequacy of the emergency response plan. Significantly, as part of the State Department's review of the project, Keystone was required to present its approach to oil spill response under specific hypothetical spill scenarios to DOS and PHMSA. Based on review of Keystone's response to those scenarios, the SDEIS found that Keystone's spill response planning "is appropriate and consistent with accepted industry practice" (SDEIS p. 3-122). Moreover, PHMSA has already approved the emergency response plan for the Keystone Pipeline, which will serve as the model for the Keystone XL plan.

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15. **Slow leaks could go undetected for long periods of time (e.g., up to 90 days). (Stansbury document at p.7).**

While it is theoretically possible for a very small leak to go undetected for 90 days, data from actual pipeline spills demonstrate that substantial leaks do not go undetected for long periods of time. Further, those spills that are not detected within the first 48 hours are typically relatively small. PHMSA records (2001 through 2009) indicate that the majority of spills are detected within 2 hours, with 99 percent of spills detected within 7 days. Additionally given that leak occurrence is effectively random in time, if a patrol interval is fixed and equal to 14 days, then the time between leak occurrence and leak detection by patrol will range between zero days and 14 days, and it can be shown through modelling that the average time between occurrence and detection will be equal to one-half of the patrol interval (i.e., 7 days). Furthermore, in the context of a risk assessment, where the consequences are weighted by probability of occurrence, the average time is the most appropriate value.

16. **Stansbury assumes a shut-down time of 2 hours for the worst case spill for a large leak (Stansbury document at p. 8).**

See response to Item number 3.

17. **Given the difficulty for operators to distinguish between an actual leak and other pressure fluctuations, the shut-down time for the worst case volume calculation should not be considered to be less than 30 minutes for a leak greater than 50 percent of the pumping rate. This would allow for 4 alarms (5 minutes apart) to be evaluated by operators and a 5th alarm to cause the decision to shut down. In addition, the time to shut down the systems (pumps and valves) would require another 5 minutes. The assumption that the decision to shut the pipeline down can be made after a single alarm, as is suggested by TransCanada (ERP, 2009) is unreasonable considering the difficulty in distinguishing between a leak and a pressure anomaly. (Stansbury report at p. 8).**

As noted in Item 3, Keystone allows for a 10 minute trouble shoot period to confirm if the alarm is a pressure fluctuation or an actual leak. This time period was incorporated into Keystone XL's worst case discharge calculation in addition to the pump shut down time and valve closure time. Keystone's OCC procedures require immediate shut down of the pipeline upon expiry of the trouble shoot period. Stansbury's assumption of four alarms, five minutes apart, bears no relationship to Keystone operating policies and procedures.

18. **TransCanada arbitrarily assigned a drain-down factor of 0.6 for the Keystone XL pipeline. Stansbury report at p. 9).**

Keystone's methodology incorporates the results of an independent assessment by the California Fire Marshal in its role as a regulator in California. The report is well known and respected among pipeline industry, regulators and risk assessors.

19. **Stansbury assumes a discovery and shut-down time of 14 days, which corresponds to the time between pipeline inspections. Stansbury document at p. 20).**

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See response to Item number 15.

20. Stansbury states his estimated worst case releases for major river crossings (i) Missouri R.; (ii) Yellowstone R.; (ii) Platte R. (Stansbury document at pp.10-13).

Stansbury's estimates for these major river crossings are grossly overstated. Based on actual elevation profile, spill calculation inputs and hydraulic engineering data the worst case discharges for these three rivers is less than 20 percent of the volumes stated by Stansbury.

21. "Impacts to Air, Terrestrial Resources, Surface Water, Groundwater Resources (Stansbury document at pp. 14 – 23)

Please refer to the Keystone XL Project Pipeline Risk Assessment and Environmental Consequence Analysis in April 2009.

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CERTIFICATE OF SERVICE

I hereby certify that on the 26th day of June, 2015, I sent by United States first-class mail, postage prepaid, or e-mail transmission, a true and correct copy of the foregoing Rebuttal Testimony of Heidi Tillquist, to the following:

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

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HP 14-001

IN THE MATTER OF THE PETITION OF TRANSCANADA KEYSTONE PIPELINE, LP FOR ORDER ACCEPTING CERTIFICATION OF PERMIT ISSUED IN DOCKET HP09-001 TO CONSTRUCT THE KEYSTONE XL PROJECT

REBUTTAL TESTIMONY OF JEFF MACKENZIE

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Pursuant to the Commission's Order Granting Motion to Define Issues and Setting Procedural Schedule, Petitioner TransCanada Keystone Pipeline, LP, offers the following rebuttal testimony of Jeff Mackenzie.

1. Please state your name and occupation.

A. Jeff Mackenzie, Senior Emergency Preparedness and Response Specialist with TransCanada.

2. Did you provide direct testimony in this proceeding?

A. No. I'm a highly-skilled Senior Emergency Manager with more than 20 years' experience in Emergency Management & Preparedness, Risk Management, Facilities and H&S. I have specialized knowledge in Emergency Services Management, EH&S Programs Development, Risk Management and Emergency Services Administration. A current copy of my resume is attached as Exhibit A.

3. To whose direct testimony are you responding in your rebuttal testimony?

A. I am responding to the direct testimony of Richard Kuprewicz and Dr. Arden Davis.

4. Mr. Kuprewicz's testimony (pg. 1) states "effective cleanup/remediation of ruptures into the rivers would be most unlikely, despite extensive and expensive efforts in this challenging terrain, and could be devastating to the state." Can you comment on this statement?

A. While the likelihood of a release is very low, TransCanada takes full responsibility for emergency response and clean-up for any of the pipelines that we own and operate. TransCanada will assume the responsibility for managing spill events and will pay for remediating any environmental impact or for any property damage that may result from a spill. Section 1002 of the Oil Pollution Act of 1990 states that TransCanada is liable for: (1) certain specified damages resulting from the discharged oil; and (2) removal costs incurred in a manner consistent with the National Contingency Plan (NCP). Additionally, PHMSA regulations at 49 CFR 194.115 require each operator to identify and ensure the resources necessary to remove a worst case discharge, to the maximum extent practicable, and to mitigate or prevent a substantial threat of a worst case discharge. This capability is demonstrated through the Keystone Pipeline System Emergency Response Plan. The Keystone Pipeline System Emergency Response Plan describes various techniques for containing spilled oil in water (e.g. deflection/diversion boom, containment boom). The Response Plan also describes the techniques used to recover spilled product using weir skimmers, oleophilic skimmers, and suction skimmers. These tactics are proven to be the most effective means to recover spilled product, and TransCanada has access to

all of the resources required to employ these tactics through internally owned equipment, trained company personnel, and contact resources. More detail specific to emergency response in rivers is provided in response to Question 9 herein.

TransCanada has extensive, recent experience working in challenging terrain where site access was challenging. In those instances, TransCanada proved it has ability to gain access and appropriately respond. For example, in 2013, TransCanada experienced a natural gas pipeline rupture in northern Alberta where swamp and muskeg made access to the site extremely challenging. TransCanada successfully responded to the incident by building roads with rig mats, using tracked vehicles to navigate swamps and sloughs, and employing heavy-lift helicopters to transport equipment to the isolated location. In addition, TransCanada is constructing pipelines in some of the most rugged mountains in Mexico. There, TransCanada has used winches and cable systems to transport personnel and equipment up and down steep, isolated, mountainous terrain. TransCanada has contractual agreements in place with helicopter companies in the United States having the ability to sling and lift emergency response equipment and resources into remote areas.

In addition to challenging terrain, TransCanada is prepared to respond to emergencies in harsh climates and weather conditions. Since the Keystone Pipeline has been in service, TransCanada has conducted emergency response exercises in extremely cold weather allowing personnel to test such tactics as ice slotting for product containment under frozen waterways. Similarly, TransCanada has responded to actual emergencies in Canada where ambient temperatures were dangerously low; still TransCanada was able to respond safely in those

conditions, which are comparable to those experienced in western South Dakota during the winter season.

5. Mr. Kuprewicz's testimony (pg. 2) references what he calls "past failures of [oil spill response] plans to be truly effective." Can you comment on this assertion?

A. Oil spill response plans are developed by pipeline operators as required by PHMSA regulations at 49 CFR Section 194.115. PHMSA is the federal agency with the technical expertise to review the adequacy of these plans. To the extent Mr. Kuprewicz has concerns with the efficacy of oil spill response plans across the industry, that would be an issue to be addressed with PHMSA.

The existing Keystone Pipeline System Emergency Response Plan was developed in accordance with 49 CFR Part 194. The Keystone ERP was reviewed and approved by PHMSA prior to Keystone commencing operations in 2010. Required Worst Case Discharge scenarios were calculated using the U.S. Coast Guard criteria. Using these figures, TransCanada identified and ensured, by contract or other approved means, the resources necessary to remove, to the maximum extent practicable, a worst case discharge and to mitigate or prevent a substantial threat of a worst case discharge. Keystone will augment the Keystone Pipeline System ERP to address these same issues along the route of the Keystone XL Pipeline. The augmented plan will be reviewed by PHMSA.

In the course of reviewing Keystone's Presidential Permit application, the State Department (DOS) tendered a data request to Keystone in which it required Keystone to describe its response to two spill scenarios. These scenarios are presented in the excerpt from the August 2011 Final Environmental Impact Statement, which is attached as Appendix A to my testimony.

DOS stated that Keystone's response to these scenarios provided an opportunity to review the level of preparedness and foresight that would be in place relative to potential spills from the proposed Project.

As stated in the FEIS, DOS and PHMSA reviewed these hypothetical spill response scenarios prepared by Keystone. Based on its review of the hypothetical spill response scenarios, DOS stated that it considers Keystone's response planning appropriate and consistent with accepted industry practice.

6. Mr. Kuprewicz's testimony (pg. 2) states "An oil spill plan should also include dealing with a possible release in the critical Ogallala Aquifer." Can you comment on this statement?

A. TransCanada will include the possibility of a release in the Ogallala Aquifer in the Emergency Response Plan for Keystone XL. As I have stated, the existing Keystone Pipeline System Emergency Response Plan will be augmented to include the risks and hazards associated with the Keystone XL route. Such risks and hazards include a release to groundwater, and the tactics for remediating this type of spill are already addressed in the Keystone Emergency Response Plan. Specifically, the following procedures and potential remediation techniques are included in the Keystone Emergency Response Plan:

<u>Procedures:</u>

- Evaluate the topography and evidence of surface contamination.
- Establish containment, accounting for public safety, spill volume, terrain, and presence of surface water.
- Notify landowner and appropriate public agencies of potential groundwater contamination.
- Immediately retain an independent consultant with expertise in this area to evaluate impacts and remediation options.

- Consult with appropriate agencies regarding remediation, including water and soil cleanup levels, and need for groundwater monitoring.
- Notify and procure additional response equipment and personnel as necessary to address site-specific conditions.

Remediation Techniques:

- Dig intercept trench down-gradient of release point.
- Line trench and stage vacuum truck to remove contaminated oil/water mixture.
- Excavate surface catchment up-gradient of the intercept trench and near leading edge of visible contamination.
- Excavate until contaminated soil is completely removed and clean soil is encountered or conditions prohibit continued digging.
- Line the catchment to limit or prohibit further groundwater contamination.
- Move vacuum truck from intercept trench to catchment to recover oil and/or oily water.
- Line drop down area to stage contaminated soil as excavated.
- Segregate waste streams to minimize later disposal.
- Based on anticipated release, stage temporary storage and additional vacuum trucks to ensure recovery efforts continue without interruption.

- Options for Long-term Remediation:
  - Air sparging
  - Vacuum extraction
  - Conventional pump and treat
  - Bio-slurping
  - Excavation
  - Enhanced biodegradation/bioremediation
  - Chemical addition/oxidation
  - Natural Attenuation
  - Enlist additional experts, as appropriate, for continuing remediation and coordination with appropriate agencies.
  -

7. Mr. Kuprewicz's testimony (pg. 2) states "The Keystone XL oil spill plans should be independently reviewed and made public to assure their effectiveness." Can you comment on that assertion?

A. The existing Keystone Pipeline System Emergency Response Plan was developed in accordance with 49 CFR Part 194 and is distributed, retained, and submitted to PHMSA in accordance with that federal regulation. Additionally, the plan satisfies South Dakota Codified

Laws 34A-12-9, 34A-18-2, and 34A-18-9. The South Dakota Department of Environment and Natural Resources – Division of Environmental Services is a plan holder of Controlled Copy #26 of the Keystone Pipeline System Emergency Response Plan, and the Department receives notification within 30 days of any change to the plan. A redacted version of the ERP for the Keystone System is available to the public as Appendix I to the State Department's January 2014 Final Supplemental Environmental Impact Statement.

8. Mr. Kuprewicz's testimony (pg. 6) states "[t]he potential to rapidly spread in this [steep terrain] environment raises a serious question as to whether the 12-hour or even the 6-hour Tier 1 time limit in federal regulations will be appropriate." Do you have a comment on that testimony?

A. First, the response time limits set forth at 49 CFR 194.115 have been established by the federal agency with demonstrated expertise in this area. If Mr. Kuprewicz believes they are inadequate, he should take that position up with the agency having responsibility and jurisdiction over this area.

TransCanada places great emphasis on ensuring the ability to promptly respond to an emergency. In fact, TransCanada has designed exercises to specifically assess the ability of their contracted response organizations to provide resource for a worst case scenario within the required time limits. These exercises evaluate contractor's availability to respond in specified time frames. In 2013, a Third Party Contractor Assessment Exercise was conducted in Yankton, SD to ensure adequate resources were available, and similar exercises are anticipated across the pipeline system in the future.

9. As recent ruptures have indicated in the Yellowstone River, Oil Spill Response can be highly ineffective at containing or recovering spilled oil, which can rapidly spread tens of miles downstream in major river ways.

A. TransCanada maintains contracts with US Coast Guard classified Oil Spill Removal Organizations. These organizations have access to the most efficient and technologically advanced containment and recovery equipment available.

The Keystone Pipeline System Emergency Response Plan describes various tactics for containing and recovering spilled oil in flowing waterways. Dikes, berms, and dams are land-based tactics, with the objective of containing spilled oil and limiting spreading of oil slicks, thus minimizing impacts to the environment. Dikes, berms and dams are embankment structures built-up from the existing terrain, placed to contain and accumulate oil for recovery. These barriers can serve to:

- Contain and stabilize a contaminated area.
- Contain or divert oil on water or oil that has potential to migrate.
- Create cells for recovery.
- Use natural depressions to act as containment areas for recovery.

The Response Plan also describes the techniques and equipment used to recover spilled product in waterways through the use of skimmers, which fall into three types:

- Weir skimmers draw liquid from the surface by creating a sump in the water into which oil and water pour. The captured liquid is pumped from the sump to storage. Weir skimmers can recover oil at high rates, but they can also recover more water than oil, especially when the oil is in thin layers on the surface of the water. This creates the need to separate the water from the oil and decant it back into the environment. Otherwise, the recovered water takes available storage volume. Weir skimmers are best employed where oil has been concentrated into thick pools or where there are very large volumes of oil and recovered liquid storage capacity.

- Oleophilic skimmers pick up oil that adheres to a collection surface, leaving most of the water behind. The oil is then scraped from the collection surface and pumped to a

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storage device. Oleophilic skimmers do not recover oil as fast as weir skimmers, but they have the advantage of recovering very little water. Oleophilic skimmers may be used where oil is very thin on the surface. Oleophilic skimmers are a good choice where liquid storage capacity is limited.

- Suction skimmers use a vacuum to lift oil from the surface of the water. These skimmers require a vacuum pump or air conveyor system. Like weir skimmers, suction skimmers may also collect large amounts of water if not properly operated. Most suction skimmers are truck mounted and work best at sites with road access.

These tactics are proven to be the most effective means to recover spilled product, and TransCanada has access to all of the resources required to employ these tactics through internally owned equipment, trained Company personnel, and contacts resources.

10. Kuprewicz testifies that oil spill response and remediation for the segment of the pipeline in Tripp County spanning the Ogallala Aquifer should focus on surrounding the release site with "reverse flow" injection and soil capture and remediation methods to limit its spread and involves removing underground soil contaminated from spill plumes that may be developed.

A. TransCanada will implement the most effective strategies, techniques, and equipment available to respond to any emergency in all our operating environments along the pipeline. During an emergency, TransCanada will work in collaboration with regulatory agencies to develop our strategies based on site specific conditions such as land or surface water, weather, geology, soil type, etc. While reverse flow injection may be one tactic to respond to an oil spill, TransCanada will not limit itself to a single response tactic. Instead, TransCanada will maintain contracts with US Coast Guard classified Oil Spill Removal Organizations who have access to the most efficient and technologically advanced containment and recovery equipment available.

11. Dr. Davis testifies that diluted bitumen that sinks in water is significantly more difficult to clean up. Can you comment on that statement?

A. TCP considers the potential for sinking and submerged oil as part of our Emergency Response plans and in the execution of such plans. In the unlikely event of a spill, TCP would work hand-in-hand with regulatory bodies to determine the correct response and remedial actions given to the specific variables of the event. While sinking crude oils do pose a greater challenge for containment and clean up compared to floating oil, the industry has emergency response containment and clean up procedures that have substantially improved, in part because of the lessons learned from the Kalamazoo spill.

Such emergency response tactics may include, but not limited to the following:

- Mechanical methods such as suction dredging and air bubbling.
- Non-Mechanical methods could include chemical treatment / dispersants, bio-mediation and in-situ burning.

Petroleum hydrocarbon plumes do not sink within groundwater as observed with chlorinated solvent plumes (e.g., trichloroethylene [TCE], perchloroethylene [PCE]); instead, they form along the uppermost layer of groundwater.

Therefore, contamination of groundwater would be limited to the uppermost volume associated with the groundwater surface. Petroleum hydrocarbons are naturally degraded by microbial communities naturally found within soils. As a result, petroleum hydrocarbon plumes would be expected to result in highly localized effects. Removal of the source oil and remediation actions would help to further minimize groundwater impacts. Kuprewicz reaches the same conclusion (p. 7), specifically stating that impacts to RST groundwater wells are not anticipated due to the slow-moving nature of the groundwater plumes.

Dated this 26TH day of June, 2015.

Jeff Mackenzie

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APPENDIX A

Jeff Mackenzie

Calgary, Alberta

SUMMARY

Highly skilled Senior Emergency Manager with more than 20 years' experience in Emergency Management & Preparedness, Risk Management, Facilities and H&S. Specialized knowledge in Emergency Services Management, EH&S Programs Development, Risk Management and Emergency Services Administration.

EXPERIENCE

TransCanada Pipeline *08/2014 - Present*
Senior Emergency Preparedness & Response Specialist, Major Projects

- Responsible for coordinating emergency preparedness and response-related activities in support of all phases of the Major Project life-cycle.
- Manages a variety of project activities by creating and updating scorecards that provide stakeholders with the status of EP&R deliverables.
- Maintains project deliverables and budgets by creating project plans and identifying and addressing any gaps or project conflicts - proactively communicates with stakeholders and team members accordingly.
- Provides permit application support by creating work plans and submitting timely and accurate documentation to ensure all applicable regulatory and Company standards are met.
- Engages in stakeholder outreach and consulting by developing business fact sheets, presentations and talking points for meetings and open houses.
- Plans and coordinates EP&R activities by creating work plans that incorporate operation requirements - ensures that plans are filed, approved, and submitted in a timely matter and with respect to all applicable regulatory and Company standards; ensures that Company is prepared to respond to emergencies.
- Conducts design and document reviews to ensure EP&R requirements are understood by the project and identify hazards and mitigation measures to be implemented through engineering design and other means.
- Ensures that the Company is able to meet or exceed all regulatory requirements and is adequately staffed to effectively respond to emergencies.
- Coordinates equipment procurement by ensuring the proper identification, budgeting and delivery of emergency-response related equipment.
- Develops and maintains a network of EP&R consultants, contractors, and industry and agency organizations by working with external resources leads and supply chain to identify needs for supplemental support by third parties - ensures corresponding agreements are active and in accordance with resource strategies.

Bissett Resource Consultants
Senior Emergency Planner *11/2013 – 08/2014*

- Development of Regulatory projects completed in accordance with governing regulatory body (Alberta Energy Regulator - AER).
- Preparation of projects for public consultation, the analysis and processing of field work, the writing of an Emergency Response Plan (ERPs – Corporate, Site Specific, Facility/Area) for the approval by the regulator and for the protection of workers, the public, and the environment in the event of an emergency.
- Full scale & table top exercise AER regulated training for corporate (Emergency Command Centre), site leaders and field. Some clients include: Suncor Energy, Sinopec, ConocoPhillips, Bonavista Energy, and Harvest Energy.
- Liaise with all departments (Petroleum Engineers, Hazard Assessors, GIS Technologists, Dispersion Modelers) that have input required for writing emergency response plans

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- Development of regulatory projects completed in accordance with the AER Directive 056 and AER Directive 71 for projects in Alberta and BC Oil and Gas Commission Emergency Response Plan Requirements for projects in BC.

Suncor Energy *11/2006 – 09/2013*
Natural Gas, North America Onshore Emergency Management & EH&S Advisor

Risk Management

- Completion and compiling of a Security Risk Registry/All Hazards to identify probable and potential risks to the organization by using a task risk analysis approach. Security risk registry range from Bomb threats, to terrorism to environmental issues (WCSS, loss of containment and spill prevention & response).
- Detailed understanding and on hands experience of Integrated Risk Management System (IRMS) and Operational Excellence Management System (OEMS).
- Experience with Incident Learning Prevention, Action Management, Management of Change, EH&S and Risk Matrix.
- Experience in a variety of settings that were primarily in the oil & gas sector: Remote drilling sites, Production (Oil Sands Mining & InSitu), H2S, Natural Gas and Well site services.

Emergency Preparedness & Management

- Emergency Management Advisor & Team Leader of the development of the North America Onshore, Natural Gas Emergency Management Guideline G503. Successfully implemented to maintain, test and continuous improvement for Suncor's emergency/security preparedness.
- Assist businesses, manage, implement, plan, test, guide and facilitate emergency management components: Full Scale ERP Exercises, Evacuation drills, Revision of fire protection systems, confined space consulting. and the Incident Command System (Level 3).
- Interaction with external parties AER (ERCB), CEPA, DOT, Canutec, …
- Maintenance and update of resource material and essential information for ERPs.
- Interaction with federal, municipal, local and mutual aid agreements to coordinate emergency response planning and preparedness.

EH&S

- EH&S Advisor for Suncor Energy's largest Natural Gas Plant, Hanlan Robb and the Medicine Hat & Saskatchewan field.
- Advisor for OH&S code regulations, Policies & Procedures, Best Practices and occupational classifications. Board member of Workplace Health & Safety Committee.
- Authorization & revision of safety contingency plans and site specific work plans.
- Completion of on-site safety audits inspections
- Incident Investigation for EH&S & Security (Injuries, Fatalities, Incidents, Preventive Maintenance,…)
- Emergency preparedness planning creation & implementation for hazardous operations.
- Process Safety Management (PSM): Field Level Risk Assessments, Work place observations and pre-start up safety reviews and process analysis.
- Environmental issue responsibility: Environmental spills, Hazardous Materials, Call Outs and Crisis Communication (CEPA & E2 Plans).
- Support the EH&S team through active participation in the development of EH&S safety programs and plans to support Suncor's ongoing commitment to the Journey to Zero injuries program.

Emergency Response Officer

- Paramedic, Medical Clinic and firefighter duties provided at Suncor Energy Oil Sands, Fort McMurray and In-situ, Firebag.
- Active daily involvement with WCB Policies & Procedures (referrals, diagnosis, initial/re-visit medical – occupational & non-occupational classification, short & long term disability involvement.
- Perform a wide variety of duties relating to fire, medical, security, hazmat and environmental monitoring, oil response preparedness and training according to standard practices and procedures.
- Provide leadership and training to personnel while ensuring the effective choice and application of appropriate fire and medical response tactics and techniques at the scene.

City of Calgary Fire Department *02/2006 – 11/2006*

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Firefighter

- Emergency Response, fire ground operations, pump operations, primary searches, ventilation, interior attack, salvage/overhaul, pre-hospital care, vehicle extrication, fire prevention/inspections, training/drills, public relations, aircraft rescue, hazardous materials, high angle, urban search and rescue and administrative duties.

City of Calgary Emergency Medical Services *03/1999 – 02/2006*
Advanced Care Paramedic

- Provide treatment and transport to emergent medical requests, inter-facility transfers and facility based medical support with the Calgary Zone and the Province of Alberta. Provided Alberta Residents with the highest quality Advanced Cardiac Life Support (ACLS) services in accordance with legislation. A patient advocate who effectively communicated and interacted with other allies health care professionals and public safety partners.
- Incident analysis training/conducting (Calgary EMS – Medical Examiner's Office fatality classification.

Crowsnest Pass Emergency Medical Services – Industrial *01/2004 – 11/2006*
Advanced Care Paramedic

- Provide advanced care paramedical services in the industrial setting.
- Experience in a variety of settings that were in the oil & gas sector: Remote drilling sites, Production (Oil Sands Mining & InSitu), H2S, Natural Gas and Well site services in Northern Alberta and BC. Some clients include: EnCana, CNRL and Husky Oil.

Grande Prairie Regional Emergency Medical Services *03/1998 – 03/1999*
Flight Paramedic

- Provided advanced care flight paramedic duties for STARS (formerly Northern Life Flight).

EDUCATION

- Bachelor of Applied Business: Specializing in Emergency Management, with Distinction *2011*
- Canadian Registered Safety Professional & Certified Emergency Manager (currently completing). *2014*
- Texas – TEEX Advanced Industrial Firefighter. *2007*
- National Fire Protection Assoc. Standard 1001,1003,1006 Fire Fighter Level II *2006*
- Emergency Medical Technician – Paramedic, S.A.I.T., Calgary, AB. *1994-1998*
- Advanced High School Diploma, John G. Diefenbaker H.S., Calgary, AB. *1991*

SPECIALIZED KNOWLEDGE & SKILLS

~ Emergency Services Management
~ Risk Management
~ Ethics for Emergency Services
~ Interpersonal Communications
~ Organizational Behaviour
~ Team Leadership & Development
~ Financial Statement Analysis
~ Statistics for Administrators
~ Resource Management
~ Legal Issues in Emerg Services
~ Labour Relations/Contract Law
~ Future of Leadership

~ OH&S Programs Development
~ Emergency Services Administration
~ Public Relations/Media Skills
~ Crisis Communication
~ Human Resources Management Emergency Services
~ Accounting Principles
~ Capital Budgeting
~ Strategic Business Planning
~ Personal Performance Management
~ Critical Thinking
~ Critical Incident Stress Management
~ Reflective Thinking

~ Advanced Cardiac Life Support
~ Aircraft Rescue Fire Fighting
~ Calgary Fire Dept. HazMat Awareness

~ Pediatric Advanced Life Support
~ Advanced Basic Trauma Life Support
~ Calgary Fire Dept. HazMat Operations

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- ~ HazMat Paramedic Team (1st in Canada)
- ~ Incident Command System 100,200,300
- ~ Flight Paramedic, Aeromedical Evacuations
- ~ High Angle Rescue Tech
- ~ Emergency Operations Centre Management
- ~ Crew Chief, City of Calgary, Cochrane & Grande Prairie EMS

PROFESSIONAL & RECREATIONAL AFFILIATIONS

- ~ Canadian Society of Safety Engineers (CSSE)
- ~ Alberta College of Paramedics Association
- ~ Health Sciences Association of Alberta
- ~ Heart and Stroke Foundation of Canada
- ~ C.U.S.A. Calgary United Soccer Association
- ~ Lakeland College
- ~ International Association of Firefighters.
- ~ Emergency Cardiac Care Task Force, GPREMS
- ~ S.A.I.T. Alumni Association
- ~ N.C.A.A Calgary Junior Hockey League Alumni

AWARDS

City of Calgary – Employment Recognition Awards
Rutherford Scholarship - Awarded on the basis of consistent academic merit in High School.
Northwest Athletic Association Scholarship – Calgary Junior Hockey League (C.J.H.L.)
Calgary Old Time Hockey Players Association – Sweeney Schriner Memorial Scholarship

011865

APPENDIX B

small stream or river crossings not spanned by HDD[4]. If spilled oil is released to the flooded area, especially to flowing waters, oil could be distributed to adjacent terrestrial, wetland, and aquatic habitats that normally would not be exposed. These habitats and natural resources, as well as human uses of the habitats and resources, may be exposed to the spilled material.

Concern was expressed in comments on the draft EIS relative to potential spray zones associated with operational leaks from the proposed pipeline. Winds, especially high-velocity sustained winds, could spread material released under pressure from hole(s) in the top hemisphere of an exposed portion of the pipeline to create a "spray zone." To generate a spray zone a potential leak would need to occur on the upper hemisphere of the proposed pipeline. If corrosion related leaks occurred, they would typically occur on the lower hemisphere of the pipeline and would likely be associated with entrained water. The implementation of the Project-specific Special Conditions developed in consultation with PHMSA would make such leaks highly unlikely. Potential leaks on the upper hemisphere of the proposed pipeline would likely be associated with accidental equipment impact. However, the likelihood of such events is significantly reduced by the 4-foot minimum cover requirement in most areas and the implementation of public awareness and damage prevention programs. However, if such a release were to occur, ejected material could form a cloud of mist and fine particles, and could be carried downwind. The extent of distribution would depend on wind velocity, direction of the released spray (e.g., downward into the ground, horizontal, or skyward), and characteristics of the release (e.g., pressure in the pipeline, type of oil, size of hole). Under most scenarios, the pressure in the pipeline would drop quickly, the release would be highly visible, and immediate pipeline spill control and shutdown actions would be taken[5] by the CMP and SCADA as well as the onsite personnel. If a leak would occur on the upper hemisphere of the pipeline, Keystone has estimated that the maximum spray zone for an exposed portion of the pipeline would be in the range of 75 to 400 feet (i.e., the areal extent of the release to land would be limited to a few acres or less in the immediate area of the release point and downwind of the release point).

Major flooding or adverse weather conditions (e.g., high winds, tornados, blizzards, and extreme cold) could limit Keystone's ability to detect small releases and/or hinder the spill response contractors from implementing timely and effective oil spill containment and cleanup operations. Response actions appropriate for these conditions would be addressed in the ERP and the PSRP (see Section 2.4.2.2).

3.13.5.2 Keystone Response Time and Actions

For spills ranging in magnitude from very small to substantive, response time and actions by responders would most likely prevent the oil from reaching sensitive receptors or would contain and clean up the spills before significant environmental impacts occurred. Most spills in this category are likely to occur on construction sites or at operations and maintenance facilities, and would not be released to the environment outside of these Project-related areas.

For large spills, very large spills and potentially some substantive spills, especially those that reach aquatic habitats, the response time between initiation of the spill event[6] and arrival of the response contractors would influence the magnitude of impacts to the environmental resources and human uses. This would be particularly true if the oil reaches flowing waters in major rivers. Once the responders are

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[4] These type of events account for less than 4 percent of spills (see Table 3.13.1-3) and Keystone has a proactive, preventative plan to shut down the pipeline if severe weather or any other natural event poses a threat to the pipeline integrity.

[5] The SCADA system would shut down the pipeline within 12 minutes of detection of the release (Sections2.4.2.1 and 3.13.5.5).

[6] "Initiation of the event" means when the oil began to leak or spill to the environment, not when it is detected by either the SCADA or other means. There may be a substantive delay between initiation and detection, particularly for slow or pinhole leaks under snow or below ground.

at the spill scene, the efficiency, effectiveness, and environmental sensitivity of the response actions (e.g., containment and clean up of oil, and protection of resources and human uses from further oiling) would substantively influence the type and magnitude of additional environmental impacts.

In response to a DOS data request, Keystone presented its approach to spill response under two hypothetical spill scenarios defined by DOS. The two spill scenarios presented to Keystone and its response to these scenarios provide an opportunity to review the level of preparedness and foresight that would be in place relative to potential spills from the proposed Project.

The first hypothetical spill occurs in the summer in an area with deep groundwater, relatively flat terrain, at least 2 miles from any navigable stream, no wetlands within 1 mile, and with no nearby private water wells or public water intakes. The second hypothetical spill occurs in the winter in an area of relatively shallow groundwater (25 feet bgs), sloping terrain, nearby wetlands, and a navigable stream within 1,000 feet, including private water wells within 100 feet of the release site and a public water intake 2 miles downstream.

For each of these scenarios, Keystone describes the following:

- Response procedures including pipeline shutdown, commencement of field response, spill assessment, and development of incident command post;
- The potential horizontal and vertical spread of crude oil into the environment;
- Response tactics employed for source control;
- Cleanup approaches for spills on land including containment methods and removal methods;
- Cleanup approaches for spills to groundwater including options for short- and long-term remediation;
- Cleanup approaches for spills on calm or slow moving water (lake or pond) and to flowing water (stream or river);
- Cleanup approaches for spills that occur on ice or under ice; and
- Cleanup approaches for spills in wetland areas.

DOS and PHMSA have reviewed these hypothetical spill response scenarios prepared by Keystone and would also review a final ERP to be prepared by Keystone prior to startup of the proposed pipeline (see Section 2.4.2.2 for additional information on the Keystone ERP). Based on its review of the hypothetical spill response scenarios, DOS considers Keystone's response planning appropriate and consistent with accepted industry practice.

3.13.5.3 Factors Affecting the Behavior and Fate of Spilled Oil

The primary and shorter-term processes that affect the fate of spilled oil are spreading, evaporation, dispersion, dissolution, and emulsification (Payne et al. 1987, Boehm 1987, Boehm et al. 1987, Overstreet and Galt 1995). These processes are called weathering. Weathering dominates during the first few days to weeks of a spill. A number of longer term processes also occur, including photo-degradation and biodegradation, auto-oxidation, and sedimentation. These longer-term processes are more important in the later stages of weathering and usually determine the ultimate fate of the spilled oil that is not recovered by the cleanup program.

CERTIFICATE OF SERVICE

I hereby certify that on the 26th day of June, 2015, I sent by United States first-class mail, postage prepaid, or e-mail transmission, a true and correct copy of the foregoing Rebuttal Testimony of Jeff Mackenzie, to the following:

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

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	HP 14-001
IN THE MATTER OF THE PETITION OF TRANSCANADA KEYSTONE PIPELINE, LP FOR ORDER ACCEPTING CERTIFICATION OF PERMIT ISSUED IN DOCKET HP09-001 TO CONSTRUCT THE KEYSTONE XL PROJECT	AMENDED REBUTTAL TESTIMONY OF HEIDI TILLQUIST

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Pursuant to the Commission's Order Granting Motion to Define Issues and Setting Procedural Schedule, Petitioner TransCanada Keystone Pipeline, LP, offers the following rebuttal testimony of Heidi Tillquist.

1. Please state your name and occupation.

Answer: Heidi Tillquist, Director of Oil and Gas Risk Management, Stantec Consulting Services Inc., Fort Collins, CO.

2. Did you provide direct testimony in this proceeding?

Answer: Yes.

3. To whose direct testimony are you responding in your rebuttal testimony?

Answer: I am responding to the direct testimony of Arden Davis, Ph.D., P.E.

4. Dr. Davis' testimony (p.1) states that "the proposed Keystone XL pipeline would cross the recharge areas of several shallow aquifers in the western part of the State,

including the Ogallala aquifer and Sand Hills type material, especially in Tripp County." Will the pipeline adversely affect these areas?

Answer: Adverse impacts to these areas are highly unlikely. The Keystone XL pipeline crosses a number of formations in western South Dakota that outcrop in hills, stream cuts, and along mesas. Many of these formations are covered by shallow soil. In Tripp County, the pipeline crosses the Tertiary Ogallala Formation of the High Plains Aquifer system. South of the town of Buffalo, in Harding County, the pipeline crosses a section of wind-blown sand mapped as Qe (Quaternary eolian). As discussed in the State Department's January 2014 Final Supplemental Environmental Impact Statement (FSEIS) for the Keystone XL pipeline project, *"typical recharge rates to the Ogallala Formation and associated alluvial aquifers range from 0.5 to 5 inches per year along the proposed route, with the highest recharge rates in the areas of the aquifer associated with the Sand Hills Unit"* (US Department of State [DOS] 2014). The 50-foot permanent right-of-way for the Keystone XL pipeline will occupy less than 0.1% of the total recharge area associated with the Fox Hills, Hell Creek, and Ogallala formations, as well as areas of wind-blown deposits (Qe), within counties crossed by the pipeline.

5. Dr. Davis' testimony (p. 2) states "the proposed pipeline also would have major stream crossings at water courses…These drainages have associated alluvial aquifers." Will the pipeline adversely affect these areas?

Answer: Adverse impacts to these areas are highly unlikely. The Keystone XL pipeline will cross major drainages with alluvial aquifers in South Dakota. Spills at individual river crossings are rare with occurrence intervals of no more than once in 22,000 years to 830,000 years based on representative stream crossing distances (Appendix P of the FSEIS; DOS 2014). Most spills are less than 3 barrels.

The Keystone XL pipeline is designed with a minimum depth of cover of 5 feet below the bottom of waterbodies and that depth is maintained over a distance of 15 feet on each side of the waterbody, measured from the ordinary high water mark. Depth of cover is an important factor to reduce the threat of outside force damage and stream scour.

The Project's depth of cover meets or exceeds the federal requirements noted in 49 CFR Section 195.248 of 48 inches for inland bodies of water with a width of at least 100 feet from high water mark to high water mark (for normal excavation, 18 inches for rock excavation) and PHMSA Special Condition 19 regarding depth of cover.

6. Dr. Davis' testimony (p. 2) states "in Harding County, the proposed route would cross permeable wind-blown deposits shown as Qe on Figure 4. These wind-blown deposits of silt and sand recharge from rainfall and snowmelt, they are capable of supplying water to shallow wells in the area." Will the pipeline adversely affect these areas?

Answer: Adverse impacts to these areas are highly unlikely. The wind-blown sand south of Buffalo in Harding County has been mapped by Erickson (1956) and Petsch (1956). The deposits are mostly sand overlying the Cretaceous Hell Creek Formation. Erickson (1956) interprets these deposits to be derived from the underlying Hell Creek Formation. Rainfall falling on these sand deposits would infiltrate and form a local, temporary water-bearing zone near the base of the deposits. Because the deposits are found on bluffs and the underlying Hell Creek has a much lower permeability, it is likely that water entering the sand may form temporary springs and seeps at the base of the sand deposits, rather than migrating downward into the Hell Creek Formation.

The Keystone XL pipeline crosses these sand deposits near their eastern edge, where the deposits are thin. Examination of well logs for wells within the 1-mile buffer zone around the

pipeline indicates that none of the wells are screened in the wind-blown sands. In the area of the pipeline ROW, the wind-blown deposits are thin and not likely to be water-bearing most of the year. Based on this, along the ROW in areas of wind-blown deposits, a potential release from the pipeline would most likely not encounter permanent groundwater.

References:

Erickson, H.D., 1956. GQ 62K-045. Areal geology of the Buffalo quadrangle, scale 1:62,500 (22 x 17 in. map).

Petsch, B.C., 1956. GQ 62K-052. Areal geology of the Mouth of Bull Creek quadrangle, scale 1:62,500 (22 x 17 in. map).

7. Dr. Davis' testimony (p. 3) states "South of the Cheyenne River in Haakon County, the proposed route would cross permeable Quaternary terrace gravels (Qt on Figure 6) and wind-blown deposits (Qe on Figure 6)...The terrace gravels and wind-blown deposits are permeable and are recharged by precipitation" and in places "are capable of supplying water to wells." Will the pipeline adversely affect these areas?

Answer: Adverse impacts to these areas are highly unlikely. The wind-blown deposits crossed in Haakon County south of the Cheyenne River are relatively thin and not likely to form a major aquifer. Wells within 1 mile of the pipeline ROW are not screened in wind-blown material. The Cheyenne River will be crossed employing the HDD method, whereby the pipe is installed at a depth of 50 feet below the river bottom, thereby eliminating the potential for key threats including excavation damage and outside force associated with potential stream scour.

8. Dr. Davis' testimony (p. 3) states "In Jones and Lyman counties, the proposed pipeline route would cross permeable wind-blown deposits (Qe on Figure 8) and also would

cross Quaternary terrace deposits north of the White River (Qt on Figure 8)." The terrace deposits have a shallow water table, are recharged by rainfall, and provide water to springs. Will the pipeline adversely affect these areas?

Answer: Adverse impacts to these areas are highly unlikely. The wind-blown deposits crossed in Jones and Lyman counties associated with the White River are relatively thin and not likely to form a major aquifer. Wells within 1 mile of the pipeline ROW are not screened in wind-blown material. The White River will be crossed employing the HDD method, whereby the pipe is installed at a depth of 70 feet below the river bottom, thereby eliminating the potential for key threats including excavation damage and outside force associated with potential stream scour.

9. Dr. Davis' testimony (p. 3) states "In Tripp County...the route would cross the Ogallala aquifer (To on Figure 9)" and "wind-blown Sand Hills type material (Qe on Figure 9)...The hydrologic situation is similar to the Sand Hills of Nebraska...and therefore deserves consideration for special protection as a high consequence area. As noted by Stansbury (2011), areas with shallow groundwater that are overlain by permeable soils...pose risks of special concern because leaks could go undetected for long periods of time." Please comment on this assertion.

Answer: "The High Plains Aquifer area in southern Tripp County" has been identified as a hydrologically sensitive area, as defined by the Public Utilities Commission's June 2010 Amended Final Order in Docket HP09-001. Keystone has elected to treat "hydrologically sensitive areas" as operator-defined HCAs based on a number of factors, including those identified by the Public Utilities Commission Amended Final Order Condition 35.

The Keystone XL pipeline in South Dakota was routed to reduce impacts to a number of valuable resources, including but not limited to, unconfined aquifers. Keystone has attempted to identify vulnerable aquifers through consultation with State agencies and rural water districts, as well as through the use of data provided by South Dakota Department of Environment and Natural Resources (SD DENR) (http://denr.sd.gov/data.aspx) and published literature. The location of unconfined aquifers is documented in the literature on the hydrogeology of South Dakota. The SD DENR website provides well logs for wells near the pipeline ROW. It is possible that, during construction and through discussion with landowners crossed by the Project, Keystone may identify shallow wells located in unconfined aquifers.

There are multiple leak detection processes that help identify small leaks, as stated in the Public Utilities Commission Amended Final Order Finding of Fact 94. While detection of a smaller leak may require additional confirmation time, examination of historical incident data confirms that small leaks do not remain undetected for long periods of time. PHMSA records (2001 through 2009) indicate that the majority of spills are 3 barrels or less, regardless of detection time. These data also indicate that the majority of spills are detected within 2 hours, with 99 percent of spills detected within 7 days. Of those spills not detected within the first 48 hours, the majority of spills were 15 barrels or less. These data do not support the contention that small leaks remain undetected for long periods of time.

10. Dr. Davis' testimony (p. 3) states that diluted bitumen is "more corrosive than conventional crude oil transported in existing pipelines." Do you agree with this statement?

Answer: No. A number of recent studies have investigated the claim that diluted bitumen is more corrosive to pipelines than conventional crude oil, but none found evidence of

corrosion that is unique to the transportation of diluted bitumen. Although some diluted bitumen contains higher concentrations of naphthenic acids than conventional crude oils, these compounds are only corrosive at temperatures above 200 degrees Celsius (392 degrees Fahrenheit). These temperatures do not occur in pipelines (Been 2011). The Keystone XL pipeline will not exceed temperatures of 150 degrees Fahrenheit per PHMSA Special Condition 15. Other compounds within diluted bitumen that are capable of causing corrosion, including water and sediments, occur at very low levels that are consistent with or lower than levels found in other crude oils (NAS 2013). Copies of these reports have been attached as Exhibits 2 and 3 of my testimony.

References:

Been, J. 2011. Comparison of the Corrosivity of Dilbit and Conventional Crude. Corrosion Engineering, Advanced Materials, Alberta Innovates Technology Futures. 29 pp. Internet website: http://www.ai-ees.ca/media/6860/1919_corrosivity_of_dilbit_vs_conventional_crude-nov28-11_rev1.pdf

National Academy of Sciences (NAS). 2013. Special Report 311: Effect of Diluted Bitumen on Crude Oil Transmission Pipelines. 110 pp.

11. Dr. Davis' testimony (p. 3) states benzene is "known to produce leukemia in humans." Please comment on this assertion.

Answer: While benzene is a known human carcinogen, cancer formation is associated with long-term chronic exposure, not the short-term exposure that could occur following an oil spill. For instance, a cohort study of 79 individuals exposed to benzene through their work in the Australian petroleum industry found an increased risk of leukemia following

cumulative exposures above 2 ppm-years (Glass et al. 2003). This is equivalent to being exposed to 1 ppm of benzene for 8-hours per day for two working years (500 days). Exposures such as these would not be expected to occur following a crude oil spill due to the low persistence of benzene and preventative actions such as localized evacuations. Further, emergency response personnel would evacuate the area if there were concerns for human health effects. A copy of this report has been attached as Exhibit 10 of my testimony.

Reference:

Glass, Deborah C.; Gray, Christopher N.; Jolley, Damien J.; Gibbons, Carl; Sim, Malcolm R.; Fritschi, Lin; Adams, Geoffrey G.; Bisby, John A.; Manuell, Richard. 2003. Leukemia Risk Associated with Low-Level Benzene Exposure. Epidemiology. 2003;14: 569-577.

12. Dr. Davis's testimony (p. 3 and 4) discusses concerns with benzene being "transported downgradient toward receptors, such as public water-supply wells, private wells, and springs or seeps" as well as pipeline releases that have occurred in the past that have threatened groundwater supplies. How will Keystone address these concerns?

Answer: With regard to surface water intakes, Keystone's Emergency Response Plan would identify downstream public water intakes and associated contact information. In the event of a release, Keystone would immediately notify downstream water users so that the intakes can be proactively shut down. With regard to groundwater, municipal and residential intake users would be notified through the implementation of Keystone's Emergency Response Plan. Potential impacts would take months to years to occur.

In terms of the potential effects from a release to groundwater, the following points demonstrate why a release would not threaten groundwater sources:

- The subsurface movement of petroleum hydrocarbons is very limited, moving 312 feet or less in 90 percent of the cases (Newell and Connor 1998, as presented in Exhibit 4 of my testimony). Additional studies support this plume transport distance, as presented in Exhibits 4 through 9 of my testimony.
- A plume of dissolved petroleum hydrocarbons could begin to develop if crude oil reached groundwater and was allowed to remain in contact with the groundwater for a period of months.
- The plume would then move in the direction of the groundwater; however, plume movement would be slower than for groundwater.
- The plume would form along the uppermost surface of groundwater; they do not sink within groundwater as observed with solvent plumes. As such, contamination of groundwater would be limited to the volume associated with the groundwater surface.
- Petroleum hydrocarbons are degraded by microbial communities naturally found within soils, and as a result, only highly localized effects would be expected.
- Removal of the source oil and remediation actions would help to minimize groundwater impacts further.

Based on the PHMSA pipeline incident database (2002 to 2009), only 3.8% and 3.2% of spills affected surface water or groundwater resources; however, only 0.16% of spills actually affect drinking water resources. Consequently, the possibility of a spill occurring and affecting drinking water is very remote.

Data from actual pipeline spills demonstrate that substantial leaks do not go undetected for long periods of time. Further, those spills that are not detected within the first 48 hours are typically relatively small. PHMSA records (2001 through 2009) indicate that the majority of

spills are 3 barrels or less, regardless of detection time. These data also indicate that the majority of spills are detected within 2 hours, with 99 percent of spills detected within 7 days. Of those spills not detected within the first 48 hours, the majority of spills were 15 barrels or less. In summary, large spills do not remain undetected for substantial periods of time.

Keystone will utilize an integrated leak detection system as stated in the Public Utilities Commission Amended Final Order Finding of Fact 94. Keystone also will have an Emergency Response Plan (ERP) in place to respond to incidents. The ERP contains comprehensive manuals, detailed training plans, equipment requirements, resource plans, and auditing, change management and continuous improvement processes. The Integrity Management Program (IMP) (49 CFR Section 195) and ERP will ensure Keystone will operate the pipeline in an environmentally responsible manner.

Reference:

Newell, C. J. and J. A. Connor. 1998. Characteristics of Dissolved Petroleum Hydrocarbon Plumes: Results from Four Studies. American Petroleum Institute Soil / Groundwater Technical Task Force. December 1998.

13. Dr. Davis' testimony (p. 5) restates Stansbury (2011) concerns regarding questionable assumptions and calculations by TransCanada of expected frequency of spills. Do you agree with that analysis?

Answer: No. The majority of pipeline infrastructure in North America was constructed many decades ago at a time when the materials, coating systems, and ongoing inspection capabilities that will be used for Keystone XL were not available. Studies show the benefits of these technologies in reducing pipeline incidents. Approximately two thirds of the pipelines in the US were constructed prior to 1970. It is therefore entirely appropriate to use an

incident frequency for Keystone XL that is derived from pipelines of its class. This is corroborated by observations included in the FSEIS, "*[i]t is reasonable to conclude that modern and larger-diameter pipelines would experience a lower spill rate than older pipelines. Modern pipelines have built-in measures to reduce the likelihood of a spill (e.g., modern protective coatings, SCADA monitoring)...with the application of the Special Conditions and various studies that indicate more modern pipelines are less likely to leak, it is reasonable to expect a sizable reduction in spills when compared to the historic spill record*" (DOS 2014).

14. Dr. Davis' testimony (p. 5) restates the Stansbury (2011) argument that "worst-case spill volumes from the proposed Keystone XL pipeline are likely to be significantly larger than those estimated by TransCanada." Do you agree with that analysis?

Answer: No. Stansbury's estimate of worst case discharge was based on incorrect assumptions. Keystone has calculated the worst case discharge for the Keystone XL pipeline in accordance with 49 CFR Section 194.105. The Stansbury document suggests that, because shutdown on another pipeline took longer, that increased time should be used as the shut down time assumption for the Keystone XL pipeline. The referenced Enbridge pipeline was constructed in 1969, while the Keystone XL pipeline would be constructed to meet or exceed current regulatory standards. Stansbury does not take into account that the Keystone XL pipeline is instrumented at every mainline valve, which enhances the leak detection system, and that Keystone has incorporated API's recommended practices for computational pipeline monitoring as well as ASME's Pipeline Personnel Qualification standards per Special Conditions 27 and 30. This makes it unlikely that Keystone operators would experience difficulty detecting a leak. Nor does he address industry information sharing or the workings of the regulatory regime, both of which serve to make it unlikely that alleged operational errors on one system are repeated on

another system. For example, TransCanada requires the pipeline be shut down if an operator cannot definitively determine the cause of an alarm within a 10-minute validation period.

In addition, Stansbury does not take into account the fact that worst case discharge is determined using a large leak that would be instantaneously detected by the leak detection system resulting in immediate initiation of shutdown procedures. Nonetheless, in determining its worst case discharge, Keystone conservatively assumed a 10-minute leak confirmation period, plus 9 minutes for pump shut down, plus a 3-minute valve closure time, for a total of 22 minutes. While detection of a smaller leak may require additional confirmation time, the small volumes released would not approach worst case discharge amounts. As discussed in my response to Question 26, it is incorrect to assume that there could be a small leak that remained undetected for an extended period of time, as suggested by the Stansbury document. A copy of this report has been attached as Exhibit 11 of my testimony.

15. Dr. Davis' testimony (p. 5) states concerns regarding transport distance (e.g., up to 120 miles downstream) of petroleum contaminants if a release were to occur at a major water course. What is your response to these concerns?

Answer: Dr. Davis' testimony does not account for containment and cleanup efforts by the operator that limit downstream movement. As discussed in my response to Question 29, most spills do not affect water resources. Exceptional spills that occur during flood conditions represent the worst case for downstream transport, but these do not support a 120-mile downstream transport distance. For example, following a 10,000 barrel release in 2007 from the Coffeeville Refinery in Kansas into the Verdigris River, the USEPA found no detectable concentrations of petroleum products 20 miles downstream at the closest municipal water intake. USEPA samples reported concentration of petroleum hydrocarbons to be below threshold limits

at the first sampling point, located 12 downstream miles of the spill. In 2010, an Enbridge 30-inch pipeline ruptured, spilling 19,500 barrels of oil into the Kalamazoo River system. While the majority of contamination occurred in close proximity to the source, USEPA reported that contamination had been documented in localized areas within 30 miles of the spill's origin. The material downstream was sedimented oil, which lost most of its BTEX compounds through weathering and consisted primarily of asphaltenes and other heavy molecular weight petroleum hydrocarbons. As a group, these compounds tend to have low environmental toxicity, adhere to sediments, have low bioavailability, and do not biomagnify in food chains. The BTEX values at these locations did not exceed EPA human heath exposure thresholds. Sedimented oil was removed by dredging due to their environmental persistence.

As part of its Integrity Management Program and consistent with Federal pipeline safety regulations (49 CFR Section 195), Keystone has evaluated the downstream transport of a spill to identify those pipeline segments with the potential to affect High Consequence Areas.

16. Dr. Davis testifies that diluted bitumen that sinks in water is significantly more difficult to clean up. Can you comment on that statement?

A. TransCanada considers the potential for sinking and submerged oil as part of our Emergency Response plans and in the execution of such plans. In the unlikely event of a spill, TransCanada would work hand-in-hand with regulatory bodies to determine the correct response and remedial actions given to the specific variables of the event. While sinking crude oils do pose a greater challenge for containment and clean up compared to floating oil, the industry has emergency response containment and clean up procedures that have substantially improved, in part because of the lessons learned from the Kalamazoo spill.

Such emergency response tactics may include, but not limited to the following:

- Mechanical methods such as suction, dredging, and air bubbling.
- Non-Mechanical methods could include chemical treatment / dispersants, bio-mediation and in-situ burning.

Petroleum hydrocarbon plumes do not sink within groundwater as observed with chlorinated solvent plumes (e.g., trichloroethylene [TCE], perchloroethylene [PCE]); instead, they form along the uppermost layer of groundwater.

Therefore, contamination of groundwater would be limited to the uppermost volume associated with the groundwater surface. Petroleum hydrocarbons are naturally degraded by microbial communities naturally found within soils. As a result, petroleum hydrocarbon plumes would be expected to result in highly localized effects. Removal of the source oil and remediation actions would help to further minimize groundwater impacts.

Dated this 25 day of July, 2015.

Heidi Tillquist

CERTIFICATE OF SERVICE

I hereby certify that on the 27th day of July, 2015, I sent by United States first-class mail, postage prepaid, or e-mail transmission, a true and correct copy of the foregoing Amended Rebuttal Testimony of Heidi Tillquist, to the following:

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Exhibit 1 : Bear. J. 2011 (Corrosivity of Pitbit)

Exhibit 2 : National Academy of Science (NAS). 2013. (Special Report 311)

Exhibit 3 : Glass et al. 2003. (Leukemia Risk)

Exhibit 4 : Newell and Connor. 1998. (Groundwater plumes)

Exhibit 5 : Kamath et al. 2012

Exhibit 6 : Connor et al. 2015

Exhibit 7 : Ruiz-Aguilar et al. 2003

Exhibit 8 : Shih et al. 2004

Exhibit 9 : Kothari, Bajnak, Tillquist _ USDOS

Designed by

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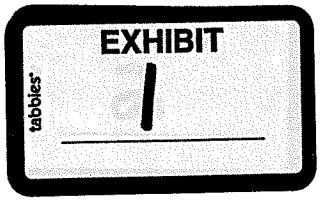

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EXECUTIVE SUMMARY

Pipeline expansions for the transportation of Canadian crude to refining markets in the United States are currently under regulatory review. The transported oil originates primarily from the Alberta oil sands and consists of diluted bitumen, also referred to as dilbit. Alberta Innovates – Technology Futures completed a project for Alberta Innovates – Energy and Environment Solutions reviewing the current status on the corrosivity of dilbit in pipelines as compared to conventional or 'non-oil sands derived' crude oil.

It has been suggested that dilbit has higher acid, sulfur, and chloride salts concentrations, as well as higher concentrations of more abrasive solids. It is furthermore suggested that dilbit transmission pipelines operate at higher operating temperatures compared with conventional crude, which would make the dilbit more corrosive, thus leading to a higher failure rate than observed for pipelines transporting conventional crude. This review examines these concerns in light of the properties of dilbit in comparison with conventional oils. In addition, statistical data are presented to show if the concerns are supported by operating experience.

Conventional crude and dilbit are subject to quality control measures and regulation. Pipeline operators employ further measures during transportation to manage and control the quality of delivered crude. Alberta crude quality information is available online and accessible to the public. The properties of heavy, medium, and light conventional Alberta crude oils were compared with three dilbit and one dilsynbit crude.

Whereas two of the four dilbit crudes displayed a slightly higher naphthenic acid and sulfur concentration than the conventional Alberta heavy crudes, there are conventional crudes on the market that have displayed higher values yet. The chloride salt concentrations were either comparable or lower than all grades of conventional crude. Naphthenic acid, sulfur, and chloride salt concentrations can result in corrosion at temperatures greater than 200 C at refineries, where mitigation is addressed through upgrading of materials and the use of inhibitors. At the much lower pipeline transportation temperatures, the compounds are too stable to be corrosive and some may even decrease the corrosion rate.

The sediment levels of the dilbit crudes were comparable to or lower than the conventional crudes, except for a dilsynbit crude, which showed more than double the quantity of solids than most other crudes, but was still well below the limit set by regulatory agencies and industry. The solids size distribution is unknown as is the role of larger size solids in the formation of pipeline deposits. Erosion corrosion was found to be improbable and erosion, if present, is expected to be gradual and observed by regular mitigation practices.

The dilbit viscosities are comparable to those of heavy conventional crudes, where the viscosity is controlled and adjusted for temperature through the addition of diluent. The

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resulting dilbit viscosity supports acceptable operating temperatures, which will be monitored at and downstream of the pumping stations.

Adjustment of the Alberta and U.S. pipeline failure statistics to compare similar crude oil pipeline systems on an equivalent basis indicated that the Alberta systems (with a large percentage of dilbit lines) experienced comparable internal corrosion failure rates than the U.S. systems (predominantly conventional crude lines).

Pipeline steel wet by oil does not corrode. The basic sediment and water (BS&W) content of crude oil transmission pipelines is limited to 0.5 volume percent. This water is primarily present as a stable emulsion, maintaining an oil wet pipe, protected from corrosion. Pitting corrosion has been observed underneath sludge deposits. These deposits are a mix of sand and clay particles, water, and oil products. The corrosivity of these sludges varies but seems to be linked to water content, which can exceed 10%, and large bacterial populations. The sludge deposition mechanism and the contributions of each of its components to its corrosivity are not clear. Sludge deposition and similar underdeposit corrosion is not unique to dilbit lines and also has been observed in pipelines transporting conventional crudes.

This review has indicated that the characteristics of dilbit are not unique and are comparable to conventional crude oils. Additional work is recommended in areas of sludge formation, deposition, and underdeposit corrosion. It is further recommended to expand the current crude oil property database to include downstream qualities, as well as information on H_2S concentration, asphaltene and water content, and viscosity. Finally, it is recommended that better statistics be made publicly available with separate information on dilbit and conventional crude oil pipelines as well as for upstream gathering lines and transmission pipelines.

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1.0 INTRODUCTION

TransCanada Pipeline's (TCPL's) $13 billion Keystone pipeline system will provide a secure and growing supply of Canadian crude oil to the largest refining markets in the Unites States. The second Phase of this project has been completed in February 2011, enabling the transport of 591,000 barrels of oil per day from Hardesty, Alberta to Cushing, Oklahoma, and Patoka, Illinois. Phases III and IV will increase the pipeline's capacity to 1.3 million barrels of oil per day to major refineries in the Houston area. These latter two phases are under regulatory review. The transported oil primarily originates from the oil sands. Crude or bitumen obtained from the oil sands is too viscous to transport by pipeline and needs to be diluted with diluent, hence the name 'dilbit.' In the context of this report, conventional oil refers to 'non-oil sands derived' crude oil.

The same month that TCPL completed Phase II of the Keystone pipeline system, a report was issued by a group of environmental action groups on Tar Sands Pipeline Safety Risks [1]. The report contains many damaging statements to the use of dilbit, most notably that "diluted bitumen is more corrosive than conventional or crude products and is more likely to result in pipeline failures," and that "Alberta pipelines have had a higher failure rate than similar U.S. pipelines due to leaks caused by internal corrosion from transportation of diluted bitumen (dilbit)." The ERCB responded within hours of the release of the report and twice on the same day with news releases responding to 'falsehood' of the report's statements [2].

Environmental groups opposed to the pipelines continue to find material to fuel their concerns: the more than 800,000 gallons of oil spilled into the Kalamazoo River in Michigan last year came from the Cold Lake oil sands region, and the Exxon Mobil spill of 42,000 barrels of oil in the Yellowstone River may have contained dilbit. Protestors against the Keystone pipeline are gathering in demonstrations across North America leading to mass arrests and drawing widespread attention.

The arguments of these environmental groups don't go unheard with congressmen and other government officials, who have iterated reported statements and concerns [3]. The United States Department of States (DOS) has spent the last three years in review with the industry, scientific community, and other interest parties (including numerous public meetings), evaluating the purpose and need for the Project (pipeline), alternatives, and the associated potential environmental impacts. The result was issued on August 26, 2011 in a Final Environmental Impact Statement (FEIS), a comprehensive, detailed volume of work that is available to the public [4]. Public hearings were held and online comments were accepted.

The US Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) administers the national regulatory program to ensure the safe transportation of hazardous materials by pipeline. In February 2011, PHMSA issued 57 Project-specific Special Conditions above and beyond the requirements of the pipeline code for the Keystone pipeline [Appendix U, 4]. In a news release on August 26, TCPL stated that they are pleased with the FEIS, which reaffirmed the environmental integrity of the project and concluded that oil sands derived crude oil does not have unique characteristics that would suggest the potential of higher corrosion rates during pipeline transportation. The company noted that incorporation of the 57 Special Conditions would result in a pipeline with a greater degree of safety than typical domestic pipelines.

Despite the review completed by the US DOS, there still exists confusion with regard to the corrosivity of dilbit versus that of conventional oil. The 57 Special Conditions are not sufficient according to the environmental groups opposed to the pipelines. Alberta Energy Minister Ron Liepert considers it a challenge of combating emotion with facts, and assures that the facts could be obtained without too much difficulty [5]. Concerns continue to surface in the media [6] and in the face of few factual studies and a strong confidence in the ERCB tracking statistics that dilbit is not more corrosive than conventional oil, corrosivity claims continue to be used as fuel by certain environmental groups. The current work will review the current status of information and concerns regarding the corrosivity of dilbit in pipeline transportation as compared to conventional crude oil. The focus of this work will be on transmission or transportation pipelines that transport oil over large distances to delivery points such as refineries and are subject to tariff quality specifications that include a limitation on the total amount of allowable sediment and water of 0.5 percent by volume. The Keystone pipeline is such a pipeline.

2.0 OBJECTIVES

To provide a confidential report including:

- Summary of the current concerns
- Status review on the corrosivity of dilbit in pipeline transportation as compared to conventional oil and
- Description and analysis of the current scientific information, assessing the validity of the concerns, identifying significant gaps, and recommending follow-up studies.

3.0 CURRENT CONCERNS

The Natural Resources Defense Council [1] has done an excellent job in summarizing the concerns presented by interest groups regarding the corrosivity of dilbit as compared to conventional crude oil and many of the same concerns have been expressed in other conversations and publications. The following is a summary of claims with regard to dilbit corrosivity [1] and include a few corrosion concerns from comments to the FEIS [4].

It has been suggested that dilbit may be more corrosive to pipeline systems than conventional crude and the following claims have been made:

Claim #1: Dilbit contains fifteen to twenty times higher corrosive acid concentrations than conventional crude oil [1].

Claim #2: Dilbit contains five to ten times as much sulfur as conventional crudes; the additional sulfur can lead to the weakening or embrittlement of pipelines [1].

Claim #3: Dilbit has a high concentration of chloride salts, which can lead to chloride stress corrosion cracking in high temperature pipelines [1].

Claim #4: Oil sands crude contains higher quantities of abrasive quartz sand particles than conventional crude, which can erode the pipelines [1].

Claim #5: It has been suggested that dilbit could be up to seventy times more viscous than conventional crude oil. It has been claimed that the increase in viscosity creates higher temperatures as a result of friction [1].

Claim #6: The Alberta pipeline system has had approximately sixteen times as many spills due to internal corrosion than the U.S. system, indicating that the dilbit is much more corrosive than the conventional oil that is primarily flowing through U.S. lines [1].

Claim #7: An increased risk of internal corrosion may be related to the sediment composition of dilbits and specific sediment characteristics, including particle hardness and size distribution [4].

Claim #8: A combination of chemical corrosion and physical abrasion can dramatically increase the rate of pipeline deterioration [1].

Claim #9: As a result of the high viscosity of dilbit, pipelines operate at temperatures up to 158 F, whereas conventional crude pipelines generally run at ambient temperatures. The high temperature would significantly increase the corrosion rate which doubles with every 20 degree Fahrenheit increase in temperature [1].

Claim #10: Dilbit pipelines may be subject to a higher incidence of external stress corrosion cracking [4].

These claims will be examined in light of the properties of dilbit in comparison with conventional oils. In addition, statistical data are presented to show if the concerns are supported by operating experience.

4.0 QUALITY CONTROL OF DILBIT PROPERTIES

Any discussion on the different risks and hazards of the transportation of dilbit versus that of conventional crude should start with a consideration of the differences in properties of the oils that enter the transmission pipeline system and how these properties are controlled and managed by the industry using regulatory and industrial quality assurance guidelines.

The Canadian Association of Petroleum Producers (CAPP) has established a crude oil committee to work with regulated segments of the industry such as transportation, storage, and market access. Crude oil quality subcommittees address specific crude quality issues and issues inherent in refining and shipping these crudes. Priorities that are addressed on an ongoing basis include [14]:

- management of oil quality issues to ensure maximum value amid growing crude oil types and blends, specifically,
    - condensate quality specifications and quality recommendations
    - new crude approvals process
    - quality test method improvements

One significant effort pertains to the definition of quality specifications of the condensate stream managed by Enbridge, also referred to as CRW [7]. This condensate stream consists of field condensates, ultra-light sweet crudes, and refinery and upgrader naptha streams from several supply sources. Historically, this condensate commodity was sold to downstream refiners. Currently, its main use is as diluent for Canadian heavy crude. Dilbit uses typically ~25% of condensate, where companies use their own supply sources of light hydrocarbons or

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purchase CRW. Establishment of a CRW criteria document provides a guideline for new streams that are proposed to be blended with the CRW stream and ensures that the CRW pool characteristics remain acceptable for the use as diluent. Quality specifications include minimum and/or maximum levels, a referee test method and test frequency, as well as comments on enforcement measures to be taken [8].

Crude Quality Inc. (CQI) is a private company in Edmonton with a mandate "to produce, provide, and manage crude quality information that increases the productivity of our customers and the petroleum industry" [9]. CQI's crude quality measurement and management system is supported by Canadian producer associations, Alberta/Canadian and US government departments, including the Energy Resources Conservation Board (ERCB), and Canadian and US technical organizations. CQI maintains a website with available data for most western Canadian crude oils, including conventional crudes as well as dilbit and other nonconventional grades and blends [10]. The site was established to enhance communication of data on the quality and quality issues of western Canadian crudes. Figure 1 summarizes some of the data in a series of graphs (see also Table 1). These are the properties of the crude oils entering the transmission pipeline system to be delivered to the refineries, after the addition of diluent in case of the dilbits. Enbridge has additional crude oil characteristics on their website [11]. Petroleum quality specifications of crude permitted in the pipeline system is further defined in National Energy Board (NEB) and Federal Energy Regulatory Commission (FERC) regulatory documents outlined in pipeline Tariffs (e.g. [12], [13], and [14]).

The above illustrates that conventional crude or dilbit is not transported indiscriminately without quality control measures and regulation. Work is ongoing continuously to improve overall quality control and product quality, primarily considering the effects on refining of the product.

The majority of pipelines are used for batches of different categories of crude. The pipeline operators are responsible for managing and controlling the quality of delivered crude and a number of measures are applied, including [15, 16]:

1. The use of turbulent flow, which minimizes the mixing area between batches. In laminar flow, the flow velocity near the pipe wall is much smaller than the velocity in the center of the pipe, which results in a relatively large mixing zone when one crude is followed by a different crude. The flow velocity is more even throughout the pipe cross-section in the case of turbulent flow, decreasing the subsequent mixing zone between different crudes.
2. The establishment of a crude ranking order, which serves as a guideline when changing crudes (e.g. a Medium Crude may be followed by a Medium Sour Crude, but not by a Heavy Crude).
3. The use of buffers at the front and the back of the batch to prevent mixing with the preceding batch or the following batch when the crude contains components that are undesirable by the refineries. In some instances, interface pigs can be used, but some contamination can occur at the pump and pig trap locations.
4. Maximization of batch size will minimize contamination from the mixing zones.
5. Minimization of start/stop operations.
6. Minimization of contamination in tanks from receipt to delivery

Although the operator will make an effort to deliver the same type of crude as received, the operator is not obligated to deliver the identical crude [12, 13, 14]. Changes in density, specification, quality and characteristics as a result of the transportation in the pipeline system are acknowledged. Unfortunately, crude quality information of the received oil product is not currently readily available. CQI is currently working with industry partners on the development of a downstream quality database for direct comparison with the upstream qualities with the goal to provide financial incentives for consistency and rateability [9]. The transparency offered by the information of crude oil quality databases on both the shipped and delivered product will be of tremendous assistance in communications between industry and the public.

Table 1 Crude Designation Used in Figure 1

Crude	Type of Crude and Designation Used in Figure 1
Bow River North	Heavy Sour A
Bow River South	Heavy Sour B
Lloyd Blend	Heavy Sour C
Fosterton	Heavy Sour D
Lloyd Kerrobert	Heavy Sour E
Midale	Medium Sour A
Mixed Sour Blend	Medium Sour B
Sour High Edmonton	Medium Sour C
Sour Light Edmonton	Light Sour A
Light Sour Blend	Light Sour B
Mixed Sweet Blend Crude	Light Sweet A
Access Western Blend	Dilbit A
Cold Lake	Dilbit B
Seal Heavy	Dilbit C
Albian Heavy Synthetic Crude	Dilsynbit A

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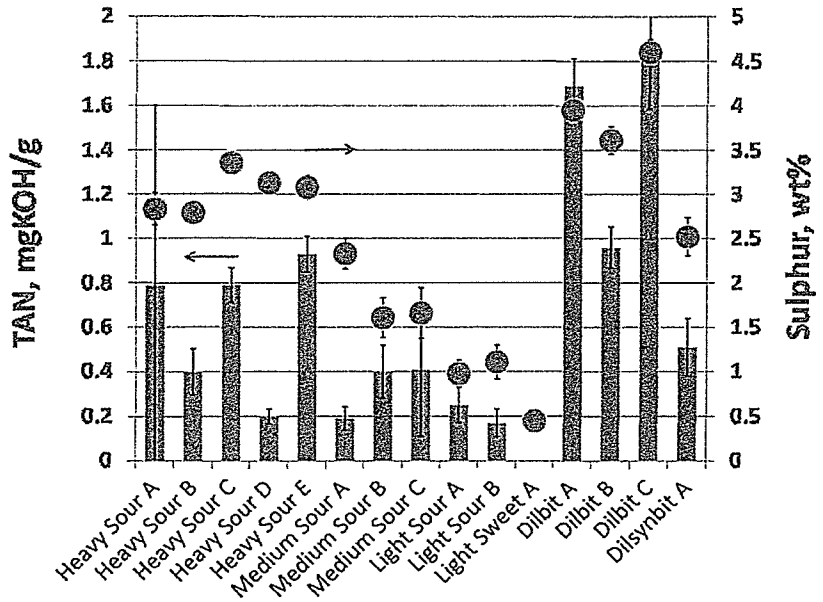

Figure 1a Properties of various conventional crudes and dilbits in Western Alberta illustrating acidity and sulphur contents. The data were obtained from Crude Quality Inc.'s website crudemonitor.ca [10]. Error bars represent the standard deviation over five years of data.

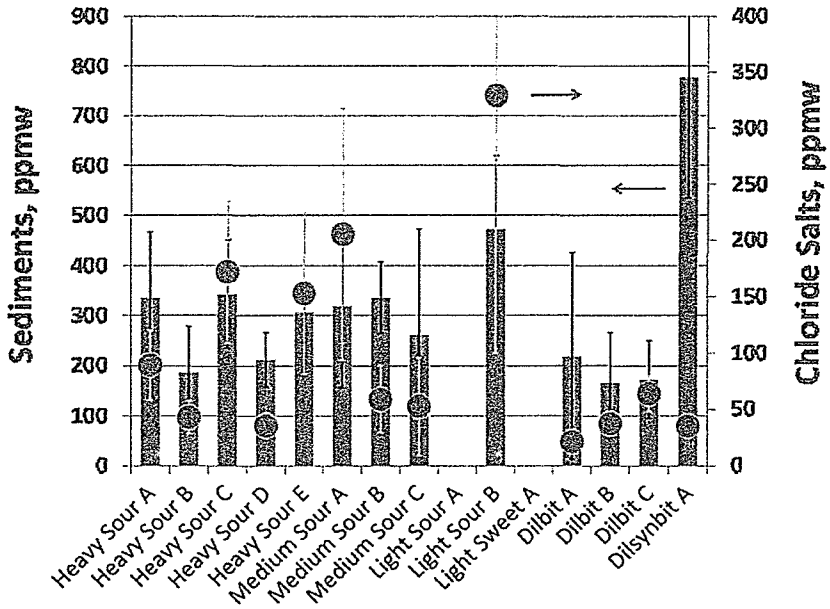

Figure 1b Properties of various conventional crudes and dilbits in Western Alberta illustrating the content of sediments and chloride salts. The data were obtained from Crude Quality Inc.'s website crudemonitor.ca [10]. Error bars represent the standard deviation over five years of data.

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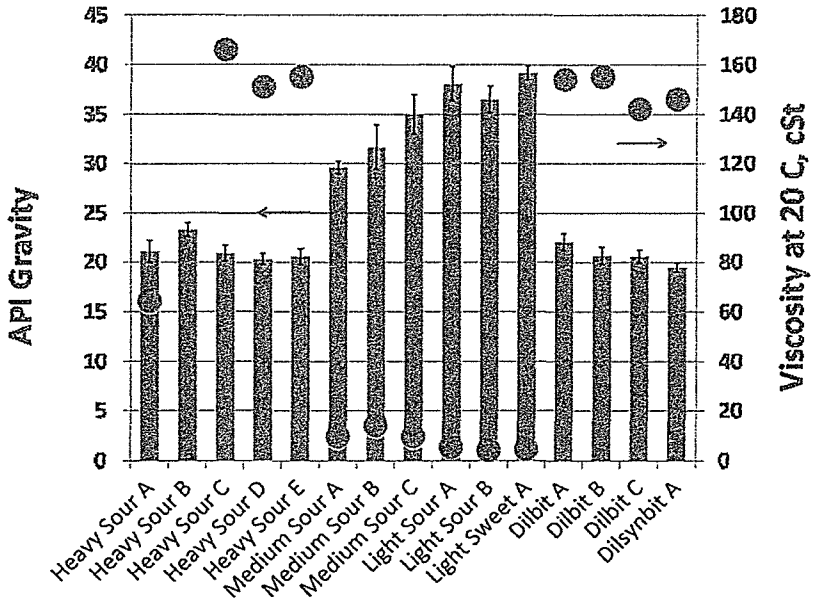

Figure 1c Properties of various conventional crudes and dilbits in Western Alberta illustrating the degree of API gravity and viscosity (after ref [11]). The API gravity data were obtained from Crude Quality Inc.'s website crudemonitor.ca [10]. Error bars represent the standard deviation over five years of data. One representative set of viscosity data is plotted.

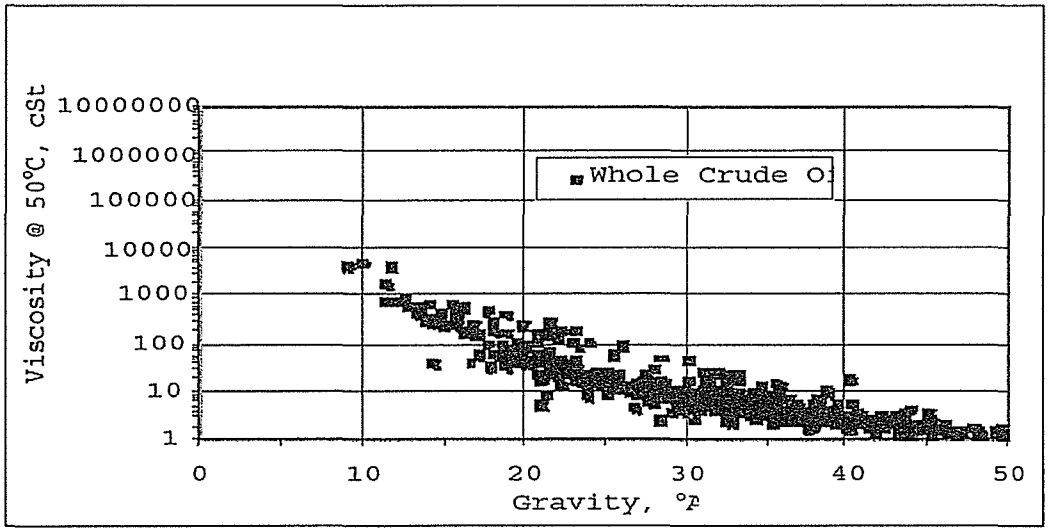

Figure 1d The gravity-viscosity relationship of conventional crude oils (after ref [17]).

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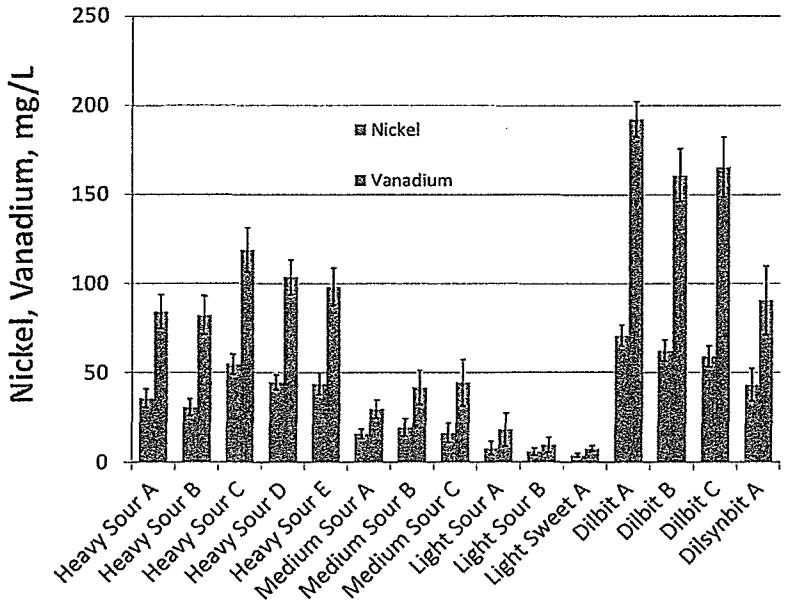

Figure 1e Properties of various conventional crudes and dilbits in Western Alberta illustrating heavy metal concentrations. The data for were obtained from Crude Quality Inc.'s website crudemonitor.ca [10]. Error bars represent the standard deviation over five years of data.

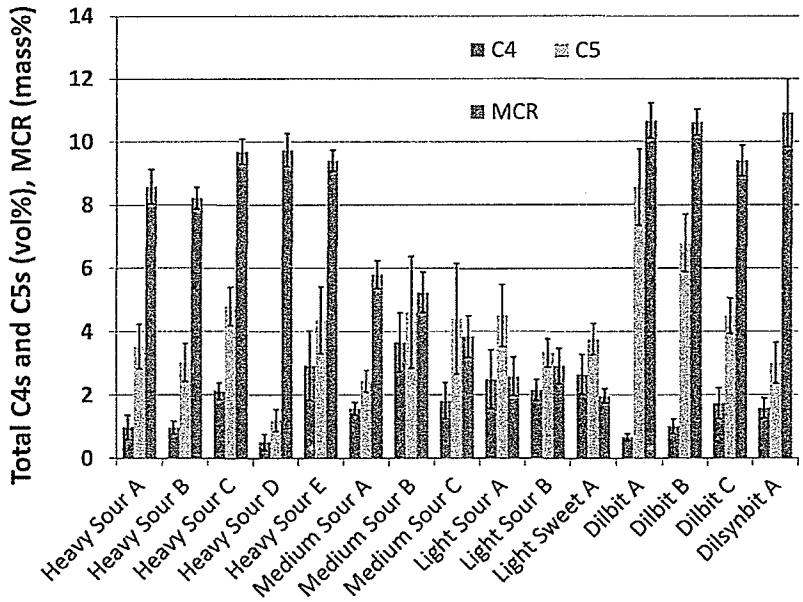

Figure 1f Properties of various conventional crudes and dilbits in Western Alberta illustrating fractions of light carbons and Micro Carbon Residue (MCR). The data were obtained from Crude Quality Inc.'s website crudemonitor.ca [10]. Error bars represent the standard deviation over five years of data.

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5.0 DILBIT AND CONVENTIONAL CRUDE OIL PROPERTIES

With quality control measures in place, the properties of crudes entering the pipeline will be within defined boundaries. Yet, differences can be observed across the different crudes as well as within each crude category. Figure 1 displays data obtained from the Crude Monitor [10], where the plotted data are averages over periods of approximately five years. Error bars indicate the standard deviation. Data is presented for five different conventional heavy sour crudes, three conventional medium sour crudes, two conventional light sour crudes, one conventional light sweet crude, three dilbit crudes and one dilsynbit crude. Whereas dilbit can also refer to heavy conventional crudes that have been diluted with diluent or diluted crudes obtained by other means e.g. enhanced oil recovery, the dilbits in Figure 1 refer to oil sands crudes, where dilbit A is obtained from steam assisted gravity drainage (SAGD) processes and dilbits B and C from cyclic steam stimulation (CSS). Oil sands crude obtained from mining operations were either upgraded or blended with other crudes. For this reason, dilsynbit A has been added, which originates from mining operations, but is partially upgraded.

5.1 Naphthenic acids

Claim #1: Dilbit contains fifteen to twenty times higher corrosive acid concentrations than conventional crude oil [1].

Under refinery conditions and temperatures, naphthenic acids compounds can be corrosive. Naphthenic acids are a group of organic acids measured in terms of a total acid number (TAN), which is obtained by titration of the oil with KOH. TAN numbers have, therefore the units of mg KOH/g. Crude oils with TAN values greater than 0.5 are generally considered corrosive. However, recent work has indicated that not all naphthenic acids are equally corrosive and the acid groups attached to large hydrocarbon molecules found in heavy crudes and dilbits are more stable and less corrosive [19, 20, 21, 22]. Consequently, the TAN number is not necessarily reflective of the corrosivity of crude at elevated temperatures.

Figure 1a indicates a higher TAN for dilbits A and C, whereas dilbit B and dilsynbit A are comparable to the conventional heavy sour crudes. Research is continuing into the effects of these parameters at refineries, where upgrading of materials and the use of inhibitors can be used to mitigate any increase in corrosivity [19]. However, the acids are too stable to be corrosive under transmission pipeline temperatures. On the contrary, long chain organic acids have been found to decrease the corrosion rate at room temperature [23]. Furthermore, a number of Californian crudes have TAN numbers up to 3.2, and these crudes have been produced and transported by pipeline throughout California for many years [24].

5.2 Sulphur content

Claim #2: Dilbit contains five to ten times as much sulfur as conventional crudes; the additional sulfur can lead to the weakening or embrittlement of pipelines [1].

Under refinery conditions and temperatures, organic sulphur compounds can be corrosive. A wide variety of sulphur compounds are present in crude oil, which, when heated, will be released as corrosive hydrogen sulphide. The release of hydrogen sulphide again depends on

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the stability of the organic sulphur compound, and high temperatures between 220 and 400 C are required. With a wide variety of sulphur compounds and stabilities, the sulphur content of crude is also not a good measure of the corrosivity of crude at refinery conditions [22].

Similar to the TAN numbers, Figure 1a indicates a higher sulphur concentration for dilbits A and C, whereas dilbit B and dilsynbit A are comparable to the conventional heavy sour crudes. Under transmission pipeline temperatures, organic sulphur compounds are too stable to be corrosive. At room temperature, sulphur containing compounds were found to have no effect or resulted in a decrease in the corrosion rate [23].

The sulphur content does not correlate to the hydrogen sulfide content, which is not typically reported. As an example, two Mexican crudes with sulfur contents of 3.4% and 0.9% contained 100 ppm and 116 ppm of H_2S, respectively [4]. Small concentrations of H_2S may be present in sour as well as sweet crudes. Concentrations could vary from a few ppm to over a hundred ppm. The CRW diluent is limited to 20 ppm of H_2S [8]. Although the H_2S concentrations in dilbits are not available, there is no indication that these levels would be higher than in conventional crudes [4]. If available hydrogen sulfide could separate from the oil into an aqueous phase in the pipeline, the corrosivity of the water could increase. This would be valid for all oil systems and not specific to dilbit lines.

5.3 Chlorides

Claim #3: Dilbit has a high concentration of chloride salts, which can lead to chloride stress corrosion cracking in high temperature pipelines [1].

Figure 1b illustrates the levels of chloride salts for the crudes; light sour crude A and light sweet crude A did not have any data. The highest chloride salt concentration was observed for the conventional light sour B crude, with the dilbits displaying some of the lowest salt concentrations. Chloride salts can lead to the formation of strong hydrochloric acid in the presence of steam at upgrading and processing temperatures greater than 150 C, which can result in serious corrosion problems [26]. These conditions are not encountered in transmission pipelines. In fact, it has been shown that high salinity brines in contact with oils did not affect the corrosion rate [25]. Chloride stress corrosion cracking can be an issue in stainless steel equipment, but is not a mechanism encountered in carbon steel transmission pipelines [53].

5.4 Sediments

Claim #4: Oil sands crude contains higher quantities of abrasive quartz sand particles than conventional crude, which can erode the pipelines [1].

Figure 1b illustrates the levels of sediments for the crudes; light sour crude A and light sweet crude A did not have any data. The sediment content in Figure 1b is far below the limit of 0.5 volume percent (water + sediment) specified in the pipeline tariffs [12, 13, 14]. The sediment levels of the dilbit crudes were comparable to or lower than the conventional crudes, except for the dilsynbit crude with an oil sands mining origin, which showed more than double the quantity of solids than most other crudes. However, at ~800 ppmw (~0.027 volume percent), it is still well below the limit set by regulatory agencies and industry.

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5.5 API gravity and viscosity

Claim #5: It has been suggested that dilbit could be up to seventy times more viscous than conventional crude oil. It has been claimed that the increase in viscosity creates higher temperatures as a result of friction [1].

The API gravity is a measure of how 'heavy' the crude is; heavy crudes have low degrees of API gravity (10-25) and light crudes have high degrees of API gravity (30-40). The formula for API gravity is defined by:

$$\text{API gravity (in degrees)} = (141.5/SG) - 131.5 \qquad \text{Equation 1}$$

where SG = specific gravity at 15.6 C

Based on the density of water, any oil with an API value greater than 10 degrees at ~15.6 C is lighter than water. Figure 1c illustrates that the dilbit crudes have similar degrees of API and viscosities to the conventional heavy sour crudes. All of the crudes are well above the minimum of 19 degrees API gravity; only dilsynbit A has an average value below 20 at 19.5 degrees API gravity. Also, the viscosities are well below the limited receipt viscosity of 350 cSt specified by the crude petroleum tariffs [12, 13, 14]. The lower the viscosity, the easier the oil flows, where water has a viscosity of one cSt at 20 C. The viscosity is very sensitive to temperature and will increase at colder temperatures. To compensate for fluctuations in viscosity as a result of varying seasonal temperatures, the amount of diluent added to the crude will be adjusted to control the viscosity to the desired level. Figure 1d [17], shows how the API gravity is related to the viscosity at 50 C, representing gravities and viscosities of conventional heavy crudes. Based on the data from Figures 1c and 1d, the dilbit viscosities are not different from the conventional oil viscosities as a function of degrees API gravity.

Figure 1c shows that viscosities of the dilbit are comparable to those of conventional heavy crudes, but are significantly lower for the conventional medium and low sour crudes, which means that these crudes are easier to pump. Consequently, they require less pumping energy and/or the pumping capacity can be increased. The requirement for higher pumping energy to maintain a certain throughput of more viscous oil can translate into an increase in temperature at the pump station. Downstream of the pump station, the pipeline temperature decreases as a result of heat loss to the environment [18]. The maximum allowable temperature on the proposed Keystone line has been set at 70 C with a normal operating temperature of 49 C. Temperatures must be measured at the pump and at a downstream location to ensure compliance ([48], Appendix U). The dilbit crude quality and viscosity that are accepted for transportation support operating temperatures within an acceptable range.

5.6 Other properties for consideration

The following properties are important for downstream processing of the crude and further illustrate where differences can be expected between dilbit and conventional crude. These properties have not been linked to pipeline transmission corrosion.

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5.6.1 Heavy metals: nickel and vanadium

Crude oil analyses often include the nickel and vanadium content, since these metals have detrimental effects on catalysts used in refinery cracking and desulphurization processes. Figure 1e shows that the vanadium levels are markedly higher for the dilbit crudes as compared to the conventional crudes. The nickel levels are more comparable with the conventional heavy sour crude levels. These metals have not been linked to corrosive processes in oil transmission pipelines [25].

5.6.2 Total C4s and C5s

The C4s and C5s in Figure 1f represent the lighter fractions of the crude. The higher fractions of C5s in Dilbits A and B are likely largely originating from the added diluent.

5.6.3 Total MCR

The Micro Carbon Residue (MCR) content in Figure 1f is a measure of the crude oil tendency to form coke, where crudes with a high MCR are more expensive to refine. The MCR content increases with the content of large high carbon molecules and can, therefore, be considered a measure of the heavy fraction of the crude [17, 27]. The MCR content of the dilbits are only slightly higher than that of the conventional heavy sour crudes. The asphaltenes content was not reported in the Crude Monitor database [10].

The above illustrates that the dilbit properties as displayed in Figure 1 are not significantly different from the conventional heavy crude oils for pipeline transportation. However, internal pipeline corrosion has occurred in some dilbit lines whereas others have enjoyed a long trouble free existence [28]. Our understanding of some of the parameters and their interactions are discussed in the following sections.

6.0 INTERNAL PIPELINE CORROSION IN WATER-WET CONDITIONS

Steel wet by oil does not corrode. Consequently, for corrosion to occur, separation of a water phase from the oil is required. Unlike transmission pipelines, gathering oil pipelines can contain significant quantities of water when transporting oil from wells to nearby treatment facilities and internal corrosion is observed when the pipe is water-wet. The corrosion generally consists of localized pitting. The corrosivity of the water phase depends on the water chemistry, which is also dependent on the oil chemistry. Water soluble inhibitive or corrosive components may separate from the oil into the water phase, either inhibiting corrosion or increasing the water corrosivity [23, 25]. Work by Papavinasam et al. has considered pipeline characteristics, and operating conditions in the development of an internal pitting corrosion model using laboratory and field measurements [29, 30]. The model addresses water-wet conditions with no corrosion occurring in oil-wet conditions. Parameters that increased the pitting corrosion rate included flow turbulence, temperature, and chlorides. The pitting corrosion was decreased by protective scale formation (sulfide or carbonate scales) [31]. The model was validated using data obtained from seven operating pipelines [29]. A comprehensive review of other predictive models of internal pipeline corrosion is provided from a corrosion science perspective [32], electrochemical perspective [33], and using a corrosion engineering approach [34].

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7.0 INTERNAL CORROSION OF DILBIT TRANSMISSION PIPELINES

Claim #6: The Alberta pipeline system has had approximately sixteen times as many spills due to internal corrosion than the U.S. system, indicating that the dilbit is much more corrosive than the conventional oil that is primarily flowing through U.S. lines [1].

The ERCB responded to the above statement that the comparison is not valid since the ERCB statistics includes a much broader array of pipelines [2]. For example, the US Code of Federal Regulations does not include all gathering lines in their hazardous liquids classification [35], whereas a large percentage of all Alberta lines are upstream gathering lines. Gathering lines are generally more prone to failure since they contain more water and can contain corrosive carbon dioxide and hydrogen sulfide gases. Furthermore, the ERCB requires operators to report any pipeline incident that results in a loss of pipeline product, whereas the US data is based on incidents with a release of 5 gallons or more. In response to the above concern, PHMSA and the ERCB adjusted the statistics to comparable crude oil systems, where the oil sands derived crude oil consisted of a much larger percentage in Alberta than in the entire U.S. [4]. The criteria used to produce the Alberta statistics are quite open and based on pipe diameter, where, as a rule, larger diameter pipelines (12" dia. and up) transport oil over longer distances and are oil-wet [54]. Table 2 is reproduced from the FEIS, page 3.13-38 [4]. The data shows that the internal corrosion rates in Alberta and in the U.S. are comparable, which indicates that there is no evidence that dilbit would be more corrosive than conventional crudes.

The publicly available ERCB data do not separate the statistics for dilbit and conventional crude pipelines or for upstream gathering lines and long distance transmission pipelines. Whereas the ERCB licenses pipelines for the use of crude oil, they may not be aware of what type of crude is shipped through the lines, which is further complicated by the fact that lines can transport dilbit and conventional crude at different points in time. It is recommended that better statistics be provided as an improved presentation of the integrity of the Alberta pipeline system and to facilitate continuous monitoring of the performance of dilbit pipelines. The required information for these statistics may need to come from the operators and could be managed by the ERCB or other company organizations such as CAPP or the Canadian Energy Pipeline Association (CEPA). CEPA represents Canada's transmission pipeline companies; its members transport 97% of Canada's daily production of crude oil and natural gas.

The remainder of this chapter considers how a corrosive situation can occur in crude oil pipelines and considers the role of dilbit and conventional crude oil properties.

Table 2 Crude Oil Pipeline Failures U.S. and Alberta (2002-2010) [4]

Incident/Failure Case	Failures/Year	Failures per 1,000 Pipeline Miles per Year
U.S. Crude Oil Pipeline Incident History[a]		
Corrosion - External	9.8	0.19
Corrosion - Internal	22.1	0.42
All Failures	89.3	1.70
Alberta Crude Oil Pipeline Incident History[b]		
Corrosion - External	2.3	0.21
Corrosion - Internal	3.6	0.32
All Failures	22.0	1.97

[a]PHMSA includes spill incidents greater than 5 gallons. U.S. has 52,475 miles of crude oil pipelines in 2008.
[b]Alberta Energy and Utility Board Report. Alberta has 11,187 miles of crude oil pipelines in 2006.

7.1 Presence of Water

The internal corrosion models referred to in the previous chapter have been developed for a wide range of operating pipelines varying from upstream to transmission, for both oil and gas lines, as well as multi-phase pipelines with high cuts of water. The current review is aimed primarily at transmission pipelines, which will have a limitation on the basic sediment and water (BS&W) content entering the pipe of 0.5 volume percent [12,13,14]. The presence of a small quantity of water is inevitable, since complete removal of emulsified water is not possible with the current techniques such as desalting and naphtha-froth treatment. A survey performed in 1997 of Western Canadian oil producers indicated an average BS&W of 0.35%, with solids up to 60% of the BS&W [36]. At that time, some American pipeline companies shipped crude containing as much as 3% water, but did not experience a great increase in the corrosion rate. A typical BS&W of the CRW diluent is as low as 0.003 vol% [8]. The critical water content that will lead to water-wet conditions during transportation can vary widely depending on chemistry and operating conditions, but is generally much greater than 10 percent [30]. Consequently, less than 0.5% of water is usually not a corrosion concern unless conditions exist that enable the precipitation and accumulation of this water on the pipe wall. The following paragraphs discuss some of the crude oil components that could promote the accumulation of water and the formation of a corrosive environment. The discussion does not consider entry of water through batch upsets or water remaining in the system after hydrostatic testing. These are operational issues and not unique to the transported crude.

7.2 Asphaltenes

Asphaltenes are found in heavy crude oil and consist of positively charged complex large multi-ring hydrocarbon systems. They are in effect a solubility class, i.e. a fraction of the crude oil that is not soluble in paraffinic solvents, which are chained non-polar hydrocarbons [37, 38]. They are known to aggregate in solutions in a micro-emulsion, where an asphaltene core is surrounded by resins (with fewer hydro-carbon rings), which are surrounded by

smaller hydro-carbon ring molecules, which in turn are dissolved in the non-polar solvent. This micro-emulsion structure allows the asphaltenes to dissolve in the crude oil [39]. When this micro-emulsion structure is disrupted through, for example, the addition of a paraffinic solvent that removes the protective resin layer, the asphaltenes will become insoluble and precipitate out.

Depending on the characteristics of the diluent, its addition to bitumen could result in the formation of unstable asphaltene micro-emulsions that could deposit during pipeline transportation [37, 40]. The asphaltene content of typical oil sand bitumens is 15-17 wt% and is partly responsible for the high viscosity. Complete removal of the asphaltenes does not reduce the viscosity to the required 350 cSt, but partial removal of the asphaltenes reduces the diluent requirement significantly. The additional benefit is that asphaltene precipitation is much less likely to occur [37].

The quality specifications of the CRW pool are primarily directed towards the downstream properties of the crude for refinery purposes, which affects the economic value of the crude. The Crude Monitor database contains 5-year averages of the CRW hydrocarbon composition, which indicates that ~80% consists of paraffinic solvents of eight carbons or less [10]. The remaining 20%, however, may contain the required properties to provide suitable compatibility with the mixed heavy crude oil. The Canadian Crude Quality Technical Association (CCQTA) is considering the compatibility of blending crude oils and diluent [52] in an effort to ensure that the product can be processed and refined. Calculator tools are provided on the Crude Monitor website [10]. Whereas asphaltene deposition can occur in response to incompatible blends in pipelines, the role of asphaltenes in pipeline sludge formation is unclear.

7.3 Emulsified water droplets

The solubility of water in oil is very small and of the order of 50 – 100 ppm [41]. The remainder of the water is primarily present as an emulsion, where the pipeline surface remains protected from corrosion by the continuous oil phase. These water droplets are very small and typically less than 10 microns in diameter [42, 43]. They carry chlorides and solids and can result in corrosion when the emulsion breaks up on the pipe wall, wetting the carbon steel surface. The stability of water-in-oil emulsions is a function of the oil chemistry, the water chemistry, and operating conditions.

One of the major players in stabilizing water in oil emulsions is asphaltene, forming an interfacial layer together with smaller surface active molecules and submicron mineral solids that is several tens of nanometers thick [44]. Ultrafine submicron clay particles are thought to be just as important in the stabilization of the water droplets, behaving similar to the asphaltenes [45, 46]. The formed skin is strong enough to resist coalescence of the droplets when they touch each other. These small micro-emulsions are too light to settle out in turbulent flow of crude oil and are expected to travel harmlessly through the pipeline. However, if bitumen is mixed with paraffinic solvents resulting in the precipitation of asphaltenes, these polar asphaltene flocs could bind to water droplets and clay particles forming much larger 100 to 1000 micron clusters that could settle out during transportation [43].

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7.4 Pipeline sediment and sludge formation

Claim #7: An increased risk of internal corrosion may be related to the sediment composition of dilbits and specific sediment characteristics, including particle hardness and size distribution [4].

Figure 1b did not indicate a much higher content of sediments for the dilbit crudes compared to the conventional crudes, except for dilsynbit A. The data, however, only indicates the total amount of sediments and does not provide information on the size distribution. It is unknown how the solids in the conventional crudes compare to those in dilbits.

Analyses of pipeline deposits obtained from pigging operations have indicated the presence of larger solids to over 400 microns [47]. Most of the solids, however, were fine particles less than 44 microns in diameter (see Figure 2a), where the larger and fine particles consist primarily of silica sand and iron compounds. The larger sand particles were uniformly coated with very fine clays surrounded by a film of water in oil (see Figure 2b) [47]. Under low flow conditions, these particles are heavy enough to precipitate out with the water, oil products, and possibly asphaltenes, forming a sludge deposit. Sludge deposits are mixtures of hydrocarbons, sand, clays, corrosion by-products, biomass, salts, and water.

One might expect deposition of sludge to occur at the lowest spots. However, Enbridge observed underdeposit corrosion in their dilbit lines near over-bends, which are locations of low fluid shear stress (low fluid flow pressure) [47]. Little is known about the sludge deposition mechanism and it is not known if sludge formation would occur in the presence of only fines.

7.5 Underdeposit corrosion

The water layer on deposited sand particles in a pipeline sludge can subsequently join to form a water layer on the pipeline steel [47]. The water will contain chloride salts as well as bacteria, which now form a corrosive mix. The sludge chemistry can vary widely, where some sludges have a large percentage of waxy oil and exhibit low or no corrosion. Other sludges can contain more than 10% water and large bacterial populations, which can contribute to underdeposit pitting corrosion [48]. Figure 3 shows extensive pitting of a sludge covered test coupon, whereas a bare coupon showed no corrosion after both were exposed to dilbit for a month. No significant corrosion has been measured in a wide variety of different dilbit crudes in the absence of sludge, where the measured corrosion rate generally was within the standard deviation of the measurement technique.

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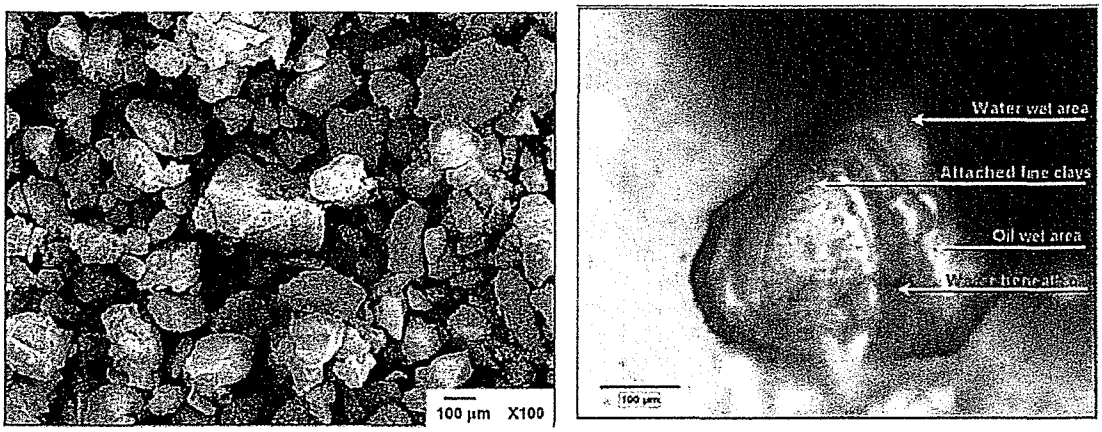

Figure 2 Micrograph of (a) washed sludge solids and (b) a large solid (from [47])

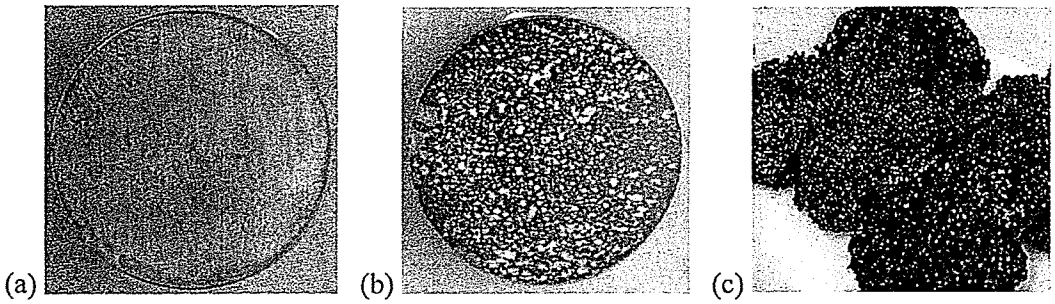

Figure 3 Corrosion coupons exposed to dilbit for 4 weeks, where (a) was left bare and (b) was covered with (c) sludge

The pipeline sludges used for analysis and testing are obtained from pigging runs and are considered averages over the length of the pipe and the time between pigging runs. The actual sludge chemistry may vary within a stratified sludge deposit or between different locations or with time as a function of transported crude. Questions remain regarding the controlling corrosion parameters and little is known with regard to the sludge deposition mechanism and the role of the dilbit chemistry. Whereas underdeposit corrosion has been observed on transmission pipelines transporting dilbit, there are also dilbit pipelines that have operated trouble-free for 25 years [28].

Underdeposit corrosion, however, is not unique to dilbit lines. Earlier this year, BP shut down their Trans-Alaska pipeline, which transports oil from their Prudhoe field. Previous leaks in 2006 resulted in the shutdown of 57 oil wells in Alaska [49]. Corrosion was attributed to the deposition of sludge, the presence of carbon dioxide, and, what was considered to be the biggest threat, the presence of bacterial populations resulting in microbiologically influenced corrosion (MIC) [50]. It is not known what the solid content or solid size distribution was in this line, but the conditions obviously favoured sludge deposition.

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7.6 Erosion and Erosion Corrosion

Claim #8: A combination of chemical corrosion and physical abrasion can dramatically increase the rate of pipeline deterioration [1].

Erosion by sediment particles would occur by impact. Since corrosion can only occur in the presence of a water phase, which most likely requires sludge formation in dilbit pipelines, a combination of erosion and corrosion is improbable. No information could be found on dilbit pipeline erosion in the scientific literature or from field experience. Erosion in a uniform smooth pipeline generally displays itself as even wear as opposed to the localized pitting corrosion observed underneath sludge deposits. If present, effects are generally more gradual and should not be a concern due to the fact that regular mitigation strategies such as intelligent pigging and monitoring technologies will catch this wall loss.

8.0 TEMPERATURE EFFECTS

8.1 The effect of temperature on the internal corrosion rate

Claim #9: As a result of the high viscosity of dilbit, pipelines operate at temperatures up to 158 F, whereas conventional crude pipelines generally run at ambient temperatures. The high temperature would significantly increase the corrosion rate which doubles with every 20 degree Fahrenheit increase in temperature [1].

An increase in the temperature can increase the rate of corrosion if the corrosion mechanism is controlled by kinetics or diffusion. There are, however, many other factors that affect the rate of corrosion such as scale formation, limiting concentration of reactants, or chemical reactions. Especially in a complex aqueous environment, possibly with dissolved organics, acid gases, oxygen, sub-micron clay particles, etc., the corrosion rate can either increase or decrease as a function of temperature. The concentration of oxygen or carbon dioxide is generally not known and, if present, may change along the length of the pipeline. The most likely internal corrosion mechanism in dilbit pipelines consists of underdeposit corrosion as a result of sludge formation. As discussed in the preceding section, microbiologically induced corrosion could play a dominant role in the corrosion process. Complex populations containing multiple types of bacteria are known to be present and support each other's viability such as sulfate reducing bacteria (SRB), heterotrophic aerobic bacteria (HAB), and acid producing bacteria (APB) [48]. These bacteria are most active between 10 C and 40 C. Consequently, higher temperatures up to 70 C may reduce the corrosion rate underneath sludge deposits, if the mechanism is controlled by microbial action.

Little is known about the controlling factors of corrosion underneath sludge deposits and it is recommended that research continue to improve our understanding of sludge formation, the resulting corrosion mechanism, the role of dilbit chemistry and solids, mitigation practices and frequencies, and preventive measures. Enbridge has been quite successful in mitigating underdeposit corrosion through a pigging and inhibition program. However, there are still many uncertainties regarding the effectiveness of each and the required frequency [47].

8.2 The effect of temperature on external stress corrosion cracking

Claim #10: Dilbit pipelines may be subject to a higher incidence of external stress corrosion cracking [4].

In the field, the pipeline is protected by coatings and cathodic protection. Increased temperatures may result in coating disbondment, which would expose the bare pipe to the soil environment, which can be corrosive containing water, dissolved oxygen and carbon dioxide. Together with fluctuating pipeline operating stresses, this has resulted in stress corrosion cracking (or fatigue cracking) of pipelines covered with tape or asphalt coatings. These coatings can behave as shielding coatings, preventing the secondary protection of applied cathodic current. The Keystone pipeline is coated with Fusion Bonded Epoxy (FBE), which is considered permeable to the cathodic protection current. Temperatures up to 60 C have indicated a higher rate and extent of coating disbondment, but it has also been shown that, in the presence of cathodic protection, the pipe will remain protected, and blistering and coating disbondment does not present an integrity threat to a pipeline [51]. No stress corrosion cracking failures have been reported for FBE coatings in over 40 years of experience.

9.0 SUMMARY

Pipeline expansions for the transportation of Canadian crude to refining markets in the United States are currently under regulatory review. The transported oil originates primarily from the Alberta oil sands and consists of diluted bitumen, also referred to as dilbit. Alberta Innovates – Technology Futures completed a project for Alberta Innovates – Energy and Environment Solutions reviewing the current status on the corrosivity of dilbit in pipelines as compared to conventional or 'non-oil sands derived' crude oil.

It has been suggested that dilbit has higher acid, sulfur, and chloride salts concentrations, as well as higher concentrations of more abrasive solids. It is furthermore suggested that dilbit transmission pipelines operate at higher operating temperatures compared with conventional crude, which would make the dilbit more corrosive, thus leading to a higher failure rate than observed for pipelines transporting conventional crude. This review examines these concerns in light of the properties of dilbit in comparison with conventional oils. In addition, statistical data are presented to show if the concerns are supported by operating experience.

Conventional crude and dilbit are subject to quality control measures and regulation. Pipeline operators employ further measures during transportation to manage and control the quality of delivered crude. Alberta crude quality information is available online and accessible to the public. The properties of heavy, medium, and light conventional Alberta crude oils were compared with three dilbit and one dilsynbit crude.

Whereas two of the four dilbit crudes displayed a slightly higher naphthenic acid and sulfur concentration than the conventional Alberta heavy crudes, there are conventional crudes on the market that have displayed higher values yet. The chloride salt concentrations were either comparable or lower than all grades of conventional crude. Naphthenic acid, sulfur, and chloride salt concentrations can result in corrosion at temperatures greater than 200 C at refineries, where mitigation is addressed through upgrading of materials and the use of

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inhibitors. At the much lower pipeline transportation temperatures, the compounds are too stable to be corrosive and some may even decrease the corrosion rate.

The sediment levels of the dilbit crudes were comparable to or lower than the conventional crudes, except for a dilsynbit crude, which showed more than double the quantity of solids than most other crudes, but was still well below the limit set by regulatory agencies and industry. The solids size distribution is unknown as is the role of larger size solids in the formation of pipeline deposits. Erosion corrosion was found to be improbable and erosion, if present, is expected to be gradual and observed by regular mitigation practices.

The dilbit viscosities are comparable to those of heavy conventional crudes, where the viscosity is controlled and adjusted for temperature through the addition of diluent. The resulting dilbit viscosity supports acceptable operating temperatures, which will be monitored at and downstream of the pumping stations.

Adjustment of the Alberta and U.S. pipeline failure statistics to compare similar crude oil pipeline systems on an equivalent basis indicated that the Alberta systems (with a large percentage of dilbit lines) experienced comparable internal corrosion failure rates than the U.S. systems (predominantly conventional crude lines).

Pipeline steel wet by oil does not corrode. The basic sediment and water (BS&W) content of crude oil transmission pipelines is limited to 0.5 volume percent. This water is primarily present as a stable emulsion, maintaining an oil wet pipe, protected from corrosion. Pitting corrosion has been observed underneath sludge deposits. These deposits are a mix of sand and clay particles, water, and oil products. The corrosivity of these sludges varies but seems to be linked to water content, which can exceed 10%, and large bacterial populations. The sludge deposition mechanism and the contributions of each of its components to its corrosivity are not clear. Sludge deposition and similar underdeposit corrosion is not unique to dilbit lines and also has been observed in pipelines transporting conventional crudes.

This review has indicated that the characteristics of dilbit are not unique and are comparable to conventional crude oils.

10.0 RECOMMENDATIONS

The following recommendations are provided based on the completed review. It has to be understood that this was a high-level review and a focused, peer-reviewed study has not been conducted. The scope of the work did not include interviews with industry, regulators, or colleagues.

1. CQI is currently working with industry partners on the development of a downstream quality database for direct comparison with the upstream qualities with the goal to provide financial incentives for consistency and rateability. The data provided on upstream qualities has been instrumental in the evaluation of differences between dilbit oils and conventional crude oils. The transparency offered by the information of crude oil quality databases on both the shipped and delivered product will be of tremendous assistance in communications between industry and the public. It will

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also be a valuable resource for the evaluation of sludge deposition and underdeposit corrosion during transportation. It is recommended that this effort be supported.

2. To further increase the value of the above database, it is recommended that the following information be added:
   a. H_2S concentration
   b. Asphaltene content
   c. Water content
   d. Viscosity (currently available from [11])
   e. Sediments' identity and size distribution, if possible

3. The compatibility between diluent and bitumen should be investigated further with regard to sludge formation and deposition, and the role of asphaltenes. It is recommended that current efforts by CCQTA on crude oil compatibility be supported and expanded to link the crude oil chemistry to pipeline sludge formation and sludge corrosivity, including the ability of the sludge to support microbial populations.

4. The underdeposit corrosion mechanism should be studied further with regard to the effect of dilbit chemistry, sludge deposition mechanism, microbial activity, temperature, and effectiveness of mitigation tools (chemicals and cleaning pigs). Current work by Enbridge as well as by the industry working group PiCoM (Pipeline Corrosion Management) is addressing these issues through long-term testing and correlating sludge corrosivity with a chemical and microbial geochemical characterization of the sludge. The work is further considering and optimizing monitoring technologies to enable measurement of the effectiveness of mitigation treatments. It is recommended that this effort will continue to be supported.

5. The publicly available ERCB data does not separate the statistics for dilbit and conventional crude pipelines or for upstream gathering lines and transmission pipelines. It is recommended that better statistics be provided as an improved presentation of the integrity of the Alberta pipeline system and to facilitate continuous monitoring of the performance of dilbit pipelines. The required information for these statistics may need to come from the operators and could be managed by the ERCB or other company organizations such as CAPP or the Canadian Energy Pipeline Association (CEPA).

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Preface

This National Research Council (NRC) study was sponsored by the Pipeline and Hazardous Materials Safety Administration (PHMSA) of the U.S. Department of Transportation.[1] The study charge and origins are explained in Chapter 1. The contents and findings of the report represent the consensus effort of a committee of technical experts, who served uncompensated in the public interest. Drawn from multiple disciplines, the members brought expertise from chemistry and chemical engineering; corrosion and materials science; risk analysis; and pipeline operations, research, and safety regulation. Committee member biographical information is provided at the end of the report.

The study committee convened five times over 10 months, including a visit by several members to a pipeline terminal and energy research laboratory in the Edmonton and Fort McMurray areas of Alberta, Canada. Data-gathering activities during and between meetings were extensive. All but the final meeting contained sessions open to the public. During meetings, the committee heard from speakers from the oil and pipeline industries, environmental interest groups, research and standards organizations, oil testing companies, and government agencies from the United States and Canada. The committee also provided a forum for private individuals to contribute information relevant to the study. In sum, more than 40 people spoke before the committee during public meetings and site visits. To obtain additional information on the practice of transporting diluted bitumen by pipeline, the committee provided the Canadian Energy Pipeline Association with a questionnaire for distribution to pipeline operators with experience transporting diluted bitumen and other crude oils in North America. The questionnaire responses and agendas for the public meetings are provided in appendices to this report.

ACKNOWLEDGMENTS

The committee thanks the many individuals who contributed to its work.

During data-gathering sessions open to the public, the committee met with the following officials from PHMSA: Jeffrey Wiese, Associate Administrator; Linda Daugherty, Deputy Associate Administrator for Policy and Programs; Alan Mayberry, Deputy Associate Administrator for Field Operations; Blaine Keener, National Field Coordinator; and Jeffery Gilliam, Senior Engineer and Project Manager. The contributions of all were appreciated, especially those of Mr. Gilliam, who served as PHMSA's technical representative for the project.

Several officials and researchers from government agencies and laboratories in Canada briefed the committee during meetings: Iain Colquhoun, National Energy Board; John Zhou, Alberta Innovates Energy and Environment Solutions; Haralampos Tsaprailis and Michael Mosher, Alberta Innovates Technology Futures; and Parviz Rahimi, Heather Dettman, and Sankara Papavinasam, Natural Resources Canada. The committee thanks them all, especially Dr. Papavinasam, who twice briefed the committee, and Dr. Tsaprailis, who arranged a tour of the Alberta Innovates and Natural Resources Canada energy laboratory in Devon, Alberta.

[1] The contract was awarded on March 12, 2012.

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Early in its deliberations, the committee invited several nationally recognized experts to provide briefings on pipeline design, operations, and maintenance; corrosion evaluation and control; and developments in the North American petroleum market. The committee is indebted to Thomas O. Miesner, Pipeline Knowledge and Development; Arthur Diefenbach, Westpac Energy Group; Oliver Moghissi, DNV Columbus, Inc.; and Geoffrey Houlton, IHS. Their uncompensated briefings provided essential background for the committee's work.

The committee met with and received information from the following individuals representing the oil production and pipeline industries: Dale McIntyre, ConocoPhillips; Randy Segato, Suncor Energy, Inc.; Dennis Sutton, Marathon Petroleum Company; Bruce Dupuis, Jenny Been, and Bruce Wascherol, TransCanada Corporation; Colin Brown, Kinder Morgan Canada; Terri Funk and Shoaib Nasin, Inter Pipeline; and Trevor Place, Ashok Anand, Martin DiBlasi, and Scott Ironside, Enbridge Pipelines, Inc. The committee expresses its gratitude to all, especially to Mr. Ironside, who assisted in arranging presentations and the tour of a pipeline terminal in Alberta.

In seeking information on the properties of diluted bitumen and other crude oils, the committee received valuable information from the following individuals and organizations: Harry Giles, Crude Oil Quality Association; Bill Lywood, Crude Quality, Inc.; and Andre Lemieux, Canadian Crude Quality Technical Association. The information received on the chemical and physical properties of diluted bitumen and other crude oils was critical to many of the analyses in the study. The committee thanks each of them and their organizations for this assistance.

Finally, the committee thanks several individuals who briefed it or were otherwise helpful in identifying issues and providing relevant sources of data and other information. They are Anthony Swift, Natural Resources Defense Council; Peter Lidiak, American Petroleum Institute; Cheryl Trench, Allegro Energy Consulting; and Ziad Saad, Canadian Energy Pipeline Association. Mr. Saad was instrumental in distributing and collecting responses to the pipeline operator questionnaire.

Thomas R. Menzies and Douglas Friedman were the principal project staff. Menzies managed the study and drafted much of the report under the guidance of the committee and the supervision of Stephen R. Godwin, Director, Studies and Special Programs, Transportation Research Board (TRB). Additional technical assistance and oversight were provided by James Zucchetto, Director of the Board on Energy and Environmental Systems, and Dorothy Zolandz, Director of the Board on Chemical Sciences and Technology. Norman Solomon edited the report, and Jennifer J. Weeks prepared the edited manuscript for prepublication web posting, under the supervision of Javy Awan, Director of Publications, TRB. Claudia Sauls provided extensive support to the committee in arranging its meetings and managing documents.

The report has been reviewed in draft form by individuals chosen for their diverse perspectives and technical expertise in accordance with procedures approved by NRC's Report Review Committee. The purpose of this independent review is to provide candid and critical comments that will assist the institution in making the report as sound as possible and to ensure that the report meets institutional standards for objectivity, evidence, and responsiveness to the study charge. The review comments and draft manuscript remain confidential to protect the integrity of the deliberative process.

NRC thanks the following individuals for their review of this report: Khalid Aziz (NAE), Stanford University; John Beavers, DNV Columbus, Inc.; Jos Derksen, University of Alberta; Melvin F. Kanninen (NAE), MFK Consulting Services; John Kiefner, Kiefner & Associates,

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Inc.; Thomas Miesner, Pipeline Knowledge and Development; Gene Nemanich, Chevron Technology Ventures (retired); Stephen Pollock (NAE), University of Michigan; Massoud Tahamtani, Commonwealth of Virginia State Corporation Commission; and Patrick Vieth, Dynamic Risk USA, Inc. The review of this report was overseen by Elisabeth Drake (NAE), Massachusetts Institute of Technology, and Susan Hanson (NAS), Clark University. Appointed by NRC, they were responsible for making certain that an independent examination of this report was carried out in accordance with institutional procedures and that all review comments were carefully considered. Responsibility for the final content of the report rests solely with the authoring committee and the institution. Karen Febey managed the report review process under the supervision of Suzanne Schneider, Associate Executive Director, TRB.

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Executive Summary

Legislation enacted in January 2012 called on the Secretary of Transportation to determine whether any increase in the risk of a release exists for pipelines transporting diluted bitumen.[1] Bitumen is a dense and viscous form of petroleum that will flow in unheated pipelines only when it is diluted with lighter oils. The source of the diluted bitumen in North America is the oil sands region of Alberta, Canada. Diluted bitumen has been imported from Canada for more than 30 years and is currently transmitted through numerous pipelines in the United States. As imports of this and other Canadian crude oils have grown, new U.S. pipelines have been constructed, the flow directions of several existing pipelines have been reversed, and additional pipeline capacity is planned.

Determination of the risk of a pipeline release requires an assessment of both the likelihood and the consequences of a release. To inform its review of the former, the U.S. Department of Transportation asked the National Research Council to convene an expert committee to study whether shipments of diluted bitumen differ sufficiently from shipments of other crude oils in such a way as to increase the likelihood of releases from transmission pipelines. A finding of increased likelihood would lead the committee to conduct a follow-up review of the adequacy of federal pipeline safety regulations. In the absence of such a finding, the committee was tasked with issuing this final report, which documents the study approach and results.

STUDY APPROACH

The committee analyzed information in a variety of forms. Early in its deliberations, the committee provided a public forum for individuals to contribute information relevant to the study. The committee reviewed pipeline incident statistics and investigations; examined data on the chemical and physical properties of shipments of diluted bitumen and other crude oils; reviewed the technical literature; consulted experts in pipeline corrosion, cracking, and other causes of releases; and queried pipeline operators about their experience in transporting diluted bitumen.

The review of incident data revealed the ways in which transmission pipelines fail. Some failures can be affected by the properties of the transported crude oil, such as its water and sediment content, viscosity and density, and chemical composition. These properties were examined for diluted bitumen and a range of other crude oils to determine whether pipelines transporting diluted bitumen are more likely to experience releases. In addition, the committee considered whether pipeline operations and maintenance (O&M) practices, including internal and external corrosion control capabilities, are subject to changes that inadvertently increase the likelihood of release when pipelines transport diluted bitumen.

[1] Public Law 112-90, enacted January 3, 2012.

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RESULTS

Central Findings

The committee does not find any causes of pipeline failure unique to the transportation of diluted bitumen. Furthermore, the committee does not find evidence of chemical or physical properties of diluted bitumen that are outside the range of other crude oils or any other aspect of its transportation by transmission pipeline that would make diluted bitumen more likely than other crude oils to cause releases.

Specific Findings

Diluted bitumen does not have unique or extreme properties that make it more likely than other crude oils to cause internal damage to transmission pipelines from corrosion or erosion. Diluted bitumen has density and viscosity ranges that are comparable with those of other crude oils. It is moved through pipelines in a manner similar to other crude oils with respect to flow rate, pressure, and operating temperature. The amount and size of solid particles in diluted bitumen are within the range of other crude oils and do not create an increased propensity for deposition or erosion. Shipments of diluted bitumen do not contain higher concentrations of water, sediment, dissolved gases, or other agents that cause or exacerbate internal corrosion, including microbiologically influenced corrosion. The organic acids in diluted bitumen are not corrosive to steel at pipeline operating temperatures.

Diluted bitumen does not have properties that make it more likely than other crude oils to cause damage to transmission pipelines from external corrosion and cracking or from mechanical forces. The contents of a pipeline can contribute to external corrosion and cracking by causing or necessitating operations that raise the temperature of a pipeline, produce higher internal pressures, or bring about more fluctuation in pressure. There is no evidence that operating temperatures and pressures are higher or more likely to fluctuate when pipelines transport diluted bitumen than when they transport other crude oils of similar density and viscosity. Furthermore, the transportation of diluted bitumen does not differ from that of other crude oils in ways that can lead to conditions that cause mechanical damage to pipelines.

Pipeline O&M practices are the same for shipments of diluted bitumen as for shipments of other crude oils. O&M practices are designed to accommodate the range of crude oils in transportation. The study did not find evidence indicating that pipeline operators change or would be expected to change their O&M practices in transporting diluted bitumen.

In accordance with the study charge, these results focus on whether pipeline shipments of diluted bitumen have a likelihood of release greater than that of other crude oils. As indicated at the outset of this summary, the committee was not asked or constituted to study whether pipeline releases of diluted bitumen and other crude oils differ in consequences or to determine whether such a study is warranted. Accordingly, the report does not address these questions and should not be construed as having answered them.

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Introduction

This chapter describes the study charge and scope, analytic approach, and report structure.

STUDY CHARGE

Section 16 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 calls for the Secretary of Transportation to "complete a comprehensive review of hazardous liquid pipeline facility regulations to determine whether the regulations are sufficient to regulate pipeline facilities used for the transportation of diluted bitumen. In conducting the review, the Secretary shall conduct an analysis of whether any increase in the risk of a release exists for pipeline facilities transporting diluted bitumen."[1]

Bitumen is a dense and viscous form of petroleum that will flow through unheated pipelines only when it is diluted with lighter oils. At present, the source of bitumen supplied to refineries in North America is the oil sands region of Alberta, Canada. Bitumen from Canada has been diluted for pipeline transportation to the United States for more than 30 years, primarily to refineries located along the Great Lakes and elsewhere in the Midwest. Bitumen production and imports from Canada have grown during the past decade, and this traditional U.S. oil-processing market no longer has the capacity to refine all of the supply. Meanwhile, refineries on the Gulf Coast, which have traditionally processed South American and Mexican crude oils with properties similar to bitumen, have sought access to the heavy crude oils from Canada. To accommodate the Canadian imports as well as the growth in domestic crude oil production, the flow directions of several existing pipelines have been reversed, new transmission pipelines have been constructed, and additional pipeline capacity is planned.

Within the U.S. Department of Transportation (USDOT), the regulation of pipeline safety resides with the Pipeline and Hazardous Materials Safety Administration (PHMSA). USDOT has thus delegated to PHMSA the responsibility of determining whether pipelines transporting diluted bitumen have an increased risk of release. A determination of risk requires an assessment of both the likelihood and the consequences of a release. To inform its assessment of the former, PHMSA contracted with the National Research Council (NRC) to conduct the study documented in this report. Specifically, PHMSA asked NRC to convene a committee of experts in pipeline operations; risk analysis; safety regulation; and chemical, materials, and corrosion engineering to "analyze whether transportation of diluted bitumen by transmission pipeline has an increased likelihood of release compared with pipeline transportation of other crude oils." PHMSA did not ask NRC to study the consequences of potential pipeline releases of diluted bitumen.

The full statement of task (SOT) for the study is contained in Box 1-1. The SOT calls for a two-phase study, with the conduct of the second phase contingent on the outcome of the first. In the first phase, the study committee is asked to examine whether shipments of diluted bitumen can affect transmission pipelines and their operations so as to increase the likelihood of release

[1] Public Law 112-90, enacted January 3, 2012.

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Box 1-1

Statement of Task

The committee will analyze whether transportation of diluted bitumen (dilbit) by transmission pipeline has an increased likelihood of release compared with pipeline transportation of other crude oils. Should the committee conclude that an increased likelihood of release exists, it will review the federal hazardous liquid pipeline facility regulations to determine whether they are sufficient to mitigate the increased likelihood of release.

In the first phase of the project, the committee will examine whether dilbit can affect transmission pipelines and their operations so as to create an increased likelihood of release when compared with other crude oils transported through pipelines. Should the committee conclude there is no increased likelihood of release or find there is insufficient information to reach such a conclusion, a second phase of the project will not be required and the committee will prepare a final report to the Office of Pipeline Safety (OPS) of the Pipeline and Hazardous Materials Safety Administration (PHMSA). This report may include recommendations for improving information to assess the likelihood of failure.

Should the committee conclude there is an increased likelihood of release on the basis of dilbit's effects on transmission pipelines and their operations, it will issue a brief Phase 1 report of its findings and then proceed to the second phase of the project to determine whether hazardous liquids pipeline regulations are sufficient to mitigate the increased likelihood of release. The committee's final report following completion of this second phase will contain the complete set of findings, conclusions, and recommendations of both project phases.

when compared with shipments of other crude oils transported by pipeline. In the potential second phase—to be undertaken only in case of a finding of increased likelihood—the committee is asked to review federal pipeline safety regulations to determine whether they are sufficient to mitigate an increased likelihood of release from diluted bitumen. If the committee does not find an increased likelihood of release or the information available is insufficient for a finding, the committee is expected to prepare a final report documenting the study approach and results.

STUDY SCOPE

The SOT makes reference to several terms that delineate the study scope and require explication. First, the SOT specifically requests an examination of "transmission" pipeline facilities. The pipelines in these facilities contain large-capacity pipe, usually 20 inches or more in diameter, and generally transport fluids over long distances under relatively high pressure (400 to 1,400 pounds per square inch). Transmission facilities also contain storage tanks, pumping equipment, and piping within terminals. Gathering pipelines used for collecting crude oil from production fields do not transport diluted bitumen in the United States and are not part of this study.

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As used in the SOT, the term "diluted bitumen" does not define a single product composition or specific set of product or shipment properties. Blending bitumen with lighter oils to lower viscosity is the common method of transporting this form of petroleum by pipeline. The volume of bitumen in a pipeline shipment will vary with the diluent, as will the chemical and physical properties of the shipment. The Canadian diluted bitumen transported in transmission pipelines to the United States generally contains 50 to 75 percent bitumen by volume, with light oils constituting the remainder. These bitumen blends are the subject of this study. It is recognized that the source and composition of bitumen shipments may change depending on technological advances, diluent supplies, refinery demands, and other technical and economic developments.

Finally, the SOT asks the committee to examine whether pipelines transporting diluted bitumen have a higher likelihood of release than pipelines transporting "other crude oils." Accordingly, the aim of this study is to determine whether shipments of diluted bitumen have a release history or specific properties associated with pipeline failures that lie outside the range of experience and properties represented by the full spectrum of crude oils transported by pipeline in the United States.

ANALYTIC APPROACH

An assessment of release likelihood requires information on the potential sources of pipeline failure. PHMSA mandates the reporting of releases from U.S. transmission pipelines and categorizes each according to its immediate, or proximate, cause. Historically, about one-third of reported releases have involved corrosion damage (Figure 1-1). Other causes include outside force damage, such as an excavator striking a buried pipe, and faulty equipment, operator error, and deficiencies in welds and materials used in pipeline manufacturing and installation.

The committee reviewed U.S. and Canadian data on reported pipeline releases. The review provided insight into the main causes of releases, but the incident statistics alone could not be used to determine whether pipelines are more likely to experience releases when they transport diluted bitumen than when they transport other crude oils. Few incident records contain information on the type of crude oil released in an incident or document the properties of the shipments moved through the pipeline over time. Causal details are also limited. Incidents categorized as corrosion damage, for example, do not specify whether the damage occurred as a result of the action of microorganisms, in combination with stress cracking, or at sites of previous mechanical damage. Such detailed information is important in determining the causative role of the crude oils being transported in the pipeline, particularly for failures arising from cumulative and time-dependent degradation mechanisms such as corrosion and cracking.

Having identified the main causes of pipeline releases, the committee assessed each cause with respect to its potential to be affected by the chemical and physical properties of the transported crude oil. Consideration was given to specific shipment properties that can contribute to internal degradation, external degradation, and mechanical damage in pipelines. While the committee did not perform its own testing of crude oil shipments, information on many of the chemical and physical properties of diluted bitumen and other crude oils was obtained from public websites and assay sheets. Additional information was obtained from a review of government reports and technical literature, queries of oil producers and pipeline

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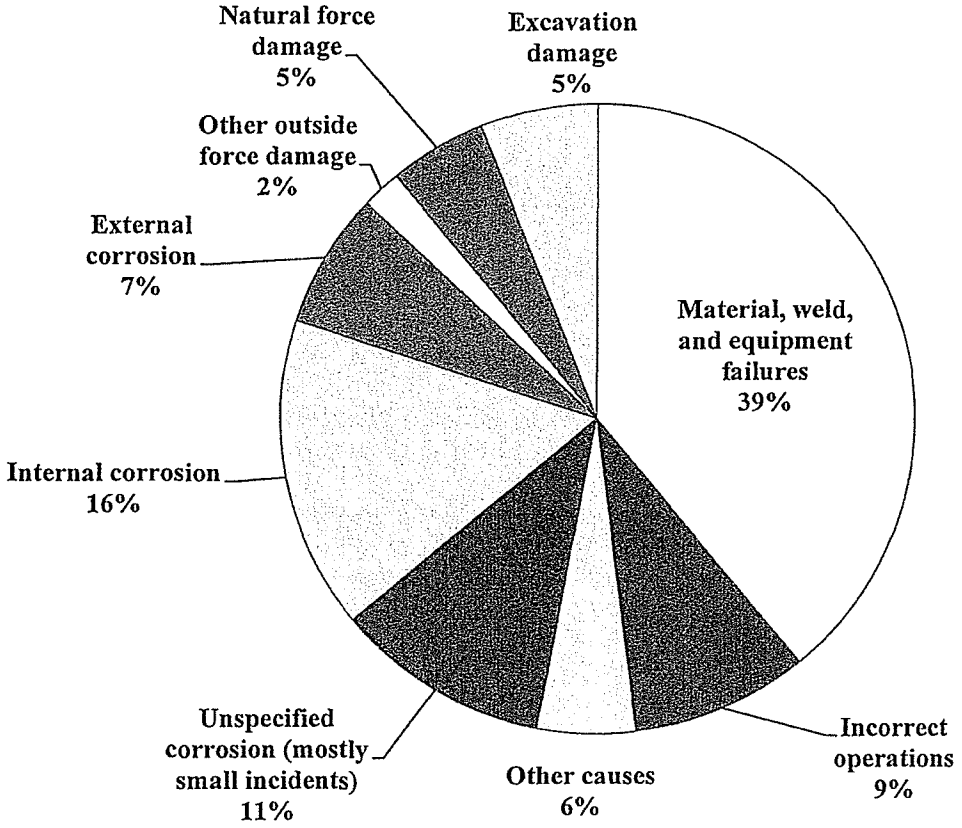

FIGURE 1-1 Causes of crude oil pipeline releases reported to PHMSA, 2002 to 2011. (Source: Incident data provided to committee by PHMSA Office of Pipeline Safety during presentations on October 23, 2012. http://onlinepubs.trb.org/onlinepubs/dilbit/Keener102312.pdf.)

operators, field visits, and inferences from secondary sources such as the maximum water and sediment content specified in pipeline tariffs. The committee then compared the relevant properties of diluted bitumen with the range of properties observed in other crude oils and looked for instances in which diluted bitumen fell outside or at an extreme end of the range.

Recognizing the possibility that some pipeline operators may modify their operating and maintenance practices when they transport diluted bitumen, the committee asked operators about their procedures in transporting diluted bitumen and other crude oils. The committee looked for evidence of changes in standard procedures, including corrosion monitoring and control practices, that could inadvertently make pipelines more susceptible to failure.

REPORT ORGANIZATION

The remainder of the report is organized into five chapters. Chapter 2 provides background on the transportation of crude oil by pipeline, including the main components of pipeline systems

and common aspects of their operations and maintenance. Chapter 3 describes the production, properties, and pipeline transportation of diluted bitumen. Chapter 4 reviews pipeline incident data from the United States and Canada. The analyses of how the comparative properties of diluted bitumen and other crude oils pertain to sources of pipeline failure are carried out in Chapter 5. Chapter 6 summarizes the main discussion points from the preceding chapters and presents the study results.

Appendix A contains the questionnaire developed for pipeline operators and the responses. A brief description of the federal hazardous liquid pipeline regulations and PHMSA safety oversight is provided in Appendix B. Agendas from the information-gathering sessions of committee meetings are provided in Appendix C.

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Crude Oil Pipelines in the United States

This chapter provides background on the network of crude oil transmission pipelines in the United States; the main components of these systems; and common aspects of their operations, maintenance, and integrity management. The background was derived from several sources: National Petroleum Council 2011, Argonne National Laboratory 2008, Rabinow 2004, and a presentation to the committee by Thomas Miesner.[1]

NATIONAL PIPELINE NETWORK

Crude oil is transported, both onshore and offshore, in gathering systems and transmission pipelines. The gathering systems are made up of low-capacity pipelines—typically less than 8 inches in diameter—that move crude oil from wells to high-capacity transmission pipelines that are usually 8 to 48 inches in diameter. Before the crude oil leaves the production field, it is processed to remove excess water, gases, and sediments as necessary to meet the quality specifications of transmission pipelines and the refineries they access.

Most of the estimated 55,000 miles of crude oil transmission pipeline in the United States are interconnected to form a national network that links oil production regions, storage hubs, and refineries.[2] This extensive network accounts for more than 90 percent of the ton-mileage of crude oil transported within the United States.[3]

Transmission pipelines are critical in providing refineries with a steady supply of feedstock consisting of various types of crude oil. About 140 refineries operate nationwide. Some are vast complexes that can process more than 500,000 barrels of crude oil per day, while others serve relatively small and specialized markets and process less than 50,000 barrels per day.[4]

About 40 percent of U.S. refining capacity is located along the Gulf Coast, and the next largest center is in the Upper Midwest. Originally, the Gulf Coast refineries were supplied by domestic sources, primarily from Texas and Louisiana and from shallow waters in the Gulf of Mexico. As domestic production declined in the 1970s, the Gulf Coast refineries increasingly sourced their crude oil from Mexico, Venezuela, and the Middle East. Because the imports tended to be denser and higher in sulfur, refiners invested in facilities capable of processing such feedstock. In recent years, increased production from Canada, deep Gulf waters, and domestic shale fields has replaced waterborne imports. These supply shifts have had significant implications for the transmission pipelines that once moved crude oil from Gulf Coast ports to inland refineries as far north as Illinois and Ohio. Many of these systems have had their flow directions reversed and are now being used to transport Canadian crude oil to the Gulf Coast

[1] October 23, 2012 (http://onlinepubs.trb.org/onlinepubs/dilbit/Miesner102312.pdf).

[2] The Pipeline and Hazardous Materials Safety Administration (PHMSA) has estimated that the crude oil transmission pipeline network extended for 55,330 miles as of 2011.

[3] "Ton-mile" is a measure of the weight of a substance carried multiplied by the distance over which it is carried.

[4] One U.S. barrel of crude oil contains 42 gallons.

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refineries. The transition is under way, with major investments to add more north-to-south capacity by reversing more lines and building new ones.

For many decades, U.S. crude oil produced in the northern Rocky Mountains and Dakotas, as well as that produced in the western provinces of Canada, was transported to refining centers in Eastern Canada and the Upper Midwest. In recent years, as output from these oil-producing regions has grown significantly, crude oil supplies have exceeded refining capacity and are being transported south, where they are displacing crude oil traditionally sourced from Mexico, South America, and the Gulf of Mexico.

Both the East and West Coasts have remained largely independent markets for crude oil supplies. The eastern states have little oil production and no significant crude oil transmission pipelines. While the recent development of shale resources in New York and Pennsylvania is adding production capacity, truck and rail remain the dominant regional modes of crude oil transportation. The main East Coast refining centers in northern New Jersey, Philadelphia, and coastal Virginia receive most of their supplies from tanker vessels. In comparison, California has an extensive network of crude oil transmission pipelines because of significant in-state oil production. These pipeline systems, some of which consist of heated lines to move the native viscous crude oils, do not connect to pipeline systems in other states. Refineries in Washington State receive crude oil by tanker and from Western Canada by pipeline.

PIPELINE SYSTEM COMPONENTS

The individual pipeline systems that make up the U.S. crude oil transmission network vary in specific design features and components. Nevertheless, the systems have many common elements.

Line Pipe

Pipelines are made of sections of line pipe that are welded together and generally buried 3 or more feet below grade. Virtually all line pipe is made of mild carbon steel that is coated externally but not internally. Pipe sections are typically 40 feet long, manufactured with longitudinally welded seams and joined by circumferential girth welds during installation. Pipe wall thickness depends on many factors, including planned capacity and operating pressure. Most line pipe in crude oil transmission systems is operated at pressures between 400 and 1,400 pounds per square inch, is 20 or more inches in diameter, and has a nominal wall thickness ranging from 0.2 to 0.75 inches. Federal regulations in the United States require that pipeline operating pressures and other forces not generate stresses that exceed 72 percent of the specified minimum yield strength (SMYS) of the pipe, and therefore a higher operating pressure requires thicker pipe or pipe with higher yield strength.[5] Depending on pipeline design and routing factors, thicker-walled pipe may also be used where the pipeline crosses a body of water or in areas that are densely populated, environmentally sensitive, or prone to additional external forces such as seismic activity.

[5] Federal regulations concerning SMYS are contained in 49 CFR §195.406. The federal hazardous liquid pipeline safety regulations, as administered by PHMSA, are outlined in Box B-1, Appendix B. Some pipelines operate at 80 percent of SMYS with permission of PHMSA.

Inlet Stations and Tank Farms

Transmission pipelines originate at one or more inlet stations, or terminals, where custody of the shipment is transferred from the owner to the pipeline operator. Accordingly, inlet stations are access points for truck tankers, railroad tank cars, and tanker vessels as well as other pipelines, including gathering lines connecting production areas. Along with pumping stations, sampling and metering facilities are located at inlets to ensure that the crude oils injected into the pipeline meet the quality control requirements of the pipeline operator and intended recipients. Metering instruments usually include densitometers and may include viscometers, which are used to measure density and viscosity, respectively.

Tanks at inlet stations are used to consolidate shipments into batches sized for main-line movement, blend crude oils to meet quality specifications, and schedule shipments according to the needs of refiners. Tanks can vary in capacity from tens of thousands to hundreds of thousands of barrels.[6] All are made of steel and are unpressurized. They are usually designed with floating roofs that rise and fall with the liquid level to limit hydrocarbon loss from vaporization and minimize emissions of volatile organic compounds. Tanks usually have lined floors and are inspected and cleaned periodically to remove any water and sediment settling to the floor.

Pump Stations

To maintain desired flow rates, booster pumps are positioned at points along the pipeline at intervals of 20 to 100 miles depending on many factors, including topography, line configuration, pipe diameter, operating pressure, and the properties of the fluids being transported. Pump stations are often automated and are equipped with sensors, programmable logic controllers, switches, alarms, and other instrumentation allowing the continuous monitoring and control of the pipeline as well as its orderly shutdown if an alarm condition occurs or if established operating parameters are violated.

Valves

Shutoff valves are strategically located at pump stations, certain road and water crossings, and other points to facilitate the starting and stopping of flow and to minimize the impact of leaks. These valves, many of which can be controlled remotely, ensure that portions of the line can be isolated in the event of a leak or the need for repair or maintenance. In addition, check valves that prevent backflows may be located at elevation changes and other intermediate points. The opening and closing of valves, along with pumping station operations, are sequenced to prevent flow reversals and problems associated with over- and underpressurization. Bypass lines, safety valves (e.g., pressure and thermal relief), and surge tanks may be sited at stations to relieve pressure.

Intermediate and Terminal Facilities

Depending on the scope of operations, a transmission pipeline system may have intermediate points, in addition to terminal facilities, that connect to other pipelines, other modes of transport,

[6] Larger underground caverns are used for storage at some pipeline terminals.

and refineries. These stations usually contain tanks and crude oil sampling and metering facilities. Smaller "breakout" tanks at intermediate points may also be used to support maintenance and emergency activities; for example, to relieve pressure or to allow for temporary draining of a pipeline segment.

OPERATIONS AND CONTROL

Batch Operations

A transmission pipeline will rarely carry a single type of crude oil. At any given time, a large pipeline will usually be transporting dozens of shipments, typically in batches of at least 50,000 barrels and covering a variety of crude oil grades. Sometimes the batches are physically separated by plugs known as pigs, but most of the time they are not. To reduce undesirable mixing at interfaces, the batches are separated and sequenced according to characteristics such as density, viscosity, and sulfur content. Accordingly, batches are scheduled to permit the proper lineup of crude oils being moved into and out of storage tanks. Maintaining batch separation requires that operators closely monitor the flow characteristics of the pipeline, since reductions in flow velocity and loss of flow turbulence can lead to undesirable intermixing of batches.

Flow Regime

Most shipments flow through the pipeline at 1.5 to 3 meters per second (3 to 6 miles per hour), which equates to a delivery rate of 500,000 to 1,000,000 barrels of crude oil per day in a 36-inch transmission pipeline.[7] Flow conditions in the pipeline will remain turbulent within this range of flow velocities.[8] Pipeline operators strive to maintain turbulent flow, characterized by chaotic motion and the formation of eddies, to reduce intermixing of batches and to keep impurities such as water and sediment suspended in the crude oil stream. Choosing a desired flow regime requires the balancing of many technical and economic factors. Increasing operating pressure will increase pipeline throughput, which is generally desired by an operator to increase revenue capacity. Higher operating pressures, however, require a larger investment in pipe materials and pumping capacity and will increase energy use and operating costs.

The characteristics of the crude oil to be shipped are important considerations in establishing the flow regime. More energy is needed to pump dense, viscous crude oils than light crude oils with lower viscosity. Some crude oils are too viscous naturally to be pumped. The normal response when a highly viscous crude oil is transported is to dilute it with lighter oil. When a diluent is too costly or unavailable, an alternative approach is to transport the crude oil in a heated pipeline. However, heating a pipeline is an expensive option and presents construction

[7] http://www.aopl.org/aboutPipelines/?fa=faqs.

[8] Whether a flow is turbulent or nonturbulent (i.e., laminar) depends on the diameter of the pipeline, the velocity of the flow, and the viscosity of the crude oil. These parameters can be used to calculate the Reynolds number, which defines the flow regime as laminar to turbulent. As described later in Chapter 3, the kinematic viscosity of heavy crude oils can range up to about 250 centistokes (0.00025 square meter per second) at room temperature. These oils will need to be transported at about 2 meters per second (6.5 feet per second or 4.4 miles per hour) in a pipe with a diameter of 20 inches to achieve a Reynolds number higher than 4,000, which is at the transition from laminar to turbulent flow. In a larger pipe, lower velocities are required to maintain turbulence (e.g., 1 meter per second or 2 miles per hour for a 42-inch pipe). Further consideration is given to the beneficial effects of maintaining turbulent flow in Chapter 5.

and operating challenges that preclude its common use. Where the throughput capacity of a line needs to be increased without adding pumping capacity, an operator may inject drag-reducing agents to enhance flow. These chemicals, which consist of long-chain polymers, dampen turbulence at the interface between the crude oil and the pipe wall to reduce friction and enable increased flow velocity.

Pipeline flows are usually monitored and controlled by operators from one or more central control centers, where supervisory control and data acquisition systems collect and analyze data signals from sensors and transmitters positioned at pumps, valves, tanks, and other points en route. Parameters other than flow rate, such as line pressure, pump discharge pressures, and temperatures, are also monitored for routine operational and maintenance decisions and for leak detection.

Shipment Quality Control

In the United States, the Federal Energy Regulatory Commission (FERC) oversees the tariffs that interstate pipeline operators are required to publish as common carriers. For intrastate transmission pipelines, state authorities such as the Texas Railroad Commission and the California Energy Commission function much like FERC in overseeing tariffs for in-state movements.

Pipeline tariffs define the terms and conditions for the transportation service, including the quality specifications applicable to all shipments in the pipeline. The specifications are driven by both operational and commercial considerations. Measurements to ensure adherence to the specifications are usually taken at custody transfer points. It is common for these specifications to define the maximum allowable sediment and water content, viscosity, density, vapor pressure, and temperature of the shipment. Other shipment qualities, such as levels of sulfur, acid, and trace metals, are seldom delineated in published tariffs but may be specified in private agreements. Quality specifications are designed to protect the integrity of the pipeline and the ancillary facilities, ensure that the shipped crude oil meets the specifications of the refiner, and prevent valuable throughput capacity from being consumed by transporting sediment and water.

MAINTENANCE

Each operator tailors pipeline maintenance and integrity management practices within the parameters allowed by safety regulations and according to the demands of the specific system, including its age, construction materials, location, and stream of products transported. Nevertheless, many practices are standardized. Some of the most common cleaning, inspection, and mitigation practices are described below. Regulatory requirements that govern integrity management are outlined in Appendix B.

Cleaning

Periodic cleaning of crude oil pipelines and equipment is often performed to facilitate inspection as well as to maintain operational performance. Cleaning intervals, typically measured in weeks or months, will vary depending on operating conditions and crude oil properties. A variety of tools are used for cleaning the pipe and monitoring interior condition. Mechanical pigs equipped

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with scrapers and brushes remove debris from the inner wall. The scraped deposits and scale are transported to clean-out traps. The scrapings may be tested for contaminants and corrosion by-products.

Inspection and Monitoring

A regular inspection regime that assesses the condition of rights-of-way, pipes, pumps, valves, tanks, and other components is important to maintaining pipeline operational integrity and preventing unplanned shutdowns. Rights-of-way are routinely monitored by aerial patrols looking for threatening activities and encroachments and by field inspectors conducting detailed surveillance of line and equipment conditions. While visual inspection of buried pipe is not possible, pipes exposed for repair are usually inspected for evidence of mechanical damage or signs of degradation that may be indicative of problems elsewhere on the line.

From time to time, instrumented, or "smart," pigs are run through the line to detect anomalies. The three primary instruments are geometry, metal loss, and crack tools. Geometry tools are normally equipped with mechanical arms that survey the pipe wall to detect dents and other geometry changes. Metal loss tools use either magnetic or ultrasonic technology. Crack tools are designed to detect cracks in the pipe body, especially those that are longitudinally oriented. The frequency of instrumented pig runs is determined by the risk management program of the operator, as influenced by government regulation. Some pipeline sections, mostly in older systems, are not configured to accept some instrumented pigs.

Other techniques for monitoring conditions inside the pipe include the use of corrosion coupons and electrical resistance probes. Coupons are steel samples inserted into the pipeline and periodically removed for examination. Because the coupons are weighed before and after the exposure, the amount of corrosion can be determined by weight loss. Electrical resistance probes inserted into the pipe provide information on the corrosivity of the stream. External corrosion is monitored primarily through the use of pipe-to-soil potential surveys, whereby the voltage is measured with respect to a reference electrode to determine whether adequate cathodic protection levels are present along the length of the pipeline. Techniques are also used to measure the voltage gradients in the soil above a protected pipeline to determine the size and location of coating defects. Coupons buried in the soil can supplement this external corrosion monitoring. In addition, coatings are inspected whenever portions of the pipeline are uncovered.

Corrosion Mitigation Practices

It is standard practice for buried transmission pipelines to be coated externally to provide a physical barrier between the steel and the surrounding corrosive environment. Desired coating characteristics include low permeability to water and salts, strong adhesion to steel, and good abrasion resistance (Beavers and Thompson 2006). The coating also needs to be durable and resist chemical and thermal degradation at pipeline operating temperatures.

Pipeline coatings have improved over the past several decades. Along with cold and hot applied tapes, field-applied coatings made from coal tar, asphalt, and grease were the dominant systems used through the 1950s (Michael Baker Jr., Inc. 2008; Beavers and Thompson 2006). Because of nonoptimal conditions for field applications, early coatings often had poor adhesion characteristics, with pinholes and other imperfections. Some also exhibited degradation of the

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polymers. After time in service, the coatings tended to become porous or to detach from the pipe surface.

During the 1960s and 1970s, fusion bonded epoxy (FBE) coatings were introduced. Unlike other coatings, FBE coatings are formed by heating a powder on the surface of the metal. The components of the powder melt and flow to initiate a cross-linking process. These heat-cured coatings exhibit good mechanical and physical properties, including adhesive strength and resistance to degradation, and they are widely used today.

Even a well-coated pipe may have imperfections and develop small holes in the coating that can expose the pipe to corrosion attack. To counter this effect, pipelines are fitted with cathodic protection systems. In some systems, the electrochemical potential of the pipe is reduced by galvanically coupling to sacrificial anodes typically made of magnesium, aluminum, or zinc alloys that will preferentially corrode instead of the pipe. Other systems employ an impressed current applied to the pipeline with the use of a power supply to lower the pipeline potential. The cathodic protection system is designed to supply enough current to a pipe to prevent external corrosion at defects or holes that form in the coating where the external environment can come in contact with the steel surface. Defects in coatings are especially problematic when the disbonded coating shields distribution of the cathodic current to the defect site. This shielding is most often associated with the impermeable tapes and shrink sleeves used on some older pipelines. An advantage of modern FBE systems is that they are permeable to ionic flow and thus do not shield the exposed sites from cathodic protection.[9]

Preventing the internal corrosion of pipes starts with basic quality control and operational procedures that limit the entry and accumulation of water and other contaminants. As noted above, transmission pipelines are typically constructed of steel with no internal coatings, so the transported product is in contact with the steel. While oil is not corrosive, even small amounts of contaminants such as water and salts in the oil can be corrosive if they are allowed to accumulate on the steel surface. Certain gases dissolved in the product stream, especially oxygen, hydrogen sulfide, and carbon dioxide, can also increase the rate of corrosion. Actions to mitigate internal corrosion include controlling ingress of air at pumps and other entry points, limiting water and sediment content, and chemical treatment of the crude oil stream.

The chemicals injected into the crude oil stream usually consist of a mixture of additives that inhibit corrosion by various means. The most common mixtures contain surfactant chemicals that adsorb onto the steel surface and provide a barrier between the corrosive water and pipe steel. Many surfactants confer additional benefits by reducing the surface tension at the oil–water interface, which keeps the water entrained in the flow rather than depositing on the pipe wall. Chemical additives may also have properties that repel the water from the pipe wall, neutralize acids, and act as biocides to help inhibit microbiologically influenced corrosion. The rates of flow in transmission pipelines are normally sufficient to prevent the deposition of contaminants and to sweep away deposits that settle to the pipe bottom. Areas of low flow, such as steep angles of elevation and sections of isolated piping (called dead legs), are vulnerable to water and sediment accumulation and subsequent internal corrosion. Because the hydrodynamic and chemical processes of water and sediment accumulation are well understood, models for

[9] Inspections performed on gas gathering lines equipped with an early generation FBE coating (from the mid-1970s) revealed that less than 0.2 percent of pipeline sections exhibited blistering of the coating despite some operating in temperatures as high as 76°C (170°F). Removal of the blistered coating revealed no underlying corrosion because of the permeability of FBE to cathodic fields (Boerschel 2010; Batallas and Singh 2008).

analysis are available to guide pipeline construction and operating parameters to decrease the tendency for accumulations and to identify areas of greatest vulnerability to corrosion.

Additional details on the mechanisms of pipeline damage and factors that contribute to them are discussed in Chapter 5.

SUMMARY

The crude oil transmission network in the United States consists of an interconnected set of pipeline systems. Shipments traveling through the network often move from one pipeline system to another, sometimes being stored temporarily in holding tanks at terminals. Most operators of transmission systems are common carriers who do not own the crude oil they transport but provide transportation services for a fee. Few major transmission pipelines are dedicated to transporting specific grades or varieties of crude oil. They usually move multiple batches of crude oil, which are often provided by different shippers and include a range of chemical and physical properties. Crude oil shipments are treated to meet the quality requirements of the pipeline operator as well as the content and quality demands of the refinery customer.

Pipeline systems traverse different terrains and can vary in specific design features, components, and configurations. These differences require that each operator tailor operating and maintenance strategies to fit the circumstances of its systems in accordance with regulatory requirements. Nevertheless, the systems tend to share many of the same basic components and follow similar operating and maintenance procedures. Together, regulatory and industry standards, system connectivity, and economic demands compel both a commonality of practice and a shared capability of handling different crude oils.

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3

Bitumen Properties, Production, and Transportation by Pipeline

This chapter describes the chemical composition and physical properties of bitumen, the methods used to produce it, and the properties of the bitumen shipments that are diluted for pipeline transportation to the United States.

BITUMEN COMPOSITION AND PROPERTIES

Like all forms of petroleum, bitumen is a by-product of decomposed organic materials rich in hydrocarbons. According to the World Energy Council, bitumen deposits exist in about 20 countries, but the largest are in Canada, Kazakhstan, and Russia (WEC 2010, 123–150). Because only the Canadian bitumen is diluted for transportation by pipeline to the United States, it is the subject of the description in this chapter.[1]

Canadian bitumen deposits are concentrated in the Western Canadian Sedimentary Basin (WCSB), and particularly in the province of Alberta. Three regions in the WCSB have large reserves: the Athabasca, Peace River, and Cold Lake regions (Strausz and Lown 2003, 21). According to the government of Alberta, about two-thirds of the world reserves of recoverable bitumen are contained in the three regions, which total some 140,000 square kilometers (55,000 square miles) (ERCB 2012a). In some locations in Alberta, surface deposits are easy to spot, since the black bitumen is impregnated in sandstone along the sides of lakes and rivers. Most of the bitumen is not visible because it is deposited below the surface.

The bitumen-impregnated sands in the WCSB are referred to as bituminous sands, oil sands, and tar sands (Strausz and Lown 2003, 29). Canadians use the term oil sands, which is also used in this report. The typical composition of the WCSB oil sands is 85 percent sand and clay fines,[2] 10 percent bitumen, and 5 percent water by weight.[3] Oil sands also contain salts, trace gases, and small amounts of nonpetroleum organic matter.[4] These components exist together in a specific microstructure with a film of water that surrounds each sand and clay particle, and the bitumen surrounds the film, as shown in Figure 3-1. When freed from this microstructure, bitumen has a typical elemental composition of 81 to 84 percent carbon; 9 to 11 percent hydrogen; 1 to 2 percent oxygen, nitrogen, and other elements; and 4 to 6 percent sulfur, most of which is bound in the bitumen in stable (e.g., heterocyclic rings) hydrocarbon structures (Dettman 2012; Strausz et al. 2011; Gogoi and Bezbaruah 2002; Strausz and Lown 2003).

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[1] Canada contains the vast majority of the natural bitumen in North America. According to the U.S. Geological Survey, bitumen deposits exist in the United States in several states, mainly in Utah, California, and Alabama. While commercial mining operations are being planned in Utah, many technical and economic challenges remain to exploit this resource (USGS 2006).
[2] The solid particles consist of sand grain minerals, mostly of quartz but also feldspar, mica, and chert. The solid particles also consist of clay minerals, mostly kaolinite and illites (Strausz and Lown 2003, 31–32).
[3] Up to 18 percent of the ore can be made up of bitumen (Strausz and Lown 2003, 62).
[4] The organic matter consists of humin, humic acids, fulvic acids, and chemiabsorbed aliphatic carboxylic acids (Strausz and Lown 2003, 29–32).

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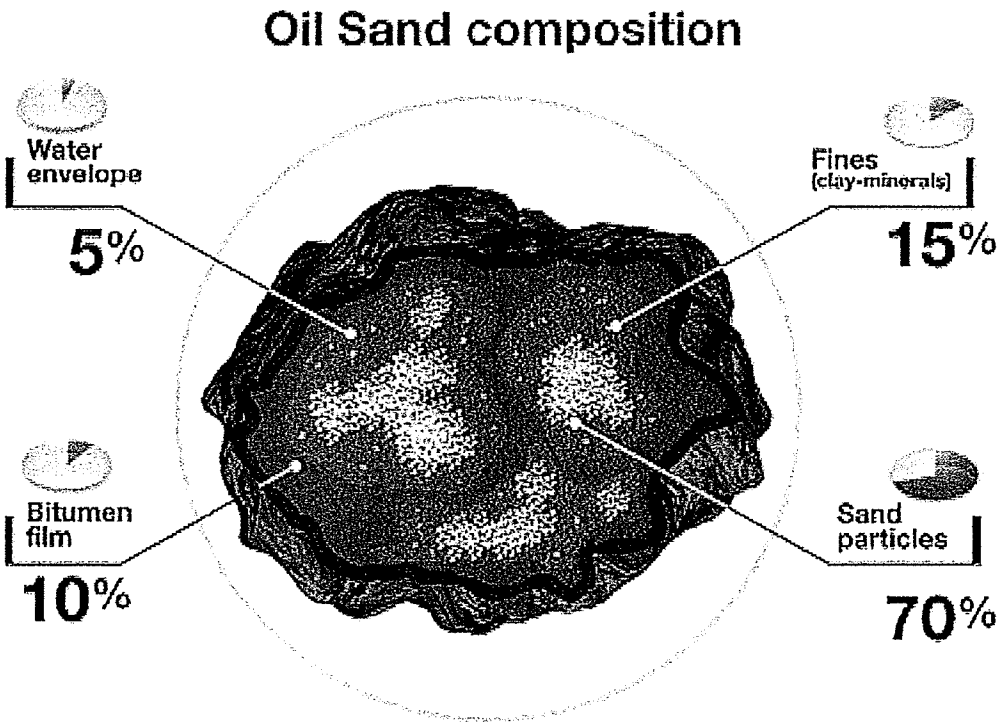

FIGURE 3-1 Composition of oil sands.

Hydrocarbon molecules account for 92 to 95 percent of the weight of bitumen.[5] These molecules range from light alkanes, such as ethane, to long-chain compounds with relatively high molecular weights and boiling points. The latter molecules are more common in bitumen than in the lighter, more paraffinic crude oils that have undergone less microbial degradation.[6] Bitumen contains relatively high concentrations of asphaltenes, which account for 14 to 17 percent of the total weight of the material (Strausz and Lown 2003, 95; Rahimi and Gentzis 2006, 151). Trace elements, such as vanadium and nickel, usually reside in the asphaltenes along with sulfur, nitrogen, and oxygen (Strausz and Lown 2003, 93–99, 495–498). The nitrogen in the bitumen is bonded with carbon in pyridinic structures, including quinolines and acridines (Rahimi and Gentzis 2006). The asphaltenes, as well as other nonparaffinic compounds such as naphthenes, give bitumen its high density and high viscosity (Strausz and Lown 2003, 99).

Bitumen is usually distinguished from other forms of petroleum on the basis of physical properties that derive in part from its relatively high asphaltene content. The U.S. Geological Survey (USGS) has used the following definition to distinguish bitumen from other heavy crude oils:

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[5] The ratio of hydrogen to carbon atoms is about 1.5 in bitumen, compared with 2.0 for very light oils (Strausz and Lown 2003, 95–96).

[6] Bitumen has undergone more biodegradation than have other petroleum oils. Because straight-chain paraffinic hydrocarbons are more readily metabolized by microorganisms, these hydrocarbons are depleted in bitumen (Strausz and Lown 2003, 90).

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> Natural bitumen is defined as petroleum with a gas-free viscosity greater than 10,000 centipoises (cp) at original reservoir temperature. Petroleum with a gas-free viscosity between 10,000 and 100 cp is generally termed heavy crude oil. In the absence of viscosity data, oil with API gravity less than 10 degrees is generally considered natural bitumen, whereas oil with API gravity ranging from 10 degrees API to about 20 degrees API is considered heavy crude oil. The term extra-heavy crude oil is used for oil with a viscosity less than 10,000 cp but with API gravity less than 10 degrees. (USGS 2006)

The American Petroleum Institute (API) gravity scale referenced by USGS is an inverse measure of the density of a liquid relative to that of water at room temperature. A liquid with API gravity greater than 10 degrees will float on water; if the API gravity is lower than 10 degrees, it will sink.[7] Canadian bitumen (undiluted) typically has an API gravity between 7 and 13 degrees, whereas most heavy crude oils have values that are 5 to 15 degrees higher (Strausz and Lown 2003, 100). The viscosity of bitumen is also high compared with that of other crude oils across a range of temperatures. Figure 3-2 compares the effects of temperature on viscosity [in centipoise units (cp)] for bitumen derived from two WCSB reservoirs (Cold Lake and Athabasca), a Canadian heavy crude (Lloydminster), and typical light crude oils.[8] At most pipeline operating temperatures [0°C to 40°C (32°F to 100°F)], the lighter crude oils will behave as liquids, while the bitumen will remain in a semisolid state, having viscosities comparable with that of peanut butter. Although they are less viscous than bitumen, the heaviest conventionally drilled Canadian crude oils have relatively high viscosities as well.[9] Several Canadian crude oils, including the Lloydminster crude oils shown in Figure 3-2, are routinely diluted with lighter oils to improve their flow in transmission pipelines.[10]

BITUMEN PRODUCTION

The WCSB has long been a major oil-producing region of North America. Oil exploration commenced in the early 20th century, and by the 1960s hundreds of millions of barrels of Western Canadian crude oil were being exported each year through pipelines to the United States. Nearly all of this oil was produced with conventional drilling and well technology. By the 1990s, Western Canadian exports of conventionally produced oil were declining just as new technologies were being introduced to recover the vast deposits of bitumen contained in oil sands.

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[7] API gravity values are referred to as "degrees." Most crude oils have API gravities in the range of 20 to 40 degrees, but some range 10 degrees higher or lower.

[8] Centipoise is a measure of resistance to shear flow, or the dynamic viscosity of a fluid. A more common measure of resistance to flow by crude oils is the centistoke (cSt), which is the ratio of dynamic viscosity to fluid density, also known as kinematic viscosity. At room temperature, the kinematic viscosity of bitumen will exceed 100,000 cSt, compared with about 25 cSt for a medium-density crude oil. Kinematic viscosity is referenced more often in this report.

[9] This Canadian heavy crude oil is usually diluted with lighter oils for pipeline transportation.

[10] Lloydminster heavy crude oils have API gravities of 12 to 23 degrees (Strausz and Lown 2003, 26).

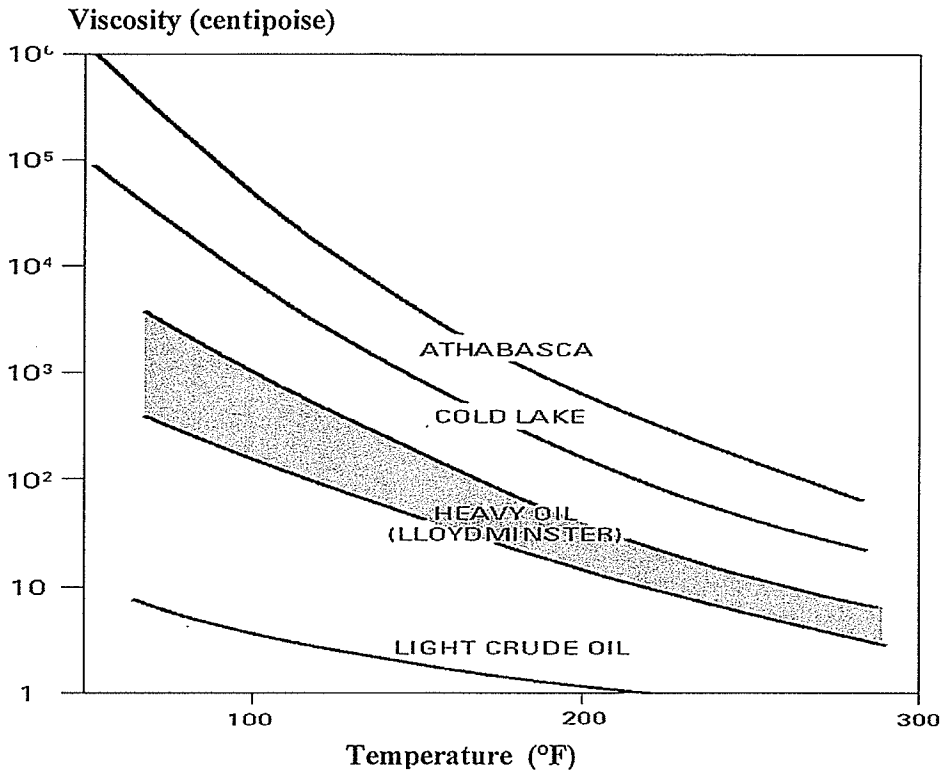

FIGURE 3-2 Response of crude oil viscosity to changes in temperature (Raicar and Procter 1984; WEC 2010, 126).

While natural bitumen had long been used as sealing material, Canadian entrepreneurs started mining deposits for refinery feed during the early 20th century. However, separating the bitumen from the mined ore required significant amounts of heated water, which made recovery expensive compared with the lighter crude oils that were less costly to drill elsewhere in Canada and the United States. Commercial ventures to mine bitumen began in the 1920s, but it took another 40 years of declining North American crude oil reserves, increasing consumer demand for gasoline and other refined petroleum, and advances in extraction and processing technologies to transform the mined bitumen into a commercially viable refinery feedstock.[11]

During the 1990s, thermally assisted in situ recovery methods were introduced in the WCSB to exploit the large reserves of bitumen located too deep for surface mining. After this development, the quantity of bitumen produced surpassed the quantity of conventionally produced oil from the basin. Today, bitumen accounts for more than 70 percent of the petroleum produced in Alberta, and in situ recovery methods account for nearly half of this bitumen production (ERCB 2012a).

[11] Oil Sands Discovery Centre. Facts About Alberta's Oil Sands and Its Industry. http://history.alberta.ca/oilsands/docs/facts_sheets09.pdf.

One in situ method in particular—steam-assisted gravity drainage (SAGD)—led to the recent growth in Canadian bitumen production for export to the United States. Indeed, no significant quantities of mined bitumen are diluted for pipeline transportation to the United States, the main market for bitumen recovered by using the SAGD process.[12]

Bitumen Mining and Upgrading to Synthetic Crude Oil

About 20 percent of the bitumen deposits in the WCSB are less than 60 meters (200 feet) deep and can be recovered by surface mining. Mining operations use diesel-powered shovels to excavate the ore, which is transported by truck to field facilities containing crushers. The crushed ore is mixed, or washed, with hot water to create a slurry that is piped a short distance, where it is agitated and filtered in separation vessels. The hot water heats and releases the water that surrounds the sand and clay particles. The agitation causes air bubbles to attach to bitumen droplets, which float in a froth to the top of the vessel. The froth is then deaerated with steam and diluted with a hydrocarbon solvent such as naphtha. The solvent coalesces and causes settlement of emulsified water and mineral solids. The suspended bitumen is then separated with a centrifuge and skimmer.

The extraction process for mined bitumen yields a product that typically contains 0.5 percent solids and 1 to 2 percent water by volume. This solid and water content is generally too high to be accepted by transmission pipelines. As a consequence, mined bitumen is nearly always upgraded, usually at nearby field plants, into synthetic crude oil. The field plants consist of refinery-type cokers that crack the bitumen into lighter products that are then processed in hydrotreating units to remove sulfur and nitrogen.[13] The processed streams are then mixed to produce a low-viscosity, low-sulfur synthetic crude oil that can be transported by transmission pipeline to refineries in Canada and the United States. The synthetic crude oils are also blended with other heavy Canadian crude oils, including in situ–produced bitumen, for pipeline transportation to the United States.

Nearly all of the bitumen mined in the WCSB is upgraded to synthetic crude oil.[14] This situation is subject to change as alternative methods are introduced to yield mined bitumen with reduced viscosity and water and sediment content comparable with that of the bitumen produced in situ and transported in diluted form through transmission pipelines. One alternative is to deasphalt the mined bitumen partially to produce synthetic crude oil that retains some of the heavier hydrocarbon fraction by substituting a paraffinic solvent for the aromatic-rich naphtha solvent traditionally used during removal of water and solids (Rahimi et al. 1998). Composed largely of pentanes and hexanes, a paraffinic solvent is more effective than naphtha in promoting aggregation and settlement of asphaltenes and suspended water and solids. Removal of asphaltenes through paraffinic treatment yields a processed bitumen that is less viscous and has lower levels of water and solids than mined bitumen that is processed with a traditional naphtha solvent.

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[12] The discussion focuses on surface mining and SAGD, which are the most common bitumen recovery methods. Other methods not discussed include cyclic steam stimulation, toe-to-heel air injection, vapor-assisted petroleum extraction, and cold heavy oil production with sand. More information on recovery methods can be found at http://www.oilsands.alberta.ca/.

[13] According to the Alberta Energy Ministry, the five upgraders operating in Alberta in 2011 had the capacity to process approximately 1.3 million barrels of bitumen per day (ERCB 2013).

[14] According to the Alberta Energy Ministry, in 2011 about 57 percent of oil sands bitumen production was upgraded to synthetic crude oil in Alberta. Most upgraders produce synthetic crude oil, but some also produce refined products such as diesel (ERCB 2013).

Mined bitumen processed with paraffinic solvent can be transported by transmission pipeline, usually by retaining some of the solvent as diluent.[15] Mined bitumen treated in this manner is being piped several hundred miles from oil sands production regions to large, centrally based upgraders elsewhere in Alberta, where it is processed into synthetic crude oil. The mined bitumen, however, is not transported through pipelines to the United States (except when upgraded to synthetic crude oil) because paraffinic solvents are too expensive to use as diluent for long-distance transportation. Instead, the solvent is recovered at the Canadian upgraders and piped back to bitumen production fields for reuse as a solvent.

In Situ Recovery

Because most Canadian bitumen is located deep underground, it can only be recovered in place. Although reaching the deposits is not difficult,[16] the challenge in recovering them is in separating and thinning the bitumen for pumping to the surface. A recovery method that is now common involves the injection of pressurized steam into the deposit. The steam thins the bitumen and separates it from the sand while the pressure helps to push the bitumen up the well.

A number of thermally assisted recovery methods are used in the WCSB. The two main methods are cyclic steam stimulation (CSS) and SAGD. CSS involves injecting steam into the bitumen deposit and letting it soak for several weeks. This process causes the bitumen to separate from the sand and become sufficiently fluid for pumping. Over the past decade, SAGD has surpassed CSS as the preferred thermal recovery method because a higher proportion of the bitumen is recovered. SAGD involves drilling two horizontal wells, one located a few feet above the other as shown in Figure 3-3. Steam is injected into the upper well, which heats the bitumen and causes it and steam condensate to drain into the lower well for pumping to the surface. At the surface, condensed water is separated from the recovered bitumen and recycled to produce steam for subsequent applications.

The high recovery ratio of SAGD is an important reason for the growth in Canadian bitumen production. SAGD now accounts for about half the bitumen recovered from the WCSB.[17] Compared with mining, SAGD has the advantage of eliminating the need to wash the ore with hot water because the bitumen is separated from the sand and clay underground. After further treatment (e.g., standard degassing, dewatering, and desalting), the recovered bitumen contains much lower levels of water and sediments (generally less than 0.5 percent by volume) than mined bitumen, and it is sufficiently stable for acceptance by long-distance pipelines. Whereas nearly all mined bitumen is upgraded into synthetic crude oil in Alberta, less than 10 percent of the SAGD-derived bitumen is processed into synthetic crude oil (NEB 2009). Most SAGD-derived bitumen is diluted with lighter oils for transportation by pipeline to U.S. refineries.

[15] While asphaltene concentrations have significant implications for bitumen viscosity, the removal of all asphaltenes would not reduce viscosity enough for undiluted bitumen to meet pipeline specifications (Rahimi and Gentzis 2006).

[16] The exploited deposits are generally less than 750 meters (2,500 feet) underground.

[17] In 2011, about 1.7 million barrels per day of bitumen were produced, with surface mining accounting for 51 percent and in situ processes accounting for 49 percent of the production (ERCB 2013).

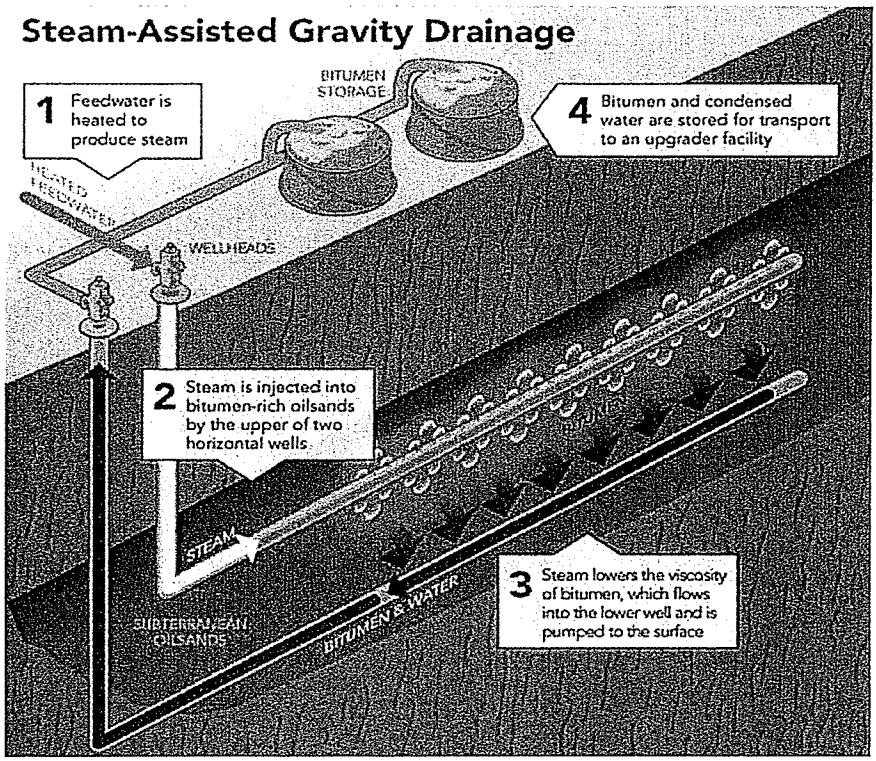

FIGURE 3-3 Bitumen recovered using SAGD (ERCB 2012b).

PIPELINE TRANSPORTATION OF DILUTED BITUMEN

According to the U.S. Department of Energy, imports of Canadian diluted bitumen and other crude oils have grown by more than one-third since 2000.[18] Partially as a result of Canadian supplies as well as newly exploited domestic oil shale, crude oil imports from other regions of the world are declining. In particular, the Canadian feedstock has supplanted heavy crude oils once imported in large volume from Venezuela and Mexico (Figure 3-4). While more than two-thirds of the Canadian crude oil is refined in the Midwest, refinery demand for this feedstock has been growing in other regions of the country, particularly at Gulf Coast refineries that are equipped to process heavy feed.

U.S. Pipelines Transporting Diluted Bitumen

Figure 3-5 shows U.S. refinery destinations for diluted bitumen and other Canadian crude oils, and Figure 3-6 shows the main pipeline corridors that access these refineries. Major export pipelines from Canada include the Enbridge Lakehead network, which serves several Great Lakes refineries; the TransCanada Keystone pipeline, which accesses the Cushing, Oklahoma, hub and refineries in southern and central Illinois; and the Kinder Morgan Express and Prairie

[18] http://www.eia.gov/countries/cab.cfm?fips=CA.

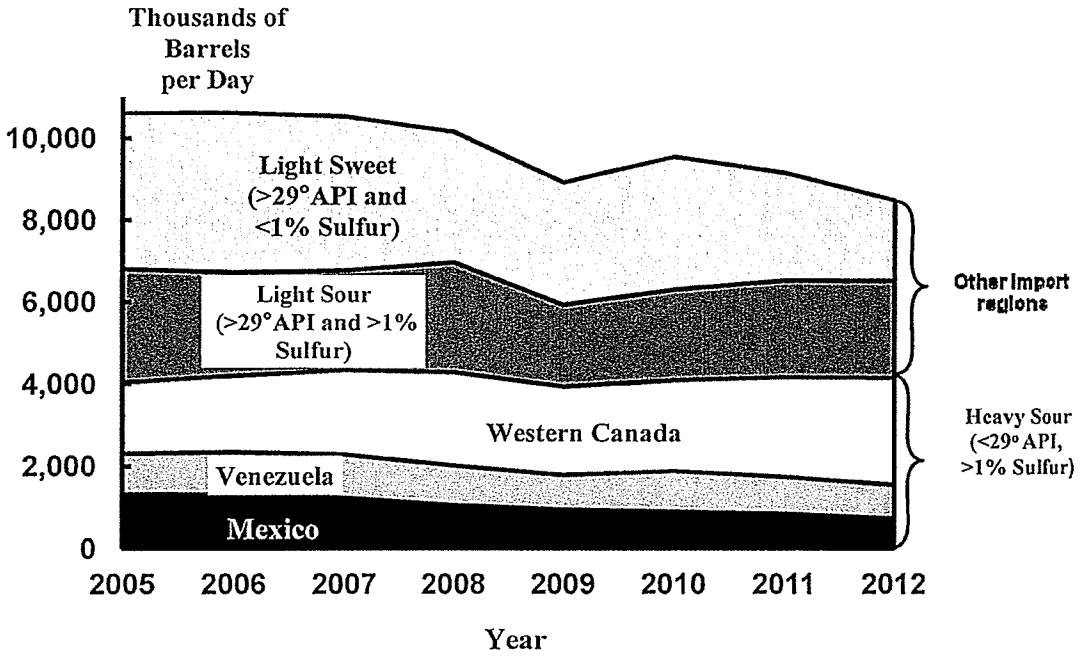

FIGURE 3-4 Annual U.S. crude oil imports by grade and origin. [Chart is derived from January 31, 2012, presentation to the committee by G. Houlton. Source data on crude oil imports were obtained from the Energy Information Administration, U.S. Department of Energy (http://www.eia.gov/countries/cab.cfm?fips=CA).]

pipelines, which transport Canadian crude oils to refineries in the Rocky Mountains and provide surplus to refineries farther east and south. These trunk lines are connected to pipelines that deliver feed to refineries as far east as Ohio and western Pennsylvania and as far south as the Texas Gulf Coast and New Mexico. Several connecting pipelines have recently undergone flow reversals, such as the 375-mile Occidental Centurion line, which now runs southwest from Cushing in the direction of El Paso, Texas; the 858-mile ExxonMobil Pegasus line, which runs south from Illinois to refineries on the Gulf Coast; and the 670-mile Enbridge Seaway line, which crosses East Texas and is expected to become fully operational during 2013.

Properties of Diluted Bitumen Shipped by Pipeline

In Canada, the National Energy Board (NEB) administers the tariffs, or terms and conditions, that govern the transportation of crude oil by transmission pipeline. For shipments entering the United States, pipeline operators must also file tariffs with the Federal Energy Regulatory Commission. As explained in Chapter 2, tariffs contain quality specifications for crude oil shipments that are intended to ensure compliance with the operational requirements of pipelines as well as possession of properties required by refiners. At custody transfer points, pipeline operators sample shipments to confirm compliance with tariff specifications.

011958

Density and Viscosity Levels

To ensure pipeline transportability, NEB tariffs specify that the density of crude oil shipments not exceed 940 kilograms per cubic meter (kg/m^3) (about 20 degrees API gravity) and that viscosity not exceed 350 cSt[19] when measured at the posted pipeline operating temperature.[20] To meet the specifications, Canadian bitumen is diluted into either "dilbit" or "synbit." The Canadian Association of Petroleum Producers describes dilbit as a bitumen blend consisting of diluent that has a density of less than 800 kg/m^3 (45 degrees API). If it has a density greater than or equal to 800 kg/m^3, the diluent is presumed to be synthetic crude oil, and the blend is called synbit (CAPP 2013).

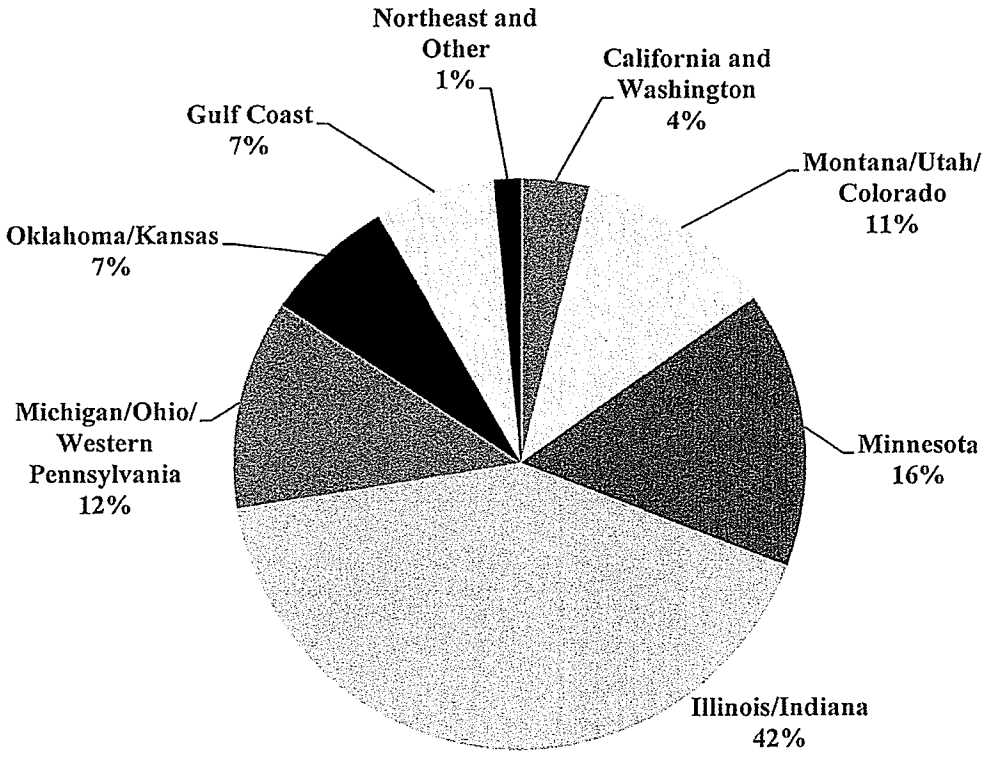

FIGURE 3-5 U.S. refinery destinations for Canadian heavy crude oil imports in 2011. [Source: National Energy Board fact sheet "Disposition of Heavy Crude Oil and Imports" (http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/sttstc/crdlndptrlmprdct/dspstnfdmstccrdlndmprts-eng.html#s1).]

[19] Kinematic viscosity and the centistoke (cSt) unit of viscosity measurement have been defined earlier in this chapter.

[20] For an example, see Article 1, page 3 (Definition for Heavy Crude) of NEB Tariff Number 4, Keystone Pipeline System Petroleum Tariff (http://www.transcanada.com/docs/Key_Projects/06_NEB_Tariff_No_4_Rules_and_Regs_CL.pdf).

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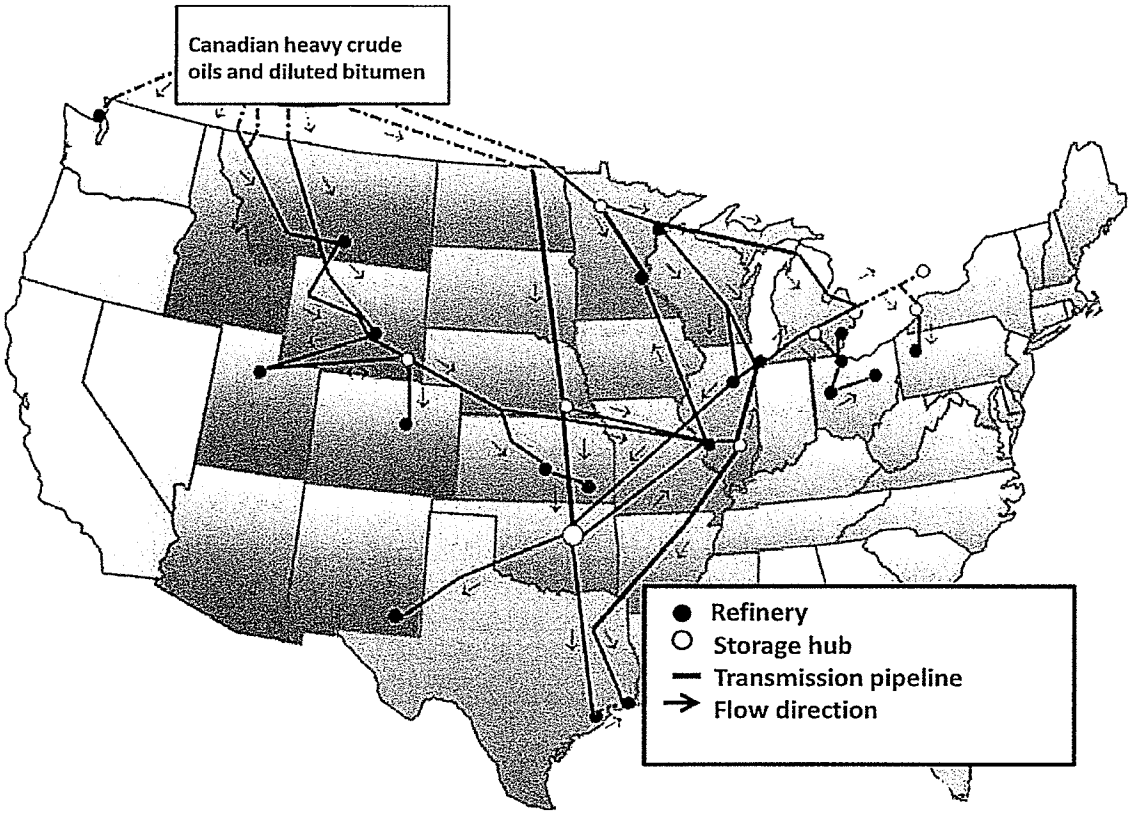

FIGURE 3-6 Main pipeline corridors moving Canadian crude oil to U.S. refineries.

In the case of dilbit, the most common diluents are naphtha-based oils, including natural gas condensate.[21] The light oils that are used have low densities (<750 kg/m^3), high API gravities (>60 degrees), and low viscosities (<1 cSt at room temperature). Compared with condensate, synthetic crude oils have higher densities (825 to 875 kg/m^3), lower API gravities (30 to 40 degrees), and higher viscosities (5 to 20 cSt). Some bitumen shipments are diluted with both condensate and synthetic crude oil to produce "dilsynbit."

Dilution and blending activity is common in the petroleum industry, as distillates and light oils are regularly mixed with heavier oils to alter shipment density and viscosity characteristics. The chemical compatibility of the oils and distillates must be considered before blending, particularly to avoid precipitation of asphaltenes. Thick deposits of these components can foul pipelines, pumps, and other equipment to create an increased need for pig cleaning to prevent flow assurance problems (Cimino et al. 1995; Saniere et al. 2004; Leontaritis and Mansoori 1988). Dilution with distillates containing high concentrations of light hydrocarbons such as pentanes and hexanes can cause asphaltenes to precipitate from oils if the distillate makes up a majority of the volume of the blend (Maqbool et al. 2009). The acceptable types and ratios of distillates blended with bitumen have therefore been analyzed to ensure chemical compatibility as well as a transportable product that does not deposit asphaltenes during postproduction storage and transportation (Schermer et al. 2004).

[21] Condensate liquid is produced from raw natural gas when the temperature is reduced below the boiling temperature of the gas.

As discussed earlier, distillates such as naphtha are usually mixed with bitumen at the production plant to facilitate water and sediment removal. Indeed, all or most of the diluent in diluted bitumen is blended during the processing stage before delivery of shipments for transmission by pipeline. In some cases, more diluent may be added after delivery to the transmission pipeline if further dilution is necessary to meet the density and viscosity levels required for long-distance transportation.[22] Like all crude oil blending, the mixing of diluent and bitumen is designed to make the shipped product miscible, or fully mixed in all proportions. As discussed in Chapter 2, once in the pipeline, batch shipments of diluted bitumen and other heavy crude oils are sequenced to avoid contact with lighter crude oil and condensate shipments. Meters along the pipelines track the batched stream to detect any changes in shipment density and viscosity.

After blending, diluted bitumen becomes a mixture of hydrocarbons with a range of molecular weights. As in the case of other crude oils, these hydrocarbons are separated by distillation at recipient refineries. Table 3-1 compares the distilled volume of light (low-molecular-weight) hydrocarbons in three diluted bitumen crude oils and five light, medium, and heavy crude oils imported from Canada. The light hydrocarbons in all crude oils are mainly

TABLE 3-1 Percentage (by Volume) of Low-Molecular-Weight Hydrocarbons in Selected Diluted Bitumen Blends and Other Canadian Crude Oils

	Access Western Blend (Diluted Bitumen)	Wabasca Heavy (Diluted Bitumen)	Borealis Heavy Blend (Diluted Bitumen)	Koch Alberta (Light Crude Oil)	Light Sour Blend (Light Crude Oil)	Sour High Edmonton (Medium Crude Oil)	Smiley–Coleville (Heavy Crude Oil)	Lloyd Kerrobert (Heavy Crude Oil)
Butanes	0.72	1.93	0.38	4.50	2.43	2.43	0.54	2.04
Pentanes	8.53	1.92	4.01	2.39	3.25	2.56	4.88	6.00
Hexanes	7.06	3.00	5.75	4.54	6.13	4.59	3.95	3.96
Heptanes	4.73	3.47	4.57	5.61	7.44	5.31	2.7	2.12
Octanes	2.74	3.53	5.28	6.09	8.72	5.58	2.12	1.38
Nonanes	1.43	2.64	4.04	4.97	7.18	4.60	2.05	1.36
Decanes	0.70	1.21	1.49	2.49	3.46	2.46	1.10	0.81
Total	25.91	17.7	25.52	30.59	38.61	27.53	17.34	17.67
Mass Recovered	**Distillation Temperature °C (°F)**							
5%	38 (101)	93 (200)	64 (147)	45 (114)	69 (156)	64 (147)	62 (144)	51 (123)
10%	70 (158)	152 (307)	93 (200)	92 (198)	87 (188)	93 (200)	114 (237)	136 (276)

SOURCE: Data obtained from CrudeMonitor.com by Crude Quality, Inc. (http://www.crudemonitor.ca/condensate.php?acr=SLD; http://www.crudemonitor.ca/crude.php?acr=SYN). Accessed March 1, 2013.

[22] Information on production processes was obtained from briefings by and interviews with bitumen producers and pipeline operators.

pentanes or heavier, with some measurable butanes and trace amounts of lighter molecules. Because of the diluent, the light fraction of diluted bitumen is comparable with that of medium and heavy crude oils and accounts for 17 to 27 percent of hydrocarbon volume.

The specific diluents used in blending are selected on the basis of many factors, including their availability in bitumen production regions. Table 3-2 shows the chemical and physical properties of the common diluent Southern Lights, a condensate produced in the United States and piped to Alberta. Because of its low viscosity, this condensate and others can be mixed with bitumen at a ratio of about 30:70 by volume.[23] Table 3-2 also shows the chemical and physical properties of a Suncor synthetic crude oil. Because it has a higher density than condensate, this and other synthetic crude oils are usually blended in even (50:50) ratios with bitumen. Illustrative blending ratios and resulting density and viscosity values for synbit and dilbit are given in Table 3-3.

TABLE 3-2 Selected Properties of Two Common Diluents

Property	Southern Lights Condensate Diluent	Suncor Synthetic Crude Oil Diluent
Density (kg/m^3)	675	861
API gravity (°)	78	33
Sulfur (weight percent)	0.03	0.17
Viscosity at 20°C (68°F) (cSt)	<0.5	6.3
Sediment (parts per million by weight)	16	0

SOURCE: Data obtained from CrudeMonitor.com by Crude Quality, Inc. (http://www.crudemonitor.ca/condensate.php?acr=SLD; http://www.crudemonitor.ca/crude.php?acr=SYN) and from Enbridge website (http://www.enbridge.com/DeliveringEnergy/Shippers/~/media/www/Site%20Documents/Delivering%20Energy/2012CrudeCharaceristics.ashx). Both accessed March 1, 2013.

TABLE 3-3 Example Blending Ratios and Density and Viscosity Levels for Synbit and Dilbit

Blend Component	Volume Percent	Density (kg/m^3)	Viscosity [cSt at 15°C (59°F)]
Synbit			
Bitumen	51.7	1,010	760,000
Synthetic crude oil	48.3	865	5.9
Total	100	940	128
Dilbit			
Bitumen	74.6	1,010	760,000
Condensate	25.4	720	0.6
Total	100	936	350

SOURCE: Illustrative blending ratios provided by R. Segato, Suncor Energy, October 23, 2012 (http://onlinepubs.trb.org/onlinepubs/dilbit/Segato102312.pdf).

[23] These blending ratios are nominal and will vary somewhat depending on seasonal temperatures and the flow regime of individual pipeline operators.

Once they are diluted for transportation, shipments of bitumen have physical properties comparable with those of other heavy crude oil shipments, and they can be stored and transported through the same pipeline facilities in a similar manner—that is, without a need to heat the crude oil to increase fluidity. API gravities for dilbit and synbit blends are generally in the low 20 degrees (a density of about 925 kg/m^3), and viscosities generally range between 75 and 200 cSt at pipeline operating temperatures.

Table 3-4 shows average density, API gravity, and viscosity values for six common diluted bitumen blends. The values are compared with those of six other heavy Canadian crude oils that are commonly piped to the United States. In some cases, these other heavy crude oils are also blended with lighter oils. As would be expected of commercial crude oils, the 12 sampled products have viscosities that conform to requisite pipeline tariff specifications.

According to API, shipments of diluted bitumen enter transmission pipelines at the same temperatures as other Canadian crude oils, generally in the range of 4°C to 25°C (40°F to 75°F) (API 2013). Temperatures will increase as a result of friction as the crude oil flows through the pipeline and because of high ambient temperatures during summer months. Because more pumping energy is needed for viscous crude oils, the temperature will be elevated in pipeline segments downstream from pumps. The temperature gain from pumping, however, will be the same for diluted bitumen as for other crude oils with similar densities and viscosities. Increasing pumping energy to boost the flow rate will raise the temperature further, but this effect will remain the same for all crude oils with corresponding levels of density and viscosity. Within the constraints of the design and safety factors of a pipeline, an operator may elect to increase the flow rate of any crude oil type as a means of adding throughput capacity, but this is strictly an economic decision.

TABLE 3-4 Comparison of Density, API Gravity, and Viscosity of Diluted Bitumen and Other Canadian Crude Oils

Canadian Heavy Crude Oils						
	Bow River	Fosterton	Lloydminster Blend	Lloydminster Kerrobert	Smiley–Coleville	Western Canadian Blend
Density (kg/m^3)	914	927	927	930	932	929
API gravity (°)	23	21	21	20	20	21
Viscosity at 20°C (68°F) (cSt)	100	96	145	146	144	145
Viscosity at 40°C (104°F) (cSt)	37	36	52	52	51	52
Diluted Bitumen						
	Access Western	Cold Lake	Peace River Heavy	Christina Lake	Wabasca Heavy	Surmount Heavy (Synbit)
Density (kg/m^3)	926	928	931	923	935	936
API gravity (°)	21	21	20	22	20	19
Viscosity at 20°C (68°F) (cSt)	150	153	113	178	134	131
Viscosity at 40°C (104°F) (cSt)	53	54	44	62	49	47

SOURCE: Data obtained from CrudeMonitor.com by Crude Quality, Inc. (http://www.crudemonitor.ca/tools/comp/crudecomparisons.php#results) and from Enbridge website (http://www.enbridge.com/DeliveringEnergy/Shippers/~/media/www/Site%20Documents/Delivering%20Energy/2012CrudeCharaceristics.ashx). Both websites accessed March 1, 2013.

011963

Water and Sediment Content

Refiners dislike crude oil feed containing excess water and sediment that requires filtration and added treatment for effluent disposal. Furthermore, they do not want to pay for the transportation of these impurities in crude oil shipments. Water and sediment are also undesirable from the standpoint of pipeline operators because of the potential for internal corrosion, as discussed in Chapter 5. Canadian pipeline tariffs specify that basic sediment and water (BS&W) in crude oil shipments not exceed 0.5 percent by volume. While U.S. tariffs tend to allow higher BS&W limits (1 percent in most cases), the lower Canadian threshold becomes the constraining factor for diluted bitumen and other crude oils piped into the United States from Canada.

Data specifically on the water content of pipeline shipments are difficult to obtain (as distinguished from data on combined water and sediment volumes). Nevertheless, because the Canadian tariffs are generally more restrictive than those in the United States, it can be inferred that shipments of Canadian crude oils, including diluted bitumen, do not contain more water than other crude oils transported in U.S. transmission pipelines. In the case of sediment, any amounts measured in diluted bitumen are likely to derive from the bitumen, since the diluents are largely free of sediment (as shown in Table 3-2). Some sediment sampling data are available to compare diluted bitumen with other Canadian crude oils. Figure 3-7 shows the average sediment levels for

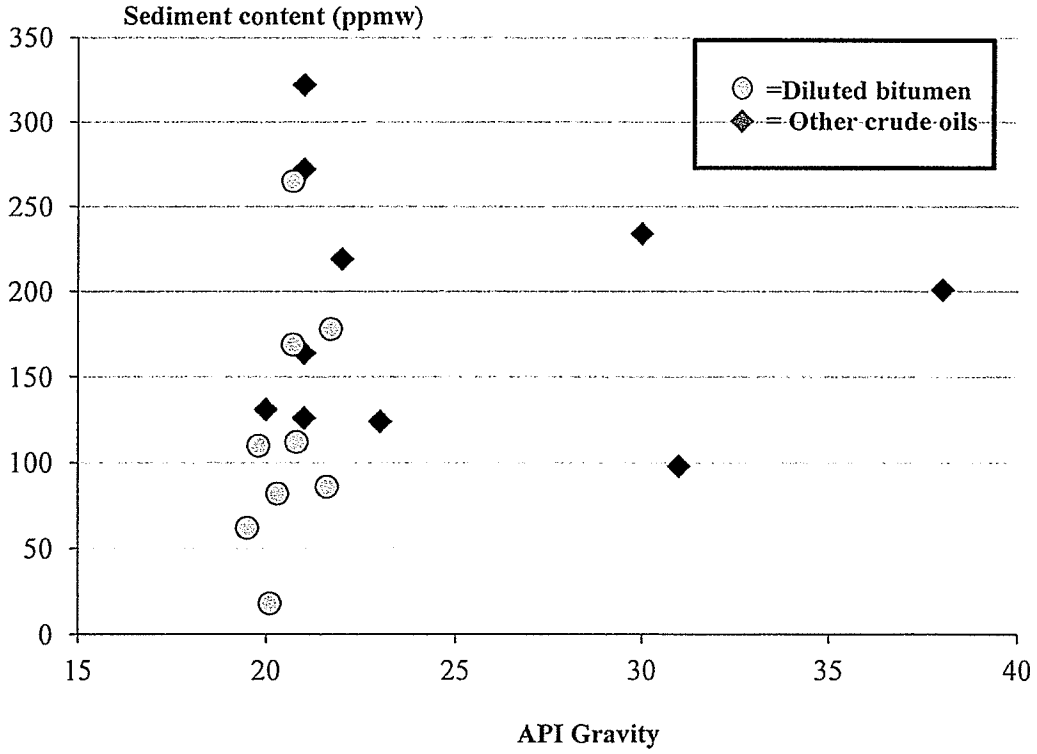

FIGURE 3-7 Average sediment content for nine diluted bitumen blends and 10 light, medium, and heavy Canadian crude oils. [Data obtained from CrudeMonitor.com by Crude Quality, Inc. (http://www.crudemonitor.ca/condensate.php?acr=SLD; http://www.crudemonitor.ca/crude.php?acr=SYN). Accessed March 1, 2013.]

011964

nine diluted bitumen blends and 10 light, medium, and heavy Canadian crude oils. Average sediment levels range from 18 to 265 parts per million by weight (ppmw) for the diluted bitumen and from 98 to 322 ppmw for the selection of Canadian crude oils.[24] Sediment quantities in this general range (<500 ppmw) will constitute less than 0.05 percent of the crude oil stream. The comparisons suggest that shipments of diluted bitumen contain sediment levels that are within the range of other crude oils piped into the United States.

Other characteristics of entrained sediments, such as the size, shape, mass, and hardness of solid particles, are seldom measured in pipeline shipments or reported in standard crude oil assays. Particle size is a potentially important factor in the tendency of sediments to clog pumps and other pipeline equipment and settle to the pipe bottom to form sludge. The shape, mass, and hardness of solid particles in sediment can also affect the potential for internal erosion.

While data on physical properties are limited, some values for particle size and other properties have been reported in laboratory studies of diluted bitumen and other crude oils. Figure 3-8 shows the particle size distribution of solids in diluted bitumen as measured by McIntyre et al. (2012). Median particle size was 0.1 micron (μm) and rarely exceeded 1 μm. Other data indicate that the distribution of particle size observed by McIntyre et al. (2012) is well within the range of other crude oils shipped by pipeline. The Canadian Crude Quality Technical Association (CCQTA) has spot sampled the desalter effluent from three refineries in Canada and the United States. The effluent was derived from crude oils other than diluted bitumen. The

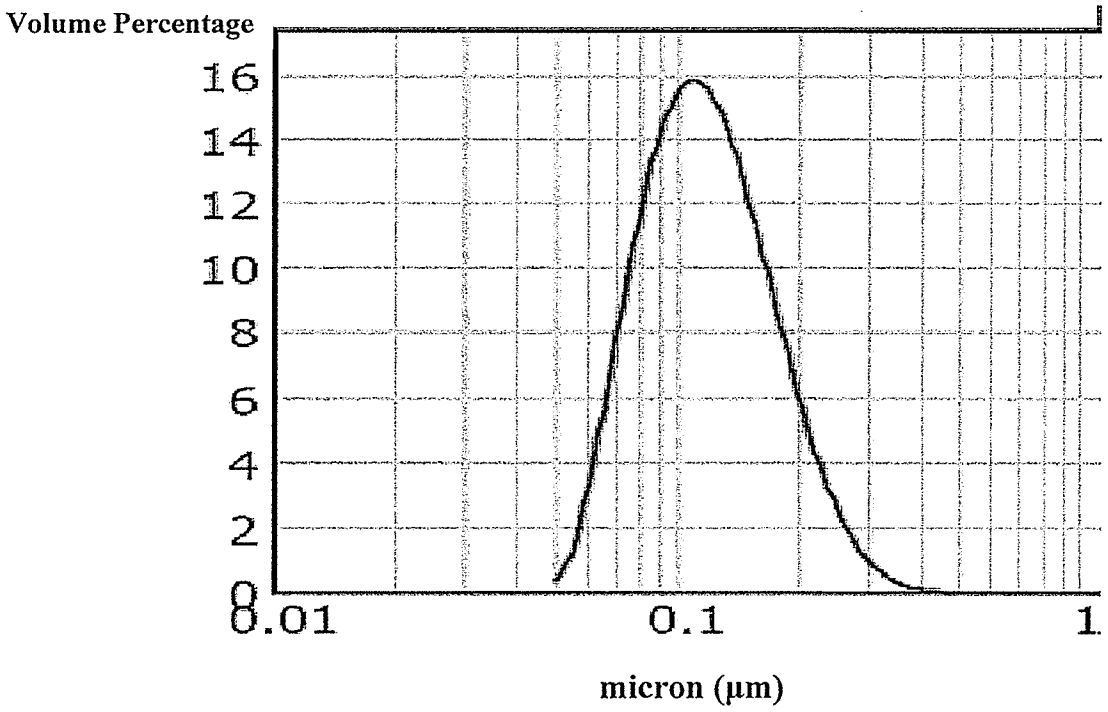

FIGURE 3-8 Particle size distribution of solids in diluted bitumen. (Source: McIntyre et al. 2012.)

[24] Most contaminants are expressed as parts per million (ppm), which is 1 milligram per kilogram for weight (noted as 1 ppmw) or 1 milligram per liter for volume (noted as 1 ppmv). 1,000 ppmw = 0.1 percent of weight.

011965

particle size distributions from these samples are shown in Table 3-5. The median particle sizes for the samples ranged from about 0.4 to 1.6 μm, higher than the median particle size reported for the diluted bitumen sampled by McIntyre et al. (2012).

CCQTA data on the nature of solids filtered from five diluted bitumen and two heavy crude oil samples show median particle sizes that are comparable across the samples, ranging from 1.0 to 2.4 microns for four of the five diluted bitumen samples and from 1.9 to 2.3 microns for the two heavy crude oil samples.[25] The fifth diluted bitumen sample had a median particle size of 5.6 microns. The maximum particle sizes in the five diluted bitumen samples ranged from 11 to 92 microns, while the maximum value for the two heavy crude oils was 33 microns. Data are more limited for characterizing the shape, mass, and hardness of solids in diluted bitumen and other crude oils. As noted earlier, the sand grains in unprocessed bitumen contain hard silicate minerals such as quartz, feldspar, and mica, in addition to the softer minerals found in clay fines (Strausz and Lown 2003, 31–32). However, the in situ–produced bitumen that is processed and diluted for pipeline transportation does not contain the same high levels of sand, clay fines, and other sediments found in bitumen in its native state. McIntyre et al. (2012) reported that about 1 percent of the solids in sampled diluted bitumen consisted of quartz, while clay materials (16 percent) and hydrocarbon and coke-like materials (83 percent) accounted for the remainder. X-ray diffraction analysis of the solids in the five diluted bitumen and two heavy oil samples taken by CCQTA indicate that silicate particles are more abundant in the solids of diluted bitumen (accounting for 13 to 45 percent of crystalline solids) than in the solids of other heavy crude oils sampled (accounting for 5 to 8 percent of crystalline solids).[26] However, the five diluted bitumen samples did not contain high levels of sediment, with none exceeding 350 ppmw (0.035 percent).

TABLE 3-5 Size Distribution of Solid Particles Obtained from Refinery Effluent for Crude Oils Other Than Diluted Bitumen

	Refinery A					Refinery B			Refinery C
Particle Size (μm)	Sample 1	Sample 2	Sample 3	Sample 4	Sample 5	Sample 1	Sample 2	Sample 3	Sample 1
Mean	0.85	1.1	1.13	0.74	1.14	2.67	1.23	0.82	0.98
Mode	0.32	0.31	0.28	0.33	0.39	2.33	0.26	0.53	0.54
Median	0.66	0.86	0.76	0.49	0.81	1.61	0.8	0.43	0.84
Minimum	0.13	0.17	0.13	0.06	0.13	0.06	0.1	0.07	0.15
Maximum	3.38	4.5	9.74	4.0	6.55	21.59	13.3	17.7	4.64
Standard deviation	0.55	0.76	1.05	0.67	0.9	3.09	1.3	1.36	0.6

SOURCE: Data provided by CCQTA and derived from Oil Sands Bitumen Processability Project. Presented to the committee on October 23, 2012 (http://onlinepubs.trb.org/onlinepubs/dilbit/SegatoLimieux102312.pdf).

[25] Data obtained from the CCQTA Oil Sands Bitumen Processability Project. Presented to the committee on October 23, 2012 (http://onlinepubs.trb.org/onlinepubs/dilbit/SegatoLimieux102312.pdf).

[26] Data obtained from the CCQTA Oil Sands Bitumen Processability Project. Presented to the committee on October 23, 2012 (http://onlinepubs.trb.org/onlinepubs/dilbit/SegatoLimieux102312.pdf). According to the CCQTA representative presenting the data, X-ray diffraction analysis does not measure the noncrystalline solids, which can account for 30 percent or more of the solids of sediment.

011966

Other Properties

Pipeline tariffs in Canada and the United States generally do not contain specifications for shipment properties apart from those discussed above, although crude oil producers and refiners may have private agreements that specify qualities such as acidity and sulfur content. Table 3-6 shows the acidity and sulfur content for several sampled Canadian heavy crude oils and diluted bitumen blends.

The acidity of crude oil is generally referenced by using total acid number (TAN), a measure of the amount (in milligrams) of potassium hydroxide (KOH) needed to neutralize the acid in a gram of oil. TAN usually increases with the extent of oil biodegradation and generally is in the range of 0.5 to 3.0 for heavy oils (Strausz and Lown 2003, 430). Although it overlaps with the range of TANs found in heavy Canadian crude oils (as shown in Table 3-6), the range of acid content in diluted bitumen blends is generally higher than the range in other crude oils because of the greater biodegradation of the natural bitumen and resulting concentrations of high-molecular-weight organic acids.

The type of acid in diluted bitumen is more important to pipeline operators than total acid content. High-molecular-weight organic acids, such as naphthenic acids, are stable in the

TABLE 3-6 Sulfur and Total Acid Content in Sampled Canadian Heavy Crude Oils and Diluted Bitumen Blends

	Total Sulfur (percentage by weight)	TAN (mg KOH/g oil)
Canadian Heavy Crude Oils		
Fosterton	3.26	0.2
Lloydminster Blend	3.56	0.82
Lloydminster Kerrobert	3.12	0.92
Western Canadian Select	3.51	0.94
Diluted Bitumen Blends		
Albian Heavy Synthetic	2.5	0.57
Access Western Blend	3.93	1.72
Black Rock Seal Heavy	4.32	1.72
Cold Lake	3.75	0.99
Christina Lake	3.79	1.53
Peace River Heavy	5.02	2.5
Smiley–Coleville Heavy	2.97	0.98
Statoil Cheecham Blend	3.69	1.77
Surmount Heavy Blend Synbit	3.02	1.38
Western Canadian Blend	3.1	0.82

SOURCE: TAN data obtained from CrudeMonitor.com by Crude Quality, Inc. (http://www.crudemonitor.ca/condensate.php?acr=SLD; http://www.crudemonitor.ca/crude.php?acr=SYN). Sulfur data obtained from Enbridge (http://www.enbridge.com/DeliveringEnergy/Shippers/~/media/www/Site%20Documents/Delivering%20Energy/2012CrudeCharaceristics.ashx). Accessed March 1, 2013.

pipeline transportation environment. These acids have boiling points higher than water and do not react at pipeline operating temperatures. Although the organic acids can be corrosive to metals used in refineries processing crude oils at temperatures above 300°C (570°F), they are not corrosive to steels at pipeline temperatures (Nesic et al. 2012). This distinction is discussed further in Chapter 5.

The Canadian heavy crude oils and diluted bitumen contain 2.5 to 5 percent sulfur by weight. Whereas condensate and synthetic crude oils are largely free of sulfur (as shown in Table 3-2), natural bitumen contains 4 to 6 percent sulfur. As described earlier, most of the sulfur in bitumen is bound in stable hydrocarbon structures. Sulfur levels in the 2.5 to 5 percent range, as found in processed bitumen diluted for transportation, are high for light- and medium-density crude oils but not unusual for heavy crude oils. While high sulfur content in crude oil is generally undesirable for refining, it is problematic for transmission pipelines mainly if it exists in surface-active compounds and hydrogen sulfide (H_2S). H_2S is a weak acid that is corrosive to pipelines for reasons explained in Chapter 5. Available test data on the H_2S content in crude oil indicate lower levels in diluted bitumen (less than 25 ppmw in liquid phase) than in other crude oils of various densities (Figure 3-9).

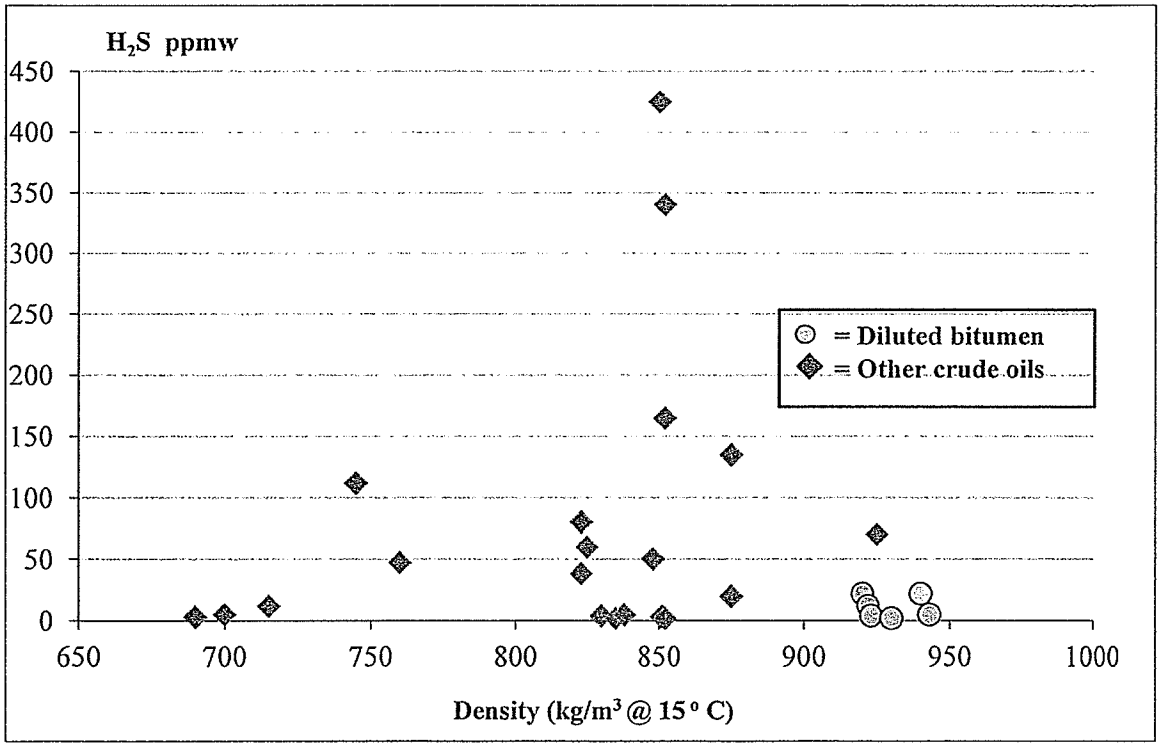

FIGURE 3-9 H_2S content of diluted bitumen and other crude oils. (H_2S is measured in liquid phase by using ASTM Test Method 5263. H_2S remains in a liquid state in pipelines because the partial pressures of operating pipelines are below the bubble point.) (Data submitted to the committee on November 13, 2012, by the Pipeline Sour Service Project Group of CCQTA.)

011968

Shipment Properties and Operating Parameters Reported by Operators

For additional data on the transport properties of diluted bitumen, the committee prepared a questionnaire for the Canadian Energy Pipeline Association (CEPA). CEPA distributed the questionnaire to member companies that regularly transport diluted bitumen by transmission pipeline. The questionnaire and responses from five Canadian operators are provided in Appendix A. A summary of the operator responses on the properties of diluted bitumen is provided in Table 3-7. All of the reported values for BS&W, H_2S, sulfur, density, TAN, and operating temperature are within the ranges provided in the preceding tables and figures.

With respect to the pipeline flow regime, the surveyed pipeline operators reported average flow velocities of 0.75 to 2.5 meters per second (2.5 to 6.7 feet per second) in transmission pipelines that mostly range in diameter from 20 to 42 inches but that include some mileage consisting of pipe having smaller (8 inches) and larger (up to 48 inches) diameters. Without knowledge of the pipe diameter associated with each reported flow velocity, the resulting flow cannot be verified as turbulent. In general, flow velocities ranging between 0.75 and 2.5 meters per second would be expected to maintain turbulent flow in pipelines ranging from 8 to 48 inches in diameter when they transport crude oils with the range of viscosities (113 to 153 cSt at 20°C) reported for the diluted bitumen and other heavy crude oils shown in Table 3-4.

The committee asked pipeline operators for information on the content of oxygen and carbon dioxide in shipments because these dissolved gases can be an important factor in the corrosion of pipe steel, for reasons explained in Chapter 5. Pipeline operators do not routinely measure oxygen and carbon dioxide concentrations in crude oil shipments because of the difficulty associated with sampling and detecting these gases. Nevertheless, the operators reported that because diluted bitumen and other crude oils enter the pipeline system deaerated, there should be no significant difference in the concentrations of oxygen and carbon dioxide gas in products transported in the same pipelines. Operators also reported that as a general matter they aggressively seek to limit avenues for air entry into the pipeline at all times, including periods of storage and blending and pumping operations.

TABLE 3-7 Properties and Operating Parameters of Diluted Bitumen Shipments Reported by Five Canadian Pipeline Operators

Property or Parameter	Unit	Range of Reported Averages	Lowest and Highest Values in Reported Normal Ranges	Highest Reported Extremes
BS&W	Volume percent	0.18 to 0.35	0.05 to 0.40	0.50
H_2S	ppmw	<0.50 to 6.77	<0.50 to 11.0	11.0
Sulfur	Weight percent	3.10 to 4.00	2.45 to 4.97	5.20
Density	API gravity	19.8 to 22.1	19.0 to 23.3	23.3
TAN	mg KOH/g	1.00 to 1.30	0.85 to 2.49	3.75
Operating temperature	°C (°F)	10 to 27 (50 to 81)	4 to 43 (39 to 109)	50 (122)
Flow rate	feet/second	2.5 to 6.7	0.5 to 8.2	8.2
Pressure	psi	430 to 930	43.5 to 1,440	1,440

NOTE: Operators reported that oxygen and carbon dioxide concentrations are not routinely measured in shipments of crude oil. See Appendix A for complete survey results.

011969

SUMMARY

The bitumen imported into the United States is produced from Canadian oil sands. The bitumen is both mined or recovered in situ by using thermally assisted techniques. Because a large share of the bitumen deposits is too deep for mining, in situ recovery accounts for an increasing percentage of production. Because mined bitumen does not generally have qualities suitable for pipeline transportation and refinery feed, it is processed in Canada into synthetic crude oil. Bitumen recovered through use of thermally assisted methods has water and sediment content that is sufficiently low for long-distance pipeline transportation. The bitumen imported for refinery feed in the United States is recovered through in situ methods rather than mining.

Like all forms of petroleum, Canadian bitumen is a by-product of decomposed organic materials and thus a mixture of many hydrocarbons. The bitumen contains a large concentration of asphaltenes and other complex hydrocarbons that give bitumen its high density and viscosity. At ambient temperatures, bitumen does not flow and must be diluted for transportation by unheated pipelines. The diluents consist of light oils, including natural gas condensate and light synthetic crude oils. Although the diluents consist of low-molecular-weight hydrocarbons, diluted bitumen does not contain a higher percentage of these light hydrocarbons than do other crude oils. The dilution process yields a stable and fully mixed product for shipping by pipeline with density and viscosity levels in the range of other crude oils transported by pipeline in the United States.

Shipments of diluted bitumen are transported at operating temperatures, flow rates, and pressure settings typical of crude oils with similar density and viscosity. Water and sediment content conforms to the Canadian tariff limits, which are more restrictive than those in U.S. pipeline tariffs. Solids in the sediment of diluted bitumen are comparable in quantity and size with solids in other crude oils transported by pipeline. While the sulfur in diluted bitumen is at the high end of the range for crude oils, it is bound in stable hydrocarbon compounds and is not a source of corrosive hydrogen sulfide. Diluted bitumen has higher total acid content than many other crude oils because of relatively high concentrations of high-molecular-weight organic acids that are not reactive at pipeline temperatures.

REFERENCES

Abbreviations

API	American Petroleum Institute
CAPP	Canadian Association of Petroleum Producers
ERCB	Energy Resources Conservation Board
NEB	National Energy Board
USGS	U.S. Geological Survey
WEC	World Energy Council

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4

Review of Pipeline Incident Data

This chapter reviews U.S. and Canadian pipeline incident statistics and investigations for insight into whether transmission pipelines experience more releases when they transport diluted bitumen than when they transport other crude oils.

U.S. AND CANADIAN INCIDENT DATA

The Pipeline and Hazardous Materials Safety Administration (PHMSA) requires that all regulated pipeline operators report unintended releases that meet certain thresholds of release quantities or impact severity. PHMSA tracks and analyzes these reports to inform its inspection, investigation, and enforcement activities.[1] PHMSA inspectors also conduct more in-depth investigations of selected incidents. Incidents involving especially severe consequences, such as deaths, injuries, evacuations, and environmental damage, may also be investigated by the National Transportation Safety Board (NTSB). Through field and forensic investigations, NTSB assesses both causal and contributing factors and recommends preventive and follow-up actions, including regulatory responses.[2] The National Energy Board (NEB) and Transportation Safety Board (TSB) serve similar functions, respectively, for incidents involving pipelines in Canada. PHMSA and NEB incident statistics and investigations, as well as relevant investigations by NTSB and TSB, are reviewed next.

PHMSA Incident Data and Investigations

PHMSA regulations require that operators of hazardous liquid pipelines, which include crude oil pipelines, report any incident that involves a release of 5 gallons or more or explosion, fire, serious injury, or significant property damage.[3] Incidents that involve any component of the pipeline facility, including line pipe, tanks, valves, manifolds, and pumps, must be reported. A short reporting form is required for notifying the agency of small releases, and a longer form is required for larger releases and any release into water exceeding 5 gallons. Before 2002 the threshold for reporting releases was 50 barrels. The reporting changes make comparisons of recent release data with historical performance difficult. A further complication of the reporting system is that while PHMSA reporting covers most crude oil pipelines, there are exceptions to coverage, such as some intrastate pipelines and gathering systems.

The number of incidents reported for regulated crude oil pipelines during 2002 to 2011 is shown in Figure 4-1. During the 10-year period, the number of large incidents fluctuated from about 80 to 120 per year. Total releases trended downward from about 190 to 150 per year, with small releases accounting for between one-third and one-half of the total. System components involved in the releases are shown in Figure 4-2. Main-line pipe and tanks were involved in

[1] More discussion of PHMSA safety oversight programs can be found in Appendix B.

[2] NTSB recommendations pertaining to PHMSA's pipeline safety authorities can be found at http://www.phmsa.dot.gov/pipeline/regs/ntsb.

[3] 49 CFR 195.50.

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about one-third of the incidents, while all other equipment, such as pumps, valves, and fittings, accounted for the rest. A generalization that can be made is that the larger releases tend to be associated with main-line pipe, and sometimes with tanks, whereas the other system components tend to experience smaller releases on average. For 2002 to 2012, the pattern of releases by system component and cause is shown in Figure 4-3 and Table 4-1. The causal distribution differed by component. For main-line pipe, internal corrosion was the cause of about one-third of releases, while external corrosion and outside force damage accounted for most of the remainder. For most other pipeline components, incorrect operation and malfunctioning equipment were the main causes of incidents. Most of the corrosion-related incidents reported to PHMSA occurred in pipes and pumps. Main-line pipe was the dominant location for external corrosion. Whereas main-line pipe also accounted for about one-third of incidents involving internal corrosion, more of these incidents occurred in pumps.

Each year, PHMSA inspectors select as many as two dozen pipeline incidents for more thorough investigation on the basis of the severity of the consequences, the nature of the suspected failure modes, and the incident and compliance history of the pipeline system involved. The investigations normally consist of site visits, forensic tests, interviews with operating personnel, and reviews of operator records. Since 2005, PHMSA has conducted 63 investigations of natural gas and hazardous liquid pipelines, including 14 incidents involving onshore crude oil transmission pipelines.[4] The latter incidents are referenced in Table 4-2. In the

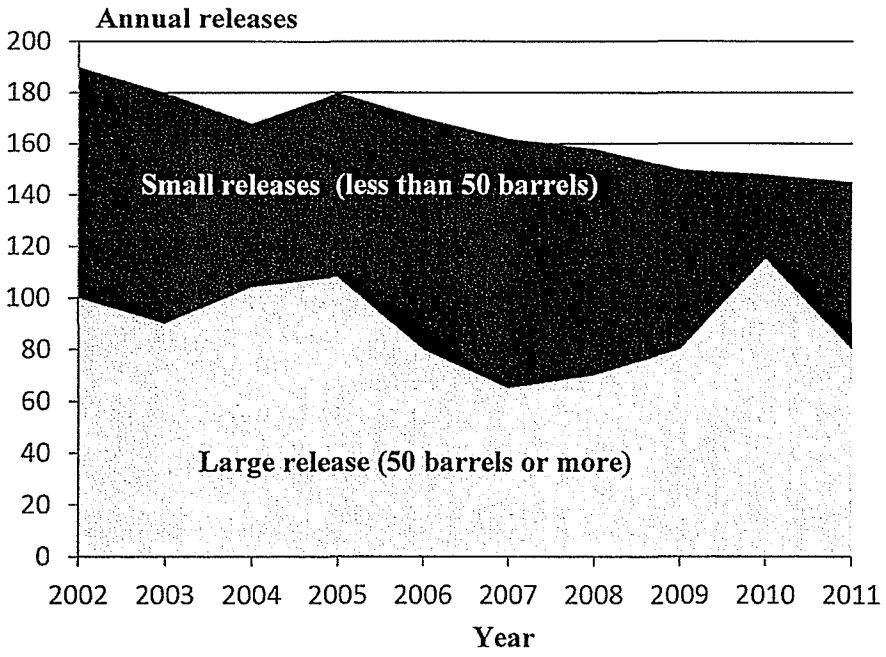

FIGURE 4-1 Crude oil pipeline incidents reported to PHMSA, 2002 to 2011. (Incident data were provided to the committee by PHMSA during the October 23, 2012, committee meeting.)

[4] http://phmsa.dot.gov/pipeline/library/failure-reports.

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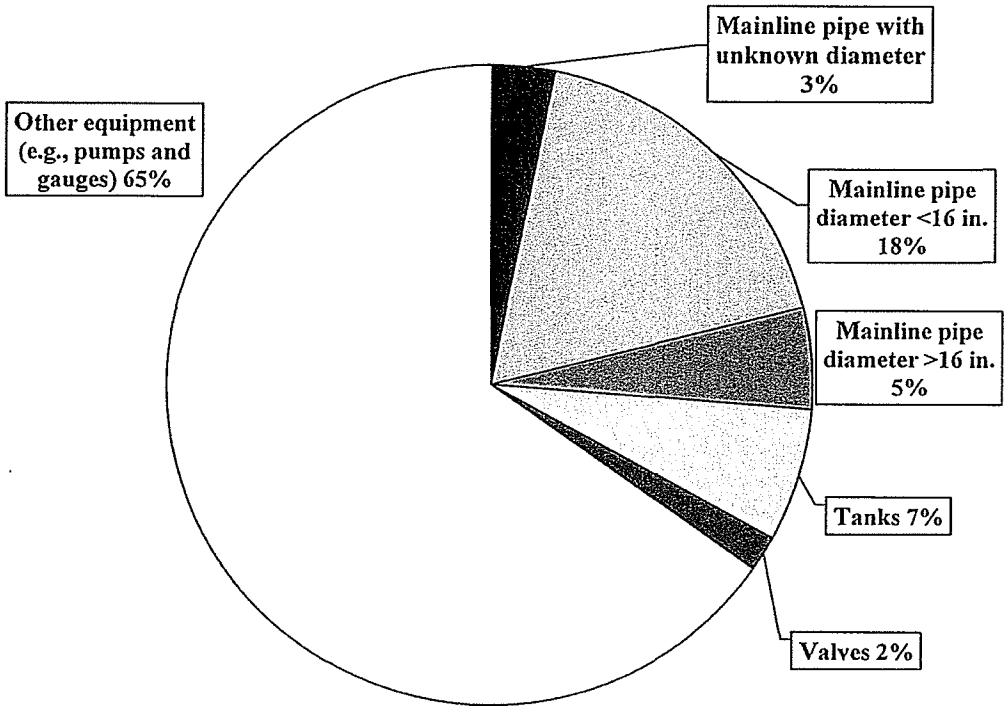

FIGURE 4-2 Crude oil pipeline incidents reported to PHMSA by system component involved, 2002 to 2012. [Data were obtained from analysis of PHMSA data from the Environmental Impact Statement of TransCanada XL permit application (U.S. Department of State 2013, Volume IV, Appendix K).]

two cases found to have involved internal corrosion, factors other than the properties of the crude oils transported were cited as causes. In three other cases, investigators reported that internal pressure cycles and associated stress loadings may have contributed to the formation and growth of cracks initiated at sites of external corrosion.

Apart from providing some examples of possible failures related to the transported product, the PHMSA investigations do not provide evidence that pipelines transporting diluted bitumen are more susceptible to release. In the next chapter, the chemical and physical properties of diluted bitumen are examined to deduce possible susceptibilities to pipeline damage.

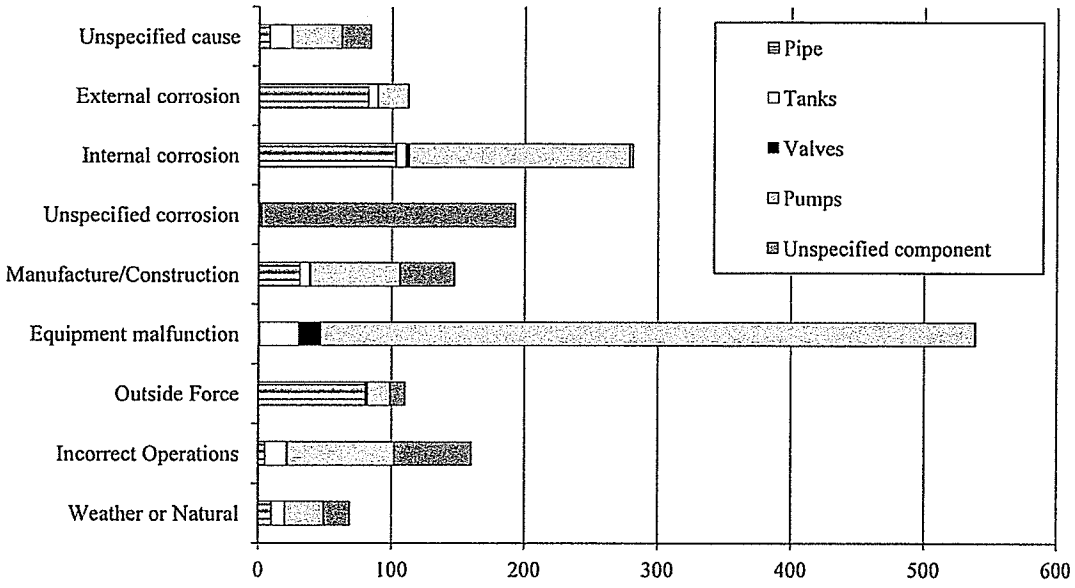

FIGURE 4-3 Crude oil pipeline incident reports to PHMSA by cause of release and system component involved, 2002 to 2012. (Source: U.S. Department of State 2013, Volume IV, Appendix K.)

TABLE 4-1 Crude Oil Pipeline Incident Reports to PHMSA by Cause of Release and System Component Involved, 2002 to 2012

Reports of Pipeline Releases to PHMSA, 2002–2012						
	Pipe	Tanks	Valves	Pumps	Unspecified Component	Total
Weather or natural force	10	10	0	29	20	69
Incorrect operations	5	16	1	80	58	160
Outside force	80	0	2	17	11	110
Equipment malfunction	1	29	17	491	1	539
Manufacture or construction	31	7	1	67	41	147
Unspecified corrosion	1	1	0	0	191	193
Internal corrosion	103	7	3	165	3	281
External corrosion	82	7	0	23	0	112
Unspecified cause	8	16	1	37	22	84
Total	321	93	25	909	347	1,695

SOURCE: U.S. Department of State 2013, Volume IV, Appendix K.

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TABLE 4-2 PHMSA Crude Oil Pipeline Incident Investigations, 2005 to 2012

Date of Failure	Operator	Location	Commodity Released	System Component	Attributed Cause	Summary
4/12/05	Jayhawk Pipeline	Stevens, Kansas	Crude oil	7-in. main-line pipe section	Internal corrosion	Sand and saltwater collected in a low point in the pipeline, resulting in corrosive conditions.
1/1/07	Enbridge Energy Partners	Clark County, Wisconsin	Crude oil from Canada	24-in. main-line pipe section	Defect in manufacture	Weld seams did not fuse during pipe manufacture. The defect grew to a critical size by fatigue from operating pressure cycles.
11/13/07	Enbridge Energy Partners	Clearbrook, Minnesota	Crude oil from Canada	34-in. main-line pipe section	Defect in manufacture	Pipe was transported to the construction site on rail cars, causing fatigue cracks from cyclical loading. Pressure cycling during operations may have caused the cracks to grow to failure.
2/18/09	Mid-Valley Pipeline	Cygnet, Ohio	Crude oil	12-in. branch connection to main line	Material failure	The combined loading of the branch connection, valve, and flanging caused the branch attachment to crack at the weld.
6/9/09	Enbridge Energy Partners	Gowan, Minnesota	Crude oil from Canada	26-in. main-line pipe section	Material failure	A sleeve installed 20 years earlier to repair a pipe split opened at a deficient weld.
12/23/09	Enterprise Products	Galveston, Texas	Crude oil from offshore	Meter station component	Material failure in a fitting	Cap screws on a stainless steel pressure switch failed because of hydrogen-assisted cracking promoted by galvanic corrosion.
3/1/10	Mid-Valley Pipeline	Gregg County, Texas	Crude oil	Tank farm manifold piping	Internal corrosion	Internal corrosion occurred in a dead-leg section of pipe with no flow during normal operations.
6/11/10	Chevron Pipe Line	Salt Lake County, Utah	Crude oil	10-in. main-line pipe section	Outside force damage	An electric charge jumped from a metal fence to the pipe, creating a 0.5-in. hole in the top of the pipe.
6/14/10	Suncor Energy Pipeline	Laramie, Wyoming	Crude oil	Breakout tank	Incorrect operation	Operating personnel did not respond to an alarm indicating tank capacity had been reached.

(*continued*)

TABLE 4-2 (*continued*) PHMSA Crude Oil Pipeline Incident Investigations, 2005 to 2012

Date of Failure	Operator	Location	Commodity Released	System Component	Attributed Cause	Summary
11/16/10	Shell Pipeline	Vinton, Louisiana	Crude oil from offshore	22-in. main-line pipe section	Material failure	The coating disbonded at a bend in the pipe allowing the onset of corrosion. Cyclical loading due to normal batch operations may have contributed to crack growth.
12/1/10	Chevron Pipe Line	Salt Lake County, Utah	Crude oil (condensate)	Valve used for water injection in main line	Incorrect operation	Water was not properly drained from the valve. Internal pressure brought on by freezing water caused the valve connection to leak.
1/26/11	Chevron Pipe Line	Plaquemines Parish, Louisiana	Crude oil from offshore	10-in. main-line pipe section at river crossing	Excavation damage	The pipeline was being lowered while in service. Stress concentrations from the procedure caused fracturing in an area with preexisting dents.
2/21/11	Enterprise Products	Cushing, Oklahoma	Crude oil	8-in. pipe within terminal area	Incorrect operation	Personnel purging a pipe failed to shut down the pump, which resulted in the delivery being pumped against a closed valve, causing a pipe with preexisting manufacturing defects to fail.
7/1/11	ExxonMobil Pipeline	Laurel, Montana	Crude oil	12-in. main-line pipe section	Outside force damage	River flooding caused debris to strike and rupture the line.

SOURCE: PHMSA's pipeline failure investigation reports can be found at http://phmsa.dot.gov/pipeline/library/failure-reports.

NEB Incident Statistics

NEB regulates interprovincial pipelines in Canada. The regulated network consists of 11,000 miles of crude oil pipeline, nearly all of which are in transmission systems. Regulated operators must file an "accident" record if a pipeline facility experiences a fatal or serious injury, fire, or explosion due to a release; any other damage to the pipeline that causes a release; and any form of outside force damage, even if it does not lead to a release. In addition, operators are required to file an "incident" report in the event of an uncontrolled release, operations that exceed design limits, an abnormality that reduces structural integrity, or a shutdown for safety reasons. These reported incidents do not necessarily involve releases.

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From 2004 to 2011,[5] NEB received 12 accident reports and 292 incident reports involving crude oil transmission pipelines (TSB 2012, Table 5). Of the 292 incidents involving pipeline integrity issues—such as internal and external degradation—cracks accounted for the largest share, almost 30 percent (see Figure 4-4). Metal loss, mainly from corrosion, was reported in 16 percent of incidents. Of the 12 accident reports, one involved combined corrosion and cracking (stress corrosion cracking), as discussed in more detail below.

NTSB and TSB Investigations

The main transportation safety investigative bodies in the United States and Canada are NTSB and TSB, respectively. Although their pipeline investigations are thorough, they are infrequent and selective. For example, over the past decade NTSB has investigated fewer than a dozen

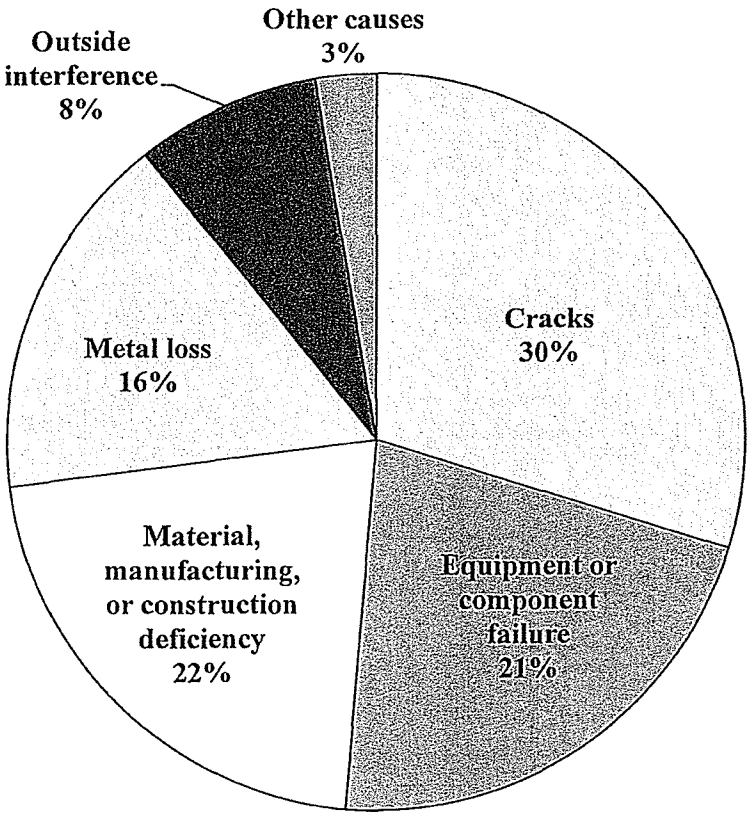

FIGURE 4-4 Causes of crude oil transmission pipeline incidents reported to NEB, 2004 to 2011. (Source: TSB 2012, Table 5.)

[5] Before 2004, the definition of reportable incident used by NEB was different from that used today. The reporting change makes longer-term trend analysis less meaningful.

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pipeline incidents, most involving pipelines carrying volatile commodities such as natural gas and refined products.[6] The investigations are helpful in understanding factors that can interact to cause pipeline damage and failures, but they produce limited information useful in assessing the effect of specific crude oil types or crude oil properties on pipeline release probabilities.

In 2012, NTSB completed an investigation of a pipeline failure in which diluted bitumen was reported to have been released. The incident involved a 30-inch transmission pipeline that ruptured and released 20,000 barrels of product into a river near Marshall, Michigan (NTSB 2012). The investigators determined that the cause of the rupture was cracks that had formed in a corrosion pit on the outside of the pipe under a disbonded polyethylene tape coating. The cracks coalesced and grew as a result of stresses on the pipe, a process known as environmentally assisted cracking (EAC), which is described in more detail in Chapter 5. The Marshall release attracted considerable attention because of the consequences of the release and the actions of the operator. However, NTSB did not report that specific properties of the products transported through the pipeline at the time of the event or in the past had caused or contributed to the pipeline damage.

As noted above, one of the 12 crude oil pipeline accidents reported to NEB since 2004 involved a corroded and cracked pipeline. This release, which occurred in 2007, was investigated by TSB.[7] The release was from a 34-inch transmission pipeline originating in Alberta and transporting crude oil to the United States (TSB 2007). A forensic analysis of the ruptured pipe joint detected a shallow corrosion pit at a weld on the outside of the pipe that led to a stress corrosion crack, which eventually spread and fractured the pipe. TSB investigators determined that the polyethylene tape coating had tented over the weld, shielding the pipe from the beneficial effects of the cathodic protection current.[8] The corrosion pit that developed because of the tape failure became a stress concentration site where cracks formed and grew. TSB noted that 2 years earlier the operator had converted the pipeline to batch operations and surmised that this operational change may have contributed to crack growth as a result of more cyclic stress loadings from internal pressure fluctuations. Whether specific varieties of crude oil in the stream had properties that contributed to more severe pressure cycling was not reported by TSB.

A review of other NTSB and TSB investigations over the past decade did not indicate any cases in which specific crude oil types or shipment properties were associated with causes of pipeline damage or failure.

Assessment of Information from Incident Reports

The causes of pipeline incidents reported to PHMSA are proximate and broadly categorized. Incidents categorized as corrosion damage, for example, do not distinguish among those occurring as a result of the action of microorganisms, in combination with stress cracking, or at sites of preexisting mechanical damage. Some types of damage, such as EAC, may be categorized alternatively as caused by corrosion, a manufacturing defect, or a material failure. Whereas NTSB and TSB investigations provide detailed information on factors causing and

[6] NTSB pipeline investigation reports are available at http://www.ntsb.gov/investigations/reports_pipeline.html.

[7] NEB may conduct its own investigations of a reported incident to ensure that safety regulations are being followed and to determine the need for remedial actions.

[8] When the tape disbonds from the pipe steel, moisture can accumulate beneath the tape surface. Because the tape has fairly high electrical insulation properties, it can prevent cathodic protection current from reaching the exposed steel subject to corrosion.

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contributing to pipeline releases, the investigations are too few in number to assess the causal effects of specific crude oil types and their properties.

Because of the potentially large number of factors associated with a given release, it is often difficult to isolate the role of any single causative factor, such as the effect of the specific crude oil being transported on time-dependent mechanisms such as corrosion and cracking. Sources of pipeline damage affected by the crude oils transported, either at the time of the release or in earlier shipments, are most pertinent to this study. Neither PHMSA nor NEB incident data contain informationon the types of crude oils transported or the properties of past shipments in the affected pipeline.

STATE AND PROVINCIAL INCIDENT DATA

Some U.S. states and Canadian provinces maintain reporting systems for incidents in intrastate and intraprovincial pipeline systems, including gathering lines. The Energy Resources Conservation Board (ERCB) holds this responsibility in Alberta. In the United States, several state regulators have authority over intrastate pipelines, including the state fire marshal of California. Pipeline incident data and analyses derived from both of these jurisdictions were considered.

Alberta ERCB Incident Data

The Alberta ERCB regulates and monitors the safe performance of oil pipelines in the province, with the exception of approximately 700 miles of NEB-regulated transmission pipeline crossing into other provinces and the United States.[9] ERCB mandates reporting of all pipeline incidents involving a release or damage from an outside force. In 2007, the agency reviewed the causes of 411 crude oil pipeline incidents reported from 1990 to 2005 (EUB 2007). The ERCB analysis showed that the largest single cause was internal corrosion, which the agency ascribed to the effects of the large percentage of gathering pipelines in the province. These small-diameter lines were described as susceptible to internal corrosion because of repeated low-flow conditions; frequent stopping and idling of movements; and the mixture of raw crude oil, gases, sediments, and waters carried from production fields (EUB 2007, 30). About 29 percent of the roughly 11,000 miles of ERCB-regulated pipeline mileage consisted of pipe with a diameter of 4 inches or less, and 73 percent had a diameter of 12 inches or less. Only about 1 percent of the mileage consisted of pipelines having a diameter of more than 22 inches.

Although ERCB release statistics have at times been cited as evidence of a corrosive effect of diluted bitumen on pipelines (Swift et al. 2011), the regulated systems represented by these incident statistics are not comparable with transmission pipelines in size, operations, or, most important, contents. As a result, the committee concluded that the ERCB data were not useful for the purposes of this study.

California Pipeline Safety Study

Pipeline operators in California have a long history of transporting crude oils with physical properties similar to those of Canadian crude oils and diluted bitumen. Most of the oil from the

[9] The Energy and Utilities Board regulated pipelines in Alberta until it was replaced in 2008 by ERCB.

San Joaquin Valley, for instance, has an American Petroleum Institute (API) gravity of 18 degrees or less, with the Kern River field producing especially dense crude oil with an API gravity of about 13 degrees (Sheridan 2006). Like bitumen producers, California oil producers commonly use thermal recovery techniques, such as injecting steam through the wellbore, to reduce crude oil viscosity and facilitate pumping to the surface. Heavier California crude oils are often transported undiluted through heated pipelines. This is not the case for Canadian bitumen, which is diluted for transportation.[10]

California has nearly 3,300 miles of transmission pipelines subject to federal safety regulation.[11] In addition, the state contains 3,000 to 4,000 miles of state-regulated pipeline, most of it in gathering systems. Responsibility for regulating the safety of hazardous liquid pipelines in California is shared by PHMSA and the California State Fire Marshal (CSFM).

In 1993, CSFM issued a report of the incident history of hazardous liquid pipelines in the state from 1981 to 1990 (CSFM 1993). The report examined releases from state and federally regulated lines, including those transporting refined petroleum products. Operators were required to submit records of releases during the period regardless of release quantity or consequences, along with information on pipeline diameter, length, age, operating temperature, and external coating type. Although the report is now 20 years old, its results have been cited as indicative of the potential effects of diluted bitumen on pipeline integrity (NRDC 2011).

The CSFM study documented 502 releases from hazardous liquid pipelines in California during the 10-year period. Analyses of the incident records indicated that external corrosion was the leading cause of releases, accounting for 59 percent, followed by third-party damage (20 percent), equipment malfunctions (5 percent), and weld failures (4 percent). Internal corrosion accounted for 3 percent, while operator error accounted for 2 percent.[12] Crude oil pipelines generated 62 percent of total releases, including 70 percent of the releases attributed to external corrosion.

While the CSFM study did not investigate each reported incident in depth, statistical analyses of the 502 records presented some patterns of interest. The age of the pipeline was correlated with a higher release rate. For example, 62 percent of the releases occurred in pipelines constructed before 1950, even though these lines accounted for only 18 percent of pipeline mileage. CSFM noted that many of the pipelines built in California during the first half of the 20th century lacked cathodic protection for most of their service lives, which suggests that the lack of cathodic protection, coupled with the absence of coatings or use of older coating materials, may have led to the high incidence of external corrosion relative to other failure causes.[13] The CSFM analysis revealed that 22 percent of the external corrosion incidents occurred in pipelines that were uncoated, and another 53 percent occurred in pipelines coated or wrapped with certain materials, most often asphalt and tar.

One finding that stood out among pipelines experiencing external corrosion was the disproportionate number of small-diameter pipelines that were operating at relatively high temperatures. Operating temperature was highly correlated with external corrosion—more than half the releases from external corrosion occurred in the 21 percent of pipeline mileage in which

[10] As discussed in Chapter 2, California oil fields are served by transmission pipelines that connect to refineries elsewhere in the state. The transmission pipelines do not cross state borders.

[11] Pipeline mileage by state is available at the following PHMSA website: http://primis.phmsa.dot.gov/comm/reports/safety/CA_detail1.html?nocache=9253#_OuterPanel_tab_5.

[12] All other causes accounted for 7 percent of releases.

[13] As is discussed in Chapter 5, some older coating technologies shield cathodic protection currents.

the operating temperature regularly reached or exceeded 55°C (130°F). In addition, a large portion of the pipelines experiencing external corrosion consisted of small-diameter pipe. Although they accounted for only 13 percent of pipeline mileage, pipelines with diameters of less than 8 inches accounted for 21 percent of external corrosion incidents. Larger pipelines, with diameters of 16 inches or more, accounted for 23 percent of mileage but only 6 percent of the external corrosion incidents.

The preponderance of external corrosion incidents in smaller-diameter pipe and pipelines with high operating temperatures does not indicate that transmission pipelines contributed to the high rate of pipeline releases in California during the 1980s. Instead, the results suggest that older lines, many of which lacked modern coatings and cathodic protection for much of their operating history, were the main source of the releases. The high operating temperatures of many of these pipelines can be attributed to the thermal recovery methods used for California crude oil production. While the California experience illustrates the problems that can arise when pipelines are not properly protected against external corrosion, it is not indicative of the protections afforded crude oil transmission pipelines today.[14]

SUMMARY

A logical step in addressing the question of whether shipments of diluted have a greater propensity to causes pipeline releases than shipments of other crude oils is to examine historical release records. The incident statistics can be used to identify the general sources of pipeline failure. However, the information contained in the U.S. and Canadian incident records is insufficient to draw definitive conclusions. One reason is that the causal categories in the databases lack the specificity needed to assess the particular ways in which transporting diluted bitumen can affect the susceptibility of pipelines to failure. Another reason is that incident records do not contain information on the types of crude oil transported and the properties of past shipments in the affected pipeline. Because many pipeline releases involve cumulative and time-dependent damage, there is no practical way to trace the transportation history of a damaged pipeline to assess the role played by each type of crude oil and its properties in transport.

Incident reporting systems in Canada and the United States do not have uniform reporting criteria and coverage. Given the relatively small number of pipeline incidents, even minor variations in reporting criteria can lead to significant differences in incident frequencies and causal patterns. Some reporting systems combine incident reports from oil gathering and transmission systems, while others do not. Variation in reporting coverage is problematic because gathering pipelines are fundamentally different from transmission pipelines in design, maintenance, and operations and in the quality and quantity of the liquids they carry.

REFERENCES

Abbreviations

CSFM	California State Fire Marshal
EUB	Energy and Utilities Board
NRDC	Natural Resources Defense Council

[14] All hazardous liquid transmission pipelines are required by federal regulation to have cathodic protection.

NTSB	National Transportation Safety Board
TSB	Transportation Safety Board of Canada

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5

Assessing the Effects of Diluted Bitumen on Pipelines

This chapter examines the main causes of pipeline failure and the physical and chemical properties of the transported crude oils that can affect each. The relevant properties of diluted bitumen and other crude oil shipments are compared to make judgments about whether transporting diluted bitumen increases the likelihood that a pipeline will fail. Consideration is then given to whether pipeline operators, in transporting diluted bitumen, alter their operating and maintenance procedures in ways that can inadvertently make pipelines more prone to failure.

The following sections examine the potential sources of failure in pipelines from (*a*) internal degradation, (*b*) external degradation, and (*c*) mechanical forces. Because it is exposed to the shipped liquid, the inside of the pipe is the most obvious location to look for possible sources of damage from shipments. Corrosion is the main cause of internal degradation in crude oil transmission pipelines, followed to a lesser extent by erosion. Although the outside of the pipeline is not in contact with the shipped liquid, pipeline operating conditions associated with the shipment can affect the exterior of a transmission pipeline. Corrosion and cracking are the main sources of external degradation that can be affected by these conditions. Mechanical damage to the pipeline from overpressurization and outside forces also can be affected indirectly by the liquid in the pipeline.

SOURCES OF INTERNAL DEGRADATION

Pipelines sustain internal damage primarily as a result of progressive deterioration caused by corrosion and erosion of the mild steel used to manufacture line pipe. Internal corrosion is an electrochemical process that typically causes damage to the bottom of the pipe when water is present. Erosion is a mechanical process that causes metal loss along the interior wall of the pipe because of the repeated impact of solid particles, particularly at bends and other areas of flow disturbance. Both forms of attack reduce pipe wall thickness and can penetrate the wall fully to cause leaks or decrease the strength of the metal remaining in the wall to produce a rupture. Internal corrosion is more prevalent than erosion in crude oil transmission pipelines. Both sources of internal pipeline damage are reviewed next, and the potential for diluted bitumen to affect their occurrence in crude oil transmission pipelines is assessed.

Internal Corrosion

The electrochemical process that causes iron in steel to corrode involves anodic and cathodic reactions. The main anodic reaction is the oxidative dissolution of iron. The main cathodic reaction is reductive evolution of hydrogen. The main species that contribute to a higher rate of corrosion are dissolved acid gases such as carbon dioxide (CO_2) and hydrogen sulfide (H_2S) as well as organic acids. For the electrochemical reactions to occur, an ionizing solvent must be present, which in the pipeline environment is usually water. Salts, acids, and bases dissolved in the water create the necessary electrolyte.

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To prevent external corrosion, pipes are coated on the outside surface and cathodic protection is applied. In the case of internal corrosion, protecting the steel through the use of a coating or cathodic protection is impractical for various reasons. To prevent internal corrosion, therefore, pipeline operators try to keep water and other contaminants out of the crude oil stream and to design their systems so as to reduce places where any residual quantities can accumulate on the pipe bottom. They also use operational means to limit deposition, including maintenance of turbulent flow; periodic cleaning with pigs; and the injection of chemicals, called corrosion inhibitors, that disperse and suspend water in the crude oil and form a protective barrier on the pipe surface.

When crude oil is pumped from the ground, it is accompanied by some water and varying amounts of CO_2 and H_2S as well as certain organic acids. Crude oil producers try to minimize these impurities in delivering a stabilized product to the transmission pipeline, but eliminating them is prohibitively expensive. Transmission pipelines carrying crude oil therefore typically have some small amount of water and sediment (usually less than 1 percent by volume), and dissolved CO_2 and H_2S will exist in even smaller quantities. Of interest to this study is whether diluted bitumen contains any more of these corrosive contaminants than do other crude oils or whether these contaminants are more likely to settle and accumulate on the bottom surface of pipelines transporting diluted bitumen.

The various means by which water, sediment, dissolved gases, and other materials can cause internal corrosion of crude oil transmission pipelines are reviewed next.

Water Deposition and Wetting

Oil by itself is not corrosive to mild steel pipe in the temperature range in which transmission pipelines operate, which is typically well below 100°C. Water contact with the inside pipe wall is an essential precondition for internal corrosion. Pure water is not a significant source of corrosion when it acts alone. As discussed in more detail below, however, water in the presence of certain dissolved contaminants, such as CO_2, H_2S, and oxygen (O_2), will cause corrosion if the water is allowed to contact and wet the steel surface of the pipe. In theory, a pipeline carrying oil and a small amount of water will not experience internal corrosion if the water is dispersed and suspended in the oil rather than flowing as a separate phase in contact with the bottom of the pipe. The following factors can affect whether water falls out of the oil flow to cause water wetting of the steel surface:

- *Flow rate:* When oil and water move through a horizontal pipeline at low flow rates, gravitational force will dominate turbulent forces and cause the water to flow as a separate layer. As the rate of flow increases, the turbulence energy of the flow will increase, causing the water to become gradually more dispersed and entrained in the oil. The turbulence will cause water to break up into smaller droplets, and it will keep these finer droplets suspended.
- *Water content:* The more water present in the flow, the harder it becomes for the flowing oil to suspend all water droplets. Thus, water settles more readily when there is more of it in the pipeline stream.
- *Pipe diameter and inclination:* Water is more difficult to keep entrained as the diameter of the pipeline increases as long as other parameters remain the same, including the flow rate and physical properties of the crude oil. Pipe inclination has a comparatively small effect on the ability of oil to entrain water if the inclination is less than 45 degrees.

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- *Physical properties of the oil and water:* The density and viscosity of water and oil play an important role in water entrainment and settling. In general, oils that have high density and viscosity are better able to entrain water than are lighter oils, in part because the density of a heavy oil will be close to that of water. Another important physical property is the oil and water interfacial tension, or tendency of the water and oil to mix or separate. Interfacial tension is affected by the presence of surface-active substances naturally found in the crude oil as well as by surfactant chemicals that may be injected into the flow by the pipeline operator.
- *Chemical additives:* Chemicals injected into the flow stream can significantly influence water entrainment, primarily by affecting interfacial tension. As explained in Chapter 2, pipeline operators add corrosion-inhibiting chemicals to the oil stream to adsorb onto the steel surface and provide a protective layer against corrosion and water wetting. Another benefit of these additives is that they usually contain surface-active compounds that decrease oil and water interfacial tension so as to make it more difficult for water to separate from the oil flow. Conversely, chemical demulsifiers that are added to oil to remove water during processing before delivery to the pipeline can have the undesired effect of increasing the interfacial tension and thus causing easier separation of oil and water in the pipeline flow. Finally, the drag-reducing agents that are sometimes added by pipeline operators to enhance throughput can lower the ability of flowing oil to entrain water by dampening turbulence.

Solids Deposition

Solids in the crude oil stream settle to the pipe bottom for the same hydrodynamic reasons described above for water dropout. Typically the settled solids consist of a mix of inorganic and organic components. Sand, clay, detached scale, and corrosion products (such as carbonates and sulfides) are usually the main inorganic components of settled solids. Organic components commonly consist of asphaltenic and paraffinic compounds as well as other organic material formed by the action of microorganisms (Mosher et al. 2012; Friesen et al. 2012). The corrosive effect of microorganisms in pipeline deposits is discussed in more detail later in the section.

When the flow rate and associated turbulence are low, solids can settle and accumulate, particularly at the bottom of horizontal lines. When no water is present, the deposition of solids can impede flow to create a flow assurance problem. When the solids settle with water, the mix is often referred to as sludge. A porous layer of settled solids can retard corrosion by water containing aggressive species, because the solids will cover part of the steel surface and make it harder for those species to reach the surface. However, a porous layer of solids can also impede access to the steel surface by corrosion-inhibiting chemicals. In this case, the internal surface of the pipe that is covered by a layer of solids may corrode faster than the rest of the surface not covered by solids but protected by the chemical inhibitors. This adverse effect can be compounded by an unfavorable galvanic coupling between the unprotected area covered by the solids and the surrounding areas that are chemically inhibited.

The basic sediment and water (BS&W) content of a crude oil shipment, as described in the previous chapters, is a common measure of the amount of solids and water carried and can be used to predict the likelihood of deposit formation. Even when BS&W is very low (less than 0.5 percent by volume) and the fluid velocity is relatively high (>1 meter per second or >2 miles per hour), some accumulated solids and water may be found in low spots in the pipeline and in dead legs, where the flow rate is low or stagnant. Sludge deposits holding water containing the

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dissolved gases, acids, and microorganisms discussed next are the source of a common form of localized internal corrosion commonly referred to as underdeposit corrosion.

Corrosive Effect of CO_2

CO_2 dissolved in water can have a particularly corrosive effect in pipelines, as evidenced by the series of reactions that ensue (DeWaard and Milliams 1975). Water containing dissolved CO_2 that forms carbonic acid (H_2CO_3) and wets the pipe surface leads to the dissolution of iron (Fe) from the pipe steel and the evolution of hydrogen (H_2) from the water. This weak acid partially dissociates in water to produce the bicarbonate ion (HCO_3^-) and protons (H); in water the protons are present as hydronium ions (H_3O^+). Bicarbonate ions dissociate further to produce more hydronium ions and carbonate ions (CO_3^{2-}). The hydronium ion is highly reactive as it seeks to obtain a missing electron from nearby species. In giving up electrons to hydronium ions, the iron atoms on the pipe surface are destabilized, and they dissolve in the water to form iron ions (Fe^{2+}). By obtaining the resulting electrons, the hydronium ions are converted to dissolved hydrogen gas (H_2). The corrosion by-product is iron carbonate ($FeCO_3$), which may deposit on the steel surface and be protective in some cases.

Keeping CO_2 out of the crude oil stream is particularly important because the ensuing corrosion process can occur rapidly. The reason is that as the hydronium ions are consumed by the corrosion reaction, the carbonic acid dissociates further to replenish the reactive ions, which allows the corrosion process to continue at a fast rate. As long as there is sufficient CO_2 to produce the carbonic acid, the iron in pipe steel that is water wet will continue to corrode. The full series of chemical reactions involved in CO_2 corrosion is detailed in Box 5-1.

Corrosive Effect of H_2S

H_2S is another gas that may be present in the crude oil stream to create corrosive conditions inside pipelines when it is dissolved in water. Crude oil is often extracted with some amount of H_2S. The concentrations in crude oil can be small [less than 100 parts per million (ppm) in the gas phase] or substantially larger. Other sulfur compounds in crude oil are less common, and they are typically soluble in oil rather than water, requiring high temperatures (>300°C) to become reactive (Nesic et al. 2012). Thus, their concentrations do not present a corrosion problem in transmission pipelines.

The reactions that cause H_2S to corrode pipe steel are generally similar to those described for CO_2. Like CO_2, H_2S gas is soluble in water. As a weak acid, the dissolved H_2S behaves in a manner similar to carbonic acid (H_2CO_3) by providing a reservoir of reactive hydronium ions. An important difference is that the layer of protective iron sulfide (FeS) always forms on the steel surface as a result of the reactions involving H_2S. Experimental evidence indicates that H_2S corrosion initially proceeds by adsorption of the H_2S to the steel surface. This adsorption is followed by a fast surface reaction at the steel and water interface to form a thin (about 1 micron) film of the iron sulfide mackinawite (Wikjord et al. 1980). The formation of mackinawite is an important factor governing the corrosion rate because the surface film can create a barrier that impedes the ability of other species to reach the steel. Accordingly, corrosion due to other contaminants such as CO_2 can be reduced when small amounts of H_2S (in the low ppm range in the gas phase) are present in crude oil.

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Box 5-1

CO_2 Corrosion of Mild Pipe Steel

CO_2 gas dissolved in water forms a weak carbonic acid (H_2CO_3):

$$CO_2 + H_2O \Leftrightarrow H_2CO_3$$

Carbonic acid partially dissociates in water to produce acidity [i.e., hydronium ions (H^+); water is omitted for simplicity]:

$$H_2CO_3 \Leftrightarrow H^+ + HCO_3^-$$

Further dissociation occurs in the bicarbonate ion (HCO_3^-) to produce more H^+ and form carbonate ions (CO_3^{2-}):

$$HCO_3^- \Leftrightarrow H^+ + CO_3^{2-}$$

The surface atoms of iron (Fe) in the steel will readily give up electrons to hydronium ions and dissolve into the water in the form of iron ions (Fe^{2+}):

$$Fe \rightarrow Fe^{2+} + 2e^-$$

In obtaining the additional electron, the hydronium ion will form hydrogen gas (H_2), and the reaction is complete.

$$2H^+ + 2e^- \rightarrow H_2$$

When the concentrations of the corrosion products in water (Fe^{2+} and CO_3^{2-} ions) exceed the solubility limit (typically at neutral and alkaline pH), they form solid iron carbonate on the surface of the steel:

$$Fe^{2+} + CO_3^{2-} \Leftrightarrow FeCO_3(s)$$

The layer of iron carbonate can become fairly protective and reduce the rate of underlying steel corrosion by blocking the surface and preventing the corrosive species from reaching it.

The rapid kinetics of mackinawite formation favor it as the initial product of H_2S reactions. However, with time, and as H_2S concentrations increase, mackinawite is less prevalent, and other forms of iron sulfide are seen, such as pyrrhotite. At high H_2S concentrations, pyrite and elemental sulfur are formed. While layers of any iron sulfide will offer some corrosion protection, there is no well-defined relationship between the type of iron sulfide layer and the ensuing rate of corrosion. It is well understood that high H_2S levels accompanied by elemental sulfur can lead to high rates of localized corrosion. However, elemental sulfur is usually associated with the production of natural gas with a high H_2S content. For a crude oil to have similarly high H_2S and elemental sulfur content would be unusual.

Corrosive Effect of Oxygen

Oxygen dissolved in water is undesirable in pipelines because it is highly reactive with iron. Corrosion generally becomes a problem when levels of dissolved oxygen reach those found in aerated surface water (typically about 8 ppm). Smaller amounts of oxygen (below 1 ppm) can become a problem when the oxygen reacts and impairs protective iron carbonate and iron sulfide

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layers. In general, the water associated with oil production does not contain oxygen, and therefore such high concentrations are seldom observed in shipments of stabilized crude oil transported in pressurized pipelines with controlled air entry points. Oxygen may become elevated when air is introduced into the pipeline inadvertently. Air may be introduced during shutdowns for inspections and repairs. Chronic sources of air ingress, such as during injection of chemicals and in storage tanks holding liquids at atmospheric pressure, are potentially more problematic. Nevertheless, how and why these air entry points would differ from one crude oil shipment to the next in the same pipeline facility are not evident.

Corrosive Effect of Organic Acids

Organic acids with low molecular weights are water soluble and thus present a significant corrosion threat when they are found in settled water that wets the steel surface of crude oil pipelines. A common representative of the family of water-soluble organic acids is acetic acid (CH_3COOH).[1] Other low-molecular-weight organic acids that can lead to corrosion of mild steel include propionic and formic acids. These weak acids create a corrosion scenario similar to the one described for CO_2 attack, with the organic acid taking the place of carbonic acid. Much like carbonic acid, organic acids provide a reservoir of hydronium ions. Their corrosive effect is particularly pronounced at low pH and higher temperatures, when their abundance can increase corrosion rates dramatically. At a higher pH (>6), the corrosive effect of organic acids on mild steel is negligible, regardless of concentrations.

Other organic acids found in crude oil—and notably in bitumen—are compounds with high molecular weight, which are often referred to as naphthenic acids. While these organic acids can be a significant corrosion threat at the high temperatures (>300°C) reached in refineries, they are not a threat to pipe steel because they are not soluble in water but are rather dissolved in the oil phase (Nesic et al. 2012). Accordingly, high-molecular-weight organic acids do not pose a corrosion threat to steel at pipeline temperatures. In some crude oils these acids may even have moderately inhibitive properties (Nesic et al. 2012).

Effect of Microbiologically Influenced Corrosion

The term microbiologically influenced corrosion (MIC) is used to designate the localized corrosion affected by the presence and actions of microorganisms (Little and Lee 2007). The types of damage that can be caused by these microorganisms are not unique, which means that MIC cannot be identified by visual inspection of the damage. Although MIC is discussed here with respect to internal corrosion, it can also contribute to corrosion on the outside of the pipe, as noted later.

Microorganisms that cause MIC are bacteria, archaea, and fungi. Some occur naturally in crude oils, while others may be introduced as contaminants from air, sediment, and water. The temperature range in which these organisms can grow is that in which liquid water can exist, approximately 0°C to 100°C (32°F to 212°F) (Little and Lee 2007). However, individual groups of microorganisms have temperature optima, including sometimes narrow ranges, for growth. The temperature range over which transmission pipelines operate will therefore select for specific microorganisms, but it will not prevent microbial growth.

[1] A household name for acetic acid is vinegar, which consists of 2 to 3 percent acetic acid dissolved in water.

For microorganisms to grow and proliferate, they require not only liquid water but also nutrients and electron acceptors for respiration. Accordingly, how microorganisms use water, nutrients, and electron acceptors to grow and how they influence corrosion is explained, and consideration is then given to whether levels of any of these essentials are likely to be affected by diluted bitumen.

Water Availability Microbial growth is limited by the availability of liquid water. Growth is therefore concentrated at oil–water interfaces and in the aqueous phase, including the water in deposits of sludge in pipelines. The volume of water required for microbial growth in hydrocarbon liquids is extremely small (Little and Lee 2007). Because water is a product of the microbial mineralization of organic substrates, microbial mineralization of hydrocarbon can generate the additional water needed for proliferation.

Nutrient Availability Microorganisms need suitable forms of carbon, nitrogen, phosphorus, and sulfur as nutrients (Little and Lee 2007).[2] In oil pipelines, hydrocarbons can be degraded by aerobic or anaerobic processes to yield assimilable carbon. Aerobic degradation of hydrocarbons is faster than anaerobic degradation, with the rate depending on the specific electron acceptors used in the process. In general, the susceptibility of hydrocarbon compounds to degradation can be ranked as follows: linear alkanes, branched alkanes, small aromatics, and cyclic alkanes (Atlas 1981; Das and Chandran 2011; Perry 1984). As the chain length of alkanes increases, bacteria show decreasing ability to degrade these compounds (Walker and Colwell 1975). Some high-molecular-weight polycyclic aromatics may not be degraded at all (Atlas 1981). As a practical matter, however, carbon availability is often not the main constraint for crude oil biodegradation. Both nitrogen and phosphorus are required for microbial growth. Low concentrations of assimilable forms of these elements can limit biodegradation.[3]

Electron Acceptors Microorganisms can use a variety of electron acceptors for respiration. In aerobic respiration, energy is derived when electrons are transferred to oxygen, which is the terminal electron acceptor. In anaerobic respiration, a variety of organic and inorganic compounds may be used as the terminal electron acceptor, including sulfate, nitrate, nitrite, iron (III), manganese (IV), and chromium (VI) (Little and Lee 2007). Anaerobic bacteria can therefore be grouped on the basis of the terminal electron acceptor, such as sulfate-, nitrate-, and metal-reducing bacteria.[4] In petroleum environments, the bacteria most often associated with MIC are sulfate reducers. In anaerobic environments, sulfate reducers produce H_2S when they use the sulfate as an electron acceptor.[5] In addition, many archaea can produce sulfides, and therefore the inclusive term for this group of anaerobes is sulfide-producing prokaryotes (SPP).

SPP-related corrosion of metals used in oil exploration and production has been reported around the world (Mora-Mendoza et al. 2001; Ciaraldi et al. 1999; El-Raghy et al. 1998; Jenneman et al. 1998). A main concern is that these microorganisms produce H_2S. As discussed

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[2] A representation of the major elements required for a typical microorganism composition is $C_{169}(H_{280}O_{80})N_{30}P_2S$.

[3] Atlas (1981) reported that when a major oil spill occurred in marine and freshwater environments, the supply of carbon was significantly increased and the availability of nitrogen and phosphorus generally became the limiting factor for oil degradation.

[4] There is specificity among anaerobes for particular electron acceptors. Facultative anaerobic bacteria can use oxygen or other electron acceptors. Obligate anaerobic microorganisms cannot tolerate oxygen for growth and survival. Obligate anaerobic bacteria are, however, routinely isolated from oxygenated environments associated with particles and crevices and, most important, are in association with other bacteria that effectively remove oxygen from the immediate vicinity of the anaerobe.

[5] Some anaerobes can also reduce nitrate, sulfite, thiosulfate, or fumarate (Little and Lee 2007).

earlier, H_2S reacts with the iron ions to form a thin layer of the iron sulfide mackinawite that adheres to the steel surface. In the absence of oxygen, and if the concentration of iron ions in the solution is low, this mineral layer will protect the iron in the steel pipe surface from dissolution (Wikjord et al. 1980). However, if oxygen is introduced, the iron sulfide can be converted to an iron oxide and elemental sulfur, which will cause the rate of corrosion to increase substantially for reasons already given.[6] Pipelines operators, therefore, seek to prevent the formation of colonies of SPP and other microorganisms in pipelines through design, operations, maintenance, and chemical means.

Internal Erosion

Solid particles flowing in the crude oil stream can cause erosion of pipe wall, particularly at flow disturbances such as pipe bends. The propensity for erosion is affected by the pipe material; angles of flow impact; flow velocity; and the amount, shape, mass, and hardness of solid particles in the stream. While pipeline erosion is common in the oil production industry, it occurs to a greater extent in production (field) pipelines that contain fluids with high levels of sand and minerals. For example, slurry flow in the pipelines used to move oil sands ore before bitumen extraction can be highly abrasive (Zhang et al. 2012). Because processed crude oils do not contain similarly high concentrations of solids, erosion is not observed to a significant degree in transmission pipelines. Of interest to this study is whether the diluted bitumen delivered to transmission pipelines contains significantly higher concentrations of abrasive solids than do other crude oils and whether it is transported at higher flow rates conducive to erosion.

Assessment of Effects of Diluted Bitumen on Sources of Internal Degradation

The properties of diluted bitumen as they pertain to the identified factors affecting susceptibility to internal degradation from corrosion and erosion are examined next.

Internal Corrosion

Water Wetting and Solids Deposition An important factor in water dropout and wetting is the total water content of the crude oil stream, which is measured by pipeline operators as part of shipment BS&W sampling. As reported earlier, Canadian transmission pipelines require that crude oil shipments not have a BS&W exceeding 0.5 percent. These levels are comparable with, and more often lower than, the levels commonly required by U.S. transmission pipelines. Accordingly, the level of water contained in shipments of diluted bitumen and other crude oils imported by pipeline from Canada will not be higher than that contained in shipments of other crude oils piped in the United States.

Even relatively small amounts of water in crude oil can settle to the pipe bottom. In considering the propensity of water to drop out of the oil stream, important factors include the viscosity, density, and surface tension of the oil and whether it is transported in a flow that is sufficiently turbulent to disperse and suspend water droplets. Shipments of diluted bitumen are

[6] The impact of oxygen on corrosion from anaerobic SPP was examined by Hardy and Bown (1984) by using mild steel and weight loss measurements. Successive aeration–deaeration shifts caused variations in the corrosion rate. The highest corrosion rates were observed during periods of aeration. Hamilton (2003) concluded that oxygen was the terminal electron acceptor in all MIC reactions. In laboratory seawater and fuel incubations, Aktas et al. (2013) demonstrated that there was no biodegradation of hydrocarbon fuels, little sulfate reduction, and no corrosion of carbon steel in the absence of oxygen.

transported at the same pressures and under the same turbulent flow regimes as shipments of other heavy crude oils. The report has demonstrated that diluted bitumen is more viscous than light and medium-density crude oils and is comparable in viscosity with heavy crude oils. A stream of diluted bitumen in turbulent flow should therefore confer the beneficial effect, relative to lighter crude oils, of dispersing and suspending any free water that may exist in the pipeline stream.

A low likelihood that a shipment of diluted bitumen contains water that will settle and wet the bottom of the pipeline will lead to a low likelihood of internal corrosion regardless of the corrosion mechanism or the presence of other contaminants that can contribute to corrosion. All crude oil shipments can carry particles consisting of sand, clay, organic materials, and hydrocarbons that have the potential to drop out of the stream at vulnerable locations in the pipelines. Given its high viscosity, diluted bitumen will suspend the very fine particles that may be contained in its sediment. The solids contained in diluted bitumen are not unusual in quantity or particle size but are within the range of other heavy crude oils, as established in the earlier comparisons. Whether any of the sediments that settle to the pipe bottom threaten underdeposit corrosion will depend critically on associated water, as well as the presence of corrosive gases, acids, and microorganisms.

Corrosive Gases (CO_2, H_2S, and Oxygen) If water does settle and wet the bottom of a pipeline carrying diluted bitumen, such as at low spots and dead legs, consideration of whether shipments of this type of crude oil contain comparatively high levels of dissolved gases that will increase the potential for corrosion is warranted. Data on the CO_2 contained in crude oil lines, including those carrying diluted bitumen, are not readily available. Nevertheless, concentrations can be inferred from the CO_2 levels present at the last point of gas–liquid separation upstream of delivery to the transmission pipeline. As is the case for shipments of other crude oils, various tanks will hold shipments of diluted bitumen before they are delivered to the transmission pipeline facility. This upstream storage, which occurs at atmospheric pressure, will provide the same opportunity for shipments of diluted bitumen as it does for shipments of other crude oils to degas CO_2 before entry to transmission pipelines. Such a comparable upstream environment will produce similarly low CO_2 concentrations and corrosion rates.

Likewise, the quantities of H_2S reported for diluted bitumen (>25 parts per million by weight in liquid phase), as reported in Chapter 3, are lower than in many other crude oils and do not pose a corrosion threat. Even if other corrosive agents are present, the small concentrations of H_2S would contribute little to the corrosive effect, except perhaps to provide a mildly mitigative impact because of the formation of protective iron sulfide layers. The conclusion is that concentrations of dissolved CO_2 and H_2S in diluted bitumen shipments are likely to be low and not greater than those found in other crude oil shipments that are stored and transported similarly.

Transmission pipeline operators restrict air entry points to prevent ingress of oxygen. There are no data on the oxygen content in crude oil pipelines to assess the effectiveness of these restrictions. However, diluted bitumen is transported in the same pipelines as other crude oils, and the number of air entry points can be assumed the same and purposefully restricted. Because crude oils are stored by pipeline operators in large atmospheric pressure tanks, the possibility of air ingress cannot be eliminated, but the ingress will be as low for shipments of diluted bitumen as it is for shipments of other crude oils stored similarly. Even if some free water is assumed to settle to the bottom of a pipeline carrying shipments of diluted bitumen, low levels of oxygen

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(e.g., below 1 ppm) will not constitute a serious corrosion threat or one that differs from that of a pipeline carrying shipments of other crude oils.

Acids In reviewing the chemistry of diluted bitumen in Chapter 3, no evidence emerged that it contains relatively high levels of low-molecular-weight organic acids such as acetic acid. The high total acid number of diluted bitumen derives from the presence of high-molecular-weight organic acids. These oil-soluble naphthenic acids do not pose an internal corrosion threat under pipeline conditions and may have mitigative effects on corrosion. The acid contained in diluted bitumen is therefore not a threat to internal corrosion of transmission pipelines.

Microbiologically Influenced Corrosion To understand whether diluted bitumen is more likely than other crude oils to cause MIC, it is helpful to examine whether this crude oil is more prone to providing the essential resources required for microbial growth. The water content of diluted bitumen shipments is comparable with that of other crude oil shipments, and diluted bitumen does not have constituents or operating requirements that make pipelines more prone to forming sludge that can harbor microorganisms. The other essential resources that deserve consideration are the availability of critical nutrients (especially carbon and nitrogen) and electron acceptors (especially oxidized sulfur compounds).

While microbial growth requires carbon, it may be limited more by the scarcity of nitrogen in petroleum. As reported earlier, most of the nitrogen in bitumen is bound in carbon structures and unavailable.[7] Lighter oils provide a more readily available source of degradable carbon than do heavy oils, including bitumen. The percentage of low-molecular-weight hydrocarbons is similar in diluted bitumen and other heavy crude oils and lower than the percentages in lighter crude oils. More of the carbon in diluted bitumen is contained in relatively high concentrations of asphaltenes. The molecular weight and structure of asphaltenes vary, but biodegradation of these compounds is an extremely slow process that does not provide a readily available source of carbon for microorganisms (Pineda-Flores and Mesta-Howard 2001).

With regard to the availability of electron acceptors, it was reported earlier that sulfur content is higher in diluted bitumen than in many other crude oils, but the sulfur is not in oxidized forms available for sustained sulfate reduction by SPP. Furthermore, the high sulfur content of bitumen is not correlated with high H_2S content. Most of the sulfur in bitumen is organic sulfur bonded to carbon in heterocyclic rings, which are not easily degraded by microorganisms and thus largely unavailable for metabolism.

In sum, the chemistry of diluted bitumen is not more favorable for microbial growth and activity than is that of other crude oils.

Erosion

The propensity for erosion is affected by the presence and physical properties of the solid particles in the stream, pipe material, angles of particle impact, and impact velocity. Pipe materials and impact angles are the same for diluted bitumen as for other crude oils transported through the same pipelines. Chapter 3 indicated that the velocity of diluted bitumen flowing through pipelines is not higher than the velocity of other crude oil flows. Furthermore, the diluted bitumen imported by pipeline into the United States is produced by using in situ methods that limit the amount of sand, minerals, and other solid particles recovered with the bitumen. The

[7] See Chapter 3.

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extracted bitumen is processed to remove water and solids to achieve the requisite BS&W for pipeline transportation to yield solids levels that are similar to those of other crude oil shipments. While limited data are available on the specific physical properties of the solid particles in diluted bitumen, the generally low levels of solids (less than 0.05 percent) do not suggest that shipments of diluted bitumen increase the already low potential for erosion in crude oil transmission pipelines.

Summary of Effects on Sources of Internal Degradation

A review of product properties relevant to internal pipeline corrosion and erosion does not indicate that diluted bitumen is more likely than other crude oils to lead to these failure mechanisms. Shipments of diluted bitumen do not contain unusually high levels of water, sediment, dissolved gases, or other agents that can cause internal corrosion. The organic acids contained in diluted bitumen are not corrosive to steel at pipeline temperatures. Diluted bitumen has density and viscosity levels comparable with those of other crude oils, and it flows through pipelines with velocity and turbulence comparable with other crude oils so as to limit the accumulation of corrosive deposits. On the basis of an examination of the factors influencing microbial growth and activity, shipments of this crude oil do not have a higher likelihood than other crude oil shipments of causing MIC in pipelines. Because it has solids content and flow regimes comparable with those of other crude oils, diluted bitumen does not have a higher to propensity to cause erosion of transmission pipelines.

SOURCES OF EXTERNAL DEGRADATION

External Corrosion

External corrosion of pipelines is usually characterized by uneven metal loss over localized areas covering a few to several hundred square centimeters of the outside steel surface of the pipe (Beavers and Thompson 2006). The electrochemical reactions that are involved usually occur at physically separate locations on the surface. While the anodic reaction is primarily oxidation of iron, the cathodic reaction can be either the hydrogen evolution that occurs in the anaerobic electrolyte trapped under an impermeable pipe coating or the reduction of oxygen under a permeable coating. The water and soluble compounds needed to create the electrolyte can be present in the soil surrounding the buried pipe or in the atmosphere when a pipe is above grade. In addition, a portion of external corrosion incidents involve MIC (Koch et al. 2002; Beavers and Thompson 2006). As discussed later in the section, external corrosion pits can also be sites for the formation and growth of stress corrosion cracks.

External corrosion is thus affected by the pipe material, the corrosivity of the environment, and the performance of coatings and cathodic protection systems. For mild grades of carbon steel commonly used in transmission pipelines, the main concern is the corrosivity of the surrounding environment and the performance of coatings and cathodic protection systems. Although the transported product does not come in contact with either the coating or the environment surrounding the pipeline, it can influence both factors by affecting the operating pressure and temperature of the pipeline.

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Because pipeline segments are located below and above ground, they can be exposed to corrosive conditions in the soil and atmosphere. Many factors affect soil corrosivity, including moisture and oxygen content, electrical resistivity, pH, temperature, porosity, microbial activity, and the presence of dissolved salts (Uhlig and Revie 1985; Escalante 1989; Beavers and Thompson 2006). For pipeline segments exposed to the atmosphere, the primary environmental factors influencing corrosion are relative humidity, salt deposition, pollution, and temperature. Operating pressure does not affect these corrosive conditions, but elevated pipeline temperatures and resulting heat flux to the air or soil medium can increase corrosion rates.

Pipeline temperature and pressure can both affect the condition and performance of coatings and cathodic protection systems. As discussed in Chapter 2, coatings provide a barrier between the pipe and the corrosive environment. Coatings can fail in a variety of ways including disbonding from the steel surface. In pipelines using some older coating technologies, such as asphalt mastic systems, elevated temperatures can cause the coating material to deform and potentially reduce surface coverage. Elevated pipeline temperatures can also result in degradation of adhesive properties and increase the diffusion of moisture through the coating in the direction of the steel surface. Moisture diffusion can cause swelling of the coating relative to the steel and bring about increased surface stresses that lead to disbondment. Fluctuating line pressures can cause interfacial strain between the coating and the pipe surface to produce mechanical disbondment of the coating.

An intact coating that prevents contact between the corrosive environment and the steel surface will generally prevent external corrosion. However, all coatings contain some defects that expose the steel. Accordingly, a critical defense against external corrosion is the application of cathodic protection. As discussed in Chapter 2, many cathodic protection systems use an electric current to prevent corrosion where coating coverage is imperfect. Temperature and pressure conditions that cause coating disbondment, therefore, can be more problematic if they impede, or shield, the distribution of cathodic current to sites where steel is exposed. An advantage of modern coating systems, such as fusion bonded epoxy, is that they are compatible with cathodic protection. Shielding is nevertheless a problem observed in some older pipelines wrapped with impermeable tapes and at girth welds treated with field applied shrink sleeves.

Cracking

The potential for transported products to affect the two main forms of cracking in pipelines is reviewed. Consideration is given to the mechanical process of fatigue cracking and forms of environmentally assisted cracking (EAC) that involve interactions of mechanical and corrosion processes.

Fatigue Cracking

Fatigue is characterized by the formation and growth of microscopic cracks on one or both sides of the pipe wall.[8] The first stage in the fatigue process is crack initiation, or nucleation. Nucleated cracks do not cause a fracture, but some may coalesce into a dominant crack as the variable amplitude loading continues. In the second stage, the dominant crack grows in a more stable manner and may eventually reach the thickness of the wall to produce a leak. Alternatively, the dominant crack may grow to a critical length and depth that the pipe steel can

[8] See Beavers and Thompson (2006) for additional description of stress cracking processes.

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no longer endure, leading to a rupture. Pipeline internal and external surface conditions caused by factors other than fatigue can lead to initial cracks or enhance crack fatigue crack growth from stress concentration. These factors can include preexisting dents, weld defects, corrosion pits, manufacturing flaws, and damage incurred during pipe transportation to the installation site.

Fatigue cracking can ensue as a result of repetitive, or cyclic, stress loadings on a pipe. Cyclic stresses can be axial (parallel to the axis of pipeline), circumferential (stress in the tangential direction), or radial (perpendicular to the axis). Circumferential, or hoop, stress is usually the most important source of cyclic loadings because the stress created by internal pressure is normally the largest stress on the pipeline.

Because viscous crude oils create more friction, they will require a higher operating pressure than do less viscous crude oils to achieve the same flow rate. In practice, pipeline operators reduce the flow rate when they transport viscous crude oils rather than increase operating pressure. Operating pressure cannot be increased if the pipeline is at the stress limit prescribed in regulations. Thus, only when a pipeline is operating below its stress limit can operating pressure be raised to increase the flow rate of a viscous crude oil.

The pipe segments vulnerable to cracking are those with preexisting flaws or dents and other surface deformities caused by mechanical forces during installation or while in service. Stresses can concentrate at these damage sites, enabling cracks to form and grow after a relatively small number of load cycles, a phenomenon known as low-cycle fatigue.[9] Other locations on the pipe susceptible to stress concentrations include discontinuities at longitudinal and girth welds and at voids formed during pipe manufacturing (Zhang and Cheng 2009).

Pressure cycling is reported to have contributed to fatigue failures in crude oil transmission pipelines. An example is the July 2002 rupture of a 34-inch crude oil pipeline near Cohasset, Minnesota (NTSB 2004). In that incident, the originating crack formed at the seam of the longitudinal weld as a result of vibrations experienced during railroad transportation of the pipe to the installation site. According to the National Transportation Safety Board report, the preexisting crack grew to reach a critical size in response to pressure cycling stresses associated with normal in-service operations.

Environmentally Assisted Cracking

EAC results from the combined action of a corrosive environment and a cyclic or sustained stress loading. In general, EAC emerges in three basic forms: corrosion fatigue, stress corrosion cracking (SCC), and hydrogen-assisted cracking. EAC requires both a sufficient stress and a corrosive environment specific to the metal and thus is rare in crude oil transmission pipelines. However, when EAC failures do occur, they can be destructive; for example, the 2010 failure of a pipeline near Marshall, Michigan, was caused by EAC (NTSB 2012).

Corrosion fatigue cracking arises from a combination of corrosion and the same pressure-related cyclic stresses that produce fatigue cracking. In corrosion fatigue, the stresses sufficient to cause failure can be less severe because of the corrosion reaction and resulting damage. For example, corrosion pits can become stress concentrators that allow normal in-service pressure cycling to cause the formation and growth of cracks in the pit. In the case of pipeline SCC, the same corrosive factors may exist, but the main acting stress is the sustained hoop forces generated by the operating pressure as well as its cycling. The acting stress may also be residual

[9] Conversely, high-cycle fatigue occurs under a low-amplitude loading in which a large number of load cycles is required to produce failure.

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in nature, introduced during bending and welding in manufacturing, or it may arise from external soil pressure or differential settlement. The same locations on the pipe that concentrate cyclic stresses, such as dents, scrapes, and other surface discontinuities, can concentrate static stresses. Furthermore, breaks in the surface film may occur at these discontinuities to make the area more prone to electrochemical corrosion.[10]

The factors that create corrosive environments enabling EAC, such as soil properties and the performance of coatings and cathodic protection, have already been discussed with respect to external corrosion. As with external corrosion, the maintenance of coating performance and cathodic protection is critical in controlling EAC (CEPA 2007). In the case of SCC, limiting the introduction of residual stresses during pipe manufacturing, transportation, and installation is also important in reducing susceptibility. Operating pressure is the major in-service source of static hoop stress. Lowering the operating pressure of a pipeline would be expected to reduce the potential for SCC. However, the specific relationship between SCC and hoop stress is not well established. For example, SCC failures have occurred in pipelines experiencing hoop stresses that have varied from 46 to 77 percent of the specified minimum yield strength of the pipeline.[11] Accordingly, adjusting operating pressures as a way to prevent SCC can be difficult.

EAC can be caused or exacerbated by hydrogen-assisted cracking. For example, when sources of hydrogen are present—such as from agents in the crude oil stream (e.g., H_2S) or from external sources (e.g., excessive cathodic protection voltage)—cracking potential may increase. Although hydrogen-assisted cracking is rare in crude oil transmission pipelines, it can occur as a result of the diffusion and concentration of atomic hydrogen at the crack tip or other microstructural trap site in a metal. The ingress of hydrogen into a metal is enhanced in the presence of sulfur species. The trapped hydrogen can cause internal stresses within the metallurgical structure favorable to enhanced cracking or act to reduce local roughness in the region of the crack tip. Hydrogen can also adsorb to the metal surface to reduce surface energy and migrate into the microstructure, thereby reducing interatomic bond strength and providing nucleation sites for cracks. Hydrogen-assisted cracking can occur on the inside or outside of the pipe, depending on the source of the hydrogen and its ability to reach the pipe surface.

Assessment of Effects of Diluted Bitumen on Sources of External Degradation

Because diluted bitumen only contacts the inside of a pipeline, it can contribute to external degradation only indirectly. In the case of external corrosion and EAC, one concern is that elevated operating temperatures can adversely affect the performance of the coating as a barrier to corrosion. The relevant question with respect to both external corrosion and EAC is whether diluted bitumen creates operating temperatures and pressures that are sufficiently different from those of other crude oils to increase coating disbondment. As has been reported, diluted bitumen and other heavy crude oils have similar densities and viscosities and flow through pipelines at the same rate and within comparable pressure and temperature ranges (see Chapter 3, Tables 3-4 and 3-7). For this reason, the likelihood of coating degradation and any associated external damage resulting from the operating parameters of diluted bitumen should be equivalent to that of other crude oils with comparable density and viscosity.

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[10] At sites of surface damage, such as dents and corrosion pits, stress levels in the circumferential and axial directions are higher than on undamaged portions of the pipe surface.

[11] National Energy Board, notes from January 12, 1996, meeting between National Energy Board SCC Inquiry Panel and Camrose Pipe Company Ltd., Exhibit No. A-58.

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Pipelines transporting diluted bitumen and other heavy crude oils should not differ in the stress loadings generated by their transportation because operating pressures are comparable. Other sources of static stress, such as residual stresses from pipe fabrication and installation, would not be affected by the product in the pipeline. Transmission pipelines, therefore, should not experience more stress cracking from transporting diluted bitumen than from transporting other crude oils of similar density and viscosity.

Finally, if the exterior coating of the pipe disbonds, hydrogen may diffuse into the surface metal with a rate of uptake and subsequent potential for embrittlement that will depend on a number of factors, including pH and temperature. However, the operating parameters of diluted bitumen should not increase the potential for coating disbondment. With respect to the interior of the pipeline, the availability of H_2S and free sulfur to form hydrogen in diluted bitumen is relatively low. Thus, transporting diluted bitumen is not likely to increase the potential for hydrogen-assisted cracking.

SOURCES OF MECHANICAL DAMAGE

Mechanical damage to the pipeline and its components can occur as a result of overpressurization or outside forces. Mechanical forces can cause an immediate, and sometimes catastrophic, breach and release or make the pipeline more susceptible to releases by destabilizing support structures and damaging other components such as valves, joints, and other fittings. Damage from mechanical forces can also weaken the resistance of the pipeline to other failure mechanisms. Sites on the pipeline that sustain even light damage, such as scrapes, are vulnerable to corrosion attacks and stress-related cracking. Accordingly, consideration of whether the transportation of diluted bitumen creates an elevated potential for phenomena that can lead to mechanical damage is warranted.

Overpressurization

Various events can generate excessive pressure in a pipeline, including surges, thermal overpressure, column collapse, and human error. If the pipe is already weakened by corrosion, cracking, or deformities from earlier mechanical damage, overpressure events can increase the potential for damage and failure.

Pipeline operators prevent overpressure events through personnel training; standardized procedures; system design; and safety systems such as pressure relief valves, pressure switches, surge tanks, and bypass systems. Nevertheless, excessive pressure in a pipeline can occur as a result of operator error, thermal overpressure, and column separation. A transported fluid that increases the likelihood of any of these outcomes could increase the potential for mechanical damage.

Surge

Any action in a pipeline system that causes a rapid reduction in the velocity of the transported fluid could cause a pressure surge. Transient, high-amplitude pressure waves, or surges, are not normal and can cause mechanical damage to pipes, components (e.g., valves, seals, joints), instrumentation (e.g., meters and gauges), and support structures. Because all crude oils have

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relatively high bulk modulus (incompressibility), they have a comparable propensity for energy to be transferred in high-pressure waves when events trigger abrupt reductions in flow velocity.

Operator Error

Overpressurization can be caused by direct human error. Unintentional pumping of fluids against a closed valve with coincidental failure of pressure switches, pressure relief valves, and other protective devices is an example of a rare-event overpressurization scenario. Most pipelines are equipped with safeguards such as pressure switches and relief devices to avoid damage from these scenarios. If a transported liquid adds complexity to operational requirements, operator errors could increase.

Column Collapse

Pressure surges can arise from pressure differentials, or slack conditions, in the pipeline. A slack line can occur when the liquid being transported develops a vapor void at a point in the pipeline where line pressure drops below the vapor pressure of the liquid. The void will temporarily restrict the flow of liquid. When the void collapses, a pressure wave comparable with that of a rapid valve closure can be produced. The transformation of the liquid into a vapor phase is known as column separation. To prevent the occurrence of column separation, pipeline operators strive to maintain line pressure above the vapor pressure of the liquid. Locations vulnerable to pressure differentials are elevation peaks and the downstream side of slopes. A liquid that has certain properties, such as a relatively high fraction of hydrocarbons with high vapor pressure, can theoretically increase the potential for column separation.

Thermal Overpressure

A pipe segment that is full of liquid will experience a rapid pressure increase when it is exposed to a heat source and when volume expansion is restricted. Special procedures and thermal relief valves are used to prevent this occurrence in aboveground pipe segments where the flow may be impeded or blocked and the segment may be subsequently exposed to a heat source such as sunlight or fire. Because the chemistry of the trapped fluid determines the amount of pressure increase corresponding to an incremental increase in temperature, some transported liquids could have greater potential for thermal overpressure.

Outside Force Damage

Pipelines can sustain external mechanical damage from both natural forces and human activity. Natural forces include seismic movements and other ground shifts, such as those from landslides and subsidence. Examples of damage from human activity include accidental strikes from vehicles, earth moving activity, and surface loading by farm equipment. Intentional damage to a pipeline, or sabotage, is a potential source of mechanical damage, although it is rare.

There are ways in which the contents of a pipeline can affect or interact with an outside force failure mechanism. One possibility is that a denser, heavier fluid adds weight to a pipe that is free-spanning (i.e., unsupported) or traverses a terrain susceptible to inadequate support. Another possibility is that the heat flux from a fluid transported at an elevated operating

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temperature reduces the stability of a pipeline in a frost zone. Similar interactions with the outside environment related to pipe vibrations, expansion, and contraction may be postulated as potential sources of mechanical damage.

Assessment of Effects of Diluted Bitumen on Sources of Mechanical Damage

Mechanical damage to the pipeline and its components can occur as a result of outside forces and overpressurization events. Several causes of outside force damage that could be affected to some degree by the properties of the transported liquid have been postulated. The most relevant properties of the transported liquid are density, viscosity, and operating temperatures. However, because these properties are the same for diluted bitumen as many other crude oils, there is no reason to believe their interactions with outside forces will differ. The same conclusion can be reached concerning the potential for mechanical damage due to chemical or physical properties that can affect the propensity for surge, column separation, or thermal expansion. The potential for these sources of mechanical damage should be indistinguishable from that of other crude oils. Diluted bitumen is blended like many other crude oils to remain fully mixed in the pipeline environment and it does not contain a high percentage of light (high vapor pressure) hydrocarbons.

EFFECTS ON OPERATIONS AND MAINTENANCE PROCEDURES

The preceding analysis has consistently found that the properties of diluted bitumen are within the range of other crude oils. These findings do not indicate a need for operations and maintenance (O&M) procedures that are customized to diluted bitumen, nor do they suggest that pipeline operators apply O&M procedures in transporting diluted bitumen that are different from those applied in transporting other crude oils with similar properties. Of course, if operators who traditionally carry only light crude oils do not make appropriate adjustments to line pressure and flow rates when they transport diluted bitumen or any other similarly dense and viscous crude oil, a greater potential for some of the failure mechanisms examined above could result.

Because most pipeline operators transport many varieties of crude oil, they routinely make adjustments to operational parameters to accommodate different crude oil grades. There is no reason to believe that operators fail to make these adjustments when they transport heavy crude oils generally or, more specifically, when they transport diluted bitumen. Nevertheless, to be comprehensive, a search was undertaken for evidence of O&M practices being altered in inadvertent ways that could be detrimental to pipeline integrity.

Operational Procedures

As discussed in Chapter 2, the operation of most pipelines is monitored and controlled by a combination of local and remote systems by using a centralized supervisory control and data acquisition system. Instrumentation at pump stations, tank farms, and other facilities includes sensors, programmable logic controllers, switches, and alarms. Remote systems allow for monitoring and coordination at centralized locations distant from the pipeline facilities. Together, these local and remote capabilities provide protection against abnormal operations—for example, by allowing for the orderly shutdown of pumps and cessation of flow if an alarm

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condition occurs or if certain operating parameters are violated. Maintaining the integrity of control systems is essential in ensuring safe pipeline operations.

Therefore, whether there are any characteristics of diluted bitumen that could introduce more complexity into or otherwise compromise the satisfactory functioning of pipeline control systems and their components is worth investigating. As previously noted, none of the chemical and physical properties of diluted bitumen suggests that such an effect could be expected, because the properties fall within the range of other crude oils commonly transported by pipeline. Nevertheless, the committee undertook a search of any instances in which operators modified or were advised to modify their standard control and monitoring activities in transporting diluted bitumen. A search of published documents did not reveal any noteworthy reports, special standards, or guidance documentation. In consulting Canadian pipeline operators (see Appendix A), the committee asked whether the transportation of diluted bitumen required changes to set points for safety and control instrumentation. The response was as follows: "There are no differences. Standards and procedures are in place for control that are generic for all crude oil commodities shipped. The standards and procedures are structured to ensure safe operation regardless of the commodity." Likewise, all pipeline operators interviewed in public meetings convened by the committee stated that transporting diluted bitumen did not require different control or monitoring procedures.[12]

In its investigation of the July 25, 2010, EAC-related rupture near Marshall, Michigan, the National Transportation Safety Board found that the control center made repeated errors by increasing the delivery rate of the pipeline under the impression that low-pressure readings caused by the undetected rupture were indicative of slack line conditions caused by column separation (NTSB 2012). The product released in the incident, discussed in Chapter 4, was diluted bitumen. The phenomenon of column separation has already been reviewed, and no evidence that diluted bitumen has properties associated with it was found. Furthermore, the National Transportation Safety Board did not indicate that the shipment of diluted bitumen that was being delivered through the ruptured pipeline had actually experienced column separation or that any of the properties of the shipment had any other specific effect on the actions of the control center.

Maintenance Procedures

As described in Chapter 2, pipeline operators use various methods for preventing, detecting, and mitigating damage in pipelines. Methods for preventing external cracking and corrosion include use of coatings and cathodic protection. Methods for preventing internal corrosion include chemical treatments, flow maintenance, and in-line cleaning. Operators also monitor pipeline conditions by using various inspection tools, probes, and surveys. If transporting diluted bitumen compromises the ability of operators to carry out any of these activities, more adverse conditions could arise and persist and thereby increase the potential for failures.

[12] Representatives from Enbridge, Inc., and TransCanada Pipeline Company were invited to make presentations to the committee during its first meeting on July 23, 2012. During the public meeting, the representatives were asked to identify any special operational or maintenance demands associated with transporting diluted bitumen. None was identified. On October 9–10, 2012, committee members convened a public meeting in Edmonton, Alberta, in which representatives of several pipeline companies that transport diluted bitumen were interviewed. In conjunction with the meeting, committee members also visited a transmission pipeline terminal in Fort McMurray, Alberta, where representatives from the pipeline company explained operational and control procedures associated with diluted bitumen transportation. They also responded to questions from committee members. None of the interviews and information obtained from the site visit suggested that operators use different procedures for system control and monitoring when they transport diluted bitumen.

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As with other potential issues, the absence of significant differences in the chemical and physical properties of diluted bitumen compared with other heavy crude oils suggests that no changes are required in pipeline maintenance and inspection regimes. Nevertheless, the committee searched for reports of operators experiencing difficulties in carrying out standard maintenance, mitigation, and inspection activities while transporting diluted bitumen. The committee also searched for standards and other guidance documentation alerting operators to issues associated with maintenance and inspection, such as advisories on the use of in-line inspection tools, chemical inhibitors, and coupons and probes for corrosion monitoring. The search did not uncover any issues or added complexities.

In addition, in its questionnaire to Canadian pipeline operators (see Appendix A), the committee asked whether the transportation of diluted bitumen required changes in pipeline cleaning intervals or predictive and preventive maintenance programs. No differences in cleaning intervals or predictive and preventive maintenance programs were reported. Pipeline operators who met with the committee during public meetings (as noted above) were asked similar questions, and all stated that no special maintenance and inspection issues arose in transporting diluted bitumen. They did not report any adverse affects on their ability to carry out their normal maintenance and inspection activities.

Assessment of Effects of Diluted Bitumen on O&M Procedures

As common carriers, operators of transmission pipelines generally have the ability to transport the wide range of crude oil varieties that are in the commercial stream. Accordingly, operations and maintenance procedures are designed to be robust, capable of ensuring operational reliability and safety without the need for significant procedural modifications from one crude oil shipment to the next. The chemical and physical properties of diluted bitumen do not suggest that transporting this product by pipeline requires O&M procedures that differ from those of other crude oils having similar properties. Likewise, inquiries with operators and searches of industry guidelines and advisories did not indicate any specific issues associated with transporting diluted bitumen that would negatively affect operators as they carry out their standard O&M programs, including their corrosion detection and control capabilities.

SUMMARY

The chemical and physical properties of diluted bitumen shipments have been examined to determine whether there are any differences from those of other crude oil shipments that increase the likelihood of pipeline failures from internal degradation, external degradation, or mechanical damage. Any differences that could affect either the frequency or the severity of a failure mechanism or the ability to mitigate it would suggest a difference in failure likelihood. The chemical and physical properties of diluted bitumen shipments were not found to differ in ways that would be expected to create a likelihood of release that is higher for a transmission pipeline transporting diluted bitumen than one transporting other crude oils. An assessment was also made with regard to whether pipeline operators transporting diluted bitumen alter their O&M procedures in ways that can inadvertently make pipelines more prone to the sources of failure. No differences were found in these procedures. The assessment results are summarized in the next chapter.

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Abbreviations

CEPA	Canadian Energy Pipeline Association
NTSB	National Transportation Safety Board

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Summary of Results

The study charge and approach and the main points from the preceding chapters are summarized in this chapter. The discussion summaries provide the basis for the findings presented at the end of the chapter.

RECAP OF STUDY CHARGE AND APPROACH

Section 16 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 calls for the Secretary of Transportation to "complete a comprehensive review of hazardous liquid pipeline facility regulations to determine whether the regulations are sufficient to regulate pipeline facilities used for the transportation of diluted bitumen. In conducting the review, the Secretary shall conduct an analysis of whether any increase in the risk of a release exists for pipeline facilities transporting diluted bitumen."[1] A determination of release risk requires an assessment of both the likelihood and the consequences of a release. To inform its assessment of the former, the U.S. Department of Transportation contracted with the National Research Council to convene an expert committee to "analyze whether transportation of diluted bitumen by transmission pipeline has an increased likelihood of release compared with pipeline transportation of other crude oils."

As detailed in Chapter 1, the project statement of task calls for a two-phase study, with the conduct of the second phase contingent on the outcome of the first. In the first phase, the study committee was asked to examine whether shipments of diluted bitumen can affect transmission pipelines and their operations so as to increase the likelihood of release when compared with shipments of other crude oils transported by pipeline. In the potential second phase—to be undertaken only if a finding of increased likelihood of release is made in the first—the committee was asked to review federal pipeline safety regulations to determine whether they are sufficient to mitigate an increased likelihood of release from diluted bitumen. If the committee did not find an increased likelihood of release, or the information available was insufficient to make a finding, the committee was expected to prepare a final report documenting the study approach and results.

The committee reviewed data on reported pipeline releases. The review provided insight into the general causes of pipeline failures, but the incident records alone could not be used to determine whether pipelines are more likely to fail when they transport diluted bitumen than when they transport other crude oils. Having examined the general causes of failures, the committee focused on the specific sources of pipeline damage that can be influenced by the transported crude oil. Specifically, it identified the chemical and physical properties of crude oil that can cause or contribute to sources of pipeline failure from damage sustained internally or externally or as a result of mechanical forces.

The committee did not perform its own testing of pipelines or crude oil shipments. Information on the properties of shipments of diluted bitumen and other crude oils was obtained from public websites and assay sheets. Additional information was obtained from a review of

[1] Public Law 112-90, enacted January 3, 2012.

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government reports and technical literature, queries of oil producers and pipeline operators, field visits, and inferences from secondary sources such as the maximum water and sediment content for pipeline shipments as specified in pipeline tariffs. The committee then compared the relevant properties of shipments of diluted bitumen with the range of properties observed in other crude oil shipments to identify instances in which diluted bitumen fell outside or at an extreme end of the range.

In view of the possibility that some pipeline operators may modify their operating and maintenance practices in transporting diluted bitumen, the committee first posited potential differences and then sought evidence. Operators were questioned about their practices. The committee looked for indications of changes in standard procedures, including corrosion control practices, that could inadvertently make pipelines more susceptible to sources of failure.

MAIN POINTS FROM CHAPTER DISCUSSIONS

Crude Oil Pipeline Transportation in the United States

As described in Chapter 2, the crude oil transmission network in the United States consists of an interconnected set of pipeline systems. Crude oil shipments traveling through the network often move from one pipeline system to another and are sometimes stored at terminals. Most operators of transmission systems are common carriers who do not own the crude oil they transport but provide transportation services for a fee. Few major transmission pipelines are dedicated to transporting specific grades or varieties of crude oil. They usually move multiple batches of crude oil, often provided by different shippers and encompassing a range of chemical and physical properties. Crude oil shipments are treated to meet the quality requirements of the pipeline operator as well as the content and quality demands of the refinery customer.

Pipeline systems traverse different terrains and can vary in specific design features, components, and configurations. The differences require that each operator tailor operating and maintenance strategies to fit the circumstances of its systems in accordance with the federal pipeline safety regulations. Nevertheless, the systems tend to share many of the same basic components and follow similar operating and maintenance procedures. Together, regulatory and industry standards, system connectivity, and economic demands compel both a commonality of practice and a shared capability of handling different crude oils.

Bitumen Properties, Production, and Pipeline Transportation

As discussed in Chapter 3, the bitumen imported into the United States is derived from Canadian oil sands. Canadian bitumen is both mined and recovered in situ using thermally assisted techniques. A large share of the bitumen deposits is too deep for mining, so in situ recovery accounts for an increasing percentage of bitumen production. Because mined bitumen does not generally have qualities suitable for pipeline transportation and refinery feed, it is processed into synthetic crude oil in Canada. Bitumen recovered in situ with thermally assisted methods has lower water and sediment content and is thus better suited to long-distance transportation by pipeline than is mined bitumen. Bitumen imported into the United States is produced in situ through thermally assisted methods rather than by mining.

Like all forms of petroleum, Canadian bitumen is a by-product of decomposed organic materials and thus a mixture of many hydrocarbons. The bitumen contains a relatively large

012006

concentration of asphaltenes that contribute to its high density and viscosity. At ambient temperatures, bitumen does not flow and must be diluted for transportation by unheated pipelines. Diluents consist of light oils, including natural gas condensate and light synthetic crude oils created from bitumen. Although the diluents consist of low-molecular-weight hydrocarbons, shipments of diluted bitumen do not contain a higher percentage of these light hydrocarbons than do other crude oil shipments. The dilution process yields a stable and fully mixed product for shipment by pipeline with density and viscosity levels in the range of other crude oils transported by pipeline in the United States.

Shipments of diluted bitumen are piped at operating temperatures, flow rates, and pressure settings typical of crude oils with similar density and viscosity levels. Shipment water and sediment content conforms to the Canadian tariff limits, which are more restrictive than those in U.S. pipeline tariffs. Solids in diluted bitumen shipments are comparable in quantity and size with solids in other crude oil shipments transported by pipeline. While the sulfur in diluted bitumen is at the high end of the range for crude oils, it is bound with hydrocarbons and not a source of corrosive hydrogen sulfide. Diluted bitumen has higher acid content than many other crude oils, but the stable organic acids that raise acidity levels are not corrosive at pipeline temperatures.

Review of Pipeline Incident Data

A logical step in addressing the question of whether shipments of diluted have a greater propensity to cause pipeline releases than shipments of other crude oils is to examine historical release records. The incident statistics can be used to identify the general sources of pipeline failure. However, the information contained in the U.S. and Canadian incident records is insufficient to draw definitive conclusions. As explained in Chapter 4, one reason is that the causal categories in the databases lack the specificity needed to assess the particular ways in which transporting diluted bitumen can affect the susceptibility of pipelines to failure. Another reason is that incident records do not contain information on the types of crude oil transported and the properties of past shipments in the affected pipeline. Because many pipeline releases involve cumulative and time-dependent damage, there is no practical way to trace the transportation history of a damaged pipeline to assess the role played by each type of crude oil and its properties in transport.

Incident reporting systems in Canada and the United States do not have uniform reporting criteria and coverage. Given the relatively small number of pipeline incidents, even minor variations in reporting criteria can lead to significant differences in incident frequencies and causal patterns. Some reporting systems combine incident reports from oil gathering and transmission systems, while others do not. Variation in reporting coverage is problematic because gathering pipelines are fundamentally different from transmission pipelines in design, maintenance, and operations and in the quality and quantity of the liquids they carry.

Effects of Diluted Bitumen on Sources of Pipeline Damage

The chemical and physical properties of diluted bitumen were examined in Chapter 5 to determine whether any differ sufficiently from those of other crude oils to increase the likelihood of pipeline failures from sources of damage internally or externally or from mechanical forces. Any differences that could affect either the frequency or severity of the failure mechanism or the ability to mitigate a potential failure mechanism would suggest a difference in failure likelihood.

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No properties were found to differ in any way that may change the likelihood of pipeline damage and failure. An assessment was also made with regard to whether pipeline operators transporting diluted bitumen alter their operating and maintenance procedures in ways that can make pipelines more prone to the causes of failure the procedures are intended to prevent. No differences were found in these procedures. Summaries of the assessments are presented in Box 6-1.

Box 6-1

Summary of Assessments of the Effects of Diluted Bitumen on Causes of Pipeline Damage

Internal Degradation

A review of product properties pertaining to internal pipeline corrosion and erosion did not find that shipments of diluted bitumen are any more likely than shipments of other crude oils to cause these failure mechanisms. Shipments of diluted bitumen do not contain unusually high levels of water, sediment, dissolved gases, or other agents that can cause internal corrosion. The organic acids contained in diluted bitumen are not corrosive to steel at pipeline temperatures. The densities and viscosities of diluted bitumen shipments are within the range of other crude oils, and the velocity and turbulence with which shipments flow through pipelines are comparable and limit the formation of corrosive deposits. On the basis of an examination of the factors that influence microbial growth, diluted bitumen does not have a higher likelihood than other crude oils of causing microbiologically influenced corrosion. Because shipments of diluted bitumen have solids content and flow regimes comparable with those of other crude oil shipments, they do not differ in their propensity to cause erosion of transmission pipelines.

External Degradation

Pipelines can sustain external damage from corrosion and cracking. Because diluted bitumen only contacts the inside of a pipeline, it can contribute to external degradation only as a result of changes in pipeline operational parameters, specifically pipeline temperature and pressure levels. Elevated operating temperatures can increase the likelihood of external corrosion and cracking by causing or contributing to the degradation of protective coatings and by accelerating rates of certain degradation mechanisms. Elevated operating pressures can cause stress loadings and concentrations that lead to stress-related cracking, particularly at sites of corrosion and preexisting damage. Because the densities and viscosities of diluted bitumen are comparable with those of other crude oils, it is transported at comparable operating pressures and temperatures. For this reason, the likelihood of temperature- and pressure-related effects is indistinguishable for diluted bitumen and other crude oils of similar density and viscosity. Consequently, diluted bitumen will not create a higher propensity for external corrosion and cracking in transmission pipelines.

(*continued*)

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Box 6-1 (*continued*)

Mechanical Damage
Mechanical damage to the pipeline and its components can occur as a result of overpressurization or outside forces. Mechanical forces can cause an immediate release or make the pipeline more susceptible to release by destabilizing support structures; damaging other components such as valves and joints; and weakening resistance to other failure mechanisms, such as corrosion attack. The study examined several possible causes of an increased potential for mechanical damage due to the properties of the transported liquid, including the potential for shipments of diluted bitumen to cause pressure surges or to interact with outside forces that can cause damage in pipelines. None of the properties or operating parameters of diluted bitumen shipments was found to be sufficiently different from those of other crude oils to suggest a higher potential to cause or exacerbate mechanical damage in pipelines.

Effects on Operations and Maintenance Procedures
As common carriers, operators of transmission pipelines generally have the ability to transport the wide range of crude oil varieties that are in the commercial stream. Accordingly, operations and maintenance procedures are designed to be robust, capable of ensuring operational reliability and safety without the need for procedural modifications from one crude oil shipment to the next. The chemical and physical properties of diluted bitumen shipments do not suggest that transporting them by pipeline requires operations and maintenance procedures that differ from those of other crude oil shipments having similar properties. Likewise, inquiries with operators and searches of industry guidelines and advisories did not indicate any specific issues associated with transporting diluted bitumen that would negatively affect operators as they carry out their standard operations and maintenance programs, including their corrosion detection and control capabilities.

STUDY RESULTS

Central Findings

The committee does not find any causes of pipeline failure unique to the transportation of diluted bitumen. Furthermore, the committee does not find evidence of chemical or physical properties of diluted bitumen that are outside the range of other crude oils or any other aspect of its transportation by transmission pipeline that would make diluted bitumen more likely than other crude oils to cause releases.

Specific Findings

Diluted bitumen does not have unique or extreme properties that make it more likely than other crude oils to cause internal damage to transmission pipelines from corrosion or erosion. Diluted bitumen has density and viscosity ranges comparable with those of other crude oils. It is moved through pipelines in a manner similar to other crude oils with respect to flow rate, pressure, and

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operating temperature. The amount and size of solid particles in diluted bitumen are within the range of other crude oils so as not to create an increased propensity for deposition or erosion. Shipments of diluted bitumen do not contain higher concentrations of water, sediment, dissolved gases, or other agents that cause or exacerbate internal corrosion, including microbiologically influenced corrosion. The organic acids in diluted bitumen are not corrosive to steel at pipeline operating temperatures.

Diluted bitumen does not have properties that make it more likely than other crude oils to cause damage to transmission pipelines from external corrosion and cracking or from mechanical forces. The contents of a pipeline can contribute to external corrosion and cracking by causing or necessitating operations that raise the temperature of a pipeline, produce higher internal pressures, or cause more fluctuation in pressure. There is no evidence that operating temperatures and pressures are higher or more likely to fluctuate when pipelines transport diluted bitumen than when they transport other crude oils of similar density and viscosity. Furthermore, the transportation of diluted bitumen does not differ from that of other crude oils in ways that can lead to conditions that cause mechanical damage to pipelines.

Pipeline operating and maintenance practices are the same for shipments of diluted bitumen and shipments of other crude oils. Operating and maintenance practices are designed to accommodate the range of crude oils in transportation. The study did not find evidence indicating that pipeline operators change or would be expected to change such practices while transporting diluted bitumen.

These study results do not suggest that diluted bitumen will experience pipeline releases at a rate that is higher than its proportion of the crude oil stream. Future pipeline releases can be expected to occur, and some will involve diluted bitumen. All pipeline releases can be consequential. As explained at the outset of this report, the committee was not asked or constituted to study whether pipeline releases of diluted bitumen and other crude oils differ in their consequences or to determine whether such a study is warranted. Accordingly, the report does not address these questions and should not be construed as having answered them.

012010

APPENDIX A

Questionnaire to Pipeline Operators on Transporting Diluted Bitumen

The following questions were developed by the committee and given to the Canadian Energy Pipeline Association (CEPA) in January 2013. CEPA distributed the questionnaire to member pipeline companies and returned the results in March 2013. Operator responses are indicated in bold text.[1]

1. Please provide the following information:
   a. Total amount of transmission crude oil pipeline mileage: **Approximately 24,000**
   b. Mileage dedicated to dilbit service: **Approximately 890**
   c. Mileage in batch service: **Approximately 20,530**
   d. Percentage of barrels transported per day consisting of diluted bitumen:
      Operator A: 82 percent
      Operator B: 15 to 65 percent
      Operator C: 65 percent
      Operator D: 65 percent
      Operator E: 28 percent dilbit; 3 percent synbit

2. Please provide the following parameters on the properties of diluted bitumen measured at points of custody transfer or in-line (as appropriate and available):
   Table A-1 includes information gathered on a best-effort basis. One operator also reported some data for synbit, and these data were included for reference. In addition, H_2S data for a large number of crude oils are available from a study performed by Omnicon supported by several pipeline operators. These data were collected by using ASTM D5263 and have been included below for reference (see Figure A-1).

3. How often (e.g., percentage of barrels transported) is specified basic water and sediment (BS&W) exceeded at diluted bitumen initial custody transfer?
   For dilbit batches, between 0 and 0.6 percent of the barrels transported exceeded specified limits.

4. Is BS&W exceeded more often for diluted bitumen compared with other crude oils transported?
   Three operators reported no differences. In two cases, dilbit batches did exceed specified limits more often than other crude oils by a small margin of between 0.1 and 0.3 percent.

[1] API = American Petroleum Institute; CO_2 = carbon dioxide; H_2S = hydrogen sulfide; KOH = potassium hydroxide; O_2 = oxygen; ppm = parts per million; ppmw = parts per million by weight; psi = pounds per square inch; TAN = total acid number.

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TABLE A-1 Operator Responses to Question 2

Parameter	Operator	Average	Normal Range	Extreme High
Total BS&W (volume percentage)	A	0.35	0.25 to 0.40	0.5
	B	0.21	0.05 to 0.36	0.36
	C	0.18	0.11 to 0.25	0.5
	D	0.26	0.05 to 0.5	0.5
	E (dilbit)	0.28	0.1 to 0.38	0.5
	E (synbit)	0.31	0.28 to 0.34	0.5
Water share of BS&W	C	50 percent	40 to 60 percent	100 percent
Sediment share of BS&W	C	50 percent	40 to 60 percent	100 percent
Solid content (ppmw)	B		0 to 0.01	
Solids particle size (microns)	Not routinely measured in crude oil			
H_2S (ppmw)	B	6.77	0.1 to 11.1	11.1
	C	<0.5		10
	E	<0.5	<0.5	
Carbon dioxide (ppm)	Not routinely measured in crude oil			
Oxygen (ppm)	Not routinely measured in crude oil			
Sulfur (weight percentage)	A	3.8	3.62 to 3.85	
	B	3.3	2.45 to 4.76	4.8
	C	3.8	3.79 to 3.89	4.0
	D	3.7	3.0 to 4.1	4.1
	E (dilbit)	4.0	3.46 to 4.97	5.2
	E (synbit)	3.1	3.04 to 3.21	3.5
API gravity	A	21.5	19.0 to 23.1	
	B	20.6	19.3 to 21.3	
	C	22.1	21.4 to 22.2	
	D	21	19.0 to 23.3	
	E (dilbit)	21.5	20.3 t 21.9	
	E (synbit)	19.8	19.5 to 20.1	
Reid vapor pressure (psi)	B	5.1	2.54 to 7.58	7.58
	C	7		
	D	8	3 to 11.8	11.8
	E (dilbit)	7.3	5.85 to 7.79	14.9
	E (synbit)	3.1	2.4 to 3.0	14.9
TAN (mg KOH/g)	A	1	0.85 to 1.05	
	B	1.6	1.0 to 2.17	3.34
	C	1.6	1.52 to 1.64	1.82
	D	1.06	0.6 to 1.9	1.9
	E (dilbit)	1.3	0.92 to 2.49	3.75
	E (synbit)	1.6	1.4 to 2.22	2.5

(continued)

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TABLE A-1 (*continued*) Operator Responses to Question 2

Parameter	Operator	Average	Normal Range	Extreme High
Transport temperature (°C), transmission pipelines	A	30	26 to 34	40
	B	10 (winter); 22 (summer)	4 to 29	32
	C	15	5 to 35	50
	D	27	13 to 43	43
	E	17	9.5 to 22.7	25.4
Flow rate (ft/s) in transmission pipelines	A	4	2.0 to 6.0	
	B	6.56	4.5 to 7.2	8.2
	C	2.5	0.5 to 4.7	5.0
	D	6.7	4.8 to 8.2	8.2
	E	3.63	3.63	4.04
Pressure (psi) in transmission pipelines	A	930	700 to 1,200	1,300
	B	600	43.5 to 1,160	1,440
	C	500	175 to 1,350	1,440
	D	430	50 to 1,440	1,440
	E	750	750	1,095

5. Do tank storage methods for diluted bitumen differ from those of other crudes to possibly affect level of O_2, CO_2, water, and other contaminants?
   No, the storage method is the same as for all crude oil commodities. Dilbits are generally stored in their own commodity group to reduce downgrading.

6. Note any differences in set points for safety and control instrumentation for pipelines in diluted bitumen service as opposed to lines in other service:
   There are no differences. Standards and procedures are in place for control that are generic for all crude oil commodities shipped. The standards and procedures are structured to ensure safe operation regardless of the commodity.

7. Note any differences in the frequency of shutdowns, low-flow, and non-turbulent flow conditions while in diluted bitumen service:
   There are typically no differences that are related to dilbit service. One operator reported a small increase of shutdown frequency due to BS&W exceedance.

8. Note any special surge control equipment and/or vibration monitors on pipelines that carry diluted bitumen:
   No special equipment has been installed specifically to accommodate dilbit.

9. Are drag reducing agents used for diluted bitumen transportation?
   If so, does their use differ (more or less?) compared with other crude types?
   Three of five operators are currently not using drag-reducing agents for dilbit transportation. The use of drag-reducing agents is not specific to dilbit transportation. Their use is based on the operational requirements of a particular pipeline segment and throughput required.

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10. Do pipelines undergo more pressure cycling when in diluted bitumen service?
The operating philosophy and function of a pipeline drive pressure cycling, not the type of product transported. Batching between heavy and light products in the same pipeline may cause additional cycling; however, this is related to the switch in products rather than the products themselves. One operator reported that dilbit service lines cycle less frequently than those in conventional crude oil service.

11. Are pressure cycles measured and monitored for use in fatigue calculations?
Three of five operators currently monitor and use pressure cycles in fatigue calculations, and one operator is planning to complete this activity in the future. One operator does not currently complete this activity.

12. Are corrosion inhibitors, including biocides, used for diluted bitumen shipments?
If so, do quantities differ from those used for other crude types?
Three of the operators use chemical treatment for bacteria or corrosion control in at least some of their pipelines. Chemical treatment requirement is determined by the flow conditions and pipeline condition. When such treatments are required, the volume and quantities are the same as for other crude oil pipelines.

13. Is cleaning required at different intervals for pipelines in diluted bitumen service versus pipelines in other service?
The requirement for a cleaning program and cleaning intervals are primarily determined by consideration of flow conditions and the potential for water and sediment deposition for all crude oil types. No differences in cleaning intervals were reported by any operator.

14. Is the debris from pig cleaning analyzed?
If so, note any differences in composition for pipelines in diluted bitumen service?
Four of five operators complete testing of debris from pig cleaning, and no differences in composition have been reported for pipelines in dilbit service versus other heavy commodity pipelines. For pipelines in batch service with multiple products including dilbit, it is not possible to differentiate the sediment collected.

15. Is there any evidence from in-line inspection and/or other corrosion monitoring activities indicating unusual or unexpected corrosion locations for lines in diluted bitumen service?
Corrosion in heavy-oil pipelines can occur in areas where water or sediment accumulates—including low areas, critical inclines, and overbends. The latter location was unexpected when it was identified in 2005, but this does not appear to be unique to dilbit pipelines and is common to heavy commodities in general. No unusual or unexpected corrosion locations have been attributed to dilbit service.

16. Note any difference in clogging or wear of equipment, such as pumps, for lines in diluted bitumen service:
No clogging or unusual wear has been identified for lines in dilbit service.

17. Note any differences in predictive/preventive maintenance practices for lines in dilbit service:
No special predictive or preventive maintenance practices are required for dilbit pipelines.

18. More generally, do you have integrity management programs specific to lines in dilbit service?
No, dilbit lines are incorporated into overall integrity management programs. In more than 25 years of diluted bitumen service on some pipelines, no unique or more severe threats specific to diluted bitumen service have been observed.

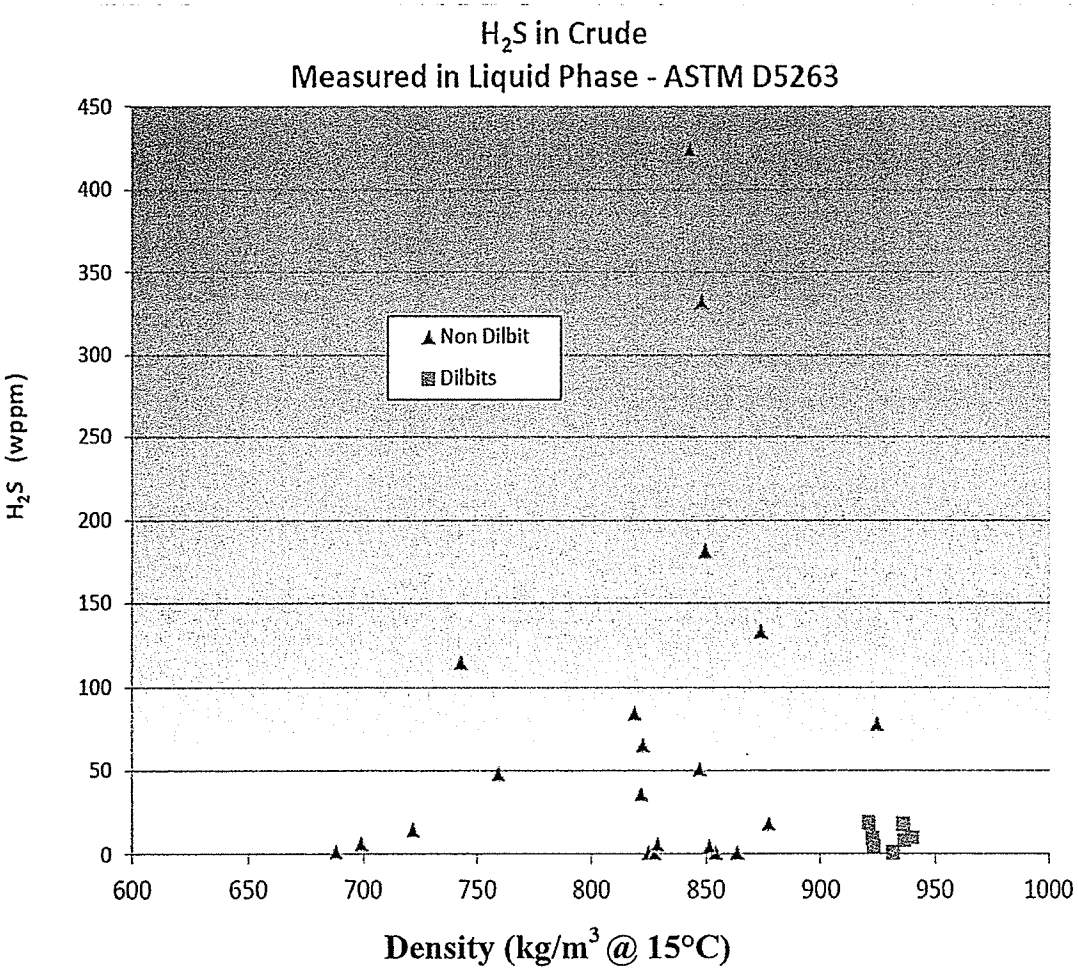

FIGURE A-1 Supplemental information on H_2S content.

APPENDIX B

Federal Pipeline Safety Regulatory Framework

ORIGINS OF HAZARDOUS LIQUIDS PIPELINE SAFETY REGULATION

The Hazardous Liquid Pipeline Safety Act (HLPSA) of 1979, as amended, provides the statutory authority for the U.S. Department of Transportation (USDOT) to establish regulatory standards for the transportation of hazardous liquid by pipelines, including those transporting crude oil.[1] Within the department, authority to carry out the act is delegated to the Pipeline and Hazardous Materials Safety Administration (PHMSA), which implements its authority through the Office of Pipeline Safety (OPS). OPS promulgates rules governing the design, construction, testing, inspection, maintenance, and operations of hazardous liquid pipelines. The regulations are intended to establish minimum safety standards applicable to all hazardous liquid pipeline facilities, thereby setting a safety floor that all operators must meet across the spectrum of pipeline systems. The regulations cover pipelines that transport crude as well as refined products.

A review of past OPS rulemaking notices reveals that as the regulatory program evolved and matured, USDOT and Congress began to question whether the regulatory program was having sufficient effect in reducing the risk of transporting hazardous liquid by pipeline. A central concern was that individual pipeline operators could be complying with each of the actions prescribed in the federal rules in a procedural, or "checklist," manner without really knowing whether these actions were collectively producing the desired safety assurance. Because pipeline facilities vary in their designs, construction, environments, and operating histories, specific safety assurance methods—including those not prescribed in federal rules—might be more suitable for one facility than for another. Moreover, OPS had long been concerned that it could not identify all facility-specific risks, which made a strictly prescriptive approach to safety regulation impractical. The changes made in response to these concerns have led to changes in the role of OPS and to new expectations for safety assurance by the pipeline industry.

PRESCRIPTIVE AND PERFORMANCE-BASED STANDARDS

After several major pipeline releases during the late 1980s and early 1990s, OPS started experimenting with other regulatory approaches to accompany its rules, which prescribed such specific actions as maintaining operating pressure at levels not to exceed 72 percent of specified minimum yield strength (SMYS).[2] The agency sponsored a series of demonstration projects that gave operators the incentive and flexibility to tailor their safety assurance methods to their specific circumstances. OPS reasoned that because pipeline operators have the most comprehensive and detailed knowledge of their systems, they are in the best position to devise their safety assurance programs, as long as they are given the motivation, tools, and regulatory flexibility to make effective choices.[3]

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[1] Rulemaking to begin implementation of HLPSA began in 1981 (*Federal Register*, Vol. 46, No. 143, July 27, 1981) and can be found at http://phmsa.dot.gov/staticfiles/PHMSA/hrmpdfs/1981%20hist%20rulemakings/46%20FR%2038357.pdf.

[2] §195.406.

[3] See *Federal Register*, Vol. 65, No. 237, Dec. 8, 2000.

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In 2000, OPS issued a landmark rulemaking titled Pipeline Integrity Management in High Consequence Areas.[4] Rather than prescribing specific operations and maintenance procedures, new rules laid out the key steps to be followed in developing and implementing a rationalized integrity management program based on principles of risk management. The regulations defined the core elements of the required program, such as the development of a written plan explaining how risks are to be identified; the logic used in choosing the tools, methods, and schedules employed for detecting and assessing risks; and the timetable for completing risk assessments and correcting deficiencies. The rules were written in performance-based language that does not tell operators exactly how they must conduct the risk assessments or precisely how they must act to mitigate identified risks. For example, if internal corrosion is identified as a threat in a particular pipeline segment, the operator is held responsible for selecting the best means to mitigate it—by using corrosion inhibitors, increasing the frequency of line cleaning, shortening inspection intervals, or selecting other defensible options.

Although performance-based rules have the advantage of allowing customized responses to specific circumstances, they can at times lack the clarity of a specific measure prescribed in rules applicable to all.[5] Accordingly, OPS has retained many of its prescriptive rules and continues to adopt new ones, depending on the safety concern. Box B-1 outlines the basic set of rules governing the transportation of hazardous liquids by pipeline, as contained in the Code of Federal Regulations, Title 49, Part 195. Examples of prescriptive rules, in addition to the aforementioned standard for maximum operating pressure, are those concerning pipeline design and construction features, such as the requirement for shutoff valves located at each side of a water crossing.[6] Nevertheless, in instances where alternatives to prescribed measures have safety merit, the operator can seek a waiver, or special permit, from OPS by demonstrating that the alternative measures will yield the same or higher levels of safety than the prescribed ones.[7]

An example of a special permit application is the original plan of TransCanada Corporation to construct the Keystone XL pipeline. When the pipeline was first proposed in 2008, the company petitioned OPS to allow for maximum operating pressures of 80 percent of SMYS. OPS agreed to the special permit conditioned on TransCanada Corporation implementing 57 measures not currently delineated in the regulations and on adding a degree of rigor not currently required. The conditions covered, among other things, quality control checks during the manufacture and coating of the pipe, tighter valve spacing, remote control valves, monitoring and control of operating temperatures, more frequent pig cleaning, and specific limits on the levels of water and sediment contained in the products transported. Although TransCanada Corporation eventually withdrew the special permit application, it agreed to comply with the 57 conditions as part of its separate presidential application to build and operate a pipeline that crosses a national border.[8]

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[4] See *Federal Register*, Vol. 65, No. 237, Dec. 8, 2000.

[5] For example, the National Transportation Safety Board recently urged PHMSA to revise the integrity management–high consequence area rule to better define when an assessment of environmental cracks must be performed, acceptable engineering methods for such assessments, and specific treatments that must be applied when cracks are found. http://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&SID=4c83a26cf5fcbaf90e350dddcff30166&rgn=div8&view=text&node=49:3.1.1.1.11.6.22.28&idno=49.

[6] §195.260.

[7] These are general regulations also pertaining to natural gas pipelines and are thus contained in 49 CFR Part 190.

[8] In 2008, TransCanada Corporation proposed the addition of a new hazardous liquid transmission pipeline, called the Keystone XL, which would originate in Alberta and terminate in Steele City, Nebraska. Because the pipeline crossed the U.S. border, it required presidential approval. Public Law 112-78 required the president to act on the application within 60 days of the law's enactment on December 23, 2011. In early 2012, President Barack Obama denied the application, citing a review by the U.S. Department of State that expressed the need for more information to consider relevant environmental issues and the

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Finally, in addition to having special permit authority, OPS has broad authority in the name of public safety to demand that pipeline operators take certain actions not specifically called for in regulations. For example, if the agency discovers a hazardous condition, it can issue orders requiring operators to take certain responsive or precautionary measures.[9] On discovering a condition that may be of concern to multiple pipelines, OPS can issue advisory bulletins that notify operators about the condition and how it should be corrected.

SUPPORTIVE PROGRAMS

The emphasis on risk- and performance-based standards has not only affected OPS rulemaking activity but also changed other aspects of its safety oversight program. Where it does not prescribe specific safety actions or practices, OPS seeks to ensure that operators are in compliance with the performance-oriented demands outlined in the regulations. Aided by its inspection and enforcement capabilities, OPS will verify that pipeline operators are developing and implementing risk management programs that have a rigorous and technically sound basis. A checklist compliance inspection approach is not considered adequate. Inspecting for compliance under these circumstances requires an approach more akin to a quality assurance audit to ensure that operators are following a well-defined set of actions. In addition, the advent of performance-based regulations has meant that OPS safety researchers now have responsibility for providing technical guidance to aid operators in developing rigorous risk management programs, including development of the requisite analytic tools.

About half of the 200-person OPS staff is responsible for inspecting pipeline facilities, with assistance from more than 300 state inspectors. Inspectors are authorized to review the manual for operations and maintenance required of each operator. Inspectors also review records documenting the evaluations that have been performed to identify and prioritize risk factors, devise integrity management strategies, and prioritize the preventive and mitigative measures. If OPS has reason to believe that a specific risk factor is escaping the scrutiny of a pipeline operator, it can review company records to determine whether and how the risk is being treated. As described in Chapter 4, PHMSA also requires operators to report incidents involving releases from pipelines. The agency uses the reports to guide its regulatory, inspection, and enforcement priorities.

Through its research and engineering capacity, OPS can assist pipeline operators in complying with both prescriptive and performance-based rules. In 2012, the agency funded about $7 million in research, with most projects conducted in collaboration with industry through cooperative programs such as the Pipeline Research Council International, Inc. Much of the research is designed to help operators comply with regulatory demands; for example, by developing tools and methodologies to detect and map pipeline leaks, locate and diagnose faults in cathodic protection systems, inspect lines that cannot be pigged, and conduct risk analyses. Research projects are also designed to provide technical support for industry standard-setting activities; for example, by evaluating new test methods being considered by standards development committees.

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consequences of the project on energy security, the economy, and foreign policy (*Federal Register*, Vol. 77, No. 23, Feb. 3, 2012, p. 5614).

[9] 49 CFR §190.

Box B-1

Summary of Coverage of Federal Hazardous Liquid Pipeline Safety Regulations

Title 49, Part 195—Transportation of Hazardous Liquids by Pipeline

Subpart A—General

§195.0 to §195.12	Regulation coverage, definitions, incorporations by reference of consensus standards, and compliance responsibility.

Subpart B—Reporting

§195.48 to §195.64	Includes reporting requirements for accidents and safety-related conditions as well as requirements for operators to provide assistance during investigations.

Subpart C—Design

§195.100 to §195.134	Includes pipe and component design requirements governing design temperature, internal design pressure, external pressure and loads, valves and fittings, closures and connections, and station pipe and breakout tanks.

Subpart D—Construction

§195.200 to §195.266	Includes construction-related requirements governing material inspection, transportation of pipe, location of pipe, installation and coverage of pipe, welding procedures and welder qualifications, weld testing and inspection, valve location, pumping stations, and crossings of railroads and highways.

Subpart E—Pressure Testing

§195.300 to §195.310	Includes requirements governing pressure testing of pipe, components, tie-ins, and breakout tanks. Also contains requirements for risk-based alternatives to pressure testing of older pipelines.

Subpart F—Operations and Maintenance

§195.400 to §195.452	Includes requirements for an operations, maintenance, and emergency response manual; maximum operating pressure; inspections of breakout tanks and rights-of-way; valve maintenance; pipe repairs; line markers and signs; public awareness and damage prevention programs; leak detection and control room management; and integrity management in high-consequence areas.

(*continued*)

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Box B-1 (*continued*)

Subpart G—Qualification of Pipeline Personnel

§195.501 to §195.509	Requirements for qualification programs and record keeping.

Subpart H—Corrosion Control

§195.551 to §195.589	Includes regulations on coatings for external corrosion control, coating inspection, cathodic protection and test leads, inspection of exposed pipe, protections from internal corrosion, protections against atmospheric corrosion, and assessment of corroded pipe.
Appendix A	Delineates federal and state jurisdiction.
Appendix B	Risk-based alternative to pressure testing older pipelines.
Appendix C	Guidance for integrity management program implementation.

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APPENDIX C

Data-Gathering Sessions

Committee for a Study of Pipeline Transportation of Diluted Bitumen

First Meeting
July 23–24, 2012
Washington, D.C.

July 23

9:45 a.m. Briefing by study sponsor, Pipeline and Hazardous Materials Safety Administration (PHMSA)
Linda Daugherty, Deputy Associate Administrator for Policy and Programs
Alan Mayberry, Deputy Associate Administrator of Field Operations
Jeffery Gilliam, Senior Engineer and Project Manager
- Origins and scope of study
- Overview of PHMSA's regulatory program
- Agency data sources and technical reports
- Additional background

11:30 a.m. Overview of relevant industry consensus standards and state of the practice in detecting, preventing, and mitigating internal corrosion of oil pipelines
Oliver Moghissi, President, National Association of Corrosion Engineers (NACE), and Director, DNV Columbus, Inc

1:00 p.m. Alberta Innovates report, *Comparison of Corrosivity of Dilbit and Conventional Crude*
John Zhou, Alberta Innovates Energy and Environment Solutions
Harry Tsaprailis, Alberta Innovates Technology Futures

1:45 p.m. Industry associations
Peter Lidiak, Director, Pipelines, American Petroleum Institute

2:30 p.m. Operator experiences—Enbridge Pipelines, Inc.
Scott Ironside, Director, Integrity Programs

3:30 p.m. Operator experiences—TransCanada Corporation
Bruce Dupuis, Program Manager, Liquid Pipeline Integrity
Jenny Been, Corrosion Specialist, Pipe Integrity

4:15 p.m. Concerns raised in Natural Resources Defense Council (NRDC) report
Anthony Swift, Attorney, International Program, NRDC

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5:00 p.m.	General discussion
5:45	Adjournment

July 24

9:35 a.m.	National Energy Board (NEB)—Overview of Regulatory, Data, and Technical Activities Iain Colquhoun, Chief Engineer, NEB
10:15 a.m.	Standard and Non-Standard Methodologies to Evaluate Crude Oil Corrosivity Under Pipeline Operating Conditions Sankara Papavinasam, Senior Research Scientist, CanmetMATERIALS
11:00 a.m.	Public forum
12:15 p.m.	Adjournment

Subcommittee Meeting
October 9, 2012
Edmonton, Alberta

8:40 a.m.	Introductions: Enbridge Pipelines, Inc.; TransCanada; Inter Pipeline; Kinder Morgan; Crude Quality, Inc.
9:30 a.m.	Experience with diluted bitumen quality and cleanliness when entering the pipeline system
10:45 a.m.	Pipeline control and operations: diluted bitumen versus conventional crude oils
12:30 p.m.	Integrity knowledge of pipelines Findings from inspecting pipelines in high consequence areas for anomalies
1:30 p.m.	Other presentations
3:00 p.m.	Tour of Natural Resources Canada, CanmetENERGY laboratory

Second Committee Meeting
October 23, 2012
Washington, D.C.

10:50 a.m. Overview of pipeline equipment, field operations, control center, leak detection, maintenance, regulation, and economics
Thomas Miesner, Pipeline Knowledge and Development

1:30 p.m. Background on crude oils and diluted bitumen
Harry Giles, Executive Director, Crude Oil Quality Association
Randy Segato, Suncor Energy
Andre Lemieux, Canadian Crude Quality Technical Association

2:30 p.m. Diluted bitumen: chemical and physical properties
Heather Dettman, Natural Resources Canada, CanmetENERGY

3:30 p.m. Evidence from pipeline incident reporting systems
PHMSA data: Jeffery Gilliam and Blaine Keener, PHMSA
Pipeline Performance Tracking System: Peter Lidiak, American Petroleum Institute, and Cheryl Trench, Allegro Energy Consulting

4:30 p.m. Overview of PHMSA supplemental regulatory authorities to mitigate risk
Jeffery Gilliam, PHMSA

5:00 p.m. Adjournment

Third Committee Meeting
January 31, 2013
Washington, D.C.

10:30 a.m. Summary of NACE conference proceedings on heavy oil and corrosion
Sankara Papavinasam, Senior Research Scientist, Natural Resources Canada, CanmetMATERIALS

11:15 a.m. Operational experience transporting heavy crude oils by pipeline in California
Art Diefenbach, Vice President of Engineering, Westpac Energy

1:00 p.m. Overview of federal hazardous liquid pipeline regulatory approach
Jeffrey Wiese and Jeffery Gilliam, PHMSA

2:00 p.m. Changing patterns of crude oil supply and demand
Geoffrey Houlton, Senior Director, Global Crude Oil Market Analysis, IHS

3:00 p.m. Adjournment

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Study Committee Biographical Information

Mark A. Barteau, *Chair*, is DTE Energy Professor of Advanced Energy Research, Professor of Chemical Engineering, and Director of the University of Michigan Energy Institute. Before accepting his appointments at the University of Michigan in 2012, he retired from the University of Delaware as Senior Vice Provost for Research and Strategic Initiatives and Robert L. Pigford Chair in Chemical Engineering. He was a National Science Foundation Postdoctoral Fellow at the Technische Universität München before joining the University of Delaware as Assistant Professor of Chemical Engineering and Associate Director of the Center for Catalytic Science and Technology in 1982. He became Director of the Center for Catalytic Science and Technology in 1996. He has held visiting appointments at the University of Pennsylvania and the University of Auckland, New Zealand. His research in surface chemistry and heterogeneous catalysis has been recognized with numerous awards, including the International Catalysis Award. He was the founding director of the University of Delaware Energy Institute. He is active in the National Research Council, serving as cochair of the Chemical Sciences Roundtable and as a member of the Chemical Engineering Peer Committee. He has also served on the Panel on Chemical Science and Technology, the Committee on the Review of Basic Energy Sciences Catalysis Program, and the Committee on Challenges for the Chemical Sciences in the 21st Century. He was elected to the National Academy of Engineering in 2006. He received a BS in chemical engineering from Washington University in St. Louis, Missouri, and an MS and a PhD in chemical engineering from Stanford University.

Y. Frank Cheng is Professor and Canada Research Chair in Pipeline Engineering in the Department of Mechanical and Manufacturing Engineering at the University of Calgary. His research has focused on pipeline corrosion, stress corrosion cracking, erosion–corrosion, coatings, metallurgical microelectrochemistry, and defect assessment. Before joining the faculty of the University of Calgary in 2005, he was a Natural Sciences and Engineering Research Council of Canada postdoctoral fellow at the Nova Research and Technology Center and a research scientist at the Center for Nuclear Energy Research at the University of New Brunswick. He is a member of the editorial board of *Corrosion Engineering, Science and Technology* and has published more than 120 articles in refereed journals on corrosion and pipeline engineering. He is the sole author of *Stress Corrosion Cracking of Pipelines*, published by Wiley. He is also Theme Editor of Pipeline Engineering for the *Encyclopedia of Life Support Systems* developed under the auspices of the United Nations Educational, Scientific, and Cultural Organization. He holds a BS in corrosion from Hunan University, an MS in materials engineering from the Institute of Metal Research from the Chinese Academy of Sciences, and a PhD in materials engineering from the University of Alberta.

James F. Dante is Manager of the Environmental Performance of Materials Section of the Southwest Research Institute. In this capacity, he supervises 15 staff engineers and technicians involved in basic and applied corrosion research for the energy industry and the U.S. Departments of Defense, Transportation, and Energy. Current programs include corrosion sensor research and implementation involving fluidized sensors, atmospheric corrosion sensors, and sensors for corrosion under insulation. His unit also conducts research on accelerated corrosion test methods and research to advance the mechanistic understanding of corrosion processes in

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various industries. Before joining Southwest Research Institute in 2009, he was Senior Research Scientist at Luna Innovations and leader of the University of Dayton Research Institute's group specializing in corrosion mechanisms, detection, and protection. He began his career as a materials research engineer at the National Institute of Standards and Technology. He holds a BA in physics from Johns Hopkins University and an MS in materials science and engineering from the University of Virginia.

H. Scott Fogler is Vennema Professor of Chemical Engineering and Arthur F. Thurnau Professor at the University of Michigan. He is internationally recognized for his research and teaching in chemical reaction engineering in petroleum engineering, including reaction in porous media, fused chemical relations, kinetics of wax deposition, gelation kinetics, asphaltene deposition kinetics, remediation colloidal phenomena, and catalyzed dissolution. The Chemical Manufacturers Association honored him with the National Catalyst Award in 1999. He has published more than 200 articles in peer-reviewed journals and books. He is author of *Elements of Chemical Reaction Engineering*, which is in its fourth edition and is estimated to be used by three-quarters of all chemical engineering programs in the United States. He has received numerous awards from the American Society for Engineering Education, including the Dow Outstanding Young Faculty Award in 1972, the Corcoran Award for Best Paper in Chemical Engineering Education in 1993, and the Lifetime Achievement Award from the Chemical Engineering Division in 2005. He earned a BS in chemical engineering from the University of Illinois and an MS and a PhD in chemical engineering from the University of Colorado.

O. B. Harris is President of O. B. Harris, LLC, an independent consultancy specializing in the regulation, engineering, and planning of petroleum liquids pipelines. From 1995 to 2009, he was Vice President of Longhorn Partners Pipeline, LP, which operates a 700-mile pipeline that carries gasoline and diesel fuel from Gulf Coast refineries to El Paso, Texas. In this position, he was responsible for engineering, design, construction, and operation of the system. From 1991 to 1995, he was President of ARCO Transportation Alaska, Inc., a company owning four pipeline systems, including the Alyeska Pipeline Service Company, which transports 25 percent of the crude oil from the North Slope of Alaska to the Port of Valdez. From 1977 to 1990, he held several supervisory and managerial positions at ARCO Pipeline Company, including District Manager for Houston and Midland, Texas; Manager of the Northern Area; and Manager of Products Business. At ARCO Transportation, he directed the efforts of a team of corrosion engineers advising Alyeska on making repairs to the Trans-Alaska Pipeline System. He is a past member of the Board of Directors of the Association of Oil Pipe Lines and the Pipeline and Hazardous Materials Safety Administration's Technical Hazardous Liquids Pipeline Safety Standards Committee. He holds a bachelor's degree in civil engineering from the University of Texas and an MBA from Texas Southern University.

Brenda J. Little is Senior Scientist for Marine Molecular Processes in the Naval Research Laboratory (NRL) at the Stennis Space Center. Earlier she was a Supervisory Research Chemist, Principal Investigator in the Biological and Chemical Oceanography Branch, Supervisory Oceanographer, and Head of the Biological and Chemical Oceanography Branch. During her 35-year career at NRL, she has made major contributions in identifying and understanding microbiologically influenced corrosion of marine materials, which has had a significant impact on a broad spectrum of Navy applications. Her research has been used to prevent and mitigate

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corrosion problems in seawater piping systems, fire protection systems, weapon cooling systems, helicopter interiors, and nuclear waste storage. She participated in a special U.S. Department of Transportation investigation of corrosion mechanisms in the Alaska North Slope pipeline. She is Assistant Editor of *Biofouling,* the *Journal of Bioadhesion,* and *Biofilm Research*. She coauthored (with J. S. Lee) *Microbiologically Influenced Corrosion* (John Wiley and Sons, 2007). She has published more than 80 journal articles, more than 100 papers in symposium proceedings, and more than 20 book chapters. Her publications have earned her numerous NRL publication awards. She is a Fellow of the National Association of Corrosion Engineers (NACE) and a recipient of the Navy Meritorious Civilian Service Award and Women in Science and Engineering Award for Scientific Achievement. She holds a BS in biochemistry from Baylor University and a PhD in chemistry from Tulane University.

Mohammad Modarres is Minta Martin Professor of Engineering and Professor of Nuclear and Reliability Engineering and Director of the Reliability Engineering Program at the University of Maryland, College Park. His research centers on probabilistic risk assessment; uncertainty analysis; and the physics of failure mechanisms of mechanical components, systems, and structures. He has served as a consultant to several governmental agencies, private organizations, and national laboratories in areas related to probabilistic risk assessment, especially applications to complex systems such as nuclear power plants and pipelines. He has authored more than 300 papers in archival journals and proceedings of conferences and three books in various areas of risk and reliability engineering. He is a member of several journal editorial boards, including the *Reliability Engineering and System Safety Journal*, *Journal of Risk and Reliability,* and *International Journal of Reliability and Safety*. He is Associate Editor of the *International Journal on Performability Engineering*. He holds a master's degree in mechanical engineering and a PhD in nuclear engineering, both from the Massachusetts Institute of Technology.

W. Kent Muhlbauer is Founder and President of WKM Consultancy, which provides consulting services on all aspects of pipeline design, operations, and maintenance with an emphasis on risk management. Clients include major U.S. and international pipeline operators, federal and state regulatory agencies, engineering companies, and insurance companies. Pipeline risk assessment techniques developed by WKM are in use by pipeline operating companies worldwide. Before forming WKM in 1995, he designed, constructed, and maintained pipeline systems for Dow Chemical's Pipeline Division. He held a variety of engineering and management positions starting in 1982, including operations engineer, technology center specialist, pipeline and salt dome storage quality manager, control center supervisor, and regional operations and maintenance manager. He is author of the *Pipeline Risk Management Manual* (Elsevier 1992, 1996, 2004) and author of numerous articles and papers on pipeline risk management. He is a frequent speaker and instructor at conferences, workshops, training sessions, and seminars on pipeline risk management and integrity preservation. He holds a BS in civil engineering from the University of Missouri.

Srdjan Nešić is Professor of Chemical Engineering and Director of the Institute for Corrosion and Multiphase Flow Technology at Ohio University. Before joining the faculty of Ohio University in 2002, he was a Senior Lecturer in the Mechanical Engineering Department of the University of Queensland, Brisbane, Australia; Principal Research Scientist at the Institute for Energy Technology, Kjeller, Norway; and Research Scientist at Vincha Institute for Nuclear

Sciences, Belgrade, Hungary. His expertise is in flow effects and erosion of pipelines, electrochemical corrosion, computational and experimental fluid dynamics, and multiphase flow. He has authored more than 50 peer-reviewed journal articles on these subjects and more than 100 conference papers. He is a Fellow of NACE and has chaired numerous NACE technical sessions and conferences on internal pipeline corrosion and erosion. He is a member of the editorial board of the *Corrosion Journal.* He holds bachelor's and master's degrees in mechanical engineering from the University of Belgrade and a PhD in chemical engineering from the University of Saskatchewan.

Joe H. Payer is Chief Scientist at the National Center for Education and Research on Corrosion and Materials Performance and Research Professor of Corrosion and Reliability Engineering at the University of Akron. In this position he directed the University Corrosion Collaboration for the U.S. Defense Department's Office of Corrosion Policy and Oversight. Before joining the University of Akron in 2009, he was Professor of Materials Science at Case Western Reserve University, where he directed the U.S. Department of Energy's multiuniversity Corrosion and Materials Performance Cooperative for improved performance assessment for long-term disposal of spent nuclear fuel. His expertise is in materials selection, failure analysis, corrosion control methods, monitoring systems, and degradation mechanisms. His research has focused on localized corrosion of highly corrosion-resistant materials, gas and oil pipeline integrity, the effects of manufacturing processes on the performance and reliability of materials in service, coatings and surface treatments, and hydrogen and materials interactions. He is a Fellow of the American Society for Metals International; a Fellow and Past President of NACE; and a recipient of the American Society for Testing and Materials Sam Tour Award for Distinguished Contributions to Research, Development, and Evaluation of Corrosion Testing Methods. He earned a BS and a PhD in metallurgical engineering from Ohio State University.

Richard A. Rabinow is President of the Rabinow Consortium, LLC, which provides economic and business consulting services to the pipeline industry. He retired from ExxonMobil after a 34-year career with the corporation. At the time of his retirement in 2002, he was President of ExxonMobil Pipeline Company (EMPCo), a position he had held at EMPCo and its predecessor, Exxon Pipeline Company, since 1996. Before that, he was Vice President and Lower 48 Manager of Exxon Pipeline Company. He began his career at the Exxon Company in 1968, where he held several engineering and supervisory positions in refineries. He rose to Executive Assistant to the President of Exxon Company, Baytown Refinery Manager, Manager of Corporate Affairs, Manager of the Environmental and Safety Department. He is a past Chairman of the Association of Oil Pipe Lines and the Owners Committee of the Trans-Alaska Pipeline System. He has served on the Transportation Research Board's Committee for Pipelines and Public Safety and the Committee on Alaska's Oil and Gas Pipeline Infrastructure. He received a BS in engineering mechanics from Lehigh University and MS degrees in mechanical engineering and management, both from the Massachusetts Institute of Technology.

George W. Tenley, Jr., retired in 2010 as President of the Pipeline Research Council International (PRCI). PRCI is the collaborative research and development program for the energy pipeline industry. He joined PRCI in 1999 after working as an independent consultant on pipeline integrity planning and as a strategic advisor on pipeline risk management for Battelle Memorial Institute. From 1989 to 1995, he was Associate Administrator for Pipeline Safety in

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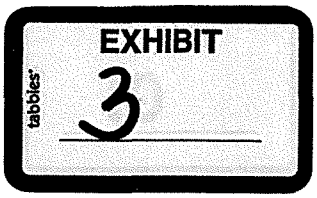
the U.S. Department of Transportation. In this position, he was the senior federal official responsible for safety regulations governing the pipeline transportation of hazardous liquids and natural gases. From 1976 to 1989, he was a senior attorney and then Chief Counsel for the Research and Special Programs Administration. He began his career as an attorney for the Federal Aviation Administration and the Drug Enforcement Administration. He earned a BA in political science from the University of Maryland and a JD from the University of Maryland.



Leukemia Risk Associated With Low-Level Benzene Exposure

Deborah C. Glass,[*] Christopher N. Gray,[†] Damien J. Jolley,[‡] Carl Gibbons,[‡] Malcolm R. Sim,[*] Lin Fritschi,[§] Geoffrey G. Adams,[¶] John A. Bisby,[#] and Richard Manuell[#]

Background: Men who were part of an Australian petroleum industry cohort had previously been found to have an excess of lympho-hematopoietic cancer. Occupational benzene exposure is a possible cause of this excess.

Methods: We conducted a case-control study of lympho-hematopoietic cancer nested within the existing cohort study to examine the role of benzene exposure. Cases identified between 1981 and 1999 (N = 79) were age-matched to 5 control subjects from the cohort. We estimated each subject's benzene exposure using occupational histories, local site-specific information, and an algorithm using Australian petroleum industry monitoring data.

Results: Matched analyses showed that the risk of leukemia was increased at cumulative exposures above 2 ppm-years and with intensity of exposure of highest exposed job over 0.8 ppm. Risk increased with higher exposures; for the 13 case-sets with greater than 8 ppm-years cumulative exposure, the odds ratio was 11.3 (95% confidence interval = 2.85-45.1). The risk of leukemia was not associated with start date or duration of employment. The association with type of workplace was explained by cumulative exposure. There is limited evidence that short-term high exposures carry more risk than the same amount of exposure spread over a longer period. The risks for acute nonlymphocytic leukemia and chronic lymphocytic leukemia were raised for the highest exposed workers. No association was found between non-Hodgkin lymphoma or multiple myeloma and benzene exposure, nor between tobacco or alcohol consumption and any of the cancers.

Conclusions: We found an excess risk of leukemia associated with cumulative benzene exposures and benzene exposure intensities that were considerably lower than reported in previous studies. No evidence was found of a threshold cumulative exposure below which there was no risk.

Key Words: benzene, occupational exposure, leukemia, lymphoma, multiple myeloma, petroleum industry

(*Epidemiology* 2003;14: 569–577)

Benzene is present in crude oil, at most stages of petroleum production and distribution, and is a component of gasoline fuels, typically less than 3%. It is also a byproduct of combustion of fuels and other materials such as tobacco, wood, and coal. Benzene is present in indoor environments from activities such as cooking and heating, and it is ubiquitous in urban air at low concentrations. Nonsmokers living in an urban environment are typically exposed to average benzene concentrations in the order of 0.005 ppm.[1]

Benzene is classified as a group 1 human carcinogen by the International Agency for Research on Cancer,[2] and there is general agreement that benzene can cause leukemia in highly exposed individuals.[3] The extent of the risk of leukemia with exposure to low concentrations of benzene (less than 10 ppm) has been debated.[3-11] This debate has centered on 2 issues: whether the exposures were underestimated in previous epidemiologic studies and what model should be used to extrapolate the risk to lower concentrations of benzene, including whether there is a threshold exposure below which there is no risk.

In addition, there is debate about which subtypes of leukemia are associated with benzene exposure. Some but not all authorities consider that acute nonlymphocytic leukemias or, more specifically, acute myeloid leukemia, are the only subtypes clearly associated with benzene exposure.[3,8,9,12,13] Benzene has also been associated with increased risk of

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multiple myeloma,[3,14,15] although this too is disputed.[9,16] A review of 308,000 benzene-exposed workers from 26 cohorts in 5 countries found no increased rate of non-Hodgkin lymphoma.[17] In the U.K., the occupational exposure limit for benzene (maximum exposure limit) is 3 ppm as an 8-hour time-weighted average.[18] This was introduced in 2000 as the first part of a phased reduction to 1 ppm in 2003 in accordance with the Carcinogens Directive of the Council of the European Union.[19] The current American Conference of Governmental Industrial Hygienists' threshold limit value for benzene is 0.5 ppm.[20]

A prospective cohort study of all-cause mortality and cancer incidence in the Australian petroleum industry, known as Health Watch, was established in 1980 at the University of Melbourne for the Australian Institute of Petroleum. In 1999 the study was transferred to the University of Adelaide. The cohort consists of all employees except head office staff and those employed at Australian sites with fewer than 10 employees. Employees in the industry have been surveyed at approximately 5-year intervals using an interviewer-administered job and health questionnaire. This questionnaire obtained information on jobs and tasks, on possible confounding variables (including smoking and alcohol), and on specific health outcomes. The first survey was conducted from 1981-1983 and resulted in an original cohort of 10,979 men and 626 women. More subjects were recruited in the second and subsequent surveys. Approximately 95% of eligible employees in the industry have participated in Health Watch surveys. Employees were recruited into the Health Watch cohort after having served 5 years in the petroleum industry, and they remain in the cohort for life. Copies of death certificates are obtained and cancer incidence is validated through state cancer registries and the treating doctor. Cancer registration in Australia is a legal requirement of pathology laboratories and hospitals. In 1998 the cohort comprised 15,732 men and 1178 women.

Men in the cohort have been shown to have increases in the standardized incidence ratios for leukemia of 2.0 (95% confidence interval [CI] = 1.3-2.9) and for multiple myeloma of 1.9 (95% CI = 1.0-3.3).[21] We designed a case-control study to assess the association between lympho-hematopoietic cancers and occupational benzene exposure among men in the cohort. We report the exposure-response relationships for lympho-hematopoietic cancers, including the subtypes of leukemia, and benzene exposure based on matched analyses.

METHODS

This case-control study is nested within the Health Watch cohort. We estimated the occupational exposure to benzene of the cases and control subjects, drawing on the subject's entire job history and using measured exposures for a wide range of tasks in the petroleum industry.

Cases were defined as men in the Health Watch cohort who reported a newly diagnosed lympho-hematopoietic cancer to Health Watch (either by himself or by his family) that was confirmed by pathology report, cancer registration, letter from a medical practitioner, or death certificate. Registry cases who had not self-reported to Health Watch could be included under the terms of the ethics committee approval only if the man had been lost to follow up or had died.

Seventy-nine cohort members met the definition of lympho-hematopoietic cancer cases. They were identified by searching the cancer registries and through self-report to Health Watch. One man was found in the cancer registry, but under the terms of the ethics approval he could not be a case because he had not self-reported the disease and was not deceased or lost to contact.

All documentation on the cases was reviewed by the investigators and cases were assigned to International Classification of Diseases groupings according to the highest level of evidence (Table 1). For 9 cases with uncertain histology the documentation was reviewed by a hematologist who classified cases using the French-American-British system.[22]

We selected 5 male control subjects for each case. Control subjects were selected randomly from a list of all cohort members who were eligible at the time of diagnosis and matched by year of birth. As a result of the random selection, 5 workers were used as control subjects for more than 1 case, 4 of whom were used in 2 case-control sets and 1 in 3 sets. Thus, the total number of control subjects was 395. One worker selected as a control subject subsequently became a case; this subject was retained as a control subject because he was not diagnosed at the time of selection. As a control subject, his exposure was truncated at the time of the matched-case diagnosis (as with all control subjects). As a case his exposure was estimated up to the time of his diagnosis.

Each subject's smoking, alcohol, and job history had been collected as part of the Health Watch cohort surveillance.[21] For employees interviewed in either the first or second Health Watch surveys in 1981-1983 and 1986-1987, detailed information had been collected only on their current job and jobs held in the previous 5 years. During the third Health Watch survey in 1991-1993, full job histories were obtained for all current employees interviewed. For those Health Watch members no longer employed in the petroleum industry, lists of jobs held in the industry were obtained during the annual health check mail-out in 1994. The lists included job titles, company, site, area of work and dates, but no details of individual tasks or products handled. The job histories were cross-checked with company personnel records. In those instances in which discrepancies were found, the more detailed record (usually the subject's) was used.

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TABLE 1. Type of Cancer by Highest Level of Evidence for the Diagnosis

Type of Lympho-hematopoietic Cancer	ICD-9 Code	Highest Level of Evidence: Histology (N = 39)	Doctors' Letters (N = 17)	Cancer Registry Alone (N = 14)	Death Certificate (N = 9)	Total No. (N = 79)
Non-Hodgkin lymphoma	200, 202	14	6	5	6	31
Multiple myeloma	203	8	4	2	1	15
Leukemia	204–208	17	7	7	2	33
Chronic lymphocytic leukemia	204.1	5	5	0	1	11
Chronic myeloid leukemia	205.1	1	1	4	0	6
Acute lymphocytic leukemia	204.0	2	0	0	0	2
Acute nonlymphocytic leukemia*	205.0, 208.0	7	1	2	1	11
Other leukemia†	202.4, 204.9	2	0	1	0	3

*This group includes 9 acute myeloid leukemias and 2 acute undifferentiated leukemias.
†The 3 "other" leukemias were a hairy cell leukemia and 2 unspecified lymphocytic leukemias. ICD-9, World Health Organization International Classification of Diseases, 9th revision.

Cases were not themselves interviewed about their tasks, because this information might have been subject to recall bias. Instead, we interviewed contemporaries at the site who were familiar with the requirements of the job. These surrogate respondents provided information on the tasks that each subject would have performed for each job he had recorded in the job history, the technology used at that time, and products handled. Current and past employees were interviewed, and the interviews were structured using standard questionnaires for each job type based on those developed for previous petroleum industry epidemiologic studies.[23,24] The interviewers had no knowledge of the names and health status of the subjects.

We calculated the benzene exposure of each individual using a task-based algorithm involving the subject's occupational history; previously measured exposures for particular tasks in the Australian petroleum industry; and task-, site-, and period-specific data. This exposure model was similar to those used in some other petroleum industry epidemiologic studies[23,24] but more detailed in that it was task-based and applied to each individual's job history. This provided an estimate of cumulative exposure to benzene in parts per million-years (ppm-years) for each subject. The subjects were divided into geometric exposure groups. The exposure estimation process is described more fully elsewhere.[25,26]

We used the following additional exposure metrics to test the association with risk of leukemia, with and without adjustment for cumulative exposure:

1. Start date: Subjects were divided into 3 groups by their start date in the industry: pre-1965, 1965-1975, and post-1975.
2. Duration of employment: The duration of employment (in participating companies) was defined as the difference between the earliest start date and the latest finish date for each subject, truncated by date of diagnosis. We calculated quintiles of duration with cut-points approximately every 7 years.
3. Whether most of the career was spent as an office worker or as a blue collar worker.
4. Site of longest-held job and highest-exposed job: Each site where a subject worked was allocated to a site type. The period of time and associated exposure for each subject was then allocated to that site type. If a subject worked in the office at a refinery or a distribution terminal, he was included as an office worker rather than being assigned to a site type.
5. Intensity of exposure: We calculated the average exposure intensity (cumulative benzene exposure estimate divided by duration of employment) in ppm for each job. We divided the subjects into geometric exposure intensity groups based on their highest exposed job.
6. Subjects with exposure to benzene concentrate: We identified those subjects who had handled benzene concentrate that is 100% benzene or BTX (benzene-toluene-xylene, which is principally an aromatic fraction derived from coke oven operations, containing approximately 70% benzene).

All odds ratios and 95% confidence intervals are from matched analyses.

The study was carried out with the clearance of Monash University Standing Committee on Ethics in Research Involving Humans, and the Ethics Committees from Melbourne

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and Adelaide Universities. All subjects signed a consent form to allow access to their job histories, and cases consented to our contacting their treating doctor for diagnostic details.

RESULTS

The cases and control subjects were well matched demographically (Table 2). They were similar with regard to alcohol consumption and country of birth. Control subjects were slightly more likely than the cases to be exsmokers. The risk of leukemia was not associated with smoking; odds ratios (ORs) were 0.55 (95% CI = 0.18-1.32) for previous smokers and 1.28 (95% CI = 0.52-3.14) for current smokers compared with never-smokers. We estimated the OR for leukemia associated with smoking score (pack-years) and alcohol score (standard drink-years) both as continuous measures. The OR per 100 pack-years was 0.98 (95% CI = 0.80-1.19) and per 1000 drink-years was 0.78 (95% CI = 0.52-1.16).

The ages of the cases at the date of case diagnosis ranged from 26-79 years with a mean of 54 years (Table 2). The mean duration of employment, prior to diagnosis, was 20.4 years (standard deviation, 9.0 y), and ranged from 4.3-43 years. A control subject, employed for only 4.3 years at the time of diagnosis of the case to which he was matched, had satisfied the cohort criteria of being employed in the industry for 5 years or more.

Cases had, on average, a higher lifetime cumulative exposure than control subjects, and a greater proportion of cases were in higher exposure categories (Table 3). The subjects were grouped by cumulative exposure (ppm-years) into 6 geometric groups, and conditional logistic regression (case-matched) was used to calculate stratum-specific ORs (Table 4). No increase in risk for non-Hodgkin lymphoma/multiple myeloma was found with increasing exposure to benzene. However, the ORs for leukemia were found to be elevated for 3 of the 5 exposure groups compared with the lowest (≤1 ppm-years) as illustrated in Figure 1. The highest exposure group (>16 ppm-years) contained 7 of 33 leukemia cases, but only 3 of their 165 matched control subjects. For the 2 highest exposure categories combined (13 case-sets with >8 ppm-years cumulative exposure), the OR was 11.3 (95% CI = 2.85-45.1).

In a comparable study in the U.K. petroleum industry,[27] a cut-point of 4.79 ppm-years was used in the analysis. For comparison purposes we analyzed our data using the same cut-point and obtained an OR of 2.51 (95% CI = 1.1-5.7).

The OR associated with cumulative exposure as a continuous measure was 1.65 (95% CI = 1.25-2.17), which is consistent with an increase of 65% for each doubling of mean cumulative exposure.

There was no association between leukemia (with or without adjustment for cumulative benzene exposure) and date of starting work in industry or duration of employment (Table 5). Blue collar workers had a 3-fold risk of leukemia compared with office workers, but this risk disappeared when adjustment was made for cumulative benzene exposure (data not shown). Subjects who had worked longest at an airport had nearly 4 times the risk of leukemia compared with terminal workers but this result was based on small numbers. This finding did not change after adjustment for cumulative

TABLE 2. Lifestyle and Demographic Characteristics of the Cases and Control Subjects

Characteristic	Control Subjects (N = 395)	All Cases (N = 79)	Types of Cancer			
			Leukemia (N = 33)	NHL/MM (N = 46)	MM (N = 15)	NHL (N = 31)
Age in years; mean (range)	54 (26–76)	54 (26–79)	52 (34–71)	54 (26–75)	55 (39–75)	54 (26–70)
Tobacco; no. (%)*						
Never smoked	125 (32)	28 (35)	11 (33)	17 (37)	8 (53)	9 (29)
Previous smoker	166 (42)	21 (27)	8 (24)	13 (28)	6 (40)	7 (23)
Current smoker	103 (26)	30 (38)	14 (42)	16 (35)	1 (7)	15 (48)
Alcohol; no. (%)						
Never drank	79 (20)	16 (20)	7 (21)	9 (20)	1 (7)	8 (26)
Previous drinker	10 (3)	2 (3)	1 (3)	1 (2)	0	1 (3)
Current drinker	305 (77)	61 (77)	25 (76)	36 (78)	14 (93)	22 (71)
Country of birth; no. (%)						
Australia	259 (66)	56 (71)	25 (76)	31 (67)	10 (67)	21 (68)
UK	75 (19)	14 (18)	4 (12)	10 (22)	3 (20)	7 (23)
Other	60 (15)	9 (11)	4 (12)	5 (11)	2 (13)	3 (10)

*One control did not record smoking data.
NHL/MM, combined non-Hodgkin lymphoma and multiple myeloma; MM, multiple myeloma; NHL, non-Hodgkin lymphoma.

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TABLE 3. Cases and Control Subjects Grouped by Exposure to Benzene Expressed as Cumulative Exposure (ppm-years)

Characteristic	Control Subjects (N = 395)	All Cases (N = 79)	Types of Cancer			
			Leukemia (N = 33)	NHL/MM (N = 46)	MM (N = 15)	NHL (N = 31)
Mean and range of cumulative exposure (ppm-years)	4.7 (0.01–57.3)	7.27 (0.01–52.7)	10.63 (0.09–52.7)	4.85 (0.01–23.4)	4.73 (0.17–23.4)	4.91 (0.01–21.8)
Cumulative exposure (ppm-years); no. (%)						
≤1	138 (35)	18 (23)	3 (9)	15 (33)	4 (27)	11 (35)
>1–2	56 (14)	12 (15)	6 (18)	6 (13)	2 (13)	4 (13)
>2–4	67 (17)	16 (20)	8 (24)	8 (17)	5 (33)	3 (10)
>4–8	64 (16)	12 (18)	3 (9)	9 (20)	2 (13)	7 (23)
>8–16	53 (13)	11 (14)	6 (18)	5 (11)	1 (7)	4 (13)
>16	17 (4)	10 (13)	7 (21)	3 (7)	1 (7)	2 (6)

NHL/MM, combined non-Hodgkin lymphoma and multiple myeloma; MM, multiple myeloma; NHL, non-Hodgkin lymphoma.

benzene exposure. Similar results were found for those whose highest benzene-exposed job was at an airport.

There was a strong association between leukemia risk and exposure to benzene concentrate that was somewhat reduced when cumulative exposure was controlled for. That is, exposure to benzene concentrate resulted in a higher risk of leukemia than exposure to the same amount of benzene encountered in a more dilute form such as in gasoline.

The proportion of subjects whose highest exposed job was in high-intensity exposure categories was greater for cases than control subjects (Table 5). Exposure intensity in the highest exposed job was strongly related to leukemia risk, with the increase starting at around 0.8-1.6 ppm and with those in the highest exposure category being nearly 20 times more likely to develop leukemia than those who were unexposed. Adjusting for cumulative exposure removed the association between high-intensity exposure and leukemia. However, exposure intensity and cumulative exposure are highly correlated, and goodness-of-fit statistics and the stepwise conditional logistic regression algorithm did not provide unequivocal evidence that would distinguish between the relative contributions of cumulative exposure and exposure intensity to leukemia risk.

The ORs were also calculated by using conditional logistic regression for the leukemia subtypes acute nonlymphocytic leukemia, chronic lymphocytic leukemia, and chronic myeloid leukemia (Table 6); such calculations were not possible for acute

TABLE 4. Association of Leukemia and Non-Hodgkin Lymphoma/Multiple Myeloma by Benzene Exposure Group, From Conditional Logistic Regression Analysis

Cumulative Lifetime Benzene Exposure (ppm-years)	Leukemia OR (95% CI)	NHL/MM OR (95% CI)
≤1*	1.0	1.0
>1–2	3.9 (0.9–17.1)	1.1 (0.4–2.9)
>2–4	6.1 (1.4–26.0)	1.2 (0.5–3.0)
>4–8	2.4 (0.4–13.6)	1.3 (0.5–3.2)
>8–16	5.9 (1.3–27.0)	0.8 (0.3–2.6)
> 16	98.2 (8.8–1090)	1.1 (0.3–4.5)

* Reference category.

NHL/MM, combined non-Hodgkin lymphoma and multiple myeloma; OR, odds ratio; CI, confidence interval.

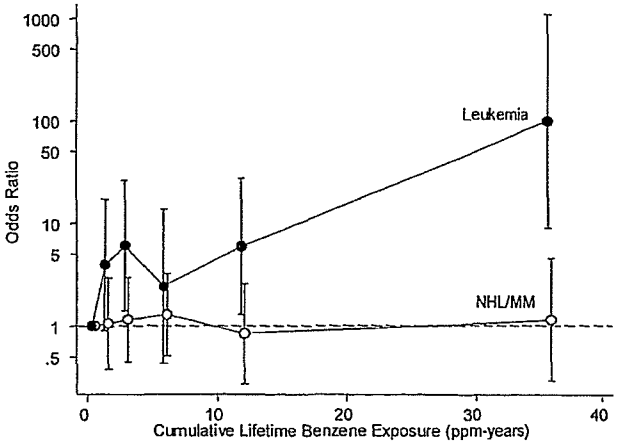

FIGURE 1. Leukemia and Non-Hodgkin Lymphoma/Multiple Myeloma (NHL/MM) odds ratios by geometric benzene exposure groups (ppm-years) displayed at the midpoint of the exposure group. (Circles indicate odds ratios; vertical lines depict confidence intervals).

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TABLE 5. Distribution of Exposure Variables for Leukemia Cases and Control Subjects and Results of Matched Analyses of the Risk of Leukemia Using These Variables

Exposure Characteristic	Cases (N = 33) No. (%)	Control Subjects (N = 165) No. (%)	Odds Ratio (95% CI)	Adjusted Odds Ratio* (95% CI)
Start date in industry				
Before 1965†	15 (45)	63 (38)	1.0	1.0
1965–1975	12 (36)	60 (36)	0.6 (0.2–1.9)	0.9 (0.3–3.2)
1975 or later	6 (18)	42 (25)	0.4 (0.1–1.6)	1.0 (0.2–4.8)
Duration of employment truncated at date of diagnosis (y)				
≤11†	15 (19)	77 (19)	1.0	1.0
>11–17	18 (23)	83 (21)	1.2 (0.4–4.0)	0.7 (0.2–2.5)
>17–22.5	12 (15)	81 (21)	1.6 (0.4–5.5)	1.2 (0.3–5.4)
>22.5–29	16 (20)	80 (20)	1.0 (0.2–4.2)	0.4 (0.1–1.9)
>29–43	18 (23)	74 (19)	1.6 (0.4–6.8)	0.4 (0.1–2.7)
Exposure to benzene concentrate				
No†	28 (84)	163 (99)	1.0	1.0
Yes	5 (16)	2 (1)	12.5 (2.4–64)	6.3 (1.1–36)
Exposure intensity group based on highest benzene-exposed job (ppm)				
≤0.1†	5 (15)	65 (39)	1.0	1.0
>0.1–0.2	9 (27)	26 (16)	3.9 (1.2–12.6)	1.2 (0.3–4.9)
>0.2–0.4	4 (12)	25 (15)	2.2 (0.5–9.4)	0.5 (0.1–3.2)
>0.4–0.8	4 (12)	11 (7)	6.6 (1.7–25.7)	0.6 (0.1–6.2)
>0.8–1.6	3 (9)	31 (19)	1.6 (0.4–6.7)	0.2 (0.0–2.0)
>1.6–3.2	6 (18)	6 (4)	5.6 (1.0–31.2)	0.4 (0.0–6.1)
>3.2	2 (6)	1 (1)	20.4 (1.6–270)	1.6 (0.1–38)

*Adjusted for cumulative benzene exposure.
†Reference category.
CI, confidence interval.

lymphocytic leukemia because there were only 2 cases. Because there were relatively few cases of the leukemia subtypes, it was necessary to combine the 3 lowest exposure groups and the 2 highest exposure groups. The ORs in the combined higher exposure group were raised relative to the combined lower exposure group for both chronic lymphocytic leukemia and acute nonlymphocytic leukemia.

DISCUSSION

These data provide strong evidence for an association between previous benzene exposure in the Australian petroleum industry and an increased risk of leukemia. However, we did not find an association of benzene with multiple myeloma or non-Hodgkin lymphoma, which is consistent with previous findings.[9,16,17]

In our data, leukemia seems to be associated with lower cumulative exposures than has been observed in other studies. The estimated cumulative exposures were generally similar to those reported for other petroleum industry studies, except that the most highly exposed subjects in our study had cumulative exposures of less than 60 ppm-years, whereas those in other studies were as high as 220 ppm-years.[27,28]

TABLE 6. Association of Leukemia Subtype With Cumulative Benzene Exposure From Conditional Logistic Regression Analysis

Cumulative Lifetime Benzene Exposure (ppm-years)	Leukemia Subtype ANLL (N = 11)	CLL (N = 11)	CML (N = 6)
≤4*	1.00	1.00	1.00
>4–8	0.52 (0.05–5.0)	2.76 (0.42–18.1)	-
>8	7.17 (1.27–40.4)	4.52 (0.89–22.9)	0.91 (0.08–9.8)

*Reference category.
ANLL, acute nonlymphocytic; CLL, chronic lymphocytic leukemia; CML, chronic myeloid leukemia.

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It has been suggested that there might be no increased risk at cumulative exposures below 200 ppm-years[9] or intensity of less than 20-60 ppm.[10] In a recent large cohort study of Chinese workers, the relative risk for all hematologic neoplasms was 2.2 (95% CI = 1.1-4.2) for workers exposed to benzene at estimated average levels of less than 10 ppm.[11] Over a working lifetime this could amount to a cumulative exposure of up to several hundred ppm-years. In our study, the risk of leukemia was increased at all cumulative exposures above 1 ppm-year, with a strong exposure–response relationship. There was no evidence of a threshold.

Leukemia risk in the highest exposure category was 98 (95% CI = 8.8-1090). Combining the 2 highest cumulative exposure groups resulted in an OR of 11.3 (95% CI = 2.85-45.1). This is considerably higher than that observed in a similar petroleum industry study,[28] which found an OR of 2.11 (95% CI = 0.01-138) for leukemia for those in the highest quartile of exposure (8-220 ppm-years). In a similar study,[27] the leukemia OR was 2.13 (95% CI = 0.90-5.03) for those in the highest quintile of exposure (>4.79 ppm-years). In our study, the matched OR for those exposed to greater than 4.79 ppm-years was similar at 2.51 (95% CI = 1.1-5.7).

We found a positive association of benzene exposure with both acute nonlymphocytic leukemia and chronic lymphocytic leukemia. An association between acute nonlymphocytic leukemia and benzene exposure has only been reported previously associated with exposures above 200 ppm-years.[9,16] In a U.K. petroleum industry study,[27] the risk of acute myeloid and monocytic leukemia did not increase with cumulative exposure when analyzed as a continuous variable. However, when categorized into discrete ranges, an odds ratio of 2.8 (95% CI = 0.8-9.4) was found for a cumulative exposure of 4.5-45 ppm-years.[27]

There are a number of possible confounders, including tobacco and alcohol consumption and exposure to other chemicals and radiation. Tobacco and alcohol were not confounding factors in our data. Workers in the petroleum industry are exposed to a wide range of aliphatic and aromatic hydrocarbons found in or derived from crude oil, ranging from natural gas (methane) to bitumen. Known carcinogenic exposures include sunlight, polycyclic aromatic hydrocarbons, asbestos, and possibly other insulating materials. A few, mainly older, workers have had exposure to paint, and some workers in the lubricating oils operations had exposure to white spirit (Stoddard Solvents), methyl ethyl ketone, and toluene. The subjects include some laboratory workers who have had exposure to a number of laboratory reagents.

In 1996, a comprehensive review of risk factors for leukemia concluded that the only confirmed occupational risk factors were exposure to benzene, radiation, and some retroviruses. There is some inconsistent evidence for leukemogenic potential from some pesticides, styrene and butadiene manufacturing, and ethylene oxide.[29] We consider it unlikely that subjects in this study were occupationally exposed to retroviruses or these other agents. Some workers employed in the petroleum extraction, refining, and distribution industries might have used x-ray machines in laboratories or pipe surveys, but the sources are thought to have been well shielded.

The present study has a number of strengths and weaknesses. The diagnoses of the cases were well established. However, the study was based on a relatively small number[79] of lympho-hematopoietic cancer cases, including 33 leukemias of which there were only 11 acute nonlymphocytic leukemias and only 11 chronic lymphocytic leukemias. This limits the power of the study to detect excess risks for leukemia subgroups, particularly when we stratified the subjects by exposure.

The cases were individually age-matched to control subjects, and both were drawn from the same prospective cohort of workers in the Australian petroleum industry. The cohort has been followed for 20 years with serial identification of jobs, smoking habits, and health status. Only 10 of the 474 subjects (2%) had incomplete job histories. Relatively few subjects in the cohort (6%) have been lost to follow up,[21] and vital status was confirmed every 5 years; thus we are confident that the control subjects were selected from an appropriate risk set.

We estimated the subjects' exposure to benzene quantitatively, on an individual basis, with an algorithm based on a substantial body of exposure data from the Australian petroleum industry.[25] The exposure assessment method was validated,[26] but there are always uncertainties and unknown sources of variation in retrospective exposure assessments. Between-worker variation in exposure measurements, resulting from personal factors such as individual work practice, was not included in the exposure assessment reported here. There was also uncertainty about exposures before 1975 because jobs have changed over the years, but the available exposure data used in the algorithm postdated this period. However, the Health Watch cohort is relatively recent compared with other similar studies in which jobs held before 1920 were assessed.[27,28] Most of the subjects in our case-control study started work after 1965; the earliest start date was 1941. This means that jobs have changed less in our study, and for most jobs we were able to identify changes by interviewing contemporary coworkers. These individuals did not have to recall far distant exposure conditions so their uncertainty was reduced.

For 33 cases, including 13 leukemia cases, the complete job history was obtained after lympho-hematopoietic cancer diagnosis. These cases provided information after diagnosis, about jobs held before 1975, thus introducing some potential for recall bias. These subjects' job histories were constructed from the information gathered during the Health Watch surveys and from company records. This was then sent to the

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subject for cross-checking. However, the high degree of agreement with the company records suggests that the self-reported job histories were reasonably accurate and that possible recall bias was low. For the remaining 46 cases, either the complete job history was obtained before diagnosis or only the company job history was used because, for example, the case died before the complete job history collection.

All smoking and drinking data were collected before individual diagnoses, thereby avoiding a potential cause of recall bias.

The benzene exposure assessments were carried out without any knowledge of the names and health status of the subjects to reduce observer bias. Detailed information on the circumstances of the exposure was provided, usually by contemporary work colleagues of the cases and control subjects. Some of the site interviewees might have been able to identify the subjects but were instructed not to reveal their names or health status to the interviewer. This could have given rise to some recall bias, because more effort might have been applied to recalling the tasks with benzene exposure for some of the cases because the connection between benzene exposure and lympho-hematopoietic cancer is widely known within the industry. However, it is unlikely that the employees would distinguish between the risk from benzene exposure of different cancers (leukemia compared with multiple myeloma or non-Hodgkin lymphoma). Our finding of increased risk specifically for leukemia but not for multiple myeloma or non-Hodgkin lymphoma suggests that recall and observer biases do not affect our main results.

It is unlikely that the baseline comparison group was incorrectly defined because this was a nested case-control study with the control subjects selected from the cohort matched by age. However, misclassification of only a few cases from the baseline group into higher exposure groups could markedly distort the exposure–response relation. Although the lowest exposed group contained many office workers, there is no strong socioeconomic gradient for risk of leukemia and the analysis of smoking suggested that this was not a confounding exposure. If there was a strong bias in the exposure estimates leading to differential misclassification, this should have affected the results for multiple myeloma and non-Hodgkin lymphoma as well; the questionnaire respondents would have been unlikely to draw a distinction between one form of hematopoietic cancer or another. The fact that no association was found between multiple myeloma/non-Hodgkin lymphoma and benzene exposure suggests that such bias, if present, was small. We cannot rule out the possibility that some bias was introduced in gathering the occupational histories, although such an effect would presumably be small. If such bias occurred, it could not explain the association between leukemia and benzene exposure that was found, but might have exaggerated the exposure–risk relationship and hidden a low-exposure threshold.

In summary, these data demonstrate a strong association between benzene exposure and the risk of acute and chronic leukemia. No association was found between benzene and non-Hodgkin lymphoma or multiple myeloma, or between any of the cancers and tobacco or alcohol consumption. The excess risk of leukemia was associated with lower cumulative exposures and lower exposure intensity than have been observed in other studies. We found no evidence of a threshold cumulative exposure below which there is no risk.

ACKNOWLEDGMENTS

We acknowledge the work carried out by the Health Watch team at Melbourne University and lately at Adelaide University and the petroleum industry occupational hygienists. We also thank Julianna O'Keefe of Monash University for recordkeeping and Alison Street of the Alfred Hospital who reviewed the diagnoses for several of the cases in the study. Finally, we thank the many retirees and current employees from all participating companies who freely answered the lengthy questionnaires.

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CHARACTERISTICS OF DISSOLVED PETROLEUM HYDROCARBON PLUMES

RESULTS FROM FOUR STUDIES

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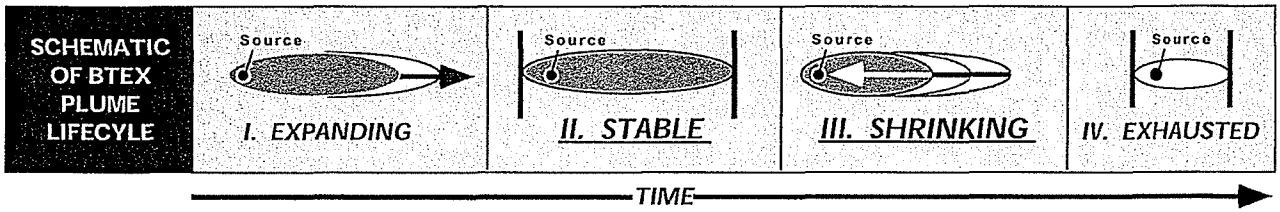
API Soil / Groundwater Technical Task Force

EXECUTIVE SUMMARY

Recent studies of over 600 groundwater contamination sites throughout the U.S. provide important information regarding the fate and transport of petroleum hydrocarbons in the subsurface. This API research summary examines the findings of four independent research studies and addresses several key technical issues regarding the assessment and remediation of BTEX (benzene, toluene, ethylbenzene, xylene) plumes. On-going research regarding MTBE plume characteristics will be addressed in a future bulletin as data become available.

Key Finding: Most BTEX groundwater plumes are less than 200 ft in length and are in a STABLE or SHRINKING condition.



THE FOUR STUDIES

This bulletin summarizes information from four separate multi-site plume studies. Each study involved detailed analysis of data from a large number of sites (primarily underground storage tank facilities) to identify the key characteristics of groundwater contaminant plumes caused by petroleum hydrocarbon releases. Two comprehensive studies (California and Texas) evaluated how dissolved petroleum hydrocarbon plumes change over time.

In all four studies, detailed technical information regarding groundwater flow parameters and plume characteristics for each site were compiled from technical reports or questionnaires completed by site hydrogeologists or engineers. In combination, the four studies define the typical features of a dissolved hydrocarbon plume based on a cumulative database of 604 sites.

This API bulletin reviews the general methodology and principal conclusions of each study and uses these findings to answer several important questions related to the assessment and remediation of groundwater impacts associated with petroleum releases.

Technical Issues Regarding Dissolved BTEX in Groundwater:

- Typical plume length
- Persistence over time
- Effect of remediation
- Key factors in plume length
- Plume stability condition
- BTEX vs. other contaminants
- Drinking water impacts

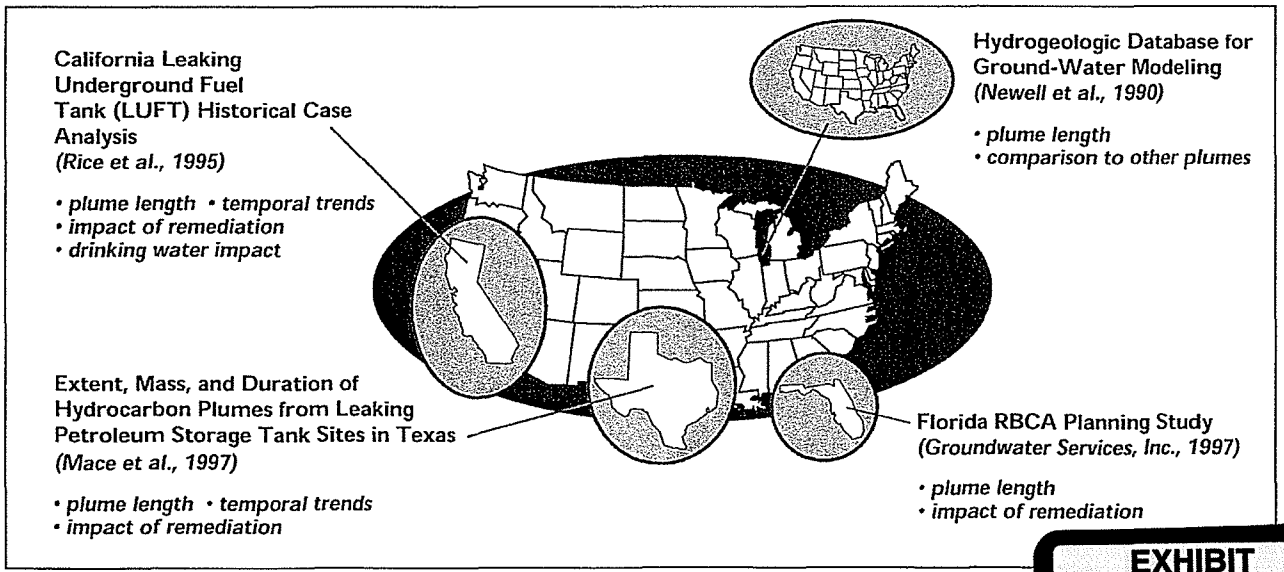


EXHIBIT 4 tabbies

012038

California Leaking Underground Fuel Tank (LUFT) Historical Case Analysis

Rice, D.W., R.D. Grose, J.C. Michaelsen, B.P. Dooher, D.H. MacQueen, S.J. Cullen, W.E. Kastenberg, L.G. Everett, M.A. Marino. CA Environmental Protection Dept., Nov. 16, 1995.

APPROACH: This study, also referred to as the Lawrence Livermore National Laboratory (LLNL) Study, involved compilation and analysis of a detailed electronic database for 271 LUFT sites. Groundwater flow gradients and the average length and concentration of benzene plume were characterized on the basis of static water level data and groundwater time-series sampling records.

KEY RESULTS: Plume lengths "change slowly and stabilize at relatively short distances from the FHC (fuel hydrocarbon) release site" (90% of sites less than 255 ft). The median plume length was 101 ft for one of the two methods of calculation (see the following page). Plume lengths tend to change slowly with time, while average plume concentrations decline more rapidly. Hydrogeologic parameters (e.g., hydraulic conductivity, gradient) appear to have little relationship to plume length. Finally, "while active remediation may help reduce plume benzene concentrations, significant reductions in benzene concentrations can occur over time, even without active remediation."

Extent, Mass, and Duration of Hydrocarbon Plumes from Leaking Petroleum Storage Tank Sites in Texas

Mace, R.E., R.S. Fisher, D.M. Welch, and S.P. Parra. Bureau of Economic Geology, University of Texas at Austin, Austin, Texas. Geologic Circular 97-1, 1997.

APPROACH: The Texas Bureau of Economic Geology (BEG) evaluated groundwater impacts from fuel hydrocarbon releases at 217 sites in Texas. Groundwater plume lengths and concentration trends were analyzed in a manner similar to the California study (see Rice et al., above). In addition, hydraulic gradient and groundwater flow directions were characterized for various hydrogeologic and climatic regions of Texas.

KEY RESULTS: Most benzene plumes (75%) are less than 250 ft long and have either stabilized or are decreasing in length and concentration. The median plume length was 181 ft. Only 14% are increasing in concentration, and only 3% are increasing in length. The length of a benzene plume cannot be predicted on the basis of either site hydrogeology or previous remediation activities. Benzene plume characteristics are not statistically different between sites where groundwater remediation activities have or have not been implemented, although the authors state that these activities should "logically shorten the time required to decrease plume length and concentration."

Florida RBCA Planning Study

Groundwater Services, Inc. Prepared for Florida Partners in RBCA Implementation, Groundwater Services, Inc., Houston, Texas. 1997. www.GSI-net.com

APPROACH: The Florida RBCA (Risk-Based Corrective Action) Planning Study involved collection and analysis of groundwater data from 117 leaking underground storage tank (LUST) sites distributed throughout 33 counties in Florida. Using these data, the report addresses the cost significance of various policy decisions related to development of the Florida RBCA regulations. For use in this bulletin, the plume maps and detailed site questionnaires compiled for 74 sites were reanalyzed to define typical plume properties.

KEY RESULTS: The median plume length among these Florida LUST sites is 90 ft based on available benzene and BTEX data. The shorter plume lengths observed in this database may be related to the varying detection limits used for plume delineation. For plumes delineated to a 50 ppb benzene limit (51 sites), median plume length was 90 ft, compared to 120 ft for plumes delineated to 1 ppb benzene (21 sites). In addition, 51% of the Florida database sites are currently or had previously been subject to groundwater remediation efforts.

A Hydrogeologic Database for Ground-Water Modeling

Newell, C.J., L.P. Hopkins, and P.B. Bedient. Ground Water, Vol. 28, No. 5, Sept./Oct. 1990. pp. 703-714.
API, 1989. Hydrogeologic Data Base for Groundwater Modeling, API Publication No. 4476, Washington, D.C.

APPROACH: Hydrogeologic and chemical information from 400 site investigations across the U.S. was obtained in a national survey of National Ground Water Association members conducted in 1990. This 400-site database (available in spreadsheet form from the API Information Specialist, ehs@api.org) includes groundwater plume dimensions for a broad range of groundwater contaminants, including 42 service station BTEX sites, 40 non-service station BTEX sites, 78 chlorinated ethene sites, 25 non-ethene solvent sites, and 21 inorganic sites. For use in this bulletin, these data were reanalyzed to define typical plume properties for each chemical class.

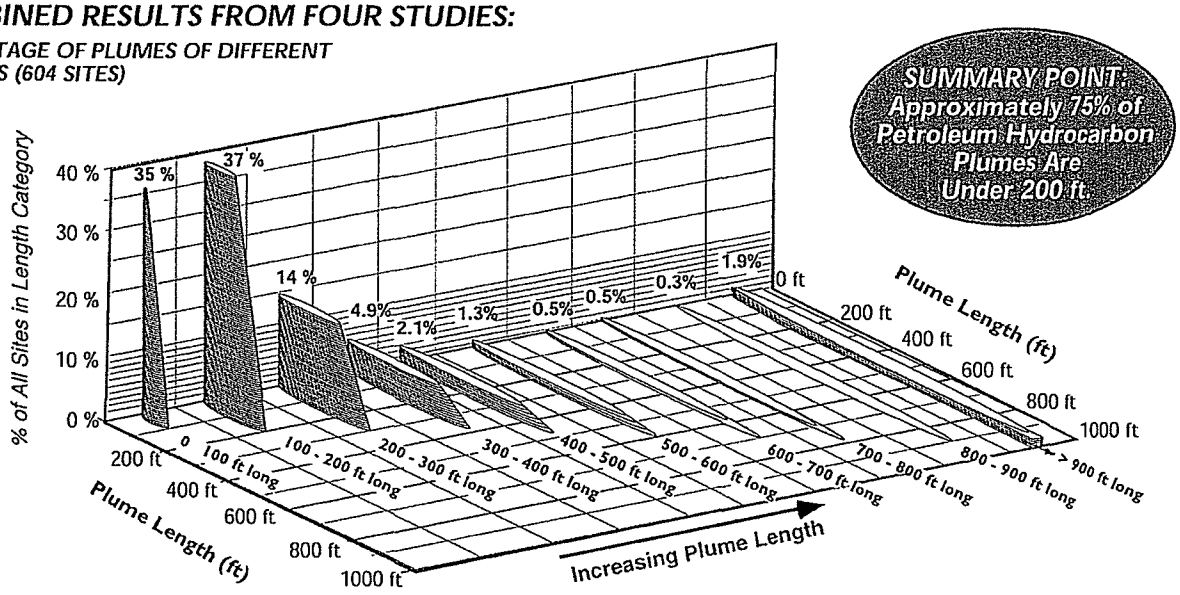
KEY RESULTS: The 42 service station sites show a median benzene/BTEX plume length of 213 ft. This database includes a higher percentage of longer plumes, with six BTEX plume lengths greater than 900 ft. On average, however, BTEX plumes are significantly smaller than the other chemical classes reported in this study, as discussed later in this Bulletin.

012039

WHAT IS THE LIMIT OF MIGRATION OF DISSOLVED PETROLEUM HYDROCARBON PLUMES?

COMBINED RESULTS FROM FOUR STUDIES:

PERCENTAGE OF PLUMES OF DIFFERENT LENGTHS (604 SITES)



SUMMARY POINT: Approximately 75% of Petroleum Hydrocarbon Plumes Are Under 200 ft.

INDIVIDUAL STUDY RESULTS:

ALL SITES	CALIFORNIA (271 Sites)	TEXAS (217 Sites)	FLORIDA (74 Sites)	HGDB (42 Sites)
SUMMARY - ALL SITES	Summary	Summary	Summary	Summary
Maximum Length: 3020 ft	Max 1713 ft	Max 1619 ft	Max 600 ft	Max 3020 ft
90th Percentile: 319 ft	90th % 255 ft	90th % 382 ft	90th % 211 ft	90th % 945 ft
75th Percentile: 203 ft	75 % 146 ft	75 % 250 ft	75 % 158 ft	75 % 400 ft
MEDIAN LENGTH: 132 ft	MEDIAN 101 ft	MEDIAN 181 ft	MEDIAN 90 ft	MEDIAN 213 ft
25th Percentile: 80 ft	25th % 66 ft	25th % 137 ft	25th % 60 ft	25th % 85 ft
Minimum Length: 8 ft	Min 8 ft	Min 54 ft	Min 12 ft	Min 15 ft

• LOCATION OF SITES:	CALIFORNIA	TEXAS	FLORIDA	ENTIRE U.S.
• Plume constituent(s):	Benzene	Benzene	Benzene, BTEX	Mostly benzene, BTEX constituents
• Plume Delineation Limit:	10 ppb	10 ppb	1 - 50 ppb	Not reported; probably analytical detection limit.
• Types of Sites:	UST sites with affected groundwater. No fractured rock sites.	UST sites with affected groundwater. Includes limestone aquifers.	UST sites with affected groundwater.	UST sites at service stations located in various hydrogeologic settings.
• Method For Determining Plume Length:	*Modeled:* Length extrapolated from 2-D transport models fit to site monitoring data. Reported results for exponential and error-function equations (summary stats above from error function).	*Modeled:* Length extrapolated from 2-D GW transport model fit to site monitoring data. Used exponential equation only.	*Measured:* Length derived from site plume maps. Data analyzed as part of this bulletin.	*Reported:* Plume lengths reported by site consultants in survey questionnaires. Data analyzed as part of this bulletin.
• Sites w/ Soil Vapor Extract. • Sites w/ GW Pump & Treat • Sites w/ GW Sparging	— Not reported — 53 of 208 sites (26 %) — Not reported	—105 of 479 (22%) —92 of 479 sites (19 %) —22 of 479 sites (5 %)	— Not reported — 32 of 74 sites (43 %) — 6 of 74 sites (8 %)	—Not reported —Not reported —Not reported

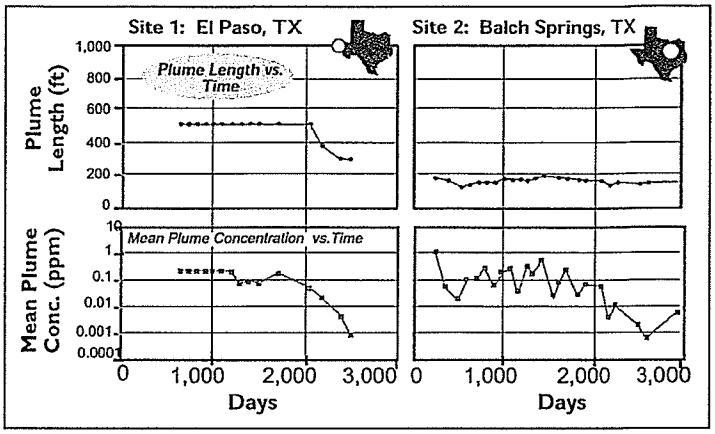
(note different #s of sites reported)

012040

HOW MANY PETROLEUM PLUMES ARE SHRINKING? STABLE? EXPANDING?

APPROACH

Both the California and the Texas studies (Rice et al., 1995; Mace et al., 1997) analyzed changes over time in the length and average concentration of dissolved hydrocarbon plumes. For the California study, these evaluations were conducted on a subset of sites having at least 6 wells and 8 sampling episodes extending over multiple years. Typical monitoring records for the Texas study ranged from 4 to 7 years as shown in data from two typical sites to the right.



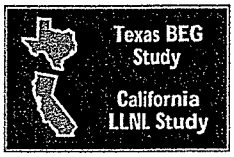
Plume stability trends were determined as follows:

Plume Length Trend: For each sampling episode, the plume length from the source to the 10 ppb concentration point was extrapolated using a 2-D groundwater transport model calibrated to the site monitoring data. Length vs. time was plotted for each site to define change over time.

Plume Concentration Trend: For each sampling episode, the average benzene concentration in the plume area was estimated using Delauney triangulation (Isaaks and Srivastava, 1989), an area-weighted averaging procedure involving subdivision of the plume area into triangular segments defined by adjacent wells. Average concentration vs. time was plotted for each site to define change over time.

These methods do not account for plume spreading beyond the area described by the monitoring well array. However, both studies found this approach to be sufficiently robust to accurately characterize plume trends over time.

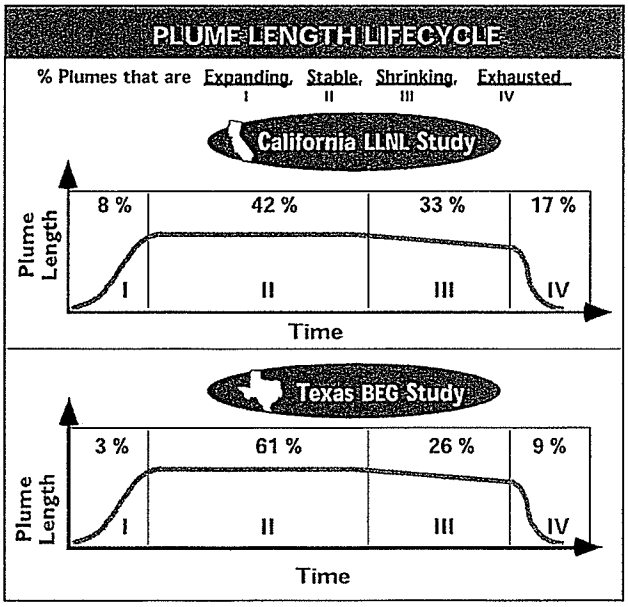
KEY RESULTS

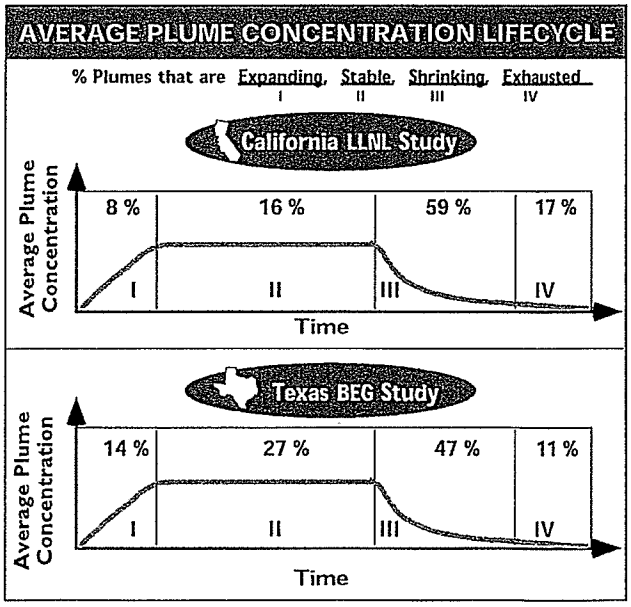


Based on the observed trends, the studies grouped the plumes into four categories:

- ***Expanding:*** Residual source present. Mass flux of contaminants exceeds assimilative capacity of aquifer.
- ***Stable:*** Insignificant changes. Active or passive remediation processes are controlling plume length.
- ***Shrinking:*** Residual source nearly exhausted, and active or passive remediation processes significantly reducing plume mass.
- ***Exhausted:*** Average plume concentration very low (e.g., 1 ppb) and unchanging over time. Final stages of source zone dissolution over a relatively small area at a site.

As shown in the conceptual plume lifecycle figures below, of the nearly 500 sites addressed by this analysis, nearly 75% were found to be in either a stable or shrinking condition, based on analyses of both plume length and concentration. Plume concentrations were predominantly shrinking (47 to 59%), whereas lengths were frequently stable (42 to 61%). These results suggest that dissolved hydrocarbon plumes tend to reduce more rapidly in concentration than in length. Similar results were observed in a plume study performed by Buscheck et al. (1996), where 67% of 119 plumes in northern California were found to be stable/shrinking in length, and 91% had stable/diminishing concentrations.





Figures adapted from Rice et al., 1996.

012041

HOW LONG WILL BTEX PLUMES PERSIST?

CALIFORNIA & TEXAS STUDIES: *90% Attenuation of Average Concentration of Shrinking Plumes*

For those plumes characterized as **shrinking** (see page 4), both the California and Texas studies (Rice et al., 1995; Mace et al., 1997) included an evaluation of the time required for the average plume concentration to reduce by 90%. The rates of change calculated for each data set are shown in the table to the right.

Time Required for 90% Attenuation in Average Concentration for Shrinking Plumes:

MEDIAN SITE IN CALIFORNIA:	3.2 yrs
10th Percentile:	1.5 yrs
90th Percentile:	7 yrs

MEDIAN SITE IN TEXAS:	1.4 yrs
10th Percentile:	0.7 yrs
90th Percentile:	2.7 yrs

Note that, in these analyses, the ***average concentration*** term corresponds to an area-weighted average BTEX concentration derived using the Delauney triangulation method for each groundwater sampling episode. Consequently, trends in this concentration term should be representative of the total plume mass. Data from the California and Texas studies show that, once a dissolved BTEX plume begins to shrink (a condition observed at roughly 50 - 60% of the LUST sites in these studies), the rate of decline in plume mass is relatively rapid. Based on the median rate of mass reduction reported in these studies, *for a shrinking plume, only 5 to 10 years are required for the average plume BTEX concentration to drop from an initial level of 1 ppm down to 1 ppb.* (This assumes a first order decay model applies over three orders of magnitude of concentration reduction.) At this point, the plume reaches an ***exhausted*** condition, which may represent low levels of BTEX persisting in source-area wells for an extended time period thereafter.

WHAT IS THE EFFECT OF REMEDIATION ON BTEX PLUMES?

Three of the four studies evaluated the performance of remediation efforts in reducing or controlling petroleum hydrocarbon plumes. Based on a review of large site populations, the studies consistently draw a conclusion that runs counter to expectations: soil and groundwater remediation efforts did not result in smaller BTEX plumes.

QUOTES

(Rice et. al, 1995)

"While active remediation may help reduce plume benzene concentrations, significant reductions in benzene concentrations can occur with time, even without active remediation." (pg. EX-2)

"At low concentration sites, pump and treat increases the probability of having a negative average benzene concentration trend by roughly a factor of two, while it has essentially no impact on probability at high concentration sites." (pg. 13)

"An analysis of plume length categories shows that none of the remediation treatment variables have a significant impact on the relative frequencies of the different categories." (pg. 13)

PROBABILITY (P) OF DECREASING CONCENTRATION TREND*

Pump & Treat Site?	Site Over-Excavated?	P
–	–	52 %
√	–	71 %
–	√	64 %
√	√	80 %

* 208 Sites > 1 ppb avg. conc.

(Mace et. al, 1997)

"The use of active ground-water remediation has not yet resulted in a lower median plume length at LPST sites throughout the state where corrective action is under way. This does not mean that remediation does not improve ground-water conditions at individual sites, but that when all LPST sites are reviewed, plume lengths at sites with remediation do not appear different from plume lengths at sites without remediation." (pg. 34)

"This probably means that significant spills occur before being detected and that most plumes are in place and in equilibrium before active remediation takes effect." (pg. 34)

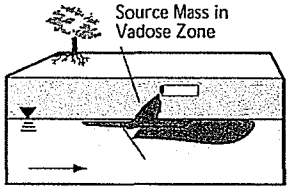
	% OF PLUMES THAT ARE:		
	Stable	Shrinking	Exhaus.
67 Sites WITH Pump & Treat	35 %	61 %	4 %
117 WITHOUT Pump & Treat	38 %	52 %	10 %

"We found no difference in plume length between different remediation techniques and sites with no remedial action." (pg. 33)

(GSI, 1997)

"Of the 117 sites included in this study, affected soils have been previously removed at 28 sites. For these 28 sites, the estimated median groundwater source mass is approximately 34% lower than the median groundwater source mass where overlying soils have not yet been removed. These data suggest that, while the soil removal actions have served to reduce groundwater impacts, a significant percentage of the contaminant source (66%) remains in place in the saturated, water-bearing unit." (pg. 21)

"..soil removal would not significantly affect groundwater remediation requirements." (pg. 21)



012042

WHAT ARE THE FACTORS THAT CONTROL BTEX PLUME LENGTH?

TEXAS AND CALIFORNIA STUDIES

The California and Texas studies attempted to correlate plume length with various hydrogeologic factors. In both studies, plumes were segregated into two subsets (shallow vs. deep) and correlation coefficients were calculated for plume length vs. a range of site parameters. Results of these analyses are summarized below.

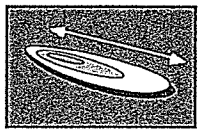
RESULTS: TEXAS STUDY

The Texas study (Mace et al., 1997) concluded that plume length could not be predicted by the following variables:

- *Depth to water*
- *Hydraulic gradient*
- *% Organic Carbon in water-bearing zone*
- *Thickness of sweep (smear) zone*
- *Hydrogeologic setting (in unconsolidated media)*
- *Previous remediation activities (see page 5)*

The authors concluded that "hydrogeologic site characteristics and site activities considered in this study do not explain the variation in average plume length or plume mass and concentration."

The report identifies other factors, such as the amount of spilled fuel and natural biodegradation rate, as having a greater influence than hydrogeology or previous remediation activities.



RESULTS: CALIFORNIA STUDY

The California study (Rice et al., 1995) concluded that plume length was not correlated to:

- *Groundwater depth*
- *Saturated thickness*
- *Free product thickness*
- *Hydraulic gradient*
- *Number of site layers*
- *Previous remediation activities (see page 5)*

The authors concluded that: "Individual or combinations of other hydrogeologic variables have little apparent relationship to plume characteristics. Correlations among a variety of hydrogeologic variables and plume length show no indications of interaction. Transport indices that in theory should affect plume length, such as groundwater flow velocity, show no correlation."

They attributed the lack of correlation to the presence of controlling but not measured variables (such as source mass and biodegradation rate), scatter in the hydrogeologic data, and cyclical change in hydrogeologic variables that causes a delayed effect on plume length, and general site complexity wherein each site has a unique set of controlling variables.

These studies suggest that the size of the release is probably one of the key variables that controls plume length. Larger sources (in terms of mass, width, and affected soil volume) mean that more dissolved-phase constituents are transferred to groundwater, creating longer dissolved phase plumes.

HOW MUCH GROUND WATER IS AFFECTED BY BTEX PLUMES?

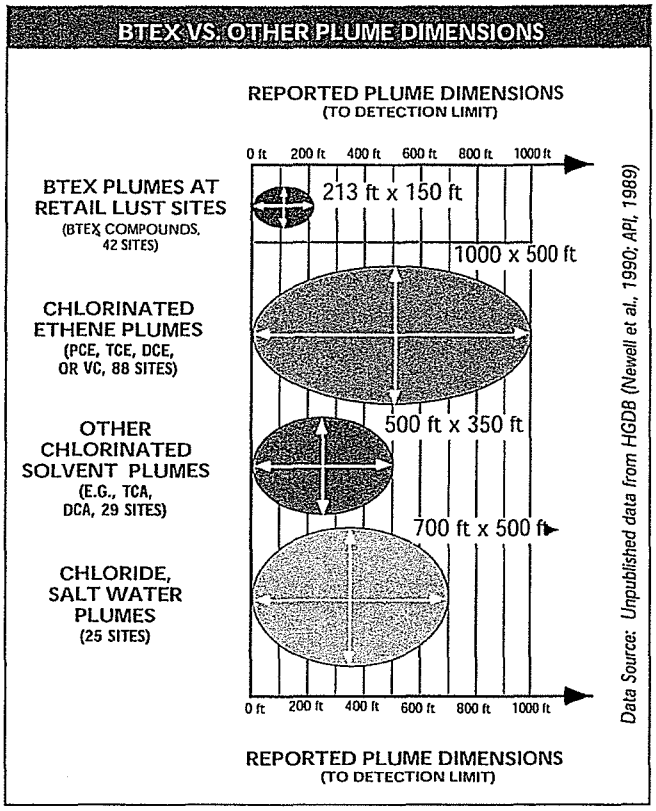
An upper-range estimate of the total volume of groundwater resources impacted by releases from LUST sites can be obtained using a calculation method described in the California study (Rice et al., 1995). In this method, the 95th percentile BTEX plume volume observed in the California study (i.e., 0.7 acre ft. or 230,000 gallons) is multiplied by the total number of reported LUST sites to obtain a total affected groundwater volume. Dividing this value by the total groundwater basin storage capacity provides an estimate of the percentage of resources impacted by LUST sites. Results for both California and the U.S. are provided below. Note that LUST sites usually affect shallow water table aquifers not typically used for public supply.

	BTEX Plume Volume (95%)	X	No. of LUST Sites	=	Total BTEX GW Volume	÷	Total GW Resource Volume	=	% Total GW Resource Impacted
	0.7 acre-ft		10,000		7000 acre-ft		1.3 billion acre-ft		**0.0005 %**
	0.7 acre-ft.		358,000 (U.S. EPA, 1998)		250,000 acre-ft		614.3 billion acre-ft (Lehr, 1985)		**0.00004 %**

012043

HOW ARE BTEX PLUMES DIFFERENT FROM OTHER PLUMES?

The HGDB Study (Newell et al., 1990) provides plume length data for a variety of contaminants, including BTEX, chlorinated solvents, and brine releases. This chart shows plume widths and lengths as reported by HGDB respondents. As shown, BTEX plumes are much smaller than other types of plumes. Likely causes for this difference include: i) the smaller source zone area associated with BTEX releases from LUST sites, and ii) the more bio-degradable nature of BTEX constituents relative to the other contaminants. Note that other studies are in progress to characterize other types of plumes (e.g., Happel et al., 1998; Mace, 1998; Newell et al., 1998).



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API Soil & Groundwater Research Publications

Publ *4668*, Delineation and Characterization of the Borden MTBE Plume: An Evaluation of Eight Years of Natural Attenuation Processes, June 1998
In 1988, a natural gradient tracer test was performed in the shallow sand aquifer at Canada Forces Base (CFB) Borden to investigate the fate of a methyl-tertiary-butyl-ether (MTBE) plume introduced into the aquifer. Solutions of groundwater mixed with oxygenated gasoline were injected below the water table along with chloride (Cl^-), a conservative tracer. The migration of benzene, toluene, ethylbenzene, the xylenes (BTEX); MTBE; and Cl^- was monitored in detail for about 16 months. The mass of BTEX in the plume diminished significantly with time due to intrinsic biodegradation. MTBE, however, was not measurably attenuated. In 1995-96, a comprehensive groundwater sampling program was undertaken to define the mass of MTBE still present in the aquifer. Only about 3 percent of the initial MTBE mass was found, and it is hypothesized that biodegradation played an important role in its attenuation. Additional evidence is necessary to confirm this possibility. Pages: 88.
Order Number: I46680, Price: $30.00

Publ *4657*, Effects of Sampling and Analytical Procedures on the Measurement of Geochemical Indicators of Intrinsic Bioremediation: Laboratory and Field Studies, November 1997
This study evaluates the effects of various sampling and analytical methods of collecting groundwater geochemical data for intrinsic bioremediation studies. Sampling and analytical methods were tested in the laboratory and in the field. Several groundwater sampling and analytical methods may be appropriate for measuring geochemical indicators of intrinsic bioremediation. The methods vary in accuracy, level of effort, and cost. Pages: 86.
Order Number: I46570, Price: $30.00

Publ *4658*, Methods for Measuring Indicators of Intrinsic Bioremediation: Guidance Manual, November 1997
This guidance manual is intended to be a resource for practitioners of intrinsic bioremediation in allowing selection of sampling and analytical methods that meet project-specific and site-specific needs in scoping field investigations, provides procedures that will improve the representative quality of the collected data, and considers potential biases introduced into data through the sampling and analytical techniques employed in the site investigation. Pages: 96.
Order Number: I46580, Price: $35.00

Publ *4654*, Field Studies of BTEX and MTBE Intrinsic Bioremediation, October 1997
A gasoline release field site in the Coastal Plain of North Carolina was monitored for more than three years to allow calculation of in situ biodegradation rates. Laboratory microcosm experiments were performed to further characterize the biodegradation of BTEX and MTBE under ambient, in situ conditions. Finally, groundwater modeling studies were conducted to facilitate the interpretation of field data and to evaluate various approaches for predicting the fate and effects of these gasoline constituents in the subsurface. Pages: 244.
Order Number: I46540, Price: $40.00

Publ *4627*, *In Situ* and On-Site Biodegradation of Refined and Fuel Oils: A Review of Technical Literature 1988-1991, June 1995
This report reviews more than 200 technical articles published between 1988 and 1991 in the area of on-site and in situ bioremediation of petroleum hydrocarbons. It focuses specifically on current field and laboratory research related to petroleum hydrocarbon biodegradation including biodegradation of crude oil and solvents. Recent work in fate and transport modeling that can be applied to petroleum hydrocarbon contamination in groundwater is also covered. The review is designed to complement an earlier (pre-1988) review published by the U.S. Navy. Pages: 146.
Order Number: I46270, Price: $30.00

DR *200*, Modeling Aerobic Biodegradation of Dissolved Hydrocarbons in Groundwater, April 1995
This report describes a 3-D groundwater transport model that accurately characterizes the nature of aerobic biodegradation, i.e., the mixing of oxygen and dissolved hydrocarbons at plume edges of petroleum spills to the subsurface. The report also demonstrates the differences between spreading and mixing phenomena. The approaches in this report will be used to develop user-friendly biodegradation models which will be helpful in site-specific evaluations. The use of such models could lead to shorter and less expensive cleanups at some sites. Pages: 76.
Order Number: I00200, Price: $30.00

Publ *4593*, Transport and Fate of Non-BTEX Petroleum Chemicals in Soils and Groundwater, September 1994
Order Number: I45930, Price: $40.00

Publ *4601*, Transport and Fate of Dissolved Methanol, MTBE and Monoaromatic Hydrocarbons in a Shallow Sand Aquifer, April 1994
Order Number: I46010, Price: $65.00

Publ *4551*, Treatment of Gasoline-Contaminated Groundwater Through Surface Application: Laboratory Experiments, July 1994
Order Number: I45510, Price: $55.00

Publ *4552*, Treatment of Gasoline-Contaminated Groundwater through Surface Application: A Prototype Field Study, July 1994
Order Number: I45520, Price: $40.00

Publ *4415*, Literature Survey: Unassisted Natural Mechanisms to Reduce Concentrations of Soluble Gasoline Components, August 1985
Order Number: I44150, Price: $25.00

Publ *4476*, Hydrogeologic Data Base for Groundwater Modeling, February 1989
Order Number: I44760, Price: $25.00

NOTE: *Prices are subject to change.*

Copies of these publications are available from API's Publications Department, (202) 682-8375. For more information about the research, contact the Health, Environment, & Safety Information Specialist at the American Petroleum Institute by phone (202) 682-8319 or email ehs@api.org.

EXHIBIT
tabbies
5

Use of Long-Term Monitoring Data to Evaluate Benzene, MTBE, and TBA Plume Behavior in Groundwater at Retail Gasoline Sites

R. Kamath[1]; J. A. Connor[2]; T. E. McHugh[3]; A. Nemir[4]; M. P. Le[5]; and A. J. Ryan[6]

Abstract: Long-term groundwater monitoring data for 48 retail gasoline sites were analyzed to define the characteristics of affected groundwater plumes containing benzene, methyl tert-butyl ether (MTBE), and tert-butyl alcohol (TBA). Results of this analysis were used to determine the observed range and statistical distribution of current plume lengths, plume stability conditions, constituent concentration trends and attenuation rates, and the remediation timeframe for this population of sites. The goal of this evaluation was to characterize plume behavior as observed across a variety of hydrogeologic settings, on the basis of detailed groundwater monitoring records, rather than to define the site-specific factors controlling plume behavior. The results indicate that MTBE plumes in groundwater underlying a majority of these underground storage tank sites that were monitored for five years or longer (1) have significantly diminished in concentration over time, (2) are comparable in length to benzene plumes, (3) are, like benzene plumes, principally stable or shrinking in size and concentration, and (4) are on track to achieve remedial goals within a timeframe comparable to or faster than that of benzene plumes. At these same sites, TBA plumes were found to be comparable to benzene and MTBE plumes in terms of plume length. However, whereas most TBA plumes are also stable or shrinking, the percentage of TBA plumes that are currently stable or shrinking (68%) is less than that for benzene plumes (95%) or MTBE plumes (90%), likely reflecting the temporary build-up of TBA concentrations in groundwater attributable to methyl tert-butyl ether (MTBE) biodegradation. Nevertheless, overall trends for TBA concentrations in groundwater indicate that TBA is attenuating at rates comparable to benzene and MTBE and can be expected to meet applicable remediation goals in a similar timeframe as the other gasoline constituents. **DOI: 10.1061/(ASCE)EE.1943-7870.0000488.** © *2012 American Society of Civil Engineers.*

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Introduction

In the 1990s, detections of methyl tert-butyl ether (MTBE) in the groundwater at petroleum storage tank sites and water supply wells generated considerable scientific and regulatory concern regarding the potential effect of this relatively new gasoline fuel additive on groundwater resources [USGS 1995; California Environmental Protection Agency (CEPA) 1999; USGS 2001]. In contrast to non-oxygenated gasoline fuel constituents, MTBE was known to be highly soluble in water, with low sorption coefficients, and was understood to be relatively recalcitrant to natural biological activity (Yeh and Novak 1991; Suflita and Mormile 1993; Hubbard et al. 1994; Mormile et al. 1994; Neilson 1994). As a result, some scientists predicted that, in comparison with non-MTBE gasoline, releases of MTBE-containing gasoline from underground storage tank (UST) sites would result in relatively long plumes of affected groundwater that would cause much longer-term effects on groundwater resources and drinking water supplies (Fogg et al. 1998; Odencrantz 1998; Weaver and Small 2002). These predictions were supported by the discovery of a few exceptionally long MTBE plumes extending thousands of feet down-gradient of the release point, such as in Long Island, New York (Weaver et al. 1996; Weaver et al. 1999).

However, studies evaluating actual field measurements of hundreds of MTBE plumes across the United States and abroad have found the true extent and duration of MTBE effects on groundwater to be much less than previously anticipated. Specifically, monitoring data for groundwater plumes at nearly 400 gasoline release sites in California (Happel et al. 1998; Shih et al. 2004), Texas (Mace and Choi 1998; Shorr and Rifai 2002; Rifai et al. 2003), South Carolina (Wilson et al. 2003), and Florida (Reid et al. 1999; Reisinger et al. 2000) show that MTBE plumes typically stabilize at relatively short lengths (< 200 ft), which are comparable to those of benzene plumes. Additionally, groundwater monitoring results from a total of 81 sites evaluated in Texas in 2002 (Shorr and Rifai 2002) and in Florida in 1999 (Reid et al. 1999) indicate that the majority of MTBE plumes (75%) are stable or decreasing in length. Furthermore, with regard to MTBE concentrations in individual monitoring wells, data from a total of 1628 monitoring wells in Texas (Rifai et al. 2003) and Connecticut (Stevens et al. 2006) indicate that MTBE concentrations in the groundwater are stable or decreasing over time in 74% of the wells evaluated. Research outside of the United States similarly reported the effects of MTBE

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on potable groundwater sources to be relatively limited on a regional scale. For example, in England and Wales, modeling analyses based on 3,000 groundwater samples from over 800 sites found that the potential plume dimensions for ether oxygenates, such as MTBE, did not pose a major threat to public water supplies (Environment Agency 2000). Additionally, a review of groundwater conditions at a number of sites with exceptionally large MTBE plumes discovered in the 1990s (Fogg et al. 1998; Odencrantz 1998; Weaver and Small 2002) indicate that the MTBE plume length and concentrations have diminished significantly over time [Environmental Assessment & Remediations (EAR) 2005; EAR 2011; New York State Department of Environmental Conservation (NYSDEC) 2011].

Nevertheless, some of these studies indicate that their conclusions may be of limited applicability or certainty owing to the short duration of groundwater monitoring history analyzed for individual sites (< 1 to 3 years) and/or insufficient evaluation of the plume stability condition (Happel et al. 1998; Shih et al. 2004). Employing short-term data to predict long-term plume trends can entail uncertainty because (1) short-term groundwater monitoring data are more vulnerable to seasonal fluctuations and sampling variability; and (2) employing short-term monitoring records could underestimate the true rate of attenuation of compounds, such as MTBE, that require longer acclimation periods to undergo biodegradation. Similarly, characterization of the plume stability condition is important for understanding whether the current plume length represents the maximum area of effect or if further plume expansion could occur.

In addition, recent reports on complex groundwater plumes (e.g., detached and/or diving plumes), such as those located in the Long Island, New York area (Weaver and Wilson 2000; Nichols and Roth 2006), in California (Wilson et al. 2004), in Illinois (Wilson et al. 2005), and in dual-porosity aquifers such as the Cretaceous Chalk in the United Kingdom (Thornton et al. 2006), note the importance of adequate monitoring networks to achieve detailed horizontal and vertical delineation of groundwater plumes at typical UST sites. In the absence of adequate horizontal and vertical delineation, failure to identify detached plumes or diving plume conditions could result in misinterpretation of the groundwater conditions at UST sites, such as underestimation of actual plume lengths. This study evaluates hydrogeologic conditions at each site to identify those sites at which diving plumes may be of concern because of elevated recharge rates, vertical flow gradients, and/or absence of stratigraphic features serving to impede downward plume migration.

The present study attempts to improve the understanding of MTBE plume behavior by (1) evaluating a database of geographically diverse sites with long-term groundwater monitoring records and (2) employing a comprehensive analytical approach that includes evaluation of current plume stability (including the potential for detached and diving plume conditions), current plume length, temporal concentration trends in groundwater, and attenuation rates for MTBE at these sites. In addition to MTBE, the behavior of benzene and tert-butyl alcohol (TBA) plumes in groundwater are evaluated and the long-term behavior of these three constituents in groundwater at these sites are compared. Benzene is used in this study as a representative component of non-MTBE fuel, for which the fate and transport characteristics in groundwater were well defined in prior studies, such as Weidemeier et al. 1999. TBA, an intermediate biodegradation product of MTBE, was shown to biodegrade in both aerobic and anaerobic environments (Zeeb and Weidemeier 2007). Evaluation of these three chemicals in groundwater at petroleum release sites is intended to characterize the behavior of MTBE relative to that of benzene, and the MTBE degradation product, TBA.

Methodology

This study was conducted using monitoring records from a database of 48 retail gasoline sites with historical detections of benzene and MTBE in groundwater. For this purpose, long-term monitoring records for UST sites, corresponding to sites with complete records for at least six monitoring wells for five years or more, were solicited from regulatory agencies, energy companies, and environmental consultants. Of an initial population of 54 sites, the number of sites found to meet the screening criteria was 48 for benzene, 48 for MTBE, and 38 for TBA. At each site meeting the minimum data requirements, plume behavior for each constituent was characterized by evaluating the current length, the current stability condition, the temporal concentration trends, the observed attenuation rates, and the timeframe necessary to achieve applicable remediation goals.

The groundwater remediation goals used to define the length of the affected groundwater plumes and evaluate the timeframe to achieve remediation endpoints are as follows: 5 μg/L for benzene, 10 μg/L for MTBE, and 12 μg/L for TBA. For benzene, the remediation goal corresponds to the federal maximum contaminant level (MCL) for drinking water (5 μg/L), (EPA 2009). For MTBE, the value corresponds to the New York State Department of Environmental Conservation (NYSDEC) groundwater standard for MTBE (10 μg/L), (NYSDEC 2008) and for TBA, the value corresponds to the California drinking water action goal (12 μg/L) (RWQCB 2004). The reported laboratory detection limits for groundwater analyses at the 48 sites evaluated in this study were rarely above the concentration limits (benzene = 6%; MTBE = 9%; TBA = 14%), providing an appropriate level of sensitivity to evaluate current compliance with remediation goals.

The following section describes the site database used in this study and the methodology used to evaluate plume behavior at each site.

Database of Long-Term Groundwater Monitoring Records for UST Sites

Key characteristics of the groundwater monitoring database for the 48 sites included in this study are as follows:

- Geographic location: The sites are located in various states in the United States with different histories of MTBE use; specifically, 63% of the sites are in California, 19% in New Jersey 10% in Alaska, 6% in Oregon, and 2% in Nevada. A majority of the sites (82%) are located in California and New Jersey, two states that together, represented 45% of the total MTBE consumption in the United States in 2001 (Lidderdale 2003).
- Current site use: Of the 48 UST sites, 30 are active service stations and 18 are inactive stations or vacant lots with no further potential for releases of gasoline.
- Release history: Available information indicates that underground fuel storage tanks and dispenser islands were principal sources of release of leaded and/or unleaded gasoline at the 48 sites evaluated. More than 70% of the 48 sites have records of releases occurring after 1992 or are active service stations that handled MTBE reformulated gasoline (RFG) after 1992.
- Environmental effects: Non-aqueous phase liquid (NAPL) or sheen was reported in monitoring wells at 34 of the 48 sites. Groundwater impacts were reported to be limited to a shallow aquifer unit at a majority of the sites, with only 6% of the sites reporting effects to more than one aquifer zone.

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- Groundwater monitoring program: For the 48 sites included in this study, the median number of groundwater monitoring wells per site is 17, with a median of four wells located in the source area ("source wells"), seven wells located within the plume downgradient of the source ("plume wells"), and six wells located outside of the affected groundwater plume ("delineation wells"). In this study, only wells designated as either source wells or plume wells were used to evaluate plume concentration trends. The median length of time that groundwater monitoring was underway at the 48 sites is 15 years for benzene, 11 years for MTBE, and eight years for TBA. Additionally, for the purpose of calculation of point attenuation rates, only those wells with more than eight years of monitoring data were used.
- Remediation history: For 44 of the 48 sites evaluated in this study, information was available regarding past or on going remedial actions for affected groundwater. In sum, seven sites (16%) were managed only by monitored natural attenuation (MNA); nine sites (20%) were addressed only with NAPL recovery; 13 sites (30%) received some form of active groundwater remediation (e.g., pump and treat, air sparging) without NAPL recovery; and 15 sites (34%) received some form of active groundwater remediation in combination with NAPL recovery.

As indicated by the relatively extensive monitoring well networks, the long groundwater monitoring periods, the past presence of NAPL, and the implementation of active remedies at a majority of the sites in this study, this database is more representative of sites with larger fuel releases and more extensive groundwater impacts as opposed to sites with only minor MTBE effects on groundwater (e.g., with a few monitoring wells showing low-μg/L concentrations of MTBE in groundwater). Consequently, the findings of this study should be understood to pertain to plumes at sites with relatively significant fuel releases and not to sites with de minimis releases of MTBE at which much shorter plume lengths and durations may be observed.

Evaluation of Groundwater Plume Behavior

For each of the 48 sites in this study, the behavior of the affected groundwater plume was evaluated as follows:

1. Plume stability: The current plume stability condition was characterized by two methods: (1) comparing the maximum spatial extent of the groundwater plume observed historically with the spatial extent observed during the most recent sampling event at the site and (2) evaluating long-term concentration trends in the wells located at the downgradient edge of the plume using the Mann-Kendall statistical method, as described in the MAROS software system [Air Force Center for Environmental Excellence (AFCEE) 2000]. For each constituent, the plumes were then classified as shrinking, stable, expanding, no trend, or detached. Plume concentration trends were characterized using the Mann-Kendall statistical method, as described in Aziz et al. (2003), as follows: (1) an increasing trend refers to a Mann-Kendall result of increasing with a significance level > 90%; (2) a decreasing trend refers to a Mann-Kendall result of decreasing with a significance level > 90%; (3) a stable condition refers to a Mann Kendall result of no trend at a significance level > 90% and with a coefficient of variation (COV) < 1 (indicating low degree of variability); and (4) no trend refers to a Mann-Kendall result of no trend but with a significance level < 90% and a high degree of variability ($COV > 1$). Using this approach, plume stability was evaluated for benzene at 42 sites, for MTBE at 41 sites, and for TBA at 34 sites.
2. Current measured and estimated plume length: Current plume lengths were determined either by (1) measuring the distance from the source location to the downgradient location meeting the remediation goal (i.e., a clean location), for those sites in which the existing monitoring well network included at least one clean downgradient well (designated as well-delineated plumes in this study); or (2) estimating the distance from the source to a clean downgradient location, using an empirical estimation method on the basis of the observed bulk attenuation rate (Newell et al. 2002), for those sites at which the current monitoring well network did not include a clean downgradient well. Plumes for which the lengths could not be either directly measured or estimated were designated as indeterminate.

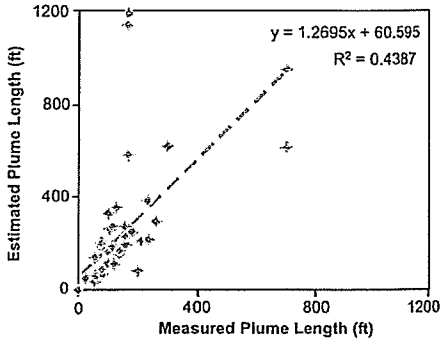

Fig. 1. Correlation between estimated ersus measured plume lengths at 30 UST sites with well-delineated MTBE, benzene, and TBA plumes

The available data were sufficient to provide measurements of plume length for 26 benzene plumes, 28 MTBE plumes, and 19 TBA plumes. These well-delineated plumes were considered the more reliable measure of plume length and were consequently used to check the plume length estimation method used for plumes with less complete delineation. As shown in Fig. 1, the estimated plume lengths for the well-delineated plumes, derived using the bulk attenuation rate, show a reasonable correlation to the true measured plume lengths at these sites (slope = 1.2, $R^2 = 0.43$), with the error tending toward overestimation of the true plume length in most cases. On this basis, this calculation method was considered a conservative method for estimating the plume length for those sites with less complete delineation. Using this methodology, estimated plume lengths were derived for an additional eight sites for benzene, seven sites for MTBE, and three sites for TBA.

Indeterminate plume lengths were found at 19% of the benzene sites, 15% of the MTBE sites, and 35% of the TBA sites in this study. To account for the effect of these indeterminate lengths on the plume population statistics (specifically, the median plume length), as a highly conservative measure the indeterminate plumes were assumed to be equal to or longer than the longest measured or estimated plume length determined for each constituent.

Additionally, to ensure that the available monitoring data provided a reliable measure of true plume dimensions, at each site and for each constituent the possible occurrence of a diving plume was evaluated on the basis of available data for vertical delineation of the plume. This entailed review of groundwater test results from the deeper monitoring wells on each site to confirm that the plume did not extend downward beyond the depth of the monitoring network, resulting in possible mischaracterization of the true plume length. Furthermore, each site was evaluated using the EPA plume dive calculator (Weaver and Wilson 2000) to determine whether site-specific hydrogeologic conditions could result in downward displacement of the plume

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sufficient to extend beyond the depth of the monitoring well network. Results of this analysis found none of the sites to pose a concern with regard to diving plumes. Stratigraphic features at each site may have played an important role in limiting plume dive in the groundwater underlying these sites (Wilson et al. 2005).

3. Current plume concentration trends: To evaluate the long-term temporal trends of constituent concentrations in groundwater at the 48 sites, monitoring data from individual wells that was sampled during eight or more sampling events, with detectable concentrations reported in four or more of these sampling events, were evaluated as follows:

   (1) Concentration trends in individual wells: To assess the trend of concentration versus time within each well, monitoring data from individual wells were statistically evaluated using the Mann-Kendall method, as described in the MAROS software system (AFCEE 2000). Additionally, to minimize the effect of analytical variability and data censoring attributable to the detection limit, only wells in which individual constituents had historically been detected above 20 μg/L were evaluated for concentration trends. Of the 589 source wells and plume wells installed at the 48 sites, 288 wells (43 sites), 306 wells (42 sites), and 241 wells (34 sites) met these minimum criteria for benzene, MTBE, and TBA, respectively.
   (2) Current versus historical compliance with applicable remediation goals: Monitoring data from individual wells that were sampled during at least one event after 2007 were evaluated for past and current compliance with the applicable remediation goals. In total, 218 wells (33 sites), 279 wells (34 sites), and 134 wells (22 sites) met these selection criteria for benzene, MTBE, and TBA, respectively.
   (3) Changes in maximum groundwater concentrations at individual sites over time: Additionally, as a simple measure of the change in plume concentrations over time on a site-wide basis, the maximum historical concentration of each gasoline constituent detected in any well during the initial 20% of the monitoring history at a site was compared with the maximum concentration reported at any well during the most recent sampling event conducted at the site after 2007. At the 48 sites, maximum concentrations of gasoline constituents measured in groundwater ranged between 45 μg/L and 120,000 μg/L for benzene, between 23 μg/L and 1,700,000 μg/L for MTBE, and between 68 μg/L and 700,000 μg/L for TBA. Reduction in maximum groundwater concentrations over time were evaluated at 42 sites for benzene, 41 sites for MTBE, and 34 sites for TBA.

4. Point attenuation rates in individual wells and at sites: A first-order rate of attenuation of chemical concentrations in the groundwater aquifer was calculated for each source well and plume well that exhibited a stable or decreasing concentration trend by estimating the slope of the lognormal plot of concentration versus time [lnC versus t; point attenuation rate, as defined in Newell et al. (2002)] for benzene, MTBE, and TBA at each well.
5. Additional and total remediation timeframe: For the purpose of this study, the additional remediation timeframe corresponds to the estimated future period required from the date of the last monitoring episode for each site (typically 2009) until the maximum constituent concentration measured at the site is reduced to the applicable remediation goal. This additional timeframe for each site was calculated using the site-specific average point attenuation rates (see point 4 above) and the most recent maximum concentration for each constituent (Newell et al. 2002). The total remediation timeframe for each compound was calculated as the sum of (1) the duration of groundwater monitoring period following the first detection of the constituent at the site and (2) the maximum estimated additional remediation timeframe necessary to meet the applicable remediation goal for that constituent. Using this approach, additional and total remediation timeframes were evaluated at 37 sites for benzene, 31 sites for MTBE, and 15 sites for TBA.

MTBE-degrading microbes are understood to require longer acclimation periods than the microbes that degrade benzene, toluene, ethylbenzene, and xylene (BTEX) constituents (Shah et al. 2009). Consequently, to avoid underestimating the true rate of biodegradation of MTBE in the groundwater, this evaluation included only those wells with long-term monitoring records (> 8 years) with detectable concentrations of gasoline constituents measured above the detection limit during four or more sampling events. Additionally, to ensure that the observed changes in the concentration were attributable to attenuation rather than an artifact of variable laboratory results or detection limits between sampling events, only those wells that exhibited concentrations above 200 μg/L for each gasoline constituent during the initial 20% of its monitoring history were used to calculate the point attenuation rate for that constituent. Using this approach, point attenuation rates were calculated for 187 wells (38 sites), 165 wells (30 sites), and 62 wells (16 sites) for benzene, MTBE, and TBA, respectively.

The "total remediation timeframe" for each compound was calculated as the sum of (1) the duration of groundwater monitoring period following the first detection of the constituent at the site and (2) the maximum estimated additional remediation timeframe necessary to meet the applicable remediation goal for that constituent. Using this approach, additional and total remediation timeframes were evaluated at 37 sites for benzene, 31 sites for MTBE, and 15 sites for TBA.

Results of Data Evaluation

Plume Stability

The results show that the vast majority of the benzene plumes (95%) and the MTBE plumes (90%) evaluated in this study are stable or diminishing in size (see Fig. 2). Less than 5% of benzene

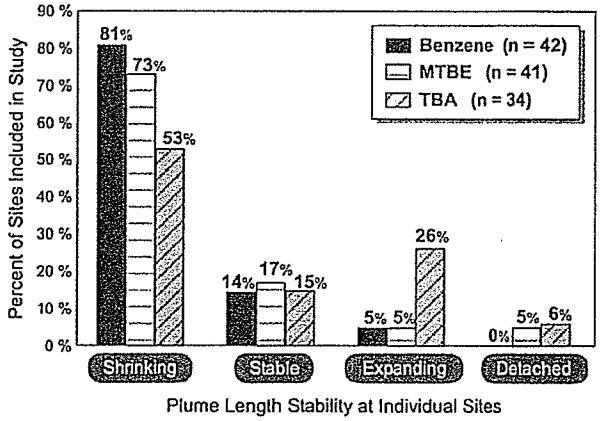

Fig. 2. Results of groundwater plume stability evaluation at individual sites

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plumes (2 of 42 sites) and MTBE plumes (2 of 41 sites) were observed to be expanding in size over time. MTBE plumes showed evidence of being detached from the original release area at a small number of sites (2 of 41 sites); however, comparison of the past and current dimensions of these detached MTBE plumes shows that the spatial extent of on-site and off-site groundwater impacts for these detached plumes is also diminishing in size. None of the 42 benzene plumes exhibited detached conditions.

For TBA, 68% of the plumes evaluated (23 of 34 sites) are currently stable or shrinking in size, whereas 26% (9 of 34 sites) were observed to be expanding in size over time. At the remaining two sites (6%), TBA was detected at higher concentrations in the plume wells than in the source wells, indicating a detached plume condition. The higher percentage of expanding TBA plumes (26%) compared with that of its parent compound MTBE (approx. 5%) suggests that, at some sites, biodegradation of MTBE has contributed to increased concentrations of TBA in the areas downgradient of the plume source area.

In summary, in terms of plume stability, MTBE plumes closely match the behavior of benzene plumes, with the vast majority of the MTBE plumes investigated (> 90%) being in a stable or diminishing condition. Additionally, preliminary evaluation of the MTBE footprint at the few sites with detached plumes shows that on-site and off-site groundwater impacts are now much smaller in size than in the past, thus suggesting that, similar to normal groundwater plumes, detached plumes also stabilize and attenuate over time and distance. Although a majority of the observed TBA plumes are also stable or diminishing (68%), the lower percentage relative to MTBE and benzene plumes likely reflects the temporary build-up of TBA concentrations in groundwater attributable to MTBE biodegradation. In general, TBA may persist within the portion of the plume where biodegradation of benzene, MTBE, and other gasoline constituents has depleted available electron acceptors, and then preferentially biodegrade in the downgradient portions of the plume, where higher concentrations of suitable electron acceptors are encountered.

Current Measured and Estimated Plume Lengths

For the purpose of this evaluation, plumes lengths were (1) measured directly for well-delineated plumes, (2) estimated using a conservative empirical relationship, or (3) characterized as indeterminate on the basis of available data (see the discussion in the Methodology section above). Results of the plume length evaluation for each category of plume are provided below and in Fig. 3.

(1) Measured plume lengths for well-delineated plumes: For sites with well-delineated plumes, the current median plume lengths, as measured by the monitoring well network, are 105 feet for benzene (26 sites), 75 feet for MTBE (28 sites), and 118 feet for TBA (19 sites) [see Fig. 3(a)]. The 90th percentile plume lengths for benzene, MTBE, and TBA at these same sites were 208 ft, 210 ft, and 226 ft, respectively. As a population, no statistically significant difference existed between MTBE plume lengths and benzene plume lengths at the same sites, as determined using the Student's t-test ($p = 0.69$). The two MTBE plumes found to be detached from the source area exhibited plume lengths of 550 ft (with a maximum downgradient extent 700 ft from the original source zone) and 510 ft (with a maximum downgradient extent 885 ft from the original source zone).

(2) Estimated plume lengths: For sites with stable or shrinking plumes at which the existing well network was not adequate to delineate the plume length but for which a bulk attenuation rate could be calculated (on the basis of a lnC versus distance plot), plume lengths were estimated using the method described in Newell et al. (2002) (see the discussion in the Methodology section above). For this population of sites, the current median estimated plume lengths are 354 feet for benzene (eight sites), 379 feet for MTBE (seven sites), and 371 feet for TBA (three sites) [see Fig. 3(b)].

(3) Measured and estimated plume lengths: In combination, the current median plume lengths were measured or were estimated to be 125 feet for benzene (34 of 42 sites), 110 feet for MTBE (35 of 41 sites), and 145 feet for TBA (22 of 34 sites) [see Fig. 3(c)]. For this data set, the 90th percentile plume lengths for benzene, MTBE, and TBA are 356 ft, 454 ft, and 366 ft, respectively [see Fig. 3(b)].

(4) Measured, estimated and indeterminate plume lengths: The plume length values presented above do not include indeterminate plumes, for which the plume lengths could not be measured or estimated on the basis of available data, corresponding to 19% of the benzene plumes (8 of 42), 15% of

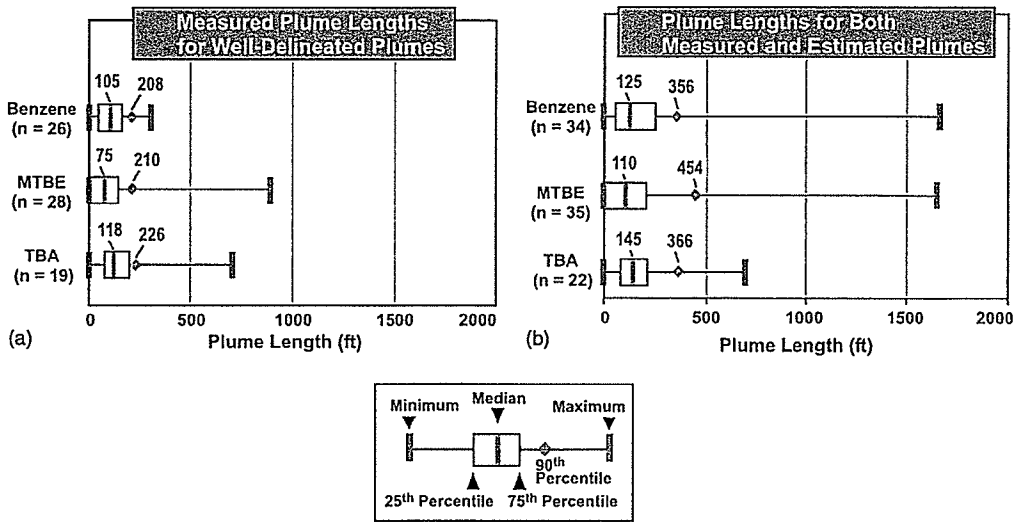

Fig. 3. Distribution of (a) measured plume lengths for well-delineated plumes; (b) measured and estimated plume lengths for all plumes

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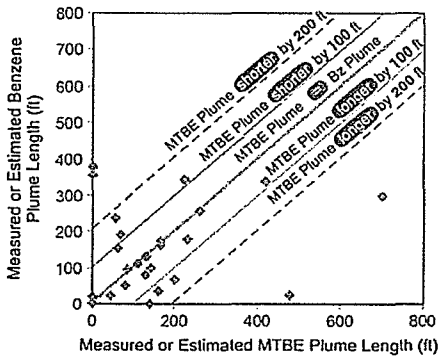

Fig. 4. Comparison of measured or estimated plume lengths for benzene versus MTBE

MTBE plumes (6 of 41), and 35% of TBA plumes (12 of 34) in our data set.

Given that these indeterminate plumes extended beyond the extent of the existing monitoring well networks, expecting that the average length of these plumes would exceed the average length of the plumes whose lengths were delineated or estimated is reasonable. Therefore, as a conservative measure, the median lengths of the full plume population, including the indeterminate plumes, were estimated using highly conservative assumption that all of the indeterminate plumes are equal to or longer than the longest measured or estimated plume length. Given this assumption, the adjusted median plume lengths for the full population of measured, estimated, and indeterminate plumes are 171 feet for benzene, 140 feet for MTBE, and 235 feet for TBA. These values correspond to a very conservative high-end estimate of median plume lengths and may significantly over estimate the true median plume length for this population.

(5) Comparison of MTBE and benzene plume lengths: On a site-by site basis, at the 33 sites at which both MTBE and benzene plumes were measured or estimated, the MTBE and benzene plumes are not statistically different on the basis of a Student's t-test analysis (assuming two-tail distribution and unequal variances between populations; p = 0.23). Fig. 4 provides a comparison of the MTBE and benzene plume lengths determined for these 33 sites. As shown, 70% of the MTBE and benzene plumes (23 of 33) are within +/ − 100 feet in length, whereas only 12% of sites (4 of 33) contained plumes that differed by more than 200 ft (see Fig. 4).

In summary, for the sites in this study, the lengths of MTBE plumes are comparable to those of benzene plumes (adjusted median values of 140 feet for MTBE versus 171 feet for benzene for all plumes, and unadjusted 90 percentile plume lengths of 454 feet for MTBE versus 356 feet for benzene for measured and estimated plumes). TBA plume lengths are also comparable to those of MTBE plumes (adjusted medians of 235 feet for TBA versus 140 feet for MTBE for all plumes, and unadjusted 90 percentile plume lengths of 366 feet for TBA versus 454 feet for MTBE for measured and estimated plumes).

Note that the applicable MTBE remediation goal employed in this study (i.e., 10 μg/L) is more stringent than groundwater standards applied in some states in the United States, including California (primary $MCL = 13$ μg/L) [California Department of Public Health (CDPH) 2009] and New Jersey ($MCL = 70$ μg/L) [New Jersey Department of Environmental Protection (NJDEP) 1997]. Consequently, the plume lengths presented in this paper represent a conservative overestimate of MTBE plume lengths subject to remedial action goals in those states.

Current Groundwater Concentrations and Concentration Trends

(1) Reductions in the maximum plume concentrations observed at each site: The monitoring records show that the maximum plume concentrations recorded within the initial 20% of the monitoring period decreased over time for 93, 90, and 74% of the benzene (40 sites), MTBE (38 sites), and TBA (26 sites) plumes evaluated in this study. Among these sites, the median reductions over time in the maximum historical groundwater concentration were 90%

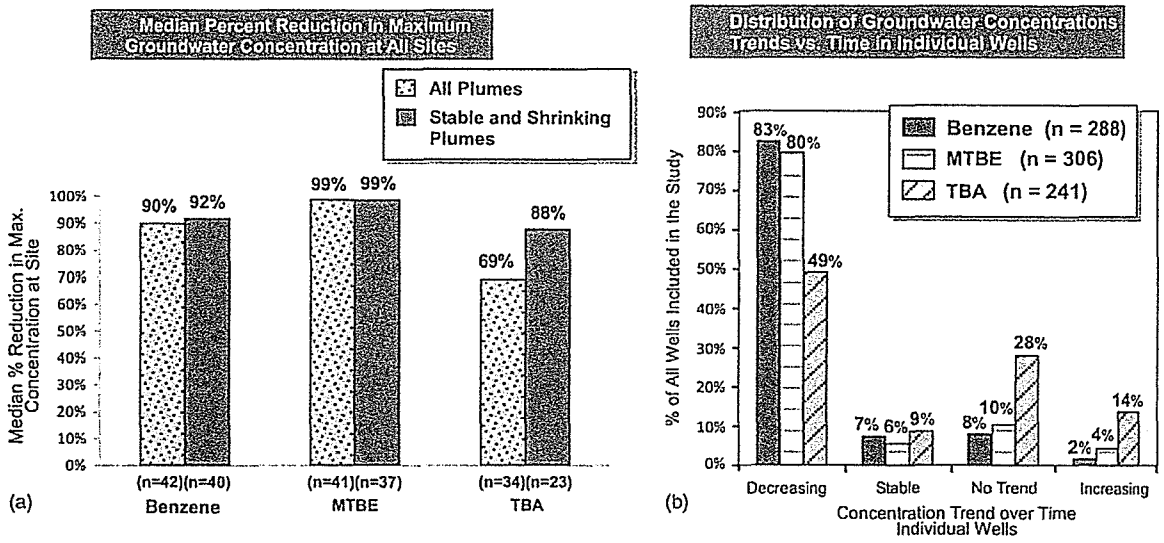

Fig. 5. Concentration Trends: (a) Median percent reduction in maximum groundwater concentration at all sites; (b) distribution of groundwater concentrations trends versus time in individual wells (Both stable plumes and no trend plumes have a Mann-Kendall result of "no trend." However, for our evaluation, consistent with the MAROS guidelines (Aziz et al. 2003), "stable" is used for "no trend" results for which the level of significance is > 90% and $COV < 1$, whereas no trend refers to no trend results with level of significance < 90% and/or COV > 1)

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for benzene, 99% for MTBE, and 69% for TBA [see Fig. 5(a). For those sites with shrinking or stable plumes, the percentage reductions in the maximum historical concentrations were slightly higher than for the full plume population, at 92% for benzene (40 sites), 99% for MTBE (37 sites), and 88% for TBA (23 sites). At sites with detached MTBE plumes (two sites) or TBA plumes (two sites), the concentration reduction was observed to be approximately 92% for MTBE and 81% for TBA.

(2) Concentration Trends in Individual Monitoring Wells: Evaluation of the concentration trends in individual monitoring wells found concentrations to be stable or diminishing over time for 90% of wells with detectable benzene and for 86% of wells with detectable MTBE [see Fig. 5(b)]. Less than 2% of the wells containing benzene and less than 4% of the wells containing MTBE exhibit increasing concentration trends. For TBA, 58% of individual wells show stable or diminishing concentration trends over time, whereas 13% of the wells exhibit increasing trends.

(3) Current versus historical compliance with applicable remediation goals:

All wells: The number of monitoring wells that meet the remediation goals for benzene and MTBE increased significantly over the monitoring periods [see Fig. 7(a)]. Specifically, the percentage of individual monitoring wells that meet the selected remediation goals (i.e., 5 μg/L for benzene and 10 μg/L for MTBE) increased from 10 to 48% for benzene and from 11 to 57% for MTBE, representing an approximate five-fold increase in compliance for each constituent. The percent of individual monitoring wells for which TBA meets the selected remediation goal (12 μg/L) also increased, but by a lesser margin than the other two constituents, increasing to 25% in the most recent sampling episodes compared with 16% historically, an approximate 60% increase. In general, the percentage of plume wells in compliance with the remediation goal is greater than those located in the source area, which is consistent with the commonly observed pattern of concentrations diminishing more rapidly in the downgradient portion of the plume, with measurable concentrations persisting for a longer period in the source area.

Site-wide evaluation: On a site-wide basis (i.e., in 100% of monitoring wells), 12% of the 43 sites affected by benzene, 24% of the 42 sites affected by MTBE, and 14% of the 35 sites affected with TBA presently meet the applicable remediation goal for all monitoring wells [see Fig. 6(b)]. Historically, none of these sites met the remediation goal on a site-wide basis for all monitoring wells.

In summary, during the monitoring period, the majority of sites investigated in this study experienced significant reductions in maximum plume concentrations for benzene, MTBE, and TBA (i.e., > 69% of sites for all three compounds). The median reduction observed in the maximum concentration in MTBE plumes (99%) exceeds that of benzene plumes (90%) for the full plume populations [see Fig. 5(a)]. Within individual monitoring wells, MTBE exhibits concentration trends comparable to those of benzene, with 86 to 90% of wells showing stable or diminishing concentrations over time. As a result, a much larger percentage of wells now comply with these remediation goals than was observed at the beginning of the monitoring period. Relative to benzene and MTBE plumes, a smaller percentage of TBA wells (58%) exhibit stable or diminishing concentrations, whereas a larger percentage indicate increasing concentrations (13%), which may reflect the temporary increase in TBA concentrations attributable to biodegradation of MTBE.

Detached MTBE and TBA plumes exhibit concentration reductions (MTBE: 85 to 99% reduction; TBA: 71 to 91% reduction) similar to those of non-detached plumes (MTBE: 29 to 100% reduction; TBA: 11 to 100% reduction). The median concentration reduction exhibited by all TBA plumes (69%) is less than that of MTBE (99%) and benzene plumes (90%), possibly reflecting the temporary build-up of TBA concentrations attributable to biodegradation of MTBE.

Point Attenuation Rates in Individual Wells

For wells exhibiting a trend of stable or diminishing concentrations over time, the data are amenable to calculation of a point attenuation rate (i.e., on the basis of C versus t) using the standard methods described in Newell et al. (2002). (Note that, in this paper, when concentrations are declining over time, the rate constant has a negative value; when concentrations are increasing over time, the rate constant is positive). The concentration attenuation rates observed in individual wells for the three gasoline constituents under study are as follows.

(1) Point attenuation rates in individual wells: First-order point attenuation rates estimated for benzene in 188 wells (39 sites)

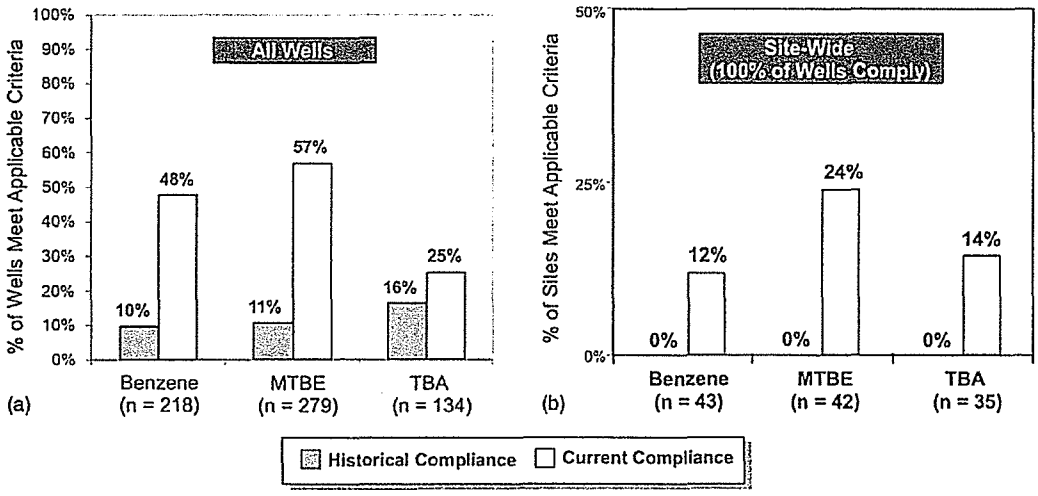

Fig. 6. Comparison of historical versus current compliance with remediation goals

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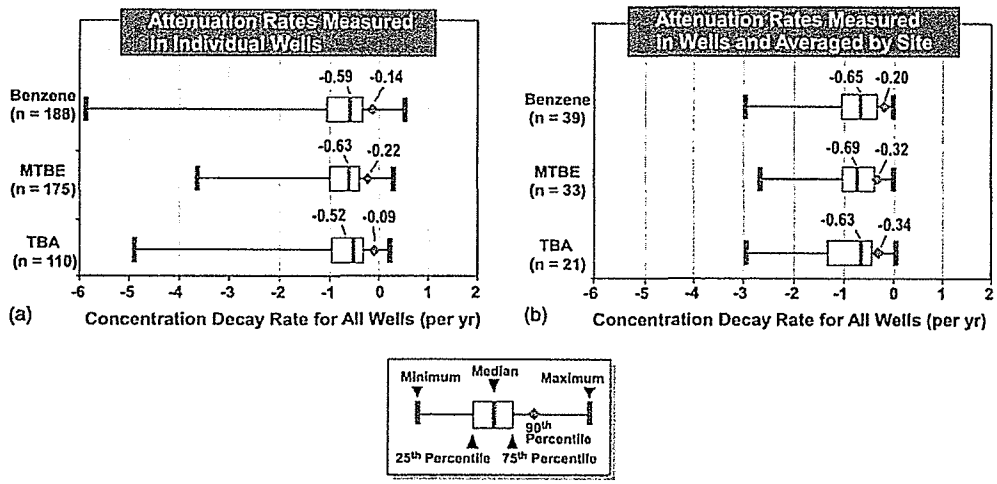

Fig. 7. Comparison of point attenuation rates for benzene, MTBE, and TBA at sites with stable or shrinking plumes

ranged from −5.8 per year to 0.52 per year, with a median value of −0.59 per year [see Fig. 7(a)]. For MTBE, first-order attenuation rates were estimated for 175 wells (33 sites) and were observed to range from −3.6 per year to 0.29 per year, with a median value of −0.63 per year. TBA degradation rates were estimated for 110 wells (21 sites) and ranged from −4.9 per year to 1.71 per year, with a median value of −0.52 per year.

(2) Median point attenuation rates in wells at each site: Site-wide attenuation rates obtained by calculating the median attenuation rate for individual wells at each site are shown in Fig. 8(b). Attenuation rates ranged between −0.12 and −2.9 per year (median = −0.65 per year) for benzene, −2.7 and 0.01 per year (median = −0.69 per year) for MTBE, and −2.94 and 0.025 per year (median = −0.63 per year) for TBA. These median attenuation values are comparable, but slightly faster (i.e., more negative), than the values determined for each chemical on the basis the full well population [see Fig. 7(a)].

In summary, concentration trends in individual wells and on a site-wide basis indicate that the point attenuation rates of benzene, MTBE, and TBA are similar

Overall Plume Attenuation Rates Based on Trend of Median and Maximum Concentrations among All Sites

As an alternative measure of the relative behavior of benzene, MTBE, and TBA in groundwater, the overall concentration trend for each constituent among the full population of sites was characterized as the change in the median and maximum concentrations versus time among all sites, as shown on Figs. 9(a) and 9(b) and discussed below.

(1) Reduction in overall median concentration versus time for full site population: The median concentrations of benzene, MTBE, and TBA in groundwater for the full site population all decreased significantly over the past 10 years. As indicated in Fig. 8(a), the overall attenuation rates (C versus t) exhibited by these median concentration values over the past 10 years are −0.20 per year, −0.47 per year, and −0.27 per year for benzene, MTBE, and TBA, respectively, corresponding to half lives of 3.4, 1.5, and 2.5 years.

(2) Reduction in maximum concentration versus time for full site population: Similar to the median values, the maximum concentrations of benzene, MTBE, and TBA in groundwater for this site population also decreased significantly over the past 10 years.

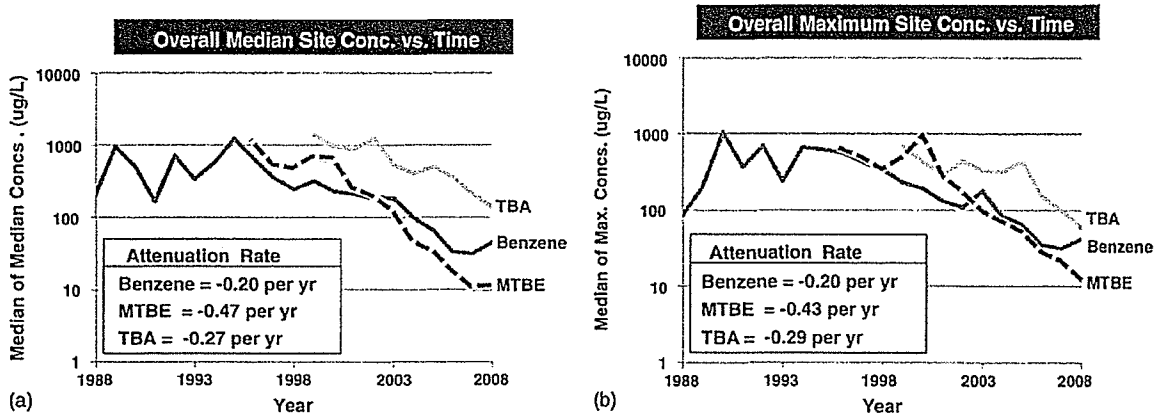

Fig. 8. Trend in site-wide median and maximum plume Concentrations versus time

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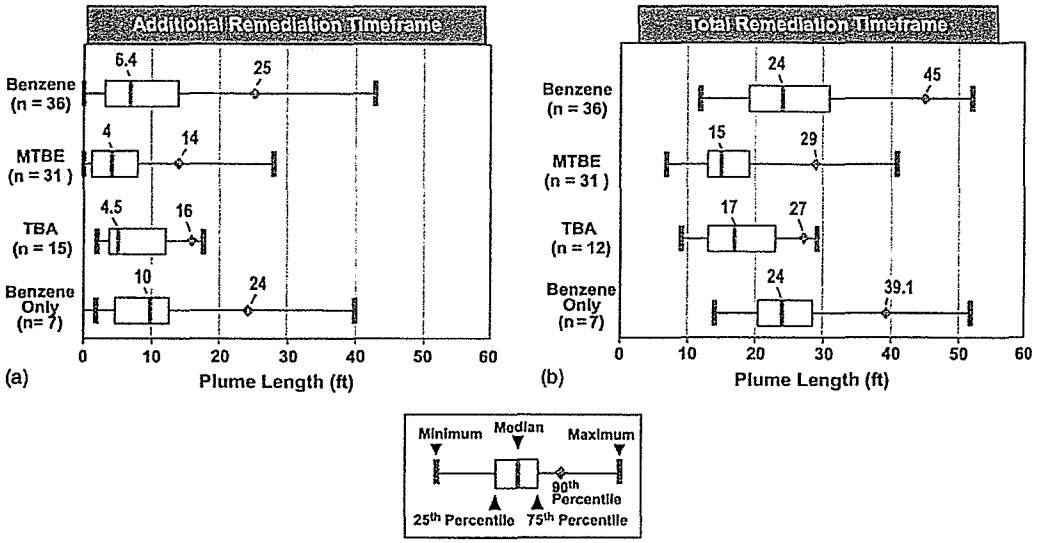

Fig. 9. Time to Remediation for Sites with Stable or Shrinking Plumes ("Benzene Only" refers to those sites where only benzene, not MTBE or TBA, exceeded the applicable remediation goal.)

As indicated in Fig. 8(b), the overall attenuation rates (C versus t) exhibited by these maximum concentration values over the past 10 years are −0.20 per year, −0.43 per year, and −0.29 per year for benzene, MTBE, and TBA, respectively, corresponding to half lives of 3.5, 1.6, and 2.4 years.

In summary, when evaluated on the basis of the full site population, both the median and maximum MTBE concentrations measured in groundwater are observed to decrease at a faster rate than the median and maximum concentrations of benzene. The faster attenuation rate observed for MTBE relative to benzene may reflect the effect of (1) the discontinued use of MTBE in the past decade, as a result of which unlike benzene, additional releases of MTBE cannot occur at active UST sites and/or (2) the much higher solubility of MTBE, compared with benzene, which can result in a more rapid rate of dissolution and depletion of MTBE from the source, eventually resulting in lower contributions of MTBE from the source to the plume, relative to benzene.

The median and maximum TBA concentrations observed for this site population are generally higher than either MTBE or benzene. In addition, TBA exhibits an overall average attenuation rate that is slower than MTBE. These observations are consistent with a temporary build-up of TBA, as a biodegradation product of MTBE, and limited biodegradation of TBA within the more concentrated portions of the plume in which electron acceptors were depleted by preferential biodegradation of BTEX and MTBE.

Effect of Active Groundwater Remediation on Plume Attenuation Rates

To evaluate the influence of active remediation on plume concentration trends, attenuation rates at sites at which active groundwater remediation and/or LNAPL recovery were conducted were compared with attenuation rates at those sites that were managed by MNA only. Table 1 summarizes the median attenuation rates determined for sites classified as: (1) MNA only, (2) NAPL recovery only, (3) groundwater remedy only, or (4) groundwater remedy plus NAPL recovery, on the basis of whether such actions were conducted for any period of time in the site history.

Student's t-tests (two-sided) comparing these four groups found that, for all three plume constituents, no statistically significant difference existed between the attenuation rates observed between (1) MNA-only sites versus groundwater remedy only sites (groups 1 and 3 in Table 1; p-value range for the three compounds = 0.10–0.43) or between (2) the combined population of MNA-only plus NAPL recovery only sites (groups 1 and 2 in Table 1) versus the combined population of groundwater remedy only and groundwater remedy with NAPL recovery sites (groups 3 and 4 in Table 1) (p-value range for the three compounds = 0.33–0.62). This analysis indicates that, for this set of sites, active groundwater remedies did not serve to measurably alter the rate of attenuation of plume concentrations versus time for the benzene, MTBE, or TBA. Rather, the fact that groundwater remedy only sites display attenuation rates comparable with those of MNA-only sites suggests that

Table 1. Comparison of Attenuation Rates of Median Plume Concentration versus Time for Different Remedial Action Conditions

	Benzene		MTBE		TBA	
Groundwater remediation method	No. of Sites	Median attenuation rate (1/yr)	No. of sites	Median attenuation rate (1/yr)	No. of sites	Median attenuation rate (1/yr)
1) MNA only	7	−0.20	6	−0.56	3	−0.23
2) NAPL recovery only	9	−0.13	9	−0.42	7	−0.18
3) Groundwater remedy only	13	−0.27	14	−0.47	12	−0.24
4) Groundwater remedy with NAPL recovery	13	−0.09	13	−0.46	11	−0.06

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natural attenuation is likely the dominant attenuation mechanism for this population of sites. This observation is supported by the overall trend of TBA and MTBE concentrations across the full population of sites (see point 5 above). The presence of TBA in groundwater at concentrations greater than MTBE similarly indicates that biodegradation of MTBE (i.e., conversion to TBA) is the dominant mass removal mechanism for MTBE and that this natural attenuation process is more significant than active remediation for this site population.

The finding that groundwater plumes at sites managed by MNA only versus sites managed by active groundwater remediation are comparable is consistent with prior investigations of large populations of BTEX plumes (benzene, ethylbenzene, toluene, and xylene), as reported in Newell and Connor (1998). Specifically, studies by Rice et al. (1995) of 208 BTEX plumes in California and by Mace et al. (1997) of 93 BTEX plumes in Texas found no statistical difference in plume lengths between active groundwater remediation sites and MNA only sites.

In summary, the attenuation rates of the median concentrations of the three plume constituents are equivalent for sites in which active groundwater remediation was conducted versus sites in which only MNA was applied. In the absence of more detailed information regarding the remediation activities at each of the sites in this study, particularly with regard to the mass of constituents removed or destroyed, and a comparison of plume conditions before and after the remedy, a degree of uncertainty in this analysis is recognized with respect to the effect of remediation on plume conditions. For example, remediation efforts that remove a significant portion of the source mass from the groundwater can certainly serve to reduce the maximum plume size and increase the rate of plume shrinkage. However, at face value, the similarity of the attenuation rates observed at actively remediated versus nonactively remediated sites suggests that natural attenuation of benzene, MTBE, and TBA may be the principal mechanism of mass removal for this population of plumes.

Additional and Total Remediation Timeframe

For sites with stable or shrinking plumes, which are amenable to calculation of point attenuation rates (C versus t), the average attenuation rates calculated for each site (see item 4b above) were used to calculate the additional time necessary for the site to meet the applicable groundwater remediation goal [see Fig. 9(a)]. The additional remediation timeframe was estimated to range from 0 to 43 years for benzene (median = 6.4 years for 36 sites), 0 to 28 years for MTBE (median = 4 years for 31 sites), and 2 to 18 years for TBA (median = 4.5 years for 15 sites).

For this same population of sites, the total remediation timeframe was determined as the sum of the additional remediation timeframe plus the number of years since monitoring first began on the site. The total remediation timeframe was estimated to range from 12 to 52 years for benzene (median = 24 years for 36 sites), 7 to 41 years for MTBE (median = 15 years for 31 sites), and 9 to 29 years for TBA [median = 17 years for 15 sites; see Fig. 9(b)]. For sites with MTBE and/or benzene plumes, the combined total timeframe to reach applicable remediation goals is within the range 16 to 53 years, with a median timeframe of 28 years. For sites at which only benzene ever exceeded the applicable remediation goal (i.e., no exceedance for either MTBE or TBA), the total remediation timeframe was estimated to be from 14 to 52 years (median = 24 years; 7 sites).

In summary, evaluation of the additional and total timeframe required to achieve remediation goals again shows benzene and MTBE plumes to exhibit similar behavior. Note that the total remediation timeframes for benzene and/or MTBE plumes combined (range of 16 to 53 years, with a median timeframe of 28 years) are comparable to the total remediation timeframes for sites at which groundwater impacts are limited to the presence of benzene only, with no MTBE effects above the applicable remediation goal (range of 14 to 52 years, with a median of 24 years). These results indicate that MTBE plumes are not recalcitrant in comparison to benzene plumes; in contrast, they can be expected to attenuate within the same general timeframe. Indeed, as suggested by the data in this study, at many sites, MTBE plumes may be observed to reach remediation goals more quickly than the benzene plume.

Comparison to Previous Studies

Earlier studies predicted that, in comparison to non-MTBE gasoline, releases of MTBE-containing gasoline from UST sites would result in relatively long plumes and much longer-term effects on groundwater resources (Fogg et al. 1998; Odencrantz 1998; Weaver and Small 2002). However, the results of the evaluation of gasoline plume behavior at 48 sites located in diverse hydrogeologic settings across the nation indicate that at a majority of UST sites that were monitored for five or more years: (1) the MTBE concentrations in groundwater significantly diminished over time, (2) MTBE plume lengths and stability conditions are comparable to benzene plumes, and (3) MTBE plume attenuation is on track to achieve remedial goals within a timeframe comparable to or less than that of benzene plumes. These findings are consistent with other studies that examined monitoring data for large populations of UST sites across the nation and found that the spatial extent and duration of MTBE effects on groundwater resources is much less than previously anticipated (Mace and Choi 1998; Reid et al. 1999; Shorr and Rifai 2002; Rifai et al. 2003; Wilson et al. 2003; Shih et al. 2004; Stevens et al. 2006). Review of our specific findings with regard to those of previous studies is summarized in Table 2 and discussed in further detail below.

1. Plume stability: The percentage of stable or shrinking MTBE plumes at the 41 sites evaluated in this study (90%) is toward the upper end of the range of values (50 to 96%) published in previous studies for a total of 81 sites evaluated in Texas in 2002 (Shorr and Rifai 2002) and in Florida in 1999 (Reid et al. 1999). These results suggest that, given the longer monitoring periods that were the focus of the current study and the greater passage of time since the release, a larger percentage of MTBE plumes will attenuate to a stable or shrinking condition.
2. Plume length: The median MTBE plume length determined in this study (adjusted upper-end median of 140 feet) is on the lower end of the range of median lengths (140 feet to 178 feet) reported in earlier studies (Mace and Choi 1998; Wilson et al. 2003; Reid et al. 1999). Again, this shorter median plume length may reflect the longer monitoring periods for the sites included in this study, which is consistent with continued attenuation of MTBE plume lengths over time.
3. Point attenuation rate: The median attenuation rate for MTBE in groundwater (–0.63 per year) reported for the sites include in this study is faster than the attenuation rate values published in previous studies (median of –0.35 per year) for MTBE-affected sites undergoing natural attenuation only (Schirmer et al. 1999; Wilson and Kolhatkar 2002; Hansen et al. 2003; Rifai et al. 2003; EPA 2005). The faster MTBE attenuation rates observed in this study may reflect the effect of the longer monitoring period, which may provide a more accurate estimate for attenuation rates for compounds, such as MTBE, that entail longer periods for acclimation of the in situ bacterial population.

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Table 2. MTBE Plume Characteristics Reported in the Current Study versus that Reported in Literature

	Results for MTBE plumes					
	Current study		Prior studies of data for multiple plumes			
MTBE plume characteristic	No. of sites	Value	No. of sites	Value	Reference	Comments
Percent of stable or shrinking plume	41	90%	81	50% to 96%	(Shorr and Rifai 2002; Reid et al. 1999)	Results fit within the range of previous findings, but indicate higher % of stable/ shrinking plumes.
Plume length (feet)	35	Median = 140 ft[a]	356	Median = 140–178 ft	(Mace and Choi 1998; Wilson et al. 2003; Reid et al. 1999)	The study finds median MTBE plume length to be at lower end of range in prior studies.
Point attenuation rate (per year)	33	−3.6 to 0.29 (Median = −0.63)	100[b]	−1.2 to − 0.15 (Median = −0.35)	(Schirmer et al. 1999; Wilson and Kolhatkar 2002; Hansen et al. 2003; EPA 2005; Rifai et al. 2003)	The study finds MTBE attenuation rates to be faster than previous studies.

[a]Table shows the adjusted median plume length for sites at which plume lengths were either measured, estimated, or considered indeterminate.
[b]Results reported from MNA-only sites.

In addition, given the discontinued use of MTBE as a fuel additive, additional releases of MTBE can no longer occur at active UST sites; therefore, in the absence of such additional source contributions, faster attenuation rates are likely to be observed within the population of existing MTBE plumes (Stevens 2006). Furthermore, the higher solubility of MTBE compared with benzene may contribute to more rapid dissolution and depletion of MTBE from the source, resulting in larger reductions in source contributions of MTBE to the plume over the long term.

Conclusions

This study addresses the characteristics of benzene, MTBE, and TBA plumes in groundwater for a population of 48 retail service station sites, specifically in terms of plume length, plume stability condition, concentration reduction trends over time, attenuation rates, and the timeframe within which natural attenuation achieved remedial goals for each constituent. The goal of this evaluation was to characterize plume behavior as observed across a variety of hydrogeologic settings on the basis of detailed groundwater monitoring records, rather than to define the site-specific factors controlling plume behavior. The groundwater monitoring data analyzed in this study confirm that, over the long term for this site population, the behavior of MTBE plumes in groundwater is similar to that of benzene plumes with respect to current plume lengths and plume stability trends. However, overall MTBE concentrations are decreasing more quickly than benzene, and may, on average, reach the applicable remediation goals more quickly than benzene plumes. The faster attenuation of MTBE plumes compared with benzene is consistent with the discontinued use of MTBE as a fuel additive.

TBA plumes were also found to be comparable to benzene and MTBE plumes in terms of plume length. However, whereas most TBA plumes are stable or shrinking, the percentage of TBA plumes currently stable or shrinking (68%) is less than that for benzene plumes (95%) and MTBE plumes (90%), likely reflecting the temporary build-up of TBA concentrations in groundwater attributable to MTBE biodegradation. Nevertheless, overall trends for the median and maximum concentrations of TBA in groundwater at these sites indicate that TBA is attenuating at rates somewhat faster than benzene and can therefore be expected diminish to applicable remediation goals in a similar timeframe as the other gasoline constituents.

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Groundwater

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Review of Quantitative Surveys of the Length and Stability of MTBE, TBA, and Benzene Plumes in Groundwater at UST Sites

by John A. Connor[1], Roopa Kamath[2], Kenneth L. Walker[2], and Thomas E. McHugh[2]

Abstract

Quantitative information regarding the length and stability condition of groundwater plumes of benzene, methyl tert-butyl ether (MTBE), and tert-butyl alcohol (TBA) has been compiled from thousands of underground storage tank (UST) sites in the United States where gasoline fuel releases have occurred. This paper presents a review and summary of 13 published scientific surveys, of which 10 address benzene and/or MTBE plumes only, and 3 address benzene, MTBE, and TBA plumes. These data show the observed lengths of benzene and MTBE plumes to be relatively consistent among various regions and hydrogeologic settings, with median lengths at a delineation limit of 10 µg/L falling into relatively narrow ranges from 101 to 185 feet for benzene and 110 to 178 feet for MTBE. The observed statistical distributions of MTBE and benzene plumes show the two plume types to be of comparable lengths, with 90th percentile MTBE plume lengths moderately exceeding benzene plume lengths by 16% at a 10-µg/L delineation limit (400 feet vs. 345 feet) and 25% at a 5-µg/L delineation limit (530 feet vs. 425 feet). Stability analyses for benzene and MTBE plumes found 94 and 93% of these plumes, respectively, to be in a nonexpanding condition, and over 91% of individual monitoring wells to exhibit nonincreasing concentration trends. Three published studies addressing TBA found TBA plumes to be of comparable length to MTBE and benzene plumes, with 86% of wells in one study showing nonincreasing concentration trends.

Introduction

Over the past two decades, thousands of underground storage tank (UST) sites across the United States have been investigated to assess the potential impacts of gasoline fuel leaks on the underlying soil and groundwater. This experience has generated extensive information regarding the nature and extent of groundwater plumes containing benzene, methyl tert-butyl ether (MTBE), and tert-butyl alcohol (TBA). In the 1990s, when regulations required that gasolines be blended with oxygenate additives like MTBE for more efficient combustion, some researchers predicted that, in the event of a gasoline release to groundwater, MTBE would form much longer groundwater plumes compared to benzene (Fogg et al. 1998; Odencrantz 1998; Weaver and Small 2002). These authors based their predictions upon considerations that (1) MTBE is more soluble and less sorptive than benzene and could therefore travel farther than benzene in groundwater, in the absence of other attenuation mechanisms; and (2) MTBE, unlike benzene, was suspected to be relatively resistant to biodegradation by native soil bacteria (Yeh and Novak 1991; Suflita and Mormile 1993; Mormile et al. 1994).

These predictions were initially supported by the discovery of a few exceptionally long MTBE plumes extending thousands of feet downgradient of the release

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point, such as in Long Island, New York (Weaver et al. 1996, 1999). In contrast to these few exceptionally long plumes, several studies conducted in the mid-1990s that compiled information from numerous UST sites found the measured lengths of benzene and MTBE plumes to be comparable (Happel et al. 1998; Mace and Choi 1998). However, some authors questioned whether these results were reliable, postulating that younger MTBE plumes could be continuing to expand while older benzene plumes might be stable or diminishing in size, and/or noting that proper delineation of plume lengths could be hampered by diving plume conditions or other limitations (Happel et al. 1998; Mace and Choi 1998; Shih et al. 2004).

Subsequent scientific studies have improved our understanding of the lifecycle of contaminant plumes and the behavior of gasoline additives in groundwater. Specifically, field and laboratory investigations have found MTBE to biodegrade in groundwater under both aerobic and anaerobic conditions (Mackay et al. 2001, 2007; Wilson et al. 2002; Gray et al. 2002; McKelvie et al. 2007a). Published studies conducted from 1995 to 2013 have compiled field data from thousands of UST sites across the country, providing information on the measured lengths of MTBE and benzene plumes in groundwater and/or the observed plume stability condition (Rice et al. 1995; Buscheck et al. 1996; Mace et al. 1997; Happel et al. 1998; Reid et al. 1999; Reisinger et al. 2000; Shorr and Rifai 2002; Wilson 2003; Rifai and Rixey 2004; Shih et al. 2004; Stevens et al. 2006; Tarr and Galonski 2007; Kamath et al. 2012). In addition, three studies have addressed the behavior of TBA plumes found in conjunction with MTBE gasoline releases (Shih et al. 2004; Kamath et al. 2012; McHugh et al. 2013).

Purpose of Review

In this paper, we have reviewed the results of 13 published studies of multiple plumes to characterize the statistical distribution of plume lengths, plume stability conditions, and concentration trends for benzene, MTBE, and TBA plumes at UST sites. These studies have applied a variety of technical criteria and methodologies to achieve a representative measurement of plume lengths and stability conditions at retail gasoline sites. In total, the studies provide quantitative data on over 550 MTBE plumes and over 1300 benzene plumes at retail gasoline sites in a variety of hydrogeologic settings.

This review paper updates prior publications that compiled information on large populations of benzene and MTBE plumes (Newell and Connor 1998) by incorporating the results of additional multi-plume studies conducted over the past 15 years. In addition, this study incorporates the results of three studies that have addressed TBA plume behavior in addition to benzene and MTBE (Shih et al. 2004; Kamath et al. 2012; McHugh et al. 2013). This paper describes the methodology employed to review and compile these data, presents statistical summaries of benzene, MTBE, and TBA plume characteristics, and addresses the significance and limitations of these data.

Compilation of the data from these 13 separate studies is intended to provide a more complete understanding of plume behavior across multiple regions, as well as summary statistics on the observed length and stability condition of these plumes. This review serves to compile information generated over two decades of scientific investigation so as to provide the reader the benefit of the accumulated knowledge and weight of evidence that could not be obtained from the individual studies on their own.

Compilation of Data from Published Studies

We have surveyed the published literature to identify prior studies that have compiled quantitative data on groundwater plume conditions at multiple UST sites in the United States. Table 1 lists 13 studies that provide quantitative information and statistical summaries regarding the lengths and/or stability conditions of benzene, MTBE, and/or TBA groundwater plumes. Appendix S1 includes summary data from each paper tabulated as the basis for this paper.

Technical Specifications of Quantitative Surveys of Plume Characteristics

Each of the studies compiled in this paper has employed one or more technical criteria to obtain a representative sampling of plume characteristics from among existing groundwater monitoring records at UST sites. Key considerations include the following:

1. *Nature of Release.* These studies provide information on plume conditions associated with gasoline fuel releases from UST systems, principally retail fuel marketing facilities. Plumes associated with other potential sources of release (pipelines, refineries, tank farms, truck spills, etc.) or materials (diesel fuel, bulk additives, etc.) were not included in these databases.
2. *Survey of Multiple Site Locations.* Each of the studies provides quantitative data on multiple benzene, MTBE, and/or TBA plumes. Individual studies on plume lengths include 22 to 289 sites per study. Studies on plume stability conditions include 34 to 271 sites per study, with one study addressing the overall plume concentration trends observed at over 4000 UST sites in California (McHugh et al. 2013).
3. *Duration of Groundwater Monitoring History.* A number of the studies selected sites with longer-term monitoring periods so as establish plume trends with less uncertainty associated with seasonal fluctuations, sampling variability, and attenuation rates for compounds, such as MTBE, which have been observed to require longer acclimation periods for biodegradation. For those studies that specified minimum monitoring periods, the minimum monitoring periods required exceeded one year in duration, with most of the studies requiring three or more years.
4. *Number of Groundwater Monitoring Points.* For most of the studies reviewed, plume characterization was based upon a minimum number of three to eight monitoring points per site to define the plume length or

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Table 1
Summary of Studies on Plume Length and Plume Stability Conditions Based upon Data from Multiple UST Sites

Study	State	No. of Sites Meeting Minimum Specifications	Minimum Specifications for Evaluation Sites	Plume Length Reported?	M, B in Same Wells?	Plume Stability Condition Evaluated?	
						Length Versus Time	GW Conc. Trend
1. Rice et al. (1995)	CA	271	8 events; 6 wells	B (271 sites)	—	B (271 sites)	B (271 sites)
2. Buscheck et al. (1996)	CA	119	NR	BTEX/Benzene (62 sites)[1]	—	—	BTEX (119 sites)
3. Mace et al. (1997)	TX	227	6 wells	B (217 sites)[2]	—	B (217 sites)	B (227 sites)
4. Happel et al. (1998)	CA	63	1 sampling event; 8 wells	M (50 sites), B (50 sites)[3]	Yes (43 sites)	—	—
5. Mace and Choi (1998)	TX	289	Three events (1995–1997)	M (89 sites[4]), B (289 sites)	—	M, B (20 sites)[5]	M (471 wells)
6. Reid et al. (1999), Reisinger et al. (2000)	FL	55	3 years; Minimum 3 wells with detections MTBE	M (55 sites), B (54 sites)	Yes	M (45 sites)	—
7. Shorr and Rifai (2002), Rifai et al. (2003), Rifai and Rixey (2004)	TX	36	3 years; Minimum 6 wells; Minimum 3 years MTBE data	M (36 sites), B (36 sites)	Yes	M (36 sites), B (36 sites)	M (1074 wells), B (1206 wells)[6]
8. Wilson (2003)	SC	212	NR	M (212 sites), BTEX (212 sites)	Yes	—	—
9. Shih et al. (2004)	CA	96	1 year; sufficient wells; proper lab QA/QC	M (96 sites), B (95 sites), TBA (86 sites)	Yes	M (96 sites), B (94 sites), TBA (86 sites)[7]	—
10. Stevens et al. (2006)	CT	22	4 years; active UST; no NAPL; consistent monitoring program; no active remediation	—	—	—	M (83 wells)
11. Tarr and Galonski (2007)	NH	25	M detections	—	—	—	M (78 wells)
12. Kamath et al. (2012)	CA, NJ, AK, OR, NV	48	Min. 6 wells	M (35 sites), B (34 sites), TBA (22 sites)	Yes, including TBA	M (41 sites), B (42 sites), TBA (34 sites)	M (42 sites, 306 wells), B (43 sites, 288 wells), TBA (34 sites, 241 wells)
13. McHugh et al. (2013)	CA	>4000	2001 to 2011	—	—	—	M (4190 sites) B (4404 sites), TBA (3675 sites)
Total	—	—	—	M (573 sites), B (1320 sites), TBA (108 sites)	474 sites	M (238 sites), B (680 sites), TBA (120 sites)	—

M = Methyl tert-butyl ether (MTBE); B = Benzene; BTEX = Benzene, toluene, ethylbenzene, and xylenes; TBA = tert-butyl alcohol; NR = not reported; — = not analyzed; NAPL = nonaqueous phase liquid; QA/QC = quality assurance/quality control; UST = underground storage tank.

[1] Buscheck et al. (1996) reported the percentage of sites with BTEX plume lengths less than 50 feet, between 50 and 100 feet, between 100 and 200 feet, and greater than 200 feet. The terms BTEX and benzene appear to be used interchangeably within this study.

[2] Mace and Choi (1998) also presented benzene plume length data, and these data were used to compare with MTBE; Mace et al. (1997) benzene plume length results are not presented in this paper to prevent double-counting the same dataset.

[3] Benzene plume lengths were estimated based on a 1-µg/L contour limit, inconsistent with the other studies, and therefore could not be used for weighted mean calculations in our paper.

[4] Mace and Choi (1998) estimated plume lengths at 99 sites, but 10 of these sites had plume lengths of 0 feet.

[5] Mace and Choi (1998) estimated plume behavior (i.e., plume stability) over time at 20 sites based on plume lengths measured at three different events but did not present the full results of their analysis, and their incomplete results are not analyzed in this paper.

[6] Shorr and Rifai (2002) only presented the number of wells with near zero or decreasing trends, and their plume stability results are not aggregated in this paper because relative percentages of wells in each trend category were not specified.

[7] Shih et al. (2004) aggregated the plume length dataset before statistical analysis of plume stability and concluded that while the plume length decreased for MTBE and increased for benzene and TBA, these results were not statistically significant at a 95% confidence interval.

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stability condition, with most of these studies requiring six or more monitoring points. The actual number of monitoring wells employed at most sites exceeded this minimum specification, with reported average numbers of monitoring points ranging from approximately 4 to 17 per site.

Methodologies for Characterization of Plume Length

The studies reviewed for this paper evaluated plume length based upon a site-by-site evaluation of groundwater monitoring data. Plume lengths were determined based upon measured site data by either of two methods: (1) hand-contouring of the measured concentrations on a scaled map of the sampling locations to the designated concentration limit, or (2) using an empirical or analytical method to estimate the plume length when the existing monitoring well network did not extend downgradient to the specified plume delineation limit. We refer the reader to the individual studies for method particulars.

The prior studies have employed a variety of concentration limits for the purpose of delineating plume length. In our review, based upon consideration of the action levels employed under many state regulatory programs in the United States, we have focused on MTBE and benzene plumes that have been delineated to a 5 or 10 µg/L (micrograms per liter) concentration limit. For benzene, many state agencies employ a 5 µg/L action level (corresponding to the Federal Primary Maximum Contaminant Level [MCL] for benzene in drinking water) for remediation of groundwater that is considered a potential drinking water source. MTBE action levels are generally higher and more variable among state agencies, with levels as low as 5 µg/L applied in California (Secondary MCL for MTBE; CDPH 2006). Evaluation of the plumes delineated to concentration limits of 5 or 10 µg/L provides a conservative basis for characterization of plumes subject to remedial action, as a number of states employ less stringent groundwater cleanup criteria, particularly for MTBE. TBA plumes were evaluated at a 10 µg/L (Shih et al. 2004) and 12 µg/L (Kamath et al. 2012) limit, consistent with California's drinking water notification level of 12 µg/L. Although these contour limits were not identical, the two datasets were combined in this study at an assumed level of 10 µg/L to increase the number of TBA sites, which have been evaluated in far fewer studies than either benzene or MTBE.

Methodologies for Classification of Plume Stability Conditions

As defined in prior publications (Rice et al. 1995; Newell and Connor 1998; ASTM 2010), the stability condition of an affected groundwater plume can be characterized according to the following stages (Figure 1):

1. *Expanding Plume*: The plume length and/or concentrations are increasing over time. Commonly observed immediately after the spill material reaches the groundwater and the dissolved chemicals are transported by moving groundwater.
2. *Stable/No Trend Plume*: The plume length and/or concentrations are not changing over time, indicating that the rate at which the dissolved chemical mass is entering the groundwater is balanced by natural attenuation mechanisms, such as dilution, dispersion, sorption, and biodegradation. "Stable" and "No Trend" were considered equivalent designations in a number of the studies. For those papers that distinguished between stable and no trend plumes, both designations indicate the plume concentration to be neither decreasing nor increasing with time; however, the "No Trend" designation entails a higher amplitude of variation (i.e., higher coefficient of variation) than the "Stable" designation.
3. *Shrinking Plume*: The plume length and/or concentrations are diminishing over time, indicating that the rate of mass release from the source area has reduced to the extent that the attenuation factors remove and disperse mass faster than it is entering the groundwater system.
4. *Non-Detect or Exhausted Plume*: In some cases, the affected groundwater zone may diminish to non-detectable levels in the groundwater, while at other sites, the process may slow or terminate in an "exhausted" condition, with trace concentrations of gasoline components remaining near the original source location.

At a given site, measurements can be conducted to determine if a plume is in an expanding, stable, shrinking, or exhausted condition (ASTM 2010). The plume stability condition can be characterized either on the *trend of the plume length* over time or the *trend of plume concentrations* over time in individual monitoring wells.

In the various studies identified on Table 1, the stability of the plume length over time was determined either by: (1) evaluating plume contour maps at different times to determine changes in the length of the plume, or (2) conducting statistical trend analyses on the concentrations measured at monitoring wells, typically located at the downgradient toe of the plume. For the purpose of analysis of plume concentration trends over time, various visual and statistical methods were employed to categorize trends as increasing, decreasing, or stable; we refer the reader to the individual studies for method particulars. While the reports used a variety of methods to characterize plume stability, the similarity of their results points to the consistency of MTBE, benzene, and TBA plume behavior across the various published studies and supports aggregating these results, as done in our study.

Statistical Review of Published Studies

To facilitate comparison of the typical lengths of MTBE, benzene, and TBA plumes at UST sites, overall median and 90th percentile plume lengths have been estimated as the weighted mean of the median and 90th percentile values reported in the individual studies. This calculation is based upon the understanding that, for sufficiently large datasets, order statistics, such as the median and 90th percentile values, are normally

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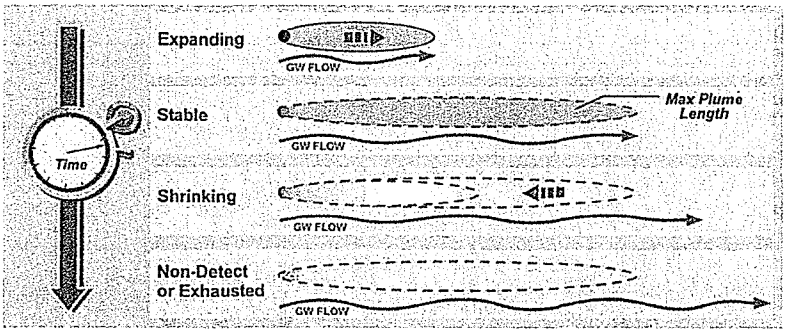

Figure 1. Schematic of groundwater plume stages at a typical UST site following termination of a spill or leak.

distributed, even if the underlying populations are not normally distributed. A weighted mean, based on the number of samples, has been employed to reduce the influence of smaller sample populations, which may exhibit greater variability in order statistics than larger sample populations. In other words, studies with more sites were weighted more heavily than studies with fewer sites. Similarly, the weighted mean approach was utilized to combine the results of the plume stability and concentration trend analyses.

The McHugh et al. (2013) study considered over 4000 UST sites to evaluate the overall trends of the maximum concentrations of MTBE, TBA, and benzene in groundwater over time. They did not address site-specific plume length or stability conditions, but provided important information regarding the net change in chemical concentrations over time in groundwater across these sites. Given the large number of sites they evaluated compared to the other published studies we reviewed, these results were not combined into the concentration trend summary statistics because they would overwhelm the weighted mean calculations; however, the results of McHugh et al. (2013) are compared with the summary statistics in this paper.

Limitations of These Studies

The authors of the various studies have identified possible limitations in their databases and, when feasible, have employed steps to mitigate the effects of these limitations on their findings. For example, a number of the studies note that, at many UST sites, the affected groundwater plumes are not fully delineated due to access restrictions or other limitations on the number and placement of groundwater sampling points. In addition, some authors note that, if the plume stability condition is not considered, comparison of older, stable plume lengths to younger, expanding plumes could be misleading, as the expanding plumes will not have achieved full length. Some authors also suggest that differences in MTBE and benzene plume lengths could reflect the effect of variable site conditions if the MTBE and benzene plumes are from different sites with distinctly different distributions of key attenuation parameters.

These limitations have been addressed by the authors of the 13 plume studies in a variety of manners. In some studies, plume lengths have been evaluated only for plumes with full delineation, based on a specified minimum number of monitoring points. In other studies, the maximum downgradient extent of the plume has been estimated based upon extrapolation of measured monitoring points, using the method described by Freeze and Cherry (1979) or Newell et al. (2002). Kamath et al. (2012) found this plume length estimation method to provide a reasonably conservative match to measured plume lengths on sites where both measurement and estimation methods were applied. Furthermore, six of the 10 studies that evaluate plume length compare benzene and MTBE plumes lengths from the same sites under the same hydrogeologic conditions.

In addition, 11 of the 13 studies have addressed the stability condition of the plumes, providing a basis for determining whether variations in plume age and associated stability condition (e.g., young expanding plume vs. older shrinking plume) could account for observed differences in the lengths of MTBE and benzene plumes. The vast majority of both benzene and MTBE plumes were found to be in a nonexpanding condition, showing that the concern of young versus old plumes is not a factor for plume length. The McHugh et al. (2013) study relied upon the maximum annual concentration of each plume constituent as a conservative basis to track plume concentration trends over time, based upon the consideration that the maximum concentration is likely near the source and therefore less likely to be affected by the extent of plume delineation or the change in the number of monitoring wells over time.

Findings of Previous Studies

Evaluation of Plume Lengths: MTBE, Benzene, and TBA

Statistical Distribution of MTBE, Benzene, and TBA Plume Lengths

As identified in Table 1, 10 of the 13 published studies address benzene and MTBE plume lengths, providing data on a total of 391 and 132 sites for MTBE plumes at 10

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and 5 µg/L delineation limits, respectively, and 826 and 165 sites for benzene plumes at 10 and 5 µg/L delineation limits, respectively. Two published studies also estimated plume lengths for TBA at a total of 108 sites (see Table S1 for tabulated values). Figure 2A and 2B provides side-by-side comparisons of the reported lengths of benzene and MTBE plumes from each of the 13 studies that evaluated plumes at a 5 and 10 µg/L plume delineation limit. Figure 3A and 3B summarize the weighted mean plume dimensions for MTBE, benzene, and TBA at delineation limits of 10 and 5 µg/L, respectively.

Consistency of MTBE and Benzene Plume Lengths Among Various Studies

The distributions of plume lengths shown in Figure 2 are relatively consistent among studies conducted in a variety of regions in the United States. For example, for plumes delineated to a 10 µg/L concentration limit (see Figure 2A), the median lengths of benzene plumes (826 sites) fall within the range of 101 to 185 feet, while the median lengths of MTBE plumes (391 sites) fall within a slightly narrower range of 110 to 178 feet (Table S1). Similarly, at this same delineation limit, the 90th percentile plume lengths range from 386 to 454 feet for MTBE (336 sites) and 261 to 480 feet for benzene (772 sites; Table S1).

The relatively narrow range of these plume length statistics across hundreds of UST sites suggests that plume lengths are consistent across a broad range of hydrogeologic settings and conditions. This observation is in agreement with prior studies that have found factors such as groundwater hydraulic conductivity and site lithology to be poor predictors of plume length among large numbers of plumes (Reid et al. 1999; Mace et al. 1997; Newell and Connor 1998; Shorr and Rifai 2002; Wilson 2003).

Comparable Lengths of MTBE and Benzene Plumes

The lengths of the benzene and MTBE plumes reported in the various studies are relatively comparable at both the median and 90th percentile levels, as illustrated by the weighted means of plume length statistics shown in Figure 3. The 90th percentile statistic is of particular interest in this regard as it incorporates the vast majority (90%) of gasoline plumes for which these data have been compiled. At a 10 µg/L delineation limit, the 90th percentile MTBE and benzene plume lengths are 400 feet (336 sites) and 345 feet (772 sites), respectively, showing MTBE plume lengths to be only 16% greater than those of benzene plumes (Figure 3A; Table S1).

At a delineation limit of 5 µg/L, the MTBE and benzene plume lengths are still found to be comparable, although with a moderately more pronounced difference; the 90th percentile MTBE (only evaluated in the Shih et al. 2004 study) and benzene plume lengths are 530 feet (96 sites) and 425 feet (165 sites), respectively, showing MTBE plumes to be 25% longer than benzene plumes (Figure 3B; Table S1). In general, the benzene plume lengths reported in the various studies are consistent with the study by Buscheck et al. (1996) that evaluated 62 UST sites in California and found that 85% of benzene plumes were less than 200 feet long. The Buscheck et al. (1996) study presented a range of plume lengths rather than a statistical distribution and thus could not be directly included in our statistical summary.

In absolute terms, the difference in these MTBE and benzene plume lengths ranges from only 55 to 105 feet (for 90th percentile plume lengths at the 10 and 5 µg/L delineation limits, respectively). The similar plume behavior of benzene and MBTE may reflect their biodegradation characteristics, as both compounds are biodegraded in aerobic groundwater and in most anaerobic geochemical settings.

Exceptionally Long Plumes

The maximum MTBE plume lengths identified in the studies addressed in this review paper generally fall in the range of 1000 to 1700 feet (see Figure 2). However, other publications have reported longer MTBE plumes (e.g., greater than 2000 feet) at individual UST sites (Weaver et al. 1996, 1999; ESTCP 2003; Thuma et al. 2001; McKelvie et al. 2007b). Consequently, while it is recognized that such exceptionally long MTBE plumes do exist, the small number of such plumes is consistent with the statistical distribution observed in the 13 studies, where MTBE plumes greater than 1400 feet in length correspond to less than 1% of the plume population. Incorporation of this small number of exceptionally long MTBE plumes into the data sets addressed in our review would not affect the weighted means of the median and 90th percentile plume lengths presented on Figure 3.

Lengths of TBA Plumes Compared to MTBE and Benzene Plumes

Two studies addressed the behavior of TBA plumes in addition to benzene and MTBE (Kamath et al. 2012; Shih et al. 2004) for a total of 108 sites. The weighted mean results from these studies (Figure 3A) indicate that the 90th percentile TBA plume length (420 feet at 10 µg/L; Table S1) is 5% greater than the 90th percentile MTBE plume determined from these and other studies. Similarly, the median TBA plume from the two studies at 10 µg/L is 15% longer than the median MTBE plume determined from a larger number of studies. However, the two studies that addressed TBA (Shih et al. 2004; Kamath et al. 2012) found TBA plume lengths to be comparable to benzene and MTBE plume lengths, with TBA plume lengths falling in between benzene and MTBE plume lengths. Shih et al. (2004) calculated 90th percentile values of the benzene, MTBE, and TBA plume lengths to be 341, 531, and 433 feet, respectively. Kamath et al. (2012) calculated the 90th percentile values of the measured and estimated plume lengths for benzene, MTBE, and TBA to be 356, 454, and 366 feet, respectively. Taken together, the aggregated results and individual studies suggest that TBA plume lengths are similar to MTBE and benzene plumes.

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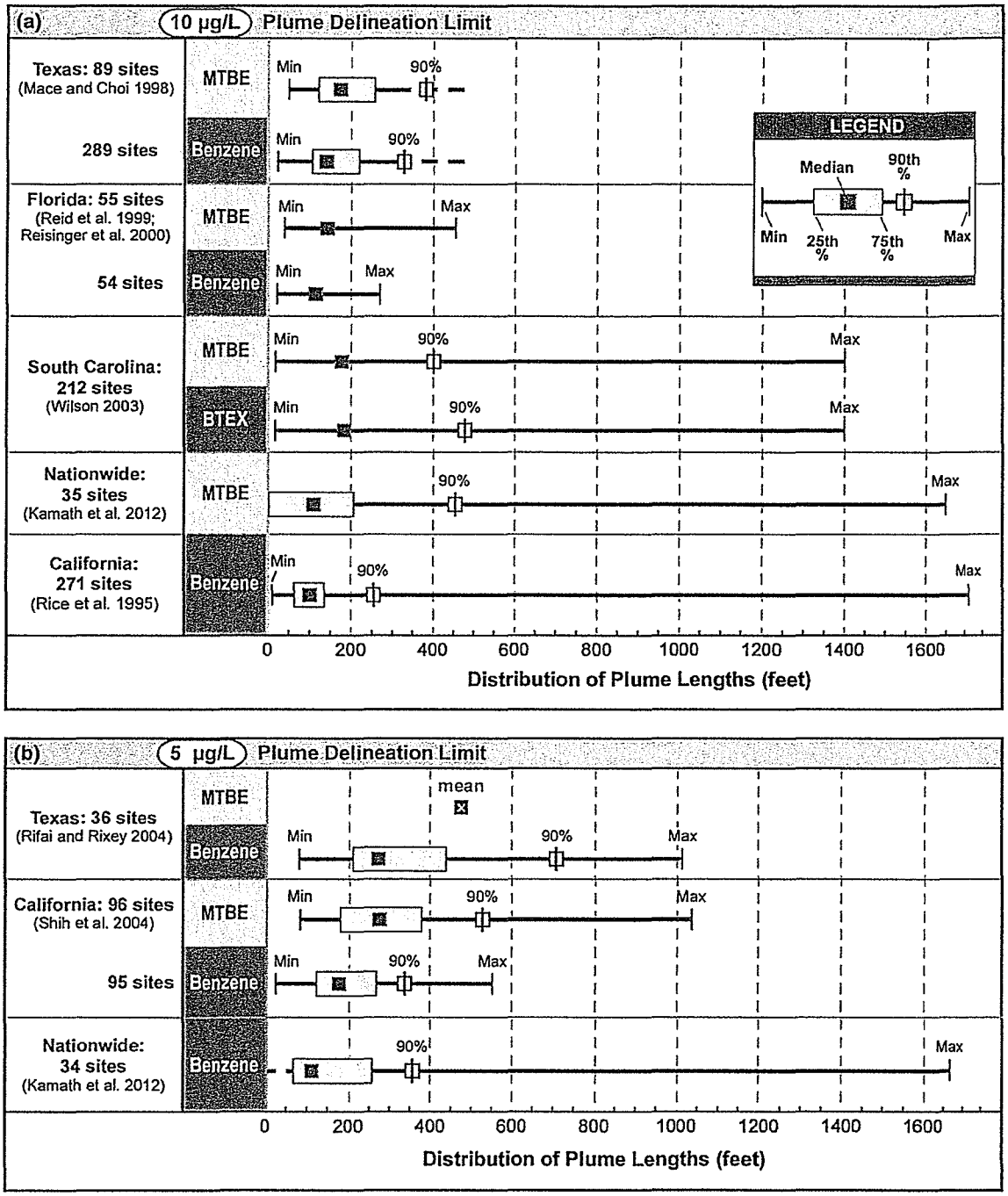

Figure 2. Summary of surveys of plume lengths in groundwater: MTBE versus benzene.

Evaluation of Plume Stability Conditions: MTBE, Benzene, and TBA

Stability Condition of Plume Lengths Over Time

Five studies have evaluated the stability of plume length over time for a combined 122 sites for MTBE plumes, 566 sites for benzene plumes, and 34 sites for TBA plumes (Reid et al. 1999; Reisinger et al. 2000; Kamath et al. 2012; Shorr and Rifai 2002; Rice et al. 1995; Mace et al. 1997). For each stability category, we have computed a weighted mean of the percentage of sites falling into that category. Table S2 reports these weighted mean values, as well as the values reported in each study, rounded to the nearest whole number for consistency.

Figure 4 compares the combined plume length trend distributions for MTBE, benzene, and TBA. These studies consistently found that the vast majority of both MTBE and benzene plume lengths are not increasing in length over time. For MTBE plumes, the percent of plume lengths found to be stable, no trend, decreasing, or

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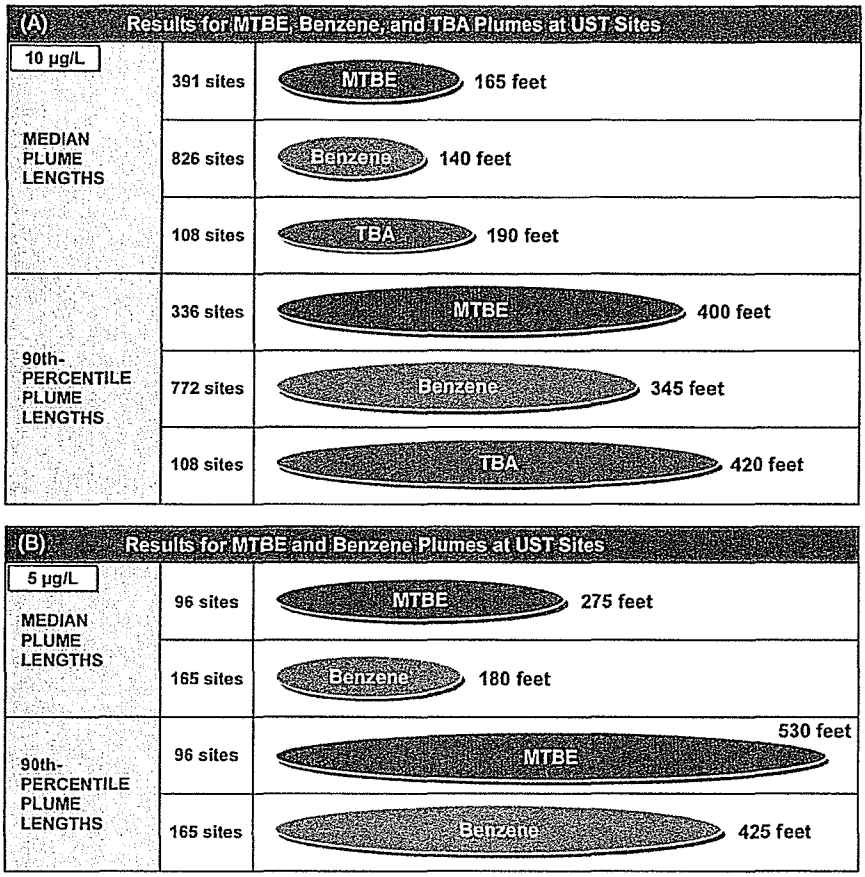

Figure 3. Weighted means of median lengths and 90th percentile lengths of MTBE, TBA, and benzene plumes. (A) Weighted means of plume lengths defined by 10 µg/L concentration limit. (B) Weighted means of plume lengths defined by 5 µg/L concentration limit. Lengths are estimated as the weighted mean of median and 90th percentile plume length values reported in various scientific surveys, rounded to the nearest 5 feet, for plumes delincated to a 10 µg/L concentration limit and 5 µg/L concentration limit. Data have been compiled for MTBE, benzene, and TBA plumes in groundwater underlying UST sites across the nation (see Table S1 for studies used to compile these summary lengths).

exhausted ranges from 90 to 96% among three studies, with the weighted mean percentage of plumes that are nonincreasing equal to 93%. Similarly, for benzene plumes, among four studies, the percent of plume lengths found to be stable, no trend, decreasing, or exhausted ranges from 92 to 97%, with the weighted mean percentage of plumes found to be nonincreasing equal to 94%. The overall percentages of plume lengths observed to be increasing over time is 6% for both MTBE plumes and benzene plumes.

The study by Kamath et al. (2012) specifically addressed the presence of detached MTBE plumes, that is, displacement of the plume mass downgradient from the original source point. They found this condition to occur at only 5% of MTBE sites (2 of 41 sites). Furthermore, these detached plumes were observed to be decreasing in area over time (Kamath et al. 2012). For the purposes of our analysis, the detached plumes were not considered as either increasing or nonincreasing.

Figure 4 also displays the trend distributions for TBA, as determined by Kamath et al. (2012). These data show that the majority of TBA plumes (68%) are stable or shrinking in length, while 26% are increasing. The percentage of nonincreasing plumes for TBA is lower than for benzene and MTBE (94 and 93%, respectively, are not increasing in length), which may reflect the temporary build-up of TBA concentrations in groundwater following biodegradation of MTBE (Kamath et al. 2012).

Concentration Trends in Individual Monitoring Wells Over Time

Seven studies have evaluated concentration trends of benzene and MTBE in individual wells over time (Mace and Choi 1998; Stevens et al. 2006; Tarr and Galonski 2007; Kamath et al. 2012; Buscheck et al. 1996; Rice et al. 1995; Mace et al. 1997), for a combined 938 wells for MTBE and 905 wells for benzene. Kamath et al. (2012) evaluated TBA concentration trends over time in 241 wells. Figure 5 shows the concentration trend distributions for MTBE, benzene, and TBA, with the percentage of plumes falling into each stability category calculated as weighted means among the seven

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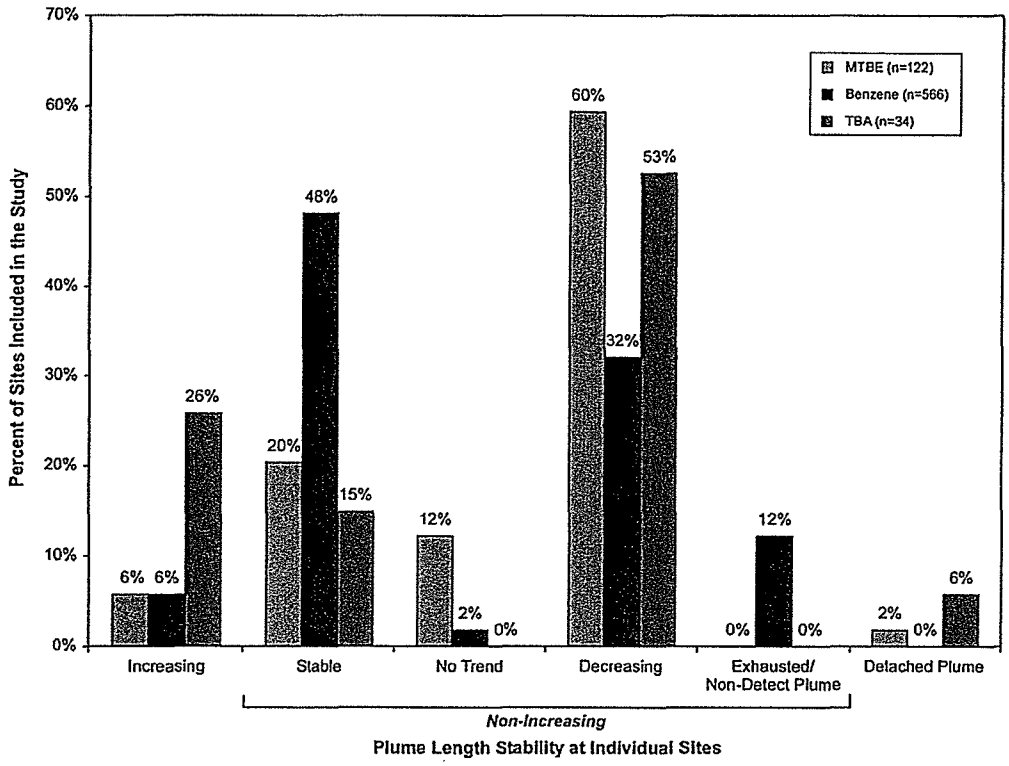

Figure 4. Comparison of plume length stability conditions for MTBE, benzene, and TBA plumes at UST sites. Data have been compiled for MTBE, benzene, and TBA plumes in groundwater underlying UST sites across the nation (see Table S2 for studies used to compile these stability percentages).

studies (see Table S3 for detailed data). In addition to these studies, McHugh et al. (2013) evaluated overall plume concentration trends for MTBE, benzene, and TBA for over 4000 sites in California. The McHugh study addressed the net change in the maximum plume concentrations at each site but did not characterize the plume stability condition per se in the same manner as the other studies; consequently, the weighted means shown on Figure 5 do not include the McHugh et al. (2013) results.

Figure 5 compares the combined distributions of well concentration trends for MTBE (938 wells), benzene (905 wells), and TBA (241 wells). As shown, MTBE and benzene again exhibit similar distributions, with the vast majority of wells showing nonincreasing concentrations over time for both MTBE (91%) and benzene (92%). However, unlike the plume length distribution, a higher percentage of wells exhibit decreasing concentrations for benzene (63%) than for MTBE (45%). Nevertheless, the combined percentage of stable, decreasing, or no trend wells is again comparable for the two compounds, corresponding to 80% of wells for MTBE and 84% of wells for benzene.

Evaluation of TBA concentration trends by Kamath et al. (2012) found stability condition distributions to be roughly comparable to those of benzene and MTBE, with 86% of the wells demonstrating nonincreasing trends. The moderately higher percentage of wells with increasing TBA concentration trends (14%, compared to 9% and 8% for MTBE and benzene, respectively) may reflect the production of TBA as a by-product of MTBE biodegradation, resulting in temporary replenishment of TBA concentrations until the MTBE source is depleted. Under this scenario, TBA concentrations in turn decrease as the MTBE source mass diminishes and the TBA itself is biodegraded.

Two studies specifically addressed MTBE plume conditions before and after the end of MTBE use as a gasoline additive in Connecticut (Stevens et al. 2006) and New Hampshire (Tarr and Galonski 2007). In both studies, in the 2 years following termination of MTBE use, the percentage of monitoring wells displaying a *decreasing* MTBE concentration trend was observed to increase. In Connecticut, Stevens et al. (2006) found that 93% of the 83 monitoring wells evaluated showed decreasing concentrations of MTBE 2 years after termination of MTBE use. By pooling the monitoring wells across 22 sites, they also determined that 55% of the sites showed a statistically significant decrease in MTBE concentrations between pre- and post-ban data (90th confidence level); only 5% (1 site) showed a statistically significant increase in MTBE concentrations. A similar study of 78 wells in New Hampshire (Tarr and Galonski 2007) reported that, after termination of MTBE use, 85% of monitoring wells exhibited decreasing concentrations, compared to decreasing concentrations at 68% of monitoring wells

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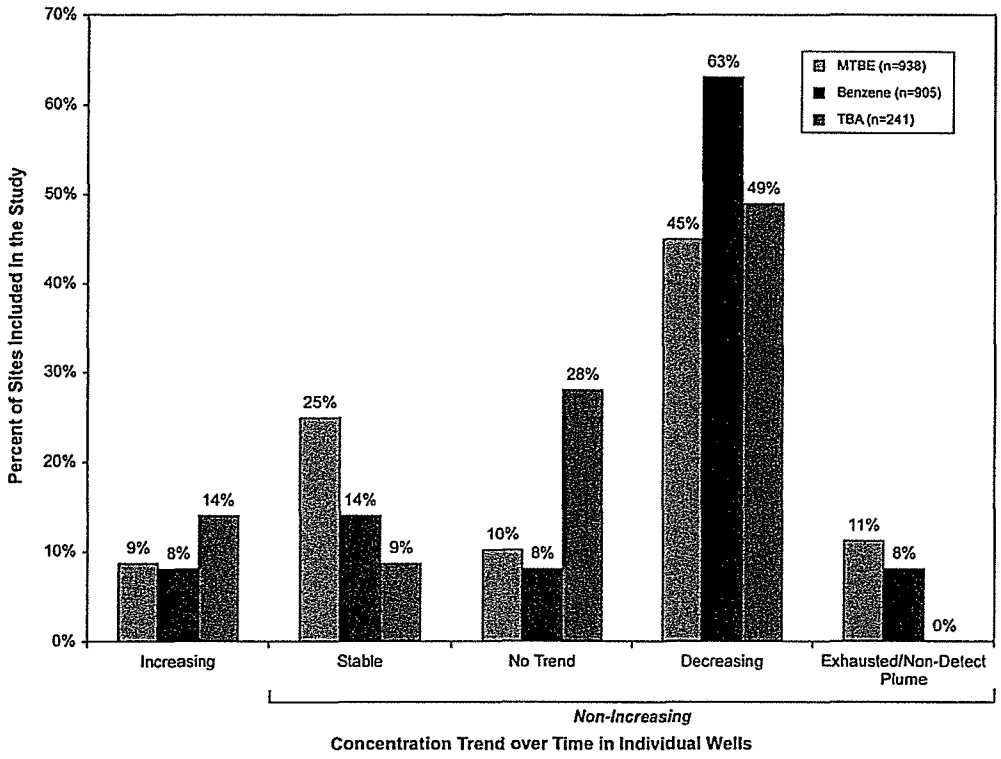

Figure 5. Comparison of concentration versus time trends for MTBE, benzene, and TBA in monitoring wells at UST sites. Data have been compiled for MTBE, benzene, and TBA concentration trends in groundwater underlying UST sites across the nation (see Table S3 for studies used to compile these concentration trends).

prior to the termination of MTBE use in gasoline. These studies demonstrated the decrease in MTBE concentrations with time following termination of MTBE use in these states.

McHugh et al. (2013) compiled data from over 4000 UST sites from the California GeoTracker database to evaluate the overall trends of benzene, MTBE, and TBA concentrations in groundwater over time. These monitoring data showed a large decrease in the groundwater concentrations of gasoline constituents over the period of 2001 to 2011 (85% decrease for benzene, 96% for MTBE, and 87% for TBA), measured as the change in the median of the maximum site concentrations over time. In addition, records of the sites for which continuous monitoring records were available for the full 10-year period (benzene: 1128 sites; MTBE: 1109 sites, TBA: 816 sites) showed benzene and MTBE levels to decrease continuously over this time period, while the maximum concentrations of TBA increased moderately over the period of 2001 to 2004 and then decreased from 2005 to 2011. The study found that the temporary build-up and subsequent decrease of TBA concentrations could be closely matched by a sequential first-order degradation model, which accounted for the generation of TBA as a product of MTBE degradation, followed by the biodegradation of the TBA itself (McHugh et al. 2013).

Conclusions

In this paper, we have combined the results of 13 previously published studies that surveyed the length and stability condition of affected groundwater plumes associated with releases of gasoline fuels from USTs at numerous service station facilities. These studies combined have addressed over 500 plumes for MTBE, over 1300 plumes for benzene, and 108 plumes for TBA, plus evaluation of concentration trends of all three gasoline constituents over a 10-year period for over 4000 UST sites in California. Employing a variety of approaches, these studies arrive at similar findings with regard to plume length and stability, which suggests that, in combination, these data and the related statistical parameters presented in this review paper provide a reliable characterization of benzene, MTBA, and TBA plume behavior at the majority of UST sites across the United States. Key findings regarding the statistical distribution of plume lengths and plume stability conditions at UST sites include the following:

1. *Comparison of MTBE and Benzene Plumes.* The plume delineation studies show MTBE and benzene plumes to be of comparable length at most sites. For example, at a 10 µg/L delineation limit, the 90th percentile MTBE and benzene plume lengths are 400 feet (336 sites) and 345 feet (772 sites), respectively, a relative difference of 16%. Similarly, at a 5 µg/L delineation limit, the 90th percentile MTBE and benzene plume lengths are

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530 feet (96 sites) and 425 feet (165 sites), respectively, a relative difference of 25%, although these values should be considered tentative due to smaller numbers of wells and only one study for MTBE. The vast majority of wells for both MTBE (91%) and benzene (92%) exhibit nonincreasing concentrations over time (i.e., stable, no trend, decreasing, or exhausted), and plume lengths also are predominantly nonincreasing over time for MTBE (93%) and benzene (94%). Consequently, reported plume lengths for benzene and MTBE are likely indicative of their maximum future lengths, as the plumes are generally not increasing in size and concentration.

2. *TBA Plumes Compared to MTBE and Benzene Plumes.* TBA plumes have been found to be of comparable length to benzene and MTBE plumes, with the majority of TBA plumes also nonexpanding (68%), although at a lower percentage than observed for MTBE or benzene plumes (Kamath et al. 2012). At over 4000 sites evaluated, TBA concentration trends over time showed an initial increase, followed by a decreasing concentration at rates comparable to those observed for MTBE and benzene (McHugh et al. 2013).
3. *Consistency Among Various Studies:* The various plume studies, conducted in different geographic regions and in a variety of hydrogeologic regimes, have found plume length statistics to fall into a relatively narrow range, suggesting that hydrogeologic conditions may be less important than other factors (such as the spill volume and biodegradation effects) in defining plume behavior, as has been observed in these and other studies (Reid et al. 1999; Mace et al. 1997; Newell and Connor 1998; Shorr and Rifai 2002; Wilson 2003). Rather, the similar biodegradation characteristics of MTBE and benzene, both of which are degradable in aerobic and most anaerobic geochemical settings, may be responsible for the comparable dimensions and stability conditions of these plumes.

Supporting Information

Additional Supporting Information may be found in the online version of this article:

Appendix S1. Review of Quantitative Surveys of the Length and Stability of MTBE, TBA, and Benzene Plumes in Groundwater at UST Sites.

Table S1. Statistical plume length data from the literature for MTBE, benzene, and TBA

Table S2. Plume stability results for MTBE, benzene, and TBA

Table S3. Concentration trend results for MTBE, benzene, and TBA

Table S4. Results from Stevens et al. (2006) analysis

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Ground Water Monitoring&Remediation

FORUM

A Comparison of Benzene and Toluene Plume Lengths for Sites Contaminated with Regular vs. Ethanol-Amended Gasoline

by G.M.L. Ruiz-Aguilar, K. O'Reilly, and P.J.J. Alvarez

Abstract

This article describes various statistical analyses of plume-length data to evaluate the hypothesis that the presence of ethanol in gasoline may hinder the natural attenuation of hydrocarbon releases. Plume dimensions were determined for gasoline-contaminated sites to evaluate the effect of ethanol on benzene and toluene plume lengths. Data from 217 sites in Iowa (without ethanol; set 1) were compared to data from 29 sites in Kansas that were contaminated by ethanol-amended gasoline (10% ethanol by volume; set 2). The data were log-normally distributed, with mean benzene plume lengths (± standard deviation) of 193 ± 135 feet for set 1 and 263 ± 103 feet for set 2 (36% longer). The median lengths were 156 feet and 263 feet (69% longer), respectively. Mean toluene plume lengths were 185 ± 131 feet for set 1 and 211 ± 99 feet for set 2 (14% longer), and the median lengths were 158 feet and 219 feet (39% longer), respectively. Thus, ethanol-containing BTEX plumes were significantly longer for benzene ($p < 0.05$), but not for toluene. A Wilcoxon signed rank test showed that toluene plumes were generally shorter than benzene plumes, which suggests that toluene was attenuated to a greater extent than benzene. This trend was more pronounced for set 2 (with ethanol), which may reflect that benzene attenuation is more sensitive to the depletion of electron acceptors caused by ethanol degradation. These results support the hypothesis that the presence of ethanol in gasoline can lead to longer benzene plumes. The importance of this effect, however, is probably site-specific, largely depending on the release scenario and the available electron acceptor pool.

Introduction

The use of ethanol as a gasoline additive is likely to increase in the near future as a substitute for the oxygenate MtBE (Powers et al. 2001a, 2001b). Regulatory renewable fuel requirements will also lead to additional ethanol use. Therefore, it is important to understand how ethanol affects the fate and transport of hydrocarbons in ground water. Previous laboratory studies have shown that the presence of ethanol could have undesirable effects on the biodegradation of BTEX (i.e., benzene, toluene, ethylbenzene, and *ortho-*, *para-*, and *meta-xylene*). Specifically, ethanol is often degraded preferentially and contributes to the depletion of nutrients and electron acceptors (e.g., O_2) that would otherwise be available to support BTEX biodegradation (Corseuil et al. 1998; da Silva and Alvarez 2002; Ruiz-Aguilar et al. 2002). In addition, high ethanol concentrations (>10%), which could occur initially at the source, could also enhance BTEX solubility and decrease sorption-related retardation, enhancing hydrocarbon migration (da Silva and Alvarez 2002; Powers et al. 2001b; Rao et al. 1990). These findings suggest that ethanol may hinder BTEX natural attenuation, which could result in longer BTEX plumes and a greater risk of exposure. Nevertheless, little is known about the magnitude and significance of this potential plume-elongation effect.

Plume dimensions and stability are important parameters to characterize for risk management because they determine the area of influence and the potential duration of exposure. Several investigators have developed mathematical models for predicting the effect of ethanol (added to gasoline at 10% by volume) on BTEX plume length (Table 1). These screening models predict that ethanol would increase the maximum BTEX plume length (i.e., when steady state is reached) by anywhere from ~10% to 150%. Whereas these models provide valuable insight into the potential ground water impacts of ethanol in gasoline, they are based on simplifying and influential assumptions and have not yet been validated with field data. Therefore, there is a need for empirical evaluations of the effect of ethanol on BTEX plume length.

This article describes statistical analyses of plume-length data to evaluate the general hypothesis that the presence of ethanol in gasoline hinders the natural attenuation of hydrocarbons, resulting in longer BTEX plumes compared to reg-

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Table 1
Modeling Efforts to Assess the Effect of Ethanol on Benzene Plume Length

Citation	Conceptual Model	Increase in Benzene Plume Length
Heermann and Powers (1996)	2-D transport from a pool of gasoline. Focus on cosolvency and interface mass transfer. Biodegradation not included.	≤ + 10% (for xylene not benzene)
Malcom Pirnie Inc. (1998)	Steady-State, 2-D transport from a gasoline pool. First-order decay of benzene when C_{EtOH}<3 mg l^{-1}. First-order decay of ethanol.	+ 17-34 %
McNab et al. (1999)	3-D aqueous transport. Continuous slow release of gasoline (up to 3 gpd) to a growing NAPL pool at the water table. First-order decay of ethanol and benzene. Benzene degradation rate constant defined by inverse correlation to BOD conc. at the source.	~ + 100 %
Molson et al. (2002)	3-D transport from a gasoline source at the water table at a residual saturation. Aerobic decay with O_2 as the sole electron acceptor quantified by Monod kinetics. Microbial growth incorporated.	+ 10–150 %

ular-gasoline releases. This article also addresses the likelihood that ethanol would hinder the natural attenuation of benzene to a greater extent than toluene due to differences in their biodegradability under the strictly anaerobic conditions induced by ethanol.

Methodology

Plume Data

Two sets of ground water data were collected from about 600 gasoline-contaminated sites. One of the data sets (set 1) was obtained from the Iowa Department of Natural Resources, Underground Storage Tanks Section (IDNR TIER-2 database). This database contained no information about the presence of ethanol; thus, the data were screened to exclude sites with suspected contamination by ethanol-amended gasoline. A review of site investigation reports and telephone surveys were conducted for this purpose. Many of the set 1 sites were also discarded because of insufficient data to plot the required plume contours (e.g., plumes not bracketed by downgradient wells) or because contamination resulted from multiple sources (e.g., overlapping plumes). Therefore, only 217 Iowa sites (contaminated with regular gasoline) were included in set 1. The other data set (set 2) was obtained from the Kansas Department of the Environment and Health (KDEH), and corresponded to 29 sites contaminated with gasohol (i.e., gasoline with 10% ethanol by volume). Site investigation reports did not show salient differences between the two data sets regarding release and response scenario (e.g., amount released, age of spill, or remedial activities). None of these sites reported MTBE contamination. In addition, MTBE is unlikely to affect BTEX or ethanol degradation in contaminated aquifers (da Silva and Alvarez 2002; Deeb et al. 2001; Ruiz-Aguilar et al. 2002). Thus, MTBE was not a factor in this study.

Determination of Plume Lengths

Benzene and toluene plume lengths were determined by contouring data from monitoring wells (which were typically separated by about 100 feet), using a computer algorithm based on Hardy's multiquadric method for plotting two-dimensional concentration contours (Saunderson 1994). This algorithm was incorporated into the Iowa RBCA TIER2 Interpolation Program version 2.17, which interfaces with the IDNR TIER-2 database. This approach eliminated subjectivity associated with drawing the plumes by hand. Selected computer-generated plumes were compared to the corresponding hand-drawn plumes for validation purposes. Plume lengths were then measured as the longest distance between the identified source and the 5 µg/L contour, which corresponds to the drinking water standard for benzene.

Statistical Analyses

Plume length data were imported into Minitab (version 13.1, State College, Pennsylvania), which was used to calculate population statistics for each data set. These statistics included the population mean, standard deviation, median, maximum, and minimum. Distribution analyses were performed using the Anderson-Darling test for log-normality at the 95% significance level (Freedman et al. 1998). A Kruskal-Wallis test was also performed to determine whether BTEX plumes were significantly longer in set 2 (with ethanol) than in set 1 (without ethanol). This nonparametric test, which ranks plume lengths from low to high and then analyzes the ranks (Lehmann 1975), is very robust to test differences in population medians (Johnson and Mizoguchi 1978). Two-sample

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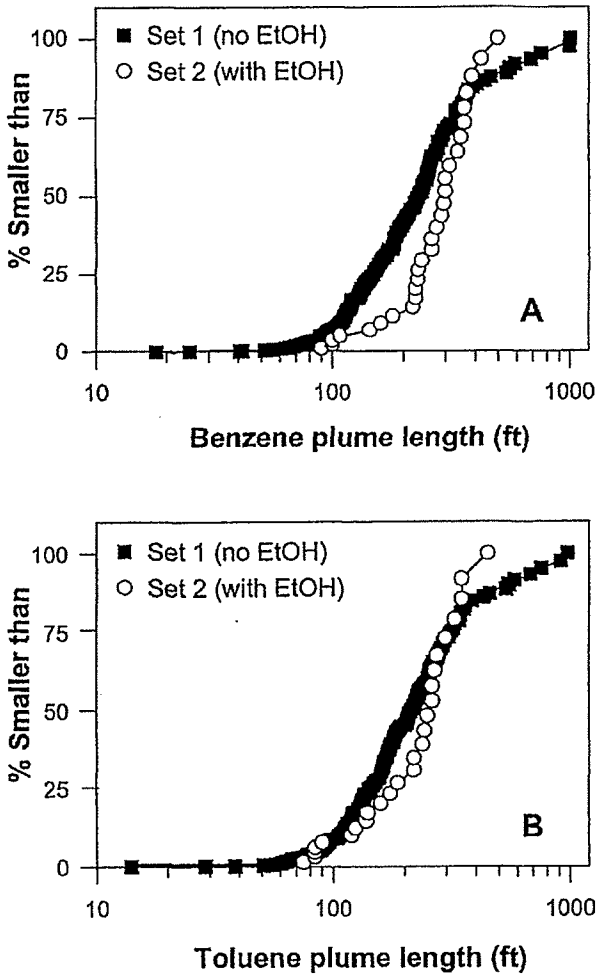

Figure 1. Cumulative distribution of (a) benzene and (b) toluene plume lengths for set 1 (Iowa data, without ethanol) and set 2 (Kansas data, with ethanol).

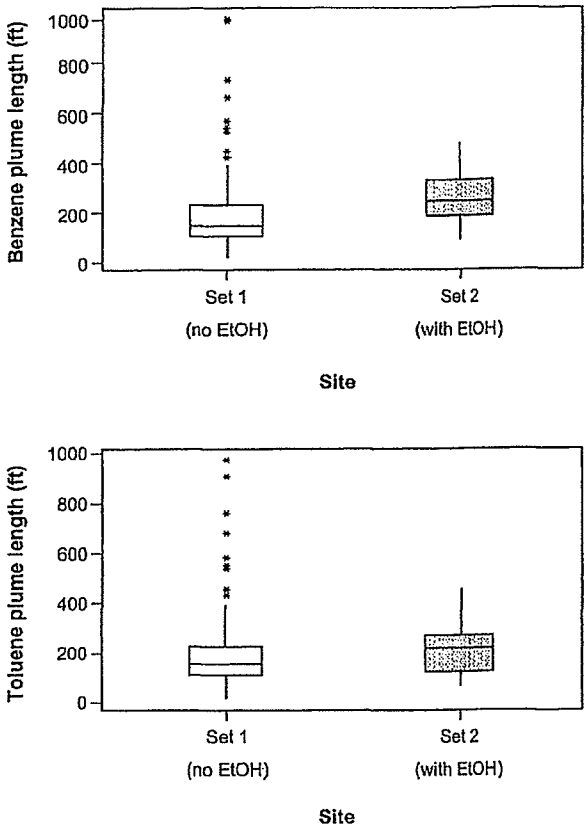

Figure 2. Box plots of the benzene and toluene plume length data. The line across the box represents the median. The bottom and top of the box represent the first and third quartiles (Q1 and Q3). The whiskers extend to the lowest and highest observations inside the region defined by Q1 −1.5(Q3–Q1) and Q3 +1.5(Q3–Q1). Individual points with values outside these limits (outliers) are plotted with asterisks.

Student's t-tests (Freedman et al. 1998) were also performed to determine if average benzene and toluene plume lengths were significantly different between the two data sets. Finally, a Wilcoxon signed-rank test was performed to test if benzene plumes were generally longer than toluene plumes, and to determine if this trend was statistically significant.

Results and Discussion

Plume length data were log-normally distributed ($p = 0.275$ for benzene and 0.394 for toluene) according to an Anderson-Darling test. The cumulative distribution of the plume lengths shows that benzene plumes were generally longer for set 2 (with ethanol) than for set 1 (without ethanol) (Figure 1a). For example, 92% of benzene plumes in set 2 were longer than 150 feet, compared to only 74% for set 1. The same trend was observed for plumes longer than 250 feet. In this case, 69% of benzene plumes in set 2 were longer than 250 feet, compared to 45% for set 1. However, none of the 29 plumes in set 2 was longer than 500 feet, compared to 12% of the 217 plumes in set 1. This trend reversal reflects that set 1 was a much larger data set and contained both the smallest and largest plumes. Note that these longer plumes are statistical outliers, as determined by the Tukey method (Tukey 1977; Figure 2). Similar results were observed for toluene, although the apparent elongation effect of ethanol was not as pronounced (Figure 1b).

Box plots corroborated that BTEX plumes with ethanol (set 2) were generally longer than those from set 1, without ethanol (Figure 2). A Kruskal-Wallis test showed that the median length of benzene plumes was significantly longer for set 2 than for set 1 (263 versus 156 ft $p < 0.001$; Figure 3). On the other hand, the difference for toluene plumes was not statistically significant (219 versus 158 feet, $p = 0.073$). Note that the median length for benzene and toluene plumes without ethanol is within 15% of that reported by Newell and Connor (1998) (i.e., 132 feet). This value was obtained from a compilation of four surveys (Groundwater Services 1997; Mace et al. 1997; Rice et al. 1995; Newell and Connor 1990), covering a total of 604 sites presumably contaminated with gasoline without ethanol.

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Table 2
Summary Statistics for Benzene and Toluene Plume Length Data

Parameters	Compound: Benzene Set 1 (no EtOH)	Benzene Set 2 (with EtOH)	Toluene Set 1 (no EtOH)	Toluene Set 2 (with EtOH)
Number of sites	217	29	211	26
Minimum (ft)	18	90	14	75
Median (ft)	156	263	158	219
Maximum (ft)	1005	500	973	450
Mean (ft) ± Std. deviation	193 ± 135	263 ± 103	185 ± 131	211 ± 99
p – value	0.002*		0.243	

*Data were significantly different ($p < 0.05$) as determined by a two-sample student's t-test.

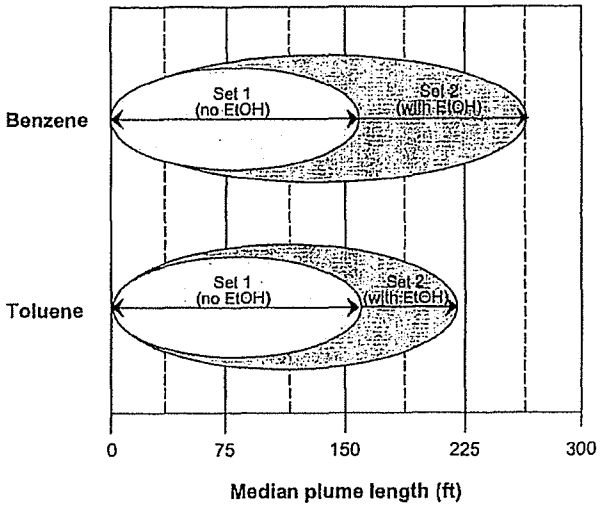

Figure 3. Median length of set 1 (Iowa data, without ethanol) versus set 2 plumes (Kansas data, with ethanol). The difference was significantly different for benzene ($p < 0.001$), but not for toluene ($p = 0.073$), as established by a Kruskal–Wallis test.

Table 2 summarizes the central tendencies of benzene and toluene plume lengths. The average length of BTEX plumes with ethanol was higher than the corresponding value without ethanol (by 36% or 70 feet for benzene, and by 17% or 26 feet for toluene). Similar to the Kruskal-Wallis test, two-sample student's t-tests showed that these differences were statistically significant for benzene ($p = 0.002$) but not for toluene ($p = 0.243$). Whereas an increase of 70 feet in the average length of benzene plumes is statistically significant, this does not imply that the corresponding increase in public health risk will also be significant.

Benzene plumes were generally longer than toluene plumes, and this difference was more pronounced for the data set with ethanol (set 2). Specifically, the average benzene plume was 20% longer than the average toluene plume for set 2, compared to a 4% difference for the data set without ethanol (set 1). A Wilcoxon signed rank test showed that both of these

Table 3
Predominant Lithologic Characteristics of the Sites Considered in This Study

Material	Percent of Sites Where Material was Dominant: Set 1 (no ethanol)	Set 2 (with ethanol)
Clay	40	31
Limestone	4	0
Mixed	28	34
Sand	15	23
Shale	0	3
No data available	13	9

Table 4
Benzene Plume Length Statistics, Segregated by Dominant Type of Aquifer Material*

Dominant Aquifer Material	Number of sites	Benzene Plume Length: Average (ft)	Standard Deviation (ft)
Set 1 (no ethanol, Iowa)			
Clay	85	184	107
Limestone	8	155	105
Mixed	59	172	84
Sand	35	249	215
No data available	31	199	164
Set 2 (with ethanol, Kansas)			
Clay	8	242	89
Mixed	9	283	105
Sand	8	250	92
Shale	1	288	0
No data available	3	292	201

*For a given set, differences between categories were not significantly different.

differences were statistically significant ($p < 0.05$), which suggests that the potential elongating effect of ethanol could be more pronounced for benzene than for toluene (Figure 3). Benzene, which is the most toxic of the BTEX compounds, is relatively recalcitrant under the anaerobic conditions exacerbated by an ethanol-driven consumption of electron acceptors (Corseuil et al. 1998; Heider et al. 1998). Toluene is more frequently reported to degrade under anaerobic conditions. The methyl group in toluene is electrophilic and facilitates nucleophilic attack by water (Alvarez and Vogel 1995) or by anaerobic catabolic enzymes such as benzyl succinate synthase (Heider et al. 1998). This facilitates the initiation of degradation without the action of an oxygen requiring oxygenase enzyme. The higher biodegradability of toluene and its higher tendency than benzene to be retarded by sorption (Alvarez et al. 1998) are conducive to shorter plumes.

As is commonly the case for many epidemiological studies, it should be pointed out that the inferences of our statistical analysis are constrained by other factors besides the presence of ethanol that could influence plume length. Although Iowa and Kansas have a similar geologic history, unaccounted confounding factors include hydrogeologic and geochemical characteristics that control the rates of advection,

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dilution, sorption, volatilization, and biodegradation, as well as site heterogeneity and the release and response scenarios. Unfortunately, logistical and cost constraints often preclude the quantification of these processes at gasoline-contaminated sites. Therefore, these factors could not be included in our statistical analysis, with the exception of considering borehole data that permitted the categorization of the sites according to the dominant type of aquifer material (Table 3). These data suggest that a slightly higher percentage of sites in set 1 were less permeable than in set 2 (i.e., 46% vs. 33% were clay-rich and 19% vs. 24% were sandy). Although plumes were generally longer in sandy than in clay-rich aquifers, the standard deviations for a given lithologic category were relatively large, as illustrated for benzene plumes (Table 4). Therefore, the dominant type of aquifer material did not have a statistically significant effect on plume length. This finding is consistent with previous plume studies (Rice et al. 1995; Mace et al. 1997). This does not mean that the type of aquifer material (and its associated permeability and sorption capacity) does not affect plume length. Rather, it implies that other factors that were not quantified could be more influential.

In spite of the many potentially confounding factors associated with field data, it should be recognized that (1) such confounding factors were likely randomized by the relatively large data set considered; (2) Kansas plumes were longer even though temperatures tend to be slightly warmer in Kansas than in Iowa, which is conducive to faster biodegradation; and (3) the results of the statistical analysis show a strong consistency of association with experimental and modeling results and with biologically plausible explanations discussed previously. Therefore, this work supports the hypothesis that the presence of ethanol in gasoline can lead to longer benzene plumes. These results should provide a basis for further field studies involving controlled gasohol releases to improve our gasohol-release risk assessment capabilities.

Conclusion

This study investigated the potential magnitude and significance of BTEX plume elongation by the presence of ethanol in gasoline. There was a statistically significant difference in mean benzene plume lengths between gasoline- versus gasohol-contaminated sites. The mean toluene plume lengths were not significantly different. Ethanol apparently hinders the biodegradation of benzene to a greater extent than toluene because benzene is less degradable under strictly anaerobic conditions that are exacerbated by the depletion of electron acceptors during ethanol degradation. The significance of this effect, however, is probably site-specific, largely depending on the release scenario and the available electron acceptor pool.

Acknowledgments

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EXHIBIT
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Evaluation of the Impact of Fuel Hydrocarbons and Oxygenates on Groundwater Resources

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The environmental behavior of fuel oxygenates (other than methyl *tert*-butyl ether [MTBE]) is poorly understood because few data have been systematically collected and analyzed. This study evaluated the potential for groundwater resource contamination by fuel hydrocarbons (FHCs) and oxygenates (e.g., *tert*-butyl alcohol [TBA], *tert*-amyl methyl ether [TAME], diisopropyl ether [DIPE], ethyl *tert*-butyl ether [ETBE], and MTBE) by examining their occurrence, distribution, and spatial extent in groundwater beneath leaking underground fuel tank (LUFT) facilities, focusing on data collected from over 7200 monitoring wells in 868 LUFT sites from the greater Los Angeles, CA, region. Excluding the composite measure total petroleum hydrocarbons as gasoline (TPH_G), TBA has the greatest site maximum (geometric mean) groundwater concentration among the study analytes; therefore, its presence needs to be confirmed at LUFT sites so that specific cleanup strategies can be developed. The alternative ether oxygenates (DIPE, TAME, and ETBE) are less likely to be detected in groundwater beneath LUFT facilities in the area of California studied and when detected are present at lower dissolved concentrations than MTBE, benzene, or TBA. Groundwater plume length was used as an initial indicator of the threat of contamination to drinking water resources. Approximately 500 LUFT sites were randomly selected and analyzed. The results demonstrate MTBE to pose the greatest problem, followed by TBA and benzene. The alternative ether oxygenates were relatively localized and indicated lesser potential for groundwater resource contamination. However, all indications suggest the alternative ether oxygenates would pose groundwater contamination threats similar to MTBE if their scale of usage is expanded. Plume length data suggest that in the absence of a completely new design and construction of the underground storage tank (UST) system, an effective management strategy may involve placing greater emphasis on UST program for ensuring adequate enforcement and compliance with existing UST regulations.

1. Introduction

The production and use of fuel oxygenates, particularly methyl *tert*-butyl ether (MTBE), have increased dramatically since the early 1990s as a consequence to federal and state regulations designed to improve air quality. The 1990 Federal Clean Air Act (CAA) Amendments mandated the use of winter oxyfuel or reformulated gasoline (RFG) to reduce carbon monoxide or ozone-forming hydrocarbon emissions in carbon monoxide and ozone nonattainment regions, respectively (*1*). In theory, the federal oxyfuel and RFG requirements do not specify a particular oxygenate, and gasoline refiners have several oxygenate options, including ethers (e.g., MTBE, diisopropyl ether [DIPE], ethyl *tert*-butyl ether [ETBE], *tert*-amyl methyl ether [TAME]) and alcohols (e.g., ethanol or *tert*-butyl alcohol [TBA]). In practice, however, MTBE has emerged as the dominant oxygenate in oxyfuel and RFG due to its lower cost and favorable transfer and blending characteristics (*2*). Currently, MTBE accounts for 85% of all oxygenates used in the United States or roughly 15 billion L $year^{-1}$ (*3*). While ethanol accounts for about 7% of the United States oxygenated fuel supply, ethanol is generally not used outside of the Midwest (*4*).

Fuel oxygenates can be accidentally introduced to subsurface environments during the refining, distribution, and storage of oxygenated fuels. Spills and leaks of oxygenate-containing gasoline pose a greater risk to groundwater resources as compared to that caused by other petroleum constituents (e.g., monoaromatics such as benzene, toluene, ethylbenzene, and total xylenes [BTEX]). Comparing to other petroleum constituents, fuel oxygenates are significantly more water soluble and are not adsorbed as readily to soil particles (see Table S1, Supporting Information), allowing them to travel farther and faster in groundwater (*4–6*). In addition, owing in part to their molecular structure, ether oxygenates including MTBE have been shown to resist biodegradation (*7–11*). The persistence and mobility of MTBE in subsurface environment, combined with its relative quantity in oxyfuel and RFG as compared to other gasoline constituents, have contributed to its dominant presence and frequent detection in groundwater plumes (*4*) and community water systems (CWS) (*12*). The relatively low odor threshold of MTBE renders many of these drinking water supplies with even low-level MTBE contamination to be unusable (*13*).

Concerns about potential groundwater contamination from MTBE have led several states to consider or enact MTBE bans (*4*). Unless the oxygenate requirements are removed through modification of the CAA, state- and federal-level bans of MTBE mean refiners must replace MTBE with another oxygenate. As a result, interest in the use and the environmental fate and transport of alternative oxygenates has increased significantly (*14*). However, to date, the state of knowledge is still quite limited for oxygenates DIPE, ETBE, TAME, and TBA (which together make up a total of up to 8% of United States oxygenates market). There are virtually no data on the environmental behavior of these other oxygenates (*15*), due primarily to difficulties in delineating their extent in the environment, lack of systematic analytical procedures for their determination as a group, and lack of regulatory requirement for their analysis. The extent and magnitude of

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oxygenate contamination (other than MTBE) in the United States remains unknown. It is imperative that the environmental impacts of alternative oxygenates be properly assessed, since limited evidence available suggests they would pose groundwater contamination threats similar to MTBE (*4*), if used in similar percent by volume amounts.

This paper characterizes the potential for groundwater contamination of fuel hydrocarbons (FHCs) and oxygenates by examining their occurrence, distribution, and extent at leaking underground fuel tank (LUFT) sites. Specifically, data on the frequency of detection, maximum concentration, and contaminant plume length in groundwater of FHCs and oxygenates at LUFT sites in the greater Los Angeles region are presented. Contaminant plume length is the primary measure in this research because it reflects the potential of the contaminant to impact receptors. Secondary analysis of the correlation among FHC and oxygenate plume lengths and concentrations and time series analysis of contaminant plume length are also presented. In addition, this paper addresses the role of fuel oxygenates in influencing the behavior of FHC plumes at LUFT sites. Analysis of these data provides information on the current extent/magnitude of impact to groundwater resources caused by fuel releases, addresses the fate and transport of released gasoline constituents, and provides a basis for making preliminary predictions on the implications of the expected shift to alternative oxygenates as MTBE is phased out, or reduced, in gasoline.

The approach utilized is to treat LUFT sites as statistical populations (*1*). LUFT sites are particularly important because they represent major point sources of gasoline constituents and the leading cause of FHC and oxygenate groundwater contamination. According to U.S. Environmental Protection Agency's (USEPA) Safe Drinking Water Information System, some 385 000 known releases of gasoline have already occurred at LUFT sites nationally (*5*) and approximately 35% of the CWS wells have one or more LUFT sites within a 1-km radius of the well (*5*). This paper focuses California, specifically the Los Angeles region, as California's large consumption of fuel oxygenates makes the state an important environmental indicator for the national impacts of oxygenates. In fact, California's consumption of MTBE accounts for approximately one-fourth of global MTBE consumption (*4*) and some 6700 MTBE LUFT sites are located within 0.8-km radius of CWS wells in the state (*16*). Los Angeles, which comprises about 28% of the population in California (*17*), exemplifies a typical RFG-program participating metropolitan area.

2. Experimental Section

2.1.1. Characterization of Contaminant Spatial Extent at LUFT Sites. Groundwater plume length for a given contaminant is defined as the distance from the source area to the farthest edge of the plume at a predetermined concentration contour. In this paper, the dissolved plume length in groundwater for FHC (benzene), oxygenates (MTBE, DIPE, ETBE, TAME, and TBA), and total petroleum hydrocarbons as gasoline (TPH_G) were investigated. TPH_G is a useful indicator of the presence and magnitude of gasoline contamination and includes C_4–C_{12} compounds. Dissolved concentration contours were defined to 5 $\mu g\ L^{-1}$ for benzene and ether oxygenates to 10 $\mu g\ L^{-1}$ for TBA, and to 100 $\mu g\ L^{-1}$ for TPH_G, taking into account both uniformity across different analytes as well as their method detection limits (MDLs). For each site, analytical data from groundwater monitoring wells, estimates of average groundwater gradient directions, and best professional judgment in extrapolating the most downgradient well contaminant concentrations to the respective predetermined concentration contours were used to contour the groundwater plume for estimating spatial extent. Other investigators (*1, 16, 18*) have applied similar methods for characterizing plume length.

Clearly, plume length as defined is two-dimensional. The lack of depth-specific data and other site-specific knowledge across the population of LUFT sites investigated in this paper preclude evaluation of plume transport in the vertical direction. In areas of significant recharge, this can bias the measurements toward shorter plumes, since a typical monitoring well screened across the water table may fail to detect the leading edge of the plume as it is deflected downward in response to the infiltration of recharge from above. Further, fluctuating flow directions as well as errors in their determination can result in monitoring well network configurations that create additional biases in plume length measurement. Despite these shortcomings, plume length remains an important indicator of the spatial extent of solute plumes and, in this paper, reflects the potential/relative potential of the FHCs and oxygenates to impact receptors.

2.1.2. Site Selection and Sampling Protocol for Contaminant Plume Length Study. From a list of over 1100 active LUFT facilities in the greater Los Angeles region, 500 facilities were randomly selected for site evaluation. Facilities qualified for inclusion in the plume length study if (a) sufficient groundwater monitoring data were available to define the contaminant plume lengths, (b) groundwater monitoring data covered at least the time period from 3rd quarter 2000 to 2nd quarter 2001, (c) at least one of the five fuel oxygenates of interest (MTBE, TBA, DIPE, ETBE, and TAME) was used or detected at the site, (d) at least one of the FHCs (TPH_G and benzene) was used or detected at the site, and (e) site analytical data met California Regional Water Quality Control Board–Los Angeles Region's (CRWQCB-LA) laboratory quality assurance testing requirements (*19*).

To investigate the influence of oxygenates on FHC plume length at LUFT sites, a distinct "FHC-only" population of LUFT facilities was identified for comparison. From the same list of LUFT facilities referenced above, 700 facilities were randomly selected for site evaluation. The "FHC-only" population was selected based on identical facility inclusion criteria as above, with the exception that none of the five oxygenates of interest was used or detected at the site (as demonstrated by soil and groundwater historical data). For TPH_G and benzene, only for 53 and 52 facilities, respectively, were plume lengths able to be estimated after examination of all 700 randomly selected sites.

2.2. Occurrence and Distribution of FHCs and Oxygenates at LUFT Sites. To investigate the occurrence/distribution of FHCs and oxygenates, data from LUFT sites were analyzed to determine the frequency of detection of FHCs and oxygenates at LUFT sites, their maximum site concentrations, and the correlation among these gasoline constituents. As part of the recent regulatory requirements adopted by the California State Water Resources Control Board, responsible parties for LUFT sites were required to submit laboratory analytical data and reports to the state Geotracker Internet Database in the Electronic Deliverable Format (EDF). From a list of over 1100 active LUFT facilities in the greater Los Angeles region, over 850 facilities had submitted their laboratory analytical data and reports in EDF, which ensured the data that were transmitted were of known quality and met all laboratory testing requirements specified by the regulatory agency (section 2.4). The resulting EDF from these facilities uniformly analyzed, at a minimum, FHC (BTEX), oxygenates (MTBE, DIPE, ETBE, TAME, and TBA) and TPH_G. An extensive data analysis was conducted of the electronic data and hardcopy reports from these facilities. For the time period between January and March of 2002, a total of over 7200 monitoring wells were sampled for these facilities.

2.3. Site Setting and Representativeness. To determine whether the LUFT sites selected for this study were repre-

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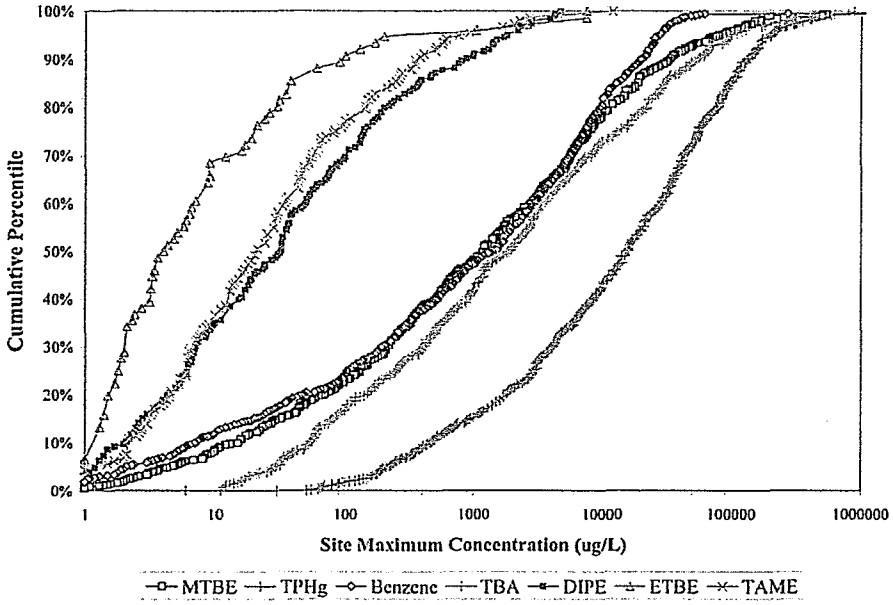

FIGURE 1. Plot of cumulative percentile of site maximum concentration for FHCs (TPH_G and benzene) and oxygenates (MTBE, TBA, DIPE, ETBE, and TAME).

TABLE 1. Summary Statistics on LUFT Site Maximum Analyte Concentrations and Site Analyte Detection Frequencies[a]

	MTBE	TPH_G	benzene	DIPE	ETBE	TAME	TBA
minimum ($\mu g\ L^{-1}$)	0.46	30	0.3	0.36	0.35	0.38	6
maximum ($\mu g\ L^{-1}$)	1.6×10^7	9.98×10^8	4.2×10^7	4 700	7 500	12 000	4.4×10^6
median ($\mu g\ L^{-1}$)	1 200	15 000	1 370	30	4	20	1 880
mean ($\mu g\ L^{-1}$)	44 840	3 783 500	83 750	290	260	240	30 120
g-mean ($\mu g\ L^{-1}$)	900	11 400	700	31	7	24	1 730
LUFT sites with detected analyte (*n*)	718	797	716	206	77	159	530
analyte site detection frequency (%)	82.7	91.8	82.5	23.7	8.9	18.3	61.1

[a] Note: *g*-mean denotes geometric mean.

sentative of the majority of LUFT sites in California, statistical analyses of site hydrogeology and contaminant impact were conducted in manner similar to Happel et al. (*1*) and reported in detail in text and figures in the Supporting Information.

2.4. Analytical Methods. The analysis of oxygenates as a group using conventional analytical procedures designed for petroleum hydrocarbons has been shown to be problematic (*1, 20*). USEPA Method 8020/21B, a protocol routinely employed for the analysis of LUFT samples, was unfit for monitoring of TBA and frequently yielded false-positive and inaccurate results when ether oxygenates were monitored in aqueous samples containing high TPH_G concentrations (>1000 $\mu g\ L^{-1}$). In contrast, Halden et al. (*20*) demonstrated that USEPA Method 8260B (gas chromatography/mass spectrometry) was a robust protocol for oxygenates over a wide range of TPH_G background concentrations. To ensure that appropriate protocols for the analysis of oxygenates were utilized, only those groundwater samples from LUFT sites that had been analyzed for BTEX and ether and alcohol oxygenates using USEPA Method 8260B were used for this study. TPH_G was analyzed using USEPA Method 8015 nonaromatic, nonhalogenated chromatograph procedure. Laboratory MDLs for TPH_G, BTEX, TBA, and ether oxygenates were set at 100, 1, 10, and 2 $\mu g\ L^{-1}$, respectively.

3. Results and Discussions

3.1. Occurrence and Distribution of FHCs and Oxygenates at LUFT Sites. To determine the frequency of detection of FHCs and oxygenates at LUFT sites, their maximum site concentrations, and the correlation among these gasoline constituents, groundwater monitoring data from over 7200 monitoring wells in EDF were analyzed from 868 LUFT sites in the greater Los Angeles region. At a reporting limit of 100, 1, 10, and 2 $\mu g\ L^{-1}$, for TPH_G, benzene, TBA, and ether oxygenates, respectively, 96% of the EDF-LUFT sites contained at least one FHC or oxygenate, 92% contained at least two analyzed compounds, 60% contained at least four compounds, and 1.5% contained all seven FHC and oxygenate compounds. TPH_G was the analyte most frequently detected at 91.8% of EDF-LUFT study sites, followed by MTBE and benzene at 82.7% and 82.5%, TBA at 61.1%, and the alternative ether oxygenates DIPE, TAME, and ETBE at 23.7%, 18.3%, and 8.9%, respectively.

The site maximum analyte concentration (SMAC) was a good indicator of the source analyte concentration or strength in groundwater. SMAC was determined for each of the seven FHCs and oxygenates at individual EDF-LUFT study sites. Figure 1 depicts a comparison of the SMAC cumulative distributions. The results indicate that, excluding the composite measure TPH_G, TBA has the greatest site maximum concentrations, followed by MTBE/benzene and DIPE, TAME, and ETBE. The mean, geometric mean, median, and other relevant measures are displayed in Table 1 for LUFT sites with detectable levels of analyte. The log-normality of the data sets, confirmed by graphical tools and more quantitative measures (e.g., coefficient of variation, the Shapiro–Wilk Test (*21*), and skewness), necessitated a natural log data transformation before computation of the *t*-test (*21*–

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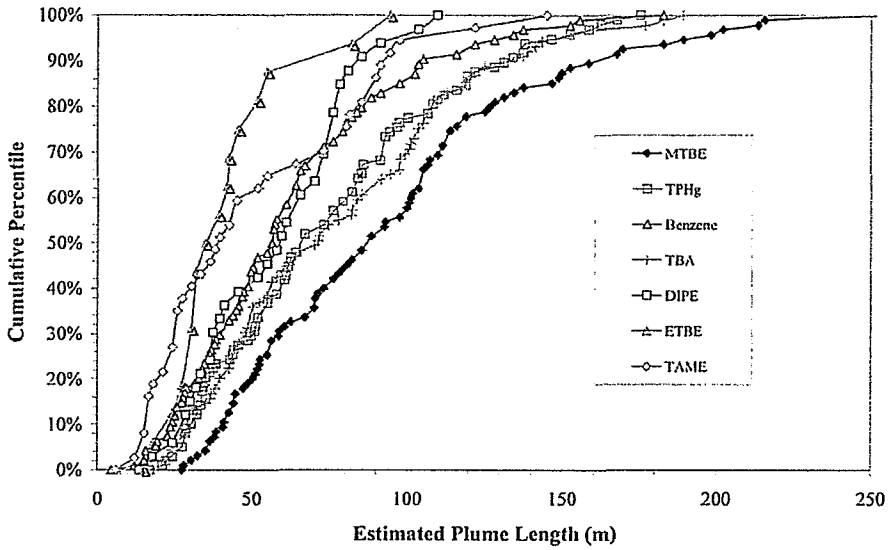

FIGURE 2. Plot of plume length cumulative percentile for FHCs (TPH_G and benzene) and oxygenates (MTBE, TBA, DIPE, ETBE, and TAME). Note: benzene, ether oxygenate, TBA, and TPH_G plume lengths were defined to 5, 5, 10, and 100 $\mu g\ L^{-1}$ dissolved concentration contours, respectively.

23) to examine the significance of variations in concentration observed among the FHC and oxygenate compounds. Bonferroni probability (*Bon. p*) was provided as protection for performing multiple *t*-tests simultaneously. Among the FHC and oxygenates, TPH_G has the greatest geometric mean site maximum concentration, followed by TBA, MTBE, benzene, and the ether oxygenates DIPE, TAME, and ETBE (Table 1), confirming what is observed in Figure 1. The student *t*-test verified statistically significant ($\alpha = 0.05$, *Bon.* $p < 0.05$) differences for 20 out of 21 possible pairwise comparisons among the seven FHC and oxygenate compounds.

The study observations indicate low concentrations of alternative ether oxygenates (DIPE, ETBE, and TAME) at LUFT sites (e.g., 50% of the detected maximum site concentrations for ETBE, TAME, and DIPE were less than 5, 20, and 30 $\mu g\ L^{-1}$, respectively (Figure 1)). Examinations of gasoline surveys provide definitive knowledge of which oxygenate and what volumes of that oxygenate are being used in a particular region of the country. As demonstrated by the 1995–1997 EPA Oxygenate Type Analysis and RFG Survey Data (*24*), the quantity of alternative ether oxygenates (DIPE, ETBE, and TAME) in Los Angeles area gasoline are near trace amounts ($\ll$1% by weight), which may explain their low soluble source concentrations observed.

In addition, high TBA source concentrations were observed. In fact, excluding the composite measure TPH_G, TBA has the greatest geometric mean site maximum groundwater concentration among our study analytes. This finding may be explained in terms of the solubility and sources of TBA. Even though TBA was added to gasoline in significantly lesser amounts than MTBE or benzene, its high miscibility meant that small quantities of TBA could translate into high groundwater concentrations. Further, different sources of TBA (as gasoline additive, impurity, or oxidation byproduct of MTBE) could by themselves, or in combination, result in the detected TBA in groundwater at LUFT sites.

3.2. Characterization of Contaminant Spatial Extent at LUFT Sites. Contaminant plume length was used as an initial indicator of the threat of contamination to drinking water sources by contaminants present in shallow groundwater at LUFT sites and was estimated according to procedures in section 2.1.1. Figure 2 presents FHC and oxygenate plume lengths in terms of cumulative percentile. The results indicate that among the FHCs and oxygenates, MTBE has the greatest plume length, followed by TBA/TPH_G, benzene, and the alternative oxygenates DIPE, TAME, and ETBE. The difference in plume length is clearly distinguishable, as in the case of MTBE versus FHC and MTBE versus other oxygenates. In contrast, pairwise comparisons between TBA/TPH_G, benzene/DIPE, and TAME/ETBE cumulative distributions indicate that for these pairs, the variation in plume length is difficult to distinguish as demonstrated by the overlapping cumulative percentile curves.

The statistical significance of the plume length differences among the FHC and oxygenate groups was examined using the two sample *t*-test (after log-transformation). The log-normality of the data sets indicates that the geometric mean and the median are better descriptors of the LUFT plume population. Table 2 summarizes the data. Among the FHC and oxygenates, MTBE has the greatest geometric mean plume length at 83 m, followed by TPH_G/TBA at 64 and 63 m, benzene/DIPE at 51 and 50 m, and TAME/ETBE at 36 and 34 m. The student *t*-test verified statistically significant ($\alpha = 0.05$, *Bon.* $p < 0.05$) differences for pairwise comparisons of MTBE and TBA to DIPE, ETBE, and TAME as well as comparisons between MTBE and TBA, MTBE and benzene, and TBA and benzene. In contrast, pairwise comparisons of DIPE, ETBE, and TAME to one another as well as benzene to DIPE or ETBE were not.

Contaminant groundwater plume length is influenced by factors such as hydrogeologic characteristics, matrix chemical interactions, source strength, biodegradation, and intrinsic properties of the chemical of interest. Under steady-state conditions, the differences in plume length among the FHCs and oxygenates at a particular site may be attributed primarily to differences in source strength and degradability of the contaminant. The lower source strengths of alternative ether oxygenates (DIPE, ETBE, and TAME) (Figure 1) as compared to MTBE, TBA, or FHCs may have contributed in large part to the observed localization of these plumes. In contrast, since the FHCs have source strengths of similar magnitudes as compared to MTBE and TBA (Figure 1), it is likely the significantly greater biodegradability of the FHCs (TPH_G and benzene) relative to TBA and ether oxygenates favored the more restricted plume migrations from the source areas as compared to MTBE and TBA plumes.

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TABLE 2. Summary Statistics on Estimated LUFT Site Analyte Plume Length in Groundwater[a]

	MTBE (5 $\mu g\ L^{-1}$)	TPH_G (100 $\mu g\ L^{-1}$)	benzene (5 $\mu g\ L^{-1}$)	DIPE (5 $\mu g\ L^{-1}$)	ETBE (5 $\mu g\ L^{-1}$)	TAME (5 $\mu g\ L^{-1}$)	TBA (10 $\mu g\ L^{-1}$)
facilities (*n*)	96	99	95	34	17	37	86
min (m)	26	11	7	14	15	6	15
max (m)	317	259	168	119	94	137	192
median (m)	84	66	51	58	35	40	61
mean (m)	96	75	60	55	39	47	73
g-mean (m)	83	64	51	50	34	36	63

[a] Note: *g*-mean denotes geometric mean.

TABLE 3. Change in Analyte Groundwater Plume Length over Time (1 year)[a]

	MTBE (5 $\mu g\ L^{-1}$)	TPH_G (100 $\mu g\ L^{-1}$)	benzene (5 $\mu g\ L^{-1}$)	DIPE (5 $\mu g\ L^{-1}$)	ETBE (5 $\mu g\ L^{-1}$)	TAME (5 $\mu g\ L^{-1}$)	TBA (10 $\mu g\ L^{-1}$)
case (*n*)	96	99	94	33	16	35	86
g-mean change (m)	−1.5	−0.3	0.6	0	1.5	1.2	3.7
g-mean (m)	83	64	51	50	34	36	63
% change	−1.8	−0.5	1.2	0	4.4	3.3	5.9
P value	0.28	0.89	0.61	0.94	0.58	0.19	0.06

[a] Note: negative *g*-mean change indicates that the plume length for the selected analyte decreased over time, while positive *g*-mean change indicates the opposite.

3.3. Time Series Analysis of Contaminant Spatial Extent at LUFT Sites. Contaminant plume lengths in groundwater were tracked for 1 year for a population of LUFT sites (section 2.1.2 for site selection). A total of 464 individual plumes were tracked resulting in a total of 1856 plume lengths estimated over four quarters (Figure S3, Supporting Information). Comparison of the cumulative percentile (CP) curves over four quarters indicate that for MTBE, TPH_G, and benzene, the overlapping CP curves suggest the changes in plume length over this time period are not discernible—either the plume lengths are stable or the time period examined is not sufficient for changes to develop and/or be detected. In contrast, comparison of the CP curves for the alternative oxygenates ETBE, TAME, and TBA indicates a somewhat discernible trend of increasing plume lengths over the 1-year period. This trend is most apparent in the case of TBA, where the plume length increase over 1 year is ~6%. Decreases in contaminant plume length beneath LUFT study sites over time are likely to be the result of decreasing source strength from ongoing source removal and cleanup as well as biodegradation. Increases in contaminant plume length over time, on the other hand, may be due to a variety of factors. The more recent release of gasoline formulations containing significantly greater quantities of oxygenates may not have afforded sufficient time for oxygenate plumes to reach maximum plume configurations. As for TBA, since it is also a degradation product of MTBE, it is possible that as the MTBE plume farther away from the source area continues to degrade into TBA at concentrations above detection limit; these changes in TBA concentration would be detected by the peripheral monitoring network and thus result in increases in plume length contour.

To assess whether the plume length differences that develop over time were statistically significant, paired *t*-tests were performed (after log-transformation) for each FHC and oxygenate compound. The results indicate that after 1 year, none of the plume length differences that occurred during this period was significant at $\alpha = 0.05$ (Table 3).

Rice et al. (*25*) conducted a trend analysis for benzene plume lengths with time and determined that approximately 60% of the sites studied contained no significant temporal trends, while 32% and 8% of the sites have decreasing and increasing temporal trends, respectively. While the vast majority of benzene and TPH_G plumes are apparently stable (*1, 25*), it remains to be seen whether oxygenate plumes have reached steady state. The different release histories of these compounds can be a factor in interpreting the plume length results. If the oxygenate plumes have not reached steady state, then the observed plume length results may not be indicative of future plume lengths. Time-series analysis of plume length data presented in this paper does lend some support to the stability of the plumes, FHC or oxygenate. However, substantially longer time-series analyses are needed to verify this assumption.

3.4. Impact of Fuel Oxygenates on FHC Plume Lengths. Several laboratory, modeling, and small-scale case studies have been conducted to investigate the impact of ethanol on FHC plumes (*26–28*). It has been demonstrated that high concentrations of ethanol have the potential to increase the spatial extent of FHC plumes primarily through (1) the reduction in the biotransformation rates of FHC attributed to a reduction of available electron-acceptor species that participate in biogeochemical oxidation/reduction reactions (*27*) and (2) increases in the solubility of FHCs through a cosolvency effect (*26*). To investigate whether the presence of fuel oxygenates other than ethanol can influence the mobility and spatial extents of FHC in a similar manner, two distinct populations of LUFT sites were identified. One population was composed of LUFT sites where oxygenates had been used or detected, versus another where none of the five oxygenates of interest had been used or detected (see section 2.1.2 for site selection/protocol). Figure 3 compares the FHC plume lengths at "FHCs only" versus at "FHCs and oxygenates" LUFT sites. A student *t*-test (after log-transformation) was used to test the significance of variations in TPH_G and benzene plume lengths between the two populations of LUFT sites. The results indicate that TPH_G and benzene plumes are significantly (at $\alpha = 0.1$) longer (+20–30%) in the presence of oxygenates.

By comparing FHC (TPH_G and benzene) plume lengths at LUFT sites that differ only in one respect (e.g., the presence or absence of oxygenates), an attempt was made to adjust for other differences between the population of LUFT sites. However, the presence or absence of oxygenates at LUFT sites may itself be indicative of the relative age of the spill. Not until the passage of 1990s CAA mandating the use of RFG or oxyfuel has the addition of oxygenate been so widespread and at such a dramatic scale. Consequently, LUFT

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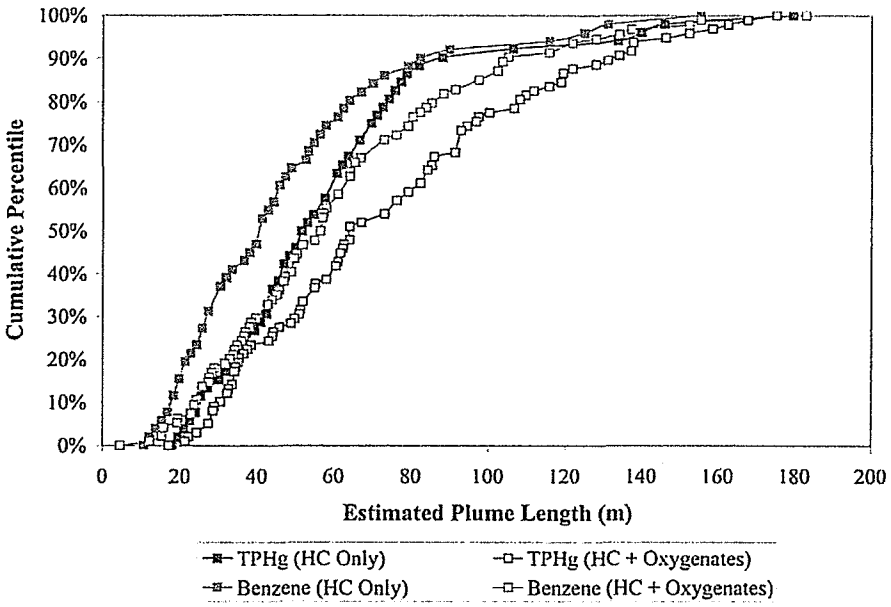

FIGURE 3. Comparison of TPH_G and benzene plume lengths at "hydrocarbons only" versus at "hydrocarbons and oxygenates" LUFT sites. TPH_G and benzene plume lengths were defined to 100 and 5 $\mu g\ L^{-1}$ dissolved concentration contours, respectively.

sites contaminated with both FHCs and oxygenates tend to have at least one or more recent fuel release(s). Conversely, LUFT sites impacted by only FHCs tend to have more aged source zones created by older spills from gasoline without oxygenate additives. Differences in the age of the spill can influence the length of FHC plumes since LUFT sites with more aged source zones also tend to have plumes that, relative to plumes at newer source zones, are stabilized or shrinking. Future work is needed to determine whether the increase in the FHC spatial extent is caused by the presence of oxygenates (e.g., through the mechanism of competition for electron acceptor species or the cosolvency effect) or is merely an artifact created by the inherent differences in the age of the spill resulting from the study design of separating LUFT sites into discrete populations ('FHCs-only' versus 'FHCs and oxygenates').

4. Implications

The site detection frequencies and maximum groundwater concentrations for TBA, MTBE, and benzene were elevated. While the groundwater samples beneath LUFT sites across the states frequently are analyzed for a suite of FHC (e.g., BTEX) and some oxygenate (e.g., MTBE) compounds, the analysis for other oxygenates in most states has seldom been performed. Site groundwater concentrations and plume length data indicate TBA contamination at a scale similar to MTBE. In addition, due to its physical/chemical properties, TBA is often the regulatory driver for treatment considerations at LUFT sites. Therefore, the presence of TBA needs to be confirmed at gasoline-impacted sites, and if confirmed, a specific cleanup strategy needs to be developed that accounts for its presence along with any other FHC or oxygenate compounds that are present. In contrast to benzene, MTBE, and TBA, the site detection frequencies and maximum groundwater concentrations for alternative ether oxygenate DIPE, ETBE, and TAME beneath LUFT facilities were low. Plume length comparisons also indicate these alternative ether oxygenates to be localized relative to MTBE, TBA, or FHCs. Even though data from this study suggests that current risk from the alternative ether oxygenates to groundwater resources at LUFT sites should be minimal, caution should be applied against over-interpretation of the data in anticipating the consequences of possible scale-up in usage of these compounds. An appropriate parallel may be found in the progression of the MTBE problem. Prior to the 1990s, when MTBE was used primarily as an octane booster, it made up only 1−3% by volume of some gasoline. It was only after the scale of MTBE usage escalated in response to the 1990s CAA Amendments that the environmental consequences associated with its use became apparent. All indications (e.g., physical/chemical characteristics such as high solubilities and low biodegradabilities (relative to FHCs)) suggest that the alternative ethers would pose groundwater contamination threats similar to MTBE if their scales of usage were expanded.

With the staggering number of LUFT facilities located in close proximity to community drinking water sources, LUFT sites represent major point sources of gasoline constituents and the leading cause of FHC and oxygenate groundwater contamination. There is little doubt that a large proportion of underground storage tank (UST) systems at gasoline stations leak, and that is apparently true even for upgraded, double-tank systems. The number of leaks indicates that the problem is primarily in the design of the system, which arises from real estate limitations, fire defense considerations, and a defense against accidents and vandalism (*29*). In the absence of completely new design and construction of the system that emphasizes detection, repair, and containment, an effective management strategy may involve placing greater emphasis on a UST program for ensuring adequate enforcement and compliance with existing UST regulations. In California, existing UST regulations require, specifically, the upgrading of USTs and the institution of leak detection systems. The plume lengths data indicate that under a well-managed UST program, with prompt detection and cleanup of source contaminants associated with failed UST systems, FHC and oxygenate plume lengths in the hundreds of meters were quite rare. The overwhelming majority of plumes associated with release(s) from LUFT facilities were relatively "localized". For instance, an examination of plume lengths of alternative ether oxygenate DIPE, ETBE, and TAME found 90% of the plumes were less than 100 m from the source area. Even in the case of MTBE, 90% of the MTBE plumes were observed to be less than 165 m. The adequate compliance with existing UST regulations may decrease the prob-

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ability of future leakage and allow for prompt response and cleanup of possible sources. This scenario could provide adequate safeguard against widespread and catastrophic impact of FHC and oxygenate plumes on groundwater sources since under these conditions the FHC and oxygenate plumes are likely to be localized.

Acknowledgments

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Supporting Information Available

Analyses of site setting and representativeness and correlation among SMAC and among contaminant plume lengths are reported in detail in text, tables, and figures in the Supporting Information. This material is available free of charge via the Internet at http://pubs.acs.org.

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Reference: Keystone XL Project
Risk Analysis

Request:

DOS recently received a copy of a report that questions the validity of the risk analysis for the proposed Keystone XL Project that is summarized in the Section 3.13 of the supplemental draft EIS and included, in part, in Appendix P to the draft EIS. The undated report, ***Analysis of Frequency, Magnitude and Consequence of Worst-Case Spills From the Proposed Keystone XL Pipeline***, was prepared by John Stansbury, Ph.D., P.E. DOS requests that Keystone provide a response to that report, indicating whether or not the author has accurately portrayed the Keystone risk analysis, whether or not the author has made valid assumptions regarding the analysis of risk included in the report, and any other responses that would assist DOS in comparing the information in the report to the risk analysis submitted by Keystone. Please include in your response any clarification to the existing risk assessment that may be required to adequately address valid concerns (if any) raised in the Stansbury report.

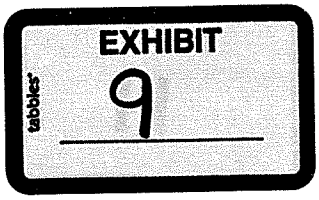
Response Part A:

An initial response to the Stansbury Report was previously provided to DOS. That response is repeated below. It is supplemented with the information in Response Part B.

The Stansbury/Friends of the Earth Report (Stansbury Report) attempts to build on a foundation of inaccurate assumptions that lead to greatly exaggerated estimates of releases of oil and consequences. This is simply the latest case of opportunistic fear-mongering, dressed up as an academic study.

The Keystone Pipeline system is subject to comprehensive pipeline safety regulation under the jurisdiction of the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA). As the recent State Department Supplemental Draft Environmental Impact Statement (SDEIS) recognizes, PHMSA is responsible for protecting the American public and the environment by ensuring the safe and secure movement of hazardous materials to industry and consumers by all transportation modes, including pipelines. To protect the public and environmental resources, Keystone is required to construct, operate, maintain, inspect, and monitor the pipeline in compliance with the PHMSA regulations at 49 CFR Part 195, as well as relevant industry standards and codes. These regulations specify pipeline material and qualification standards, minimum design requirements, required measures to protect the pipeline from internal, external corrosion, and many other aspects of safe operation.

Above and beyond the PHMSA regulations, Keystone has agreed to comply with 57 additional Special Conditions developed by PHMSA for the Keystone XL Project. Keystone has agreed to



incorporate these conditions into its design and construction, and its manual for operations, maintenance, and emergencies required by 49 CFR 195.402. These 57 Special Conditions are attached as Appendix C to the SDEIS.

PHMSA and the State Department took these 57 Special Conditions into account in the SDEIS. It is significant to note the finding in the SDEIS with respect to these conditions:

Incorporation of those conditions would result in a Project that would have a degree of safety over any other typically constructed domestic oil pipeline system under current code and a degree of safety along the entire length of the pipeline system similar to that which is required in High Consequence Areas (HCAs) as defined in 49 CFR 195.450. (SDEIS p. 2-9)

Based on an initial review, below are some of the major mistakes and misrepresentations in the Stansbury Report.

1. Stansbury Report Mistake: "River crossings are especially vulnerable," going on to describe "the pipeline is more susceptible to corrosion because it is below ground and pressures are relatively high."

The Facts: Keystone XL Pipeline is not vulnerable at river crossings; document referenced in report does not suggest it is.

Background: The Summary report states (p. 2) that that "River crossings are especially vulnerable," going on to describe that here "the pipeline is more susceptible to corrosion because it is below ground and pressures are relatively high."

In the corresponding section of Professor Stansbury's full report, headed "Most Likely Spill Locations" (p. 6), the author states that adjacent to rivers, "the pipeline is susceptible to high rates of corrosion because it is below ground (DNV, 2006)." (Note that there is no reference in this section of the report to the additional claim in the Summary that at river crossings "pressures are relatively high.")

Nowhere in the 2006 DNV document cited is there any suggestion that buried pipe at river crossings is more vulnerable to corrosion than any other portion of the buried pipeline. Nor is there any support for the statement in the summary about relative operating pressure at river crossings increasing susceptibility to corrosion.

The only statement in the DNV report remotely related to this unfounded assertion is this: "The Keystone Pipeline is being designed to consist entirely of below ground pipe except within Pump Station fence lines. Sections of the pipeline below ground were considered to be more likely to incur corrosion than above ground sections."

Further, the statement in the DNV report was made within a section that highlights special measures Keystone will employ to eliminate risk of external corrosion. Keystone employs an approach to corrosion protection that has virtually eliminated failure due to external corrosion in the 30-plus years it has been in use. It includes fusion bond epoxy coating (FBE) coupled with active cathodic protection, which places a small current on the pipe preventing loss of metal due to corrosion. Keystone also will be inspected more frequently than standard regulations require, to ensure the effectiveness of this system.

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Relative to other failure modes at river crossings, such as flooding or increased river flows scouring the river bottom or banks and exposing the pipe and making it vulnerable to damage or breakage, Keystone will utilize the horizontal directional drill (HDD) crossing method that places the pipe 25 feet or more below the river bottom at locations where scour is considered a potential threat. Other measures at river crossings further reduce the likelihood of failure. For instance, each of the river crossings mentioned in the report (Yellowstone, Missouri, Platte) will be installed using the HDD method and will utilize heavy-walled pipe with sacrificial abrasion-resistant coating applied over the FBE to further ensure the protective capability of the coating. These measures make these locations among the **least likely for a release** on the entire pipeline.

2. Stansbury Report Mistake: The report incorrectly asserts that TransCanada ignored 23% of statistical pipeline failures (pp. 1, 4).

The Facts: TransCanada's analysis accurately represents historical data and does not overlook 23% of incidents as claimed

Background: The report incorrectly asserts that TransCanada ignored 23% of statistical pipeline failures (pp. 1, 4). In part because the PHMSA data does not identify the cause for 23% of pipeline incidents, TransCanada used a more detailed assessment of causes of historical pipeline incidents, evaluating Keystone against each of these threats to establish an accurate risk profile. The applicable threats to the pipeline were determined using established pipeline industry standards ASME B31.8S and API 1160. This fact was noted within the DNV report itself:

> "It should be noted that the factors are similar but not identical to the U.S. Department of Transportation Office of Pipeline Safety (OPS) categories of failure (e.g., third party harm)." (DNV 2006, p. 3)

3. Stansbury Report Mistake: TransCanada "arbitrarily assigned a drain-down factor" for the pipeline

The Facts: TransCanada estimates of volume released – arbitrarily adjusted in the Stansbury Report – use results of a detailed study prepared by the California Fire Marshal

In calculating how much oil might be released from a pipeline after it is secured and isolated, the author claims TransCanada "arbitrarily assigned a drain-down factor" for the pipeline (p. 9). Not noted, however, is that TransCanada's methodology reflects not TransCanada's judgment but rather the results of an independent assessment by the California Fire Marshal in its role as a regulator in California. The report is well known and respected among pipeline regulators and risk assessors. After labeling use of the California Fire Marshal figure for retained volume "arbitrary," it is ironic that the author goes on to say the factor "is likely too high" and cuts it in half with no further justification.

4. Stansbury Report Mistake: TransCanada's adjustment to risk factors are arbitrary and improper

The Facts: TransCanada adjustments to risk factors are consistent with industry experience

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Background: The Summary report states that "TransCanada arbitrarily and improperly adjusted spill factors" (p. 1). The full report written by Professor Stansbury is less strident, suggesting the adjustments are "probably not appropriate" (p. 4).

The majority of pipeline infrastructure in North America was constructed many decades ago at a time when the materials, coating systems, and ongoing inspection capabilities that will be used for Keystone XL were not available. Studies show the benefits of these technologies in reducing pipeline incidents. For instance (as described in para. #1 above), the corrosion protection Keystone uses has virtually eliminated external corrosion as a cause of failure. Approximately two thirds of the pipelines in the US were constructed prior to 1970. It is therefore entirely appropriate to use an incident frequency for Keystone XL that is derived from pipelines of its class. To do otherwise would be like trying to estimate the gas mileage of a 2011 model car by using the average gas mileage of all cars built since the 1920s.

This is corroborated by observations included in the SDEIS, including:

> "It is likely that both incident frequency analyses tend to overestimate the likely spill frequency of the proposed Project since both analyses rely on data that include incidents on older pipelines that would not be operated under the Project-specific Special Conditions developed by PHMSA and incorporated into the design, construction, operations, and maintenance plans for the proposed Project." (SDEIS, p. 3-98)

Examples of measures taken by TransCanada to reduce risk on Keystone include:

- External corrosion – Keystone employs an approach to corrosion protection that has virtually eliminated failure due to external corrosion in the 30-plus years it has been in use. It includes fusion bond epoxy coating and active cathodic protection, which places a small current on the pipe preventing loss of metal due to corrosion. Keystone has agreed to a special regulatory condition requiring the pipeline to be internally inspected with an instrumented device that monitors the pipe wall for anomalies. Any wall degradation due to corrosion would be detected and addressed prior to failure. (These requirements are covered by several PHMSA Special Conditions, including #9, 10, 11, 33, 35-39, 42, 53.)
- External impact – Keystone will be buried at a deeper depth to minimize risk of external impact. In addition, pipe walls will exhibit greater puncture resistance and fracture control properties. Keystone will take additional steps to minimize risk of accidental excavation damage. (Required by PHMSA Special Conditions #7, 19, 40, 41, 48, 53, 54).
- Internal corrosion – Limit sediment and water content of oil shipped to 0.5%. Run cleaning tools twice per year in the first year and as necessary based on integrity analysis. Implement a crude oil monitoring and sampling program to ensure products transported meet specifications. Perform internal inspections at increased frequency. (Required by PHMSA Special Conditions #33, 34, 42, 53)
- Mechanical defect – enhanced material requirements and QA/QC program as described in PHMSA Special Conditions #1, 2, 4, 5, 6, 8, 12, 22.

5. Stansbury Report Mistake: The report erroneously relies on disproven assumptions on corrosivity of oil to be shipped.

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The Facts: Independent analysis of oil sands derived crude oils has conclusively demonstrated that, below 450 degrees Fahrenheit, these oils are not corrosive to steel.

Background: The Stansbury Report states Keystone is subject to higher failure rates due to corrosivity of oil to be shipped (p. 5). Independent analysis of oil sands derived crude oils has conclusively demonstrated that, below 450 degrees Fahrenheit, these oils are not corrosive to steel. The maximum operating temperature anywhere in the pipeline is 150 degrees. (Supplemental Draft EIS, Keystone XL, p. 3-112.) A recent independent assessment of crude oil quality by the firm Crude Quality Inc., including corrosion potential, has been completed and provided to the U.S. Department of State supporting these findings.

Keystone XL will ship a wide variety of crude oil types including conventional oil, shale oil, partially upgraded synthetic oil and oil sands derived bitumen blends. None of these crude types create a risk of destroying the pipeline from within and causing leaks. Furthermore these products have shipped and are currently being shipped across to the US via other cross-border pipelines from Canada. It would be an uneconomic business proposition to spend $13 billion dollars constructing a pipeline system that would be destroyed by the product it transported.

6. Stansbury Report Mistake: The erroneously states that abrasive sediment in the crude oil will cause higher failure rates

The Facts: The oil that will be shipped on Keystone XL "shall have no physical or chemical characteristics" that would damage or harm the pipeline.

Background: Report states Keystone is subject to higher failure rates due to abrasive sediment (p. 5). However, as clarified in the SDEIS, oil transported by Keystone must meet strict limits for sediment and water. (SDEIS, p. 3-116)

> Special Condition 34 (see Appendix C of this SDEIS) addresses the sediment and water content of the crude oil that would be transported by the proposed Project and states the following:
>
> "Internal Corrosion: Keystone shall limit basic sediment and water (BS&W) to 0.5% by volume and report BS&W testing results to PHMSA in the annual report."

The FERC-approved tariff for transport of oil on the Keystone Pipeline system also requires that all oil to be shipped:

> "shall have no physical or chemical characteristics that may render such Petroleum not readily transportable by Carrier or that may materially affect the quality of other Petroleum transported by Carrier or that may otherwise cause disadvantage or harm to Carrier or the Pipeline System, or otherwise impair Carrier's ability to provide service on the Pipeline System." (SDEIS, Pp. 3-116.)

7. Stansbury Report Mistake: The report erroneously states bitumen will sink, therefore "posing significant threat" to water resources.

The Facts: The gravity of crude oils that Keystone XL would transport are less than the specific gravity of water.

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Background: The report states bitumen will sink "posing significant threat" (p. 19). This issue was addressed in the SDEIS, which includes the following summary statement: "the specific gravity of the crude oils that would be transported on the proposed pipeline ranges from about 0.85 to about 0.93, less than the specific gravity of water. These crude oils, therefore, tend to float on water…" (SDEIS, p. 3-104)

8. Stansbury Report Mistake: The report suggests that TransCanada will cut back on monitoring and maintenance activities, causing increased risk in out years (p. 5).

The Facts: Contrary to a suggestion in the Stansbury Report, monitoring and maintenance activities are a required condition of operation.

Background: The report suggests that TransCanada will cut back on monitoring and maintenance activities, causing increased risk in out years (p. 5). However, the U.S. Code of Federal Regulations requires many of these monitoring and maintenance activities as a condition of operation. TransCanada has voluntarily committed to 57 additional safety conditions that include other enhanced monitoring and maintenance activities as additional conditions of continued operation. For instance, in order to continue to operate the pipeline, TransCanada must perform in-line inspection with a smart pig, conduct corrosion surveys, and perform valve inspections at specified frequencies – these are not discretionary. Additionally, TransCanada must meet requirements to patrol the pipeline every two weeks.

In addition to regulatory requirements, continuing to invest in the safety of the pipeline makes sense from a business perspective. Paying for increased maintenance is built into TransCanada's contracts with its shippers such that variable integrity spending costs are flowed through to the shippers. Additionally, the FERC rate allows the uncommitted toll to rise at a greater than inflation rate which allows for recovery of maintenance costs. There is therefore no financial incentive for TransCanada to cut back on monitoring and maintenance and a substantial financial penalty associated with leaks in the form of fines, cleanup costs, lawsuits and reputational damage. It is therefore not reasonable to suggest that TransCanada or another owner would increase their liability in order to reduce an expense that is flowed through to the customers.

9. Stansbury Report Mistake: The report tries to suggest that because shutdown on another pipeline took longer, that increased time should be the new assumption on shutdown time (pp. 7-8).

The Facts: Keystone time to shutdown has been accurately reflected in the risk analysis and is consistent with Keystone's record.

Background: The Stansbury Report tries to suggest that because shutdown on another pipeline took longer, that increased time should be the new assumption on shutdown time (pp. 7-8). However, the author does not address the differences in system design and operating characteristics (including single phase flow in Keystone) that make it unlikely that Keystone operators would experience difficulty detecting a leak. Nor does he address industry information sharing nor the workings of the regulatory regime, both of which serve to make it unlikely that operational errors are repeated.

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Additionally, Keystone has established its own operating record that demonstrates prompt reaction time to any indication of an operational abnormality. These response records align with the shut down times conveyed in Keystone's risk assessment report.

10. Stansbury Report Mistake: Report suggests that enough oil to fill a dozen Olympic-sized swimming pools would go unnoticed in Nebraska (pp. 8-9).

The Facts: The report's calculation of spill volume for "small" leak not credible because it ignores leak detection methodologies designed to detect low rate or seepage releases.

Background: In assessing worst-case "small" leak, the Stansbury Report suggests that enough oil to fill a dozen Olympic-sized swimming pools would go unnoticed in Nebraska (pp. 8-9). The estimate ignores leak detection methodologies designed to detect low rate or seepage releases.

As described below, Keystone will utilize a state-of-the-art integrated leak detection system. Real-time computerized systems can detect spills as low as 1.5 percent of throughput. In addition to surveillance and public reporting, Keystone will implement a non-real time mass balance procedure that can detect spills below 1.5 percent of throughput.

Data from actual pipeline spills demonstrate that substantial leaks do not go undetected for long periods of time. Further, those spills that are not detected within the first 48 hours are typically relatively small. PHMSA records (2001 through 2009) indicate that the majority of spills are 3 barrels or less, regardless of detection time. These data also indicate that the majority of spills are detected within 2 hours, with 99 percent of spills detected within 7 days. Of those spills not detected within the first 48 hours, the majority of spills were 15 barrels or less. In summary, large spills do not remain undetected for substantial periods of time.

The pipeline will be monitored 24 hours a day, 365 days a year from the Operations Control Center (OCC) using a sophisticated Supervisory Control and Data Acquisition (SCADA) system. Keystone will utilize multiple leak detection methods and systems that are overlapping in nature and progress through a series of leak detection thresholds. The leak detection methods are as follows:

- Remote monitoring performed by the OCC Operator 24/7, which consists of monitoring pressure and flow data received from pump stations and valve sites fed back to the OCC by the Keystone SCADA system. Remote monitoring is typically able to detect leaks down to approximately 25 to 30 percent of the pipeline flow rate.
- Software-based volume balance systems that monitor receipt and delivery volumes. These systems are typically able to detect leaks down to approximately 5 percent of the pipeline flow rate.
- Computational Pipeline Monitoring or model-based leak detection systems that break the pipeline into smaller segments and monitor each of these segments on a mass balance basis. These systems are typically capable of detecting leaks down to a level of approximately 1.5 to 2 percent of pipeline flow rate.
- Computer-based, non-real time accumulated gain/(loss) volume trending to assist in identifying low rate or seepage releases below the 1.5 to 2 percent by volume detection thresholds.

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- Direct observation methods, which include aerial patrols, ground patrols, and public and landowner awareness programs that are designed to encourage and facilitate the reporting of suspected leaks and events that may suggest a threat to the integrity of the pipeline.

The leak detection system will be configured in a manner capable of sending an alarm to the OCC operators through the SCADA system and also will provide the OCC operators with a comprehensive assortment of display screens for incident analysis and investigation. In addition, there will be a redundant, stand-by OCC to be used in case of emergency.

Keystone also will have an Emergency Response Program (ERP) in place to respond to incidents. The ERP contains comprehensive manuals, detailed training plans, equipment requirements, resources plans, auditing, change management and continuous improvement processes. The Integrity Management Program (IMP) (49 CFR Part 195) and ERP will ensure Keystone will operate the pipeline in an environmentally responsible manner.

11. Stansbury Report Mistake: The report relies on old claims that the emergency response plan for the Keystone pipeline is "woefully inadequate"

The Facts: Contrary to assumptions in the Stansbury Report, the Emergency Response capability for Keystone XL will meet or exceed requirements.

Background: The Stansbury Report relies on old claims that the emergency response plan for the Keystone pipeline is "woefully inadequate" (p. 3). This accusation was one of the items reviewed in detail in the SDEIS.

> "DOS and PHMSA have reviewed these hypothetical spill response scenarios prepared by Keystone and would also review a final ERP to be prepared by Keystone prior to startup of the proposed pipeline…Based on its review of the hypothetical spill response scenarios, ***DOS considers Keystone's response planning appropriate and consistent with accepted industry practice.***" (SDEIS, p. 3-122)

12. Stansbury Report Mistake: The report includes exaggerated descriptions of the physical extent of benzene.

The Facts: The exaggerated claims in the report do not match any oil-spill experience; furthermore, benzene concentration in heavy oils Keystone will ship will be comparable to other heavy oils shipped in the U.S. and will generally be lower than benzene concentrations in lighter crudes and in refined products such as gasoline.

Background: Benzene concentration in heavy oils Keystone will ship will be comparable to other heavy oils shipped in the U.S. and will generally be lower than benzene concentrations in lighter crudes and in refined products such as gasoline.

Exaggerated descriptions of the physical extent of benzene in the Stansbury Report do not match any oil-spill experience. The report does not account for emergency response containment and cleanup. Examination of field data collected from large spills into rivers typically finds that concentrations of petroleum products become undetectable in a relatively short distance. For example, following a 10,000 barrel release in 2007 from the Coffeeville Refinery in Kansas into

the Verdigris River, the EPA found no detectable concentrations of petroleum products 20 miles downstream at the closest municipal water intake.

13. Stansbury Report Mistake: The report claims TransCanada cut risk factors in half.

The Facts: TransCanada reflected the results of industry studies regarding failure rates of pipe-related equipment, reducing by half the anticipated number of failures caused by material defect.

Background: TransCanada assumed that its pipeline would be constructed so well that it would have only half as many spills as the other pipelines in service. Not true. Rather, TransCanada reflected the results of industry studies regarding failure rates of pipe-related equipment, reducing by half the anticipated number of failures caused by material defect. As discussed in item #4 above, measures that help achieve this performance are among the Special Conditions to which TransCanada has committed.

Here is the statement from the TransCanada report: "A 50% reduction in the DOT leak frequency was applied to the entire pipeline because the U.S. portion of Keystone will consist of entirely new materials and be constructed to meet current standards and requirements." [DNV section 4.1.13, page 13] The statement occurs in a section of the DNV report describing risk of mechanical defect. Other risk factors are adjusted differently for above-ground and below-ground pipe for instance.

14. Stansbury Report Mistake: The report suggests that releases at pump station sites means Keystone is using less reliable pipe.

The Facts: None of the pump stations releases involved pipeline.

Background: As of June 1, 2011 the Keystone pipeline has experienced fourteen (14) unplanned releases within pump/valve station facility sites, averaging 5-10 barrels each. None of these incidents have involved the pipeline itself. In two cases, nearby adjacent property was affected by spray. Otherwise, the incidents were contained within our pump station facility. Equipment has been replaced or repaired. In all cases, Keystone's operation personnel immediately isolate all releases and clean up and remediation efforts are employed to mitigate any effects to the environment.

TransCanada meets or exceeds all notification and reporting requirements to all state and federal agencies. In many of these cases, reporting to regulatory agencies was not required due to the very small volume of these spills. TransCanada has taken a transparent approach to proactively report all spills to federal and state regulatory agencies regardless of volume. Pipelines are the safest method of transporting the oil that must be moved throughout North America everyday.

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Response Part B:

Mr. Stansbury's document referenced above (the "Stansbury document") does not accurately portray the Keystone XL risk analysis nor has the author made valid assumptions regarding the analysis of the risk included in the report. The discussion below responds to a number of the points in the Stansbury document.

1. **The expected frequency of spills from the Keystone XL pipeline reported by TransCanada (DNV, 2006) was evaluated. (Stansbury document at p. 1)**

The DNV 2006 report is irrelevant to Keystone XL Pipeline Project. The Keystone XL pipeline project risk assessment is based on the Keystone XL Pipeline Project Risk and Consequence Analysis, April 2009 and Appendix A, Analysis of Incident Frequencies and Spill Volumes For Environmental Consequence Estimation for the Keystone XL Project, July 2009.

2. **The worst-case spill volume at the Hardisty Pumping Station was understated. (Stansbury document at pp. 1-2).**

The Hardisty Pump Station in Alberta Canada is irrelevant to the risk assessment for the US segments of the Keystone XL pipeline Project. Moreover, Stansbury's worst case spill estimates are based on incorrect assumptions, as discussed below.

3. **The primary difference between Stansbury's worst-case spill estimate and TransCanada's estimate is that TransCanada used 19 minutes as the expected time to shut down pumps and close valves (TransCanada states that it expects the time to be 11.5 minutes for the Keystone XL pipeline). Since a very similar pipeline recently experienced a spill (the Enbridge spill), and the time to finally shut down the pipeline was approximately 12 hours, and during those 12 hours the pipeline pumps were operated for at least 2 hours, the assumption of 19 minutes or 11.5 minutes is not appropriate for the shut-down time for the worst-case spill analysis. Therefore, worst-case spill volumes are likely to be significantly larger than those estimated by TransCanada. (Stansbury document at p. 2).**

Keystone has calculated the worst case discharge for the Keystone XL pipeline in accordance with 49 CFR §194.105. The Stansbury document suggests that, because shutdown on another pipeline took longer, that increased time should be used as the shut down time assumption for the Keystone XL Pipeline. Enbridge's pipeline was constructed in 1969, while Keystone XL Pipeline would be constructed in 2013 and would meet or exceed current regulatory standards. Stansbury does not take into account that the Keystone XL pipeline is instrumented at every mainline valve and has new, state-of-the-art leak detection and operator training systems that make it unlikely that Keystone operators would experience difficulty detecting a leak. Nor does he address industry information sharing or the workings of the regulatory regime, both of which serve to make it unlikely that alleged operational errors on one system are repeated on another system.

In addition, Stansbury does not take into account the fact that worst case discharge is determined using a large leak that would be instantaneously detected by the leak detection system resulting

in immediate initiation of shut down procedures. Nonetheless, in determining its worst case discharge, Keystone conservatively assumed a 10 minute leak confirmation period, plus nine minutes for pump shut down, plus a 3 minute valve closure time, for a total of 22 minutes. While detection of a smaller leak may require additional confirmation time, the small volumes released would not approach worst case discharge amounts. For example, Keystone has experienced small leaks at pumping stations on the Keystone system which resulted in releases that were a fraction of the estimated worst case discharge volumes. Despite being small, these leaks were identified by the sophisticated leak detection system employed on the pipeline and appropriate shut down and isolation measures were initiated. It is incorrect to assume that there could be a small leak that remained undetected for an extended period of time, as suggested by the Stansbury document (see item 15).

4. **The worst-case spill volumes from the Keystone XL pipeline for the Missouri, Yellowstone, and Platte River crossings were estimated by Stansbury to be 122,867 Bbl, 165,416 Bbl, and 140,950 Bbl, respectively. In addition, this analysis estimated the worst-case spill for a subsurface release to groundwater in the Sandhills region of Nebraska to be 189,000 Bbl (7.9 million gallons). (Stansbury document at p. 2)**

The results of the risk assessment for the Keystone XL pipeline are conservative as the largest spill on record from PHMSA records January 1986-May 2011 for large diameter hazardous liquid pipelines is 40,500 bbl of which 39,800 bbl was recovered. This occurred in 1991 on a 1967 vintage pipeline. Spills greater than 10,000 barrels are uncommon, occurring in less than 0.5 percent of all pipeline spills. Moreover, these estimates are based on incorrect assumptions regarding shut down times as outlined in response #3.

5. **The benzene released by the worst-case spill to groundwater in the Sandhills region of Nebraska would be sufficient to contaminate 4.9 billion gallons of water at concentrations exceeding the safe drinking water levels. This water could form a plume 40 feet thick by 500 feet wide by 15 miles long. (Stansbury document at p. 2).**

This claim is unsupported and disproven by field studies throughout the US. The groundwater study (Newell and Connor 1998) summarized the results of four nationwide studies looking at groundwater plumes from petroleum hydrocarbon contamination. The results show that movement of petroleum hydrocarbons is very limited, moving 312 feet or less in 90 percent of the cases. The longest plume was approximately 3,000 feet in length. Therefore, if groundwater became contaminated, any plume would be expected to result in highly localized effects. Importantly, these limits tend to be independent of the rate of groundwater flow. In contrast, chemicals used in some industries and in agriculture, such as commercial solvents, such as PCE and TCE (tetrachloroethylene and trichloroethylene) and pesticides, have much greater mobility and environmental persistence when compared to oil and its constituents.

6. **Among numerous toxic chemicals that would be released in a spill, the benzene (a human carcinogen) released from the worst-case spill into a major river (e.g., Missouri River) could contaminate enough water to form a plume that could extend more than 450 miles. (Stansbury document at p. 2).**

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This claim is unsubstantiated and unsupported by actual field data nor does it account for containment and cleanup efforts by the operator that limit downstream movement. For example, reference is made to a 2007 spill in Coffeeville, Kansas that released 10,000 barrels of crude oil that entered the flooded Verdigris River. EPA samples reported concentration of petroleum hydrocarbons to be below threshold limits at the first sampling point, located 12 downstream miles of the spill. In 2010, an Enbridge 30-inch pipeline ruptured, spilling 19,500 barrels of oil into the Kalamazoo River system. EPA reports that contamination has been documented in localized areas within 30 miles of the spill's origin. These case studies demonstrate that actual contamination is much less than implied by the Stansbury document.

7. **In estimating spill frequency, TransCanada ignored historical data for spills from "other causes," which represents 23 percent of historical pipeline spills (Stansbury document at pp. 1, 4).**

In its failure frequency analysis, Keystone determined the threats that are actually applicable to the Keystone XL Pipeline by using the combination of variables in the Time Dependant, Stable and Time Independent categories listed in API 1160[1] Section 8.7 and ASME B31.8S[2]. Keystone then used the PHMSA data for the categories of incidents that are associated with these applicable threats. The data for "other causes" was not used because it consists of offshore pipeline, offshore platform, tankage, tankage piping and terminal incidents data that are not applicable to the Keystone XL Pipeline. Keystone did however consider spills at pumping and metering facilities in its analysis of the PHMSA data.

8. **In estimating spill frequency, TransCanada assumed that its pipeline would be constructed so well that it would have only half as many spills as the other pipelines in service. The modification of historical pipeline incident data to account for modern pipeline materials and methods is "probably" overstated for this pipeline. (Stansbury document at pp. 1, 46)**

The modification for modern materials and methods is fully appropriate. Based on the PHMSA incident database January 1, 1986 through May 31, 2011, there are two (2) reported pipeline incidents on crude oil pipelines manufactured with high strength steel (grade X70 or higher) due to pipeline material and methods. This first incident was due to external corrosion and occurred in 1998 on a 1985 vintage pipeline. The second pipeline incident occurred on small diameter (24inch or less). This incident was due to electric flash resistance (ERW) pipe seam failure and occurred in 2007 on a 1998 vintage pipeline. As Keystone is a large diameter pipeline, its method of joining is double submerged arc welding (DSAW) and not ERW. Furthermore,

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[1] Section 8.7. In any risk assessment method, the likelihood is estimated using a combination of variables in categories such as the following: external corrosion, internal corrosion, third party damage, ground movement, design and materials, system operations

[2] ASME B31.8 S "*Managing System Integrity of Gas Pipelines*" classifies threats to pipelines in terms of "Time Dependant", "Stable" and "Time Independent" categories. Time Dependant Threats include: External Corrosion; Internal Corrosion; and, Stress Corrosion Cracking (SCC); Stable Threats include: Manufacturing Defects; Welding / Fabrication Related; and, Equipment Failure; and, Time Independent Threats include: Third Party / Mechanical Damage; Incorrect Operations, and Weather and Outside Force (Geotechnical)

Keystone will protect the pipeline from external corrosion using fusion bond epoxy (FBE) and a cathodic protection (CP) system. The combination of FBE and CP has proven effective over TransCanada's 30+ years of operation. Keystone implements 24 hour surveillance during pipe manufacturing and coating. Lastly, Keystone has implemented nine (9) specific material related conditions and will implement thirteen (13) construction method related conditions set forth in the PHMSA Special Condition Appendix C, over and above current regulations, which would ensure that Keystone is the safest pipeline built in North America, thereby minimizing any potential for spills resulting from materials and construction methods.

In order to establish the particular incident threats that would apply to the Keystone XL pipeline during its operational life, three key points were considered:

- Keystone XL is a new construction project, developed with the benefit of TransCanada's more than 50 years of pipeline construction and operating experience;
- The pipeline will be constructed and operated in accordance with comprehensive regulatory guidelines (49 CFR Part 195) and pipeline design standards (ASME B31.4), and;
- At the time the risk assessment was prepared, Keystone had applied to PHMSA for a Special Permit to allow it to design, construct and operate the pipeline up to 80% of the steel pipeline's specified minimum yield strength (SMYS). The Special Permit application provided that Keystone would comply with a number of pipeline integrity conditions over and above the applicable PHMSA regulations and industry standards. This included the 51 conditions from the Special Permit 2006-26617 issued by PHMSA to TransCanada for the Keystone Pipeline Project in April 2007. Keystone included these conditions in the base design of the Keystone XL Project and recognized their impact in modifying historic failure frequency data in preparing the Risk Assessment. Subsequent to the completion and submittal of the Keystone XL Project Pipeline Risk Assessment and Environmental Consequence Analysis in April 2009, Keystone withdrew the Special Permit Application. Nonetheless, PHMSA ultimately developed and recommend that Keystone adopt 57 conditions over and above the applicable regulations and industry standards and in some cases exceeding the requirements of the 51 conditions listed in the Keystone Special Permit 2006-26617. Keystone agreed to adopt these conditions, which are set forth in Appendix C of the Supplemental Draft EIS. Accordingly, the design assumptions underlying the failure frequency modifications remain conservative.

Taking these factors into consideration, the applicable threats were determined using both the American Society of Mechanical Engineers (ASME) B31.8S Managing System Integrity of Gas Pipelines and American Petroleum Institute (API) 1160 Managing System Integrity of Hazardous Liquid Pipelines as guidance. These standards outline processes for pipeline operators which can be used to assess risks and make decisions about risks in operating pipelines in order to reduce both the number of incidents and the adverse effects of errors and incidents. Moreover, in view of Keystone's adoption of additional conditions beyond those taken into account during preparation of the Risk Assessment, the modifications to historic failure frequency data reflected in the 2009 Risk Assessment are actually even more conservative.

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9. **Keystone will operate the pipeline at higher temperatures and pressures and the crude oil that will be transported through the Keystone XL pipeline will be more corrosive than the conventional crude oil transported in existing pipelines, which tends to increase failure frequency. The diluted bitumen to be transported through the Keystone XL Pipeline will be significantly more corrosive and abrasive than conventional crude oil. (Stansbury document at pp.1, 4-5).**

Keystone has withdrawn its application to operate up to 80% SMYS thereby reducing its throughput and operating pressure. PHMSA Special Condition 15 provides that "under no circumstances may the pump station discharge temperatures exceed 150° Fahrenheit (°F) without sufficient justification that Keystone's long-term operating tests show that the pipe coating will withstand the higher operating temperature for long term operations, and approval from the appropriate PHMSA region(s)."

The potential for internal corrosion (IC) to develop during transportation of oil sands derived crude oils due to sediment and solids is considered low. The following factors support the conclusion that the risk of corrosion from sediments and solids is low:

- Keystone's tariff specifications group sediments/solids with water content. The tariff contains a restriction of 0.5% solids and water by volume.
- "Solids and water" is comprised mostly of water, with solids typically at 5% of the solids/water content (reference www.crudemonitor.ca)
- Keystone will utilize a number of operating measures that will minimize solids in the pipeline:
    - periodic cleaning
    - turbulent flow operating regime
    - sediments are benign at the pipeline's proposed operating temperature (not to exceed 150°F per PHMSA Special Condition 15)

PHMSA Special Condition 34 requires Keystone to limit basic sediment and water (BS&W) to 0.5% by volume and report BS&W testing results to PHMSA annually. Keystone must run cleaning pigs twice in the first year and as necessary in succeeding years based on the analysis of oil constituents, liquid test results, and weight loss coupons in corrosion threat areas. At a minimum, in years after the first year, Keystone must run cleaning pigs once per year, at intervals not to exceed 15 months. Liquids collected during the pig runs, including BS&W, must be sampled, collected, and analyzed and internal corrosion plans must be developed, based on lab test results. This mitigation plan will be incorporated in the Keystone XL Integrity Management Plan and must be reviewed at least quarterly based upon crude oil quality. Keystone will also monitor and implement adjustments for the presence of deleterious crude oil stream constituents as per the PHMSA Special Conditions.

Furthermore, an independent analysis performed by Crude Quality Inc of oil sands derived crude oils has conclusively demonstrated that, below 450 degrees Fahrenheit, the oil sand crude oils are not corrosive to steel.[3]

In addition, the Energy Resources Conservation Board of Alberta issued a statement on February

[3] CAPP Response to US DOS re Keystone XL

16, 2011 stating "the ERCB can identify only three spills resulting from internal corrosion between 1990 and 2005 (and only eight from 1975 to 2010) [for Alberta pipelines]. The resulting average failure frequency for the grouping of crude oil pipelines from 1990 to 2005 is thus 0.03 per 1000 km per year. This is significantly lower than the U.S. rate quoted in [a recent Natural Resources Defense Council] study of 0.08 per 1000 km per year."[4] The ERCB stated further that:

> Analysis of pipeline failure statistics in Alberta has not identified any significant differences in failure frequency between pipelines handling conventional crude versus pipelines carrying crude bitumen, crude oil or synthetic crude oil. Diluent by nature is a lower viscosity, higher-vapour pressure solvent. It could then be considered to be more "volatile" in its natural state, as it consists of lighter end hydrocarbons. However, when blended with bitumen, the resulting blend is a "new" product consisting of thinned bitumen that more closely resembles conventional crude products. Once mixed with diluent, DilBit should behave in much the same manner as other crude oils of similar characteristics. In conventional oils sands processing, sulphur is removed during processing, as well as water (which is a primary concern in regards to corrosivity). The tariff specification for the Keystone XL project, for example, is virtually the same in regards to water content and solids contents as that specified for other heavy oil pipelines, thus there is no reason to expect this product to behave in any substantially different way than other oil pipelines. It should also be noted that pipelines in Alberta have never been safer. In 2009, Alberta posted a record-low pipeline failure rate of 1.7 pipeline failures per 1,000 km of pipeline (considering all substances), bettering the previous record-low of 2.1 set in both 2008 and 2007."[5]

10. **Although pipeline technology has improved, new pipelines are subject to proportionately higher stress as companies use this improved technology to maximize pumping rates through increases in operational temperatures and pressures, rather than to increase safety margins. (Stansbury document at p.5)**

Keystone XL pipeline is design in accordance with 49 CFR §195.106 and ASME B31.4. The federal regulation limits the pipeline's operating stress to no more than 72% of the pipeline steel material's specified minimum yield strength. Operating temperature is addressed in Item 9 above.

11. **TransCanada relies on "soft" technological improvements which require an on-going commitment to monitoring and maintenance resources and which should not be assumed to be constant over the projected service life of the pipeline, and are**

[4] ERCB ADDRESSES STATEMENTS IN NATURAL RESOURCES DEFENSE COUNCIL PIPELINE SAFETY REPORT February 16, 2011
[5] ERCB ADDRESSES STATEMENTS IN NATURAL RESOURCES DEFENSE COUNCIL PIPELINE SAFETY REPORT February 16, 2011

subject to an ongoing risk of error in judgment during operations. (Stansbury document at p.5).

The PHMSA regulations at 49 CFR Part 195 require many of these monitoring and maintenance activities as a condition of operation. Keystone has voluntarily committed to 57 additional safety conditions that include other enhanced monitoring and maintenance activities as additional conditions of continued operation. For instance, in order to continue to operate the pipeline, Keystone must perform in-line inspections, conduct corrosion and depth of cover surveys, and perform valve inspections at specified frequencies – these are not discretionary. Additionally, Keystone must patrol the pipeline 26 times per year, at intervals not to exceed three weeks.

In addition to regulatory requirements, continuing to invest in the safety of the pipeline makes sense from a business perspective. Paying for increased maintenance is built into Keystone's contracts with its shippers such that variable integrity spending costs are flowed through to the shippers. Additionally, the FERC rate allows the uncommitted toll to rise at a greater than inflation rate which allows for recovery of maintenance costs. There is therefore no financial incentive for Keystone to cut back on monitoring and maintenance and a substantial financial penalty associated with leaks in the form of fines, cleanup costs, lawsuits and reputational damage. It is therefore not reasonable to suggest that Keystone or another owner would increase their liability in order to reduce an expense that is flowed through to the shippers.

12. **The TransCanada spill frequency estimation consistently stated the frequency of spills in terms of spills per year per mile. This is a misleading way to state the risk or frequency of pipeline spills. Spill frequency estimates averaged per mile can be useful; e.g., for extrapolating frequency data across varying pipeline lengths. However, stating the spill frequency averaged per mile obfuscates the proper value to consider; i.e., the frequency of a spill somewhere along the length of the pipeline. (Stansbury document at p. 5).**

Keystone was transparent in its use of statistics, including where and how they were derived, how they were applied, and by expressing the potential risk in a variety of ways to promote greater understanding and clarity to a broad audience. Spill frequencies are expressed several ways throughout the document to facilitate comparison with other pipelines and modes of transport, and to promote project-specific understanding. As suggested, spill frequencies expressed as an average per mile facilitates comparison with pipelines of various lengths and to national averages, which are also expressed in this normalize expression of risk. Within the same sentence of expressing the average risk value in terms of incidents/per mile*year (page 3-2), risk was immediately expressed in terms of risk for the whole pipeline over a 10-year period and as an occurrence interval for any single mile of pipe. This provides decision-makers multiple opportunities to understand spill risk and how it applies to the project as a whole as well as to an individual's piece of property. The risk assessment addresses risk specifically to the project as a whole and by pipeline segment (Table 3-1), providing an estimate of the number of spills that could occur over a ten-year period. The risk assessment also uses the spill frequency and historical spill volume data to estimate the potential frequency of different sizes of spills (Table 3-2). In Section 4 of the risk assessment, these same statistics are used to generate estimates of spill frequency and spill volumes in high consequence areas.

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13. **Likely failure points include welds, valve connections, and pumping stations. A vulnerable location of special interest along the pipeline system is near the side of a major stream where the pipeline is underground but at a relatively shallow depth. (Stansbury document at p. 6)**

Keystone is required to conduct non-destructive examination of 100% of the pipeline and pump station welds, in addition to a hydrostatic pressure test. (PHMSA Special Conditions 5, 8, 20, 22). Furthermore, below-ground mainline valve connections are welded, hydrostatically tested and capable of inspection by an in-line inspection tool. Pump station infrastructure undergoes regular maintenance and inspection, piping and equipment is contained within property boundaries which are contained by berms.

The Keystone XL pipeline is designed with a minimum depth of cover of 5 feet below the bottom of waterbodies including rivers, creeks, streams, ditches and drains for a depth normally maintained over a distance of 15 feet on each side of the waterbody measured from the top of the defined stream channel. The depth of cover may be modified by Keystone based on site specific conditions and in accordance with PHMSA Special Condition 19. The Project's depth of cover meets or exceeds the federal requirements noted in 49 CFR 195.248 of 48 inches for inland bodies of water with a width of at least 100 feet from high water mark to high water mark (for normal excavation, 18 inches for rock excavation) and PHMSA Special Condition 19 on depth of cover. Furthermore, major rivers will be crossed employing the horizontal directional drill (HDD) method, whereby the pipe is installed at a minimum of 25 feet below the river bottom there by eliminating the potential for scour to affect the pipeline's integrity. HDD crossings also utilize pipe with a wall thickness of 0.748 inch and abrasion resistant coating applied over top of the FBE coating.

14. **An independent assessment of TransCanada's emergency response plans for the previously built Keystone pipeline was done by Plains Justice (Blackburn, 2010). This document clearly shows that the emergency response plan for the Keystone pipeline is woefully inadequate. Considering that the proposed Keystone XL pipeline will cross much more remote areas (e.g., central Montana, Sandhills region of Nebraska) than was crossed by the Keystone pipeline, there is little reason to believe that the emergency response plan for Keystone XL will be adequate. (Stansbury document at p. 3).**

Keystone is required to submit its emergency response plan for the Keystone XL Pipeline to PHMSA prior to commencing operations for review and approval. As contrasted with Mr. Blackburn, a lawyer, PHMSA has the professional and technical expertise necessary to perform an independent and competent evaluation of the adequacy of the emergency response plan. Significantly, as part of the State Department's review of the project, Keystone was required to present its approach to oil spill response under specific hypothetical spill scenarios to DOS and PHMSA. Based on review of Keystone's response to those scenarios, the SDEIS found that Keystone's spill response planning "is appropriate and consistent with accepted industry practice" (SDEIS p. 3-122). Moreover, PHMSA has already approved the emergency response plan for the Keystone Pipeline, which will serve as the model for the Keystone XL plan.

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15. **Slow leaks could go undetected for long periods of time (e.g., up to 90 days). (Stansbury document at p.7).**

While it is theoretically possible for a very small leak to go undetected for 90 days, data from actual pipeline spills demonstrate that substantial leaks do not go undetected for long periods of time. Further, those spills that are not detected within the first 48 hours are typically relatively small. PHMSA records (2001 through 2009) indicate that the majority of spills are detected within 2 hours, with 99 percent of spills detected within 7 days. Additionally given that leak occurrence is effectively random in time, if a patrol interval is fixed and equal to 14 days, then the time between leak occurrence and leak detection by patrol will range between zero days and 14 days, and it can be shown through modelling that the average time between occurrence and detection will be equal to one-half of the patrol interval (i.e., 7 days). Furthermore, in the context of a risk assessment, where the consequences are weighted by probability of occurrence, the average time is the most appropriate value.

16. **Stansbury assumes a shut-down time of 2 hours for the worst case spill for a large leak (Stansbury document at p. 8).**

See response to Item number 3.

17. **Given the difficulty for operators to distinguish between an actual leak and other pressure fluctuations, the shut-down time for the worst case volume calculation should not be considered to be less than 30 minutes for a leak greater than 50 percent of the pumping rate. This would allow for 4 alarms (5 minutes apart) to be evaluated by operators and a 5th alarm to cause the decision to shut down. In addition, the time to shut down the systems (pumps and valves) would require another 5 minutes. The assumption that the decision to shut the pipeline down can be made after a single alarm, as is suggested by TransCanada (ERP, 2009) is unreasonable considering the difficulty in distinguishing between a leak and a pressure anomaly. (Stansbury report at p. 8).**

As noted in Item 3, Keystone allows for a 10 minute trouble shoot period to confirm if the alarm is a pressure fluctuation or an actual leak. This time period was incorporated into Keystone XL's worst case discharge calculation in addition to the pump shut down time and valve closure time. Keystone's OCC procedures require immediate shut down of the pipeline upon expiry of the trouble shoot period. Stansbury's assumption of four alarms, five minutes apart, bears no relationship to Keystone operating policies and procedures.

18. **TransCanada arbitrarily assigned a drain-down factor of 0.6 for the Keystone XL pipeline. Stansbury report at p. 9).**

Keystone's methodology incorporates the results of an independent assessment by the California Fire Marshal in its role as a regulator in California. The report is well known and respected among pipeline industry, regulators and risk assessors.

19. **Stansbury assumes a discovery and shut-down time of 14 days, which corresponds to the time between pipeline inspections. Stansbury document at p. 20).**

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See response to Item number 15.

20. Stansbury states his estimated worst case releases for major river crossings (i) Missouri R.; (ii) Yellowstone R.; (ii) Platte R. (Stansbury document at pp.10-13).

Stansbury's estimates for these major river crossings are grossly overstated. Based on actual elevation profile, spill calculation inputs and hydraulic engineering data the worst case discharges for these three rivers is less than 20 percent of the volumes stated by Stansbury.

21. "Impacts to Air, Terrestrial Resources, Surface Water, Groundwater Resources (Stansbury document at pp. 14 – 23)

Please refer to the Keystone XL Project Pipeline Risk Assessment and Environmental Consequence Analysis in April 2009.

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

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		HP 14-001
IN THE MATTER OF THE PETITION OF TRANSCANADA KEYSTONE PIPELINE, LP FOR ORDER ACCEPTING CERTIFICATION OF PERMIT ISSUED IN DOCKET HP09-001 TO CONSTRUCT THE KEYSTONE XL PIPELINE	:	AMENDED REBUTTAL TESTIMONY OF MEERA KOTHARI

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Pursuant to the Commission's Order Granting Motion to Define Issues and Setting Procedural Schedule, Petitioner TransCanada Keystone Pipeline, LP, offers the following rebuttal testimony of Meera Kothari.

1. Please state your name and occupation.

Answer: Meera Kothari

2. Did you provide direct testimony in this proceeding?

Answer: Yes.

3. To whose direct testimony are you responding in your rebuttal testimony?

Answer: I am responding to the direct testimony of Dr. Arden Davis.

4. Dr. Davis' testimony (p. 4) discusses concerns involving the stability of steep slopes where Pierre Shale or other expansive clays, such as bentonite, can "absorb large amounts of water during wet periods, leading to instability and potential failure," and subsequent surface water contamination. How will Keystone address these concerns?

Answer: Ground movement, including landslides, seismic events and subsidence, and heavy rains and flooding, account for a very small percentage (1.08%) of pipeline incidents (PHMSA 2008). To prevent pipeline damage, Keystone considered slope stability during the routing and design process. Once the pipeline is operating, Keystone will conduct aerial patrols to monitor the pipeline right-of-way for signs of slope instability as well as other threats to pipeline integrity. This surveillance is required by Federal Regulation at 49 CFR 195.412. Keystone continually evaluates slope stability over the life of the pipeline. If Keystone suspected damage to the pipeline's integrity, Keystone would inspect the pipeline as required by PHMSA Special Condition 53c.

Dated this 24 day of July, 2015.

Meera Kothari

CERTIFICATE OF SERVICE

I hereby certify that on the 27th day of July, 2015, I sent by United States first-class mail, postage prepaid, or e-mail transmission, a true and correct copy of the foregoing Amended Rebuttal Testimony of Meera Kothari, to the following:

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE PETITION OF TRANSCANADA KEYSTONE PIPELINE, LP FOR ORDER ACCEPTING CERTIFICATION OF PERMIT ISSUED IN DOCKET HP09-001 TO CONSTRUCT THE KEYSTONE XL PIPELINE	)	Docket 14-001
	)	**REBUTTAL TESTIMONY OF EVAN VOKES ON BEHALF OF DAKOTA RURAL ACTION**

This statement is submitted by Evan Vokes on behalf of Dakota Rural Action ("DRA") in response to the written testimony provided by Corey Goulet PEng and Meera Kothani PEng on behalf of TransCanada Keystone Pipeline, LP ("TransCanada"), in the above-captioned proceedings governing recertification of the South Dakota Public Utilities Commission's June 29, 2010, Amended Final Decision and Order (Docket HP 09-001) (the "Permit"):

1. Permit Condition No. 1 requires TransCanada to comply with all applicable laws and regulations in its construction and operation of the Project. These laws and regulations include, but are not necessarily limited to: the federal Hazardous Liquid Pipeline Safety Act of 1979 and Pipeline Safety Improvement Act of 2002, as amended by the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006, and the various other pipeline safety statutes currently codified at 49 U.S.C. § 601 01 et seq. (collectively, the "PSA"); the regulations of the United States Department of Transportation implementing the PSA, particularly 49 C.F.R Parts 194 and 195.

a. TransCanada systemically violated these same conditions on the Gulf Coast pipelines. PHMSA project reports and notices of violations for the KXL Gulf Coast portion of the pipeline indicate that TransCanada was non-compliant in several areas, demonstrating that both TransCanada and their third party inspection contractor display an unwillingness or inability to comply with the conditions imposed upon them.

b. As a result of construction methods and inspections used on the KXL Gulf Coast section of the pipeline, many anomalies were introduced to the pipeline – some of a minor, others severe.

c. Throughout a pipeline segment of 300 miles in length, one can expect a small number of girth welds among the thousands of girth welds that will not be pressure tested. In the case of KXL Gulf Coast, TransCanada has admitted to approximately 200 pipe replacements, meaning 400 welds that are not of the same standard of quality inspection or subjected to the pressure testing of the original pipeline. If a pipeline is properly constructed in accord with the spirit of the requirements of 49 C.F.R Part 195, there would be no need for such pipe replacements.

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d. PHMSA Gulf Coast project inspection reports indicate that even though PHMSA engaged in minimal oversight over the pipeline right-of-way, multiple violations were found. PHMSA has never stopped TransCanada from constructing or required remediation of these shortcomings.

e. TransCanada's failure to ensure that the land was properly restored has been documented from the original Keystone to Bison, to Keystone Gulf Coast. TransCanada's unwillingness to take care of other stakeholders and willingness to shift blame for their own shortcomings is systemic.

f. Landowners along the Gulf Coast route of TransCanada's KXL pipeline took extensive photographs documenting substandard construction and reclamation practices. Noteworthy photograph showing peeling coating on the pipeline was taken by a family named Holland near Beaumont, Texas, and was one of hundreds of pictures of poor practices ranging from pipe handling damage, insufficient coverage of pipe to not skidding pipe correctly. OH&S violations with pipe falling of the skids were also documented similar to the allegations of the death on Keystone Gulf Coast. Many of these photographs document violations of both Part 195 and the 57 conditions agreed to by TransCanada as set forth in Appendix Z to the US State Department's FSEIS.

g. The Toronto Star documented that TransCanada did not have sufficient organizational capacity to ensure compliance in the United States with respect to PHMSA's pipeline regulations, notwithstanding similar issues in Canada. Further evidence of failure to comply with Part 195 was documented by the Houston Chronicle, which published photographs showing multiple instances of non-compliance with Part 195 and OHSA conditions.

2. Information provided by TransCanada concerning Finding No. 68, with respect to issues concerning cathodic protection of pipeline coating due to alleged interference by an adjacent foreign utility is both incomplete and appears to be factually incorrect, in that the failure can be traced to several violations of Part 195 on the part of TransCanada. Regardless of TransCanada's assurances, the event occurred, it was severe, and it was due to TransCanada management's failure to comply with Part 195. Understanding that all corrosion is the exchange of metal electrons, the scenario should have been fully investigated, as TransCanada's explanation is not descriptive of what occurred. TransCanada's official public communications and communications with PHMSA show that the event which required instant shut-in of the Keystone pipeline was a very serious threat to public safety. This evidence of cathodic interference correctly belonged in Condition No.1, as it was not a coating failure.

3. Contrary to TransCanada's submitted testimony on Findings No. 68, problems exist with respect to its use of Fusion Bonded Epoxy (FBE) pipeline coatings. TransCanada failed to reveal that there was a mass disbondment on the GTN pipeline of newly-installed FBE coatings. It would be relevant for TransCanada's engineers to present this evidence of what can go wrong with FBEs. Additionally, when repairing damaged FBEs and coating of welds, some of TransCanada's practices have been flagged as substandard by PHMSA and TransCanada

contractors. TransCanada should be compelled to produce the reports on substandard practices taking place during Keystone system construction in 2009, the PHMSA audit and compare those to landowner observations of coating falling off the Keystone Gulf Coast Pipeline in 2013 under the same special permit conditions for enhanced inspections.

4. The dilbit mix shipped on the Keystone pipeline is subject to column separation. This requires particular engineering controls to ensure the mixture does not separate and overpressure segments of the pipeline. Not only is this an ongoing risk in the Keystone system, but it is also a risk in pipelines it feeds such as Pegasus in Mayflower, Arkansas. Column separation would explain many of the observations derived from the Mayflower incident – from the rupture, to the separation of dilbit in the water.

5. TransCanada has had a systemic problem with materials quality. In a public presentation, Kenneth Lee of PHMSA highlighted problems with TransCanada's construction of the Keystone system, including back-beveled transitions, substandard welding, but more importantly, elbows from Keystone. There are approximately 1,200 elbows of unproven quality in TransCanada's Keystone system, which have not been replaced. In October 17, 2013 an elbow with exactly the same non compliant microstructure blew out on a directional drill. The elbows at North Central Corridor Buffalo West and Keystone do not meet the minimum federal standards, yet are in service. Some of these elbows are now fiberglass reinforced but that does not make them complaint.

6. Documents received from a Freedom of Information Act request relating to the October 2012 repair of Keystone shows that the pipeline was not restored to the original design conditions. The Armor Plate repair can compensate for hoop strength of a pipeline but it cannot restore the mandatory toughness of the original design and would not meet the requirement for puncture resistance under current PHMSA conditions.

EVAN VOKES

June 26, 2015
Date

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE PETITION OF TRANSCANADA KEYSTONE PIPELINE, LP FOR ORDER ACCEPTING CERTIFICATION OF PERMIT ISSUED IN DOCKET HP09-001 TO CONSTRUCT THE KEYSTONE XL PIPELINE	)	Docket 14-001 **REBUTTAL TESTIMONY OF JOHN HARTER ON BEHALF OF DAKOTA RURAL ACTION**

1. This is my testimony in rebuttal to the pre-filed testimony of TransCanada Keystone Pipeline, LP ("TransCanada") officer Corey Goulet, in Paragraph 15 of his pre-filed testimony, in which he claimed that TransCanada "is or will be able to satisfy all the conditions imposed by the Commission." My testimony is about how this is not the case.

2. Contrary to what TransCanada has publicly stated, it does not have an agreement with me. By letter dated 10/17/14 I terminated all agreements as a result of a breach of contract by TransCanada of its settlement agreement with respect to the forced taking of my property through eminent domain. At this point, any entry on my property will be deemed trespassing.

3. The State of South Dakota has allowed the Keystone 1 pipeline to be built and is considering recertification of the permit for the proposed Keystone XL pipeline primarily so the state can have an ongoing flow of revenue from TransCanada. The State of South Dakota has engaged in this while denying its residents who are having the pipelines forced upon them through a taking of their private property the ability to do the same. I am of the opinion that the State's permitting TransCanada to exercise eminent domain to take citizens' private property is unconstitutional.

4. My wife and I will have a loss of income as a result of the proposed KXL pipeline crossing our land. We will be unable to use our own property during construction and reclamation, resulting in losses in excess of $35,000 per year. TransCanada's use of eminent domain enabled it to leverage landowners to prevent them from being made whole for the economic losses that would be incurred should the pipeline cross their property.

5. Because I will have to travel to the property to check cattle and the land much more than normal, which will add thousands of dollars to my annual expenses. TransCanada was unwilling to compensate for these losses, even though they state that the property owners are their first eyes on the ground.

6. I informed Tim Irons, a TransCanada land agent, that I wanted to be fairly compensated for each day I was unable to use my own private property. I was told that TransCanada did not do business that way, meaning that TransCanada was not willing to negotiate with me in fair and good faith. Being unwilling to sign an easement I believed to be fundamentally unfair, TransCanada simply took my private property using eminent domain.

7. During Commission meetings held in Winner, SD, and in western South Dakota, TransCanada stated they would use almost 3/4 inch pipe under the roads and in high consequence areas. However, TransCanada has downgraded the pipe wall thickness from this baseline. The Commission witnessed these statements. TransCanada's subsequent actions demonstrate that it does not intend

on building the safest pipeline, or to comply with their agreements.

8. I had a conversation with an employee of the South Dakota Department of Environment and Natural Resources, and asked why they allowed TransCanada to build a pipeline so close to the City of Colome's water source. I was told that it must have just been overlooked.

9. With respect to reclamation of land, based on TransCanada's conduct, we do not believe it intends to reclaim our land back to the condition it was in prior to their taking of our private property.

10. TransCanada stated in public documents (including the FSEIS) that they rely on property owners to provide oversight on the pipelines. I suggest this demonstrates that TransCanada's SCADA system does not detect the leaks to the extent needed.

11. When asked, TransCanada has no answer as to how they will clean up a spill into an aquifer. Eight years into their effort, with no emergency response plan disclosed to date, TransCanada has no answer for this question. Recent pipeline spills into waterways have demonstrated that South Dakota cannot risk our agriculture and tourism industries.

12. As it is not possible to cover all topics in this pre-filed testimony that may arise during a hearing, I reserve the right to rebut any additional testimony presented during the hearing by TransCanada.

Dated this 26th day of June, 2015.

/s/ John Harter
John Harter

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE PETITION OF TRANSCANADA KEYSTONE PIPELINE, LP FOR ORDER ACCEPTING CERTIFICATION OF PERMIT ISSUED IN DOCKET HP09-001 TO CONSTRUCT THE KEYSTONE XL PIPELINE	)	Docket 14-001 **CERTIFICATE OF SERVICE**

I hereby certify that on this 26th day of June 2015, Dakota Rural Action filed its *Rebuttal Testimony of Evan Vokes and Rebuttal Testimony of John Harter* in Case Number HP 14-001, was filed on the Public Utilities Commission of the State of South Dakota e-filing website. Also on this day, a true and accurate copy of the foregoing was transmitted via email to the following:

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And on June 26, 2015, a true and accurate copy of the foregoing was mailed via U.S. Mail, first class postage prepaid, to the following:

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/s/ *Robin S. Martinez*
Attorney for Dakota Rural Action

PREFILED REBUTTAL TESTIMONY

OF

MEMBER OF THE YANKTON SIOUX TRIBE BUSINESS & CLAIMS COMMITTEE (CONSISTING OF ELECTED MEMBERS: ROBERT FLYING HAWK, QUENTIN JB BRUGIER, JR., MONA WRIGHT, JUSTIN SONGHAWK, LEO O'CONNER, JEAN ARCHAMBEAU, GLENFORD SAM SULLY, JASON COOKE, AND EVERDALE SONG HAWK)

Docket No. HP14-001

IN THE MATTER OF THE APPLICATION OF TRANSCANADA KEYSTONE PIPELINE, LP FOR ORDER ACCEPTING CERTIFICATION OF PERMIT ISSUED IN DOCKET HP09-001 TO CONSTRUCT THE KEYSTONE XL PIPELINE

1. Are you a member of the Yankton Sioux Tribe or any other tribe?

A. I am an enrolled member of the Yankton Sioux Tribe.

2. What is your occupation or what kinds of work do you do?

A. I am an elected member of the Yankton Sioux Tribe Business and Claims Committee.

3. On whose behalf was this testimony prepared?

A. This testimony was prepared on behalf of the Yankton Sioux Tribe.

4. Under what authority are you providing this testimony?

A. Pursuant to Article IV of the Amended Bylaws of the Yankton Sioux Tribal Business and Claims Committee, the Business and Claims Committee shall act as liaison between the Tribe and state governments.

5. Please state the purpose of your testimony in this proceeding.

A. The main objective of the Yankton Sioux Tribe through this testimony is to rebut the testimony provided by TransCanada and any other party providing testimony in support of TransCanada's position because TransCanada does not or cannot continue to meet all conditions upon which the permit was issued. I can provide testimony on subjects including the interactions between TransCanada and the Yankton Sioux Tribe, the status of the Tribe as a local unit of government (please see TransCanada's response to Interrogatory No. 11 of Exhibit A attached to this testimony), the position of the Yankton Sioux Tribe on the proposed Keystone XL pipeline, the Programmatic Agreements executed in conjunction with the Final Environmental Impact Statement and the Final Supplemental Environmental Impact Statement (attached to this prefiled testimony as Exhibits B and C, respectively), governing treaties between the United States and the Yankton Sioux Tribe, and the threats posed by the proposed project to the Yankton Sioux Tribe and its members as appropriate based on the testimony offered by TransCanada.

EXHIBIT A

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

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IN THE MATTER OF THE APPLICATION BY TRANSCANADA KEYSTONE PIPELINE, LP FOR A PERMIT UNDER THE SOUTH DAKOTA ENERGY CONVERSION AND TRANSMISSION FACILITIES ACT TO CONSTRUCT THE KEYSTONE XL PROJECT	:	HP 14-001 KEYSTONE'S RESPONSES TO YANKTON SIOUX TRIBE'S FIRST INTERROGATORIES AND REQUEST FOR PRODUCTION OF DOCUMENTS

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Applicant TransCanada makes the following responses to interrogatories pursuant to SDCL § 15-6-33, and responses to requests for production of documents pursuant to SDCL § 15-6-34(a). These responses are made within the scope of SDCL 15-6-26(e) and shall not be deemed continuing nor be supplemented except as required by that rule. Applicant objects to definitions and directions in answering the discovery requests to the extent that such definitions and directions deviate from the South Dakota Rules of Civil Procedure.

GENERAL OBJECTION

Keystone objects to the instructions and definitions contained in Yankton Sioux Tribe's First Set of Interrogatories and Requests for Production of Documents to the extent that they are inconsistent with the provisions of SDCL Ch. 15-6. *See* ARSD

20:10:01:01.02. Keystone's answers are based on the requirements of SDCL §§ 15-6-26, 15-6-33, 15-6-34, and 15-6-36.

INTERROGATORIES

1. State the name, current address, and telephone number of the person answering these interrogatories.

ANSWER: Given the extremely broad scope volume of more than 800 discovery requests received by Keystone in this docket, a range of personnel were involved in answering the interrogatories. Keystone will designate the following witnesses with overall responsibility for the responsive information as related to the Conditions and proposed changes to the Findings of Fact, which are identified in Appendix C to Keystone's Certification Petition: Corey Goulet, President, Keystone Projects, 450 1st Street S.W., Calgary, AB Canada T2P 5H1; Steve Marr, Manager, Keystone Pipelines & KXL, TransCanada Corporation, Bank of America Center, 700 Louisiana, Suite 700, Houston, TX 77002; Meera Kothari, P. Eng., 450 1st Street, S.W., Calgary, AB Canada T2P 5H1; David Diakow, Vice President, Commercial, Liquids Pipeline, 450 1st Street S.W., Calgary, AB Canada T2P 5H1; Jon Schmidt, Vice President, Environmental & Regulatory, exp Energy Services, Inc., 1300 Metropolitan Boulevard, Suite 200, Tallahassee, FL 32308; Heidi Tillquist, Senior Associate, Stantec Consulting Ltd., 2950 E. Harmony Rd., Suite 290, Fort Collins, CO 80528.

2. State the name, current address, and telephone number of any person, other than legal counsel, who Keystone talked with about answering these interrogatories, who assisted Keystone in answering these interrogatories, or who provided information that Keystone relied on in answering these interrogatories.

ANSWER: Given the extremely broad scope volume of more than 800 discovery requests received by Keystone in this docket, a range of personnel were involved in answering the interrogatories. Keystone will designate the following witnesses with overall responsibility for the responsive information as related to the Conditions and proposed changes to the Findings of Fact, which are identified in Appendix C to Keystone's Certification Petition: Corey Goulet, President, Keystone Projects, 450 1st Street S.W., Calgary, AB Canada T2P 5H1; Steve Marr, Manager, Keystone Pipelines & KXL, TransCanada Corporation, Bank of America Center, 700 Louisiana, Suite 700, Houston, TX 77002; Meera Kothari, P. Eng., 450 1st Street, S.W., Calgary, AB Canada T2P 5H1; David Diakow, Vice President, Commercial, Liquids Pipeline, 450 1st Street S.W., Calgary, AB Canada T2P 5H1; Jon Schmidt, Vice President, Environmental & Regulatory, exp Energy Services, Inc., 1300 Metropolitan Boulevard, Suite 200, Tallahassee, FL 32308; Heidi Tillquist, Senior Associate, Stantec Consulting Ltd., 2950 E. Harmony Rd., Suite 290, Fort Collins, CO 80528.

3. Identify each witness that you will or may call as a fact witness or expert witness in any evidentiary hearing or trial of this matter. For each individual, identify and provide the name, business address, and business telephone and the name of his or her employer and/or other organization(s) with which he or she is associated in any professional capacity; the substance of the facts to which he or she is expected to testify and the substance of the opinions to which he or she is expected to testify; the individual's profession or occupation, educational background, specialized training, and employment history relevant to the proposed testimony; and the individual's previous publications within the preceding 10 years; and all other cases or proceedings in which the witness has testified as an expert within the preceding four years.

ANSWER: Keystone will offer prefiled direct testimony from the following persons, each of whom will testify to the changes identified in Keystone's tracking table for that person's area of expertise:

(1) Corey Goulet, President, Keystone Projects, 450 1st Street S.W., Calgary, AB Canada T2P 5H1; (403) 920-2546; Project purpose, Overall description; Construction schedule; Operating parameters; Overall design; Cost; Tax Revenues
(2) Steve Marr, Manager, Keystone Pipelines & KXL, TransCanada Corporation, Bank of America Center, 700 Louisiana, Suite 700, Houston, TX 77002; (832) 320-5916; same; CMR Plan, Con/Rec Units, HDD's
(3) Meera Kothari, P. Eng., 450 1st Street S.W., Calgary, AB Canada T2P 5H1; (832) 320-5190; same; Design and Construction; PHMSA compliance
(4) David Diakow, Vice President, Commercial, Liquids Pipeline, 450 1st Street S.W., Calgary, AB Canada T2P 5H1; (403) 920-6019; Demand for the Facility

(5) Jon Schmidt, Vice President, Environmental & Regulatory, exp Energy Services, Inc., 1300 Metropolitan Boulevard, Suite 200, Tallahassee, FL 32308; (850) 385-5441; Environmental Issues; CMR Plan, Con/Rec Units, HDD's
(6) Heidi Tillquist, Senior Associate, Stantec Consulting Ltd., 2950 E. Harmony Rd., Suite 290, Fort Collins, CO 80528; (970) 449-8609; High Consequence Areas, Spill Calculations

4. Identify any other names that Keystone conducts business under, in the United States and Canada.

ANSWER: None.

5. Pursuant to Condition Two of the Commission's Amended Final Decision and Order, has Keystone received any communications from any regulatory body or agency that may have jurisdiction over the project which alleges that Keystone has failed to comply with any applicable permits, law, or regulation?

ANSWER: No.

6. Pursuant to Condition Two, has Keystone a permit by any regulatory body or agency that may have jurisdiction over the construction, maintenance, or operation of any pipeline located in the United States or Canada ever been denied, revokes, or suspended by the regulatory body or agency?

ANSWER: No.

7. Pursuant to Condition Two, has Keystone been given notice by any regulatory body or agency that may have jurisdiction over the construction, maintenance or operation of any pipeline located in the United States or Canada alleging that Keystone

has failed to comply with any applicable permits for the construction, operation or maintenance of any pipeline located in the United States?

ANSWER: No.

8. Pursuant to Condition One, please identify all required permits that Keystone has applied for within the State of South Dakota regarding the use of public water for construction, testing, drilling, or temporary discharges to waters of the state and temporary discharges of water from construction dewatering and hydrostatic testing.

ANSWER: Keystone has submitted a Notice and Intent and Certificate of Application Form to Receive Coverage Under the General Permit for Temporary Discharges and a Temporary Water Use Permit. Other permits, as required, will be filed closer to the time period of construction.

9. Pursuant to Condition Six, identify the most recent depiction of the Project route and facility locations as they currently exist as compared to the information provided in Exhibit TC-14.

ANSWER: Maps showing changes to the route since the permit was granted are attached as Keystone 0470-0583.

10. Pursuant to Condition Six, identify the dates, addresses, phone numbers, emails, and names of person(s) responsible for conducting surveys, addressing property specific issues and civil survey information.

OBJECTION AND RESPONSE: The identity of persons conducting civil surveys is not relevant or likely to lead to the discovery of admissible evidence. Without waiving the objection, American Burying Beetle Habitat Assessment was conducted by W. Wyatt Hoback, Department of Biology, University of Nebraska at Kearney; Biological Surveys (i.e., habitat, wetland delineations) were conducted by AECOM (Scot Patti was the principal investigator) and SCI (Scott Billing was the principal investigator); Phase I ESA Surveys were conducted by AECOM (Brian Bass was the principal investigator); Biological Surveys (i.e., threatened and endangered species, noxious weeds, reclamation) were conducted by Westech (John Beaver was the principal investigator); Cultural resources surveys were conducted by SWCA Environmental Consultants (principal investigator was Scott Phillips); the paleontological surveys were conducted by SWCA Environmental Consultants (principal investigator was Paul Murphey).

11. Pursuant to Condition Six, does Keystone recognize the Yankton Sioux Tribe, a federally recognized sovereign Indian Nation, as a "local governmental unit?"

ANSWER: Because the Project does not cross Tribal land and because the Yankton Sioux Tribe is a sovereign nation, Keystone does not consider the Tribe to be a "local governmental unit" as referenced in Condition 6.

12. Condition Seven requires Keystone to appoint a public liaison officer. Accordingly, has Keystone:

1. Appointed such public liaison officer, and if so please provide such officer's:

a. Name;

b. Address;

c. Phone number; and

d. Email address.

2. Directed such public liaison officer to contact and or consult with the Yankton Sioux Tribe?

ANSWER:

1.a. Sarah Metcalf's appointment was approved by the PUC by order dated June 2, 2010, in an order which is a matter of public record.

1.b. PO Box 904, Aberdeen, SD 57402.

1.c. 1-888-375-1370

1.d. smetcalf12@gmail.com

2. No. The project does not cross Yankton Sioux lands and Keystone does not consider the Tribe to be a "local government" in the vicinity of the project as stated in Amended Permit Condition 7.

13. Pursuant to Condition Thirteen, identify and provide the phone number, address, and email address of every each environmental inspector that Keystone has incorporated into the CMR.

OBJECTION AND ANSWER: The identity of environmental inspectors is not relevant or reasonably calculated to lead to the discovery of admissible evidence. Without waiving the objection, no Environmental Inspectors have been identified or hired, because the construction of the Project has not yet started.

14. Pursuant to Condition Thirty-Seven, has Keystone ever been found non-compliant with any other permits, from any state regarding the Keystone XL Project?

ANSWER: No.

15. Pursuant to Conditions One and Two, have any contractors hired by Keystone to construct any pipeline owned or operated by Keystone or any of its affiliates received any communication from any agency or regulatory body having jurisdiction over each pipeline regarding alleged safety concerns or safety violations regarding the construction, maintenance or operation of any pipeline in the United States.

OBJECTION: This request is overlybroad and unduly burdensome and is not reasonably calculated to lead to the discovery of admissible evidence under SDCL 15-6-26(b). It also seeks information that is not in Keystone's custody or control and is not maintained by Keystone in the ordinary course of business.

16. Pursuant to Conditions One and Two, have any contractors hired by Keystone to construct any pipeline owned or operated by Keystone or any of its affiliates received any communication from any agency or regulatory body having jurisdiction over each pipeline regarding alleged safety concerns or safety violations regarding the construction, maintenance or operation of any pipeline in Canada.

OBJECTION: This request is overlybroad and unduly burdensome and is not reasonably calculated to lead to the discovery of admissible evidence under SDCL 15-6-26(b). It also seeks information that is not in Keystone's custody or control and is not maintained by Keystone in the ordinary course of business.

17. Pursuant to Condition Forty-Four, what steps has Keystone or any of its affiliates taken to ensure that the cultural and historic resources of the Yankton Sioux Tribe are protected?

OBJECTION AND ANSWER: Condition 44 refers to paleontological studies. Notwithstanding the objection, cultural resources survey reports are listed in Section 3.11 of the Department of State FSEIS (2014), with results of the SD surveys detailed in Table 3.11-3. Any further discussions regarding these surveys would be addressed through the course of government to government consultation with the DOS when the Yankton Sioux were afforded the opportunity to not only review those studies but also participate in the surveys themselves.

18. Pursuant to Condition Forty-Four, how many times has Keystone contacted the Yankton Sioux Tribe?

1. If Keystone did make such contact please provide the following:

a. Name(s) of the person(s) notified;

b. Title of the person(s) notified;

c. The physical address of the person(s) notified;

d. The telephone number(s) of the person(s) notified; and

e. The means by which Keystone made notification, i.e. written, oral, electronic, etc.;

ANSWER: A precise record of the number of contacts with the Yankton Sioux Tribe, either through the body politic or through tribal members does not exist. Typically contacts came through the TransCanada Tribal Liaison staff. *See* Keystone documents 1304-1340 that document some of the contacts. With respect to Condition 44, there may not have been any paleontological specific contacts.

19. Pursuant to Condition Forty-Four, has Keystone made any new cultural and/or historic surveys along the route of the Project since its original permit was granted?

OBJECTION AND ANSWER: Condition 44 refers to paleontological studies, not cultural studies. However, all cultural resources survey reports are listed in Section

3.11 of the Department of State FSEIS (2014), with results of the SD surveys detailed in Table 3.11-3.

20. According to Keystone's original application, Keystone began cultural and historic surveys in May 2008 and at that time it had found several pre-historic stone circles were uncovered. Please provide a detailed description of these sites, including location.

ANSWER: These sites are addressed during the course of government to government consultation with the DOS. Site locations are confidential and cannot be disclosed outside of the consultation process.

21. Pursuant to Condition Forty-Four, please provide the name, address, phone number, and email of all persons involved in any cultural or historic survey conducted by Keystone. In addition, please provide a detailed description of all pertinent professional training that qualifies the surveyor as a professional who meets the standards of the Secretary of the Interior's Historic Preservation Professional Qualification Standards (48 FR 44716, September 29, 1983).

OBJECTION AND ANSWER: The identity of the surveyors is not relevant or reasonably calculated to lead to the discovery of admissible evidence. Without waiving the objection, SWCA Environmental Consultants performed the survey work. The cultural resources principal investigator was Scott Phillips; the paleontological principal

investigator was Paul Murphey. Both individuals meet the SOI standards for their particular field.

22. Pursuant to Condition Forty-Four, has Keystone made any attempt to contact the Yankton Sioux Tribe Business and Claims Committee, its officers, or its Tribal Historic Preservation Office? If so, please provide the following:

a. Name(s) of the person(s) contacted;

b. Title of the person(s) contacted;

c. The physical address of the person(s) contacted;

d. The telephone number(s) of the person(s) contacted; and

e. The means by which Keystone made contact, i.e. written, oral, electronic, etc.;

ANSWER: *See* response to interrogatory no. 18 above.

23. Pursuant to Condition Forty-Four, provide a detailed description of cultural and historic training that Keystone provides to its construction personnel.

ANSWER: Training material developed by Keystone will be finalized and available for distribution to the construction personnel after the inventory phase is complete and prior to construction.

24. Pursuant to Condition Forty-Four, does Keystone or any of its affiliates recognize that if approved and constructed, the Keystone Pipeline will travel through the

identified Indian Country territory from the Fort Laramie Treaty of 1851 and 1868, and as such will likely encounter undiscovered cultural and/or historic sites?

ANSWER: Keystone recognizes that the KXL Pipeline will travel through territory considered in the Treaties of Fort Laramie of 1851 and 1868. Keystone does not believe that any part of its route as currently permitted passes through Indian Country or across tribally owned lands. Keystone recognizes the possibility that undiscovered cultural and/or historic sites may be found in the course of construction. Keystone believes Conditions 43 and 44, and the provisions provided for therein, suitably accommodate cultural and paleontological resource discoveries. Tribal monitors will be hired by Keystone to monitor designated areas during ground disturbing activities relating to construction to assist in managing previously undiscovered cultural and/or historic sites that are found in the course of construction and in complying with the unanticipated discoveries plan.

25. Pursuant to Condition Forty-Four, does Keystone plan to consult with the Yankton Sioux Tribe and its General Council, Business and Claims Committee, and its Tribal Historic Preservation Office in the future?

ANSWER: Condition 44 applies to paleontological discoveries. Condition 43 applies to unanticipated discoveries. See the answer to Interrogatory 24 above.

26. Pursuant to Conditions One and Two, does Keystone recognize and acknowledge that the Yankton Sioux Tribe has federally protected Winters Doctrine water rights and that these rights apply to any permit application to use water for the construction, operation or maintenance of the Keystone Pipeline project?

ANSWER: Keystone recognizes the so-called Winters Doctrine arising from *Winters v. The United States*, 207 U.S. 564 (1908) and its progeny. Keystone does not believe that the Yankton Sioux Tribe's Winters Doctrine water rights are affected by Keystone's use of water for construction, operation, or maintenance.

27. Pursuant to Conditions One and Two, what steps, if any, has Keystone or any of its affiliates taken to ensure that the Yankton Sioux Tribe's federally protected Winters Doctrine water rights are be protected?

ANSWER: Keystone does not believe that the Yankton Sioux Tribe's Winters doctrine water rights are affected by the use of water for the construction, operation, or maintenance of the Keystone Pipeline.

28. Pursuant to Conditions One and Two, are any waterways situated on or near the Pipeline route subject to designation under the Wild and Scenic River Act of 1968? If so, identify each of the waterways.

OBJECTION AND RESPONSE: To the extent that it seeks information on the Pipeline route outside South Dakota, this request is not relevant or reasonably likely to

lead to the discovery of admissible evidence. Without waiving the objection, the Project route does not cross any waterways that are subject to designation under the Wild and Scenic River Act of 1968. There are no waterways that are subject to designation under the Wild and Scenic River Act of 1968 near the Project route in South Dakota. An evaluation of Wild and Scenic Rivers as per related to the Project is found on page 4.3-24 of the Department of State FSEIS (2014).

29. Pursuant to Conditions One and Two, are there any land areas along or near the Keystone Pipeline route that have been designated as critical habitat under the Endangered Species Act? If so identify each of the land areas.

OBJECTION AND RESPONSE: To the extent that it seeks information on the Pipeline route outside South Dakota, this request is not relevant or reasonably likely to lead to the discovery of admissible evidence. Without waiving the objection, there are no lands along or near the Project route in South Dakota that are designated as critical habitat under the Endangered Species Act. Endangered species are discussed in Section 4.8 of the Department of State FSEIS (2014).

30. Pursuant to Conditions One and Two, are there any land areas along or nearby the Keystone Pipeline route that have any Endangered Species located in that area? If so, identify the land areas and the endangered species.

OBJECTION AND RESPONSE: To the extent that it seeks information on the Pipeline route outside South Dakota, this request is not relevant or reasonably likely to lead to the discovery of admissible evidence. Without waiving the objection, the following federally-listed threatened or endangered species have the potential to occur along the Project route in South Dakota: interior least tern; piping plover; rufa red knot; whooping crane; and the American burying beetle. Section 4.8.3 of the Department of State FSEIS (2014) and Appendix H, Biological Opinion in the Department of State FSEIS (2014) discusses the potential occurrence of these federally-listed threatened and endangered species along the Project route in South Dakota and Sections 4.8.3 and 4.8.4 and Appendix H of the Department of State FSEIS (2014) discusses the potential impacts and conservation measures the Project will implement to protect listed species.

31. Pursuant to Condition Twenty-Three, will employees of Keystone or any of its contractors or subcontractors enter the exterior boundaries of the Yankton Sioux Reservation during construction of the Project? If so, for what purposes?

ANSWER: Employees of Keystone or any of its contractors or subcontractors will not enter the exterior boundaries of the Yankton Sioux Reservation during construction.

32. Pursuant to Conditions One, Two, and Thirty-Six, identify the location of all equipment staging areas, construction staging areas, construction camps, and housing

camps in South Dakota that will be used for emergency response, construction, and/or temporary housing.

OBJECTION AND RESPONSE: The request for the location of equipment and construction staging areas is not relevant and not likely to lead to the discovery of admissible evidence. It is confidential for reasons related to security. Keystone currently has not determined the specific locations that will be used for emergency response, but as required by Permit Condition 10, will timely consult with the appropriate agencies. Without waiving the objection, emergency response locations will be determined prior to the project going into service and will be in determined in accordance with Federal response requirements.

Construction

Keystone has leased 11 pipe yards and 6 contractor yards in South Dakota. Pipe yards are planned in Harding, Meade, Butte, Haakon, Jones and Tripp counties. The 6 contractor yards are located in Harding, Meade, Haakon and Tripp counties. Each pipe yard is approximately 30 acres in size.

Temporary Housing

Some areas within Montana, South Dakota, and Nebraska do not have sufficient temporary housing in the vicinity of the proposed route for all construction personnel working in those areas. Temporary work camps would be constructed to meet the housing

needs of the construction workforce in these remote locations. A total of eight temporary construction camps would be established. It is currently anticipated that four construction camps would be needed in Montana (McCone, Valley [two], and Fallon counties), three camps would be required in South Dakota (Tripp, Harding, and Meade counties), and one camp would be required in Nebraska (Holt county). Figure 2.1.5-1 shows the anticipated location of six of the eight camps. The locations of two camps are unknown at this time (one in Montana and one in Nebraska). The final number and size of camps would be determined based on the time available to complete construction and to meet Keystone's commercial commitments. All construction camps would be permitted, constructed, and operated consistent with applicable county, state, and federal regulations. (FSEIS, page 2.1-31)

33. Pursuant to Condition Thirty-Six and Changed Finding of Fact No. 107, identify the contractor or company that is responsible for providing emergency response services.

ANSWER: TransCanada has agreements/contracts with corporations such as the National Response Copr. that meet the Oil Spill Response Organization (OSRO) requirements (Keystone ERP, Appendix I to the FSEIS).

The resources will be secured from a Company approved contractor.

34. Pursuant to Changed Finding of Fact No. 107, provide a breakdown of crime statistics (including violent crimes, sexual crimes, and drug and/or alcohol-related crimes) for areas in which temporary housing camps have been located for construction of comparable projects showing crime rates both before and during construction of said projects. Please also identify the source of this data and the method used to collect this data.

OBJECTION: This request seeks information that is not in Keystone's custody or control and is not maintained by Keystone in the ordinary course of business. It is also overlybroad and unduly burdensome.

35. Pursuant to Changed Finding of Fact No. 107, identify the precautionary measures Keystone has or will implement at the temporary housing camps to protect the surrounding area from crime resulting from the temporary influx of construction workers at the temporary housing camps.

ANSWER: TransCanada Keystone will implement policies and procedures that all residents will be required to comply with during their residency at the camp. Violations may lead to removal from the camp or the appropriate level of disciplinary action. TransCanada will liaise with and engage law enforcement if any issues arise from the man-camps, as appropriate. TransCanada will consider augmenting local law enforcement staffing impacts resulting from camp operations.

Ref: FSEIS 4.10-13

Each camp site would be fully fenced and have a guard house at a single entrance. A contract security officer manning the guard house would be provided on a 24/7 basis. In addition, at all times there would be at least one additional roving security officer supplemented with off-duty law enforcement personnel, as needed. Local law enforcement agencies would also respond to violent, criminal, or illegal activities.

36. Pursuant to Changed Finding of Fact No. 107, identify the protocols and guidelines that will be utilized to respond to reports of crime in or near the temporary housing camps that reportedly involve temporary construction workers or other employees of Keystone or of its contractor or subcontractor.

ANSWER: Any reports of crime or criminal activity in or near temporary housing camps will be reported to local law enforcement for investigation and follow up. TransCanada is committed to cooperating with and assisting law enforcement with their investigation, where appropriate.

Ref: FSEIS 4.10.33

Each camp site would be fully fenced and have a guard house at a single entrance. A contract security officer manning the guard house would be provided on a 24/7 basis. In addition, at all times there would be at least one additional roving security officer

supplemented with off-duty law enforcement personnel, as needed. Local law enforcement agencies would also respond to violent, criminal, or illegal activities.

37. Pursuant to Condition Twenty-Three and the changed Finding of Fact Number Forty-One, will any of Keystone's construction equipment or crew access the Project from trust land? If so, has Keystone received the necessary consent of the United States government to access trust land on the Yankton Sioux Reservation or the affected Reservation?

ANSWER: Keystone does not cross any trust land with access to the Project in South Dakota.

38. Pursuant to Condition Twenty-Three, has Keystone made contact with or otherwise taken any action to plan for road closures which may affect the Yankton Sioux Tribe? If so, does Keystone plan to notify, coordinate or otherwise consult with the Yankton Sioux Tribe?

ANSWER: Keystone does not expect any road closures will affect the Yankton Sioux Tribe, but if such road closures should occur, Keystone will consult with the Yankton Sioux Tribe regarding same.

39. Pursuant to Condition Twenty-Three, has Keystone made contact with or otherwise taken any action to plan for emergency response which may affect the Yankton

Sioux Tribe? If so, does Keystone plan to notify, coordinate, or otherwise consult with the Yankton Sioux Tribe?

ANSWER: Yes, the Yankton Sioux Tribe will be notified if the tribe is affected by an incident. The final version of the Keystone Pipeline Emergency Response Plan (ERP) is complete and complies with 49 C.F.R. Part 194. The Keystone ERP will be amended to include Keystone XL. A redacted version of the ERP is found at Appendix I of the FSEIS.

40. Pursuant to Condition Two, please provide the following information with respect to each instance of tribal consultation with the Yankton Sioux Tribe referenced in Appendix E of the Final Supplemental Environmental Impact Statement.

a. Name(s) of the Tribal official(s) or other person(s) contacted;

b. Title of the Tribal official(s) or other person(s) contacted;

c. The physical address of the Tribal official(s) or other person(s) contacted;

d. The telephone number(s) of the Tribal official(s) or other person(s) contacted;

e. The means by which contact with the Tribe was made, i.e. written, oral, electronic, etc.;

f. Whether any employee, official, or other agent of Keystone was present during the particular instance of consultation and if so, the name and contact information for that individual(s); and

g. Whether Keystone actively or otherwise participated during the particular instance of consultation.

ANSWER: Tribal consultation is the responsibility of the Department of State.

41. Pursuant to Conditions 6 and 43 how much land along Keystones proposed route for the KXL Project has yet to be TCP surveyed. If any, identify the land.

ANSWER: The status of TCP surveys can be found in Table 3.11-8 of the Department of State FSEIS (2014). The Yankton Sioux Tribe's report was received and accepted in March and April 2011. Any outstanding issues would be addressed through the course of government to government consultation with the DOS.

42. Pursuant to Condition 2, how many other state permits and federal permits are pending or not yet received by Keystone for the Keystone XL project.

ANSWER: The Presidential Permit is currently pending before the United States Department of State. Permit authorization from the USACE under Section 404 of the Clean Water Act has not yet been sought.

43. Pursuant to Conditions 6 and 43, have any tribes surveyed the land along the proposed route for the KXL Project? If so, which tribes and for what portion of the route, respectively?

ANSWER: Yes. The route surveys performed are summarized in Keystone documents 1151-1169.

44. Pursuant to Condition 10, has Keystone yet commenced a program of contacts with state, county and municipal emergency response, law enforcement and highway, road and other infrastructure management agencies serving the Project area? If so, please describe the program and any steps taken in furtherance of meeting Condition 10. If not, when does Keystone plan to do so?

ANSWER: No. Keystone will commence such a program not later than six months before commencing construction.

REQUESTS FOR PRODUCTION OF DOCUMENTS

1. All documents that Keystone intends to offer as exhibits at the evidentiary hearing in this matter.

ANSWER: Keystone has not yet identified hearing exhibits, but will disclose them as required by the PUC.

2. All documents relating to environmental and hydrological surveys. Changed Finding of Fact Number Forty-One.

OBJECTION: This request is overlybroad, unduly burdensome, and is not reasonably calculated to lead to the discovery of admissible evidence under SDCL 15-6-26(b). The request is unlimited in time and does not refer to any specific project.

3. All documents relating to cultural and historic surveys, training, and response plans. Condition Forty-Four.

OBJECTION: This request is overlybroad, unduly burdensome, and is not reasonably calculated to lead to the discovery of admissible evidence under SDCL 15-6-26(b). The request is unlimited in time and does not refer to any specific project.

4. All documents relating to required permits, both in South Dakota and outside South Dakota, including permit applications which were denied, revoked, or suspended.

OBJECTION: This request is overlybroad, unduly burdensome, and is not reasonably calculated to lead to the discovery of admissible evidence under SDCL 15-6-26(b).

5. All documents related to Interrogatory No. 40, including but not limited to any correspondence between any employee, official, or other agent of Keystone and any other party pertaining to each instance of consultation and any notes or other documents generated by any employee, official, or other agent of Keystone pertaining to each instance of consultation.

ANSWER: As indicated in the answer to number 40, consultation is the responsibility of the Department of State.

6. All documents constituting Keystone's Emergency Response Plan.

OBJECTION: This request seeks information that is beyond the scope of the PUC's jurisdiction and Keystone's burden under SDCL § 49-41B-27. This request also seeks information addressing an issue that is governed by federal law and is within the exclusive province of PHMSA. The PUC's jurisdiction over the emergency response plan is preempted by federal law, which has exclusive jurisdiction over issues of pipeline safety. *See* 49 C.F.R. Part 194; 49 U.S.C. § 60104(c). This request further seeks information that is confidential and proprietary. See Amended Final Order, HP 09-001, Condition ¶ 36. Public disclosure of the emergency response plan would commercially disadvantage Keystone. In addition, Keystone is not required to submit its Emergency Response Plan to PHMSA until sometime close to when the Keystone Pipeline is placed into operation. Keystone's Emergency Response Plan is addressed in The Final Supplemental Environmental Impact Statement at http://keystonepipeline-xl.state.gov/documents/organization/221189.pdf.

7. All documents that support the proposed changes to the Findings of Fact identified in Appendix C to Keystone's application filed on September 14, 2014 with the PUC.

OBJECTION: This request is overlybroad, unduly burdensome, and is not reasonably calculated to lead to the discovery of admissible evidence under SDCL 15-6-26(b). Appendix C to Keystone certification petition includes citations to sources for many of the statements in the document.

Dated this 5th day of February, 2015.

TRANSCANADA KEYSTONE PIPELINE, LP
by its agent, TC Oil Pipeline Operations, Inc.

By _____

Its Director, Authorized Signatory

Subscribed and sworn to before me

this 5th day of February, 2015.

_____

John W. Love, Lawyer
Notary Public - Canada

OBJECTIONS

The objections stated to Yankton Sioux Tribe's Interrogatories and Request for Production of Documents were made by James E. Moore, one of the attorneys for Applicant TransCanada herein, for the reasons and upon the grounds stated therein.

Dated this 6th day of February, 2015.

WOODS, FULLER, SHULTZ & SMITH P.C.

By _____
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CERTIFICATE OF SERVICE

I hereby certify that on the 6th day of February, 2015, I sent by e-mail transmission, a true and correct copy of Keystone's Responses to Yankton Sioux Tribe's First Interrogatories and Request for Production of Documents, to the following:

Thomasina Real Bird
Fredericks Peebles & Morgan LLP
1900 Plaza Drive
Louisville, CO 80027
trealbird@ndnlaw.com

One of the attorneys for TransCanada

EXHIBIT B

Appendix S

Programmatic Agreement and Record of Tribal Contact

Programmatic Agreement

Among
The U.S. Department of State,
U.S. Bureau of Land Management,
U.S. Army Corps of Engineers,
U. S. Bureau of Reclamation,
National Park Service,
Western Area Power Administration,
U.S. Department of Agriculture Rural Utilities Service,
U.S. Department of Agriculture Natural Resources Conservation Service,
U.S. Department of Agriculture Farm Service Agency
U.S. Bureau of Indian Affairs
Montana Department of Natural Resources and Conservation,
Montana Department of Environmental Quality,
Advisory Council on Historic Preservation,
Montana State Historic Preservation Officer,
Kansas State Historic Preservation Officer,
Texas State Historic Preservation Officer,
Nebraska State Historic Preservation Officer,
Oklahoma State Historic Preservation Officer,
South Dakota State Historic Preservation Officer, and
TransCanada Keystone Pipeline, LP
Regarding the Keystone XL Pipeline Project

WHEREAS, the U.S. Department of State (DOS) receives and considers applications for permits for cross border oil pipelines pursuant to the authority delegated by the President of the United States under Executive Order (EO) 13337 (69 Federal Register 25299); and

WHEREAS, on September 19, 2008, the DOS received an application for a Presidential Permit from TransCanada Keystone Pipeline, LP (Keystone) for the Keystone XL Pipeline Project (Keystone XL Project or the Project); and

WHEREAS, DOS has determined that issuance of a Presidential Permit for the Keystone XL Project includes review under Section 106 of the National Historic Preservation Act (NHPA) (16 U.S.C. 470f, as amended) and its implementing regulations, "Protection of Historic Properties," (36 CFR Part 800); and

WHEREAS, the Project undertaking consists of construction of approximately 1,375 miles of new crude oil pipeline in the United States and utilizes 298 miles of the previously approved Keystone Cushing Extension, associated aboveground facilities (such as pump stations and transmission facilities and substations), and ancillary facilities (such as lateral pipeline, temporary workplace areas and pipe storage, access roads, and contractor yards); and

WHEREAS, the proposed Keystone XL Project pipeline alignment crosses Montana, South Dakota, Nebraska, Kansas, Oklahoma, and Texas; and

WHEREAS, the proposed Keystone XL Project pipeline alignment crosses seven National Historic Trails: the Lewis and Clark National Historic Trail (LCNHT); Oregon, California, Mormon Pioneer, and Pony Express National Historic Trails; the Santa Fe National Historic Trial; and the El Camino Real de los Tejas National Historic Trail (ELTE). Each of these trails was designated by the U.S. Congress and have as their purpose "the identification and protection of the historic route and its historic remnants and artifacts for public use and enjoyment;" (National Trails System Act, P.L. 90-543, as amended); and

WHEREAS, on February 2, 2011, the Advisory Council on Historic Preservation (ACHP) entered consultation finding that criteria 3 and 4 of Appendix A, Criteria for Council Involvement in Reviewing Individual Section 106 Cases, of the regulations (36 CFR Part 800) implementing Section 106 of NHPA, had the potential to be met; and

WHEREAS, the United States Army Corps of Engineers (USACE) has determined that the approval for the Keystone XL Project to cross USACE administered lands (30 U.S.C. § 185) and to place structures in, under, or over navigable waters of the United States, as defined under 33 CFR 329, pursuant to Section 10 of the Rivers and Harbors Act of 1899 (33 U.S.C. § 403), and a permit for the placement of dredge or fill material in waters of the United States as part of the Keystone XL Project in accordance with Section 404 of the Clean Water Act (334 U.S.C. § 344; see 33 CFR 323), are federal actions related to the undertaking that require the USACE to comply with Section 106 of NHPA and 36 CFR Part 800; and

WHEREAS, the U.S. Bureau of Land Management (BLM) has determined the approval of the Keystone XL Project to cross Federal lands administered by the BLM would require authorization under Section 28 of the Mineral Leasing Act of 1920, as amended [(MLA) 30 USC 185]; and

WHEREAS, the BLM has determined that Keystone will require access roads crossing public lands administered by the BLM in support of the Keystone XL Pipeline Project and that the access roads will require authorization under Title V of the Federal Land Policy and Management Act, as amended [(FLMPA) 43 USC 1701]; and

WHEREAS, the BLM has determined that the Keystone XL Project will require electrical power from rural electrical cooperatives and that portions of the transmission lines will cross public lands administered by the BLM and that the transmission lines crossing public lands will require authorization under Title V of the Federal Land Policy and Management Act, as amended [(FLMPA) 43 USC 1701]; and

WHEREAS, the BLM approvals of these Project crossings in areas under its jurisdiction is a federal action associated with the undertaking that requires the BLM to comply with Section 106 of the NHPA and 36 CFR Part 800; and

WHEREAS, the U.S. Bureau of Reclamation (RECLAMATION) manages lands and facilities that will be crossed by the Keystone XL Project and this is a federal action related to the undertaking that requires RECLAMATION to comply with Section 106 of the NHPA and 36

CFR Part 800; and

WHEREAS, the Natural Resources Conservation Service (NRCS) has determined that it retains rights to a 2,693 acre parcel subject to the Wetlands Reserve Program (WRP) (16 U.S.C. 3837 et. seq.) easements in Fannin County, Texas and that the installation and maintenance of the Project pipeline on this WRP easement is a federal action associated with the undertaking that requires compliance with Section 106 of NHPA and 36 CFR Part 800; and

WHEREAS, the Farm Service Agency (FSA), manages private lands with federal easements along the Project APE as part of its Grasslands Reserve Program (jointly administered with the NRCS) as well as the Conservation Resource Program, and the Farmable Wetlands Program; and

WHEREAS, the FSA approval of the Project crossings in these areas is a federal action associated with the undertaking that requires the FSA to comply with Section 106 of the NHPA and 36 CFR Part 800; and

WHEREAS, the Rural Utilities Service (RUS) has determined that the financial assistance it may provide to rural electric cooperatives and other entities for construction or modification of electrical transmission facilities (including transmission lines and substations) to power some Keystone XL Project pump stations or to ensure transmission system reliability, under USDA Rural Development's Utilities Programs, are Federal actions related to the undertaking that require RUS to comply with Section 106 of NHPA and 36 CFR Part 800; and

WHEREAS, the Bureau of Indian Affairs (BIA) has responsibility for approving any right-of-ways crossing Indian Trust lands and this is a federal action related to the undertaking that requires the BIA to comply with Section 106 of the NHPA and 36 CFR Part 800; and

WHEREAS, the Western Area Power Administration (WESTERN) has determined that the modification and construction of substations and transmission lines that WESTERN will own and that will provide power to the Keystone XL project, will require review under Section 106 of NHPA and 36 CFR Part 800; and

WHEREAS, the National Park Service (NPS) has been invited to consult with the DOS concerning the Project due to the potential for adverse effects to several National Historic Trails including the LCNHT and ELTE; and

WHEREAS, the Montana Department of Natural Resources and Conservation has participated in consultation and has been invited by DOS under 36 CFR § 800.6(c) (2) to sign this Programmatic Agreement (PA) as an invited signatory; and

WHEREAS, the Montana Department of Environmental Quality has participated in consultation and has been invited by DOS under 36 CFR § 800.6(c) (2) to sign this PA as an invited signatory; and

WHEREAS, the USACE, BLM, RUS, BIA, NRCS, WESTERN, RECLAMATION, and FSA have designated the DOS as the lead federal agency for purposes of Section 106 of the NHPA in

accordance with 36 CFR § 800.2(a)(2); and

WHEREAS, the Keystone XL Project area of potential effect (APE) includes: (1) in Montana –a 300 foot wide corridor, 150 feet on each side from the centerline; (2) in South Dakota – a 300 foot wide corridor, 150 feet on each side from the centerline; (3) in Nebraska – a 300 foot wide corridor, 150 feet from each side from the centerline; (4) in Kansas – all areas of disturbance related to the construction of two pump stations; (5) in Oklahoma – a 300 foot wide corridor, from centerline of outermost existing pipeline; and (6) in Texas - a 300 foot wide corridor, with 200 feet from the existing infrastructure feature centerline on the side where the proposed pipeline is to be collocated and 100 feet from the existing feature centerline on the opposite side, or, if the route is not collocated with existing infrastructure, then the survey area will be centered on the proposed pipeline (150 feet on each side). For transmission lines and access roads in each state, a 100 foot wide corridor centered on the Project centerline will be used. For pumping stations and other areas that are to be disturbed by construction related activities and ancillary facilities (including construction camps and pump stations), the APE will include all areas of disturbance and areas to be indirectly affected; and

WHEREAS, the DOS has determined that the construction of the Keystone XL Project may have an adverse effect on properties listed in or eligible for listing in the National Register of Historic Places (NRHP), and has consulted with the Montana, South Dakota, Nebraska, Kansas, Oklahoma, and Texas State Historic Preservation Officers (SHPOs), Tribal Historic Preservation Officers (THPOs), Indian Tribes, and the ACHP, pursuant to 36 CFR Part 800; and

WHEREAS, the BLM will incorporate this PA into its decisional process on any authorization under the MLA or FLPMA it may issue for the Keystone XL Project, and will include in any authorization it issues on the Keystone XL Project, a condition that Keystone will abide by its commitments in this PA; and

WHEREAS, in accordance with 36 CFR §§ 800.4(b)(2) and 800.5(a)(3), the DOS has elected to phase identification and evaluation of historic properties, and application of the criteria of adverse effect, respectively, because access to those areas identified in Attachment A has been restricted by property owners' refusal to grant Keystone permission to enter their private property; and

WHEREAS, Attachment G includes summary information on the identification, evaluation, and effect assessment updates on the Project that were included in the Final Environmental Impact Statement (FEIS); and

WHEREAS, additional identification, evaluation and effect assessments for the Project will need to be undertaken as all areas of construction have yet to be determined; and

WHEREAS, pursuant to 36 CFR § 800.14(b), the DOS has elected to execute this PA for the Keystone XL Project because effects on historic properties cannot be fully determined prior to the issuance of a permit for the undertaking; and

WHEREAS, Attachment G also summarizes consultation with Indian tribes and Nations,

SHPOs, and other agencies; and

WHEREAS, the DOS will incorporate this PA into its decisional process on any Presidential Permit that it may issue for the Keystone XL Project and will include in any permit it issues on the Keystone XL Project a condition that Keystone will abide by its commitments in this PA; and

WHEREAS, Keystone, which will construct the Keystone XL Project pipeline, has participated in consultation, has been invited by DOS under 36 C.F.R. §§ 800.2(c)(4) and 800.6(c)(2) to sign this agreement as an invited signatory and intends to sign this agreement as an invited signatory; and

WHEREAS, for the purposes of this agreement, "Indian tribes and Nations" shall have the same definition as "Indian tribes" which appears in Section 301(4) of the NHPA; and

WHEREAS, DOS invited the Indian tribes listed in Attachment B to participate in consultation; and

WHEREAS, the Absentee-Shawnee Tribe of Indians of Oklahoma; the Alabama-Coushatta Tribe of Texas, Blackfeet Tribe, Caddo Nation of Oklahoma, Cheyenne River Sioux, Cheyenne-Arapaho Tribe of Oklahoma, Chippewa-Cree Indians, Choctaw Nation of Oklahoma, Crow Tribe of Indians, Delaware Nation, Fort Peck Tribes, Gros Ventre and Assiniboine Tribe of Ft. Belknap, Ho-Chunk Nation of Wisconsin, Iowa Tribe of Kansas and Nebraska, Iowa Tribe of Oklahoma, Kaw Nation, Kialegee Tribal Town of the Creek Nation in Oklahoma, Kickapoo Tribe of Kansas, Kiowa Indian Tribe of Oklahoma, Lower Sioux Indian Community, Miami Tribe of Oklahoma, Mille Lacs Band of Ojibwe, Muscogee (Creek) Nation, Northern Arapaho Tribe, Northern Cheyenne Tribe, Northern Ute Tribe, Oglala Sioux Tribe, Osage Nation, Pawnee Nation of Oklahoma, Ponca Tribe of Indians of Oklahoma, Ponca Tribe of Nebraska, Rosebud Sioux Tribe, Sac & Fox Nation of Oklahoma, Santee Sioux Tribe of Nebraska, Shoshone-Bannock Tribe, Sisseton-Wahpeton Oyate Sioux, Spirit Lake Tribe, Standing Rock Sioux Tribe, Three Affiliated Tribes, Tonkawa Tribe, Turtle Mountain Band of Chippewa, Wichita and Affiliated Tribes, Winnebago Tribe, and Yankton Sioux have participated in consultation and have been invited to concur in this PA, in accordance with 36 C.F.R. §§ 800.2(c)(2) and 800.6(c)(3);

NOW, THEREFORE, the DOS, USACE, BLM, RUS, BIA, FSA, NRCS, WESTERN, RECLAMATION, NPS, ACHP, and the Montana, South Dakota, Nebraska, Kansas, Oklahoma, and Texas SHPOs agree that the following stipulations will be implemented in order to take into account the effect of the undertaking on historic properties and to satisfy all responsibilities under Section 106 of the NHPA.

STIPULATIONS

The DOS, BLM, RUS, BIA, FSA, NRCS, WESTERN, USACE, RECLAMATION, and NPS as appropriate, will ensure that the following stipulations are carried out.

I. STANDARDS AND DEFINITIONS

A. Identification and evaluation studies and treatment measures required under the terms of this PA will be carried out by or under the direct on-site supervision of a professional(s) who meets, at a minimum, the *Secretary of the Interior's Historic Preservation Professional Qualification Standards* (48 FR 44716, September 29, 1983).

B. In developing scopes of work for identification and evaluation studies, and treatment measures required under the terms of this PA, Keystone and RUS applicants will take into account the following regulations and guidelines:

1. The ACHP's guidance on conducting archaeology under Section 106 (2007);
2. The ACHP's *Policy Statement Regarding the Treatment of Burial Sites, Human Remains and Funerary Objects* (February 23, 2007);
3. Applicable SHPO guidance;
4. The Secretary of the Interior's *Standards and Guidelines for Archaeology and Historic Preservation* (48 FR 44716-42, September 29, 1983);
5. The "*Treatment of Archaeological Properties*" (ACHP 1983);
6. The *Guidelines for Reporting on Cultural Resources Investigations for Pipeline Projects*" (Federal Energy Regulatory Commission, Office of Energy Projects, December 2002);
7. Section 10 of the Rivers and Harbors Act of 1899 (33 U.S.C. § 403);
8. Section 404 of the Clean Water Act (334 U.S.C. § 344);
9. BLM 8110 Manual: Identifying and Evaluating Cultural Resources;
10. Montana/Dakotas Cultural Resources Handbook 8110-1: Guidelines for Identifying Cultural Resources;
11. The National Trails System Act (P.L. 90-543, as amended);
12. Section 28 of the Mineral Leasing Act of 1920 (30 USC 185);
13. Title V of the Federal Land Policy and Management Act of 1976 (43 USC 1701); and
14. *National Register Bulletin 38, Guidelines for Evaluating and Documenting Traditional Cultural Properties* (NPS 1990; Revised 1992: 1998)

C. Definitions

Coordination Plan: A plan (more fully explained in Stipulation V.B and V.D.) that describes the coordination of construction with identification and evaluation of cultural resources, treatment of adverse effects, and protection of unanticipated discoveries.

Concurring Parties: An invited consulting party to this PA that agrees with the content of the PA. The refusal of a concurring party to sign the PA does not invalidate this PA as noted in 36 C.F.R. § 800.6(c)(3). Concurring parties may not terminate the PA.

Construction spread: A construction unit or segment of a pipeline alignment or corridor to be determined by Keystone prior to construction.

Consulting Parties: Parties that have consultative roles in the Section 106 process, as defined in 36 C.F.R. § 800.2(c).

Data Recovery: The recovery of archaeological information from a historic property subject to an adverse effect.

Determination of Effect: A determination made by a federal agency in regards to a Project's effect upon a historic property as defined in 36 C.F.R. Part 800.

Determination of Eligibility: A determination made by a federal agency in regards to a cultural resource's eligibility for inclusion in the National Register of Historic Places (NRHP) and more fully described in 36 C.F.R. Part 60 and 36 C.F.R. § 800.16(l)(2).

Effect: An alteration to the characteristics of a historic property qualifying it for inclusion in or eligibility for the NRHP (see 36 C.F.R. § 800.16(i)).

Environmental Impact Statement: An analysis of a major federal action's environmental impacts conducted consistent with NEPA.

Historic Property: Any prehistoric or historic district, site, building, structure, or object included in, or eligible for inclusion in, the NRHP maintained by the Secretary of the Interior. This term includes artifacts, records, and remains that are related to and located within such properties. The term includes properties of traditional religious and cultural importance to an Indian Tribe or Native Hawaiian organization and that meet the National Register criteria (see 36 C.F.R. § 800.16(l)(a)).

Invited Signatory: The DOS has invited TransCanada Keystone Pipeline LP, the Montana Department of Natural Resources and Conservation, and the Montana Department of Environmental Quality to be signatories to this PA pursuant to 36 C.F.R. § 800.6(c)(2). The refusal of any invited signatory to sign the PA does not invalidate the PA.

Historic Trail and Archaeological Monitoring Plan: A plan (more fully described in Stipulation V.E and Attachment F.) that identifies appropriate areas for monitoring construction by professionals under the supervision of individuals that meet the professional qualifications in Stipulation I. The plan's principal goal is to reduce the potential for impacts to unidentified historic properties.

Signatory Parties: All signatories to this PA, which includes the DOS, BLM, RECLAMATION, USACE, NPS, WESTERN, RUS, NRCS, FSA, BIA, Montana Department of Natural Resources and Conservation, Montana Department of Environmental Quality, and the SHPOs of Montana, South Dakota, Nebraska, Kansas,

Oklahoma, and Texas. (Signatory parties include the federal agency(ies), SHPOs, THPOs (or designee) if the undertaking is carried out on Tribal land or affects historic properties on Tribal land, and also any invited signatories [not including invited concurring parties]).

Tribal Monitoring Plan: A plan (more fully described in Stipulation V.E. and Attachment E) that identifies appropriate areas for monitoring construction by tribal members appointed by their respective tribes. These tribal members shall meet the qualifications as noted in Stipulation V.E.3. The plan's principal goal is to reduce the potential for impacts to previously unidentified historic properties that may also be properties of religious and cultural significance that meet the National Register criteria (see 36 CFR § 800.16(1)(a)).

Treatment Plan: A plan developed in consultation with the parties to this PA that identifies the minimization, and mitigation measures for historic properties located within the APE that will be adversely affected by the Project.

II. CONFIDENTIALITY

DOS, BLM, NRCS, BIA, RUS, WESTERN, RECLAMATION, NPS and USACE will safeguard information about historic properties of religious and cultural significance to Indian tribes, including location information, or information provided by Indian tribes to assist in the identification of such properties, to the extent allowed by Section 304 of NHPA [16 U.S.C. 470w3] and other applicable laws.

III. THE RESPONSIBILITIES OF FEDERAL AGENCIES WITH LAND MANAGEMENT AND OTHER PERMITTING AUTHORITIES

A. The USACE will ensure that the requirements of this PA have been met for that part of the APE under its jurisdiction, pursuant to Section 10 and Section 404 permitting authority.

B. The USACE will comply with Section 106 and its implementing regulations (36 CFR Part 800) for the issuance of permits for those actions under its jurisdiction.

C. The BLM will comply with Section 106 and its implementing regulations (36 CFR Part 800) for the issuance of permits for those actions under its jurisdiction.

D. RECLAMATION will review and comment on the evaluation and treatment of any historic properties managed by RECLAMATION.

E. Attachment H includes maps that illustrate the Project areas cross lands managed by the BLM and RECLAMATION.

F. Consultation for this Project between Indian tribes and federal land management and permitting agencies will be coordinated through the DOS.

IV. KEYSTONE XL PROJECT – CONSTRUCTION OR MODIFICATION OF ELECTRICAL DISTRIBUTION/TRANSMISSION FACILITIES

A. Prior to granting approval of financial assistance to construct or modify electrical transmission facilities by rural electric cooperatives or other entities, RUS will complete the requirements of 36 CFR §§ 800.3 through 800.7.

B. In implementing Stipulation IV.A, RUS may authorize an applicant to initiate Section 106 consultation in accordance with 36 CFR § 800.2(c) (4). In doing so, RUS may not delegate its responsibility to conduct government-to-government consultation with Indian tribes to an applicant, unless RUS and that tribe agree, in writing, to conduct consultation in that manner.

C. Prior to construction of the 230kV transmission line WESTERN will own, WESTERN will complete the requirements of 36 CFR §§ 800.3 through 800.7. In implementing Stipulation IV.C., WESTERN will serve as a signatory party under the DOS PA. WESTERN shall coordinate implementation of Stipulation IV.C with the DOS.

D. RUS will ensure that the terms of Stipulation VI.B and Attachment C are incorporated into construction contracts to ensure that its applicants and construction contractors meet their responsibility for notification of any unanticipated discoveries. When RUS funded projects occur on BLM land, the RUS will coordinate with BLM to ensure compliance with Stipulation VI.B. and Attachment C of this Agreement.

E. Prior to granting approval or financial assistance for construction or modification of electrical distribution/transmission facilities that are necessary components of the pipeline project and therefore considered within the Project APE, any federal agency that is incorporated into this agreement pursuant to Stipulation XIV will complete the requirements of 36 CFR §§ 800.3 through 800.7 for those facilities under its jurisdiction if not already carried out elsewhere in this agreement.

F. DOS retains responsibility for completing the requirements of 36 CFR §§ 800.3 through 800.7 for those electrical distribution/transmission facilities that are necessary components of the Project if they are not under the jurisdiction of any federal agency and not referenced in Stipulation IV. A through E above.

V. KEYSTONE XL PROJECT – PIPELINE CONSTRUCTION

A. The DOS provided SHPOs, consulting Indian tribes, and other consulting parties with an opportunity to provide their views on the identification and evaluation of historic properties (as defined in 36 CFR § 800.16(l), including historic properties of religious and cultural significance to Indian tribes, and the treatment of affected historic properties,

in connection with the construction of the Keystone XL Project as described in Stipulation V.C of this PA.

B. Identification and Evaluation of Historic Properties

1. In consultation with the SHPOs, consulting Indian tribes, and other consulting parties, the DOS will make a reasonable and good faith effort to complete the identification and evaluation of historic properties within the APE for each construction spread prior to the initiation of construction of that spread, in accordance with 36 CFR §§ 800.4(a), (b) and (c). On federal lands, the scope of the identification effort will be determined by the appropriate federal land managing agency in consultation with the DOS, applicable SHPOs, consulting Indian tribes, and other consulting parties.

2. For the APE in Montana, South Dakota, Nebraska, Kansas, Oklahoma, and Texas, DOS will make a reasonable and good faith effort to complete the identification and evaluation of historic properties, in accordance with 36 CFR §§ 800.4(a), (b) and (c), before Keystone initiates construction activities (including vegetative clearing to comply with the Migratory Bird Treaty Act if clearing is undertaken).

   a. In the identification and evaluation of historic properties to which Indian tribes attach religious and cultural significance, the DOS will take into consideration information submitted by Indian tribes to DOS prior to construction.

   b. In the event identification of historic properties cannot be completed for any construction spreads prior to construction, Keystone will develop and submit a Coordination Plan to DOS for review and approval pursuant to Stipulation V.D that describes the measures it will implement to complete the identification and evaluation of historic properties before such properties are adversely affected by vegetation clearing and construction activities related to that spread.

C. Treatment of Historic Properties

1. Whenever feasible, avoidance of adverse effects to historic properties will be the preferred treatment. In consultation with the DOS, ACHP, SHPOs, THPOs, and consulting parties, Keystone may elect to consider and implement avoidance measures prior to completing the evaluation of historic properties.

   Avoidance and minimization measures may include:
   a. Avoidance through pipeline or access road route variation or Project feature relocation;
   b. Avoidance through abandonment;
   c. Avoidance through bore or horizontal directional drill;
   d. Avoidance by narrowing the construction corridor (“neck down”); and
   e. Avoidance through the use of existing roadways as Project access roads to the extent practicable.

2. When historic properties are identified in the APE pursuant to Stipulation V.B, DOS will apply the criteria of adverse effect in accordance with 36 CFR § 800.5(a) in consultation with the ACHP, SHPO and other consulting parties. If DOS finds that historic properties might be adversely affected by actions covered under this PA and within the APE, DOS will consult with the ACHP, SHPOs, consulting Indian tribes, and other consulting parties to determine prudent and feasible ways to avoid adverse effects.

    a. Once DOS approves avoidance measures, Keystone will implement those measures.

3. If DOS determines that the adverse effect cannot be avoided, DOS will consult with the ACHP, SHPOs, consulting Indian tribes, and other consulting parties to determine those measures to be implemented by Keystone to minimize and mitigate adverse effects on affected historic properties identified in the APE.

4. If, after consultation, DOS determines that the adverse effect cannot be avoided, Keystone will draft a comprehensive Treatment Plan for each adversely affected historic property. The Treatment Plan describes the measures identified by DOS under Stipulation V.C.3 to minimize and mitigate the adverse effect of pipeline construction activities on historic properties, the manner in which these measures will be carried out, and a schedule for their implementation.

    a. When mitigation consists of or includes data recovery, the Treatment Plan also will identify the specific research questions to be addressed by data recovery with an explanation of their relevance, the archaeological methods to be used, and provisions for public interpretation and education, subject to Stipulation II restrictions, if any.

    b. A Treatment Plan may also include mitigation for adverse effects to historic districts, buildings and structures. This mitigation may include the recordation of historic properties according to Historic American Building Survey/Historic American Engineering Record Standards and Guidelines for Architectural and Engineering Documentation. Other types of mitigation for adverse effects to historic districts, buildings, and structures may also be described in the Treatment Plan. The mitigation proposed for an adverse effect to a historic district, building, and/or structure will be commensurate with the level of significance and extent of adverse effect and will be determined in a manner consistent with Stipulation V.C.4.c.

    c. Keystone will submit the draft Treatment Plan to the DOS, BLM (if applicable), ACHP, THPOs, the SHPO of the applicable state, MT DEQ (if applicable), MT DNRC (if applicable), and other applicable consulting parties for a thirty (30) calendar day review. Keystone shall address timely comments and recommendations submitted by SHPOs, consulting Indian tribes, and other consulting parties in preparation of the Final Treatment Plan.

d. When it has addressed all of the timely comments and recommendations, Keystone will submit the Final Treatment Plan to DOS for review and approval. Keystone will also submit the Final Treatment Plan to BLM for review and approval when involving lands subject to Stipulation III.C. DOS and BLM shall issue their final decision on the Treatment Plan within thirty (30) calendar days. Once the Final Treatment Plan is approved by DOS (and the BLM if involving BLM-managed lands), copies of the Treatment Plan will be distributed to all SHPOs, consulting Indian tribes, and other consulting parties.

5. Keystone will make a reasonable and good faith effort to complete implementation of the Final Treatment Plan approved by DOS prior to beginning construction of any spread for which the Treatment Plan is required. If it is not possible to meet this schedule, Keystone will develop a Coordination Plan in accordance with Stipulation V.D that establishes how appropriate treatment will be determined and implemented during construction of the respective spread.

D. Coordination of Construction and Historic Preservation Activities

1. The DOS will make a reasonable and good faith effort to complete the identification and evaluation of historic properties, and the mitigation of adverse effects to them in accordance with Stipulations V.B and V.C prior to the initiation of vegetative clearing if vegetative clearing and construction on the Keystone XL spreads, including the Montana, South Dakota, Nebraska, Kansas, Oklahoma and Texas spreads, is to be undertaken.

2. If these DOS activities cannot be completed prior to the start of vegetative clearing and construction of these spreads, Keystone shall develop and provide to DOS a detailed plan describing how the requirements of Stipulations V.B and V.C – identification, evaluation and treatment of historic properties – will be completed in coordination with vegetative clearing and construction activities in such a way that historic properties will not be adversely affected prior to the implementation of any mitigation measures.

   a. A Coordination Plan will be prepared for each state and will include those measures developed by Keystone pursuant to Stipulations V.B and V.C to complete the identification and evaluation of historic properties, and, as appropriate, mitigation of adverse effects to them during and coordinated with vegetation clearing and construction activities. In addition, the Coordination Plan will include a schedule for all proposed activities and recommended measures for the protection of unanticipated discoveries in accordance with Attachment C, as appropriate.

   b. Keystone will submit the draft Coordination Plan for each state for such spreads, including the Montana, South Dakota, Nebraska, Kansas, Oklahoma and Texas spreads, to the DOS, BLM (as applicable) ACHP, SHPOs, THPOs, and consulting

parties for thirty (30) calendar day review. Keystone shall address timely comments and recommendations submitted by the applicable SHPO, consulting Indian tribes, and other consulting parties in preparation of the Final Coordination Plan for each state. When it has addressed all of the comments and recommendations, Keystone will submit the Final Coordination Plan for each state to DOS for review. DOS shall issue its final decision on the Coordination Plan for each state within thirty (30) calendar days. Following approval by DOS, the Final Coordination Plan for each state will be distributed to all of the SHPOs, consulting Indian tribes, and other consulting parties.

3. Keystone will complete implementation of the Final Coordination Plan approved by DOS during construction of the Montana, South Dakota, Nebraska, Kansas, Oklahoma and Texas spreads.

E. Historic Trail and Archaeological Monitoring Plan ("HTAM Plan") and Tribal Monitoring Plan

1. In consultation with the SHPOs and Indian tribes, Keystone will monitor construction in selected areas of the APE of each spread as a supplement to identification efforts. Any historic properties identified by Keystone during monitoring will be treated in accordance with Stipulation VI.A and C.

   a. The HTAM Plan outlines areas that have been previously identified by DOS during identification and evaluation efforts that warrant monitoring during soil disturbing activities for potential effects to historic properties.

   b. The Tribal Monitoring Plan outlines areas that have been previously identified by Indian Tribes, either through the preparation of Traditional Cultural Property reports or through consultation, that warrant monitoring during clearing and trenching for potential effects to previously unidentified historic properties that may include properties of religious and cultural importance to an Indian tribe and that meet the National Register criteria (See 36 C.F.R. § 800.16(1)(a)).

2. Historic Trail monitoring will be performed by a professional who either meets the qualification standards for archaeology established in Stipulation I.A or is under the on-site supervision of such a professional. When the monitoring occurs on BLM managed lands, all monitors must have a valid Archaeological Resources Protection Act (ARPA) permit or be included on a BLM Cultural Resource Use Permit.

3. For tribal monitoring, other types of experience with construction monitoring and/or traditional cultural knowledge may be substituted for degrees required by the Standards at the discretion of the DOS. When the monitoring occurs on BLM managed lands, all monitors must have a valid Archaeological Resources Protection Act (ARPA) permit or be included on a BLM Cultural Resource Use Permit.

4. Keystone shall consider information provided by Indian tribes in a timely manner when completing the identification of historic properties before construction begins under Stipulation V.B and in implementing a HTAM Plan and Tribal Monitoring Plan provided for under Stipulation V.E. Keystone shall provide Indian tribes a reasonable opportunity to participate as monitors during Project construction. In those areas previously identified by Indian tribes as needing monitoring, the Tribal Monitoring Plan stipulates that at least one and at most two monitors will be used per construction spread depending upon the extent and location of construction activities.

5. Keystone has submitted a plan for historic trail and archaeological monitoring and tribal monitoring for each spread to the DOS, BLM, ACHP, SHPO, THPOs, and Consulting Parties for review and comment prior to the signing of this Agreement. The Tribal Monitoring Plan and HTAM Plan are attached to this agreement in Attachments E and F.

6. Keystone will implement the HTAM Plan and Tribal Monitoring Plan for each spread that has been approved by DOS.

F. Construction

1. Lead Environmental Inspector (EI): Prior to initiating vegetative clearing or construction, Keystone will employ the Lead EI whose responsibilities will include ensuring compliance with the terms of this PA. In meeting this responsibility, the Lead EI will rely on the technical expertise of on-site professionals who meet the standards established in Stipulation I.A and tribal monitors with experience outlined in Stipulation V.E.3.

    a. The Lead EI will monitor construction activities on-site and prepare a daily log reporting to Keystone on activities performed to implement the terms of this PA, as appropriate. Keystone will make the daily log available to the DOS and SHPOs, consulting Indian tribes, and other consulting parties upon request.

    b. Keystone will ensure through the construction contract that the Lead EI will possess the authority to stop construction in the event of an inadvertent discovery in accordance with Stipulation VI.A and Attachment C.

2. Training: Keystone will ensure that if the Lead EI does not meet the professional qualification standards established in Stipulation I.A, the Lead EI receives appropriate training in historic preservation from a professional who meets the standards established in Stipulation I.A in order to perform the requirements of this PA. Keystone also will provide an appropriate level of training in historic preservation conducted by a professional who meets the standards established in Stipulation I.A to all construction personnel (including new, added, replaced workers) so that PA requirements are understood and unanticipated discoveries quickly identified. Keystone will conduct this training prior to initiating vegetative clearing or

construction activities on a spread, and conduct periodic refresher training during construction of the spread.

3. This Programmatic Agreement and Attachment E, the Tribal Monitoring Plan, have given tribes the opportunity to provide information about historic properties of concern to the tribe(s).

4. Construction Contract: Keystone will incorporate the terms of Stipulation VI.A and Attachment C into construction contracts to ensure that its Lead EI and construction contractors meet their responsibility for notification of the unanticipated discoveries.

G. Scheduling

The DOS may authorize the start of vegetative clearing and construction for an individual spread when the plans prepared in accordance with Stipulations V.D and V.E as appropriate for that spread, have been submitted by Keystone and approved by DOS in accordance with the terms of this PA.

VI. UNANTICIPATED DISCOVERIES DURING CONSTRUCTION OF THE KEYSTONE XL PROJECT

A. Pipeline Construction

1. "Applicable federal agency" is the federal agency with jurisdiction for the land on which construction is occurring or, in the absence of such an agency, DOS, as appropriate.

2. If previously unidentified historic properties are discovered by monitors or construction personnel unexpectedly as pipeline construction activities are carried out within the one-hundred and ten (110) foot-wide construction corridor or other ancillary facilities and access roads within the APE, the construction contractor will immediately halt all construction activity within a one-hundred and fifty (150) foot radius of the discovery, notify Keystone's Lead EI of the discovery and implement interim measures to protect the discovery from looting and vandalism. Within forty-eight (48) hours of receipt of this notification of the discovery, the Lead EI shall:

   a. Inspect the work site to determine the extent of the discovery and ensure that construction activities have halted;
   b. Clearly mark the area of the discovery;
   c. Implement additional measures other than those mentioned above, as appropriate, to protect the discovery from looting and vandalism; and
   d. Notify the applicable federal agency SHPOs, consulting Indian tribes, and other consulting parties of the discovery.

3. The applicable federal agency shall notify all consulting parties that it will be receiving comments concerning the unanticipated discovery and provide contact information. The applicable federal agency will have seven (7) calendar days following notification provided in accordance with Stipulation VI.A.2 to determine the National Register eligibility of the discovery after considering the timely filed views of the SHPOs, consulting Indian tribes, and other consulting parties and Keystone . The applicable federal agency may assume the newly discovered property to be eligible for the National Register for the purposes of Section 106 pursuant to 36 CFR § 800.13(c).

4. For properties determined eligible or assumed to be eligible pursuant to Stipulation VI.A.3, the applicable federal agency will notify the ACHP, SHPOs, consulting Indian tribes, and other consulting parties of those actions that it proposes to resolve adverse effects which may include a Treatment Plan as outlined in Stipulation V.C.

    a. SHPOs, consulting Indian tribes, and other consulting parties will have forty-eight (48) hours to provide their views on the proposed actions.
    b. The applicable federal agency will ensure that the timely filed recommendations of SHPOs, consulting Indian tribes, and other consulting parties are taken into account prior to granting approval of the measures that Keystone will implement to resolve adverse effects.
    c. Keystone will carry out the approved measures prior to resuming construction activities in the location of the discovery.

5. Dispute Resolution: The applicable federal agency will seek and take into account the recommendations of the ACHP in resolving any disagreements that may arise regarding resolution of adverse effects that relate to the implementation of Stipulation VI. The applicable federal agency will use the contact information provided in Attachment C or D in order to notify the ACHP. Within seven (7) calendar days of receipt of such a written request, the ACHP will provide the applicable federal agency with recommendations on resolving the dispute. The applicable federal agency will take into account any timely filed recommendations provided by the ACHP in making a final decision about how to proceed.

B. Construction or Modification of Electrical Transmission Facilities

1. If previously unidentified historic properties are discovered unexpectedly during construction or modification of transmission facilities funded by RUS, the RUS applicant's construction contractor will immediately halt all construction activity within a one-hundred and fifty (150) foot radius of the discovery, notify the RUS applicant of the discovery and implement interim measures to protect the discovery from looting and vandalism. Within forty-eight (48) hours of receipt of this notification of the discovery, the RUS applicant shall:

    a. Notify the RUS Contact (and BLM Contact if discovery occurs on BLM land);

b. Inspect the work site to determine the extent of the discovery and ensure that construction activities have halted;
c. Clearly mark the area of the discovery; and
d. Implement additional measures, as appropriate, to protect the discovery from looting and vandalism.

2. Upon receipt of such notification RUS and BLM (if applicable) will coordinate the notification of SHPOs, consulting Indian tribes, and other consulting parties and notify the SHPOs, consulting Indian tribes, and other consulting parties of the discovery.

3. RUS and BLM (if applicable) will have seven (7) calendar days following notification provided in accordance with Stipulation VI.B.1 to determine the National Register eligibility of the discovery in consultation with the SHPOs, consulting Indian tribes, other consulting parties, and Keystone. RUS may assume the newly discovered property to be eligible for the National Register for the purposes of Section 106 pursuant to 36 CFR § 800.13(c).

4. For properties determined eligible pursuant to Stipulation VI.B.3, RUS, in coordination with the BLM (if applicable), will notify the SHPOs, consulting Indian tribes, and other consulting parties of those actions that it proposes to resolve adverse effects. SHPOs, consulting Indian tribes, and other consulting parties will provide their views on the proposed actions within forty-eight (48) hours. RUS will ensure that the timely filed recommendations of the SHPOs, consulting Indian tribes, and other consulting parties are taken into account prior to granting approval of those actions that the applicant will implement to resolve adverse effects. Once RUS approval has been granted, its applicant will carry out the approved measures prior to resuming construction activities in the location of the discovery.

5. Dispute Resolution: RUS and BLM (if applicable) will seek and take into account the recommendations of the ACHP in resolving any disagreements that may arise regarding the resolution of adverse effects that relate to the implementation of Stipulation VI. The applicable federal agency will use the contact information provided in Attachment D in order to notify the ACHP. Within seven (7) calendar days of receipt of such a written request, the ACHP will provide RUS and BLM (if applicable) with its recommendations for resolving the dispute. RUS and BLM (if applicable) will take into account any recommendations provided by the ACHP in making a final decision about how to proceed.

6. Reporting: No later than six (6) months following the resumption of construction within the location of the discovery, RUS will submit a final report to the SHPOs, consulting Indian tribes, and other consulting parties describing implementation of the actions taken in accordance with Stipulation VI.B and, as appropriate, the analysis and interpretation of recovered information.

C. Unanticipated Discovery of Human Burials and Remains, and Funerary Objects

1. When Native American human remains or funerary objects or objects of cultural patrimony are unexpectedly discovered during construction of the Keystone XL Project on federal or tribal lands within the APE, Keystone or a RUS applicant, as appropriate, will notify immediately the federal agency responsible for compliance with the Native American Graves Protection and Repatriation Act (NAGPRA) [25 U.S.C. 3001 et. seq.] and its implementing regulations, 43 C.F.R. Part 10.

2. Non-Native American human burials and remains, and funerary objects discovered on federal lands within the APE will be treated by the federal agency having jurisdiction of the remains in accordance with applicable federal law, taking into account the ACHP's *Policy Statement on the Treatment of Burial Sites, Human Remains and Funerary Objects* (February 23, 2007).

3. DOS, WESTERN, and RUS will treat human burials and remains discovered on non-federal land in accordance with the provisions of Attachment C and any applicable laws. In those instances where the USACE has jurisdiction under Section 10 or 404 permitting authority for non-federal lands in the APE, the applicable federal agencies will ensure that Keystone complies with the provisions of Attachment C acting in the place of the DOS. In determining appropriate actions to be carried out, DOS, RUS, and/or other federal agencies will be guided by the ACHP's *Policy Statement on the Treatment of Burial Sites, Human Remains and Funerary Objects* (February 23, 2007).

VII. CURATION

A. Federal agencies will curate any artifacts, materials or records resulting from archaeological identification and mitigation conducted on federal lands under their jurisdiction in accordance with 36 CFR Part 79, "*Curation of Federally-Owned and Administered Archaeological Collections*." Federal agencies with jurisdiction over the federal lands will consult with Indian tribes as required in 36 CFR 79.

B. Keystone and RUS applicants will return all artifacts recovered from private lands to the respective landowner after analysis is complete, unless applicable state law requires otherwise. Keystone and RUS applicants will encourage and assist landowners in donating any returned artifacts to a local curation facility identified by the respective SHPO. Keystone and RUS applicants shall pay all required curation fees associated with the donation of artifacts to the local curation facility.

C. On federally controlled or owned properties, federal agencies will determine the disposition of human burials, human remains and funerary objects in accordance with applicable federal law.

VIII. REPORTING

A. Within three months of completion of pipeline construction of a spread, Keystone will submit a comprehensive draft report to DOS describing the results and findings of the implementation of the actions and plans specified in Stipulations V.C through G, VI.A, including Attachment C.

B. Keystone will submit a draft comprehensive report for each spread to the SHPOs, consulting Indian tribes, and other consulting parties of the respective states in which the spread is located, for thirty (30) day review and comment. Keystone shall address timely comments and recommendations submitted by SHPOs, consulting Indian tribes, and other consulting parties in preparation of the Final Comprehensive Report for that spread. Keystone will submit the final report to DOS for review and approval. The final comprehensive report will be provided by DOS to the SHPOs, consulting Indian tribes, and other consulting parties once approved.

IX. MONITORING IMPLEMENTATION OF THE PA

Each quarter following the execution of this PA until it expires or is terminated, the DOS with the assistance of the USACE, BLM, RUS, FSA, NRCS, BIA, and RECLAMATION as necessary will provide the SHPOs, consulting Indian tribes, and other consulting parties to this PA a progress report summarizing the work carried out pursuant to its terms. Such report will include any scheduling changes proposed, any problems encountered, and any disputes and objections received in the efforts to carry out the terms of this PA. DOS will maintain and update a list of the current contact for the SHPOs, consulting Indian tribes, and other consulting parties and will be distributed in each quarterly report.

X. DISPUTE RESOLUTION

A. "Appropriate federal agency" refers to the DOS, BLM, RUS, RECLAMATION, and USACE, or other federal land managing and/or permitting agency as applicable.

B. Should any signatory or concurring party to this PA object at any time to any actions proposed or the manner in which the terms of this PA are implemented, the appropriate federal agency will consult with such party to resolve the objection. If the appropriate federal agency determines that such objection cannot be resolved, the appropriate federal agency will:

1. Forward all documentation relevant to the dispute, including the applicable federal agency's proposed resolution, to the ACHP. The ACHP will provide the appropriate federal agency with its advice on the resolution of the objection within thirty (30) calendar days of receiving adequate documentation. Prior to reaching a final decision on the dispute, the appropriate federal agency will prepare a written response that takes into account any timely advice or comments regarding the dispute from the ACHP, signatories and concurring parties, and provide them with a copy of this written response. The appropriate federal agency will then proceed according to its final decision.

2. If the ACHP does not provide its advice regarding the dispute within the thirty (30) calendar day time period, the applicable federal agency may make a final decision on the dispute and proceed accordingly. Prior to reaching such a final decision, the appropriate federal agency will prepare a written response that takes into account any timely comments regarding the dispute from the signatories and concurring parties to the PA, and provide them and the ACHP with a copy of such written response.

C. The federal agencies are responsible for carrying out all other actions subject to the terms of this PA that are not the subject of the dispute.

D. The process of dispute resolution outlined in Stipulation X does not pertain to disputes that arise from unanticipated discoveries covered in Stipulation VI.

XI. DURATION

This PA will be null and void if all of its stipulations have not been carried out within five (5) years from the date of its execution. At such time, and prior to work continuing on the Keystone XL Project, the DOS, USACE, BLM, RUS, WESTERN, RECLAMATION and NPS will either (a) execute a Memorandum of Agreement (MOA) or PA pursuant to 36 CFR §§ 800.6 or 800.14(b), respectively, or (b) request, take into account, and respond to the comments of the ACHP under 36 CFR. § 800.7. Prior to such time, the DOS may consult with the other signatories to reconsider the terms of the PA and amend it in accordance with Stipulation XII. The DOS, USACE, BLM, RUS, WESTERN, RECLAMATION and NPS will notify the signatories and concurring parties as to the course of action they will pursue.

XII. AMENDMENT

Any signatory party to this PA may propose in writing to the other signatory parties that it be amended. The signatory parties will consult in an effort to reach agreement on an amendment. Any amendment will be effective on the date it is signed by all of the signatories and filed with the ACHP.

XIII. TERMINATION

A. If any signatory to this PA determines that its terms will not or cannot be carried out, that party will immediately consult with the other parties to attempt to develop an amendment per Stipulation XII. If within thirty (30) calendar days an amendment cannot be reached, any signatory may terminate its participation in the PA upon written notification to the other signatories.

B. Termination by an individual SHPO shall only terminate the application of this Agreement within the jurisdiction of the SHPO.

C. If the PA is terminated in its entirety, and prior to work continuing on the undertaking, the DOS shall request, take into account, and respond to the comments of the ACHP in accordance with 36 CFR § 800.7(a). Following consultation with the ACHP, the DOS will notify the signatories and concurring parties as to the course of action it will pursue.

XIV. COORDINATION WITH OTHER FEDERAL REVIEWS

In the event that Keystone or a federal agency applies for additional federal funding or approvals for the Keystone XL Project and the undertaking remains unchanged, such funding or approving agency may comply with Section 106 by agreeing in writing to the terms of this PA and notifying and consulting with the applicable SHPO and the ACHP. Any necessary modifications will be considered in accordance with Stipulation XII.

XV. SCOPE OF THE PA

This Agreement is limited in scope to actions that will facilitate the construction of the Keystone XL Project and related facilities, and is entered into solely for that purpose.

EXECUTION of this PA by the DOS, ACHP, BLM, RUS, WESTERN, USACE, RECLAMATION, NPS, NRCS, FSA, BIA, the Montana SHPO, South Dakota SHPO, Nebraska SHPO, Kansas SHPO, Oklahoma SHPO, and Texas SHPO and implementation of its terms evidence that the DOS, WESTERN, BLM, RUS, NRCS, FSA, BIA, USACE, RECLAMATION, and NPS have taken into account the effects of the Keystone XL Project on historic properties and afforded the ACHP an opportunity to comment.

4 Aug 2011

United States Department of State | Date

2 Aug 11

Robert J. Ruch
Colonel, Corps of Engineers
District Commander

Date

Deborah K. Johnson Morford — Aug. 10, 2011

Deborah Johnson Morford
Field Manager, Miles City Field Office
Bureau of Land Management

Date

July 11, 2011

Michael J. Ryan
Regional Director, Great Plains Region
Bureau of Reclamation

Date

RECEIVED
JUL 14 2011
Cardno ENTRIX
Seattle

Alice A. Harwood 7/15/11

Weldon Loudermilk
Great Plains Regional Director
UnitedStates Bureau of Indian Affairs

Date

Mark S. Plank 7/12/11

Mark S. Plank
Director, Engineering and Environmental Staff
United States Department of Agriculture Rural Utilities Service

Date

July 21, 2011

Matthew T. Ponish
National Environmental Compliance Manager
United States Department of Agriculture Farm Service Agency

Date

RECEIVED

AUG 01 2011

Cardno ENTRIX
Seattle

AUG 0 3 2011

~~Don Gohmert~~ Salvador Salinas **Acting** Date

State Conservationist

United States Department of Agriculture Natural Resources Conservation Services

Robert D. Harris 7/14/11

Robert Harris
Regional Manager, Upper Great Plains Region
Western Area Power Administration (WESTERN)

Date

for Charlene Dwin Vaughn 8/12/11

John M. Fowler
Executive Director
Advisory Council on Historic Preservation

Date

Mark Wolfe 7/21/11

Mark Wolfe
State Historic Preservation Officer
Texas

Date

RECEIVED
JUL 25 2011
Cardno ENTRIX
Seattle

Jennie Chinn
State Historic Preservation Officer
Kansas

7-7-11
Date

Mark Baumler 7/8/2011

Mark Baumler, Ph.D. Date
State Historic Preservation Officer
Montana

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JUL 14 2011
Cardno ENTRIX
Seattle

Michael J. Smith
State Historic Preservation Officer
Nebraska

08-03-2011
Date

Bob L. Blackburn July 13, 2011

Dr. Bob L. Blackburn
State Historic Preservation Officer
Oklahoma

Date

Jay D. Vogt 07-08-2011

Mr. Jay D. Vogt
State Historic Preservation Officer
South Dakota

Date

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JUL 11 2011

Cardno ENTRIX
Seattle

4 August 2011

Date

John Wessels
Regional Director, Intermountain Region
National Park Service
(invited signatory)

7-25-2011

Mary Sexton
Director
Montana Department of Natural Resources and Conservation
(invited signatory)

Date

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JUL 29 2011
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Seattle

7/18/11

Richard Opper
Director
Montana Department of Environmental Quality
(invited signatory)

Date

July 21/2011

David Montemurro
TransCanada Keystone XL Pipeline, L.P.
(invited signatory)

21-July-2011

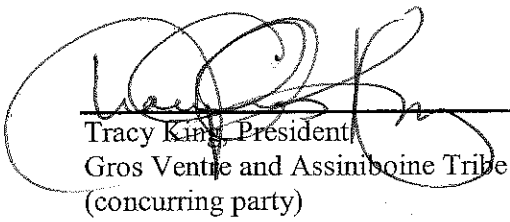
Robert Jones
Vice President

Carlos Bullock 8-8-11

Carlos Bullock, Tribal Council Chairman — Date
Alabama-Coushatta Tribe of Texas
(concurring party)

Willie Sharp, Chairman
Blackfeet Nation
(concurring party)

8/4/11
Date



7/28/2014
Date

Tracy King, President
Gros Ventre and Assiniboine Tribe of Ft. Belknap
(concurring party)

7-8-11

Tim Rhodd, Chairman
Iowa Tribe of Kansas and Nebraska
(concurring party)

Date

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JUL 14 2011
Cardno ENTRIX
Seattle

Thomas Gamble, ~~Chairman~~ Chief
Miami Tribe of Oklahoma
(concurring party)

7-25-11
Date

For [signature] 8/5/11

Jim Shakespeare, Chairman
Northern Arapaho Tribe
(concurring party)

Date

8-2-11

Marshall Gover, President
Pawnee Nation of Oklahoma
(concurring party)

Date

ATTACHMENT A

The following Tables show properties for which Keystone has been denied access to conduct identification and evaluation studies as of the finalization of the PA.

Table 1: Areas Not Surveyed along Mainline Route in Montana					
State	**County**	**From Milepost**	**To Milepost**	**Status**	**Miles**
Montana	Fallon	249.1	250.2	Needs survey	1.1
Montana	Fallon	227.2	227.4	Needs survey	0.2
Montana	Fallon	228.1	228.1	Surveyed on November 2010 CL; Addendum 6 in progress	0.01
Montana	Dawson	0.2	1.4	Needs survey	1.2
Montana	Dawson	4.8	6.3	Needs survey	1.5
Montana	Dawson	7.6	9.1	Needs survey	1.5
Montana	Dawson	17.2	17.6	Needs survey	0.5
Montana	Dawson	17.9	18.4	Needs survey	0.5
Montana	Dawson	18.4	19.1	Needs survey	0.7
Montana	Dawson	20.4	20.7	Surveyed on November 2010 CL; Addendum 6 in progress	0.3
Montana	Dawson	21.7	22.2	Surveyed on November 2010 CL; Addendum 6 in progress	0.4
Montana	McCone	148.4	149.7	Needs survey; Incorporated into November 2010 CL	1.3
Montana	McCone	144.4	144.5	Needs survey; Incorporated into November 2010 CL	0.1
Montana	Valley	1.1	1.2	Needs survey; Incorporated into November 2010 CL-MT-LO-01	0.1
Montana	Dawson	1.9	2	Needs survey; Incorporated into November 2010 CL	0.1
Montana	Fallon	0	0.01	Needs survey	0.01
Montana	McCone	0	0.5	Needs survey	0.5

Table 1: Areas Not Surveyed along Mainline Route in Montana					
State	**County**	**From Milepost**	**To Milepost**	**Status**	**Miles**
Montana	McCone	0	2.2	Surveyed on November 2010 CL; Addendum 6 in progress	2.2
Montana	Dawson	0	1.9	Surveyed on November 2010 CL; Addendum 6 in progress	1.9
Montana	Dawson	1	2	Surveyed on November 2010 CL; Addendum 6 in progress	2
Montana	Sheridan			Surveyed on November 2010 CL; Addendum 6 in progress	
Montana	Roosevelt			Surveyed on November 2010 CL; Addendum 6 in progress	
Montana	Prairie			Needs survey	

Table 2: Areas Not Surveyed along Mainline Route in South Dakota					
State	**County**	**From Milepost**	**To Milepost**	**Status**	**Miles**
South Dakota	Harding	352.8	353.7	Needs survey	0.9
South Dakota	Meade	417.9	418.2	Needs survey	0.3
South Dakota	Haakon	481.4	481.5	Surveyed on November 2010 CL; Addendum 7 in progress	0.1
South Dakota	Jones	492	492.6	Needs survey	0.6
South Dakota	Dawson	194	194.5	Surveyed on November 2010 CL; Addendum 7 in progress	0.5
South Dakota	Harding	2.9	3.2	Needs survey	0.3
South Dakota	Harding	3.8	4.4	Needs survey	0.3
South Dakota	Meade	1.1	1.3	Surveyed on November 2010 CL; Addendum 7 in progress	0.1

Table 2: Areas Not Surveyed along Mainline Route in South Dakota					
State	**County**	**From Milepost**	**To Milepost**	**Status**	**Miles**
South Dakota	Hughes			Surveyed on November 2010 CL; Addendum 7 in progress	

Table 3: Areas Not Surveyed along Mainline Route in Nebraska					
State	**County**	**From Milepost**	**To Milepost**	**Status**	**Miles**
Nebraska	Keya Paha	599.70	600.50	Surveyed 6-4-11 on Nov 2010 CL; Addendum No. 7 report in progress	0.80
Nebraska	Keya Paha	600.90	601.50	Needs survey	0.60
Nebraska	Keya Paha	614.20	614.45	Needs survey	0.25
Nebraska	Holt	630.80	631.65	Surveyed 6-2-11 on Nov 2010 CL; Addendum No. 7 report in progress	0.85
Nebraska	Holt	632.70	633.15	Surveyed 6-7-11 on Nov 2010 CL; Addendum No. 7 report in progress	0.45
Nebraska	Holt	634.75	635.45	Surveyed 6-3-11 on Nov 2010 CL; Addendum No. 7 report in progress	0.70
Nebraska	Holt	653.55	655.45	Surveyed 6-7-11 on Nov 2010 CL; Addendum No. 7 report in progress	1.90
Nebraska	Holt	656.80	657.90	Surveyed 6-3-11 on Nov 2010 CL; Addendum No. 7 report in progress	1.10
Nebraska	Garfield	672.55	679.50	Not on Nov 2010 CL	6.95
Nebraska	Wheeler	687.60	687.90	Surveyed 6-10-11 on Nov 2010 CL; Addendum No. 7 report in progress	0.30
Nebraska	Wheeler	688.15	688.35	Surveyed 6-10-11 on Nov 2010 CL; Addendum No. 7 report in progress	0.20

Table 3: Areas Not Surveyed along Mainline Route in Nebraska					
State	County	From Milepost	To Milepost	Status	Miles
Nebraska	Wheeler	688.70	688.95	Surveyed 6-10-11 on Nov 2010 CL; Addendum No. 7 report in progress	0.25
Nebraska	Wheeler	691.40	691.65	Surveyed 6-11-11 on Nov 2010 CL; Addendum No. 7 report in progress by applicant	0.25
Nebraska	Wheeler	692.70	693.35	Surveyed 6-11-11 on Nov 2010 CL; Addendum No. 7 report in progress	0.65
Nebraska	Greeley	698.35	698.70	Surveyed 6-6-11 on Nov 2010 CL; Addendum No. 7 report in progress	0.35
Nebraska	Greeley	700.10	700.35	Surveyed 6-6-11 on Nov 2010 CL; Addendum No. 7 report in progress	0.25
Nebraska	Greeley	700.55	702.55	Surveyed 6-6-11 on Nov 2010 CL; Addendum No. 7 report in progress	2.00
Nebraska	Greeley	703.25	705.35	Partially surveyed 6-6-11 on Nov 2010 CL with 1.35 miles no access from MP 704.0 to 705.35; Addendum No. 7 report in progress	1.35
Nebraska	Greeley	709.80	709.80	Surveyed 5-31-11 on Nov 2010 CL; Addendum No. 7 report in progress	0.00
Nebraska	Greeley	716.40	717.10	Surveyed 6-1-11 on Nov 2010 CL; Addendum No. 7 report in progress	0.70
Nebraska	Greeley	799.00	799.10	Surveyed 5-27-11 on Nov 2010 CL; Addendum No. 7 report in progress	0.10
Nebraska	Fillmore	799.40	799.60	Not on Nov 2010 CL	0.20
Nebraska	Fillmore	800.15	800.60	Needs survey	0.45

Table 4: Areas Not Surveyed along Mainline Route in Oklahoma					
State	County	From Milepost	To Milepost	Status	Miles
Oklahoma	Seminole	42.460	n/a	Needs survey	0.39 ac
Oklahoma	Grady	Offline	n/a	Needs survey	74.2 ac
Oklahoma	Hughes	75.650	n/a	Needs survey	0.250
Oklahoma	Hughes	75.70	75.80	Needs survey	0.100
Oklahoma	Pottawatomie	Offline	n/a	Needs survey	17 ac
Oklahoma	Pittsburg	Offline	n/a**	Needs survey	9.12 ac
Oklahoma	Coal	88.640	n/a	Needs survey	0.122
Oklahoma	Atoka	127.440	n/a	Needs survey	3.1 ac
Oklahoma	Atoka	127.60	128.34	Needs survey	0.737
Oklahoma	Bryan	132.800	n/a**	Needs survey	2.529

**Not applicable

Table 5: Areas Not Surveyed along Mainline Route in Texas					
State	County	From Milepost	To Milepost	Status	Miles
Texas	Fannin	160.650	n/a	Needs survey	3 ac
Texas	Fannin	161.85	n/a	Needs survey	0.65 ac
Texas	Lamar	162.30	162.43	Needs survey	0.130
Texas	Lamar	173.980	n/a	Needs survey	2 ac
Texas	Lamar	185.110	n/a	Needs survey	2 ac
Texas	Hopkins	206.880	n/a	Needs survey	0.48 ac
Texas	Franklin	231.31	n/a	Needs survey	0.049
Texas	Wood	233.42	n/a	Needs survey	0.082
Texas	Wood	251.34	251.55	Needs survey	0.210
Texas	Upshur	262.31	262.35	Needs survey	0.040
Texas	Upshur	262.42	n/a	Needs survey	0.002
Texas	Upshur	262.580	n/a	Needs survey	1.29 ac
Texas	Smith	274.64	275.18	Needs survey	0.540
Texas	Smith	275.19	n/a	Needs survey	0.880
Texas	Nacogdoches	Offline	n/a	Needs survey	12.8 ac
Texas	Houston	Offline	n/a	Needs survey	8.3 ac
Texas	Polk	392.290	n/a	Needs survey	0.62 ac
Texas	Liberty	Offline	n/a	Needs survey	13.4 ac
Texas	Jefferson	Offline	n/a	Needs survey	72.6 ac
Texas	Jefferson	453.44	n/a	Needs survey	0.755

Table 5: Areas Not Surveyed along Mainline Route in Texas					
State	County	From Milepost	To Milepost	Status	Miles
Texas	Jefferson	480.77	481.43	Needs survey	0.665
Texas	Jefferson	483.49	483.80	Needs survey	0.300
Texas	Jefferson	482.970	n/a	Needs survey	4.9 ac

ATTACHMENT B

List of Indian Tribes Invited by the Department of State to Participate in Consultation:

Absentee-Shawnee Tribe of Indians of Oklahoma, Alabama Quassarte Tribal Town, Alabama-Coushatta Tribe of Texas, Apache Tribe, Blackfeet Nation, Caddo Nation of Oklahoma, Cherokee Nation, Cheyenne River Sioux, Cheyenne-Arapaho Tribe of Oklahoma, Chickasaw Nation of Oklahoma, Chippewa-Cree Indians, Choctaw Nation of Oklahoma, Citizen Potawatomi Nation, Comanche Nation, Confederated Salish and Kootenai Tribes of the Flathead Indian Nation, Crow Creek Reservation, Crow Creek Sioux Tribe, Crow Tribe of Indians, Delaware Nation, Delaware Tribe of Indians, Eastern Band of Cherokee Indians, Eastern Shawnee Tribe, Eastern Shoshone Tribe, Flandreau Santee Sioux Tribe, Forest County Potawatomi Community of Wisconsin Potawatomi Indians, Fort Berthold Reservation, Fort Peck Tribes, Fort Sill Apache Tribe, Gros Ventre and Assiniboine Tribe of Ft. Belknap, Gun Lake Potawatomi, Hannahville Indian Community of Michigan, Ho-Chunk Nation of Wisconsin, Huron Potawatomi Nation, Iowa Tribe of Kansas and Nebraska, Iowa Tribe of Oklahoma, Jena Band of Choctaw Indians, Jicarilla Apache Tribe, Kaw Nation, Kialegee Tribal Town of the Creek Nation of Oklahoma, Kickapoo Traditional Tribe of Texas, Kickapoo Tribe of Kansas, Kickapoo Tribe of Oklahoma, Kiowa Indian Tribe of Oklahoma, Lower Brule Sioux Tribe, Lower Sioux Indian Community, Miami Tribe of Oklahoma, Mille Lacs Band of Ojibwe, Modoc Tribe of Oklahoma, Muscogee Creek Nation, Nez Perce, Northern Arapaho Tribe, Northern Cheyenne Tribe, Northern Ute Tribe, Oglala Sioux, Omaha Tribe of Nebraska, Osage Nation, Otoe-Missouri Tribe, Ottawa Tribe of Oklahoma, Pawnee Nation of Oklahoma, Peoria Indian Tribe of Oklahoma, Poarch Band of Creek Indians, Pokagon Band of Potawatomi Indians of Michigan, Ponca Tribe of Indians of Oklahoma, Ponca Tribe of Nebraska, Prairie Band of Potawatomi Indians, Prairie Island Indian Community, Quapaw Tribal Business Committee, Quapaw Tribe, Red Lake Band of Chippewa Indians of Minnesota, Rosebud Sioux Tribe, Sac & Fox Nation of Oklahoma, Sac & Fox Nation of Missouri in Kansas and Nebraska, Sac & Fox Tribe of the Mississippi in Iowa, Santee Sioux Tribe of Nebraska, Seminole Nation, Seneca-Cayuga Tribe of Oklahoma, Shakopee Mdewakanton Sioux, Shawnee Tribe, Shoshone-Bannock Tribe, Sisseton-Wahpeton Oyate Sioux, Sisseton-Wahpeton Oyate Wahpekutze, Southern Ute Indian Tribe, Spirit Lake Tribe, Standing Rock Sioux Tribe, Stockbridge-Munsee Tribe, Thlopthlocco Tribal Town, Three Affiliated Tribes, Tonkawa Tribe, Trenton Indian Service Area, Turtle Mountain Band of the Chippewa, United Keetoowah Band of Cherokee Indians, Upper Sioux -Pezihutazizi Kapi, Ute Mountain Tribe, White Earth Band of Minnesota Chippewa, Wichita and Affiliated Tribes, Winnebago Tribe, Wyandotte Nation, Yankton Sioux, Ysleta del Sur Pueblo

ATTACHMENT C

STATE-BY-STATE PLANS FOR THE UNANTICIPATED DISCOVERY OF HUMAN REMAINS OR BURIALS ON NON-FEDERAL LANDS DURING CONSTRUCTION OF THE KEYSTONE XL PIPELINE PROJECT

I. For construction of the Keystone XL Project in Montana, Keystone will implement the following measures:

1. When an unmarked human burial or unregistered grave is encountered during construction activities, Keystone will comply with the Human Skeletal Remains and Burial Site Protection Act (Montana Code Ann. §22-3-801 through §22-3-811).

2. Upon encountering an unmarked human burial or unregistered grave during ground disturbing construction activities, the construction contractor will immediately stop work within a one-hundred and fifty (150) foot radius from the point of discovery and notify Keystone's Lead Environmental Inspector (EI). The construction contractor will implement interim measures to protect the discovery from vandalism and looting, but must not remove or otherwise disturb any human remains or other items in the immediate vicinity of the discovery.

3. Immediately following receipt of such notification, the Lead EI will ensure that construction activities have halted within a one-hundred and fifty (150) foot radius from the point of discovery and assume responsibility for implementing additional measures, as appropriate, to protect the discovery from looting and vandalism until the requirements of state law have been completed.

4. The Lead EI will notify the county coroner, the DOS, ACHP, SHPO, consulting Indian tribes, and other consulting parties within forty-eight (48) hours of the discovery.

5. Within seventy-two (72) hours after notification, the county coroner will determine jurisdiction. If the coroner refers the matter to the SHPO, the SHPO will determine the treatment, including mitigation and disposition of the unmarked human burial or unregistered grave in accordance with Montana Code Ann. §22-3-801 through §22-3-811. Keystone will implement the treatment and disposition measures deemed appropriate by the SHPO.

6. Keystone will resume construction activities in the area of the discovery upon receipt of written authorization from either the county coroner or the Montana SHPO, whoever has jurisdiction under state law.

II. For construction of the Keystone XL Project in Kansas, Keystone will implement the following measures:

1. When unmarked human burial sites or human skeletal remains are encountered during construction activities, Keystone will comply with Kansas' Unmarked Burial Sites Preservation Act (KSA 75-2741 to 75-2754) and its implementing regulations (KAR 126-1-1 through 126-1-2).

2. Upon encountering unmarked human burials or unregistered graves during ground disturbing construction activities, the construction contractor will immediately stop work within a one-hundred and fifty (150) foot radius from the point of discovery and notify Keystone's Lead EI.

The construction contractor will implement interim measures to protect the discovery from vandalism and looting, but must not remove or otherwise disturb any human remains or other items in the immediate vicinity of the discovery.

3. Immediately following receipt of such notification, the Lead EI will:

    a. Ensure that construction activities have halted within a one-hundred and fifty (150) foot radius from the point of discovery;
    b. Implement additional measures, as appropriate, to protect the discovery from looting and vandalism until the requirements of state law have been completed; and
    c. Notify the appropriate county sheriff's office, the chairperson of the Unmarked Burial Sites Preservation Board (Kansas State Archaeologist), the DOS, the ACHP SHPOs, consulting Indian tribes, and other consulting parties of the discovery.

4. If Keystone determines that disturbance to the unmarked burial site or human remains cannot be avoided, Keystone will consult with the DOS, the SHPO, consulting Indian tribes, and other consulting parties to develop a detailed work plan for treatment of the burial site or human remains that includes provisions for the removal, treatment and disposition of human remains. In accordance with state law, Keystone will submit this work plan to the Unmarked Burial Sites Preservation Board as part of its request for a permit under KAR 126-1-2.

5. Keystone will resume construction activities in the area of the discovery once implementation of the measures authorized under the permit has been completed.

III. For construction of the Keystone XL Project in Nebraska, Keystone will implement the following measures:

1. When unmarked human skeletal remains or burial goods are discovered during construction activities, Keystone will comply with Nebraska Rev. Stat. § 12-1201 through § 12-1212, et seq. and § 28-1301.

2. Upon encountering unmarked human skeletal remains or burial goods during ground disturbing construction activities, the construction contractor will immediately stop work within a one-hundred and fifty (150) foot radius from the point of discovery and notify Keystone's Lead EI. The construction contractor will implement interim measures to protect the discovery from vandalism and looting, but must not remove or otherwise disturb any human remains or other items in the immediate vicinity of the discovery.

3. Immediately following receipt of such notification, the Lead EI will ensure that construction activities have halted within a one-hundred and fifty (150) foot radius from the point of discovery and assume responsibility for implementing additional measures, as appropriate, to protect the discovery from looting and vandalism until the requirements of state law have been completed.

4. Keystone will notify the local law enforcement officer in the county, the DOS, the ACHP, the SHPO, consulting Indian tribes, and other consulting parties within forty-eight (48) hours of the discovery.

5. If local law enforcement determines that the remains are not associated with a crime, Keystone will determine if it is prudent and feasible to avoid disturbing the remains. If Keystone

determines that disturbance cannot be avoided, the Nebraska State Historical Society will notify the Commission on Indian Affairs in writing and seek associated tribes or kin.

6. Keystone will resume construction activities in the area of the discovery when the human skeletal remains or burial goods have been accepted by the Nebraska State Historical Society for the purposes of disposition.

IV. For construction of the Keystone XL Project in Texas, Keystone will implement the following measures:

1. When unmarked human burials or human remains are discovered during construction activities, Keystone will comply with Antiquities Code (Texas Code Ann. §191); Health and Safety (Texas Code Ann. §711.004).

2. Upon encountering unmarked human burials or human remains during ground disturbing construction activities, the construction contractor will immediately stop work within a one-hundred and fifty (150) foot radius from the point of discovery and notify Keystone's Lead EI. The construction contractor will implement interim measures to protect the discovery from vandalism and looting, but must not remove or otherwise disturb any human remains or other items in the immediate vicinity of the discovery.

3. Immediately following receipt of such notification, the Lead EI will:

    a. Ensure that construction activities have halted within a one-hundred and fifty (150) foot radius from the point of discovery;
    b. Implement additional measures, as appropriate, to protect the discovery from looting and vandalism until the requirements of state law have been completed; and
    c. Notify the local law enforcement agency, the DOS, the ACHP, the State Historic Preservation Office (SHPO)/Texas Historical Commission (THC), consulting Indian tribes, and other consulting parties and the State Department of Health of the discovery.

4. If local law enforcement determines that the remains are not associated with a crime, Keystone will determine if it is prudent and feasible to avoid disturbing the remains. If Keystone determines that disturbance cannot be avoided, Keystone will remove and reinter the human remains in accordance with rules adopted by the SHPO and the State Health Department.

5. Keystone will resume construction activities in the area of the discovery once implementation of the measures required by the SHPO/THC and State Health Department has been completed.

V. For construction of the Keystone Project in Oklahoma, Keystone will implement the following measures:

1. When a burial ground, human remains or burial furniture is discovered during construction activities, Keystone will comply with Okla. Stat. Ann. 21 §1161-1168.7 (Oklahoma Burial Law).

2. Upon encountering a burial ground, human remains or burial furniture during ground disturbing construction activities, the construction contractor will immediately stop work within a one-hundred and fifty (150) foot radius from the point of discovery and notify Keystone's Lead EI. The construction contractor will implement interim measures to protect the discovery from

vandalism and looting, but must not remove or otherwise disturb any human remains or other items in the immediate vicinity of the discovery.

3. Immediately following receipt of such notification, the Environmental Inspector will

    a. ensure that construction activities have halted within a one-hundred and fifty (150) foot radius from the point of discovery;
    b. implement additional measures, as appropriate, to protect the discovery from looting and vandalism until the requirements of state law have been completed; and
    c. notify the appropriate law enforcement officer in the county in which the remains have been discovered, the Chief Medical Examiner, the DOS, the ACHP, the SHPO, consulting Indian tribes, other consulting parties, and the landowner of the discovery.

4. Upon learning that remains are not associated with a crime, Keystone has fifteen (15) calendar days within which to notify the SHPO and the Oklahoma State Archaeologist. If the remains have a direct historical relationship to a tribe, the State Archaeologist will notify the SHPO and consults with the tribal leader within fifteen (15) calendar days. If Keystone determines that disturbance cannot be avoided, Keystone will treat the burial site or human remains in accordance with procedures established by the SHPO, the Oklahoma State Archaeologist, and consultation with the tribal leader.

5. Keystone will resume construction activities in the area of the discovery upon completion of the measures authorized by the SHPO and Oklahoma State Archaeologist.

VI. For construction of the Keystone XL Project in South Dakota, Keystone will implement the following measures:

1. When unmarked human skeletal remains and/or funerary objects are discovered during construction activities, Keystone will comply with South Dakota State Law Chapter 34-27.

2. Upon encountering an unmarked human skeletal remains and/or funerary objects during ground disturbing construction activities, the construction contractor will immediately stop work within a one-hundred and fifty (150) foot radius from the point of discovery and notify Keystone's Lead EI. The construction contractor will implement interim measures to protect the discovery from vandalism and looting, but must not remove or otherwise disturb any human remains or other items in the immediate vicinity of the discovery.

3. Immediately following receipt of such notification, the Lead EI will ensure that construction activities have halted within a one-hundred and fifty (150) foot radius from the point of discovery and assume responsibility for implementing additional measures, as appropriate, to protect the discovery from looting and vandalism until the requirements of state law have been completed.

4. The Lead EI will notify the local law enforcement agency, the DOS, the ACHP, the SHPO, the South Dakota State Archaeologist, consulting Indian tribes, and other consulting parties within forty-eight (48) hours of the discovery.

5. If local law enforcement determines that the remains are not associated with a crime, Keystone will determine if it is prudent and feasible to avoid disturbing the remains. If Keystone determines that disturbance cannot be avoided, Keystone will consult with the South Dakota State Archaeologist, SHPOs, consulting Indian tribes, and other consulting parties to determine

acceptable procedures for the removal, treatment and disposition of the human skeletal remains and funerary objects within five (5) calendar days. Keystone will implement the plan for removal, treatment, and disposition of the human skeletal remains and funerary objects as authorized by the South Dakota State Archaeologist.

6. Keystone may resume construction activities in the area of the discovery upon completion of the plan authorized by the State Archaeologist.

EXHIBIT C

APPENDIX E

Amended Programmatic Agreement and Record of Consultation

E1 Amended Programmatic Agreement

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Programmatic Agreement

Among
The U.S. Department of State,
National Park Service,
U.S. Army Corps of Engineers,
U.S. Department of Agriculture Farm Service Agency,
U.S. Department of Agriculture Natural Resources Conservation Service,
U.S. Department of Agriculture Rural Utilities Service,
U.S. Bureau of Indian Affairs,
U.S. Bureau of Land Management,
U. S. Bureau of Reclamation,
Western Area Power Administration,

Advisory Council on Historic Preservation,
Kansas State Historic Preservation Officer,
Montana Department of Environmental Quality,
Montana Department of Natural Resources and Conservation,
Montana State Historic Preservation Officer,
Nebraska State Historic Preservation Officer,
South Dakota State Historic Preservation Officer,
and
TransCanada Keystone Pipeline, LP

Regarding the Keystone XL Pipeline Project

WHEREAS, the U.S. Department of State (DOS) receives and considers applications for permits for cross-border oil pipelines pursuant to the authority delegated by the President of the United States under Executive Order (EO) 13337 (69 Federal Register 25299); and

WHEREAS, the DOS received an application for a Presidential Permit from TransCanada Keystone Pipeline, LP (Keystone) in September 2008 for the Keystone XL Pipeline Project (Keystone XL Project or the Project) which consisted of approximately 1,375 miles of new crude oil pipeline in Montana, South Dakota, Nebraska, Oklahoma, and Texas with associated effects in Kansas; and

WHEREAS, the DOS determined that issuance of a Presidential Permit for the proposed Keystone XL Project include a consultation and review process consistent with Section 106 of the National Historic Preservation Act (NHPA) (16 U.S.C. 470f, as amended) and its implementing regulations, “Protection of Historic Properties”; and

WHEREAS, the DOS developed a Programmatic Agreement (PA) in consultation with relevant state and federal agencies, Indian tribes, Keystone, and the public and executed this PA in August 2011; and

WHEREAS, the Keystone XL Project Presidential Permit application was denied in January 2012; and

WHEREAS, on May 4, 2012, Keystone submitted an application for a revised Keystone XL Pipeline Project using a route in Montana and South Dakota largely unchanged from that proposed in the 2008 Keystone application and a substantially changed route in Nebraska that sought to avoid the Sands Hills Region identified by the Nebraska Department of Environmental Quality and terminates at Steele City, Nebraska; and

WHEREAS, the Oklahoma and Texas sections of the pipeline proposed in the 2008 Keystone application are no longer part of the application received in 2012 and, therefore, the Oklahoma and Texas State Historic Preservation Offices have no further obligations under this PA; and

WHEREAS, the proposed Project undertaking consists of construction of approximately 875 miles of new crude oil pipeline in the United States, as described in section 2.1 of the Final Supplemental Environmental Impact Statement (SEIS) and Attachment H, of which approximately 209 miles (24%) were not part of the 2008 Keystone XL Presidential Permit application; and

WHEREAS, the revised Keystone XL Project Area of Potential Effects (APE) includes: (1) in Montana—a 300-foot-wide corridor, 150 feet on each side of the centerline; (2) in South Dakota—a 300-foot-wide corridor, 150 feet on each side of the centerline; (3) in Nebraska—a 300-foot-wide corridor, 150 feet on each side of the centerline in areas consistent with the route evaluated in the Final EIS for the 2008 Keystone XL application. Within those areas outside the route evaluated in the Final EIS for the 2008 Keystone XL application, the APE consists of a 500-foot-wide corridor, 250 feet on each side of the centerline. For construction or modification of electrical facilities (including distribution lines, transmission lines, and substations), a 100-foot-wide corridor centered on the Project centerline will be used. For pumping stations, including two new pump stations in Kansas on the existing Keystone Cushing Extension pipeline, and other areas that are to be disturbed by construction-related activities and ancillary facilities (including construction camps and pump stations), the APE will include all areas of disturbance and areas to be indirectly affected; and

WHEREAS, the DOS, in consultation with the Advisory Council on Historic Preservation (ACHP), has determined that the Keystone XL PA executed in August 2011 should be amended to reflect the route proposed in the new Presidential Permit application and input from subsequent consultation; and

WHEREAS, the DOS has determined that the construction of the Keystone XL Project may have an adverse effect on historic properties listed in or eligible for listing in the National Register of Historic Places (NRHP), as defined in Stipulation I.C below, and has consulted with the Montana, South Dakota, Nebraska, and Kansas State Historic Preservation Officers (SHPOs), Indian tribes who may ascribe religious and cultural significance to historic properties that may be affected by the undertaking, the ACHP, other federal agencies with actions related to this undertaking, and other consulting parties consistent with 36 C.F.R. Part 800; and

WHEREAS, consistent with 36 C.F.R. §§ 800.4(b)(2) and 800.5(a)(3), the DOS has elected to phase identification and evaluation of historic properties, and application of the criteria of adverse effect, respectively, because the undertaking and APE have changed necessitating additional efforts to identify historic properties and because access to some areas as identified in Attachment A has been restricted by property owners' refusal to grant Keystone permission to enter their private property; and

WHEREAS, consistent with 36 C.F.R. § 800.14(b), the DOS has elected to execute this PA for the Keystone XL Project because effects on historic properties cannot be fully determined prior to the issuance of a permit for the undertaking; and

WHEREAS, on February 2, 2011 the ACHP entered consultation for the Keystone XL pipeline as originally proposed finding that criteria 3 and 4 of Appendix A, Criteria for Council Involvement in Reviewing Individual Section 106 Cases, of the regulations (36 C.F.R. Part 800) implementing Section 106 of NHPA, had the potential to be met; and

WHEREAS, the United States Army Corps of Engineers (USACE) has determined that the approval for the Keystone XL Project to cross USACE-administered lands (30 U.S.C. § 185) and to place structures in, under, or over navigable waters of the United States, as defined under 33 C.F.R. Part 329, pursuant to Section 10 of the Rivers and Harbors Act of 1899 (33 U.S.C. § 403), and a permit for the placement of dredge or fill material in waters of the United States as part of the Keystone XL Project in accordance with Section 404 of the Clean Water Act (334 U.S.C. § 344), are Federal actions related to the undertaking that require the USACE to comply with Section 106 of NHPA; and

WHEREAS, the U.S. Bureau of Land Management (BLM) has determined that approving the Keystone XL Project to cross Federal lands administered by the BLM would require authorization under Section 28 of the Mineral Leasing Act of 1920, 30 U.S.C. § 185, as amended; and

WHEREAS, the BLM has determined that Keystone will require access roads crossing public lands administered by the BLM in support of the Keystone XL Pipeline Project and that the access roads will require authorization under Title V of the Federal Land Policy and Management Act (FLMPA), 43 U.S.C. § 1701, as amended; and

WHEREAS, the BLM has determined that the Keystone XL Project will require electrical power from rural electrical cooperatives and that portions of the transmission lines will cross public lands administered by the BLM and that the transmission lines crossing public lands will require authorization under Title V of the FLMPA; and

WHEREAS, the BLM approvals of these Project crossings in areas under its jurisdiction is a Federal action associated with the undertaking that requires the BLM to comply with Section 106 of the NHPA and 36 C.F.R. Part 800; and

WHEREAS, the U.S. Bureau of Reclamation (USBR) manages lands and facilities that will be crossed by the Keystone XL Project and USBR approval of such crossings is a Federal action

related to the undertaking that requires the USBR to comply with Section 106 of the NHPA and 36 C.F.R. Part 800; and

WHEREAS, the Farm Service Agency (FSA), assists landowners on private lands and may have federal responsibilities and requirements on some of these lands, which are part of the Project APE, as part of its loan and conservation programs, including the Conservation Reserve Program and the Farmable Wetlands Program; and

WHEREAS, the FSA approval of the Project crossings in these areas is a Federal action associated with the undertaking that requires the FSA to comply with Section 106 of the NHPA and 36 C.F.R. Part 800; and

WHEREAS, the Rural Utilities Service (RUS) has determined that the financial assistance it may provide to rural electric cooperatives and other entities for construction or modification of electrical facilities (including distribution lines, transmission lines, and substations) to power some Keystone XL Project pump stations or to ensure transmission system reliability, under the U.S. Department of Agriculture (USDA) Rural Development Utilities Programs, are Federal actions related to the undertaking that require the RUS to comply with Section 106 of NHPA and 36 C.F.R. Part 800; and

WHEREAS, the Bureau of Indian Affairs (BIA) has responsibility for approving any right-of-ways crossing Indian Trust lands, such as those being considered as part of the route for a 230-kilovolt (kV) transmission line in south-central South Dakota associated with the Keystone project and described in Appendix J to the SEIS, and this is a Federal action related to the undertaking that requires the BIA to comply with Section 106 of the NHPA and 36 C.F.R. Part 800; and

WHEREAS, the Western Area Power Administration (Western) has determined that the modification and construction of substations and transmission lines that Western will own and that will provide power to the Keystone XL Pipeline Project, will require review under Section 106 of NHPA and 36 C.F.R. Part 800; and

WHEREAS, the Natural Resources Conservation Service (NRCS) has conservation easement interests in the states through which the Keystone XL pipeline will traverse; and

WHEREAS, the NRCS has determined that approving the Keystone XL Pipeline to cross an NRCS easement constitutes a federal action associated with the undertaking that requires NRCS to comply with Section 106 of the NHPA and 36 C.F.R. Part 800; and

WHEREAS, the proposed revised Keystone XL Project pipeline alignment crosses five National Historic Trails (the Lewis and Clark, Oregon, California, Mormon Pioneer, and Pony Express National Historic Trails), all of which were designated by the U.S. Congress and have as their purpose “the identification and protection of the historic route and its historic remnants and artifacts for public use and enjoyment” (National Trails System Act, P.L. 90-543, as amended); and

WHEREAS, the National Park Service (NPS) administers National Historic Trails and is a signatory to this PA due to the potential for adverse effects to five National Historic Trails including the Lewis and Clark National Historic Trail; and

WHEREAS, the USACE, BLM, RUS, BIA, NRCS, NPS, Western, USBR, and FSA have designated the DOS as the lead Federal agency for purposes of Section 106 of the NHPA consistent with 36 C.F.R. § 800.2(a)(2); and

WHEREAS, the DOS will incorporate this PA into its decisional process on any Presidential Permit that it may issue for the Keystone XL Project and will include in any permit it issues on the Keystone XL Project a condition that Keystone will abide by its commitments in this PA; and

WHEREAS, the USACE, BLM, RUS, BIA, NRCS, NPS, Western, USBR, and FSA will each incorporate this PA into its decisional process on any authorization, approval, permit, or assistance it may issue for the Keystone XL Project, and will include in any authorization, approval, permit, or assistance it issues on the Keystone XL Project, a condition that Keystone will abide by its commitments in this PA; and

WHEREAS, cultural resource identification, evaluation, and effect assessment efforts, including those needed to address the changes in the APE, are summarized in Section 3.11 of the SEIS and Attachment G of this PA; and

WHEREAS, additional efforts to identify, evaluate and assess effects to historic properties for the Project will take place after the execution of this PA because access to some areas has been restricted, as summarized in Attachment A, and all areas of construction have yet to be determined; and

WHEREAS, for the purposes of this PA, “Indian tribes and Nations” shall have the same definition as “Indian tribes” which appears in Section 301(4) of the NHPA; and

WHEREAS, the DOS invited the 84 Indian tribes listed in Appendix B to participate in consultation; and

WHEREAS, the DOS provided Indian tribes the opportunity to provide information about historic properties of concern to Indian tribes and conduct Traditional Cultural Property (TCP) studies within the proposed Project APE, as summarized in Attachment I; and

WHEREAS, the DOS invited Indian tribes that participated in consultation in 2011 and 2013 to sign as Concurring Parties to this PA, consistent with 36 C.F.R. §§ 800.2(c)(2) and 800.6(c)(3); and

WHEREAS, other federal agencies that develop actions related to this undertaking subsequent to the execution of this PA may comply with Section 106 by following the requirements set forth in Stipulation XIV of this PA; and

WHEREAS, the Montana Department of Natural Resources and Conservation has participated in consultation and was invited by the DOS consistent with 36 C.F.R. § 800.6(c)(2) to sign the PA in 2011 and amendments to the PA in 2013 as an invited signatory; and

WHEREAS, the Montana Department of Environmental Quality has participated in consultation and was invited by the DOS consistent with 36 C.F.R. § 800.6(c)(2) to sign the PA in 2011 and amendments to the PA in 2013 as an invited signatory; and

WHEREAS, Keystone, which would construct the Keystone XL Project pipeline if approved, has participated in consultation, and was invited by the DOS consistent with 36 C.F.R. §§ 800.2(c)(4) and 800.6(c)(2) to sign the PA in 2011 and amendments to the PA in 2013 as an invited signatory; and

WHEREAS, the DOS has provided the public with information about the undertaking and its effects on historic properties and sought public comment and input consistent with 36 C.F.R. §§ 800.2(d) from April 2009 through Federal Register notices, direct mailings, extensive scoping and comment meetings, and inviting comments from the public by phone, mail, fax, and email during public comment periods on the Keystone XL Pipeline Presidential Permit applications; and

NOW, THEREFORE, the DOS, USACE, BLM, RUS, BIA, FSA, NRCS, Western, USBR, NPS, ACHP, and the Montana, South Dakota, Nebraska, and Kansas SHPOs agree that the following stipulations will be implemented in order to take into account the effect of the undertaking on historic properties and to ensure actions consistent with Section 106 of the NHPA.

STIPULATIONS

The DOS, BLM, RUS, BIA, FSA, NRCS, Western, USACE, USBR, and NPS as appropriate, will ensure that the following stipulations are carried out.

I. STANDARDS AND DEFINITIONS

A. Identification and evaluation studies and treatment measures required under the terms of this PA will be carried out by or under the direct on-site supervision of a professional who meets, at a minimum, the *Secretary of the Interior's Historic Preservation Professional Qualification Standards* (48 FR 44716, September 29, 1983). These qualification standards do not apply to individuals recognized by consulting Indian tribes to have expertise in identification, evaluation, assessment of effect, and treatment of effects to historic properties of religious and cultural significance to Indian tribes.

B. In developing scopes of work for identification and evaluation studies, and treatment measures required under the terms of this PA, Keystone and RUS borrowers, and other contractors working with Federal agencies, will take into account the following regulations and guidelines:

1. The ACHP's guidance on conducting archaeology under Section 106 (2007);
2. The ACHP's *Policy Statement Regarding the Treatment of Burial Sites, Human Remains and Funerary Objects* (February 23, 2007);
3. Applicable SHPO and Tribal Historic Preservation Office guidance;
4. The Secretary of the Interior's *Standards and Guidelines for Archaeology and Historic Preservation* (48 FR 44716-42, September 29, 1983);
5. The "*Treatment of Archaeological Properties*" (ACHP 1983);
6. The *Guidelines for Reporting on Cultural Resources Investigations for Pipeline Projects*" (Federal Energy Regulatory Commission, Office of Energy Projects, December 2002);
7. Section 10 of the Rivers and Harbors Act of 1899 (33 U.S.C. § 403);
8. Section 404 of the Clean Water Act (334 U.S.C. § 344);
9. BLM 8110 Manual: Identifying and Evaluating Cultural Resources;
10. Montana/Dakotas Cultural Resources Handbook 8110-1: Guidelines for Identifying Cultural Resources;
11. The National Trails System Act (P.L. 90-543, as amended);
12. Section 28 of the Mineral Leasing Act of 1920 (30 USC 185);
13. Title V of the Federal Land Policy and Management Act of 1976 (43 USC 1701); and
14. *National Register Bulletin 38, Guidelines for Evaluating and Documenting Traditional Cultural Properties* (NPS 1990; Revised 1992: 1998)

C. Definitions

Coordination Plan: A plan that, pursuant to Stipulations V.B and V.D, describes the coordination of construction with identification and evaluation of cultural resources, treatment of adverse effects, and protection of unanticipated discoveries.

Concurring Parties: An invited consulting party to this PA that agrees with the content of the PA. Consistent with 36 C.F.R. § 800.6(c)(3), the refusal of a Concurring Party to sign the PA does not invalidate this PA. Concurring Parities may not terminate the PA.

Construction Spread: A construction unit or segment of a pipeline alignment or corridor to be determined by Keystone prior to construction.

Consulting Indian Tribes: Indian tribes that have consultative roles in the Section 106 process consistent with 36 C.F.R. § 800.2(c).

Consulting Parties: Parties that have consultative roles in the Section 106 process consistent with 36 C.F.R. § 800.2(c).

Data Recovery: The recovery of archaeological information from a historic property subject to an adverse effect.

Determination of Effect: A determination made by a Federal agency in regards to a Project's effect upon a historic property consistent with 36 C.F.R. Part 800.

Determination of Eligibility: A determination made by a Federal agency, in coordination with the SHPO and/or designated representatives of consulting Indian tribes, as appropriate, respecting a cultural resource's eligibility for inclusion in the NRHP and more fully described in 36 C.F.R. Part 60 and 36 C.F.R. § 800.16(l)(2).

Effect: An alteration to the characteristics of a historic property qualifying it for inclusion in or eligibility for the NRHP (see 36 C.F.R. § 800.16(i)).

Environmental Impact Statement: An analysis of a major Federal action's environmental impacts conducted consistent with NEPA.

Historic Property: Any prehistoric or historic district, site, building, structure, or object included in, or eligible for inclusion in, the NRHP maintained by the Secretary of the Interior. This term includes artifacts, records, and remains that are related to and located within such properties. The term includes properties of traditional religious and cultural importance to an Indian tribe or Native Hawaiian organization and that meet the National Register criteria (see 36 C.F.R. § 800.16(l)(1)).

Invited Signatory: The DOS has invited Keystone, the Montana Department of Natural Resources and Conservation, and the Montana Department of Environmental Quality to sign this PA consistent with 36 C.F.R. § 800.6(c)(2). The refusal of any invited signatory to sign the PA does not invalidate the PA. An invited signatory, listed above, that has signed the PA, may terminate the PA consistent with 36 C.F.R. § 800.6(c)(8).

Historic Trail and Archaeological Monitoring Plan: A plan that, pursuant to Stipulation V.E and Attachment F, identifies appropriate areas for monitoring construction by professionals under the supervision of individuals who meet the professional qualifications in Stipulation I. The plan's principal goal is to reduce the potential for impacts to unidentified historic properties.

Signatory: The signatories are: the DOS, BLM, USBR, USACE, NPS, Western, RUS, NRCS, FSA, BIA, ACHP, and the SHPOs of Kansas, Montana, South Dakota, and Nebraska. Only signatories and the invited signatories, as defined, may terminate the PA consistent with 36 C.F.R. § 800.6(c)(8).

Tribal Monitoring Plan: A plan that, pursuant to Stipulation V.E and Attachment E, identifies appropriate areas for monitoring construction by tribal members appointed by their respective Indian tribes. These tribal members shall meet the qualifications as noted in Stipulation V.E.3. The plan's principal goal is to reduce the potential for impacts to previously unidentified historic properties that may also be properties of religious and cultural significance to Indian tribes that meet the National Register criteria (see 36 C.F.R. § 800.16(1)(a)).

Treatment Plan: A plan developed in consultation with the parties to this PA that identifies the minimization and mitigation measures for historic properties located within the APE that will be adversely affected by the Project.

II. CONFIDENTIALITY

The DOS, BLM, NRCS, BIA, FSA, RUS, Western, USBR, NPS, USACE, and Keystone will safeguard information about historic properties of religious and cultural significance to Indian tribes, including location information, or information provided by Indian tribes to assist in the identification of such properties, consistent with Section 304 of NHPA, 16 U.S.C. § 470w3, and all other applicable laws.

III. THE RESPONSIBILITIES OF FEDERAL AGENCIES WITH LAND MANAGEMENT AND OTHER PERMITTING AUTHORITIES

A. The USACE will ensure, for that part of the APE under its jurisdiction, that it has met its compliance obligations pursuant to Section 10 and Section 404 permitting authority.

B. The BLM will comply with Section 106 and its implementing regulations (36 C.F.R. Part 800) for the issuance of permits for those actions under its jurisdiction.

C. The USBR will review and comment on the evaluation and treatment of any historic properties managed by the USBR.

D. Attachment H includes maps that illustrate the Project areas that cross lands managed by the BLM and the USBR.

E. Consultation for this Project between Indian tribes and Federal land management and permitting agencies will be coordinated through the DOS.

IV. KEYSTONE XL PROJECT—CONSTRUCTION OR MODIFICATION OF ELECTRICAL DISTRIBUTION/TRANSMISSION FACILITIES

A. Prior to granting approval of financial assistance to construct or modify electrical facilities by rural electric cooperatives or other entities, the RUS will complete the requirements of 36 C.F.R. §§ 800.3 through 800.7 and notify the DOS of the outcome.

B. In implementing Stipulation IV.A, the RUS may authorize a borrower to initiate Section 106 consultation in accordance with 36 C.F.R. § 800.2(c) (4). The RUS issued a blanket delegation for its borrowers to initiate Section 106 consultation in July 2009 and reissued the blanket delegation with some revision in August 2012. As the RUS recognized in those memos, the RUS may not delegate its responsibility to conduct government-to-government consultation with Indian tribes to a borrower, unless the RUS and that Indian tribe agree, in writing, to conduct consultation in that manner.

C. Prior to construction of the 230-kV transmission line that Western will own, Western will complete the requirements of 36 C.F.R. §§ 800.3 through 800.7. In implementing

Stipulation IV.C., Western will serve as a signatory under the PA. Western shall coordinate implementation of Stipulation IV.C with the DOS.

D. The RUS will ensure that the terms of Stipulations VI.B and VI.C are incorporated into construction contracts to ensure that its borrowers and construction contractors meet their responsibility for notification of any unanticipated discoveries. When RUS-funded projects occur on BLM land, the RUS will coordinate with the BLM to ensure compliance with Stipulations VI.B and VI.C of this PA.

E. Prior to granting approval or financial assistance for construction or modification of electrical distribution/transmission facilities that are necessary components of the pipeline project and therefore considered within the Project APE, any Federal agency that is incorporated into this PA pursuant to Stipulation XIV will complete the requirements of 36 C.F.R. §§ 800.3 through 800.7 for those facilities under its jurisdiction and notify the DOS of the outcome if not already carried out elsewhere in this PA.

F. The DOS retains responsibility for completing the requirements of 36 C.F.R. §§ 800.3 through 800.7 for those electrical distribution/transmission facilities that are necessary components of the Project if they are not under the jurisdiction of any Federal agency and not referenced in Stipulation IV, A through E above.

V. KEYSTONE XL PROJECT – PIPELINE CONSTRUCTION

A. The DOS has provided SHPOs, designated representatives of consulting Indian tribes, and other consulting parties with an opportunity to provide their views on the identification and evaluation of historic properties, consistent with 36 C.F.R. § 800.16(l)(1), including historic properties of religious and cultural significance to Indian tribes, and the treatment of affected historic properties, in connection with the construction of the Keystone XL Project. It will continue to provide all consulting parties with an opportunity to provide their views on the identification and evaluation of historic properties, assessment of effects, and treatment of adverse effects after approval of amendments to this PA.

B. Identification and Evaluation of Historic Properties

1. In consultation with the SHPOs, designated representatives of consulting Indian tribes, and other consulting parties, the DOS will make a reasonable and good faith effort to complete the identification and evaluation of historic properties within the APE for each construction spread, including in areas yet to be surveyed outlined in Attachment A, prior to the initiation of construction of that spread, consistent with 36 C.F.R. §§ 800.4(a), (b), and (c). On Federal lands, the scope of the identification effort will be determined by the DOS in consultation with the appropriate Federal land managing agency, applicable SHPOs, designated representatives of consulting Indian tribes, and other consulting parties.

2. The DOS will make a reasonable and good faith effort to complete the identification and evaluation of historic properties, as appropriate, consistent with 36 C.F.R. §§ 800.4(a), (b), and (c), before Keystone initiates construction activities (including vegetative clearing to comply with the Migratory Bird Treaty Act, if clearing is undertaken).

    a. In the identification and evaluation of historic properties to which Indian tribes may attach religious and cultural significance, the DOS will take into consideration information submitted by Indian tribes to the DOS prior to construction through consultations and through the protocols for TCP studies, post-review discovery, and the Tribal Monitoring Plan, as set forth in this PA.
    b. In the event identification of historic properties cannot be completed for any Construction Spreads prior to construction, Keystone will develop and submit a Coordination Plan to the DOS for review and approval pursuant to Stipulation V.D. The Coordination Plan must describe the measures Keystone will use to implement and complete the identification and evaluation of cultural resources and appropriate consultation before any historic properties are adversely affected by vegetation clearing and construction activities related to that spread.

C. Treatment of Historic Properties

1. Whenever feasible, avoidance of adverse effects to historic properties will be the preferred treatment. In consultation with the DOS, ACHP, SHPOs, designated representatives of consulting Indian tribes, and other consulting parties, Keystone may elect to consider and implement avoidance measures prior to completing the evaluation of historic properties.

    Avoidance measures may include:
    a. Avoidance through pipeline or access road route variation or Project feature relocation;
    b. Avoidance through abandonment;
    c. Avoidance through bore or horizontal directional drill;
    d. Avoidance by narrowing the construction corridor (“neck down”); or
    e. Avoidance through the use of existing roadways as Project access roads to the extent practicable.

2. When historic properties are identified in the APE pursuant to Stipulation V.B, the DOS will apply criteria of adverse effect consistent with 36 C.F.R. § 800.5(a) in consultation with the ACHP, SHPO, designated representatives of consulting Indian tribes, and other consulting parties. If the DOS finds that historic properties might be adversely affected by actions covered under this PA and within the APE, the DOS will consult with the ACHP, SHPOs, designated representatives of consulting Indian tribes, and other consulting parties to determine prudent and feasible ways to avoid adverse effects.

a. Once the DOS approves avoidance measures, Keystone will implement those measures.

3. If the DOS determines that the adverse effect cannot be avoided, the DOS will consult with the ACHP, SHPOs, designated representatives of consulting Indian tribes, and other consulting parties to determine those measures to be implemented by Keystone to minimize and mitigate adverse effects on affected historic properties identified in the APE.

4. If, after consultation, the DOS determines that the adverse effect cannot be avoided, Keystone will draft a comprehensive Treatment Plan for each adversely affected historic property. The Treatment Plan will describe the measures identified by the DOS under Stipulation V.C.3 to minimize and mitigate the adverse effect of pipeline construction activities on historic properties, the manner in which these measures will be carried out, and a schedule for their implementation.

   a. When mitigation consists of or includes Data Recovery, the Treatment Plan also will identify the specific research questions to be addressed by Data Recovery with an explanation of their relevance, the archaeological methods to be used, and provisions for public interpretation and education, subject to Stipulation II restrictions, if any. Management summaries of all archaeological investigations must be submitted to the DOS, relevant Federal agencies, and the SHPO for review and approval prior to the commencement of construction activities and construction may be authorized on the basis of information contained in those summaries. Designated representatives of consulting Indian tribes will be notified for their information and awareness and may provide any relevant information to DOS and SHPO within nine (9) calendar days to inform their review of the summaries. Final reports must be submitted to the DOS and the SHPO for review within six months of the completion of the fieldwork.

   b. A Treatment Plan may also include mitigation for adverse effects to historic districts, buildings and structures, and to TCPs and other properties of religious and cultural significance to Indian tribes. This mitigation may include the recordation of historic properties according to Historic American Building Survey/Historic American Engineering Record Standards and Guidelines for Architectural and Engineering Documentation. Other types of mitigation for adverse effects to historic districts, buildings, and structures, and to TCPs and other properties of religious and cultural significance to Indian tribes may also be described in the Treatment Plan. The mitigation proposed for an adverse effect to a historic district, building, and/or structure, and to TCPs and other properties of religious and cultural significance to Indian tribes will be commensurate with the level of significance and extent of adverse effect and will be determined in a manner consistent with Stipulation V.C.4.c.

   c. Keystone will submit the draft Treatment Plan to the DOS, BLM (if applicable), ACHP, designated representatives of consulting Indian tribes, the SHPO of the

applicable state, Montana Department of Environmental Quality (if applicable), Montana Department of Natural Resources and Conservation (if applicable), and other applicable consulting parties for a forty-five (45) calendar day review. Keystone will address timely comments and recommendations submitted by SHPOs, designated representatives of consulting Indian tribes, and other consulting parties in preparation of the Final Treatment Plan.

d. When it has addressed all of the timely comments and recommendations, Keystone will submit the Final Treatment Plan to the DOS for review and approval. Keystone will also submit the Final Treatment Plan to the BLM for review and approval when involving lands subject to Stipulation III.C. The DOS and BLM will issue their final decision on the Treatment Plan within thirty (30) calendar days. Once the Final Treatment Plan is approved by the DOS (and the BLM if involving BLM-managed lands), copies of the Treatment Plan will be distributed to all SHPOs, designated representatives of consulting Indian tribes, and other consulting parties.

5. Keystone will make a reasonable and good faith effort to complete implementation of the Final Treatment Plan approved by the DOS prior to beginning construction of any spread for which the Treatment Plan is required. If it is not possible to meet this schedule, Keystone will develop a Coordination Plan in accordance with Stipulation V.D that establishes how appropriate treatment will be determined and implemented during construction of the respective spread.

D. Coordination of Construction and Historic Preservation Activities

1. The DOS will make a reasonable and good faith effort to complete the identification and evaluation of historic properties and potential historic properties, and the mitigation of adverse effects to them in accordance with Stipulations V.B and V.C prior to the initiation of vegetative clearing if vegetative clearing and construction on the Keystone XL spreads, including the Montana, South Dakota, and Nebraska spreads, is to be undertaken.

2. If these DOS activities cannot be completed prior to the start of vegetative clearing and construction of these spreads, Keystone will develop and provide to the DOS a detailed plan describing how the requirements of Stipulations V.B and V.C—identification, evaluation and treatment of historic properties—will be completed in coordination with vegetative clearing and construction activities in such a way that historic properties will not be adversely affected prior to the implementation of any mitigation measures.

a. A Coordination Plan will be prepared for each state and will include those measures developed by Keystone pursuant to Stipulations V.B and V.C to complete the identification and evaluation of historic properties, and, as appropriate, mitigation of adverse effects to them during and coordinated with vegetation clearing and construction activities. In addition, the Coordination Plan

will include a schedule for all proposed activities and recommended measures for the protection of unanticipated discoveries in accordance with Attachment C, as appropriate.

b. Keystone will submit the draft Coordination Plan for each state for such spreads, including the Kansas, Montana, South Dakota, and Nebraska spreads, to the DOS, BLM (as applicable), ACHP, SHPOs (as applicable), designated representatives of consulting Indian tribes, and consulting parties for forty-five (45) calendar day review. Keystone shall address timely comments and recommendations submitted by the applicable SHPO, designated representatives of consulting Indian tribes, and other consulting parties in preparation of the Final Coordination Plan for each state. When it has addressed all of the comments and recommendations, Keystone will submit the Final Coordination Plan for each state to the DOS for review. The DOS shall issue its final decision on the Coordination Plan for each state within thirty (30) calendar days. Following approval by the DOS, the Final Coordination Plan for each state will be distributed to all of the SHPOs, designated representatives of consulting Indian tribes, and other consulting parties.

3. Keystone will complete implementation of the Final Coordination Plan approved by the DOS during construction of the Kansas, Montana, South Dakota, and Nebraska spreads.

E. Historic Trail and Archaeological Monitoring Plan ("HTAM Plan") and Tribal Monitoring Plan

1. In consultation with the SHPOs and designated representatives of consulting Indian tribes, Keystone will monitor construction in selected areas of the APE of each spread as a supplement to identification efforts. Any historic properties identified by Keystone during monitoring will be treated in accordance with Stipulation VI.A and C.

a. The HTAM Plan outlines areas that have been previously identified by the DOS during identification and evaluation efforts that warrant monitoring during soil disturbing activities for potential effects to historic properties.

b. The Tribal Monitoring Plan outlines areas that have been previously identified by Indian tribes, either through the preparation of Traditional Cultural Property reports or through consultation, that warrant monitoring during clearing and trenching for potential effects to previously unidentified historic properties that may include properties of religious and cultural significance to an Indian tribe and that meet the National Register criteria (See 36 C.F.R. § 800.16(l)(1)).

2. Historic Trail monitoring will be performed by a professional who either meets the qualification standards for archaeology established in Stipulation I.A or is under the on-site supervision of such a professional.

3. At the discretion of the DOS, tribal monitors may substitute other types of experience with construction monitoring and/or traditional cultural knowledge for the degrees required by the Professional Qualification Standards. DOS may also consider other accommodations regarding education and experience where allowed by the Standards and implementing guidance.

4. In consultation with the DOS, Keystone will consider information provided by Indian tribes in a timely manner when completing the identification of historic properties before construction begins as set forth in Stipulation V.B and in the HTAM Plan and Tribal Monitoring Plan provided for under Stipulation V.E. Keystone will ensure that tribal monitors have reasonable access to Project construction sites and activities. In those areas previously identified by Indian tribes as needing monitoring, the Tribal Monitoring Plan stipulates that at least one monitor will be used per Construction Spread depending upon the extent and location of construction activities, as well as the relative historic importance of each Spread to each Indian tribe.

5. Keystone has submitted a plan for historic trail and archaeological monitoring and tribal monitoring for each spread to the DOS, BLM, ACHP, SHPO, designated representatives of consulting Indian tribes, and Consulting Parties for review and comment prior to the signing of this PA. The Tribal Monitoring Plan and HTAM Plan are attached to this PA in Attachments E and F.

6. Keystone will implement the HTAM Plan and Tribal Monitoring Plan for each spread that has been approved by the DOS.

F. Construction

1. Lead Environmental Inspector (EI): Prior to initiating vegetative clearing or construction, Keystone will employ the Lead EI whose responsibilities will include ensuring compliance with the terms of this PA. In meeting this responsibility, the Lead EI will rely on the technical expertise of on-site professionals who meet the standards established in Stipulation I.A and tribal monitors with experience outlined in Stipulation V.E.3.

   a. The Lead EI will monitor construction activities on-site and prepare a daily log, reporting to Keystone and designated representatives of consulting Indian tribes on activities performed to implement the terms of this PA, as appropriate. Keystone will make the daily log available to the DOS and SHPOs, and other consulting parties upon request.

   b. Keystone will ensure through the construction contract that the Lead EI will possess the authority to stop construction in the event of an inadvertent discovery in accordance with Stipulation VI.A and Attachment C.

2. Training: Keystone will ensure that, if the Lead EI does not meet the professional qualification standards established in Stipulation I.A, the Lead EI will receive appropriate training in historic preservation from a professional who meets the standards established in Stipulation I.A in order to perform the requirements of this PA. Keystone also will provide an appropriate level of training in historic preservation conducted by a professional who meets the standards established in Stipulation I.A to all construction personnel (including new, added, replaced workers) so that PA requirements are understood and unanticipated discoveries quickly identified. Keystone will conduct this training prior to initiating vegetative clearing or construction activities on a spread. Keystone also will conduct periodic refresher training during construction of the spread.

3. Construction Contract: Keystone will incorporate the terms of Stipulation VI.A and Attachment C into construction contracts to ensure that its Lead EI and construction contractors meet their responsibility for notification of the unanticipated discoveries.

F. Scheduling

The DOS may authorize the start of vegetative clearing and construction for an individual spread when the plans prepared in accordance with Stipulations V.D and V.E as appropriate for that spread, have been submitted by Keystone and approved by the DOS in accordance with the terms of this PA.

VI. UNANTICIPATED DISCOVERIES OR ADVERSE EFFECTS DURING CONSTRUCTION OF THE KEYSTONE XL PROJECT

A. Pipeline Construction

1. "Applicable Federal agency" is the Federal agency with jurisdiction for the land on which construction is occurring or, in the absence of such an agency, the DOS, as appropriate.

2. If previously unidentified historic properties are discovered by monitors or construction personnel unexpectedly or unanticipated adverse effects on previously identified historic properties occur as pipeline construction activities are carried out within the one-hundred-and-ten (110) foot-wide construction corridor or other ancillary facilities and access roads within the APE, the construction contractor will immediately halt all construction activity within a one-hundred-and-fifty (150) foot radius of the discovery or adversely affected historic property, notify the Lead EI of the discovery and implement interim measures to protect the discovery from looting and vandalism. Within forty-eight (48) hours of receipt of this notification of the discovery, the Lead EI shall:

   a. Inspect the work site to determine the extent of the discovery or adverse effect and ensure that construction activities have halted;
   b. Clearly mark the area of the discovery or adverse effect;

c. Implement additional measures other than those mentioned above, as appropriate, to protect the discovery or adversely affected historic property from looting and vandalism; and
d. Notify the applicable Federal agency, SHPOs, designated representatives of consulting Indian tribes, and other consulting parties of the discovery or adverse effect.

3. In the case of an unanticipated discovery, the applicable Federal agency will notify all consulting parties that it will be receiving comments concerning the unanticipated discovery and provide contact information. The applicable Federal agency will have seven (7) calendar days following notification provided in accordance with Stipulation VI.A.2 to determine the National Register eligibility of the discovery after considering the timely filed views of the SHPOs, designated representatives of consulting Indian tribes, other consulting parties, and Keystone. The applicable Federal agency may assume the newly discovered property to be eligible for the National Register for the purposes of Section 106 consistent with 36 C.F.R. § 800.13(c).

4. For discovered properties determined eligible or assumed to be eligible pursuant to Stipulation VI.A.3, the applicable Federal agency will notify the ACHP, SHPOs, designated representatives of consulting Indian tribes, and other consulting parties of those actions that it proposes to resolve adverse effects which may include a Treatment Plan as outlined in Stipulation V.C.

   a. SHPOs, designated representatives of consulting Indian tribes, and other consulting parties will have ninety-six (96) hours to provide their views on the proposed actions.
   b. The applicable Federal agency will ensure that the timely filed recommendations of SHPOs, designated representatives of consulting Indian tribes, and other consulting parties are taken into account prior to granting approval of the measures that Keystone will implement to resolve adverse effects.
   c. Keystone will carry out the approved measures prior to resuming construction activities in the location of the discovery.

5. In the case of unanticipated adverse effects to a previously identified historic property, the applicable Federal agency will notify the ACHP, SHPOs, designated representatives of consulting Indian tribes, and other consulting parties of those actions that it proposes to resolve adverse effects which may include a Treatment Plan as outlined in Stipulation V.C.

   a. SHPOs, designated representatives of consulting Indian tribes, and other consulting parties will have forty-eight (48) hours to provide their views on the proposed actions.
   b. The applicable Federal agency will ensure that the timely filed recommendations of SHPOs, designated representatives of consulting Indian tribes, and other

consulting parties are taken into account prior to granting approval of the measures that Keystone will implement to mitigate adverse effects.

c. Keystone will carry out the approved measures prior to resuming construction activities in the location of the affected property.

6. Dispute Resolution: The applicable Federal agency will seek and take into account the recommendations of the ACHP in resolving any disagreements that may arise regarding resolution of adverse effects that relate to the implementation of Stipulation VI.A. The applicable Federal agency will use the contact information provided in Attachment D to notify the ACHP. Within seven (7) calendar days of receipt of such a written request, the ACHP will provide the applicable Federal agency recommendations on resolving the dispute. The applicable Federal agency will take into account any timely filed recommendations provided by the ACHP in making a final decision about how to proceed.

B. Construction or Modification of Electrical Facilities

1. If previously unidentified historic properties are discovered unexpectedly during construction or modification of transmission facilities funded by the RUS, the RUS borrower's construction contractor will immediately halt all construction activity within a one-hundred-and-fifty (150) foot radius of the discovery, notify the RUS borrower of the discovery and implement interim measures to protect the discovery from looting and vandalism. Within forty-eight (48) hours of receipt of this notification of the discovery, the RUS borrower shall:

   a. Notify the RUS Contact (and BLM Contact if discovery occurs on BLM land);
   b. Inspect the work site to determine the extent of the discovery and ensure that construction activities have halted;
   c. Clearly mark the area of the discovery; and
   d. Implement additional measures, as appropriate, to protect the discovery from looting and vandalism.

2. Upon receipt of such notification the RUS and, if applicable, BLM will coordinate the notification of SHPOs, designated representatives of consulting Indian tribes, and other consulting parties and notify the SHPOs, designated representatives of consulting Indian tribes, and other consulting parties of the discovery.

3. The RUS and, if applicable, BLM will have seven (7) calendar days following notification provided in accordance with Stipulation VI.B.1 to determine the National Register eligibility of the discovery in consultation with the SHPOs, designated representatives of consulting Indian tribes, other consulting parties, and the borrower. The RUS and, if applicable, BLM may assume the newly discovered property to be eligible for the National Register for the purposes of Section 106 pursuant to 36 C.F.R. § 800.13(c).

4. For properties determined eligible, or treated as such, pursuant to Stipulation VI.B.3, the RUS, in coordination with the BLM (if applicable), will notify the SHPOs, designated representatives of consulting Indian tribes, and other consulting parties of those actions that it proposes to resolve adverse effects. SHPOs, designated representatives of consulting Indian tribes, and other consulting parties will provide their views on the proposed actions within ninety-six (96) hours. The RUS will ensure that the timely filed recommendations of the SHPOs, designated representatives of consulting Indian tribes, and other consulting parties are taken into account prior to granting approval of those actions that the borrower will implement to resolve adverse effects. Once RUS approval has been granted, its borrower will carry out the approved measures prior to resuming construction activities in the location of the discovery.

5. Dispute Resolution: The RUS and, if applicable, BLM will seek and take into account the recommendations of the ACHP in resolving any disagreements that may arise regarding the resolution of adverse effects that relate to the implementation of Stipulation VI.B. The applicable Federal agency will use the contact information provided in Attachment D in order to notify the ACHP. Within seven (7) calendar days of receipt of such a written request, the ACHP will provide the RUS and, if applicable, BLM with its recommendations for resolving the dispute. The RUS and, if applicable, BLM will take into account any recommendations provided by the ACHP in making a final decision about how to proceed.

6. Reporting: No later than six (6) months following the resumption of construction within the location of the discovery, the RUS will submit a final report to the SHPOs, designated representatives of consulting Indian tribes, and other consulting parties describing implementation of the actions taken in accordance with Stipulation VI.B and, as appropriate, the analysis and interpretation of recovered information.

C. Unanticipated Discovery of Human Burials and Remains, and Funerary Objects

1. When Native American human remains or funerary objects or objects of cultural patrimony are unexpectedly discovered during construction of the Keystone XL Project on Federal or tribal lands within the APE, Keystone or an RUS borrower, as appropriate, will notify immediately the Federal agency responsible for compliance with the Native American Graves Protection and Repatriation Act, 25 U.S.C. 3001 et. seq., and its implementing regulations, 43 C.F.R. Part 10.

2. Non-Native American human burials and remains, and funerary objects discovered on Federal lands within the APE will be treated by the Federal agency having jurisdiction of the remains in accordance with applicable Federal law, taking into account the ACHP's *Policy Statement on the Treatment of Burial Sites, Human Remains and Funerary Objects* (February 23, 2007).

3. The DOS, Western, and RUS will treat human burials and remains discovered on non-Federal land consistent with the provisions of Attachment C and any applicable

federal, state, and local burial laws. In those instances where the USACE has jurisdiction under Section 10 or 404 permitting authority for non-Federal lands in the APE, the applicable Federal agencies will ensure that Keystone complies with the provisions of Attachment C acting in the place of the DOS. In determining appropriate actions to be carried out, the DOS, RUS, and/or other Federal agencies will be guided by the ACHP's *Policy Statement on the Treatment of Burial Sites, Human Remains and Funerary Objects* (February 23, 2007).

VII. CURATION

A. Federal agencies will curate any artifacts, materials or records resulting from archaeological identification and mitigation conducted on Federal lands under their jurisdiction in accordance with 36 C.F.R. Part 79, "*Curation of Federally-Owned and Administered Archaeological Collections*." Federal agencies with jurisdiction over the Federal lands will consult with Indian tribes consistent with 36 C.F.R. 79.

B. Keystone and RUS borrowers will return all artifacts recovered from private lands to the respective landowner after analysis is complete, unless applicable state law requires otherwise. Keystone and RUS borrowers will encourage and assist landowners in donating any returned artifacts to a local curation facility identified by the respective SHPO. Keystone shall pay all required curation fees associated with the donation of artifacts to the local curation facility.

C. On Federally controlled or owned properties, Federal agencies will determine the disposition of human burials, human remains and funerary objects in accordance with applicable Federal law.

VIII. REPORTING

A. Within three (3) months of completion of pipeline construction of a spread, Keystone will submit a comprehensive draft report to the DOS describing the results and findings of the implementation of the actions and plans specified in Stipulations V.C through G, VI.A, including Attachment C.

B. Keystone will submit a draft comprehensive report for each spread to the ACHP, SHPOs, designated representatives of consulting Indian tribes, and other consulting parties of the respective states in which the spread is located, for forty-five (45) day review and comment. Keystone shall address timely comments and recommendations submitted by ACHP, SHPOs, designated representatives of consulting Indian tribes, and other consulting parties in preparation of the Final Comprehensive Report for that spread. Keystone will submit the final report to the DOS for review and approval. The final comprehensive report will be provided by the DOS to the ACHP, SHPOs, designated representatives of consulting Indian tribes, and other consulting parties once approved.

IX. MONITORING IMPLEMENTATION OF THE PA

Each quarter following the execution of this PA until it expires or is terminated, the DOS with the assistance of the USACE, BLM, RUS, FSA, NRCS, BIA, and USBR as necessary will provide the ACHP, SHPOs, designated representatives of consulting Indian tribes, and other consulting parties to this PA a progress report summarizing the work carried out pursuant to its terms. Such report will include any scheduling changes proposed, any problems encountered, and any disputes and objections received in the efforts to carry out the terms of this PA. The DOS will maintain and update a list of the current contact for the ACHP, SHPOs, designated representatives of consulting Indian tribes, and other consulting parties and will be distributed in each quarterly report.

X. DISPUTE RESOLUTION

A. "Appropriate Federal agency" refers to the DOS, BLM, RUS, USBR, and USACE, or other Federal land managing and/or permitting agency as applicable.

B. Should any signatory, invited signatory, or concurring party to this PA object at any time to any actions proposed or the manner in which the terms of this PA are implemented, the appropriate Federal agency will consult with such party to resolve the objection. If the appropriate Federal agency determines that such objection cannot be resolved, the appropriate Federal agency will:

   1. Forward all documentation relevant to the dispute, including the applicable Federal agency's proposed resolution, to the ACHP. The ACHP will provide the appropriate Federal agency with its advice on the resolution of the objection within thirty (30) calendar days of receiving adequate documentation. Prior to reaching a final decision on the dispute, the appropriate Federal agency will prepare a written response that takes into account any timely advice or comments regarding the dispute from the ACHP, signatories, invited signatories, and concurring parties, and provide them with a copy of this written response. The appropriate Federal agency will then proceed according to its final decision.

   2. If the ACHP does not provide its advice regarding the dispute within the thirty (30) calendar day time period, the applicable Federal agency may make a final decision on the dispute and proceed accordingly. Prior to reaching such a final decision, the appropriate Federal agency will prepare a written response that takes into account any timely comments regarding the dispute from the signatories, invited signatories, and concurring parties to the PA, and provide them and the ACHP with a copy of such written response.

C. The Federal agencies are responsible for carrying out all other actions subject to the terms of this PA that are not the subject of the dispute.

D. The process of dispute resolution outlined in Stipulation X does not pertain to disputes that arise from unanticipated discoveries covered in Stipulation VI.

XI. DURATION

This PA will be null and void if all of its stipulations have not been carried out within seven (7) years from the date of its execution. At such time, and prior to work continuing on the Keystone XL Project, the DOS will either: (a) execute a Memorandum of Agreement (MOA) or PA consistent with 36 C.F.R. §§ 800.6 or 800.14(b), respectively; or (b) request, take into account, and respond to the comments of the ACHP consistent with 36 C.F.R. § 800.7. Prior to such time, the DOS may consult with the other signatories and invited signatories to reconsider the terms of the PA and amend it in accordance with Stipulation XII. The DOS will notify the signatories, invited signatories, and concurring parties as to the course of action they will pursue.

XII. AMENDMENT

Any signatory or invited signatory to this PA may propose in writing that it be amended. The signatories and invited signatories will consult in an effort to reach agreement on an amendment. Any amendment will be effective on the date it is signed by all of the signatories and invited signatories and filed with the ACHP.

XIII. TERMINATION

A. If any signatory or invited signatory to this PA determines that its terms will not or cannot be carried out, that party will immediately consult with the other signatories and invited signatories to attempt to develop an amendment per Stipulation XII. If within thirty (30) calendar days an amendment cannot be reached, any signatory or invited signatory may terminate the PA upon written notification to the other signatories and invited signatories.

B. Termination by an individual SHPO shall only terminate the application of this PA within the jurisdiction of the SHPO.

   1. Once the PA is terminated for an individual state, and prior to work continuing on the undertaking in that state, DOS must either (a) execute a PA pursuant to 36 CFR § 800.6 or (b) request, take into account, and respond to the comments of the ACHP under 36 CFR § 800.7. DOS shall notify the signatories as to the course of action it will pursue.

C. If the PA is terminated in its entirety, and prior to work continuing on the undertaking, the DOS shall request, take into account, and respond to the comments of the ACHP consistent with 36 C.F.R. § 800.7(a). Following consultation with the ACHP, the DOS will notify the signatories, invited signatories and concurring parties as to the course of action it will pursue.

XIV. COORDINATION WITH OTHER FEDERAL REVIEWS

In the event that Keystone or a Federal agency applies for additional Federal funding or approvals for the Keystone XL Project and the undertaking remains unchanged, such funding or approving agency may comply with Section 106 by agreeing in writing to the terms of this PA and notifying and consulting with the applicable SHPOs, designated representatives of consulting Indian tribes, and the ACHP. Any necessary modifications will be considered in accordance with Stipulation XII.

XV. SCOPE OF THE PA

This PA is limited in scope to actions that will facilitate the construction of the Keystone XL Project and related facilities, and is entered into solely for that purpose.

EXECUTION of this PA by the DOS, ACHP, BLM, RUS, Western, USACE, USBR, NPS, NRCS, FSA, BIA, the Montana SHPO, South Dakota SHPO, Nebraska SHPO, and Kansas SHPO and implementation of its terms evidence that the DOS, Western, BLM, RUS, NRCS, FSA, BIA, USACE, USBR, and NPS have taken into account the effects of the Keystone XL Project on historic properties and afforded the ACHP an opportunity to comment.

Deborah Klepp /PK for December 23, 2013

Deborah Klepp **Date**
Director
Office of Environmental Quality and Transboundary Issues
Bureau of Oceans and International Environmental and Scientific Affairs
United States Department of State

Corm Cam s ell
Acting Regional Director, Intermountain Region
National Park Service

434 0/3
Date

18 DEC 2013

Joel R. Cross
Colonel, Corps of Engineers
District Commander

Date

12/17/2013

Date

Bennet Horter
Federal Preservation Officer
United States Department of Agriculture Farm Service Agency

Salvador Salinas 12-17-13

Salvador Salinas **Date**
State Conservationist
United States Department of Agriculture Natural Resources Conservation Services

Mark S. Plank 12/17/13

Mark S. Plank
Director, Engineering and Environmental Staff
United States Department of Agricultural Rural Utilities Service

Date

12-18-13

Weldon Loudermilk
Great Plains Regional Director
United States Bureau of Indian Affairs

Date

Diane M Friez 12/18/2013

Diane Friez **Date**
District Manager, Eastern Montana/Dakotas District
Bureau of Land Management

DECEMBER 18, 2013

Michael J. Ryan
Regional Director, Great Plains Region
Bureau of Reclamation

Date

Robert J. Harris 12/19/13

Robert Harris
Regional Manager, Upper Great Plains Region
Western Area Power Administration (WESTERN)

Date

John M. Fowler

12/19/13

John M. Fowler
Executive Director
Advisory Council on Historic Preservation

Date

Patrick Zelnar DSHPO for 12-17-13

Jennie Chinn
State Historic Preservation Officer
Kansas

Date

12·19·13

Tracy Stone-Manning
Director
Montana Department of Environmental Quality
(Invited Signatory)

Date

12-19-13

John Tubbs
Director
Montana Department of Natural Resources and Conservation
(Invited Signatory)

Date

Mark Baumler
State Historic Preservation Officer
Montana

12/18/2013
Date

Michael J. Smith
State Historic Preservation Officer
Nebraska

Dec. 18, 2013
Date

17 Dec 13

Jay D. Vogt
State Historic Preservation Officer
South Dakota

Date

Dec 18/13

Corey Goulet
Vice President
TransCanada Pipelines Limited
(Invited Signatory)

Date

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ATTACHMENT A

The following table summarizes the proposed Project areas for which Keystone has yet to conduct identification and evaluation studies as of the finalization of the PA. The majority of these proposed Project areas have been denied access versus new areas that have yet to surveyed.

Areas Not Surveyed Along the Proposed Project APE		
State	**Project Area Type**	**Cultural Survey Remaining (acres)**
Montana	ROW	0.00
Montana	Pump Stations	0.00
Montana	Ancillary facilities	0.00
Montana	Access Roads	0.00
South Dakota	ROW	23.70
South Dakota	Pump Stations	0.00
South Dakota	Ancillary facilities	0.00
South Dakota	Access Roads	0.00
Nebraska	ROW	937.65
Nebraska	Pump Stations	43.45[1]
Nebraska	Ancillary facilities	N/A[2]
Nebraska	Access Roads	33.05[3]
Total		**1037.85**[1, 2, 3]

[1] Pump stations in Nebraska have been surveyed for multiple locations.
[2] Additional ancillary facilities may be needed, however, are not known at this time.
[3] Additional access roads may be needed, however, are not known at this time.

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ATTACHMENT B

1. Absentee-Shawnee Tribe of Indians of Oklahoma
2. Alabama-Coushatta Tribes of Texas
3. Alabama-Quassarte Tribal Town, Oklahoma
4. Apache Tribe of Oklahoma
5. Arapahoe Tribe of the Wind River Reservation, Wyoming (aka Northern Arapaho Tribe)
6. Assiniboine and Sioux Tribes of the Fort Peck Indian Reservation, Montana (aka Fort Peck Tribes)
7. Blackfeet Tribe of the Blackfeet Indian Reservation of Montana
8. Cherokee Nation, Oklahoma
9. Cheyenne and Arapaho Tribes, Oklahoma
10. Cheyenne River Sioux Tribe of the Cheyenne River Reservation, South Dakota
11. Chickasaw Nation, Oklahoma
12. Chippewa-Cree Indians of the Rocky Boy's Reservation, Montana
13. Choctaw Nation of Oklahoma
14. Comanche Nation, Oklahoma
15. Confederated Salish & Kootenai Tribes of the Flathead Indian Nation, Montana
16. Confederated Tribes of the Goshute Reservation, Nevada and Utah
17. Crow Creek Sioux Tribe of the Crow Creek Reservation, South Dakota
18. Crow Tribe of Montana
19. Delaware Tribe of Indians, Oklahoma
20. Duckwater Shoshone Tribe of the Duckwater Reservation, Nevada
21. Eastern Band of Cherokee Indians of North Carolina
22. Eastern Shawnee Tribe of Oklahoma
23. Ely Shoshone Tribe of Nevada
24. Flandreau Santee Sioux Tribe of South Dakota
25. Forest County Potawatomi Community, Wisconsin
26. Fort Belknap Indian Community of the Fort Belknap Reservation of Montana (aka Gros Ventre and Assiniboine Tribe of Ft. Belknap)
27. Hannahville Indian Community, Michigan
28. Ho-Chunk Nation of Wisconsin
29. Iowa Tribe of Kansas and Nebraska
30. Iowa Tribe of Oklahoma
31. Jena Band of Choctaw Indians, Louisiana
32. Kaw Nation, Oklahoma
33. Kialegee Tribal Town, Oklahoma
34. Kickapoo Traditional Tribe of Texas
35. Kickapoo Tribe of Indians of the Kickapoo Reservation in Kansas
36. Kiowa Indian Tribe of Oklahoma
37. Lower Brule Sioux Tribe of the Lower Brule Reservation, South Dakota
38. Lower Sioux Indian Community in the State of Minnesota
39. Match-e-be-nash-she-wish Band of Pottawatomi Indians of Michigan (aka Gun Lake Potawatomi)

40. Mille Lacs Band of Minnesota Chippewa Tribes, Minnesota
41. Modoc Tribe of Oklahoma
42. Nez Perce Tribe, Idaho
43. Northern Cheyenne Tribe of the Northern Cheyenne Indian Reservation, Montana
44. Nottawaseppi Huron Band of the Potawatomi, Michigan (aka Huron Potawatomi Nation)
45. Oglala Sioux Tribe of the Pine Ridge Reservation, South Dakota
46. Omaha Tribe of Nebraska
47. Osage Nation, Oklahoma
48. Otoe-Missouria Tribe of Indians, Oklahoma
49. Pawnee Nation of Oklahoma
50. Poarch Band of Creek Indians of Alabama
51. Pokagon Band of Potawatomi Indians, Michigan and Indiana
52. Ponca Tribe of Indians of Oklahoma
53. Ponca Tribe of Nebraska
54. Prairie Band of Potawatomi Nation, Kansas
55. Prairie Island Indian Community in the State of Minnesota
56. Red Lake Band of Chippewa Indians, Minnesota
57. Rosebud Sioux Tribe of the Rosebud Indian Reservation, South Dakota
58. Sac & Fox Nation of Missouri in Kansas and Nebraska
59. Sac & Fox Nation, Oklahoma
60. Sac & Fox Tribe of the Mississippi in Iowa
61. Santee Sioux Nation, Nebraska
62. Seneca-Cayuga Tribe of Oklahoma
63. Shakopee Mdewakanton Sioux Community of Minnesota
64. Shoshone-Bannock Tribes of the Fort Hall Reservation of Idaho
65. Shoshone Tribe of the Wind River Reservation, Wyoming (aka Eastern Shoshone Tribe)
66. Sisseton-Wahpeton Oyate of the Lake Traverse Reservation, South Dakota
67. Skull Valley Band of Goshute Indians of Utah
68. Southern Ute Indian Tribe of the Southern Ute Reservation, Colorado
69. Spirit Lake Tribe, North Dakota
70. Standing Rock Sioux Tribe of North & South Dakota
71. Stockbridge Munsee Community, Wisconsin
72. Thlopthlocco Tribal Town, Oklahoma
73. Three Affiliated Tribes of the Fort Berthold Reservation, North Dakota
74. Tonkawa Tribe of Indians of Oklahoma
75. Turtle Mountain Band of Chippewa Indians of North Dakota
76. United Keetoowah Band of Cherokee Indians in Oklahoma
77. Upper Sioux Community, Minnesota
78. Ute Indian Tribe of the Uintah & Ouray Reservation, Utah (aka Ute Indian Tribe, also Northern Ute Tribe)
79. Ute Mountain Tribe of the Ute Mountain Reservation, Colorado, New Mexico and Utah
80. White Earth Band of Minnesota Chippewa Tribes, Minnesota
81. Wichita and Affiliated Tribes (Wichita, Keechi, Waco & Tawakonie), Oklahoma
82. Winnebago Tribe of Nebraska
83. Yankton Sioux Tribe of South Dakota
84. Ysleta Del Sur Pueblo of Texas

ATTACHMENT C

Plans for the Unanticipated Discovery of Cultural Resources

If previously unidentified cultural resources are discovered by monitors or construction personnel unexpectedly, Keystone will follow the procedures described in the state-specific plans included in this attachment for (1) Montana, (2) South Dakota, (3) Nebraska, (4) North Dakota, and (5) Kansas. If the following plans conflict in any way with Keystone's obligations under the Programmatic Agreement and Tribal Monitoring Plan, Keystone will follow the procedures described in the Programmatic Agreement and Tribal Monitoring Plan.

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UNANTICIPATED DISCOVERIES PLAN

I. Unanticipated Discoveries Plan for the Keystone XL project corridor (Project) in Montana

If previously unidentified historic properties are discovered by monitors or construction personnel unexpectedly or unanticipated adverse effects on previously identified historic properties occur as pipeline construction activities are carried out within the one-hundred-and-ten (110) foot-wide construction corridor or other ancillary facilities and access roads within the APE, the construction contractor will immediately halt all construction activity within a one-hundred-and-fifty (150) foot radius of the discovery or adversely affected historic property, notify the Lead EI of the discovery and implement interim measures to protect the discovery from looting and vandalism.

Within forty-eight (48) hours of receipt of this notification of the discovery, the Lead EI shall:

a. Inspect the work site to determine the extent of the discovery or adverse effect and ensure that construction activities have halted;
b. Clearly mark the area of the discovery or adverse effect;
c. Implement additional measures other than those mentioned above, as appropriate, to protect the discovery or adversely affected historic property from looting and vandalism; and
d. Notify the DOS, SHPO, MDEQ, designated representatives of consulting Indian tribes, and other consulting parties of the discovery or adverse effect.

In the case of an unanticipated discovery, DOS will notify all consulting parties that it will be receiving comments concerning the unanticipated discovery and provide contact information. The DOS will have seven (7) calendar days following notification provided in accordance with Stipulation VI.A.2 to determine the National Register eligibility of the discovery after considering the timely filed views of the SHPO, MDEQ, designated representatives of consulting Indian tribes, other consulting parties, and Keystone. The applicable Federal agency may assume the newly discovered property to be eligible for the National Register for the purposes of Section 106 consistent with 36 C.F.R. § 800.13(c).

For discovered properties determined eligible or assumed to be eligible pursuant to Stipulation VI.A.3, the applicable Federal agency will notify the ACHP, SHPO, MDEQ, designated representatives of consulting Indian tribes, and other consulting parties of those actions that it proposes to resolve adverse effects which may include a Treatment Plan as outlined in Stipulation V.C.

a. SHPO, MDEQ, designated representatives of consulting Indian tribes, and other consulting parties will have ninety-six (96) hours to provide their views on the proposed actions.
b. DOS will ensure that the timely filed recommendations of SHPO, MDEQ, designated representatives of consulting Indian tribes, and other consulting parties are taken into account prior to granting approval of the measures that Keystone will implement to resolve adverse effects.

c. Keystone will carry out the approved measures prior to resuming construction activities in the location of the discovery.

In the case of unanticipated adverse effects to a previously identified historic property, the applicable Federal agency will notify the ACHP, SHPO, MDEQ, designated representatives of consulting Indian tribes, and other consulting parties of those actions that it proposes to resolve adverse effects which may include a Treatment Plan as outlined in Stipulation V.C.

a. SHPO, MDEQ, designated representatives of consulting Indian tribes, and other consulting parties will have forty-eight (48) hours to provide their views on the proposed actions.
b. DOS will ensure that the timely filed recommendations of SHPO, MDEQ, designated representatives of consulting Indian tribes, and other consulting parties are taken into account prior to granting approval of the measures that Keystone will implement to mitigate adverse effects.
c. Keystone will carry out the approved measures prior to resuming construction activities in the location of the affected property.

Dispute Resolution: DOS will seek and take into account the recommendations of the ACHP in resolving any disagreements that may arise regarding resolution of adverse effects that relate to the implementation of Stipulation VI. DOS will use the contact information provided in Attachment C or D to notify the ACHP. Within seven (7) calendar days of receipt of such a written request, the ACHP will provide DOS recommendations on resolving the dispute. DOS will take into account any timely filed recommendations provided by the ACHP in making a final decision about how to proceed.

II. Accidental Discovery of Human Remains on state or private lands

All human burials and funerary objects in the state of Montana are protected pursuant to the Human Skeletal Remains and Burial Site Protection Act (Montana Code Ann. §22-3-801 through §22-3-811).

In the event that human remains or burials are encountered during additional archaeological investigations or construction activities, Keystone or its designated representative shall immediately cease work within 150 foot radius from the point of discovery and implement measures to protect the discovery from looting and vandalism. No digging, collecting or moving human remains or other items shall occur after the initial discovery. Protection measures will include the following.

a) Flag the buffer zone around the find spot.
b) Keep workers, press, and curiosity seekers, away from the find spot.
c) Tarp the find spot.
d) Prohibit photography of the find unless requested by an agency official.
e) Have an individual stay at the location to prevent further disturbance until a law enforcement officer arrives.

Keystone will immediately notify local law enforcement, DOS, SHPO, and MDEQ within forty-eight (48) hours of the discovery. DOS shall notify the SHPO, MDEQ, Indian tribes, and other consulting parties within forty-eight (48) hours of the discovery. If local law enforcement determines that the remains are not associated with a crime, DOS shall determine if it is prudent and feasible to avoid disturbing the remains. If DOS in consultation with the Keystone determines that disturbance cannot be avoided, the DOS shall consult with the SHPO, MDEQ, Indian tribes, and other consulting parties to determine acceptable procedures for the removal, treatment and disposition of the burial or remains. The DOS shall ensure that Keystone implements the plan for removal, treatment and disposition of the burial or remains as authorized by the SHPO. The DOS shall notify Keystone that they may resume construction activities in the area of the discovery upon completion of the plan authorize as by the SHPO.

Contact Information:

Stan Wilmoth
State Archaeologist
State Historic Preservation Office
P.O. Box 201203
Helena, MT 59620
406-444-7719
swilmoth@mt.gov

James Strait, RPA
Montana DEQ/EMB/MFSA
1520 East 6th Avenue
P.O. Box 200901
Helena, MT 59620
Office: 406-444-6765
Cell: 406-696-1267
jstrait@mt.gov

Craig Jones
Montana DEQ/EMB/MFSA
1520 East 6th Avenue
P.O. Box 200901
Helena, MT 59620
406-444-0514
crajones@mt.gov

III. Unanticipated Discovery of Human Burials, Remains, and Funerary Objects on Federal Lands

For the accidental discovery of human burials, remains, and funerary objects on Federal lands please reference Stipulation VI.(C) of the PA.

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UNANTICIPATED DISCOVERIES PLAN

I. Unanticipated Discoveries Plan for the Keystone XL project corridor (Project) in South Dakota

1. In the event that previously unidentified archaeological resources are discovered during ground disturbing activities within the project area (area of potential effect), Project shall halt immediately all construction work within 100 feet (30.5 m) of the discovery and in the surrounding area where further subsurface remains can reasonably be expected to occur. The area of the discovery will be clearly marked by means of flagging or fencing.

2. The construction contractor will notify a designated representative of Project of the discovery. Following notification of the discovery, the designated representative of Project will immediately inspect the work site and determine the extent of the affected archaeological resource as defined by the State Historic Preservation Office (SHPO) or by the SHPO in consultation with the archaeologist retained by Project.

3. Within 14 calendar days of the original notification of discovery, the archaeologist retained by Project, in consultation with the SHPO, will determine the National Register eligibility of the resource. The SHPO or Project may extend this 14-day calendar period one time by an additional 7 calendar days, with Project providing written notice to the SHPO prior to the expiration date of the said 14-day calendar period.

4. If the resource is determined eligible for the National Register, Project shall submit to the SHPO and the Department of State (DOS) a plan for its avoidance, protection, recovery of information, or destruction without data recovery. Said plan will be submitted to the SHPO and the DOS within 14 calendar days of a determination of eligibility, and shall be approved by the SHPO and the DOS prior to implementation.

5. Work in the affected area may resume per SHPO authorization pending either:
    i. development and implementation of an appropriate data recovery plan or other recommended mitigation procedures, or
    ii. determination that the located remains are not eligible for inclusion on the National Register.

6. Any disputes concerning the evaluation or treatment of previously unidentified resources will be resolved through consultation among the SHPO, a designated representative of Project, and the archaeologist retained by Project.

II. Accidental Discovery of Human Remains on state or private lands

All human burials and funerary objects in the state of South Dakota are protected pursuant to South Dakota Codified Law Chapter 34-27-25, 34-27-28, 34-27-31.

In the event that human remains or burials are encountered during additional archaeological investigations or construction activities, Project or its designated representative shall immediately cease work within 150 foot radius from the point of discovery and implement measures to protect the discovery from looting and vandalism. No digging, collecting or moving human remains or other items shall occur after the initial discovery. Protection measures will include the following.

a) Flag the buffer zone around the find spot.
b) Keep workers, press, and curiosity seekers, away from the find spot.
c) Tarp the find spot.
d) Prohibit photography of the find unless requested by an agency official.
e) Have an individual stay at the location to prevent further disturbance until a law enforcement officer arrives.

Project will immediately notify local law enforcement, the DOS, and the South Dakota State Archaeologist (State Archaeologist) within forty-eight (48) hours of the discovery. The DOS shall notify the SHPO, Indian tribes and other consulting parties within forty-eight (48) hours of the discovery. If local law enforcement determines that the remains are not associated with a crime, the DOS shall determine if it is prudent and feasible to avoid disturbing the remains. If the DOS in consultation with the Project determines that disturbance cannot be avoided, the DOS shall consult with the State Archaeologist, SHPO, Indian tribes and other consulting parties to determine acceptable procedures for the removal, treatment and disposition of the burial or remains. The DOS shall ensure that the Project implements the plan for removal, treatment and disposition of the burial or remains as authorized by the State Archaeologist. The DOS shall notify the Project that they may resume construction activities in the area of the discovery upon completion of the plan authorize as by the State Archaeologist.

Contact Information:

James K. Haug, State Archaeologist
South Dakota State Historical Society
Archaeological Research Center
PO Box 1257
Rapid City, SD 57709
(605) 394-1936

Katie Lamie, Repository Manager
South Dakota State Historical Society
Archaeological Research Center
PO Box 1257
Rapid City, SD 57709
(605) 394-1936

Paige Olson, Review and Compliance Coordinator
South Dakota State Historical Society
State Historic Preservation Office
900 Governors Drive
Pierre, SD 57501
(605) 773-3458

Amy Rubingh, Review and Compliance Archaeologist
South Dakota State Historical Society
State Historic Preservation Office
900 Governors Drive
Pierre, SD 57501
(605) 773-3458

III. Unanticipated Discovery of Human Burials, Remains, and Funerary Objects on Federal Lands

For the accidental discovery of human burials, remains, and funerary objects on Federal lands please reference Stipulation VI.(C) of the PA.

PREFILED REBUTTAL TESTIMONY

OF

FAITH SPOTTED EAGLE

Docket No. HP14-001

IN THE MATTER OF THE APPLICATION OF TRANSCANADA KEYSTONE PIPELINE, LP FOR ORDER ACCEPTING CERTIFICATION OF PERMIT ISSUED IN DOCKET HP09-001 TO CONSTRUCT THE KEYSTONE XL PIPELINE

1. Please state your name and you home address.

A. My name is Faith Spotted Eagle. My home address is Box 667, Lake Andes, SD, 57356.

2. Are you a member of the Yankton Sioux Tribe or any other tribe?

A. I am an enrolled member of the Yankton Sioux Tribe.

3. What is your occupation or what kinds of work do you do?

A. Private consultant in PTSD Counseling for veterans and veteran's organization; Trainer/facilitator in Historical Trauma for all populations; school certified counselor work in schools, Dakota Language teacher, Manager of Brave Heart Lodge in Lake Andes.

4. Please describe your educational background and professional experience.

A. I have an MA in Educational Psychology and Counseling from USD, Vermillion, SD. I have held professional positions as a teacher, counselor, principal, manager of Human Service Programs, Family and Individual therapist, Grantwriter and currently am Chair of the Ihanktonwan Treaty Committee.

5. Did you provide a copy of your resume?

A. I attached a biography as Attachment A to my prefiled direct testimony.

6. On whose behalf was this testimony prepared?

A. This testimony was prepared on behalf of the Yankton Sioux Tribe.

7. Do you currently hold any positions with the Yankton Sioux Tribe?

A. I am an official elected by the General Council to be on the Ihanktonwan Treaty Committee and serve as the Chair for that body.

8. Please state the purpose of your testimony in this proceeding.

A. The purpose of my testimony is to rebut any testimony in support of the Applicant's position because the Applicant cannot prove that it continues to meet all conditions upon which the permit was granted. I can provide testimony on subjects including the interactions between TransCanada and the Yankton Sioux Tribe, the Yankton Sioux Tribe's position on the proposed project, the Programmatic Agreements executed in conjunction with the Final Environmental Impact Statement and the Final Supplemental Environmental Impact Statement (attached to this prefiled testimony as Exhibits A and B, respectively), cultural resources and sacred sites, the governing treaties between the United States and the Yankton Sioux Tribe, and the threats posed by the proposed project to the Yankton Sioux Tribe and its Tribal members as appropriate based on the testimony offered by the Applicant. Based on my knowledge, the Applicant cannot meet the conditions of the original permit.

EXHIBIT A

Appendix S

Programmatic Agreement and Record of Tribal Contact

Programmatic Agreement

Among
The U.S. Department of State,
U.S. Bureau of Land Management,
U.S. Army Corps of Engineers,
U. S. Bureau of Reclamation,
National Park Service,
Western Area Power Administration,
U.S. Department of Agriculture Rural Utilities Service,
U.S. Department of Agriculture Natural Resources Conservation Service,
U.S. Department of Agriculture Farm Service Agency
U.S. Bureau of Indian Affairs
Montana Department of Natural Resources and Conservation,
Montana Department of Environmental Quality,
Advisory Council on Historic Preservation,
Montana State Historic Preservation Officer,
Kansas State Historic Preservation Officer,
Texas State Historic Preservation Officer,
Nebraska State Historic Preservation Officer,
Oklahoma State Historic Preservation Officer,
South Dakota State Historic Preservation Officer, and
TransCanada Keystone Pipeline, LP
Regarding the Keystone XL Pipeline Project

WHEREAS, the U.S. Department of State (DOS) receives and considers applications for permits for cross border oil pipelines pursuant to the authority delegated by the President of the United States under Executive Order (EO) 13337 (69 Federal Register 25299); and

WHEREAS, on September 19, 2008, the DOS received an application for a Presidential Permit from TransCanada Keystone Pipeline, LP (Keystone) for the Keystone XL Pipeline Project (Keystone XL Project or the Project); and

WHEREAS, DOS has determined that issuance of a Presidential Permit for the Keystone XL Project includes review under Section 106 of the National Historic Preservation Act (NHPA) (16 U.S.C. 470f, as amended) and its implementing regulations, "Protection of Historic Properties," (36 CFR Part 800); and

WHEREAS, the Project undertaking consists of construction of approximately 1,375 miles of new crude oil pipeline in the United States and utilizes 298 miles of the previously approved Keystone Cushing Extension, associated aboveground facilities (such as pump stations and transmission facilities and substations), and ancillary facilities (such as lateral pipeline, temporary workplace areas and pipe storage, access roads, and contractor yards); and

WHEREAS, the proposed Keystone XL Project pipeline alignment crosses Montana, South Dakota, Nebraska, Kansas, Oklahoma, and Texas; and

WHEREAS, the proposed Keystone XL Project pipeline alignment crosses seven National Historic Trails: the Lewis and Clark National Historic Trail (LCNHT); Oregon, California, Mormon Pioneer, and Pony Express National Historic Trails; the Santa Fe National Historic Trial; and the El Camino Real de los Tejas National Historic Trail (ELTE). Each of these trails was designated by the U.S. Congress and have as their purpose "the identification and protection of the historic route and its historic remnants and artifacts for public use and enjoyment;" (National Trails System Act, P.L. 90-543, as amended); and

WHEREAS, on February 2, 2011, the Advisory Council on Historic Preservation (ACHP) entered consultation finding that criteria 3 and 4 of Appendix A, Criteria for Council Involvement in Reviewing Individual Section 106 Cases, of the regulations (36 CFR Part 800) implementing Section 106 of NHPA, had the potential to be met; and

WHEREAS, the United States Army Corps of Engineers (USACE) has determined that the approval for the Keystone XL Project to cross USACE administered lands (30 U.S.C. § 185) and to place structures in, under, or over navigable waters of the United States, as defined under 33 CFR 329, pursuant to Section 10 of the Rivers and Harbors Act of 1899 (33 U.S.C. § 403), and a permit for the placement of dredge or fill material in waters of the United States as part of the Keystone XL Project in accordance with Section 404 of the Clean Water Act (334 U.S.C. § 344; see 33 CFR 323), are federal actions related to the undertaking that require the USACE to comply with Section 106 of NHPA and 36 CFR Part 800; and

WHEREAS, the U.S. Bureau of Land Management (BLM) has determined the approval of the Keystone XL Project to cross Federal lands administered by the BLM would require authorization under Section 28 of the Mineral Leasing Act of 1920, as amended [(MLA) 30 USC 185]; and

WHEREAS, the BLM has determined that Keystone will require access roads crossing public lands administered by the BLM in support of the Keystone XL Pipeline Project and that the access roads will require authorization under Title V of the Federal Land Policy and Management Act, as amended [(FLMPA) 43 USC 1701]; and

WHEREAS, the BLM has determined that the Keystone XL Project will require electrical power from rural electrical cooperatives and that portions of the transmission lines will cross public lands administered by the BLM and that the transmission lines crossing public lands will require authorization under Title V of the Federal Land Policy and Management Act, as amended [(FLMPA) 43 USC 1701]; and

WHEREAS, the BLM approvals of these Project crossings in areas under its jurisdiction is a federal action associated with the undertaking that requires the BLM to comply with Section 106 of the NHPA and 36 CFR Part 800; and

WHEREAS, the U.S. Bureau of Reclamation (RECLAMATION) manages lands and facilities that will be crossed by the Keystone XL Project and this is a federal action related to the undertaking that requires RECLAMATION to comply with Section 106 of the NHPA and 36

CFR Part 800; and

WHEREAS, the Natural Resources Conservation Service (NRCS) has determined that it retains rights to a 2,693 acre parcel subject to the Wetlands Reserve Program (WRP) (16 U.S.C. 3837 et. seq.) easements in Fannin County, Texas and that the installation and maintenance of the Project pipeline on this WRP easement is a federal action associated with the undertaking that requires compliance with Section 106 of NHPA and 36 CFR Part 800; and

WHEREAS, the Farm Service Agency (FSA), manages private lands with federal easements along the Project APE as part of its Grasslands Reserve Program (jointly administered with the NRCS) as well as the Conservation Resource Program, and the Farmable Wetlands Program; and

WHEREAS, the FSA approval of the Project crossings in these areas is a federal action associated with the undertaking that requires the FSA to comply with Section 106 of the NHPA and 36 CFR Part 800; and

WHEREAS, the Rural Utilities Service (RUS) has determined that the financial assistance it may provide to rural electric cooperatives and other entities for construction or modification of electrical transmission facilities (including transmission lines and substations) to power some Keystone XL Project pump stations or to ensure transmission system reliability, under USDA Rural Development's Utilities Programs, are Federal actions related to the undertaking that require RUS to comply with Section 106 of NHPA and 36 CFR Part 800; and

WHEREAS, the Bureau of Indian Affairs (BIA) has responsibility for approving any right-of-ways crossing Indian Trust lands and this is a federal action related to the undertaking that requires the BIA to comply with Section 106 of the NHPA and 36 CFR Part 800; and

WHEREAS, the Western Area Power Administration (WESTERN) has determined that the modification and construction of substations and transmission lines that WESTERN will own and that will provide power to the Keystone XL project, will require review under Section 106 of NHPA and 36 CFR Part 800; and

WHEREAS, the National Park Service (NPS) has been invited to consult with the DOS concerning the Project due to the potential for adverse effects to several National Historic Trails including the LCNHT and ELTE; and

WHEREAS, the Montana Department of Natural Resources and Conservation has participated in consultation and has been invited by DOS under 36 CFR § 800.6(c) (2) to sign this Programmatic Agreement (PA) as an invited signatory; and

WHEREAS, the Montana Department of Environmental Quality has participated in consultation and has been invited by DOS under 36 CFR § 800.6(c) (2) to sign this PA as an invited signatory; and

WHEREAS, the USACE, BLM, RUS, BIA, NRCS, WESTERN, RECLAMATION, and FSA have designated the DOS as the lead federal agency for purposes of Section 106 of the NHPA in

accordance with 36 CFR § 800.2(a)(2); and

WHEREAS, the Keystone XL Project area of potential effect (APE) includes: (1) in Montana –a 300 foot wide corridor, 150 feet on each side from the centerline; (2) in South Dakota – a 300 foot wide corridor, 150 feet on each side from the centerline; (3) in Nebraska – a 300 foot wide corridor, 150 feet from each side from the centerline; (4) in Kansas – all areas of disturbance related to the construction of two pump stations; (5) in Oklahoma – a 300 foot wide corridor, from centerline of outermost existing pipeline; and (6) in Texas - a 300 foot wide corridor, with 200 feet from the existing infrastructure feature centerline on the side where the proposed pipeline is to be collocated and 100 feet from the existing feature centerline on the opposite side, or, if the route is not collocated with existing infrastructure, then the survey area will be centered on the proposed pipeline (150 feet on each side). For transmission lines and access roads in each state, a 100 foot wide corridor centered on the Project centerline will be used. For pumping stations and other areas that are to be disturbed by construction related activities and ancillary facilities (including construction camps and pump stations), the APE will include all areas of disturbance and areas to be indirectly affected; and

WHEREAS, the DOS has determined that the construction of the Keystone XL Project may have an adverse effect on properties listed in or eligible for listing in the National Register of Historic Places (NRHP), and has consulted with the Montana, South Dakota, Nebraska, Kansas, Oklahoma, and Texas State Historic Preservation Officers (SHPOs), Tribal Historic Preservation Officers (THPOs), Indian Tribes, and the ACHP, pursuant to 36 CFR Part 800; and

WHEREAS, the BLM will incorporate this PA into its decisional process on any authorization under the MLA or FLPMA it may issue for the Keystone XL Project, and will include in any authorization it issues on the Keystone XL Project, a condition that Keystone will abide by its commitments in this PA; and

WHEREAS, in accordance with 36 CFR §§ 800.4(b)(2) and 800.5(a)(3), the DOS has elected to phase identification and evaluation of historic properties, and application of the criteria of adverse effect, respectively, because access to those areas identified in Attachment A has been restricted by property owners' refusal to grant Keystone permission to enter their private property; and

WHEREAS, Attachment G includes summary information on the identification, evaluation, and effect assessment updates on the Project that were included in the Final Environmental Impact Statement (FEIS); and

WHEREAS, additional identification, evaluation and effect assessments for the Project will need to be undertaken as all areas of construction have yet to be determined; and

WHEREAS, pursuant to 36 CFR § 800.14(b), the DOS has elected to execute this PA for the Keystone XL Project because effects on historic properties cannot be fully determined prior to the issuance of a permit for the undertaking; and

WHEREAS, Attachment G also summarizes consultation with Indian tribes and Nations,

SHPOs, and other agencies; and

WHEREAS, the DOS will incorporate this PA into its decisional process on any Presidential Permit that it may issue for the Keystone XL Project and will include in any permit it issues on the Keystone XL Project a condition that Keystone will abide by its commitments in this PA; and

WHEREAS, Keystone, which will construct the Keystone XL Project pipeline, has participated in consultation, has been invited by DOS under 36 C.F.R. §§ 800.2(c)(4) and 800.6(c)(2) to sign this agreement as an invited signatory and intends to sign this agreement as an invited signatory; and

WHEREAS, for the purposes of this agreement, "Indian tribes and Nations" shall have the same definition as "Indian tribes" which appears in Section 301(4) of the NHPA; and

WHEREAS, DOS invited the Indian tribes listed in Attachment B to participate in consultation; and

WHEREAS, the Absentee-Shawnee Tribe of Indians of Oklahoma; the Alabama-Coushatta Tribe of Texas, Blackfeet Tribe, Caddo Nation of Oklahoma, Cheyenne River Sioux, Cheyenne-Arapaho Tribe of Oklahoma, Chippewa-Cree Indians, Choctaw Nation of Oklahoma, Crow Tribe of Indians, Delaware Nation, Fort Peck Tribes, Gros Ventre and Assiniboine Tribe of Ft. Belknap, Ho-Chunk Nation of Wisconsin, Iowa Tribe of Kansas and Nebraska, Iowa Tribe of Oklahoma, Kaw Nation, Kialegee Tribal Town of the Creek Nation in Oklahoma, Kickapoo Tribe of Kansas, Kiowa Indian Tribe of Oklahoma, Lower Sioux Indian Community, Miami Tribe of Oklahoma, Mille Lacs Band of Ojibwe, Muscogee (Creek) Nation, Northern Arapaho Tribe, Northern Cheyenne Tribe, Northern Ute Tribe, Oglala Sioux Tribe, Osage Nation, Pawnee Nation of Oklahoma, Ponca Tribe of Indians of Oklahoma, Ponca Tribe of Nebraska, Rosebud Sioux Tribe, Sac & Fox Nation of Oklahoma, Santee Sioux Tribe of Nebraska, Shoshone-Bannock Tribe, Sisseton-Wahpeton Oyate Sioux, Spirit Lake Tribe, Standing Rock Sioux Tribe, Three Affiliated Tribes, Tonkawa Tribe, Turtle Mountain Band of Chippewa, Wichita and Affiliated Tribes, Winnebago Tribe, and Yankton Sioux have participated in consultation and have been invited to concur in this PA, in accordance with 36 C.F.R. §§ 800.2(c)(2) and 800.6(c)(3);

NOW, THEREFORE, the DOS, USACE, BLM, RUS, BIA, FSA, NRCS, WESTERN, RECLAMATION, NPS, ACHP, and the Montana, South Dakota, Nebraska, Kansas, Oklahoma, and Texas SHPOs agree that the following stipulations will be implemented in order to take into account the effect of the undertaking on historic properties and to satisfy all responsibilities under Section 106 of the NHPA.

STIPULATIONS

The DOS, BLM, RUS, BIA, FSA, NRCS, WESTERN, USACE, RECLAMATION, and NPS as appropriate, will ensure that the following stipulations are carried out.

I. STANDARDS AND DEFINITIONS

A. Identification and evaluation studies and treatment measures required under the terms of this PA will be carried out by or under the direct on-site supervision of a professional(s) who meets, at a minimum, the *Secretary of the Interior's Historic Preservation Professional Qualification Standards* (48 FR 44716, September 29, 1983).

B. In developing scopes of work for identification and evaluation studies, and treatment measures required under the terms of this PA, Keystone and RUS applicants will take into account the following regulations and guidelines:

1. The ACHP's guidance on conducting archaeology under Section 106 (2007);
2. The ACHP's *Policy Statement Regarding the Treatment of Burial Sites, Human Remains and Funerary Objects* (February 23, 2007);
3. Applicable SHPO guidance;
4. The Secretary of the Interior's *Standards and Guidelines for Archaeology and Historic Preservation* (48 FR 44716-42, September 29, 1983);
5. The "*Treatment of Archaeological Properties*" (ACHP 1983);
6. The *Guidelines for Reporting on Cultural Resources Investigations for Pipeline Projects*" (Federal Energy Regulatory Commission, Office of Energy Projects, December 2002);
7. Section 10 of the Rivers and Harbors Act of 1899 (33 U.S.C. § 403);
8. Section 404 of the Clean Water Act (334 U.S.C. § 344);
9. BLM 8110 Manual: Identifying and Evaluating Cultural Resources;
10. Montana/Dakotas Cultural Resources Handbook 8110-1: Guidelines for Identifying Cultural Resources;
11. The National Trails System Act (P.L. 90-543, as amended);
12. Section 28 of the Mineral Leasing Act of 1920 (30 USC 185);
13. Title V of the Federal Land Policy and Management Act of 1976 (43 USC 1701); and
14. *National Register Bulletin 38, Guidelines for Evaluating and Documenting Traditional Cultural Properties* (NPS 1990; Revised 1992: 1998)

C. Definitions

Coordination Plan: A plan (more fully explained in Stipulation V.B and V.D.) that describes the coordination of construction with identification and evaluation of cultural resources, treatment of adverse effects, and protection of unanticipated discoveries.

Concurring Parties: An invited consulting party to this PA that agrees with the content of the PA. The refusal of a concurring party to sign the PA does not invalidate this PA as noted in 36 C.F.R. § 800.6(c)(3). Concurring parties may not terminate the PA.

Construction spread: A construction unit or segment of a pipeline alignment or corridor to be determined by Keystone prior to construction.

Consulting Parties: Parties that have consultative roles in the Section 106 process, as defined in 36 C.F.R. § 800.2(c).

Data Recovery: The recovery of archaeological information from a historic property subject to an adverse effect.

Determination of Effect: A determination made by a federal agency in regards to a Project's effect upon a historic property as defined in 36 C.F.R. Part 800.

Determination of Eligibility: A determination made by a federal agency in regards to a cultural resource's eligibility for inclusion in the National Register of Historic Places (NRHP) and more fully described in 36 C.F.R. Part 60 and 36 C.F.R. § 800.16(l)(2).

Effect: An alteration to the characteristics of a historic property qualifying it for inclusion in or eligibility for the NRHP (see 36 C.F.R. § 800.16(i)).

Environmental Impact Statement: An analysis of a major federal action's environmental impacts conducted consistent with NEPA.

Historic Property: Any prehistoric or historic district, site, building, structure, or object included in, or eligible for inclusion in, the NRHP maintained by the Secretary of the Interior. This term includes artifacts, records, and remains that are related to and located within such properties. The term includes properties of traditional religious and cultural importance to an Indian Tribe or Native Hawaiian organization and that meet the National Register criteria (see 36 C.F.R. § 800.16(l)(a)).

Invited Signatory: The DOS has invited TransCanada Keystone Pipeline LP, the Montana Department of Natural Resources and Conservation, and the Montana Department of Environmental Quality to be signatories to this PA pursuant to 36 C.F.R. § 800.6(c)(2). The refusal of any invited signatory to sign the PA does not invalidate the PA.

Historic Trail and Archaeological Monitoring Plan: A plan (more fully described in Stipulation V.E and Attachment F.) that identifies appropriate areas for monitoring construction by professionals under the supervision of individuals that meet the professional qualifications in Stipulation I. The plan's principal goal is to reduce the potential for impacts to unidentified historic properties.

Signatory Parties: All signatories to this PA, which includes the DOS, BLM, RECLAMATION, USACE, NPS, WESTERN, RUS, NRCS, FSA, BIA, Montana Department of Natural Resources and Conservation, Montana Department of Environmental Quality, and the SHPOs of Montana, South Dakota, Nebraska, Kansas,

Oklahoma, and Texas. (Signatory parties include the federal agency(ies), SHPOs, THPOs (or designee) if the undertaking is carried out on Tribal land or affects historic properties on Tribal land, and also any invited signatories [not including invited concurring parties]).

Tribal Monitoring Plan: A plan (more fully described in Stipulation V.E. and Attachment E) that identifies appropriate areas for monitoring construction by tribal members appointed by their respective tribes. These tribal members shall meet the qualifications as noted in Stipulation V.E.3. The plan's principal goal is to reduce the potential for impacts to previously unidentified historic properties that may also be properties of religious and cultural significance that meet the National Register criteria (see 36 CFR § 800.16(1)(a)).

Treatment Plan: A plan developed in consultation with the parties to this PA that identifies the minimization, and mitigation measures for historic properties located within the APE that will be adversely affected by the Project.

II. CONFIDENTIALITY

DOS, BLM, NRCS, BIA, RUS, WESTERN, RECLAMATION, NPS and USACE will safeguard information about historic properties of religious and cultural significance to Indian tribes, including location information, or information provided by Indian tribes to assist in the identification of such properties, to the extent allowed by Section 304 of NHPA [16 U.S.C. 470w3] and other applicable laws.

III. THE RESPONSIBILITIES OF FEDERAL AGENCIES WITH LAND MANAGEMENT AND OTHER PERMITTING AUTHORITIES

A. The USACE will ensure that the requirements of this PA have been met for that part of the APE under its jurisdiction, pursuant to Section 10 and Section 404 permitting authority.

B. The USACE will comply with Section 106 and its implementing regulations (36 CFR Part 800) for the issuance of permits for those actions under its jurisdiction.

C. The BLM will comply with Section 106 and its implementing regulations (36 CFR Part 800) for the issuance of permits for those actions under its jurisdiction.

D. RECLAMATION will review and comment on the evaluation and treatment of any historic properties managed by RECLAMATION.

E. Attachment H includes maps that illustrate the Project areas cross lands managed by the BLM and RECLAMATION.

F. Consultation for this Project between Indian tribes and federal land management and permitting agencies will be coordinated through the DOS.

IV. KEYSTONE XL PROJECT – CONSTRUCTION OR MODIFICATION OF ELECTRICAL DISTRIBUTION/TRANSMISSION FACILITIES

A. Prior to granting approval of financial assistance to construct or modify electrical transmission facilities by rural electric cooperatives or other entities, RUS will complete the requirements of 36 CFR §§ 800.3 through 800.7.

B. In implementing Stipulation IV.A, RUS may authorize an applicant to initiate Section 106 consultation in accordance with 36 CFR § 800.2(c) (4). In doing so, RUS may not delegate its responsibility to conduct government-to-government consultation with Indian tribes to an applicant, unless RUS and that tribe agree, in writing, to conduct consultation in that manner.

C. Prior to construction of the 230kV transmission line WESTERN will own, WESTERN will complete the requirements of 36 CFR §§ 800.3 through 800.7. In implementing Stipulation IV.C., WESTERN will serve as a signatory party under the DOS PA. WESTERN shall coordinate implementation of Stipulation IV.C with the DOS.

D. RUS will ensure that the terms of Stipulation VI.B and Attachment C are incorporated into construction contracts to ensure that its applicants and construction contractors meet their responsibility for notification of any unanticipated discoveries. When RUS funded projects occur on BLM land, the RUS will coordinate with BLM to ensure compliance with Stipulation VI.B. and Attachment C of this Agreement.

E. Prior to granting approval or financial assistance for construction or modification of electrical distribution/transmission facilities that are necessary components of the pipeline project and therefore considered within the Project APE, any federal agency that is incorporated into this agreement pursuant to Stipulation XIV will complete the requirements of 36 CFR §§ 800.3 through 800.7 for those facilities under its jurisdiction if not already carried out elsewhere in this agreement.

F. DOS retains responsibility for completing the requirements of 36 CFR §§ 800.3 through 800.7 for those electrical distribution/transmission facilities that are necessary components of the Project if they are not under the jurisdiction of any federal agency and not referenced in Stipulation IV. A through E above.

V. KEYSTONE XL PROJECT – PIPELINE CONSTRUCTION

A. The DOS provided SHPOs, consulting Indian tribes, and other consulting parties with an opportunity to provide their views on the identification and evaluation of historic properties (as defined in 36 CFR § 800.16(l), including historic properties of religious and cultural significance to Indian tribes, and the treatment of affected historic properties,

in connection with the construction of the Keystone XL Project as described in Stipulation V.C of this PA.

B. Identification and Evaluation of Historic Properties

1. In consultation with the SHPOs, consulting Indian tribes, and other consulting parties, the DOS will make a reasonable and good faith effort to complete the identification and evaluation of historic properties within the APE for each construction spread prior to the initiation of construction of that spread, in accordance with 36 CFR §§ 800.4(a), (b) and (c). On federal lands, the scope of the identification effort will be determined by the appropriate federal land managing agency in consultation with the DOS, applicable SHPOs, consulting Indian tribes, and other consulting parties.

2. For the APE in Montana, South Dakota, Nebraska, Kansas, Oklahoma, and Texas, DOS will make a reasonable and good faith effort to complete the identification and evaluation of historic properties, in accordance with 36 CFR §§ 800.4(a), (b) and (c), before Keystone initiates construction activities (including vegetative clearing to comply with the Migratory Bird Treaty Act if clearing is undertaken).

   a. In the identification and evaluation of historic properties to which Indian tribes attach religious and cultural significance, the DOS will take into consideration information submitted by Indian tribes to DOS prior to construction.

   b. In the event identification of historic properties cannot be completed for any construction spreads prior to construction, Keystone will develop and submit a Coordination Plan to DOS for review and approval pursuant to Stipulation V.D that describes the measures it will implement to complete the identification and evaluation of historic properties before such properties are adversely affected by vegetation clearing and construction activities related to that spread.

C. Treatment of Historic Properties

1. Whenever feasible, avoidance of adverse effects to historic properties will be the preferred treatment. In consultation with the DOS, ACHP, SHPOs, THPOs, and consulting parties, Keystone may elect to consider and implement avoidance measures prior to completing the evaluation of historic properties.

   Avoidance and minimization measures may include:
   a. Avoidance through pipeline or access road route variation or Project feature relocation;
   b. Avoidance through abandonment;
   c. Avoidance through bore or horizontal directional drill;
   d. Avoidance by narrowing the construction corridor (“neck down”); and
   e. Avoidance through the use of existing roadways as Project access roads to the extent practicable.

2. When historic properties are identified in the APE pursuant to Stipulation V.B, DOS will apply the criteria of adverse effect in accordance with 36 CFR § 800.5(a) in consultation with the ACHP, SHPO and other consulting parties. If DOS finds that historic properties might be adversely affected by actions covered under this PA and within the APE, DOS will consult with the ACHP, SHPOs, consulting Indian tribes, and other consulting parties to determine prudent and feasible ways to avoid adverse effects.

    a. Once DOS approves avoidance measures, Keystone will implement those measures.

3. If DOS determines that the adverse effect cannot be avoided, DOS will consult with the ACHP, SHPOs, consulting Indian tribes, and other consulting parties to determine those measures to be implemented by Keystone to minimize and mitigate adverse effects on affected historic properties identified in the APE.

4. If, after consultation, DOS determines that the adverse effect cannot be avoided, Keystone will draft a comprehensive Treatment Plan for each adversely affected historic property. The Treatment Plan describes the measures identified by DOS under Stipulation V.C.3 to minimize and mitigate the adverse effect of pipeline construction activities on historic properties, the manner in which these measures will be carried out, and a schedule for their implementation.

    a. When mitigation consists of or includes data recovery, the Treatment Plan also will identify the specific research questions to be addressed by data recovery with an explanation of their relevance, the archaeological methods to be used, and provisions for public interpretation and education, subject to Stipulation II restrictions, if any.

    b. A Treatment Plan may also include mitigation for adverse effects to historic districts, buildings and structures. This mitigation may include the recordation of historic properties according to Historic American Building Survey/Historic American Engineering Record Standards and Guidelines for Architectural and Engineering Documentation. Other types of mitigation for adverse effects to historic districts, buildings, and structures may also be described in the Treatment Plan. The mitigation proposed for an adverse effect to a historic district, building, and/or structure will be commensurate with the level of significance and extent of adverse effect and will be determined in a manner consistent with Stipulation V.C.4.c.

    c. Keystone will submit the draft Treatment Plan to the DOS, BLM (if applicable), ACHP, THPOs, the SHPO of the applicable state, MT DEQ (if applicable), MT DNRC (if applicable), and other applicable consulting parties for a thirty (30) calendar day review. Keystone shall address timely comments and recommendations submitted by SHPOs, consulting Indian tribes, and other consulting parties in preparation of the Final Treatment Plan.

d. When it has addressed all of the timely comments and recommendations, Keystone will submit the Final Treatment Plan to DOS for review and approval. Keystone will also submit the Final Treatment Plan to BLM for review and approval when involving lands subject to Stipulation III.C. DOS and BLM shall issue their final decision on the Treatment Plan within thirty (30) calendar days. Once the Final Treatment Plan is approved by DOS (and the BLM if involving BLM-managed lands), copies of the Treatment Plan will be distributed to all SHPOs, consulting Indian tribes, and other consulting parties.

5. Keystone will make a reasonable and good faith effort to complete implementation of the Final Treatment Plan approved by DOS prior to beginning construction of any spread for which the Treatment Plan is required. If it is not possible to meet this schedule, Keystone will develop a Coordination Plan in accordance with Stipulation V.D that establishes how appropriate treatment will be determined and implemented during construction of the respective spread.

D. Coordination of Construction and Historic Preservation Activities

1. The DOS will make a reasonable and good faith effort to complete the identification and evaluation of historic properties, and the mitigation of adverse effects to them in accordance with Stipulations V.B and V.C prior to the initiation of vegetative clearing if vegetative clearing and construction on the Keystone XL spreads, including the Montana, South Dakota, Nebraska, Kansas, Oklahoma and Texas spreads, is to be undertaken.

2. If these DOS activities cannot be completed prior to the start of vegetative clearing and construction of these spreads, Keystone shall develop and provide to DOS a detailed plan describing how the requirements of Stipulations V.B and V.C – identification, evaluation and treatment of historic properties – will be completed in coordination with vegetative clearing and construction activities in such a way that historic properties will not be adversely affected prior to the implementation of any mitigation measures.

   a. A Coordination Plan will be prepared for each state and will include those measures developed by Keystone pursuant to Stipulations V.B and V.C to complete the identification and evaluation of historic properties, and, as appropriate, mitigation of adverse effects to them during and coordinated with vegetation clearing and construction activities. In addition, the Coordination Plan will include a schedule for all proposed activities and recommended measures for the protection of unanticipated discoveries in accordance with Attachment C, as appropriate.

   b. Keystone will submit the draft Coordination Plan for each state for such spreads, including the Montana, South Dakota, Nebraska, Kansas, Oklahoma and Texas spreads, to the DOS, BLM (as applicable) ACHP, SHPOs, THPOs, and consulting

parties for thirty (30) calendar day review. Keystone shall address timely comments and recommendations submitted by the applicable SHPO, consulting Indian tribes, and other consulting parties in preparation of the Final Coordination Plan for each state. When it has addressed all of the comments and recommendations, Keystone will submit the Final Coordination Plan for each state to DOS for review. DOS shall issue its final decision on the Coordination Plan for each state within thirty (30) calendar days. Following approval by DOS, the Final Coordination Plan for each state will be distributed to all of the SHPOs, consulting Indian tribes, and other consulting parties.

3. Keystone will complete implementation of the Final Coordination Plan approved by DOS during construction of the Montana, South Dakota, Nebraska, Kansas, Oklahoma and Texas spreads.

E. Historic Trail and Archaeological Monitoring Plan ("HTAM Plan") and Tribal Monitoring Plan

1. In consultation with the SHPOs and Indian tribes, Keystone will monitor construction in selected areas of the APE of each spread as a supplement to identification efforts. Any historic properties identified by Keystone during monitoring will be treated in accordance with Stipulation VI.A and C.

   a. The HTAM Plan outlines areas that have been previously identified by DOS during identification and evaluation efforts that warrant monitoring during soil disturbing activities for potential effects to historic properties.

   b. The Tribal Monitoring Plan outlines areas that have been previously identified by Indian Tribes, either through the preparation of Traditional Cultural Property reports or through consultation, that warrant monitoring during clearing and trenching for potential effects to previously unidentified historic properties that may include properties of religious and cultural importance to an Indian tribe and that meet the National Register criteria (See 36 C.F.R. § 800.16(1)(a)).

2. Historic Trail monitoring will be performed by a professional who either meets the qualification standards for archaeology established in Stipulation I.A or is under the on-site supervision of such a professional. When the monitoring occurs on BLM managed lands, all monitors must have a valid Archaeological Resources Protection Act (ARPA) permit or be included on a BLM Cultural Resource Use Permit.

3. For tribal monitoring, other types of experience with construction monitoring and/or traditional cultural knowledge may be substituted for degrees required by the Standards at the discretion of the DOS. When the monitoring occurs on BLM managed lands, all monitors must have a valid Archaeological Resources Protection Act (ARPA) permit or be included on a BLM Cultural Resource Use Permit.

4. Keystone shall consider information provided by Indian tribes in a timely manner when completing the identification of historic properties before construction begins under Stipulation V.B and in implementing a HTAM Plan and Tribal Monitoring Plan provided for under Stipulation V.E. Keystone shall provide Indian tribes a reasonable opportunity to participate as monitors during Project construction. In those areas previously identified by Indian tribes as needing monitoring, the Tribal Monitoring Plan stipulates that at least one and at most two monitors will be used per construction spread depending upon the extent and location of construction activities.

5. Keystone has submitted a plan for historic trail and archaeological monitoring and tribal monitoring for each spread to the DOS, BLM, ACHP, SHPO, THPOs, and Consulting Parties for review and comment prior to the signing of this Agreement. The Tribal Monitoring Plan and HTAM Plan are attached to this agreement in Attachments E and F.

6. Keystone will implement the HTAM Plan and Tribal Monitoring Plan for each spread that has been approved by DOS.

F. Construction

1. Lead Environmental Inspector (EI): Prior to initiating vegetative clearing or construction, Keystone will employ the Lead EI whose responsibilities will include ensuring compliance with the terms of this PA. In meeting this responsibility, the Lead EI will rely on the technical expertise of on-site professionals who meet the standards established in Stipulation I.A and tribal monitors with experience outlined in Stipulation V.E.3.

    a. The Lead EI will monitor construction activities on-site and prepare a daily log reporting to Keystone on activities performed to implement the terms of this PA, as appropriate. Keystone will make the daily log available to the DOS and SHPOs, consulting Indian tribes, and other consulting parties upon request.

    b. Keystone will ensure through the construction contract that the Lead EI will possess the authority to stop construction in the event of an inadvertent discovery in accordance with Stipulation VI.A and Attachment C.

2. Training: Keystone will ensure that if the Lead EI does not meet the professional qualification standards established in Stipulation I.A, the Lead EI receives appropriate training in historic preservation from a professional who meets the standards established in Stipulation I.A in order to perform the requirements of this PA. Keystone also will provide an appropriate level of training in historic preservation conducted by a professional who meets the standards established in Stipulation I.A to all construction personnel (including new, added, replaced workers) so that PA requirements are understood and unanticipated discoveries quickly identified. Keystone will conduct this training prior to initiating vegetative clearing or

construction activities on a spread, and conduct periodic refresher training during construction of the spread.

3. This Programmatic Agreement and Attachment E, the Tribal Monitoring Plan, have given tribes the opportunity to provide information about historic properties of concern to the tribe(s).

4. Construction Contract: Keystone will incorporate the terms of Stipulation VI.A and Attachment C into construction contracts to ensure that its Lead EI and construction contractors meet their responsibility for notification of the unanticipated discoveries.

G. Scheduling

The DOS may authorize the start of vegetative clearing and construction for an individual spread when the plans prepared in accordance with Stipulations V.D and V.E as appropriate for that spread, have been submitted by Keystone and approved by DOS in accordance with the terms of this PA.

VI. UNANTICIPATED DISCOVERIES DURING CONSTRUCTION OF THE KEYSTONE XL PROJECT

A. Pipeline Construction

1. "Applicable federal agency" is the federal agency with jurisdiction for the land on which construction is occurring or, in the absence of such an agency, DOS, as appropriate.

2. If previously unidentified historic properties are discovered by monitors or construction personnel unexpectedly as pipeline construction activities are carried out within the one-hundred and ten (110) foot-wide construction corridor or other ancillary facilities and access roads within the APE, the construction contractor will immediately halt all construction activity within a one-hundred and fifty (150) foot radius of the discovery, notify Keystone's Lead EI of the discovery and implement interim measures to protect the discovery from looting and vandalism. Within forty-eight (48) hours of receipt of this notification of the discovery, the Lead EI shall:

   a. Inspect the work site to determine the extent of the discovery and ensure that construction activities have halted;
   b. Clearly mark the area of the discovery;
   c. Implement additional measures other than those mentioned above, as appropriate, to protect the discovery from looting and vandalism; and
   d. Notify the applicable federal agency SHPOs, consulting Indian tribes, and other consulting parties of the discovery.

3. The applicable federal agency shall notify all consulting parties that it will be receiving comments concerning the unanticipated discovery and provide contact information. The applicable federal agency will have seven (7) calendar days following notification provided in accordance with Stipulation VI.A.2 to determine the National Register eligibility of the discovery after considering the timely filed views of the SHPOs, consulting Indian tribes, and other consulting parties and Keystone . The applicable federal agency may assume the newly discovered property to be eligible for the National Register for the purposes of Section 106 pursuant to 36 CFR § 800.13(c).

4. For properties determined eligible or assumed to be eligible pursuant to Stipulation VI.A.3, the applicable federal agency will notify the ACHP, SHPOs, consulting Indian tribes, and other consulting parties of those actions that it proposes to resolve adverse effects which may include a Treatment Plan as outlined in Stipulation V.C.

    a. SHPOs, consulting Indian tribes, and other consulting parties will have forty-eight (48) hours to provide their views on the proposed actions.
    b. The applicable federal agency will ensure that the timely filed recommendations of SHPOs, consulting Indian tribes, and other consulting parties are taken into account prior to granting approval of the measures that Keystone will implement to resolve adverse effects.
    c. Keystone will carry out the approved measures prior to resuming construction activities in the location of the discovery.

5. Dispute Resolution: The applicable federal agency will seek and take into account the recommendations of the ACHP in resolving any disagreements that may arise regarding resolution of adverse effects that relate to the implementation of Stipulation VI. The applicable federal agency will use the contact information provided in Attachment C or D in order to notify the ACHP. Within seven (7) calendar days of receipt of such a written request, the ACHP will provide the applicable federal agency with recommendations on resolving the dispute. The applicable federal agency will take into account any timely filed recommendations provided by the ACHP in making a final decision about how to proceed.

B. Construction or Modification of Electrical Transmission Facilities

1. If previously unidentified historic properties are discovered unexpectedly during construction or modification of transmission facilities funded by RUS, the RUS applicant's construction contractor will immediately halt all construction activity within a one-hundred and fifty (150) foot radius of the discovery, notify the RUS applicant of the discovery and implement interim measures to protect the discovery from looting and vandalism. Within forty-eight (48) hours of receipt of this notification of the discovery, the RUS applicant shall:

    a. Notify the RUS Contact (and BLM Contact if discovery occurs on BLM land);

b. Inspect the work site to determine the extent of the discovery and ensure that construction activities have halted;
c. Clearly mark the area of the discovery; and
d. Implement additional measures, as appropriate, to protect the discovery from looting and vandalism.

2. Upon receipt of such notification RUS and BLM (if applicable) will coordinate the notification of SHPOs, consulting Indian tribes, and other consulting parties and notify the SHPOs, consulting Indian tribes, and other consulting parties of the discovery.

3. RUS and BLM (if applicable) will have seven (7) calendar days following notification provided in accordance with Stipulation VI.B.1 to determine the National Register eligibility of the discovery in consultation with the SHPOs, consulting Indian tribes, other consulting parties, and Keystone. RUS may assume the newly discovered property to be eligible for the National Register for the purposes of Section 106 pursuant to 36 CFR § 800.13(c).

4. For properties determined eligible pursuant to Stipulation VI.B.3, RUS, in coordination with the BLM (if applicable), will notify the SHPOs, consulting Indian tribes, and other consulting parties of those actions that it proposes to resolve adverse effects. SHPOs, consulting Indian tribes, and other consulting parties will provide their views on the proposed actions within forty-eight (48) hours. RUS will ensure that the timely filed recommendations of the SHPOs, consulting Indian tribes, and other consulting parties are taken into account prior to granting approval of those actions that the applicant will implement to resolve adverse effects. Once RUS approval has been granted, its applicant will carry out the approved measures prior to resuming construction activities in the location of the discovery.

5. Dispute Resolution: RUS and BLM (if applicable) will seek and take into account the recommendations of the ACHP in resolving any disagreements that may arise regarding the resolution of adverse effects that relate to the implementation of Stipulation VI. The applicable federal agency will use the contact information provided in Attachment D in order to notify the ACHP. Within seven (7) calendar days of receipt of such a written request, the ACHP will provide RUS and BLM (if applicable) with its recommendations for resolving the dispute. RUS and BLM (if applicable) will take into account any recommendations provided by the ACHP in making a final decision about how to proceed.

6. Reporting: No later than six (6) months following the resumption of construction within the location of the discovery, RUS will submit a final report to the SHPOs, consulting Indian tribes, and other consulting parties describing implementation of the actions taken in accordance with Stipulation VI.B and, as appropriate, the analysis and interpretation of recovered information.

C. Unanticipated Discovery of Human Burials and Remains, and Funerary Objects

1. When Native American human remains or funerary objects or objects of cultural patrimony are unexpectedly discovered during construction of the Keystone XL Project on federal or tribal lands within the APE, Keystone or a RUS applicant, as appropriate, will notify immediately the federal agency responsible for compliance with the Native American Graves Protection and Repatriation Act (NAGPRA) [25 U.S.C. 3001 et. seq.] and its implementing regulations, 43 C.F.R. Part 10.

2. Non-Native American human burials and remains, and funerary objects discovered on federal lands within the APE will be treated by the federal agency having jurisdiction of the remains in accordance with applicable federal law, taking into account the ACHP's *Policy Statement on the Treatment of Burial Sites, Human Remains and Funerary Objects* (February 23, 2007).

3. DOS, WESTERN, and RUS will treat human burials and remains discovered on non-federal land in accordance with the provisions of Attachment C and any applicable laws. In those instances where the USACE has jurisdiction under Section 10 or 404 permitting authority for non-federal lands in the APE, the applicable federal agencies will ensure that Keystone complies with the provisions of Attachment C acting in the place of the DOS. In determining appropriate actions to be carried out, DOS, RUS, and/or other federal agencies will be guided by the ACHP's *Policy Statement on the Treatment of Burial Sites, Human Remains and Funerary Objects* (February 23, 2007).

VII. CURATION

A. Federal agencies will curate any artifacts, materials or records resulting from archaeological identification and mitigation conducted on federal lands under their jurisdiction in accordance with 36 CFR Part 79, "*Curation of Federally-Owned and Administered Archaeological Collections*." Federal agencies with jurisdiction over the federal lands will consult with Indian tribes as required in 36 CFR 79.

B. Keystone and RUS applicants will return all artifacts recovered from private lands to the respective landowner after analysis is complete, unless applicable state law requires otherwise. Keystone and RUS applicants will encourage and assist landowners in donating any returned artifacts to a local curation facility identified by the respective SHPO. Keystone and RUS applicants shall pay all required curation fees associated with the donation of artifacts to the local curation facility.

C. On federally controlled or owned properties, federal agencies will determine the disposition of human burials, human remains and funerary objects in accordance with applicable federal law.

VIII. REPORTING

A. Within three months of completion of pipeline construction of a spread, Keystone will submit a comprehensive draft report to DOS describing the results and findings of the implementation of the actions and plans specified in Stipulations V.C through G, VI.A, including Attachment C.

B. Keystone will submit a draft comprehensive report for each spread to the SHPOs, consulting Indian tribes, and other consulting parties of the respective states in which the spread is located, for thirty (30) day review and comment. Keystone shall address timely comments and recommendations submitted by SHPOs, consulting Indian tribes, and other consulting parties in preparation of the Final Comprehensive Report for that spread. Keystone will submit the final report to DOS for review and approval. The final comprehensive report will be provided by DOS to the SHPOs, consulting Indian tribes, and other consulting parties once approved.

IX. MONITORING IMPLEMENTATION OF THE PA

Each quarter following the execution of this PA until it expires or is terminated, the DOS with the assistance of the USACE, BLM, RUS, FSA, NRCS, BIA, and RECLAMATION as necessary will provide the SHPOs, consulting Indian tribes, and other consulting parties to this PA a progress report summarizing the work carried out pursuant to its terms. Such report will include any scheduling changes proposed, any problems encountered, and any disputes and objections received in the efforts to carry out the terms of this PA. DOS will maintain and update a list of the current contact for the SHPOs, consulting Indian tribes, and other consulting parties and will be distributed in each quarterly report.

X. DISPUTE RESOLUTION

A. "Appropriate federal agency" refers to the DOS, BLM, RUS, RECLAMATION, and USACE, or other federal land managing and/or permitting agency as applicable.

B. Should any signatory or concurring party to this PA object at any time to any actions proposed or the manner in which the terms of this PA are implemented, the appropriate federal agency will consult with such party to resolve the objection. If the appropriate federal agency determines that such objection cannot be resolved, the appropriate federal agency will:

1. Forward all documentation relevant to the dispute, including the applicable federal agency's proposed resolution, to the ACHP. The ACHP will provide the appropriate federal agency with its advice on the resolution of the objection within thirty (30) calendar days of receiving adequate documentation. Prior to reaching a final decision on the dispute, the appropriate federal agency will prepare a written response that takes into account any timely advice or comments regarding the dispute from the ACHP, signatories and concurring parties, and provide them with a copy of this written response. The appropriate federal agency will then proceed according to its final decision.

2. If the ACHP does not provide its advice regarding the dispute within the thirty (30) calendar day time period, the applicable federal agency may make a final decision on the dispute and proceed accordingly. Prior to reaching such a final decision, the appropriate federal agency will prepare a written response that takes into account any timely comments regarding the dispute from the signatories and concurring parties to the PA, and provide them and the ACHP with a copy of such written response.

C. The federal agencies are responsible for carrying out all other actions subject to the terms of this PA that are not the subject of the dispute.

D. The process of dispute resolution outlined in Stipulation X does not pertain to disputes that arise from unanticipated discoveries covered in Stipulation VI.

XI. DURATION

This PA will be null and void if all of its stipulations have not been carried out within five (5) years from the date of its execution. At such time, and prior to work continuing on the Keystone XL Project, the DOS, USACE, BLM, RUS, WESTERN, RECLAMATION and NPS will either (a) execute a Memorandum of Agreement (MOA) or PA pursuant to 36 CFR §§ 800.6 or 800.14(b), respectively, or (b) request, take into account, and respond to the comments of the ACHP under 36 CFR. § 800.7. Prior to such time, the DOS may consult with the other signatories to reconsider the terms of the PA and amend it in accordance with Stipulation XII. The DOS, USACE, BLM, RUS, WESTERN, RECLAMATION and NPS will notify the signatories and concurring parties as to the course of action they will pursue.

XII. AMENDMENT

Any signatory party to this PA may propose in writing to the other signatory parties that it be amended. The signatory parties will consult in an effort to reach agreement on an amendment. Any amendment will be effective on the date it is signed by all of the signatories and filed with the ACHP.

XIII. TERMINATION

A. If any signatory to this PA determines that its terms will not or cannot be carried out, that party will immediately consult with the other parties to attempt to develop an amendment per Stipulation XII. If within thirty (30) calendar days an amendment cannot be reached, any signatory may terminate its participation in the PA upon written notification to the other signatories.

B. Termination by an individual SHPO shall only terminate the application of this Agreement within the jurisdiction of the SHPO.

C. If the PA is terminated in its entirety, and prior to work continuing on the undertaking, the DOS shall request, take into account, and respond to the comments of the ACHP in accordance with 36 CFR § 800.7(a). Following consultation with the ACHP, the DOS will notify the signatories and concurring parties as to the course of action it will pursue.

XIV. COORDINATION WITH OTHER FEDERAL REVIEWS

In the event that Keystone or a federal agency applies for additional federal funding or approvals for the Keystone XL Project and the undertaking remains unchanged, such funding or approving agency may comply with Section 106 by agreeing in writing to the terms of this PA and notifying and consulting with the applicable SHPO and the ACHP. Any necessary modifications will be considered in accordance with Stipulation XII.

XV. SCOPE OF THE PA

This Agreement is limited in scope to actions that will facilitate the construction of the Keystone XL Project and related facilities, and is entered into solely for that purpose.

EXECUTION of this PA by the DOS, ACHP, BLM, RUS, WESTERN, USACE, RECLAMATION, NPS, NRCS, FSA, BIA, the Montana SHPO, South Dakota SHPO, Nebraska SHPO, Kansas SHPO, Oklahoma SHPO, and Texas SHPO and implementation of its terms evidence that the DOS, WESTERN, BLM, RUS, NRCS, FSA, BIA, USACE, RECLAMATION, and NPS have taken into account the effects of the Keystone XL Project on historic properties and afforded the ACHP an opportunity to comment.

4 Aug 2011

United States Department of State | Date

2 Aug 11

Robert J. Ruch
Colonel, Corps of Engineers
District Commander

Date

Deborah K. Johnson Morford — Aug. 10, 2011

Deborah Johnson Morford — Date
Field Manager, Miles City Field Office
Bureau of Land Management

July 11, 2011

Michael J. Ryan
Regional Director, Great Plains Region
Bureau of Reclamation

Date

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Seattle

Alice A. Harwood 7/15/11

Weldon Loudermilk
Great Plains Regional Director
UnitedStates Bureau of Indian Affairs

Date

Mark S. Plank 7/12/11

Mark S. Plank Date
Director, Engineering and Environmental Staff
United States Department of Agriculture Rural Utilities Service

July 21, 2011

Matthew T. Ponish
National Environmental Compliance Manager
United States Department of Agriculture Farm Service Agency

Date

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~~Don Gohmert~~ Salvador Salinas Acting AUG 0 3 2011
Date

State Conservationist
United States Department of Agriculture Natural Resources Conservation Services

Robert J. Harris 7/14/11

Robert Harris
Regional Manager, Upper Great Plains Region
Western Area Power Administration (WESTERN)

Date

8/12/11

John M. Fowler
Executive Director
Advisory Council on Historic Preservation

Date

Mark Wolfe 7/21/11

Mark Wolfe
State Historic Preservation Officer
Texas

Date

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Jennie Chinn
State Historic Preservation Officer
Kansas

7-7-11
Date

Mark Baumler, Ph.D.
State Historic Preservation Officer
Montana

7/8/2011
Date

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08-03-2011

Michael J. Smith
State Historic Preservation Officer
Nebraska

Date

Bob Blackburn July 13, 2011

Dr. Bob L. Blackburn
State Historic Preservation Officer
Oklahoma

Date

Jay D. Vogt 07-08-2011

Mr. Jay D. Vogt
State Historic Preservation Officer
South Dakota

Date

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4 August 2011

John Wessels
Regional Director, Intermountain Region
National Park Service
(invited signatory)

Date

7-25-2011

Mary Sexton
Director
Montana Department of Natural Resources and Conservation
(invited signatory)

Date

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7/18/11

Richard Opper
Director
Montana Department of Environmental Quality
(invited signatory)

Date

July 21/2011

David Montemurro
TransCanada Keystone XL Pipeline, L.P.
(invited signatory)
Date

21-July-2011

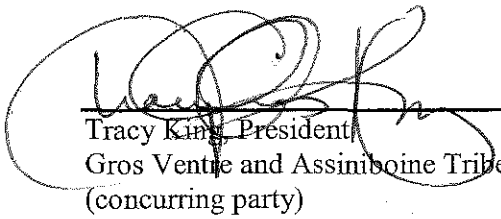
Robert Jones
Vice President

Carlos Bullock 8-8-11

Carlos Bullock, Tribal Council Chairman — Date
Alabama-Coushatta Tribe of Texas
(concurring party)

Willie Sharp, Chairman
Blackfeet Nation
(concurring party)

8/4/11
Date



7/28/2014

Tracy King, President
Gros Ventre and Assiniboine Tribe of Ft. Belknap
(concurring party)

Date

7-8-11

Tim Rhodd, Chairman
Iowa Tribe of Kansas and Nebraska
(concurring party)

Date

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7-25-11

Thomas Gamble, ~~Chairman~~ Chief
Miami Tribe of Oklahoma
(concurring party)

Date

For Darrell Hea 8/5/11

Jim Shakespeare, Chairman
Northern Arapaho Tribe
(concurring party)

Date

8-2-11

Marshall Gover, President
Pawnee Nation of Oklahoma
(concurring party)

Date

ATTACHMENT A

The following Tables show properties for which Keystone has been denied access to conduct identification and evaluation studies as of the finalization of the PA.

Table 1: Areas Not Surveyed along Mainline Route in Montana					
State	**County**	**From Milepost**	**To Milepost**	**Status**	**Miles**
Montana	Fallon	249.1	250.2	Needs survey	1.1
Montana	Fallon	227.2	227.4	Needs survey	0.2
Montana	Fallon	228.1	228.1	Surveyed on November 2010 CL; Addendum 6 in progress	0.01
Montana	Dawson	0.2	1.4	Needs survey	1.2
Montana	Dawson	4.8	6.3	Needs survey	1.5
Montana	Dawson	7.6	9.1	Needs survey	1.5
Montana	Dawson	17.2	17.6	Needs survey	0.5
Montana	Dawson	17.9	18.4	Needs survey	0.5
Montana	Dawson	18.4	19.1	Needs survey	0.7
Montana	Dawson	20.4	20.7	Surveyed on November 2010 CL; Addendum 6 in progress	0.3
Montana	Dawson	21.7	22.2	Surveyed on November 2010 CL; Addendum 6 in progress	0.4
Montana	McCone	148.4	149.7	Needs survey; Incorporated into November 2010 CL	1.3
Montana	McCone	144.4	144.5	Needs survey; Incorporated into November 2010 CL	0.1
Montana	Valley	1.1	1.2	Needs survey; Incorporated into November 2010 CL-MT-LO-01	0.1
Montana	Dawson	1.9	2	Needs survey; Incorporated into November 2010 CL	0.1
Montana	Fallon	0	0.01	Needs survey	0.01
Montana	McCone	0	0.5	Needs survey	0.5

Table 1: Areas Not Surveyed along Mainline Route in Montana					
State	**County**	**From Milepost**	**To Milepost**	**Status**	**Miles**
Montana	McCone	0	2.2	Surveyed on November 2010 CL; Addendum 6 in progress	2.2
Montana	Dawson	0	1.9	Surveyed on November 2010 CL; Addendum 6 in progress	1.9
Montana	Dawson	1	2	Surveyed on November 2010 CL; Addendum 6 in progress	2
Montana	Sheridan			Surveyed on November 2010 CL; Addendum 6 in progress	
Montana	Roosevelt			Surveyed on November 2010 CL; Addendum 6 in progress	
Montana	Prairie			Needs survey	

Table 2: Areas Not Surveyed along Mainline Route in South Dakota					
State	**County**	**From Milepost**	**To Milepost**	**Status**	**Miles**
South Dakota	Harding	352.8	353.7	Needs survey	0.9
South Dakota	Meade	417.9	418.2	Needs survey	0.3
South Dakota	Haakon	481.4	481.5	Surveyed on November 2010 CL; Addendum 7 in progress	0.1
South Dakota	Jones	492	492.6	Needs survey	0.6
South Dakota	Dawson	194	194.5	Surveyed on November 2010 CL; Addendum 7 in progress	0.5
South Dakota	Harding	2.9	3.2	Needs survey	0.3
South Dakota	Harding	3.8	4.4	Needs survey	0.3
South Dakota	Meade	1.1	1.3	Surveyed on November 2010 CL; Addendum 7 in progress	0.1

Table 2: Areas Not Surveyed along Mainline Route in South Dakota					
State	**County**	**From Milepost**	**To Milepost**	**Status**	**Miles**
South Dakota	Hughes			Surveyed on November 2010 CL; Addendum 7 in progress	

Table 3: Areas Not Surveyed along Mainline Route in Nebraska					
State	**County**	**From Milepost**	**To Milepost**	**Status**	**Miles**
Nebraska	Keya Paha	599.70	600.50	Surveyed 6-4-11 on Nov 2010 CL; Addendum No. 7 report in progress	0.80
Nebraska	Keya Paha	600.90	601.50	Needs survey	0.60
Nebraska	Keya Paha	614.20	614.45	Needs survey	0.25
Nebraska	Holt	630.80	631.65	Surveyed 6-2-11 on Nov 2010 CL; Addendum No. 7 report in progress	0.85
Nebraska	Holt	632.70	633.15	Surveyed 6-7-11 on Nov 2010 CL; Addendum No. 7 report in progress	0.45
Nebraska	Holt	634.75	635.45	Surveyed 6-3-11 on Nov 2010 CL; Addendum No. 7 report in progress	0.70
Nebraska	Holt	653.55	655.45	Surveyed 6-7-11 on Nov 2010 CL; Addendum No. 7 report in progress	1.90
Nebraska	Holt	656.80	657.90	Surveyed 6-3-11 on Nov 2010 CL; Addendum No. 7 report in progress	1.10
Nebraska	Garfield	672.55	679.50	Not on Nov 2010 CL	6.95
Nebraska	Wheeler	687.60	687.90	Surveyed 6-10-11 on Nov 2010 CL; Addendum No. 7 report in progress	0.30
Nebraska	Wheeler	688.15	688.35	Surveyed 6-10-11 on Nov 2010 CL; Addendum No. 7 report in progress	0.20

Table 3: Areas Not Surveyed along Mainline Route in Nebraska					
State	County	From Milepost	To Milepost	Status	Miles
Nebraska	Wheeler	688.70	688.95	Surveyed 6-10-11 on Nov 2010 CL; Addendum No. 7 report in progress	0.25
Nebraska	Wheeler	691.40	691.65	Surveyed 6-11-11 on Nov 2010 CL; Addendum No. 7 report in progress by applicant	0.25
Nebraska	Wheeler	692.70	693.35	Surveyed 6-11-11 on Nov 2010 CL; Addendum No. 7 report in progress	0.65
Nebraska	Greeley	698.35	698.70	Surveyed 6-6-11 on Nov 2010 CL; Addendum No. 7 report in progress	0.35
Nebraska	Greeley	700.10	700.35	Surveyed 6-6-11 on Nov 2010 CL; Addendum No. 7 report in progress	0.25
Nebraska	Greeley	700.55	702.55	Surveyed 6-6-11 on Nov 2010 CL; Addendum No. 7 report in progress	2.00
Nebraska	Greeley	703.25	705.35	Partially surveyed 6-6-11 on Nov 2010 CL with 1.35 miles no access from MP 704.0 to 705.35; Addendum No. 7 report in progress	1.35
Nebraska	Greeley	709.80	709.80	Surveyed 5-31-11 on Nov 2010 CL; Addendum No. 7 report in progress	0.00
Nebraska	Greeley	716.40	717.10	Surveyed 6-1-11 on Nov 2010 CL; Addendum No. 7 report in progress	0.70
Nebraska	Greeley	799.00	799.10	Surveyed 5-27-11 on Nov 2010 CL; Addendum No. 7 report in progress	0.10
Nebraska	Fillmore	799.40	799.60	Not on Nov 2010 CL	0.20
Nebraska	Fillmore	800.15	800.60	Needs survey	0.45

Table 4: Areas Not Surveyed along Mainline Route in Oklahoma					
State	County	From Milepost	To Milepost	Status	Miles
Oklahoma	Seminole	42.460	n/a	Needs survey	0.39 ac
Oklahoma	Grady	Offline	n/a	Needs survey	74.2 ac
Oklahoma	Hughes	75.650	n/a	Needs survey	0.250
Oklahoma	Hughes	75.70	75.80	Needs survey	0.100
Oklahoma	Pottawatomie	Offline	n/a	Needs survey	17 ac
Oklahoma	Pittsburg	Offline	n/a**	Needs survey	9.12 ac
Oklahoma	Coal	88.640	n/a	Needs survey	0.122
Oklahoma	Atoka	127.440	n/a	Needs survey	3.1 ac
Oklahoma	Atoka	127.60	128.34	Needs survey	0.737
Oklahoma	Bryan	132.800	n/a**	Needs survey	2.529

**Not applicable

Table 5: Areas Not Surveyed along Mainline Route in Texas					
State	County	From Milepost	To Milepost	Status	Miles
Texas	Fannin	160.650	n/a	Needs survey	3 ac
Texas	Fannin	161.85	n/a	Needs survey	0.65 ac
Texas	Lamar	162.30	162.43	Needs survey	0.130
Texas	Lamar	173.980	n/a	Needs survey	2 ac
Texas	Lamar	185.110	n/a	Needs survey	2 ac
Texas	Hopkins	206.880	n/a	Needs survey	0.48 ac
Texas	Franklin	231.31	n/a	Needs survey	0.049
Texas	Wood	233.42	n/a	Needs survey	0.082
Texas	Wood	251.34	251.55	Needs survey	0.210
Texas	Upshur	262.31	262.35	Needs survey	0.040
Texas	Upshur	262.42	n/a	Needs survey	0.002
Texas	Upshur	262.580	n/a	Needs survey	1.29 ac
Texas	Smith	274.64	275.18	Needs survey	0.540
Texas	Smith	275.19	n/a	Needs survey	0.880
Texas	Nacogdoches	Offline	n/a	Needs survey	12.8 ac
Texas	Houston	Offline	n/a	Needs survey	8.3 ac
Texas	Polk	392.290	n/a	Needs survey	0.62 ac
Texas	Liberty	Offline	n/a	Needs survey	13.4 ac
Texas	Jefferson	Offline	n/a	Needs survey	72.6 ac
Texas	Jefferson	453.44	n/a	Needs survey	0.755

Table 5: Areas Not Surveyed along Mainline Route in Texas					
State	**County**	**From Milepost**	**To Milepost**	**Status**	**Miles**
Texas	Jefferson	480.77	481.43	Needs survey	0.665
Texas	Jefferson	483.49	483.80	Needs survey	0.300
Texas	Jefferson	482.970	n/a	Needs survey	4.9 ac

ATTACHMENT B

List of Indian Tribes Invited by the Department of State to Participate in Consultation:

Absentee-Shawnee Tribe of Indians of Oklahoma, Alabama Quassarte Tribal Town, Alabama-Coushatta Tribe of Texas, Apache Tribe, Blackfeet Nation, Caddo Nation of Oklahoma, Cherokee Nation, Cheyenne River Sioux, Cheyenne-Arapaho Tribe of Oklahoma, Chickasaw Nation of Oklahoma, Chippewa-Cree Indians, Choctaw Nation of Oklahoma, Citizen Potawatomi Nation, Comanche Nation, Confederated Salish and Kootenai Tribes of the Flathead Indian Nation, Crow Creek Reservation, Crow Creek Sioux Tribe, Crow Tribe of Indians, Delaware Nation, Delaware Tribe of Indians, Eastern Band of Cherokee Indians, Eastern Shawnee Tribe, Eastern Shoshone Tribe, Flandreau Santee Sioux Tribe, Forest County Potawatomi Community of Wisconsin Potawatomi Indians, Fort Berthold Reservation, Fort Peck Tribes, Fort Sill Apache Tribe, Gros Ventre and Assiniboine Tribe of Ft. Belknap, Gun Lake Potawatomi, Hannahville Indian Community of Michigan, Ho-Chunk Nation of Wisconsin, Huron Potawatomi Nation, Iowa Tribe of Kansas and Nebraska, Iowa Tribe of Oklahoma, Jena Band of Choctaw Indians, Jicarilla Apache Tribe, Kaw Nation, Kialegee Tribal Town of the Creek Nation of Oklahoma, Kickapoo Traditional Tribe of Texas, Kickapoo Tribe of Kansas, Kickapoo Tribe of Oklahoma, Kiowa Indian Tribe of Oklahoma, Lower Brule Sioux Tribe, Lower Sioux Indian Community, Miami Tribe of Oklahoma, Mille Lacs Band of Ojibwe, Modoc Tribe of Oklahoma, Muscogee Creek Nation, Nez Perce, Northern Arapaho Tribe, Northern Cheyenne Tribe, Northern Ute Tribe, Oglala Sioux, Omaha Tribe of Nebraska, Osage Nation, Otoe-Missouri Tribe, Ottawa Tribe of Oklahoma, Pawnee Nation of Oklahoma, Peoria Indian Tribe of Oklahoma, Poarch Band of Creek Indians, Pokagon Band of Potawatomi Indians of Michigan, Ponca Tribe of Indians of Oklahoma, Ponca Tribe of Nebraska, Prairie Band of Potawatomi Indians, Prairie Island Indian Community, Quapaw Tribal Business Committee, Quapaw Tribe, Red Lake Band of Chippewa Indians of Minnesota, Rosebud Sioux Tribe, Sac & Fox Nation of Oklahoma, Sac & Fox Nation of Missouri in Kansas and Nebraska, Sac & Fox Tribe of the Mississippi in Iowa, Santee Sioux Tribe of Nebraska, Seminole Nation, Seneca-Cayuga Tribe of Oklahoma, Shakopee Mdewakanton Sioux, Shawnee Tribe, Shoshone-Bannock Tribe, Sisseton-Wahpeton Oyate Sioux, Sisseton-Wahpeton Oyate Wahpekutze, Southern Ute Indian Tribe, Spirit Lake Tribe, Standing Rock Sioux Tribe, Stockbridge-Munsee Tribe, Thlopthlocco Tribal Town, Three Affiliated Tribes, Tonkawa Tribe, Trenton Indian Service Area, Turtle Mountain Band of the Chippewa, United Keetoowah Band of Cherokee Indians, Upper Sioux -Pezihutazizi Kapi, Ute Mountain Tribe, White Earth Band of Minnesota Chippewa, Wichita and Affiliated Tribes, Winnebago Tribe, Wyandotte Nation, Yankton Sioux, Ysleta del Sur Pueblo

ATTACHMENT C

STATE-BY-STATE PLANS FOR THE UNANTICIPATED DISCOVERY OF HUMAN REMAINS OR BURIALS ON NON-FEDERAL LANDS DURING CONSTRUCTION OF THE KEYSTONE XL PIPELINE PROJECT

I. For construction of the Keystone XL Project in Montana, Keystone will implement the following measures:

1. When an unmarked human burial or unregistered grave is encountered during construction activities, Keystone will comply with the Human Skeletal Remains and Burial Site Protection Act (Montana Code Ann. §22-3-801 through §22-3-811).

2. Upon encountering an unmarked human burial or unregistered grave during ground disturbing construction activities, the construction contractor will immediately stop work within a one-hundred and fifty (150) foot radius from the point of discovery and notify Keystone's Lead Environmental Inspector (EI). The construction contractor will implement interim measures to protect the discovery from vandalism and looting, but must not remove or otherwise disturb any human remains or other items in the immediate vicinity of the discovery.

3. Immediately following receipt of such notification, the Lead EI will ensure that construction activities have halted within a one-hundred and fifty (150) foot radius from the point of discovery and assume responsibility for implementing additional measures, as appropriate, to protect the discovery from looting and vandalism until the requirements of state law have been completed.

4. The Lead EI will notify the county coroner, the DOS, ACHP, SHPO, consulting Indian tribes, and other consulting parties within forty-eight (48) hours of the discovery.

5. Within seventy-two (72) hours after notification, the county coroner will determine jurisdiction. If the coroner refers the matter to the SHPO, the SHPO will determine the treatment, including mitigation and disposition of the unmarked human burial or unregistered grave in accordance with Montana Code Ann. §22-3-801 through §22-3-811. Keystone will implement the treatment and disposition measures deemed appropriate by the SHPO.

6. Keystone will resume construction activities in the area of the discovery upon receipt of written authorization from either the county coroner or the Montana SHPO, whoever has jurisdiction under state law.

II. For construction of the Keystone XL Project in Kansas, Keystone will implement the following measures:

1. When unmarked human burial sites or human skeletal remains are encountered during construction activities, Keystone will comply with Kansas' Unmarked Burial Sites Preservation Act (KSA 75-2741 to 75-2754) and its implementing regulations (KAR 126-1-1 through 126-1-2).

2. Upon encountering unmarked human burials or unregistered graves during ground disturbing construction activities, the construction contractor will immediately stop work within a one-hundred and fifty (150) foot radius from the point of discovery and notify Keystone's Lead EI.

The construction contractor will implement interim measures to protect the discovery from vandalism and looting, but must not remove or otherwise disturb any human remains or other items in the immediate vicinity of the discovery.

3. Immediately following receipt of such notification, the Lead EI will:

    a. Ensure that construction activities have halted within a one-hundred and fifty (150) foot radius from the point of discovery;
    b. Implement additional measures, as appropriate, to protect the discovery from looting and vandalism until the requirements of state law have been completed; and
    c. Notify the appropriate county sheriff's office, the chairperson of the Unmarked Burial Sites Preservation Board (Kansas State Archaeologist), the DOS, the ACHP SHPOs, consulting Indian tribes, and other consulting parties of the discovery.

4. If Keystone determines that disturbance to the unmarked burial site or human remains cannot be avoided, Keystone will consult with the DOS, the SHPO, consulting Indian tribes, and other consulting parties to develop a detailed work plan for treatment of the burial site or human remains that includes provisions for the removal, treatment and disposition of human remains. In accordance with state law, Keystone will submit this work plan to the Unmarked Burial Sites Preservation Board as part of its request for a permit under KAR 126-1-2.

5. Keystone will resume construction activities in the area of the discovery once implementation of the measures authorized under the permit has been completed.

III. For construction of the Keystone XL Project in Nebraska, Keystone will implement the following measures:

1. When unmarked human skeletal remains or burial goods are discovered during construction activities, Keystone will comply with Nebraska Rev. Stat. § 12-1201 through § 12-1212, et seq. and § 28-1301.

2. Upon encountering unmarked human skeletal remains or burial goods during ground disturbing construction activities, the construction contractor will immediately stop work within a one-hundred and fifty (150) foot radius from the point of discovery and notify Keystone's Lead EI. The construction contractor will implement interim measures to protect the discovery from vandalism and looting, but must not remove or otherwise disturb any human remains or other items in the immediate vicinity of the discovery.

3. Immediately following receipt of such notification, the Lead EI will ensure that construction activities have halted within a one-hundred and fifty (150) foot radius from the point of discovery and assume responsibility for implementing additional measures, as appropriate, to protect the discovery from looting and vandalism until the requirements of state law have been completed.

4. Keystone will notify the local law enforcement officer in the county, the DOS, the ACHP, the SHPO, consulting Indian tribes, and other consulting parties within forty-eight (48) hours of the discovery.

5. If local law enforcement determines that the remains are not associated with a crime, Keystone will determine if it is prudent and feasible to avoid disturbing the remains. If Keystone

determines that disturbance cannot be avoided, the Nebraska State Historical Society will notify the Commission on Indian Affairs in writing and seek associated tribes or kin.

6. Keystone will resume construction activities in the area of the discovery when the human skeletal remains or burial goods have been accepted by the Nebraska State Historical Society for the purposes of disposition.

IV. For construction of the Keystone XL Project in Texas, Keystone will implement the following measures:

1. When unmarked human burials or human remains are discovered during construction activities, Keystone will comply with Antiquities Code (Texas Code Ann. §191); Health and Safety (Texas Code Ann. §711.004).

2. Upon encountering unmarked human burials or human remains during ground disturbing construction activities, the construction contractor will immediately stop work within a one-hundred and fifty (150) foot radius from the point of discovery and notify Keystone's Lead EI. The construction contractor will implement interim measures to protect the discovery from vandalism and looting, but must not remove or otherwise disturb any human remains or other items in the immediate vicinity of the discovery.

3. Immediately following receipt of such notification, the Lead EI will:

    a. Ensure that construction activities have halted within a one-hundred and fifty (150) foot radius from the point of discovery;
    b. Implement additional measures, as appropriate, to protect the discovery from looting and vandalism until the requirements of state law have been completed; and
    c. Notify the local law enforcement agency, the DOS, the ACHP, the State Historic Preservation Office (SHPO)/Texas Historical Commission (THC), consulting Indian tribes, and other consulting parties and the State Department of Health of the discovery.

4. If local law enforcement determines that the remains are not associated with a crime, Keystone will determine if it is prudent and feasible to avoid disturbing the remains. If Keystone determines that disturbance cannot be avoided, Keystone will remove and reinter the human remains in accordance with rules adopted by the SHPO and the State Health Department.

5. Keystone will resume construction activities in the area of the discovery once implementation of the measures required by the SHPO/THC and State Health Department has been completed.

V. For construction of the Keystone Project in Oklahoma, Keystone will implement the following measures:

1. When a burial ground, human remains or burial furniture is discovered during construction activities, Keystone will comply with Okla. Stat. Ann. 21 §1161-1168.7 (Oklahoma Burial Law).

2. Upon encountering a burial ground, human remains or burial furniture during ground disturbing construction activities, the construction contractor will immediately stop work within a one-hundred and fifty (150) foot radius from the point of discovery and notify Keystone's Lead EI. The construction contractor will implement interim measures to protect the discovery from

vandalism and looting, but must not remove or otherwise disturb any human remains or other items in the immediate vicinity of the discovery.

3. Immediately following receipt of such notification, the Environmental Inspector will

    a. ensure that construction activities have halted within a one-hundred and fifty (150) foot radius from the point of discovery;
    b. implement additional measures, as appropriate, to protect the discovery from looting and vandalism until the requirements of state law have been completed; and
    c. notify the appropriate law enforcement officer in the county in which the remains have been discovered, the Chief Medical Examiner, the DOS, the ACHP, the SHPO, consulting Indian tribes, other consulting parties, and the landowner of the discovery.

4. Upon learning that remains are not associated with a crime, Keystone has fifteen (15) calendar days within which to notify the SHPO and the Oklahoma State Archaeologist. If the remains have a direct historical relationship to a tribe, the State Archaeologist will notify the SHPO and consults with the tribal leader within fifteen (15) calendar days. If Keystone determines that disturbance cannot be avoided, Keystone will treat the burial site or human remains in accordance with procedures established by the SHPO, the Oklahoma State Archaeologist, and consultation with the tribal leader.

5. Keystone will resume construction activities in the area of the discovery upon completion of the measures authorized by the SHPO and Oklahoma State Archaeologist.

VI. For construction of the Keystone XL Project in South Dakota, Keystone will implement the following measures:

1. When unmarked human skeletal remains and/or funerary objects are discovered during construction activities, Keystone will comply with South Dakota State Law Chapter 34-27.

2. Upon encountering an unmarked human skeletal remains and/or funerary objects during ground disturbing construction activities, the construction contractor will immediately stop work within a one-hundred and fifty (150) foot radius from the point of discovery and notify Keystone's Lead EI. The construction contractor will implement interim measures to protect the discovery from vandalism and looting, but must not remove or otherwise disturb any human remains or other items in the immediate vicinity of the discovery.

3. Immediately following receipt of such notification, the Lead EI will ensure that construction activities have halted within a one-hundred and fifty (150) foot radius from the point of discovery and assume responsibility for implementing additional measures, as appropriate, to protect the discovery from looting and vandalism until the requirements of state law have been completed.

4. The Lead EI will notify the local law enforcement agency, the DOS, the ACHP, the SHPO, the South Dakota State Archaeologist, consulting Indian tribes, and other consulting parties within forty-eight (48) hours of the discovery.

5. If local law enforcement determines that the remains are not associated with a crime, Keystone will determine if it is prudent and feasible to avoid disturbing the remains. If Keystone determines that disturbance cannot be avoided, Keystone will consult with the South Dakota State Archaeologist, SHPOs, consulting Indian tribes, and other consulting parties to determine

acceptable procedures for the removal, treatment and disposition of the human skeletal remains and funerary objects within five (5) calendar days. Keystone will implement the plan for removal, treatment, and disposition of the human skeletal remains and funerary objects as authorized by the South Dakota State Archaeologist.

6. Keystone may resume construction activities in the area of the discovery upon completion of the plan authorized by the State Archaeologist.

EXHIBIT B

APPENDIX E

Amended Programmatic Agreement and Record of Consultation

E1 Amended Programmatic Agreement

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Programmatic Agreement

Among
The U.S. Department of State,
National Park Service,
U.S. Army Corps of Engineers,
U.S. Department of Agriculture Farm Service Agency,
U.S. Department of Agriculture Natural Resources Conservation Service,
U.S. Department of Agriculture Rural Utilities Service,
U.S. Bureau of Indian Affairs,
U.S. Bureau of Land Management,
U. S. Bureau of Reclamation,
Western Area Power Administration,

Advisory Council on Historic Preservation,
Kansas State Historic Preservation Officer,
Montana Department of Environmental Quality,
Montana Department of Natural Resources and Conservation,
Montana State Historic Preservation Officer,
Nebraska State Historic Preservation Officer,
South Dakota State Historic Preservation Officer,
and
TransCanada Keystone Pipeline, LP

Regarding the Keystone XL Pipeline Project

WHEREAS, the U.S. Department of State (DOS) receives and considers applications for permits for cross-border oil pipelines pursuant to the authority delegated by the President of the United States under Executive Order (EO) 13337 (69 Federal Register 25299); and

WHEREAS, the DOS received an application for a Presidential Permit from TransCanada Keystone Pipeline, LP (Keystone) in September 2008 for the Keystone XL Pipeline Project (Keystone XL Project or the Project) which consisted of approximately 1,375 miles of new crude oil pipeline in Montana, South Dakota, Nebraska, Oklahoma, and Texas with associated effects in Kansas; and

WHEREAS, the DOS determined that issuance of a Presidential Permit for the proposed Keystone XL Project include a consultation and review process consistent with Section 106 of the National Historic Preservation Act (NHPA) (16 U.S.C. 470f, as amended) and its implementing regulations, “Protection of Historic Properties”; and

WHEREAS, the DOS developed a Programmatic Agreement (PA) in consultation with relevant state and federal agencies, Indian tribes, Keystone, and the public and executed this PA in August 2011; and

WHEREAS, the Keystone XL Project Presidential Permit application was denied in January 2012; and

WHEREAS, on May 4, 2012, Keystone submitted an application for a revised Keystone XL Pipeline Project using a route in Montana and South Dakota largely unchanged from that proposed in the 2008 Keystone application and a substantially changed route in Nebraska that sought to avoid the Sands Hills Region identified by the Nebraska Department of Environmental Quality and terminates at Steele City, Nebraska; and

WHEREAS, the Oklahoma and Texas sections of the pipeline proposed in the 2008 Keystone application are no longer part of the application received in 2012 and, therefore, the Oklahoma and Texas State Historic Preservation Offices have no further obligations under this PA; and

WHEREAS, the proposed Project undertaking consists of construction of approximately 875 miles of new crude oil pipeline in the United States, as described in section 2.1 of the Final Supplemental Environmental Impact Statement (SEIS) and Attachment H, of which approximately 209 miles (24%) were not part of the 2008 Keystone XL Presidential Permit application; and

WHEREAS, the revised Keystone XL Project Area of Potential Effects (APE) includes: (1) in Montana—a 300-foot-wide corridor, 150 feet on each side of the centerline; (2) in South Dakota—a 300-foot-wide corridor, 150 feet on each side of the centerline; (3) in Nebraska—a 300-foot-wide corridor, 150 feet on each side of the centerline in areas consistent with the route evaluated in the Final EIS for the 2008 Keystone XL application. Within those areas outside the route evaluated in the Final EIS for the 2008 Keystone XL application, the APE consists of a 500-foot-wide corridor, 250 feet on each side of the centerline. For construction or modification of electrical facilities (including distribution lines, transmission lines, and substations), a 100-foot-wide corridor centered on the Project centerline will be used. For pumping stations, including two new pump stations in Kansas on the existing Keystone Cushing Extension pipeline, and other areas that are to be disturbed by construction-related activities and ancillary facilities (including construction camps and pump stations), the APE will include all areas of disturbance and areas to be indirectly affected; and

WHEREAS, the DOS, in consultation with the Advisory Council on Historic Preservation (ACHP), has determined that the Keystone XL PA executed in August 2011 should be amended to reflect the route proposed in the new Presidential Permit application and input from subsequent consultation; and

WHEREAS, the DOS has determined that the construction of the Keystone XL Project may have an adverse effect on historic properties listed in or eligible for listing in the National Register of Historic Places (NRHP), as defined in Stipulation I.C below, and has consulted with the Montana, South Dakota, Nebraska, and Kansas State Historic Preservation Officers (SHPOs), Indian tribes who may ascribe religious and cultural significance to historic properties that may be affected by the undertaking, the ACHP, other federal agencies with actions related to this undertaking, and other consulting parties consistent with 36 C.F.R. Part 800; and

WHEREAS, consistent with 36 C.F.R. §§ 800.4(b)(2) and 800.5(a)(3), the DOS has elected to phase identification and evaluation of historic properties, and application of the criteria of adverse effect, respectively, because the undertaking and APE have changed necessitating additional efforts to identify historic properties and because access to some areas as identified in Attachment A has been restricted by property owners' refusal to grant Keystone permission to enter their private property; and

WHEREAS, consistent with 36 C.F.R. § 800.14(b), the DOS has elected to execute this PA for the Keystone XL Project because effects on historic properties cannot be fully determined prior to the issuance of a permit for the undertaking; and

WHEREAS, on February 2, 2011 the ACHP entered consultation for the Keystone XL pipeline as originally proposed finding that criteria 3 and 4 of Appendix A, Criteria for Council Involvement in Reviewing Individual Section 106 Cases, of the regulations (36 C.F.R. Part 800) implementing Section 106 of NHPA, had the potential to be met; and

WHEREAS, the United States Army Corps of Engineers (USACE) has determined that the approval for the Keystone XL Project to cross USACE-administered lands (30 U.S.C. § 185) and to place structures in, under, or over navigable waters of the United States, as defined under 33 C.F.R. Part 329, pursuant to Section 10 of the Rivers and Harbors Act of 1899 (33 U.S.C. § 403), and a permit for the placement of dredge or fill material in waters of the United States as part of the Keystone XL Project in accordance with Section 404 of the Clean Water Act (334 U.S.C. § 344), are Federal actions related to the undertaking that require the USACE to comply with Section 106 of NHPA; and

WHEREAS, the U.S. Bureau of Land Management (BLM) has determined that approving the Keystone XL Project to cross Federal lands administered by the BLM would require authorization under Section 28 of the Mineral Leasing Act of 1920, 30 U.S.C. § 185, as amended; and

WHEREAS, the BLM has determined that Keystone will require access roads crossing public lands administered by the BLM in support of the Keystone XL Pipeline Project and that the access roads will require authorization under Title V of the Federal Land Policy and Management Act (FLMPA), 43 U.S.C. § 1701, as amended; and

WHEREAS, the BLM has determined that the Keystone XL Project will require electrical power from rural electrical cooperatives and that portions of the transmission lines will cross public lands administered by the BLM and that the transmission lines crossing public lands will require authorization under Title V of the FLMPA; and

WHEREAS, the BLM approvals of these Project crossings in areas under its jurisdiction is a Federal action associated with the undertaking that requires the BLM to comply with Section 106 of the NHPA and 36 C.F.R. Part 800; and

WHEREAS, the U.S. Bureau of Reclamation (USBR) manages lands and facilities that will be crossed by the Keystone XL Project and USBR approval of such crossings is a Federal action

related to the undertaking that requires the USBR to comply with Section 106 of the NHPA and 36 C.F.R. Part 800; and

WHEREAS, the Farm Service Agency (FSA), assists landowners on private lands and may have federal responsibilities and requirements on some of these lands, which are part of the Project APE, as part of its loan and conservation programs, including the Conservation Reserve Program and the Farmable Wetlands Program; and

WHEREAS, the FSA approval of the Project crossings in these areas is a Federal action associated with the undertaking that requires the FSA to comply with Section 106 of the NHPA and 36 C.F.R. Part 800; and

WHEREAS, the Rural Utilities Service (RUS) has determined that the financial assistance it may provide to rural electric cooperatives and other entities for construction or modification of electrical facilities (including distribution lines, transmission lines, and substations) to power some Keystone XL Project pump stations or to ensure transmission system reliability, under the U.S. Department of Agriculture (USDA) Rural Development Utilities Programs, are Federal actions related to the undertaking that require the RUS to comply with Section 106 of NHPA and 36 C.F.R. Part 800; and

WHEREAS, the Bureau of Indian Affairs (BIA) has responsibility for approving any right-of-ways crossing Indian Trust lands, such as those being considered as part of the route for a 230-kilovolt (kV) transmission line in south-central South Dakota associated with the Keystone project and described in Appendix J to the SEIS, and this is a Federal action related to the undertaking that requires the BIA to comply with Section 106 of the NHPA and 36 C.F.R. Part 800; and

WHEREAS, the Western Area Power Administration (Western) has determined that the modification and construction of substations and transmission lines that Western will own and that will provide power to the Keystone XL Pipeline Project, will require review under Section 106 of NHPA and 36 C.F.R. Part 800; and

WHEREAS, the Natural Resources Conservation Service (NRCS) has conservation easement interests in the states through which the Keystone XL pipeline will traverse; and

WHEREAS, the NRCS has determined that approving the Keystone XL Pipeline to cross an NRCS easement constitutes a federal action associated with the undertaking that requires NRCS to comply with Section 106 of the NHPA and 36 C.F.R. Part 800; and

WHEREAS, the proposed revised Keystone XL Project pipeline alignment crosses five National Historic Trails (the Lewis and Clark, Oregon, California, Mormon Pioneer, and Pony Express National Historic Trails), all of which were designated by the U.S. Congress and have as their purpose “the identification and protection of the historic route and its historic remnants and artifacts for public use and enjoyment” (National Trails System Act, P.L. 90-543, as amended); and

WHEREAS, the National Park Service (NPS) administers National Historic Trails and is a signatory to this PA due to the potential for adverse effects to five National Historic Trails including the Lewis and Clark National Historic Trail; and

WHEREAS, the USACE, BLM, RUS, BIA, NRCS, NPS, Western, USBR, and FSA have designated the DOS as the lead Federal agency for purposes of Section 106 of the NHPA consistent with 36 C.F.R. § 800.2(a)(2); and

WHEREAS, the DOS will incorporate this PA into its decisional process on any Presidential Permit that it may issue for the Keystone XL Project and will include in any permit it issues on the Keystone XL Project a condition that Keystone will abide by its commitments in this PA; and

WHEREAS, the USACE, BLM, RUS, BIA, NRCS, NPS, Western, USBR, and FSA will each incorporate this PA into its decisional process on any authorization, approval, permit, or assistance it may issue for the Keystone XL Project, and will include in any authorization, approval, permit, or assistance it issues on the Keystone XL Project, a condition that Keystone will abide by its commitments in this PA; and

WHEREAS, cultural resource identification, evaluation, and effect assessment efforts, including those needed to address the changes in the APE, are summarized in Section 3.11 of the SEIS and Attachment G of this PA; and

WHEREAS, additional efforts to identify, evaluate and assess effects to historic properties for the Project will take place after the execution of this PA because access to some areas has been restricted, as summarized in Attachment A, and all areas of construction have yet to be determined; and

WHEREAS, for the purposes of this PA, “Indian tribes and Nations” shall have the same definition as “Indian tribes” which appears in Section 301(4) of the NHPA; and

WHEREAS, the DOS invited the 84 Indian tribes listed in Appendix B to participate in consultation; and

WHEREAS, the DOS provided Indian tribes the opportunity to provide information about historic properties of concern to Indian tribes and conduct Traditional Cultural Property (TCP) studies within the proposed Project APE, as summarized in Attachment I; and

WHEREAS, the DOS invited Indian tribes that participated in consultation in 2011 and 2013 to sign as Concurring Parties to this PA, consistent with 36 C.F.R. §§ 800.2(c)(2) and 800.6(c)(3); and

WHEREAS, other federal agencies that develop actions related to this undertaking subsequent to the execution of this PA may comply with Section 106 by following the requirements set forth in Stipulation XIV of this PA; and

WHEREAS, the Montana Department of Natural Resources and Conservation has participated in consultation and was invited by the DOS consistent with 36 C.F.R. § 800.6(c)(2) to sign the PA in 2011 and amendments to the PA in 2013 as an invited signatory; and

WHEREAS, the Montana Department of Environmental Quality has participated in consultation and was invited by the DOS consistent with 36 C.F.R. § 800.6(c)(2) to sign the PA in 2011 and amendments to the PA in 2013 as an invited signatory; and

WHEREAS, Keystone, which would construct the Keystone XL Project pipeline if approved, has participated in consultation, and was invited by the DOS consistent with 36 C.F.R. §§ 800.2(c)(4) and 800.6(c)(2) to sign the PA in 2011 and amendments to the PA in 2013 as an invited signatory; and

WHEREAS, the DOS has provided the public with information about the undertaking and its effects on historic properties and sought public comment and input consistent with 36 C.F.R. §§ 800.2(d) from April 2009 through Federal Register notices, direct mailings, extensive scoping and comment meetings, and inviting comments from the public by phone, mail, fax, and email during public comment periods on the Keystone XL Pipeline Presidential Permit applications; and

NOW, THEREFORE, the DOS, USACE, BLM, RUS, BIA, FSA, NRCS, Western, USBR, NPS, ACHP, and the Montana, South Dakota, Nebraska, and Kansas SHPOs agree that the following stipulations will be implemented in order to take into account the effect of the undertaking on historic properties and to ensure actions consistent with Section 106 of the NHPA.

STIPULATIONS

The DOS, BLM, RUS, BIA, FSA, NRCS, Western, USACE, USBR, and NPS as appropriate, will ensure that the following stipulations are carried out.

I. STANDARDS AND DEFINITIONS

A. Identification and evaluation studies and treatment measures required under the terms of this PA will be carried out by or under the direct on-site supervision of a professional who meets, at a minimum, the *Secretary of the Interior's Historic Preservation Professional Qualification Standards* (48 FR 44716, September 29, 1983). These qualification standards do not apply to individuals recognized by consulting Indian tribes to have expertise in identification, evaluation, assessment of effect, and treatment of effects to historic properties of religious and cultural significance to Indian tribes.

B. In developing scopes of work for identification and evaluation studies, and treatment measures required under the terms of this PA, Keystone and RUS borrowers, and other contractors working with Federal agencies, will take into account the following regulations and guidelines:

1. The ACHP's guidance on conducting archaeology under Section 106 (2007);
2. The ACHP's *Policy Statement Regarding the Treatment of Burial Sites, Human Remains and Funerary Objects* (February 23, 2007);
3. Applicable SHPO and Tribal Historic Preservation Office guidance;
4. The Secretary of the Interior's *Standards and Guidelines for Archaeology and Historic Preservation* (48 FR 44716-42, September 29, 1983);
5. The "*Treatment of Archaeological Properties*" (ACHP 1983);
6. The *Guidelines for Reporting on Cultural Resources Investigations for Pipeline Projects*" (Federal Energy Regulatory Commission, Office of Energy Projects, December 2002);
7. Section 10 of the Rivers and Harbors Act of 1899 (33 U.S.C. § 403);
8. Section 404 of the Clean Water Act (334 U.S.C. § 344);
9. BLM 8110 Manual: Identifying and Evaluating Cultural Resources;
10. Montana/Dakotas Cultural Resources Handbook 8110-1: Guidelines for Identifying Cultural Resources;
11. The National Trails System Act (P.L. 90-543, as amended);
12. Section 28 of the Mineral Leasing Act of 1920 (30 USC 185);
13. Title V of the Federal Land Policy and Management Act of 1976 (43 USC 1701); and
14. *National Register Bulletin 38, Guidelines for Evaluating and Documenting Traditional Cultural Properties* (NPS 1990; Revised 1992: 1998)

C. Definitions

Coordination Plan: A plan that, pursuant to Stipulations V.B and V.D, describes the coordination of construction with identification and evaluation of cultural resources, treatment of adverse effects, and protection of unanticipated discoveries.

Concurring Parties: An invited consulting party to this PA that agrees with the content of the PA. Consistent with 36 C.F.R. § 800.6(c)(3), the refusal of a Concurring Party to sign the PA does not invalidate this PA. Concurring Parities may not terminate the PA.

Construction Spread: A construction unit or segment of a pipeline alignment or corridor to be determined by Keystone prior to construction.

Consulting Indian Tribes: Indian tribes that have consultative roles in the Section 106 process consistent with 36 C.F.R. § 800.2(c).

Consulting Parties: Parties that have consultative roles in the Section 106 process consistent with 36 C.F.R. § 800.2(c).

Data Recovery: The recovery of archaeological information from a historic property subject to an adverse effect.

Determination of Effect: A determination made by a Federal agency in regards to a Project's effect upon a historic property consistent with 36 C.F.R. Part 800.

Determination of Eligibility: A determination made by a Federal agency, in coordination with the SHPO and/or designated representatives of consulting Indian tribes, as appropriate, respecting a cultural resource's eligibility for inclusion in the NRHP and more fully described in 36 C.F.R. Part 60 and 36 C.F.R. § 800.16(l)(2).

Effect: An alteration to the characteristics of a historic property qualifying it for inclusion in or eligibility for the NRHP (see 36 C.F.R. § 800.16(i)).

Environmental Impact Statement: An analysis of a major Federal action's environmental impacts conducted consistent with NEPA.

Historic Property: Any prehistoric or historic district, site, building, structure, or object included in, or eligible for inclusion in, the NRHP maintained by the Secretary of the Interior. This term includes artifacts, records, and remains that are related to and located within such properties. The term includes properties of traditional religious and cultural importance to an Indian tribe or Native Hawaiian organization and that meet the National Register criteria (see 36 C.F.R. § 800.16(l)(1)).

Invited Signatory: The DOS has invited Keystone, the Montana Department of Natural Resources and Conservation, and the Montana Department of Environmental Quality to sign this PA consistent with 36 C.F.R. § 800.6(c)(2). The refusal of any invited signatory to sign the PA does not invalidate the PA. An invited signatory, listed above, that has signed the PA, may terminate the PA consistent with 36 C.F.R. § 800.6(c)(8).

Historic Trail and Archaeological Monitoring Plan: A plan that, pursuant to Stipulation V.E and Attachment F, identifies appropriate areas for monitoring construction by professionals under the supervision of individuals who meet the professional qualifications in Stipulation I. The plan's principal goal is to reduce the potential for impacts to unidentified historic properties.

Signatory: The signatories are: the DOS, BLM, USBR, USACE, NPS, Western, RUS, NRCS, FSA, BIA, ACHP, and the SHPOs of Kansas, Montana, South Dakota, and Nebraska. Only signatories and the invited signatories, as defined, may terminate the PA consistent with 36 C.F.R. § 800.6(c)(8).

Tribal Monitoring Plan: A plan that, pursuant to Stipulation V.E and Attachment E, identifies appropriate areas for monitoring construction by tribal members appointed by their respective Indian tribes. These tribal members shall meet the qualifications as noted in Stipulation V.E.3. The plan's principal goal is to reduce the potential for impacts to previously unidentified historic properties that may also be properties of religious and cultural significance to Indian tribes that meet the National Register criteria (see 36 C.F.R. § 800.16(1)(a)).

Treatment Plan: A plan developed in consultation with the parties to this PA that identifies the minimization and mitigation measures for historic properties located within the APE that will be adversely affected by the Project.

II. CONFIDENTIALITY

The DOS, BLM, NRCS, BIA, FSA, RUS, Western, USBR, NPS, USACE, and Keystone will safeguard information about historic properties of religious and cultural significance to Indian tribes, including location information, or information provided by Indian tribes to assist in the identification of such properties, consistent with Section 304 of NHPA, 16 U.S.C. § 470w3, and all other applicable laws.

III. THE RESPONSIBILITIES OF FEDERAL AGENCIES WITH LAND MANAGEMENT AND OTHER PERMITTING AUTHORITIES

A. The USACE will ensure, for that part of the APE under its jurisdiction, that it has met its compliance obligations pursuant to Section 10 and Section 404 permitting authority.

B. The BLM will comply with Section 106 and its implementing regulations (36 C.F.R. Part 800) for the issuance of permits for those actions under its jurisdiction.

C. The USBR will review and comment on the evaluation and treatment of any historic properties managed by the USBR.

D. Attachment H includes maps that illustrate the Project areas that cross lands managed by the BLM and the USBR.

E. Consultation for this Project between Indian tribes and Federal land management and permitting agencies will be coordinated through the DOS.

IV. KEYSTONE XL PROJECT—CONSTRUCTION OR MODIFICATION OF ELECTRICAL DISTRIBUTION/TRANSMISSION FACILITIES

A. Prior to granting approval of financial assistance to construct or modify electrical facilities by rural electric cooperatives or other entities, the RUS will complete the requirements of 36 C.F.R. §§ 800.3 through 800.7 and notify the DOS of the outcome.

B. In implementing Stipulation IV.A, the RUS may authorize a borrower to initiate Section 106 consultation in accordance with 36 C.F.R. § 800.2(c) (4). The RUS issued a blanket delegation for its borrowers to initiate Section 106 consultation in July 2009 and reissued the blanket delegation with some revision in August 2012. As the RUS recognized in those memos, the RUS may not delegate its responsibility to conduct government-to-government consultation with Indian tribes to a borrower, unless the RUS and that Indian tribe agree, in writing, to conduct consultation in that manner.

C. Prior to construction of the 230-kV transmission line that Western will own, Western will complete the requirements of 36 C.F.R. §§ 800.3 through 800.7. In implementing

Stipulation IV.C., Western will serve as a signatory under the PA. Western shall coordinate implementation of Stipulation IV.C with the DOS.

D. The RUS will ensure that the terms of Stipulations VI.B and VI.C are incorporated into construction contracts to ensure that its borrowers and construction contractors meet their responsibility for notification of any unanticipated discoveries. When RUS-funded projects occur on BLM land, the RUS will coordinate with the BLM to ensure compliance with Stipulations VI.B and VI.C of this PA.

E. Prior to granting approval or financial assistance for construction or modification of electrical distribution/transmission facilities that are necessary components of the pipeline project and therefore considered within the Project APE, any Federal agency that is incorporated into this PA pursuant to Stipulation XIV will complete the requirements of 36 C.F.R. §§ 800.3 through 800.7 for those facilities under its jurisdiction and notify the DOS of the outcome if not already carried out elsewhere in this PA.

F. The DOS retains responsibility for completing the requirements of 36 C.F.R. §§ 800.3 through 800.7 for those electrical distribution/transmission facilities that are necessary components of the Project if they are not under the jurisdiction of any Federal agency and not referenced in Stipulation IV, A through E above.

V. KEYSTONE XL PROJECT – PIPELINE CONSTRUCTION

A. The DOS has provided SHPOs, designated representatives of consulting Indian tribes, and other consulting parties with an opportunity to provide their views on the identification and evaluation of historic properties, consistent with 36 C.F.R. § 800.16(l)(1), including historic properties of religious and cultural significance to Indian tribes, and the treatment of affected historic properties, in connection with the construction of the Keystone XL Project. It will continue to provide all consulting parties with an opportunity to provide their views on the identification and evaluation of historic properties, assessment of effects, and treatment of adverse effects after approval of amendments to this PA.

B. Identification and Evaluation of Historic Properties

1. In consultation with the SHPOs, designated representatives of consulting Indian tribes, and other consulting parties, the DOS will make a reasonable and good faith effort to complete the identification and evaluation of historic properties within the APE for each construction spread, including in areas yet to be surveyed outlined in Attachment A, prior to the initiation of construction of that spread, consistent with 36 C.F.R. §§ 800.4(a), (b), and (c). On Federal lands, the scope of the identification effort will be determined by the DOS in consultation with the appropriate Federal land managing agency, applicable SHPOs, designated representatives of consulting Indian tribes, and other consulting parties.

2. The DOS will make a reasonable and good faith effort to complete the identification and evaluation of historic properties, as appropriate, consistent with 36 C.F.R. §§ 800.4(a), (b), and (c), before Keystone initiates construction activities (including vegetative clearing to comply with the Migratory Bird Treaty Act, if clearing is undertaken).

    a. In the identification and evaluation of historic properties to which Indian tribes may attach religious and cultural significance, the DOS will take into consideration information submitted by Indian tribes to the DOS prior to construction through consultations and through the protocols for TCP studies, post-review discovery, and the Tribal Monitoring Plan, as set forth in this PA.
    b. In the event identification of historic properties cannot be completed for any Construction Spreads prior to construction, Keystone will develop and submit a Coordination Plan to the DOS for review and approval pursuant to Stipulation V.D. The Coordination Plan must describe the measures Keystone will use to implement and complete the identification and evaluation of cultural resources and appropriate consultation before any historic properties are adversely affected by vegetation clearing and construction activities related to that spread.

C. Treatment of Historic Properties

1. Whenever feasible, avoidance of adverse effects to historic properties will be the preferred treatment. In consultation with the DOS, ACHP, SHPOs, designated representatives of consulting Indian tribes, and other consulting parties, Keystone may elect to consider and implement avoidance measures prior to completing the evaluation of historic properties.

    Avoidance measures may include:
    a. Avoidance through pipeline or access road route variation or Project feature relocation;
    b. Avoidance through abandonment;
    c. Avoidance through bore or horizontal directional drill;
    d. Avoidance by narrowing the construction corridor (“neck down”); or
    e. Avoidance through the use of existing roadways as Project access roads to the extent practicable.

2. When historic properties are identified in the APE pursuant to Stipulation V.B, the DOS will apply criteria of adverse effect consistent with 36 C.F.R. § 800.5(a) in consultation with the ACHP, SHPO, designated representatives of consulting Indian tribes, and other consulting parties. If the DOS finds that historic properties might be adversely affected by actions covered under this PA and within the APE, the DOS will consult with the ACHP, SHPOs, designated representatives of consulting Indian tribes, and other consulting parties to determine prudent and feasible ways to avoid adverse effects.

a. Once the DOS approves avoidance measures, Keystone will implement those measures.

3. If the DOS determines that the adverse effect cannot be avoided, the DOS will consult with the ACHP, SHPOs, designated representatives of consulting Indian tribes, and other consulting parties to determine those measures to be implemented by Keystone to minimize and mitigate adverse effects on affected historic properties identified in the APE.

4. If, after consultation, the DOS determines that the adverse effect cannot be avoided, Keystone will draft a comprehensive Treatment Plan for each adversely affected historic property. The Treatment Plan will describe the measures identified by the DOS under Stipulation V.C.3 to minimize and mitigate the adverse effect of pipeline construction activities on historic properties, the manner in which these measures will be carried out, and a schedule for their implementation.

   a. When mitigation consists of or includes Data Recovery, the Treatment Plan also will identify the specific research questions to be addressed by Data Recovery with an explanation of their relevance, the archaeological methods to be used, and provisions for public interpretation and education, subject to Stipulation II restrictions, if any. Management summaries of all archaeological investigations must be submitted to the DOS, relevant Federal agencies, and the SHPO for review and approval prior to the commencement of construction activities and construction may be authorized on the basis of information contained in those summaries. Designated representatives of consulting Indian tribes will be notified for their information and awareness and may provide any relevant information to DOS and SHPO within nine (9) calendar days to inform their review of the summaries. Final reports must be submitted to the DOS and the SHPO for review within six months of the completion of the fieldwork.

   b. A Treatment Plan may also include mitigation for adverse effects to historic districts, buildings and structures, and to TCPs and other properties of religious and cultural significance to Indian tribes. This mitigation may include the recordation of historic properties according to Historic American Building Survey/Historic American Engineering Record Standards and Guidelines for Architectural and Engineering Documentation. Other types of mitigation for adverse effects to historic districts, buildings, and structures, and to TCPs and other properties of religious and cultural significance to Indian tribes may also be described in the Treatment Plan. The mitigation proposed for an adverse effect to a historic district, building, and/or structure, and to TCPs and other properties of religious and cultural significance to Indian tribes will be commensurate with the level of significance and extent of adverse effect and will be determined in a manner consistent with Stipulation V.C.4.c.

   c. Keystone will submit the draft Treatment Plan to the DOS, BLM (if applicable), ACHP, designated representatives of consulting Indian tribes, the SHPO of the

applicable state, Montana Department of Environmental Quality (if applicable), Montana Department of Natural Resources and Conservation (if applicable), and other applicable consulting parties for a forty-five (45) calendar day review. Keystone will address timely comments and recommendations submitted by SHPOs, designated representatives of consulting Indian tribes, and other consulting parties in preparation of the Final Treatment Plan.

d. When it has addressed all of the timely comments and recommendations, Keystone will submit the Final Treatment Plan to the DOS for review and approval. Keystone will also submit the Final Treatment Plan to the BLM for review and approval when involving lands subject to Stipulation III.C. The DOS and BLM will issue their final decision on the Treatment Plan within thirty (30) calendar days. Once the Final Treatment Plan is approved by the DOS (and the BLM if involving BLM-managed lands), copies of the Treatment Plan will be distributed to all SHPOs, designated representatives of consulting Indian tribes, and other consulting parties.

5. Keystone will make a reasonable and good faith effort to complete implementation of the Final Treatment Plan approved by the DOS prior to beginning construction of any spread for which the Treatment Plan is required. If it is not possible to meet this schedule, Keystone will develop a Coordination Plan in accordance with Stipulation V.D that establishes how appropriate treatment will be determined and implemented during construction of the respective spread.

D. Coordination of Construction and Historic Preservation Activities

1. The DOS will make a reasonable and good faith effort to complete the identification and evaluation of historic properties and potential historic properties, and the mitigation of adverse effects to them in accordance with Stipulations V.B and V.C prior to the initiation of vegetative clearing if vegetative clearing and construction on the Keystone XL spreads, including the Montana, South Dakota, and Nebraska spreads, is to be undertaken.

2. If these DOS activities cannot be completed prior to the start of vegetative clearing and construction of these spreads, Keystone will develop and provide to the DOS a detailed plan describing how the requirements of Stipulations V.B and V.C—identification, evaluation and treatment of historic properties—will be completed in coordination with vegetative clearing and construction activities in such a way that historic properties will not be adversely affected prior to the implementation of any mitigation measures.

a. A Coordination Plan will be prepared for each state and will include those measures developed by Keystone pursuant to Stipulations V.B and V.C to complete the identification and evaluation of historic properties, and, as appropriate, mitigation of adverse effects to them during and coordinated with vegetation clearing and construction activities. In addition, the Coordination Plan

will include a schedule for all proposed activities and recommended measures for the protection of unanticipated discoveries in accordance with Attachment C, as appropriate.

b. Keystone will submit the draft Coordination Plan for each state for such spreads, including the Kansas, Montana, South Dakota, and Nebraska spreads, to the DOS, BLM (as applicable), ACHP, SHPOs (as applicable), designated representatives of consulting Indian tribes, and consulting parties for forty-five (45) calendar day review. Keystone shall address timely comments and recommendations submitted by the applicable SHPO, designated representatives of consulting Indian tribes, and other consulting parties in preparation of the Final Coordination Plan for each state. When it has addressed all of the comments and recommendations, Keystone will submit the Final Coordination Plan for each state to the DOS for review. The DOS shall issue its final decision on the Coordination Plan for each state within thirty (30) calendar days. Following approval by the DOS, the Final Coordination Plan for each state will be distributed to all of the SHPOs, designated representatives of consulting Indian tribes, and other consulting parties.

3. Keystone will complete implementation of the Final Coordination Plan approved by the DOS during construction of the Kansas, Montana, South Dakota, and Nebraska spreads.

E. Historic Trail and Archaeological Monitoring Plan ("HTAM Plan") and Tribal Monitoring Plan

1. In consultation with the SHPOs and designated representatives of consulting Indian tribes, Keystone will monitor construction in selected areas of the APE of each spread as a supplement to identification efforts. Any historic properties identified by Keystone during monitoring will be treated in accordance with Stipulation VI.A and C.

a. The HTAM Plan outlines areas that have been previously identified by the DOS during identification and evaluation efforts that warrant monitoring during soil disturbing activities for potential effects to historic properties.

b. The Tribal Monitoring Plan outlines areas that have been previously identified by Indian tribes, either through the preparation of Traditional Cultural Property reports or through consultation, that warrant monitoring during clearing and trenching for potential effects to previously unidentified historic properties that may include properties of religious and cultural significance to an Indian tribe and that meet the National Register criteria (See 36 C.F.R. § 800.16(l)(1)).

2. Historic Trail monitoring will be performed by a professional who either meets the qualification standards for archaeology established in Stipulation I.A or is under the on-site supervision of such a professional.

3. At the discretion of the DOS, tribal monitors may substitute other types of experience with construction monitoring and/or traditional cultural knowledge for the degrees required by the Professional Qualification Standards. DOS may also consider other accommodations regarding education and experience where allowed by the Standards and implementing guidance.

4. In consultation with the DOS, Keystone will consider information provided by Indian tribes in a timely manner when completing the identification of historic properties before construction begins as set forth in Stipulation V.B and in the HTAM Plan and Tribal Monitoring Plan provided for under Stipulation V.E. Keystone will ensure that tribal monitors have reasonable access to Project construction sites and activities. In those areas previously identified by Indian tribes as needing monitoring, the Tribal Monitoring Plan stipulates that at least one monitor will be used per Construction Spread depending upon the extent and location of construction activities, as well as the relative historic importance of each Spread to each Indian tribe.

5. Keystone has submitted a plan for historic trail and archaeological monitoring and tribal monitoring for each spread to the DOS, BLM, ACHP, SHPO, designated representatives of consulting Indian tribes, and Consulting Parties for review and comment prior to the signing of this PA. The Tribal Monitoring Plan and HTAM Plan are attached to this PA in Attachments E and F.

6. Keystone will implement the HTAM Plan and Tribal Monitoring Plan for each spread that has been approved by the DOS.

F. Construction

1. Lead Environmental Inspector (EI): Prior to initiating vegetative clearing or construction, Keystone will employ the Lead EI whose responsibilities will include ensuring compliance with the terms of this PA. In meeting this responsibility, the Lead EI will rely on the technical expertise of on-site professionals who meet the standards established in Stipulation I.A and tribal monitors with experience outlined in Stipulation V.E.3.

   a. The Lead EI will monitor construction activities on-site and prepare a daily log, reporting to Keystone and designated representatives of consulting Indian tribes on activities performed to implement the terms of this PA, as appropriate. Keystone will make the daily log available to the DOS and SHPOs, and other consulting parties upon request.

   b. Keystone will ensure through the construction contract that the Lead EI will possess the authority to stop construction in the event of an inadvertent discovery in accordance with Stipulation VI.A and Attachment C.

2. Training: Keystone will ensure that, if the Lead EI does not meet the professional qualification standards established in Stipulation I.A, the Lead EI will receive appropriate training in historic preservation from a professional who meets the standards established in Stipulation I.A in order to perform the requirements of this PA. Keystone also will provide an appropriate level of training in historic preservation conducted by a professional who meets the standards established in Stipulation I.A to all construction personnel (including new, added, replaced workers) so that PA requirements are understood and unanticipated discoveries quickly identified. Keystone will conduct this training prior to initiating vegetative clearing or construction activities on a spread. Keystone also will conduct periodic refresher training during construction of the spread.

3. Construction Contract: Keystone will incorporate the terms of Stipulation VI.A and Attachment C into construction contracts to ensure that its Lead EI and construction contractors meet their responsibility for notification of the unanticipated discoveries.

F. Scheduling

The DOS may authorize the start of vegetative clearing and construction for an individual spread when the plans prepared in accordance with Stipulations V.D and V.E as appropriate for that spread, have been submitted by Keystone and approved by the DOS in accordance with the terms of this PA.

VI. UNANTICIPATED DISCOVERIES OR ADVERSE EFFECTS DURING CONSTRUCTION OF THE KEYSTONE XL PROJECT

A. Pipeline Construction

1. "Applicable Federal agency" is the Federal agency with jurisdiction for the land on which construction is occurring or, in the absence of such an agency, the DOS, as appropriate.

2. If previously unidentified historic properties are discovered by monitors or construction personnel unexpectedly or unanticipated adverse effects on previously identified historic properties occur as pipeline construction activities are carried out within the one-hundred-and-ten (110) foot-wide construction corridor or other ancillary facilities and access roads within the APE, the construction contractor will immediately halt all construction activity within a one-hundred-and-fifty (150) foot radius of the discovery or adversely affected historic property, notify the Lead EI of the discovery and implement interim measures to protect the discovery from looting and vandalism. Within forty-eight (48) hours of receipt of this notification of the discovery, the Lead EI shall:

   a. Inspect the work site to determine the extent of the discovery or adverse effect and ensure that construction activities have halted;
   b. Clearly mark the area of the discovery or adverse effect;

c. Implement additional measures other than those mentioned above, as appropriate, to protect the discovery or adversely affected historic property from looting and vandalism; and
d. Notify the applicable Federal agency, SHPOs, designated representatives of consulting Indian tribes, and other consulting parties of the discovery or adverse effect.

3. In the case of an unanticipated discovery, the applicable Federal agency will notify all consulting parties that it will be receiving comments concerning the unanticipated discovery and provide contact information. The applicable Federal agency will have seven (7) calendar days following notification provided in accordance with Stipulation VI.A.2 to determine the National Register eligibility of the discovery after considering the timely filed views of the SHPOs, designated representatives of consulting Indian tribes, other consulting parties, and Keystone. The applicable Federal agency may assume the newly discovered property to be eligible for the National Register for the purposes of Section 106 consistent with 36 C.F.R. § 800.13(c).

4. For discovered properties determined eligible or assumed to be eligible pursuant to Stipulation VI.A.3, the applicable Federal agency will notify the ACHP, SHPOs, designated representatives of consulting Indian tribes, and other consulting parties of those actions that it proposes to resolve adverse effects which may include a Treatment Plan as outlined in Stipulation V.C.

   a. SHPOs, designated representatives of consulting Indian tribes, and other consulting parties will have ninety-six (96) hours to provide their views on the proposed actions.
   b. The applicable Federal agency will ensure that the timely filed recommendations of SHPOs, designated representatives of consulting Indian tribes, and other consulting parties are taken into account prior to granting approval of the measures that Keystone will implement to resolve adverse effects.
   c. Keystone will carry out the approved measures prior to resuming construction activities in the location of the discovery.

5. In the case of unanticipated adverse effects to a previously identified historic property, the applicable Federal agency will notify the ACHP, SHPOs, designated representatives of consulting Indian tribes, and other consulting parties of those actions that it proposes to resolve adverse effects which may include a Treatment Plan as outlined in Stipulation V.C.

   a. SHPOs, designated representatives of consulting Indian tribes, and other consulting parties will have forty-eight (48) hours to provide their views on the proposed actions.
   b. The applicable Federal agency will ensure that the timely filed recommendations of SHPOs, designated representatives of consulting Indian tribes, and other

consulting parties are taken into account prior to granting approval of the measures that Keystone will implement to mitigate adverse effects.

c. Keystone will carry out the approved measures prior to resuming construction activities in the location of the affected property.

6. Dispute Resolution: The applicable Federal agency will seek and take into account the recommendations of the ACHP in resolving any disagreements that may arise regarding resolution of adverse effects that relate to the implementation of Stipulation VI.A. The applicable Federal agency will use the contact information provided in Attachment D to notify the ACHP. Within seven (7) calendar days of receipt of such a written request, the ACHP will provide the applicable Federal agency recommendations on resolving the dispute. The applicable Federal agency will take into account any timely filed recommendations provided by the ACHP in making a final decision about how to proceed.

B. Construction or Modification of Electrical Facilities

1. If previously unidentified historic properties are discovered unexpectedly during construction or modification of transmission facilities funded by the RUS, the RUS borrower's construction contractor will immediately halt all construction activity within a one-hundred-and-fifty (150) foot radius of the discovery, notify the RUS borrower of the discovery and implement interim measures to protect the discovery from looting and vandalism. Within forty-eight (48) hours of receipt of this notification of the discovery, the RUS borrower shall:

   a. Notify the RUS Contact (and BLM Contact if discovery occurs on BLM land);
   b. Inspect the work site to determine the extent of the discovery and ensure that construction activities have halted;
   c. Clearly mark the area of the discovery; and
   d. Implement additional measures, as appropriate, to protect the discovery from looting and vandalism.

2. Upon receipt of such notification the RUS and, if applicable, BLM will coordinate the notification of SHPOs, designated representatives of consulting Indian tribes, and other consulting parties and notify the SHPOs, designated representatives of consulting Indian tribes, and other consulting parties of the discovery.

3. The RUS and, if applicable, BLM will have seven (7) calendar days following notification provided in accordance with Stipulation VI.B.1 to determine the National Register eligibility of the discovery in consultation with the SHPOs, designated representatives of consulting Indian tribes, other consulting parties, and the borrower. The RUS and, if applicable, BLM may assume the newly discovered property to be eligible for the National Register for the purposes of Section 106 pursuant to 36 C.F.R. § 800.13(c).

4. For properties determined eligible, or treated as such, pursuant to Stipulation VI.B.3, the RUS, in coordination with the BLM (if applicable), will notify the SHPOs, designated representatives of consulting Indian tribes, and other consulting parties of those actions that it proposes to resolve adverse effects. SHPOs, designated representatives of consulting Indian tribes, and other consulting parties will provide their views on the proposed actions within ninety-six (96) hours. The RUS will ensure that the timely filed recommendations of the SHPOs, designated representatives of consulting Indian tribes, and other consulting parties are taken into account prior to granting approval of those actions that the borrower will implement to resolve adverse effects. Once RUS approval has been granted, its borrower will carry out the approved measures prior to resuming construction activities in the location of the discovery.

5. Dispute Resolution: The RUS and, if applicable, BLM will seek and take into account the recommendations of the ACHP in resolving any disagreements that may arise regarding the resolution of adverse effects that relate to the implementation of Stipulation VI.B. The applicable Federal agency will use the contact information provided in Attachment D in order to notify the ACHP. Within seven (7) calendar days of receipt of such a written request, the ACHP will provide the RUS and, if applicable, BLM with its recommendations for resolving the dispute. The RUS and, if applicable, BLM will take into account any recommendations provided by the ACHP in making a final decision about how to proceed.

6. Reporting: No later than six (6) months following the resumption of construction within the location of the discovery, the RUS will submit a final report to the SHPOs, designated representatives of consulting Indian tribes, and other consulting parties describing implementation of the actions taken in accordance with Stipulation VI.B and, as appropriate, the analysis and interpretation of recovered information.

C. Unanticipated Discovery of Human Burials and Remains, and Funerary Objects

1. When Native American human remains or funerary objects or objects of cultural patrimony are unexpectedly discovered during construction of the Keystone XL Project on Federal or tribal lands within the APE, Keystone or an RUS borrower, as appropriate, will notify immediately the Federal agency responsible for compliance with the Native American Graves Protection and Repatriation Act, 25 U.S.C. 3001 et. seq., and its implementing regulations, 43 C.F.R. Part 10.

2. Non-Native American human burials and remains, and funerary objects discovered on Federal lands within the APE will be treated by the Federal agency having jurisdiction of the remains in accordance with applicable Federal law, taking into account the ACHP's *Policy Statement on the Treatment of Burial Sites, Human Remains and Funerary Objects* (February 23, 2007).

3. The DOS, Western, and RUS will treat human burials and remains discovered on non-Federal land consistent with the provisions of Attachment C and any applicable

federal, state, and local burial laws. In those instances where the USACE has jurisdiction under Section 10 or 404 permitting authority for non-Federal lands in the APE, the applicable Federal agencies will ensure that Keystone complies with the provisions of Attachment C acting in the place of the DOS. In determining appropriate actions to be carried out, the DOS, RUS, and/or other Federal agencies will be guided by the ACHP's *Policy Statement on the Treatment of Burial Sites, Human Remains and Funerary Objects* (February 23, 2007).

VII. CURATION

A. Federal agencies will curate any artifacts, materials or records resulting from archaeological identification and mitigation conducted on Federal lands under their jurisdiction in accordance with 36 C.F.R. Part 79, "*Curation of Federally-Owned and Administered Archaeological Collections*." Federal agencies with jurisdiction over the Federal lands will consult with Indian tribes consistent with 36 C.F.R. 79.

B. Keystone and RUS borrowers will return all artifacts recovered from private lands to the respective landowner after analysis is complete, unless applicable state law requires otherwise. Keystone and RUS borrowers will encourage and assist landowners in donating any returned artifacts to a local curation facility identified by the respective SHPO. Keystone shall pay all required curation fees associated with the donation of artifacts to the local curation facility.

C. On Federally controlled or owned properties, Federal agencies will determine the disposition of human burials, human remains and funerary objects in accordance with applicable Federal law.

VIII. REPORTING

A. Within three (3) months of completion of pipeline construction of a spread, Keystone will submit a comprehensive draft report to the DOS describing the results and findings of the implementation of the actions and plans specified in Stipulations V.C through G, VI.A, including Attachment C.

B. Keystone will submit a draft comprehensive report for each spread to the ACHP, SHPOs, designated representatives of consulting Indian tribes, and other consulting parties of the respective states in which the spread is located, for forty-five (45) day review and comment. Keystone shall address timely comments and recommendations submitted by ACHP, SHPOs, designated representatives of consulting Indian tribes, and other consulting parties in preparation of the Final Comprehensive Report for that spread. Keystone will submit the final report to the DOS for review and approval. The final comprehensive report will be provided by the DOS to the ACHP, SHPOs, designated representatives of consulting Indian tribes, and other consulting parties once approved.

IX. MONITORING IMPLEMENTATION OF THE PA

Each quarter following the execution of this PA until it expires or is terminated, the DOS with the assistance of the USACE, BLM, RUS, FSA, NRCS, BIA, and USBR as necessary will provide the ACHP, SHPOs, designated representatives of consulting Indian tribes, and other consulting parties to this PA a progress report summarizing the work carried out pursuant to its terms. Such report will include any scheduling changes proposed, any problems encountered, and any disputes and objections received in the efforts to carry out the terms of this PA. The DOS will maintain and update a list of the current contact for the ACHP, SHPOs, designated representatives of consulting Indian tribes, and other consulting parties and will be distributed in each quarterly report.

X. DISPUTE RESOLUTION

A. "Appropriate Federal agency" refers to the DOS, BLM, RUS, USBR, and USACE, or other Federal land managing and/or permitting agency as applicable.

B. Should any signatory, invited signatory, or concurring party to this PA object at any time to any actions proposed or the manner in which the terms of this PA are implemented, the appropriate Federal agency will consult with such party to resolve the objection. If the appropriate Federal agency determines that such objection cannot be resolved, the appropriate Federal agency will:

   1. Forward all documentation relevant to the dispute, including the applicable Federal agency's proposed resolution, to the ACHP. The ACHP will provide the appropriate Federal agency with its advice on the resolution of the objection within thirty (30) calendar days of receiving adequate documentation. Prior to reaching a final decision on the dispute, the appropriate Federal agency will prepare a written response that takes into account any timely advice or comments regarding the dispute from the ACHP, signatories, invited signatories, and concurring parties, and provide them with a copy of this written response. The appropriate Federal agency will then proceed according to its final decision.

   2. If the ACHP does not provide its advice regarding the dispute within the thirty (30) calendar day time period, the applicable Federal agency may make a final decision on the dispute and proceed accordingly. Prior to reaching such a final decision, the appropriate Federal agency will prepare a written response that takes into account any timely comments regarding the dispute from the signatories, invited signatories, and concurring parties to the PA, and provide them and the ACHP with a copy of such written response.

C. The Federal agencies are responsible for carrying out all other actions subject to the terms of this PA that are not the subject of the dispute.

D. The process of dispute resolution outlined in Stipulation X does not pertain to disputes that arise from unanticipated discoveries covered in Stipulation VI.

XI. DURATION

This PA will be null and void if all of its stipulations have not been carried out within seven (7) years from the date of its execution. At such time, and prior to work continuing on the Keystone XL Project, the DOS will either: (a) execute a Memorandum of Agreement (MOA) or PA consistent with 36 C.F.R. §§ 800.6 or 800.14(b), respectively; or (b) request, take into account, and respond to the comments of the ACHP consistent with 36 C.F.R. § 800.7. Prior to such time, the DOS may consult with the other signatories and invited signatories to reconsider the terms of the PA and amend it in accordance with Stipulation XII. The DOS will notify the signatories, invited signatories, and concurring parties as to the course of action they will pursue.

XII. AMENDMENT

Any signatory or invited signatory to this PA may propose in writing that it be amended. The signatories and invited signatories will consult in an effort to reach agreement on an amendment. Any amendment will be effective on the date it is signed by all of the signatories and invited signatories and filed with the ACHP.

XIII. TERMINATION

A. If any signatory or invited signatory to this PA determines that its terms will not or cannot be carried out, that party will immediately consult with the other signatories and invited signatories to attempt to develop an amendment per Stipulation XII. If within thirty (30) calendar days an amendment cannot be reached, any signatory or invited signatory may terminate the PA upon written notification to the other signatories and invited signatories.

B. Termination by an individual SHPO shall only terminate the application of this PA within the jurisdiction of the SHPO.

   1. Once the PA is terminated for an individual state, and prior to work continuing on the undertaking in that state, DOS must either (a) execute a PA pursuant to 36 CFR § 800.6 or (b) request, take into account, and respond to the comments of the ACHP under 36 CFR § 800.7. DOS shall notify the signatories as to the course of action it will pursue.

C. If the PA is terminated in its entirety, and prior to work continuing on the undertaking, the DOS shall request, take into account, and respond to the comments of the ACHP consistent with 36 C.F.R. § 800.7(a). Following consultation with the ACHP, the DOS will notify the signatories, invited signatories and concurring parties as to the course of action it will pursue.

XIV. COORDINATION WITH OTHER FEDERAL REVIEWS

In the event that Keystone or a Federal agency applies for additional Federal funding or approvals for the Keystone XL Project and the undertaking remains unchanged, such funding or approving agency may comply with Section 106 by agreeing in writing to the terms of this PA and notifying and consulting with the applicable SHPOs, designated representatives of consulting Indian tribes, and the ACHP. Any necessary modifications will be considered in accordance with Stipulation XII.

XV. SCOPE OF THE PA

This PA is limited in scope to actions that will facilitate the construction of the Keystone XL Project and related facilities, and is entered into solely for that purpose.

EXECUTION of this PA by the DOS, ACHP, BLM, RUS, Western, USACE, USBR, NPS, NRCS, FSA, BIA, the Montana SHPO, South Dakota SHPO, Nebraska SHPO, and Kansas SHPO and implementation of its terms evidence that the DOS, Western, BLM, RUS, NRCS, FSA, BIA, USACE, USBR, and NPS have taken into account the effects of the Keystone XL Project on historic properties and afforded the ACHP an opportunity to comment.

Deborah Klepp /PK for December 23, 2013

Deborah Klepp **Date**
Director
Office of Environmental Quality and Transboundary Issues
Bureau of Oceans and International Environmental and Scientific Affairs
United States Department of State

Corm Cam s ell
Acting Regional Director, Intermountain Region
National Park Service

434 0/3
Date

18 DEC 2013

Joel R. Cross
Colonel, Corps of Engineers
District Commander

Date

12/17/2013

Date

Bennet Horter
Federal Preservation Officer
United States Department of Agriculture Farm Service Agency

Salvador Salinas 12-17-13

Salvador Salinas **Date**
State Conservationist
United States Department of Agriculture Natural Resources Conservation Services

Mark S. Plank 12/17/13

Mark S. Plank
Director, Engineering and Environmental Staff
United States Department of Agricultural Rural Utilities Service

Date

12-18-13

Weldon Loudermilk
Great Plains Regional Director
United States Bureau of Indian Affairs

Date

Diane M Friez 12/18/2013

Diane Friez **Date**
District Manager, Eastern Montana/Dakotas District
Bureau of Land Management

DECEMBER 18, 2013

Michael J. Ryan
Regional Director, Great Plains Region
Bureau of Reclamation

Date

Robert J. Harris 12/19/13

Robert Harris
Regional Manager, Upper Great Plains Region
Western Area Power Administration (WESTERN)

Date

John M. Fowler

12/19/13

John M. Fowler
Executive Director
Advisory Council on Historic Preservation

Date

Patrick Zelnar DSHPO for 12-17-13

Jennie Chinn
State Historic Preservation Officer
Kansas

Date

12·19·13

Tracy Stone-Manning
Director
Montana Department of Environmental Quality
(Invited Signatory)

Date

12-19-13

John Tubbs
Director
Montana Department of Natural Resources and Conservation
(Invited Signatory)

Date

Mark Baumler
State Historic Preservation Officer
Montana

12/18/2013
Date

Michael J. Smith
State Historic Preservation Officer
Nebraska

Dec. 18, 2013
Date

17 Dec 13

Jay D. Vogt
State Historic Preservation Officer
South Dakota

Date

Dec 18/13

Corey Goulet
Vice President
TransCanada Pipelines Limited
(Invited Signatory)

Date

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ATTACHMENT A

The following table summarizes the proposed Project areas for which Keystone has yet to conduct identification and evaluation studies as of the finalization of the PA. The majority of these proposed Project areas have been denied access versus new areas that have yet to surveyed.

Areas Not Surveyed Along the Proposed Project APE		
State	**Project Area Type**	**Cultural Survey Remaining (acres)**
Montana	ROW	0.00
Montana	Pump Stations	0.00
Montana	Ancillary facilities	0.00
Montana	Access Roads	0.00
South Dakota	ROW	23.70
South Dakota	Pump Stations	0.00
South Dakota	Ancillary facilities	0.00
South Dakota	Access Roads	0.00
Nebraska	ROW	937.65
Nebraska	Pump Stations	43.45[1]
Nebraska	Ancillary facilities	N/A[2]
Nebraska	Access Roads	33.05[3]
Total		**1037.85**[1, 2, 3]

[1] Pump stations in Nebraska have been surveyed for multiple locations.
[2] Additional ancillary facilities may be needed, however, are not known at this time.
[3] Additional access roads may be needed, however, are not known at this time.

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ATTACHMENT B

1. Absentee-Shawnee Tribe of Indians of Oklahoma
2. Alabama-Coushatta Tribes of Texas
3. Alabama-Quassarte Tribal Town, Oklahoma
4. Apache Tribe of Oklahoma
5. Arapahoe Tribe of the Wind River Reservation, Wyoming (aka Northern Arapaho Tribe)
6. Assiniboine and Sioux Tribes of the Fort Peck Indian Reservation, Montana (aka Fort Peck Tribes)
7. Blackfeet Tribe of the Blackfeet Indian Reservation of Montana
8. Cherokee Nation, Oklahoma
9. Cheyenne and Arapaho Tribes, Oklahoma
10. Cheyenne River Sioux Tribe of the Cheyenne River Reservation, South Dakota
11. Chickasaw Nation, Oklahoma
12. Chippewa-Cree Indians of the Rocky Boy's Reservation, Montana
13. Choctaw Nation of Oklahoma
14. Comanche Nation, Oklahoma
15. Confederated Salish & Kootenai Tribes of the Flathead Indian Nation, Montana
16. Confederated Tribes of the Goshute Reservation, Nevada and Utah
17. Crow Creek Sioux Tribe of the Crow Creek Reservation, South Dakota
18. Crow Tribe of Montana
19. Delaware Tribe of Indians, Oklahoma
20. Duckwater Shoshone Tribe of the Duckwater Reservation, Nevada
21. Eastern Band of Cherokee Indians of North Carolina
22. Eastern Shawnee Tribe of Oklahoma
23. Ely Shoshone Tribe of Nevada
24. Flandreau Santee Sioux Tribe of South Dakota
25. Forest County Potawatomi Community, Wisconsin
26. Fort Belknap Indian Community of the Fort Belknap Reservation of Montana (aka Gros Ventre and Assiniboine Tribe of Ft. Belknap)
27. Hannahville Indian Community, Michigan
28. Ho-Chunk Nation of Wisconsin
29. Iowa Tribe of Kansas and Nebraska
30. Iowa Tribe of Oklahoma
31. Jena Band of Choctaw Indians, Louisiana
32. Kaw Nation, Oklahoma
33. Kialegee Tribal Town, Oklahoma
34. Kickapoo Traditional Tribe of Texas
35. Kickapoo Tribe of Indians of the Kickapoo Reservation in Kansas
36. Kiowa Indian Tribe of Oklahoma
37. Lower Brule Sioux Tribe of the Lower Brule Reservation, South Dakota
38. Lower Sioux Indian Community in the State of Minnesota
39. Match-e-be-nash-she-wish Band of Pottawatomi Indians of Michigan (aka Gun Lake Potawatomi)

40. Mille Lacs Band of Minnesota Chippewa Tribes, Minnesota
41. Modoc Tribe of Oklahoma
42. Nez Perce Tribe, Idaho
43. Northern Cheyenne Tribe of the Northern Cheyenne Indian Reservation, Montana
44. Nottawaseppi Huron Band of the Potawatomi, Michigan (aka Huron Potawatomi Nation)
45. Oglala Sioux Tribe of the Pine Ridge Reservation, South Dakota
46. Omaha Tribe of Nebraska
47. Osage Nation, Oklahoma
48. Otoe-Missouria Tribe of Indians, Oklahoma
49. Pawnee Nation of Oklahoma
50. Poarch Band of Creek Indians of Alabama
51. Pokagon Band of Potawatomi Indians, Michigan and Indiana
52. Ponca Tribe of Indians of Oklahoma
53. Ponca Tribe of Nebraska
54. Prairie Band of Potawatomi Nation, Kansas
55. Prairie Island Indian Community in the State of Minnesota
56. Red Lake Band of Chippewa Indians, Minnesota
57. Rosebud Sioux Tribe of the Rosebud Indian Reservation, South Dakota
58. Sac & Fox Nation of Missouri in Kansas and Nebraska
59. Sac & Fox Nation, Oklahoma
60. Sac & Fox Tribe of the Mississippi in Iowa
61. Santee Sioux Nation, Nebraska
62. Seneca-Cayuga Tribe of Oklahoma
63. Shakopee Mdewakanton Sioux Community of Minnesota
64. Shoshone-Bannock Tribes of the Fort Hall Reservation of Idaho
65. Shoshone Tribe of the Wind River Reservation, Wyoming (aka Eastern Shoshone Tribe)
66. Sisseton-Wahpeton Oyate of the Lake Traverse Reservation, South Dakota
67. Skull Valley Band of Goshute Indians of Utah
68. Southern Ute Indian Tribe of the Southern Ute Reservation, Colorado
69. Spirit Lake Tribe, North Dakota
70. Standing Rock Sioux Tribe of North & South Dakota
71. Stockbridge Munsee Community, Wisconsin
72. Thlopthlocco Tribal Town, Oklahoma
73. Three Affiliated Tribes of the Fort Berthold Reservation, North Dakota
74. Tonkawa Tribe of Indians of Oklahoma
75. Turtle Mountain Band of Chippewa Indians of North Dakota
76. United Keetoowah Band of Cherokee Indians in Oklahoma
77. Upper Sioux Community, Minnesota
78. Ute Indian Tribe of the Uintah & Ouray Reservation, Utah (aka Ute Indian Tribe, also Northern Ute Tribe)
79. Ute Mountain Tribe of the Ute Mountain Reservation, Colorado, New Mexico and Utah
80. White Earth Band of Minnesota Chippewa Tribes, Minnesota
81. Wichita and Affiliated Tribes (Wichita, Keechi, Waco & Tawakonie), Oklahoma
82. Winnebago Tribe of Nebraska
83. Yankton Sioux Tribe of South Dakota
84. Ysleta Del Sur Pueblo of Texas

ATTACHMENT C

Plans for the Unanticipated Discovery of Cultural Resources

If previously unidentified cultural resources are discovered by monitors or construction personnel unexpectedly, Keystone will follow the procedures described in the state-specific plans included in this attachment for (1) Montana, (2) South Dakota, (3) Nebraska, (4) North Dakota, and (5) Kansas. If the following plans conflict in any way with Keystone's obligations under the Programmatic Agreement and Tribal Monitoring Plan, Keystone will follow the procedures described in the Programmatic Agreement and Tribal Monitoring Plan.

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UNANTICIPATED DISCOVERIES PLAN

I. Unanticipated Discoveries Plan for the Keystone XL project corridor (Project) in Montana

If previously unidentified historic properties are discovered by monitors or construction personnel unexpectedly or unanticipated adverse effects on previously identified historic properties occur as pipeline construction activities are carried out within the one-hundred-and-ten (110) foot-wide construction corridor or other ancillary facilities and access roads within the APE, the construction contractor will immediately halt all construction activity within a one-hundred-and-fifty (150) foot radius of the discovery or adversely affected historic property, notify the Lead EI of the discovery and implement interim measures to protect the discovery from looting and vandalism.

Within forty-eight (48) hours of receipt of this notification of the discovery, the Lead EI shall:

a. Inspect the work site to determine the extent of the discovery or adverse effect and ensure that construction activities have halted;
b. Clearly mark the area of the discovery or adverse effect;
c. Implement additional measures other than those mentioned above, as appropriate, to protect the discovery or adversely affected historic property from looting and vandalism; and
d. Notify the DOS, SHPO, MDEQ, designated representatives of consulting Indian tribes, and other consulting parties of the discovery or adverse effect.

In the case of an unanticipated discovery, DOS will notify all consulting parties that it will be receiving comments concerning the unanticipated discovery and provide contact information. The DOS will have seven (7) calendar days following notification provided in accordance with Stipulation VI.A.2 to determine the National Register eligibility of the discovery after considering the timely filed views of the SHPO, MDEQ, designated representatives of consulting Indian tribes, other consulting parties, and Keystone. The applicable Federal agency may assume the newly discovered property to be eligible for the National Register for the purposes of Section 106 consistent with 36 C.F.R. § 800.13(c).

For discovered properties determined eligible or assumed to be eligible pursuant to Stipulation VI.A.3, the applicable Federal agency will notify the ACHP, SHPO, MDEQ, designated representatives of consulting Indian tribes, and other consulting parties of those actions that it proposes to resolve adverse effects which may include a Treatment Plan as outlined in Stipulation V.C.

a. SHPO, MDEQ, designated representatives of consulting Indian tribes, and other consulting parties will have ninety-six (96) hours to provide their views on the proposed actions.
b. DOS will ensure that the timely filed recommendations of SHPO, MDEQ, designated representatives of consulting Indian tribes, and other consulting parties are taken into account prior to granting approval of the measures that Keystone will implement to resolve adverse effects.

c. Keystone will carry out the approved measures prior to resuming construction activities in the location of the discovery.

In the case of unanticipated adverse effects to a previously identified historic property, the applicable Federal agency will notify the ACHP, SHPO, MDEQ, designated representatives of consulting Indian tribes, and other consulting parties of those actions that it proposes to resolve adverse effects which may include a Treatment Plan as outlined in Stipulation V.C.

a. SHPO, MDEQ, designated representatives of consulting Indian tribes, and other consulting parties will have forty-eight (48) hours to provide their views on the proposed actions.
b. DOS will ensure that the timely filed recommendations of SHPO, MDEQ, designated representatives of consulting Indian tribes, and other consulting parties are taken into account prior to granting approval of the measures that Keystone will implement to mitigate adverse effects.
c. Keystone will carry out the approved measures prior to resuming construction activities in the location of the affected property.

Dispute Resolution: DOS will seek and take into account the recommendations of the ACHP in resolving any disagreements that may arise regarding resolution of adverse effects that relate to the implementation of Stipulation VI. DOS will use the contact information provided in Attachment C or D to notify the ACHP. Within seven (7) calendar days of receipt of such a written request, the ACHP will provide DOS recommendations on resolving the dispute. DOS will take into account any timely filed recommendations provided by the ACHP in making a final decision about how to proceed.

II. Accidental Discovery of Human Remains on state or private lands

All human burials and funerary objects in the state of Montana are protected pursuant to the Human Skeletal Remains and Burial Site Protection Act (Montana Code Ann. §22-3-801 through §22-3-811).

In the event that human remains or burials are encountered during additional archaeological investigations or construction activities, Keystone or its designated representative shall immediately cease work within 150 foot radius from the point of discovery and implement measures to protect the discovery from looting and vandalism. No digging, collecting or moving human remains or other items shall occur after the initial discovery. Protection measures will include the following.

a) Flag the buffer zone around the find spot.
b) Keep workers, press, and curiosity seekers, away from the find spot.
c) Tarp the find spot.
d) Prohibit photography of the find unless requested by an agency official.
e) Have an individual stay at the location to prevent further disturbance until a law enforcement officer arrives.

Keystone will immediately notify local law enforcement, DOS, SHPO, and MDEQ within forty-eight (48) hours of the discovery. DOS shall notify the SHPO, MDEQ, Indian tribes, and other consulting parties within forty-eight (48) hours of the discovery. If local law enforcement determines that the remains are not associated with a crime, DOS shall determine if it is prudent and feasible to avoid disturbing the remains. If DOS in consultation with the Keystone determines that disturbance cannot be avoided, the DOS shall consult with the SHPO, MDEQ, Indian tribes, and other consulting parties to determine acceptable procedures for the removal, treatment and disposition of the burial or remains. The DOS shall ensure that Keystone implements the plan for removal, treatment and disposition of the burial or remains as authorized by the SHPO. The DOS shall notify Keystone that they may resume construction activities in the area of the discovery upon completion of the plan authorize as by the SHPO.

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III. Unanticipated Discovery of Human Burials, Remains, and Funerary Objects on Federal Lands

For the accidental discovery of human burials, remains, and funerary objects on Federal lands please reference Stipulation VI.(C) of the PA.

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UNANTICIPATED DISCOVERIES PLAN

I. Unanticipated Discoveries Plan for the Keystone XL project corridor (Project) in South Dakota

1. In the event that previously unidentified archaeological resources are discovered during ground disturbing activities within the project area (area of potential effect), Project shall halt immediately all construction work within 100 feet (30.5 m) of the discovery and in the surrounding area where further subsurface remains can reasonably be expected to occur. The area of the discovery will be clearly marked by means of flagging or fencing.

2. The construction contractor will notify a designated representative of Project of the discovery. Following notification of the discovery, the designated representative of Project will immediately inspect the work site and determine the extent of the affected archaeological resource as defined by the State Historic Preservation Office (SHPO) or by the SHPO in consultation with the archaeologist retained by Project.

3. Within 14 calendar days of the original notification of discovery, the archaeologist retained by Project, in consultation with the SHPO, will determine the National Register eligibility of the resource. The SHPO or Project may extend this 14-day calendar period one time by an additional 7 calendar days, with Project providing written notice to the SHPO prior to the expiration date of the said 14-day calendar period.

4. If the resource is determined eligible for the National Register, Project shall submit to the SHPO and the Department of State (DOS) a plan for its avoidance, protection, recovery of information, or destruction without data recovery. Said plan will be submitted to the SHPO and the DOS within 14 calendar days of a determination of eligibility, and shall be approved by the SHPO and the DOS prior to implementation.

5. Work in the affected area may resume per SHPO authorization pending either:
    i. development and implementation of an appropriate data recovery plan or other recommended mitigation procedures, or
    ii. determination that the located remains are not eligible for inclusion on the National Register.

6. Any disputes concerning the evaluation or treatment of previously unidentified resources will be resolved through consultation among the SHPO, a designated representative of Project, and the archaeologist retained by Project.

II. Accidental Discovery of Human Remains on state or private lands

All human burials and funerary objects in the state of South Dakota are protected pursuant to South Dakota Codified Law Chapter 34-27-25, 34-27-28, 34-27-31.

In the event that human remains or burials are encountered during additional archaeological investigations or construction activities, Project or its designated representative shall immediately cease work within 150 foot radius from the point of discovery and implement measures to protect the discovery from looting and vandalism. No digging, collecting or moving human remains or other items shall occur after the initial discovery. Protection measures will include the following.

a) Flag the buffer zone around the find spot.
b) Keep workers, press, and curiosity seekers, away from the find spot.
c) Tarp the find spot.
d) Prohibit photography of the find unless requested by an agency official.
e) Have an individual stay at the location to prevent further disturbance until a law enforcement officer arrives.

Project will immediately notify local law enforcement, the DOS, and the South Dakota State Archaeologist (State Archaeologist) within forty-eight (48) hours of the discovery. The DOS shall notify the SHPO, Indian tribes and other consulting parties within forty-eight (48) hours of the discovery. If local law enforcement determines that the remains are not associated with a crime, the DOS shall determine if it is prudent and feasible to avoid disturbing the remains. If the DOS in consultation with the Project determines that disturbance cannot be avoided, the DOS shall consult with the State Archaeologist, SHPO, Indian tribes and other consulting parties to determine acceptable procedures for the removal, treatment and disposition of the burial or remains. The DOS shall ensure that the Project implements the plan for removal, treatment and disposition of the burial or remains as authorized by the State Archaeologist. The DOS shall notify the Project that they may resume construction activities in the area of the discovery upon completion of the plan authorize as by the State Archaeologist.

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III. Unanticipated Discovery of Human Burials, Remains, and Funerary Objects on Federal Lands

For the accidental discovery of human burials, remains, and funerary objects on Federal lands please reference Stipulation VI.(C) of the PA.

PREFILED REBUTTAL TESTIMONY

OF

CHRIS SAUNCOSI

Docket No. HP14-001

IN THE MATTER OF THE APPLICATION OF TRANSCANADA KEYSTONE PIPELINE, LP FOR ORDER ACCEPTING CERTIFICATION OF PERMIT ISSUED IN DOCKET HP09-001 TO CONSTRUCT THE KEYSTONE XL PIPELINE

1. Are you a member of the Yankton Sioux Tribe or any other tribe?

A. I am an enrolled member of the Yankton Sioux Tribe.

2. What is your occupation or what kinds of work do you do?

A. I am the Chief of Police for the Yankton Sioux Tribe.

3. On whose behalf was this testimony prepared?

A. This testimony was prepared on behalf of the Yankton Sioux Tribe.

4. Please state the purpose of your testimony in this proceeding.

A. The purpose of my testimony is to rebut the testimony of TransCanada and its witnesses and to show that TransCanada cannot continue to meet the conditions upon which its original permit was issued. I can provide testimony about the lack of interaction or communication between TransCanada and Tribal law enforcement and emergency response personnel.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF:	)	**Docket HP 14-001**
PETITION OF TRANSCANADA KEYSTONE PIPELINE, LP FOR ORDER ACCEPTING CERTIFICATION OF PERMIT ISSUED IN DOCKET HP09-001 TO CONSTRUCT THE KEYSTONE XL PIPELINE	)	**INTERTRIBAL COUP'S PRE-FILING OF REBUTTAL WITNESS TESTIMONY OF DR. JAMES HANSEN AND DR. ROBERT OGLESBY**

Comes now the Intertribal Council On Utility Policy (COUP), by and through counsel, Robert Gough, to Pre-File Rebuttal Testimony for Dr. James Hansen and Dr. Robert Oglesby in the above entitle action by the required deadline. Attached are two statements, one from each of the Rebuttal Witnesses.

Intertribal COUP will also file a separate motion for reconsideration of the PUC's Order of May 28, 2015.

Submitted this 26th day of June 2015.

Respectfully submitted,

Robert P. Gough, SD SB# 620
Secretary of, and Attorney for,
Intertribal Council On Utility Policy (COUP)
P.O. 25, Rosebud, SD 57570
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CERTIFICATION OF SERVICE

I, Robert Gough, hereby certify that on the 26th day of June 2015, I sent by United States first-class mail, postage prepaid, or e-mail transmission, a true and correct copy of **INTERTRIBAL COUP'S PRE-FILING OF REBUTTAL WITNESS TESTIMONY OF DR. JAMES HANSEN and DR. ROBERT OGLESBY,** to the following:

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And on or about June 26, 2015, a true and accurate copy of the foregoing was mailed via U.S. Mail, first class postage prepaid, to the following:

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Bonny Kilmurry
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Elizabeth Lone Eagle
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Howes, SD 57748

Dated this 26th Day of June 2015.

Respectfully submitted,

Robert P. Gough, SD SB# 620
Secretary of, and Attorney for,
Intertribal Council On Utility Policy
P.O. 25, Rosebud, SD 57570
605-441-8316
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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

	)	
	)	
IN THE MATTER OF TRANSCANADA	)	HP14-001
KEYSTONE PIPELINE, LP	)	
FOR ORDER ACCEPTING CERTIFICATION	)	PREFILED TESTIMONY
OF PERMIT ISSUED IN DOCKET HP09-001	)	of Dr. Robert Oglesby
TO CONSTRUCT THE KEYSTONE XL	)	
PIPELINE	)	

1, Please state your name and address for the record:
Dr. Robert J. Oglesby
835 S. 36th St
Lincoln, NE 68510

2. Please state your position and area of responsibility with respect to the Keystone XL pipeline.

Expert witness on behalf of the Intertribal Council On Utility Policy

3. Please state your professional qualifications:
PhD, 1990, Yale University in Large-Scale Climate Dynamics
Professor, Purdue University 1992-2000
Senior Scientist, NASA 2001-2005
Professor, University of Nebraska Lincoln 2006-present

4. Do you believe that the conditions are the same as when the Keystone XL permit was issued in 2010?

No

5. Do you believe the Keystone XL pipeline will comply with all applicable laws and rules of the State of South Dakota and the United States?

I am not a lawyer and therefore do not know all of these laws and rules. My expertise is on the impact that the pipeline will have on the environment, and vice-versa.

6. Do you know about the 30 Changed Conditions that TransCanada Keystone has submitted with the recertification of its permit?

Yes, and I have read them.

6. Do you believe the given these 30 changed conditions Keystone XL pipeline pose a threat of serious injury to the environment of South Dakota?

Yes. South Dakota lies in the Great Plains region of the United States. Its continental, semi-arid climate is always variable and subject to extremes, and can be, at times, harsh. Despite this apparent harshness, the past 150 years of settlement (referred to as the 'historic' period) occurred under a relatively moderate climate. In particular, this past 150-year period appears to have been remarkably wet. A dominant feature of the climate of the Great Plains, including South Dakota, over the past 2,000 years is the presence of prolonged periods of drought, termed megadroughts. We have every reason to think these megadroughts will recur in the future, indeed, quite likely in the very near future. Human activities appear to be making the problem even worse, through the emission of greenhouse gases, especially carbon dioxide, into the atmosphere. The above is based on analyses of records and instrumental observations of what actually occurred. Future projections based on climate models suggest additional temperature increases for South Dakota ranging from 3-4°F (low greenhouse gas emission scenario) to 8-9°F (high emission scenario) by the end of the 21st century. Clearly, the burning of the oil transmitted by the pipeline will exacerbate global warming in coming years.

But it is also not clear that TransCanada (TC) has adequately considered the implications of the extremely variable climate of South Dakota on the physical infrastructure of the pipeline itself, such as the likelihood of increased spillage events. Even if for the present-day climate extremes such an assessment were to be performed, how would the conclusions change under an even more extreme climate? The obvious a priori assumption would be that such events would be more, not less likely to occur.

7. Do you believe that given these 30 changed conditions that Keystone XL pipeline poses a threat to the social or economic condition of inhabitants or expected inhabitants in the siting area?

Yes. The past, known record of South Dakota climate, as well as future projections suggest that these climate, extremes, for which it is already well-known, can be, well, even more extreme than anything we have already experienced. To be blunt, if we keep on the present course, by later in this century large portions of South Dakota could simply become unlivable.

8. Do you believe that given these 30 changed conditions that Keystone XL pipeline will substantially impair the health, safety or welfare of the inhabitants?

9. Do you consider federally recognized Tribes to be "local units of government?"

This is outside my area of expertise.

10. Do you believe that given these 30 changed conditions that Keystone XL pipeline will unduly interfere with the orderly development of the region with due consideration having been given to the views of the governing bodies of affected local units of government?

This is outside my area of expertise.

11. Does this conclude your prepared testimony?

Yes.

Dated this 26th Day of June, 2015.

/S/ Robert Oglesby

_____

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF TRANSCANADA KEYSTONE PIPELINE, LP FOR ORDER ACCEPTING CERTIFICATION OF PERMIT ISSUED IN DOCKET HP09-001 TO CONSTRUCT THE KEYSTONE XL PIPELINE	)	HP14-001 Comments of Dr. James E. Hansen

Members of the Commission:

I offer these Comments in opposition to the proposal before you to accept certification of a 2010 permit that this Commission issued to TransCanada Corporation to enable it to construct the Keystone XL pipeline.

By way of background, I am the Director of the Climate Science, Awareness and Solutions (CSAC) program of Columbia University's Earth Institute. I was formerly Director of the NASA Goddard Institute for Space Studies. My formal training is in physics and astronomy. Much of my scholarly work is in the area of climate science, particularly human-caused disruption of Earth's energy balance through the burning of fossil fuels and alterations in land use. I provide a reasonably complete depiction of my qualifications in Exhibit 1: James E. Hansen C.V., which I incorporate herein by reference.

Intertribal Council on Utility Policy, an Intervenor in these proceedings, sought my participation as an expert rebuttal witness, so that the Commission would consider the full implications of its proposed action with respect to the global climate system and future generations. On May 26, 2015 this Commission granted TransCanada's motion to preclude my testimony. You based your decision on a finding that my testimony would have been "beyond the scope of the certification hearing."[1] With respect, it is unfathomable to me that the law properly can be deemed to blind the Commission to consideration of the most fateful consequences of this project. I submit these Comments with the understanding that the Commission is able to reconsider its finding and, barring that, for the record on review.

My specific concern is that, if constructed and put into operation, Keystone XL will substantially increase greenhouse gas emissions and that, in turn, will increase Earth's energy imbalance, thus further disrupting the global climate system.

[1] South Dakota PUC Order Granting TransCanada's Motion to Preclude Witnesses in HP14-001 (May 28, 2015).

Others have provided or, I believe, will provide the Commission with detailed information on risks that may be imposed by crude oil spills on local natural resources, including the regional aquifer. So as to avoid duplication and to keep this comment letter to a manageable length, I will simply add my considered view that the prospect of such risks must not be discounted.

Critical conditions germane to my central concern in these Comments clearly have changed since 2010, when this Commission issued its permit for the TransCanada Keystone XL project. First, our nation and others to date have failed to constrain carbon dioxide (CO_2) emissions. In part as a consequence of that, the atmospheric concentration of CO_2 has risen well beyond the safe level. Accordingly, it is now clearer than before that there is no room for the additional emissions from the burning of the oil that this pipeline will carry to market. Instead, and indeed, the perpetuation of human civilization and nature as we have come to know it alike require a determined and rapid phase-out of fossil fuel emissions so as to avoid looming climate system tipping points.[2]

Second, it is now more apparent than in 2010 that Keystone XL will result in additional CO_2 emissions.

These changed conditions amplify the concern that the project you are now asked to affirm gravely threatens the environmental, social and economic circumstances of current and future inhabitants in the siting area, as well as that of inhabitants currently or anticipated to be outside the siting area. I believe that final action by this Commission affirming certification of the 2010 permit, and thus allowing TransCanada to complete the Keystone XL pipeline, would violate the fundamental constitutional right of young children and future generations to a habitable climate system on which they must depend for their survival and well being.

I will now briefly consider the additional CO_2 emissions that the Keystone XL project would yield, before turning to discuss the major elements of the climate crisis that, in my view, should comprise the appropriate context for any rational modern deliberation of options relevant to fossil fuel projects like Keystone XL.

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[2] Support for this point is contained in a 2013-published study that I published in conjunction with 17 colleagues, entitled "Assessing "Dangerous Climate Change": Required Reduction of Carbon Emissions to Protect Young People, Future Generations and Nature" (hereinafter "Dangerous Climate Change"). I have attached *Dangerous Climate Change* as Exhibit 2, and hereby incorporate its information and analysis by reference into these Comments. For convenience of the reader, that study may also be found here: www.plosone.org/article/info%3Adoi%2F10.1371%2Fjournal.pone.0081648.

A. Keystone XL Pipeline and Additional CO_2 Emissions

As the U.S. Government and others have pointed out, oil sands crude "has significantly higher lifecycle greenhouse gas emissions than other crudes."[3] The implication of this is that development and exploitation of the tar sands will yield up to an additional 27.4 MMTCO_2-e/year, or 1.37 billion MMT CO_2-e additional emissions for the 50-year lifetime of the pipeline.[4]

In 2014, however, the U.S. State Department's concluded, that although oil sands development and use will lead to increased GHG emissions, the Keystone XL pipeline itself would not increase emissions because, it presumed, the carbon-dense oil sands would be exploited regardless of the pipeline. But the State Department's presumption was based on its expectation that oil prices would stay high.[5] If long-term prices fell to less than $75/barrel, the expense of alternative transport to market, namely rail, would render oil sands exploitation uneconomic. Thus, the implications of the State Department's analysis is that the Keystone XL pipeline is essential to economic exploitation of oil sands crude where long-term market prices are below $75/barrel. In its most recent letter pointing out the State Department's elementary errors, the Environmental Protection Agency noted that "oil was trading at below $50 per barrel."[6]

Accordingly, I think it fair to conclude that the Keystone XL pipeline is essential to oil sands exploitation at reasonably foreseeable crude market prices. It is thus also fair to attribute to the Keystone XL project those additional GHG emissions, as discussed above, that will result from oil sands development and consumption.

Finally, in this brief review, there is the too-little considered interaction with world oil prices and the impact on demand. As the Stockholm Environment Institute recently pointed out, in the event Keystone XL is completed the increase in

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[3] U.S. State Department, Final Supplemental Environmental Impact Statement for the Keystone XL Project (January 2014) Executive Summary, ES-15. *See also* EPA letter to State (Feb. 2, 2015) at 2. ("The Final SEIS states that lifecycle greenhouse gas emissions from development and use of oil sands crude is about 17% greater than emissions from average crude oil refined in the United States on a wells-to-wheels basis.").

[4] *Id*.

[5] FSEIS Executive Summary, p. ES-12 ("Above approximately $75 per barrel for West Texas Intermediate (WTI)-equivalent oil, revenues to oil sands producers are likely to remain above the long-run supply costs of most projects responsible for expected levels of oil sands production growth.").

[6] Feb. 2, 2015 EPA Letter at 3. At the time of the writing, June 22, 2015, crude was trading at $59 per barrel. It has remained below $75 per barrel since late November 2014. *See* http://www.bloomberg.com/quote/CL1:COM (1Y Time Frame) and http://www.nasdaq.com/markets/crude-oil.aspx?timeframe=1y.

crude oil supply will depress the global market price. That in turn will spur global consumption "by as much as 510,000 barrels per day," resulting in increased emissions from this market effect alone by as much as 93 MMTCO_2-e per year.[7] If the Institute's analysis is correct, then the 50-year lifespan of the Keystone XL pipeline will produce additional emissions amounting to as much as 4.65 trillion tCO_2-e, a climate pollution load more than three times the outer limit of that which can be pieced together from the State Department's FSEIS.

Accordingly, we must conclude that, if allowed by the Commission and other authorities, the massive private investment in Keystone XL will accomplish what TransCanada Corporation clearly aims to achieve, namely, additional exploitation of the Alberta oil sands. This will result in increased CO_2 emissions stemming both from the burning of oil extracted from those deposits, and from the increased demand for crude being sold at a depressed global market price.

B. THE CLIMATE CRISIS, AND THE ROAD TO CLIMATE STABILITY

As indicated above, a study that I published along with colleagues in late-2013 provides a detailed treatment of our present predicament and the route that must be taken to sufficiently reduce atmospheric CO_2 to preserve a habitable climate system. In the following, I outline the signal features of the problem and that prescription.

First: Human burning of fossil fuels has disrupted Earth's energy balance, and in response the planet is heating up – with no end in sight, unless we alter our present path. Atmospheric CO_2 concentration, for example, is now at its highest level in 3 million years, and global surface temperatures now have reached the prior maximum of the Holocene era, the period of relatively moderate climate that, over the last 10,000 years, has enabled civilization to develop.

Second: We are observing impacts of the relatively small amount of warming that has already occurred, and these constitute harbingers of far more dangerous change to come. We can discuss the observable consequences, and their implications. But the key point is that, if unabated, continued carbon emissions will initiate dynamic climate change and effects that spin out of control of future generations as the planet's energy imbalance triggers amplifying feedbacks and the climate system and biological system pass critical tipping points.

Third: There is still time and opportunity to preserve a habitable climate system -- if we pursue a rational course. I will outline the glide path that we think remains feasible, though much further delay in taking effective action will consign that effort to failure. Objectively, then, the situation is urgent and what governments and other decision-makers do, or do not do, today to reduce carbon pollution matters immensely.

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[7] Stockholm Environment Institute, Working Paper 2013-11 at pp. 4-5.

I. Our Planet is Now Out of Energy Balance

Chart 1 shows global fossil fuel CO_2 emissions on an annual basis from the burning of coal, oil, and natural gas, and from cement production and flaring, along with the total emissions from these major sources. [*See* Appendix 1 to this comment letter for charts.]

Although it is more than twenty years since 170 nations agreed to limit fossil fuel emissions in order to avoid dangerous human-made climate change, the stark reality – as illustrated here – is that global emissions have accelerated. Specifically, the growth rate of fossil fuel emissions increased from 1.5%/year during 1980–2000 to 3%/year in 2000–2013, mainly because of increased use of coal.

Our increased emissions are reflected, at least in part, in the rising concentration of atmospheric CO_2, which is now approximately 400 ppm, over 40 percent more than the preindustrial level.

Moreover, the increase in the atmospheric CO_2 concentration is itself speeding up, as is illustrated in Chart 2. The graphic, by NOAA's Earth System Research Laboratory, shows a doubling, over the last half-century, of the average annual increase in the concentration of atmospheric of CO_2 to 2ppm per year.

This increased concentration of CO_2 and other GHGs in the atmosphere operates to reduce Earth's heat radiation to space, thus causing an energy imbalance – less energy going out than coming in. This imbalance causes Earth to heat-up until it again radiates as much energy to space as it absorbs from the sun.

In point of fact, warming of Earth caused by the increasingly thick CO_2 "blanket" persisted even during the recent five-year solar minimum of 2005-2010. Had changes in insolation been the dominant forcing, the planet would have had a negative energy balance in that period, when solar irradiance was at its lowest level in the period of accurate data, i.e., since the 1970s. Instead, even though much of the greenhouse gas forcing had been expended in causing observed 0.8°C global warming, the residual positive forcing overwhelmed the negative solar forcing.

This illustrates, unequivocally, that it is human activity, and not the sun, that is the dominant driver of recent climate change.

Turning, now to Chart 3, we see the upward march of recent average global surface temperature. Earth has now warmed about 0.8°C above the pre-industrial level. That is now close to, and probably slightly above, the prior maximum of the Holocene era – the period of relatively stable climate over the last 10,000 years that has enabled civilization to develop.

That warming increases Earth's radiation to space, thus reducing Earth's energy imbalance. However, because of the ocean's great thermal inertia, it requires centuries for the climate system to reach a new equilibrium consistent with a changed atmospheric composition. The planet's energy imbalance confirms that substantial additional warming is "in the pipeline". That energy imbalance is now measured by an international fleet of more than 3000 submersible floats that plumb the depths of the world's ocean measuring the increasing heat content.

Earth's energy imbalance now averages about 0.6 Watts/m2 averaged over the entire planet, but I am uncertain whether this conveys to the Commission the scale of what is going on. I can note that the total energy surplus is 300 trillion joules per second, but that large number may still be insufficiently evocative. Accordingly, it may be more useful to observe, and with equal validity, that Earth's energy imbalance is equivalent to exploding more than 400,000 Hiroshima atomic bombs per day, 365 days per year. That is how much extra energy Earth is now gaining each day because of our use of the atmosphere as a waste dump for our carbon pollution.

We can turn now to Chart 4. Here, we summarize the average global surface temperature record of the last 65 million years. This record is based on high-resolution ice core data covering the most recent several hundred thousand years, and ocean cores on time scales of millions of years. That record provides us with insight as to global temperature sensitivity to external forcings such as added CO_2, and sea level sensitivity to global temperature. It also provides quantitative information about so-called "slow" feedback processes – such as melting ice sheets and lessened surface reflectivity attributable to the darker surfaces resulting from the melting ice sheets and reduced area of ice.

Several relevant conclusions can be drawn. First, the mechanisms that account for the relatively rapid oscillations between cold and warm climates were the same as those operating today. Those past climate oscillations were initiated not by fossil fuel burning, but by slow insolation changes attributable to perturbations of Earth's orbit and spin axis tilt. However, the mechanisms that caused these historical climate changes to be so large were two powerful amplifying feedbacks: the planet's surface albedo (its reflectivity, literally its whiteness) and atmospheric CO_2.

Second, the longer paleoclimate record shows that warming coincident with atmospheric CO_2 concentrations as low as 450-500 ppm may have been enough to melt most of Antarctica. Our emissions have already driven up the CO_2 concentration in the atmosphere to about 400 ppm from 280 ppm of the preindustrial era.

I conclude that the present level of CO_2 and its warming effect, both realized and latent, is already in the dangerous zone. Indeed, we are now in a period of overshoot, with early consequences that are already hazardous and that will rise to

severe unless action is taken without delay to restore energy balance at a lower atmospheric CO_2 amount.

All that said, we can turn now to a brief review of these increasingly unacceptable, but still avoidable, consequences.

II. Climate Change May Devastate Life As We Know It, Absent Effective Action

As I earlier noted, global warming to date measures "only" 0.8°C above the pre-industrial period. And yet, that level of warming has already led to a 40 percent reduction of Arctic sea ice cover at the end of the melt season, and an even faster decline in sea ice thickness.

Mountain glaciers, the source of fresh water to major world rivers during dry seasons, already are receding rapidly all around the world. To cite a close-to-home example, glaciers in iconic Glacier National Park appear to be in full retreat: In 1850, according to the Park Service, Glacier had 150 glaciers measuring larger than twenty-five acres. Today, it has just twenty-five.

As well, tropospheric water vapor and heavy precipitation events have increased, as we would expect. A warmer atmosphere holds more moisture, thus enabling precipitation to be heavier and cause more extreme flooding. Higher temperatures, on the other hand, increase evaporation and can intensify droughts when they occur, as can the expansion of the subtropics that occurs as a consequence of global warming.

Coral reef ecosystems, harboring more than 1,000,000 species as the "rainforests" of the ocean, are impacted by a combination of ocean warming, acidification from rising atmospheric CO2, and other human-caused stresses, resulting in a 0.5-2% per year decline in geographic extent.

World health experts have concluded with "very high confidence" that climate change already contributes to the global burden of disease and premature death with expansion of infectious disease vectors. Increasing climate variability is being examined as a possible contributor to the expansion of Ebola.

Subtropical climate belts have expanded, contributing to more intense droughts, summer heat waves, and devastating wildfires. Further, summer mega-heat-waves, such as those in Europe in 2003, the Moscow area in 2010, Texas and Oklahoma in 2011, Greenland in 2012, and Australia in 2013 have become more widespread with the increase demonstrably linked to global warming. The probability of such extreme heat events has increased by several times because of global warming, and the probability will increase even further if global warming continues to increase.

Recent estimates of sea level rise by 2100 have been on the order of 1 meter, which is higher than earlier assessments. However, these estimates still in part assume linear relations between warming and sea level rise. It is likely that continued business-as-usual CO_2 emissions will spur a nonlinear response, with multi-meter sea level rise realized this century. Needless to say, we are not close to being prepared for that. Very recent research that colleagues and I have undertaken serves to underscore this danger and, with the Commission's leave, I will supplement this Comment letter with that detailed study upon its publication and ask that it be included in the record of these proceedings.

Turning, then, to Charts 5 and 6: measurement reveals that both Greenland and Antarctica have been losing mass at rapidly increasing rates during the period of accurate satellite data, i.e., approximately the last 20 years.

Recently published data indicate that, in the most recent 3-year period, the combined volume loss for Greenland and Antarctica is approximately 500 km3/yr. Greenland has contributed nearly 75% of that loss. Red areas in Charts 5 and 6 mark locations of ice sheet loss over the period, while blue areas mark ice gains as a result of increased snowfall associated with higher amounts of atmospheric water vapor. As noted, the two ice sheets together appear now to be thinning at a rate of 500 cubic kilometers per year – the highest rate of ice thinning that has been observed.

A word about the atmospheric residence time of CO_2 is in order, and we can do that with the aid of Chart 7.

A pulse of CO_2 injected into the air decays by half in about 25 years, as CO_2 is taken up by the ocean, biosphere and soil, but nearly one-fifth remains in the atmosphere after 500 years. Indeed, that estimate is likely optimistic, in light of the well-known nonlinearity in ocean chemistry and saturation of carbon sinks, implying that the airborne fraction probably will remain larger for a century and more. It requires hundreds of millennia for the chemical weathering of rocks to eventually deposit all of this initial CO_2 pulse on the ocean floor as carbonate sediments.

The critical point here is that carbon from fossil fuel burning remains in the climate system, with much of it in the atmosphere, and thus continues to affect the climate system for many millennia, ensuring that over time sea level rise of many meters will occur – tens of meters if most of the fossil fuels are burned.

That order of sea level rise would result in the loss of hundreds of historical coastal cities worldwide, with incalculable economic consequences. It would also create hundreds of millions of global warming refugees from highly populated low-lying areas, and thus likely cause or exacerbate major international conflicts.

We have seen, in the past decade, that sea level increased about 3cm—a rate of about one foot per century, nearly twice as fast as the rate of increase during the preceding century. This rise in the sea has resulted in losses of coastal wetland areas and greater levels of damage from coastal flooding. For example, in Louisiana, increased sea level and regional land subsidence have led to the loss of 1900 square miles of coastal wetland, which in turn exacerbates the area's vulnerability to storm surges as occurred during Hurricane Katrina.

Other impacts abound. Acidification stemming from ocean uptake of a portion of increased atmospheric CO_2 will increasingly disrupt coral reef ecosystem health, with potentially devastating impacts to certain nations and communities. Inland, fresh water security will be compromised, due to the effects of receding mountain glaciers and snowpack on seasonal freshwater availability of major rivers.

As to human health: increasing concentrations of CO_2 and associated increased global temperatures will deepen impacts, with children being especially vulnerable. Climate threats to health move through various pathways, including by placing additional stress on the availability of food, clean air, and clean water. Accordingly, unabated climate change will increase malnutrition and consequent disorders, including those related to child growth and development, increased death, disease and injuries from heat waves, floods, storms, fires and droughts, and increased cardio-respiratory morbidity and mortality associated with increased ground-level ozone.

With regard to other species, we see that climate zones are already shifting at rates that exceed natural rates of change; this trend will continue as long as the planet is out of energy balance. As the shift of climate zones becomes comparable to the range of some species, the less mobile species will be driven to extinction. According to the UN Panel on Climate Change, with global warming of 1.6°C or more relative to pre-industrial levels, 9-31 percent of species are anticipated to be driven to extinction, while with global warming of 2.9°C, an estimated 21-52 percent of species will be driven to extinction. These temperature/extinction thresholds will not be avoided absent concerted, rational action on carbon emissions.

At present, we remain on track to burn a significant fraction of readily available fossil fuels, including coal and tar sands, and so to raise average surface temperature, over time, to far above pre-industrial levels.

High global surface temperatures have been recorded previously, in the age of mammals, with some successful adaptation through evolution of higher surface-area-to-mass ratio body types -- for example transient dwarfing of mammals and even soil fauna. However, human-made warming is occurring rapidly and will be fully realized in only centuries, as opposed to millennia, thus providing little opportunity for evolutionary dwarfism to alleviate impacts of global warming. Along with several colleagues, I have been forced to conclude that the large climate

change that will result from burning all or most fossil fuels threatens the survival of humanity.

Which brings me to my third and last point.

III. Restoration of Our Climate System, and so Protection of Our Future, Is Still Possible, But We Must Act With Reason, Courage, and No Further Delay.

As I indicated above, the energy imbalance of Earth is about 0.6 W/m2. In the light of that imbalance, colleagues and I have calculated the level to which atmospheric CO_2 must be drawn down in order to increase Earth's heat radiation to space by the same amount and thus restore energy balance -- the fundamental requirement to stabilize climate and avoid further dangerous warming.

The measured energy imbalance indicates that CO_2 must be reduced to a level below 350 ppm, assuming that the net of other human-made climate forcings remains at today's level. Specification now of a CO_2 target more precise than <350 ppm is difficult due to uncertain future changes of radiative forcing from other gases, aerosols and surface albedo, but greater precision should be feasible during the time that it takes to turn around CO_2 growth and approach the initial 350 ppm target.

Let us return, for a moment, to Chart 7, so as to consider again the question of delay. On the left side of the chart, the long-residence time for atmospheric CO_2 is illustrated. It is reflected in the length of time it would take to return CO_2 to lower concentrations even if, as indicated on the right side of the chart, fossil fuel emissions were to cease entirely.

Of course, an abrupt cessation of all CO_2 emissions, whether in 2015 or 2030, is unrealistic. Industry, other business, and consumers all need time to retool and reinvest in emission-free options to fossil fuels.

Accordingly, we have evaluated emissions reduction scenarios to devise the path that is both technically and economically feasible, while being sufficiently rigorous to constrain the period of "carbon overshoot" and avoid calamitous consequences (greatly accelerating warming, ecosystem collapse, and widespread species extermination). See Chart 8. Our analysis constitutes the best science available on the subject, and prescribes a glide path towards achieving energy balance by the end of the century. It is characterized by large, long-term emissions reductions (of approximately 6 percent annually), coupled with programs to limit and reverse land use emissions via reforestation and improved agricultural and forestry practices (drawing down approximately 100 GtC by the year 2100).

These actions could achieve the goal of restoring the atmosphere to approximately 350 ppm within this century if the plan were commenced without delay, and then adhered to. As I have indicated, such action is minimally needed to

restore earth's energy balance, preserve the planet's climate system, and avert irretrievable damage to human and natural systems – including agriculture, ocean fisheries, and fresh water supply -- on which civilization depends. However, consistent with the abrupt phase out scenarios discussed in the prior paragraph supra, if rapid annual emission reductions are delayed until 2030, then the global temperature will remain more than 1°C higher than preindustrial levels for about 400 years. Were the emissions cessation only to commence after 40 years, then the atmosphere would not return to 350 ppm CO_2 for nearly 1000 years. Overshooting the safe level of atmospheric CO_2 and the safe range of global ambient temperature for anything approaching these periods will consign succeeding generations to a vastly different, less hospitable planet.

Considered another way, the required rate of emissions reduction would have been about 3.5% per year if reductions had started in 2005 and continued annually thereafter, while the required rate of reduction, if commenced in 2020, will be approximately 15% per year. Accordingly, the dominant factor is the date at which fossil fuel emission phase out begins, again presuming the rate of annual emissions reductions thereafter are sustained.

C. CONCLUSION

Based on the above, I think it is clear that a decision by this Commission to certify the Keystone XL pipeline permit will shove the planet hard towards, and perhaps beyond, climate tipping points of no return. Moreover, I think there is no question but that, once approved and operational, the TransCanada Corporation will fight tooth and nail to keep KXL open and pumping, notwithstanding the increasingly overwhelming evidence that burning the crude that it will bring to market threatens our children, the unborn, future generations, and the natural world as we have known it.

My colleagues and I have outlined a fundamentally different course, one that, if vigorously pursued, could restore Earth's energy balance and preserve a habitable climate system. Delay in its adoption will defeat those prospects.

TransCanada's ringing demand for certification, on the other hand, constitutes a death knell for the planet. Reject it to help secure a viable future for our children.

Thank you for your consideration.

Dated this 22 Day of June, 2015.

James E Hansen

Dr. James E. Hansen

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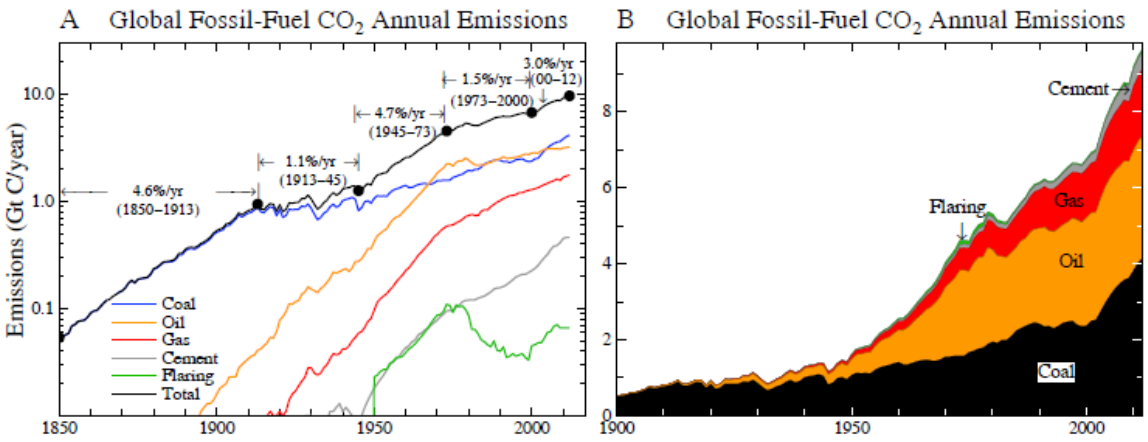

Chart 1.

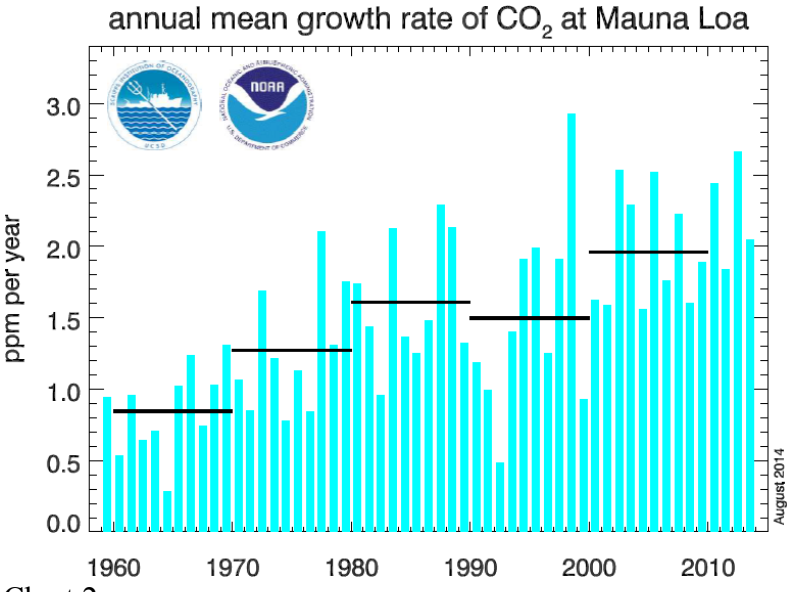

Chart 2.

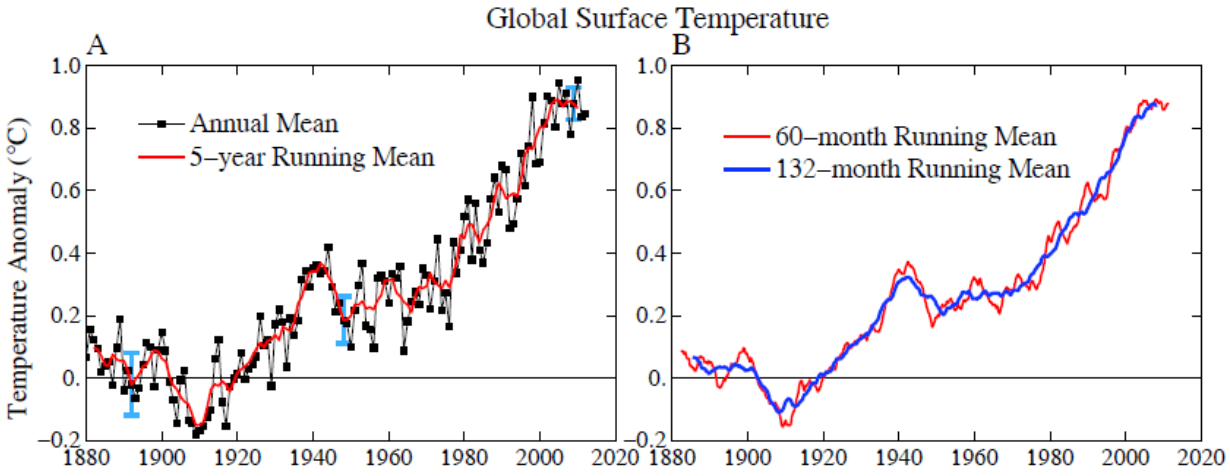

Chart 3.

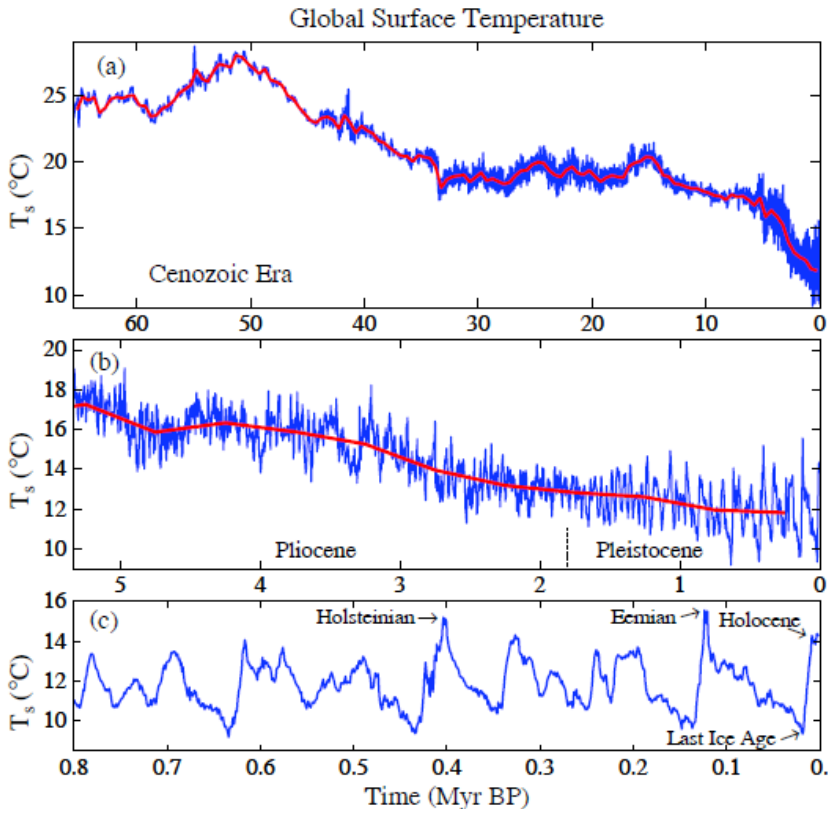

Chart 4.

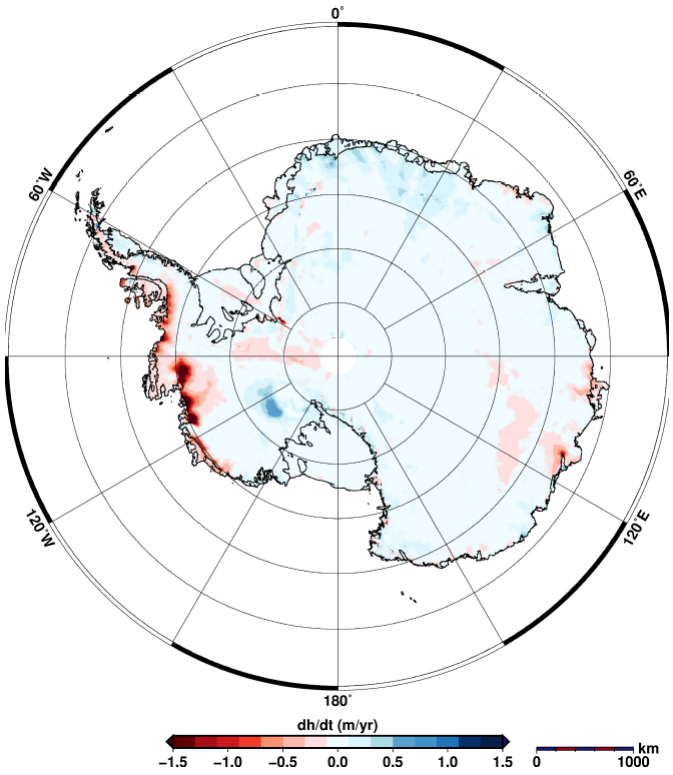

Chart 5.

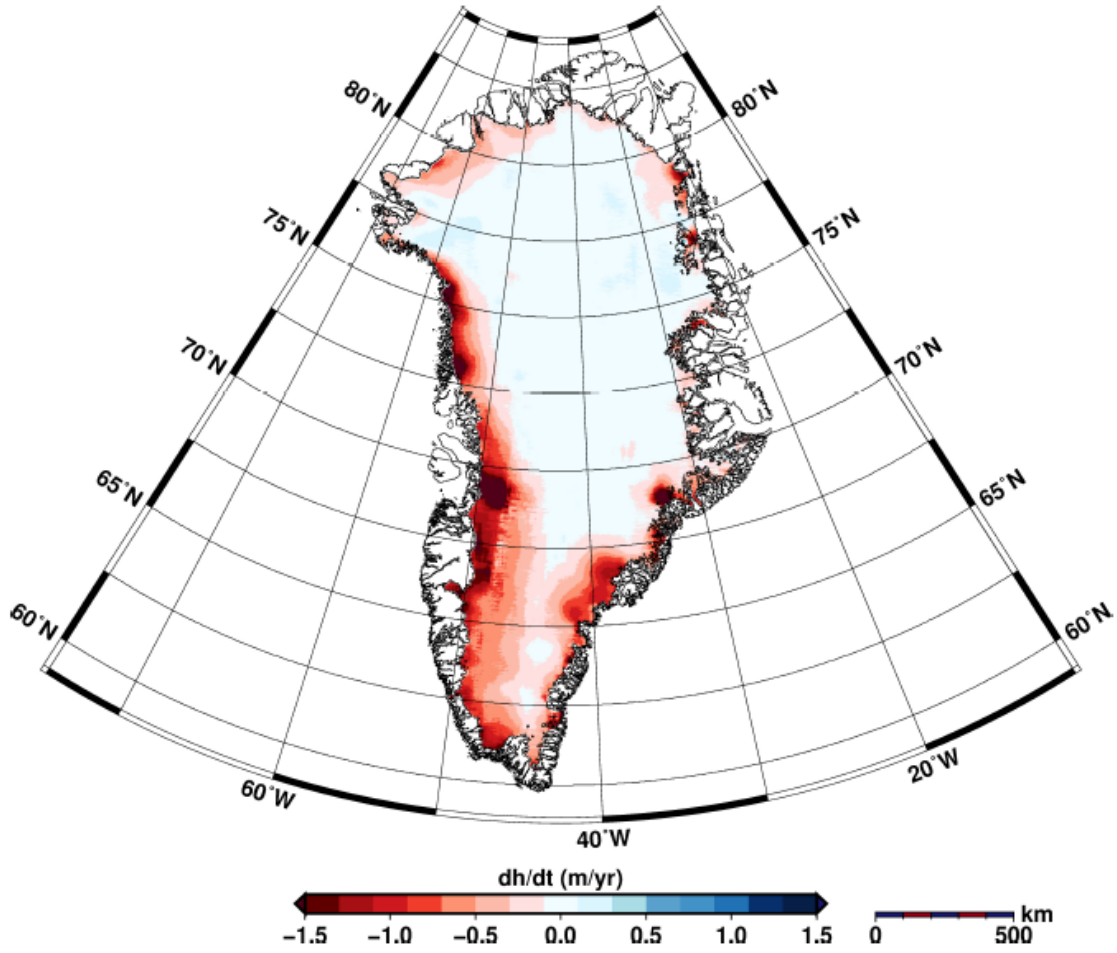
80˚N
75˚N
70˚N
65˚N
60˚N
60˚W
40˚W
20˚W
dh/dt (m/yr)
−1.5
−1.0
−0.5
0.0
0.5
1.0
1.5
km
0
500

CHART 6

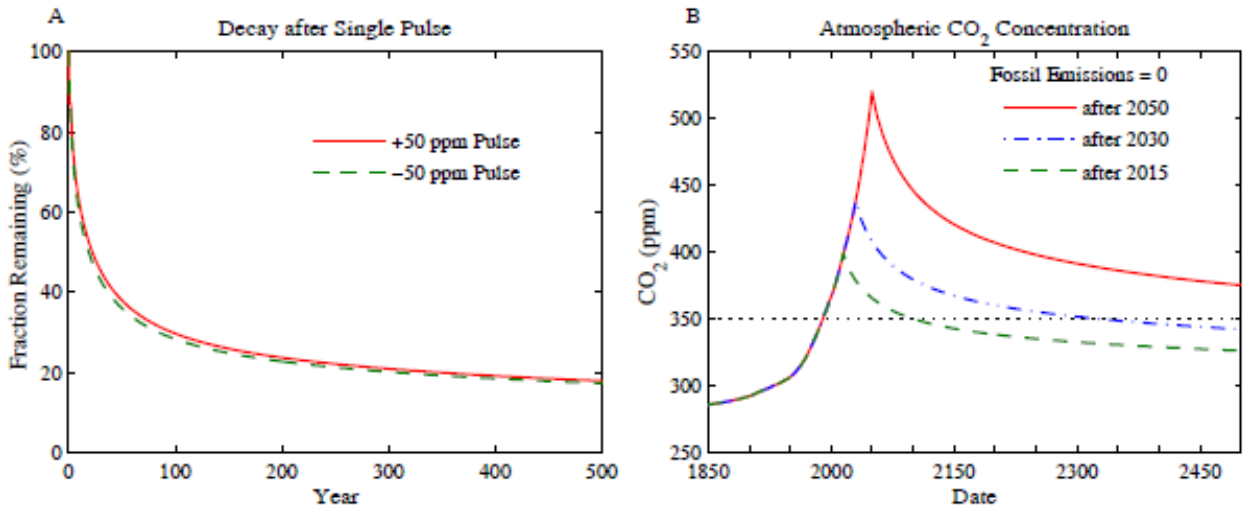

Chart 7.

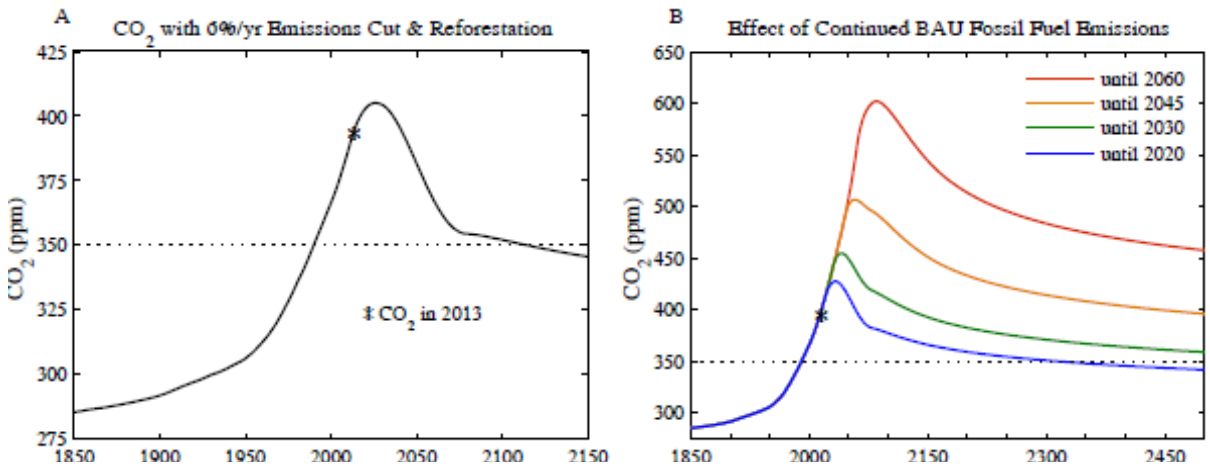

Chart 8.

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Education:

BA with highest distinction (Physics and Mathematics), University of Iowa, 1963
MS (Astronomy), University of Iowa, 1965
Visiting student, Inst. of Astrophysics, University of Kyoto & Dept. of Astronomy, Tokyo University, Japan, 1965-1966
Ph.D. (Physics), University of Iowa, 1967

Research Interests:

Analysis of the causes and consequences of global climate change using the Earth's paleoclimate history, ongoing global observations, and interpretive tools including climate models. Connecting the dots all the way from climate observations to the policies that are needed to stabilize climate and preserve our planet for young people and other species.

Professional Employment:

1967-1969	NAS-NRC Resident Research Associate: Goddard Institute for Space Studies (GISS), NY
1969	NSF Postdoctoral Fellow: Leiden Observatory, Netherlands
1969-1972	Research Associate: Columbia University, NY
1972-1981	Staff Member/Space Scientist: Goddard Institute for Space Studies (GISS), Manager of GISS Planetary and Climate Programs
1978-1985	Adjunct Associate Professor: Department of Geological Sciences, Columbia University
1981-2013	Director: NASA Goddard Institute for Space Studies
1985-present	Adjunct Professor: Earth and Environmental Sciences, Columbia University
2013-present	Director: Program on Climate Science, Awareness and Solutions, Columbia University

Project Experience:

1971-1974	Co-Principal Investigator AEROPOL Project (airborne terrestrial infrared polarimeter)
1972-1985	Co-Investigator, Voyager Photopolarimeter Experiment
1974-1994	Principal Investigator (1974-8) and subsequently Co-Investigator, Pioneer Venus Orbiter Cloud-Photopolarimeter Experiment
1977-2000	Principal Investigator, Galileo (Jupiter Orbiter) Photopolarimeter Radiometer Experiment

Teaching Experience:

Atmospheric Radiation (graduate level): New York Univ., Dept. of Meteorology & Oceanography
Intro. to Planetary Atmospheres & Climate Change: Columbia Univ., Dept. of Geological Sciences

Awards:

1977	Goddard Special Achievement Award (Pioneer Venus)
1978	NASA Group Achievement Award (Voyager, Photopolarimeter)
1984	NASA Exceptional Service Medal (Radiative Transfer)
1989	National Wildlife Federation Conservation Achievement Award
1990	NASA Presidential Rank Award of Meritorious Executive
1991	University of Iowa Alumni Achievement Award
1992	American Geophysical Union Fellow
1993	NASA Group Achievement Award (Galileo, Polarimeter/Radiometer)
1996	Elected to National Academy of Sciences
1996	GSFC William Nordberg Achievement Medal
1996	Editor' Citation for Excellence in Refereeing for Geophysical Research Letters
1997	NASA Presidential Rank Award of Meritorious Executive
2000	University of Iowa Alumni Fellow
2000	GISS Best Scientific Publication (peer vote): 'Global warming - alternative scenario'
2001	John Heinz Environment Award
2001	Roger Revelle Medal, American Geophysical Union
2004	GISS Best Scientific Publication (peer vote): 'Soot Climate Forcing'
2005	GISS Best Scientific Publication (peer vote): 'Earth's Energy Imbalance'
2006	Duke of Edinburgh Conservation Medal, World Wildlife Fund (WWF)
2006	GISS Best Scientific Publication (peer vote): 'Global Temperature Change'
2006	*Time Magazine* designation as one of World's 100 Most Influential People.

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2007	Laureate, Dan David Prize for Outstanding Achievements & Impacts in Quest for Energy
2007	Leo Szilard Award, American Physical Society for Outstanding Promotion & Use of Physics for the Benefit of Society
2007	Haagen-Smit Clean Air Award
2008	American Association for the Advancement of Science Award for Scientific Freedom and Responsibility
2008	Nevada Medal, Desert Research Institute
2008	Common Wealth Award for Distinguished Service in Science
2008	Bownocker Medal, Ohio State University
2008	Rachel Carson Award for Integrity in Science, Center for Science in the Public Interest
2009	Carl-Gustaf Rossby Research Medal, American Meteorological Society
2009	Peter Berle Environmental Integrity Award
2010	Sophie Prize for Environmental and Sustainable Development
2010	Blue Planet Prize, Asahi Glass Foundation
2011	American Association of Physics Teachers Klopsteg Memorial Award for communicating physics to the general public.
2011	Edinburgh Medal from City of Edinburgh, Edinburgh Science Festival
2012	Steve Schneider Climate Science Communications Award
2012	*Foreign Policy* designation as one of its Top 100 Global Thinkers
2013	Ridenhour Courage Prize

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Rockström, J., W. Steffen, K. Noone, Å. Persson, F.S. Chapin, III, E.F. Lambin, T.M. Lenton, M. Scheffer, C. Folke, H.J. Schellnhuber, B. Nykvist, C.A. de Wit, T. Hughes, S. van der Leeuw, H. Rodhe, S. Sörlin, P.K. Snyder, R. Costanza, U. Svedin, M. Falkenmark, L. Karlberg, R.W. Corell, V.J. Fabry, J. Hansen, B. Walker, D. Liverman, K. Richardson, P. Crutzen, and J.A. Foley, 2009: A safe operating space for humanity. *Nature*, **461**, 472-475, doi:10.1038/461472a.

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Review

Assessing "Dangerous Climate Change": Required Reduction of Carbon Emissions to Protect Young People, Future Generations and Nature

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Abstract: We assess climate impacts of global warming using ongoing observations and paleoclimate data. We use Earth's measured energy imbalance, paleoclimate data, and simple representations of the global carbon cycle and temperature to define emission reductions needed to stabilize climate and avoid potentially disastrous impacts on today's young people, future generations, and nature. A cumulative industrial-era limit of ~500 GtC fossil fuel emissions and 100 GtC storage in the biosphere and soil would keep climate close to the Holocene range to which humanity and other species are adapted. Cumulative emissions of ~1000 GtC, sometimes associated with 2°C global warming, would spur "slow" feedbacks and eventual warming of 3–4°C with disastrous consequences. Rapid emissions reduction is required to restore Earth's energy balance and avoid ocean heat uptake that would practically guarantee irreversible effects. Continuation of high fossil fuel emissions, given current knowledge of the consequences, would be an act of extraordinary witting intergenerational injustice. Responsible policymaking requires a rising price on carbon emissions that would preclude emissions from most remaining coal and unconventional fossil fuels and phase down emissions from conventional fossil fuels.

Introduction

Humans are now the main cause of changes of Earth's atmospheric composition and thus the drive for future climate change [1]. The principal climate forcing, defined as an imposed change of planetary energy balance [1–2], is increasing carbon dioxide (CO_2) from fossil fuel emissions, much of which will remain in the atmosphere for millennia [1,3]. The climate response to this forcing and society's response to climate change are complicated by the system's inertia, mainly due to the ocean and the ice sheets on Greenland and Antarctica together with the long residence time of fossil fuel carbon in the climate system. The inertia causes climate to appear to respond slowly to this human-made forcing, but further long-lasting responses can be locked in.

More than 170 nations have agreed on the need to limit fossil fuel emissions to avoid dangerous human-made climate change, as formalized in the 1992 Framework Convention on Climate Change [6]. However, the stark reality is that global emissions have accelerated (Fig. 1) and new efforts are underway to massively expand fossil fuel extraction [7–9] by drilling to increasing ocean depths and into the Arctic, squeezing oil from tar sands and tar shale, hydro-fracking to expand extraction of natural gas, developing exploitation of methane hydrates, and mining of coal via mountaintop removal and mechanized long-wall mining. The growth rate of fossil fuel emissions increased from 1.5%/year during 1980–2000 to 3%/year in 2000–2012, mainly because of increased coal use [4–5].

The Framework Convention [6] does not define a dangerous level for global warming or an emissions limit for fossil fuels. The

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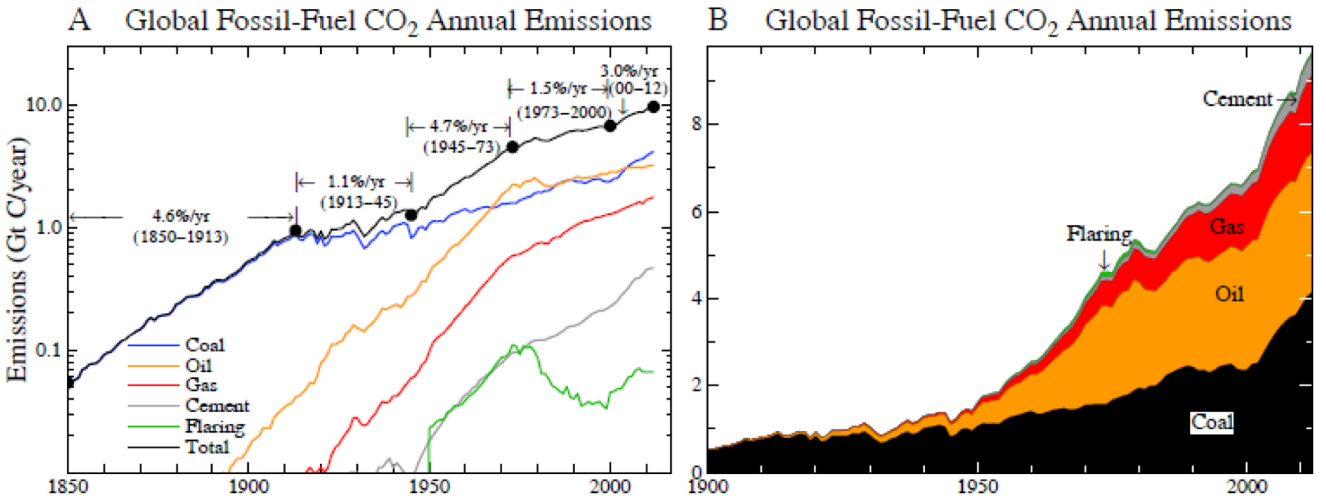

Figure 1. CO_2 annual emissions from fossil fuel use and cement manufacture, based on data of British Petroleum [4] concatenated with data of Boden et al. [5]. (A) is log scale and (B) is linear.
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European Union in 1996 proposed to limit global warming to 2°C relative to pre-industrial times [10], based partly on evidence that many ecosystems are at risk with larger climate change. The 2°C target was reaffirmed in the 2009 "Copenhagen Accord" emerging from the 15th Conference of the Parties of the Framework Convention [11], with specific language "We agree that deep cuts in global emissions are required according to science, as documented in the IPCC Fourth Assessment Report with a view to reduce global emissions so as to hold the increase in global temperature below 2 degrees Celsius…".

A global warming target is converted to a fossil fuel emissions target with the help of global climate-carbon-cycle models, which reveal that eventual warming depends on cumulative carbon emissions, not on the temporal history of emissions [12]. The emission limit depends on climate sensitivity, but central estimates [12–13], including those in the upcoming Fifth Assessment of the Intergovernmental Panel on Climate Change [14], are that a 2°C global warming limit implies a cumulative carbon emissions limit of the order of 1000 GtC. In comparing carbon emissions, note that some authors emphasize the sum of fossil fuel and deforestation carbon. We bookkeep fossil fuel and deforestation carbon separately, because the larger fossil fuel term is known more accurately and this carbon stays in the climate system for hundreds of thousands of years. Thus fossil fuel carbon is the crucial human input that must be limited. Deforestation carbon is more uncertain and potentially can be offset on the century time scale by storage in the biosphere, including the soil, via reforestation and improved agricultural and forestry practices.

There are sufficient fossil fuel resources to readily supply 1000 GtC, as fossil fuel emissions to date (370 GtC) are only a small fraction of potential emissions from known reserves and potentially recoverable resources (Fig. 2). Although there are uncertainties in reserves and resources, ongoing fossil fuel subsidies and continuing technological advances ensure that more and more of these fuels will be economically recoverable. As we will show, Earth's paleoclimate record makes it clear that the CO_2 produced by burning all or most of these fossil fuels would lead to a very different planet than the one that humanity knows.

Our evaluation of a fossil fuel emissions limit is not based on climate models but rather on observational evidence of global climate change as a function of global temperature and on the fact that climate stabilization requires long-term planetary energy balance. We use measured global temperature and Earth's measured energy imbalance to determine the atmospheric CO_2 level required to stabilize climate at today's global temperature, which is near the upper end of the global temperature range in the current interglacial period (the Holocene). We then examine climate impacts during the past few decades of global warming and in paleoclimate records including the Eemian period, concluding that there are already clear indications of undesirable impacts at the current level of warming and that 2°C warming would have major deleterious consequences. We use simple representations of the carbon cycle and global temperature, consistent with observations, to simulate transient global temperature and assess carbon emission scenarios that could keep global climate near the Holocene range. Finally, we discuss likely overshooting of target emissions, the potential for carbon extraction from the atmosphere, and implications for energy and economic policies, as well as intergenerational justice.

Global Temperature and Earth's Energy Balance

Global temperature and Earth's energy imbalance provide our most useful measuring sticks for quantifying global climate change and the changes of global climate forcings that would be required to stabilize global climate. Thus we must first quantify knowledge of these quantities.

Temperature

Temperature change in the past century (Fig. 3; update of figures in [16]) includes unforced variability and forced climate change. The long-term global warming trend is predominantly a forced climate change caused by increased human-made atmospheric gases, mainly CO_2 [1]. Increase of "greenhouse" gases such as CO_2 has little effect on incoming sunlight but makes the atmosphere more opaque at infrared wavelengths, causing infrared (heat) radiation to space to emerge from higher, colder levels, which thus reduces infrared radiation to space. The resulting planetary energy imbalance, absorbed solar energy exceeding heat emitted to space, causes Earth to warm. Observations, discussed below, confirm that Earth is now substantially out of energy balance, so the long-term warming will continue.

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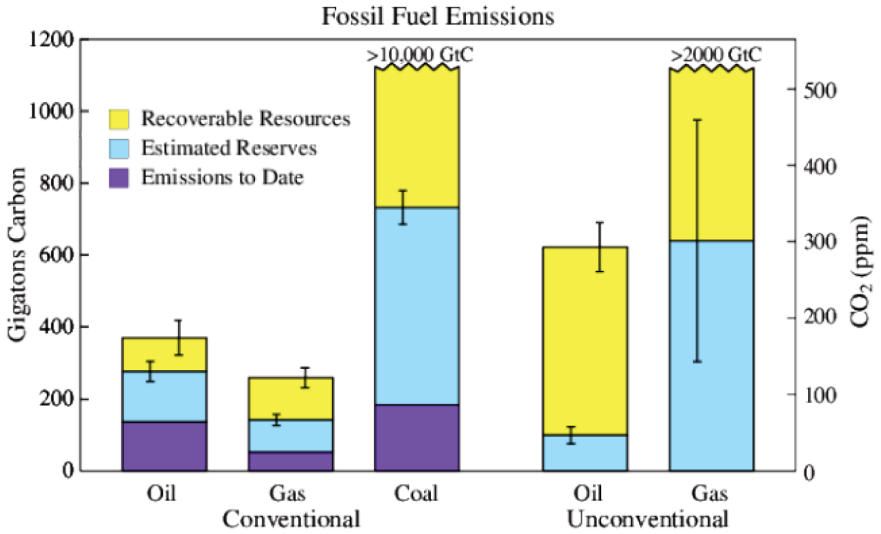

Figure 2. Fossil fuel CO_2 emissions and carbon content (1 ppm atmospheric CO_2 ~ 2.12 GtC). Estimates of reserves (profitable to extract at current prices) and resources (potentially recoverable with advanced technology and/or at higher prices) are the mean of estimates of Energy Information Administration (EIA) [7], German Advisory Council (GAC) [8], and Global Energy Assessment (GEA) [9]. GEA [9] suggests the possibility of >15,000 GtC unconventional gas. Error estimates (vertical lines) are from GEA and probably underestimate the total uncertainty. We convert energy content to carbon content using emission factors of Table 4.2 of [15] for coal, gas and conventional oil, and, also following [15], emission factor of unconventional oil is approximated as being the same as for coal. Total emissions through 2012, including gas flaring and cement manufacture, are 384 GtC; fossil fuel emissions alone are ~370 GtC.
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Global temperature appears to have leveled off since 1998 (Fig. 3a). That plateau is partly an illusion due to the 1998 global temperature spike caused by the El Niño of the century that year. The 11-year (132-month) running mean temperature (Fig. 3b) shows only a moderate decline of the warming rate. The 11-year averaging period minimizes the effect of variability due to the 10–12 year periodicity of solar irradiance as well as irregular El Niño/La Niña warming/cooling in the tropical Pacific Ocean. The current solar cycle has weaker irradiance than the several prior solar cycles, but the decreased irradiance can only partially account for the decreased warming rate [17]. Variability of the El Niño/La Niña cycle, described as a Pacific Decadal Oscillation, largely accounts for the temporary decrease of warming [18], as we discuss further below in conjunction with global temperature simulations.

Assessments of dangerous climate change have focused on estimating a permissible level of global warming. The Intergovernmental Panel on Climate Change [1,19] summarized broad-based assessments with a "burning embers" diagram, which indicated that major problems begin with global warming of 2–3°C. A probabilistic analysis [20], still partly subjective, found a median "dangerous" threshold of 2.8°C, with 95% confidence that the dangerous threshold was 1.5°C or higher. These assessments were relative to global temperature in year 1990, so add 0.6°C to these values to obtain the warming relative to 1880–1920, which is the base period we use in this paper for preindustrial time. The conclusion that humanity could tolerate global warming up to a few degrees Celsius meshed with common sense. After all, people readily tolerate much larger regional and seasonal climate variations.

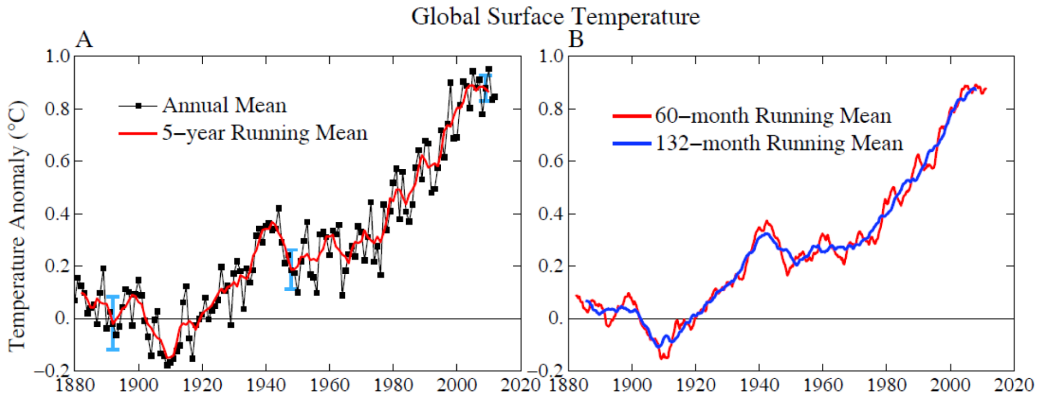

Figure 3. Global surface temperature relative to 1880–1920 mean. B shows the 5 and 11 year means. Figures are updates of [16] using data through August 2013.
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The fallacy of this logic emerged recently as numerous impacts of ongoing global warming emerged and as paleoclimate implications for climate sensitivity became apparent. Arctic sea ice end-of-summer minimum area, although variable from year to year, has plummeted by more than a third in the past few decades, at a faster rate than in most models [21], with the sea ice thickness declining a factor of four faster than simulated in IPCC climate models [22]. The Greenland and Antarctic ice sheets began to shed ice at a rate, now several hundred cubic kilometers per year, which is continuing to accelerate [23–25]. Mountain glaciers are receding rapidly all around the world [26–29] with effects on seasonal freshwater availability of major rivers [30–32]. The hot dry subtropical climate belts have expanded as the troposphere has warmed and the stratosphere cooled [33–36], contributing to increases in the area and intensity of drought [37] and wildfires [38]. The abundance of reef-building corals is decreasing at a rate of 0.5–2%/year, at least in part due to ocean warming and possibly ocean acidification caused by rising dissolved CO_2 [39–41]. More than half of all wild species have shown significant changes in where they live and in the timing of major life events [42–44]. Mega-heatwaves, such as those in Europe in 2003, the Moscow area in 2010, Texas and Oklahoma in 2011, Greenland in 2012, and Australia in 2013 have become more widespread with the increase demonstrably linked to global warming [45–47].

These growing climate impacts, many more rapid than anticipated and occurring while global warming is less than 1°C, imply that society should reassess what constitutes a "dangerous level" of global warming. Earth's paleoclimate history provides a valuable tool for that purpose.

Paleoclimate Temperature

Major progress in quantitative understanding of climate change has occurred recently by use of the combination of data from high resolution ice cores covering time scales of order several hundred thousand years [48–49] and ocean cores for time scales of order one hundred million years [50]. Quantitative insights on global temperature sensitivity to external forcings [51–52] and sea level sensitivity to global temperature [52–53] are crucial to our analyses. Paleoclimate data also provide quantitative information about how nominally slow feedback processes amplify climate sensitivity [51–52,54–56], which also is important to our analyses.

Earth's surface temperature prior to instrumental measurements is estimated via proxy data. We will refer to the surface temperature record in Fig. 4 of a recent paper [52]. Global mean temperature during the Eemian interglacial period (120,000 years ago) is constrained to be 2°C warmer than our pre-industrial (1880–1920) level based on several studies of Eemian climate [52]. The concatenation of modern and instrumental records [52] is based on an estimate that global temperature in the first decade of the 21st century (+0.8°C relative to 1880–1920) exceeded the Holocene mean by 0.25±0.25°C. That estimate was based in part on the fact that sea level is now rising 3.2 mm/yr (3.2 m/millennium) [57], an order of magnitude faster than the rate during the prior several thousand years, with rapid change of ice sheet mass balance over the past few decades [23] and Greenland and Antarctica now losing mass at accelerating rates [23–24]. This concatenation, which has global temperature 13.9°C in the base period 1951–1980, has the first decade of the 21st century slightly (~0.1°C) warmer than the early Holocene maximum. A recent reconstruction from proxy temperature data [55] concluded that global temperature declined about 0.7°C between the Holocene maximum and a pre-industrial minimum before recent warming brought temperature back near the Holocene maximum, which is consistent with our analysis.

Climate oscillations evident in Fig. 4 of Hansen et al. [52] were instigated by perturbations of Earth's orbit and spin axis tilt relative to the orbital plane, which alter the geographical and seasonal distribution of sunlight on Earth [58]. These forcings change slowly, with periods between 20,000 and 400,000 years, and thus climate is able to stay in quasi-equilibrium with these forcings. Slow insolation changes initiated the climate oscillations, but the mechanisms that caused the climate changes to be so large were two powerful amplifying feedbacks: the planet's surface albedo (its reflectivity, literally its whiteness) and atmospheric CO_2 amount. As the planet warms, ice and snow melt, causing the surface to be darker, absorb more sunlight and warm further. As the ocean and soil become warmer they release CO_2 and other greenhouse gases, causing further warming. Together with fast feedbacks processes, via changes of water vapor, clouds, and the vertical temperature profile, these slow amplifying feedbacks were responsible for almost the entire glacial-to-interglacial temperature change [59–62].

The albedo and CO_2 feedbacks amplified weak orbital forcings, the feedbacks necessarily changing slowly over millennia, at the pace of orbital changes. Today, however, CO_2 is under the control of humans as fossil fuel emissions overwhelm natural changes. Atmospheric CO_2 has increased rapidly to a level not seen for at least 3 million years [56,63]. Global warming induced by increasing CO_2 will cause ice to melt and hence sea level to rise as the global volume of ice moves toward the quasi-equilibrium amount that exists for a given global temperature [53]. As ice melts and ice area decreases, the albedo feedback will amplify global warming.

Earth, because of the climate system's inertia, has not yet fully responded to human-made changes of atmospheric composition. The ocean's thermal inertia, which delays some global warming for decades and even centuries, is accounted for in global climate models and its effect is confirmed via measurements of Earth's energy balance (see next section). In addition there are slow climate feedbacks, such as changes of ice sheet size, that occur mainly over centuries and millennia. Slow feedbacks have little effect on the immediate planetary energy balance, instead coming into play in response to temperature change. The slow feedbacks are difficult to model, but paleoclimate data and observations of ongoing changes help provide quantification.

Earth's Energy Imbalance

At a time of climate stability, Earth radiates as much energy to space as it absorbs from sunlight. Today Earth is out of balance because increasing atmospheric gases such as CO_2 reduce Earth's heat radiation to space, thus causing an energy imbalance, as there is less energy going out than coming in. This imbalance causes Earth to warm and move back toward energy balance. The warming and restoration of energy balance take time, however, because of Earth's thermal inertia, which is due mainly to the global ocean.

Earth warmed about 0.8°C in the past century. That warming increased Earth's radiation to space, thus reducing Earth's energy imbalance. The remaining energy imbalance helps us assess how much additional warming is still "in the pipeline". Of course increasing CO_2 is only one of the factors affecting Earth's energy balance, even though it is the largest climate forcing. Other forcings include changes of aerosols, solar irradiance, and Earth's surface albedo.

Determination of the state of Earth's climate therefore requires measuring the energy imbalance. This is a challenge, because the imbalance is expected to be only about 1 W/m^2 or less, so accuracy approaching 0.1 W/m^2 is needed. The most promising

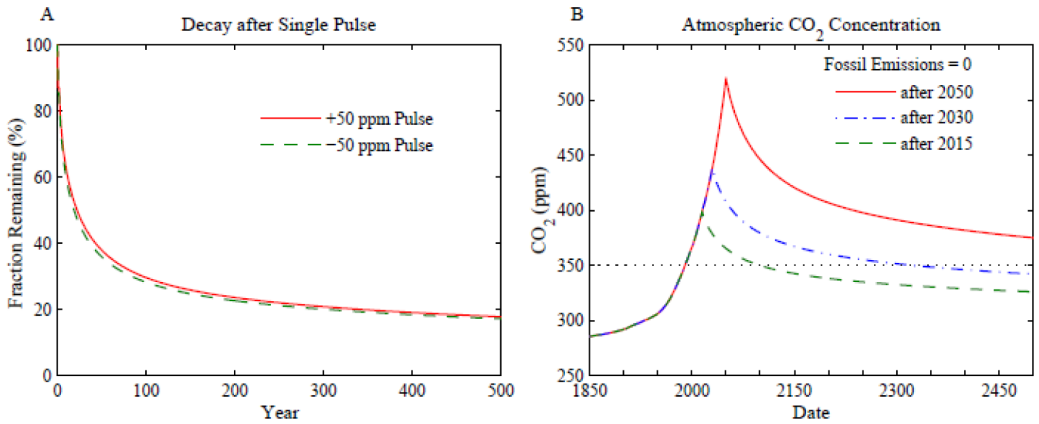

Figure 4. Decay of atmospheric CO_2 perturbations. (A) Instantaneous injection or extraction of CO_2 with initial conditions at equilibrium. (B) Fossil fuel emissions terminate at the end of 2015, 2030, or 2050 and land use emissions terminate after 2015 in all three cases, i.e., thereafter there is no net deforestation.
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approach is to measure the rate of changing heat content of the ocean, atmosphere, land, and ice [64]. Measurement of ocean heat content is the most critical observation, as nearly 90 percent of the energy surplus is stored in the ocean [64–65].

Observed Energy Imbalance

Nations of the world have launched a cooperative program to measure changing ocean heat content, distributing more than 3000 Argo floats around the world ocean, with each float repeatedly diving to a depth of 2 km and back [66]. Ocean coverage by floats reached 90% by 2005 [66], with the gaps mainly in sea ice regions, yielding the potential for an accurate energy balance assessment, provided that several systematic measurement biases exposed in the past decade are minimized [67–69].

Argo data reveal that in 2005–2010 the ocean's upper 2000 m gained heat at a rate equal to 0.41 W/m^2 averaged over Earth's surface [70]. Smaller contributions to planetary energy imbalance are from heat gain by the deeper ocean (+0.10 W/m^2), energy used in net melting of ice (+0.05 W/m^2), and energy taken up by warming continents (+0.02 W/m^2). Data sources for these estimates and uncertainties are provided elsewhere [64]. The resulting net planetary energy imbalance for the six years 2005–2010 is +0.58±0.15 W/m^2.

The positive energy imbalance in 2005–2010 confirms that the effect of solar variability on climate is much less than the effect of human-made greenhouse gases. If the sun were the dominant forcing, the planet would have a negative energy balance in 2005–2010, when solar irradiance was at its lowest level in the period of accurate data, i.e., since the 1970s [64,71]. Even though much of the greenhouse gas forcing has been expended in causing observed 0.8°C global warming, the residual positive forcing overwhelms the negative solar forcing. The full amplitude of solar cycle forcing is about 0.25 W/m^2 [64,71], but the reduction of solar forcing due to the present weak solar cycle is about half that magnitude as we illustrate below, so the energy imbalance measured during solar minimum (0.58 W/m^2) suggests an average imbalance over the solar cycle of about 0.7 W/m^2.

Earth's measured energy imbalance has been used to infer the climate forcing by aerosols, with two independent analyses yielding a forcing in the past decade of about −1.5 W/m^2 [64,72], including the direct aerosol forcing and indirect effects via induced cloud changes. Given this large (negative) aerosol forcing, precise monitoring of changing aerosols is needed [73]. Public reaction to increasingly bad air quality in developing regions [74] may lead to future aerosol reductions, at least on a regional basis. Increase of Earth's energy imbalance from reduction of particulate air pollution, which is needed for the sake of human health, can be minimized via an emphasis on reducing absorbing black soot [75], but the potential to constrain the net increase of climate forcing by focusing on black soot is limited [76].

Energy Imbalance Implications for CO_2 Target

Earth's energy imbalance is the most vital number characterizing the state of Earth's climate. It informs us about the global temperature change "in the pipeline" without further change of climate forcings and it defines how much greenhouse gases must be reduced to restore Earth's energy balance, which, at least to a good approximation, must be the requirement for stabilizing global climate. The measured energy imbalance accounts for all natural and human-made climate forcings, including changes of atmospheric aerosols and Earth's surface albedo.

If Earth's mean energy imbalance today is +0.5 W/m^2, CO_2 must be reduced from the current level of 395 ppm (global-mean annual-mean in mid-2013) to about 360 ppm to increase Earth's heat radiation to space by 0.5 W/m^2 and restore energy balance. If Earth's energy imbalance is 0.75 W/m^2, CO_2 must be reduced to about 345 ppm to restore energy balance [64,75].

The measured energy imbalance indicates that an initial CO_2 target "<350 ppm" would be appropriate, if the aim is to stabilize climate without further global warming. That target is consistent with an earlier analysis [54]. Additional support for that target is provided by our analyses of ongoing climate change and paleoclimate, in later parts of our paper. Specification now of a CO_2 target more precise than <350 ppm is difficult and unnecessary, because of uncertain future changes of forcings including other gases, aerosols and surface albedo. More precise assessments will become available during the time that it takes to turn around CO_2 growth and approach the initial 350 ppm target.

Below we find the decreasing emissions scenario that would achieve the 350 ppm target within the present century. Specifically, we want to know the annual percentage rate at which emissions must be reduced to reach this target, and the dependence of this rate upon the date at which reductions are initiated. This approach is complementary to the approach of estimating cumulative emissions allowed to achieve a given limit on global warming [12].

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If the only human-made climate forcing were changes of atmospheric CO_2, the appropriate CO_2 target might be close to the pre-industrial CO_2 amount [53]. However, there are other human forcings, including aerosols, the effect of aerosols on clouds, non-CO_2 greenhouse gases, and changes of surface albedo that will not disappear even if fossil fuel burning is phased out. Aerosol forcings are substantially a result of fossil fuel burning [1,76], but the net aerosol forcing is a sensitive function of various aerosol sources [76]. The indirect aerosol effect on clouds is non-linear [1,76] such that it has been suggested that even the modest aerosol amounts added by pre-industrial humans to an otherwise pristine atmosphere may have caused a significant climate forcing [59]. Thus continued precise monitoring of Earth's radiation imbalance is probably the best way to assess and adjust the appropriate CO_2 target.

Ironically, future reductions of particulate air pollution may exacerbate global warming by reducing the cooling effect of reflective aerosols. However, a concerted effort to reduce non-CO_2 forcings by methane, tropospheric ozone, other trace gases, and black soot might counteract the warming from a decline in reflective aerosols [54,75]. Our calculations below of future global temperature assume such compensation, as a first approximation. To the extent that goal is not achieved, adjustments must be made in the CO_2 target or future warming may exceed calculated values.

Climate Impacts

Determination of the dangerous level of global warming inherently is partly subjective, but we must be as quantitative as possible. Early estimates for dangerous global warming based on the "burning embers" approach [1,19–20] have been recognized as probably being too conservative [77]. A target of limiting warming to 2°C has been widely adopted, as discussed above. We suspect, however, that this may be a case of inching toward a better answer. If our suspicion is correct, then that gradual approach is itself very dangerous, because of the climate system's inertia. It will become exceedingly difficult to keep warming below a target smaller than 2°C, if high emissions continue much longer.

We consider several important climate impacts and use evidence from current observations to assess the effect of 0.8°C warming and paleoclimate data for the effect of larger warming, especially the Eemian period, which had global mean temperature about +2°C relative to pre-industrial time. Impacts of special interest are sea level rise and species extermination, because they are practically irreversible, and others important to humankind.

Sea Level

The prior interglacial period, the Eemian, was at most ~2°C warmer than 1880–1920 (Fig. 3). Sea level reached heights several meters above today's level [78–80], probably with instances of sea level change of the order of 1 m/century [81–83]. Geologic shoreline evidence has been interpreted as indicating a rapid sea level rise of a few meters late in the Eemian to a peak about 9 meters above present, suggesting the possibility that a critical stability threshold was crossed that caused polar ice sheet collapse [84–85], although there remains debate within the research community about this specific history and interpretation. The large Eemian sea level excursions imply that substantial ice sheet melting occurred when the world was little warmer than today.

During the early Pliocene, which was only ~3°C warmer than the Holocene, sea level attained heights as much as 15–25 meters higher than today [53,86–89]. Such sea level rise suggests that parts of East Antarctica must be vulnerable to eventual melting with global temperature increase of a few degrees Celsius. Indeed, satellite gravity data and radar altimetry reveal that the Totten Glacier of East Antarctica, which fronts a large ice mass grounded below sea level, is now losing mass [90].

Greenland ice core data suggest that the Greenland ice sheet response to Eemian warmth was limited [91], but the fifth IPCC assessment [14] concludes that Greenland very likely contributed between 1.4 and 4.3 m to the higher sea level of the Eemian. The West Antarctic ice sheet is probably more susceptible to rapid change, because much of it rests on bedrock well below sea level [92–93]. Thus the entire 3–4 meters of global sea level contained in that ice sheet may be vulnerable to rapid disintegration, although arguments for stability of even this marine ice sheet have been made [94]. However, Earth's history reveals sea level changes of as much as a few meters per century, even though the natural climate forcings changed much more slowly than the present human-made forcing.

Expected human-caused sea level rise is controversial in part because predictions focus on sea level at a specific time, 2100. Sea level on a given date is inherently difficult to predict, as it depends on how rapidly non-linear ice sheet disintegration begins. Focus on a single date also encourages people to take the estimated result as an indication of what humanity faces, thus failing to emphasize that the likely rate of sea level rise immediately after 2100 will be much larger than within the 21st century, especially if CO_2 emissions continue to increase.

Recent estimates of sea level rise by 2100 have been of the order of 1 m [95–96], which is higher than earlier assessments [26], but these estimates still in part assume linear relations between warming and sea level rise. It has been argued [97–98] that continued business-as-usual CO_2 emissions are likely to spur a nonlinear response with multi-meter sea level rise this century. Greenland and Antarctica have been losing mass at rapidly increasing rates during the period of accurate satellite data [23]; the data are suggestive of exponential increase, but the records are too short to be conclusive. The area on Greenland with summer melt has increased markedly, with 97% of Greenland experiencing melt in 2012 [99].

The important point is that the uncertainty is not about whether continued rapid CO_2 emissions would cause large sea level rise, submerging global coastlines – it is about how soon the large changes would begin. The carbon from fossil fuel burning will remain in and affect the climate system for many millennia, ensuring that over time sea level rise of many meters will occur – tens of meters if most of the fossil fuels are burned [53]. That order of sea level rise would result in the loss of hundreds of historical coastal cities worldwide with incalculable economic consequences, create hundreds of millions of global warming refugees from highly-populated low-lying areas, and thus likely cause major international conflicts.

Shifting Climate Zones

Theory and climate models indicate that the tropical overturning (Hadley) atmospheric circulation expands poleward with global warming [33]. There is evidence in satellite and radiosonde data and in observational data for poleward expansion of the tropical circulation by as much as a few degrees of latitude since the 1970s [34–35], but natural variability may have contributed to that expansion [36]. Change in the overturning circulation likely contributes to expansion of subtropical conditions and increased aridity in the southern United States [30,100], the Mediterranean region, South America, southern Africa, Madagascar, and southern Australia. Increased aridity and temperature contribute to increased forest fires that burn hotter and are more destructive [38].

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Despite large year-to-year variability of temperature, decadal averages reveal isotherms (lines of a given average temperature) moving poleward at a typical rate of the order of 100 km/decade in the past three decades [101], although the range shifts for specific species follow more complex patterns [102]. This rapid shifting of climate zones far exceeds natural rates of change. Movement has been in the same direction (poleward, and upward in elevation) since about 1975. Wild species have responded to climate change, with three-quarters of marine species shifting their ranges poleward as much as 1000 km [44,103] and more than half of terrestrial species shifting ranges poleward as much as 600 km and upward as much as 400 m [104].

Humans may adapt to shifting climate zones better than many species. However, political borders can interfere with human migration, and indigenous ways of life already have been adversely affected [26]. Impacts are apparent in the Arctic, with melting tundra, reduced sea ice, and increased shoreline erosion. Effects of shifting climate zones also may be important for indigenous Americans who possess specific designated land areas, as well as other cultures with long-standing traditions in South America, Africa, Asia and Australia.

Human Extermination of Species

Biodiversity is affected by many agents including overharvesting, introduction of exotic species, land use changes, nitrogen fertilization, and direct effects of increased atmospheric CO_2 on plant ecophysiology [43]. However, an overriding role of climate change is exposed by diverse effects of rapid warming on animals, plants, and insects in the past three decades.

A sudden widespread decline of frogs, with extinction of entire mountain-restricted species attributed to global warming [105–106], provided a dramatic awakening. There are multiple causes of the detailed processes involved in global amphibian declines and extinctions [107–108], but global warming is a key contributor and portends a planetary-scale mass extinction in the making unless action is taken to stabilize climate while also fighting biodiversity's other threats [109].

Mountain-restricted and polar-restricted species are particularly vulnerable. As isotherms move up the mountainside and poleward, so does the climate zone in which a given species can survive. If global warming continues unabated, many of these species will be effectively pushed off the planet. There are already reductions in the population and health of Arctic species in the southern parts of the Arctic, Antarctic species in the northern parts of the Antarctic, and alpine species worldwide [43].

A critical factor for survival of some Arctic species is retention of all-year sea ice. Continued growth of fossil fuel emissions will cause loss of all Arctic summer sea ice within several decades. In contrast, the scenario in Fig. 5A, with global warming peaking just over 1°C and then declining slowly, should allow summer sea ice to survive and then gradually increase to levels representative of recent decades.

The threat to species survival is not limited to mountain and polar species. Plant and animal distributions reflect the regional climates to which they are adapted. Although species attempt to migrate in response to climate change, their paths may be blocked by human-constructed obstacles or natural barriers such as coast lines and mountain ranges. As the shift of climate zones [110] becomes comparable to the range of some species, less mobile species can be driven to extinction. Because of extensive species interdependencies, this can lead to mass extinctions.

Rising sea level poses a threat to a large number of uniquely evolved endemic fauna living on islands in marine-dominated ecosystems, with those living on low lying islands being especially vulnerable. Evolutionary history on Bermuda offers numerous examples of the direct and indirect impact of changing sea level on evolutionary processes [111–112], with a number of taxa being extirpated due to habitat changes, greater competition, and island inundation [113]. Similarly, on Aldahabra Island in the Indian Ocean, land tortoises were exterminated during sea level high stands [114]. Vulnerabilities would be magnified by the speed of human-made climate change and the potentially large sea level rise [115].

IPCC [26] reviewed studies relevant to estimating eventual extinctions. They estimate that if global warming exceeds 1.6°C above preindustrial, 9–31 percent of species will be committed to extinction. With global warming of 2.9°C, an estimated 21–52 percent of species will be committed to extinction. A comprehensive study of biodiversity indicators over the past decade [116] reveals that, despite some local success in increasing extent of protected areas, overall indicators of pressures on biodiversity including that due to climate change are continuing to increase and indicators of the state of biodiversity are continuing to decline.

Mass extinctions occurred several times in Earth's history [117–118], often in conjunction with rapid climate change. New species evolved over millions of years, but those time scales are almost beyond human comprehension. If we drive many species to extinction we will leave a more desolate, monotonous planet for our children, grandchildren, and more generations than we can imagine. We will also undermine ecosystem functions (e.g., pollination which is critical for food production) and ecosystem resilience (when losing keystone species in food chains), as well as reduce functional diversity (critical for the ability of ecosystems to respond to shocks and stress) and genetic diversity that plays an important role for development of new medicines, materials, and sources of energy.

Coral Reef Ecosystems

Coral reefs are the most biologically diverse marine ecosystem, often described as the rainforests of the ocean. Over a million species, most not yet described [119], are estimated to populate coral reef ecosystems generating crucial ecosystem services for at least 500 million people in tropical coastal areas. These ecosystems are highly vulnerable to the combined effects of ocean acidification and warming.

Acidification arises as the ocean absorbs CO_2, producing carbonic acid [120], thus making the ocean more corrosive to the calcium carbonate shells (exoskeletons) of many marine organisms. Geochemical records show that ocean pH is already outside its range of the past several million years [121–122]. Warming causes coral bleaching, as overheated coral expel symbiotic algae and become vulnerable to disease and mortality [123]. Coral bleaching and slowing of coral calcification already are causing mass mortalities, increased coral disease, and reduced reef carbonate accretion, thus disrupting coral reef ecosystem health [40,124].

Local human-made stresses add to the global warming and acidification effects, all of these driving a contraction of 1–2% per year in the abundance of reef-building corals [39]. Loss of the three-dimensional coral reef frameworks has consequences for all the species that depend on them. Loss of these frameworks also has consequences for the important roles that coral reefs play in supporting fisheries and protecting coastlines from wave stress. Consequences of lost coral reefs can be economically devastating for many nations, especially in combination with other impacts such as sea level rise and intensification of storms.

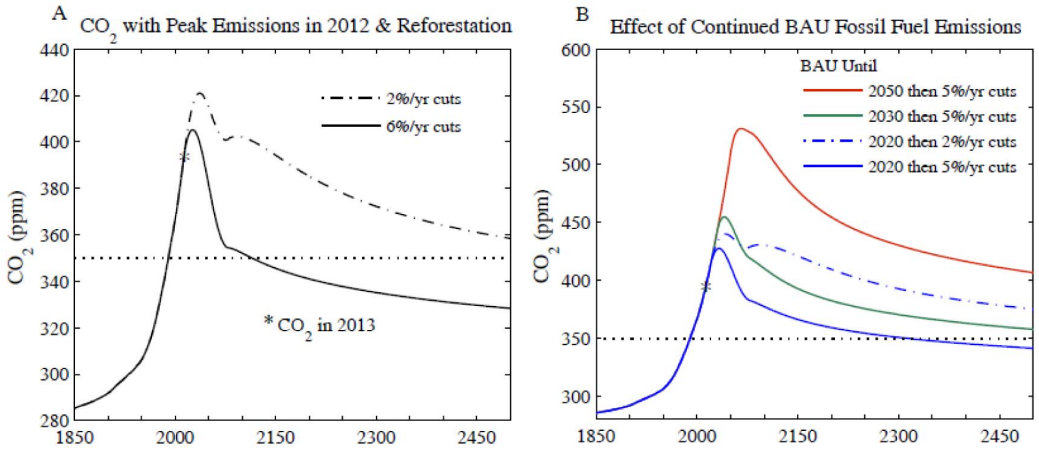

Figure 5. Atmospheric CO_2 if fossil fuel emissions reduced. (A) 6% or 2% annual cut begins in 2013 and 100 GtC reforestation drawdown occurs in 2031–2080, (B) effect of delaying onset of emission reduction.
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Climate Extremes

Changes in the frequency and magnitude of climate extremes, of both moisture and temperature, are affected by climate trends as well as changing variability. Extremes of the hydrologic cycle are expected to intensify in a warmer world. A warmer atmosphere holds more moisture, so precipitation can be heavier and cause more extreme flooding. Higher temperatures, on the other hand, increase evaporation and can intensify droughts when they occur, as can expansion of the subtropics, as discussed above. Global models for the 21st century find an increased variability of precipitation minus evaporation [P-E] in most of the world, especially near the equator and at high latitudes [125]. Some models also show an intensification of droughts in the Sahel, driven by increasing greenhouse gases [126].

Observations of ocean salinity patterns for the past 50 years reveal an intensification of [P-E] patterns as predicted by models, but at an even faster rate. Precipitation observations over land show the expected general increase of precipitation poleward of the subtropics and decrease at lower latitudes [1,26]. An increase of intense precipitation events has been found on much of the world's land area [127–129]. Evidence for widespread drought intensification is less clear and inherently difficult to confirm with available data because of the increase of time-integrated precipitation at most locations other than the subtropics. Data analyses have found an increase of drought intensity at many locations [130–131] The magnitude of change depends on the drought index employed [132], but soil moisture provides a good means to separate the effect of shifting seasonal precipitation and confirms an overall drought intensification [37].

Global warming of ~0.6°C since the 1970s (Fig. 3) has already caused a notable increase in the occurrence of extreme summer heat [46]. The likelihood of occurrence or the fractional area covered by 3-standard-deviation hot anomalies, relative to a base period (1951–1980) that was still within the range of Holocene climate, has increased by more than a factor of ten. Large areas around Moscow, the Mediterranean region, the United States and Australia have experienced such extreme anomalies in the past three years. Heat waves lasting for weeks have a devastating impact on human health: the European heat wave of summer 2003 caused over 70,000 excess deaths [133]. This heat record for Europe was surpassed already in 2010 [134]. The number of extreme heat waves has increased several-fold due to global warming [45–46,135] and will increase further if temperatures continue to rise.

Human Health

Impacts of climate change cause widespread harm to human health, with children often suffering the most. Food shortages, polluted air, contaminated or scarce supplies of water, an expanding area of vectors causing infectious diseases, and more intensely allergenic plants are among the harmful impacts [26]. More extreme weather events cause physical and psychological harm. World health experts have concluded with "very high confidence" that climate change already contributes to the global burden of disease and premature death [26].

IPCC [26] projects the following trends, if global warming continue to increase, where only trends assigned very high confidence or high confidence are included: (i) increased malnutrition and consequent disorders, including those related to child growth and development, (ii) increased death, disease and injuries from heat waves, floods, storms, fires and droughts, (iii) increased cardio-respiratory morbidity and mortality associated with ground-level ozone. While IPCC also projects fewer deaths from cold, this positive effect is far outweighed by the negative ones.

Growing awareness of the consequences of human-caused climate change triggers anxiety and feelings of helplessness [136–137]. Children, already susceptible to age-related insecurities, face additional destabilizing insecurities from questions about how they will cope with future climate change [138–139]. Exposure to media ensures that children cannot escape hearing that their future and that of other species is at stake, and that the window of opportunity to avoid dramatic climate impacts is closing. The psychological health of our children is a priority, but denial of the truth exposes our children to even greater risk.

Health impacts of climate change are in addition to direct effects of air and water pollution. A clear illustration of direct effects of fossil fuels on human health was provided by an inadvertent experiment in China during the 1950–1980 period of central planning, when free coal for winter heating was provided to North China but not to the rest of the country. Analysis of the impact was made [140] using the most comprehensive data file ever compiled on mortality and air pollution in any developing country. A principal conclusion was that the 500 million residents of North China experienced during the 1990s a loss of more than 2.5 billion life years owing to the added air pollution, and an average reduction in life expectancy of 5.5 years. The degree of air pollution in China exceeded that in most of the world, yet

assessments of total health effects must also include other fossil fuel caused air and water pollutants, as discussed in the following section on ecology and the environment.

The Text S1 has further discussion of health impacts of climate change.

Ecology and the Environment

The ecological impact of fossil fuel mining increases as the largest, easiest to access, resources are depleted [141]. A constant fossil fuel production rate requires increasing energy input, but also use of more land, water, and diluents, with the production of more waste [142]. The increasing ecological and environmental impact of a given amount of useful fossil fuel energy is a relevant consideration in assessing alternative energy strategies.

Coal mining has progressively changed from predominantly underground mining to surface mining [143], including mountaintop removal with valley fill, which is now widespread in the Appalachian ecoregion in the United States. Forest cover and topsoil are removed, explosives are used to break up rocks to access coal, and the excess rock is pushed into adjacent valleys, where it buries existing streams. Burial of headwater streams causes loss of ecosystems that are important for nutrient cycling and production of organic matter for downstream food webs [144]. The surface alterations lead to greater storm runoff [145] with likely impact on downstream flooding. Water emerging from valley fills contain toxic solutes that have been linked to declines in watershed biodiversity [146]. Even with mine-site reclamation intended to restore pre-mined surface conditions, mine-derived chemical constituents are found in domestic well water [147]. Reclaimed areas, compared with unmined areas, are found to have increased soil density with decreased organic and nutrient content, and with reduced water infiltration rates [148]. Reclaimed areas have been found to produce little if any regrowth of woody vegetation even after 15 years [149], and, although this deficiency might be addressed via more effective reclamation methods, there remains a likely significant loss of carbon storage [149].

Oil mining has an increasing ecological footprint per unit delivered energy because of the decreasing size of new fields and their increased geographical dispersion; transit distances are greater and wells are deeper, thus requiring more energy input [145]. Useful quantitative measures of the increasing ecological impacts are provided by the history of oil development in Alberta, Canada for production of both conventional oil and tar sands development. The area of land required per barrel of produced oil increased by a factor of 12 between 1955 and 2006 [150] leading to ecosystem fragmentation by roads and pipelines needed to support the wells [151]. Additional escalation of the mining impact occurs as conventional oil mining is supplanted by tar sands development, with mining and land disturbance from the latter producing land use-related greenhouse gas emissions as much as 23 times greater than conventional oil production per unit area [152], but with substantial variability and uncertainty [152–153]. Much of the tar sands bitumen is extracted through surface mining that removes the "overburden" (i.e., boreal forest ecosystems) and tar sand from large areas to a depth up to 100 m, with ecological impacts downstream and in the mined area [154]. Although mined areas are supposed to be reclaimed, as in the case of mountaintop removal, there is no expectation that the ecological value of reclaimed areas will be equivalent to predevelopment condition [141,155]. Landscape changes due to tar sands mining and reclamation cause a large loss of peatland and stored carbon, while also significantly reducing carbon sequestration potential [156]. Lake sediment cores document increased chemical pollution of ecosystems during the past several decades traceable to tar sands development [157] and snow and water samples indicate that recent levels of numerous pollutants exceeded local and national criteria for protection of aquatic organisms [158].

Gas mining by unconventional means has rapidly expanded in recent years, without commensurate understanding of the ecological, environmental and human health consequences [159]. The predominant approach is hydraulic fracturing ("fracking") of deep shale formations via injection of millions of gallons of water, sand and toxic chemicals under pressure, thus liberating methane [155,160]. A large fraction of the injected water returns to the surface as wastewater containing high concentrations of heavy metals, oils, greases and soluble organic compounds [161]. Management of this wastewater is a major technical challenge, especially because the polluted waters can continue to backflow from the wells for many years [161]. Numerous instances of groundwater and river contamination have been cited [162]. High levels of methane leakage from fracking have been found [163], as well as nitrogen oxides and volatile organic compounds [159]. Methane leaks increase the climate impact of shale gas, but whether the leaks are sufficient to significantly alter the climate forcing by total natural gas development is uncertain [164]. Overall, environmental and ecologic threats posed by unconventional gas extraction are uncertain because of limited research, however evidence for groundwater pollution on both local and river basin scales is a major concern [165].

Today, with cumulative carbon emissions ~370 GtC from all fossil fuels, we are at a point of severely escalating ecological and environmental impacts from fossil fuel use and fossil fuel mining, as is apparent from the mountaintop removal for coal, tar sands extraction of oil, and fracking for gas. The ecological and environmental implications of scenarios with carbon emissions of 1000 GtC or greater, as discussed below, would be profound and should influence considerations of appropriate energy strategies.

Summary: Climate Impacts

Climate impacts accompanying global warming of 2°C or more would be highly deleterious. Already there are numerous indications of substantial effects in response to warming of the past few decades. That warming has brought global temperature close to if not slightly above the prior range of the Holocene. We conclude that an appropriate target would be to keep global temperature at a level within or close to the Holocene range. Global warming of 2°C would be well outside the Holocene range and far into the dangerous range.

Transient Climate Change

We must quantitatively relate fossil fuel emissions to global temperature in order to assess how rapidly fossil fuel emissions must be phased down to stay under a given temperature limit. Thus we must deal with both a transient carbon cycle and transient global climate change.

Global climate fluctuates stochastically and also responds to natural and human-made climate forcings [1,166]. Forcings, measured in W/m^2 averaged over the globe, are imposed perturbations of Earth's energy balance caused by changing forcing agents such as solar irradiance and human-made greenhouse gases (GHGs). CO_2 accounts for more than 80% of the added GHG forcing in the past 15 years [64,167] and, if fossil fuel emissions continue at a high level, CO_2 will be the dominant driver of future global temperature change.

We first define our method of calculating atmospheric CO_2 as a function of fossil fuel emissions. We then define our assumptions

about the potential for drawing down atmospheric CO_2 via reforestation and increase of soil carbon, and we define fossil fuel emission reduction scenarios that we employ in our study. Finally we describe all forcings employed in our calculations of global temperature and the method used to simulate global temperature.

Carbon Cycle and Atmospheric CO_2

The carbon cycle defines the fate of CO_2 injected into the air by fossil fuel burning [1,168] as the additional CO_2 distributes itself over time among surface carbon reservoirs: the atmosphere, ocean, soil, and biosphere. We use the dynamic-sink pulse-response function version of the well-tested Bern carbon cycle model [169], as described elsewhere [54,170].

Specifically, we solve equations 3–6, 16–17, A.2.2, and A.3 of Joos et al. [169] using the same parameters and assumptions therein, except that initial (1850) atmospheric CO_2 is assumed to be 285.2 ppm [167]. Historical fossil fuel CO_2 emissions are from Boden et al. [5]. This Bern model incorporates non-linear ocean chemistry feedbacks and CO_2 fertilization of the terrestrial biosphere, but it omits climate-carbon feedbacks, e.g., assuming static global climate and ocean circulation. Therefore our results should be regarded as conservative, especially for scenarios with large emissions.

A pulse of CO_2 injected into the air decays by half in about 25 years as CO_2 is taken up by the ocean, biosphere and soil, but nearly one-fifth is still in the atmosphere after 500 years (Fig. 4A). Eventually, over hundreds of millennia, weathering of rocks will deposit all of this initial CO_2 pulse on the ocean floor as carbonate sediments [168].

Under equilibrium conditions a negative CO_2 pulse, i.e., artificial extraction and storage of some CO_2 amount, decays at about the same rate as a positive pulse (Fig. 4A). Thus if it is decided in the future that CO_2 must be extracted from the air and removed from the carbon cycle (e.g., by storing it underground or in carbonate bricks), the impact on atmospheric CO_2 amount will diminish in time. This occurs because carbon is exchanged among the surface carbon reservoirs as they move toward an equilibrium distribution, and thus, e.g., CO_2 out-gassing by the ocean can offset some of the artificial drawdown. The CO_2 extraction required to reach a given target atmospheric CO_2 level therefore depends on the prior emission history and target timeframe, but the amount that must be extracted substantially exceeds the net reduction of the atmospheric CO_2 level that will be achieved. We clarify this matter below by means of specific scenarios for capture of CO_2.

It is instructive to see how fast atmospheric CO_2 declines if fossil fuel emissions are instantly terminated (Fig. 4B). Halting emissions in 2015 causes CO_2 to decline to 350 ppm at century's end (Fig. 4B). A 20 year delay in halting emissions has CO_2 returning to 350 ppm at about 2300. With a 40 year delay, CO_2 does not return to 350 ppm until after 3000. These results show how difficult it is to get back to 350 ppm if emissions continue to grow for even a few decades.

These results emphasize the urgency of initiating emissions reduction [171]. As discussed above, keeping global climate close to the Holocene range requires a long-term atmospheric CO_2 level of about 350 ppm or less, with other climate forcings similar to today's levels. If emissions reduction had begun in 2005, reduction at 3.5%/year would have achieved 350 ppm at 2100. Now the requirement is at least 6%/year. Delay of emissions reductions until 2020 requires a reduction rate of 15%/year to achieve 350 ppm in 2100. If we assume only 50 GtC reforestation, and begin emissions reduction in 2013, the required reduction rate becomes about 9%/year.

Reforestation and Soil Carbon

Of course fossil fuel emissions will not suddenly terminate. Nevertheless, it is not impossible to return CO_2 to 350 ppm this century. Reforestation and increase of soil carbon can help draw down atmospheric CO_2. Fossil fuels account for ~80% of the CO_2 increase from preindustrial time, with land use/deforestation accounting for 20% [1,170,172–173]. Net deforestation to date is estimated to be 100 GtC (gigatons of carbon) with ±50% uncertainty [172].

Complete restoration of deforested areas is unrealistic, yet 100 GtC carbon drawdown is conceivable because: (1) the human-enhanced atmospheric CO_2 level increases carbon uptake by some vegetation and soils, (2) improved agricultural practices can convert agriculture from a CO_2 ource into a CO_2 sink [174], (3) biomass-burning power plants with CO_2 capture and storage can contribute to CO_2 drawdown.

Forest and soil storage of 100 GtC is challenging, but has other benefits. Reforestation has been successful in diverse places [175]. Minimum tillage with biological nutrient recycling, as opposed to plowing and chemical fertilizers, could sequester 0.4–1.2 GtC/year [176] while conserving water in soils, building agricultural resilience to climate change, and increasing productivity especially in smallholder rain-fed agriculture, thereby reducing expansion of agriculture into forested ecosystems [177–178]. Net tropical deforestation may have decreased in the past decade [179], but because of extensive deforestation in earlier decades [170,172–173,180–181] there is a large amount of land suitable for reforestation [182].

Use of bioenergy to draw down CO_2 should employ feedstocks from residues, wastes, and dedicated energy crops that do not compete with food crops, thus avoiding loss of natural ecosystems and cropland [183–185]. Reforestation competes with agricultural land use; land needs could decline by reducing use of animal products, as livestock now consume more than half of all crops [186].

Our reforestation scenarios assume that today's net deforestation rate (~1 GtC/year; see [54]) will stay constant until 2020, then linearly decrease to zero by 2030, followed by sinusoidal 100 GtC biospheric carbon storage over 2031–2080. Alternative timings do not alter conclusions about the potential to achieve a given CO_2 level such as 350 ppm.

Emission Reduction Scenarios

A 6%/year decrease of fossil fuel emissions beginning in 2013, with 100 GtC reforestation, achieves a CO_2 decline to 350 ppm near the end of this century (Fig. 5A). Cumulative fossil fuel emissions in this scenario are ~129 GtC from 2013 to 2050, with an additional 14 GtC by 2100. If our assumed land use changes occur a decade earlier, CO_2 returns to 350 ppm several years earlier; however that has negligible effect on the maximum global temperature calculated below.

Delaying fossil fuel emission cuts until 2020 (with 2%/year emissions growth in 2012–2020) causes CO_2 to remain above 350 ppm (with associated impacts on climate) until 2300 (Fig. 5B). If reductions are delayed until 2030 or 2050, CO_2 remains above 350 ppm or 400 ppm, respectively, until well after 2500.

We conclude that it is urgent that large, long-term emission reductions begin soon. Even if a 6%/year reduction rate and 500 GtC are not achieved, it makes a huge difference when reductions begin. There is no practical justification for why emissions necessarily must even approach 1000 GtC.

Climate Forcings

Atmospheric CO_2 and other GHGs have been well-measured for the past half century, allowing accurate calculation of their climate forcing. The growth rate of the GHG forcing has declined

moderately since its peak values in the 1980s, as the growth rate of CH_4 and chlorofluorocarbons has slowed [187]. Annual changes of CO_2 are highly correlated with the El Niño cycle (Fig. 6). Two strong La Niñas in the past five years have depressed CO_2 growth as well as the global warming rate (Fig. 3). The CO_2 growth rate and warming rate can be expected to increase as we move into the next El Niño, with the CO_2 growth already reaching 3 ppm/year in mid-2013 [188]. The CO_2 climate forcing does not increase as rapidly as the CO_2 amount because of partial saturation of CO_2 absorption bands [75]. The GHG forcing is now increasing at a rate of almost 0.4 W/m^2 per decade [187].

Solar irradiance variations are sometimes assumed to be the most likely natural driver of climate change. Solar irradiance has been measured from satellites since the late 1970s (Fig. 7). These data are from a composite of several satellite-measured time series. Data through 28 February 2003 are from [189] and Physikalisch Meteorologisches Observatorium Davos, World Radiation Center. Subsequent update is from University of Colorado Solar Radiation & Climate Experiment (SORCE). Data sets are concatenated by matching the means over the first 12 months of SORCE data. Monthly sunspot numbers (Fig. 7) support the conclusion that the solar irradiance in the current solar cycle is significantly lower than in the three preceding solar cycles. Amplification of the direct solar forcing is conceivable, e.g., through effects on ozone or atmospheric condensation nuclei, but empirical data place a factor of two upper limit on the amplification, with the most likely forcing in the range 100–120% of the directly measured solar irradiance change [64].

Recent reduced solar irradiance (Fig. 7) may have decreased the forcing over the past decade by about half of the full amplitude of measured irradiance variability, thus yielding a negative forcing of, say, − 0.12 W/m^2. This compares with a decadal increase of the GHG forcing that is positive and about three times larger in magnitude. Thus the solar forcing is not negligible and might partially account for the slowdown in global warming in the past decade [17]. However, we must (1) compare the solar forcing with the net of other forcings, which enhances the importance of solar change, because the net forcing is smaller than the GHG forcing, and (2) consider forcing changes on longer time scales, which greatly diminishes the importance of solar change, because solar variability is mainly oscillatory.

Human-made tropospheric aerosols, which arise largely from fossil fuel use, cause a substantial negative forcing. As noted above, two independent analyses [64,72] yield a total (direct plus indirect) aerosol forcing in the past decade of about −1.5 W/m^2, half the magnitude of the GHG forcing and opposite in sign. That empirical aerosol forcing assessment for the past decade is consistent with the climate forcings scenario (Fig. 8) that we use for the past century in the present and prior studies [64,190]. Supplementary Table S1 specifies the historical forcings and Table S2 gives several scenarios for future forcings.

Future Climate Forcings

Future global temperature change should depend mainly on atmospheric CO_2, at least if fossil fuel emissions remain high. Thus to provide the clearest picture of the CO_2 effect, we approximate the net future change of human-made non-CO_2 forcings as zero and we exclude future changes of natural climate forcings, such as solar irradiance and volcanic aerosols. Here we discuss possible effects of these approximations.

Uncertainties in non-CO_2 forcings concern principally solar, aerosol and other GHG forcings. Judging from the sunspot numbers (Fig. 7B and [191]) for the past four centuries, the current solar cycle is almost as weak as the Dalton Minimum of the late 18th century. Conceivably irradiance could decline further to the level of the Maunder Minimum of the late 17th century [192–193]. For our simulation we choose an intermediate path between recovery to the level before the current solar cycle and decline to a still lower level. Specifically, we keep solar irradiance fixed at the reduced level of 2010, which is probably not too far off in either direction. Irradiance in 2010 is about 0.1 W/m^2 less than the mean of the prior three solar cycles, a decrease of forcing that

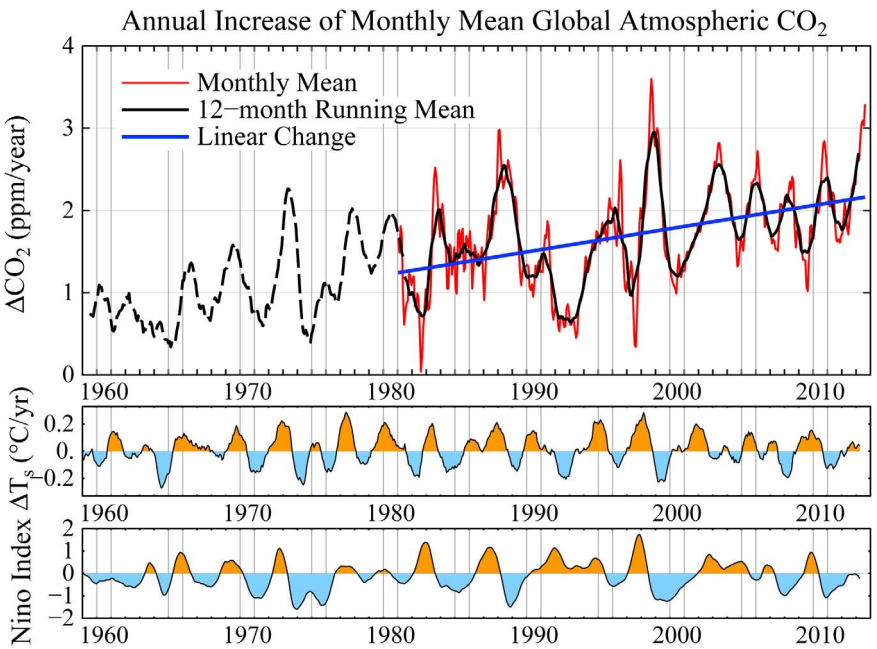

Figure 6. Annual increase of CO_2 based on data from the NOAA Earth System Research Laboratory [188]. Prior to 1981 the CO_2 change is based on only Mauna Loa, Hawaii. Temperature changes in lower diagram are 12-month running means for the globe and Niño3.4 area [16].
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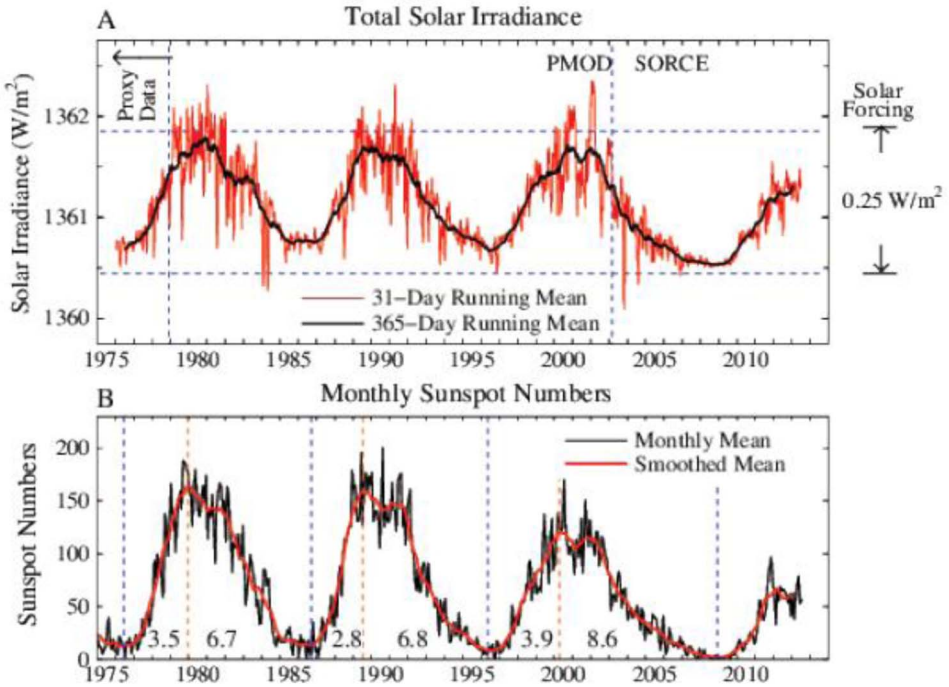

Figure 7. Solar irradiance and sunspot number in the era of satellite data (see text). Left scale is the energy passing through an area perpendicular to Sun-Earth line. Averaged over Earth's surface the absorbed solar energy is ~240 W/m^2, so the full amplitude of measured solar variability is ~0.25 W/m^2.
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would be restored by the CO_2 increase within 3–4 years at its current growth rate. Extensive simulations [17,194] confirm that the effect of solar variability is small compared with GHGs if CO_2 emissions continue at a high level. However, solar forcing can affect the magnitude and detection of near-term warming. Also, if rapidly declining GHG emissions are achieved, changes of solar forcing will become relatively more important.

Aerosols present a larger uncertainty. Expectations of decreases in large source regions such as China [195] may be counteracted by aerosol increases other places as global population continues to increase. Our assumption of unchanging human-made aerosols could be substantially off in either direction. For the sake of interpreting on-going and future climate change it is highly desirable to obtain precise monitoring of the global aerosol forcing [73].

Non-CO_2 GHG forcing has continued to increase at a slow rate since 1995 (Fig. 6 in [64]). A desire to constrain climate change may help reduce emissions of these gases in the future. However, it will be difficult to prevent or fully offset positive forcing from increasing N_2O, as its largest source is associated with food production and the world's population is continuing to rise.

On the other hand, we are also probably underestimating a negative aerosol forcing, e.g., because we have not included future volcanic aerosols. Given the absence of large volcanic eruptions in the past two decades (the last one being Mount Pinatubo in 1991), multiple volcanic eruptions would cause a cooling tendency [196] and reduce heat storage in the ocean [197].

Overall, we expect the errors due to our simple approximation of non-CO_2 forcings to be partially off-setting. Specifically, we have likely underestimated a positive forcing by non-CO_2 GHGs, while also likely underestimating a negative aerosol forcing.

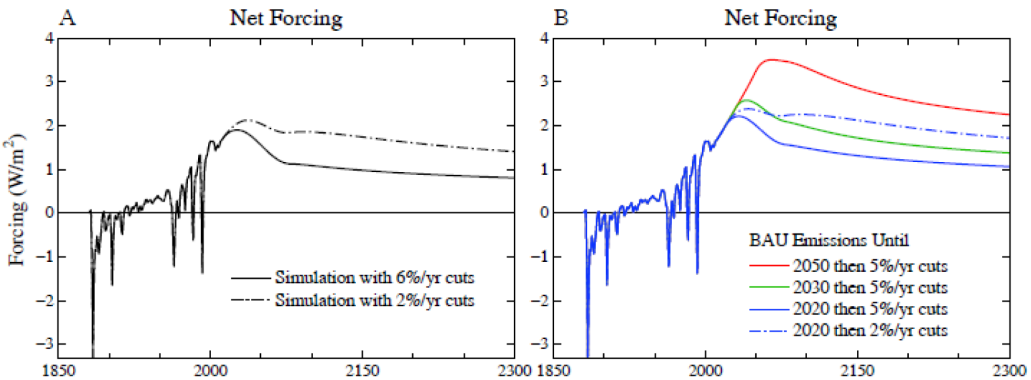

Figure 8. Climate forcings employed in our six main scenarios. Forcings through 2010 are as in [64].
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Note that uncertainty in forcings is partly obviated via the focus on Earth's energy imbalance in our analysis. The planet's energy imbalance is an integrative quantity that is especially useful for a case in which some of the forcings are uncertain or unmeasured. Earth's measured energy imbalance includes the effects of all forcings, whether they are measured or not.

Simulations of Future Global Temperature

We calculate global temperature change for a given CO_2 scenario using a climate response function (Table S3) that accurately replicates results from a global climate model with sensitivity 3°C for doubled CO_2 [64]. A best estimate of climate sensitivity close to 3°C for doubled CO_2 has been inferred from paleoclimate data [51–52]. This empirical climate sensitivity is generally consistent with that of global climate models [1], but the empirical approach makes the inferred high sensitivity more certain and the quantitative evaluation more precise. Because this climate sensitivity is derived from empirical data on how Earth responded to past changes of boundary conditions, including atmospheric composition, our conclusions about limits on fossil fuel emissions can be regarded as largely independent of climate models.

The detailed temporal and geographical response of the climate system to the rapid human-made change of climate forcings is not well-constrained by empirical data, because there is no faithful paleoclimate analog. Thus climate models necessarily play an important role in assessing practical implications of climate change. Nevertheless, it is possible to draw important conclusions with transparent computations. A simple response function (Green's function) calculation [64] yields an estimate of global mean temperature change in response to a specified time series for global climate forcing. This approach accounts for the delayed response of the climate system caused by the large thermal inertia of the ocean, yielding a global mean temporal response in close accord with that obtained from global climate models.

Tables S1 and S2 in Supporting Information give the forcings we employ and Table S3 gives the climate response function for our Green's function calculation, defined by equation 2 of [64]. The Green's function is driven by the net forcing, which, with the response function, is sufficient information for our results to be reproduced. However, we also include the individual forcings in Table S1, in case researchers wish to replace specific forcings or use them for other purposes.

Simulated global temperature (Fig. 9) is for CO_2 scenarios of Fig. 5. Peak global warming is ~1.1°C, declining to less than 1°C by mid-century, if CO_2 emissions are reduced 6%/year beginning in 2013. In contrast, warming reaches 1.5°C and stays above 1°C until after 2400 if emissions continue to increase until 2030, even though fossil fuel emissions are phased out rapidly (5%/year) after 2030 and 100 GtC reforestation occurs during 2030–2080. If emissions continue to increase until 2050, simulated warming exceeds 2°C well into the 22nd century.

Increased global temperature persists for many centuries after the climate forcing declines, because of the thermal inertia of the ocean [198]. Some temperature reduction is possible if the climate forcing is reduced rapidly, before heat has penetrated into the deeper ocean. Cooling by a few tenths of a degree in Fig. 9 is a result mainly of the 100 GtC biospheric uptake of CO_2 during 2030–2080. Note the longevity of the warming, especially if emissions reduction is as slow as 2%/year, which might be considered to be a rapid rate of reduction.

The temporal response of the real world to the human-made climate forcing could be more complex than suggested by a simple response function calculation, especially if rapid emissions growth continues, yielding an unprecedented climate forcing scenario. For example, if ice sheet mass loss becomes rapid, it is conceivable that the cold fresh water added to the ocean could cause regional surface cooling [199], perhaps even at a point when sea level rise has only reached a level of the order of a meter [200]. However, any uncertainty in the surface thermal response this century due to such phenomena has little effect on our estimate of the dangerous level of emissions. The long lifetime of the fossil fuel carbon in the climate system and the persistence of ocean warming for millennia [201] provide sufficient time for the climate system to achieve full response to the fast feedback processes included in the 3°C climate sensitivity.

Indeed, the long lifetime of fossil fuel carbon in the climate system and persistence of the ocean warming ensure that "slow" feedbacks, such as ice sheet disintegration, changes of the global vegetation distribution, melting of permafrost, and possible release of methane from methane hydrates on continental shelves, would also have time to come into play. Given the unprecedented rapidity of the human-made climate forcing, it is difficult to establish how soon slow feedbacks will become important, but clearly slow feedbacks should be considered in assessing the "dangerous" level of global warming, as discussed in the next section.

Danger of Initiating Uncontrollable Climate Change

Our calculated global warming as a function of CO_2 amount is based on equilibrium climate sensitivity 3°C for doubled CO_2. That is the central climate sensitivity estimate from climate models [1], and it is consistent with climate sensitivity inferred from Earth's climate history [51–52]. However, this climate sensitivity includes only the effects of fast feedbacks of the climate system, such as water vapor, clouds, aerosols, and sea ice. Slow feedbacks, such as change of ice sheet area and climate-driven changes of greenhouse gases, are not included.

Slow Climate Feedbacks and Irreversible Climate Change

Excluding slow feedbacks was appropriate for simulations of the past century, because we know the ice sheets were stable then and our climate simulations used observed greenhouse gas amounts that included any contribution from slow feedbacks. However, we must include slow feedbacks in projections of warming for the 21st century and beyond. Slow feedbacks are important because they affect climate sensitivity and because their instigation is related to the danger of passing "points of no return", beyond which irreversible consequences become inevitable, out of humanity's control.

Antarctic and Greenland ice sheets present the danger of change with consequences that are irreversible on time scales important to society [1]. These ice sheets required millennia to grow to their present sizes. If ice sheet disintegration reaches a point such that the dynamics and momentum of the process take over, at that point reducing greenhouse gases may be unable to prevent major ice sheet mass loss, sea level rise of many meters, and worldwide loss of coastal cities – a consequence that is irreversible for practical purposes. Interactions between the ocean and ice sheets are particularly important in determining ice sheet changes, as a warming ocean can melt the ice shelves, the tongues of ice that extend from the ice sheets into the ocean and buttress the large land-based ice sheets [92,202–203]. Paleoclimate data for sea level change indicate that sea level changed at rates of the order of a meter per century [81–83], even at times when the forcings driving climate change were far weaker than the human-

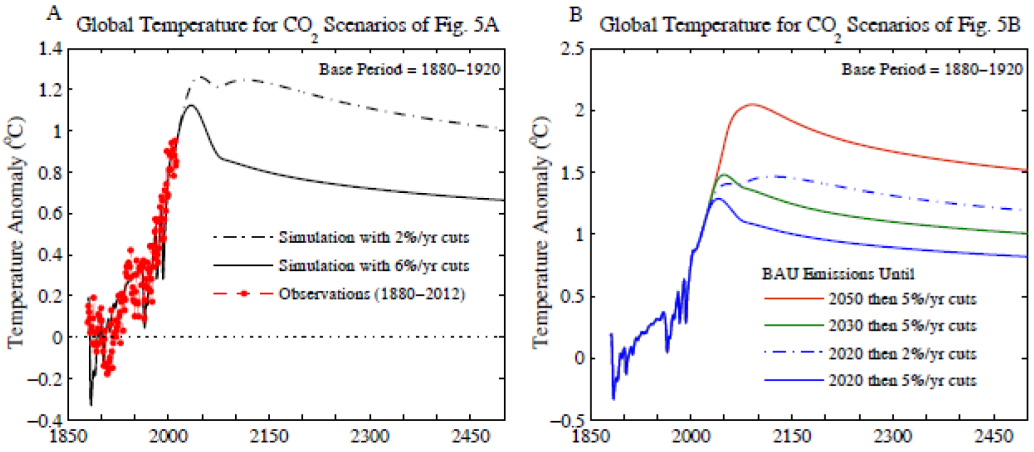

Figure 9. Simulated global temperature relative to 1880–1920 mean for CO_2 scenarios of Figure 5.
doi:10.1371/journal.pone.0081648.g009

made forcing. Thus, because ocean warming is persistent for centuries, there is a danger that large irreversible change could be initiated by excessive ocean warming.

Paleoclimate data are not as helpful for defining the likely rate of sea level rise in coming decades, because there is no known case of growth of a positive (warming) climate forcing as rapid as the anthropogenic change. The potential for unstable ice sheet disintegration is controversial, with opinion varying from likely stability of even the (marine) West Antarctic ice sheet [94] to likely rapid non-linear response extending up to multi-meter sea level rise [97–98]. Data for the modern rate of annual ice sheet mass changes indicate an accelerating rate of mass loss consistent with a mass loss doubling time of a decade or less (Fig. 10). However, we do not know the functional form of ice sheet response to a large persistent climate forcing. Longer records are needed for empirical assessment of this ostensibly nonlinear behavior.

Greenhouse gas amounts in the atmosphere, most importantly CO_2 and CH_4, change in response to climate change, i.e., as a feedback, in addition to the immediate gas changes from human-caused emissions. As the ocean warms, for example, it releases CO_2 to the atmosphere, with one principal mechanism being the simple fact that the solubility of CO_2 decreases as the water temperature rises [204]. We also include in the category of slow feedbacks the global warming spikes, or "hyperthermals", that have occurred a number of times in Earth's history during the course of slower global warming trends. The mechanisms behind these hyperthermals are poorly understood, as discussed below, but they are characterized by the injection into the surface climate system of a large amount of carbon in the form of CH_4 and/or CO_2 on the time scale of a millennium [205–207]. The average rate of injection of carbon into the climate system during these hyperthermals was slower than the present human-made injection of fossil fuel carbon, yet it was faster than the time scale for removal of carbon from the surface reservoirs via the weathering process [3,208], which is tens to hundreds of thousands of years.

Methane hydrates – methane molecules trapped in frozen water molecule cages in tundra and on continental shelves – and organic matter such as peat locked in frozen soils (permafrost) are likely mechanisms in the past hyperthermals, and they provide another climate feedback with the potential to amplify global warming if large scale thawing occurs [209–210]. Paleoclimate data reveal instances of rapid global warming, as much as 5–6°C, as a sudden additional warming spike during a longer period of gradual warming [see Text S1]. The candidates for the carbon injected into the climate system during those warmings are methane hydrates on continental shelves destabilized by sea floor warming [211] and carbon released from frozen soils [212]. As for the present, there are reports of methane release from thawing permafrost on land [213] and from sea-bed methane hydrate deposits [214], but amounts so far are small and the data are snapshots that do not prove that there is as yet a temporal increase of emissions.

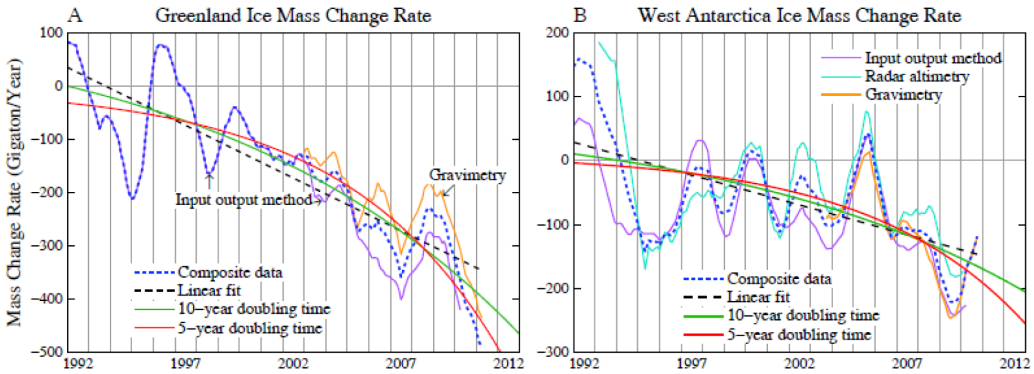

Figure 10. Annual Greenland and West Antarctic ice mass changes as estimated via alternative methods. Data were read from Figure 4 of Shepherd et al. [23] and averaged over the available records.
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There is a possibility of rapid methane hydrate or permafrost emissions in response to warming, but that risk is largely unquantified [215]. The time needed to destabilize large methane hydrate deposits in deep sediments is likely millennia [215]. Smaller but still large methane hydrate amounts below shallow waters as in the Arctic Ocean are more vulnerable; the methane may oxidize to CO_2 in the water, but it will still add to the long-term burden of CO_2 in the carbon cycle. Terrestrial permafrost emissions of CH_4 and CO_2 likely can occur on a time scale of a few decades to several centuries if global warming continues [215]. These time scales are within the lifetime of anthropogenic CO_2, and thus these feedbacks must be considered in estimating the dangerous level of global warming. Because human-made warming is more rapid than natural long-term warmings in the past, there is concern that methane hydrate or peat feedbacks could be more rapid than the feedbacks that exist in the paleoclimate record.

Climate model studies and empirical analyses of paleoclimate data can provide estimates of the amplification of climate sensitivity caused by slow feedbacks, excluding the singular mechanisms that caused the hyperthermal events. Model studies for climate change between the Holocene and the Pliocene, when Earth was about 3°C warmer, find that slow feedbacks due to changes of ice sheets and vegetation cover amplified the fast feedback climate response by 30–50% [216]. These same slow feedbacks are estimated to amplify climate sensitivity by almost a factor of two for the climate change between the Holocene and the nearly ice-free climate state that existed 35 million years ago [54].

Implication for Carbon Emissions Target

Evidence presented under Climate Impacts above makes clear that 2°C global warming would have consequences that can be described as disastrous. Multiple studies [12,198,201] show that the warming would be very long lasting. The paleoclimate record and changes underway in the Arctic and on the Greenland and Antarctic ice sheets with only today's warming imply that sea level rise of several meters could be expected. Increased climate extremes, already apparent at 0.8°C warming [46], would be more severe. Coral reefs and associated species, already stressed with current conditions [40], would be decimated by increased acidification, temperature and sea level rise. More generally, humanity and nature, the modern world as we know it, is adapted to the Holocene climate that has existed more than 10,000 years. Warming of 1°C relative to 1880–1920 keeps global temperature close to the Holocene range, but warming of 2°C, to at least the Eemian level, could cause major dislocations for civilization.

However, distinctions between pathways aimed at ~1°C and 2°C warming are much greater and more fundamental than the numbers 1°C and 2°C themselves might suggest. These fundamental distinctions make scenarios with 2°C or more global warming far more dangerous; so dangerous, we suggest, that aiming for the 2°C pathway would be foolhardy.

First, most climate simulations, including ours above and those of IPCC [1], do not include slow feedbacks such as reduction of ice sheet size with global warming or release of greenhouse gases from thawing tundra. These exclusions are reasonable for a ~1°C scenario, because global temperature barely rises out of the Holocene range and then begins to subside. In contrast, global warming of 2°C or more is likely to bring slow feedbacks into play. Indeed, it is slow feedbacks that cause long-term climate sensitivity to be high in the empirical paleoclimate record [51–52]. The lifetime of fossil fuel CO_2 in the climate system is so long that it must be assumed that these slow feedbacks will occur if temperature rises well above the Holocene range.

Second, scenarios with 2°C or more warming necessarily imply expansion of fossil fuels into sources that are harder to get at, requiring greater energy using extraction techniques that are increasingly invasive, destructive and polluting. Fossil fuel emissions through 2012 total ~370 GtC (Fig. 2). If subsequent emissions decrease 6%/year, additional emissions are ~130 GtC, for a total ~500 GtC fossil fuel emissions. This 130 GtC can be obtained mainly from the easily extracted conventional oil and gas reserves (Fig. 2), with coal use rapidly phased out and unconventional fossil fuels left in the ground. In contrast, 2°C scenarios have total emissions of the order of 1000 GtC. The required additional fossil fuels will involve exploitation of tar sands, tar shale, hydrofracking for oil and gas, coal mining, drilling in the Arctic, Amazon, deep ocean, and other remote regions, and possibly exploitation of methane hydrates. Thus 2°C scenarios result in more CO_2 per unit useable energy, release of substantial CH_4 via the mining process and gas transportation, and release of CO_2 and other gases via destruction of forest "overburden" to extract subterranean fossil fuels.

Third, with our ~1°C scenario it is more likely that the biosphere and soil will be able to sequester a substantial portion of the anthropogenic fossil fuel CO_2 carbon than in the case of 2°C or more global warming. Empirical data for the CO_2 "airborne fraction", the ratio of observed atmospheric CO_2 increase divided by fossil fuel CO_2 emissions, show that almost half of the emissions is being taken up by surface (terrestrial and ocean) carbon reservoirs [187], despite a substantial but poorly measured contribution of anthropogenic land use (deforestation and agriculture) to airborne CO_2 [179,216]. Indeed, uptake of CO_2 by surface reservoirs has at least kept pace with the rapid growth of emissions [187]. Increased uptake in the past decade may be a consequence of a reduced rate of deforestation [217] and fertilization of the biosphere by atmospheric CO_2 and nitrogen deposition [187]. With the stable climate of the ~1°C scenario it is plausible that major efforts in reforestation and improved agricultural practices [15,173,175–177], with appropriate support provided to developing countries, could take up an amount of carbon comparable to the 100 GtC in our ~1°C scenario. On the other hand, with warming of 2°C or more, carbon cycle feedbacks are expected to lead to substantial additional atmospheric CO_2 [218–219], perhaps even making the Amazon rainforest a source of CO_2 [219–220].

Fourth, a scenario that slows and then reverses global warming makes it possible to reduce other greenhouse gases by reducing their sources [75,221]. The most important of these gases is CH_4, whose reduction in turn reduces tropospheric O_3 and stratospheric H_2O. In contrast, chemistry modeling and paleoclimate records [222] show that trace gases increase with global warming, making it unlikely that overall atmospheric CH_4 will decrease even if a decrease is achieved in anthropogenic CH_4 sources. Reduction of the amount of atmospheric CH_4 and related gases is needed to counterbalance expected forcing from increasing N_2O and decreasing sulfate aerosols.

Now let us compare the 1°C (500 GtC fossil fuel emissions) and the 2°C (1000 GtC fossil fuel emissions) scenarios. Global temperature in 2100 would be close to 1°C in the 500 GtC scenario, and it is less than 1°C if 100 GtC uptake of carbon by the biosphere and soil is achieved via improved agricultural and forestry practices (Fig. 9). In contrast, the 1000 GtC scenario, although nominally designed to yield a fast-feedback climate response of ~ 2°C, would yield a larger eventual warming because of slow feedbacks, probably at least 3°C.

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Danger of Uncontrollable Consequences

Inertia of the climate system reduces the near-term impact of human-made climate forcings, but that inertia is not necessarily our friend. One implication of the inertia is that climate impacts "in the pipeline" may be much greater than the impacts that we presently observe. Slow climate feedbacks add further danger of climate change running out of humanity's control. The response time of these slow feedbacks is uncertain, but there is evidence that some of these feedbacks already are underway, at least to a minor degree. Paleoclimate data show that on century and millennial time scales the slow feedbacks are predominately amplifying feedbacks.

The inertia of energy system infrastructure, i.e., the time required to replace fossil fuel energy systems, will make it exceedingly difficult to avoid a level of atmospheric CO_2 that would eventually have highly undesirable consequences. The danger of uncontrollable and irreversible consequences necessarily raises the question of whether it is feasible to extract CO_2 from the atmosphere on a large enough scale to affect climate change.

Carbon Extraction

We have shown that extraordinarily rapid emission reductions are needed to stay close to the 1°C scenario. In absence of extraordinary actions, it is likely that growing climate disruptions will lead to a surge of interest in "geo-engineering" designed to minimize human-made climate change [223]. Such efforts must remove atmospheric CO_2, if they are to address direct CO_2 effects such as ocean acidification as well as climate change. Schemes such as adding sulfuric acid aerosols to the stratosphere to reflect sunlight [224], an attempt to mask one pollutant with another, is a temporary band-aid for a problem that will last for millennia; besides it fails to address ocean acidification and may have other unintended consequences [225].

Potential for Carbon Extraction

At present there are no proven technologies capable of large-scale air capture of CO_2. It has been suggested that, with strong research and development support and industrial scale pilot projects sustained over decades, costs as low as ~$500/tC may be achievable [226]. Thermodynamic constraints [227] suggest that this cost estimate may be low. An assessment by the American Physical Society [228] argues that the lowest currently achievable cost, using existing approaches, is much greater ($600/t$CO_2$ or $2200/tC).

The cost of capturing 50 ppm of CO_2, at $500/tC (~$135/tCO_2), is ~$50 trillion (1 ppm CO_2 is ~2.12 GtC), but more than $200 trillion for the price estimate of the American Physical Society study. Moreover, the resulting atmospheric CO_2 reduction will ultimately be less than 50 ppm for the reasons discussed above. For example, let us consider the scenario of Fig. 5B in which emissions continue to increase until 2030 before decreasing at 5%/year – this scenario yields atmospheric CO_2 of 410 ppm in 2100. Using our carbon cycle model we calculate that if we extract 100 ppm of CO_2 from the air over the period 2030–2100 (10/7 ppm per year), say storing that CO_2 in carbonate bricks, the atmospheric CO_2 amount in 2100 will be reduced 52 ppm to 358 ppm, i.e., the reduction of airborne CO_2 is about half of the amount extracted from the air and stored. The estimated cost of this 52 ppm CO_2 reduction is $100–400 trillion.

The cost of CO_2 capture and storage conceivably may decline in the future. Yet the practicality of carrying out such a program with alacrity in response to a climate emergency is dubious. Thus it may be appropriate to add a CO_2 removal cost to the current price of fossil fuels, which would both reduce ongoing emissions and provide resources for future cleanup.

Responsibility for Carbon Extraction

We focus on fossil fuel carbon, because of its long lifetime in the carbon cycle. Reversing the effects of deforestation is also important and there will need to be incentives to achieve increased carbon storage in the biosphere and soil, but the crucial requirement now is to limit the amount of fossil fuel carbon in the air.

The high cost of carbon extraction naturally raises the question of responsibility for excess fossil fuel CO_2 in the air. China has the largest CO_2 emissions today (Fig. 11A), but the global warming effect is closely proportional to cumulative emissions [190]. The United States is responsible for about one-quarter of cumulative emissions, with China next at about 10% (Fig. 11B). Cumulative responsibilities change rather slowly (compare Fig. 10 of 190). Estimated per capita emissions (Fig. 12) are based on population estimates for 2009–2011.

Various formulae might be devised to assign costs of CO_2 air capture, should removal prove essential for maintaining acceptable climate. For the sake of estimating the potential cost, let us assume that it proves necessary to extract 100 ppm of CO_2 (yielding a reduction of airborne CO_2 of about 50 ppm) and let us assign each country the responsibility to clean up its fraction of cumulative emissions. Assuming a cost of $500/tC (~$135/tCO_2) yields a cost of $28 trillion for the United States, about $90,000 per individual. Costs would be slightly higher for a UK citizen, but less for other nations (Fig. 12B).

Cost of CO_2 capture might decline, but the cost estimate used is more than a factor of four smaller than estimated by the American Physical Society [228] and 50 ppm is only a moderate reduction. The cost should also include safe permanent disposal of the captured CO_2, which is a substantial mass. For the sake of scaling the task, note that one GtC, made into carbonate bricks, would produce the volume of ~3000 Empire State buildings or ~1200 Great Pyramids of Giza. Thus the 26 ppm assigned to the United States, if made into carbonate bricks, would be equivalent to the stone in 165,000 Empire State buildings or 66,000 Great Pyramids of Giza. This is not intended as a practical suggestion: carbonate bricks are not a good building material, and the transport and construction costs would be additional.

The point of this graphic detail is to make clear the magnitude of the cleanup task and potential costs, if fossil fuel emissions continue unabated. More useful and economic ways of removing CO_2 may be devised with the incentive of a sufficient carbon price. For example, a stream of pure CO_2 becomes available for capture and storage if biomass is used as the fuel for power plants or as feedstock for production of liquid hydrocarbon fuels. Such clean energy schemes and improved agricultural and forestry practices are likely to be more economic than direct air capture of CO_2, but they must be carefully designed to minimize undesirable impacts and the amount of CO_2 that can be extracted on the time scale of decades will be limited, thus emphasizing the need to limit the magnitude of the cleanup task.

Policy Implications

Human-made climate change concerns physical sciences, but leads to implications for policy and politics. Conclusions from the physical sciences, such as the rapidity with which emissions must be reduced to avoid obviously unacceptable consequences and the long lag between emissions and consequences, lead to implications in social sciences, including economics, law and ethics. Intergov-

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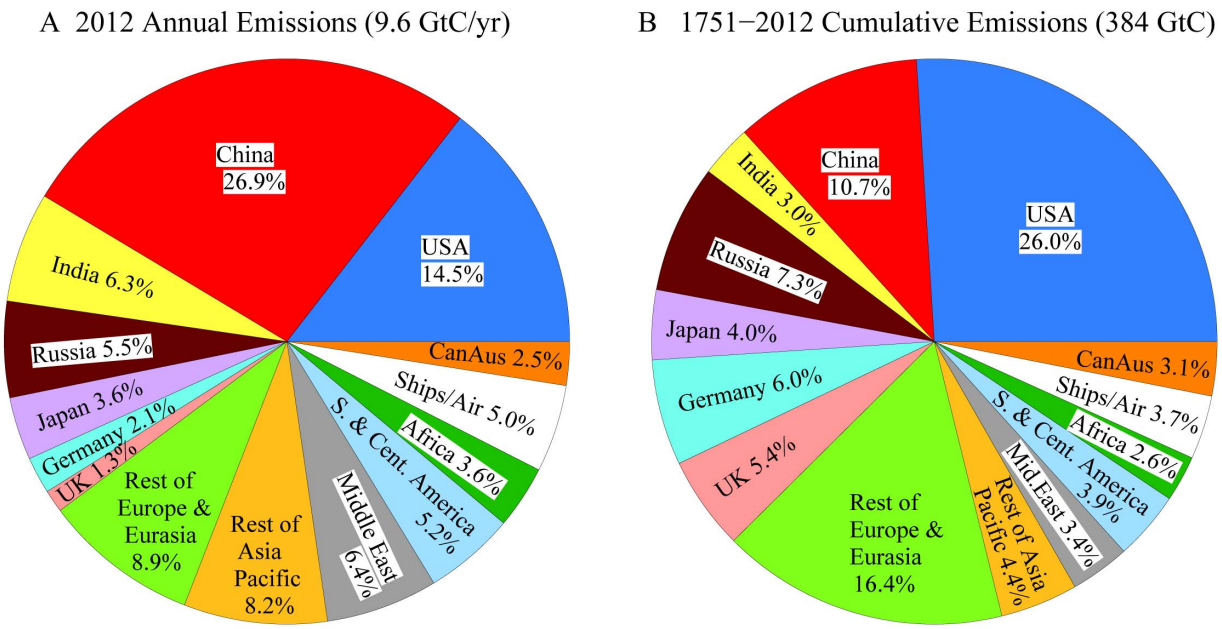

Figure 11. Fossil fuel CO_2 emissions. (A) 2012 emissions by source region, and (B) cumulative 1751–2012 emissions. Results are an update of Fig. 10 of [190] using data from [5].
doi:10.1371/journal.pone.0081648.g011

ernmental climate assessments [1,14] purposely are not policy prescriptive. Yet there is also merit in analysis and discussion of the full topic through the objective lens of science, i.e., "connecting the dots" all the way to policy implications.

Energy and Carbon Pathways: A Fork in the Road

The industrial revolution began with wood being replaced by coal as the primary energy source. Coal provided more concentrated energy, and thus was more mobile and effective. We show data for the United States (Fig. 13) because of the availability of a long data record that includes wood [229]. More limited global records yield a similar picture [Fig. 14], the largest difference being global coal now at ~30% compared with ~20% in the United States. Economic progress and wealth generation were further spurred in the twentieth century by expansion into liquid and gaseous fossil fuels, oil and gas being transported and burned more readily than coal. Only in the latter part of the twentieth century did it become clear that long-lived combustion products from fossil fuels posed a global climate threat, as formally acknowledged in the 1992 Framework Convention on Climate Change [6]. However, efforts to slow emissions of the principal atmospheric gas driving climate change, CO_2, have been ineffectual so far (Fig. 1).

Consequently, at present, as the most easily extracted oil and gas reserves are being depleted, we stand at a fork in the road to our energy and carbon future. Will we now feed our energy needs by pursuing difficult to extract fossil fuels, or will we pursue energy policies that phase out carbon emissions, moving on to the post fossil fuel era as rapidly as practical?

This is not the first fork encountered. Most nations agreed to the Framework Convention on Climate Change in 1992 [6]. Imagine if a bloc of countries favoring action had agreed on a common gradually rising carbon fee collected within each of country at domestic mines and ports of entry. Such nations might place equivalent border duties on products from nations not having a carbon fee and they could rebate fees to their domestic industry for export products to nations without an equivalent carbon fee. The legality of such a border tax adjustment under international trade law is untested, but is considered to be plausibly consistent with trade principles [230]. As the carbon fee gradually rose and as additional nations, for their own benefit, joined this bloc of nations, development of carbon-free energies and energy efficiency would have been spurred. If the carbon fee had begun in 1995, we

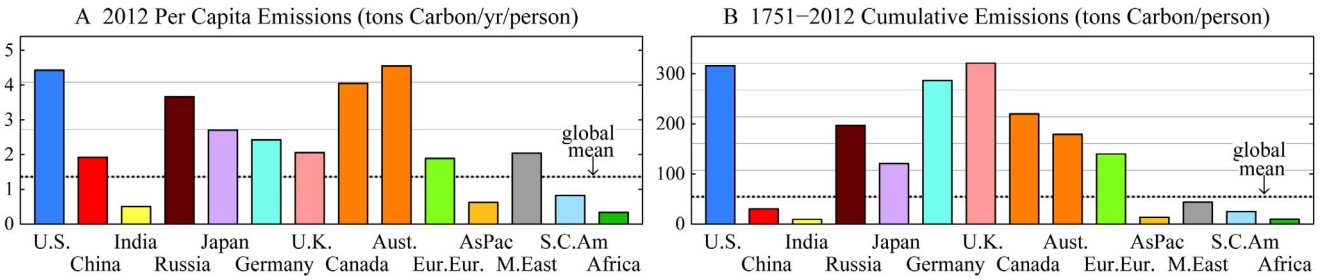

Figure 12. Per capita fossil fuel CO_2 emissions. Countries, regions and data sources are the same as in Fig. 11. Horizontal lines are the global mean and multiples of the global mean.
doi:10.1371/journal.pone.0081648.g012

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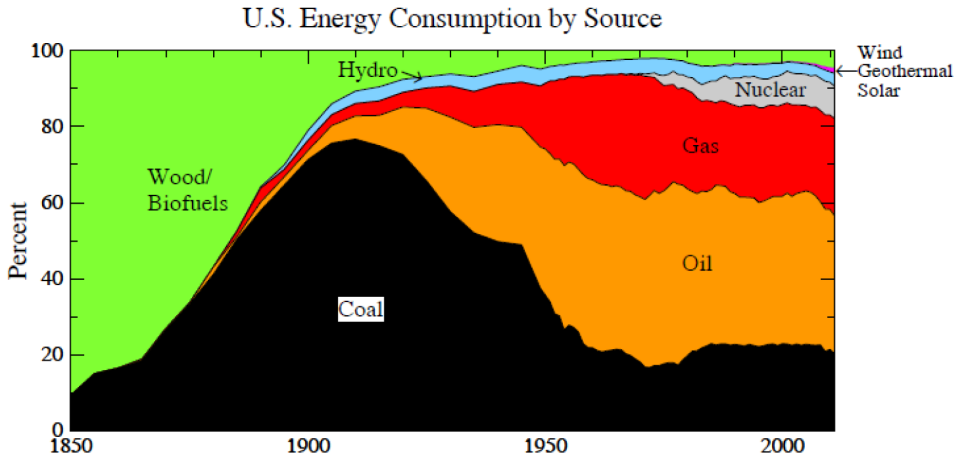

Figure 13. United States energy consumption [229].
doi:10.1371/journal.pone.0081648.g013

calculate that global emissions would have needed to decline 2.1%/year to limit cumulative fossil fuel emissions to 500 GtC. A start date of 2005 would have required a reduction of 3.5%/year for the same result.

The task faced today is more difficult. Emissions reduction of 6%/year and 100 GtC storage in the biosphere and soils are needed to get CO_2 back to 350 ppm, the approximate requirement for restoring the planet's energy balance and stabilizing climate this century. Such a pathway is exceedingly difficult to achieve, given the current widespread absence of policies to drive rapid movement to carbon-free energies and the lifetime of energy infrastructure in place.

Yet we suggest that a pathway is still conceivable that could restore planetary energy balance on the century time scale. That path requires policies that spur technology development and provide economic incentives for consumers and businesses such that social tipping points are reached where consumers move rapidly to energy conservation and low carbon energies. Moderate overshoot of required atmospheric CO_2 levels can possibly be counteracted via incentives for actions that more-or-less naturally sequester carbon. Developed countries, responsible for most of the excess CO_2 in the air, might finance extensive efforts in developing countries to sequester carbon in the soil and in forest regrowth on marginal lands as described above. Burning sustainably designed biofuels in power plants, with the CO_2 captured and sequestered, would also help draw down atmospheric CO_2. This pathway would need to be taken soon, as the magnitude of such carbon extractions is likely limited and thus not a solution to unfettered fossil fuel use.

The alternative pathway, which the world seems to be on now, is continued extraction of all fossil fuels, including development of unconventional fossil fuels such as tar sands, tar shale, hydro-fracking to extract oil and gas, and exploitation of methane hydrates. If that path (with 2%/year growth) continues for 20 years and is then followed by 3%/year emission reduction from 2033 to 2150, we find that fossil fuel emissions in 2150 would total 1022 GtC. Extraction of the excess CO_2 from the air in this case would be very expensive and perhaps implausible, and warming of the ocean and resulting climate impacts would be practically irreversible.

Economic Implications: Need for a Carbon Fee

The implication is that the world must move rapidly to carbon-free energies and energy efficiency, leaving most remaining fossil fuels in the ground, if climate is to be kept close to the Holocene range and climate disasters averted. Is rapid change possible?

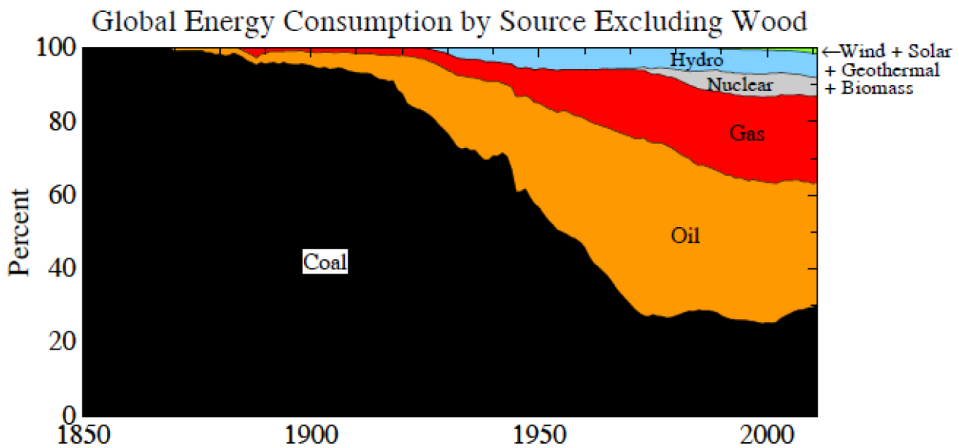

Figure 14. World energy consumption for indicated fuels, which excludes wood [4].
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The potential for rapid change can be shown by examples. A basic requirement for phasing down fossil fuel emissions is abundant carbon-free electricity, which is the most rapidly growing form of energy and also has the potential to provide energy for transportation and heating of buildings. In one decade (1977–1987), France increased its nuclear power production 15-fold, with the nuclear portion of its electricity increasing from 8% to 70% [231]. In one decade (2001–2011) Germany increased the non-hydroelectric renewable energy portion of its electricity from 4% to 19%, with fossil fuels decreasing from 63% to 61% (hydroelectric decreased from 4% to 3% and nuclear power decreased from 29% to 18%) [231].

Given the huge task of replacing fossil fuels, contributions are surely required from energy efficiency, renewable energies, and nuclear power, with the mix depending on local preferences. Renewable energy and nuclear power have been limited in part by technical challenges. Nuclear power faces persistent concerns about safety, nuclear waste, and potential weapons proliferation, despite past contributions to mortality prevention and climate change mitigation [232]. Most renewable energies tap diffuse intermittent sources often at a distance from the user population, thus requiring large-scale energy storage and transport. Developing technologies can ameliorate these issues, as discussed below. However, apparent cost is the constraint that prevents nuclear and renewable energies from fully supplanting fossil fuel electricity generation.

Transition to a post-fossil fuel world of clean energies will not occur as long as fossil fuels appear to the investor and consumer to be the cheapest energy. Fossil fuels are cheap only because they do not pay their costs to society and receive large direct and indirect subsidies [233]. Air and water pollution from fossil fuel extraction and use have high costs in human health, food production, and natural ecosystems, killing more than 1,000,000 people per year and affecting the health of billions of people [232,234], with costs borne by the public. Costs of climate change and ocean acidification, already substantial and expected to grow considerably [26,235], also are borne by the public, especially by young people and future generations.

Thus the essential underlying policy, albeit not sufficient, is for emissions of CO_2 to come with a price that allows these costs to be internalized within the economics of energy use. Because so much energy is used through expensive capital stock, the price should rise in a predictable way to enable people and businesses to efficiently adjust lifestyles and investments to minimize costs. Reasons for preference of a carbon fee or tax over cap-and-trade include the former's simplicity and relative ease of becoming global [236]. A near-global carbon tax might be achieved, e.g., via a bi-lateral agreement between China and the United States, the greatest emitters, with a border duty imposed on products from nations without a carbon tax, which would provide a strong incentive for other nations to impose an equivalent carbon tax. The suggestion of a carbon fee collected from fossil fuel companies with all revenues distributed to the public on a per capita basis [237] has received at least limited support [238].

Economic analyses indicate that a carbon price fully incorporating environmental and climate damage would be high [239]. The cost of climate change is uncertain to a factor of 10 or more and could be as high as ~\$1000/tCO_2 [235,240]. While the imposition of such a high price on carbon emissions is outside the realm of short-term political feasibility, a price of that magnitude is not required to engender a large change in emissions trajectory.

An economic analysis indicates that a tax beginning at \$15/tCO_2 and rising \$10/tCO_2 each year would reduce emissions in the U.S. by 30% within 10 years [241]. Such a reduction is more than 10 times as great as the carbon content of tar sands oil carried by the proposed Keystone XL pipeline (830,000 barrels/day) [242]. Reduced oil demand would be nearly six times the pipeline capacity [241], thus the carbon fee is far more effective than the proposed pipeline.

A rising carbon fee is the *sine qua non* for fossil fuel phase out, but not enough by itself. Investment is needed in RD&D (research, development and demonstration) to help renewable energies and nuclear power overcome obstacles limiting their contributions. Intermittency of solar and wind power can be alleviated with advances in energy storage, low-loss smart electric grids, and electrical vehicles interacting with the grid. Most of today's nuclear power plants have half-century-old technology with light-water reactors [243] utilizing less than 1% of the energy in the nuclear fuel and leaving unused fuel as long-lived nuclear "waste" requiring sequestration for millennia. Modern light-water reactors can employ convective cooling to eliminate the need for external cooling in the event of an anomaly such as an earthquake. However, the long-term future of nuclear power will employ "fast" reactors, which utilize ~99% of the nuclear fuel and can "burn" nuclear waste and excess weapons material [243]. It should be possible to reduce the cost of nuclear power via modular standard reactor design, but governments need to provide a regulatory environment that supports timely construction of approved designs. RD&D on carbon capture and storage (CCS) technology is needed, especially given our conclusion that the current atmospheric CO_2 level is already in the dangerous zone, but continuing issues with CCS technology [7,244] make it inappropriate to construct fossil fuel power plants with a promise of future retrofit for carbon capture. Governments should support energy planning for housing and transportation, energy and carbon efficiency requirements for buildings, vehicles and other manufactured products, and climate mitigation and adaptation in undeveloped countries.

Economic efficiency would be improved by a rising carbon fee. Energy efficiency and alternative low-carbon and no-carbon energies should be allowed to compete on an equal footing, without subsidies, and the public and business community should be made aware that the fee will continually rise. The fee for unconventional fossil fuels, such as oil from tar sands and gas from hydrofracking, should include carbon released in mining and refining processes, e.g., methane leakage in hydrofracking [245–249]. If the carbon fee rises continually and predictably, the resulting energy transformations should generate many jobs, a welcome benefit for nations still suffering from long-standing economic recession. Economic modeling shows that about 60% of the public, especially low-income people, would receive more money via a per capita 100% dispersal of the collected fee than they would pay because of increased prices [241].

Fairness: Intergenerational Justice and Human Rights

Relevant fundamentals of climate science are clear. The physical climate system has great inertia, which is due especially to the thermal inertia of the ocean, the time required for ice sheets to respond to global warming, and the longevity of fossil fuel CO_2 in the surface carbon reservoirs (atmosphere, ocean, and biosphere). This inertia implies that there is additional climate change "in the pipeline" even without further change of atmospheric composition. Climate system inertia also means that, if large-scale climate change is allowed to occur, it will be exceedingly long-lived, lasting for many centuries.

One implication is the likelihood of intergenerational effects, with young people and future generations inheriting a situation in which grave consequences are assured, practically out of their

control, but not of their doing. The possibility of such intergenerational injustice is not remote – it is at our doorstep now. We have a planetary climate crisis that requires urgent change to our energy and carbon pathway to avoid dangerous consequences for young people and other life on Earth.

Yet governments and industry are rushing into expanded use of fossil fuels, including unconventional fossil fuels such as tar sands, tar shale, shale gas extracted by hydrofracking, and methane hydrates. How can this course be unfolding despite knowledge of climate consequences and evidence that a rising carbon price would be economically efficient and reduce demand for fossil fuels? A case has been made that the absence of effective governmental leadership is related to the effect of special interests on policy, as well as to public relations efforts by organizations that profit from the public's addiction to fossil fuels [237,250].

The judicial branch of governments may be less subject to pressures from special financial interests than the executive and legislative branches, and the courts are expected to protect the rights of all people, including the less powerful. The concept that the atmosphere is a public trust [251], that today's adults must deliver to their children and future generations an atmosphere as beneficial as the one they received, is the basis for a lawsuit [252] in which it is argued that the U.S. government is obligated to protect the atmosphere from harmful greenhouse gases.

Independent of this specific lawsuit, we suggest that intergenerational justice in this matter derives from fundamental rights of equality and justice. The Universal Declaration of Human Rights [253] declares "All are equal before the law and are entitled without any discrimination to equal protection of the law." Further, to consider a specific example, the United States Constitution provides all citizens "equal protection of the laws" and states that no person can be deprived of "life, liberty or property without due process of law". These fundamental rights are a basis for young people to expect fairness and justice in a matter as essential as the condition of the planet they will inhabit. We do not prescribe the legal arguments by which these rights can be achieved, but we maintain that failure of governments to effectively address climate change infringes on fundamental rights of young people.

Ultimately, however, human-made climate change is more a matter of morality than a legal issue. Broad public support is probably needed to achieve the changes needed to phase out fossil fuel emissions. As with the issue of slavery and civil rights, public recognition of the moral dimensions of human-made climate change may be needed to stir the public's conscience to the point of action.

A scenario is conceivable in which growing evidence of climate change and recognition of implications for young people lead to massive public support for action. Influential industry leaders, aware of the moral issue, may join the campaign to phase out emissions, with more business leaders becoming supportive as they recognize the merits of a rising price on carbon. Given the relative ease with which a flat carbon price can be made international [236], a rapid global emissions phasedown is feasible. As fossil fuels are made to pay their costs to society, energy efficiency and clean energies may reach tipping points and begin to be rapidly adopted.

Our analysis shows that a set of actions exists with a good chance of averting "dangerous" climate change, if the actions begin now. However, we also show that time is running out. Unless a human "tipping point" is reached soon, with implementation of effective policy actions, large irreversible climate changes will become unavoidable. Our parent's generation did not know that their energy use would harm future generations and other life on the planet. If we do not change our course, we can only pretend that we did not know.

Discussion

We conclude that an appropriate target is to keep global temperature within or close to the temperature range in the Holocene, the interglacial period in which civilization developed. With warming of 0.8°C in the past century, Earth is just emerging from that range, implying that we need to restore the planet's energy balance and curb further warming. A limit of approximately 500 GtC on cumulative fossil fuel emissions, accompanied by a net storage of 100 GtC in the biosphere and soil, could keep global temperature close to the Holocene range, assuming that the net future forcing change from other factors is small. The longevity of global warming (Fig. 9) and the implausibility of removing the warming if it is once allowed to penetrate the deep ocean emphasize the urgency of slowing emissions so as to stay close to the 500 GtC target.

Fossil fuel emissions of 1000 GtC, sometimes associated with a 2°C global warming target, would be expected to cause large climate change with disastrous consequences. The eventual warming from 1000 GtC fossil fuel emissions likely would reach well over 2°C, for several reasons. With such emissions and temperature tendency, other trace greenhouse gases including methane and nitrous oxide would be expected to increase, adding to the effect of CO_2. The global warming and shifting climate zones would make it less likely that a substantial increase in forest and soil carbon could be achieved. Paleoclimate data indicate that slow feedbacks would substantially amplify the 2°C global warming. It is clear that pushing global climate far outside the Holocene range is inherently dangerous and foolhardy.

The fifth IPCC assessment Summary for Policymakers [14] concludes that to achieve a 50% chance of keeping global warming below 2°C equivalent CO_2 emissions should not exceed 1210 GtC, and after accounting for non-CO_2 climate forcings this limit on CO_2 emissions becomes 840 GtC. The existing drafts of the fifth IPCC assessment are not yet approved for comparison and citation, but the IPCC assessment is consistent with studies of Meinshausen et al. [254] and Allen et al. [13], hereafter M2009 and A2009, with which we can make comparisons. We will also compare our conclusions with those of McKibben [255]. M2009 and A2009 appear together in the same journal with the two lead authors on each paper being co-authors on the other paper. McKibben [255], published in a popular magazine, uses quantitative results of M2009 to conclude that most remaining fossil fuel reserves must be left in the ground, if global warming this century is to be kept below 2°C. McKibben [255] has been very successful in drawing public attention to the urgency of rapidly phasing down fossil fuel emissions.

M2009 use a simplified carbon cycle and climate model to make a large ensemble of simulations in which principal uncertainties in the carbon cycle, radiative forcings, and climate response are allowed to vary, thus yielding a probability distribution for global warming as a function of time throughout the 21st century. M2009 use this distribution to infer a limit on total (fossil fuel+net land use) carbon emissions in the period 2000–2049 if global warming in the 21st century is to be kept below 2°C at some specified probability. For example, they conclude that the limit on total 2000–2049 carbon emissions is 1440 $GtCO_2$ (393 GtC) to achieve a 50% chance that 21st century global warming will not exceed 2°C.

A2009 also use a large ensemble of model runs, varying uncertain parameters, and conclude that total (fossil fuel+net land use) carbon emissions of 1000 GtC would most likely yield a peak

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CO_2-induced warming of 2°C, with 90% confidence that the peak warming would be in the range 1.3–3.9°C. They note that their results are consistent with those of M2009, as the A2009 scenarios that yield 2°C warming have 400–500 GtC emissions during 2000–2049; M2009 find 393 GtC emissions for 2°C warming, but M2009 included a net warming effect of non-CO_2 forcings, while A2009 neglected non-CO_2 forcings.

McKibben [255] uses results of M2009 to infer allowable fossil fuel emissions up to 2050 if there is to be an 80% chance that maximum warming in the 21st century will not exceed 2°C above the pre-industrial level. M2009 conclude that staying under this 2°C limit with 80% probability requires that 2000–2049 emissions must be limited to 656 $GtCO_2$ (179 GtC) for 2007–2049. McKibben [255] used this M2009 result to determine a remaining carbon budget (at a time not specified exactly) of 565 $GtCO_2$ (154 GtC) if warming is to stay under 2°C. Let us update this analysis to the present: fossil fuel emissions in 2007–2012 were 51 GtC [5], so, assuming no net emissions from land use in these few years, the M2009 study implies that the remaining budget at the beginning of 2013 was 128 GtC.

Thus, coincidentally, the McKibben [255] approach via M2009 yields almost exactly the same remaining carbon budget (128 GtC) as our analysis (130 GtC). However, our budget is that required to limit warming to about 1°C (there is a temporary maximum during this century at about 1.1–1.2°C, Fig. 9), while McKibben [255] is allowing global warming to reach 2°C, which we have concluded would be a disaster scenario! This apparently vast difference arises from three major factors.

First, we assumed that reforestation and improved agricultural and forestry practices can suck up the net land use carbon of the past. We estimate net land use emissions as 100 GtC, while M2009 have land use emissions almost twice that large (~180 GtC). We argue elsewhere (see section 14 in Supporting Information of [54]) that the commonly employed net land use estimates [256] are about a factor of two larger than the net land use carbon that is most consistent with observed CO_2 history. However, we need not resolve that long-standing controversy here. The point is that, to make the M2009 study equivalent to ours, negative land use emissions must be included in the 21st century equal to earlier positive land use emissions.

Second, we have assumed that future net change of non-CO_2 forcings will be zero, while M2009 have included significant non-CO_2 forcings. In recent years non-CO_2 GHGs have provided about 20% of the increase of total GHG climate forcing.

Third, our calculations are for a single fast-feedback equilibrium climate sensitivity, 3°C for doubled CO_2, which we infer from paleoclimate data. M2009 use a range of climate sensitivities to compute a probability distribution function for expected warming, and then McKibben [255] selects the carbon emission limit that keeps 80% of the probability distribution below 2°C.

The third factor is a matter of methodology, but one to be borne in mind. Regarding the first two factors, it may be argued that our scenario is optimistic. That is true, but both goals, extracting 100 GtC from the atmosphere via improved forestry and agricultural practices (with possibly some assistance from CCS technology) and limiting additional net change of non-CO_2 forcings to zero, are feasible and probably much easier than the principal task of limiting additional fossil fuel emissions to 130 GtC.

We noted above that reforestation and improving agricultural and forestry practices that store more carbon in the soil make sense for other reasons. Also that task is made easier by the excess CO_2 in the air today, which causes vegetation to take up CO_2 more efficiently. Indeed, this may be the reason that net land use emissions seem to be less than is often assumed.

As for the non-CO_2 forcings, it is noteworthy that greenhouse gases controlled by the Montreal Protocol are now decreasing, and recent agreement has been achieved to use the Montreal Protocol to phase out production of some additional greenhouse gases even though those gases do not affect the ozone layer. The most important non-CO_2 forcing is methane, whose increases in turn cause tropospheric ozone and stratospheric water vapor to increase. Fossil fuel use is probably the largest source of methane [1], so if fossil fuel use begins to be phased down, there is good basis to anticipate that all three of these greenhouse gases could decrease, because of the approximate 10-year lifetime of methane.

As for fossil fuel CO_2 emissions, considering the large, long-lived fossil fuel infrastructure in place, the science is telling us that policy should be set to reduce emissions as rapidly as possible. The most fundamental implication is the need for an across-the-board rising fee on fossil fuel emissions in order to allow true free market competition from non-fossil energy sources. We note that biospheric storage should not be allowed to offset further fossil fuel emissions. Most fossil fuel carbon will remain in the climate system more than 100,000 years, so it is essential to limit the emission of fossil fuel carbon. It will be necessary to have incentives to restore biospheric carbon, but these must be accompanied by decreased fossil fuel emissions.

A crucial point to note is that the three tasks [limiting fossil fuel CO_2 emissions, limiting (and reversing) land use emissions, limiting (and reversing) growth of non-CO_2 forcings] are interactive and reinforcing. In mathematical terms, the problem is non-linear. As one of these climate forcings increases, it increases the others. The good news is that, as one of them decreases, it tends to decrease the others. In order to bestow upon future generations a planet like the one we received, we need to win on all three counts, and by far the most important is rapid phasedown of fossil fuel emissions.

It is distressing that, despite the clarity and imminence of the danger of continued high fossil fuel emissions, governments continue to allow and even encourage pursuit of ever more fossil fuels. Recognition of this reality and perceptions of what is "politically feasible" may partially account for acceptance of targets for global warming and carbon emissions that are well into the range of "dangerous human-made interference" with climate. Although there is merit in simply chronicling what is happening, there is still opportunity for humanity to exercise free will. Thus our objective is to define what the science indicates is needed, not to assess political feasibility. Further, it is not obvious to us that there are physical or economic limitations that prohibit fossil fuel emission targets far lower than 1000 GtC, even targets closer to 500 GtC. Indeed, we suggest that rapid transition off fossil fuels would have numerous near-term and long-term social benefits, including improved human health and outstanding potential for job creation.

A world summit on climate change will be held at United Nations Headquarters in September 2014 as a preliminary to negotiation of a new climate treaty in Paris in late 2015. If this treaty is analogous to the 1997 Kyoto Protocol [257], based on national targets for emission reductions and cap-and-trade-with-offsets emissions trading mechanisms, climate deterioration and gross intergenerational injustice will be practically guaranteed. The palpable danger that such an approach is conceivable is suggested by examination of proposed climate policies of even the most forward-looking of nations. Norway, which along with the other Scandinavian countries has been among the most ambitious and successful of all nations in reducing its emissions, nevertheless approves expanded oil drilling in the Arctic and development of tar sands as a majority owner of Statoil [258–259]. Emissions

foreseen by the Energy Perspectives of Statoil [259], if they occur, would approach or exceed 1000 GtC and cause dramatic climate change that would run out of control of future generations. If, in contrast, leading nations agree in 2015 to have internal rising fees on carbon with border duties on products from nations without a carbon fee, a foundation would be established for phaseover to carbon free energies and stable climate.

Supporting Information

Table S1
(ODS)

Table S2
(ODS)

Table S3
(ODS)

Text S1
(DOC)

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Author Contributions

Conceived and designed the experiments: JH PK MS. Performed the experiments: MS PK. Wrote the paper: JH. Wrote the first draft: JH. All authors made numerous critiques and suggested specific wording and references: JH PK MS VM-D FA DJB PJH OHG SLH CP JR EJR JS PS KS LVS KvS JCZ. Especially: PK MS VM-D.

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BEFORE THE PUBLIC UTILITIES COMMISSION
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IN THE MATTER OF TRANSCANADA KEYSTONE PIPELINE, LP FOR ORDER ACCEPTING CERTIFICATION OF PERMIT ISSUED IN DOCKET HP-09-001 TO CONSTRUCT THE KEYSTONE XL PIPELINE	Surrebuttal to Darren Kearney's rebuttal to Cindy Myers' testimony regarding Dr. Madden's socio-economic analysis HP14-001

I am responding to Darren Kearney's rebuttal to my direct testimony. My testimony stated:

> "testimonial analysis by Dr. Madden is woefully inadequate to meet SDCL 49-416-22, which requires the project must protect the health, safety and welfare of SD residents. He is not a medical doctor, but an economist."

Mr. Kearney states I misunderstood the purpose of Dr. Madden's testimony.

I understand that Dr. Madden is an economist and his testimony reflects a very brief socio-economic analysis of the project.

However, as written, the HP09-001 document, specifically Finding of Fact #107, implies that Dr. Madden's analysis from a socioeconomic standpoint was also meant to support the subpart of SDCL 49-41 B-22 which states:

"The facility will not substantially impair the health, safety or welfare of the inhabitants."

Finding of Fact #107 is included in Appendix C, South Dakota Final Decision and Order Tracking Table of Changes which was ordered by the PUC as part of the scope of discovery.

Finding of Fact #107 is listed under the heading "Socio-Economic Factors".

HP09-001, Finding of Fact #107, as directly copied from that document:

Socio-Economic Factors
107. Socio-economic evidence offered by both Keystone and Staff demonstrates that the welfare of the citizens of South Dakota will not be impaired by the Project. Staff expert Dr. Michael Madden conducted a socio-economic analysis of the Keystone Pipeline, and concluded that the positive economic benefits of the project were unambiguous, while most if not all of the social impacts were positive or neutral. S-2, Madden Assessment at 21. The Project, subject to compliance with the Special Permit and the Conditions herein, would not, from a socioeconomic standpoint: (i) pose a threat of serious injury to the socioeconomic conditions in the project area; (ii) substantially impair the health, safety, or welfare of the inhabitants in the project area; or(iii) unduly interfere with the orderly development of the region.

I agree with Mr. Kearney that Dr. Madden's testimony does not include information concerning how the project would impact the health, safety, or welfare of the inhabitants, but finding of fact #107, as written, concludes that Dr. Madden's testimony supports SDCL 49-41 B-22, including the subpart "The facility will not pose a threat of serious injury to the environment nor to the social and economic condition of inhabitants or expected inhabitants in the siting area" and also the subpart "the facility will not substantially impair the health, safety or welfare of the inhabitants"

Respectfully submitted this 29th day of April, 2015

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BEFORE THE PUBLIC UTILITIES COMMISSION
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HP 14-001

IN THE MATTER OF THE PETITION OF TRANSCANADA KEYSTONE PIPELINE, LP FOR ORDER ACCEPTING CERTIFICATION OF PERMIT ISSUED IN DOCKET HP09-001 TO CONSTRUCT THE KEYSTONE XL PROJECT

SURREBUTTAL TESTIMONY OF COREY GOULET

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Petitioner TransCanada Keystone Pipeline, LP, offers the following surrebuttal testimony of Corey Goulet.

1. Please state your name and address for the record.

Answer: My name is Corey Goulet. My business address is 450 1st Street S.W., Calgary, AB Canada T2P 5H1.

2. Please state your position with Keystone and provide a description of your areas of responsibility with respect to the Keystone XL Project.

Answer: I am President, Keystone Projects, with overall accountability for the implementation and development of the Keystone Pipeline system, including the Keystone XL Project (Project). In that capacity, I am responsible for overall leadership and direction of the Project.

3. Have you provided direct and rebuttal testimony in this proceeding?

Answer: Yes, I have.

4. Which witnesses' rebuttal testimony are you responding to in your surrebuttal testimony?

Answer: I am responding to portions of the rebuttal testimony of John Harter.

5. In paragraph 2, Mr. Harter states that TransCanada does not have an agreement with him for an easement to allow the construction and operation of the Keystone XL Pipeline across his property. Is that a correct statement?

Answer: No. Although TransCanada Keystone Pipeline, LP ("Keystone"), filed a lawsuit against John and Tammy Harter to obtain an easement through the use of eminent domain, the parties reached a settlement agreement on November 27, 2012, which was days before the case was set for trial. John Harter signed a document that day stating the settlement terms, which were confidential. He agreed that he would execute a final settlement agreement and an easement. Over the next two years, however, Mr. Harter failed to sign an easement or a formal settlement agreement. Thus, Keystone asked the Court to either set the case for trial, or enforce the terms of the settlement agreement. On August 5, 2014, the circuit court, the Honorable John L. Brown, entered an order that the settlement terms agreed to on November 27, 2012, constituted an enforceable agreement. The order was filed on August 7, 2014, in *TransCanada v. Harter*, Civ. 11-62 (6th Jud. Cir.)

6. In paragraph 6, Mr. Harter states that "TransCanada simply took my private property using eminent domain." Is that a correct statement?

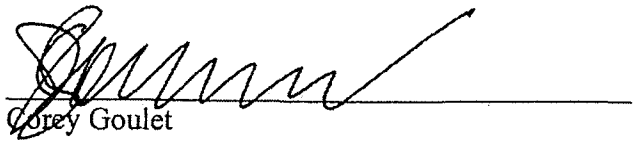
Answer: No. The circuit court in Civ. 11-62 entered judgment granting an easement in favor of Keystone based on the agreement reached between the parties. Although Keystone filed

a lawsuit against Mr. Harter based on eminent domain, the judgment granting an easement was the result of the settlement agreement.

7. **Does this conclude your prepared surrebuttal testimony?**

Answer: Yes.

Dated this 25 day of July, 2015.



Corey Goulet

CERTIFICATE OF SERVICE

I hereby certify that on the 27th day of July, 2015, I sent by United States first-class mail, postage prepaid, or e-mail transmission, a true and correct copy of the foregoing Surrebuttal Testimony of Corey Goulet, to the following:

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/s/ James E. Moore
One of the attorneys for TransCanada

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

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IN THE MATTER OF THE PETITION OF TRANSCANADA KEYSTONE PIPELINE, LP FOR ORDER ACCEPTING CERTIFICATION OF PERMIT ISSUED IN DOCKET HP09-001 TO CONSTRUCT THE KEYSTONE XL PROJECT	:	DOCKET NUMBER HP14-001 SURREBUTTAL TESTIMONY OF DAN KING

o-o-o-o-o-o-o-o-o-o-o-o-o-o-o-o-o-o-o-o-o-o-o-o-o-o-o-o-o-o-o-o-o

Petitioner TransCanada Keystone Pipeline, LP offers the following surrebuttal testimony of Dan King.

1. Please state your name and address for the record.

Answer: My name is Dan King. My role at TransCanada is Vice-President of Engineering, Asset Reliability and Chief Engineer. I am responsible for ensuring the safety and reliability of TransCanada's pipeline assets.

2. Please state your professional qualifications and experience.

Answer: I have been with TransCanada for 32 years. During that time, I have participated in the design, construction, operation and maintenance of TransCanada's natural gas and oil facilities in Canada, the United States, Mexico and overseas. I lead a team of approximately 600 engineers and other professionals whose job it is to meet or exceed regulatory requirements in the design, construction and safe operation of TransCanada's pipeline assets. I hold a Bachelor of Science degree in electrical engineering from the

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University of Calgary. I am a member of the Association of Professional Engineers and Geoscientists of Alberta, the American Society of Mechanical Engineers, and the Institute of Electrical Electronics Engineers. I sit on the board of the Common Ground Alliance, which is a U.S.-based non-profit organization that promotes the importance of safe excavation around utilities.

3. Have you provided rebuttal testimony in this proceeding?

Answer: Yes, I have.

4. Which witness's rebuttal testimony are you responding to in your surrebuttal?

Answer: I am responding to portions of the rebuttal testimony of Evan Vokes.

5. Were there any regulatory non-compliances issued by the Pipeline and Hazardous Materials Safety Administration related to the Special Conditions on the Gulf Coast Pipeline Project?

Answer: No, TransCanada was not issued any notices of probable violations by PHMSA. TransCanada did receive two Warning Letters from PHMSA. The first, issued September 10, 2013, related to pipe installation in the ditch and protection of existing pipeline coating from potential damage due to the welding. TransCanada provided a detailed response to PHMSA on October 24, 2013 pointing out that TransCanada had constructed Gulf Coast to the same rigorous Special Conditions that will apply to KXL. One of the Special Conditions requires implementation of a performance-based quality assurance (QA) program. The intent of the program is to ensure that all potentially injurious construction or manufacturing-related defects are identified and remedied prior to placing the pipeline into

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service. TransCanada had voluntarily reported to PHMSA the two areas of concern identified in PHMSA's letter and the fact that they were discovered by the secondary, post-installation QA program shows that the process works. The QA program functioned as intended to allow the coating damage and pipe body dents described in PHMSA's letter to be identified by TransCanada and repaired prior to placing the pipeline into operation.

The second Warning Letter issued on September 26, 2013 and expressed concerns regarding the manual welding process used on Spread 3 of the project. In addition to the prior 12 months of extensive meetings and discussions with PHMSA, the exhaustive records reviews, and the comprehensive voluntary supplemental destructive testing conducted to prove the safely of the welds, after receipt of PHMSA's letter, on November 26, 2013, PHMSA's Washington and Regional representatives met with TransCanada to discuss the welding issues raised in the letter. At the meeting, TransCanada's subject matter experts and independent, third-party consultant confirmed that the welder qualifications and manual welding procedures performed on Spread 3 of the Project did, in fact, comply with all applicable requirements of 49 C.F.R. Part 195 and the standards incorporated by reference into the regulations. The conclusions reached at the meeting established that TransCanada had preemptively addressed any welding issues experienced at the very initial stages of construction of Spread 3 and had taken appropriate and additional steps to ensure the integrity of the welds.

With respect to both Warning Letters, PHMSA closed the files after receiving TransCanada's responses to them and, after TransCanada certified compliance with the Special Conditions, PHMSA authorized the Gulf Coast pipeline to be placed into service.

6. Please explain the PHMSA oversight process on the Gulf Coast Pipeline Project?

Answer: PHMSA's inspection of the Gulf Coast Project spanned three years, engaged 10 PHMSA inspectors (including a dedicated Project Manager), and entailed 165.9 days PHMSA personnel either spent in the field with the project or at off-site inspection locations. PHMSA oversight included:

- Design review meetings
- Field inspection audits on specific construction activities
- Construction records audits
- Fabrication facility audits
- Pipe mill audits.

Monthly management meetings were conducted to review construction status, Special Condition compliance, and quality findings and remediation arising from the Project's quality management program and PHMSA audit observations. The Project uploaded nearly 60,000 construction and compliance documents to a dedicated SharePoint site for PHMSA to review.

7. Mr. Vokes suggests that a fatality occurred on the Gulf Coast Project caused by pipe falling off the skids. Is that accurate?

Answer: No, it is not.

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8. Can you comment on Mr. Vokes' allegations of deficiencies related to the corrosion defect found on the Keystone System in 2012?

Answer: Yes. Cathodic protection must be in operation not later than 1 year after the pipeline is constructed. The cathodic protection system on the Keystone pipeline was operational within six months of the pipeline's construction as required by Condition 36 of the PHMSA Special Conditions applicable to the base Keystone system. TransCanada began working with the operators of the nearby pipelines and adjustments were being made to the network of cathodic protection systems within the pipeline corridor to fine-tune the cathodic protection system and resolve the interference issue. The location of the small, isolated corrosion feature was subsequently identified during the baseline in-line inspection. The subsequent excavation and inspection determined the feature to be localized metal loss. The feature was repaired per criteria set forth in PHMSA Special Condition 48. This incident demonstrates our pipeline inspection systems worked as they were designed to do.

9. Mr. Vokes alleges that TransCanada has experienced widespread problems with fusion bonded epoxy (FBE) pipeline coating, including systemic coating disbondment on its natural gas GTN pipeline. Are you able to comment?

Answer: TransCanada has over thirty years of experience with FBE and uses FBE because it adheres well to the pipe and, even if it does disbond, it is easily detectable for repair and its disbondment does not interfere with the protection provided by the cathodic protection system. With specific reference to GTN, no systemic coating disbondment issues exist on the pipeline.

10. Is the Keystone XL pipeline subject to column separation?

Answer: All liquids pipelines, including water lines, are subject to column separation. Column separation or slack line is a condition that occurs when the pressure in a pipeline drops below the vapor pressure of the liquid (essentially zero pressure) and a vapor space forms within the pipeline between liquid-filled spaces. Column separation can have detrimental effects on the pipeline and equipment and is therefore avoided during flowing operations.

TransCanada utilizes both automated control systems and control center operating procedures to prevent column separation. Pipeline pump stations and other facilities are equipped with automated control systems that monitor and control the pressure along the pipeline while operating at levels significantly above the vapor pressure of the oil in the pipeline, thereby preventing column separation while the pipeline is flowing. Additionally, pressures along the entire pipeline are continually monitored 24 hours a day, 7 days a week from the pipeline control center by trained Controllers. The Controllers are trained to recognize the pending onset of column separation and are also equipped with automated advisory systems that will alert them of pending column separation. The Controllers will then adjust operating pressure set-points accordingly to prevent the onset of column separation.

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11. Do you know the cause of the failure on the ExxonMobil Pegasus pipeline in Mayflower, Arkansas?

Answer: PHMSA determined that the Pegasus pipeline failed due to manufacturing defects that were present in the pipe. The section of pipeline that failed was low-frequency ERW pipe manufactured by Youngstown in the late 1940's. This vintage of pipe is well-documented to be prone to manufacturing defects within the longitudinal ERW seam which can cause leaks and failures. The Pegasus pipeline did not fail because it was transporting heavy Canadian crude or a dilbit mix.

The manufacturing defects present on the Pegasus pipeline are a product of the pipe manufacturing processes that were used during that period in time. Modern steelmaking and pipe manufacturing processes prevent these defects from occurring on new pipelines.

12. Can you comment on Mr. Vokes' allegations that armor plate is not an effective repair technique for repair of external corrosion?

Answer: The use of composite reinforcement systems (i.e., armor plate) for pipelines has been extensively studied and they have been an accepted practice within the pipeline industry for decades and by PHMSA. Both ASME and ISO have established standards for the design and use of composite reinforcement on pipelines. The Armor Plate Pipe Wrap system that was used on Keystone has been tested more extensively than any other composite pipeline reinforcement system in the world. This system uses fiberglass to reinforce the pipeline, which is a material that has been used for structural applications since the 1930's.

012484

Dated this 26 day of July, 2015.

Dan King

CERTIFICATE OF SERVICE

I hereby certify that on the 27th day of July, 2015, I sent by United States first-class mail, postage prepaid, or e-mail transmission, a true and correct copy of the foregoing Surrebuttal Testimony of Dan King, to the following:

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION BY TRANSCANADA KEYSTONE PIPELINE, LP FOR A PERMIT UNDER THE SOUTH DAKOTA ENERGY CONVERSION AND TRANSMISSION FACILITIES ACT TO CONSTRUCT THE KEYSTONE XL PROJECT	)))))))	HP14-001 **KEYSTONE'S RESPONSES TO DAKOTA RURAL ACTION'S FIRST INTERROGATORIES TO TRANSCANADA KEYSTONE PIPELINE, LP**

Applicant TransCanada makes the following responses to interrogatories pursuant to SDCL § 15-6-33, and responses to requests for production of documents pursuant to SDCL § 15-6-34(a). These responses are made within the scope of SDCL 15-6-26(e) and shall not be deemed continuing nor be supplemented except as required by that rule. Applicant objects to definitions and directions in answering the discovery requests to the extent that such definitions and directions deviate from the South Dakota Rules of Civil Procedure.

GENERAL OBJECTION

Keystone objects to the instructions and definitions contained in Dakota Rural Action's First Set of Interrogatories and Requests for Production of Documents to the extent that they are inconsistent with the provisions of SDCL Ch. 15-6. *See* ARSD 20:10:01:01.02. Keystone's answers are based on the requirements of SDCL §§ 15-6-26, 15-6-33, 15-6-34, and 15-6-36.

INTERROGATORIES

INTERROGATORY NO. 1. Please identify the person or persons providing each answer to an Interrogatory or portion thereof, giving the full name, address of present residence, date of birth, business address and occupation. [Applicable Finding or Condition No.: all]

ANSWER: Given the extremely broad scope volume of more than 800 discovery requests received by Keystone in this docket, a range of personnel were involved in answering the interrogatories. Keystone will designate the following witnesses with overall responsibility for the responsive information as related to the Conditions and proposed changes to the Findings of Fact, which are identified in Appendix C to Keystone's Certification Petition: Corey Goulet, President, Keystone Projects, 450 1st Street S.W., Calgary, AB Canada T2P 5H1; Steve Marr, Manager, Keystone Pipelines & KXL, TransCanada Corporation, Bank of America Center, 700 Louisiana, Suite 700, Houston, TX 77002; Meera Kothari, P. Eng., 450 1st Street, S.W., Calgary, AB Canada T2P 5H1; David Diakow, Vice President, Commercial, Liquids Pipeline, 450 1st Street S.W., Calgary, AB Canada T2P 5H1; Jon Schmidt, Vice President, Environmental & Regulatory, exp Energy Services, Inc., 1300 Metropolitan Boulevard, Suite 200, Tallahassee, FL 32308; Heidi Tillquist, Senior Associate, Stantec Consulting Ltd., 2950 E. Harmony Rd., Suite 290, Fort Collins, CO 80528.

INTERROGATORY NO. 2. Prior to answering these interrogatories, have you made due and diligent search of all books, records, and papers of the Applicant with the view of eliciting all information available in this action? [Applicable Finding or Condition No.: all]

ANSWER: Yes, to the extent reasonably practicable in attempting to respond to over 800 discovery requests within the time allowed.

INTERROGATORY NO. 3. Describe the current status of the following permits and plans required prior to the start of construction of the KXL Pipeline:

A. Permits from US Army Corps of Engineers, S.D. Regulatory Office, including under:

1) §§404/401 of Clean Water Act, for authorization of discharge of fill material into waters of the United States including wetlands or other action;

2) §10 Rivers and Harbors Act, for authorization of pipeline crossings of navigable waters of the United States or other action;

3) Section 106 of the Natural Historic Preservation Act (NHPA), including consultation with potentially impacted Tribes and/or other action;

B. Permits from U.S. Fish and Wildlife Service, S.D. Ecological Services Field Office, including under the Endangered Species Act, Section 7 Consultation, to consider lead agency findings of impacts on federal-listed species, to provide a Biological Opinion if the Project is likely to adversely affect federally-listed or proposed species or their habitats, or other action;

C. Permits from Farm Service Agency of the Natural Resources Conservation Service, including the Crop Reserve Program, for authorization of crossing areas enrolled in the Crop Reserve Program, or other action;

D. Permit(s) from or Plan(s) Required to the S.D. Department of Environment and Natural Resources (DENR), including under:

1) National Pollutant Discharge Elimination System General Permit for Discharges of Hydrostatic Test Water, regarding proposed discharge into waters of the United States and construction dewatering of waters of the State, or other action;

2) Surface Water Withdrawal Permit, for temporary surface water withdrawal, or other action;

3) SDCL Chapter §34A-18, required submission of an Oil Spill Response Plan or Updated Plan to DENR, or other action;

E. Consultation with SD Game Fish and Parks Department, under State Listed Threatened and Endangered Species;

F. Any Updated Review and Comment from S.D. State Historical Society, State Preservation Office, under §106 of the NHPA, on activities regarding jurisdictional cultural resources;

G. Crossing Permits from S.D. Department of Transportation for crossing State highways;

H. Crossing Permits from County Road Departments for crossing of county roads;

I. Flood plain, Conditional Use, and building permits where required from County and Local Authorities.

[Applicable Finding or Condition No.: Conditions 1, 2; Findings 12(1)-(3), 60, 88, 90, 97-99]

ANSWER:

A. 1) No permit applications have been submitted to the US Army Corps of Engineers, S.D. Regulatory Office.

A. 2) No waterbody crossing in South Dakota requires permitting under the Section 10 of the Rivers and Harbor Act.

A. 3) The Department of State is the lead agency for the consultation process under the Section 106. See Section 4.11, Cultural Resources of the Department of State FSEIS (2014) for a full discussion of the Project's compliance with Section 106.

B. Keystone has not received any permits from the US Fish and Wildlife Service. The US Fish and Wildlife Service issued a Biological Opinion for the Project on May 15, 2013. The Biological Opinion is found in Appendix H of the Department of State FSEIS (2014)

C. In South Dakota, Keystone has not received any permits from the Farm Service Agency of Natural Resources Conservation Service.

D. 1) Keystone has received a General Permit for Temporary Discharge Activities on April 11, 2013 from the SD Department of Environment and Natural Resources.

D. 2) Keystone has not received a Surface Water Withdrawal Permit from SD Department of Environment and Natural Resources.

D. 3) Keystone has not submitted an Oil Response Plan to DENR.

E. The following is a summary of Keystone's consultation history with SD Game, Fish, and Parks as documented in the USFWS issued May 2013 Biological Opinion.

- June 10, 2008: Keystone met with staff from USFWS and South Dakota Department of Game, Fish, and Parks (SDGFP), at the SDGFP office in Pierre, South Dakota, to discuss issues pertaining to wildlife, special status species, and sensitive habitat that could potentially occur in the Project area. The goal of the meeting was to gather input on agency recommendations based on the information sent to them in April 2008 for species occurrence, habitat assessments, and future field surveys. Keystone incorporated comments from the meeting into survey protocols and BMPs for future agency verification.

- January/February 2009: Keystone initiated section 7 consultation with the USFWS. Keystone continued discussions with BLM, and state wildlife agency offices for South Dakota that included state-specific special status species survey protocols and BMPs for the species identified as potentially occurring during the 2008 meetings. A summary of the findings from the 2008 biological field surveys was included in the discussions.

- January 27, 2009: Keystone met with staff from the USFWS and SDGFP at the SDGFP office in Pierre, South Dakota, to discuss issues pertaining to special status species surveys. The goals of the meeting were to verify Keystone's survey approach, BMPs, discuss required field surveys, and review the information that was sent to the USFWS in the January/February 2009, informal consultation package. The USFWS and SDGFP provided additional recommendations to Keystone's sensitive species mitigation approach to be updated prior to final agency concurrence.

- October 23, 2012: A meeting was held between the USFWS, Department, SDGFP, BLM, and Keystone regarding the greater sage–grouse and a compensatory mitigation plan for the species in South Dakota. Discussions included a management plan and avoidance, minimization, and mitigation strategies.

F. Consultation with the SD SHPO is ongoing. Questions regarding specific cultural resources are resolved in a timely manner and would continue in the same manner in the future.

G. Thirteen crossing permits and twenty-four temporary approach permit applications have been filed with the State of South Dakota Department of Transportation (SD DOT) for the pipeline to cross under the state road rights-of-way. All crossing and temporary approach permits have been received from the SD DOT.

H. A total of 103 crossing permit applications have been filed for the pipeline to cross under all county road rights-of-way. Of the 103 applications filed, 101 have been acquired as of December 30, 2014.

I. The special use permits required for Harding County and Meade County pump stations have been approved. Of the remaining four pump stations, three do not require a special use permit. Special use permits applicable to valve sites, contractor yards, and contractor camps will be obtained prior to construction.

INTERROGATORY NO. 4. Do you agree that diluted bitumen spills require different spill response techniques and different equipment types and amounts as compared to (a) a spill of conventional crude oil and (b) a spill of Williston Basin light crude oil? Please explain your answer and list any scientific study(ies) providing the basis for your answer. [Applicable Finding or Condition No.: Amended Condition 31-42]

ANSWER: Crude oils are naturally variable; however, they share a range of common characteristics and properties that are important for emergency response purposes. The characteristics of the crude oils transported by Keystone XL are not unique and are transported throughout the US by truck, rail, pipelines, barges, and tankers. Crude oils has been safely transported by pipelines for decades. The Emergency Response Plan (ERP) will identify a range of appropriate standard response techniques that may be implemented in the event of a crude oil release. Ultimately, site-specific conditions, including the type of crude oil released, will assist in characterizing the nature of the release, its movement and fate within the environment, and selecting the most appropriate measures for containment and cleanup. The final version of the Keystone Pipeline Emergency Response Plan (ERP) is complete and complies with 49 C.F.R.

Part 194. The Keystone ERP will be amended to include Keystone XL. The ERP also addressed in the FSEIS at http://keystonepipeline-xl.state.gov/documents/organization/221189.pdf.

INTERROGATORY NO. 5. Do you agree that diluted bitumen is heavier than conventional crude and results in greater expenses to remediate leaks or spills? Please explain your answer and identify any known scientific study(ies) providing the basis for your answer. [Applicable Finding or Condition No.: Amended Condition 31-42/]

ANSWER: Physical characteristics of diluted bitumen are comparable to heavy conventional crude oil and consequently remediation costs would be anticipated to be equivalent. Diluted bitumen (API gravity of approximately 20-22) is heavier than light conventional crude oils (API gravity of approximately 35 to 40), but is consistent with heavy conventional crude oils (API gravity of approximately 19-22). All have API gravities greater than 10, indicating that the oils will float if released into water. The physicochemical properties and environmental fate of diluted bitumen are the same as that of heavy conventional crude oils. Thus, leaks and spills of diluted bitumen would not be expected to result in greater remediation expenses. A number of scientific studies have been conducted on the environmental fate and effects of diluted bitumen and other heavy crude oils, including:

Environment Canada. 2013. Properties, Composition and Marine Spill Behaviour, Fate and Transport of Two Diluted Bitumen Products from the Canadian Oil Sands. Federal Government Technical Report.

Rymell, Matthew. 2009. RP595 Sunken and submerged oils – behavior and response. February 2009. BMT Cordah. Available from:

http://www.dft.gov.uk/mca/s_mca_019_sunken__and__submerged_oils_final_report_270209_pub_1.pdf

SL Ross. 2012. Meso-scale Weathering of Cold Lake Bitumen/Condensate Blend. SL Ross Environmental Research Limited. Ottawa, Ontario.

INTERROGATORY NO. 6. Do you agree that soil and rocks that are contaminated by oil spills cannot be cleaned but instead must be removed and disposed of in hazardous waste facilities? Please explain your answer and list any scientific study(ies) providing the basis for your answer.

A. If so, do you agree that reclamation efforts for oil spills of the magnitude of the worst case discharge amount for the Keystone XL Pipeline fail to recover 100% of the oil contaminating the ground?

B. Identify the Documents created by or on your behalf which would show the basis for your answer to this Interrogatory.

[Applicable Finding or Condition No.: Amended Condition 32-38]

ANSWER: Keystone does not agree with this statement. Although removal and disposal of contaminated materials is an effective and well established means of limiting the area affected by a crude oil spill, it is not the only option. In the event of a release affecting soils in South Dakota, Keystone would be required to meet the state's soil remediation standards. This can be accomplished using a number of active remediation techniques, including removal of crude oil, dual-pump recovery, total fluids recovery, bioslurping, air sparging, chemical oxidation, and enhanced biodegradation through the addition of oxygen and nutrients into the

soil (Sutherson 1997). In addition, natural biodegradation and attenuation would ultimately allow for a return to preexisting conditions in soil.

Sutherson, S.S. 1997. Remediation Engineering: Design concepts. CRC Press, Boca Raton, FL.

A. Due to the volatility of many crude oil constituents (e.g., BTEX), a significant portion of crude oil will evaporate soon after being released to the environment. Fate modeling of diluted bitumen indicates that approximately 20% of released crude oil would evaporate within 6 hours of a spill (NOAA 2015). Additional processes such as photodegradation and biodegradation also naturally decrease the volume of crude oil in the environment. Thus, a significant fraction of the discharge volume of a crude oil spill would not be available for recovery due to these natural weathering processes.

If there is an accidental release from the proposed Project, Keystone would implement the remedial measures necessary to meet the federal, state, and local standards that are designed to help ensure protection of human health and environmental quality. Cleanup standards for the state of South Dakota are available in the South Dakota Department of Environment and Natural Resources' Petroleum Assessment and Cleanup Handbook (http://denr.sd.gov/des/gw/spills/handbook/hand_book.aspx). Additional information on remediation is presented in Section 4.13 of the FSEIS, Potential Releases.

B. NOAA. 2015. ADIOS2. Oil Spill response tool – documentation. http://response.restoration.noaa.gov/adios

INTERROGATORY NO. 7. For each incident since January 1, 2010 in which any pipeline transporting crude oil constructed by TransCanada and its Affiliates leaked or spilled pipeline contents, please provide the:

A. Date;

B. Location:

C. Amount of materials leaked or spilled;

D. Duration of leak or spill before (i) the control center being notified, (ii) pump shut down, (iii) valve shutoff, (iv) national response center notified, and (v) arrival of responders on the scene;

E. Duration of reclamation of affected soil and/or water resources;

F. Established and documented cause of leak/spill;

G. For each such spill, provide a copy of the Integrity Management Plan, the operational manual for the pipeline, the specifications for the SCADA system, and the ERP for each spill in the US and Canada;

H. Identify the documents which support your answers, above.

[Applicable Finding or Condition No.: Findings 12(2)-(3), 41-45, 47, 103; Amended Condition 32-38]

OBJECTION AND ANSWER: Please see the spreadsheet attached as Keystone 0774-0784. Keystone's Integrity Management Plan, SCADA specifications, and Emergency Response Plan are confidential and not relevant for the reasons identified elsewhere in these responses.

INTERROGATORY NO. 8. Describe any forecasts you have developed with respect to (i) re-exports of WCSB crude oil from PADD3, (ii) product exports from PADD 3, (iii) US domestic demand for PADD 3 refinery output, and (iv) total PADD 3 refinery output.

A. Identify the documents upon which this answer is based.

[Applicable Finding or Condition No.: Findings 14, 24-29]

OBJECTION AND RESPONSE: This request seeks information that is beyond the scope of the PUC's jurisdiction and Keystone's burden of proof under SDCL § 49-41B-27. It is within the purview of the United States Department of State to determine whether the proposed project is in the national interest, under the applicable Presidential Executive Order. This request also may seek information that is not within Keystone's custody or control and is not maintained by Keystone in the ordinary course of business. Keystone is a provider of transportation service. It does not own the oil that is transported, is not a refiner, and does not make decisions about potential exports of crude oil or refined products. The oil forecast information that Keystone relied on in Appendix C to its Certification was derived from the following sources: The Final Supplemental Environmental Impact Statement; the CAPP Crude Oil Forecast, Markets and Transportation June 2014; and the Energy Information Agency Annual Energy Outlook 2014. These documents, except for the FSEIS, which is available at http://keystonepipeline-xl.state.gov/finalseis/index.htm, are marked as Keystone 0001-0467.

INTERROGATORY NO. 9. What companies, if any, were partners or investors with TransCanada in the construction and operation of the KXL pipeline in 2009 which are no longer participating in the proposed project? [Applicable Finding or Condition No.: Findings 24-29]

ANSWER: Conoco Phillips is no longer participating in the Project as of August 14, 2009.

INTERRROGATORY NO. 10. Identify the companies which have binding contractual commitments with TransCanada or its Affiliates to ship WCSB or Williston Basin crude oil through the KXL Pipeline. For each such company:

A. Provide the termination dates, opt-out dates, or other material dates in the contractual commitments of shippers with the contractual commitments that underpin the viability and need for the project;

B. Identify all documents and sources for your answers.

[Applicable Finding or Condition No.: Findings 17, 24, 29]

OBJECTION: The identity of Keystone's shippers and the terms of their contracts have substantial commercial and proprietary value, are subject to substantial efforts by Keystone to protect this information from actual and potential competitors, and are required to be maintained on a confidential basis pursuant to the terms of the contracts between Keystone and its shippers and Section 15(13) of The Interstate Commerce Act.

INTERROGATORY NO. 11. Provide and describe in detail the development schedule for the Project and describe how the development schedule for the Project is consistent with the contractual commitments made by TransCanada. Identify all documents and sources for your answers. [Applicable Finding or Condition No.: Findings 17, 24, 29]

ANSWER: Currently, Keystone has not identified a date to commence construction, nor does it have a pipeline construction contract in place.

Construction of the proposed Project would begin after Keystone obtains all necessary permits, approvals, and authorizations. Keystone anticipates that he proposed Project would be placed into service approximately two years after receiving such authorizations. As currently planned, the proposed Project would be constructed using 10 spreads of approximately 46 to 122 miles long (*see* FSEIS Table 2.1-13). Final spread configurations and the final construction schedule may result in the use of more or fewer spreads than those indicated. Time periods and

key milestones including the relationship between contractor mobilization, start of construction (pre-welding), start and end of welding, post-welding and clean-up, and contractor demobilization are described in the FSEIS in Section 2.1.10.1 Schedule and Workforce. (FSEIS, pages 2.1-69 and 70).

Keystone will comply with all conditions set out in its permits including the SDPUC Order, including condition 12 to, once known, inform the Commission of the date construction will commence, report to the Commission on the date construction is started, and keep the Commission updated on construction activities. Keystone will also comply with condition 10 to, not later than six months prior to the commencement of construction, commence a program to notify and educate state, county, and municipal agencies on the planned construction schedule and the measures that such agencies should begin taking to prepare for construction impacts and the commencement of project operations. Additionally, in the Special Conditions Recommended by PHMSA, number 17 Construction Plans and Schedule, Keystone will at least 90 days prior to the anticipated construction start date submit its construction plans and schedule to the appropriate PHMSA Directors for review. Subsequent plans and schedule revisions must also be submitted to the appropriate PHMSA Directors, on a monthly basis. (FSEIS, Appendix Z, Compiled Mitigation Measures, page 70.)

INTERROGATORY NO. 12. Is there currently a growing (i) demand for crude oil US refineries, and (ii) demand for petroleum products by US consumers?

A. Please explain your answer;

B. Identify all sources for your answer;

C. How and why has this changed since 2009?

[Applicable Finding or Condition No.: Findings 14, 17]

OBJECTION AND RESPONSE: This request seeks information that is beyond the scope of the PUC's jurisdiction and Keystone's burden of proof under SDCL § 49-41B-27. It is within the purview of the United States Department of State to determine whether the proposed project is in the national interest, under the applicable Presidential Executive Order. This request also may seek information that is not within Keystone's custody or control and is not maintained by Keystone in the ordinary course of business. The oil forecast information that Keystone relied on in Appendix C to its Certification was derived from the following sources: The Final Supplemental Environmental Impact Statement; the CAPP Crude Oil Forecast, Markets and Transportation June 2014; and the Energy Information Agency Annual Energy Outlook 2014. These documents, except for the FSEIS, which is available at http://keystonepipeline-xl.state.gov/finalseis/index.htm, are marked as Keystone 0001-0467.

INTERROGATORY NO. 13. Identify the forecasts of "additional crude oil production from the WCSB" and the Williston Basin that create a need for the Keystone XL Pipeline.

A. As per such forecasts, state the potential impact of current low oil prices on these forecasts.

B. Identify the basis for your answers to these Interrogatories.

[Applicable Finding or Condition No.: Finding 24]

OBJECTION AND RESPONSE: This request seeks information that is beyond the scope of the PUC's jurisdiction and Keystone's burden of proof under SDCL § 49-41B-27. It is within the purview of the United States Department of State to determine whether the proposed project is in the national interest, under the applicable Presidential Executive Order. This request

also may seek information that is not within Keystone's custody or control and is not maintained by Keystone in the ordinary course of business. Keystone is a provider of transportation service. It does not own the oil that is transported, is not a refiner, and does not make decisions about potential exports of crude oil or refined products. The oil forecast information that Keystone relied on in Appendix C to its Certification was derived from the following sources: The Final Supplemental Environmental Impact Statement; the CAPP Crude Oil Forecast, Markets and Transportation June 2014; and the Energy Information Agency Annual Energy Outlook 2014. These documents, except for the FSEIS, which is available at http://keystonepipeline-xl.state.gov/finalseis/index.htm, are marked as Keystone 0001-0467.

INTERROGATORY NO. 14. Does TransCanada agree that domestic U.S. crude oil supplies are increasing?

A. Please explain your answer;

B. Identify documents which support your answer to this Interrogatory.

[Applicable Finding or Condition No.: Finding 26]

ANSWER: According to the Department of State FSEIS 1.4.2.3, U.S. production of crude oil has increased significantly, from approximately 5.5 million bpd in 2010 to 6.5 million bpd in 2012 and 7.5 million bpd by mid-2013. Even with the domestic production growth the U.S. is expected to remain a net importer of crude oil well into the future.

INTERROGATORY NO. 15. Provide a list of U.S. refineries that TransCanada expects to increase demand for WCSB and Williston Basin oil.

A. For each refinery, state the basis for TransCanada's claim that the refinery will increase such demand for crude oil;

B. Identify the refineries in PADD 3:

i. That could be served by the proposed KXL Project that are currently expanding refining capacity or have announced plans to expand their refining capacity;

ii. That TransCanada experts to import less offshore crude oil and replace it with crude oil that would be transported by the Project;

iii. That are "optimally configured to process heavy crude slates";

C. Identify the new refineries and refinery expansions that are currently proposed to be constructed in PADD 3;

D. Itemize the annual heavy crude oil imports into PADD 3 by country since 2010. For each, state whether the costs of crude oil production in the source country are greater, the same, or less than the cost of heavy crude oil production in the WCSB;

E. State whether pipeline expansions from the WCSB and the Williston Basin to the U.S. Gulf Coast operated by Enbridge (or companies affiliated with Enbridge) provide crude oil transportation services to the refineries that TransCanada claims would be served by the KXL Project. Please provide a detailed explanation for your answer.

F. Identify and describe the proposed delivery locations of the Keystone System in PADD 3.

G. Identify all pipelines in PADD 3 to which the Keystone System is connected;

H. State the year in which TransCanada expects the Keystone XL Pipeline to be fully utilized;

I. Describe the impact of growing crude oil production in PADD 3 on the demand in PADD 3 for crude oil from the WCSB and Williston Basin;

J. Describe the size of the potential market for Williston Basin light sweet crude oil in PADD 3 and state whether or not such market is limited in size by production of light sweet crude oil in PADD 3;

K. Identify the basis for your answers to these Interrogatories and identify all documents relied upon by you in answering this Interrogatory.

[Applicable Finding or Condition No.: Findings 24, 26 and 27]

OBJECTION AND RESPONSE: This request seeks information that is beyond the scope of the PUC's jurisdiction and Keystone's burden of proof under SDCL § 49-41B-27. It is within the purview of the United States Department of State to determine whether the proposed project is in the national interest, under the applicable Presidential Executive Order. This request also may seek information that is not within Keystone's custody or control and is not maintained by Keystone in the ordinary course of business. Keystone is a provider of transportation service. It does not own the oil that is transported, is not a refiner, and does not make decisions about potential exports of crude oil or refined products. The oil forecast information that Keystone relied on in Appendix C to its Certification was derived from the following sources: The Final Supplemental Environmental Impact Statement; the CAPP Crude Oil Forecast, Markets and Transportation June 2014; and the Energy Information Agency Annual Energy Outlook 2014. These documents, except for the FSEIS, which is available at http://keystonepipeline-xl.state.gov/finalseis/index.htm, are marked as Keystone 0001-0467.

INTERROGATORY NO. 16. Identify each existing pipeline that comprise the "insufficient pipeline capacity" identified by TransCanada as a factor driving the need for the KXL Project. For each of these pipelines:

A. Provide current usage as a percentage of each respective pipeline's total capacity;

B. Identify the basis for your answers to these Interrogatories.

[Applicable Finding or Condition No.: Finding 24]

OBJECTION AND RESPONSE: This request seeks information that is beyond the scope of the PUC's jurisdiction and Keystone's burden of proof under SDCL § 49-41B-27. It is within the purview of the United States Department of State to determine whether the proposed project is in the national interest, under the applicable Presidential Executive Order. This request also seeks information that is not within Keystone's custody or control and is not maintained by Keystone in the ordinary course of business. Without waiving the objection, the demand evidenced by Keystone's binding shipper commitments demonstrates insufficient pipeline capacity.

INTERROGATORY NO. 17. Given competing crude oil pipelines to Cushing, Oklahoma, and PADD 3 and forecast low oil prices, does TransCanada still contend its KXL pipeline is necessary and will allow North American crude oil to replace U.S. reliance on unstable sources of off-shore crude oil?

A. Please explain your answer;

B. Identify all documents and sources for your answer;

C. How and why has this changed since 2009?

[Applicable Finding or Condition No.: Findings 14, 17]

ANSWER: Shippers have committed to long-term binding contracts, which support construction of the pipeline once all regulatory, environmental, and other approvals are received. These long-term binding shipper commitments demonstrate a material endorsement of support

for the Project, its economics, proposed route, and target market, as well as the need for additional pipeline capacity to access North Dakota and Canadian crude supplies.

INTERROGATORY NO. 18. Provide the total current capacity of existing pipelines to transport crude oil from the WCSB and the Williston Basin to the U.S. Gulf Coast and identify the source(s) for your answer. [Applicable Finding or Condition No.: Finding 24]

ANSWER: Specifics to operating capacity of third-party pipelines are under the responsibility of the pipeline owners and are beyond Keystone's control.

INTERROGATORY NO. 19. Identify all other pipeline operations of TransCanada and its Affiliates, which since 2009 are utilizing the same pipeline materials, dimensions, and seals as proposed for the KXL pipeline through South Dakota, and described in Findings 18 and 28. [Applicable Finding or Condition No.: Findings 18, 28]

OBJECTION AND RESPONSE: To the extent that it seeks information for pipelines other than crude oil pipelines, this request seeks information that is not relevant and not likely to lead to the discovery of admissible evidence. Without waiving the objection, the Keystone I, Cushing Extension and Gulf Coast segments of the Keystone system are using similar materials to that of the proposed KXL pipeline.

INTERROGATORY NO. 20. Identify each pipeline operated by TransCanada and its Affiliates which have operated at 900,000 bpd, giving the pipeline name, location, dates of such operation, together with:

A. Identification of each such pipeline which subsequently developed a leak or spill, regardless of whether the pipeline was at that time operating at 900,000 bpd, giving date, location, amount spilled/leaked, damage caused;

B. Identify the documents upon which your answer(s) to these Interrogatories were based; [Applicable Finding or Condition No.: Findings 15, 18, 28]

ANSWER: Keystone and its affiliates do not operate any pipelines at 900,000 bpd.

INTERROGATORY NO. 21. State whether a failure by TransCanada to design, construct, test, or operate the proposed KXL Project in accordance with the special conditions developed by the Pipeline Hazardous Materials and Safety Administration (PHMSA), and set forth in Appendix Z to the Department of State, January 2014 Final Supplemental Environmental Impact Statement (FSEIS), would be a violation of federal law. If so:

A. Identify the law(s) under which enforcement of these special conditions would be brought;

B. Identify the enforcing agency;

C. Identify all correspondence between TransCanada and the PHMSA.

D. Identify the documents upon which your answer(s) to these Interrogatories were based; [Applicable Finding or Condition No.: Conditions 1-3; Findings 22, 28]

OBJECTION AND RESPONSE: This request seeks information that is beyond the scope of the PUC's jurisdiction and Keystone's burden under SDCL § 49-41B-27. This request also seeks information addressing an issue that is governed by federal law and is within the province of PHMSA. In addition, this request depends on a hypothetical condition and is therefore speculative and improper as to form. It is also overlybroad and burdensome to the extent that it seeks all correspondence between TransCanada and PHMSA, and asks for information that is not relevant and not likely to lead to the discovery of admissible evidence under SDCL § 15-6-26(b). Without waiving the objection, unless and until the Department

issues a Record of Decision and a Presidential Permit, the recommendations in the Final EIS are not binding on Keystone.

INTERROGATORY NO. 22: Identify all other crude oil pipeline operations of TransCanada and its Affiliates which, since 2009, have or are operating at a maximum operating pressure (MOP) of equal to or greater than 1,440 psig generally and/or 1,600 psig MOP for specific low elevation segments of pipeline with the same design factor and pipe wall thickness as described in Finding 19, close to the discharge of pump stations:

A. For each such pipeline which subsequently developed a leak or spill, regardless of the psig MOP the pipeline was operating at the time, giving date, location, amount spilled/leaked, psig MOP at which pipeline was operating at the time, and describe the amount and nature of damage caused by such a leak or spill;

B. Identify any documents upon which your answers to these Interrogatories were based; [Applicable Finding or Condition No.: Findings 19, 28]

ANSWER: There are currently no crude oil pipelines operating equal to or greater than 1,440 psig generally and/or 1,600 psig MOP.

INTERROGATORY NO. 23: For each spill/leak incident which has occurred from a pipeline transporting WCSB crude oil operated by TransCanada and its Affiliates since 2009, state the dates on which transportation of the crude oil through that pipeline was disrupted by planned maintenance, unplanned maintenance, power outages, spills, leaks, or any other causes. Identify any documents upon which your answers to this Interrogatory was based. [Applicable Finding or Condition No.: Finding 28]

ANSWER: See the spreadsheet attached as Keystone 0774-0784.

INTERROGATORY NO. 24: Explain why TransCanada has reduced the maximum operating pressure of the KXL pipeline at most locations to 1,307 psig;

A. State whether TransCanada has any plans to subsequently increase this general operating pressure;

B. If your answer to subpart A of this interrogatory is yes, what is the subsequent maximum operating pressure being contemplated for general use during pipeline operations?

[Applicable Finding or Condition No.: Conditions 31-38; Findings 19, 20]

ANSWER: On August 5 2010, TransCanada withdrew its application to the Pipeline Hazardous Materials and Safety Administration (PHMSA) for a special permit to design, construct and operate the pipeline at a 0.8 design factor and adopted the 57 additional safety measures that would have been required under the PHMSA special permit. The operating pressure reduction from 1,440 psig to 1,307 psig is a result of the use of the standard design factor (0.72) in accordance with 49 CFR 195.106 design pressure. TransCanada would be required to re-apply to PHMSA for a special permit in order to operate the pipeline at an increased design factor of 0.8 corresponding to an operating pressure of 1,440 psig. In addition, the attached Media Advisory, marked as Keystone 0647-0649, dated August 5, 2010, addresses this issue.

INTERROGATORY NO. 25: With regard to the plan for mainline valves to be remotely controlled, what guarantee can you give the PUC that TransCanada can prevent a cyber-security attack on the control system?

A. Describe the worst case scenario which could occur in the event of a computer systems security breach on the control system for the KXL Pipeline.

B. Describe the data security systems to be put in place to prevent any such system breach, identify any third-party vendor(s) providing system security software, hardware or monitoring, and identify the particular components or scopes of services such vendors will provide.

C. Identify any documents used to support your answer to this Interrogatory.

[Applicable Finding or Condition No.: Conditions 31-38; Finding 20]

ANSWER:

A. Once constructed, the Keystone XL pipeline will form part of North America's critical national energy infrastructure. Over time, actors such as terrorist organizations and hostile nation states can be expected to pursue their objectives by attempting to disrupt this critical infrastructure. Therefore, it is not prudent for TransCanada to publicly provide an opinion on how the adverse consequences of a cyber attack could be maximized.

B. Consistent with industry practice, TransCanada does not publicly disclose the details of the security systems it has in place. We believe that it is not prudent to make this information public because of the likelihood that it will assist, and, potentially encourage, attackers.

INTERROGATORY NO. 26. What is the current capacity contracted for WCSB crude oil from Canada? Identify any documents upon which you based your answer or which you are aware would be a basis for your answer. [Applicable Finding or Condition No.: Findings 14, 24-29]

OBJECTION: This request seeks information that is not within Keystone's custody and control. Keystone does not know the contractual details of other pipeline companies' commitments.

INTERROGATORY NO. 27. State whether there is a significant discount on the price currently of WCSB crude oil relative to West Texas Intermediate and Brent crude oils.

A. Please explain your answer;

B. Identify all documents which support your answers;

[Applicable Finding or Condition No.: Finding 27]

OBJECTION AND ANSWER: The scope of the question is too broad given the large number of crude oil grades available from the WCSB. The Canadian heavy benchmark discounts in 2014 range from $13 to $30.

A.
- Western Canadian crudes are priced against West Texas Intermediate (WTI).
- Canadian crudes are traded on Net Energy and TMX (NGX) trading exchanges.
- Canadian crude monthly blended indices are calculated using calendar moth volume weighted average between the two platforms.
- As an example, WCS blended indices for 2014 range from $13 to $30 discount to WTI monthly.

B. Responsive documents are attached as Keystone 1116-1118.

INTERROGATORY NO. 28: What is the current capacity contracted for Williston Basin oil? Identify any documents which would support your answer. [Applicable Finding or Condition No.: Findings 14, 24-29]

ANSWER: Shippers have committed about 65,000 barrels per day of capacity for transportation services on Bakken Marketlink.

INTERROGATORY NO. 29: Describe the changes in contracted capacity amounts and duration since 2009 from Canada and the Williston Basin and identify any documents which would support your answer. [Applicable Finding or Condition No.: Findings 14, 24-29]

ANSWER: Shippers have committed about 65,000 barrels per day of capacity for transportation services on Bakken Marketlink. Keystone also received additional commitments on Keystone XL Pipeline that would support an expansion of its total capacity from 700,000 barrels per day to 830,000 barrels per day. The contracted capacity amounts, delivery locations and duration of each of the commitments are confidential.

INTERROGATORY NO. 30. Regarding the "U.S. demand for petroleum products," i.e., produced for U.S. consumers and not for export to other countries:

A. What is the percent change since 2010?

B. What is the forecast for "U.S. demand for petroleum products" over the next 20 years?

C. What has been the annual import of crude oil for each year since 2010?

D. What is the forecast for offshore crude oil imports into the U.S. over the next 20 years?

E. Of the 15 million bpd of crude oil demand identified in revised Finding of Fact 25, state whether some of this demand is used to produce petroleum products for export from the U.S. If so provide the quantity of crude oil:

i. Needed for domestic demand for petroleum products;

ii. Needed to produce petroleum products for export;

F. Identify any documents which would support your answer;

[Applicable Finding or Condition No.: Findings 14, 24-29]

OBJECTION AND RESPONSE: This request seeks information that is beyond the scope of the PUC's jurisdiction and Keystone's burden of proof under SDCL § 49-41B-27. It is within the purview of the United States Department of State to determine whether the proposed project is in the national interest, under the applicable Presidential Executive Order. This request

also may seek information that is not within Keystone's custody or control and is not maintained by Keystone in the ordinary course of business. The oil forecast information that Keystone relied on in Appendix C to its Certification was derived from the following sources: The Final Supplemental Environmental Impact Statement; the CAPP Crude Oil Forecast, Markets and Transportation June 2014; and the Energy Information Agency Annual Energy Outlook 2014. These documents, except for the FSEIS, which is available at http://keystonepipeline-xl.state.gov/finalseis/index.htm, are marked as Keystone 0001-0467.

INTERROGATORY NO. 31. What is the status of pipeline and rail capacity to move oil from oil fields in the Williston Basin to the Baker, Montana on-ramp? Identify any documents which would support your answer. [Applicable Finding or Condition No.: Findings 14, 24-29]

OBJECTION AND ANSWER: This request seeks information that is not within Keystone's custody or control and is not maintained by Keystone in the ordinary course of business. Without waiving the objection, information regarding the Bakken on-ramp pipeline can be found in the Montana Department of Environmental Quality Certificate issued under the Montana Major Facility Siting Act available at http://www.deq.mt.gov/mfs/keystonexl/keystonecertificate.aspx.

INTERROGATORY NO. 32: Why would the existing Keystone I pipeline not be capable of shipping enough crude oil from the Western Canadian Sedimentary Basin (WCSB) to offset the need for unstable foreign oil supplies? Identify any documents which would support your answer. [Applicable Finding or Condition No.: Finding 14]

ANSWER: The Keystone Pipeline does not have sufficient capacity to meet additional demand.

INTERROGATORY NO. 33: What are the currently projected forecasts of production in the Western Canadian Sedimentary Basin (WCSB) and the Williston Basin over each of the next ten years? Identify any documents which would support your answer. [Applicable Finding or Condition No.: Findings 14, 24-29]

OBJECTION AND RESPONSE: This request seeks information that is beyond the scope of the PUC's jurisdiction and Keystone's burden of proof under SDCL § 49-41B-27. It is within the purview of the United States Department of State to determine whether the proposed project is in the national interest, under the applicable Presidential Executive Order. This request also seeks information that is not within Keystone's custody or control and is not maintained by Keystone in the ordinary course of business. The oil forecast information that Keystone relied on in Appendix C to its Certification was derived from the following sources: The Final Supplemental Environmental Impact Statement; the CAPP Crude Oil Forecast, Markets and Transportation June 2014; and the Energy Information Agency Annual Energy Outlook 2014. These documents, except for the FSEIS, which is available at http://keystonepipeline-xl.state.gov/finalseis/index.htm, are marked as Keystone 0001-0467.

INTERROGATORY NO. 34: Describe the impact of low oil prices on crude oil production in the WCSB and Williston Basin.

A. What is the effect on the forecast of demand for crude oil transportation services from the Williston Basin and WCSB given annual average West Texas Intermediate crude oil prices of $50/bbl, $60/bbl, $70/bbl, and $80/bbl?

B. In light of low oil prices, what will be the impact of the Enbridge pipelines from the WCSB and Williston Basin to the US Gulf Coast on the need for transportation services of the KXL pipeline?

C. Identify any documents which would support your answers;

[Applicable Finding or Condition No.: Findings 14, 24-29]

OBJECTION AND RESPONSE: This request seeks information that is beyond the scope of the PUC's jurisdiction and Keystone's burden of proof under SDCL § 49-41B-27. It is within the purview of the United States Department of State to determine whether the proposed project is in the national interest, under the applicable Presidential Executive Order. This request also seeks information that is not within Keystone's custody or control and is not maintained by Keystone in the ordinary course of business. The oil forecast information that Keystone relied on in Appendix C to its Certification was derived from the following sources: The Final Supplemental Environmental Impact Statement; the CAPP Crude Oil Forecast, Markets and Transportation June 2014; and the Energy Information Agency Annual Energy Outlook 2014. These documents, except for the FSEIS, which is available at http://keystonepipeline-xl.state.gov/finalseis/index.htm, are marked as Keystone 0001-0467.

INTERROGATORY NO. 35: Describe in detail, route changes in the proposed KXL pipeline since 2010, on a county by county basis, identifying specific land parcels to be affected by such changes. Identify any documents which would support your answers. [Applicable Finding or Condition No.: Finding 16]

ANSWER: Please see the attached route variation maps attached as Keystone 0470-0583.

INTERROGATORY NO. 36: Provide the dates on which pipe segments to be used in South Dakota were delivered to storage location in South Dakota or adjacent states.

A. For each such delivery of pipe segments, state the date on which an external fusion bonded epoxy (FBE) was applied;

B. Describe the materials comprising and dimensions of any covering placed over each shipment of delivered pipe segments on its arrival;

i. Provide the date of each covering of the respective pipe shipment after delivery;

C. As per the respective deliveries, state the longest time that any pipe segments were stored without protective covering;

D. Provide the FBE manufacturer's recommendations for protection of the FBE from the effects of outside storage;

E. Provide the pipeline manufacturer's recommendations for protection of FBE against the effects of outside storage;

F. Provide the manufacturer's suggested maximum amount of time of sunlight exposure of FBE without protective covering;

G. Describe the impact of UV radiation on FBE coating over time;

H. Provide the manufacturer's warrantees and guarantees for the FBE coating applied to the pipe segments;

I. Provide the manufacturer's warranties and guarantees for the pipe segments, including for the FBE;

J. Explain the elimination from use in the proposed Project of API 5L X80 high strength steel;

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i. Describe how substituted material(s) would perform better than the API 5L X80 steel;

K. Identify any documents which would support your answers;

[Applicable Finding or Condition No.: Finding 18]

ANSWER:

A. January 2011- November 2011

B. Covering application commenced in October 2012 and was completed July 2013

C. Approximately 18 months

D. The manufacturer did not provide recommendation or direction for storage. Direction for storage is per TransCanada specification.

E. The manufacturer did not provide recommendation or direction for storage. Direction for storage is per TransCanada specification.

F. Per manufacture, pipe coated with FBE coatings can be stored for 730 days under most climatic weather conditions without commencement of deterioration of the coating. TransCanada specification provides criteria for minimum coating thickness requirements which would supersede any exposure time period. Applicable manufacturer warranties are related to application and workmanship to the specification

G. Sunlight exposure over a significantly extended period of time could cause a reduction in coating thickness and coating flexibility due to degradation by UV radiation

H. WARRANTY

Unless otherwise specified in the Order for Pipe, the Supplier hereby warrants that the Pipe, including, if applicable, the Work done thereto, shall meet and conform to the Specifications and the Technical Agreements, and such other product characteristics agreed to by the Parties in

writing, for a period of twelve (12) calendar months from the day the Pipe is incorporated into the Company's pipeline and the Company's pipeline is commissioned for regular service or eighteen (18) calendar months from the date of delivery of all Pipe to the Delivery Point, whichever is earlier. If during the aforesaid warranty period, the Company discovers any Pipe which fails to conform, the Company shall forthwith notify in writing the Supplier of such non-conformance. The Company and the Supplier shall jointly investigate any such non-conformance in an effort, in good faith, to determine the cause thereof, provided that such investigation shall not unreasonably delay any repair or replacement of the Pipe. If the Parties are unable to agree upon the cause of the non-conformance with this Agreement within ten (10) days of the date of the discovery of such non-conformance, either Party shall have the right to request that the matter be arbitrated pursuant to single party arbitration conducted in accordance with the then current International Chamber of Commerce's Rules of Arbitration.

If such non-conformance is discovered after title to the Pipe passes to the Company, the Company may, after notification to the Supplier, to the extent the Company, acting reasonably, deems practical under the circumstances, repair the same at the Supplier's risk and expense. If repair is not practical in the Company's opinion, acting reasonably, the Company agrees that the Supplier may replace the non-conforming Pipe in the event that the Supplier can secure such replacement at delivery dates at least as favorable as those available to the Company from other sources.

Any Pipe that is repaired or replaced pursuant to the warranties specified herein shall be warranted for a further period of twelve (12) calendar months from the day the Pipe is incorporated into the Company's pipeline and the Company's pipeline is commissioned for

regular service or eighteen (18) calendar months from the date of delivery of the Pipe to the Delivery Point, whichever is earlier.

If the non-conforming Pipe cannot be repaired and the Company elects not to replace such Pipe, the Company shall have the right to return, at the Supplier's expense and risk, any or all of the non-conforming Pipe delivered by the Supplier to the Company whereupon the Supplier shall immediately repay the Company, without Interest, all monies previously paid by the Company to the Supplier on account of the non-conforming Pipe so returned, together with all costs and expenses incurred by the Company in returning such Pipe.

The express warranties of the Supplier in this Agreement are the only warranties as to the Pipe and are in lieu of all other warranties in respect thereof, whether written, statutory, oral, express or implied including, without limitation, any warranty of merchantability or fitness for purpose. The rights and remedies contained in this Agreement are the Company's exclusive rights and remedies against the Supplier whatsoever in relation to, or arising out of, or in connection with the performance or conformance of the Supplier's obligations under these warranties.

I. WARRANTY

Unless otherwise specified in the Order for Pipe, the Supplier hereby warrants that the Pipe, including, if applicable, the Work done thereto, shall meet and conform to the Specifications and the Technical Agreements, and such other product characteristics agreed to by the Parties in writing, for a period of twelve (12) calendar months from the day the Pipe is incorporated into the Company's pipeline and the Company's pipeline is commissioned for regular service or eighteen (18) calendar months from the date of delivery of all Pipe to the

Delivery Point, whichever is earlier. If during the aforesaid warranty period, the Company discovers any Pipe which fails to conform, the Company shall forthwith notify in writing the Supplier of such non-conformance. The Company and the Supplier shall jointly investigate any such non-conformance in an effort, in good faith, to determine the cause thereof, provided that such investigation shall not unreasonably delay any repair or replacement of the Pipe. If the Parties are unable to agree upon the cause of the non-conformance with this Agreement within ten (10) days of the date of the discovery of such non-conformance, either Party shall have the right to request that the matter be arbitrated pursuant to single party arbitration conducted in accordance with the then current International Chamber of Commerce's Rules of Arbitration. If such non-conformance is discovered after title to the Pipe passes to the Company, the Company may, after notification to the Supplier, to the extent the Company, acting reasonably, deems practical under the circumstances, repair the same at the Supplier's risk and expense. If repair is not practical in the Company's opinion, acting reasonably, the Company agrees that the Supplier may replace the non-conforming Pipe in the event that the Supplier can secure such replacement at delivery dates at least as favorable as those available to the Company from other sources.

Any Pipe that is repaired or replaced pursuant to the warranties specified herein shall be warranted for a further period of twelve (12) calendar months from the day the Pipe is incorporated into the Company's pipeline and the Company's pipeline is commissioned for regular service or eighteen (18) calendar months from the date of delivery of the Pipe to the Delivery Point, whichever is earlier.

If the non-conforming Pipe cannot be repaired and the Company elects not to replace such Pipe, the Company shall have the right to return, at the Supplier's expense and risk, any or all of the non-conforming Pipe delivered by the Supplier to the Company whereupon the Supplier shall immediately repay the Company, without Interest, all monies previously paid by the Company to the Supplier on account of the non-conforming Pipe so returned, together with all costs and expenses incurred by the Company in returning such Pipe.

The express warranties of the Supplier in this Agreement are the only warranties as to the Pipe and are in lieu of all other warranties in respect thereof, whether written, statutory, oral, express or implied including, without limitation, any warranty of merchantability or fitness for purpose. The rights and remedies contained in this Agreement are the Company's exclusive rights and remedies against the Supplier whatsoever in relation to, or arising out of, or in connection with the performance or conformance of the Supplier's obligations under these warranties.

J. API 5L X80 high strength steel was contemplated as an option during the early stages of the Project. Material evaluation and selection was finalized during the detail design phase of the Project at which time Keystone selected grade X70 materials for use in the pipeline.

INTERROGATORY NO. 37: State whether any power lines have been permitted and constructed to provide power to pump stations by local power providers;

A. Identify each such power line;

B. State the cost of construction of the power line and identify the source(s) of the funds used for construction of each power line;

C. Identify the contractors or vendors who will be engaged to construct power lines.

D. If any State or Tribal permit or other authorization is required for any planned construction of power lines to pump stations:

i. Identify the permits which have been obtained, together with date permit granted;

ii. Identify permits which have not yet been obtained;

iii. Identify which permits have been applied for and are pending.

E. Identify any documents which would support your answers to this interrogatory.

[Applicable Finding or Condition No.: Finding 20]

ANSWER: No power lines have been constructed to pump stations for KXL in South Dakota. All required permits pertaining to power lines are completed by the individual power providers.

INTERROGATORY NO. 38. Describe each increased estimated cost of the KXL pipeline due to each of the following:

A. New technical requirements;

B. Inflation;

C. Project management;

D. New regulatory requirements;

E. Material storage issues;

F. Preservation;

G. Identify documents upon which you base your answers;

[Applicable Finding or Condition No.: Finding 23]

OBJECTION: This request seeks information that is not relevant and not likely to lead to the discovery of admissible evidence under SDCL § 15-6-26(b). In addition, Keystone does not

maintain a breakdown of the estimated project cost in the way requested, and requiring such a breakdown of costs would require the disclosure of information that has substantial commercial and proprietary value, and is subject to substantial efforts by Keystone to protect it from actual and potential competitors.

INTERROGATORY NO. 39. Identify companies currently interested in using the KXL pipeline to "further" diversify supply away from offshore foreign crude supply." For each company identified,

A. State whether they are interested in "Canadian crude;"

B. Identify documents upon which you base your answers;

[Applicable Finding or Condition No.: Finding 27]

OBJECTION: The identity of Keystone's shippers and the terms of their contracts have substantial commercial and proprietary value, are subject to substantial efforts by Keystone to protect this information from actual and potential competitors, and are required to be maintained on a confidential basis pursuant to the terms of the contracts between Keystone and its shippers. This request also seeks information that is beyond the scope of the PUC's jurisdiction and Keystone's burden of proof under SDCL § 49-41B-27. It is within the purview of the U.S. Department of State to determine whether the proposed project is in the national interest, under the applicable Presidential Executive Order.

INTERROGATORY NO. 40: Describe the potential for pipeline transportation to replace rail transportation for shipments from the WCSB and the Williston Basin to PADDs 1 and 5.

A. Provide the quantity of oil exported from the WCSB and the Williston Basin to PADDs 1 through 5 by rail from 2010 to the present;

B. Identify any documents which would support your answers;

[Applicable Finding or Condition No.: Finding 27]

OBJECTION AND RESPONSE: This request seeks information that is beyond the scope of the PUC's jurisdiction and Keystone's burden of proof under SDCL § 49-41B-27. It is within the purview of the United States Department of State to determine whether the proposed project is in the national interest, under the applicable Presidential Executive Order. This request also seeks information that is not within Keystone's custody or control and is not maintained by Keystone in the ordinary course of business. The oil forecast information that Keystone relied on in Appendix C to its Certification was derived from the following sources: The Final Supplemental Environmental Impact Statement; the CAPP Crude Oil Forecast, Markets and Transportation June 2014; and the Energy Information Agency Annual Energy Outlook 2014. These documents, except for the FSEIS, which is available at http://keystonepipeline-xl.state.gov/finalseis/index.htm, are marked as Keystone 0001-0467

INTERROGATORY NO. 41: List the changes in the KXL Project route since 2010 and identify any documents which would support your answers. [Applicable Finding or Condition No.: Finding 33]

ANSWER: Please refer to the attached route variation maps attached as Keystone 0470-0583.

INTERROGATORY NO. 42: Identify paleontological studies within the Upper Cretaceous or Tertiary strata of which you have knowledge were conducted after 2009 in the

proximate location of the currently proposed KXL pipeline route and identify any documents which would support your answers. [Applicable Finding or Condition No.: Findings 34, 36; Conditions 43, 44]

ANSWER: Paleontological fieldwork methodology, literature search information, and results can be found in Sections 3.1.2.2 and 3.1.2.3 of the Department of State FSEIS (2014). A list of reports detailing the results of all pre-construction paleontological field surveys can be found in Table 3.1-4 of the Department of State FSEIS (2014).

INTERROGATORY NO. 43: Identify Section 106 type "cultural resource" studies of which you have knowledge that were conducted after 2009 in the proximate location of the currently proposed KXL pipeline route and identify any documents which would support your answers. [Applicable Finding or Condition No.: Conditions 43, 44]

ANSWER: Cultural resources survey reports are listed in Section 3.11 of the Department of State FSEIS (2014), with results of the SD surveys detailed in Table 3.11-3.

INTERROGATORY NO. 44: TransCanada is to identify the exact locations of active, shut-in, and abandoned wells and any associated underground pipelines in the construction ROW, what is the status of such identification procedures? As to the wells and pipelines to be identified:

A. How long does TransCanada expect such an identification process will take before the Company would be willing to assure the PUC that all such wells and pipelines have been identified;

B. If "appropriate precautions" prove inadequate, describe in detail a worst case scenario, especially involving a river, tributary, or other water resources, involving:

i. An unidentified well;

ii. An unidentified pipeline;

iii. An identified well where the precautions fail;

iv. An identified pipeline where the precautions fail;

C. What circumstance(s) or event(s) could potentially cause the "appropriate precautions" to fail?

i. How is it determined what the specific appropriate precautions to be undertaken are for each kind of scenario?

ii. Who determines whether each specific precaution is "appropriate" to prevent environmental and/or human damage;

iii. As to appropriate precautions to be undertaken for each possible scenario, how is the PUC assured TransCanada actually implements or undertakes the precaution(s) necessary.

D. What specific precautions have been or are planned to be taken to protect the soils in the Sand Hills from contamination;

E. What specific precautions have been or are planned to be taken to protect the underground water resources of the Oglala Aquifer and other potentially affected aquifers from contamination;

F. What specific precautions have been or are planned to protect the surface and alluvial waters of the State and respective Tribes from contamination;

G. What type of gas or oil or related solutions or gases pumped or injected by a well within a mile or more along the general route of the KXL pipeline, could be involved in such a "worst case scenario"?

H. What type of gas or oil or related solutions or gases being transported by a pipeline within a mile or more along the general route of the KXL pipeline, could be involved in such a "worst case scenario"?

I. Identify any documents which would support your answers.

[Applicable Finding or Condition No.: Conditions 15, 16, 21, 22, 42]

ANSWER: TransCanada has not yet identified the locations of the wells and pipelines as stated. TransCanada does not differentiate between active and abandoned but does identify wells and pipeline within the construction right of way utilizing public data, survey data and One Calls at the time of construction.

INTERROGATORY NO. 45: What kind of "significant problems" are anticipated by the weathering of shale underlying almost all of Haakon, Jones and portions of Tripp Counties:

A. To access roads;

B. To structural foundations for roads, power lines, or other structures constructed in connection with the KXL pipeline (in answering, identify the type of foundations are of concern);

C. To the proposed KXL pipeline or part thereof;

D. Identify any documents which would support your answers.

[Applicable Finding or Condition No.: Conditions 15, 16, 18, 21, 22, 23, 42]

ANSWER: There are no "significant problems" anticipated concerning the weathering of shale in South Dakota.

INTERROGATORY NO. 46: Describe a leak, the existence of which "may suggest a threat to the integrity of the pipeline."

A. Other than aerial patrols, ground patrols, and public awareness, what steps have been taken to prevent a leak of this nature and magnitude or prevent or minimize its effect on the pipeline's integrity?

B. Identify documents which support and/or were used to provide your answers.

[Applicable Finding or Condition No.: Finding 95; Conditions 31-38]

ANSWER: A confirmed leak is in fact a loss of integrity, however a direct observation reported leak may not be a result of a pipeline release (e.g. an apparent sheen on standing water near the ROW) or the release may be from another line in a multi-pipeline corridor or at a foreign pipeline crossing. In this context, a leak which "may suggest a threat to the integrity of the pipeline" is a reported potential leak that has yet to be confirmed as originating from a Keystone line.

Prevention of leaks of this magnitude are addressed in the sections of the FSEIS discussing pipeline integrity, Sections 3.13 and 4.13. In addition to these answer, in regard to remote sensing technologies, several initiatives have been undertaken by Keystone. A pilot implementation of a fixed thermal imaging system at a pump station will be tested this year, in addition to three industry projects that Keystone is participating in:

- C-FER Technologies' ELDER joint industry project (JIP) that is evaluating the performance of four different cable based leak detection systems.
- A second C-FER Technologies JIP that is quantifying the physical phenomenon that occur at the ground surface that could be detected by various technologies.
- PHMSA's project entitled "INO Technologies Assessment as Leak Detection Systems for Hazardous Liquid Pipelines".

INTERROGATORY NO. 47: Describe the status of the written manual for normal operations, maintenance activities, and handling abnormal operating and emergencies.

A. Identify the latest draft of the written manual and all prior drafts;

B. Identify all documents which support or were used to provide your answers.

[Applicable Finding or Condition No.: Finding 96; Conditions 31-38]

ANSWER: As required by the Department of Transportation, Pipeline and Hazardous Material Safety Administration 49 CFR §195.402 Keystone has prepared and follows a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies. The current manual is version 07 and the original manual version 01 issued August 01, 2010. Other manual revisions are defined:

- Version 02 – 11/15/2011
- Version 03 – 04/15/2012
- Version 04 – 06/07/2012
- Version 05 – 07/16/2012
- Version 06 – 07/09/2013

The Operations and Maintenance (O&M) Manual U.S. Hazardous Liquids Pipelines and referenced versions were utilized in support of TransCanada's response.

INTERROGATORY NO. 48: Calculate the worst case discharge and describe in detail the worst case scenario that would result from damage caused to the Keystone XL pipeline from the "high swelling potential" of the Cretaceous and Tertiary rocks located in the Missouri River Plateau due to this land form's susceptibility to instability in the form of slumps and earth-flows, including landslides.

A. Provide the locations where such ground swelling can be anticipated;

B. Identify any documents which would support your answer;

[Applicable Finding or Condition No.: Finding 40, 77; Conditions 31-42]

OBJECTION AND RESPONSE: This request seeks information that is confidential. The volume and location of a worst case scenario spill are kept confidential for homeland security reasons. Without waiving the objection, Section 3 of Appendix A of the 2009 Keystone XL Risk Assessment (FSEIS Appendix P) discusses the state-specific incident frequencies for a variety of pipeline hazards, including ground movement and landslides. Within Section 3.5, specific failure mechanisms and mitigation measures relating to these natural hazards are also discussed. Pipelines are remarkably resilient to landslides and seismic events (CITE). If ground movement occurred and has the potential to affect the pipe's integrity, Keystone is required by federal regulations to inspect the pipe (49 CFR 195).

TransCanada's Integrity Management Program would continue to assess the Keystone XL Pipeline Project route and threats from outside forces (e.g., landslides) would be evaluated in a comprehensive and systematic program, as required by federal pipeline safety regulations (49 CFR 195). As part of the Integrity Management Program, Keystone evaluates the potential for a release along the entire length of its pipelines and determines what resources could potentially be affected by a release. This information is shared with TransCanada's Emergency Response staff to facilitate emergency response planning and to develop appropriate training scenarios.

A. Locations of ground swelling are identified in the FSEIS, Section 3.1 Geology. In Section 3.1 of the FSEIS, Table 3.1-6 and Figure 3.1.2-3 identify the high risk category Landslide Hazard Area (LSHR) areas for swelling soils and landslides.

Table 3.1-6 Locations within LSHR High-Risk Category along the Proposed Project Corridor

State	Start (MP)	End (MP)	Length
Montana	0.2	25.5	25.3
Montana	25.5	89.2	63.7
Montana	89.2	102.0	12.8
South Dakota	308.3	313.5	5.2
South Dakota	355.6	358.1	2.5
South Dakota	358.1	370.9	12.8
South Dakota	389.5	425.9	36.4
South Dakota	425.9	426.3	0.4
South Dakota	426.3	485.1	58.8
South Dakota	485.1	525.2	40.1
South Dakota	525.2	537.1	11.9
South Dakota	537.1	571.5	34.4
Nebraska	601.5	605.3	3.8
Nebraska	606.8	637.5	30.7
Total			338.8

Sources: USGS 2009a; PHMSA-NPMS 2007b

B. 49 CFR 194.105

U.S. Department of State (USDOS). 2014. Final Supplemental Environmental Impact Statement for the Keystone XL Project. Washington D.C. Includes all appendices of the FSEIS.

INTERROGATORY NO. 49: What lessons have been learned from previous pipeline construction, current right-of-way conditions and project requirements that have been incorporated into the Construction Mitigation and Reclamation (CMR) Plan? Identify any documents which would support your answers, including but not limited to the latest version of the CMR plan. [Applicable Finding or Condition No.: Finding 32, 37, 73; Conditions 13-30]

ANSWER: Lessons learned are incorporated through the changes to Keystone's CMR Plan, the current draft of which is attached to Exhibit C to Keystone's certification petition as Attachment A.

INTERROGATORY NO. 50: Provide a list of changes in the proposed KXL pipeline route since 2010.

A. For each change in the route:

i. State why the route was changed;

ii. State how the new route improves this Project when compared with the previously submitted route;

B. Identify any documents which would support your answers.

[Applicable Finding or Condition No.: Finding 33]

ANSWER: Please refer to the attached route variation maps attached as Keystone 0470-0583.

INTERROGATORY NO. 51: Describe the status of the development of procedures for handling and disposal of unanticipated contaminated soil discovered during construction, and consultation with relevant agencies thereon.

A. Identify any draft or final procures developed to date;

B. Identify any documents which would support your answers.

[Applicable Finding or Condition No.: Conditions 13-30]

ANSWER: Keystone has not yet drafted the Unanticipated Contaminated Soils Plan.

INTERROGATORY NO. 52: State whether or not TransCanada or its Affiliates have conducted any assessments or studies of potential risks to the structural integrity of the proposed KXL Pipeline from seismic activity. If so, describe the results of any such assessment or studies and describe the maximum impacts that could occur with respect to a pipeline rupture resulting

from seismic activity. Identify any documents which would support your answers. [Applicable Finding or Condition No.: Conditions 31-38]

ANSWER: Please refer to the FEIS section 3.1.4 Geologic Hazards.

INTERROGATORY NO. 53: Describe the status of TransCanada's efforts to obtain a permit process for water body crossings.

A. List the agency(ies) to whom TransCanada has submitted a permit application;

B. Identify all permit applications submitted;

C. List any permits which TransCanada needs to obtain prior to its proposed KXL pipeline construction for each of the water body crossings desired to be crossed.

D. Explain why horizontal directional drilling will not be used on water body crossing of perennial streams and intermittent water bodies;

E. Identify any documents which would support your answers.

[Applicable Finding or Condition No.: Finding 41; Conditions 1, 2, 13-30]

ANSWER: The following is the requested information addressing the permitting of the water body crossings:

A. To date, Keystone has not submitted any permit applications to any agencies for water body crossings in South Dakota. All permits for waterbody crossings, as required, will be filed closer to the time period of construction.

B. To date, Keystone has not submitted any permit applications for water body crossings in South Dakota. All permits for waterbody crossings, as required, will be filed closer to the time period of construction.

C. Keystone will permit all of the water body crossings in South Dakota under the US Army Corps of Engineers Nationwide General Permit (NWP) 12. Additionally, the South Dakota Department of Environment and Natural Resources is responsible for Clean Water Act permit certification under Section 401 and would review proposed stream and river crossings where necessary and may issue project-specific conditions.

D. The decision to use the horizontal directional drilling (HDD) crossing method was based on and evaluation of engineering and environmental factors and use of an HDD does not always provide the most suitable methodology for a waterbody crossing. During the Project design, TransCanada has complied with all regulations and permit stipulations in determining the proposed crossing method for each waterbody in South Dakota.

E. The Department of State FEIS (2014) Sections 4.3, Water Resources; 4.7 Fisheries; 4.8 Threatened and Endangered Species; and Appendix H.

INTERROGATORY NO. 54: Describe the maximum impacts that could occur from expected loss of in-stream habitat through direct disturbance, loss of bank cover, disruption of fish movement, direct disturbance to spawning, water quality effects, and sedimentation effects by open-cut trenching of water crossings other than the Little Missouri, Cheyenne and White River crossings. Identify any documents which would support your answers. [Applicable Finding or Condition No.: Finding 41; Conditions 34, 41]

ANSWER: The Department of State FSEIS (2014) evaluates the impacts to instream habitat as a result of the construction and operation of the Project in the following locations:

a. Section 4.3.2.2, Surface Water

b. Section 4.3.3.2, Surface Water

c. Section 4.7.3.2, Construction impacts

d. Section 4.7.3.3 Proposed Project Operational Impacts

INTERROGATORY NO. 55: Describe the maximum impacts that could occur during or as a result of horizontal directional drilling to cross the Little Missouri, Cheyenne, and White River crossings. Identify any documents which would support your answers. [Applicable Finding or Condition No.: Finding 41, 82-83; Condition 22]

ANSWER: This issue is addressed several times in the FSEIS, as follows:

At page 4.3-21:

In some instances, pressurized fluids and drilling lubricants used in the HDD process have the potential to escape the active HDD bore, migrate through the soils, and come to the surface at or near the crossing construction site, an event commonly known as a frac-out. Measures identified in a required HDD contingency plan would be implemented, including monitoring of the directional drill bore, monitoring downstream for evidence of drilling fluids, and mitigation measures to address a frac-out should one occur.

At page 4.8-20 :

The HDD method avoids direct disturbance to the river, channel bed, or banks. While the HDD method poses a small risk of frac-out (i.e., release of bentonite-based drilling fluids), potential releases would be contained by best management practices that would be described within the HDD Contingency Plans required for drilled crossings. Most leaks of HDD fluids occur near the entry, exit locations for the drill, and are quickly contained and cleaned up. Frac-outs that may release drilling fluids into aquatic environments are difficult to contain primarily because bentonite readily disperses in flowing water and quickly settles in standing water.

Should this type of release occur, bentonite is non-toxic but in sufficient concentration may physically inhibit respiration of adult fish and eggs.

At page 4.7-11,12:

The HDD method for crossing waterbodies would be used to minimize disturbance to aquatic habitat, stream banks, and recreational or commercial fisheries. Impacts could occur if there is an unintended release of drilling fluids (i.e., a frac out) during the HDD operation. A frac out could release bentonitic drilling mud into the aquatic environment. The released drilling mud would readily disperse in flowing water or eventually settle in standing water.

Although bentonite is non-toxic, suspended bentonite may produce short-term impacts to the respiration of fish and aquatic invertebrates due to fouled gills. Longer-term effects could result if larval fish are covered and suffocate due to fouled gills and/or lack of oxygen. If the frac out occurred during a spawning period, egg masses of fish could be covered, thus inhibiting the flow of dissolved oxygen to the egg masses. Benthic invertebrates and the larval stages of pelagic organisms could also be covered and suffocate.

INTERROGATORY NO. 56: Describe the worst case scenario of a worst case discharge into the Little Missouri, Cheyenne, and White River crossings. Identify any documents which would support your answers. [Applicable Finding or Condition No.: Findings 41-52, 68-69, 82-83; Conditions 31-42]

OBJECTION AND RESPONSE: This request seeks information that is confidential. The location and volume of a worst case scenario spill are kept confidential for homeland security reasons. Without waiving the objection, worst case discharge data were provided to regulatory agencies in Appendix A of the 2009 Keystone XL Risk Assessment.

The 2009 Keystone XL Risk Assessment discussed the range of impacts based on abroad range of spill volumes that encompassed 99.6 percent of all historical spill volumes, thereby describing a reasonable worst case scenario for the Keystone XL Pipeline Project. The 2009 Keystone XL Risk Assessment discussed the spill volumes and a very conservative assessment (i.e., assessment intentionally overestimates) of the magnitude of potential impacts in flowing waterbodies (2009 Keystone XL Risk Assessment, Section 4.2.3.4 Water Resources).

For streams that are HDD, most spills would not be expected to reach the river since the burial depth often can prevent a release from reaching the waterbody. However, as a worst case scenario for the purposes of this information response, a worst case scenario is assumed to reach the river. In the 2009 Keystone XL Risk Assessment, Table 4-1 from the 2009 Keystone XL Risk Assessment describes stream categories based on stream flows. The White River and Little Missouri Rivers are categorized as a stream with upper moderate flow, while the Cheyenne River would fall into the high flow Stream category. All three streams are being HDD. Based on those stream flow categories, impacts to water quality and aquatic biota can be identified in 2009 Keystone XL Risk Assessment text in Section 4.2.3.4 and Tables 4.2, and 4.3 and 4.7 to 4.10.

2009 Keystone XL Risk Assessment

Table 4-1 Stream Categories

Category	Streamflow (cubic feet per second [cfs])	Top of Bank Stream Width (feet)	Representative Streams
Low Flow Stream	10 – 100	<50	Many unnamed intermittent tributaries in all states crossed, Bear Creek (MT), South Branch Timber Creek (NE)

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Lower Moderate Flow Stream	100 – 1,000	50 – 500	Upper Sevenmile Creek (MT), Lone Tree Creek (MT), Little Blue River (NE)
Upper Moderate Flow Stream	1,000 – 10,000	500 – 1,000	Yellowstone River (MT), White River (SD), Niobrara River (NE)
High Flow Stream	>10,000	1,000 – 2,500	Missouri River (MT), Loup River (NE), Platte River (NE), Canadian River (OK), Red River (TX)

INTERROGATORY NO. 57: Describe the worst case scenario which could occur from the Keystone XL pipeline as it passes under channels, adjacent flood plains and flood protection levees. Identify any documents which would support your answers. [Applicable Finding or Condition No.: Findings 41-49; Conditions 31-42]

OBJECTION: This request seeks information that is confidential by statute. The location and volume of a worst case scenario spill are kept confidential for homeland security reasons. Without waiving the objection, when the pipe crosses channels and flood plains, scenarios would be dictated by stream flow rate (discharge) and are discussed in Section 4.2.3.4 of 2009 Keystone XL Risk Assessment. Impacts are described in Section 4.2.3.4 for channels. Floodplain crossings are covered in FEIS Section 4.3.3.3 and Section 4.3.3.4 discusses impacts to floodplains. Worst case would be spill into low flow stream (Table 4-2 in 2009 Keystone XL Risk Assessment). Spills at individual river crossings are rare with occurrence interval of 1/22,000 years to 1/830,000 years based on representative crossing distances (2009 Keystone XL Risk Assessment). Most spills are less than 3 barrels.

River crossings by pipelines are very common, number of incidents are low, and safety is not affected by material transported. Predicted Project-specific incident frequencies are provided in Section 3.0 of the 2009 Keystone XL Risk Assessment. Spills at individual river crossings are rare with occurrence interval of 1/22,000 years to 1/830,000 years based on representative crossing distances (2009 Keystone XL Risk Assessment).

INTERROGATORY NO. 58: In light of the spill risk assessment provided by TransCanada in the HP09-001 docket:

A. Explain the number of leaks along the Keystone I pipeline since 2008;

B. Explain the number of leaks from the other oil pipelines constructed and/or operated by TransCanada or its Affiliates;

C. What would be a worst case scenario discharge from the KXL pipeline? Please explain your answer;

D. Identify any documents which would support your respective answers.

[Applicable Finding or Condition No.: Findings 41-49, 51-52; Conditions 31-38]

OBJECTION AND RESPONSE: Subpart(c) requests information that is confidential by statue. The location and volume of a worst case scenario spill are confidential for homeland security reasons. Subpart (d) is overlybroad and unduly burdensome. There are thousands of pages of documents supporting Keystone's spill risk assessment. In addition, many of the documents contain information that is confidential and proprietary. Without waiving the objection:

A. Keystone has delivered more than 760 million barrels of oil from Canada to the United States markets since it began operation in July 2010. The small number of leaks that

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have occurred on the pipeline have had nothing to do with the integrity of the pipe itself. They have all occurred at our pump stations and other above-ground facilities and have been related to leakage from small-diameter fittings and seals. They have all been cleaned up with no environmental impact. We designed the pipeline to ensure that all small diameter fittings, valves and seals are located above ground where they can be easily accessed for maintenance and repairs. All of our pump stations are designed to capture and contain oil on our property. In total, less than 450 barrels of oil, out of more than 760 million barrels transported, have come out of the pipeline since it began operations five years ago TransCanada is constantly striving to improve our performance and working towards our goal of having zero leaks or safety incidents. All pipeline leaks are thoroughly investigated regardless of their size in order to understand the cause and prevent future such incidents. The leaks are identified in the spreadsheet attached as Keystone 0774-0784.

B. None.

INTERROGATORY NO. 59: Describe in detail the impact of a worst case scenario spill from the proposed KXL Pipeline through the Sand Hills in South Dakota. Identify any documents which would support your answers. [Applicable Finding or Condition No.: Findings 43-49, 53; Conditions 16, 35]

OBJECTION AND ANSWER: This request seeks information that is not within Keystone's custody or control. Without waiving the objection, there are no Sand Hills in South Dakota. *See* Table 3.5.-2 of the Department of State FSEIS (2014).

INTERROGATORY NO. 60: Describe in detail the impact of a worst case scenario spill into the shallow and surficial aquifers in Tripp County from the proposed KXL Pipeline. Identify

any documents which would support your answers. [Applicable Finding or Condition No.: Findings 43-49, 53; Conditions 16, 35]

OBJECTION AND ANSWER: This request seeks information that is confidential by statute. The location and volume of a worst case scenario spill are confidential for homeland security reasons. Without waiving the objection, the 2009 Keystone XL Risk Assessment (FSEIS, Appendix P) described the movement of crude oil and its constituents in soils and groundwater. Field investigations of more than 600 historical petroleum hydrocarbon release sites indicate the migration of dissolved constituents typically stabilizes within several hundred feet of the crude oil source area (Newell and Conner 1998; USGS 1998). Over a longer period, the area of the contaminant plume may begin to reduce due to natural biodegradation. Removal of crude oil contamination will eliminate the source of dissolved constituents impacting the groundwater.

Spills are also discussed in the FSEIS in Section 4.1.3.4, including those in shallow and surficial aquifers. The fate and transport of benzene and other crude oil constituents is discussed in numerous studies and articles, including those referenced in the 2009 Keystone XL Risk Assessment, such as:

Freeze, R. A. and J. A. Cherry. 1979. Groundwater. Prentice Hall, Inc. Englewood Cliffs, New Jersey. 604 pp.

Minnesota Pollution Control Agency. 2005. Assessment of Natural Attenuation at Petroleum Release Sites. Guidance Document c-prp4-03, Petroleum Remediation Program, Minnesota Pollution Control Agency. April 2005. 11 pp.

Neff, J. M. 1979. Polycyclic aromatic hydrocarbons in the aquatic environment. Applied Science publ. Ltd., London. 262 pp.

Newell, C. J. and J. A. Connor. 1998. Characteristics of Dissolved Petroleum Hydrocarbon Plumes: Results from Four Studies. American Petroleum Institute Soil / Groundwater Technical Task Force. December 1998.

Spence, L. R., K. T. O'Reilly, R. I. Maagaw, and W. G. Rixey. 2001. Chapter 6 – Predicting the fate and transport of hydrocarbons in soil and groundwater. In :risk-based decision-making or assessing petroleum impacts at exploration and production sites. Edited by S. McMillen, R. Magaw, R. Carovillano, Petroleum Environmental Research Forum and US Department of Energy.

United States Geological Service (USGS). 1998. Groundwater Contamination by Crude Oil near Bemidji, Minnesota. US Geological Survey Fact Sheet 084-98, September 1998.

Additional references on this subject from the FSEIS include:

American Petroleum Institute (API). 1992. Review of Natural Resource Damage Assessments in Freshwater Environments: Effects of Oil Release into Freshwater Habitats. API Publ. No. 4514.

API. 1997. Petroleum in the Freshwater Environment: An annotated Bibliography 1946-1993. API Publ. No. 4640.

Grimaz, S., S. Allen, J. Steward, and G. Dolcetti. 2007. Predictive evaluation of the extent of the surface spreading for the case of accidental spillage of oil on ground. Selected Paper IcheaP8, AIDIC Conference series, Vol. 8, 2007, pp. 151-160.

Hult, M.F. 1984. Groundwater Contamination by Crude Oil at the Bemidji, Minnesota, Research Site: U.S. Geological Survey Toxic Waste—Ground-Water Contamination Study. Papers presented at the Toxic-Waste Technical Meeting, Tucson, Arizona, March 20-22. USGS Water Investigations Report 84-4188.

Weaver, J.W., R.J. Charbeneau, J.D. Tauxe, B.K. Lien, and J.B. Provost. 1994. The hydrocarbon spill screening model (HSSM) Volume 1: User's guide. USEPA/600/R-94/039a.U.S. Environmental Protection Agency, Office of Research and Development, Robert S. Kerr, Environmental Research Laboratory, Ada, OK

INTERROGATORY NO. 61: Identify the USGS or other geological, hydrological, geo-hydrological studies conducted in the areas including what is now the proposed KXL pipeline route through South Dakota, which:

A. Provide the thickness of the purportedly low permeability confining materials that would underlie the entirety of the proposed route either through the Sand Hills and over any shallow High Plains Aquifer;

B. Provide the thickness of the confining materials underlying the balance of the proposed pipeline route;

C. Provide the permeability of the sediment or bedrock underlying the proposed pipeline route for each part of the KXL pipeline;

D. Describe the composition of the sediments and/or bedrock underlying each part of the proposed route;

E. Describe the absence of any fractures (including micro-fractures), faults, karsts, sinkholes within a mile of the entirety of the proposed route and which might lengthen the "unlikely" travel of crude oil more than 300 feet from a spill site;

F. Describe the absence of channels in the underlying strata along each part of the proposed route which might lengthen the "unlikely" travel of crude oil more than 300 feet from a spill site;

G. Describe other factors which could lengthen the travel of crude oil beyond 300 feet from a spill site;

H. The location(s) of shallow aquifers along each part of the route;

I. The location(s) of surficial aquifers along each part of the route;

J. The location of domestic and livestock wells, public and private, within a mile of each part of the proposed route;

K. Describe the "appropriate" measures that TransCanada will take to prevent groundwater contamination;

L. Describe the "steps" to be taken to manage the flow of any ground water encountered;

M. Identify any documents which would support your respective answers.

[Applicable Finding or Condition No.: Findings 43-49, 53; Conditions 16, 35]

OBJECTION AND ANSWER: This request is overlybroad and unduly burdensome. This request may also seek information that is not within Keystone's custody or control and is not maintained by Keystone in the ordinary course of business.

Without waiving the objection, geological references and hydrogeological references are listed in chapters 3 and 4 in the FSEIS. Some pertinent additional references are:

Gutentag (1984): USGS Prof. Paper 1400-B

Downey (1986): USGS Prof. Paper 1402-E

Thamke et al (2014): USGS Scientific Inv. Report SIR 2014-5047.

In addition, lithologic logs available from the South Dakota Dept. Natural Resources at http://denr.sd.gov/des/wr/dblog.search.aspx and http://denr.sd.gov/data.aspx provide aquifer thickness data.

A. Geological references and hydrogeological references are listed in chapters 3 and 4 in the FSEIS. Some pertinent additional references are:

Gutentag (1984): USGS Prof. Paper 1400-B

Downey (1986): USGS Prof. Paper 1402-E

Thamke et al (2014): USGS Scientific Inv. Report SIR 2014-5047.

In addition, lithologic logs available from the South Dakota Dept. Natural Resources at http://denr.sd.gov/des/wr/dblog.search.aspx and http://denr.sd.gov/data.aspx provide aquifer thickness data.

B. Geological references and hydrogeological references are listed in chapters 3 and 4 in the FSEIS. Some pertinent additional references are:

Gutentag (1984): USGS Prof. Paper 1400-B

Downey (1986): USGS Prof. Paper 1402-E

Thamke et al (2014): USGS Scientific Inv. Report SIR 2014-5047.

In addition, lithologic logs available from the South Dakota Dept. Natural Resources at http://denr.sd.gov/des/wr/dblog.search.aspx and http://denr.sd.gov/data.aspx provide aquifer thickness data.

C. Geological references and hydrogeological references are listed in chapters 3 and 4 in the FSEIS. Some pertinent additional references are:

Gutentag (1984): USGS Prof. Paper 1400-B

Downey (1986): USGS Prof. Paper 1402-E

Thamke et al (2014): USGS Scientific Inv. Report SIR 2014-5047.

In addition, lithologic logs available from the South Dakota Dept. Natural Resources at http://denr.sd.gov/des/wr/dblog.search.aspx and http://denr.sd.gov/data.aspx provide aquifer thickness data.

D. Geological references and hydrogeological references are listed in chapters 3 and 4 in the FSEIS. Some pertinent additional references are:

Gutentag (1984): USGS Prof. Paper 1400-B

Downey (1986): USGS Prof. Paper 1402-E

Thamke et al (2014): USGS Scientific Inv. Report SIR 2014-5047.

In addition, lithologic logs available from the South Dakota Dept. Natural Resources at http://denr.sd.gov/des/wr/dblog.search.aspx and http://denr.sd.gov/data.aspx provide aquifer thickness data.

E. Geological references and hydrogeological references are listed in chapters 3 and 4 in the FSEIS. Some pertinent additional references are:

Gutentag (1984): USGS Prof. Paper 1400-B

Downey (1986): USGS Prof. Paper 1402-E

Thamke et al (2014): USGS Scientific Inv. Report SIR 2014-5047.

In addition, lithologic logs available from the South Dakota Dept. Natural Resources at http://denr.sd.gov/des/wr/dblog.search.aspx and http://denr.sd.gov/data.aspx provide aquifer thickness data.

In addition, consider the following:

Whitehead et al (1996): USGS Hydrologic Atlas HA 730-I

Hammond (1994): South Dakota Geol. Survey open file report UR-68

Lobmeyer (1985): USGS Prof. Paper 1402-D

Luckey et al (1986): USGS Prof. Paper 1400-D.

F. Geological references and hydrogeological references are listed in chapters 3 and 4 in the FSEIS. Some pertinent additional references are:

Gutentag (1984): USGS Prof. Paper 1400-B

Downey (1986): USGS Prof. Paper 1402-E

Thamke et al (2014): USGS Scientific Inv. Report SIR 2014-5047.

In addition, lithologic logs available from the South Dakota Dept. Natural Resources at http://denr.sd.gov/des/wr/dblog.search.aspx and http://denr.sd.gov/data.aspx provide aquifer thickness data.

G. Geological references and hydrogeological references are listed in chapters 3 and 4 in the FSEIS. Some pertinent additional references are:

Gutentag (1984): USGS Prof. Paper 1400-B

Downey (1986): USGS Prof. Paper 1402-E

Thamke et al (2014): USGS Scientific Inv. Report SIR 2014-5047.

In addition, lithologic logs available from the South Dakota Dept. Natural Resources at http://denr.sd.gov/des/wr/dblog.search.aspx and http://denr.sd.gov/data.aspx provide aquifer thickness data.

Lithologic logs available from the South Dakota Dept. Natural Resources at http://denr.sd.gov/des/wr/dblog.search.aspx and http://denr.sd.gov/data.aspx provide the thickness data. In addition, consider the following:

Davis and Putnam (2013): USGS Scientific Inv. Report SIR 2013-5069

Downey (1986): USGS Prof. Paper 1402-E

Gutentag (1984): USGS Prof. Paper 1400-A and 1400-B.

H. Geological references and hydrogeological references are listed in chapters 3 and 4 in the FSEIS. Some pertinent additional references are:

Gutentag (1984): USGS Prof. Paper 1400-B

Downey (1986): USGS Prof. Paper 1402-E

Thamke et al (2014): USGS Scientific Inv. Report SIR 2014-5047.

In addition, lithologic logs available from the South Dakota Dept. Natural Resources at http://denr.sd.gov/des/wr/dblog.search.aspx and http://denr.sd.gov/data.aspx provide aquifer thickness data.

In addition, consider the following:

Downey (1986): USGS Prof. Paper 1402-E

Gutentag et al (1984): USGS Prof. Paper 1400-B.

I. Geological references and hydrogeological references are listed in chapters 3 and 4 in the FSEIS. Some pertinent additional references are:

Gutentag (1984): USGS Prof. Paper 1400-B

Downey (1986): USGS Prof. Paper 1402-E

Thamke et al (2014): USGS Scientific Inv. Report SIR 2014-5047.

In addition, lithologic logs available from the South Dakota Dept. Natural Resources at http://denr.sd.gov/des/wr/dblog.search.aspx and http://denr.sd.gov/data.aspx provide aquifer thickness data.

J. Keystone has not yet identified the location of wells, but will do so before construction.

K. "In order to reduce the risk of spills, if permitted Keystone has agreed to incorporate additional mitigation measures in the design, construction, and operation of the proposed Keystone XL Project, in some instances above what is normally required, including:

- 59 Special Conditions recommended by PHMSA;
- 25 mitigation measures recommended in the Battelle and Exponent risk reports; and
- 11 additional mitigation measures.

Many of these mitigation measures relate to reductions in the likelihood of a release occurring. Other measures provide mitigation that reduces the consequences and impact of a spill should such an event occur. Mitigation measures are compiled I Appendix Z, Compiled Mitigation Measures, of this Supplemental EIS. Mitigation measures are actions that, if the proposed Project is determined to be in the national interest, Keystone would comply with as conditions of a Presidential Permit." (FSEIS Executive Summary, pg. ES-19").

In the FSEIS Appendix Z, Section 14.1, Potential Releases, Table 4, are listed the 59 Special Conditions recommended by the PHMSA. TransCanada has committed to complying with the PHMSA 59 Special Conditions as listed in Appendix Z of the FSEIS.

"These regulations are intended to ensure adequate protection for the public and to prevent crude oil pipeline accidents. Among other design standards, 49 CFR 195 and the proposed Project-specific special conditions specify pipeline material and qualification, minimum design requirements, and protection from internal, external, and atmospheric corrosion" (FSEIS Appendix H1-H2, pg. 2.0-32)".

L. Keystone would coordinate with the South Dakota Department of Environment and Natural Resources regarding specific steps to be taken in the event that potential contamination of groundwater was suspected. These steps may include, but may not be limited to, soil and groundwater sampling, installation of monitoring wells, and use of groundwater remediation technologies.

INTERROGATORY NO. 62: Describe the direct and indirect effects to people, other animals, plants and trees, fish, when exposed individually and or in combination to components of crude oil including: benzene, toluene, ethyl benzene and xylene. Identify any documents which would support your respective answers. [Applicable Finding or Condition No.: Findings 43-49; Conditions 31-37]

ANSWER: Effects to these receptors are discussed in the 2009 Keystone XL Risk Assessment and in the FSEIS (Chapter 4). Additional information, including effects of individual compounds, can be found in the Agency for Toxic Substances and Disease Registry (ATSDR) or the Hazardous Substances Data Bank (HSDB). Benzene is often used for screening for effects in petroleum products due its combined high water solubility and ability to cause toxicity at very low concentrations.

U.S. Department of Health and Human Services. 2015. Agency for Toxic Substances and Disease Registry (ATSDR). Internet website: http://www.atsdr.cdc.gov. Accessed January 21, 2015.

U.S. National Library of Medicine, Toxicology Data Network (TOXNET). 2015. Hazardous Substances Data Bank (HSDB). Internet website: http://toxnet.nlm.nih.gov/cgi-bin/sis/htmlgen?HSDB. Accessed January 21, 2015.

INTERROGATORY NO. 63: Provide an explanation of why the occurrence of a spill or leak that could affect the High Consequence Area (HCA) only once every 250 years over the 34.4 miles of HCA (Finding 50), while such a spill would purportedly occur once in 7,400 years per mile of pipeline (Finding 44). Identify any documents which would support your respective answer. [Applicable Finding or Condition No.: Findings 44, 50; Conditions 15-16, 35]

ANSWER: Finding of Fact 44 in the South Dakota Public Utilities Commission Amended Order states that, "Keystone's expert estimated the chance of a leak from the Project to be not more than one spill in 7,400 years for any given mile of pipe." This is calculated based on historical incident data from Pipeline and Hazardous Materials Safety Administration (PHMSA), as discussed in Section 3.0. The occurrence interval of 7,400 years is calculated by taking the inverse of the incident frequency (0.000135 incidents per mile per year). The result is an estimate, in years, of the time between spills. This is similar to the concept of flood recurrence intervals (i.e., 100-year floods).

Page 4-21 of the 2009 Keystone XL Risk Assessment shows that a spill affecting a High Consequence Area (HCA) in any state crossed by the Keystone XL Pipeline Project has an

occurrence interval of 53 years. This is calculated by taking the inverse of the incident frequency (measured as incidents per mile per year) multiplied by the miles of HCAs crossed (141.2 miles).

INTERROGATORY NO. 64: Describe the contents of the "information concerning activities of concern" to be made available to landowners and others. Identify any documents which would support your respective answer. [Applicable Finding or Condition No.: Finding 57; Condition 16]

ANSWER: Condition 16 does not address "information concerning activities of concern." With respect to Finding 57, it is landowners who are permitted to contact Keystone regarding "activities of concern." Accordingly, Keystone does not know specifically what activities may be of concern to individual landowners. In the context of the Finding, it is likely that such activities can be expected to involve farming operations above the pipeline.

INTERROGATORY NO. 65: Describe the worst case scenario for landowners of a spill from the proposed pipeline onto only land, as well as other risks deemed "low" by the PUC. Identify any documents which would support your respective answer. [Applicable Finding or Condition No.: Findings 57; Conditions 16, 31-38]

ANSWER: Keystone cannot speak to risks deemed "low" by the PUC.

INTERROGATORY NO. 66: Provide a list of claims or complaints (of any kind) made to the Commission by landowners along the Keystone I pipeline corridor since 2008. Identify any documents which would support your respective answer. [Applicable Finding or Condition No.: Finding 57; Conditions 49-50]

OBJECTION AND ANSWER: Assuming that the request is for a list of claims or complaints made by landowners along the Keystone Pipeline corridor in eastern South Dakota to

the PUC since 2008, this information is publicly available on the PUC website. To the extent that the request is for complaints made by landowners along the Keystone XL Pipeline corridor since 2008, the request is vague, overlybroad, unduly burdensome, and seeks discovery of information that is not relevant and not likely to lead to the discovery of admissible evidence under SDCL 15-6-26(b). All complaints reported to the liaison by the SDPUC are documented by the liaison and reported quarterly. These reports are available at: https://puc.sd.gov/dockets/hydrocarbonpipeline/2009/publicliaisonreports.aspx. Without waiving the objection, attached as Keystone 0785-1115 are documents related to landowner complaints or concerns regarding damages resulting from Keystone XL's use of the easement, which is within the scope of Amended Permit Condition 49.

INTERROGATORY NO. 67: Identify the latest version of the Unanticipated Discovery Plan, including any prior drafts. [Applicable Finding or Condition No.: Finding 58; Condition 43]

ANSWER: The Unanticipated Discovery Plan can be found within the Programmatic Agreement in Appendix E of the Department of State FSEIS (2014).

INTERROGATORY NO. 68. Explain why TransCanada has sought a special permit from the PHMSA for authorization "to design, construct, and operate the Project up to 80% of the steel pipe specified minimum yield strength at most locations."

A. Identify and describe all spills/leaks from TransCanada pipeline operations since 2009 in Canada which have involved a "0.8 design factor" and therefore involving use of steel pipe up to 80% of the specified minimum yield strength.

B. Identify documents upon which your answers are based.

[Applicable Finding or Condition No.: Findings 60-61]

ANSWER: Keystone is no longer seeking a special permit from PHMSA.

A. There are currently no TransCanada crude oil pipelines operating at 0.8 design factor in Canada.

B. Keystone's decision to withdraw its special permit request is explained in a Media Advisory dated August 5, 2010, attached as Keystone 0647-0649.

INTERROGATORY NO. 69: Explain why it is expected that any special permit issued by PHMSA would exclude pipeline segments in High Consequence Areas (HCAs).

A. Describe the potential risks of using pipeline segments with a design factor of 0.80 rather than 0.72, as required by 49 CFR § 195.106.

B. Identify documents upon which your answers are based.

[Applicable Finding or Condition No.: Findings 60-62]

ANSWER: Keystone has withdrawn its request for a Special Permit. Hypothetically, if Keystone were to reapply for a Special Permit, it is reasonable to anticipate that such a Permit would exclude pipeline segments in HCAs since the Special Permit for the original Keystone Pipeline excluded such areas.

INTERROGATORY NO. 70: Explain how application of the "0.8 design factor and API 5L PSL2 X70 high-strength steel pipe" with thinner walls would "provide a level of safety equal to or greater than that which would be provided if the pipeline were operated under the otherwise applicable regulations." [Applicable Finding or Condition No.: Finding 63]

OBJECTION: This request seeks information that is beyond the scope of the PUC's jurisdiction and Keystone's burden of proof under SDCL 49-41B-27. The issue is within the

exclusive jurisdiction of PHMSA. Keystone has withdrawn its application for a special permit. Without waiving the objection, on August 5 2010, TransCanada withdrew its application to the Pipeline Hazardous Materials and Safety Administration (PHMSA) for a special permit to design, construct and operate the pipeline at a 0.8 design factor and adopted the 57 additional safety measures that would have been required under the PHMSA special permit.

INTERROGATORY NO. 71: With regard to over-pressure events:

A. What are the potential causes of over-pressurization?

B. Describe the failures of the SCADA system that could cause a full rupture of the KXL Pipeline;

C. Describe TransCanada's maintenance and operational protocols and system redundancies that are intended to prevent failure of the SCADA system;

D. Describe the ability of the SCADA system to detect leaks in the Keystone I pipeline from 2008 through today;

E. Describe improvements in SCADA technology since 2010;

F. Describe actions TransCanada has taken to prevent a cyber-attack on the SCADA monitoring system;

G. Identify documents upon which your answers are based.

[Applicable Finding or Condition No.: Finding 72, 92-94; Conditions 31-38]

ANSWER:

A. There are two main causes of over-pressurization in pipelines: static pressure, and dynamic pressure. Static pressure excursions can occur during steady-state operation due to differences in elevation along the pipeline. In a static pressure excursion situation, it is possible

to see pressures in excess of the pipeline's MOP at points of low elevation along the line. Dynamic pressure excursions result from a disturbance which causes a change in fluid velocity. Disturbances can result from events such as valve closure and pump shutdowns. Automated and independent pressure control and overpressure protection systems are designed to protect against static and dynamic overpressure.

B. Potential threats contributing to releases from small to large volumes are described within section 3.13.3.10 of the FSEIS. Equipment malfunctions including those of SCADA components are addressed within this section. Associated threats have been addressed through the following:

- Design practices including system fail safe functionality, key component and power supply redundancy (including key pressure and level sensors).
- Functional validation of systems including factory and site acceptance testing as well as comprehensive point to point verification between SCADA and associated field devices.

C. TransCanada has a dedicated team to provide operational support for its SCADA systems. The team provides 7x24 on-call SCADA support, primarily to the Oil Control Center. Additionally, automated monitoring systems alert the SCADA team in the event that a SCADA system requires maintenance. The support team ensures that routine maintenance is performed on the SCADA systems, as required. Non-routine maintenance is managed through a risk-based integrity management process. The design of the Keystone XL SCADA system includes, at a minimum, dual redundant components at both the primary and backup Oil Control Centers.

D. TransCanada utilizes a state of the art Computational Pipeline Monitoring (CPM) leak detection system capable of identifying leaks down to the size of 1.5 to 2.0% of pipeline flow rate within a 2-hour window.

TransCanada has maintained the CPM to meet or exceed this level of leak detection sensitivity since the beginning of operations. The Keystone pipeline is monitored 24/7 by a dedicated Leak Detection controller within the Oil Control Center who is trained to identify and to respond to emerging events.

E. TransCanada actively funds and participates with Industry in the evaluation and development of leak detection technologies to augment our current systems. Examples of this effort include:

1. **New Generation of Rarefaction Wave Leak Detection**

This technology utilizes negative pressure waves generated to detect the onset of a leak. These waves travel from the origination point down both directions of the pipeline through the pipeline fluid at the speed of sound of the fluid medium and attenuate over distance as they travel. Dynamic pressure sensors installed at facilities with power and communication accesses (pump stations, mainline valves, etc.) can then measure these pulsations and detect the start of a leak and locate the leak by calculating the difference of arrival time of the pulsations at the two ends of the pipeline section.

2. **In Line Inspection Leak Detection**

An acoustic In Line Inspection (ILI) tool that is launched and received on a periodic basis like any other In Line Inspection (ILI) tool and is propelled by the commodity in the line. This technology claims to be able to detect leaks smaller than the current threshold of CPM systems; however, detection only occurs as the tool passes the leak location and is therefore not a continuous real time monitoring system.

3. **Infrared thermal camera for facilities**

The camera based leak detection technology functions by employing Infrared and color video cameras to detect temperature differences between objects of interest and the surrounding environment. Software analytics then attempt to determine whether the detection constitutes a leak or an environmental transient such as a wild animal, weather or other event (snow, rain, etc.). In the event of a detected leak, confirmation can be obtained through color cameras and

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real time notifications would be sent the Control Center and/or control room as pre-specified. This technology is still its infancy.

4. Aerial or Ground Patrol Leak Detection

This is a transportable leak detection technology designed for aerial or ground. This technology takes advantage of the difference of light absorption rates between the atmosphere and hydrocarbon vapors to detect hydrocarbon leak. Performance depends on the selected spectrum band, visible or non-visible, and the analysis algorithm vendors choose.

5. Cable Based External Leak Detection Systems

Cable based leak detection systems are buried along the pipeline to provide external means of leak detection. Different cable based technologies apply different physical principles to detect phenomena accompanying a leak as temperature change (DTS), leakage caused sound and vibration (DAS), and existence of hydrocarbon liquid (HSC) or hydrocarbon vapor molecules (VST) outside the pipe. These can be used as independent means of detection outside of the mass balance CPM systems. Despite its long history of use for leak detection at oil and gas facilities and pipeline security, application for leak detection on long-haul transmission pipelines is a recent emerging development.

Some of the above technologies are in a state of development, while others are commercially available today yet their practical application to long haul transmission pipelines such as Keystone XL has not been established. As part of our commitment to safety, TransCanada continues to evaluate these new and evolving leak detection technologies to potentially augment the best in class leak detection capabilities of our current system and for potential implementation on new pipelines including Keystone XL.

F. Consistent with industry practice, TransCanada does not publicly disclose the details of the security systems it has in place. We believe that it is not prudent to make this information public because of the likelihood that it will assist, and, potentially encourage, attackers.

INTERROGATORY NO. 72: Describe how TransCanada will report its full compliance with the CMR to the Commission, so that the Commission can confirm that TransCanada will minimize impacts on cultivated lands, grasslands, wetlands, streams, and

waterways? Identify documents upon which your answers are based. [Applicable Finding or Condition No.: Finding 73]

ANSWER: Keystone will submit quarterly progress reports to the Commission that summarize the status of construction and environmental control activities as directed by Amended Permit Condition #8. Keystone has incorporated environmental inspectors into its CMR Plan Rev4 and will obtain follow-up information reports from such inspections upon the completion of each construction spread to help ensure compliance the CMR Plan Rev4 to the Commission as directed by Amended Permit Condition #14.

INTERROGATORY NO. 73: Describe the status of TransCanada's training of each of local first responders along the proposed route of the KXL Pipeline.

A. Identify each first responder entity along the Keystone I pipeline routes for which TransCanada has provided training and describe this training;

B. Describe how the training for the Keystone XL Pipeline will differ from the training provided for the Keystone I pipeline;

C. Identify documents upon which your answers are based.

[Applicable Finding or Condition No.: Finding 100; Conditions 10, 15]

ANSWER: Emergency response training is addressed in detail at Appendix D of the Keystone Pipeline System Emergency Response Plan attached as Appendix I of the State Department January 2014 Final Supplemental EIS.

See http://keystonepipeline-xl.state.gov/documents/organization/221231.pdf

Specific training for Keystone XL has not yet been established but will be similar to that described in the Keystone ERP above.

INTERROGATORY NO. 74: Do you admit that ground movement can cause abnormal movement of the proposed KXL pipeline?

A. Describe incidents where ground movement has resulted in abnormal movement of the Keystone I or other pipeline similar to the proposed KXL Pipeline;

B. Identify documents upon which your answers are based.

[Applicable Finding or Condition No.: Finding 101; Conditions 31-38]

ANSWER: Because there are no areas of high ground movement potential along the Keystone XL route in South Dakota, Keystone does not expect any incidents of ground movement. There have been no incidents of ground movement resulting in abnormal movement of the Keystone I pipeline.

INTERROGATORY NO. 75: Since 49 CFR Part 195 would require TransCanada Keystone to conduct an "internal inspection" of any pipe section(s) potentially moved by abnormal ground movement, describe the timeframe within which an inspection would take place considering the time required to transport personnel and equipment from their staging area to the most distant segment of the KXL Pipeline in South Dakota, and the time required to notify and mobilize inspectors to their staging area. Identify documents upon which your answers are based. [Applicable Finding or Condition No.: Finding 101; Conditions 31-38]

ANSWER: It would take between one and two weeks to mobilize and conduct an internal inspection.

INTERROGATORY NO. 76: Identify the location(s) where slope instability poses a potential threat of ground movement along the Project route.

A. Identify TransCanada's most current Integrity Management Plan (IMP) showing incorporation of locations where slope instability poses a potential threat to the pipeline;

B. Identify documents upon which your answers are based.

[Applicable Finding or Condition No.: Finding 79; Conditions 8, 15, 20-21]

OBJECTION AND ANSWER: To the extent that it seeks information outside South Dakota, this request is overlybroad and unduly burdensome and seeks the discovery of information that is not relevant and not likely to lead to the discovery of admissible evidence under SDCL 15-6-26(b). In addition, the request for the Integrity Management Plan is beyond the scope of the PUC's jurisdiction and Keystone's burden under SDCL § 49-41B-27. This request also seeks information addressing an issue that is governed by federal law and is within the exclusive province of the PHMSA. The PUC's jurisdiction over the Integrity Management Plan is preempted by federal law. See 49 C.F.R. Part 194; 49 U.S.C. § 60104(c). This request further seeks information that is confidential and proprietary. See Amended Final Order, HP 09-001, Condition ¶ 36. Public disclosure of the Integrity Management Plan would commercially disadvantage Keystone. Without waiving the objection, please refer to FSEIS Chapter 3 Affected Environment, Section 3.1.2 Environmental Setting, Section 3.1.2.5 Landslide. Also, see Chapter 4 Environmental Consequences, Section 4.1.3.4 Geologic Hazards Landslides.

INTERROGATORY NO. 77: What is the status of preparation and publication of the "public awareness programs" required to be prepared by 49 CFR Part 195? Identify the documents upon which your answers are based. [Applicable Finding or Condition No.: Finding 102; Conditions 1-3, 6-7]

ANSWER: Keystone's existing public awareness program will be updated prior to KXL pipeline commencing service to incorporate any updated materials.

INTERROGATORY NO. 78: Describe the status of preparation of different construction and reclamation techniques for the variety of geological for differing soils conditions, slopes, vegetation and land use along the pipeline route, in consultation with the National Resource Conservation Service, construction/reclamation unit. Identify documents upon which your answers are based. [Applicable Finding or Condition No.: Finding 80; Conditions 15-16]

ANSWER: The preparation of different construction and reclamation techniques for the variety of geological for differing soils conditions, slopes, vegetation and land use along the pipeline route, in consultation with the National Resource Conservation Service, construction/reclamation unit has been completed. The 2013 Construction/Reclamation Unit Specifications contains this information and are found in Appendix R of the Department of State FSEIS (2014).

INTERROGATORY NO. 79: With regard to the inspectors that TransCanada will have "on a construction spread" during construction:

A. What is the number of inspectors to be onsite;

B. What is the number of such inspectors who will be "environmental inspectors;"

C. Describe the minimum qualifications for such environmental inspectors;

D. What is the distance of each construction spread that an individual environmental inspector will be responsible for monitoring on any given day of construction;

E. In what manner and how often or under what circumstances will these inspectors submit their documentation of their findings to the Commission;

F. Identify documents upon which your answers are based.

[Applicable Finding or Condition No.: Finding 85; Condition 14]

ANSWER: The final Project construction schedule has not been determined.

A. The number of inspectors including Environmental Inspectors (EIs) and the configuration of the EIs along the Project route in South Dakota will not be determined until the final Project schedule is determined.

B. There will be a minimum of one environmental inspector per spread.

C. The minimum requirements for an environmental inspector will be specified by Keystone during the hiring process.

D. Environmental inspectors are not stationary. They review procedures and activities along a spread based upon what work may be occurring on that spread on a given day. They then review and report on compliance by moving between the different spread activities that are occurring on a given day.

E. Keystone will submit quarterly progress reports to the Commission that summarize the status of construction and environmental control activities as directed by Amended Permit Condition #8. Keystone has incorporated environmental inspectors into its CMR Plan Rev4 and will obtain follow-up information reports from such inspections upon the completion of each construction spread to help ensure compliance the CMR Plan Rev4 to the Commission as directed by Amended Permit Condition #14.

F. The Department of State FSEIS (2014), The Amended Permit Conditions issued by the Commission.

INTERROGATORY NO. 80: Identify all bonding requirements with which TransCanada must comply for construction of the KXL Pipeline. In answering, also state the current bond amount under SDCL §49-41B-38 for damage to highways, roads, bridges and other related facilities during and after construction.

A. Describe in detail how figures for perceived repair and reclamation were determined;

B. Has TransCanada committed itself to pay any costs of repair or reclamation above the bond amount, should the bond amount prove too low to cover the total cost thereof?

[Applicable Finding or Condition No.: Finding 88; Condition 23]

OBJECTION AND RESPONSE: This request is not relevant or likely to lead to the discovery of admissible evidence to the extent that it seeks information outside South Dakota. Without waiving the objection, the bond requirements for Keystone XL are stated in the June 2010 Amended Final Order at Condition 23(f). The amount of the bond was proposed by Keystone and recommended by staff witness Binder in Docket HP 09-001.

INTERROGATORY NO. 81: State whether or a bond requirement exists with respect to damage to rivers, streams, shallow or surface or deeper aquifers during construction. If so, state the bond amount.

A. Describe in detail how figures for perceived repair and reclamation were determined;

B. Has TransCanada committed itself to pay any costs of repair or reclamation above the bond amount, should the bond amount prove too low to cover the total cost thereof?

[Applicable Finding or Condition No.: Finding 88; Conditions 23, 49]

ANSWER: The bond requirement referenced in the response to No. 80 above is the only bond requirement in South Dakota.

INTERROGATORY NO. 82: Describe each proposed location in South Dakota and adjacent states of spill response equipment prepositioned to respond to a spill from the KXL Pipeline.

A. For each such location, estimate the time required to mobilize personnel to their assigned equipment and the time required for this equipment to travel to the most distant point on the pipeline in South Dakota from its storage location, showing the distance travelled and assumed speeds;

B. Identify the documents upon which you relied to answer these questions;

[Applicable Finding or Condition No.: Finding 98; Conditions 31-38]

ANSWER: Oil spill response equipment (amounts, types and locations) that are owned by TransCanada are listed in Appendix A of the Keystone Emergency Response Plan, which was filed as a confidential document with the PUC in HP 07-001. The Keystone ERP will be amended to accommodate Keystone XL. PHMSA requires response times as outlined in the table below. TransCanada locates equipment and people that are transported by air, land and water to ensure that regulatory guidelines are meant.

INITIAL RESPONSE ACTIONS - SUMMARY PERSONNEL AND PUBLIC SAFETY IS FIRST PRIORITY			
RESPONSE TIMES*			
US DOT Tier	1	2	3
High Volume Area	6 HR	30 HR	54 HR
All Other Areas	12 HR	36 HR	60 HR

CONTROL

- Eliminate sources of ignition
- Isolate the source of the discharge, minimize further flow

NOTIFY

- Make internal and external notifications
- Activate local Company personnel as necessary
- Activate response contractors and other external resources as necessary

CONTAIN

- Begin spill mitigation and response activities
- Monitor and control the containment and clean-up effort
- Protect the public and environmental sensitive areas

* Response resources and personnel available to respond within time specified after discovery of a worst case discharge per US DOT 49 CFR Part 194.115 (Keystone ERP. Sec 3.1).

INTERROGATORY NO. 83: Identify the most recent IMP submitted to the Commission and other appropriate agencies, including but not limited to sections in it related to HCAs. [Applicable Finding or Condition No.: Finding 102; Conditions 1-2]

OBJECTION: This request seeks information that is beyond the scope of the PUC's jurisdiction and Keystone's burden under SDCL § 49-41B-27. This request also seeks information addressing an issue that is governed by federal law and is within the exclusive province of PHMSA. The PUC's jurisdiction over the integrity management plan is preempted by federal law. See 49 C.F.R. Part 194; 49 U.S.C. § 60104(c). This request further seeks

information that is confidential and proprietary. See Amended Final Order, HP 09-001, Condition ¶ 36. Public disclosure of the Integrity Management Plan would commercially disadvantage Keystone.

INTERROGATORY NO. 84: Itemize the property tax payments paid by TransCanada and its Affiliates to respective South Dakota towns, cities, and counties each year since 2010 for the Keystone I pipeline:

A. Compare TransCanada's property tax estimates for the Base Keystone Pipeline prepared prior to its construction to TransCanada's actual payments and explain any discrepancy;

B. Identify the documents upon which you relied to answer these questions;

[Applicable Finding or Condition No.: Finding 23, 102, 108; Conditions]

ANSWER: Keystone has paid $14,128,224 in property taxes in South Dakota from 2009 through and including 2013. 2014 real property taxes are due and payable in 2015. Keystone paid Beadle County $1,796,731; Brookings County $5,734; Clark County $1,602,403; Day County $2,294,723; Hanson County $627,561; Hutchinson County $2,015,399; Kingsbury County $955,201; Marshall County $1,533,417; McCook County $568,591; Miner County $1,782,412; and Yankton County $1,040,782; 2009 through 2013. The documents on which the answer is based are the tax bills rendered by the county treasurer in each county.

In HP07-0100, the base Keystone Pipeline docket, the company first estimated ad valorem on property taxes spread among host counties in the first year as $6.5 million, then amended the estimate to $9.1 million. Calculations were based on an "all in" cost of construction of approximately $300 million, later amended to $500, million. The estimate assumed that the pipeline would be assessed based on its construction cost. The Department of

Revenue chose not to use construction cost as the basis for the assessment. In 2011, the legislature changed the way the value of agricultural property was assessed for ad valorem real property tax purposes. The change in valuation method has resulted in a substantial increase in the assessed value of agricultural property. An increase in the assessed valuation of one category of property affects the local need and local contribution calculations under the South Dakota school aid formula and affects the way the county, city, township and school levies are spread across other categories of property. A combination of the method of assessment, levies and the change in agricultural land valuation assessment methodology explains the difference. Documents used for the answer include the tax bills rendered, a summary thereof marked as Keystone 0768-0773, and Exhibit TC14 HP07-0100 Docket.

INTERROGATORY NO. 85: With respect to the jobs you allege will be brought to South Dakota by the KXL pipeline project:

A. State the number, job title, and expected duration of the temporary construction related jobs expected;

i. State what percentage of current South Dakota citizens, as opposed to persons who move to South Dakota for a job, are expected to be hired for each job title.

ii. Is there any preference for South Dakota citizens to obtain any or all of these temporary jobs?

iii. State the number and percentage of the total construction jobs expected to be filled by out-of-state workers.

B. State the number, type, and expected duration of the permanent jobs expected in South Dakota;

i. State the number of permanent jobs expected to be held by current South Dakota citizens, as opposed to someone who moves from out of state to South Dakota to take the job.

ii. Will there any preference for South Dakota citizens to obtain any or all of the permanent jobs to be created in South Dakota?

C. Identify the documents upon which you relied to answer these questions;

[Applicable Finding or Condition No.: Finding 23, 102, 108; Conditions 1-2]

ANSWER:

A. Assuming this question refers to 'average annual jobs' - It is estimated that Project construction in South Dakota will support 3,500 jobs across all sectors, of which between 1,038 and 1,500 jobs will be directly construction-related. The 3,500 jobs supported by construction of the Project are considered 'average annual jobs', defined as one position that is filled for one year, while the 2,700 to 3,900 temporary construction personnel are expected to be employed for the 4- to 8-month seasonal construction period over 1 to 2 years.

i. It is estimated that between 270 and 390 temporary construction positions created in South Dakota will be filled by residents of the State.

ii. Jobs are filled based on the availability of qualified personnel.

iii. It is estimated that between 2,430 and 3,510 temporary construction positions created in South Dakota will be filled by non-South Dakota residents.

B. Approximately 25 permanent employees and 15 temporary contractors will be distributed along the proposed pipeline route, including the route in South Dakota. Job duration is commensurate with operations of the pipeline and titles will vary.

i. Jobs are filled based on the availability of qualified personnel.

ii. Jobs are filled based on the availability of qualified personnel.

C. Section 4.10 of the Final SEIS.

INTERROGATORY NO. 86: Should there be a worst case discharge or even a substantial release of crude oil into farmland and/or water resources and/or an explosion of the pipeline near homes or towns with people, explain how the Project will have a "minimal" effect on the health, safety, or welfare of its inhabitants. Identify the documents upon which you relied to answer these questions.

[Applicable Finding or Condition No.: Finding 23, 102, 108; Conditions 1,2, 31-36]

OBJECTION: This request is argumentative and improper in form. It calls for speculation and assumes facts not in evidence and is therefore beyond the scope of discovery under SDCL § 15-6-26(b). The PUC found in its conclusions of law, ¶ 6, that Keystone met its burden of proof on this issue.

Dated this 5TH day of February, 2015.

TRANSCANADA KEYSTONE PIPELINE, LP
by its agent, TC Oil Pipeline Operations, Inc.

By _____

Its Director, Authorized Signatory

Subscribed and sworn to before me

this 5th day of February, 2015.

_____

John W. Love, Lawyer
Notary Public - Canada

OBJECTIONS

The objections stated to Dakota Rural Action's Interrogatories and Request for Production of Documents were made by James E. Moore, one of the attorneys for Applicant TransCanada herein, for the reasons and upon the grounds stated therein.

Dated this 6th day of February, 2015.

WOODS, FULLER, SHULTZ & SMITH P.C.

By _____

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CERTIFICATE OF SERVICE

I hereby certify that on the 6th day of February, 2015, I sent by e-mail transmission, a true and correct copy of Keystone's Responses to Dakota Rural Action's First Interrogatories, to the following:

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_____
One of the attorneys for TransCanada

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION BY TRANSCANADA KEYSTONE PIPELINE, LP FOR A PERMIT UNDER THE SOUTH DAKOTA ENERGY CONVERSION AND TRANSMISSION FACILITIES ACT TO CONSTRUCT THE KEYSTONE XL PROJECT	)	HP14-001 **KEYSTONE'S SUPPLEMENTAL RESPONSES TO DAKOTA RURAL ACTION'S FIRST INTERROGATORIES TO TRANSCANADA KEYSTONE PIPELINE, LP**

Applicant TransCanada makes the following supplemental responses to interrogatories pursuant to SDCL § 15-6-33, and responses to requests for production of documents pursuant to SDCL § 15-6-34(a). These supplemental responses are made within the scope of SDCL 15-6-26(e) and shall not be deemed continuing nor be supplemented except as required by that rule. Applicant objects to definitions and directions in answering the discovery requests to the extent that such definitions and directions deviate from the South Dakota Rules of Civil Procedure.

GENERAL OBJECTION

Keystone objects to the instructions and definitions contained in Dakota Rural Action's First Set of Interrogatories and Requests for Production of Documents to the extent that they are inconsistent with the provisions of SDCL Ch. 15-6. *See* ARSD 20:10:01:01.02. Keystone's answers are based on the requirements of SDCL §§ 15-6-26, 15-6-33, 15-6-34, and 15-6-36.

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INTERROGATORIES

INTERROGATORY NO. 1. Please identify the person or persons providing each answer to an Interrogatory or portion thereof, giving the full name, address of present residence, date of birth, business address and occupation. [Applicable Finding or Condition No.: all]

ANSWER: Given the extremely broad scope volume of more than 800 discovery requests received by Keystone in this docket, a range of personnel were involved in answering the interrogatories. Keystone will designate the following witnesses with overall responsibility for the responsive information as related to the Conditions and proposed changes to the Findings of Fact, which are identified in Appendix C to Keystone's Certification Petition: Corey Goulet, President, Keystone Projects, 450 1st Street S.W., Calgary, AB Canada T2P 5H1; Steve Marr, Manager, Keystone Pipelines & KXL, TransCanada Corporation, Bank of America Center, 700 Louisiana, Suite 700, Houston, TX 77002; Meera Kothari, P. Eng., 450 1st Street, S.W., Calgary, AB Canada T2P 5H1; David Diakow, Vice President, Commercial, Liquids Pipeline, 450 1st Street S.W., Calgary, AB Canada T2P 5H1; Jon Schmidt, Vice President, Environmental & Regulatory, exp Energy Services, Inc., 1300 Metropolitan Boulevard, Suite 200, Tallahassee, FL 32308; Heidi Tillquist, Senior Associate, Stantec Consulting Ltd., 2950 E. Harmony Rd., Suite 290, Fort Collins, CO 80528.

In addition to the witnesses previously identified, Keystone may offer rebuttal testimony from Danielle Dracy regarding emergency response; Lou Thompson regarding tribal engagement; Steve Klekar regarding tax issues; and Doug Robertson regarding SCADA and leak detection. Resumes for these possible rebuttal witnesses are marked as Keystone 1930-1934.

Dated this 10 day of March, 2015.

TRANSCANADA KEYSTONE PIPELINE, LP
by its agent, TC Oil Pipeline Operations, Inc.

By _____
Joseph Brown
Its Director, Authorized Signatory

Subscribed and sworn to before me

this 10 day of March, 2015.

_____
John W. Love, Lawyer
Notary Public - Canada

CERTIFICATE OF SERVICE

I hereby certify that on the 10th day of March, 2015, I sent by e-mail transmission, a true and correct copy of Keystone's Supplemental Responses to Dakota Rural Action's First Interrogatories, to the following:

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One of the attorneys for TransCanada

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION BY TRANSCANADA KEYSTONE PIPELINE, LP FOR A PERMIT UNDER THE SOUTH DAKOTA ENERGY CONVERSION AND TRANSMISSION FACILITIES ACT TO CONSTRUCT THE KEYSTONE XL PROJECT	)))))))	HP14-001 **KEYSTONE'S SUPPLEMENTAL RESPONSES TO DAKOTA RURAL ACTION'S FIRST INTERROGATORIES TO TRANSCANADA KEYSTONE PIPELINE, LP**

Applicant TransCanada makes the following supplemental responses to interrogatories pursuant to SDCL § 15-6-33, and responses to requests for production of documents pursuant to SDCL § 15-6-34(a). These responses are made within the scope of SDCL 15-6-26(e) and shall not be deemed continuing nor be supplemented except as required by that rule. Applicant objects to definitions and directions in answering the discovery requests to the extent that such definitions and directions deviate from the South Dakota Rules of Civil Procedure. The supplemental responses are made in response to the Commission's order on Dakota Rural Action's motion to compel discovery, and are made in addition to the responses and objections previously stated.

GENERAL OBJECTION

Keystone objects to the instructions and definitions contained in Dakota Rural Action's First Set of Interrogatories and Requests for Production of Documents to the extent that they are inconsistent with the provisions of SDCL Ch. 15-6. *See* ARSD 20:10:01:01.02. Keystone's answers are based on the requirements of SDCL §§ 15-6-26, 15-6-33, 15-6-34, and 15-6-36.

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INTERROGATORIES

INTERROGATORY NO. 7. For each incident since January 1, 2010 in which any pipeline transporting crude oil constructed by TransCanada and its Affiliates leaked or spilled pipeline contents, please provide the:

A. Date;
B. Location:
C. Amount of materials leaked or spilled;
D. Duration of leak or spill before (i) the control center being notified, (ii) pump shut down, (iii) valve shutoff, (iv) national response center notified, and (v) arrival of responders on the scene;
E. Duration of reclamation of affected soil and/or water resources;
F. Established and documented cause of leak/spill;
G. For each such spill, provide a copy of the Integrity Management Plan, the operational manual for the pipeline, the specifications for the SCADA system, and the ERP for each spill in the US and Canada;
H. Identify the documents which support your answers, above.

[Applicable Finding or Condition No.: Findings 12(2)-(3), 41-45, 47, 103; Amended Condition 32-38]

ANSWER:

a. Responsive information is contained in the spreadsheet previously produced as Keystone 0774-0784.

b. Responsive information is contained in the spreadsheet previously produced as Keystone 0774-0784.

c. Responsive information is contained in the spreadsheet previously produced as Keystone 0774-0784.

d. Responsive information is contained in the spill incident reports, which are produced in a non-confidential FTP site, to which counsel will be provided access. In addition, the following incidents resulted in full shut downs of the pipeline:

Roswell Pump Station: 6/23/2010 full pipeline shut down 12:13 CST; 6/25/10 pipeline started up 07:30 CST.

Freeman Pump Station: 8/10/2010 full pipeline shut down 11:27 CST; 8/10/2010 pipeline started up 1:00 CST.

David City Pump Station: 2/02/2011 full pipeline shut down 19:30 CST; 2/4/2011 pipeline started up 06:09 CST.

Ludden Pump Station: 5/7/2011 full pipeline shutdown 05:30 CST; 05/14/2011 pipeline started up 16:53 CST.

Severance Pump Station: 05/28/2011 full pipeline shutdown 23:44 CST; 06/07/2011 pipeline started up 06/07/2011.

e. The only reclamation involved was at the Ludden Pump Station. Responsive information is contained in the incident report.

f. Responsive information is contained in the spreadsheet previously produced as Keystone 0774-0784.

g. The Integrity Management Plan for the Keystone Pipeline is included in the confidential FTP site subject to the Commission's protective order. The Operations Manual for the Keystone Pipeline is included in the confidential FTP site. The specification for Keystone's SCADA control system that is filed with PHMSA is included in the confidential FTP site. The Operations Manual and the SCADA specification are highly sensitive and proprietary documents that would substantially injure Keystone if disclosed to the public or its competitors. They should be confidential on the same basis as the IMP. The Keystone Pipeline ERP marked as Exhibit I to the FSEIS is included in the non-confidential FTP site.

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h. The responsive documents identified above are included in the FTP sites.

INTERROGATORY NO. 23: For each spill/leak incident which has occurred from a pipeline transporting WCSB crude oil operated by TransCanada and its Affiliates since 2009, state the dates on which transportation of the crude oil through that pipeline was disrupted by planned maintenance, unplanned maintenance, power outages, spills, leaks, or any other causes. Identify any documents upon which your answers to this Interrogatory was based. [Applicable Finding or Condition No.: Finding 28]

ANSWER: See the spreadsheet attached as Keystone 0774-0784. The duration of full pipeline shutdowns is provided in response to Interrogatory No. 7(d). The incidents described in the spreadsheet were not associated with planned or unplanned maintenance or power outages.

INTERROGATORY NO. 25: With regard to the plan for mainline valves to be remotely controlled, what guarantee can you give the PUC that TransCanada can prevent a cyber-security attack on the control system?
A. Describe the worst case scenario which could occur in the event of a computer systems security breach on the control system for the KXL Pipeline.
B. Describe the data security systems to be put in place to prevent any such system breach, identify any third-party vendor(s) providing system security software, hardware or monitoring, and identify the particular components or scopes of services such vendors will provide.
C. Identify any documents used to support your answer to this Interrogatory.
[Applicable Finding or Condition No.: Conditions 31-38; Finding 20]

ANSWER:

a. The response to this entirely hypothetical question is that the worst case scenario would be an intentional, extremely sophisticated, elaborately-planned attack that coordinates multiple breaches. It would be a coordinated attack combined with other attacks against other non-TransCanada critical infrastructure designed to delay a response to the attack. The attacks would be an act of war, designed to cause a loss of physical integrity at a facility or along the pipeline. The consequences would depend on the location of the loss. A coordinated attack could also be intended for the purpose of shutting down the pipeline through cyber-attacks for the purpose of creating a commodity shortage and disrupting public markets.

b. Following a layered security approach, TransCanada secures its electronic information assets (infrastructure, application and data) as follows:

Protection from the internet is delivered through next-generation firewalls that are managed and monitored by an external Managed Security Services Provider (TELUS) 24x7x365, protection capabilities include network anti-virus scanning, network intrusion detection/prevention, denial of service protection, web content filtering.

Protection of assets within TransCanada's Data Centers is delivered through network segmentation, protected by internal firewalls and managed by our CIO teams – including network segmentation between TransCanada corporate networks and the KXL environment. At the local asset level, we deploy capabilities including malware protection, host intrusion detection/prevention, security patch management and vulnerability management – managed and monitored by our CIO teams.

From an access control perspective, we leverage two-factor authentication on our corporate assets, including our remote VPN service.

Security event logging, monitoring and analysis of all controls above are centrally handled through an internal SIEM (Security Incident Event Management) infrastructure – managed internally by our CIO teams.

Incident response is managed by our CIO teams leveraging TransCanada's Major Incident Process, forensics analysis is outsourced to 3rd party partners (IBM/TELUS). Threat Intelligence is managed by our CIO teams in collaboration with 3rd party partners (TELUS, Verisign, McAfee) and Government Agencies (FBI, DHS, US-CERT, CCIRC, CSIS).

ICS Protections (Please consider that to some degree these solutions are already in place)

- Isolation (logical segmentation) of industrial control system networks from corporate systems using multiple devices such as Firewalls, Routers, and Switches. This prevents unauthorized users from accessing the ICS. Relevance: Access to the ICS systems is required to achieve worst case scenario and these controls would need to be compromised (or Access Control instead).
- Access Control (Logical Access Management) – systems in place to limit and verify identities of users accessing the ICS systems from the corporate network. Relevance: Access to the ICS systems is required to achieve worst case scenario and these controls would need to be compromised (or Isolation instead).
- Control Logic – operational and safety systems in place to manage operation and anomalies on the pipeline. Relevance: These systems would mitigate actions of attackers trying to achieve the worst case scenario and would need to be compromised directly. This includes SCADA systems & Control Centre Operators, and shutdown logic.
- Physical Controls – systems in place to protect integrity (such as pressure relief valves) or mitigate loss of integrity (such as fire protection systems, fences). Relevance: These systems would mitigate any Cyber attempts to compromise integrity and the consequences if integrity is lost.
- Environmental Controls – systems in place to mitigate loss of integrity's environmental impact (such as berms to contain leakage). Relevance: These systems reduce (mitigate) against impact of worst case situation in certain locations such as tank terminals.

Incident Management – internal TransCanada processes and procedures to respond quick to loss of integrity events. Relevance: These systems reduce (mitigate) against the breach's Health, Safety, and Environment consequences.

c. TransCanada's Information Security Policy is included in the non-confidential FTP site.

INTERROGATORY NO. 48: Calculate the worst case discharge and describe in detail the worst case scenario that would result from damage caused to the Keystone XL pipeline from the "high swelling potential" of the Cretaceous and Tertiary rocks located in the Missouri River Plateau due to this land form's susceptibility to instability in the form of slumps and earth-flows, including landslides.

A. Provide the locations where such ground swelling can be anticipated;

B. Identify any documents which would support your answer;

[Applicable Finding or Condition No.: Finding 40, 77; Conditions 31-42]

ANSWER: By definition, a worst case discharge is a catastrophic breach of the pipeline, regardless of cause. The location of the discharge determines its volume. Keystone

has not calculated a worst case discharge specifically associated with soils with high-swelling potential. The volume of a worst case discharge does not directly correlate to the cause.

A. The locations where ground swelling can be expected are identified in Table 3.1-6 of the FSEIS. Keystone has calculated the worst case discharges for those locations: They are included in the confidential FTP site.

B. Section 3.1.2.5, Geologic Hazards, of the FSEIS (which includes Table 3.1-6) is included in the non-confidential FTP site.

INTERROGATORY NO. 56: Describe the worst case scenario of a worst case discharge into the Little Missouri, Cheyenne, and White River crossings. Identify any documents which would support your answers. [Applicable Finding or Condition No.: Findings 41-52, 68-69, 82-83; Conditions 31-42.

ANSWER: The answer is included in the confidential FTP site.

INTERROGATORY NO. 57: Describe the worst case scenario which could occur from the Keystone XL pipeline as it passes under channels, adjacent flood plains and flood protection levees. Identify any documents which would support your answers. [Applicable Finding or Condition No.: Findings 41-49; Conditions 31-42]

ANSWER: Keystone has not calculated worst case discharges for locations for the generic areas described in the interrogatory. Worst case discharges and potential consequences are discussed in the Risk Assessment for the Keystone XL Pipeline, which is Appendix P to the FSEIS. The Risk Assessment, including Appendix A, is included in the non-confidential FTP site.

INTERROGATORY NO. 58: In light of the spill risk assessment provided by TransCanada in the HP09-001 docket:
A. Explain the number of leaks along the Keystone I pipeline since 2008;
B. Explain the number of leaks from the other oil pipelines constructed and/or operated by TransCanada or its Affiliates;
C. What would be a worst case scenario discharge from the KXL pipeline? Please explain your answer;

D. Identify any documents which would support your respective answers. [Applicable Finding or Condition No.: Findings 41-49, 51-52; Conditions 31-38]

ANSWER:

A. Keystone has safely delivered more than 830 million barrels domestic and WCSB oil to United States markets since it began operation in July 2010. The small number of leaks that have occurred on the pipeline have had nothing to do with the integrity of the pipe itself. They have all occurred at pump stations and other above-ground facilities and have been related to leakage from small-diameter fittings and seals. They have all been cleaned up with no environmental impact. Keystone designed the pipeline to ensure that all small diameter fittings, valves and seals are located above ground where they can be easily accessed for maintenance and repairs. All of Keystone's pump stations are designed to capture and contain oil on company property. In total, less than 450 barrels of oil, out of more than 830 million barrels transported, have come out of the pipeline since it began operations five years ago. TransCanada is constantly striving to improve its performance and working towards its goal of having zero leaks or safety incidents. All pipeline leaks are thoroughly investigated regardless of their size in order to understand the cause and prevent future such incidents. The leaks are identified in the spreadsheet attached as Keystone 0774-0784.

B. None.

C. See the Risk Assessment included in the non-confidential FTP site.

D. See the Risk Assessment included in the non-confidential FTP site.

INTERROGATORY NO. 60: Describe in detail the impact of a worst case scenario spill into the shallow and surficial aquifers in Tripp County from the proposed KXL Pipeline. Identify any documents which would support your answers. [Applicable Finding or Condition No.: Findings 43-49, 53; Conditions 16, 35]

ANSWER: Section 4 of the 2009 Keystone XL Risk Assessment (FSEIS, Appendix P) describes the impacts of a worst case spill scenario. The Risk Assessment is in the non-confidential FTP Site. Field investigations of more than 600 historical petroleum hydrocarbon release sites indicate the migration of dissolved constituents typically stabilizes within several hundred feet of the crude oil source area (Newell and Conner 1998; USGS 1998). Over a longer period, the area of the contaminant plume may begin to reduce due to natural biodegradation. Removal of crude oil contamination will eliminate the source of dissolved constituents impacting the groundwater.

Spills are also discussed in the FSEIS in Section 4.1.3.4, including those in shallow and surficial aquifers. The fate and transport of benzene and other crude oil constituents is discussed in numerous studies and articles, including those referenced in the 2009 Keystone XL Risk Assessment, such as:

Freeze, R. A. and J. A. Cherry. 1979. Groundwater. Prentice Hall, Inc. Englewood Cliffs, New Jersey. 604 pp.

Minnesota Pollution Control Agency. 2005. Assessment of Natural Attenuation at Petroleum Release Sites. Guidance Document c-prp4-03, Petroleum Remediation Program, Minnesota Pollution Control Agency. April 2005. 11 pp.

Neff, J. M. 1979. Polycyclic aromatic hydrocarbons in the aquatic environment. Applied Science publ. Ltd., London. 262 pp.

Newell, C. J. and J. A. Connor. 1998. Characteristics of Dissolved Petroleum Hydrocarbon Plumes: Results from Four Studies. American Petroleum Institute Soil / Groundwater Technical Task Force. December 1998.

Spence, L. R., K. T. O'Reilly, R. I. Maagaw, and W. G. Rixey. 2001. Chapter 6 – Predicting the fate and transport of hydrocarbons in soil and groundwater. In :risk-based decision-making or assessing petroleum impacts at exploration and production sites. Edited by S.

McMillen, R. Magaw, R. Carovillano, Petroleum Environmental Research Forum and US Department of Energy.

United States Geological Service (USGS). 1998. Groundwater Contamination by Crude Oil near Bemidji, Minnesota. US Geological Survey Fact Sheet 084-98, September 1998.

Additional references on this subject from the FSEIS include:
American Petroleum Institute (API). 1992. Review of Natural Resource Damage Assessments in Freshwater Environments: Effects of Oil Release into Freshwater Habitats. API Publ. No. 4514.

API. 1997. Petroleum in the Freshwater Environment: An annotated Bibliography 1946-1993.

API Publ. No. 4640.

Grimaz, S., S. Allen, J. Steward, and G. Dolcetti. 2007. Predictive evaluation of the extent of the surface spreading for the case of accidental spillage of oil on ground. Selected Paper IcheaP8, AIDIC Conference series, Vol. 8, 2007, pp. 151-160.

Hult, M.F. 1984. Groundwater Contamination by Crude Oil at the Bemidji, Minnesota, Research Site: U.S. Geological Survey Toxic Waste—Ground-Water Contamination Study. Papers presented at the Toxic-Waste Technical Meeting, Tucson, Arizona, March 20-22. USGS Water Investigations Report 84-4188.

Weaver, J.W., R.J. Charbeneau, J.D. Tauxe, B.K. Lien, and J.B. Provost. 1994. The hydrocarbon spill screening model (HSSM) Volume 1: User's guide. USEPA/600/R-94/039a.U.S. Environmental Protection Agency, Office of Research and Development, Robert S. Kerr, Environmental Research Laboratory, Ada, OK

INTERROGATORY NO. 76: Identify the location(s) where slope instability poses a potential threat of ground movement along the Project route.
A. Identify TransCanada's most current Integrity Management Plan (IMP) showing incorporation of locations where slope instability poses a potential threat to the pipeline;
B. Identify documents upon which your answers are based.
[Applicable Finding or Condition No.: Finding 79; Conditions 8, 15, 20-21]

RESPONSE:

A. TransCanada's most-recent Integrity Management Plan is the Integrity Management Plan for the Keystone Pipeline that has been filed with the Commission in HP07-001. It is included in the confidential FTP site. The locations where slope instability poses a potential threat to the

pipeline are included in Table 3.1-6 of the FSEIS, which is included in the non-confidential FTP site.

B. See Table 3.1-6 of the FSEIS, which is included in the non-confidential FTP site.

INTERROGATORY NO. 83: Identify the most recent IMP submitted to the Commission and other appropriate agencies, including but not limited to sections in it related to HCAs. [Applicable Finding or Condition No.: Finding 102; Conditions 1-2]

RESPONSE: The Integrity Management Plan for the Keystone Pipeline that was filed with the Commission as a confidential document in HP07-001 is included in the confidential FTP site.

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Dated this 17th day of April, 2015.

TRANSCANADA KEYSTONE PIPELINE, LP
by its agent, TC Oil Pipeline Operations, Inc.

By _____
Stephen Marr
Its Director, Authorized Signatory

Subscribed and sworn to before me

this 17th day of April, 2015.

_____
Notary Public - Texas

Gloria C. Howard
Notary Public,
State of Texas
Expires:08-24-2018

CERTIFICATE OF SERVICE

I hereby certify that on the 17th day of April, 2015, I sent by e-mail transmission, a true and correct copy of Keystone's Supplemental Responses to Dakota Rural Action's First Interrogatories, to the following:

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CAPP

CANADIAN ASSOCIATION
OF PETROLEUM PRODUCERS

Canada's Oil and Natural Gas Producers

Crude Oil

Forecast, Markets & Transportation

June 2014

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On Cover:
Top Left: Crude by Rail tank car- photo courtesy of Altex Energy
Top Right: Prince George refinery - photo courtesy of Husky Energy
Bottom Left: TransCanada Keystone construction - photo courtesy of TransCanada
Bottom: Cenovus *in situ* project

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EXECUTIVE SUMMARY

Canadian crude oil production is expected to grow over the long-term to 6.4 million b/d by 2030. These supplies will meet the demand of markets located throughout North America and beyond. The recent uncertainty regarding the timing of some transportation infrastructure projects has opened the door for several alternatives, including the transport of crude oil by rail, which is rising and adapting to meet market needs.

The key points of this year's outlook are:

- Canadian oil production growth is driven by the oil sands, which is expected to grow 2.5 times from current production of 1.9 million b/d to 4.8 million b/d by 2030. Total conventional production, inclusive of condensate, grows slightly and will contribute 1.5 million b/d to total production. This is a reversal of the declining trend in condensate production previously forecast.
- Multiple markets are expressing growing interest in crude oil from Western Canada. There are opportunities to replace foreign crude oil imports in Canada and the United States at refineries along the East Coast, West Coast and Gulf Coast. Demand from global markets, such as Asia and Europe, could be met but requires access to tidewater. There are projects in the regulatory process and others being considered to achieve this.
- Longer timelines for new pipeline capacity have led to a developing role for rail in the crude oil transportation network as the use of this mode is increasing overall crude oil transportation capacity.

Crude Oil Production and Supply

With new stability in conventional crude oil production and almost 3 million b/d in oil sands growth, Canadian crude oil production grows to 6.4 million b/d in 2030.

Canadian crude oil production is expected to grow by an average of 4 per cent annually until 2030. Western Canadian production reaches 6.4 million b/d by the end of the outlook. Production in Eastern Canada is stable in the near term but declines gradually by 2030.

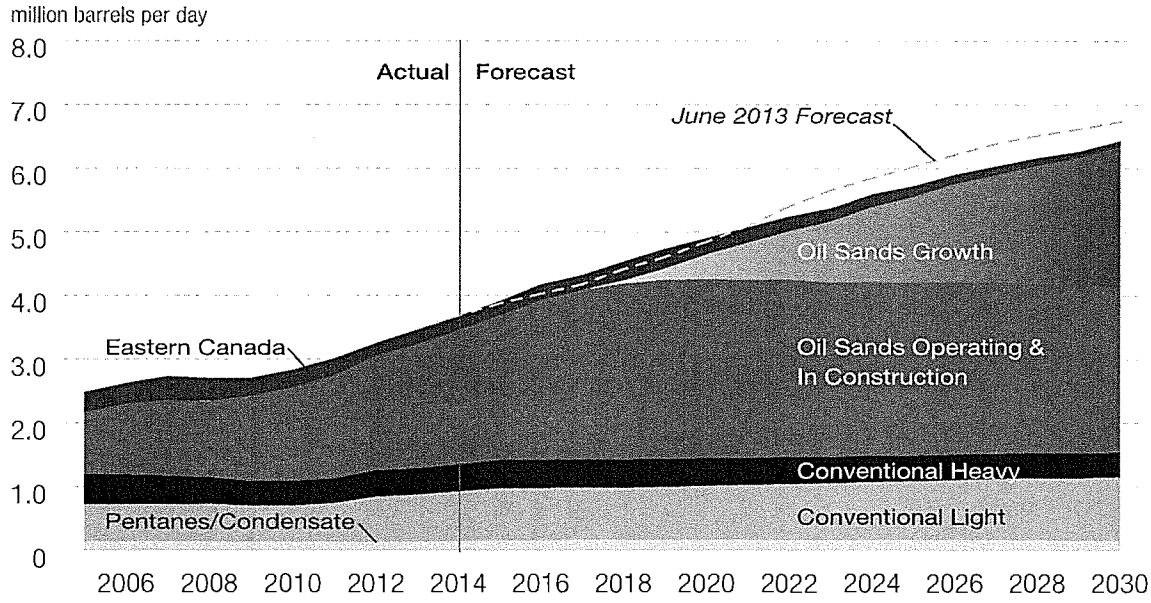
Compared to CAPP's 2013 forecast, western Canadian production is similar through 2020 and lower by about 300,000 b/d in 2030. This is the overall net effect of a higher conventional and a lower oil sands forecast. Conventional production is 100,000 b/d higher primarily due to more condensate resulting from the industry's increased focus on drilling in liquids-rich plays. The oil sands forecast is 400,000 b/d lower. A number of factors contribute to this variation including cost competitiveness and delays in project schedules.

Canadian Crude Oil Production

million b/d	2013	2015	2020	2025	2030
Total* Canadian (including oil sands)	3.5	3.9	4.9	5.7	6.4
Eastern Canada	0.2	0.2	0.3	0.2	0.1
Western Canada	3.2	3.7	4.6	5.6	6.4
Conventional (including condensate)	1.3	1.4	1.5	1.5	1.5
Oil sands	1.9	2.3	3.2	4.1	4.8

*Totals may not add up due to rounding.

Canadian Oil Sands & Conventional Production



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Conventional Oil

Conventional production in Western Canada is currently 1.3 million b/d and is expected to grow to almost 1.5 million b/d by 2020. This growth has resulted from the continuing use of horizontal and multi-fracturing drilling techniques. In addition, increased drilling in liquids-rich natural gas plays such as the Montney and emerging plays like the Duvernay has reversed the declining trend in condensate production, which was previously forecast to fall to 94,000 b/d by 2030. In this latest forecast, condensate production accounts for almost 170,000 b/d, on average, for the forecast period.

Oil Sands

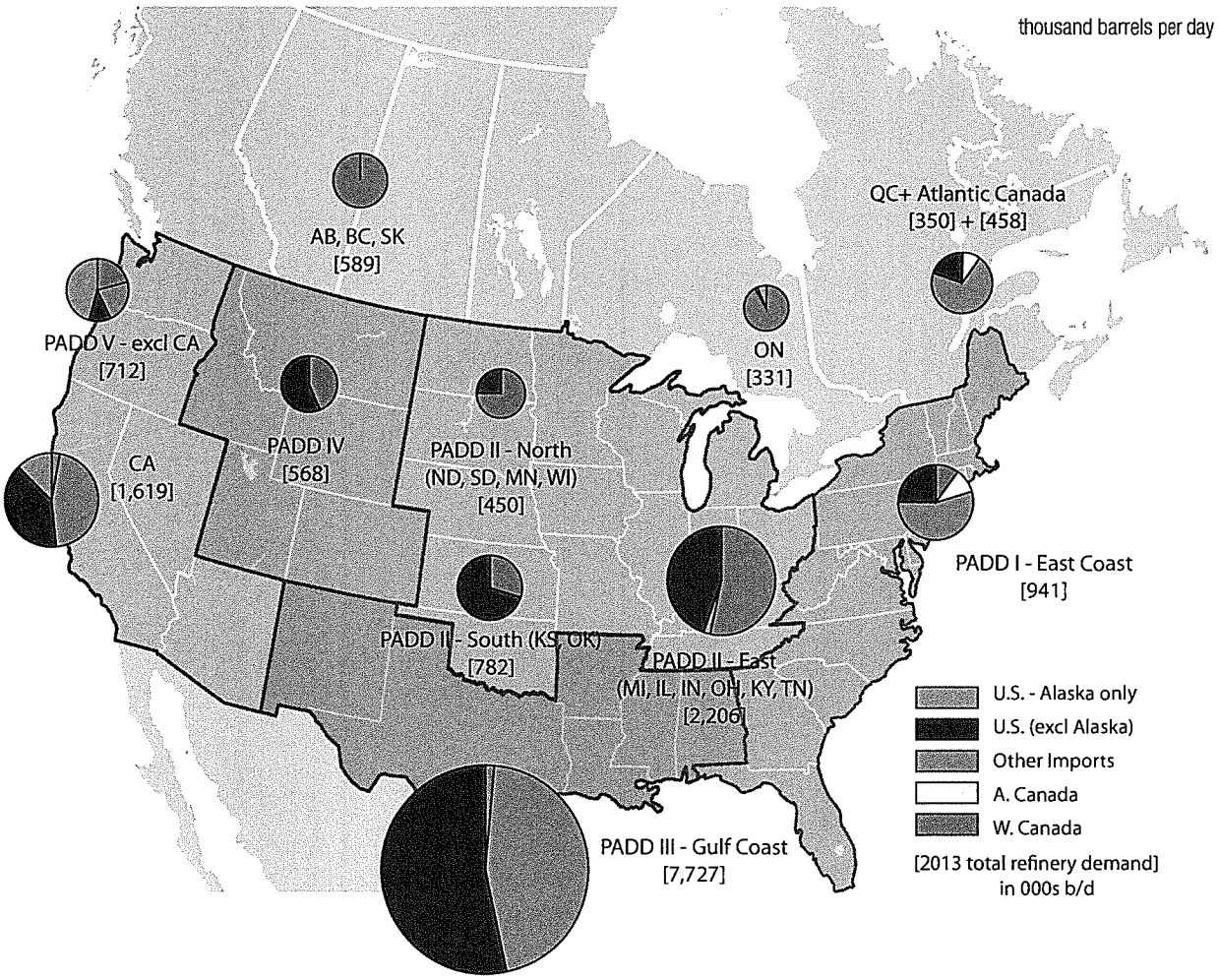
The vast majority of Canada's crude oil reserves reside in the oil sands so it is natural for this resource to be the primary driver for future overall growth. The 2014 outlook for oil sands is for an average annual growth of 170,000 b/d through to 2030.

In 2013, 1.9 million b/d were produced from the oil sands of which 850,000 b/d was from mining and 1.1 million b/d from *in situ* projects. Looking ahead to 2030, mining production is forecast to increase to 1.6 million b/d and *in situ* production is forecast to grow to 3.2 million b/d. Compared to CAPP's 2013 forecast, this is 87,000 b/d lower for mining and 312,000 b/d lower for *in situ*. Some projects were delayed beyond the current forecast period as a result of individual company decisions related to cost competitiveness and capital availability. These impacts are evident near the end of the forecast period.

Eastern Canada

In 2013, Eastern Canada accounted for about 7 per cent, or 232,000 b/d of total Canadian crude oil production. The Hebron project is scheduled to startup in 2017 and provide new volumes. By 2030, production is forecast is to gradually decline to around 90,000 b/d but this could be higher than forecast given the announcement of three recent discoveries in the Flemish Pass Basin. The largest new prospect is Bay du Nord, which is estimated to hold between 300 and 600 million barrels of recoverable oil.

2013 Canada and U.S. Crude Oil Demand by Market Region



Sources: CAPP, CA Energy Commission, EIA, Statistics Canada

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Crude Oil Markets

Canada continues to fuel growing international markets.

With 1.7 million b/d of additional crude oil supplies from Western Canada expected to be available by 2020, Canadian producers are seeking to expand their reach to Eastern Canada, the West Coast and U.S. Gulf Coast markets. Growing production from U.S. tight light oil plays has resulted in U.S. domestic supplies replacing almost all the foreign light oil imports in the Gulf Coast and a large portion in the East Coast. However, significant markets for growing heavy oil supplies are still available in the U.S. Midwest, Gulf Coast and elsewhere globally.

Eastern Canada

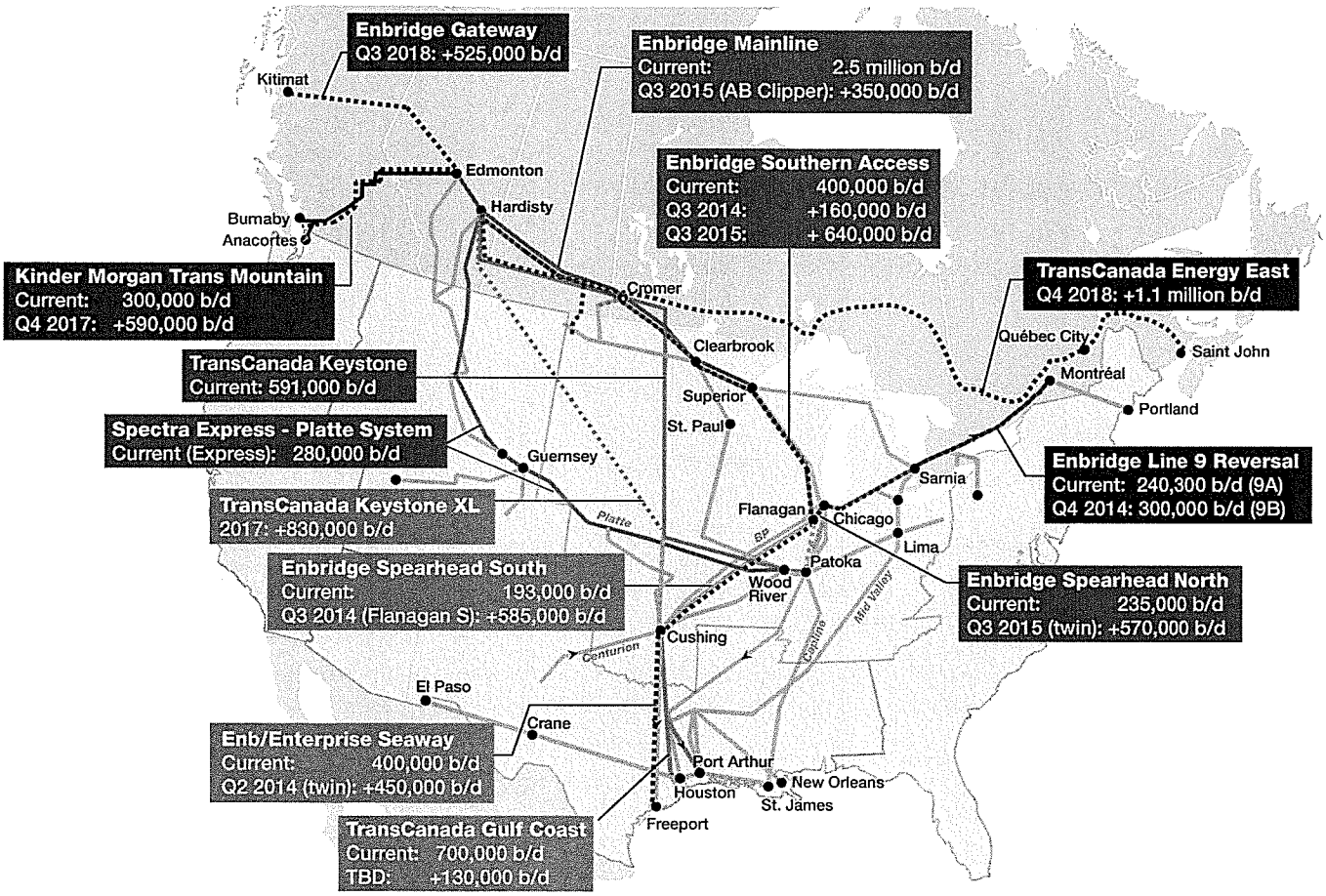
Refineries in Québec and Atlantic Canada currently import 90 per cent of their requirements. This translates to a potential 640,000 b/d domestic market opportunity for Canadian supplies, particularly conventional light and synthetic crude oil. Refineries in Ontario have already shifted their main source of crude oil feedstock to Western Canada.

United States

Refineries in the U.S. Gulf Coast processed almost 8 million b/d of crude oil in 2013, including over 2 million b/d of foreign heavy oil imports. Canadian producers could displace some of these imported volumes and are forecast to supply at least 680,000 b/d to this market by 2020, up from the 120,000 b/d that is currently supplied.

The Midwest will remain Canada's largest export market. In 2013, Canadian producers supplied 1.7 million b/d to this market. A number of refinery conversion projects for processing heavy crude oil have been completed in the last two years and are anticipated to increase demand in the region by 465,000 b/d to reach 2.2 million b/d by 2020.

Canadian & U.S. Crude Oil Pipelines and Proposals



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Refineries in Washington and California need to replace their declining traditional sources of supply. These refineries are expected to double current demand for western Canadian crude oil of 198,000 b/d to 392,000 b/d. Similarly, demand from East Coast refineries could double from 2013 demand of 104,000 b/d to almost 200,000 b/d. Refineries on both the East and West Coasts in the U.S. are making investments in rail infrastructure in order to gain access to growing U.S. domestic and western Canadian supplies.

World

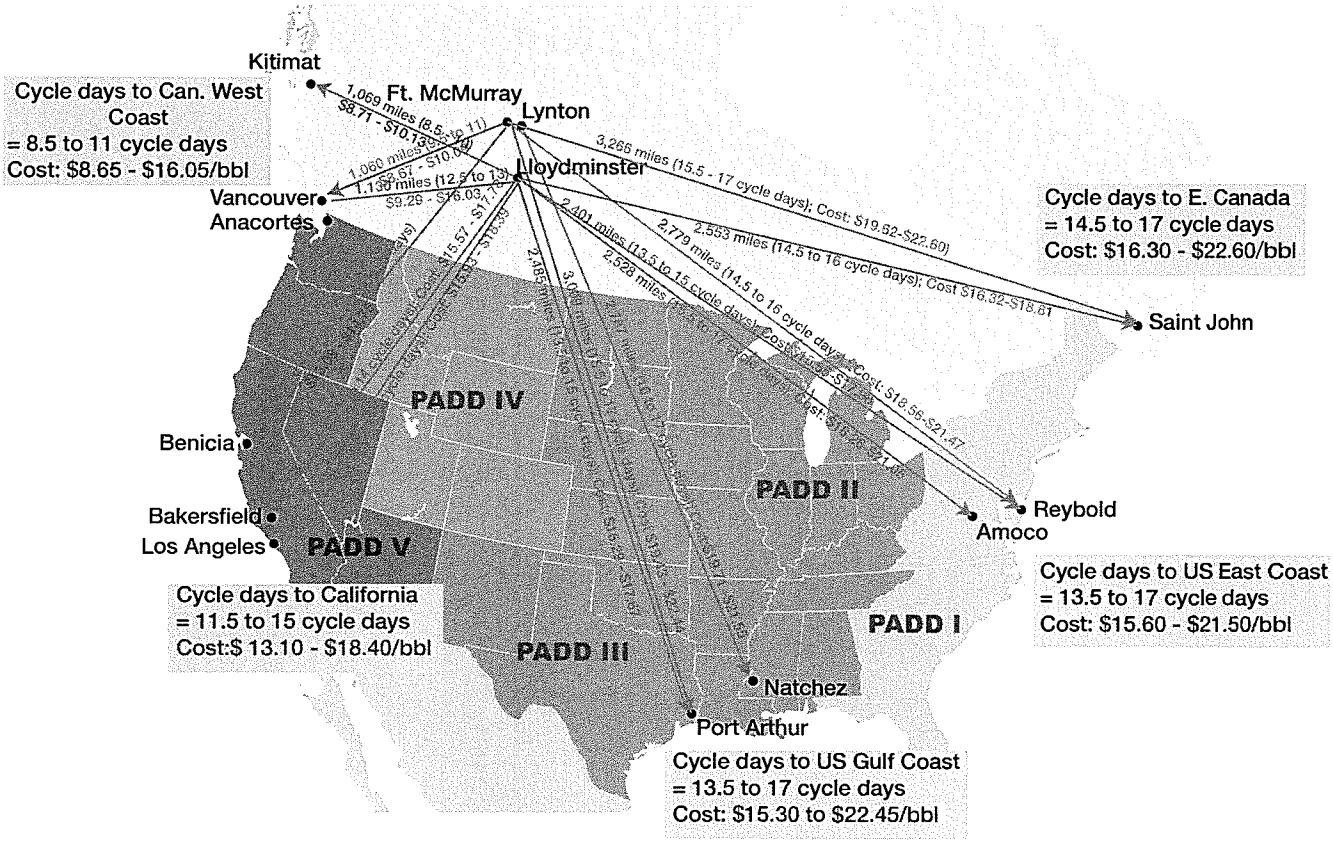
The crude oil producing regions of western Canada have limited access to tidewater and to global crude oil markets. However, there is strong interest in Asia and growing interest from Europe for Canadian crude oil. In particular, China and India are obvious potential markets as they currently have the fastest growing demand for oil in the world. According to the U.S. Energy Information Administration (EIA), combined oil imports from China and India are forecast to increase by 8.0 million b/d; going from 9.7 million b/d in 2013 to 17.7 million b/d by 2030.

Crude Oil Transportation

Pipelines projects to the East, West and South are being developed to access new markets while rail is becoming a growing alternative to supplement the existing, expanding pipeline network.

The growing supply of crude oil from Western Canada is filling the existing pipeline capacity and protracted timelines for regulatory approvals combined with other uncertainties have affected the evolution of the transportation network. Other forms of transport, such as railways, barges, and tankers are quickly becoming additional means to distribute increasing volumes to markets throughout the U.S., Eastern Canada and offshore.

Rail Cycle Times & Estimated Cost to Markets



**All rates are estimates only. Actual rates could vary depending on the density of the crude which limits the volume per carload; weather and logistical factors that could increase cycle times. Trucking costs vary depending on density of crude and distance from loading/unloading terminal.*

Data source: Keystone XL Final Supplemental Environmental Impact Statement

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Pipelines remain the primary mode of transportation for crude oil due to their relatively low cost and ability to continuously move large volumes to key markets. There are a number of pipeline projects being proposed (see figure on page iii) that could deliver large volumes of Canadian crude oil to the East Coast, West Coast, U.S. Gulf Coast and offshore markets. However, the timing and order for the various projects continues to have some uncertainty.

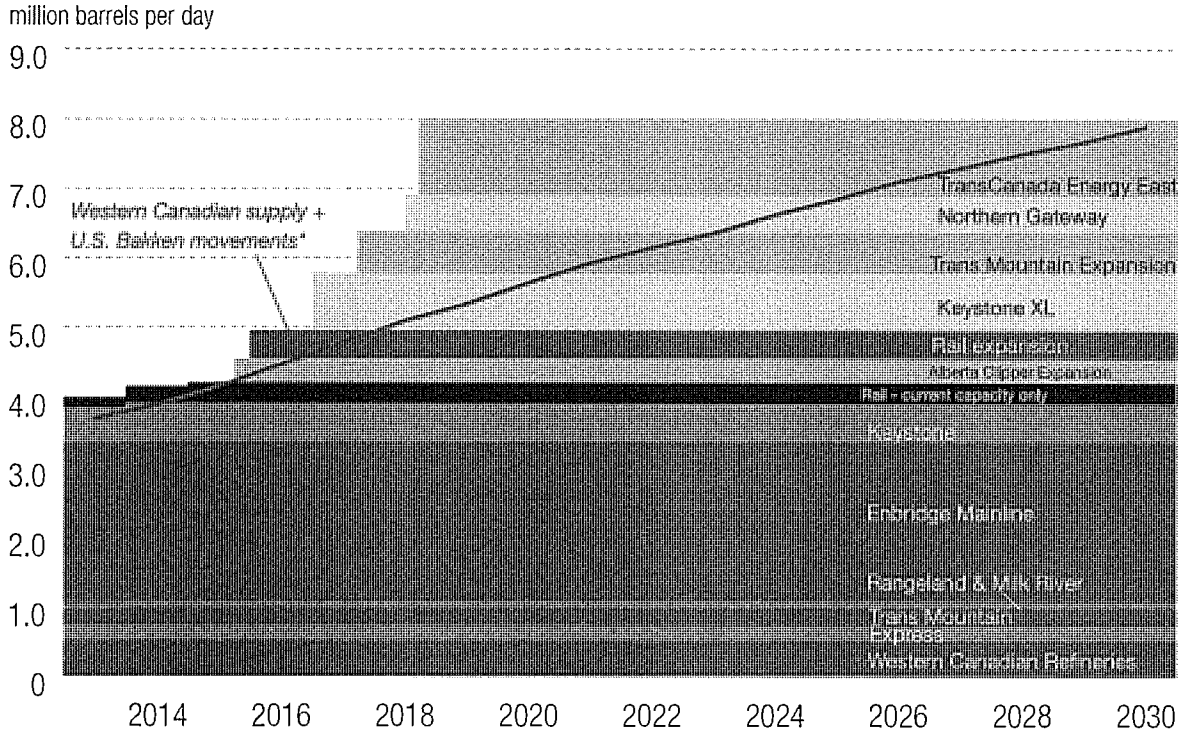
As a result, crude oil producers are increasingly using rail as an alternative means of transportation. The existing rail nework enable this mode of transportation to reach all the desired markets once capital investments in both loading and unloading facilities are made. A train loading facility can be constructed in about one year. The flexibility of rail to deliver to multiple destinations is a key component for its long-term viability.

Based on publicly reported supply contracts associated with uploading terminals located in Western Canada, CAPP estimates that about 700,000 b/d of crude oil could potentially be transported to markets by rail in 2016.

The figure below summarizes the existing and proposed takeaway capacity from the Western Canada Sedimentary Basin versus forecasted supply.

Since last year, some pipeline projects have been delayed but other alternatives are being developed and used. The figure shows that there is tight capacity in the first few years. In addition, the capacity provided by all the proposals will be needed by 2030 to meet the forecast growth.

WCSB Takeaway Capacity vs. Supply Forecast



*Refers to the portion of U.S. Bakken production that is also transported on the Canadian pipeline network. Capacity shown can be reduced by temporary operating and physical constraints.

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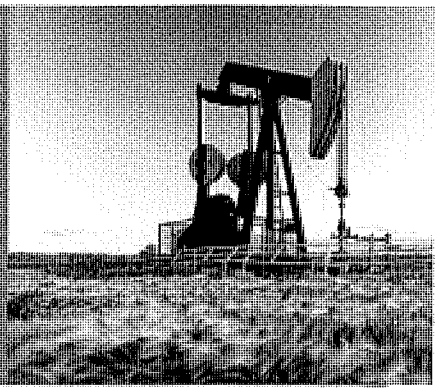
1 | INTRODUCTION



Each year CAPP publishes its long-term outlook for Canadian crude oil production. Since 2007, this outlook has been provided in conjunction with an examination of the potential demand in various markets, as well as an update on the transportation infrastructure that is both currently available and proposed to serve these markets. As such, CAPP's annual *Crude Oil Forecast, Markets & Transportation* publication provides a valuable reference document for the industry, governments and the general public.

The report is intended to help develop a common understanding regarding the growth in Canadian crude oil supply. CAPP's long-term crude oil forecast is based on the amalgamated results of the producers' latest views on their individual oil sands projects while the market demand forecast reflects an unadjusted survey of North American refiners' future demand for western Canadian crude oil.

Canadian crude oil production is expected to grow steadily to 2030 driven primarily by production from oil sands resources. The oil sands represent over 97 per cent of Canada's crude oil reserves and is the main source for future growth. CAPP's estimate of industry capital spending on oil sands development is $29 billion for 2014, which is $2 billion higher than the estimated expenditure in 2013. Conventional production grows slightly through the forecast, which offsets some of the declines in production from offshore Eastern Canada after 2020.

1.1 Production and Supply Forecast Methodology

The oil sands component of the forecast is based on CAPP's survey of all oil sands producers and as such, reflects the latest industry insight on factors such as production capability from individual projects and general market opportunities.

CAPP does not forecast crude oil prices. Producers responded to the survey using their own internal view of the long-term oil price. In this manner, CAPP is assuming that the oil price will be sufficient to make these projects economic so that this production will be available to the market.

Producers were surveyed for the following data:

a) expected production for each project by phase;

b) upgraded light crude oil production; and

c) volumes of synthetic crude oil and condensate used as diluent required to move the volumes to market.

The survey results were then adjusted or "risked" accordingly based on each project's stage of development. Past performance of each company's existing projects or phases was also considered in determining the pace of activity in future project stages, which is an important factor in the case of *in situ* projects that typically have their production capacity divided into multiple phases. The overall forecast was then verified for reasonableness against historical trends. No constraints were put on the forecast due to availability of condensate for blending purposes.

The conventional component of the forecast is undertaken at a provincial level and was developed through CAPP's internal analysis of historical trends, expected drilling activity, recent announcements, as well as discussions with industry stakeholders and government agencies.

The Saskatchewan forecast is further supported by the data from CAPP's survey of the oil producers in the province regarding their annual drilling outlook by well type (horizontal or vertical), as well as their anticipated initial production rates and declines.

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1.2 Market Demand Outlook Methodology

CAPP did not make any risk adjustments to the data submitted by refiners beyond checking it for potential errors. Certain assumptions were also made based on discussions with refiners and the review of publicly available information. Where possible, EIA data was used to complete gaps in the survey data for actual demand in 2013 for each region of the U.S.

The CAPP survey categorizes western Canadian crude oil into four main types as follows:

1. Conventional Light Sweet (greater than 27° API and less than or equal to 0.5% sulphur) including condensates and pentanes plus;
2. Heavy (equal to or less than 27° API) including conventional heavy, synthetic sour and crude oil blends such as DilBit, SynBit and DilSynBit;
3. Conventional Medium Sour (greater than 27° API and greater than 0.5% sulphur); and
4. Light Sweet Synthetic

For the purposes of the historical data presented in the source of supply pie charts in this section of the report, the following crude types and definitions apply:

- Sweet: crude oil with a sulphur content of less than or equal to 0.5%
- Sour: crude oil with a sulphur content of greater than 0.5%
- Light: crude oil with an API of at least 30°
- Medium: crude oil with an API of greater than 27° but less than 30°
- Heavy: crude oil with an API of 27° or less

No differentiation is made between sweet and sour crude oil that falls into the heavy category because heavy crude oil is generally assumed to be sour.

1.3 Transportation Outlook Methodology

CAPP's forecast of rail movements from Western Canada was developed based in part on a review of supply contract volumes attributed to individual rail loading facilities located in Western Canada.

CAPP's production forecast is not constrained by a lack of any transportation infrastructure. However, the report does compare the supply that the analysis produces against the current and proposed pipeline and rail projects to determine where bottlenecks may occur if these transportation projects fail to materialize in the time frame they are currently envisaged.

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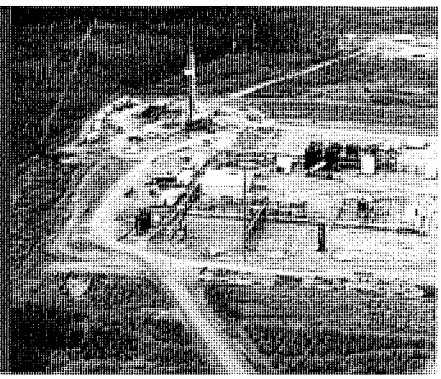
2 | CRUDE OIL PRODUCTION AND SUPPLY FORECAST



Beyond being a feedstock for transportation fuels, crude oil is used in Canada and around the world in the manufacture of many everyday items that improve our quality of life. These include heating fuels, plastics, petrochemicals and even pharmaceuticals. Canada holds 173 billion barrels of proven crude oil reserves, which according to the Oil & Gas Journal, are the world's third largest reserves after Venezuela and Saudi Arabia. The province of Alberta resides on top of the oil sands, which holds 167 billion barrels of these reserves. The strategic development of these resources is important to the industry and a key element to economic growth and achieving long-term prosperity for Canada. It provides for security of supply, creates jobs, and promotes innovation.

Technology required to access the bitumen carbonates of Northern Alberta, is under early development. Companies conducting tests in the region to commercialize these carbonates, claim that the Grosmont carbonates alone could hold more than 400 billion barrels of in place bitumen. Thus successful development of these technologies could further dramatically increase the size of Canada's crude oil resource base.

2.1 Canadian Crude Oil Production

In 2013, Canada produced 3.5 million b/d of crude oil, an increase of 225,000 b/d or 7 per cent over 2012 levels. This production, most of which comes from Western Canada, is expected to continue to grow steadily throughout the forecast period. Western Canada produced 3.2 million b/d in total, of which 1.9 million b/d came from the oil sands and 1.3 million b/d came from conventional resources. About 232,000 b/d of Canada's production originated in Eastern Canada.

Table 2.1 shows the forecast for total Canadian production and its breakdown between Eastern and Western Canada. Figure 2.1 shows the total Canadian production forecast. Conventional production from Western Canada is expected to grow slightly throughout the forecast to over 1.5 million b/d. Oil sands production will be the main driver of the overall increase in production as it is expected to increase by 2.5 times from 2013 levels of 1.9 million b/d to reach 4.8 million b/d by 2030.

Table 2.1 Canadian Crude Oil Production

million b/d	2013	2015	2020	2025	2030
Total* Canadian (including oil sands)	3.47	3.91	4.91	5.74	6.44
Eastern Canada	0.23	0.23	0.26	0.17	0.09
Western Canada	3.24	3.68	4.65	5.57	6.35

*Totals may not add up due to rounding.

2.2 Eastern Canadian Crude Oil Production

Atlantic Canada is the primary source of Eastern Canada's crude oil production. Some minor volumes have been produced from Ontario and New Brunswick but the oil resources essentially reside in offshore oil projects located off the shores of Newfoundland and Labrador. The three offshore oil fields currently in production are: Hibernia, Terra Nova and White Rose. The overall rate of decline from these facilities has slowed as a result of continued drilling at satellite fields associated with these projects (e.g. Hibernia South Extension, North Amethyst and West White Rose). First oil from Hebron, the fourth major project, is expected around the end of 2017.

012604

CAPP's forecast includes existing projects, planned satellites and the Hebron project under construction. In 2013, production increased to 232,000 b/d, up 15 per cent from 2012 levels. This 30,000 b/d increase was reflective of a return to normal operations after significant maintenance shutdowns at all three projects during 2012. Overall, there is little change compared to CAPP's 2013 forecast.

Future production could be higher than forecast given the announcement of three recent discoveries in the Flemish Pass Basin. The largest new prospect is the Bay du Nord, which is estimated to hold between 300 and 600 million barrels of recoverable oil. The Mizzen discovery is estimated to hold 100 to 200 million barrels while the Harpoon discovery is still under evaluation.

2.3 Western Canadian Crude Oil Production

Western Canadian crude oil production comes from both conventional and oil sands sources. Production from both sources is expected to contribute significantly to the forecast outlook (Table 2.2). The oil sands are essentially found in the province of Alberta, while conventional resources underlie Alberta, northeast British Columbia, Saskatchewan and parts of Manitoba and the Northwest Territories. Please refer to Appendix B.1 for detailed production data.

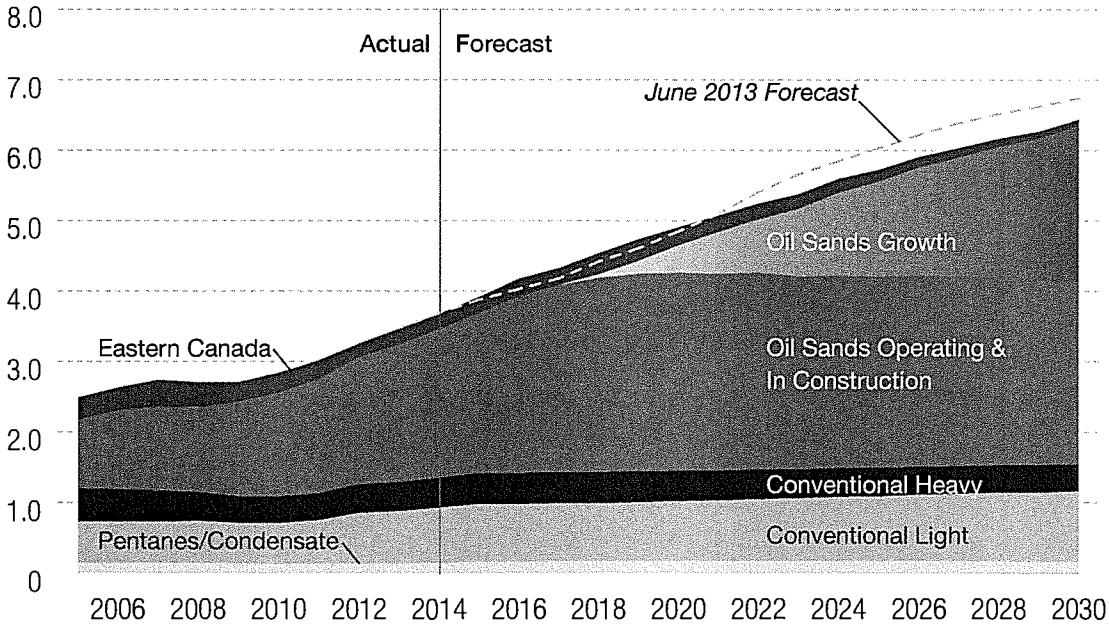
Relative to CAPP's 2013 report, western Candian production at the latter end of the outlook period is lower than previously forecast; in 2030 it is 300,000 b/d lower. Nonetheless, it is still expected to grow, on average, by 183,000 b/d per year through the forecast period. Conventional production is forecast to continue to contribute 1.5 million b/d to the total output on average over the forecast period. Compared to last year's forecast, conventional production is higher by 97,000 b/d in 2030; the majority of this uptick reflects the view that higher volumes of condensate will be available from industry's anticipated focus on drilling in liquids-rich natural gas plays.

Table 2.2 Western Canadian Crude Oil Production

million b/d	2013	2015	2020	2025	2030
Total*	3.24	3.68	4.65	5.57	6.35
Conventional (including condensate)	1.29	1.41	1.45	1.50	1.54
Oil sands (bitumen & upgraded)	1.95	2.27	3.20	4.07	4.81

*Totals may not add up due to rounding.

Figure 2.1 Canadian Oil Sands & Conventional Production
million barrels per day



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2.3.1 Conventional Crude Oil Production

The oil industry continues to search for innovative and more efficient ways to extract additional oil from conventional reservoirs. The increased use of horizontal drilling and multi-stage hydraulic fracturing techniques has reversed the steady decline in production from mature basins throughout North America since 2005.

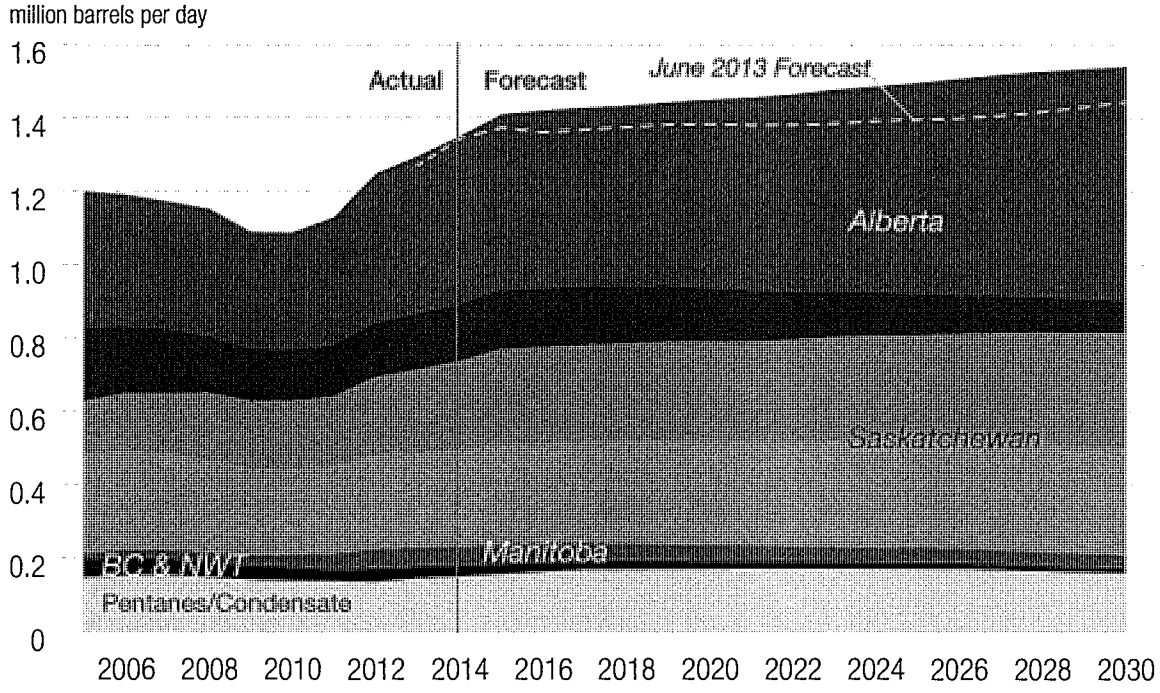
In 2013, western Canadian production, including condensates, was 1.3 million b/d, returning production to a similar level achieved 10 years ago. For purposes of this report, condensate refers to both pentanes plus and condensates. Further growth is anticipated as conventional production is forecast to ultimately exceed 1.5 million b/d, including growth in condensate production (Figure 2.2). Most of the condensate is primarily recovered from natural gas wells in Alberta and British Columbia. Increased drilling in liquids-rich plays such as the Montney and emerging plays like the Duvernay has reversed the declining trend in condensate production. Most of the conventional production comes from Alberta and Saskatchewan, of which over 60 per cent is light crude oil. By 2030, the light portion is forecast to increase to over 70 per cent of total conventional production.

Alberta

Alberta is the source for most of the condensate production in Western Canada with 123,000 b/d or 85 per cent of the total. In this year's forecast, some growth is expected in the early years followed by more stable levels of production. This is in contrast to the 2013 report, where condensate production was forecast to decline steadily. This revision reflects the increased activity and interest in west-central Alberta's Duvernay formation. The Duvernay is considered an attractive "shale gas" play because of its potential to produce liquids. There is strong demand for liquids to use as a diluent in the pipeline transportation of heavy oil production. According to the Alberta Energy Regulator (AER), the Duvernay formation holds 11.3 billion barrels of natural gas liquids resource. Early reports indicate high initial production rates and higher liquids yields for the wells drilled to date.

In 2013, conventional oil production in Alberta, excluding condensates, increased by 5 per cent compared to 2012, to 582,000 b/d. This production is forecast to increase by 144,000 b/d to 726,000 b/d by 2030. In last year's report, production was forecast to increase to 813,000 b/d by 2030. With only a few years of production data from horizontal oil wells in Western Canada, it is still too early to establish the ultimate recoveries and longer term flow rates for wells drilled using this newer technology.

Figure 2.2 Western Canada Conventional Production



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Saskatchewan

Saskatchewan is the second largest oil producing province in Canada and has exhibited exceptionally strong growth in the last two years. Light oil production grew by 12 per cent and 9 per cent in 2012 and 2013 respectively, driven by tight oil play activity. In the next two years growth is expected to be quite strong before growing at a more measured pace for the remainder of the forecast. Saskatchewan's three main tight oil plays are the Bakken, Shaunavon and Viking.

In 2013, total (light and heavy) Saskatchewan oil production was 486,000 b/d and this is forecast to increase to 607,000 b/d by 2030. This is about 118,000 b/d higher than last year's forecast and reflects a further refinement to our forecast model, using updated decline rates and drilling trends from CAPP's survey of Saskatchewan producers.

Manitoba, British Columbia, NWT

Manitoba accounts for 4 per cent of the total conventional production from Western Canada, excluding condensates. Part of the Bakken play underlies a small portion of southwest Manitoba. Current production of 51,000 b/d is expected to decline gradually to 36,000 b/d by 2030.

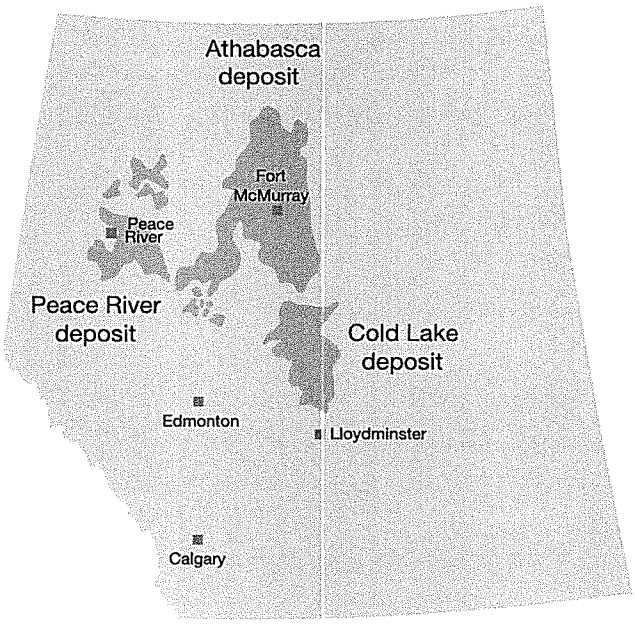
British Columbia is the second largest provincial source of condensate production, accounting for 14 per cent of total production from Western Canada. With low natural gas prices, the liquids-rich and condensate component of the natural gas production stream has become critical to economic success for some producers. As such, there has been a shift in focus towards drilling in liquids-rich areas within the province's Montney play. In addition to condensates, the province also accounts for 2 per cent of total western Canadian conventional production.

Very little production currently comes from the Northwest Territories. However, the Canol oil shale formation is estimated to contain between 2 billion and 3 billion barrels of recoverable oil according to the government of the Northwest Territories. Development is still in its very early stages. Companies seeking to develop the Canol note that although the shale play is prolific, its remoteness, distance from markets, lack of infrastructure and inclement weather all pose significant challenges.

2.3.2 Oil Sands

Three designated oil sands areas in Northern Alberta have been established in order to differentiate the extra heavy crude oil, produced from these regions, termed bitumen, from conventional crude oil production. The regions are referred to as the Athabasca, Cold Lake and Peace River deposits (Figure 2.3). The AER estimated at year-end 2013 that these areas contain remaining established reserves of 167 billion barrels. Depending on the depth of the deposit, one of two methods is used to recover the bitumen. Surface or open pit mining can be used to recover bitumen that occurs near the surface. At greater depths, *in situ* (Latin for "in-place") techniques are employed, meaning wells are drilled. The term is used in reference to both primary development, which uses methods similar to conventional crude oil production, and enhanced development techniques - the main methods being cyclic steam stimulation (CSS) and steam-assisted gravity drainage (SAGD). Of the remaining established oil sands reserves in Alberta, 33 billion barrels or 20 per cent is considered recoverable by mining and 134 billion barrels or 80 per cent can be recovered using *in situ* techniques.

Figure 2.3 Oil Sands Regions



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Up until 2020, this latest oil sands forecast is relatively unchanged from last year and is mostly comprised of the production from the phases of the oil sands projects that are either already operating or are in the process of being constructed. During the latter part of the forecast from 2021 to 2030, oil sands production is on average about 360,000 b/d lower than CAPP's 2013 forecast due to a lower outlook mostly from *in situ* production.

In 2013, oil sands production totaled 1.9 million b/d. Of these volumes, 1.1 million b/d were recovered by *in situ* techniques. Mining production is forecast to grow to 1.6 million b/d by 2030. Most of the growth can be attributable to *in situ* production, which is forecast to grow to 3.2 million b/d by 2030 (Table 2.3).

Table 2.3 Oil Sands Production

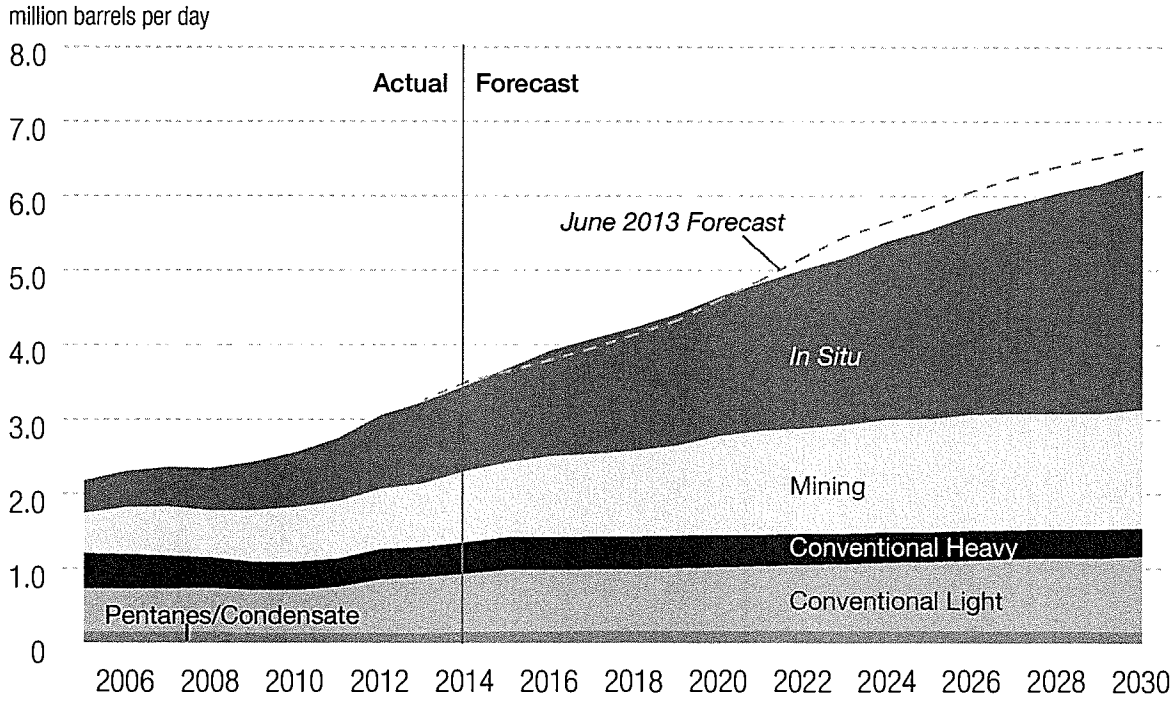
million b/d	2013	2015	2020	2025	2030
Total*	1.95	2.27	3.20	4.07	4.81
Mining	0.85	1.00	1.33	1.52	1.60
In Situ	1.10	1.27	1.87	2.55	3.21

*Total may not add up due to rounding.

Production volumes from oil sands are typically reported using the upgraded crude oil volumes from integrated projects instead of the raw bitumen volumes recovered from these projects. The yield losses associated with upgraded bitumen volumes from non-integrated projects have been accounted for in the supply volumes that are discussed in the next section of this report. Production from oil sands currently accounts for 60 per cent of Western Canada's total crude oil production. In this forecast, oil sands production rises from 1.9 million b/d in 2013, to 2.5 times this and reaches 4.8 million b/d by 2030 (Figure 2.4). The oil sands forecast in 2030, is approximately 400,000 b/d lower than forecast in the previous report due to a combination of factors including cost competitiveness and availability of financing.

Currently, Nexen's Long Lake project is the only *in situ* project coupled with upgrading facilities. Historically all mined bitumen has been transformed into upgraded light crude oil. However, Imperial's Kearl mining project started producing bitumen at the end of April 2013 and is the first mining project operating without an affiliated upgrader. This project delivers diluted bitumen to the market. Some *in situ* volumes from Suncor's Firebag and MacKay River projects are upgraded at the Suncor upgrader.

Figure 2.4 Western Canada Oil Sands & Conventional Production



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Existing integrated mining and upgrading projects are listed below:

- Suncor Steepbank and Millennium Mine;
- Syncrude Mildred Lake Mine and Aurora Mine;
- Athabasca Oil Sands Project (AOSP) and Shell Jackpine Mine; and
- Canadian Natural Horizon Project

2.4 Western Canadian Crude Oil Supply

Some volumes of raw bitumen are being transported to market by rail. However, the composition of the various crude types available in the market typically differs from crude oil at the production level. Both conventional heavy crude oil and bitumen from the oil sands are either upgraded or blended in order to be transported on pipelines or to meet optimal refinery specifications. In addition, some volumes of light crude oil may also be used for blending. In any event, it is this crude oil supply that is available after upgrading and blending that is more relevant to market observers because it is these volumes that are ultimately delivered to the end-use markets.

In this report, CAPP categorizes the various crude oil types that comprise western Canadian crude oil supply into the following main categories: Conventional Light, Conventional Heavy, Upgraded Light and Oil Sands Heavy. Oil Sands Heavy includes upgraded heavy sour crude oil, bitumen diluted with upgraded light crude oil (also known as "SynBit") and bitumen diluted with condensate (also known as "DilBit"). Blending for DilBit differs by project but requires approximately a 70:30 bitumen to condensate ratio while the blending ratio for SynBit is approximately 50:50. Bitumen volumes currently being transported by rail are relatively minor; however, these volumes would require less diluent for blending versus moving by pipeline or may even be transported as raw bitumen (also known as "RailBit").

In 2013, about 1.1 million b/d or 55 per cent of the total bitumen produced in Canada was upgraded, including volumes of bitumen that were processed at the Suncor refinery in Edmonton. This refinery intake was included since it can process oil sands feedstock.

Upgraded volumes are forecast to rise to 1.5 million b/d by 2030. The five bitumen upgraders located in Alberta produce a variety of upgraded products. Suncor produces light sweet crude and medium sour crudes, including diesel; Syncrude, Canadian Natural Horizon, and Nexen Long Lake produce light sweet synthetic crude; and Shell produces an intermediate refinery feedstock for the Shell Scotford refinery, as well as sweet and heavy synthetic crude.

Canada's upgrading capacity is not expected to rise commensurately with bitumen production growth due to a number of economic challenges. These include the high capital costs incurred with building an upgrader and the need for a sustained differential between light and heavy crude oil of at least $25 per barrel. It is difficult for a new upgrader to compete with the option of transporting heavy crude oil to existing refineries located throughout North America with spare coking capacity that are able to refine such heavy crudes.

If it is not upgraded, bitumen is so viscous at its production stage that it needs to be diluted with a lighter hydrocarbon or diluent to create a type of crude that meets pipeline specifications for density and viscosity. Bitumen at 10° Celsius has the consistency of a hockey puck. Less diluent is required when bitumen is moved by rail where it is transported in heated rail tank cars that lower the viscosity of the bitumen. The main source of diluent is condensate that is recovered from processing natural gas in Western Canada. This source of condensate is forecast to grow slightly but will be insufficient to meet the needs of growing bitumen production that currently already exceed the available supply.

In 2013, almost 300,000 b/d of imported condensates, diluents from upgraders, as well as quantities of butane were needed to supplement the condensate supply from indigenous natural gas wells. CAPP's forecast is not constrained by the availability of condensate imports as new sources of condensate are assumed to be available to meet market requirements. Refer to Section 4.7 for details on existing and proposed diluent import pipeline projects. The potential for bitumen to travel by rail with reduced diluent requirement has not been factored into the analysis of condensate demand. To the extent rail becomes a more significant delivery system the reduction in the estimated need for diluent through the use of this transportation option will be reflected in future survey results and in turn, be incorporated in CAPP's future forecasts.

012609

Table 2.4 shows the projections for total western Canadian crude oil supply. Refer to Appendix B.2 for detailed data. Light crude oil supply is projected to be relatively stable at around 1.6 million b/d on average for the outlook. Heavy crude oil supply is projected to grow from 2.0 million b/d in 2013 to 3.6 million b/d in 2020 to almost triple the current volume in 2030 when it reaches 5.7 million b/d.

Table 2.4 Western Canadian Crude Oil Supply

million b/d	2013	2015	2020	2025	2030
Total*	3.47	3.93	5.20	6.40	7.45
Light	1.46	1.54	1.57	1.71	1.78
Heavy	2.02	2.39	3.64	4.70	5.68

*Total may not add up due to rounding.

The Upgraded Light crude oil supply includes the light crude oil volumes produced from:

- Upgraders that process conventional heavy oil;
- Integrated mining and upgrading projects;
- Integrated *in situ* projects; and
- Off site upgraders.

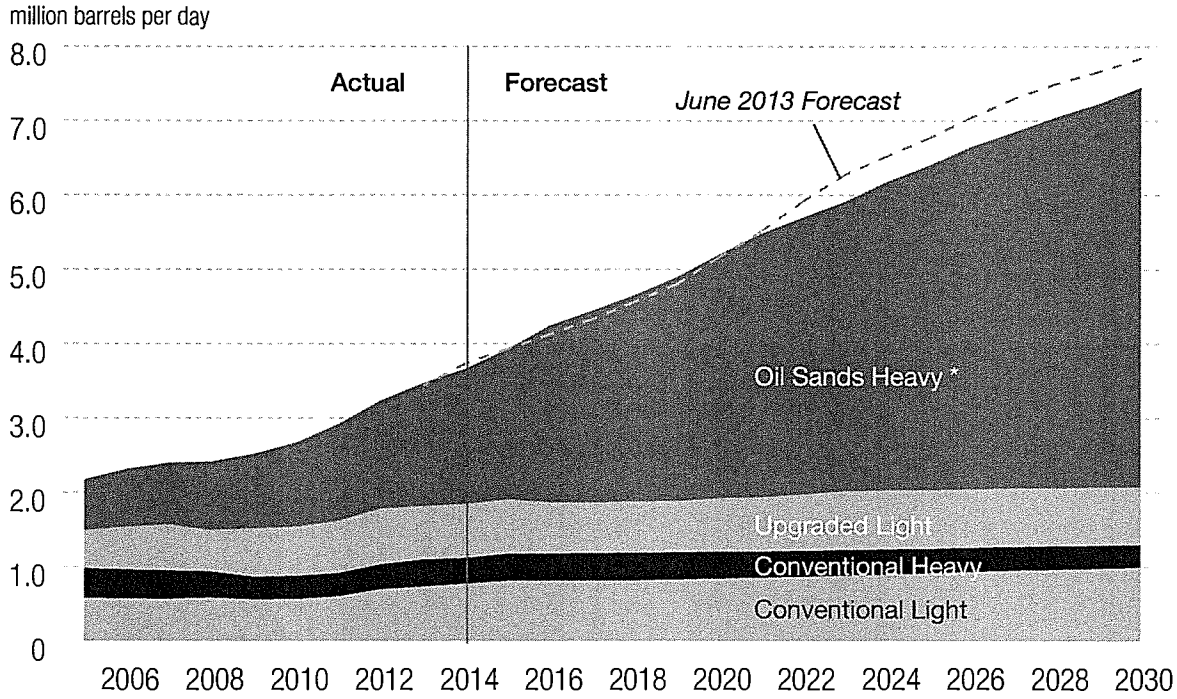
Compared to the 2013 forecast, the Upgraded Light crude oil supply is relatively unchanged. The Oil Sands Heavy category is forecast to increase from 1.7 million b/d to 5.4 million b/d by 2030 which is about 400,000 b/d lower than levels previously forecasted (Figure 2.5).

2.5 Crude Oil Production and Supply Summary

CAPP's 2014 crude oil production forecast for Western Canada predicts continued strong growth from 3.2 million b/d to 6.4 million b/d by 2030. Compared to the 2013 outlook, this latest forecast shows approximately 100,000 b/d higher forecast in conventional production, including condensates, and a 400,000 b/d lower forecast in oil sands production, the majority of which can be attributable to slower anticipated growth in *in situ* projects.

The production outlook from offshore Atlantic Canada is unchanged and is expected to be stable at levels above 200,000 b/d until 2024, supported by production from satellite fields and the Hebron project starting up in 2017. By 2030, however, production is forecast to decline to less than 100,000 b/d but could be higher than forecast given the announcement of three recent discoveries in the Flemish Pass Basin. The largest new prospect is the Bay du Nord, which is estimated to hold between 300 and 600 million barrels of recoverable oil.

Figure 2.5 Western Canada Oil Sands & Conventional Supply



* Oil Sands Heavy includes some volumes of upgraded heavy sour crude oil and bitumen blended with diluent or ugpraded crude oil.

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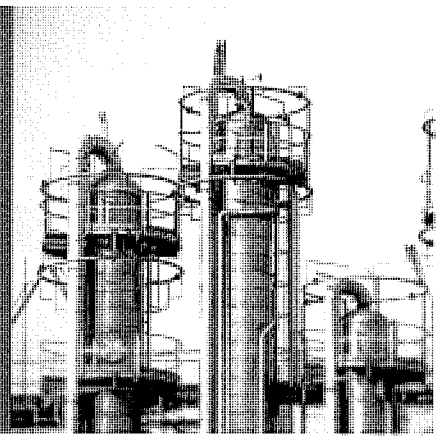
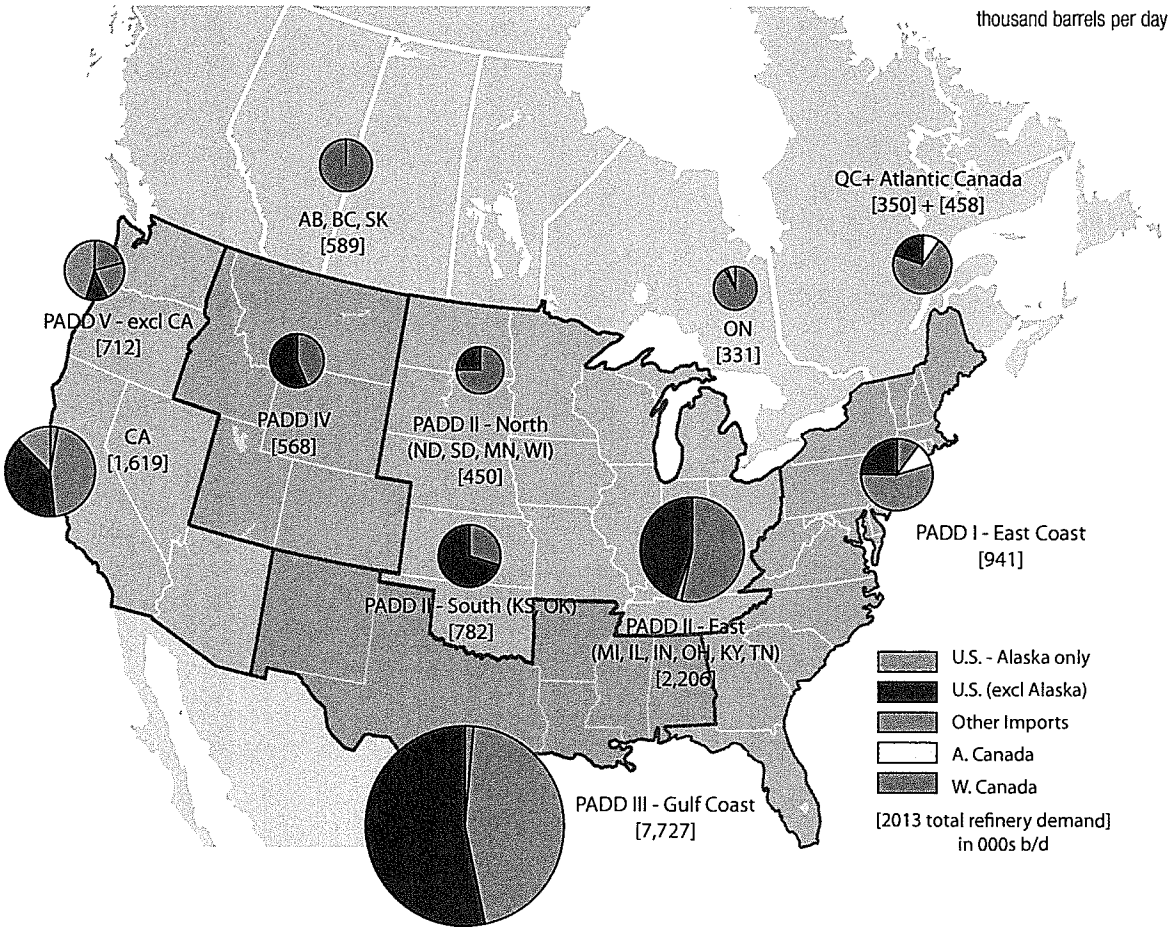
3 | CRUDE OIL MARKETS



With 1.7 million b/d of additional crude oil supplies from Western Canada forecast to be available by 2020, expansion and diversification to all potential markets is key. Figure 3.1 shows the demand for crude oil in the major refining regions in Canada and the United States (U.S.). The U.S. Gulf Coast is a major target market due to the large heavy oil processing capability in the region. As identified by the areas in green, western Canadian crude could expand its share in PADD I, Eastern Canada, and PADD V markets. Also, beyond North America, global markets in Asia and even Europe, represent a potential opportunity.

Figure 3.1 Canada and U.S. Market Demand for Crude Oil in 2013 by Source



Sources: CAPP, CA Energy Commission, EIA, Statistics Canada

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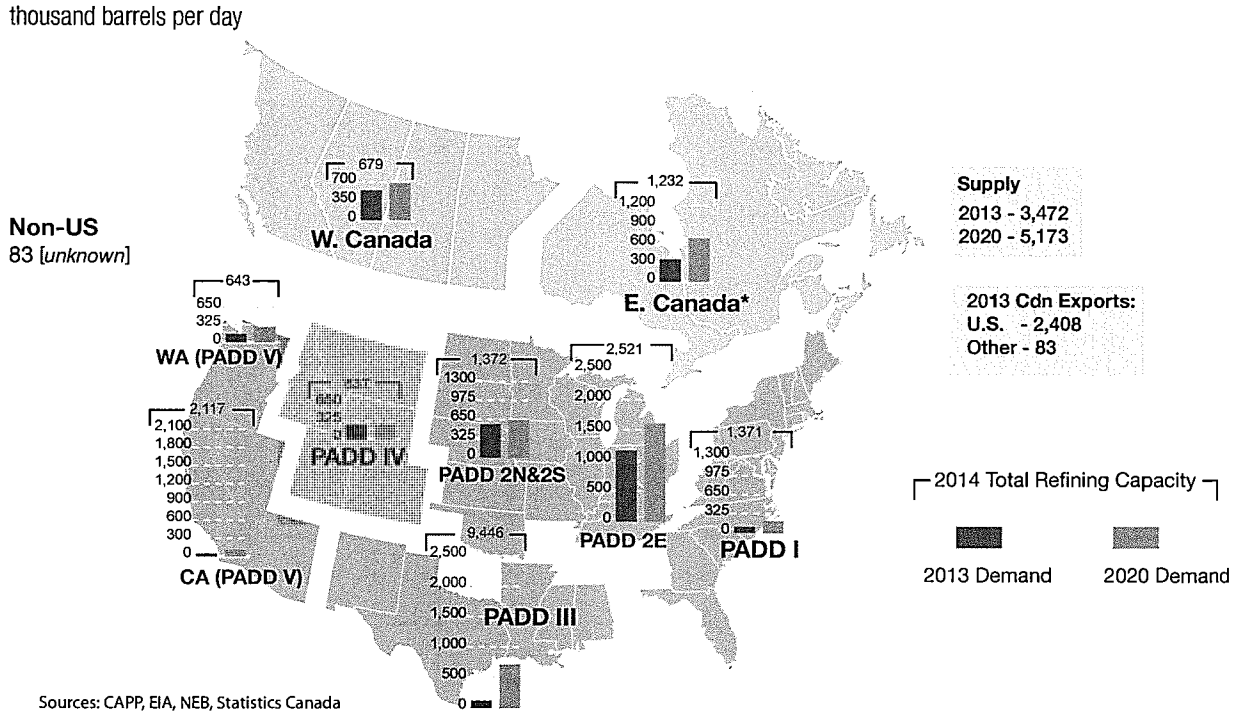
Figure 3.2 Market Demand for Western Canadian Crude Oil: Actual 2013 and 2020



Sources: CAPP, EIA, NEB, Statistics Canada

* E.Canada demand for W. Canadian crude oil in 2013 consisted almost entirely of receipts from Ontario. Projected receipts in 2020 include growth from Québec and Atlantic provinces.

Note: 2013 demand does not equal available supply due to factors such as inventory adjustment and data discrepancies in information collection.

In 2013, Canadian refineries processed 905,000 b/d of western Canadian crude oil. The remaining 2.6 million b/d or 74 per cent of available supply was exported. PADD II is the largest regional market for western Canadian crude oil. The bulk of the growth in supply volumes in 2020 is expected to flow to the U.S. Gulf Coast and Eastern PADD II. Eastern Canada and refineries on the West Coast could potentially process close to double the volume of their current intake of Canadian crude oil (Figure 3.2).

3.1 Canada

Canadian refineries have the capacity to process 1.9 million b/d of crude oil. However, only about 60 per cent of the crude oil processed in Canada is sourced from domestic production since refineries in Eastern Canada have limited access to western Canadian crude oil supplies. In 2013, Canadian refineries processed 905,000 b/d of western Canadian crude oil; 70,000 b/d of crude oil produced in Eastern Canada; and 642,000 b/d of foreign imports. The oil pipeline network exiting Western Canada currently connects to refineries in Western Canada and Ontario.

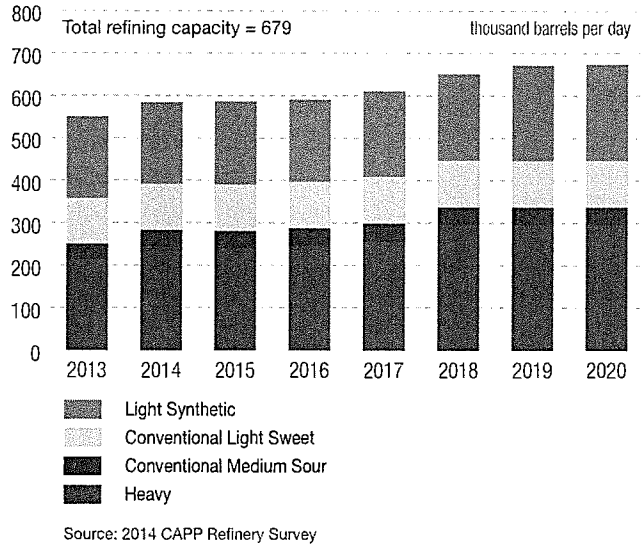
The refineries without pipeline access, however, are developing transportation solutions involving rail and/or trucks to benefit from growing North American sources of supply. The Canadian demand for western Canadian crude oil is expected to increase to 1.2 million b/d by 2020 as a result of planned refinery expansions and future transportation infrastructure developments.

3.1.1 Western Canada

Western Canada has a total refining capacity of 679,000 b/d from eight refineries. In 2013, these refineries processed 551,000 b/d of crude oil that was sourced exclusively from Western Canada. By 2020, western Canadian crude oil will remain the sole diet for these refineries and demand is expected to increase by 123,000 b/d to 675,000 b/d (Figure 3.3).

012612

Figure 3.3 Western Canada: Crude Oil Receipts from Western Canada



Source: 2014 CAPP Refinery Survey

The additional crude oil receipts in the future are related to a debottleneck project at the Moose Jaw refinery and expansion plans at the Consumer's Co-operative refinery, which are both located in Saskatchewan, and the startup of the North West Redwater Partnership's refinery near Redwater in Sturgeon County, about 45 km northeast of Edmonton, Alberta. The Sturgeon refinery is designed to process 50,000 b/d of raw bitumen feedstock under 30 year fee-for-service processing agreements. The Alberta Petroleum Marketing Commission, an agent of the province of Alberta, will supply 75 per cent of the feedstock and Canadian Natural Resources Limited will supply the rest. In December 2013, it was announced that the capital cost estimate increased to $8.5 billion from the original estimate of $5.7 billion. The original startup of operations has been extended from mid-2016 to September 2017. The project broke ground on September 20, 2013.

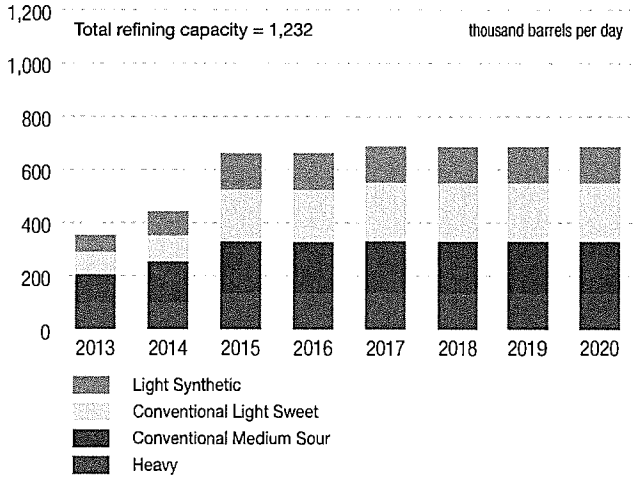
The Moose Jaw refinery is an asphalt refinery while the other refineries produce a wide range of petroleum products.

A project in the early stages of development has been proposed by newspaper publisher David Black, for a new export refinery to be located in Kitimat, British Columbia. The refinery would be designed to process 550,000 b/d of bitumen into gasoline, jet fuel and diesel for transportation to Asian markets. The estimated cost for the project is $21 billion.

3.1.2 Eastern Canada

Total capacity of refineries in Eastern Canada is about 1.2 million b/d and includes the refineries located in Ontario, Québec and Atlantic Canada. In 2013, Western Canada supplied 354,000 b/d to these refineries or only 33 per cent of total refinery demand. Almost all of these receipts were delivered to Ontario. Crude oil deliveries to the region increased in the past year through the use of rail. By 2020, overall demand in this market is expected to increase significantly (Figure 3.4). The reversal of the Enbridge Line 9 to Montréal by the end of 2014 will provide this market with access to Canadian crude oil. The TransCanada Energy East project proposes to provide access to Canadian crude in late 2018.

Figure 3.4 Eastern Canada: Crude Oil Receipts from Western Canada



Source: 2014 CAPP Refinery Survey

Ontario

The four refineries located in Ontario have a combined refining capacity of 393,000 b/d. The NOVA Chemicals refinery and petrochemical complex, located in Sarnia, has been excluded as crude oil is not the primary feedstock. The majority of the crude processed at the Ontario refineries is sourced from Western Canada but they also refine some foreign imported crude oil and crude oil transferred from Atlantic Canada.

012613

Since August 2013, with the first phase of the Enbridge Line 9 re-reversal in operation, crude oil can flow east from Sarnia to North Westover, Ontario and can provide light crude oil to Imperial's refinery in Nanticoke, Ontario. Refer to Section 4.6 for details on oil pipelines to Eastern Canada. Ultimately, all refineries in the region will have access to a variety of sources and will select their feedstock based on availability and price.

According to data from the NEB and Statistics Canada, Ontario refineries processed 380,300 b/d of crude oil in 2013. A further breakdown of these supplies shows 356,700 b/d (94 per cent) from domestic sources; with the remainder comprised of imports from Norway, United Kingdom, Nigeria, Algeria and Mexico.

Québec & Atlantic Provinces

There are two refineries in Québec that have a combined capacity of 402,000 b/d. With the closure of Imperial's refinery in Halifax in June 2013, two refineries remain in operation in Atlantic Canada and they have a combined capacity of 435,000 b/d. The crude oil processed at these refineries generally originates from either Atlantic Canada or foreign sources. Both regions are expected to ramp up receipts of crude oil deliveries from Western Canada that began in recent years. The refineries are configured to process mostly light crude oil but future demand for heavy crude oil could increase if the refineries decided to invest in capital upgrades to enable processing heavier crude types. Suncor continues to assess the feasibility of building a coker at its Montréal refinery.

Once Enbridge's complete Line 9 re-reversal is in service, western Canadian crude oil could be transported by pipeline all the way to Montréal. Refineries in these provinces would have access to the growing light oil production from both Western Canada and the U.S. Bakken in Montana and North Dakota. Once crude oil reaches Montréal, companies could barge oil from there to Québec City, and potentially ship it by rail to the Irving refinery in Saint John, New Brunswick. By the end of 2018, if TransCanada's Energy East pipeline project proceeds, there will be pipeline access all the way from Western Canada to Saint John.

3.2 United States

Canada is the top foreign supplier of crude oil to the U.S. and is likely to remain as such for the foreseeable future. In 2013, almost all of Western Canada's crude oil exports were to the U.S. Despite rising U.S. domestic production driven by drilling in the shale and tight oil plays in the Eagle Ford in Texas and Bakken in North Dakota, U.S. imports from Canada grew by 158,000 b/d or 7 per cent versus 2012. Total U.S. imports of crude oil declined by 808,000 b/d or 9 per cent in 2013, mainly as a result of the displacement of foreign (non-Canadian) imports of light crude oil with domestic light supply. Growing western Canadian crude oil supplies are predominately heavy crude oil, therefore, the U.S. Gulf Coast refineries, with their substantial heavy oil processing capabilities, remain a key target market.

The U.S. Department of Energy divides the 50 states into five market regions termed the Petroleum Administration of Defense Districts or PADDs. These PADDs were originally created during World War II to help allocate fuels derived from petroleum products. Today, this delineation continues to be used when reporting data to describe the U.S. market regions.

3.2.1 PADD I (East Coast)

The refining capacity in the US East Coast currently totals 1.4 million b/d. The 10 refineries that form this capacity are located in the states of Delaware, Georgia, New Jersey, Pennsylvania, and West Virginia.

In 2013, total refinery input increased by 13 per cent compared to 2012 with the first full year return to operations of previously idled refineries. Imports of foreign crude oil by refineries in PADD I totaled 784,000 b/d, which is significantly lower than in 2012 due to a displacement of foreign imports with growing domestic supplies. The domestic portion of the feedstock slate increased from only 60,000 b/d to 254,000 b/d. This is an increase of 194,000 b/d or 322 per cent year over year.

Historically, the refineries on the East Coast have been supplied by waterborne crude oil delivered from the U.S. Gulf Coast and internationally sourced crude oil. However, with development of new rail unloading facilities, these refineries have growing access to Bakken crude oil produced in North Dakota. Phillips 66 and PBF have signed transportation agreements for the provision of Bakken crude supplies to their refineries located on the East Coast.

012614

Table 3.1 Summary of Rail Offloading Terminals in PADD I

Operator	Location	Capacity (thousand b/d)	Scheduled In-Service	Description
PBF Energy (refinery)	Delaware City, DE	145 (105 light/40 heavy) Expand to 210 (130 light/ heavy)	Operating Q4 2014	Both light and heavy crude oil unloading capacity
Axeon Specialty Partners (refinery)	Savannah, GA	9* *based on 16 rail tank cars per day)	1H 2014	Crude oil that is shipped by rail to Savannah could conceivably move to Paulsboro via backhauls on waterborne vessels
Westville	Eagle Point (near Paulsboro), NJ			
Axeon Specialty Partners (refinery)	Paulsboro, NJ	small volumes Unit train capable	Operating 2014	Unit train capability is being contemplated
Buckeye Partners, L.P.	Perth Amboy, NJ	60-80	Q3 2014	Light crude; possible heavy in the future
Buckeye Partners, L.P.	Albany, NY	135	Operating since Nov 2012	Multi-year agreement with Irving refinery
Global Partners	Albany, NY	160 (estimated to be operating at 100)	Operating since 2011	Light crude oil receipts; seeking permit for facility to heat crude oil. Phillips 66 has 5 year contract for 50,000 b/d
Eddystone Rail Company (Enbridge JV)	Philadelphia, PA	80* *expandable to 160	Operating since May 2014	First train received on May 3, 2014.
Philadelphia Energy Solutions (refinery)	Philadelphia, PA	140	Operating since Oct 2013	
Plains All American Pipeline (PAAP)	Yorktown, VA	60	Operating since Dec 2013	First 98-car unit train received on Dec. 30, 2013
Total Existing Capacity				**709,000 b/d**

012615

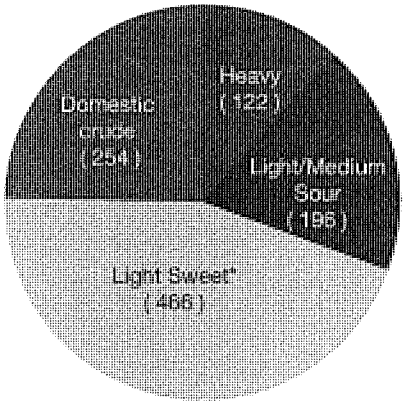
PADD I refineries imported 212,300 b/d of crude oil from Canada in 2013. About 83,900 b/d was sourced from Western Canada and was primarily delivered to the United refinery in Warren, Pennsylvania. Most of the refineries in the region process light sweet crude (Figure 3.5).

However, PBF's Paulsboro and Delaware City refineries have the coking capacity to process heavy crude oil from Western Canada. Also, modifications at Axeon Specialty Product's refinery in New Jersey will enable it to run both light and heavy crude oil feedstock.

Deliveries of U.S. domestic light crude oil supplies and imports of heavy crude oil from Western Canada could rise in the next few years as a result of growing rail transportation. Significant investments have been made in rail unloading facilities in recent years (Table 3.1). Refineries without direct access to rail unloading facilities can have rail deliveries to a terminal and then barged to the refinery.

Figure 3.5 2013 PADD I: Foreign Sourced Supply by Type and Domestic Crude Oil

Total refining capacity = 1,371 thousand barrels per day



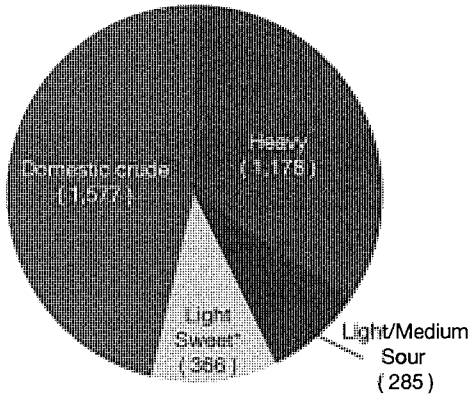
* Includes small volumes of Medium Sweet
Source: EIA

3.2.2 PADD II (Midwest)

Over 3.9 million b/d of refining capacity is located in PADD II. In 2013, these refineries received 1.8 million b/d of foreign sourced crude oil, almost all of which was from Western Canada and were predominantly heavy supplies (Figure 3.6).

Figure 3.6 2013 PADD II: Foreign Sourced Supply by Type and Domestic Crude Oil

Total refining capacity = 3,892 thousand barrels per day



* Includes small volumes of Medium Sweet
Source: EIA

PADD II can be further divided into the Northern, Eastern, and Southern PADD II states. The primary market hubs within PADD II are located at Clearbrook, Minnesota for the Northern PADD II states; Wood River-Patoka, Illinois area for the Eastern PADD II states; and Cushing, Oklahoma for the Southern PADD II states.

The Midwest region is currently Canada's largest market. However, this traditional market is becoming saturated as evidenced by the high level of inventories from growing domestic production and imports from Western Canada.

Table 3.2 Summary of Recent Refinery Upgrades in Northern & Southern PADD II

Operator	Location	Current Capacity (thousand b/d)	Scheduled In-Service	Description
Northern Tier Energy LP	St. Paul Park, MN	82	Completed May 2013	A 10% expansion of its crude distillation unit. Capacity increased from 72,000 b/d.
Tesoro	Mandan, ND	68	Completed June 2012	Increased crude capacity by 10,000 b/d to 68,000 b/d to process more Bakken crude oil.
NCRA	McPherson, KS	85	Q1 2015	Plan to expand capacity to 100,000 b/d and increase heavy crude oil processing capacity to 50% with installation of new delayed coker.

012616

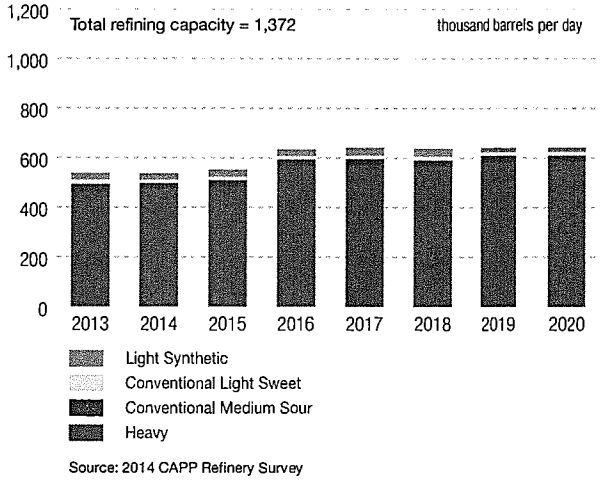
Northern and Southern PADD II

In Northern PADD II there are two refineries located in Minnesota, a refinery in Wisconsin and another refinery in North Dakota. The existing four refineries have a combined capacity of 564,500 b/d. Construction on a new refinery in North Dakota is scheduled for completion by the end of 2014. This refinery has a designed capacity of 20,000 b/d and is intended to process U.S. Bakken crude oil.

All seven refineries in Southern PADD II, are either located in Kansas or Oklahoma, and account for a combined capacity of 807,000 b/d. U.S. domestic production satisfies the majority (56 per cent) of the refinery feedstock demand in these two regions while almost all of the foreign imports into these two regions are sourced from Western Canada. Most, or 81 per cent, of the 538,000 b/d of western Canadian crude oil imports were heavy oil supplies.

Given the small relative size of these two markets and competition with U.S. domestic production, the opportunity for western Canadian crude oil demand growth is limited. It is forecast to reach an additional 100,000 b/d from today's levels by 2020 (Figure 3.7).

Figure 3.7 PADD II (North & South): Crude Oil Receipts from Western Canada

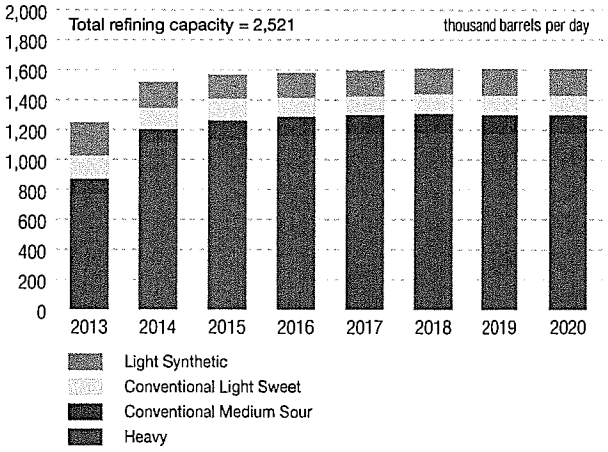


Source: 2014 CAPP Refinery Survey

Eastern PADD II

The total refining capacity in Eastern PADD II is over 2.5 million b/d from 14 refineries located throughout the six states of Michigan, Illinois, Indiana, Kentucky, Tennessee and Ohio. In 2013, this market collectively imported over 1.3 million b/d of crude oil supplies, of which 97 per cent were sourced from Western Canada. Imports of heavy western Canadian crude oil are estimated to increase from current levels by over 400,000 b/d in 2020 (Figure 3.8). A number of previously announced refinery projects designed to increase heavy oil processing capacity at various refineries have recently been completed (Table 3.3).

Figure 3.8 PADD II (East): Crude Oil Receipts from Western Canada



Source: 2014 CAPP Refinery Survey

Table 3.3 Summary of Recent Refinery Upgrades in Eastern PADD II

Operator	Location	Current Capacity (thousand b/d)	Scheduled In-Service	Description
BP	Whiting, IN	413	Distillation unit completed July 2013 Coker completed Nov 2013	Construction of 102,000 b/d new coker and a new crude distillation unit. The refinery will have the capacity to process up to 80% heavy crude and expected to process Cdn in 2014.
Marathon	Detroit, MI	120	Completed Nov 2012	Increase heavy oil processing capacity by 80,000 b/d; total crude oil refining capacity increased by 14,000 b/d.
Husky	Lima, OH	160	2017	Modifications to coker and other processing units to increase ability to process heavy crude oil by up to 40,000 b/d.

012617

3.2.3 PADD III (Gulf Coast)

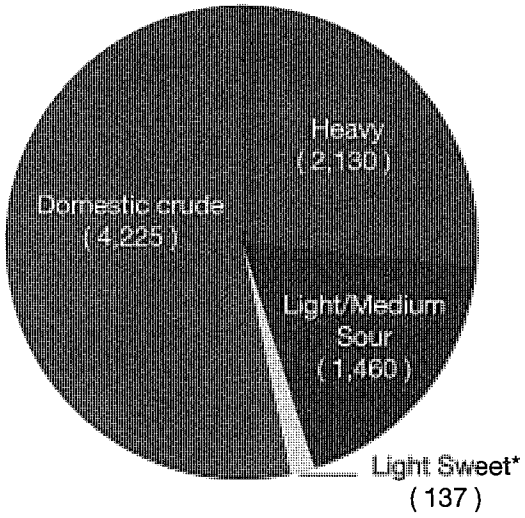
With 9.4 million b/d of refining capacity from 50 refineries, the Gulf Coast is home to half of the total refining capacity in the U.S. The vast majority of this capacity, specifically 8.6 million b/d, is located in the two states of Louisiana and Texas. The remaining refineries are located in Alabama, Arkansas, Mississippi, and New Mexico.

Greater access to this market would allow production from Canada to significantly expand its reach into the United States. Gulf Coast refineries are among the most sophisticated in the world, meaning that they are able to produce different types of petroleum products from a variety of crude oil feedstocks. These refineries have the capacity to process heavy, high sulphur crude oil, which is ideally suited for the growing supplies from Western Canada, the bulk of which are expected to be heavy crude oil.

Foreign imports of crude oil totaled 3.7 million b/d in 2013, which was a decline of 17 per cent from 2012. Surging production from U.S. shale and tight oil plays such as the Eagle Ford and Permian Basin in Texas, has enabled refineries along the U.S. Gulf Coast to satisfy their light crude oil feedstock requirements with domestic supplies instead of light-sweet crude imports.

Figure 3.9 2013 PADD III: Foreign Sourced Supply by Type and Domestic Crude Oil

Total refining capacity = 9,446 thousand barrels per day



* Includes small volumes of Medium Sweet
Source: EIA

The 2.1 million b/d of heavy crude oil imports in 2013 remained relatively unchanged from 2012. Due to pipeline constraints, only 118,000 b/d of western Canadian crude was able to reach the U.S. Gulf Coast region. The top three suppliers of foreign crude oil in declining order are: Saudi Arabia, Mexico, and Venezuela; which combined account for 67 per cent of total imports. Venezuela, Mexico, and Columbia collectively account for 77 per cent of all heavy imports. Crude oil imports from Saudi Arabia consist mostly of light and medium sour crude oils. The opportunity for growing supplies from Western Canada to gain a presence in this market once the transportation capacity is in place lies in the displacement of heavy imports and not competition with U.S. domestic production, which is primarily light crude oil.

Since 2010, crude oil imports from Mexico have been steadily declining and in 2013 fell by 116,000 b/d to 919,000 b/d, reflecting the decline in Mexico's crude oil production. The annual imports from Venezuela in 2013 hit a 20-year low, falling by a dramatic 17 per cent to 755,000 b/d. Venezuela is reported to be exporting 640,000 b/d to China with about 310,000 b/d being used to pay back loans. Despite Venezuela having the world's largest reserves of crude oil, growth in production will be difficult to achieve and significant capital investments will be required. If there is no substantial growth in production, exports to the U.S. will continue to decline as Venezuela has substantial supply commitments to China, Cuba, the Dominican Republic and Nicaragua.

There are currently two pipelines in service that provide a limited connection between western Canadian producers and the U.S. Gulf Coast market. Further expansions upstream are required for significant volumes of western Canadian crude to enter this market. The U.S. Gulf Coast was the largest market for movements of crude by rail in 2013. CAPP's 2014 refinery survey indicates that western Canadian crude oil supplied to this market could reach 709,000 b/d in 2020.

3.2.4 PADD IV (Rockies)

There are 14 refineries in PADD IV located in Colorado, Montana, Utah, and Wyoming with a combined refining capacity of 637,000 b/d. The refineries in this market process U.S. domestic crude oil supplies from the Bakken oil play and source all foreign imports from Western Canada.

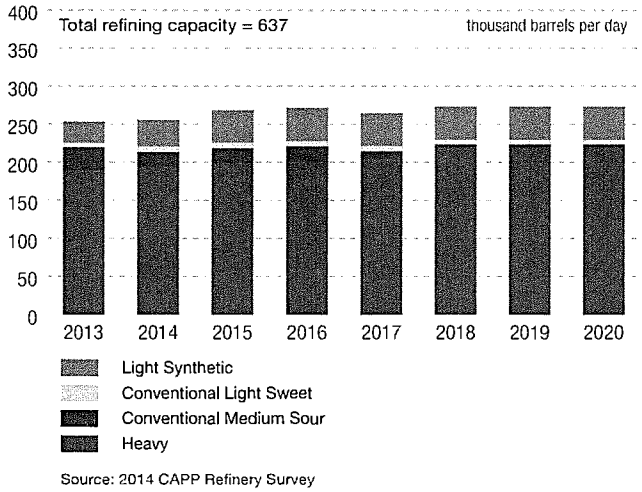
012618

Table 3.4 Summary of Recent Refinery Upgrades in PADD III

Operator	Location	Current Capacity (thousand b/d)	Scheduled In-Service	Description
Calumet Specialty Products	San Antonio, TX	17.5	Completed Dec 2013	Expansion to crude unit increased capacity from 14,500 b/d to 17,500 b/d.
Marathon	Garyville,LA	522	2018 (decision in early 2015)	Installation of hydrotreating, hydrocracking, & desulfurization equipment.
Valero	McKee, TX	170	2014	Increase capacity by 25,000 b/d. Expansion will process WTI and locally produced crude oil.
LyondellBasell Industries NV	Houston, TX	268	2015	Increase ability to process heavy crude oil from 60,000 b/d to 175,000 b/d.

In 2013, PADD IV refineries processed 253,000 b/d of Canadian crude oil, representing, 44 per cent of total feedstock requirements in the region. Receipts of heavy western Canadian supply are forecast to remain steady at current levels. If Canadian heavy crude oil continues to be priced at an attractive discount, refineries are expected to continue to process heavy volumes to optimize refinery configuration despite the light crude oil surplus in the region.

Figure 3.10 PADD IV: Crude Oil Receipts from Western Canada

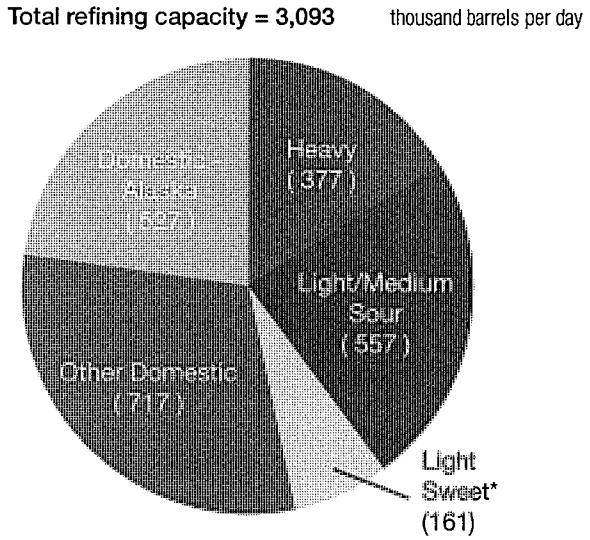


Source: 2014 CAPP Refinery Survey

3.2.5 PADD V (West Coast)

PADD V is divided from the rest of the U.S. by the Rocky Mountains and this geographical isolation has affected the development of crude supply sources to the region. The states in PADD V that have refineries are Alaska, California, Hawaii, and Washington. These refineries are located in close proximity to production in California and Alaska and also have good access to tankers that can import crude from more distant regions. There is 3.1 million b/d of refining capacity in the region. Foreign imports typically supply almost 50 per cent of the crude oil feedstock demand (Figure 3.11) and this share is expected to supplement the declining production from Alaska.

Figure 3.11 2013 PADD V: Foreign Sourced Supply by Type and Domestic Crude Oil



* Includes small volumes of Medium Sweet

Source: EIA

012619

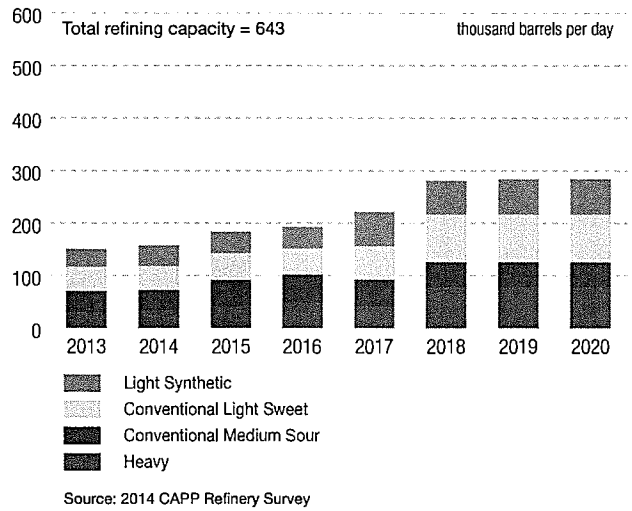
The following discussion focuses only on Washington and California as the demand from refiners located in these two states account for both the current and future prospects for western Canadian crude oil in this region.

Washington

Refining capacity in Washington totals 643,000 b/d. The state's five refineries have been primarily supplied with Alaskan production delivered by tanker but production from this source continues to decline. At 515,000 b/d in 2013, Alaskan production is only about a quarter of the peak levels achieved in 1988. Note that the state's supplies could rebound as the repeal of a production tax triggers investments that may boost output by at least 90,000 b/d within four years. However, in the meantime, Washington refineries have become increasingly dependent on foreign imports but some have also recently been able to access some of the growing crude oil production supply in North Dakota through the use of rail.

In 2013, Washington refineries received 223,000 b/d of foreign imports of which 68 per cent was supplied by Canada. Saudi Arabia and Russia are the second and third main suppliers with 14 per cent and 3 per cent shares of the market, respectively. Results from CAPP's refinery survey indicate crude oil demand from Western Canada will increase by 133,000 b/d from current levels, which translates to an 88 per cent increase (Figure 3.12). This growth in demand relies on the successful construction of proposed rail or pipeline projects that would reach the West Coast. Refer to Section 4.5 for details on the Pipelines to the West Coast.

Figure 3.12 PADD V (Washington): Crude Oil Receipts from Western Canada



Source: 2014 CAPP Refinery Survey

A few refineries began investing in rail offloading facilities in recent years in order to access growing supplies of crude oil from North Dakota and Western Canada. All the refineries in Washington either are already receiving some crude shipments by rail or have plans to do so by the end of the year.

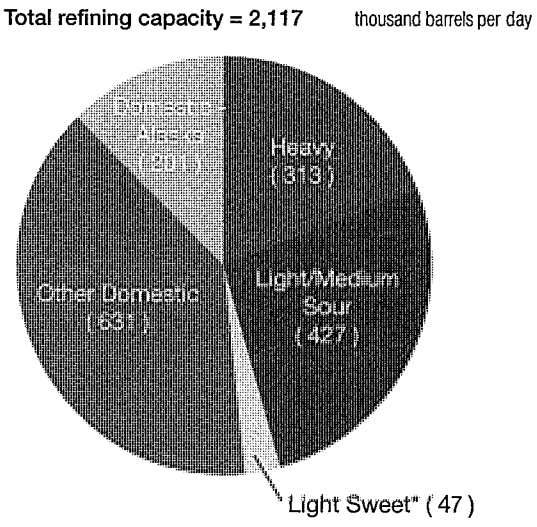
California

California dominates PADD V in terms of state oil production and refining capacity. There are 16 refineries located in California that contribute to a total refining capacity of 2.1 million b/d in the state. Almost all of the refineries are located near the coast in the Los Angeles and the San Francisco Bay areas. There is no direct pipeline to California from producing regions outside of California. Therefore, as Alaskan crude oil declines an opportunity arises to process more crude oil from the Bakken in North Dakota and potentially from Canada. Refer to Section 4.5 for pipeline proposal projects connecting western Canadian crude oil to the West Coast where the crude oil could then be loaded on to tankers to serve these refineries.

A number of rail unloading projects are being pursued that would increase access. Four major projects are currently planned that have a combined capacity of 326,000 b/d by early 2016 (Table 3.5).

In 2013, California refineries imported 786,000 b/d of crude oil from foreign sources (Figure 3.13). Almost two-thirds of these imports were sourced from Saudi Arabia (27 per cent); Ecuador (19 per cent); and Iraq (18 per cent). Canada accounted for only 5 per cent.

Figure 3.13 2013 PADD V (California): Foreign Sourced Supply by Type and Domestic Crude Oil



* Includes small volumes of Medium Sweet
Source: EIA and California Energy Commission

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Table 3.5 Summary of Rail Offloading Terminals in Western Canada and PADD V

Company	Location	Current Capacity (thousand b/d)	Scheduled In-Service	Description
Western Canada				
Chevron (refinery)	Burnaby, B.C.	8	Operating since 2013	
Tesoro/Savage	Port of Vancouver, B.C.	120 (expandable to 280)	2017	Applied for permits
Western Canada capacity subtotal		**8,000 b/d; potential for additional 120,000 b/d**		
Washington				
Shell (refinery)	Anacortes, WA	50	?	Applied for permits
Tesoro (refinery)	Anacortes, WA	50	Operating since 2012	
BP (refinery)	Cherry Point/Blaine, WA	60	Q3 2014	In construction
Phillips 66 (refinery)	Ferndale, WA	small volumes Expansion to 30	Operating Dec 2014	Currently receiving manifest trains; applied for permits for expansion
US Oil (refinery)	Tacoma, WA	?	Operating since 2012	Unit train capable
US Development Group	Grays Harbour, WA	50	2016	Applied for permits
Westway	Grays Harbour, WA	27	Q1 2015	Applied for permits
Imperium Renewables	Grays Harbour, WA	?	?	Applied for permits; would accept other products besides crude oil
Global Partners of Massachusetts	Port Westward/ Calskanie, WA	65 (expandable to 130)	Operating since Q4 2012	24 trains per month; expandable to 50
Washington capacity subtotal		**115,000 b/d; potential for additional 217,000 b/d**		
California				
Alon USA	Bakersfield, CA	manifest; Expansion to 150	Operating Q4 2015	Heavy and light crude oil capacity
Plains All American	Bakersfield, CA	65	Q1 2015	
Valero (refinery)	Benicia, CA	70	Q1 2015	western Cdn crude + US
Phillips 66 (refinery)	Santa Maria, CA	41	Q1 2016	
California capacity subtotal		**manifest trains; potential for additional 326,000 b/d**		
TOTAL		**123,000 b/d; potential for additional 663,000 b/d**		

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Recent surveys from the U.S. Energy Information Administration have indicated that 15.4 billion barrels of oil remain that could be technically recovered in California. This is 64 per cent of the total recoverable shale oil in the U.S., so the potential of California unconventional oil is enormous; but there is still a lot to be learned before these shale plays can become commercial. Plays such as the Monterey and the Kreyenhagen have yet to be properly assessed, the efficiency of regulatory compliance still has to be improved and appropriate stimulation techniques need to be identified. If these issues are resolved, California could undergo an unconventional oil renaissance similar to that of Texas.

3.3 International

There is growing interest in Canada's crude oil suppy from both Europe and Asia. It was reported in May 2014 that the first shipment of oil sands crude oil was transported to Spain to be processed at refineries in Spain. Asia is the world's fastest growing energy market. New refineries with heavy oil processing capacity are being built in Asia. In contrast, demand for oil in North America is stable and perhaps declining. Table 3.6 shows oil demand from 2011 to 2014 in major Asian markets.

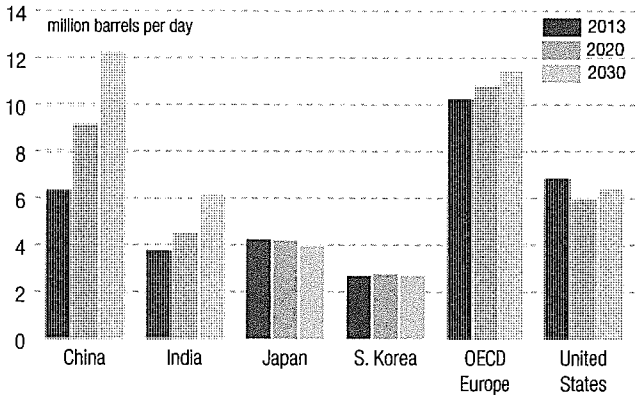
Table 3.6 **Total Oil Demand in Major Asian Countries**

million b/d	2011	2012	2013	2014
China	9.32	9.83	10.10	10.45
India	3.20	3.35	3.37	3.46
Japan	4.47	4.73	4.56	4.41
Korea	2.26	2.30	2.31	2.31

Source: IEA Oil Market Report, April 2014

Figure 3.14 shows the changing global import needs.

Figure 3.14 Global Net Oil Imports: 2013 to 2030



Source: EIA 2014 Annual Energy Outlook

3.4 Markets Summary

The anticipated growth in western Canadian crude oil production could potentially be absorbed by demand from a number of market regions subject to development in the North America transportation infrastructure.

The U.S. Gulf Coast is a target market of considerable size and is particularly suitable for supplies from Western Canada given the heavy oil processing capacity of the refineries located in the region. Eastern PADD II is currently the largest market for western Canadian crude oil and could process over 400,000 b/d of additional volumes by 2020. Refineries in Eastern Canada and PADD I have also indicated that they could potentially process double the current deliveries of western Canadian crude oil. The development of new rail infrastructure is planned in both PADD I and PADD V, some of which will have the ability to offload heavy crude oil. California refineries are configured to process a significant portion of heavy and medium sour crude oil. With the decline of Alaskan production, one of the major traditional crude sources of supply to California refineries, producers from Western Canada could deliver supplemental supplies via rail. Canadian producers are also focusing on opportunities to reach non-U.S., global markets such as China, whose net oil imports are forecast to grow by almost 3 million b/d by 2020.

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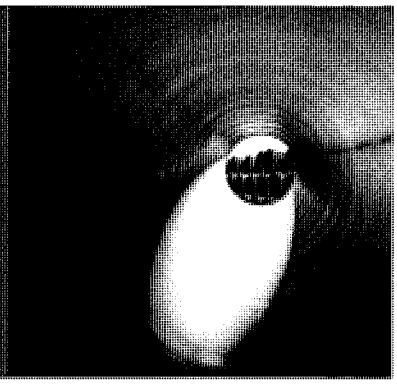
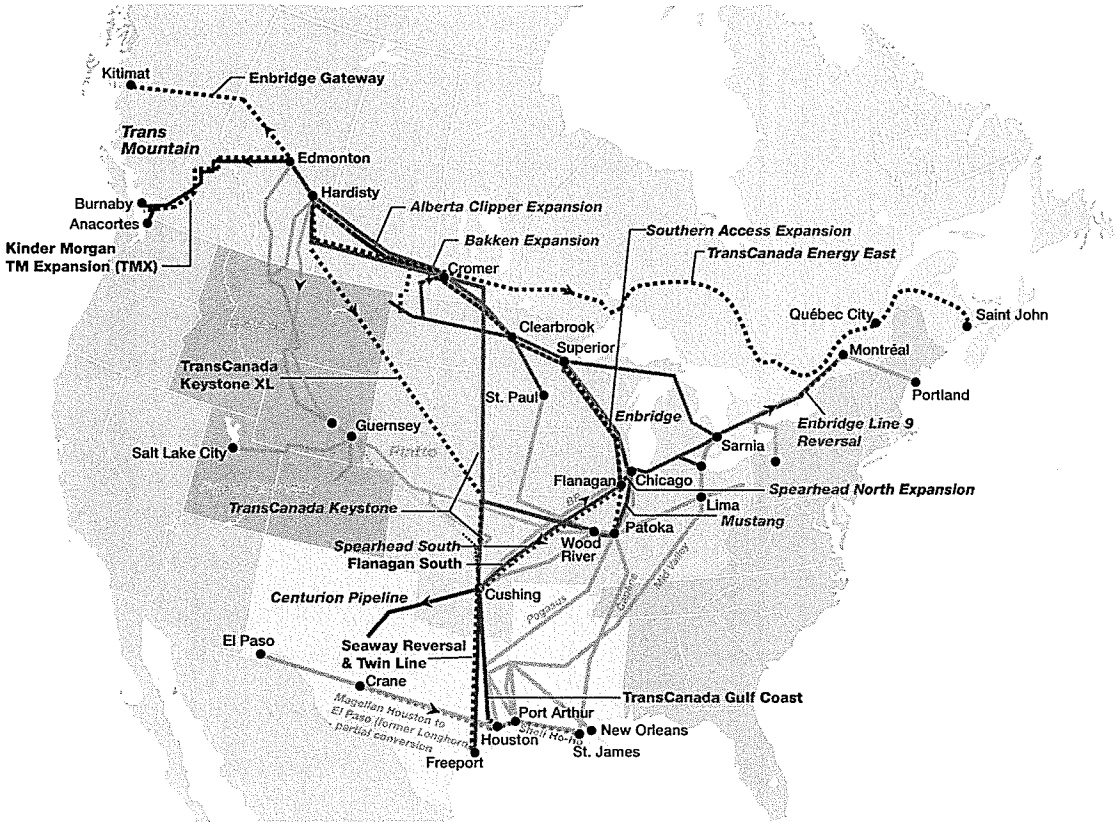
4 | TRANSPORTATION



The growing supply of crude oil from Western Canada is rapidly filling the existing pipeline capacity and extended timelines for regulatory approvals combined with other uncertainties have affected the evolution of the transportation network. Other forms of transport, such as railways, barges and marine tankers are quickly becoming additional means to distribute increasing volumes of western Canadian crude oil to markets throughout North America and beyond. The existing pipeline infrastructure and the proposed pipeline projects, however, will continue to provide essential take away capacity from the Western Canada Sedimentary Basin (WCSB) to all key markets. There are a number of pipeline projects in the regulatory process or being considered that could deliver large volumes to the East Coast, West Coast, U.S. Gulf Coast and offshore (Figure 4.1).

Figure 4.1 Canadian & U.S. Crude Oil Pipelines - All Proposals



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4.1 Existing Crude Oil Pipelines Exiting Western Canada

There are four major pipelines that move western Canadian crude out of the WCSB. Both the Enbridge Mainline pipeline and the Kinder Morgan Trans Mountain pipeline originate at Edmonton, Alberta. The Spectra Express pipeline and the TransCanada Keystone pipeline originate at Hardisty, Alberta. Together, these pipelines provide about 3.7 million b/d of capacity out of Western Canada. In addition, a number of proposals have been announced that could increase this capacity during the next five years (Table 4.1). Currently capacity is tight given growing production volumes. In addition, operational constraints can and have reduced available capacity to below nameplate capacity.

Table 4.1 Major Existing & Proposed Crude Oil Pipelines Exiting the WCSB

Pipeline	Capacity (thousand b/d)	Target In-Service
Enbridge Mainline	2,500	Operating since 1950
Enbridge Alberta Clipper Expansion	+350	Q3 2015
Kinder Morgan Trans Mountain	300	Operating since 1953
Trans Mountain Expansion	+590	Q4 2017
Spectra Express *downstream Platte operating since 1952	280	Operating since 1997*
TransCanada Keystone	591	Operating since 2010
TransCanada Keystone XL **assuming approval obtained by end 2014	+830	2017**
Enbridge Northern Gateway	+525	Q3 2018
TransCanada Energy East	+1,100	Q4 2018
Total Existing Capacity		**3,671**
Total Proposed Additional Capacity		**+3,395**

The next sections describe the existing pipeline projects. The proposed projects are discussed in the subsequent sections and are categorized by the destination markets.

4.1.1 Enbridge Mainline

The Enbridge Mainline consists of numerous lines which deliver light and heavy crude oil as well as refined products from Western Canada, Montana and North Dakota to markets in Western Canada, the U.S. Midwest and Ontario. The Mainline connects with a number of pipelines: Line 9 at Sarnia, Ontario; the Minnesota Pipeline at Clearbrook, Minnesota; Spearhead South and Flanagan South at Flanagan, Illinois; Chicap at Patoka, Illinois; Mustang at Chicago, Illinois and Toledo at Stockbridge, Michigan. The annual average receipt capacity from Western Canada into the Mainline system is about 2.5 million b/d. However, the effective capacity is slightly less due to operational pressure restrictions on certain lines and physical constraints at terminals on the system.

There is also some U.S. production which enters the Enbridge Mainline and competes for capacity on the pipeline and in turn reduces the available capacity to transport crude oil from Western Canada. The Enbridge North Dakota pipeline originates at Plentywood, Montana and ends at Clearbrook, Minnesota. It has a current capacity of 210,000 b/d which serves local markets and markets further east. Some U.S. crude oil production from the Bakken formation currently enters the Enbridge Mainline system at Clearbrook, Minnesota.

In response to significant growth in North Dakota and Montana, Enbridge is proposing an expansion of its North Dakota system. The project known as Sandpiper would include: a new 24-inch diameter pipeline from Beaver Lodge, North Dakota to Clearbrook, Minnesota with an incremental capacity of 225,000 b/d and a new 30-inch diameter pipeline from Clearbrook, Minnesota to Superior, Wisconsin with an initial capacity of 375,000 b/d. As part of the project scope, Enbridge would relocate the interconnection of the Enbridge North Dakota pipeline to the Lakehead System from Clearbrook, Minnesota. As a result, about 375,000 b/d of Bakken crude would enter the Enbridge Mainline at Superior, Wisconsin instead. The target in-service date for this project is March 2016.

The Enbridge Bakken Expansion project from Berthold, North Dakota to Cromer, Manitoba was put in service in March 2013. It provides 145,000 b/d of capacity to move U.S. Bakken crude into the Mainline destined for markets in the U.S. Midwest, Midcontinent and Eastern Canada.

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Enbridge Mainline Projects

Enbridge has announced that it will be undertaking a $7 billion project to replace its Line 3 pipeline which currently transports light crude oil from Edmonton, Alberta to Superior, Wisconsin. The new line is scheduled to be in service in the second half of 2017.

Enbridge has planned two major expansions for its Mainline which will allow western Canadian crude to reach existing markets in the Midwest and Ontario and new markets in the U.S. Gulf Coast.

Enbridge plans to expand the Alberta Clipper pipeline by 350,000 b/d in Q3 2015 through the addition of new pumps and station upgrades. The Alberta Clipper is a 36-inch diameter pipeline which extends from Hardisty, Alberta to Superior, Wisconsin and has a current capacity of 450,000 b/d. Upon completion of the expansion, the Alberta Clipper line will have reached its ultimate designed capacity of 800,000 b/d.

The Southern Access Pipeline is part of the Lakehead System (U.S. Mainline) and runs from Superior, Wisconsin to Flanagan, Illinois. The current capacity is 400,000 b/d. Enbridge has announced plans to expand the line by 160,000 b/d in Q3 2014. As part of its Light Oil Market Access program, Enbridge plans to increase capacity on the line by an additional 640,000 b/d in Q3 2015 through the addition of pumping stations. Upon completion of these expansions, the Southern Access pipeline will have reached its ultimate designed capacity of 1.2 million b/d.

4.1.2 Spectra Express-Platte

The Express Pipeline is a 24-inch diameter pipeline that originates at Hardisty, Alberta and terminates at the Casper, Wyoming facilities on the Platte Pipeline. The pipeline capacity on Express is 280,000 b/d but the ability to move crude on it is limited due to insufficient downstream capacity on the Platte pipeline. However, recent rail connections have helped to increase throughput capacity. Spectra held a successful Open Season to determine new interest in contracted capacity on Express from June 5 to August 9, 2013. Contracted capacity increased from 119,000 b/d to 225,000 b/d. The contract lengths range from 1.5 years to over 11 years. The first contract commenced in October 2013 while the remaining contracts will be phased in over two years.

The Platte Pipeline which is a 20-inch diameter pipeline moves crude oil from Western Canada, the Rockies (PADD IV), including the Bakken play area to refineries in the Midwest (PADD II). It runs from Casper, Wyoming to Wood River, Illinois. The capacity on the pipeline ranges from 164,000 b/d in Wyoming to 145,000 b/d in Illinois.

4.1.3 Kinder Morgan Trans Mountain

The Trans Mountain system is currently the only crude oil pipeline to Canada's West Coast. It originates at Edmonton, Alberta, delivering both crude oil and petroleum products, to Washington and to points in British Columbia, including the Westridge marine terminal located at Burnaby. From the marine terminal, crude oil is loaded onto vessels for offshore exports destined to California, the U.S. Gulf Coast and Asia.

The current capacity on the pipeline system is 300,000 b/d (assuming 20 per cent of the volumes being transported is heavy crude oil). Of the total capacity, 221,000 b/d is allocated to refineries with connections in British Columbia and Washington State and 79,000 b/d is allocated to the Westridge terminal for marine exports. Of the capacity designated to the marine terminal, 54,000 b/d or 68 per cent is underpinned by firm contracts and the remainder is available for spot shipments. Demand for access to this pipeline has been high and as such the nominations for service on this pipeline have been apportioned since late 2010.

4.1.4 TransCanada Keystone

The Keystone pipeline system originates at Hardisty, Alberta and connects to Steele City, Nebraska. From this juncture crude oil can be transported east to terminals in Wood River and Patoka, Illinois or south to Cushing, Oklahoma. The pipeline system can deliver a total of 590,000 b/d with each destination capable of taking this maximum capacity if shippers so elect. The pipeline started operations in June 2010 to serve the Wood River/ Patoka markets while the Cushing extension came online in February 2011. About 530,000 b/d of capacity is contracted for an average of 18 years.

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4.2 New Regional Infrastructure Projects in Western Canada

The major pipelines which move western Canadian crude out of the basin are investing significant capital in regional pipeline infrastructure to move incremental production to markets. The upstream expansions into Hardisty, Alberta could feed the Enbridge Mainline, Keystone, Keystone XL and the proposed TransCanada Energy East Pipeline into Eastern Canada.

4.2.1 Enbridge - Alberta Regional Pipeline

Enbridge - Edmonton to Hardisty

Enbridge is proposing to build a 36-inch diameter pipeline from Edmonton to Hardisty with a capacity of 800,000 b/d. The project includes five new tanks with a total capacity of 2.75 million barrels and terminal facilities at the Edmonton South terminal. The estimated cost is $1.8 billion. The target in-service Q2 2015.

4.2.2 TransCanada - Alberta Regional Pipelines

Heartland Pipeline and Terminal

TransCanada is proposing a 36-inch diameter pipeline from the Heartland region to Hardisty, Alberta, which is the starting point of its Keystone pipeline system. Heartland is an industrial area north of Edmonton, Alberta. The initial capacity would be 500,000 b/d but the pipeline could be expanded to 900,000 b/d. At Hardisty, Alberta the pipeline would have connections to Keystone, Keystone XL and Energy East. In the Heartland region, there will be up to 1.9 million barrels of tank capacity available. Regulatory approvals are expected in Q3 2014 while the target in-service date for the Heartland pipeline is 2016.

Grand Rapids Pipeline Project

TransCanada in partnership with Phoenix Energy Holdings Limited (Phoenix) is proposing to develop the Grand Rapids Pipeline in Northern Alberta. Each party will own 50 per cent of the proposed pipeline system. The project includes both a crude oil line and a diluent line between the producing area northwest of Fort McMurray and Heartland. The system could move up to 900,000 b/d of bitumen blend and up to 330,000 b/d of diluent. The crude oil pipeline is targeted to be in service by mid-2015 with the complete project targeted for in-service in 2017. TransCanada will operate the pipeline and Phoenix has entered into a long-term commitment to ship crude oil and diluent on the pipeline system.

4.3 Oil Pipelines to the U.S. Midwest

The U.S. Midwest is the largest market for western Canadian crude oil. The key market hubs in this region are located at Wood River and Patoka in Illinois and at Cushing, Oklahoma. Table 4.2 summarizes the pipelines which deliver Canadian crude oil to the Midwest.

4.3.1 Spectra Express-Platte

See Section 4.1.2.

4.3.2 TransCanada Keystone

See Section 4.1.4.

4.3.3 Southern Access Extension

Enbridge is proposing an extension to its Southern Access line which would run from Flanagan, Illinois to Patoka, Illinois. The proposed extension would be a 24-inch diameter pipeline with an initial capacity of 300,000 b/d. The pipeline is targeted to be in-service date by mid 2015.

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4.3.4 Enbridge Line 6B

As part of Enbridge's Eastern Access Phase 1 program, the segment of the 36-inch diameter Line 6B will be replaced from Griffith, Illinois to Stockbridge, Michigan in Q2 2014. This would increase capacity from 240,000 b/d to 500,000 b/d. Subsequently in Q3 2014, with Phase 2 of the program, the remaining segment from Stockbridge, Michigan to the U.S./Canada border will also be replaced and yield a corresponding increase in capacity.

As part of its Light Oil market access program, Enbridge is proposing to increase capacity of the Line 6B between Griffith, Illinois and Stockbridge, Michigan from 500,000 b/d to 570,000 b/d. The target in-service date is Q1 2016.

4.3.5 Minnesota Pipeline System

The Minnesota Pipeline system runs from Clearbrook, Minnesota to the Twin Cities. It is operated by Koch Pipeline Company. The pipeline delivers crude to the Northern Tier refinery in St. Paul Park and the Pine Bend refinery owned by Flint Hills in Rosemont. The system has a current capacity of 465,000 b/d that can be expanded to 650,000 b/d.

4.3.6 Spearhead

The Spearhead Pipeline receives crude oil from the Enbridge Mainline and originates at Flanagan, Illinois. From there, crude oil can be transported to Griffith, Indiana via Spearhead North (also referred to as Line 62) or to Cushing, Oklahoma on Spearhead South (also referred to as Line 55). The capacity on Spearhead North was recently expanded to 235,000 b/d. As part of its Light Oil Market Access project, Enbridge is considering a twin of the Spearhead North line along the existing pipeline which would provide an incremental capacity of 570,000 b/d by Q3 2015.

4.3.7 Enbridge Toledo Pipeline Expansion

Enbridge operates a pipeline that connects with the Mainline near Stockbridge, Michigan and extends east and south, terminating near Romulus, Michigan. This 20-inch diameter pipeline, known as Line 79, has been operating since May 2013 and has a capacity of 80,000 b/d. Line 17 is a 16-inch diameter pipeline that extends from Stockbridge, Michigan to Toledo, Ohio and has a capacity of 100,000 b/d. With these two pipelines, a total capacity of 180,000 b/d is now available to satisfy refineries in Toledo, Ohio and Detroit, Michigan.

Table 4.2 Summary of Crude Oil Pipelines to the U.S. Midwest

Pipeline	Originating Point	Destination	Status	Capacity (thousand b/d)
Minnesota Pipeline	Clearbrook, MN	Minnesota refineries	Operating	465
Enbridge Mainline	Superior, WI	various delivery points via L5, L6, L14/64,	Operating	1,476
Southern Access	Superior, WI	Flanagan, IL	Operating	400
Southern Access Expansion			Proposed - Q3 2014	+160
Southern Access Expansion			Proposed - Q3 2015	+640
Enbridge Spearhead North	Flanagan, IL	Chicago, IL	Operating	235
Enbridge Spearhead North Twin	Flanagan, IL	Chicago, IL	Proposed - Q3 2015	+570
Enbridge Spearhead South	Flanagan, IL	Cushing, OK	Operating	193
Enbridge Flanagan South	Flanagan, IL	Cushing, OK	Proposed - Q3 2014	+585
Enbridge Mustang	Lockport, IL	Patoka, IL	Operating	100
Spectra Express-Platte	Guernsey, WY	Wood River, IL	Operating	145
TransCanada Keystone	Hardisty, AB to Steel City, NE	east to Patoka, IL / Wood River, IL or south to Cushing, OK	Operating	591

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4.4 Oil Pipelines to the U.S. Gulf Coast

The U.S. Gulf Coast represents the most significant market growth opportunity for heavy Canadian crude oil supplies in North America. Refineries in the region rely on domestic supply and imports primarily from Mexico, Saudi Arabia, and Venezuela to meet their requirements.

Given the significant increase in western Canadian and Bakken production and a lack of takeaway capacity at Cushing, Oklahoma, two pipeline projects are designed to bring significant supply from the Midwest to the U.S. Gulf Coast (Table 4.3).

4.4.1 Enbridge Flanagan South

The Flanagan South Pipeline is a proposed 36-inch diameter pipeline that will have an initial capacity of 585,000 b/d in heavy crude oil service. The pipeline is essentially a twin pipeline to the existing Enbridge Spearhead South Pipeline, which originates at Flanagan, Illinois and terminates at Cushing, Oklahoma. The pipeline is currently under construction and is targeted to be in-service in Q3 2014.

4.4.2 Enbridge/Enterprise Seaway

The Seaway Pipeline is jointly owned by Enbridge Inc. and Enterprise Products Partners L.P. The pipeline transports crude oil from Cushing, Oklahoma to the U.S. Gulf Coast. The capacity on the pipeline was increased to 400,000 b/d (light crude equivalent) in 2013. Enbridge and Enterprise have secured sufficient commercial support to build a new twin line alongside the existing Seaway pipeline. The project scope includes laterals from Jones Creek to the Echo terminal that is connected to the Houston refinery complex and from Echo to the Port Arthur/Beaumont refinery complex.

The initial capacity on the new Seaway twin line will be 450,000 b/d. Once completed, the Seaway pipeline system would have a total capacity of 850,000 b/d. The target in-service date for the Seaway twin is Q2 2014 while the lateral from Jones Creek to Port Arthur/Beaumont is scheduled for Q3 2014.

4.4.3 TransCanada Keystone XL

Over five years ago, TransCanada first applied for a Presidential Permit to build the Keystone XL (KXL) pipeline, a proposed pipeline from Hardisty, Alberta to Steele City, Nebraska. Since then, a revised route was submitted and multiple studies have been completed indicating that the project will not have a significant impact to the environment and will provide sizeable economic benefits. A Final Supplemental Environmental Impact Statement was released on January 31, 2014. On April 18, 2014, the U.S. Department of State announced that there will be a further delay to complete the review process. Should the project be approved, it would provide 830,000 b/d of capacity.

The Bakken Marketlink project from Baker, Montana, to Cushing, Oklahoma is designed to allow receipts of up to 100,000 b/d of crude oil from the Williston Basin, using capacity on the northern leg of Keystone XL. The Bakken Marketlink project is underpinned by 65,000 b/d of firm commitments.

Keystone XL and the Bakken Marketlink Project are expected to be in service two years following the receipt of a Presidential Permit.

Table 4.3 Summary of Crude Oil Pipelines to the U.S. Gulf Coast

Pipeline	Originating Point	Destination	Status	Capacity (thousand b/d)
Seaway	Cushing, OK	Freeport, TX	Operating	400
Seaway Twin Line			Proposed - Q2 2014	+450
TransCanada Keystone XL	Hardisty, AB	Steele City, NE	Proposed - 2017	+830
TransCanada Cushing Extension	*Steele City, NE*	*Cushing, OK*	*Operating since Feb 2011*	
TransCanada Gulf Coast	*Cushing, OK*	*Nederland, TX*	*Operating since Jan 2014*	*700*
			Proposed - TBD	*+130*

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4.4.4 TransCanada Gulf Coast

TransCanada's Gulf Coast Project started delivering crude oil on January 22, 2014. The 36-inch diameter pipeline is part of the Keystone Pipeline system and provides capacity from Cushing, Oklahoma to Port Arthur and Houston, Texas. During the first year of operations, the capacity is expected to average 520,000 b/d before ramping up to 700,000 b/d.

The Keystone Pipeline System which includes Keystone, the Gulf Coast Project and the Keystone XL would provide 1.4 million b/d of capacity of which 1.1 million b/d is underpinned by long term contracts.

4.5 Oil Pipelines to the West Coast of Canada

The Kinder Morgan Trans Mountain pipeline is currently the only pipeline transporting crude oil from Alberta to the West Coast. There is significant interest in building new pipeline capacity to the West Coast. Once crude oil reaches the coast, it can be offloaded onto crude carriers to reach markets such as California, the U.S. Gulf Coast and Asia. Table 4.4 summarizes the Enbridge Northern Gateway and Kinder Morgan's pipeline proposals to the West Coast.

4.5.1 Enbridge Northern Gateway

The Northern Gateway Project includes a new 36-inch diameter crude oil pipeline with an initial capacity of 525,000 b/d from Bruderheim, Alberta (near Edmonton, Alberta) to Kitimat, British Columbia. The National Energy Board has issued a decision recommending that the project be approved and a final decision on whether the project will be approved is expected to be made by the Governor in Council in June 2014. The target in-service date for the project is Q3 2018.

4.5.2 Kinder Morgan Trans Mountain Expansion

On December 16, 2013, Kinder Morgan submitted an application to the National Energy Board (NEB) for an expansion to its existing Trans Mountain pipeline (see section 4.1.3). The capital cost for the Trans Mountain Pipeline Expansion project (TMX) is estimated at $5.5 billion. If approved and constructed, the expanded system would be comprised of two parallel pipelines. Line 1 would consist of existing pipeline segments and could transport 350,000 b/d of refined petroleum products and light crude or potentially heavy crude oil, but at a loss of capacity. The proposed Line 2 would have a capacity of 540,000 b/d and would be allocated to the transportation of heavy crude oil. This new pipeline and configuration set-up would, in effect, add 590,000 b/d to the existing system for a total capacity of 890,000 b/d.

The expansion is underpinned by contracts totaling 707,500 b/d under 15 and 20-year commitments from 13 shippers. If approval was recommended in a NEB decision by July 2015, and final approval granted by Governor in Council three months later, then construction could start in late 2015 with the proposed expanded system in operation in December 2017.

4.6 Oil Pipelines to Eastern Canada

In 2013, refineries in Eastern Canada imported 642,000 b/d of crude from foreign sources. There is currently no pipeline infrastructure that connects western Canadian crude oil supply to markets in Atlantic Canada. This market represents a significant opportunity for western Canadian producers. Table 4.5 lists the pipeline proposals that could be conduits to this market.

Table 4.4 Summary of Crude Oil Pipelines to the West Coast of Canada

Pipeline	Originating Point	Destination	Status	Capacity (thousand b/d)
Kinder Morgan Trans Mountain	Edmonton , AB	Burnaby, BC	Operating	300
Kinder Morgan Trans Mountain Expansion			Proposed - Q4 2017	+590
Enbridge Northern Gateway	Bruderheim, AB	Kitimat, BC	Proposed - Q3 2018	+525

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Table 4.5 Summary of Crude Oil Pipelines to Eastern Canada

Pipeline	Originating Point	Destination	Status	Capacity (thousand b/d)
Enbridge Line 9 re-Reversal	Sarnia, ON	Montréal, QC	Proposed	+300
9A	Sarnia, ON	North Westover, ON	Operating since Aug 2013	
9B	North Westover, ON	Montréal, QC	Q3 2014	
TransCanada Energy East	Hardisty, AB	Québec City, QC / St. John, NB	Proposed - Q4 2018	+1,100

4.6.1 Enbridge Line 9 Reversal

Enbridge Line 9 is a 30-inch diameter crude oil pipeline that recently ran westward from Montréal, Québec to Sarnia, Ontario. The 9A portion of the pipeline started operating in reversed flow, transporting crude oil east from Sarnia, Ontario to North Westover, Ontario in August 2013.

In March 2014, Enbridge received approval to reverse the remaining portion, also known as Line 9B to eventually flow east from North Westover, Ontario to Montréal, Québec and to increase the capacity by 60,000 b/d from 240,000 b/d. The target in-service date for the Line 9B reversal is Q4 2014.

4.6.2 TransCanada Energy East

The TransCanada Energy East Pipeline Project includes the conversion of a natural gas pipeline to oil service and new pipeline segments to provide transportation service from Hardisty, Alberta and Moosomin, Saskatchewan to delivery points in Québec and New Brunswick. The delivery points include three existing refineries in Eastern Canada and two marine terminals, one at Cacouna, Québec and one at Saint John, New Brunswick to allow for exports to international markets. The proposed pipeline would have a capacity of 1.1 million b/d, of which 900,000 b/d is underpinned by firm contracts. The scheduled in-service date for the project is Q4 2018.

4.7 Diluent Pipelines

Table 4.6 provides a summary of projects which aim to bring diluent supply which may be required to satisfying growing supply of heavy oil from Western Canada.

4.7.1 Enbridge Southern Lights

The Southern Lights pipeline which runs from Manhattan, Illinois (near Chicago) to Edmonton, Alberta has been moving diluent since 2010. The current capacity of the pipeline is 180,000 b/d. About 43 per cent (77,000 b/d) of this capacity is allocated to committed shippers.

Enbridge offered another 50,000 b/d of capacity on the pipeline for commitments from shippers through an Open Season held from January 28 to February 27, 2013. Potential shippers were given a choice of five available start dates between July 1, 2013 and July 1, 2014. All contracts would expire on June 30, 2025, with an option to extend the term for an additional 15 years. The minimum volume commitment will be 5,000 b/d. Due to the success of the Open Season, Enbridge is developing a future expansion of the Southern Lights system to increase capacity to 275,000 b/d through the use of additional horse power and drag reducing agents.

Table 4.6 Summary of Diluent Pipelines

Pipeline	Originating Point	Destination	Status	Capacity (thousand b/d)
Enbridge Southern Lights	Flanagan, IL	Edmonton, AB	Operating	180
Southern Lights Expansion			Proposed - TBD	+95
Enbridge Northern Gateway	Kitimat, BC	Bruderheim, AB	Proposed - Q3 2018	+193
Kinder Morgan Cochin Conversion	Kankakee County, IL	Fort Saskatchewan, AB	Proposed - Q3 2014	+95
TransCanada Grand Rapids	Heartland, AB	Fort McMurray, AB	Proposed - 2017	+330

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4.7.2 Enbridge Northern Gateway Diluent

As part of its Northern Gateway Project, Enbridge is proposing a diluent pipeline that would run from Kitimat, British Columbia to Bruderheim, Alberta. The proposed capacity of the pipeline is 193,000 b/d. A final decision on whether the project will be approved is expected to be made by the Governor in Council in June 2014. The target in-service date for the project is Q3 2018.

4.7.3 TransCanada Grand Rapids Diluent

As part of its Grand Rapids Pipeline, TransCanada is proposing a diluent line from the Heartland region of Alberta to Fort McMurray. The pipeline would have a capacity of 330,000 b/d in 2017 and anchor shipper commitments have been obtained. A regulatory application was filed with the provincial regulator in 2013.

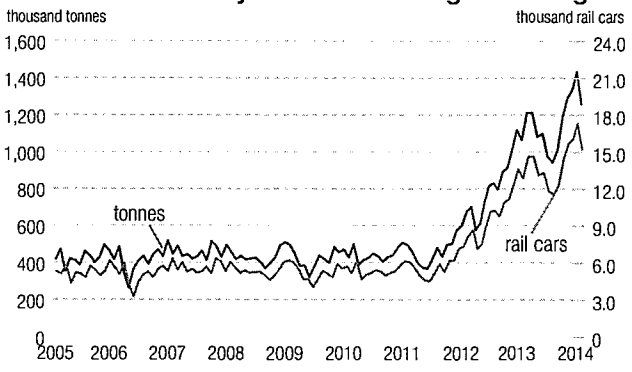
4.7.4 Kinder Morgan Cochin Reversal Project

Kinder Morgan announced on June 5, 2012 that it had completed a binding open season to reverse its Cochin propane and ethane-propane pipeline to carry 95,000 b/d of condensates from Illinois to terminals in Fort Saskatchewan, Alberta. Kinder Morgan has secured commitments for at least 10 years for 100,000 b/d of capacity during the open season. The reversal will help transport light condensate from the Eagle Ford shale and the U.S. Gulf Coast to the Canadian market. The pipeline is targeted to begin service on July 1, 2014. For a total cost of US$225 million, the project will link the Cochin pipeline with the Explorer products pipeline, which carries refined petroleum products from the U.S. Gulf Coast to the Midwest in Kankakee County, Illinois and reverse Cochin to move condensate northwest to Alberta.

4.8 Crude Oil by Rail

In recent years, rail transport of crude oil has grown to accommodate the rapid growth from new supply regions that quickly exceeded the available pipeline capacity to desirable markets. The number of Canadian rail tank car loadings of crude oil and petroleum products reached over 17,000 carloads in January 2014 (Figure 4.2).

Figure 4.2 Canadian Fuel Oil and Crude Petroleum Moved by Rail: Car Loadings & Tonnage



Source: Statistics Canada

Producer Benefits of Rail

- ***Speed to Market:*** *A unit train averages 28 km/hr. Getting oil to the refinery quickly means producers are paid sooner and refiners receive feedstock sooner.*
- ***Optionality/Flexibility:*** *There are already existing rail tracks in place to reach East Coast, West Coast and Gulf Coast markets in the U.S. Once on a rail tank car, crude oil can be delivered anywhere with an unloading facility.*
- ***Diluent:*** *Less or no diluent is required when transporting bitumen in rail tank cars, representing a significant cost savings in diluent costs. However, producers have continued to transport DilBit because raw bitumen can become too viscous as a result of cold temperatures en route which may lead to longer unloading times as the bitumen would then need to be heated to flowing temperatures.*
- ***Scalability:*** *Producers have the flexibility to adjust the volumes being shipped with manifest trains. Unit trains provide economies of scale but require larger volumes to be shipped. Manifest trains are individual cars or small groups of cars, and need to wait for additional cars to collect together before being shipped to one or multiple destinations. Unit trains are a group of rail tank cars, typically 70 to120 rail tank cars that move from one destination directly to another. New loop track unloading facilities are being standardized and are typically being built to accommodate 120 cars.*
- ***Product Integrity:*** *Commodity isolation in separate rail tank cars results in no loss of quality at destination. The crude oil loaded is not mixed with other grades of crude during transportation.*
- ***Low Capital requirements:*** *Typical costs to build unit train terminals range between $30 to $50 million with a capital payout of 5 years or less. unit. A train loading terminal can be constructed in about 12 months.*

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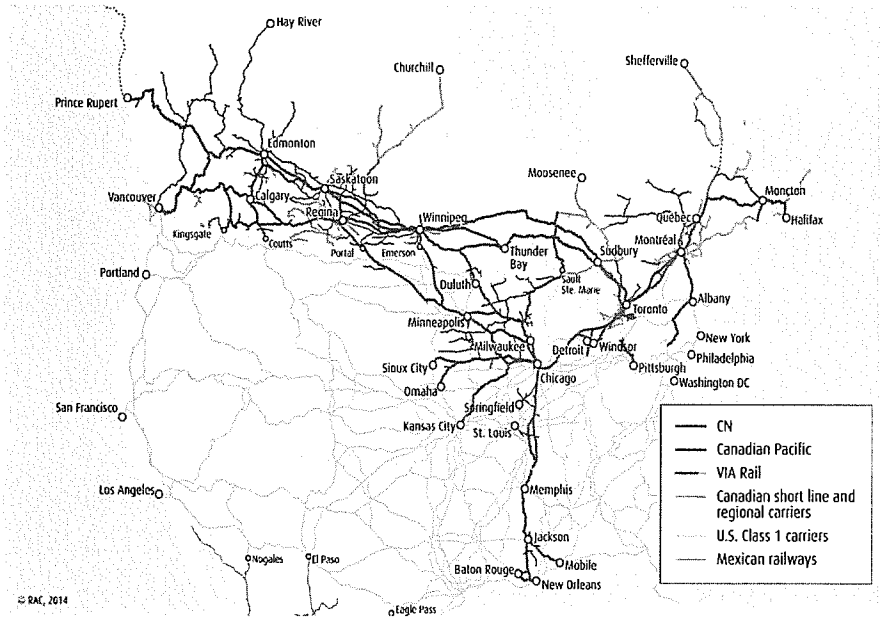
Figure 4.3 North American Rail Network



Rail Quick Facts

- Rail tank car capacity carrying light oil: 600 to 700 bbls
- Rail tank car capacity carrying heavy oil: 500 to 525 bbls
- RailBit and raw bitumen is transported in coiled and insulated rail tank cars to prevent solidifying in cold weather
- Unit train: 70 to 120 cars carrying only crude oil
- Manifest trains are mixed cargo trains delivering to different destinations
- Unit trains are used to carry one type of cargo from one location to another
- Economics for transport by rail improves with unit trains, however, unit train offloading capability is needed at destination

Source: Rail Association of Canada

Pipelines are the most efficient means of connecting large supply basins to large markets areas. However, in the absence of adequate capacity in Western Canada, rail transport is expected to continue to rise due to the protracted regulatory processes for new pipelines and other uncertainties. There can be long-term viability with this mode of transportation as there are also a number of benefits associated with this mode of transportation, including the flexibility to move to different markets to respond to demand (Figure 4.3).

Western Canada Loading Capacity

In Canada, with respect to crude oil, the rail industry is evolving from a manifest system, in which trains might have to make multiple stops to deliver different products, to a unit system, in which trains go directly from the point of origin to the point of destination. Most of the large scale facilities that can load a unit train will be moving heavy oil, DilBit, RailBit or raw (undiluted) bitumen. Unit trains are more efficient because the need for switching of rail tank cars in intermediate yards is eliminated, making the overall duration of a given trip much shorter.

The level of transportation of crude oil by rail in Canada was almost 200,000 b/d by the end of 2013. Several large unit train loading facilities have been announced for Western Canada that could be operational by the end of 2015. In addition, there is the potential for future additional phases to these projects that would add further to capacity.

At the beginning of 2013, the rail loading capacity originating in Western Canada was only about 180,000 b/d. As a result of a number of new facilities and minor expansions coming into service throughout 2013, the capacity has now increased to 300,000 b/d.

Figure 4.4 shows all the major existing and proposed rail terminals for uploading crude in Western Canada. By the end of 2015, western Canadian rail uploading capacity for crude oil is expected to exceed 1.0 million b/d. Several proposed facilities can be further expanded beyond the initial stated capacity so it is conceivable that rail capacity could be expandable to 1.4 million b/d.

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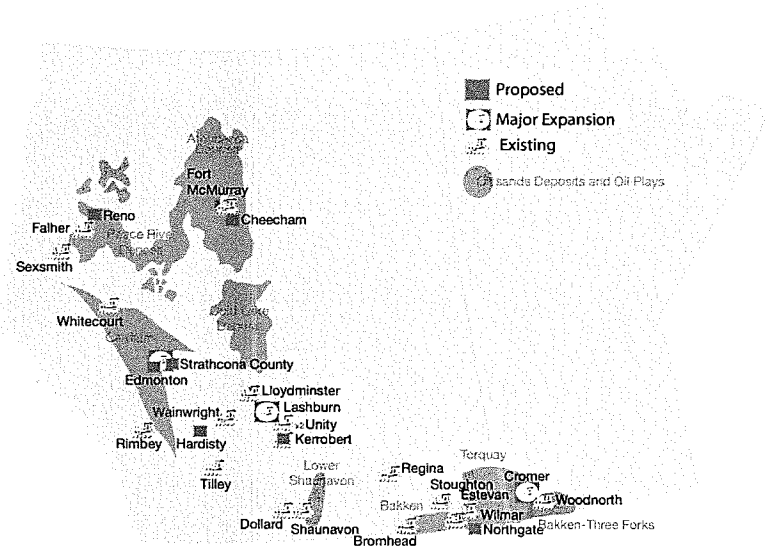
Figure 4.4 Rail Loading Terminals in Western Canada



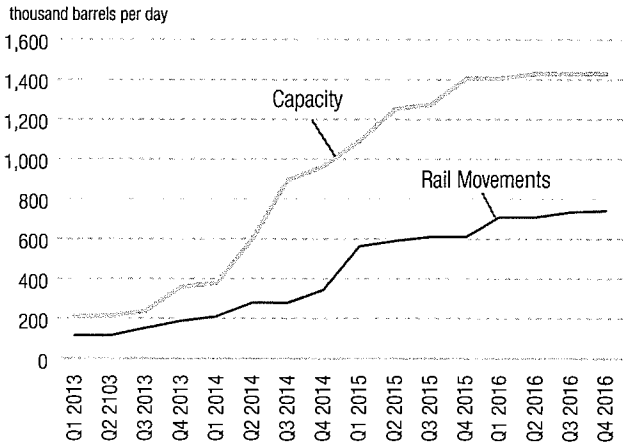
Crude by Rail Movements

Actual volumes of crude oil being moved by rail are generally lower than design capacity at loading facilities. However, it is important to note that the definition of capacity is not very standardized and there are a number of limiting factors on actual capacity that include: supply connections, system bottlenecks, operational inefficiencies, limited hours of operation, and ramp up time required to achieve full utilization.

CAPP forecasts crude oil volumes transported by rail will increase from about 200,000 b/d in late 2013 to around 700,000 b/d by 2016 (Figure 4.5). It is important to note that most of the large scale terminals are underpinned by long term take or pay contracts which should encourage utilization. Constraints on capacity include unloading time and weather. The load factor utilization should improve over time, however, particularly as producers and operators become more experienced with this mode of transportation. The schedule for future expansion phases of capacity is flexible and dependent on a number of factors including the timing of securing supply contracts for the facilities which may be influenced by the pace of pipeline expansion.

Major Announced Rail Uploading Terminals in Western Canada			
Operator	**Location**	**Expanded / Proposed Capacity** (thousand b/d)**	**Scheduled Startup**
ALBERTA			
Keyera/ Enbridge	Cheecham	32	Operating
Grizzly	Conklin	18	Q2 2014
Canexus	Bruderheim (near Edmonton)	100 +?	Operating; Expansion Q3 2014
Gibson	Edmonton	20 (expandable to 40)	Q3 2015
Keyera/Kinder Morgan	Edmonton	40 (expandable to 120)	Q3 2014 (currently in construction)
Pembina	Edmonton	40	Operating
Altex	Falher	20	Operating; expansion Q4 2014
Gibson/USDG	Hardisty	120 (expandable to 240)	Q2 2014
Altex	Lynton	20	Operating; Expansion Q4 2015
Altex	Reno	24	unknown
KinderMorgan /Imperial	Strathcona County	100 (expandable to 250)	Q4 2014 (currently in construction)
SASKATCHEWAN			
Crescent Point	Dollard	27	Operating; Expansion Q2 2014
TORQ Transloading	Kerrobert	168	Q3 2014
Altex	Lashburn	90	Operating; Expansion Q1 2015
TORQ Transloading	Lloydminister	22	Operating
Ceres Global	Northgate	35 (expandable to 70)	Q2 2014
Crescent Point	Stoughton	45	Operating
Altex	Unity	19	Operating
TORQ Transloading	Unity	36	Operating
MANITOBA			
Tundra	Cromer	60	Operating; Expansion Q2 2014
TOTAL	1.0 million b/d; further expandable to 1.4 million b/d		

Figure 4.5 Western Canada Uploading Capacity vs. Rail Movements



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Economics of Crude by Rail

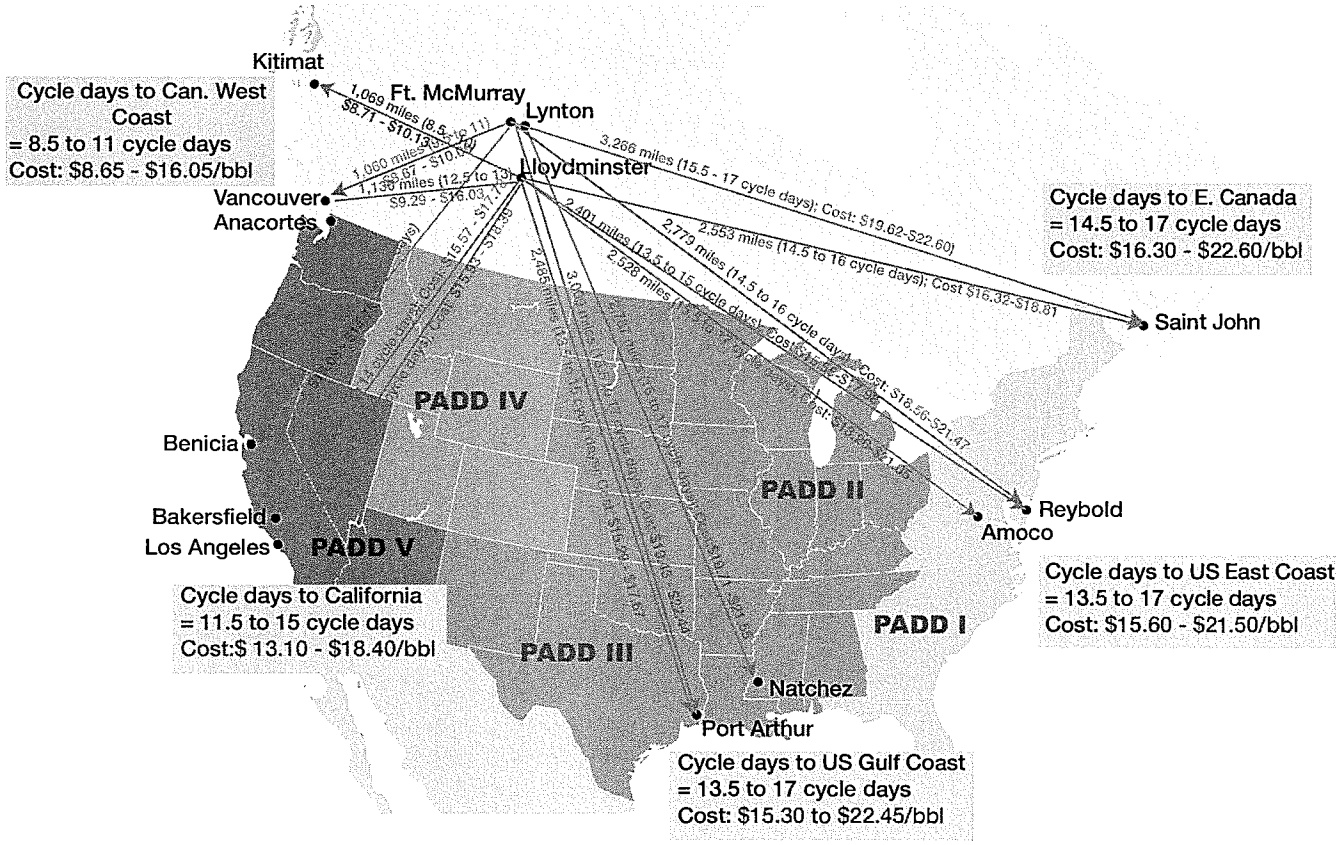
In general, the opportunity to ship by rail is greatest when the price differential between the market at a point of origin and the market price at the destination exceeds the transportation cost by rail. Recently, this has meant that the economic driver for crude by rail has been between land locked production and coastal markets where higher world oil prices can be accessed.

There are a number of factors which could impact the economics of shipping crude oil to market via rail. These include prices available in various markets that can all be accessed by rail and cost. The type of crude being moved is a key determinant of cost as the heavier the crude oil slate, the more rail tank cars are required to transport a given volume of crude. Heavy crude is typically transported in steam coiled and insulated cars in order to reduce the viscosity of the crude oil to facilitate the unloading process. The steam line and insulation also adds to the weight of the rail tank car and therefore limits the amount of the commodity that can be transported before meeting the tank car's weight limitation. In addition, more time is required for loading and unloading heavy crude which thereby adds to cycle times and, in turn increases cost.

A number of uncontrollable factors such as weather or mechanical issues, may also impact cycle times and affect producers' netbacks. The opportunity for diluent back haul can also be considered when evaluating the costs. The range is based on the movement of varying densities of the crude oil and the distance from markets. The actual costs for each component can fluctuate beyond the ranges shown due to changes to cycle times. Rail tank car leasing costs are negotiated and are subject to change depending on a number of factors, including the length of the lease.

Figure 4.6 shows the approximate cycle times and estimated cost to various key markets in Canada and the United States.

Figure 4.6 Rail Cycle Times and Estimated Cost* to Market



**All rates are estimates only. Actual rates could vary depending on the density of the crude which limits the volume per carload; weather and logistical factors that could increase cycle times. Trucking costs vary depending on density of crude and distance from loading/unloading terminal.*

Data source: Keystone XL Final Supplemental Environmental Impact Statement

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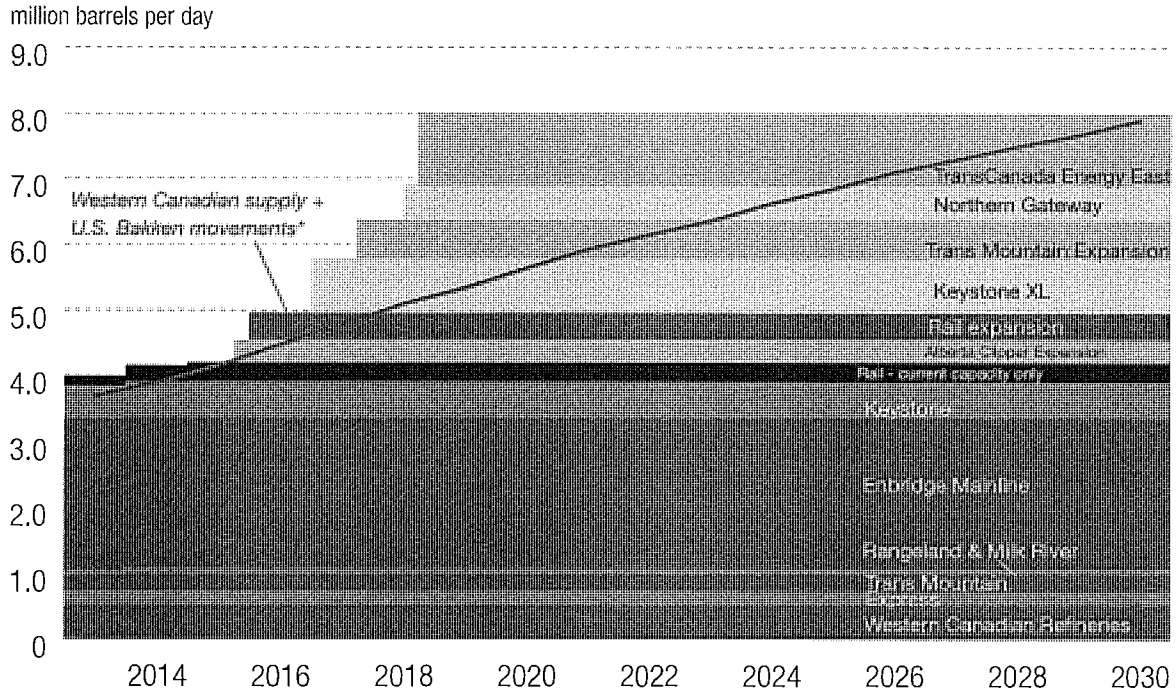
4.9 Transportation Summary

Access to new markets will be required to absorb the forecasted growth in supply from Western Canada. Pipelines are the preferred mode of transportation to move crude oil but the protracted regulatory processes has been a challenge. The Keystone XL Pipeline, which is intended to connect to the heavy crude oil processing refineries in the Gulf Coast, has seen significant delays. If approval can be obtained by the end of this year, however, then the pipeline could start operating in 2017. The Northern Gateway project, which connects to the West Coast market, has also been delayed slightly to Q3 2018.

Figure 4.7 shows the existing and proposed takeaway capacity exiting the WCSB versus forecasted supply movements. The forecasted supply movements were developed by coupling CAPP's latest supply forecast of western Canadian production with U.S. Bakken volumes that would utilize a portion of the pipeline capacity that exits Western Canada.

While pipelines will remain the dominant mode of transportation, this analysis shows that in the short to medium term, rail can provide the ability to access markets if there are constraints in available pipeline capacity. The role of rail will continue to evolve over the longer term providing producers with access to new markets and offering new transportation options (e.g. RailBit). The full extent of the development of rail transportation will hinge on the timing and size of additions to the pipeline infrastructure.

Figure 4.7 WCSB Takeaway Capacity vs. Supply Forecast



Refers to the portion of U.S. Bakken production that is also transported on the Canadian pipeline network. Capacity shown can be reduced by temporary operating and physical constraints.

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GLOSSARY

API Gravity	A specific gravity scale developed by the American Petroleum Institute (API) for measuring the relative density or viscosity of various petroleum liquids.
Barrel	A standard oil barrel is approximately equal to 35 Imperial gallons (42 U.S. gallons) or approximately 159 litres.
Bitumen	A heavy, viscous oil that must be processed extensively to convert it into a crude oil before it can be used by refineries to produce gasoline and other petroleum products.
Coker	The processing unit in which bitumen is cracked into lighter fractions and withdrawn to start the conversion of bitumen into upgraded crude oil.
Condensate	A mixture of mainly pentanes and heavier hydrocarbons. It may be gaseous in its reservoir state but is liquid at the conditions under which its volumes is measured or estimated.
Crude oil (Conventional)	A mixture of pentanes and heavier hydrocarbons that is recovered or is recoverable at a well from an underground reservoir. It is liquid at the conditions under which its volumes is measured or estimated and includes all other hydrocarbon mixtures so recovered or recoverable except raw gas, condensate, or bitumen.
Crude oil (heavy)	Crude oil is deemed, in this report, to be heavy crude oil if it has an API of 27° or less. No differentiation is made between sweet and sour crude oil that falls in the heavy category because heavy crude oil is generally sour.
Crude oil (medium)	Crude oil is deemed, in this report, to be medium crude oil if it has an API greater than 27° but less than 30°. No differentiation is made between sweet and sour crude oil that falls in the medium category because medium crude oil is generally sour.
Crude oil (synthetic)	A mixture of hydrocarbons, similar to crude oil, derived by upgrading bitumen from the oil sands.
Density	The mass of matter per unit volume.
DilBit	Bitumen that has been reduced in viscosity through addition of a diluent (or solvent) such as condensate or naphtha.
Diluent	Lighter viscosity petroleum products that are used to dilute bitumen for transportation in pipelines.
Extraction	A process unique to the oil sands industry, in which bitumen is separated from their source (oil sands).
Feedstock	In this report, feedstock refers to the raw material supplied to a refinery or oil sands upgrader.
Integrated mining project	A combined mining and upgrading operation where oil sands are mined from open pits. The bitumen is then separated from the sand and upgraded by a refining process.
***In Situ* recovery**	The process of recovering crude bitumen from oil sands by drilling.
Merchant upgrader	Processing facilities that are not linked to any specific extraction project but is designed to accept raw bitumen on a contract basis from producers.

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Oil	Condensate, crude oil, or a constituent of raw gas, condensate, or crude oil that is recovered in processing and is liquid at the conditions under which its volume is measured or estimated.
Oil sands	Refers to a mixture of sand and other rock materials containing crude bitumen or the crude bitumen contained in those sands.
Oil Sands Deposit	A natural reservoir containing or appearing to contain an accumulation of oil sands separated or appearing to be separated from any other such accumulation. The AER has designated three areas in Alberta as oil sands areas.
Oil Sands Heavy	In this report, Oil Sands Heavy includes upgraded heavy sour crude oil, and bitumen to which light oil fractions (i.e. diluent or upgraded crude oil) have been added in order to reduce its viscosity and density to meet pipeline specifications.
Open Season	A period of time designated by a pipeline company to determine shipper interest on a proposed project. Potential customers can indicate their interest/support by signing a transportation services agreement for capacity on the pipeline.
Pentanes Plus	A mixture mainly of pentanes and heavier hydrocarbons that ordinarily may contain some butanes and is obtained from the processing of raw gas, condensate or crude oil.
PADD	Petroleum Administration for Defense District that defines a market area for crude oil in the U.S.
Refined Petroleum Products	End products in the refining process (e.g. gasoline).
Specification	Defined properties of a crude oil or refined petroleum product.
SynBit	A blend of bitumen and synthetic crude oil that has similar properties to medium sour crude oil.
Train (Manifest)	Manifest trains carry multiple cargoes and make multiple stops. These are small group or single car load.
Train (Unit)	Unit trains carry a single cargo and deliver a single shipment to one destination, lowering the cost and shortening the trip.
Upgrading	The process that converts bitumen or heavy crude oil into a product with a lower density and viscosity.
West Texas Intermediate	WTI is a light sweet crude oil, produced in the United States, which is the benchmark grade of crude oil for North American price quotations.

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APPENDIX A
ACRONYMS, ABBREVIATIONS, UNITS AND CONVERSION FACTORS

Acronyms

API	American Petroleum Institute
AER	Alberta Energy Regulator
CAPP	Canadian Association of Petroleum Producers
EIA	Energy Information Administration
FERC	Federal Energy Regulatory Commission
IEA	International Energy Agency
NEB	National Energy Board
PADD	Petroleum Administration for Defense District
U.S.	United States
WCSB	Western Canada Sedimentary Basin
WTI	West Texas Intermediate

Canadian Provincial Abbreviations

AB	Alberta
BC	British Columbia
MB	Manitoba
NWT	Northwest Territories
ON	Ontario
QC	Québec
SK	Saskatchewan

Units

b/d	barrels per day

Conversion Factor

1 cubic metre = 6.293 barrels (oil)

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U.S. State Abbreviations

AL	Alabama
AK	Alaska
AZ	Arizona
AR	Arkansas
CA	California
CO	Colorado
CT	Connecticut
DE	Delaware
FL	Florida
GA	Georgia
ID	Idaho
IL	Illinois
IN	Indiana
IA	Iowa
KS	Kansas
KY	Kentucky
LA	Louisiana
ME	Maine
MD	Maryland
MA	Massachusetts
MI	Michigan
MN	Minnesota
MS	Mississippi
MO	Missouri
MT	Montana
NE	Nebraska
NV	Nevada
NH	New Hampshire
NJ	New Jersey
NM	New Mexico
NY	New York
NC	North Carolina
ND	North Dakota
OH	Ohio
OK	Oklahoma
OR	Oregon
PA	Pennsylvania
SC	South Carolina
SD	South Dakota
TN	Tennessee
TX	Texas
UT	Utah
VT	Vermont
VA	Virginia
VI	Virgin Islands
WA	Washington
WV	West Virginia
WI	Wisconsin
WY	Wyoming

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APPENDIX B.1

CAPP Canadian Crude Oil Production Forecast 2014 – 2030

thousand barrels per day	Actual	*Forecast*																
EASTERN CANADA	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Ontario	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Atlantic Provinces[1]	231	221	226	247	237	296	306	262	238	229	208	199	174	148	138	115	97	90
E. Canada Conventional	232	222	227	248	238	297	307	263	239	230	209	200	175	149	139	116	98	91
WESTERN CANADA	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Conventional Light & Medium																		
Alberta	430	459	480	486	487	491	500	514	527	538	550	561	575	589	602	615	627	639
B.C.	20	17	16	16	15	14	13	13	12	11	11	10	10	9	9	8	8	8
Saskatchewan [1,2]	229	242	261	262	263	265	269	271	274	279	285	289	292	296	302	305	308	313
Manitoba	51	51	51	48	46	45	44	43	43	42	41	40	39	39	38	37	36	36
N.W.T.	11	10	10	9	9	8	8	7	7	7	6	6	6	6	5	5	5	5
W. Canada Light & Medium	**741**	**779**	**818**	**821**	**820**	**824**	**835**	**849**	**862**	**877**	**893**	**907**	**921**	**938**	**956**	**970**	**984**	**1,000**
Conventional Heavy																		
Alberta Conv. Heavy	153	155	160	160	160	157	154	146	139	132	125	119	113	108	102	97	92	88
Saskatchewan Conv. Heavy [2]	257	265	275	277	280	283	284	285	285	285	289	291	291	291	293	296	296	294
W. Canada Heavy	**410**	**420**	**436**	**438**	**440**	**440**	**439**	**432**	**424**	**417**	**414**	**410**	**404**	**398**	**395**	**393**	**388**	**381**
PENTANES/CONDENSATE	**144**	**150**	**156**	**162**	**169**	**169**	**170**	**170**	**171**	**171**	**171**	**171**	**172**	**172**	**169**	**165**	**163**	**160**
W. Canada Conventional (incl. condensates)	1,295	1,350	1,409	1,420	1,428	1,433	1,443	1,451	1,457	1,465	1,479	1,487	1,497	1,508	1,519	1,528	1,535	1,542
OIL SANDS (BITUMEN & UPGRADED CRUDE OIL)																		
Oil Sands Mining	849	953	1,003	1,093	1,114	1,150	1,214	1,329	1,404	1,412	1,455	1,507	1,520	1,564	1,558	1,551	1,553	1,597
Oil Sands *In situ*	1,096	1,153	1,269	1,419	1,546	1,659	1,772	1,867	1,993	2,138	2,253	2,403	2,550	2,688	2,821	2,971	3,092	3,212
TOTAL OIL SANDS	1,945	2,106	2,272	2,512	2,659	2,809	2,986	3,197	3,397	3,550	3,708	3,910	4,070	4,252	4,379	4,522	4,645	4,810
W. Canada Oil Production	*3,241*	*3,456*	*3,681*	*3,932*	*4,088*	*4,243*	*4,429*	*4,647*	*4,854*	*5,016*	*5,186*	*5,398*	*5,567*	*5,760*	*5,898*	*6,050*	*6,180*	*6,351*
E. Canada Oil Production	*232*	*222*	*227*	*248*	*238*	*297*	*307*	*263*	*239*	*230*	*209*	*200*	*175*	*149*	*139*	*116*	*98*	*91*
TOTAL CANADIAN OIL PRODUCTION	**3,473**	**3,678**	**3,908**	**4,181**	**4,326**	**4,539**	**4,736**	**4,910**	**5,093**	**5,245**	**5,395**	**5,598**	**5,742**	**5,909**	**6,038**	**6,166**	**6,278**	**6,442**
OIL SANDS RAW BITUMEN**																		
Oil Sands Mining	977	1,098	1,149	1,242	1,269	1,309	1,374	1,490	1,566	1,587	1,642	1,696	1,710	1,754	1,761	1,766	1,768	1,812
Oil Sands *In Situ*	1,111	1,183	1,299	1,448	1,572	1,687	1,800	1,896	2,022	2,168	2,285	2,437	2,584	2,723	2,856	3,007	3,129	3,250
TOTAL OIL SANDS	2,087	2,281	2,448	2,690	2,841	2,995	3,174	3,386	3,588	3,754	3,927	4,132	4,294	4,477	4,617	4,773	4,897	5,062

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Notes:

1. *Atlantic Canada production includes Newfoundland & Labrador production and negligible volumes from New Brunswick. Condensates/pentanes from Nova Scotia and New Brunswick are also added.*
2. *CAPP allocates Saskatchewan Area III Medium crude as heavy crude. Also 17% of Area IV is > 900 kg/m³.*

*** Raw bitumen numbers are highlighted. The oil sands production numbers (as historically published) are a combination of upgraded crude oil and bitumen and therefore incorporate yield losses from integrated upgrader projects. Production from off-site upgrading projects are included in the production numbers as bitumen.*

Totals may not add up due to rounding.

APPENDIX B.2 CAPP Western Canadian Crude Oil Supply Forecast 2014-2030

Blended Supply to Trunk Pipelines and Markets *thousand barrels per day*

	Actual	Forecast																
CONVENTIONAL	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Total Light and Medium	737	775	814	817	816	820	831	845	858	873	889	903	917	934	952	966	980	996
Net Conventional Heavy to Market	362	348	365	368	370	370	369	361	352	345	342	337	330	324	320	318	312	305
TOTAL CONVENTIONAL	**1,099**	**1,124**	**1,179**	**1,184**	**1,186**	**1,190**	**1,199**	**1,206**	**1,211**	**1,218**	**1,231**	**1,239**	**1,247**	**1,258**	**1,272**	**1,284**	**1,292**	**1,301**
OIL SANDS																		
Upgraded Light (Synthetic)[1]	719	727	729	688	681	691	686	722	728	758	791	795	793	789	787	782	779	778
Oil Sands Heavy [2]	1,655	1,811	2,027	2,382	2,585	2,778	3,015	3,274	3,547	3,731	3,895	4,152	4,367	4,614	4,795	4,992	5,163	5,376
TOTAL OIL SANDS AND UPGRADERS	**2,373**	**2,538**	**2,756**	**3,070**	**3,266**	**3,469**	**3,701**	**3,997**	**4,275**	**4,489**	**4,686**	**4,948**	**5,160**	**5,403**	**5,582**	**5,774**	**5,941**	**6,154**
Total Light Supply	1,456	1,502	1,542	1,504	1,497	1,511	1,517	1,567	1,586	1,631	1,680	1,698	1,711	1,724	1,739	1,748	1,759	1,774
Total Heavy Supply	2,017	2,160	2,393	2,750	2,955	3,148	3,384	3,636	3,899	4,076	4,237	4,489	4,697	4,938	5,115	5,310	5,475	5,681
WESTERN CANADA OIL SUPPLY	**3,472**	**3,662**	**3,935**	**4,254**	**4,452**	**4,660**	**4,900**	**5,203**	**5,485**	**5,707**	**5,917**	**6,187**	**6,408**	**6,662**	**6,854**	**7,058**	**7,234**	**7,455**

Notes:

1. *Includes upgraded conventional.*
2. *Includes: a) imported condensate b) manufactured diluent from upgraders and c) upgraded heavy volumes coming from upgraders.*

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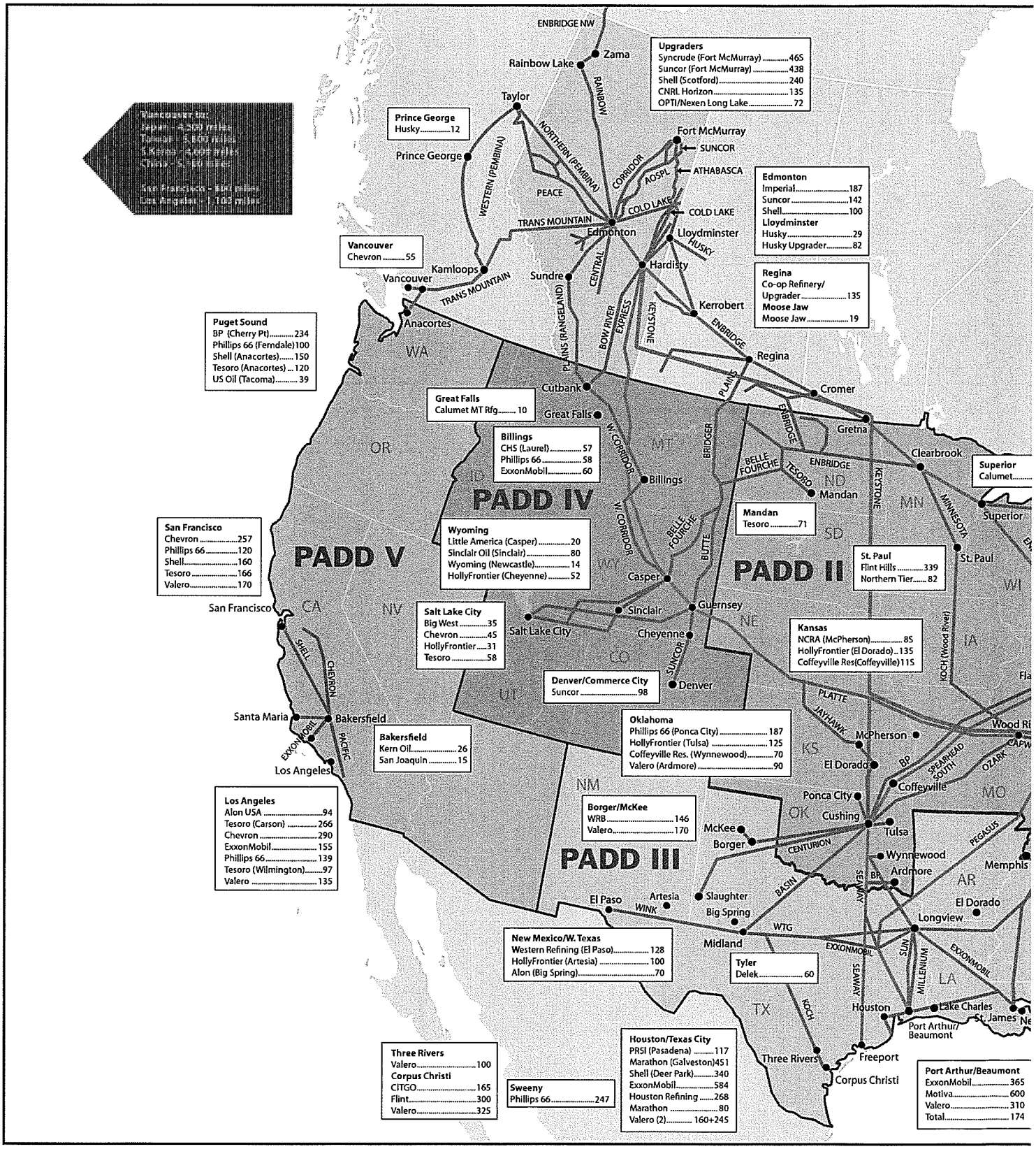
APPENDIX C

Crude Oil Pipelines and Refineries



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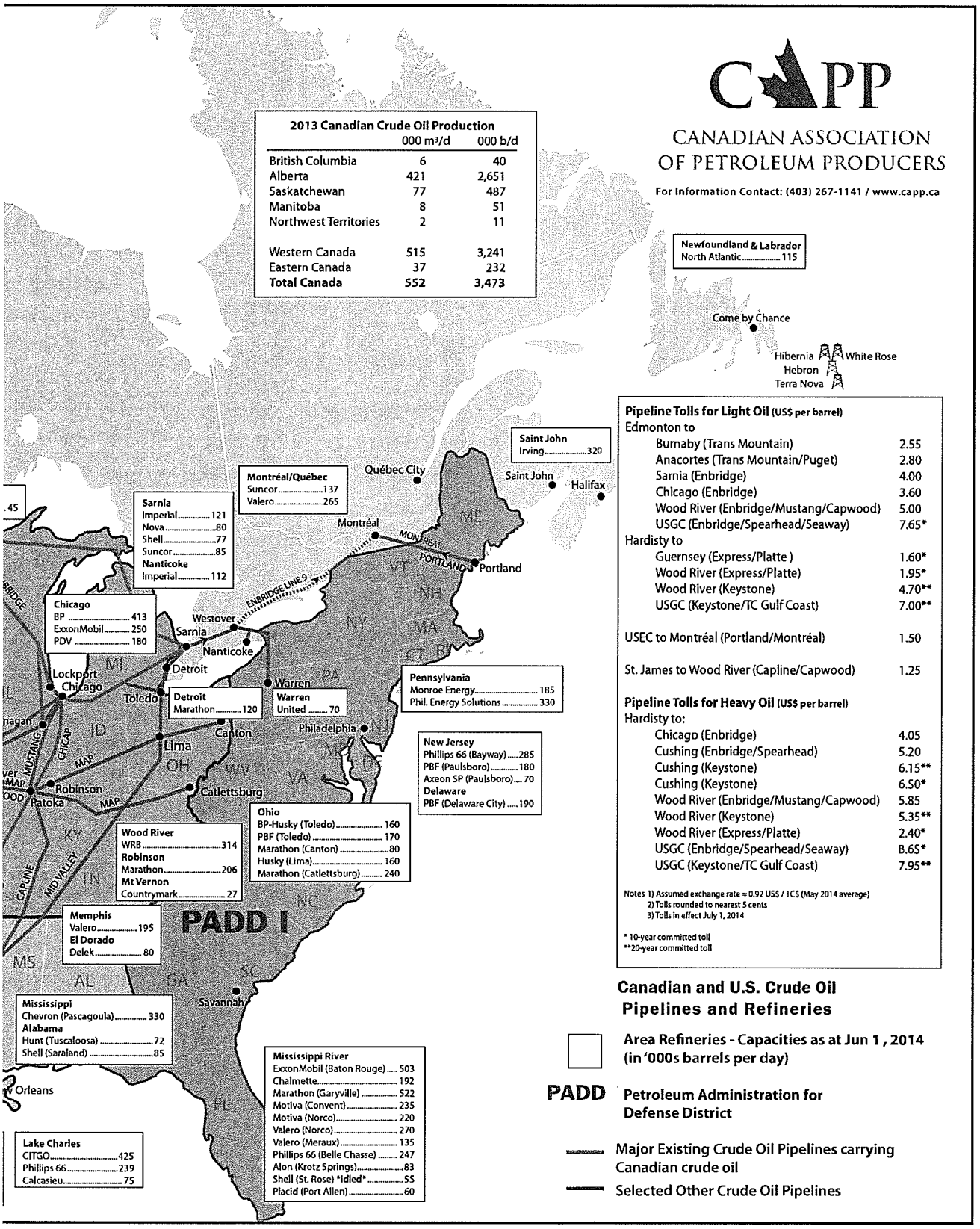
2013 Canadian Crude Oil Production
000 m³/d 000 b/d
British Columbia 6 40
Alberta 421 2,651
Saskatchewan 77 487
Manitoba 8 51
Northwest Territories 2 11
Western Canada 515 3,241
Eastern Canada 37 232
Total Canada 552 3,473
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ExxonMobil 250
PDV 180
Westover
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Nanticoke
Lockport
Chicago
Detroit
Toledo
Detroit
Marathon 120
Warren
Warren
United 70
Pennsylvania
Monroe Energy 185
Phil. Energy Solutions 330
Philadelphia
New Jersey
Phillips 66 (Bayway) 285
PBF (Paulsboro) 180
Axeon SP (Paulsboro) 70
Delaware
PBF (Delaware City) 190
Lima
Canton
Robinson
Patoka
Catlettsburg
Ohio
BP-Husky (Toledo) 160
PBF (Toledo) 170
Marathon (Canton) 80
Husky (Lima) 160
Marathon (Catlettsburg) 240
Wood River
WRB 314
Robinson
Marathon 206
Mt Vernon
Countrymark 27
Memphis
Valero 195
El Dorado
Delek 80
PADD I
Mississippi
Chevron (Pascagoula) 330
Alabama
Hunt (Tuscaloosa) 72
Shell (Saraland) 85
Savannah
Mississippi River
ExxonMobil (Baton Rouge) 503
Chalmette 192
Marathon (Garyville) 522
Motiva (Convent) 235
Motiva (Norco) 220
Valero (Norco) 270
Valero (Meraux) 135
Phillips 66 (Belle Chasse) 247
Alon (Krotz Springs) 83
Shell (St. Rose) *idled* 55
Placid (Port Allen) 60
Lake Charles
CITGO 425
Phillips 66 239
Calcasieu 75
Pipeline Tolls for Light Oil (US$ per barrel)
Edmonton to
Burnaby (Trans Mountain) 2.55
Anacortes (Trans Mountain/Puget) 2.80
Sarnia (Enbridge) 4.00
Chicago (Enbridge) 3.60
Wood River (Enbridge/Mustang/Capwood) 5.00
USGC (Enbridge/Spearhead/Seaway) 7.65*
Hardisty to
Guernsey (Express/Platte) 1.60*
Wood River (Express/Platte) 1.95*
Wood River (Keystone) 4.70**
USGC (Keystone/TC Gulf Coast) 7.00**
USEC to Montréal (Portland/Montréal) 1.50
St. James to Wood River (Capline/Capwood) 1.25
Pipeline Tolls for Heavy Oil (US$ per barrel)
Hardisty to:
Chicago (Enbridge) 4.05
Cushing (Enbridge/Spearhead) 5.20
Cushing (Keystone) 6.15**
Cushing (Keystone) 6.50*
Wood River (Enbridge/Mustang/Capwood) 5.85
Wood River (Keystone) 5.35**
Wood River (Express/Platte) 2.40*
USGC (Enbridge/Spearhead/Seaway) B.65*
USGC (Keystone/TC Gulf Coast) 7.95**
Notes 1) Assumed exchange rate = 0.92 US$ / 1C$ (May 2014 average)
2) Tolls rounded to nearest 5 cents
3) Tolls in effect July 1, 2014
* 10-year committed toll
**20-year committed toll
Canadian and U.S. Crude Oil Pipelines and Refineries
Area Refineries - Capacities as at Jun 1 , 2014 (in '000s barrels per day)
PADD Petroleum Administration for Defense District
Major Existing Crude Oil Pipelines carrying Canadian crude oil
Selected Other Crude Oil Pipelines

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The Canadian Association of Petroleum Producers (CAPP) represents companies, large and small, that explore for, develop and produce natural gas and crude oil throughout Canada. CAPP's member companies produce about 90 per cent of Canada's natural gas and crude oil. CAPP's associate members provide a wide range of services that support the upstream crude oil and natural gas industry. Together CAPP's members and associate members are an important part of a national industry with revenues of about $110 billion-a-year.

CAPP's mission is to enhance the economic sustainability of the Canadian upstream petroleum industry in a safe and environmentally and socially responsible manner, through constructive engagement and communication with governments, the public and stakeholders in the communities in which we operate.

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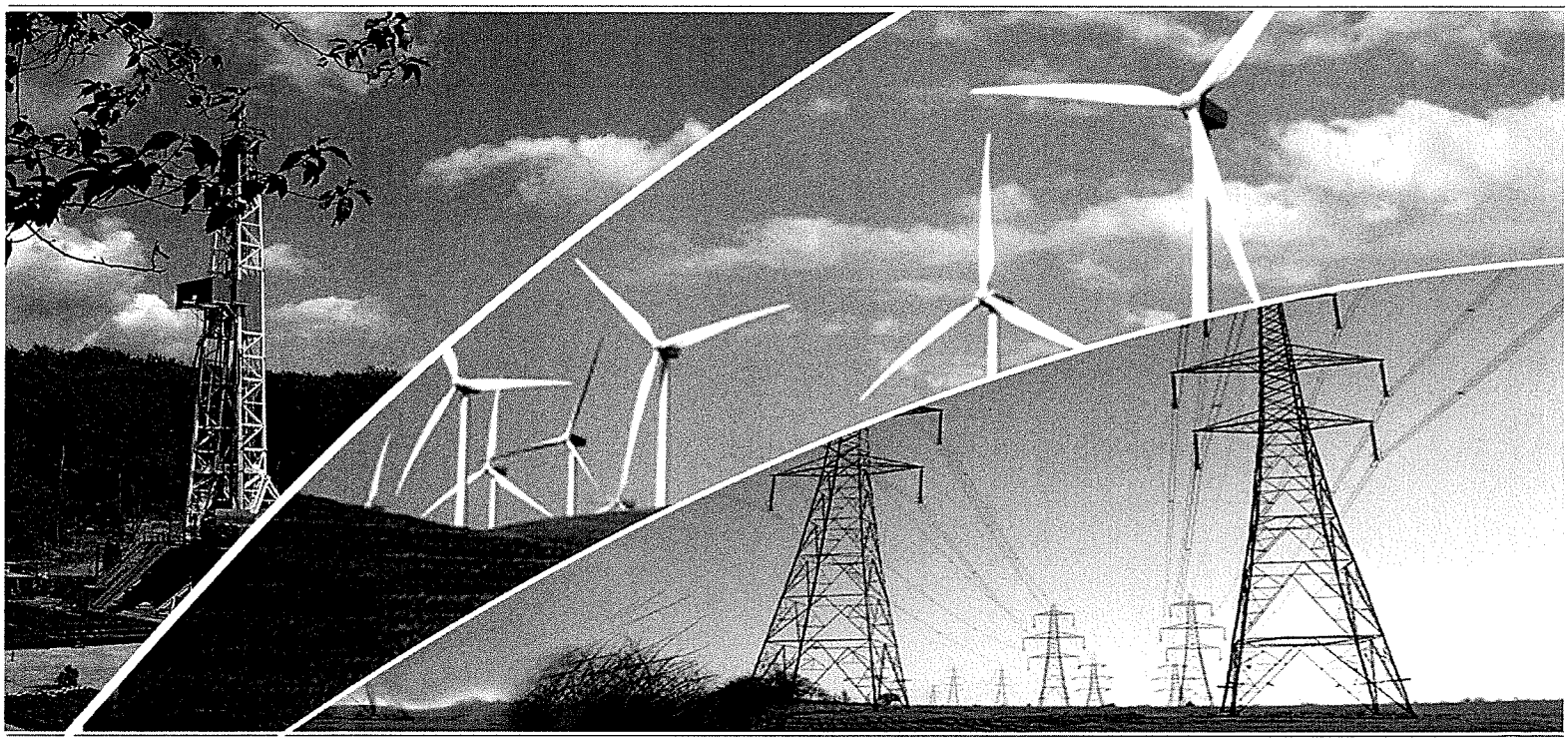
Annual Energy Outlook 2014

with projections to 2040



Independent Statistics & Analysis
U.S. Energy Information Administration

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For further information . . .

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AEO2014 is available on the EIA website at www.eia.gov/forecasts/aeo. Assumptions underlying the projections, tables of regional results, and other detailed results will also be available, at www.eia.gov/forecasts/aeo/assumptions. Model documentation reports for the National Energy Modeling System are available at website www.eia.gov/analysis/model-documentation.cfm and will be updated for the AEO2014 during 2014.

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Annual Energy Outlook 2014

With Projections to 2040

April 2014

U.S. Energy Information Administration
Office of Integrated and International Energy Analysis
U.S. Department of Energy
Washington, DC 20585

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Preface

The *Annual Energy Outlook 2014* (AEO2014), prepared by the U.S. Energy Information Administration (EIA), presents long-term annual projections of energy supply, demand, and prices focused on the U.S. through 2040, based on results from EIA's National Energy Modeling System (NEMS). NEMS enables EIA to make projections under alternative, internally-consistent sets of assumptions, the results of which are presented as cases. The analysis in AEO2014 focuses on five primary cases: a Reference case, Low and High Economic Growth cases, and Low and High Oil Price cases. Results from a number of other alternative cases also are presented, illustrating uncertainties associated with the Reference case projections. EIA published an Early Release version of the AEO2014 Reference case in December 2013.

The report begins with an Executive Summary that highlights key implications of the projections, followed by a Legislation and Regulations section that discusses how recently enacted federal and state legislation and regulations were incorporated in AEO2014, such as: the revised carbon dioxide emissions standards and banking provisions announced by the Regional Greenhouse Gas Initiative in February 2013 [1]; updated Renewable Fuel Standard target volumes to reflect actions by the U.S. Environmental Protection Agency to lower the target volume of cellulosic biofuel; and incorporation of modifications to existing state renewable portfolio standards or similar laws since the *Annual Energy Outlook 2013* was released. The Legislation and Regulations section also discusses selected legislative and regulatory issues could have major implications for energy markets and may be enacted in the near future.

The Issues in Focus section contains articles on selected energy topics, including a discussion of the results of two cases based on different assumptions about the future course of existing energy policies: one assumes the elimination of sunset provisions for various energy tax credits that are scheduled to expire under current law; the other assumes—in addition to the elimination of sunset provisions on various tax credits—the extension or expansion of three existing policies: corporate average fuel economy (CAFE) standards, appliance standards, and building code improvements. Other discussions include:

- U.S. tight oil production trends and supply projections based on alternative assumptions and a methodology using well-level data aggregated to the county level
- Potential of liquefied natural gas as a freight locomotive fuel
- Impacts of demographic issues and travel behavior on light-duty vehicle energy demand
- Effects of lower natural gas prices on projected industrial production
- Implications of accelerated power plant retirements
- Renewable electricity projections under alternative assumptions in AEO2014
- Implications of low electricity demand growth.

The Market Trends section summarizes the AEO2014 projections for energy markets by end-use market sector or energy supply source. In some instances, this section also uses alternative cases to illustrate a range of potential outcomes under difference circumstances, highlighting the uncertainty associated with the projections. Complete tables for the five primary cases are provided in Appendixes A through C, and major results from many of the other alternative cases are provided in Appendix D. Complete tables for all the alternative cases are available in a table browser on EIA's website, at http://www.eia.gov/oiaf/aeo/tablebrowser.

AEO2014 projections are based generally on federal, state, and local laws and regulations in effect as of the end of October 2013. The potential impacts of pending or proposed legislation, regulations, and standards (and sections of existing legislation that require implementing regulations or funds that have not been appropriated) are not reflected in the projections. In certain situations, however, where it is clear that a law or regulation will take effect shortly after AEO2014 is completed, it may be considered in the projection.

AEO2014 is published in accordance with Section 205c of the U.S. Department of Energy (DOE) Organization Act of 1977 (Public Law 95-91), which requires the EIA Administrator to prepare annual reports on trends and projections for energy use and supply.

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Projections by EIA are not statements of what will happen but of what might happen, given the assumptions and methodologies used for any particular scenario. The AEO2014 Reference case projection is a business-as-usual trend estimate, given known technology and technological and demographic trends. EIA explores the impacts of alternative assumptions in other scenarios with different macroeconomic growth rates, world oil prices, and rates of technology progress. The main cases in AEO2014 generally assume that current laws and regulations are maintained throughout the projections. Thus, the projections provide policy-neutral baselines that can be used to analyze policy initiatives.

While energy markets are complex, energy models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics are indicative of real-world tendencies rather than representations of specific outcomes.

Energy market projections are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated. In addition, future developments in technologies, demographics, and resources cannot be foreseen with certainty. Many key uncertainties in the AEO2014 projections are addressed through alternative cases.

EIA has endeavored to make these projections as objective, reliable, and useful as possible; however, they should serve as an adjunct to, not a substitute for, a complete and focused analysis of public policy initiatives.

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Updated *Annual Energy Outlook 2014* Reference case (April 2014)

The AEO2014 Reference case included as part of this complete report, released in April 2014, was updated from the AEO2013 Reference case released in April 2013. The Reference case was updated to reflect new legislation or regulation enacted since that time or to incorporate modeling changes. Major changes made in the Reference case include:

Macroeconomic

- Revised U.S. Census Bureau population projections [2]. The population projection for 2040 in the AEO2014 Reference case is almost 6% below the 2040 projection used for the AEO2013 Reference case. Most of the revision in overall population growth results from a lower projection for net international migration, with younger age groups showing the largest differences from the earlier projection. The slower rate of population growth leads to less labor force growth, which contributes to slower GDP growth.

Residential, commercial, and industrial

- Revised base year residential equipment stocks and energy consumption for space heating, space cooling, and water heating, based on data from EIA's 2009 Residential Energy Consumption Survey (RECS), the most recent data available [3]. Estimates of appliance stocks and energy consumption for several miscellaneous electric loads also were updated, based on a report by Navigant Consulting Inc., to better reflect recent changes and trends in the residential sector [4].
- Updated and expanded representation of miscellaneous electric loads in the commercial sector, as well as personal computers and data center servers, based on the Navigant report, reflecting recent and expected trends in electronics use [5].
- Updated costs and improved representation of residential lighting applications, including wider representation of light emitting diode (LED) lighting and outdoor lighting, based on the 2009 RECS and two U.S. Department of Energy (DOE) reports [6, 7].
- Revised handling of the regional efficiency standard for residential furnaces, based on an ongoing legal appeal of the standard. The regional standard scheduled to take effect in 2013 is not included in AEO2014 because of a court challenge and proposed settlement that would vacate the standard in question and require DOE to develop new standards for residential furnaces.
- Revised commercial capacity factors governing annual usage of major end-use equipment, based on an EIA-contracted analysis.
- Updated manufacturing sector data to reflect the 2010 Manufacturing Energy Consumption Survey (MECS) [8].
- Revised outlook for industrial production to reflect the effects of increased shale gas production and lower natural gas prices, resulting in faster growth for industrial production and energy consumption. The industries primarily affected include energy-intensive bulk chemicals and primary metals, both of which provide products used by the mining and other downstream industries, such as fabricated metals and machinery. The bulk chemicals industry is also a major user of natural gas and, increasingly, hydrocarbon gas liquid (HGL) feedstocks [9].
- Expanded process flow models for the cement and lime industry and the aluminum industry, allowing technologies based on energy efficiency to be incorporated, as well as enhancement of the cement model to include renewable fuels.

Transportation

- Implemented a new approach to vehicle miles traveled (VMT) projections for light-duty vehicles (LDVs), based on an analysis of VMT by age groups and the aging of the driving population over the course of the projection, which resulted in a significantly lower level of VMT growth after 2018 compared with AEO2013. On balance, demographic trends (such as an aging population and decreasing rates of licensing and travel among younger age groups) combine with employment and income factors to produce a 30% increase in VMT from 2012 to 2040 in AEO2014, compared with 41% growth in AEO2013.
- Added liquefied natural gas (LNG) as a potential fuel choice for freight rail locomotives and domestic marine vessels, resulting in significant penetration of natural gas as a fuel for freight rail (35% of freight rail energy consumption in 2040) but relatively minor penetration in domestic marine vessels (2% of domestic marine energy consumption in 2040).
- Adopted a new approach for estimating freight travel demand by region and commodity for heavy-duty vehicles (HDVs), rail, and domestic marine vessels, as well as updated fuel efficiencies for freight rail and domestic marine vessels.
- Updated handling of flex-fuel vehicle (FFV) fuel shares to better reflect consumer preferences and industry response. FFVs are necessary to meet the renewable fuels standard (RFS), but the phaseout of corporate average fuel economy (CAFE) credits for their sale, as well as limited demand from consumers, reduces their market penetration.
- Revised attributes for battery electric vehicles, including: (1) product availability, (2) electric drive fuel efficiency, and (3) non-battery system costs by vehicle size class, battery size, and added battery cost per kilowatthour based on vehicle power-to-energy ratio for vehicle type—applied to hybrid electric, plug-in hybrid electric, and all-electric vehicles.

Oil and natural gas production and product markets

- Revised network pricing assumptions based on benchmarking of regional natural gas hub prices to historical spot natural gas prices, using flow decisions based on spot prices, setting variable tariffs based on historical spot natural gas price differentials, and estimating the price of natural gas to the electric power sector off a netback from the regional hub prices [10].

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- Allowed secondary flows of natural gas out of the Middle Atlantic region to change dynamically in the model based on relative prices, which enables a larger volume of natural gas from the Middle Atlantic's Marcellus formation to supply neighboring regions.
- Developed the estimated ultimate recovery of tight oil and shale gas on the basis of county-level data [*11*].
- Updated oil and gas supply module that explicitly reports technically recoverable resources of liquids in natural gas, enabling estimation of dry and wet natural gas.
- Improved representation of the dynamics of U.S. gasoline and diesel exports versus U.S. demand, through adoption of endogenous modeling [*12*].
- Added representation of the U.S. crude oil distribution system (pipelines, marine, and rail), to allow crude oil imports to go to logical import regions for transport to refineries, which enables crude imports and domestic production to move among refining regions and keeps imports of Canadian crude oil from flowing directly to U.S. Gulf refiners [*13*].
- Revised production outlook for nonpetroleum other liquids—gas-to-liquids, coal-to-liquids (CTL), biomass-to-liquids, and pyrolysis [*14*]—with lower production levels than in AEO2013, as more recent experience with these emerging technologies indicates higher costs than previously assumed [*15*].
- Revised representation of CO_2-enhanced oil recovery (EOR) that better integrates the electricity, oil and gas supply, and refining modules [*16*].

Electric power sector

- Revised approach to reserve margins, which are set by region on the basis of North American Electric Reliability Corporation/Independent System Operator requirements [*17*], and to capacity payments, which are calculated as a combination of levelized costs for combustion turbines and the marginal value of capacity in the electricity model.
- Revised handling of spinning reserves, with the required levels set explicitly, depending on the mix of generating technologies used to meet peak demand by region, to allow better representation of capacity requirements and costs in regions or cases with high penetration of intermittent loads.
- Revised assumptions concerning the potential for unannounced retirements of nuclear capacity in several regions to better reflect the impacts of rising operating costs and low electricity prices. Announced nuclear retirements are already incorporated as planned.
- Updated handling of Mercury and Air Toxics Standards (MATS) [*18*] covering the electric power sector, to reflect potential upgrades of electrostatic precipitators, requirements for plants with dry scrubbers to employ fabric filters, and revised costs for retrofits of dry sorbent injection and fabric filters.
- Updated treatment of the production tax credit (PTC) for eligible renewable electricity generation technologies—consistent with the American Taxpayer Relief Act of 2012 (ATRA) passed in January 2013 [*19*]—including revision of PTC expiration dates for each PTC-eligible technology, to reflect the concept of projects being declared "under construction" as opposed to being placed "in service," and extension of the expiration date of the PTC for wind generation projects by one year.

Future analyses using the AEO2014 Reference case will start from the version of the Reference case released with this complete report.

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Endnotes

Links current as of April 2014

1. Regional Greenhouse Gas Initiative, "Program Review" (New York, New York: February 7, 2013), http://www.rggi.org/docs/ProgramReview/_FinalProgramReviewMaterials/Recommendations_Summary.pdf.
2. The new population projections were released on December 12, 2012. See U.S. Department of Commerce, "U.S. Census Bureau Projections Show a Slower Growing, Older, More Diverse Nation a Half Century from Now" (Washington, DC: December 12, 2012), https://www.census.gov/newsroom/releases/archives/population/cb12-243.html.
3. U.S. Energy Information Administration, "Residential Energy Consumption Survey (RECS): 2009 RECS Survey Data, Public Use Microdata File (Washington, DC: January 2013), http://www.eia.gov/consumption/residential/data/2009/index.cfm?view=microdata.
4. Navigant Consulting, Inc., *Analysis and Representation of Miscellaneous Electric Loads in the National Energy Modeling System (NEMS)* (Washington, DC: May 2013), prepared for U.S. Department of Energy, U.S. Energy Information Administration.
5. Navigant Consulting, Inc., *Analysis and Representation of Miscellaneous Electric Loads in the National Energy Modeling System (NEMS)* (Washington, DC: May 2013), prepared for U.S. Department of Energy, U.S. Energy Information Administration.
6. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, *Residential Lighting End-Use Consumption Study: Estimation Framework and Initial Estimates* (Washington, DC: December 2012), http://apps1.eere.energy.gov/buildings/publications/pdfs/ssl/2012_residential-lighting-study.pdf.
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8. U.S. Energy Information Administration, "Manufacturing Energy Consumption Survey (MECS): 2010 MECS Survey Data" (Washington, DC: March 19, 2013), http://www.eia.gov/consumption/manufacturing/data/2010/.
9. Growing production of wet natural gas and lighter crude oil has focused attention on natural gas liquids (NGL). EIA has developed and adopted a neutral term—"hydrocarbon gas liquid" (HGL)—to equate the supply (*natural gas plant liquids* [*NGPL*] + *liquefied refinery gases* [*LRG*]) and market (*NGL + refinery olefins*) terms. For example, liquefied petroleum gas (LPG) is currently defined by EIA as ethane, propane, normal butane, and isobutane and their olefins (ethylene, propylene, butylene, and isobutylene). This definition is inconsistent with definitions used by other federal agencies, international organizations, and trade groups, in that it implies that all the products are in a liquid state (ethane typically is not) and are used in the same way (higher-value olefins are used differently). Part of the HGL implementation redefines LPG to include only propane, butane, and isobutane and to exclude ethane and refinery olefins. The tables included in AEO2014 have been relabeled to conform to this newly adopted definition.
10. Estimating natural gas prices to the electricity generation sector based on hub prices, rather than the citygate prices as was done in prior years, is a better reflection of current market conditions, in which many large natural gas consumers are outside the citygate.
11. After accounting for infrastructure constraints and general development patterns, oil and natural gas resources in sweet spots are developed earlier than lower quality resources, based on net present value.
12. High U.S. crude oil production and low fuel costs have given U.S. refiners a competitive advantage over foreign refiners, as evidenced by high U.S. refinery utilization and increasing U.S. exports of gasoline and diesel fuel.
13. Oil imports from Canada now are required to go to Petroleum Administration for Defense District (PADD) 2 (Midwest: North Dakota, South Dakota, Nebraska, Kansas, Oklahoma, Minnesota, Iowa, Missouri, Wisconsin, Illinois, Michigan, Indiana, Ohio, Kentucky, and Tennessee); PADD 4 (Rocky Mountain: Montana, Idaho, Wyoming, Utah, and Colorado); and PADD 5 (West Coast: Washington, Oregon, Nevada, California, Arizona, Alaska, and Hawaii) for redistribution through the crude oil distribution infrastructure.
14. Pyrolysis is defined as the thermal decomposition of biomass at high temperatures (greater than 400°F, or 200°C) in the absence of air.
15. EIA undertook detailed assessments of these technologies in order to characterize key parameters considered in the model, such as capital cost, contingency factors, construction time, first year of operation, plant life, plant production capacity, efficiency, and feedstock and other operating costs.
16. When considering CO_2 EOR, the oil and gas supply module assesses a location and the availability and price of CO_2 from power plants and CTL facilities. The electric power plants now consider the market size and prices for CO_2 captured. The refining module assesses a location and the availability and price of CO_2 from CTL facilities. The power sector now assesses opportunities for plants equipped with carbon capture and storage, as the CO_2 produced at those facilities can be used for EOR operations. This enables the model to solve dynamically for the capture of CO_2 and the production of oil from anthropogenic CO_2 EOR.

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Executive summary

Projections in the U.S. Energy Information Administration's *Annual Energy Outlook 2014* (AEO2014) focus on the factors that shape the U.S. energy system over the long term. Under the assumption that current laws and regulations remain unchanged, the AEO2014 Reference case provides a basis for examination and discussion of energy production, consumption, technology, and market trends and the direction they may take in the future. AEO2014 also includes alternative cases that explore important areas of uncertainty for markets, technologies, and policies in the U.S. energy economy (see Appendix E for discussion of detailed case assumptions). Many of the implications of the alternative cases are discussed in the Issues in Focus section of AEO2014.

Key results highlighted in the AEO2014 Reference and alternative cases include:

- Growing domestic production of natural gas and oil continues to reshape the U.S. energy economy, largely as a result of rising production from tight formations, but the effect could vary substantially depending on expectations about resources and technology.
- Industrial production expands over the next 10 to 15 years as the competitive advantage of low natural gas prices provides a boost to the industrial sector with increasing natural gas use.
- There is greater upside uncertainty than downside uncertainty in oil and natural gas production; higher production could spur even more industrial growth and lower the use of imported petroleum.
- Improvement in light-duty vehicle (LDV) efficiency more than offsets modest growth in vehicle miles traveled (VMT) that reflects changing driving patterns, leading to a sharp decline in LDV energy use.
- Evolving natural gas markets spur increased use of natural gas for electricity generation and transportation, as well as expanded export opportunities.
- Improved efficiency of energy use in the residential and transportation sectors and a shift away from more carbon-intensive fuels such as coal for electricity generation help to stabilize U.S. energy-related carbon dioxide (CO_2) emissions.

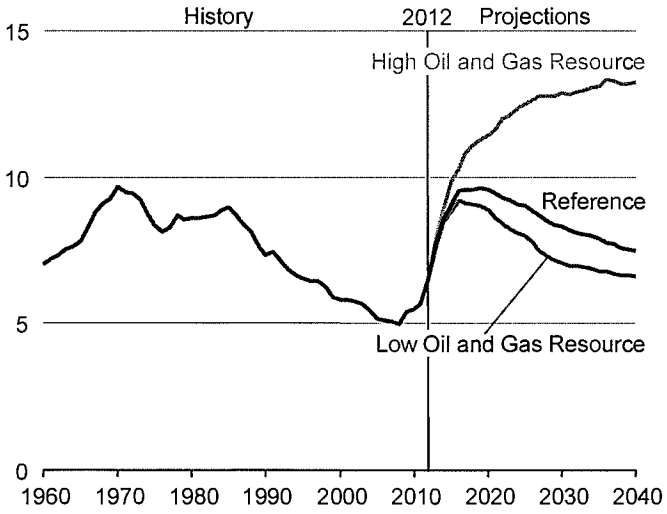
Expected gains in tight oil production drive projected growth in total petroleum and other liquids production

Growth in crude oil production from tight oil and shale formations supported by identification of resources and technology advances have supported a nearly fourfold increase in tight oil production from 2008, when it accounted for 12% of total U.S. crude oil production, to 2012, when it accounted for 35% of total U.S. production. Total projected U.S. crude oil production in the AEO2014 Reference case reaches 9.6 million barrels per day (MMbbl/d) in 2019—3.1 MMbbl/d more than in 2012. Over the same period, tight oil production grows by 2.5 MMbbl/d, to 4.8 MMbbl/d or 50% of the national total.

In the Reference case, tight oil production begins to slow after 2021, contributing to a decline in total U.S. oil production through 2040. However, tight oil development is still at an early stage, and the outlook is uncertain. Changes in U.S. crude oil production depend largely on the degree to which technological advances allow production to occur in potentially high-yielding tight and shale formations. They also depend on the assumed estimated ultimate recovery (EUR) for wells drilled in those formations, in addition to assumptions about well spacing and production patterns. To address these uncertainties, AEO2014 includes High Oil and Gas Resource and Low Oil and Gas Resource cases (Figure ES-1). In the High Oil and Gas Resource case, tight oil production reaches 8.5 MMbbl/d in 2035 (compared to 3.7 MMbbl/d in the Reference case), with total U.S. crude oil production reaching 13.3 MMbbl/d in the following year (compared to 7.8 MMbbl/d in the Reference case).

A comparison of the Reference case and High Oil and Gas Resource case demonstrates the significant impact that technological development and productivity gains in tight oil plays can have on net imports of crude oil and petroleum products. In the Reference case, the share of net crude oil and petroleum product imports as a percentage of total U.S. product consumed declines from 41% in 2012 to 25% in 2016, remains close to that level for several years, and then rises to 32% in 2040 (Figure ES-2). In the High Oil and Gas Resource case, domestically produced crude oil displaces more expensive imported crude at domestic refineries, and U.S. finished petroleum products become more competitive worldwide. The share of total U.S. product consumed represented by net crude oil and petroleum product imports in the High Oil and Gas Resource case declines to 15% in 2020 and continues to fall through 2040. The United States becomes a net exporter of crude oil and petroleum products at the end of the projection period.

Figure ES-1. U.S. crude oil production in three cases, 1960-2040 (million barrels per day)



Among the most uncertain aspects of this analysis are the potential effects of alternative resource and technology assumptions on the global market for liquid fuels, which is highly integrated. Regardless of how much the United States reduces its reliance on imported liquids, consumer prices will not be insulated from global oil prices set in global markets

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for crude oil and petroleum products. Strategic choices made by leading oil-exporting countries could result in U.S. price and quantity changes that differ significantly from those presented in this outlook.

U.S. industrial production is spurred by abundant and relatively inexpensive natural gas

The AEO2014 Reference case projects robust growth in industrial production, with the manufacturing sector benefitting from abundant and relatively inexpensive natural gas, especially in the first 15 years of the projection. Low natural gas prices and increased availability of natural gas and related resources such as hydrocarbon gas liquids (HGL) benefit the U.S. industrial sector in multiple ways. Natural gas is used as a fuel to produce heat and to generate electricity and, along with HGL products, is also used as a feedstock to produce chemicals, pharmaceuticals, and plastics. In addition, with generally lower energy prices resulting in more rapid economic growth, demand for industrial products increases.

Bulk chemicals account for much of the increased growth in manufacturing output in the Reference case (Figure ES-3). Industrial production of bulk chemicals, which also benefits from increased supply of HGL, grows by 3.4%/year from 2012 to 2025 in the AEO2014 Reference case. The near-term competitive advantage diminishes over time, however, and growing competition from abroad slows U.S. output growth after 2030 as domestic natural gas becomes less cost-advantaged compared with prices at other locations, resulting in increased competition from newer facilities that are developed abroad.

The higher level of industrial production leads to growth in natural gas consumption in the U.S. industrial sector, from 8.7 quadrillion British thermal units (Btu) in 2012 to 10.6 quadrillion Btu in 2025 in the Reference case. Most of the increase in industrial natural gas demand is the result of output growth in the manufacturing sector. Energy-intensive industries with high rates of growth include paper products, food products, bulk chemicals, and metal-based durables.

Different assumptions about economic growth or about oil and gas resources and technology result in large variations in industrial output, with bulk chemicals showing more variation in the High and Low Oil and Gas Resource cases and the rest of the manufacturing sector showing more variation in the High and Low Economic Growth cases. Output from the bulk chemicals industry is more responsive to variations in energy prices than is output from the rest of the industrial sector, and shipments continue to grow after 2035 in the High Oil and Gas Resource case, as indicated in Figure ES-3.

Transportation energy use continues to decline, with light-duty vehicles sharply reducing gasoline consumption due to fuel efficiency and changing usage patterns

Fuel use in the U.S. transportation sector has changed fundamentally in the past several years. In the AEO2014 Reference case, the factors contributing to declining light-duty vehicle (LDV) energy use continue and intensify, resulting in declines in motor gasoline consumption over the projection period.

LDV fuel efficiency is driven by increasingly stringent regulatory standards. In the Reference case, the fuel efficiency of the LDV stock in miles per gallon (mpg), excluding light-duty commercial trucks, increases by 2%/year to 37.2 mpg in 2040 from 21.5 mpg in 2012. While motor gasoline remains the dominant fuel, growing market penetration of diesel, biofuels, hybrid-electric, and plug-in electric systems gradually reduces its share of the LDV fuel market.

AEO2014 includes a new demographic profile of driving behavior by age and gender. Total vehicle miles traveled (VMT) increases at an average annual rate of 0.9% from 2012 to 2040, due to changes in driving behavior that are related to age and gender demographics. Older drivers increase as a proportion of the U.S. driving population, with their higher licensing rates but lower-than-average mileage

Figure ES-2. Net import share of U.S. petroleum and other liquids consumption in three cases, 1990-2040 (percent)

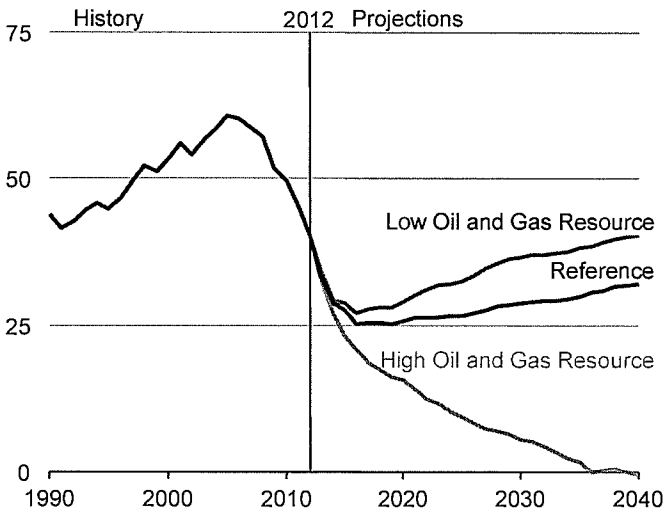
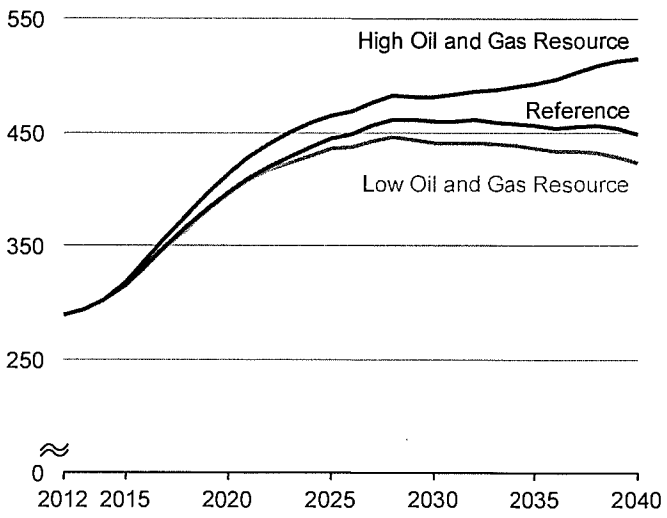


Figure ES-3. Value of shipments of bulk chemicals in three cases, 2012-40 (billion 2005 dollars)



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per capita contributing to a gradual increase in total VMT. However, rising fuel economy more than offsets the modest growth in VMT, and energy consumption by LDVs declines in the Reference case from 8.4 MMbbl/d in 2012 to 6.4 MMbbl/d in 2040.

The importance of demographic changes for VMT and transportation energy consumption is highlighted by AEO2014 alternative cases in which variations in these assumptions result in higher or lower fuel use (Figure ES-4). In a High VMT case, U.S. LDVs consume 5% more energy by 2040, while in a Low VMT case they consume 18% less energy than in the Reference case. This variation in projected energy demand from the transportation sector has further effects on other key energy sector indicators, including fuel use, imports, and CO_2 emissions.

Abundant supply of natural gas spurs greater use for electricity generation and transportation

Natural gas is an attractive fuel for new generating capacity. In some regions, natural gas-fired generation captures markets formerly supplied by coal-fired and nuclear plants, and by 2035 natural gas surpasses coal as the nation's largest source of energy for electricity generation (including the power sector and end-use sector generation) in the Reference case (Figure ES-5). In the first decade of the projection, growth in electricity generation from renewables tends to be largely policy-driven. However, as Reference case natural gas prices rise and the capital costs of renewable technologies—particularly wind and solar—decrease over time, renewable generation becomes more competitive, accounting for 16% of total electricity generation in 2040.

If additional existing coal-fired and nuclear generating capacity were retired, natural gas-fired generation could grow more quickly to fill the void. In recent years, the number of coal and nuclear plant retirements has increased, in part due to a decline in profitability as low natural gas prices have influenced the relative economics of those facilities. The Accelerated Coal Retirements case assumes that both coal prices and coal plant operating costs are higher than in the Reference case, leading to additional coal plant retirements. In this case, natural gas-fired generation overtakes coal-fired generation in 2019, and by 2040 the natural gas share of total generation reaches 43%. In the Accelerated Coal and Nuclear Retirements case, the natural gas share of total generation in 2040 grows to 47%. In both cases, renewable generation also increases relative to the Reference case. However, barring a breakthrough in electricity storage or related technologies, renewable technologies cannot fully replace the baseload generation lost as a result of coal and nuclear plant retirements, and total additions of natural gas-fired combined-cycle capacity in these cases are 32% to 50% higher than in the Reference case over the projection period.

Freight rail is considered a potential additional source of natural gas use in AEO2014. Any transition from diesel to natural gas as a fuel for freight locomotives will depend on economics, infrastructure needs, and railroads' decisions with regard to risk and uncertainty. For AEO2014, alternative cases were developed that anticipate varying degrees of natural gas penetration into the U.S. freight rail market. In the High Rail LNG case, natural gas is used to meet nearly all freight rail energy demand by 2040, while in the Reference case it gains 35% of the rail fuel market by that date. However, because the transportation sector is a relatively small consumer of natural gas compared to other sectors, the seemingly dramatic fuel switch from the perspective of freight rail is only a minor change in overall U.S. natural gas consumption.

A shift away from more carbon-intensive fuels for electricity generation helps to stabilize energy-related carbon dioxide emissions

In the AEO2014 Reference case, total U.S. energy-related emissions of CO_2 remain below the 2005 level in every year through 2040. In the Reference case, CO_2 emissions from the U.S. industrial sector exceed emissions from the transportation sector

Figure ES-4. U.S. light-duty vehicle energy use in three cases, 1995-2040 (million barrels of oil equivalent per day)

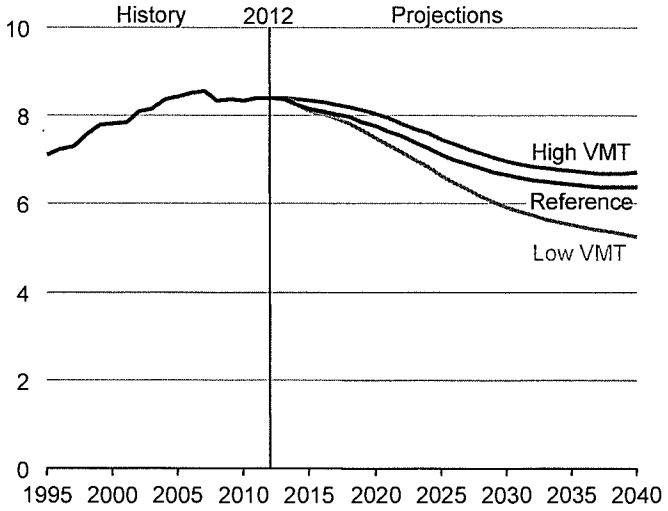
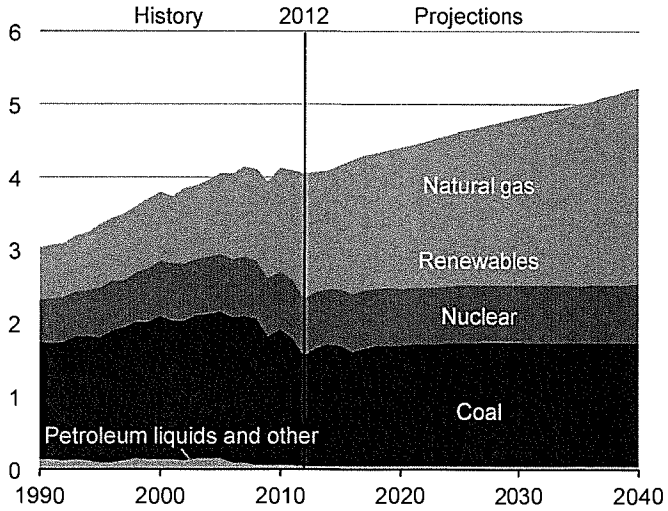


Figure ES-5. Electricity generation by fuel in the Reference case, 1990-2040 (trillion kilowatthours)



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beginning in 2024, for the first time since the late 1990s, as new fuel economy standards, biofuel mandates, and shifts in consumer behavior result in declining or stable transportation sector emissions from 2012 through 2033. After 2033 they begin to rise again, with freight transport increasing the demand for diesel, while demand for motor gasoline declines. In the electric power sector, emissions from coal combustion remain below 2011 levels through 2040 as more power plants are fueled by lower-carbon fuels, including natural gas and renewables.

CO_2 emissions in the electric power sector are dependent on the overall level of demand for electricity, as well as the mix of generating technologies used to satisfy that demand. In the Reference case, the average emission rate per kilowatthour of generation declines over time, primarily because the coal-fired share of total generation declines and is replaced predominantly with natural gas-fired generation, which is less carbon intensive than coal. In addition, the combined share of generation from nuclear and renewable fuels is gradually increasing throughout the projection, maintaining a generally consistent contribution of carbon-free generation resources. As a result, although generation in the electric power sector increases by 25% from 2012 to 2040, the sector's CO_2 emissions increase by only 11% over the same period. In most of the alternative cases, a decline in demand results in a greater decline in fossil-fueled generation and CO_2 emissions, as less efficient oil, coal, and natural gas plants reduce output or are retired. For example, in the Low Electricity Demand case, with retail electricity sales in 2040 about the same as in 2012, generation in the electric power sector is 20% lower, and CO_2 emissions are 22% lower, than projected in the Reference case.

CO_2 emissions in the power sector are highly sensitive to the relative generation shares of different fuel types, and larger shifts away from fossil fuels lead to declining emissions. While the retirement of coal-fired plants in the near term contributes to lower levels of CO_2 emissions, in the Accelerated Coal Retirements case, where coal retirements through 2040 are more than double those in the Reference case, CO_2 emissions decline by 11% from 2012 levels and are 20% below Reference case levels in 2040.

In general, growth of renewable generation is associated with a reduction in CO_2 emissions in the electric power sector. In the Low Renewable Technology Cost case, nonhydropower renewable generation grows at an average annual rate of 4.7% from 2012 to 2040 (Figure ES-6), compared to 3.2% in the Reference case, and electric power sector CO_2 emissions in 2040 are about 4% below the Reference case level. When growth in nonhydropower renewable generation is coupled with electricity demand growth that exceeds that in the Reference case, the impact on emissions may be more ambiguous. In the High Economic Growth case, although nonhydropower renewable generation grows by an average of 4.1%/year from 2012 to 2040, total electricity demand grows by 1.2%/year and electric power sector CO_2 emissions in 2040 are about 4% higher than in the Reference case.

In most cases that include high levels of nonhydropower renewable generation, electric power sector CO_2 emissions still increase slightly, if not as rapidly as in the Reference case, between 2012 and 2040, reflecting factors such as generation subsidies that reduce the cost of electricity and its price, raising demand. Cases that place a fee on CO_2 emissions throughout the energy sector, starting at either $10 or $25/ton and rising at a rate of 5%/year thereafter (the GHG10 and GHG25 cases), and a case that combines the GHG10 case with the High Oil and Gas Resource case (the GHG10 and Low Gas Prices case) are notable exceptions. In those cases, because the additional cost of operating generators that use fossil fuels results in both a decrease in overall electricity demand and significant substitution of nonhydropower renewable energy sources for fossil-fueled generation, total electric power sector CO_2 emissions in 2040 are between 36% and 82% below the Reference case total of 2,259 million metric tons, respectively, and total energy-related CO_2 emissions from all sources in 2040 are between 15% and 36% below the Reference case total of 5,599 million metric tons (Figure ES-7).

Figure ES-6. Nonhydropower renewable electricity generation in eight cases, 2005-40 (billion kilowatthours)

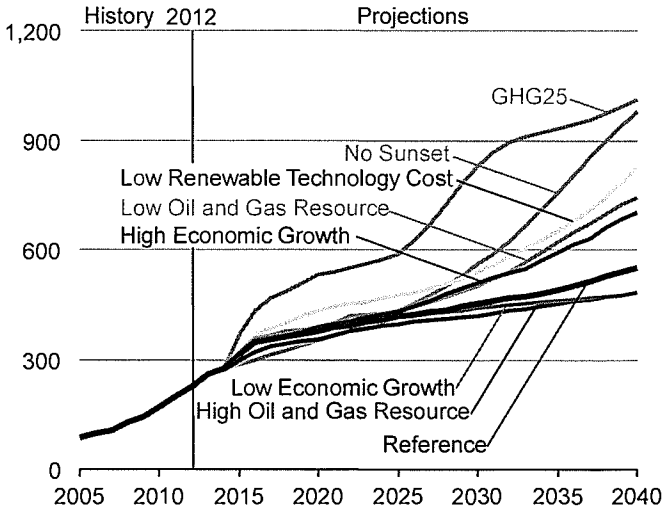

Figure ES-7. Energy-related carbon dioxide emissions in five cases, 2000-40 (million metric tons)

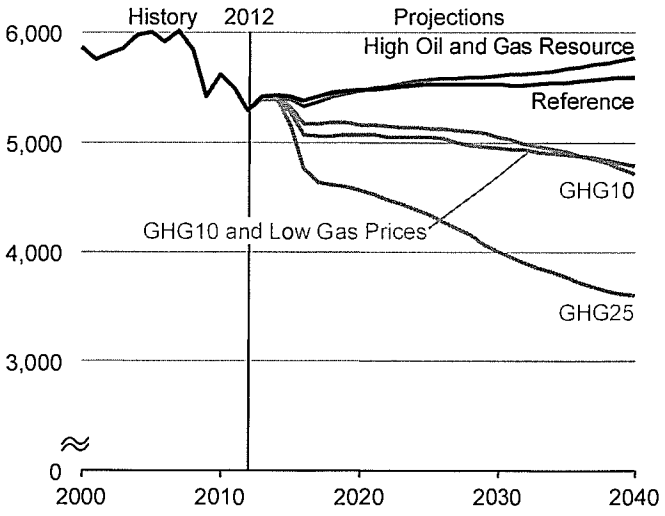

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Figure and table sources

Links current as of April 2014

Figure ES-1. U.S. crude oil production in three cases, 1960-2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure ES-2. Net import share of U.S. petroleum and other liquids consumption in three cases, 1990-2040: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure ES-3. Shipments of bulk chemicals in three cases, 2012-40: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure ES-4. U.S. light-duty vehicle energy use in three cases, 1995-2040: History: U.S. Department of Transportation, Federal Highway Administration, National Household Travel Survey, http://nhts.ornl.gov/download.shtml. Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

Figure ES-5. Electricity generation by fuel in the Reference case, 1990-2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure ES-6. Nonhydropower renewable electricity generation in eight cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, CO2FEE25.D011614A, NOSUNSET.D121713A, LCR_2014.D120613A, LOWRESOURCE.D112913A, HIGHRESOURCE.D112913B, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

Figure ES-7. Energy-related carbon dioxide emissions in five cases, 2000-40: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, HIGHRESOURCE.D112913B, CO2FEE10.D011614A, CO2FEE25.D011614A, and CO2FEE10HR.D011614A.

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Legislation and regulations

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Introduction

The *Annual Energy Outlook 2014* (AEO2014) generally represents current federal and state legislation and final implementation of regulations as of the end of October 2013. The AEO2014 Reference case assumes that current laws and regulations affecting the energy sector are largely unchanged throughout the projection period (including the implication that laws that include sunset dates are no longer in effect at the time of those sunset dates) [1]. The potential impacts of proposed legislation, regulations, or standards—or of sections of authorizing legislation that have been enacted but are not funded, or for which parameters will be set in a future regulatory process—are not reflected in the AEO2014 Reference case, but some are considered in alternative cases. This section summarizes federal and state legislation and regulations newly incorporated or updated in AEO2014 since the completion of the *Annual Energy Outlook 2013* (AEO2013). It also summarizes selected rules and regulations that have been proposed recently and have the potential to affect the projection significantly.

Examples of federal and state legislation and regulations incorporated in the AEO2014 Reference case, or whose handling has been modified, include:

- Incorporation of the revised emissions standards and banking provisions for carbon dioxide (CO_2) announced by the nine-state Regional Greenhouse Gas Initiative in February 2013, which lowered the program's emissions cap by 45% starting in 2014 [2].
- Updated handling of the mandated volume for biofuels established for the renewable fuel standard (RFS) by the Energy Policy Act of 2005 (EPACT2005) [3] and expanded by the Energy Independence and Security Act of 2007 (EISA2007) [4] to reflect final and proposed actions by the U.S. Environmental Protection Agency (EPA) to set obligations for both cellulosic biofuels and total renewable fuels below the legislated targets, using the discretion allowed by the law.
- Incorporation of modifications to existing state Renewable Portfolio Standard (RPS) or similar laws to reflect recent modifications to existing programs in Colorado, Connecticut, Maryland, Montana, Minnesota, Nevada, New Mexico, and Washington [5]. The changes that were enacted affect some aspects of the laws and implementing regulations, but in general they do not have significant substantive effects on the representation of the RPS programs in AEO2014.

There are many other pieces of legislation and regulation that might be enacted in the not-too-distant future, and some laws include sunset provisions that may be extended. However, it is difficult to discern future outcomes. Even in situations where existing legislation contains provisions to allow revision of implementing regulations, those provisions may not be exercised consistently. Many pending provisions are examined in alternative cases included in AEO2014 or in other analyses completed by the U.S. Energy Information Administration (EIA). In addition, at the request of both federal agencies and Congress, EIA has regularly examined the potential implications of other possible energy options in special analyses that can be found on the EIA website at http://www.eia.gov/analysis/reports.cfm?t=138.

LR1. Recent environmental regulations in the electric power sector

Several environmental rules recently implemented at the federal and state levels affect the AEO2014 projections for the electric power sector. While not considered in the AEO2014 Reference case, the EPA is also currently in the process of developing new rules to address electric power plant air emissions, the impact of cooling water intake systems on aquatic life, and coal ash disposal methods. New rules that may be promulgated could have significant impacts on the projected fuel mix for electric power generation. The following discussion summarizes programs and rules included in the AEO2014 Reference case.

Recent regional policy modifications

The Regional Greenhouse Gas Initiative (RGGI) is a regional cap-and-trade program for CO_2 emissions that applies specifically to fossil-fueled electric power plants larger than 25 megawatts (MW) located in each of the nine participating Northeastern states [6]. When it took effect in 2009, RGGI became the first mandatory market-based (cap-and-trade) CO_2 reduction program in the United States. The cap was tightened primarily because actual CO_2 emissions in the region since the start of the program in 2009 have been roughly 35% below the cumulative cap. The lower level of emissions is attributed primarily to historically low natural gas prices, which have shifted a large share of electricity generation in the region toward natural gas, and to lower overall electricity demand.

CO_2 emissions in the RGGI region comprised only 4% of the total emissions from the electric power sector in the United States in 2012. RGGI is one of the two legally mandated CO_2 cap-and-trade reduction programs in the United States, the other being the California cap-and-trade program that was an outgrowth of California's Assembly Bill 32, the Global Warming Solutions Act of 2006 (AB 32) [7].

In 2005, when CO_2 emissions in the participating states reached their annual peak, coal comprised 23%, natural gas 25%, and petroleum 12% of the regional generation mix. By 2012, coal's share had declined to 9%, the natural gas share had risen to 44%, and the petroleum share had fallen below 1%.

At the same time that the shift in fuels for electricity generation has lowered the carbon intensity of electricity generation in the region, demand for electricity in the Northeast has been flat or declining. Average annual retail electricity sales in the nine participating states from 2009 through 2012 were 6% below the annual sales in 2005.

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Despite the reduction in the cap beginning in 2014, it remains to be seen whether the updated program caps will result in significant emissions reductions compared to the outcomes that might occur absent the new caps. CO_2 emissions in 2012 in the participating states were still only 92 million short tons, close to the 2014 target cap of 91 million short tons. However, the cap is designed to tighten annually through 2020. In the first half of 2013, CO_2 emissions from coal-fired generation were up both in the RGGI region and nationally compared with 2012 levels, which indicates that the revised cap could become more binding in the future.

Because of a surplus of allowances during the initial years of RGGI, the CO_2 value of the allowances remained close to the program's price floor of $1.93/ton of CO_2 allowed in each quarterly auction. The value of allowances increased to $3.00/ton of CO_2 in the latest auction, as market participants may be anticipating a rise in the future value of allowances. RGGI states use allowance revenues for a variety of programs that support cleaner generation and/or energy efficiency programs that reduce demand. Unless the programs supported by RGGI auction revenues are funded at the same level using other funding sources in the absence of RGGI, they will provide a tangible incremental reduction in emissions.

The RGGI program update grants the ability for previously unused allowances from the early years of the program to be saved and applied after 2014, as limits become more stringent—a strategy often referred to as "banking allowances." Additional flexibility exists in the program through the recently created Cost Containment Reserve, which effectively creates a price ceiling for allowances. When the price hits a given level, program participants can purchase a set level of allowances at a defined fixed price. This ceiling is intended to prevent allowance prices from rising above defined levels. The price trigger starts at $4/ton of CO_2 in 2014 and rises to $10/ton of CO_2 in 2017.

The program also allows for the limited use of CO_2 offsets as a compliance option. RGGI program participants are permitted to cover 3.3% of their emissions using offsets. Although the RGGI caps have been lowered, it remains to be seen how much the new caps will affect generation choices and related emissions.

Recent federal environmental regulations modeled in AEO2014

The Mercury and Air Toxics Standards (MATS) [8] requires fossil-fuel steam electric generators to meet limits based on maximum achievable control technologies (MACT) to control emissions of acid gases, toxic metals, and mercury. The standards will take effect by April 2015 for electric generation units with capacities greater than 25 MW. The rule allows for state environmental permitting agencies to grant one-year compliance extensions, which AEO2014 assumes will be granted, and all applicable units must begin to comply with the rule at the beginning of 2016. AEO2014 assumes that, in order to comply with the rule, all qualifying coal-fired power plants will be equipped with either flue gas desulfurization (FGD) scrubbers or dry sorbent injection (DSI) systems and activated carbon injection if warranted for mercury control. The control equipment needed to reduce mercury is specific to each plant configuration and coal type [9].

MATS is currently being challenged in the U.S. Court of Appeals for the District of Columbia Circuit in *White Stallion Energy Center et al. v. U.S. EPA* [10]. The case was heard in December 2013, and a decision is expected in the spring of 2014.

The Clean Air Interstate Rule (CAIR) [11] is a cap-and-trade program aimed at reducing emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X) from fossil-fueled power plant units with capacities greater than 25 MW in 27 eastern states and the District of Columbia. The emissions caps went into effect in 2009 for NO_X and in 2010 for SO_2. Both caps are scheduled to be tightened in 2015. AEO2014 includes the CAIR cap-and-trade program for the applicable regions. The FGD scrubbers or DSI systems required by MATS result in SO_2 emissions falling to levels lower than the CAIR cap. Therefore, after MATS is in full effect starting in 2016, SO_2 emissions decline significantly below the CAIR cap, essentially making CAIR's SO_2 cap nonbinding [12].

CAIR was reinstated after the Cross-State Air Pollution Rule (CSAPR) was vacated by the U.S. Court of Appeals for the District of Columbia Circuit in August 2012 [13]. However, the U.S. Supreme Court agreed in June 2013 to review the D.C. Circuit Court's decision and heard the case in December 2013 [14]. A court decision is expected in the spring of 2014. If the Supreme Court reverses the D.C. Circuit Court's ruling, CSAPR will replace CAIR.

LR2. Handling of the Renewable Fuels Standard in AEO2014

The Renewable Fuel Standard (RFS) was established by the Energy Policy Act of 2005 [15] and was expanded by the Energy Independence and Security Act of 2007 (EISA2007) [16]. It requires the EPA to set requirements for the renewable content of gasoline and diesel fuel. Refiners and importers of gasoline and diesel fuel are obligated to blend renewable fuels in proportion to the volumes of gasoline and diesel fuel sold. There are four interrelated requirements, for cellulosic biofuels, biomass-based diesel, advanced biofuels, and total renewable fuels. Compliance with the RFS is tracked via Renewable Identification Numbers (RINs), which are generated when eligible biofuels are produced or imported and conveyed with the physical volume of renewable fuel through subsequent sales until they are blended with a petroleum product. Once the fuel is blended, the RINs can be separated from the physical volumes and "retired"—that is, turned in to the EPA to demonstrate compliance. RINs also can be sold or saved ("banked") for compliance either in the year they were generated or in the following year.

EPA sets the RFS target volumes every year in reference to legislated targets in EISA2007, public comments, and input from other government agencies. Since the expansion of the RFS program for the 2009 compliance year, the EPA has adhered to the legislated volumes of total renewable fuel, advanced biofuel, and biomass-based diesel but has often set the requirement for

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cellulosic biofuel well below the legislated target, given the very low commercial availability of cellulosic biofuel. EISA2007 also included new Corporate Average Fuel Economy (CAFE) standards, which have played and will continue to play a role in reducing gasoline consumption. Declines in gasoline consumption reduce the number of gallons of ethanol that can be used in E10, a fuel containing 10% ethanol by volume that is compatible with all existing gasoline-powered vehicles. EPA announced in its 2013 RFS final rule that it expected to reduce the total renewable fuel and advanced biofuel obligations to levels below the statutory levels for 2014, in order to allow the ethanol share of the gasoline pool to remain close to 10%.

The AEO2014 projections for quantities and costs of gasoline, diesel, and other liquid fuels are handled by the National Energy Modeling System's Liquid Fuels Market Model (LFMM), which includes a representation of the U.S. petroleum refining system, biofuels production, and marketing of liquid fuels to end users. The modeling structure allows for additions and adjustments in the liquid fuels supply chain in order to meet new demand or to comply with changing product specifications. A variety of feedstocks and technologies for the production of RIN-eligible renewable fuels can be represented, depending on the market and regulatory conditions (including future product specifications for gasoline and diesel fuel) for each AEO2014 case.

AEO2014 assumes that cellulosic fuel production and requirements will grow gradually from current low levels. For biomass-based diesel, the assumed production requirement is constant at 1.92 billion ethanol-equivalent gallons. The advanced biofuels production requirement, on the other hand, decreases by 425 million gallons from 2014 to 2015.

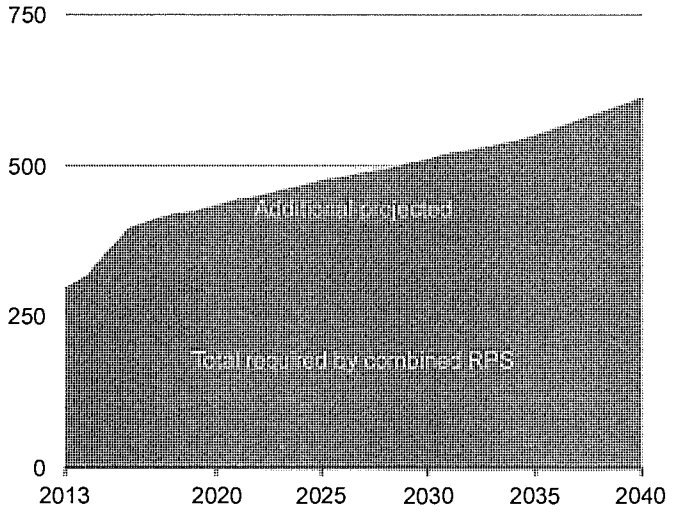
The reintroduction of the $1.00-per-gallon biodiesel blending tax credit in 2013 incentivized biodiesel production above the RFS level. That tax credit sunset at the end of 2013, and the AEO2014 Reference case does not assume that it is reinstated. The California Low Carbon Fuels Standard is expected to draw more sugarcane ethanol into California, generating more advanced RINs. After 2015, the total quantity of advanced biofuels needed to meet the RFS is assumed to increase only slowly, remaining well below the legislated target of 21 billion gallons in 2022. The total biofuels production requirement was set at 15.2 billion gallons in 2014 to reflect the gasoline market's limited ability to absorb additional ethanol in the near term. The total renewable fuels requirement is also assumed to grow slowly and remains well below the legislated target of 36 billion gallons in 2022.

LR3. State renewable energy requirements and goals: update through 2013

To the extent possible, AEO2014 reflects state laws and regulations in effect at the end of October 2013 that require the addition of renewable generation or capacity by utilities doing business in the state [*17*] to meet RPS requirements. The projection does not include laws and regulations with either voluntary goals or targets that can be substantially satisfied with nonrenewable resources. In addition, the projection does not account for fuel-specific provisions—such as those for solar and offshore wind energy—as distinct targets. Where applicable, such distinct targets (sometimes referred to as "tiers," "set-asides," or "carve-outs") may be subsumed into the broader targets, or they may not be included in the model because they could be met with existing capacity and/or projected growth based on modeled economic and policy factors.

States are projected to meet their ultimate RPS targets in the AEO2014 Reference case. The RPS compliance constraints in most regions are approximated, however, because National Energy Modeling System is not a state-level model, and each state generally represents only a portion of one of the NEMS electricity regions. In general, EIA has confirmed the states' requirements through original legislative or regulatory documentation, although the Database of State Incentives for Renewables & Efficiency was also used to support those efforts [*18*]. The aggregate RPS requirement for various mandatory state programs, as modeled for AEO2014, is shown in Figure LR3-1. In 2025, the targets account for slightly less than 10% of U.S. electricity sales.

Figure LR3-1. Total qualifying renewable generation required for combined state renewable portfolio standards and projected total achieved, 2013-40 (billion kilowatthours)



At present, most states are meeting or exceeding their required levels of renewable generation, based on qualified generation or purchase of renewable energy credits [*19*]. A number of factors have helped to create an environment favorable for RPS compliance, including:

- A surge of new RPS-qualified generation capacity timed to take advantage of federal incentives.
- Significant reductions in the cost of wind, solar, and other renewable technologies.
- Generally slower growth of electricity sales.
- Complementary state and local policies that either reduce the cost (for example, equipment rebates) or increase the revenue streams (for example, net metering) associated with RPS-eligible technologies.

EIA projects that, overall, RPS-qualified generation will continue to meet or exceed aggregate mandatory targets for state RPS programs through 2040, as shown in Figure LR3-1.

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The aggregate near-term surplus of qualified generation is supported by projected near-term renewable capacity additions but declines slightly as growth in renewable capacity slows toward the end of this decade and RPS targets catch up with supply. The surplus widens again in the final two decades of the projection period, as renewable generation technologies become increasingly competitive with conventional generation sources and state targets generally do not increase beyond 2025.

It is important to note, however, that the aggregate targets and qualifying generation shown in Figure LR3-1 may mask significant regional variation, as well as technology- or tier-specific shortfalls. While some regions may produce excess qualifying generation, others may produce just enough to meet the requirement or may need to import generation from adjoining regions to meet state targets. Furthermore, even though there is more qualifying generation in aggregate than is needed to meet the targets, states with technology-specific goals could still have deficits for certain technologies. Also, this projected pattern of aggregate surplus does not necessarily imply that projected generation would be the same without state RPS policies. State RPS policies may encourage investment in places where it otherwise would not occur or would not occur in the amounts projected, even as other parts of the country see substantial growth above state targets or in their absence. It does, however, suggest that state RPS programs will not be the sole reason for future growth in renewable generation, and that the importance of RPS targets in contributing to growth in renewable generation will decline over time.

Currently, 29 states and the District of Columbia have enforceable RPS or similar laws (Table LR3-1) [*20*]. Under such standards, each state determines its own levels of renewable generation, eligible technologies [*21*], and noncompliance penalties. No new RPS programs have been enacted since 2009. There have been a number of modifications to existing programs in recent years, however, building on state implementation experience and changing market conditions.

The year 2013 saw a large number of proposed legislative modifications to existing RPS programs [*22*], including some attempts to weaken the targets of existing programs significantly. However, only a small subset was enacted, and no states passed major rollbacks or repeals of RPS programs. The changes that were enacted affect some aspects of the laws and implementing regulations, but in general they do not have substantive effects on the representation of state RPS programs in the AEO2014 Reference case. Key changes include:

Colorado

Senate Bill 13-252 [*23*], signed into law in June 2013, doubles the renewable energy target for large electric cooperatives and cooperative associations to 20% of total electric sales by 2020. The law also adds a renewable distributed generation requirement for electric cooperatives, removes preferential credit multipliers for in-state eligible sources, and expands the set of qualifying energy sources to include coal-mine methane and pyrolysis gas from municipal solid waste.

Connecticut

Senate Bill 1138 [*24*], enacted in June 2013, relaxes restrictions on how hydroelectric generation can be applied to Connecticut's RPS. The statute expands the set of qualifying Class I resources to include run-of-river hydropower up to 30 MW—an increase over the previous cap of 5 MW—as well as additional sources, such as geothermal electric and some types of biogas. In addition, large-scale hydropower (greater than 30 MW) could, under specified circumstances, be allowed to meet an increasing portion of the RPS, starting at 1% of sales in 2016 and rising to 5% of sales by 2020.

Maryland

The Maryland Offshore Wind Energy Act of 2013, House Bill 226 [*25*], was enacted in April 2013. The legislation adds to Maryland's existing RPS an offshore wind technology-specific requirement of up to 2.5% of total sales starting in 2017. Qualifying offshore facilities must be located in specific areas of the Outer Continental Shelf and are subject to a defined process for approval by the Maryland Public Service Commission. Projects will be subject to several cost containment triggers: the impact on residential customers cannot exceed $1.50 per month, and renewable energy credits for offshore wind should not exceed $190 per MWh.

Minnesota

In May 2013 Minnesota enacted House Floor 729 [*26*], which mandates that investor-owned utilities meet a solar technology-specific standard of 1.5% of sales by 2020. This minimum is in addition to Minnesota's previously existing target, effectively raising the total percentage of required renewable generation for investor-owned utilities by 1.5%. Of the new solar mandate, 10% must be achieved via small systems that are 20 kilowatts or less. The bill also directs investor-owned utilities to design a "value of solar" tariff that could be used in lieu of a traditional retail rate-compensated net metering agreement.

Montana

Montana enacted several bills during 2013 related to the state's RPS [*27*]. Major changes include expanding the set of RPS-qualifying technologies to include generation from additional sources, such as: incremental capacity additions at existing hydropower projects; storage technologies such as flywheels, batteries; and hydroelectric pumped storage; and certain types of chemically treated biomass burned at small plants. Small utilities serving 50 or fewer customers are now exempt from the obligation to meet the state's RPS.

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Table LR3-1. Renewable portfolio standards in the 29 states and District of Columbia with current mandates

State	Target	Qualifying renewables	Qualifying other (thermal, efficiency, nonrenewable distributed generation, etc.)	Compliance mechanisms
AZ	15% by 2025	Solar, wind, biomass, hydro, landfill gas (LFG), anaerobic digestion built after January 1, 1997, geothermal	Direct use of solar heat, ground-source heat pumps, renewable-fueled combined heat and power (CHP), fuel cells	Credit trading is allowed, with some bundling restrictions. Includes distributed generation requirement, starting at 5% of target in 2007, growing to 30% by 2012 and beyond.
CA	33% by 2020	Solar, wind, biomass, geothermal, LFG and municipal solid waste (MSW), small hydro, biodiesel, anaerobic digestion, marine	Energy storage, fuel cells	Credit trading is allowed, with some restrictions. Renewable energy credit prices are capped at $50 per MWh.
CO	30% by 2020 for investor-owned utilities; 20% by 2020 for large electric cooperatives; 10% by 2020 for other cooperatives and municipal utilities serving more than 40,000 customers	Solar, wind, hydro, biomass, geothermal electric, anaerobic digestion, LFG	Recycled energy, coal-mine methane, pyrolysis gas produced from MSW, fuel cells	Credit trading is allowed. Renewable distributed generation requirement applies to investor-owned utilities (3% of sales by 2020) and electric cooperatives (0.75% or 1% of sales by 2020, depending on size). Generation associated with certain projects that have specific ownership or transmission ties with small utilities, entities, or individuals is eligible to earn credit multipliers.
CT	27% by 2020 (23% renewables, 4% efficiency and CHP)	Solar, wind, biomass, hydro (with exceptions), geothermal, LFG/MSW, anaerobic digestion and other biogas, marine	CHP, fuel cells	Credit trading is allowed. Obligated providers may comply via an alternative compliance payment of $55 per MWh. The target is made up of three class tiers, with tier-specific targets.
DE	25% by 2026	Solar, wind, biomass, hydro, geothermal, LFG, anaerobic digestion, marine	Fuel cells	Credit trading is allowed. Credit multipliers are awarded for several compliance specifications, including a 300% credit awarded for generation from in-state distributed solar and renewable-fueled fuel cells. Target increases for some suppliers can be subject to a cost threshold.
DC	20% by 2020	Solar, wind, biomass, hydro, geothermal, LFG/MSW, marine	Direct use of solar, cofiring, fuel cells	Credit trading allowed. The target includes a solar-specific set-aside, equivalent to 2.5% of sales by 2023. Obligated providers may also comply via a tier-specific alternative compliance payment.
HI	40% by 2030	Solar, wind, biomass, hydro, geothermal, LFG/MSW, anaerobic digestion, marine, certain biofuels	Direct use of solar, ground-source heat pumps, ice storage, CHP, efficiency programs, hydrogen, fuel cells	Credits cannot be traded. Eligibility of several of the "qualifying other" displacement technologies is restricted after 2015. Utility companies can calculate compliance over all utility affiliates.
IL	25% by 2026	Solar, wind, biomass, hydro, anaerobic digestion, biodiesel, LFG	None	Credit trading is allowed. Target includes specific requirements for wind, solar, and distributed generation. The procurement process is subject to a cost cap.
IA	105 MW of eligible renewable resources	Solar, wind, some types of biomass and waste, small hydro, anaerobic digestion, LFG	None	Iowa's investor-owned utilities are currently in full compliance with this standard, achieved primarily through wind capacity.

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Table LR3-1. Renewable portfolio standards in the 29 states and District of Columbia with current mandates (cont.)

State	Target	Qualifying renewables	Qualifying other (thermal, efficiency, nonrenewable distributed generation, etc.)	Compliance mechanisms
KS	20% of each peak demand capacity by 2020	Solar, wind, hydro, biomass, LFG	Direct use of solar heat, fuel cells	Credit trading is allowed. Eligible in-state capacity counts for 1.1 times its actual capacity.
ME	40% total by 2017, 10% by 2017 from new resources entering service in 2005 and beyond	Solar, wind, biomass, hydro, geothermal, LFG/MSW, marine, hydro	CHP, fuel cells	Credit trading is allowed. The Maine Public Utilities Commission sets an annually adjusted alternative compliance payment. Community-based generation projects are eligible to earn credit multipliers.
MD	20% by 2022	Solar, wind, biomass, geothermal, LFG/MSW, anaerobic digestion, marine, hydro	Solar water heating, ground-source heat pumps, fuel cells	Credit trading is allowed. The target includes minimum levels of compliance from solar and offshore wind. Utilities may pay an alternative compliance payment in lieu of procuring eligible sources, with a tier-specific compliance schedule.
MA	22.1% by 2020 (and an additional 1% per year thereafter)	Solar, wind, hydro, some biomass technologies, LFG/MSW, geothermal electric, anaerobic digestion, marine	Fuel cells	Credit trading is allowed. The target for new resources includes a solar-specific goal to achieve 400 MW of in-state solar capacity, which is translated into an annual target for obligated providers. Obligated providers may comply via an alternative compliance payment (ACP), which varies in level by the requirement class. The ACP is designed to be higher than the cost of other compliance options.
MI	10% by 2015, with specific new capacity goals for utilities that serve more than 1 million customers	Solar, wind, hydro, biomass, LFG/MSW, geothermal electric, anaerobic digestion, marine	CHP, coal with carbon capture and sequestration, energy efficiency measures for up to 10% of a utility's sales obligation	Credit trading is allowed. Solar power receives a credit multiplier; other generation and equipment features—such as peak generation, storage, and use of equipment manufactured in-state—can earn bonus credits.
MN	31.5% by 2020 (Xcel), 26.5% by 2025 (other investor-owned utilities), or 25% by 2025 (other utilities)	Solar, wind, hydro, biomass, LFG/MSW, anaerobic digestion	Cofiring, hydrogen	Credit trading is allowed. Target includes 1.5% solar standard for investor-owned utilities; Xcel's target also includes 25% of sales specifically from wind and solar (with a 1% maximum for solar). State regulators can penalize noncompliance at the estimated cost of compliance.
MO	15% by 2021, 0.3% of retail electricity sales from solar electricity by 2021	Solar, wind, hydro, biomass, LFG/MSW, anaerobic digestion, ethanol	Fuel cells	Credit trading is allowed. Noncompliance payments are set at double the market rate for renewables.
MT	15% by 2015	Solar, wind, hydro, geothermal, biomass, LFG, anaerobic digestion	Energy storage using renewable energy, fuel cells	Credit trading is allowed, with a price cap of $10 per MWh. There are specific targets for community-based projects.
NV	25% by 2025	Solar, wind, hydro, geothermal, biomass, LFG/MSW, biodiesel, anaerobic digestion	Waste tires, direct use of solar and geothermal heat, efficiency measures (which can account for one-quarter of the target in any given year)	Credit trading is allowed. Solar PV receives a credit premium, with an additional premium for customer-sited systems.
NH	24.8% by 2025	Solar, wind, small hydro, marine, LFG, biomass, anaerobic digestion, certain biodiesel fuels	Fuel cells, CHP, microturbines, direct use of solar heat, ground-source heat pumps, hydrogen	Credit trading is allowed, and utilities may pay into a fund in lieu of holding credits. The target has four separate compliance classes, by technology type.

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Table LR3-1. Renewable portfolio standards in the 29 states and District of Columbia with current mandates (cont.)

State	Target	Qualifying renewables	Qualifying other (thermal, efficiency, nonrenewable distributed generation, etc.)	Compliance mechanisms
NJ	20.38% by 2021 with an additional 4.1% solar by 2027	Solar, wind, hydro, geothermal, LFG/MSW, marine, anaerobic digestion	Fuel cells	Credit trading is allowed, with an alternative compliance payment set by state regulators. Solar and offshore wind are subject to separate requirements and have separate enforcement provisions.
NM	20% by 2020 for investor-owned utilities, 10% by 2020 for cooperatives	Solar, wind, hydro, geothermal, LFG, biomass, anaerobic digestion	Zero-emission technology (not including nuclear), fuel cells	Credit trading is allowed. The program cannot increase consumer costs beyond a threshold amount, increasing to 3% of annual costs by 2015. Technology minimums are established for wind, solar, and certain other resources.
NY	29% by 2015	Solar, wind, hydro, biomass, LFG, anaerobic digestion, certain biofuels, marine	Direct use of solar heat, CHP, fuel cells	Credit trading is not allowed. Compliance is achieved through purchases by state authorities, funded by a surcharge on investor-owned utilities. Government-owned utilities may have their own, similar programs.
NC	12.5% by 2021 for investor-owned utilities, 10% by 2018 for municipal and cooperative utilities	Solar, wind, small hydro, biomass, geothermal, LFG, marine, anaerobic digestion	Direct use of solar heat, CHP, hydrogen, demand reduction	Credit trading is allowed. Impacts on customer costs are capped at specified levels. There are specific targets for solar and certain animal waste projects.
OH	12.5% by 2024	Solar, wind, hydro, biomass, geothermal, LFG/MSW, anaerobic digestion	Energy storage, fuel cells, and a separate 12.5% target for "advanced energy technologies," including coal mine methane, advanced nuclear, efficiency, clean coal	Credit trading is allowed. Alternative compliance payments are set by law and adjusted annually. There is a separate target for solar electricity generation.
OR	5% by 2025 for utilities with less than 1.5% of total sales; 10% by 2025 for utilities with at least 1.5% but less than 3% of total sales; 25% by 2025 for all others	Solar, wind, hydro, biomass, geothermal, LFG/MSW, anaerobic digestion, marine	Hydrogen	Credit trading is allowed, with an alternative compliance payment and a limit on expenditures of 4% of annual revenue. Solar receives a credit multiplier.
PA	18% by 2020	Solar, wind, hydro, biomass, geothermal, LFG/MSW, anaerobic digestion	CHP, certain advanced coal technologies, certain energy efficiency technologies, fuel cells, direct use of solar heat, ground-source heat pumps, other distributed generation technologies	Credit trading is allowed, with an alternative compliance payment. Separate targets are set for solar and two different combinations of renewable, fossil, and efficiency technologies.
RI	16% by 2019	Solar, wind, hydro, biomass, geothermal, anaerobic digestion, LFG, biodiesel, marine	Fuel cells	Credit trading is allowed, with an alternative compliance payment. There is a separate target for 90 MW of new renewable capacity.
TX	Enforceable target of 5,880 MW by 2015	Solar, wind, hydro, biomass, geothermal, LFG, marine	Direct use of solar heat, ground-source heat pumps	Credit trading is allowed, with capacity targets converted to generation equivalents. State regulators may cap credit prices. 500 MW must be from resources other than wind.

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Table LR3-1. Renewable portfolio standards in the 29 states and District of Columbia with current mandates (cont.)

State	Target	Qualifying renewables	Qualifying other (thermal, efficiency, nonrenewable distributed generation, etc.)	Compliance mechanisms
WA	15% by 2020	Solar, wind, hydro, biomass, geothermal, LFG, anaerobic digestion, biodiesel, marine	CHP	Credit trading is allowed, with an administrative penalty for noncompliance.
WI	10% by 2015	Solar, wind, hydro, biomass, geothermal, LFG/MSW, small hydro, anaerobic digestion, marine, biogas	CHP, pyrolysis, synthetic gas, direct use of solar or biomass heat, ground-source heat pumps, fuel cells	Credit trading is allowed.

Nevada

In June 2013 Nevada enacted Senate Bill 252 [*28*], which places new limits on the extent to which energy efficiency measures count toward the state's existing standard. The bill also restricts multiplier credits for customer-sited solar generation to installations placed in service before the end of 2015. The obligated utility, Nevada Energy, is also now required by Senate Bill 123 [*29*] to meet a capacity standard of 350 MW of new renewable capacity by the end of 2021. However, the same capacity can also be applied to the existing sales-based standard and thus does not necessarily require additional capacity beyond that which may have been required to meet the existing standard.

Washington

Washington enacted two bills—Senate Bills 5400 [*30*] and 5297 [*31*]—that increase compliance flexibility options for certain providers. Under Senate Bill 5400, utilities that serve customers in multiple states are now allowed to meet their obligations with sources from those states. Senate Bill 5297 allows for the use of "coal transition power" for compliance under very specific circumstances for utilities not experiencing load growth.

LR4. U.S. response to the nuclear accident at Fukushima Daiichi

Since the March 2011 accident at Japan's Fukushima Daiichi nuclear power plant, the U.S. Nuclear Regulatory Commission (NRC) and the U.S. nuclear industry have been working to address issues related to the accident. The NRC and the U.S. nuclear industry initiated an immediate coordinated response to the accident, as well as long-term actions intended to assure the safety of operating and planned reactors in the United States. The ultimate cost of complying with NRC orders and proposed regulations and industry-led initiatives remains uncertain, as do the potential impacts on nuclear power plant operations. Although they are not specifically modeled in AEO2014, NRC actions and industry initiatives are being monitored by EIA so that potential costs and operational impacts can be included in future AEOs.

The NRC conducted a systematic and methodical review of its own processes and regulations in light of the accident at Fukushima. On July 12, 2011, the NRC's Near-Term Task Force released its report, *Recommendations for Enhancing Reactor Safety in the 21st Century* [*32*]. The report contains 12 recommendations, including both short- and long-term actions for consideration, and prioritizes the implementation of the recommendations.

In order to address the short-term recommendations, the NRC issued three orders in March 2012 that require nuclear power plants to implement measures related to lessons learned from the Fukushima accident, as follows:

- All boiling-water reactors (BWRs) with Mark I and II containment systems must have reliable hardened containment venting capability to reduce pressure and hydrogen buildup. This may require improving or replacing existing containment ventilation systems [*33*].
- Reactors must have enhanced instrumentation installed to monitor water levels in their spent fuel pools in the event of an emergency [*34*].
- Nuclear power plants must be capable of responding to multiple simultaneous events and ensuring that reactors and spent fuel pools remain cooled. The order specifies a three-phase approach involving use of installed on-site resources, use of portable on-site equipment, and indefinite use of off-site resources [*35*].

The NRC stated that, in all cases, the existing fleet of reactors can continue operating safely while implementing the orders. The orders were effective immediately and included timetables for responses and actions.

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In the three orders listed above, the NRC required an integrated plan to be submitted by February 2013, with initial status reports due in 60 days. The NRC specified that operating reactors must complete modifications within two refueling cycles after submitting an integrated plan, or by the end of 2016, whichever comes first. Any reactor with a construction permit issued under 10 CFR Part 50 (e.g., Watts Bar Unit 2) was required to comply with the above orders prior to receiving an operating license. Any reactor issued a Combined Operating License (COL) under 10 CFR Part 52 (i.e., Vogtle Units 3 and 4 and Summer Units 2 and 3) was required to implement all requirements in the orders before the initial fuel loading. Compliance assessments are underway at nuclear power plants. The requirements of the orders remain in place until superseded by other orders or rulemaking. As discussed below, NRC is considering or has initiated rulemaking on several topics, and some of the dates established in the original orders have been modified.

In November 2012, as an addition to the original order issued to address more robust containment venting systems, the NRC began considering whether to propose a rule that would require containment venting systems to filter all releases during an accident for boiling water reactors with Mark I and Mark II containments [*36*]. If the NRC decides to pursue such a rulemaking, a final rule could be issued in 2017 [*37*].

Utilities continue to provide documentation to the NRC on equipment procured to respond to a prolonged loss of power at a reactor (station blackout) as well as spent fuel pool water level monitoring instrumentation. In March 2013, the NRC decided to proceed with a rulemaking to address station blackout mitigation [*38*]. In its July 2013 regulatory basis document [*39*], the NRC noted: "One dual-unit site estimated that the order may cost approximately $25 million, while a second dual-unit site estimated the cost at $43 million." The final rule is scheduled for issuance by December 2016.

By June 2013, two detailed inspections (or "walkdowns") had been completed at each reactor to evaluate potential seismic and flooding hazards. The NRC is in the process of auditing the results of the walkdowns. All flooding re-evaluations are due to the NRC by March 2015 [*40*]. The NRC will review the analyses and issue a safety assessment for each site. For nuclear power plants requiring a seismic risk analysis, the NRC performed a prioritization of plants in the Central and Eastern United States (CEUS) and the Western United States (WUS). Plants in more seismically active WUS and CEUS locations will complete risk evaluations by June 2017, and those in less active CEUS locations will complete risk evaluations by December 2019 [*41*].

In November 2013, the NRC announced proposed rulemaking language to ". . . strengthen and integrate onsite emergency response capabilities." [*42*] The final rule, which is likely to be issued in March 2016, is expected to address accident mitigation strategies; integration of accident mitigation procedures; identification of command and control roles during an accident; conduct of drills and exercises; training; and include severe accident situations in examinations for reactor operators. In its comments [*43*] on the NRC's draft regulatory basis [*44*], the Nuclear Energy Institute (NEI) estimated a cost of $17 million for the nuclear fleet—or $275,000 per unit—to develop and implement new training plans. NEI also estimated increased training costs of $250,000 per site per year and annual severe accident drill costs of $250,000 per site.

In addition to the NRC actions described above, the Electric Power Research Institute (EPRI), the Institute of Nuclear Power Operations (INPO), and NEI formed a Fukushima Response Steering Committee to integrate and coordinate the industry's response to the accident. In February 2012, the Steering Committee jointly released a report, *The Way Forward: U.S. Industry Leadership in Response to Events at the Fukushima Daiichi Nuclear Power Plant*, which discusses activities to oversee and coordinate responses to emergencies [*45*]. INPO prepared a detailed report on post-accident events at Fukushima Daiichi [*46*], and on November 11, 2011, the detailed report was provided to the U.S. Congress, the NRC, and the U.S. nuclear industry. The nuclear industry, through NEI, developed its FLEX strategy—a comprehensive, flexible, and integrated plan to mitigate the effects of severe natural phenomena and to take steps to achieve safety benefits quickly [*47*]. The FLEX approach, implemented in 2012, was informed by the industry's response to the September 11, 2001, terrorist attacks in the United States. Two regional response centers will be located near Memphis, Tennessee, and Phoenix, Arizona. From those regional response centers, critical emergency equipment can be delivered to nuclear power plants within 24 hours. The regional response centers are planned to be fully operational by August 2014 [*48*].

In addition to activities that focus on reactors and the utilities that operate them, the NRC has spent more than two years evaluating how best to respond to the first of the 12 recommendations made in the July 2011 *Near-Term Task Force Review of Insights from the Fukushima Dai-Ichi Accident* [*49*], which recommended establishment of a "logical, systematic, and coherent regulatory framework for adequate protection that appropriately balances defense-in-depth and risk considerations." Defense-in-depth is a layered approach to safety that involves the use of multiple redundant and independent safety systems. NRC's evaluation of this recommendation [*50*] was discussed publicly in January 2014 and included proposed actions on a policy statement that would detail, among other things, the decision criteria for ensuring adequate defense-in-depth. The proposed actions also identify the need to clarify the role of voluntary industry initiatives in the NRC regulatory process.

The ultimate cost to the nuclear industry of addressing Fukushima-related issues remains uncertain, as do the potential impacts on nuclear power plant operations. In a meeting with the NRC in April 2013, Dominion Energy estimated that the cost of post-Fukushima actions could be $30 to $40 million per unit and $180 to $240 million for its fleet of six units [*51*, *52*]. AEO2014 does not include potential post-Fukushima effects on nuclear capacity and generation, but costs and operational impacts will be monitored for inclusion in future AEOs as NRC actions and industry initiatives progress.

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Endnotes for legislation and regulations

Links current as of January 2014

1. A complete list of the laws and regulations included in AEO2014 is provided in *Assumptions to the Annual Energy Outlook 2014*, Appendix A, http://www.eia.gov/forecasts/aeo/assumptions/pdf/0554(2014).pdf.
2. Regional Greenhouse Gas Initiative, "2012 Program Review" (New York, NY: February 7, 2013), http://www.rggi.org/design/program-review.
3. U.S. Government Printing Office, "Energy Policy Act of 2005, Public Law 109-58" (Washington, DC: August 8, 2005), http://www.gpo.gov/fdsys/pkg/PLAW-109publ58/pdf/PLAW-109publ58.pdf.
4. U.S. Government Printing Office, "Energy Independence and Security Act of 2007, Public Law 110-140," (Washington, DC: December 19, 2007), http://www.gpo.gov/fdsys/pkg/PLAW-110publ140/pdf/PLAW-110publ140.pdf.
5. Colorado State University, Center for the New Energy Economy, "State Renewable Portfolio Standards Hold Steady or Expand in 2013 Session" (Fort Collins, CO: 2013), http://www.aeltracker.org/graphics/uploads/2013-State-By-State-RPS-Analysis.pdf.
6. The nine participating RGGI states are Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, Connecticut, New York, Delaware, and Maryland.
7. California Environmental Protection Agency, Air Resources Board, "Assembly Bill 32: Global Warming Solutions Act" (Sacramento, CA: September 27, 2006), http://www.arb.ca.gov/cc/ab32/ab32.htm.
8. U.S. Environmental Protection Agency, "Mercury and Air Toxics Standards (MATS)" (Washington, DC: last updated March 27, 2012), http://www.epa.gov/mats.
9. U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2013*, DOE/EIA-0554(2013) (Washington, DC: May 2013), http://www.eia.gov/forecasts/aeo/assumptions. Table 8.8 indicates how much of a plant's uncontrolled mercury emissions are removed by a specific configuration of environmental control equipment for a given coal type. The strategies used by coal plants to comply with the mercury, acid gases, and toxic metals are discussed in the documentation.
10. *White Stallion Energy Center, LLC, et al. v. United States Environmental Protection Agency*, USCA Case #12-1100 (January 22, 2013), http://www.4cleanair.org/Documents/AdminBriefMATS.pdf.
11. U.S. Environmental Protection Agency, "Clean Air Interstate Rule (CAIR)" (Washington, DC: December 19, 2012), http://www.epa.gov/cair/index.html#older.
12. Further details on the modeling strategies for MATS and CAIR can be found in the forthcoming report, *Assumptions to the Annual Energy Outlook 2014*, and the forthcoming *Electricity Market Module of the National Energy Modeling System Model Documentation 2014*.
13. United States Court of Appeals for the District of Columbia Circuit, *EME Homer City Generation, L.P., v. Environmental Protection Agency, et al.*, No. 11-1302 (decided August 21, 2012), http://www.cadc.uscourts.gov/internet/opinions.nsf/19346B280C78405C85257A61004DC0E5/$file/11-1302-1390314.pdf.
14. U.S. Environmental Protection Agency, *United States Environmental Protection Agency, et al., v. EME Homer City Generation, L.P., et al., Petition for a Writ of Certiorari*, http://www.epa.gov/airmarkets/airtransport/CSAPR/pdfs/EME_Homer_City_Pet.pdf.
15. U.S. Government Printing Office, "Energy Policy Act of 2005, Public Law 109-58" (Washington, DC: August 8, 2005), http://www.gpo.gov/fdsys/pkg/PLAW-109publ58/pdf/PLAW-109publ58.pdf.
16. U.S. Government Printing Office, "Energy Independence and Security Act of 2007, Public Law 110-140" (Washington, DC: December 19, 2007), http://www.gpo.gov/fdsys/pkg/PLAW-110publ140/pdf/PLAW-110publ140.pdf.
17. Does not include the RPS policy for Hawaii, because NEMS provides electricity market projections only for the contiguous lower 48 states.
18. More information about the Database of State Incentives for Renewables & Efficiency (DSIRE) can be found at http://www.dsireusa.org.
19. G. Barbose, "Renewable Portfolio Standards in the United States: A Status Update" (November 2013), http://emp.lbl.gov/sites/all/files/rps_summit_nov_2013.pdf.
20. Enumerations of state RPS policies may vary from source to source, as these policies vary significantly from state to state with no universal definition. Previous enumerations of 30 state RPS policies by EIA have included a policy in West Virginia that allows for several types of fossil generators to be built instead of renewable generators to meet the portfolio requirement. However, because EIA does not model this in the *Annual Energy Outlook* as an RPS, it is not included in the current enumeration.
21. Eligible technologies, and even the definitions of technologies or fuel categories, vary by state. For example, one state's definition of renewables may include hydropower while another's may not. Table LR-1 provides more detail on how the technology or fuel category is defined by each state.

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22. Colorado State University, "State Renewable Portfolio Standards Hold Steady or Expand in 2013 Session," *Center for the New Energy Economy* (Fort Collins, CO: July 2013), http://www.aeltracker.org/graphics/uploads/2013-State-By-State-RPS-Analysis.pdf.
23. State of Colorado General Assembly, "Senate Bill 13-252" (June 5, 2013), http://www.leg.state.co.us/clics/clics2013a/csl.nsf/fsbillcont3/D1B329AEB8681D4D87257B3900716761?open&file=252_enr.pdf.
24. State of Connecticut General Assembly, "Senate Bill 1138" (June 5, 2013), http://www.cga.ct.gov/2013/ACT/PA/2013PA-00303-R00SB-01138-PA.htm.
25. State of Maryland General Assembly, "House Bill 226: Maryland Offshore Wind Energy Act of 2013" (April 2013), http://mgaleg.maryland.gov/2013RS/bills/hb/hb0226e.pdf.
26. State of Minnesota Legislature, "House Floor 729" (May 2013), https://www.revisor.mn.gov/laws/?id=85&year=2013&type=0.
27. State of Montana Legislature, "Summary of Energy and Telecommunications Legislation: 2013 Legislative Session" (2013), http://leg.mt.gov/content/Committees/Interim/2013-2014/Energy-and-Telecommunications/Committee-Topics/2013EnergyBills.pdf.
28. State of Nevada Legislature, "Senate Bill 252" (June 2013), http://www.leg.state.nv.us/Session/77th2013/Bills/SB/SB252_EN.pdf.
29. State of Nevada Legislature, "Senate Bill 123" (June 2013), http://www.leg.state.nv.us/Session/77th2013/Bills/SB/SB123_EN.pdf.
30. State of Washington Legislature, "Senate Bill 5400" (April 2013), http://apps.leg.wa.gov/documents/billdocs/2013-14/Pdf/Bills/Session%20Laws/Senate/5400-S.SL.pdf.
31. State of Washington Legislature, "Senate Bill 5297" (April 2013), http://apps.leg.wa.gov/documents/billdocs/2013-14/Pdf/Bills/Session%20Laws/Senate/5297.SL.pdf.
32. U.S. Nuclear Regulatory Commission, *Recommendations for Enhancing Reactor Safety in the 21st Century* (Washington, DC: July 12, 2011), http://pbadupws.nrc.gov/docs/ML1118/ML111861807.pdf.
33. U.S. Nuclear Regulatory Commission, *Issuance of Order to Modify Licenses with Regard to Reliable Hardened Containment Vents* (Washington, DC: March 12, 2012), http://www.oecd-nea.org/nsd/fukushima/documents/NRC12March2012OrderonHardenedContainmentVents.pdf.
34. U.S. Nuclear Regulatory Commission, *Order Modifying Licenses with Regard to Reliable Spent Fuel Pool Instrumentation (Effective Immediately)* (Washington, DC: March 12, 2012), http://pbadupws.nrc.gov/docs/ML1205/ML12056A044.pdf.
35. U.S. Nuclear Regulatory Commission, *Issuance of Order to Modify Licenses with Regard to Requirements for Mitigation Strategies for Beyond-Design-Basis External Events* (Washington, DC: March 12, 2012), http://pbadupws.nrc.gov/docs/ML1205/ML12054A735.pdf.
36. U.S. Nuclear Regulatory Commission, *Policy Issue Notation Vote: Consideration of Additional Requirements for Containment Venting Systems for Boiling Water Reactors with Mark I and Mark II Containments* (Washington, DC: November 26, 2012), http://www.nrc.gov/reading-rm/doc-collections/commission/secys/2012/2012-0157scy.pdf.
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Figure and table sources

Links current as of January 2014

Figure LR3-1. Total qualifying renewable generation required for combined state renewable portfolio standards and projected total achieved, 2013-40: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Table LR3-1. Renewable portfolio standards in the 29 States and District of Columbia with current mandates: U.S. Energy Information Administration, Office of Energy Analysis. Based on a review of enabling legislation and regulatory actions from the various States of policies identified by the Database of State Incentives for Renewables & Efficiency (as of January 15, 2014), website www.dsireusa.org.

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Issues in focus

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Introduction

The "Issues in focus" section of the *Annual Energy Outlook* (AEO) provides in-depth discussions on topics of special significance, including changes in assumptions and recent developments in technologies for energy production and consumption. Selected topics from recent AEOs are listed in Table IF-1.

Selected quantitative results from the issues discussed in AEO2014 are available in Appendix D. The first topic updates a discussion included in a number of previous AEOs, comparing the Reference case projections with two cases based on different assumptions about the future course of existing energy policies: one assumes the elimination of sunset provisions for various energy tax credits that are scheduled to expire under current law; the other assumes—in addition to the elimination of sunset provisions on various tax credits—the extension or expansion of three existing policies: corporate average fuel economy (CAFE) standards, appliance standards, and building code improvements.

Other topics discussed in this section include:

- U.S. tight oil production trends and supply projections based on alternative assumptions and a methodology using well-level data aggregated to the county level
- Potential of liquefied natural gas as a freight locomotive fuel
- Impacts of demographic issues and travel behavior on light-duty vehicle (LDV) energy demand
- Impacts of lower natural gas prices on industrial production
- Implications of accelerated power plant retirements
- Variations in renewable electricity projections in AEO2014 cases
- Implications of lower growth in electricity demand.

Table IF-1. Key analyses from "Issues in focus" in recent AEOs

AEO2013	AEO2012	AEO2011
U.S. reliance on imported liquid fuels in alternative scenarios	Potential efficiency improvements and their impacts on end-use energy demand	Increasing light-duty vehicle greenhouse gas and fuel economy standards for model years 2017 to 2025
Competition between coal and natural gas in the electric power sector	Energy impacts of proposed CAFE standards for light-duty vehicles, model years 2017 to 2025	Fuel consumption and greenhouse gas emissions standards for heavy-duty vehicles
Nuclear power in AEO2013	Impacts of a breakthrough in battery vehicle technology	Potential efficiency improvements in alternative cases for appliance standards and building codes
Effect of natural gas liquids growth	Heavy-duty natural gas vehicles	Potential of offshore crude oil and natural gas resources
	Changing structure of the refining industry	Prospects for shale gas
	Changing environment for fuel use in electricity generation	Cost uncertainties for new electric power plants
	Nuclear power in AEO2012	Carbon capture and storage: Economics and issues
		Power sector environmental regulations on the horizon

Sources: U.S. Energy Information Administration, *Annual Energy Outlook 2013*, DOE/EIA-0383(2013) (Washington, DC: April 2013); U.S. Energy Information Administration, *Annual Energy Outlook 2012*, DOE/EIA-0383(2012) (Washington, DC: June 2012); and U.S. Energy Information Administration, *Annual Energy Outlook 2011*, DOE/EIA-0383(2011) (Washington, DC: April 2011).

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IF1. No Sunset and Extended Policies cases

Two alternative cases are discussed in this section to provide insight into the sensitivity of the Reference case to scenarios, in which existing tax credits that have sunset dates are assumed not to sunset (No Sunset case), or other policies (i.e., CAFE standards, appliance standards, and building codes) are expanded beyond current provisions in combination with the elimination of the sunset dates on existing tax credits (Extended Policies case). No attempt is made to cover the full range of possible uncertainties in these areas, and readers should not view the cases discussed as EIA projections of how laws or regulations are likely to, or should, be changed. The cases examined here look only at federal laws or regulations and do not examine state laws or regulations.

The No Sunset and Extended Polices cases generally lead to lower estimates for overall delivered energy consumption, increased use of renewable fuels (particularly for electricity generation), reduced energy-related carbon dioxide (CO_2) emissions, lower energy prices, and lower government tax revenues.

Background

The AEO2014 Reference case is best described as a current laws and regulations case, because it generally assumes that existing laws and regulations remain unchanged throughout the projection period unless the legislation establishing the regulations sets a sunset date or specifies how they will change. The Reference case often serves as a starting point for analysis of proposed changes in legislation or regulations. While this definition of the Reference case supports a variety of further analysis, there may be interest in alternative cases that reflect updates or extensions of current laws and regulations that the AEO2014 Reference case excludes. Areas of particular interest include:

- Laws or regulations that have a history of being extended beyond their legislated sunset dates. Examples include the various tax credits for renewable fuels and technologies, which have been extended with or without modifications several times since their initial implementation.
- Laws or regulations that call for periodic updating of initial specifications. Examples include appliance efficiency standards issued by the U.S. Department of Energy (DOE) and Corporate Average Fuel Economy (CAFE) and greenhouse gas (GHG) emissions standards for vehicles issued by the National Highway Traffic Safety Administration (NHTSA) and the U.S. Environmental Protection Agency (EPA).
- Laws or regulations that allow or require the appropriate regulatory agency to issue new or revised regulations under certain conditions. Examples include the numerous provisions of the Clean Air Act that require EPA to issue or revise regulations if it finds that an environmental quality target is not being met.

Analysis cases

The two cases prepared—the No Sunset case and the Extended Policies case—incorporate all the assumptions from the AEO2014 Reference case, except as identified below.

No Sunset case

The sunset provisions for tax credits are eliminated for renewable energy sources in the utility, industrial, and buildings sectors and for energy-efficient equipment in the buildings sector, including the following:

- The production tax credit (PTC) of 1.1 or 2.3 cents/kilowatthour (kWh), depending on the technology, and the 30% investment tax credit (ITC) available for wind, geothermal, biomass, hydroelectric, and landfill gas resources are extended indefinitely as opposed to expiring at the end of 2013.
- For solar power investments, a 30% ITC that is scheduled to revert to a 10% credit in 2016 is assumed to be extended indefinitely at 30%.
- In the buildings sector, personal tax credits for the purchase of energy-efficient and renewable equipment, including photovoltaics (PV), are assumed to be extended indefinitely, as opposed to ending in 2013 or in 2016, respectively, as prescribed by current law. The business ITCs for commercial-sector generation technologies and geothermal heat pumps are assumed to be extended indefinitely, as opposed to expiring in 2016. The business ITC for solar systems is assumed to remain at 30% instead of reverting to 10%.
- In the industrial sector, the 10% ITC for combined heat and power (CHP), which is assumed to end in 2016 in the AEO2014 Reference case [1], is assumed in the No Sunset case to be preserved through 2040.
- The $1.01/gallon (nominal) subsidy for cellulosic ethanol and $1.00/gallon (nominal) biodiesel subsidy are assumed to be extended at those levels from their recent expiration at the end of 2013 through the end of the projection period [2].

Extended Policies case

The Extended Policies case includes additional updates to federal equipment efficiency standards that were not considered in the Reference case or the No Sunset case. Residential and commercial end-use technologies eligible for incentives in the No Sunset case are not subject to new standards. Other than those exceptions, the Extended Policies case adopts the same assumptions as the No Sunset case, in addition to the following:

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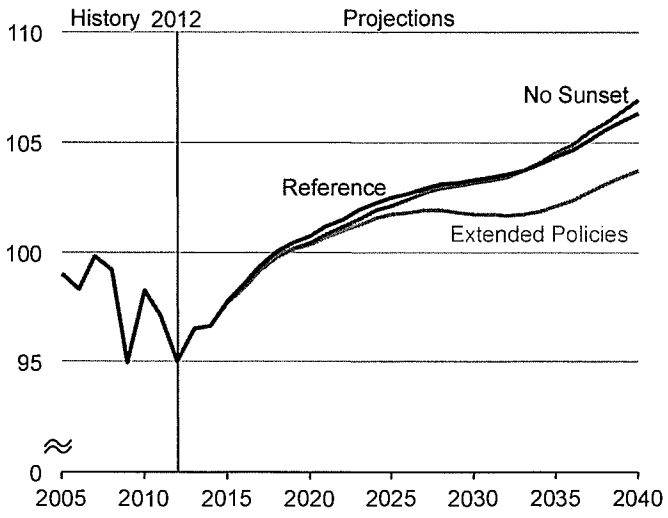
- Federal equipment efficiency standards are assumed to be updated at periodic intervals, consistent with the provisions in existing law, at levels based on ENERGY STAR specifications or on the Federal Energy Management Program purchasing guidelines for federal agencies, as applicable. Standards also are introduced for products that are not currently subject to federal efficiency standards.
- Federal energy codes for residential and commercial buildings are assumed to be updated periodically, providing additional improvement to new construction. The equipment standards and building codes assumed for the Extended Policies case are meant to illustrate the potential effects of those policies on energy consumption for buildings. No cost-benefit analysis or evaluation of impacts on consumer welfare was completed in developing the assumptions. Likewise, no technical feasibility analysis was conducted, although standards were not allowed to exceed the "maximum technologically feasible" levels described in DOE's technical support documents.
- The AEO2014 Reference, No Sunset, and Extended Policies cases include the joint attribute-based CAFE and vehicle GHG emissions standards for model year (MY) 2012 to MY 2025 for light-duty vehicles (LDVs). The Reference and No Sunset cases assume that the CAFE standards are then held constant at MY 2025 levels in subsequent model years, although the fuel economy of new LDVs continues to rise modestly over time. The Extended Policies case modifies the assumption in the Reference and No Sunset cases, assuming continued increases in CAFE standards at an annual average rate of 1.3% for new LDVs after MY 2025.
- The AEO2014 Reference, No Sunset, and Extended Policies cases include the heavy-duty vehicle (HDV) fuel consumption and GHG emissions standards for MY 2014 to MY 2018. The Reference and No Sunset cases assume that the standards are held constant at MY 2018 levels in subsequent model years, although the fuel economy of HDVs rises modestly thereafter. The Extended Policies case includes an increase in fuel consumption and GHG emissions standards for 13 vehicle size classes.
- In the industrial sector, the ITC for CHP is extended to cover all properties with CHP, no matter what the system size (which may include multiple units), instead of being limited to properties with systems smaller than 50 megawatts (MW) as in the Reference case [3]. Also, the ITC is modified to increase the eligible CHP unit cap from 15 MW to 25 MW. These extensions are consistent with previously proposed legislation.
- The extension of ethanol and biodiesel subsidies assumed in the No Sunset case is not included in the Extended Policies case, because the renewable fuel standard (RFS) program already included in the AEO2014 Reference case tends to determine the levels of ethanol and biodiesel use.

Analysis results

The changes made to the Reference case assumptions in the No Sunset and Extended Policies cases generally lead to lower estimates for overall delivered energy consumption, increased use of renewable fuels (particularly for electricity generation), and reduced energy-related carbon dioxide (CO_2) emissions. Because the Extended Policies case includes most of the assumptions in the No Sunset case but adds others, the effects of the Extended Policies case tend to be greater than those of the No Sunset case (with some exceptions discussed below). Both cases result in lower energy prices, because the assumed tax credits and end-use efficiency standards lead to lower energy demand (except in the No Sunset case after 2034, as discussed below) and lower costs for renewable technologies. Appliance purchase costs are also affected. In addition, the government receives lower tax revenues as consumers and businesses take advantage of the tax credits.

Figure IF1-1. Total energy consumption in three cases, 2005-40 (quadrillion Btu)



Energy consumption

Total energy consumption in the No Sunset case is slightly lower than in the Reference case before 2034 and slightly higher than in the Reference case in the later years of the projection (Figure IF1-1). Improvements in energy efficiency lead to reduced consumption in the No Sunset case, but the demand-increasing effect of lower energy prices fully offsets the efficiency impacts by the end of the projection period. In 2040, total energy consumption in the Extended Policies case is 2% below the Reference case projection, as the combination of tax and other policy extensions reduces overall demand even after taking price declines into account.

Buildings energy consumption

Renewable distributed generation (DG) technologies (photovoltaic systems and small wind turbines) provide much of the buildings-related energy savings in the No Sunset case. The continuation of tax credits in the No Sunset case spurs increased adoption of DG systems, leading to 59 billion kWh

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of onsite electricity generation from renewable DG in 2025, compared with 25 billion kWh in the Reference case. In 2040, onsite electricity generation from renewable sources increases to 145 billion kWh in the No Sunset case—almost three times the amount of onsite electricity generated in the Reference case in that year.

Similar adoption of renewable DG occurs in the Extended Policies case, while efficiency gains from assumed future standards and more stringent building codes further reduce delivered energy use in the buildings sectors. Delivered energy use for buildings in the Extended Policies case is 1.5%, or 0.3 quadrillion British thermal units (Btu), lower than in the Reference case in 2025 and 5.4%, or 1.1 quadrillion Btu, lower than in the Reference case in 2040. In the No Sunset case, in contrast, delivered energy consumption is only 1.0% (0.2 quadrillion Btu) and 1.8% (0.4 quadrillion Btu) lower than in the Reference case projections for 2025 and 2040, respectively.

Electricity use shows the largest reduction in the two alternative cases relative to the Reference case. Building electricity purchases in 2025 are 1.4% and 1.9% lower in the No Sunset and Extended Policies cases, respectively, and 2.8% and 6.9% lower, respectively, in 2040, when compared with the Reference case. Increased onsite generation decreases electricity purchases in both cases. Additional reductions in electricity purchases occur in the Extended Policies case, as assumed standards increase the market penetration of efficient equipment and building construction. Energy use for water heating in the Extended Policies case shows the largest drop relative to the Reference case, at 16% (0.4 quadrillion Btu) below the Reference case level in 2040. Space heating and cooling also are affected by the assumed standards for equipment and building codes in the Extended Policies case, and energy consumption for those uses is reduced by a combined 6.7% (0.5 quadrillion Btu) from the Reference case level in 2040. In 2040, natural gas use in the buildings sectors is 0.9% and 4.1% below the Reference case level in the No Sunset and Extended Policies cases, respectively.

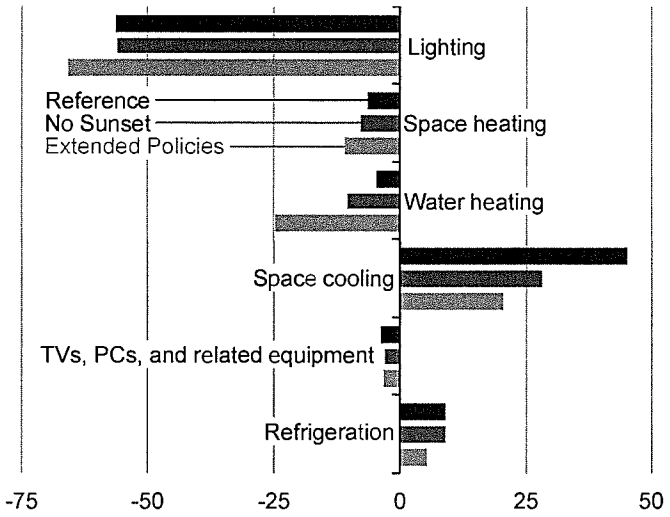
Residential energy consumption for most end uses moves in the same direction in all three cases, but at different rates (Figure IF1-2). For example, energy use for lighting, which declines in the Reference case, declines further in the Extended Policies case with additional standards; and space cooling, which increases in the Reference case, increases more slowly in the No Sunset case, which assumes the continuation of tax credits for efficient equipment and building shell thermal integrity improvement.

Industrial energy consumption

The No Sunset case modifies the Reference case assumptions by extending the existing ITC for industrial CHP through 2040. The Extended Policies case starts from the No Sunset case and expands the credit to include industrial CHP systems of all sizes, while raising the system size limit for the maximum credit that can be claimed, from 15 MW of installed capacity to 25 MW. The changes result in 1.2 gigawatts (GW) of additional industrial CHP capacity in the Extended Policies case compared with the Reference case in 2025 and 3 GW of additional capacity in 2040.

From 2025 through 2040, more CHP capacity is installed in the Extended Policies case than in the No Sunset case, but the differences narrow over time. CHP capacity is 0.3 GW higher in the Extended Policies case than in the No Sunset case in 2025, but only 0.1 GW higher in 2040. The Extended Policies case includes a tax benefit that applies to more CHP units than in the No Sunset case, which by itself provides greater incentive to build CHP capacity. However, electricity prices are slightly lower in the Extended Policies case than in the No Sunset case starting around 2024, and the difference grows over time, which reduces the economic attractiveness of CHP. These opposite effects explain why CHP capacity in the Extended Policies case is only slightly higher than in the No Sunset case, and why the difference decreases over time. Also, the median size of the nameplate capacity of industrial CHP units is 10 MW [4], and most CHP systems are well within the 50-MW total system size, which means that relaxing the size constraint is not as strong an incentive for investment as is allowing the current tax credit for new CHP investments to continue after 2016.

Figure IF1-2. Change in residential delivered energy consumption for selected end uses in three cases, 2012-40 (percent)



Natural gas consumption in the industrial sector averages 10.4 quadrillion Btu per year from 2012 to 2040 in all three cases. However, the pattern of use varies, with the No Sunset and Extended Policies cases showing higher levels of consumption than the Reference case at the end of the projection period.

Transportation energy consumption

The Extended Policies case differs from the Reference and No Sunset cases in assuming that the joint CAFE and greenhouse gas emissions standards promulgated by EPA and NHTSA for model years 2012 through 2025 are extended through 2040, with an assumed average annual increase of 1.3%. Sales of vehicles that do not rely solely on gasoline internal combustion engines for power (including those that use

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Effects of proposed energy provisions in the Energy Savings and Industrial Competitiveness Act of 2013

Senate bill S. 1392, The Energy Savings and Industrial Competitiveness Act of 2013 (ESICA) [5], introduced in July 2013, contains provisions for building energy codes, industrial energy efficiency, federal agencies, and budget offsets. Assuming appropriation of the funding authorized in the bill, EIA examined two key provisions of the proposed legislation: the adoption of updated building energy codes for residential and commercial buildings, and a rebate program for energy-efficient electric motors [6]. Other provisions require further specification by federal agencies or Congress, or they address levels of detail beyond that modeled in the National Energy Modeling System. Amendments have been introduced that may have energy impacts, but they are not part of the bill as of this writing and are not considered in this analysis. Of the two provisions analyzed for AEO2014, the updated building codes have a small effect on energy consumption and CO_2 emissions, and the industrial motors rebate program has virtually no effect. The analysis assumes that states will take advantage of incentives offered to implement the updated codes, and that once in place the codes will be effective over time.

Compared with the AEO2014 Reference case, the proposed building codes in ESICA reduce buildings delivered energy consumption by 0.7% in 2025 and 1.1% in 2040. Natural gas shows the largest reduction in buildings' energy use relative to the Reference case, as improved building shells lessen space heating requirements. Lower energy use in the ESICA case leads to lower levels of CO_2 emissions than in the Reference case. From 2014 to 2040, energy-related CO_2 emissions are reduced by a cumulative total of 307 million metric tons (an annual average of about 12 million metric tons) relative to the Reference case projection.

Residential and commercial consumers save $9.2 billion (2012 dollars) on energy purchases in 2040 in the ESICA case relative to the Reference case, as a result of lower energy demand. From 2014 to 2040, the cumulative reduction in residential and commercial energy purchases in the ESICA case totals $96.9 billion. Some of those savings are assumed to be offset by additional costs to the buildings sectors in meeting more stringent building codes, but such costs are not comprehensively modeled by EIA. The electric motor rebate program has a minimal impact on energy use, because the proposed program is limited in terms of both authorized funding and the two-year time frame for eligible installations.

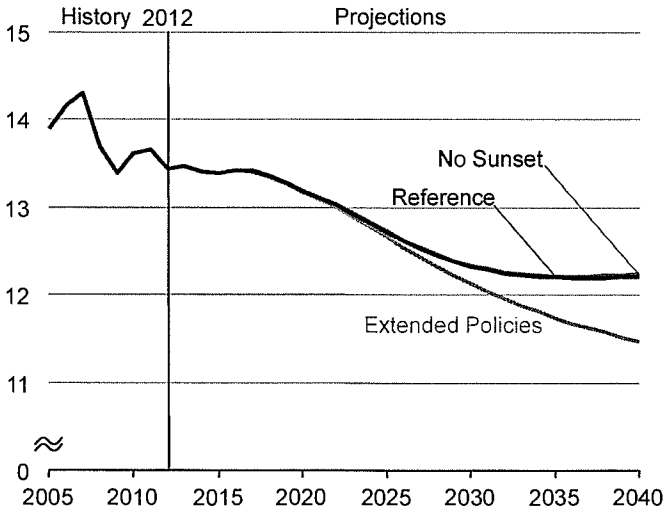
diesel, alternative fuels, or hybrid electric systems) play a substantial role in meeting the higher fuel economy standards after 2025, growing to 76% of new light-duty vehicle (LDV) sales in 2040, compared with 55% in the Reference case.

LDV energy consumption declines from 16.0 quadrillion Btu (8.7 million barrels per day [MMBbl/d] of oil equivalent) in 2012 to 13.5 quadrillion Btu (7.4 million barrels per day (MMBbl/d) of oil equivalent) in 2025 in the Reference case as a result of the increase in CAFE standards. Extension of the increases in CAFE standards in the Extended Policies case further reduces LDV energy consumption to 11.1 quadrillion Btu (6.1 MMBbl/d of oil equivalent) in 2040, which is 9% lower than in the Reference case.

The Extended Policies case differs from the Reference and No Sunset cases by extending the standards for heavy-duty vehicle (HDV) fuel consumption and GHG emissions after MY 2018. New HDV fuel economy increases from 7.7 mpg in 2018 to 8.0 mpg in 2040 in the Extended Policies case. HDV annual energy consumption still rises from 5.3 quadrillion Btu (2.5 MMBbl/d of oil equivalent) in 2012 to 6.0 quadrillion Btu (2.9 MMBbl/d of oil equivalent) in 2018 and continues to grow to 7.3 quadrillion Btu (3.5 MMBbl/d of oil equivalent) in 2040 in the Extended Policies case. However, the total is lower than the 7.5 quadrillion Btu (3.6 MMBbl/d of oil equivalent) in the Reference case in 2040.

Consumption of petroleum and other liquids in the transportation sector is nearly the same through 2025 in the Reference and Extended Policies cases but declines in the Extended Policies case from 12.7 MMBbl/d of oil equivalent in 2025 to 11.5 MMBbl/d of oil equivalent in 2040, as compared with 12.2 MMBbl/d of oil equivalent in 2040 in the Reference case (Figure IF1-3).

Figure IF1-3. Consumption of petroleum and other liquids for transportation in three cases, 2005-40 (million barrels per day)



Renewable electricity generation

The No Sunset and Extended Policies cases assume that tax credits for renewable electricity generation sources are extended through 2040, resulting in significantly more renewable generation—primarily from wind and solar—than in the Reference case in 2040 (Figure IF1-4). In general, renewable generation in the No Sunset case is slightly higher than in the Extended Policies case, which includes energy efficiency measures that result in slower load growth and lower demand for new generation capacity.

In the Extended Policies case, wind generation more than triples from 2012 to 2040, compared with a 76% increase in the Reference case. However, the short-term growth of wind generation in the Reference case exceeds that in the Extended Polices case, as qualification for the current production tax

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credit (PTC) requires that new wind capacity be under construction by 2013 and generally in service before 2016, resulting in a near-term surge in wind capacity additions.

Minimal demand for new capacity and competitive natural gas prices limit mid-term (approximately 2015 to 2025) wind growth in all the cases, but long-term sustained growth of wind generation capacity begins earlier (in the early 2020s) and proceeds at more rapid rate in the Extended Policies case as a result of relative attractiveness of wind projects under the continued support of the PTC.

Solar generation grows at a uniformly higher rate in the Extended Policies case than in the Reference case, in response to the assumed extension of the solar investment tax credits (ITC) in the Extended Policies case that either expire or are significantly reduced after 2016 in the Reference case. In both the No Sunset and Extended Polices cases, total U.S. solar generation increases by an average of about 12% per year from 2012 to 2040, compared with 7% per year in the Reference case. In general, the relatively higher growth benefits both utility-scale PV installations in the electric power sector and customer-sited rooftop PV applications in the residential and commercial sectors. The effects of tax credit extensions on other renewable generation technologies, such as hydropower, biomass, and geothermal, are minimal in comparison.

Energy-related CO_2 emissions

In the No Sunset and Extended Policies cases, lower overall fossil energy use leads to lower levels of energy-related CO_2 emissions than in the Reference case. In the Extended Policies case, the emissions reduction is larger than in the No Sunset case. From 2012 to 2040, energy-related CO_2 emissions are reduced by a cumulative total of 2.6 billion metric tons (a 1.7% reduction over the period) in the Extended Policies case relative to the Reference case, as compared with 1.2 billion metric tons (a 0.7% reduction over the period) in the No Sunset case (Figure IF1-5). The increase in fuel economy standards assumed for new LDVs in the Extended Policies case is responsible for 11.4% of the total cumulative reduction in CO_2 emissions from 2012 to 2040 in comparison with the Reference case. The balance of the reduction in CO_2 emissions is a result of greater improvement in appliance efficiencies and increased penetration of renewable electricity generation.

Most of the emissions reductions in the No Sunset case result from increases in renewable electricity generation. Consistent with current EIA conventions and EPA practice, emissions associated with the combustion of biomass for electricity generation are not counted, because they are assumed to be balanced by carbon absorption when the plant feedstock is grown. Relatively small incremental reductions in emissions are attributable to renewables in the Extended Policies case, mainly because electricity demand is lower than in the Reference case, reducing the consumption of all fuels used for generation, including biomass.

In the Extended Policies case, water heating, space cooling, and space heating together account for most of the emissions reductions from Reference case levels in the buildings sector. In the industrial sector, the Extended Policies case shows reduced emissions as a result of lower petroleum use.

Energy prices and tax credit payments

With lower natural gas use and more consumption of renewable fuels stimulated by tax credits in the No Sunset and Extended Policies cases, natural gas and electricity prices are lower than in the Reference case. In 2040, the average delivered price for natural gas is $0.44/thousand cubic feet (Mcf), or 4.2%, lower in the No Sunset case and $0.48/Mcf, or 4.5%, lower in the Extended Policies case than in the Reference case (Figure IF1-6). Similarly, average end-use electricity prices are 0.46 cents/kWh

Figure IF1-4. Renewable electricity generation in three cases, 2012, 2020, 2030, and 2040 (billion kilowatthours)

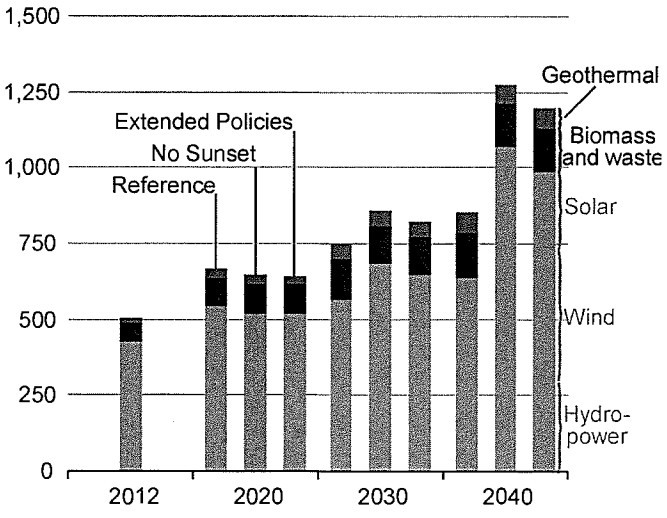
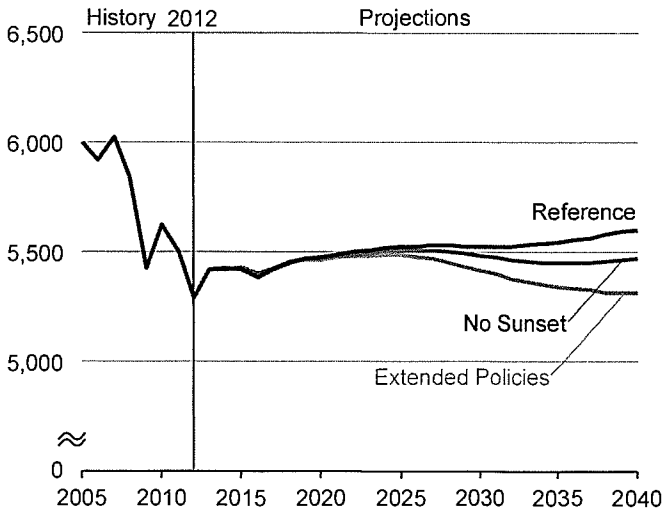


Figure IF1-5. Energy-related carbon dioxide emissions in three cases, 2005-40 (million metric tons)



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(4.1%) lower in the No Sunset case and 0.55 cents/kWh (5.0%) lower in the Extended Policies cases than in the Reference case (Figure IF1-7).

The reductions in delivered energy consumption and CO_2 emissions in the No Sunset and Extended Policies cases are accompanied by higher equipment costs for consumers and revenue reductions for the U.S. government. Compared to the Reference case, residential and commercial consumers in the No Sunset case, on average, pay an extra $1.7 billion/year (2012 dollars) for end-use equipment, residential building shell improvements, and additional distributed generation systems between 2014 and 2040. The government, on average, pays an extra $7.7 billion/year in tax credits to consumers in the buildings sector (or, from the government's perspective, receives that amount of reduced revenue). In the Extended Policies case, consumers and the government pay, on average, an additional $14.5 billion and $5.1 billion/year, respectively, over the amounts in the Reference case between 2014 and 2040.

The additional costs to the buildings sectors in the No Sunset and Extended Policies cases are more than offset by savings on energy purchases as a result of efficiency improvements and increased distributed generation. Compared to the Reference case, residential and commercial consumers save an average of $11.9 billion (2012 dollars) in annual energy costs from 2014 to 2040 in the No Sunset case and an average of $20.4 billion annually in the Extended Policies case.

The largest response to federal tax incentives for new renewable generation in the power sector is seen in the No Sunset case, where the extension of the PTC and the 30% ITC reduces government tax revenues by approximately $4.5 billion/year from 2014 to 2040, as compared with $483 million/year in the Reference case. In the Extended Policies case, the reduction in government tax revenues is similar to, but somewhat less than, that in the No Sunset case because of the lower levels of demand. From 2014 to 2040, annual government tax revenues in the Extended Policies case will be approximately $3.3 billion/year lower than in the Reference case.

Figure IF1-6. Average delivered prices for natural gas in three cases, 2005-40 (2012 dollars per thousand cubic feet)

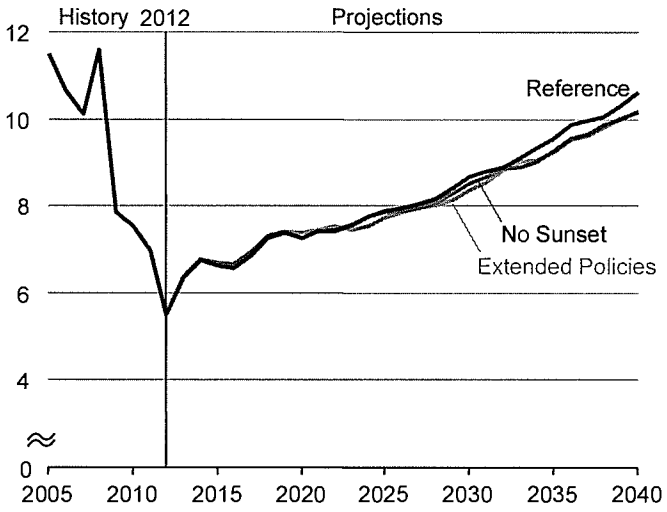
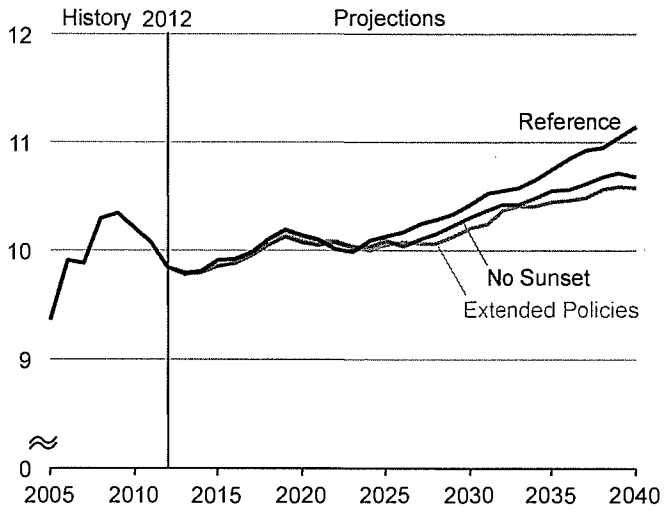


Figure IF1-7. Average electricity prices in three cases, 2005-40 (2012 cents per kilowatthour)



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Endnotes for IF1

Links current as of April 2014

1. United States Internal Revenue Code, Title 26, Subtitle A—Income Taxes, §48(a)(2)(A)(ii), http://www.gpo.gov/fdsys/pkg/USCODE-2011-title26/pdf/USCODE-2011-title26-subtitleA-chap1-subchapA.pdf.
2. A tax extenders package that includes a two-year extension of the biodiesel credit (retroactive to January 1, 2014) was passed by the Senate Finance Committee on April 3, 2014, but still must be passed by the House and the full Senate to become law. R. Kotrba, "Senate Finance Committee passes tax package with biodiesel credit," *Biodiesel Magazine* (April 3, 2014), http://biodieselmagazine.com/articles/41973/senate-finance-committee-passes-tax-package-with-biodiesel-credit.
3. United States Internal Revenue Code, Title 26, Subtitle A—Income Taxes, §48(c)(3)(B)(iii), http://www.gpo.gov/fdsys/pkg/USCODE-2011-title26/pdf/USCODE-2011-title26-subtitleA-chap1-subchapA.pdf.
4. Calculations based on U.S. Energy Information Administration, Form EIA-860, Schedule 3, 2011 data (Washington, DC, January 9, 2013), http://www.eia.gov/electricity/data/eia860/index.html.
5. U.S. Congress, "S. 1392 - Energy Savings and Industrial Competitiveness Act of 2013," http://beta.congress.gov/bill/113th-congress/senate-bill/1392?q={%22search%22:[%22S.%201392%22]}.
6. Modeled provisions based on S. 1392, Sections 101 and 221, as brought to the Senate floor in September 2013. An updated version of the bill was reintroduced on February 27, 2014, http://beta.congress.gov/bill/113th-congress/senate-bill/2074/text. As of this writing, time had not been scheduled for Senate floor discussion.

Figure sources for IF1

Links current as of April 2014

Figure IF1-1. Total energy consumption in three cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, NOSUNSET.D121713A, and EXTENDED.D022814A.

Figure IF1-2. Change in residential delivered energy consumption for selected end uses in three cases, 2012-40: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, NOSUNSET.D121713A, and EXTENDED.D022814A.

Figure IF1-3. Consumption of petroleum and other liquids for transportation in three cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, NOSUNSET.D121713A, and EXTENDED.D022814A.

Figure IF1-4. Renewable electricity generation in two cases, 2012-40: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, NOSUNSET.D121713A, and EXTENDED.D022814A.

Figure IF1-5. Energy-related carbon dioxide emissions in three cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035(2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, NOSUNSET.D121713A, and EXTENDED.D022814A.

Figure IF1-6. Average delivered prices for natural gas in three cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035(2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, NOSUNSET.D121713A, and EXTENDED.D022814A.

Figure IF1-7. Average electricity prices in three cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035(2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, NOSUNSET.D121713A, and EXTENDED.D022814A.

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IF2. U.S. tight oil production: Alternative supply projections and an overview of EIA's analysis of well-level data aggregated to the county level

U.S. production of tight oil has increased dramatically in the past few years, from less than 1 million barrels per day (MMbbl/d) in 2010 to more than 3 MMbbl/d in the second half of 2013 [1]. The *Annual Energy Outlook 2014* (AEO2014) Reference case reflects continued growth in tight oil production. However, growth potential and sustainability of domestic crude oil production hinge around uncertainties in key assumptions, such as well production decline, lifespan, drainage areas, geologic extent, and technological improvement—both in areas currently being drilled and in those yet to be drilled. As a result, High and Low Oil and Gas Resource cases were developed to examine the effects of alternate resource and technology assumptions on production, imports, and prices.

The projected trends in oil production vary tremendously in the alternative cases, and those trends hold important implications for the United States. In the High Oil and Gas Resource case, growth in tight oil production continues for a longer period of time than projected in the Reference case. Domestic crude oil production increases to nearly 13 MMbbl/d before 2035 in the High Oil and Gas Resource case, and net U.S. oil imports decline through 2036 and remain at or near zero from 2037 through 2040. The Low Oil and Gas Resource case reflects uncertainty about tight oil and shale crude oil and natural gas resources that leads to lower domestic production than in the Reference case. In this case, production reaches 9.1 MMbbl/d in 2017 before falling to 6.6 MMbbl/d in 2040, leading to higher projected dependence on net imports of petroleum and other liquids than in the Reference case. The range of production and imports in these alternative cases, as shown in Figures IF2-1 and IF2-2, illustrates the importance of uncertainty in the resource and technology assumptions.

Policymakers, industry, markets, and the public have great interest in the outlook for future domestic oil production and its key drivers. EIA continues to advance both the quality and transparency of its work in this area. Improvements made to the National Energy Modeling System (NEMS) Oil and Gas Supply Module for AEO2014 enhance its ability to capture rapid growth in tight oil production. Specifically, EIA has implemented a more disaggregated representation of estimated ultimate recovery (EUR) that uses well-level data aggregated to the county level within key producing regions to track the combined effect of technology advances and the changing quality of resources being targeted on production per well, which in turn drives an analysis of EUR for wells in each region. There is still a great deal of uncertainty in the projections of U.S. tight oil production. EIA's analysis reflects those uncertainties by varying key assumptions regarding the resource base and the rate of technology advances that lower drilling cost or raise its productivity across alternative cases. As new information is gained through drilling, production, and technology experimentation, NEMS projections for tight oil production will continue to evolve.

Improvements in data collection and projections

The domestic oil supply outlook in AEO2014 is based on data derived from measurements at production sites that are available for analysis. Those data provide a basis for improved understanding of the key factors that have contributed to the growth of tight oil production, which has improved the analysis in AEO2014; however, limitations about the use of the data should be taken into account when the Reference case results are examined.

As individual production profiles of wells drilled in tight oil formations are developed and analyzed, they provide a basis for the calculation of a production decline curve and EUR for each well. The results can be used to project potential future production from existing wells and from new wells drilled in the same plays [2].

Figure IF2-1. U.S. crude oil production in three cases, 1960-2040 (million barrels per day)

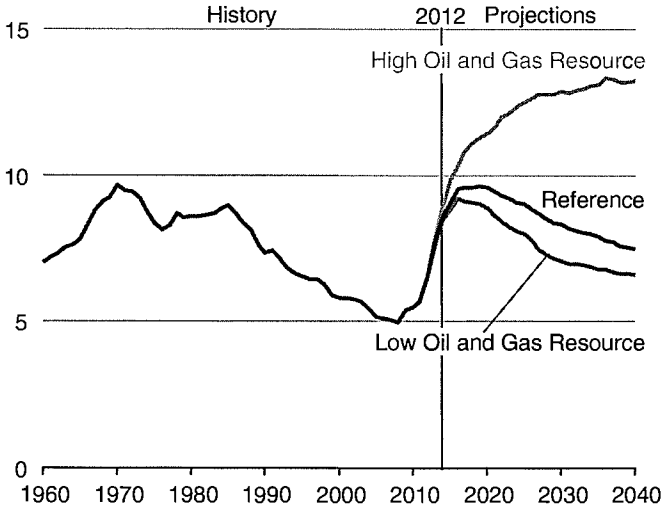
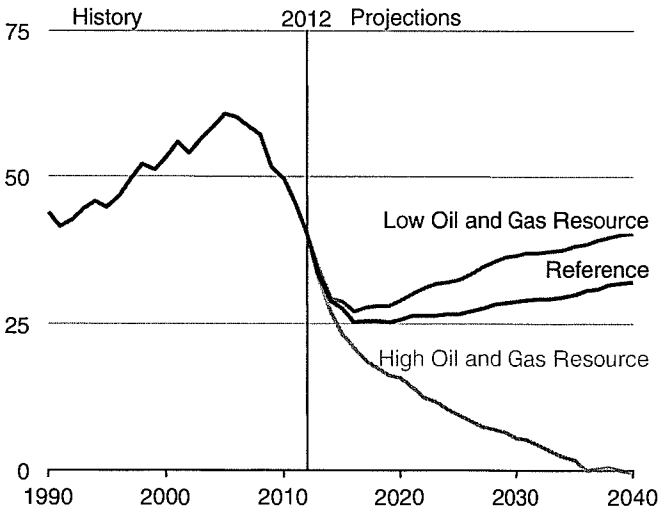


Figure IF2-2. Net import share of U.S. petroleum and other liquids consumption in three cases, 1990-2040 (percent)



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Production decline curves and the associated EURs for individual wells vary widely across plays, within single plays, and even within discrete sections (counties) of a single play. Using the Eagle Ford formation in Texas as an example, the discussion below examines the methods used to estimate EURs for tight oil wells, the distribution of EURs, the factors that contribute to variations in EURs, and the implications of using county-level representations as the basis for projections of overall production totals both for oil and for natural gas, which is often a coproduct of tight oil production. Uncertainties related to EUR estimation and advances in tight oil production technologies, and their effects on projections of domestic tight oil production in the AEO2014 High and Low Oil and Gas Resource cases, are explored by scaling production decline curves.

Estimating ultimate recovery per well

For each tight well or shale well with initial production in 2008 or later, and with at least four months of production data available, the U.S. Energy Information Administration (EIA) fits monthly production to a decline curve. The mathematical form of the curve is initially hyperbolic [3], but it shifts to exponential when the annual decline rate reaches 10% [4]. The EUR is the sum of actual past production from the well, as reported in the data, and an estimate of future production based on the fitted production decline curve over a 30-year well lifetime.

The actual production curve and the resulting actual ultimate recovery are highly uncertain and cannot be known until the well is plugged and abandoned, which may occur sooner or later than 30 years. Estimates of future production based on the first few months of initial production can differ significantly from later estimates for the same well.

As more months of production are added, the shape of the production curve and the resulting EUR for a given well can change. For example, for one well drilled in Live Oak County in the Eagle Ford formation in Texas, fitting a curve to the first year of monthly production data gave a EUR of 574,000 barrels; using four years of production data gave a EUR of 189,000 barrels for the same well. Conversely, another well in the same county had a EUR of 105,000 barrels based on the first 12 months of production data but 224,000 barrels based on four years of monthly production data. For the wells in the Eagle Ford formation with at least four years of production, EURs based on only the first year of monthly production ranged from as much as 385,000 barrels higher to 173,000 barrels lower than the EURs based on four years of production. Generally, the EUR stabilizes after three years of production, because for many wells in tight formations nearly 50% of the EUR has been produced during that period. EURs based on three years of data differ from EURs based on four years of data by 6,000 barrels on average, with a range of 65,000 barrels higher to 98,000 barrels lower. Because most Eagle Ford wells have been producing for less than three years (Table IF2-1), their EURs are likely to change as more production history is added.

County-level representation

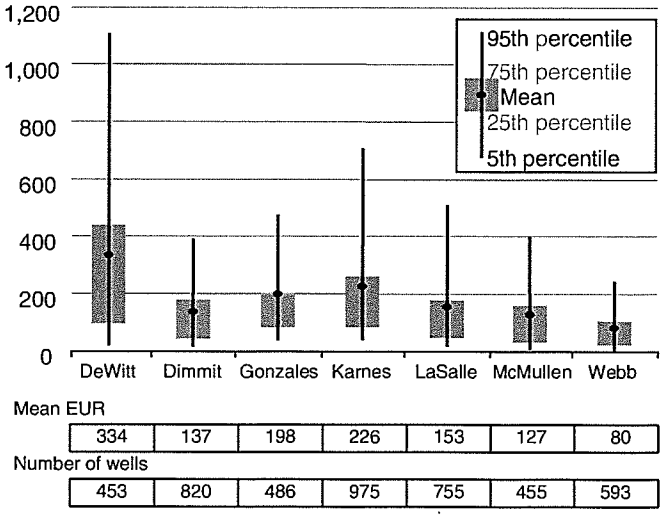
The decline curves from all wells in each county, averaged by production month, are used to generate a representative production curve that provides a basis for estimating production from future wells in that county. Wells that are newly drilled, with fewer data points and therefore greater uncertainty in the fit of their decline curves, have a tendency to inflate the average EUR. Older wells, which may have been drilled and completed using technologies and practices that are no longer representative of future practices, tend to pull the average down.

The range of EURs within a given county can be large, as shown in Figure IF2-3 for the seven counties in the Eagle Ford formation that have more than 400 oil and natural gas wells. Some wells have high initial production, but because they have been producing for less than a year, their EURs are highly uncertain. These few high-performing wells raise the county mean EUR above the county median EUR, generally skewing the mean toward the 75th percentile.

Table IF2-1. Average estimated ultimate recovery for wells in the Eagle Ford formation starting production between January 2008 and June 2013 and with at least four months of production

Vintage year	Number of wells	Average EUR (thousand barrels)
2008	33	36
2009	75	57
2010	514	117
2011	1,627	153
2012	2,717	191
2013	418	169
All years	**5,384**	**168**

Figure IF2-3. Distribution of estimated ultimate recovery per well in seven counties in the Eagle Ford formation, 2013 (thousand barrels)



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The Eagle Ford formation covers 32 counties in Texas. In 14 of those counties, fewer than 10 wells had been drilled as reported through June 2013. The EUR for counties with little or no drilling is assumed to be equal to the average of the mean estimates from adjacent counties [5]. The Eagle Ford county-level EURs range from more than 300,000 barrels per well (DeWitt county) to less than 25,000 barrels per well (Burleson and Maverick counties), with a mean average of roughly 170,000 barrels per well and a median of 103,000 barrels per well across all the Eagle Ford counties.

The county-level representation derived from well-level data implemented in AEO2014 allows the model to reflect rapid growth in production for plays in the early years of development, when producers focus on developing the most productive wells in the formation's sweet spots [6], the plateau in production as new drilling offsets the decline in production from older wells, and an eventual decline in production as development moves to less-productive areas (Figure IF2-4). However, there is still a great deal of uncertainty underlying the recovery of tight oil in known plays, as well as the potential for production from additional plays or other layers within a currently productive formation that has not been tested. The application of refinements to current technologies, as well as new technology advances, can also have significant (but uncertain) impacts on the recoverability of tight and shale crude oil.

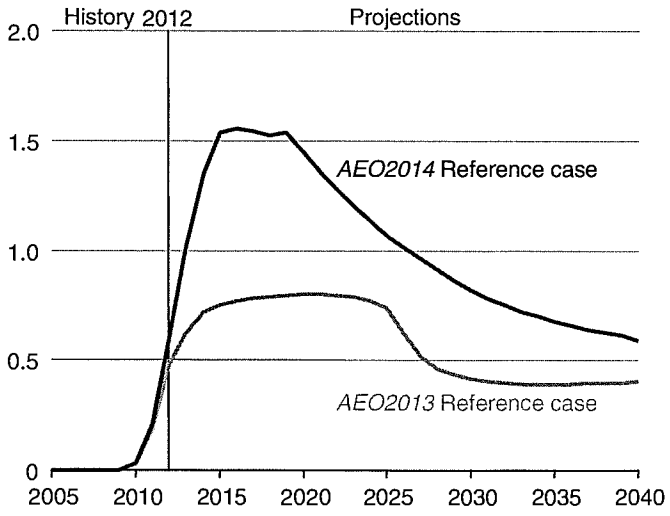
High and Low Resource cases

The High and Low Oil and Gas Resource cases in AEO2014 were developed using assumptions that result in higher and lower estimates of technically recoverable crude oil and natural gas resources than those in the Reference case [7]. These cases allow for an examination of the potential impacts of higher and lower domestic supply on energy demand, imports, and prices, but they do not represent upper and lower bounds for future domestic oil and natural gas supply. The two cases are not symmetric; currently, there is more uncertainty about the potential for greater gains in production than about the potential for lower production levels.

The High Oil and Gas Resource case assumes a broad-based future increase in crude oil and natural gas resources, not limited to production of oil and natural gas in tight sands and shales. However, optimism about increased supply has been buoyed by recent advances in the production of crude oil and natural gas from tight and shale formations. With the adjusted resource and technology advance assumptions in the High Oil and Gas Resource case, domestic crude oil production continues to increase to more than 13 MMbbl/d before 2035. Specific assumptions for the High Oil and Gas Resource case, as compared with the Reference Case, include:

- EURs for tight oil, tight gas, and shale gas wells are 50% higher [8]
- Additional tight oil resources as well as 50% lower well spacing (i.e., wells are closer together), with a downward limit of 40 acres per well for existing and potential future tight oil resources, to capture the possibility that additional layers or new areas of low-permeability zones will be identified and developed
- Diminishing returns on the EUR when drilling in a county exceeds the number of potential wells assumed in the Reference case [9], to capture the probability that greater drilling density will cause wells to interfere with each other (i.e., production from one well might reduce production from a nearby well)
- Long-term technology improvements beyond those assumed in the Reference case, represented as a 1% annual increase in the EURs for tight oil, tight gas, and shale gas wells

Figure IF2-4. Eagle Ford crude oil production in the Reference case, 2005-40 (million barrels per day)



- More resources in Alaska and in the lower 48 offshore, including the development of tight oil in Alaska and 50% higher technically recoverable undiscovered resources for other Alaska crude oil and the lower 48 offshore (which reflects more favorable resolution of the uncertainty surrounding undeveloped areas where there has been little or no exploration and development activity, and where modern seismic survey data are lacking)
- The development of lower 48 onshore oil shale (kerogen), with production reaching 135,000 barrels per day by 2025.

The High Oil and Gas Resource case does not include exploration or production activity in the Arctic National Wildlife Refuge.

The Low Oil and Gas Resource case reflects only the uncertainty around tight and shale crude oil and natural gas resources—specifically, whether the performance of current and future wells drilled will actually be less than estimated. For the Low Oil and Gas Resource case, the EUR per tight and shale well is assumed to be 50% lower than in the AEO2014

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Reference case (by scaling all applicable production decline curves). All other resource assumptions are unchanged from the Reference case.

Effects on domestic crude oil production

The difference in overall production across cases mostly reflects differences in tight oil projections. In the High Oil and Gas Resource case, higher well productivity reduces development and production costs per unit, which results in more and earlier development of tight oil resources than in the Reference case. The greater abundance of tight oil resources in the High Oil and Gas Resource case causes tight oil production to peak later in the projections, at 8.5 MMbbl/d in 2035, compared to the Reference case peak production rate of 4.8 MMbbl/d in 2021. From 2012 through 2040, cumulative tight oil production in the High Oil and Gas Resource case amounts to 75 billion barrels, compared with 44 billion barrels in the Reference case.

In the Low Oil and Gas Resource case, lower estimates of tight oil, tight gas, and shale gas resources result in a U.S. production profile that is both slower and lower than in the Reference case, with tight oil production peaking at 4.3 MMbbl/d in 2016 and then declining through 2040. Cumulative tight oil production from 2012 through 2040 amounts to 34 billion barrels in the Low Oil and Gas Resource case, which is 23% less than in the Reference Case.

Effects on U.S. net imports of petroleum and other liquids

The variations in projected domestic petroleum supply between the Reference case and the High and Low Oil and Gas Resource cases result in significant variations in the share of net imports in total U.S. liquid fuels consumption (Figure IF2-2). The net import share of petroleum and other liquids consumption, which increased steadily from 27% in 1985 to about 60% in 2005, has fallen since 2005, to roughly 40% in 2012. In the Reference case, the share of U.S. petroleum and other liquids consumption met by imports continues declining to 25% in 2016, and then begins a gradual increase starting in 2020, reaching 32% in 2040. The net import share follows a similar trend in the Low Oil and Gas Resource case, falling to 27% in 2016 and then rising to 40% in 2040. In contrast, net import dependence continues to decline through 2036, and it is at or near zero from that point until 2040 in the High Oil and Gas Resource case.

Effects on prices

As a result of higher levels of U.S. crude oil production in the High Oil and Gas Resource case, North Sea Brent crude oil prices are lower than in the Reference case: $125 per barrel (2012 dollars) in 2040, compared with $141 per barrel in 2040 in the Reference case. Lower motor gasoline and diesel prices in the transportation sector encourage more consumption.

In the Low Oil and Gas Resource case, lower levels of domestic crude oil production result in a slightly higher Brent crude oil price than in the Reference case—$145 per barrel (2012 dollars) in 2040. As noted above, because the uncertainty around production increases is greater than the uncertainty around production decreases, assumptions in the Low Oil and Gas Resource case are closer to the assumptions in the Reference case than are the assumptions in the High Oil and Gas Resource case.

012692

Endnotes for IF2

Links current as of April 2014

1. The term tight oil does not have a specific technical, scientific, or geologic definition. Tight oil is an industry convention that generally refers to oil produced from very low permeability shale, sandstone, and carbonate formations, with permeability being a laboratory measure of the ability of a fluid to flow through the rock. In limited areas of some very low permeability formations, small volumes of oil have been produced for many decades.
2. A play is defined as a set of known or postulated oil and gas accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathway, timing, trapping mechanism, and hydrocarbon type.
3. The hyperbolic decline curve is given by $Q_t = Q_i / [(1 + bD_it)^{1/b}]$, where Q_t is the production volume in time t (in months), Q_i is the initial volume at time 0 (the 30-day initial production rate or IP is Q_1), D_i is the initial decline rate, and b is the hyperbolic parameter (b of 0.001 is basically an exponential decline). Because the reported production in the first month could include 1 to 31 days of actual production, the first-month data are excluded from the fitting routine.
4. Of the 6,594 Eagle Ford wells included in the Drillinginfo database, 927 were excluded because they had less than four months of production data—leaving 5,667 to be evaluated through the automated fitting routine. For 95% of the wells, monthly production was fitted successfully to a hyperbolic decline curve.
5. Planned future enhancements to this methodology include taking into account any available geologic information (i.e., porosity, depth, thickness, total organic carbon, thermal maturity, and natural fracture density and location) to provide appropriate weights for the adjacent county EURs.
6. Sweet spot is an industry term for those selected and limited areas within a play where the well EURs are significantly higher than those for the rest of the play—sometimes as much as 10 times higher than those for the lower production areas within the play.
7. The total unproved technically recoverable crude oil resources are 401 billion barrels in the High Oil and Gas Resource case and 180 billion barrels in the Low Oil and Gas Resource case, compared to 209 billion barrels in the Reference case. Total unproved technically recoverable dry natural gas resources are 3,349 trillion cubic feet (Tcf) in the High Oil and Gas Resource case and 1,480 Tcf in the Low Oil and Gas Resource case, compared to 1,932 Tcf in the Reference case.
8. This is achieved by scaling the applicable production decline curves upward.
9. For this assumption, the initial production rate is increased by 20%, but the decline curve is shifted so that the overall EUR is reduced by 20%.

Figure and table sources for IF2

Links current as of April 2014

Figure IF2-1. U.S. crude oil production in three cases, 1960-2040: History: U.S. Energy Information Administration. Monthly Energy Review September 2013, DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure IF2-2. Net import share of U.S. petroleum and other liquids consumption in three cases, 1990-2040: History: U.S. Energy Information Administration. Monthly Energy Review September 2013, DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Table IF2-1. Average EUR for wells in the Eagle Ford formation starting production between January 2008 and June 2013 and with at least four months of production: U.S. Energy Information Administration.

Figure IF2-3. Distribution of estimated ultimate recovery per well in seven counties in the Eagle Ford formation, 2013: U.S. Energy Information Administration.

Figure IF2-4. Eagle Ford crude oil production in the Reference case, 2005-40: History: U.S. Energy Information Administration. Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A, and AEO2013 National Energy Modeling System, run REF2013.D102312A.

012693

IF3. Potential of liquefied natural gas as a freight locomotive fuel

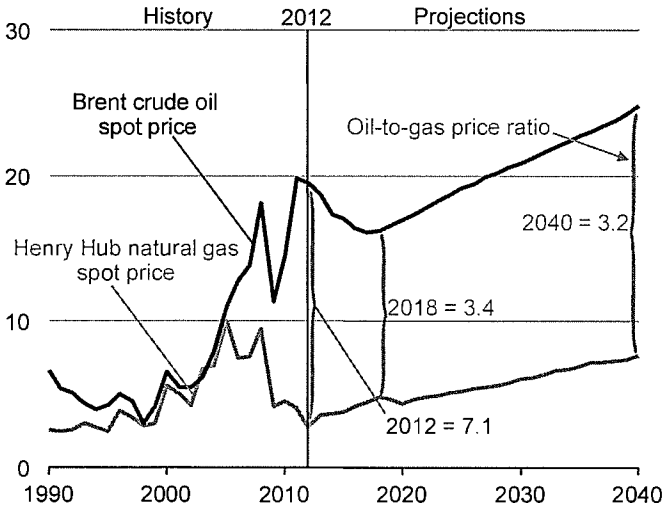
Continued growth in domestic natural gas production, along with substantially lower natural gas spot prices compared to crude oil, is reshaping the U.S. energy economy and attracting considerable interest in the potential for fueling freight locomotives with liquefied natural gas (LNG). While there is significant appeal for major U.S. railroads to use LNG as a fuel for locomotives because of its potentially favorable economics compared with diesel fuel, there are also key uncertainties as to whether, and to what extent, the railroads can take advantage of this relatively cheap and abundant fuel.

Freight railroads and the basic economics of fuel choice

Major U.S. railroads, known commonly as Class 1 railroads, are defined as line-haul freight railroads with certain minimum annual operating revenue. Currently, that classification is based on 2011 operating revenue of $433.2 million or more [*1*]. While there are 561 freight railroads operating in the United States, only seven are defined as Class 1 railroads. The Class 1 railroads account for 94% of total freight rail revenue [*2*]. They haul large amounts of tonnage over long distances, and in the process they consume significant quantities of diesel fuel. In 2012, the seven Class 1 railroads consumed more than 3.6 billion gallons (gal) of diesel fuel [3], amounting to 10 million gal/day and representing 7% of all diesel fuel consumed in the United States. The two largest consumers of diesel fuel among the Class 1 railroads—Burlington Northern Santa Fe (BNSF) and Union Pacific—consumed more than 1 billion gal each in 2012. The cost to Class 1 railroads of consuming such large quantities of diesel fuel was more than $11 billion in 2012, representing 23% of their total operating expense (Table IF3-1).

Class 1 railroads are considering the use of LNG to fuel locomotives because of the potential for significant cost savings. Following years of tight price linkage, spot prices for crude oil (North Sea Brent) and natural gas (Henry Hub) diverged around 2005. In 2012, the Brent spot price was about seven times the Henry Hub spot price on an energy equivalent basis. That differential is projected to narrow in the midterm, but a persistent gap is expected to continue, with crude oil prices more than three times higher than natural gas per million British thermal units (MMBtu) throughout the Reference case projection period, going out to 2040 (Figure IF3-1).

Figure IF3-1. Comparison of spot prices for Brent crude oil and Henry Hub natural gas, 1990-2040 (2012 dollars per million Btu)



The large differential between crude oil and natural gas commodity prices translates directly into a significant disparity between projected LNG and diesel fuel prices, even after accounting for natural gas liquefaction costs that exceed refining costs. In the AEO2014 Reference case, the long-run price difference between locomotive diesel fuel and LNG in rail applications increases from $1.48/gal of diesel equivalent in 2014 to $1.77 in 2040 (Figure IF3-2).

Given the difference between LNG and diesel fuel prices in the Reference case, railroads that switch locomotive fuels could accrue significant fuel cost savings. Locomotives are used intensively, consume large amounts of fuel, and are kept in service for relatively long periods of time. The net present value of future fuel savings across the Reference case projection for an LNG locomotive compared to a diesel counterpart is well above the roughly $1 million higher cost of the LNG locomotive and tender (Figure IF3-3).

Relatively large changes in assumptions used to evaluate investments in LNG locomotives (such as a significantly shorter payback period or much higher discount rate) or in

Table IF3-1. Class 1 railroad diesel fuel consumption, fuel cost, and fuel cost share of operating expense, 2012

Class 1 railroad (2012)	Diesel fuel consumption (gallons)	Fuel cost (thousand 2012 dollars)	Fuel cost share of total operating expense
Burlington Northern Santa Fe	1,335,417,552	$4,273,779	29%
Union Pacific	1,108,029,359	$3,505,671	24%
CSX Transportation	490,902,017	$1,542,747	18%
Norfolk Southern	462,466,433	$1,437,178	18%
Canadian National Grand Trunk	101,555,124	$326,303	16%
Canadian Pacific Soo	71,575,774	$231,211	16%
Kansas City Southern	64,078,412	$195,428	22%
Total	**3,634,024,671**	**$11,512,317**	**23%**

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fuel prices would be required to change LNG fuel economics for railroad use from favorable to unfavorable. Starting from the Reference case, the economics for switching to LNG locomotives remain favorable unless the payback period is reduced by eight years or the discount rate applied is raised by nine percentage points (Figure IF3-4). However, in the Low Oil Price case, the net present value of fuel cost savings associated with LNG use are not large enough to offset the higher additional upfront cost of LNG locomotives and tenders (Figure IF3-5). The shortfall in the value of fuel savings relative to upfront investment increases over the projection period in this case, making investments in LNG fueling less attractive over time. Clearly, uncertainty about future fuel prices suggests that there is some risk for companies in making such a fundamental change in freight rail operations.

Challenges for liquefied natural gas as a freight rail fuel

While simple economic calculations involving the comparison of fuel cost savings to additional upfront cost are relatively straightforward, other factors, including operational, financial, regulatory, and mechanical challenges, also affect fuel choices by railroads. One of the most challenging factors raised by the switch to LNG locomotives by Class 1 railroads is the effect on operations. Switching from diesel fuel to LNG would require a new delivery infrastructure for locomotive fuel. Natural gas would need to be delivered to fuel depots, either by truck in smaller quantities, as LNG [4], or perhaps by pipeline. Larger quantities of

Figure IF3-2. Comparison of prices for railroad diesel fuel and liquefied natural gas fuel, 2014-40 (2012 dollars per gallon diesel equivalent)

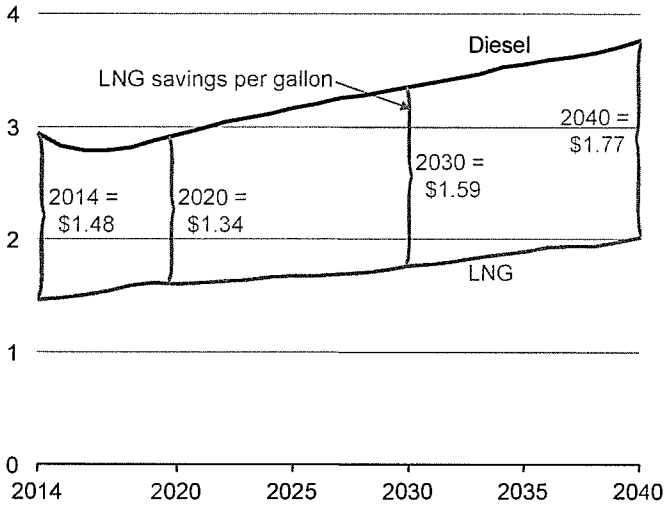


Figure IF3-3. Discounted fuel cost savings for a new locomotive and tender using liquefied natural gas as a fuel compared to diesel, 2020-40 (million 2012 dollars, net present value)

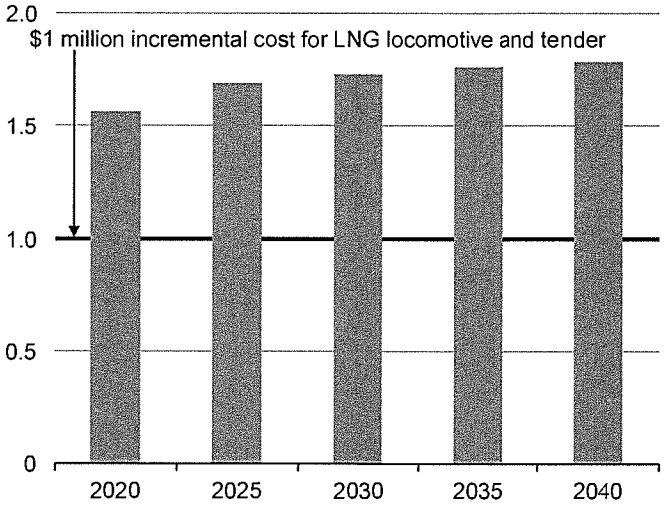


Figure IF3-4. Net present value calculation for locomotives using liquefied natural gas at Reference case fuel prices (payback years and discount rate)

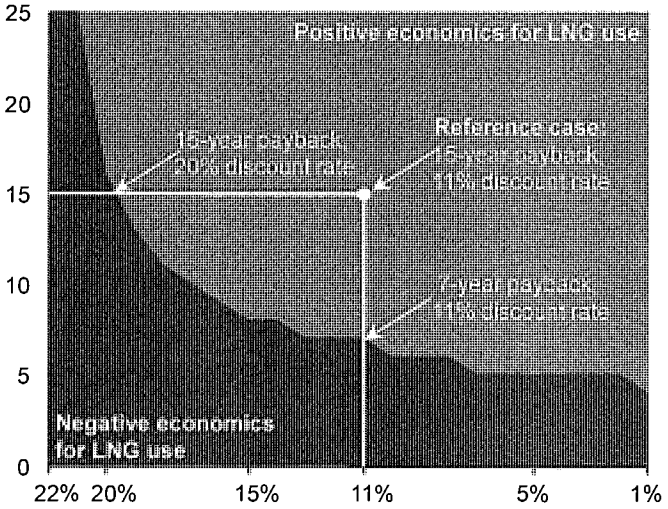
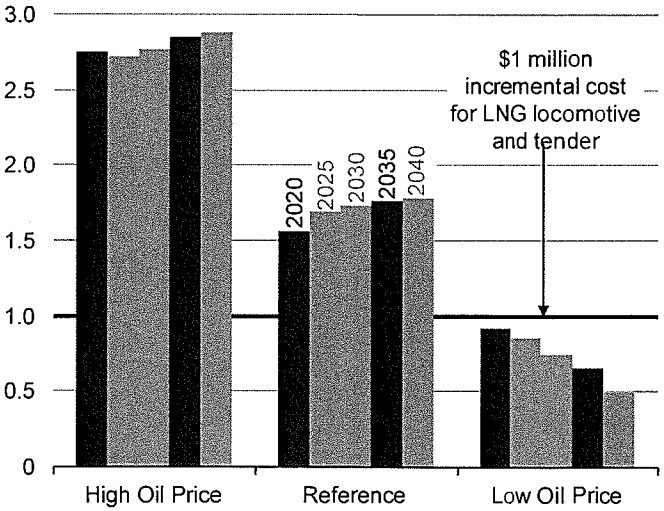


Figure IF3-5. Discounted average fuel cost savings for a new locomotive and tender using liquefied natural gas as a fuel compared to diesel in three cases, 2020-40 (net present value, million 2012 dollars)



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natural gas would require liquefaction before delivery to tender cars for use in locomotives. Building the new infrastructure would require a large financial investment in addition to the large investments made in locomotives and tender cars.

The building of LNG refueling infrastructure could also complicate the inter-operability of the rail network, depending on how quickly modifications could be made to accommodate refueling at multiple points around the nation. Impeding the ability of the rail network system to move goods because of a lack of fuel availability could drive up costs and lead to reductions in network flexibility and operational efficiency [5]. In addition, operations could be further affected by fuel switching because of the cost of training staff at refueling depots and in maintenance shops, updating maintenance facilities to handle LNG locomotives and tenders, and managing more extensive logistics [6]. Further, LNG locomotives and tender cars could require more maintenance than their diesel counterparts. All of these operational changes would create a duplicative infrastructure [7], because many diesel-fueled locomotives still would be in service at least for some significant period, and compression-ignited LNG locomotives still require at least some diesel fuel for combustion ignition.

Replacing the current stock of diesel locomotives with LNG locomotives and tender cars would represent a significant financial investment by Class 1 railroads. In 2012, there were 25,174 locomotives in the service of Class 1 railroads, the vast majority of which were line-haul locomotives [8]. A new diesel line-haul locomotive costs about $2 million [9], and rebuilt locomotives cost about half that amount. With a new LNG locomotive and tender costing about $1 million more than a diesel counterpart, the cost to replace the entire diesel locomotive stock with LNG locomotives and tenders would be tens of billions of dollars, not including additional infrastructure, training, logistics, and a potential increase in maintenance costs. Moreover, much of the cost of the transition, such as purchases of locomotives and tender cars, potentially would occur over a much shorter time period than a fuel payback period.

The financing requirement of large capital expenditures complicates the rather straightforward calculation of locomotive fuel economics. The amount of capital available to Class 1 railroads, either on hand or raised in capital markets, is an important factor in determining whether, or to what extent, railroads can take advantage of fuel cost savings over time. The decision to switch from diesel fuel to LNG is also influenced by the facts that railroads are a highly capital-intensive industry [10] with complete responsibility for maintaining the physical rail network, that they face many competing needs for financial investment, and that they must ensure adequate return on investment for their shareholders.

On the regulatory side, LNG rail cargos currently are not permitted without a waiver from the Federal Railroad Administration (FRA) under Federal Emergency Management Agency (FEMA) rules. The development of standard LNG tenders and regulations is underway, with issues related to safety, crashworthiness, and environmental impact, including methane leakage, under consideration [11].

Finally, LNG locomotives currently are undergoing extensive testing and demonstration to determine their fuel consumption, emissions, operational performance, and range under real-world conditions. Locomotives and tenders will be evaluated to ensure mechanical performance of such components as connections between tender and locomotive. Several Class 1 railroads are planning to start LNG locomotive demonstration projects to provide better understanding of the obstacles to an LNG fuel switch.

The future of liquefied natural gas in freight rail: lessons from history

The large potential fuel cost savings from the switch to LNG locomotives from diesel has resulted in great interest on the part of the freight rail industry, observers, and analysts. The companies have discussed the potential of LNG as comparable with the switch from steam propulsion to diesel in the 1940s and 50s [12], a revolution in freight rail known simply as "dieselization." Other industry experts have responded with more caution, likening the switch to the more evolutionary transformation of diesel-electric freight rail locomotives from direct current (DC) to alternating current (AC) propulsion that has been occurring since the early 1990s [13].

The diesel revolution in rail began in yard-switching operations during the mid-1920s, followed by passenger rail in the mid-1930s. After an initial period of hesitation, mainly because of the vast amount of capital already invested in steam locomotives and their refueling and watering infrastructure, diesel freight locomotives first appeared in 1941. They then captured the market at an extraordinary rate, with the last steam locomotive mustered out of service in 1961 [14].

The advantages of using diesel locomotives over steam were numerous. While diesel locomotive costs were about double per horsepower compared to steam, diesel locomotives proved superior in almost every other way. Steam locomotives had to slow or stop to take on water, requiring extensive watering infrastructure, and they needed nearly constant cleaning, maintenance, and repair, with annual costs reaching 25% of the initial cost of the locomotive. The switch to diesel allowed the railroads to avoid costly watering time and infrastructure and dramatically reduced maintenance and repair. As a result, diesel engines could travel faster and thus double the annual mileage of steam locomotives. Diesel engines, unlike steam engines, could be turned on and off with relative ease; a lead diesel locomotive could control other locomotives on a unit train; the costs of rail line maintenance were reduced because diesel locomotives were lighter and did not "pound the tracks"; and maintenance costs were lowered by the use of standardized parts and design [15].

Although diesel freight locomotives took over the market in 20 years, freight locomotives with AC traction motors, which began service in Class 1 railroads in the early 1990s, represent about 17% of the locomotive stock today [16]. AC locomotives have

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the major advantage of greater adhesion levels than their counterparts equipped with DC motors, allowing fewer locomotives to pull the same load. The ability to reduce the number of locomotives pulling a unit train represents a significant improvement in fuel efficiency, but it has not been adopted to the same extent as dieselization. Class 1 railroads have gradually adopted or decided against AC traction for a variety of reasons related to operations, upfront incremental costs, and the ability to take advantage of increased adhesion levels. For example, in recent years Union Pacific, Canadian Pacific, and CSX have chosen AC traction locomotives because of locomotive unit reductions, reliability, interoperability, and life-cycle costs. Canadian National Grand Trunk and Norfolk Southern have stayed with DC traction because of incremental cost and the inability to apply unit train reductions. BNSF has chosen AC locomotives for coal runs, where they can take advantage of unit locomotive reductions, and DC locomotives for intermodal runs, where they cannot [17].

These historical examples of the impacts of new technologies and fuels may offer insights into the future potential for LNG locomotives. As happened during the diesel revolution, freight railroads may adopt a completely new locomotive fuel and infrastructure over two decades if there is a compelling business case. However, many cost and operational efficiencies made diesel locomotives superior to steam locomotives, and the same dynamic may not be seen with LNG. Moreover, investment in existing capital stock and relevant equipment may be an impediment early in a transformation process.

The ongoing evolution of AC traction locomotives shows that Class 1 railroads will invest in a new locomotive technology, at least gradually, if there is significant reason to do so. The decision may balance factors such as cost with operational efficacy.

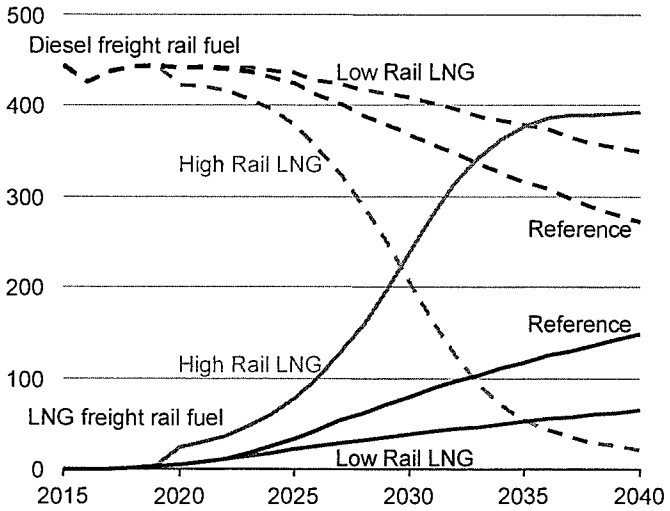
Liquefied natural gas in freight rail—revolution and evolution cases

AEO2014 includes two alternative cases that examine the potential impact of LNG in freight rail, based on the diesel revolution and AC traction evolution. The cases also look at the impact of a specific LNG engine technology. The High Rail LNG case represents a revolution in freight rail locomotive fueling similar to that of dieselization in the 1940s and 1950s. After an initial trial period starting in 2017 through 2020, Class 1 railroads take advantage of the favorable economics of LNG locomotive fuel such that after a 20-year period, all freight rail motive stock is converted to LNG capability. The new locomotives are assumed to use high-pressure direct injection (HPDI) LNG engine technology, which uses natural gas as the primary fuel and relies on a small amount of diesel fuel for ignition. HPDI engines use fuel at a ratio of about 95% LNG to 5% diesel. LNG-only engines are not expected to be adopted for locomotives.

The Low Rail LNG case represents an evolution in freight rail locomotive fueling similar to the ongoing penetration of AC traction locomotives. After an initial trial period from 2017 through 2020, Class 1 railroads take advantage of the favorable LNG locomotive fuel economics by turning over their engine stocks at an average rate of 1% per year. The new LNG locomotives are assumed to use a dynamic gas blending engine, which uses diesel fuel for combustion until intake temperature rises, at which point natural gas is used. The engines are LNG-capable up to a fuel consumption ratio of 80% LNG and 20% diesel and have the added advantage of being dual-fuel compatible, with the ability to switch back to 100% diesel fuel as needed. The Reference case does not make any assumption about the type of LNG engine used but instead allows LNG to penetrate into freight rail at the average annual turnover rate of new and rebuilt stock experienced over the last decade.

The High and Low Rail LNG cases show a dramatic change in the fuel mix used by freight rail. In the Reference case, LNG fuel use increases from 0.5 trillion Btu in 2017 to 148 trillion Btu in 2040, or 35% of total freight rail energy consumption (Figure IF3-6). In the High Rail LNG case, LNG fuel consumption increases to 392 trillion Btu in 2040, or 95% of freight rail energy consumption. LNG consumption in the Low Rail LNG case increases to just 64 trillion Btu, or 16% of total freight energy consumption.

Figure IF3-6. Comparison of energy consumption for freight rail using diesel and LNG in three cases, 2015-40 (trillion Btu)



While the impacts are dramatic in the freight rail sector, it is important to note that the impacts on total energy use in the U.S. transportation system and on the nation's total energy consumption are relatively small. In the Reference case, transportation diesel consumption increases from about 6 quadrillion Btu in 2012 to 6.5 quadrillion Btu in 2017 and 7.5 quadrillion Btu in 2040, with railroad diesel use of 0.5 quadrillion Btu in 2012 decreasing to 0.4 quadrillion Btu in 2017 and 0.3 quadrillion Btu in 2040, when LNG accounts for 35% of projected energy use by freight rail in the Reference case. Most transportation diesel fuel consumption—more than 80%—occurs in heavy-duty vehicles. Because freight rail accounts for only a small share of transportation diesel use, projected total transportation diesel fuel use in 2040 varies only modestly across cases with different levels of LNG use in freight rail, ranging from 7.3 quadrillion Btu in the High Rail LNG case to 7.6 quadrillion Btu in the Low Rail LNG case.

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Projected natural gas consumption for transportation (excluding pipeline transportation) is sensitive to variation in freight rail use of LNG, because relatively small amounts of natural gas currently are consumed in mobile applications either as compressed or liquefied natural gas. Natural gas consumption in the transportation sector (including pipeline transportation) increases from 0.9 quadrillion Btu in 2040 in the Reference case to 1.1 quadrillion Btu in the High Rail LNG case and to 0.8 quadrillion Btu in the Low Rail LNG case. The projected changes in use of LNG in rail have marginal impacts on retail natural gas prices in the transportation sector, which impact natural gas demand in other transportation uses. As a result of these price changes, heavy-duty truck natural gas demand partially offsets the consumption impacts occurring in rail.

Because the transportation sector is a relatively small consumer of natural gas compared to other sectors, the seemingly dramatic fuel switch from the perspective of freight rail is only a minor change in overall U.S. natural gas consumption. Total U.S. natural gas energy consumption varies from 32.3 quadrillion Btu in 2040 in the Reference case to 32.4 quadrillion Btu in the High Rail LNG case and 32.1 quadrillion Btu in the Low Rail LNG case.

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Endnotes for IF3

Links current as of April 2014

1. Association of American Railroads, *Class I Railroad Statistics* (July 9, 2013), https://www.aar.org/StatisticsAndPublications/Documents/AAR-Stats-2013-07-09.pdf. Accessed January 23, 2014.
2. S.C. Davis, S.W. Diegel, and R.G. Boundy, *Transportation Energy Databook: Edition 32,* ORNL-6989 (Oak Ridge, TN, July 2013), Chapter 9, Table 9.8, "Summary Statistics for Class 1 Freight Railroads, 1970-2011."
3. U.S. Department of Transportation, Surface Transportation Board, *Annual Reports Financial Data,* http://www.stb.dot.gov/econdata.nsf/f039526076cc0f8e8525660b006870c9?OpenView.
4. W.C. Vantuono, "A Closer Look at LNG," *Railway Age* (October 2013).
5. BNSF Railway Company, Union Pacific Railroad Company, Association of American Railroads, and California Environmental Associations, *An Evaluation of Natural Gas-fueled Locomotives* (November 2007).
6. W.C. Vantuono, "A Closer Look at LNG," *Railway Age* (October 2013).
7. BNSF Railway Company, Union Pacific Railroad Company, Association of American Railroads, and California Environmental Associations, *An Evaluation of Natural Gas-fueled Locomotives* (November 2007).
8. U.S. Department of Transportation, Surface Transportation Board, *Annual Report Financial Data* (2012 and various years), http://www.stb.dot.gov/econdata.nsf/f039526076cc0f8e8525660b006870c9?OpenView.
9. U.S. Department of Transportation, Surface Transportation Board, *Annual Report Financial Data* (2012 and various years), http://www.stb.dot.gov/econdata.nsf/f039526076cc0f8e8525660b006870c9?OpenView.
10. Association of American Railroads, *Railroad Infrastructure Investment,* https://www.aar.org/keyissues/Pages/Infrastructure-Investment.aspx#.Uuq3EftTUgo.
11. W.C. Vantuono, "A Closer Look at LNG," *Railway Age* (October 2013).
12. K. Smith, "LNG: fuel of the future?" *International Railway Journal* (December 9, 2013), http://www.railjournal.com/index.php/locomotives/lng-fuel-of-the-future.html.
13. W.C. Vantuono, "A Closer Look at LNG," *Railway Age* (October 2013).
14. This summary of many of the major factors related to the switch from steam locomotives to diesel locomotives is taken from C. Wolmar, *The Great Railroad Revolution: The History of Trains in America* (Perseus Books Group, 2012), ISBN 978-1-61039-179-5.
15. C. Wolmar, *The Great Railroad Revolution: The History of Trains in America* (Perseus Books Group, 2012), ISBN 978-1-61039-179-5.
16. W.C. Vantuono, "A Closer Look at LNG," *Railway Age* (October 2013).
17. Electro Motive Diesel, "The Merits of AC vs DC Locomotives" (November 2008), http://www.slideshare.net/RailwaysandHarbours/merits-of-ac-vs-dc-locomotives-presentation.

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Figure and table sources for IF3

Links current as of April 2014

Table IF3-1. Class 1 Railroad diesel fuel consumption, fuel cost, and fuel cost share of operating expense, 2012: U.S. Department of Transportation, Surface Transportation Board, "Annual Report Financial Data," http://www.stb.dot.gov/econdata.nsf/f039526076cc0f8e8525660b006870c9?OpenView.

Figure IF3-1. Comparison of spot prices for Brent crude oil and Henry Hub natural gas, 1990-2040: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure IF3-2. Comparison of prices for railroad diesel fuel and liquefied natural gas fuel, 2014-40: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure IF3-3. Discounted fuel cost savings for a new locomotive and tender using liquefied natural gas as a fuel compared to diesel, 2020-40: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure IF3-4. Net present value calculation for locomotives using liquefied natural gas at Reference case fuel prices: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure IF3-5. Discounted fuel cost savings for a new locomotive and tender using liquefied natural gas as a fuel compared to diesel in three cases, 2020-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWPRICE.D120613A, and HIGHPRICE.D120613A.

Figure IF3-6. Comparison of energy consumption for freight rail using diesel and LNG in three cases, 2015-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, RLNGLOW20.D012914C, and RLNGHIGH20.D012914C.

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IF4. Light-duty vehicle energy demand: demographics and travel behavior

In 2012, energy consumption by light-duty vehicles (LDVs) accounted for 61% of all transportation energy consumption in the United States, or 8.4 million barrels of oil equivalent per day, and represented nearly 10% of world petroleum liquids consumption. LDV energy use is driven by both LDV fuel economy and travel behavior, as measured by LDV vehicle miles traveled (VMT). LDV VMT per licensed driver peaked in 2007 at 12,900 miles per year and decreased to 12, 500 miles in 2012.

The shift in VMT highlights the importance of travel behavior and its influence on LDV energy consumption. Before the 2007 peak, travel behavior in the United States tracked closely with economic growth. Since 2007, trends in U.S. LDV travel have not followed the trends in economic indicators such as income and employment as closely (Figure IF4-1). Although economic factors continue to influence travel demand, demographic, technological, social, and environmental factors also have shown the potential to affect LDV travel.

The AEO2014 Low and High VMT cases examine variations in travel demand as compared with the Reference case. In the Reference case, VMT per licensed driver begin to increase after 2018. The compound annual rate of growth in total VMT for LDVs from 2012 to 2040 in the AEO2014 Reference case is 0.9%—below the 1.7% rate from 1995 to 2005 but higher than the 0.7% average annual growth rate from 2005 through 2012. The Low VMT case assumes an environment in which travel choices made by drivers result in lower demand for personal vehicle travel, consistent with recent trends in VMT per licensed driver. In the Low VMT case, total U.S. LDV travel demand in 2040 is 19% lower than in the Reference case with annual increase in total LDV VMT from 2012 through 2040 averaging 0.2%. The High VMT case assumes changes in travel behavior that result in an increase in VMT per licensed driver compared with the Reference case. In the High VMT case, total U.S. LDV travel demand in 2040 is nearly 6% higher than in the Reference case with annual increase in total LDV VMT from 2012 through 2040 averaging 1.1% (Figure IF4-2).

The alternative VMT cases have direct implications for both projected energy use by LDVs and associated carbon dioxide emissions. In the Low VMT case, U.S. LDVs consume 5.3 million barrels of oil equivalent per day in 2040, 18% less than in the Reference case, resulting in total transportation sector CO_2 emissions roughly 9% lower than in the Reference case. In the High VMT case, LDVs consume 6.7 million barrels of oil equivalent per day in 2040, or 5% more than in the Reference case, resulting in total transportation sector CO_2 emissions more than 2% higher than in the Reference case (Figures IF4-3 and IF4-4).

Influential travel demand factors

Fuel use by LDVs is directly related to travel demand, which in turn depends on economic, demographic, technological, social, and environmental factors. In general, the demand for LDV travel is likely to decline when licensing rates fall [1], use of telework increases, or fuel prices are relatively high. Fuel use by LDVs is likely to rise when the driving-age population grows, during periods of expanding economic activity, or when fuel prices are relatively low.

Economic factors

Although recent U.S. travel indicators have started to decouple from economic indicators, economic indicators still are a dominant influence on levels of personal travel. There are strong links between economic activity and employment and commuting. Employment rates (Figure IF4-5) largely determine the ability of individuals to travel. When people are not employed and have less income, their daily travel is likely to be much lower than when they are commuting to and from work.

The labor force participation rate, defined as the percentage of the total population ages 16 years and older that is employed or looking for work, has declined since the early 2000s [2]. Reasons for the decline include increasing retirements and lack of

Figure IF4-1. Economic indicators of travel, 1975-2012 (index, 1995 = 1.0)

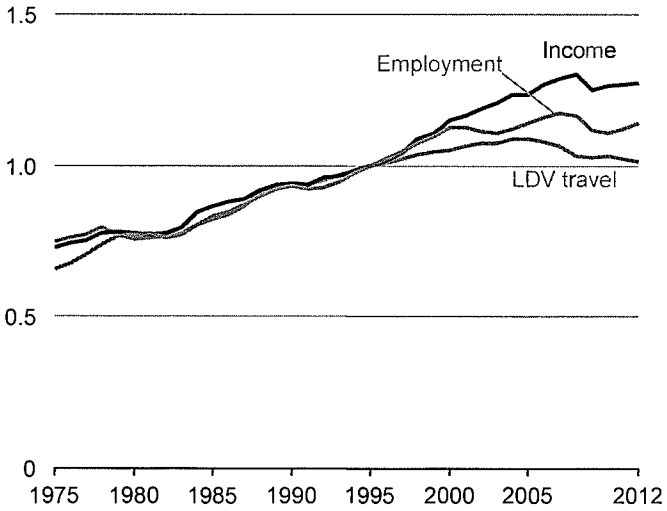
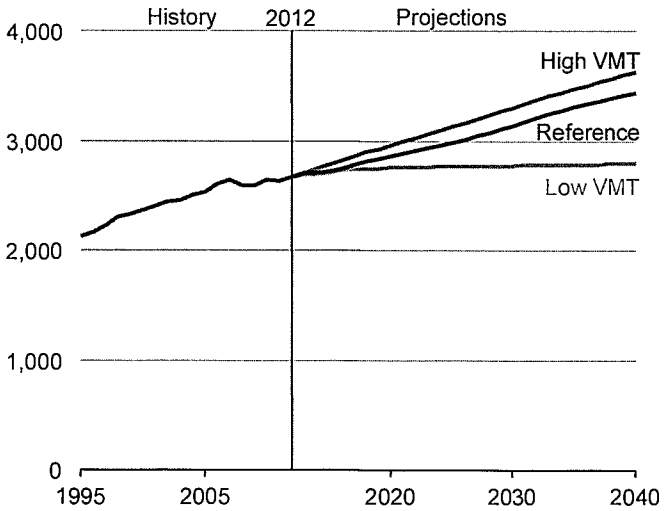


Figure IF4-2. Total light-duty vehicle miles traveled in three cases, 1995-2040 (billion miles)



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opportunities in the job market (which cause those without jobs to give up on job searches). When the labor force participation rate declines, the unemployment rate may also decline as people are removed from the labor pool, even if overall employment is stable. If the trend continues, retirees and people having difficulty finding jobs may reduce their travel as compared with people who have similar demographic profiles and are employed. When labor force participation rates rise, VMT per driver is likely to increase, particularly for millennials (those born between the early 1980s and early 2000s).

Other macroeconomic factors also influence travel behavior. Income, fuel prices, the costs of purchasing a vehicle, and other vehicle operating costs all influence the extent to which an individual can afford LDV travel. Households with vehicle ownership rates that equal or exceed the number of licensed drivers in the household have maximum non-overlapping access to vehicles. More recently, a business model that provides drivers with access to a shared-pool of vehicles has developed, particularly in urban areas. Because users of shared pool vehicles incur charges for time of use as well as fuel, this model discourages vehicle use for low-value trips. Income provides the financial means to own and operate a vehicle and, therefore, to travel; but operating costs can affect vehicle utilization rates. When fuel prices increase, the cost of driving increases, and many licensed drivers may choose to drive fewer miles, particularly if their personal incomes do not increase at the same rate as fuel prices.

Economic growth and higher employment rates are correlated with increased travel; however, it is unclear to what extent those economic effects may be offset or reinforced by other factors, such as aging of the population, driver licensing rates, telecommuting rates, and access to alternative travel options. The AEO2014 High and Low VMT cases illustrate potential impacts on overall VMT under plausible combinations of factors that could raise or lower VMT.

Figure IF4-3. U.S. light-duty vehicle energy use in three cases, 1995-2040 (million barrels of oil equivalent per day)

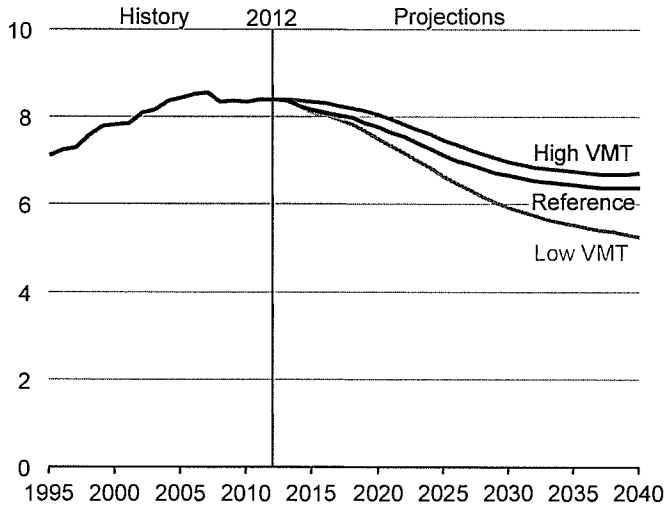
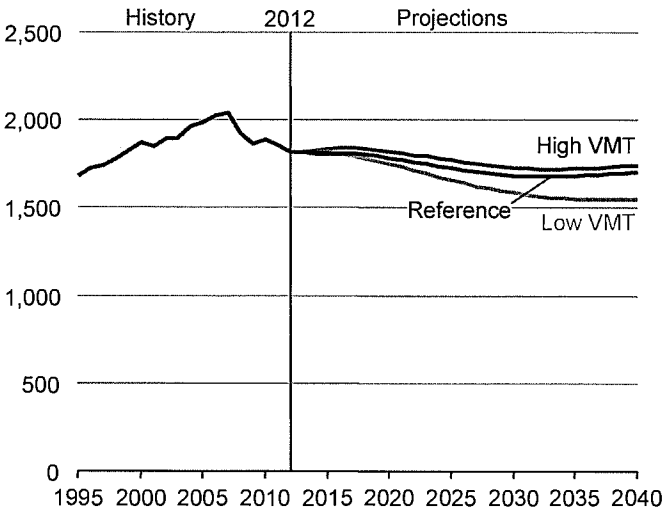


Figure IF4-4. U.S. carbon dioxide emissions in the transportation sector in three cases, 1995-2040 (million metric tons)

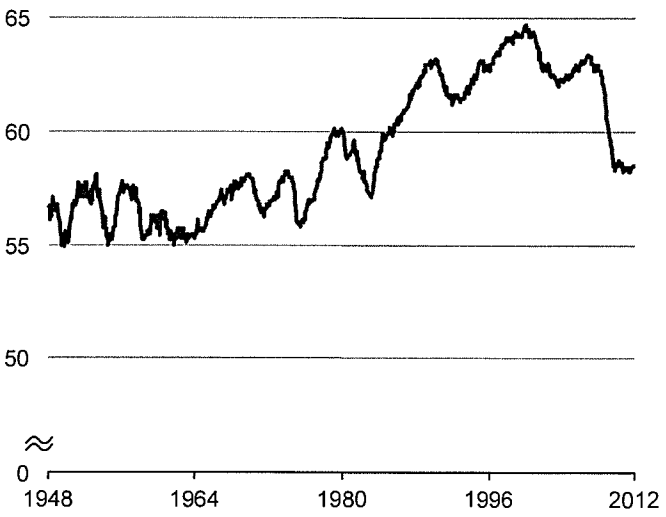


Demographic factors

Although economic factors play a significant role, demographic factors such as population, age distribution, and licensing rates also are important determinants of LDV travel demand. Population age groups have different gender distributions, licensing rates, and travel behaviors. As the age groups change over time, long-term effects on VMT will become apparent, particularly for the age groups that have the greatest influence on VMT.

A key factor in the recent shift of personal travel demand is specific travel behavior in age and gender groups. In this analysis, the driving population is divided into five age groups (Table IF4-1), and each age group is further divided into males and females (not shown in the table). Licensing rates differ across age and gender groups. Since 1990, licensing rates generally have been declining for the two youngest age groups and increasing for the two oldest groups (Figure IF4-6). For males, most age groups have seen declining or stagnant

Figure IF4-5. Ratio of U.S. civilian employment to population, 1948-2012 (percent)



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licensing rates, with the only exception being males 65 years and older. The female age groups have seen similar stagnation for most of the younger age groups and an increase for females 65 years and older.

Since about 1990, the average age of males who are licensed drivers has been higher than the average age of the male population 16 years and older (the male driving population). That trend is projected to continue as fewer young males obtain licenses or delay obtaining licenses until later in life. Conversely, the average age of female licensed drivers has been lower than the average age of the female driving population, but it is projected to be higher than the average age before 2020 and to continue rising through 2040 (Figure IF4-7). For both males and females, the average age of the driving population and average age of licensed drivers increase in the Reference case, with fewer younger individuals obtaining licenses and more choosing to wait until later in life to become licensed drivers.

The population age 34 years and below has seen a decrease in both licensing rates and VMT per licensed driver, with the licensing rate for the group falling by 5% over the past decade [3]. Some of the decline is a result of increased state restrictions on licenses. For example, for individuals under 18, states almost universally issue provisional licenses with restrictions on driving hours and passengers and do not allow full driving privileges until 18 years of age [4]. Since 2000, VMT per licensed driver for the population under 20 has dropped by 13%. In 1990, 52% of eligible individuals under 20, and 92% of those between 20 and 34 years of age, obtained their licenses. In 2010, those shares were 43% and 86%, respectively [5]. If the trend persists, licensing rates could continue to decline or flatten out for the youngest driving populations, further reducing VMT per capita. If the licensing rate returns to historic levels, total VMT will increase. Technological factors may also play a role for younger age groups, as discussed below.

The peak driving age group, between 35 and 54 years of age, has experienced a small decline in licensing, from 95% in 1990 to an estimated 92% in 2010. Drivers in this age group traveled an average of almost 15,000 miles annually in 2012, the highest rate of VMT per licensed driver for any age group. This relatively large age group, accounting for 34% of the population in 2012, has a limited influence on changes in total VMT, because neither the licensing rate nor the share of the population has changed drastically through history or is projected to change significantly in the future. Much of that stability results from high employment rates for this age group, as a result of the interaction between economic and demographic factors.

The overall population share in the oldest age group, 65 years and older, has grown steadily since 2000 and is expected to reach 24% of the total population ages 16 and above in 2025, up from a 17% share in 2012. Although the size of this segment of the population has grown since 2000, personal travel (VMT per capita) by the oldest age group dropped by 7% between 2008 and 2009, and its total VMT dropped by 10%. More members of the older population are obtaining their licenses than in the past, but they also have altered their travel behavior, increasing their use of public transportation by 40% during the period from 2001 to 2009 [6]. As the aging of the U.S. population continues, long-term effects on VMT will be apparent, particularly as seen in older driver behavior versus younger driver behavior, as well as gender and regional differences in driver behavior.

Table IF4-1. Historic and projected distribution of age groups

	Percent of population ages 16 and above		
Age (years)	2012	2025	2040
16-19	6.9	6.1	6.0
20-34	26.1	24.4	22.8
35-54	34.1	30.9	30.9
55-64	15.5	15.0	13.5
65+	17.4	23.7	26.8

Figure IF4-6. Driver licensing rates by age group, 1990-2010 (percent of total age group)

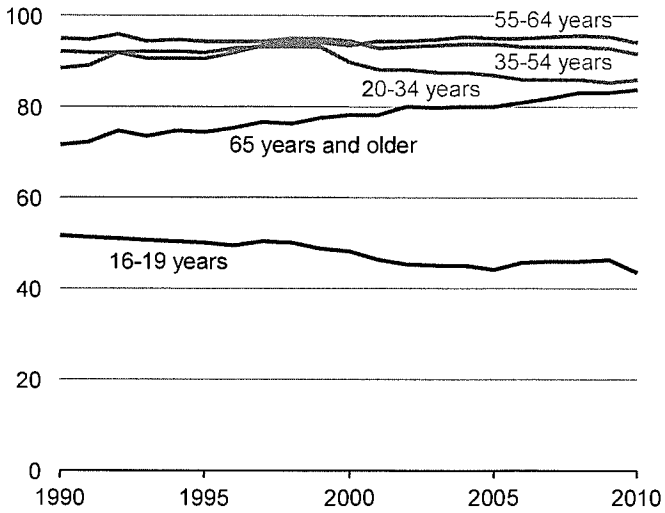
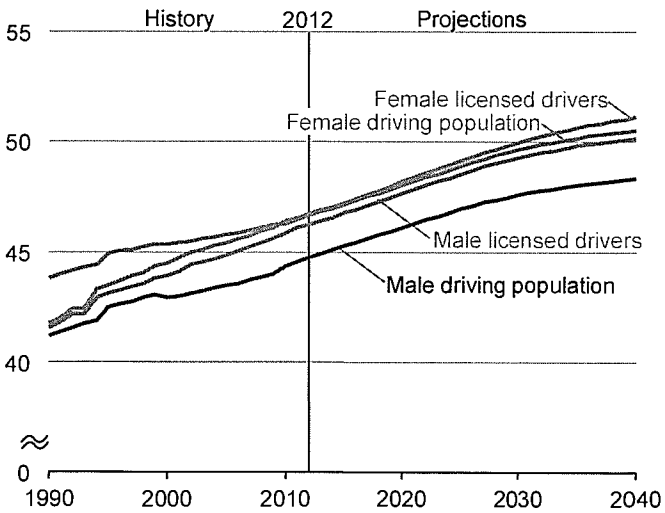


Figure IF4-7. Average ages of male and female driving-age populations and licensed drivers, 1990-2040 (years)



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Demographic changes can also interact with other factors to influence VMT. Historically, shifts in demographics coupled with economic changes have had major impacts on total travel. For example, the increasing number of women who entered the work force beginning in the 1970s—and added secondary incomes for their families—led to a rise in VMT that combined both economic activity and demographic changes. In the future, factors that influence VMT may merge in various ways that change long-term trends in U.S. travel demand.

Technological, social, and environmental factors

Technological, social, and environmental factors also can influence VMT. Alternative modes of travel affect VMT to the degree that the population has access to substitutes for personal LDVs. The decision to choose a substitute travel option depends on cost in comparison to personal LDVs, convenience, personal preferences, and the availability of mass transit, rail, biking, and pedestrian travel service options. Other opportunities may also affect personal travel, including car-sharing services, car rental and taxi services, and carpooling.

Technological changes and improvements can also affect VMT. The increasing fuel efficiency of LDVs can influence personal travel by lowering the marginal cost of driving per mile. As vehicle efficiency improves, individuals can drive the same distance with less fuel and therefore at a lower cost, which may result in an increase in VMT. In recent analyses supporting the promulgation of new final fuel economy and greenhouse gas emissions standards for LDVs in model years 2017 through 2025, the National Highway Traffic Safety Administration (NHTSA) and the U.S. Environmental Protection Agency (EPA) applied a 10% rebound in VMT to reflect the lower fueling costs of more efficient vehicles [7].

Other types of technological and environmental changes also can affect personal travel. Telecommuting, e-commerce, urbanization, and social media can supplant or complement personal vehicle use. Telecommuting, or working from home, can influence personal VMT. From 1997 to 2010, the share of the workforce working at least one day of the week from home increased from 7% to 9.5%. As that trend grows, so does the likelihood that individuals will reduce their total miles driven. The share of the working population that works exclusively from home also has increased, from 4.8% in 1997 to 6.6% in 2010 [8]. Although telecommuting can have an impact on reducing VMT, work-related travel in 2009 was only 25% of total personal travel [9].

Technological advances have increased access to and the availability of electronic devices and other opportunities that can influence VMT—including, but not limited to, social media, GPS applications, and electronic devices. Some analysts have suggested an association between rising interest in social media and a decline in the rates at which driving-age youth obtain driver licenses. Others suggest that access to social media actually increases opportunity and desire for travel. Mobile technology and changing preferences of the younger generations will play a significant part in determining the future of LDV travel.

Finally, spatial development patterns may begin to play a different role in determining VMT than is suggested by history, as suburban sprawl gives way to other development patterns. Urbanization generally results in increases in, and greater access to, public transportation and would be likely to support other forms of transportation, including biking, car sharing, and carpooling. Land use changes and related policies, mainly at the local level but supported or incentivized by state and federal policies, have had only localized impacts on VMT to date. However, the tradeoff between suburban and exurban development and urban infill development is likely to change over the coming decades, and those changes could affect VMT.

Figure IF4-8. Vehicle use by drivers 16-19 years old in three cases, 1990-2040 (VMT per licensed driver per year)

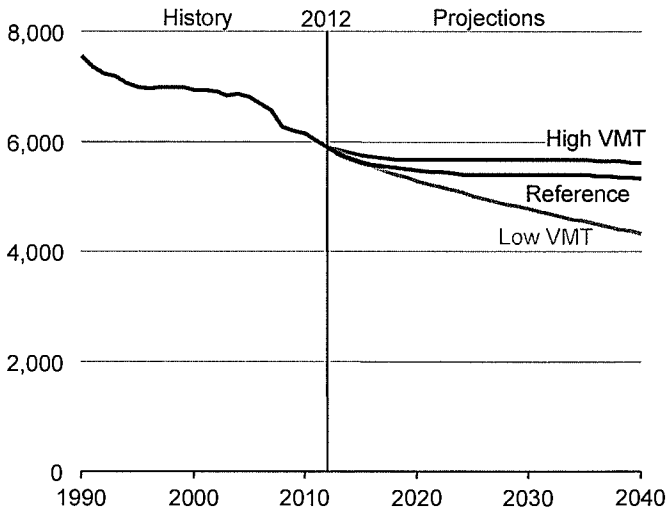
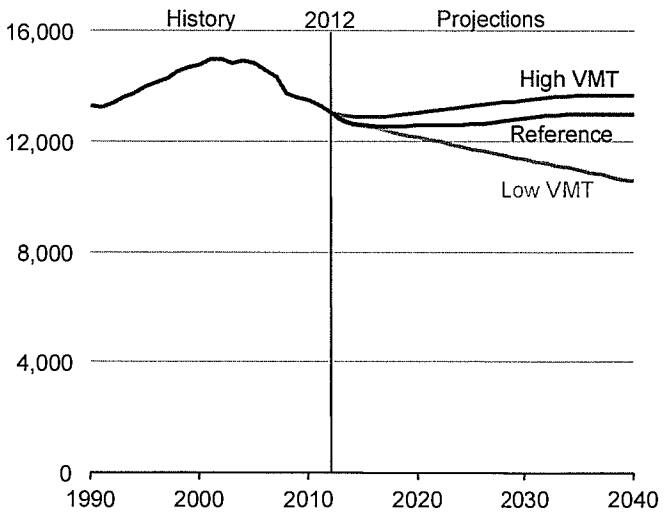


Figure IF4-9. Vehicle use by drivers 20-34 years old in three cases, 1990-2040 (VMT per licensed driver per year)



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VMT sensitivity analysis

The High and Low VMT cases suggest possible future changes in travel behavior and their potential impacts on VMT and on LDV energy demand. The Low VMT case assumes a 0.5% annual decrease in VMT per licensed driver from 2013 to 2040 for each age and gender group. The High VMT case assumes a pattern of annual increases in VMT per licensed driver: 0.3% starting in 2013, 0.4% starting in 2016, 0.5% starting in 2019, and 0.6% starting in 2023, slowing to 0.5% starting in 2027, 0.4% starting in 2032, and 0.3% from 2036 through 2040. Figures IF4-8 through IF4-12 show VMT per licensed driver in each case for five age groups.

In the Low VMT case, VMT per licensed driver for all drivers decline throughout the projection, to about 10,400 miles per year in 2040—a 19% decrease from 12,800 miles per year in 2040 in the Reference case. In the High VMT case, VMT per licensed driver for all drivers rise to 13,500 miles per year in 2040—nearly 6% higher than in the Reference case (Figure IF4-13). In the Low VMT case, VMT per licensed driver across all age groups decline by an average of 0.7% per year from 2012 to 2040, compared with an average increase of 0.1% per year in the Reference case. The High VMT case projects 0.3% average annual growth in VMT per licensed driver from 2012 through 2040.

Total LDV VMT increase only slightly in the Low VMT case, to almost 2.8 trillion miles in 2040, as compared with 3.6 trillion miles in 2040 in the High VMT case. Annual increases in total LDV VMT from 2012 to 2040 average 0.2% in the Low VMT case and 1.1% in the High VMT case.

Figure IF4-10. Vehicle use by drivers 35-54 years old in three cases, 1990-2040 (VMT per licensed driver per year)

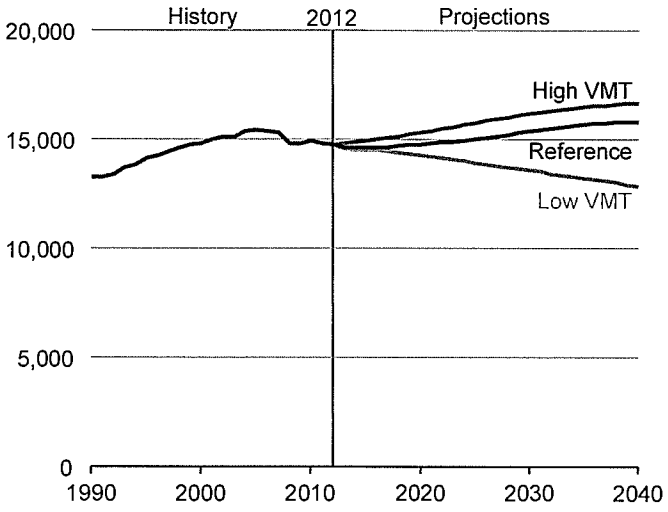


Figure IF4-11. Vehicle use by drivers 55-64 years old in three cases, 1990-2040 (VMT per licensed driver per year)

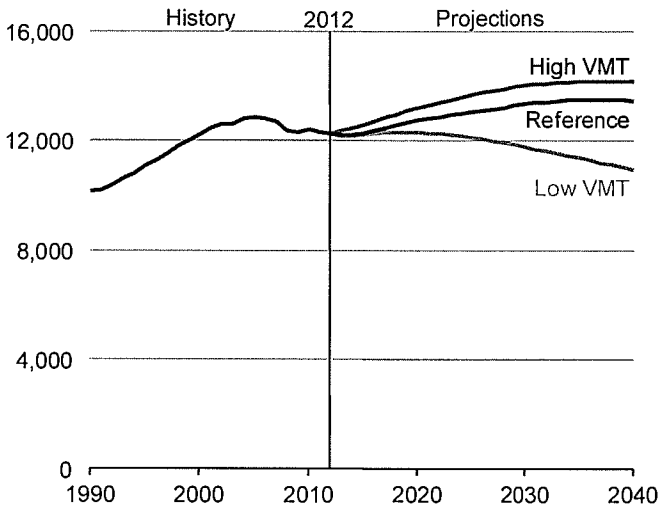


Figure IF4-12. Vehicle use by drivers 65+ years old in three cases, 1990-2040 (VMT per licensed driver per year)

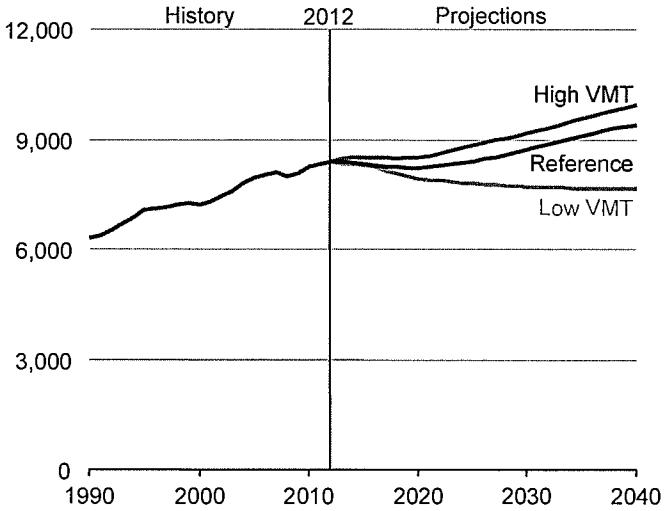
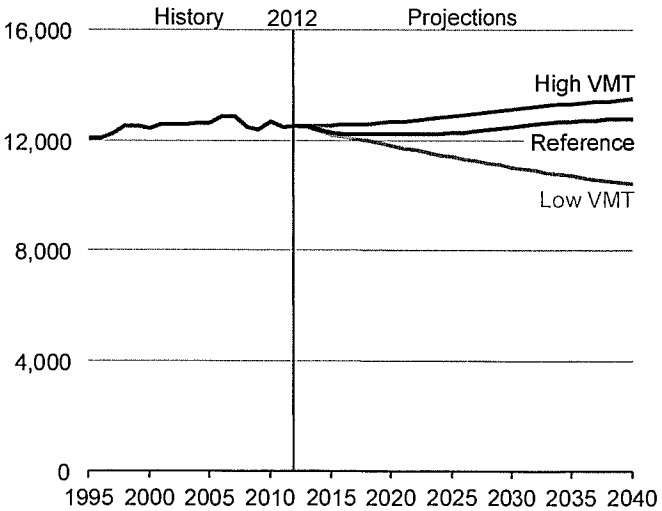


Figure IF4-13. Vehicle use by all drivers in three cases, 1995-2040 (VMT per licensed driver per year)



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Endnotes for IF4

Links current as of April 2014

1. The licensing rate is the share of a population or group 16 years old or older that have driver's licenses.
2. U.S. Department of Labor, Bureau of Labor Statistics, "Labor Force Participation Rate," http://data.bls.gov/timeseries/LNS11300000.
3. United States Public Interest Research Group (PIRG) Education Fund and Frontier Group, *Transportation and the New Generation* (April 2012), http://www.uspirg.org/reports/usp/transportation-and-new-generation.
4. Government Highway Safety Association, "Graduated Driver Licensing Laws" (March 2014), http://www.ghsa.org/html/stateinfo/laws/license_laws.html.
5. U.S. Department of Transportation, Federal Highway Administration, Highway Statistics Series (2012), https://www.fhwa.dot.gov/policyinformation/statistics.cfm.
6. J. Lynott and C. Figueiredo, "Fact Sheet 218: How the Travel Patterns of Older Adults Are Changing: Highlights from the 2009 National Household Travel Survey" (AARP Public Policy Institute, April 2011), http://assets.aarp.org/rgcenter/ppi/liv-com/fs218-transportation.pdf.
7. U.S. Environmental Protection Agency and National Highway Transportation Safety Administration, "2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards; Final Rule," *Federal Register*, Vol. 77, No. 199 (Washington, DC, October 15, 2012), https://www.federalregister.gov/articles/2012/10/15/2012-21972/2017-and-later-model-year-light-duty-vehicle-greenhouse-gas-emissions-and-corporate-average-fuel.
8. P.J. Mateyka, M.A. Rapino, and L.C. Landivar, *Home-Based Workers in the United States: 2010* (U.S. Department of Commerce, U.S. Census Bureau, Washington, DC, October 2012), https://www.census.gov/prod/2012pubs/p70-132.pdf.
9. U.S. Department of Transportation, Federal Highway Administration, "2009 NHTS - Version 2.1" (February 2011), http://nhts.ornl.gov/download.shtml.

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Figure and table sources for IF4

Links current as of April 2014

Figure IF4-1. Economic indicators of travel, 1975-2012: Income: U.S. Bureau of Economic Analysis, "GDP and Personal Income" *National Data,* http://www.bea.gov/iTable/index_nipa.cfm. Employment: U.S. Department of Labor, Bureau of Labor Statistics, *Current Employment Statistics,* http://www.bls.gov/ces/#data. LDV Travel: U.S. Department of Transportation, Federal Highway Administration, "Table VM-1," Highway Statistics Series 2011 (March 2013), https://www.fhwa.dot.gov/policyinformation/statistics/2011/.

Figure IF4-2. Total light-duty vehicle miles traveled in three cases, 1995-2040: History: U.S. Department of Transportation, Federal Highway Administration, "Table VM-1," *Highway Statistics Series 2011* (March 2013), https://www.fhwa.dot.gov/policyinformation/statistics/2011/. Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

Figure IF4-3. U.S. light-duty vehicle energy use in three cases, 1995-2040: History: U.S. Department of Transportation, Federal Highway Administration, *National Household Travel Survey,* http://nhts.ornl.gov/download.shtml. Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

Figure IF4-4. U.S. carbon dioxide emissions in the transportation sector in three cases, 1995-2040: History: S.C. Davis, S.W. Diegel, and R.G. Boundy, *Transportation Energy Data Book,* Edition 31 (July 2012), http://info.ornl.gov/sites/publications/files/Pub37730.pdf. Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

Figure IF4-5. Ratio of U.S. civilian employment to population, 1948-2012: U.S. Department of Labor, Bureau of Labor Statistics, Current Employment Statistics, http://www.bls.gov/ces/#data.

Table IF4-1. Historic and projected distribution of age groups: U.S. Department of Commerce, U.S. Census Bureau, 2010 Census Data, https://www.census.gov/2010census/data/.

Figure IF4-6. Driver licensing rates by age group, 1990-2010: U.S. Department of Transportation, Federal Highway Administration, "Table DL-22," *Highway Statistics Series 2011* (March 2013), https://www.fhwa.dot.gov/policyinformation/statistics/2011/.

Figure IF4-7. Average ages of male and female driving-age populations and licensed drivers, 1990-2040: History: U.S. Department of Transportation, Federal Highway Administration, "Table DL-22," *Highway Statistics Series 2011* (March 2013), https://www.fhwa.dot.gov/policyinformation/statistics/2011/; and U.S. Department of Commerce, U.S. Census Bureau, *2010 Census Data,* https://www.census.gov/2010census/data/. Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

Figure IF4-8. Vehicle use by drivers 16-19 years old in three cases, 1990-2040: History: U.S. Department of Transportation, Federal Highway Administration, *National Household Travel Survey,* http://nhts.ornl.gov/download.shtml. Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

Figure IF4-9. Vehicle use by drivers 20-34 years old in three cases, 1990-2040: History: U.S. Department of Transportation, Federal Highway Administration, *National Household Travel Survey,* http://nhts.ornl.gov/download.shtml. Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

Figure IF4-10. Vehicle use by drivers 35-54 years old in three cases, 1990-2040: History: U.S. Department of Transportation, Federal Highway Administration, *National Household Travel Survey,* http://nhts.ornl.gov/download.shtml. Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

Figure IF4-11. Vehicle use by drivers 55-64 years old in three cases, 1990-2040: History: U.S. Department of Transportation, Federal Highway Administration, *National Household Travel Survey,* http://nhts.ornl.gov/download.shtml. Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

Figure IF4-12. Vehicle use by drivers 65+ years old in three cases, 1990-2040: History: U.S. Department of Transportation, Federal Highway Administration, *National Household Travel Survey,* http://nhts.ornl.gov/download.shtml. Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

Figure IF4-13. Vehicle use by all drivers in three cases, 1995-2040: History: U.S. Department of Transportation, Federal Highway Administration, *National Household Travel Survey,* http://nhts.ornl.gov/download.shtml. Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

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IF5. Effects of lower natural gas prices on projected industrial production

This analysis focuses on variation in industrial output in the Low and High Oil Price cases and Low and High Oil and Gas Resource cases compared to the *Annual Energy Outlook 2014* (AEO2014) Reference case. Energy-intensive industries, including food, paper, bulk chemicals, glass, cement, iron and steel, and aluminum, are the industries that use the largest amount of energy per unit of output and are the most sensitive to natural gas prices. Of these, the most natural gas-intensive industries are food, paper, bulk chemicals, and glass [*1*].

Analysis of the industrial sector as a whole reveals strong links between natural gas prices and industrial production [*2*]. Further analyses reveal important data issues and indicate some basic sensitivity to natural gas prices for the most energy-intensive industries, subject to trade competition, when they are disaggregated [*3, 4*]. Those studies show evidence of a straightforward production decline when natural gas prices to the bulk chemicals industry increase, but the relationship does not appear to apply to the less natural gas-intensive cement industry. The same studies point to an important role for demand, both foreign and domestic, for all industries, including the energy-intensive industries. The National Energy Modeling System used to produce AEO2014 includes sufficient disaggregation to support analysis of the influence of natural gas prices on industrial output.

Demand categories

Expenditure categories, such as personal consumption, investment, government spending, and trade, measure underlying demand in the U.S. economy. Each category includes more detailed disaggregation, such as durable and nondurable goods. The AEO2014 industrial output projections use 59 different categories of final demand, with the effects of each category on industrial production differing across industries. The most important final demand categories for the industries analyzed here, according to input-output tables from the Commerce Department's Bureau of Economic Analysis (BEA) [*5*], are consumer spending, trade, and investment (see box below). In addition to demand from domestic consumers and trade, interindustry demand also affects the industrial sector.

Impact of Bureau of Economic Analysis revisions on the National Income and Product Accounts

BEA performs comprehensive National Income and Product Accounts (NIPA) revisions approximately every five years. The 2013 release was its 14th comprehensive revision. The previous release was in July 2009. The BEA comprehensive revisions incorporate changes in the methods used to measure the U.S. economy as well as the most up-to-date, most complete, and most accurate source data available. Changes in NIPA definitions, classifications, and presentations as a result of the 2013 comprehensive revision include:

- Capitalization of expenditures on research and development (R&D)
- Capitalization of expenditures on entertainment, literary, and artistic originals
- Addition of intellectual property products to the fixed investment tables, including R&D; entertainment, literary, and artistic originals; and software
- Accrual treatment of defined benefit pension plan transactions, recognizing the costs of unfunded liabilities
- Expanded set of ownership transfer costs for residential fixed assets
- Change of the reference year for price indexes and inflation-adjusted series.

The AEO2014 Reference case and High and Low Economic Growth cases started with the IHS Global Insight U.S. long-term model simulations available in March and June 2013, which do not reflect the latest comprehensive NIPA revisions for two reasons. First, the July 2013 NIPA revisions were issued late in the AEO preparation cycle. The late issuance of the NIPA revisions delayed the September and October releases of the IHS Global Insight U.S. long-term model simulations, normally used in preparation of the U.S. Energy Information Administration's (EIA) *Annual Energy Outlook* (AEO). Second, EIA uses the economic forecast together with interindustry data describing how each industry uses other industries' output, and how each industry satisfies its final demand components [*6*]. BEA released the updated interindustry tables in December 2013, much too late for the AEO. While the comprehensive NIPA revisions affect past and projected estimates of GDP, they are not expected to materially affect projected energy use. The results of the 2013 NIPA comprehensive revisions will be included in EIA's *Annual Energy Outlook 2015*.

Although the 2013 comprehensive NIPA revision did not lead to changes in broad economic trends or in the general patterns of past business cycles, it did increase gross domestic product (GDP) in every year back to 1929. The average annual growth rate of real GDP from 1929 to 2012 was revised upward to 3.3%, as compared with the previous estimate of 3.2%. More recently, the annual growth rate from 2002 to 2012 was revised upward to 1.8%, as compared with the previous estimate of 1.6%. The economic recession of 2007-09 (December 2007 to June 2009) now looks less severe than previously reported—with GDP contracting by 2.9% over that period after the comprehensive revision, compared with 3.2% before the revision. In addition, the current recovery is stronger than first reported—a 2.2% average annual expansion from the second quarter of 2009 through the first quarter of 2013, compared with 2.1% before the revision. The revised data also indicate that the economy shrank at an average annual rate of 1.3% in the first quarter of 2011, compared with 0.1% growth before the revision.

(continued on next page)

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Changes in 2012 nominal GDP as a result of the comprehensive revision total $559.8 billion, including $526 billion (94%) attributable to changes in definitions and $33.8 billion (6%) resulting from statistical changes. Research and development capitalization accounts for 75% of definitional changes, or $396.7 billion. Two-thirds of R&D expenditures are made by the private sector and one-third by government. The remaining changes to definitions include capitalization of entertainment, literary, and artistic originals ($74.3 billion, or 14%); an expanded set of ownership transfer costs for residential fixed assets ($42.3 billion, or 8%); and accrual accounting for defined benefit pension programs ($12.6 billion, or 2%).

Figure IF5-1. Bureau of Economic Analysis revisions to gross domestic product by major component, 2002-12 (billion dollars)

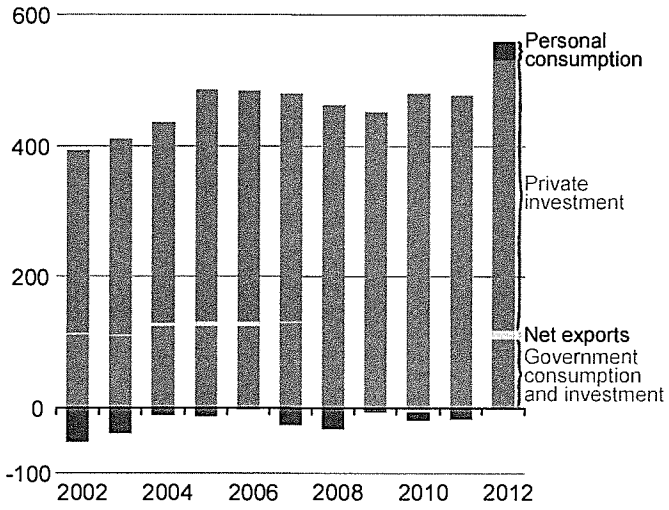


Figure IF5-1 shows the annual impacts of the NIPA revisions on the major components of GDP from 2002 to 2012. Private investment and government expenditures accounted for 92% of the $560 billion upward revision in 2012, primarily as a result of the capitalization of R&D expenditures. Revisions to gross private domestic investment contributed $413 billion, or 74% of the total; revisions to government expenditures contributed $104 billion, or 19% of the total; and revisions to personal consumption and net exports contributed $43 billion, or 7% of the total upward revision to 2012 GDP.

The increase in private and government investment spending is primarily the result of BEA's continued work to broaden the definition of GDP. With this comprehensive revision, NIPA now includes capitalization of spending on R&D and on long-lived artwork produced by artists, studios, and publishers—intangible assets that previously were considered intermediate inputs to the production of other goods or services. Although the inclusion of intangible assets does raise the measured level of overall economic activity, it has only a modest impact on economic growth rates.

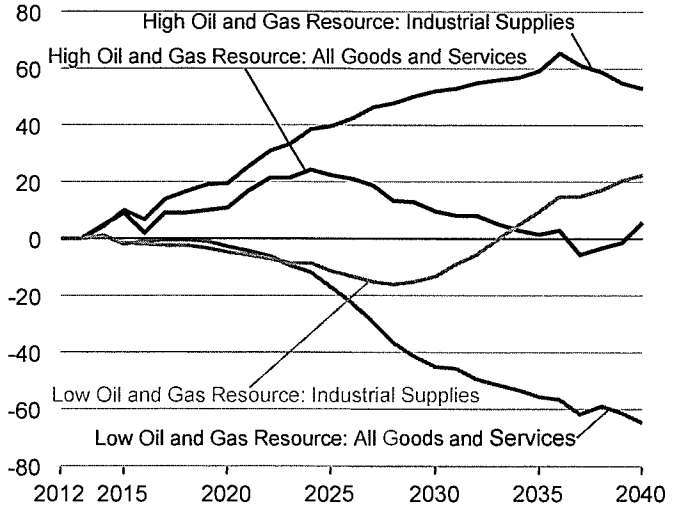
Alternative cases

Results

Oil and Gas Resource cases

Changes in the assumed size of the U.S. oil and natural gas resource base and the rate of technology advance within the sector can affect the nation's economy. In general, increases in oil and natural gas resources result in lower prices and higher industrial output, and a smaller oil and natural gas resource base results in higher prices and lower industrial output. However, the cases are not symmetric. In the High Oil and Gas Resource case, GDP is 1.2% higher in 2040 than projected in the Reference case, total industrial output is 5.1% higher in 2040, and bulk chemicals and paper industries output is 11.5% higher in 2040, as a result of improved trade advantages resulting from lower prices. The changes tend to be smaller in the Low Oil and Gas Resource case. GDP is 0.4% lower in 2040 than projected in the Reference case, total industrial output is 2.3% lower in 2040, and bulk chemicals and paper industries output is 5.0% lower in 2040, as a result of lower oil and natural gas production and higher prices in the Low Oil and Gas Resource case.

Figure IF5-2. Changes from the Reference case in annual net exports, Low and High Oil and Gas Resource cases, 2012-40 (billion 2005 dollars)



Among the final demand categories, trade of industrial supplies (Figure IF5-2) and consumer goods (Figure IF5-3) show the largest differences across the Oil and Gas Resource cases. Energy trade is a major component of industrial supplies. Trade of industrial supplies and consumer goods drives production in the bulk chemicals industry (Figure IF5-4). The price advantage of natural gas-based feedstock varies widely in the High Oil and Gas Resource case (Figure IF5-5), with corresponding impacts on the bulk chemicals industry. Differences in production of bulk chemicals account for a large portion of the differences in fuel consumption results, particularly for petroleum and other liquids and for natural gas, both of which are used as feedstocks in the bulk chemicals industry.

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In the High Oil and Gas Resource case, exports of all goods and services from 2012 to 2025 grow faster than imports, as a result of lower U.S. producer prices [7] that are attributable in part to lower natural gas prices (see Figure IF5-2). After 2025, the growth rate of imports begins to increase. Net exports of industrial supplies continue to grow throughout the projection in the High Oil and Gas Resource case, because energy imports are low. In the Low Oil and Gas Resource case, net exports of all goods and services decline through 2040, primarily as a result of slow export growth when U.S. producer prices are higher than those in the Reference case. Net exports of industrial supplies in the Low Oil and Gas Resource case are lower than in the Reference case until 2034, when nonenergy imports drop below Reference case levels as U.S. producer price inflation slows.

Oil Price cases

In comparison with the Reference case, the Low Oil Price case shows lower natural gas prices and production, and the High Oil price case shows higher natural gas prices and production. However, the magnitude of the changes in the Oil Price cases is smaller than in the Oil and Gas Resource cases. The changes in natural gas prices in the Low Oil Price case affect the economy earlier in the projection, leading to changes in inflation, unemployment, and interest rates. In the High Oil Price case, the economy shows larger losses beginning earlier than in the Low Oil and Gas Resource case but recovers as natural gas production expands.

In both the Low and High Oil Price cases, the largest changes from the Reference case are for trade in industrial supplies (Figure IF5-6) and consumer goods (Figure IF5-7), which primarily affect the bulk chemicals, glass, and paper industries. Differences

Figure IF5-3. Changes from the Reference case in consumer spending, Low and High Oil and Gas Resource cases, 2012-40 (billion 2005 dollars)

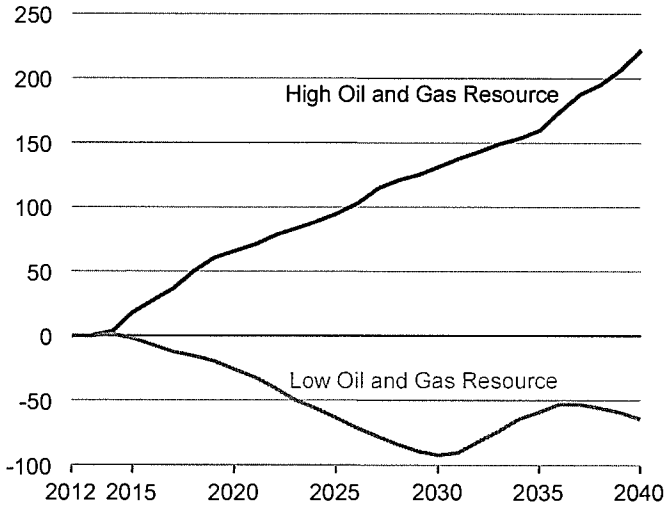

Figure IF5-4. Bulk chemicals value of shipments in three cases, 2012-40 (billion 2005 dollars)

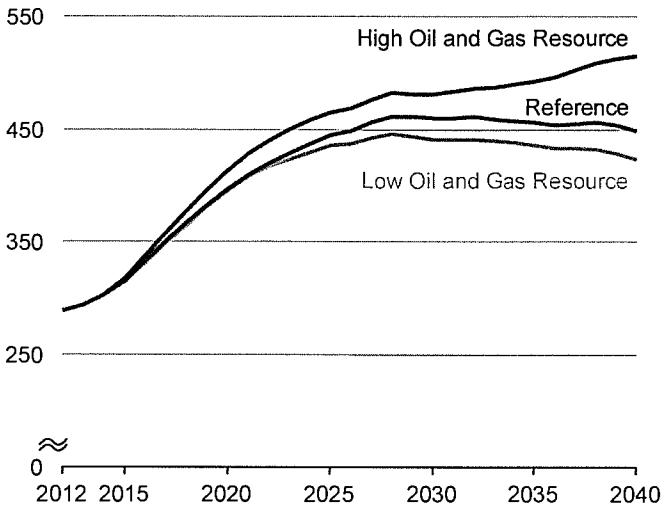

Figure IF5-5. Ratio of ethane to naphtha feedstock prices in three cases, 2012-40

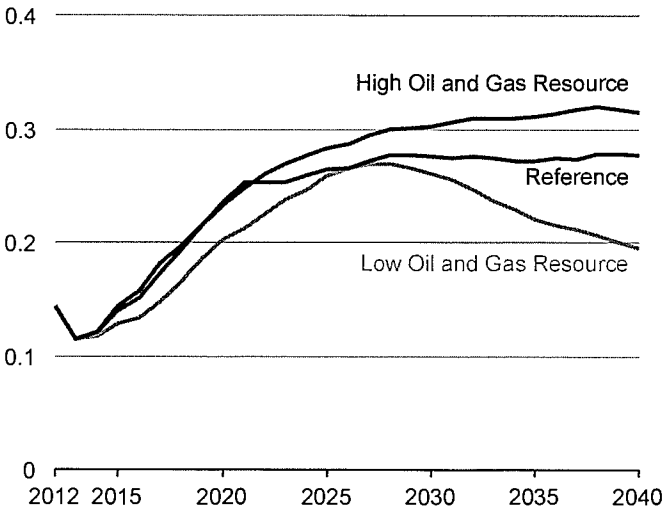

Figure IF5-6. Changes from the Reference case in net exports, Low and High Oil Price cases, 2012-40 (billion 2005 dollars)

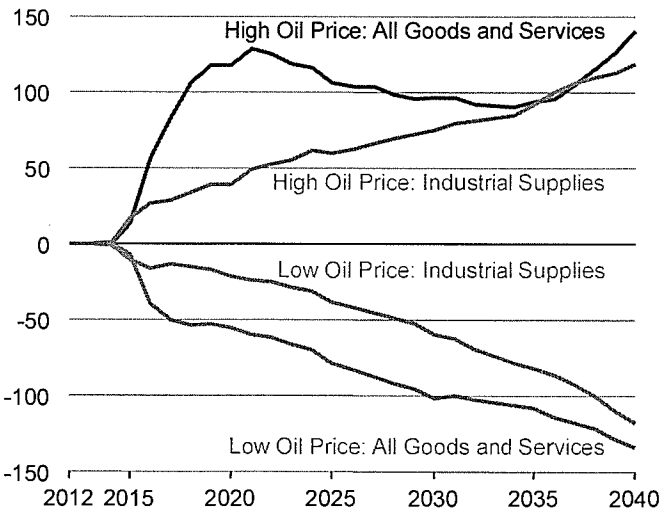

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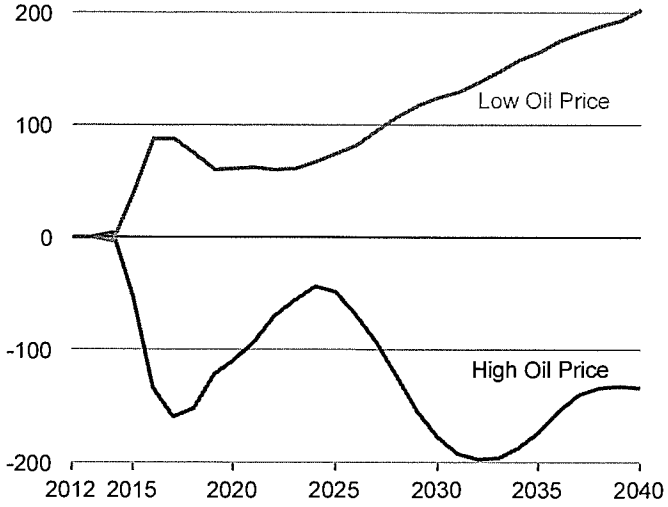
Figure IF5-7. Changes from the Reference case in consumer spending, Low and High Oil Price cases, 2012-40 (billion 2005 dollars)



in consumer spending affect output in the glass and paper industries, which are tightly linked to consumer goods and more closely tied to demand for capital goods than is the bulk chemicals industry. Fuel consumption trends in the Low and High Oil Price cases differ from those in the Low and High Oil and Gas Resource cases, primarily because of the bulk chemicals industry. The initial response of the bulk chemicals industry to higher oil prices compared with the Reference case is a decrease in output (Figure IF5-8), and the initial response to lower oil prices is an increase in output, which does not occur in the High and Low Oil and Gas Resource cases (see Figure IF5-4). In the High Oil Price case, oil prices grow faster than the prices of natural gas-based feedstocks, leading to a price advantage for natural gas feedstocks (Figure IF5-9). As a result, bulk chemicals output in the High Oil Price case in 2040 is higher than in the Reference case. In the Low Oil Price case, with natural gas prices increasing more than oil prices, bulk chemicals output remains below the Reference case level in 2040.

Figure IF5-8. Shipments of bulk chemicals in three cases, 2012-40 (billion 2005 dollars)

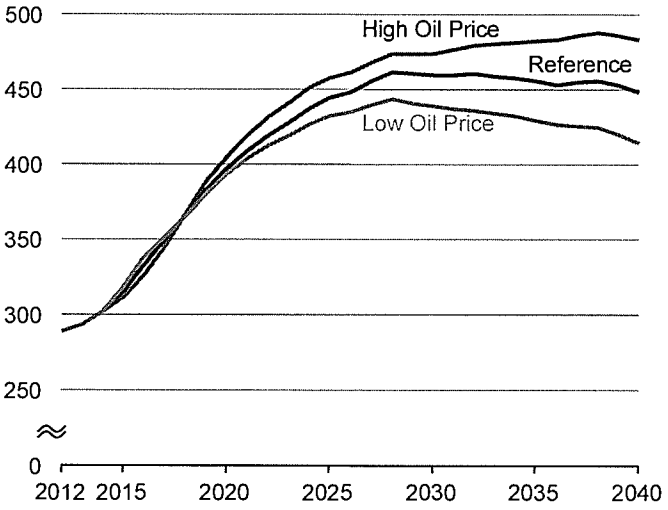
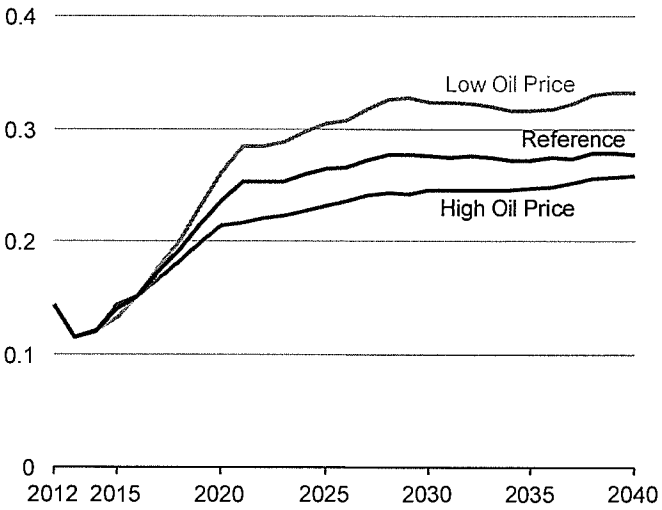


Figure IF5-9. Ratio of ethane to naphtha feedstock prices in three cases, 2012-40



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Endnotes for IF5

Links current as of April 2014

1. U.S. Energy Information Administration, 2010 Manufacturing Energy Consumption Survey (MECS), http://www.eia.gov/consumption/manufacturing/index.cfm.
2. V. Arora and J. Lieskovsky, "Natural gas and U.S. economic activity," *The Energy Journal* (forthcoming, 2014).
3. E. Sendich, "The importance of natural gas in the industrial sector with a focus on energy-intensive industries," EIA Discussion Paper (February 28, 2014), http://www.eia.gov/discussionpapers/?src=bookshelf.
4. V. Arora and E. Sendich, "Natural gas and U.S. industrial production: a closer look at four industries" (unpublished).
5. Bureau of Economic Analysis, Industry Accounts, http://bea.gov/industry/index.htm#annual.
6. For a more detailed description of the interindustry data changes, see "Benchmark input-output account of the U.S. economy, 2007" (December 18, 2013), http://www.bea.gov/newsreleases/industry/io/ionewsrelease.htm.
7. The producer price index, used to capture the selling prices received by domestic producers for their output, represents the price paid by industrial sector purchasers for inputs.

Figure sources for IF5

Links current as of April 2014

Figure IF5-1. Bureau of Economic Analysis revisions to gross domestic product by major component, 2002-12: History: U.S. Department of Commerce, Bureau of Economic Analysis, "National Income and Products Account Table," Table 1.1.5, Gross Domestic Product, First Quarter Third Release (Washington, DC, June 26, 2013), http://www.bea.gov/newsreleases/national/gdp/2013/gdp1q13_3rd.htm; and U.S. Department of Commerce, Bureau of Economic Analysis, "National Income and Products Account Table," Table 1.1.5, Gross Domestic Product, Second Quarter Advanced Release (Washington, DC, July 31, 2013), http://www.bea.gov/newsreleases/national/gdp/2013/gdp2q13_adv.htm.

Figure IF5-2. Changes from the Reference case in annual net exports, Low and High Oil and Gas Resource cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure IF5-3. Changes from the Reference case in consumer spending, Low and High Oil and Gas Resource cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure IF5-4. Shipments of bulk chemicals in three cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure IF5-5. Ratio of ethane to naphtha feedstock prices in three cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure IF5-6. Changes from the Reference case in net exports, Low and High Oil Price cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure IF5-7. Changes from the Reference case in consumer spending, Low and High Oil Price cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure IF5-8. Shipments of bulk chemicals in three cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure IF5-9. Ratio of ethane to naphtha feedstock prices in three cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

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IF6. Implications of accelerated power plant retirements

In 2012, coal-fired and nuclear power plants together provided 56% of the electricity generated in the United States. The role of these technologies in the U.S. generation mix has been changing since 2009, as both low natural gas prices and slower growth of electricity demand have altered their competitiveness relative to other fuels. Many coal-fired plants also must comply with requirements of the Mercury and Air Toxics Standards (MATS) and other environmental regulations. Some of the challenges faced by coal-fired and nuclear generators, and the implications for electricity markets if the plants are retired in significant numbers, are analyzed in this discussion.

Of the total installed 310 gigawatts (GW) of coal-fired generating capacity available at the end of 2012, 50 GW, or 16%, is projected to be retired by 2020 in the AEO2014 Reference case. Despite those projected retirements, coal continues to account for the largest share of the electricity generation mix through 2034, after which it is overtaken by natural gas. However, throughout the projection the coal share of total generation remains significantly below its 49% share in 2007, when coal set its annual generation record.

In 2012 and 2013, operators of five nuclear power reactors representing 4.2 GW of capacity announced plans to retire the reactors by 2015. Four of the reactors—San Onofre 2 and 3, Kewaunee, and Crystal River—already have ended nuclear power production, and the fifth, Vermont Yankee, is expected to end generation by the end of 2014 [1]. In addition, the Oyster Creek plant is expected to conclude operation in 2019 [2]. These are the first retirements of U.S. nuclear power plants since Millstone Unit 1 was retired in 1998. Retirements often are the result of unique circumstances, but some owners of nuclear power plants have voiced concerns about the profitability of their units, sparking discussion of possible additional nuclear retirements [3]. In order to evaluate the impacts of potential retirements beyond those in the Reference case, AEO2014 includes several alternative cases with economic assumptions that make it less likely that existing coal and nuclear power plants will be used for generation.

Factors that lead to power plant retirements

Power plant owners generally make the decision to retire plants when their expected costs exceed their expected revenues over the future life of the plants [4]. Costs incurred by power plants can include large capital projects, such as installation of flue gas desulfurization (FGD) systems or scrubbers on coal plants, increased operating costs, or higher fuel costs. Revenues are received from energy sales or capacity payments in wholesale electricity markets in regions of the country with competitive wholesale markets, or from cost-recovery mechanisms in regions with vertically integrated utilities subject to rate regulations [5].

Recent trends in the electric power industry have resulted in both declining revenues and increased operating costs for coal plants. Because natural gas often is the marginal fuel and thus sets prices in Regional Transmission Organization (RTO) markets, and natural gas influences wholesale electricity prices in non-RTO markets, the decline in natural gas prices beginning in 2008 tends to reduce electricity prices and the payments received by all generators for the electricity they produce. Lower natural gas prices also improve the competitiveness of natural gas combined-cycle (NGCC) power plants relative to coal-fired plants. When lower natural gas prices drive the cost of generating electricity from an NGCC plant below that of a nearby coal-fired plant, the coal plant is dispatched, or operated, less often and earns less revenue [6].

Slow growth of electricity demand in recent years has resulted in fewer high-cost marginal generators being dispatched. In regions with excess generating capacity, plants with relatively high variable operating costs may not be dispatched frequently enough to produce the revenue needed to cover their costs [7], making them candidates for retirement. Although the average price of coal delivered to the electric power sector declined in both 2012 and 2013, it rose by more than 4% per year from 2007 to 2011, and the resulting increase in operational costs for coal-fired power plants reinforced the impacts of lower demand and more competitive natural gas prices.

When faced with declining profitability, plant owners may choose to retire their units rather than make additional investments to keep them operating. In the AEO2014 Reference case, all coal-fired plants are required to have either a scrubber or a dry sorbent injection (DSI) system combined with a fabric filter in order to continue operating in 2016 [8] and later years. As of the end of 2012, 64% of the U.S. fleet of coal-fired generators was compliant with this requirement. The remaining plant owners are in the process of deciding whether to retrofit or retire their plants [9].

The outlook for nuclear power also has been altered by the changing conditions in U.S. electricity markets. Nuclear power plants have lower fuel costs than either coal- or natural gas-fired plants, translating to lower variable operating costs and ensuring that they are dispatched when available. The spread between the price of electricity and the fuel cost for nuclear plants is often referred to as the quark spread. Nuclear power plant owners in wholesale markets rely on sufficient quark spreads to cover nonfuel operations, maintenance, and any new capital expenses associated with the plants to provide a return on their investment. Lower wholesale electricity prices have reduced quark spreads for all nuclear power plants, especially those with increasing operations and maintenance (O&M) costs or capital addition costs.

The AEO2014 Reference case assumes an additional 6 GW of generic nuclear retirements from 2012 to 2019, beyond the six reactor retirements already announced (a total that includes the Oyster Creek plant), as higher-cost units face continued economic challenges. Those projected retirements are represented by derating of existing capacity for plants in vulnerable regions, not by

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retiring any specific plants. Higher natural gas prices in the Reference case after 2020 support the continued operation of the U.S. nuclear fleet and limit retirements from 2020 through 2040.

Accelerated retirement cases

AEO2014 includes several cases designed to explore the effects of alternative assumptions that change projected natural gas prices or electricity demand, or assigns a value to carbon dioxide (CO_2) emissions as a proxy for possible future policies to mitigate greenhouse gas emissions. However, those cases have impacts throughout the energy system and the economy, which makes it difficult to measure the independent effects of significant coal and nuclear capacity retirements. In order to isolate the effects of additional retirements on the energy system, several cases were developed by incorporating assumptions that directly accelerate retirements of coal-fired and nuclear power plants.

Accelerated Coal Retirements case

The AEO2014 High Coal Cost case assumes a decrease in coal mine productivity and an increase in coal transportation costs, causing coal prices to rise to a level 68% above those in the Reference case in 2040. In the Reference and High Coal Cost cases, real O&M costs are flat, which is consistent with long-term historical trends. However, as coal plants age, higher O&M costs may also become a concern because replacement parts and upgrades to plant equipment could be required to keep them operating effectively. In the Accelerated Coal Retirements case, the assumptions of the High Coal Cost case are combined with an assumed 3% annual increase in real O&M costs for coal-fired power plants from 2012 through 2040, with the increase intended to represent the high end of potential future O&M costs. The higher fuel prices and O&M costs in the Accelerated Coal Retirements case serve as proxies for any combination of factors that would produce a higher rate of coal plant retirements.

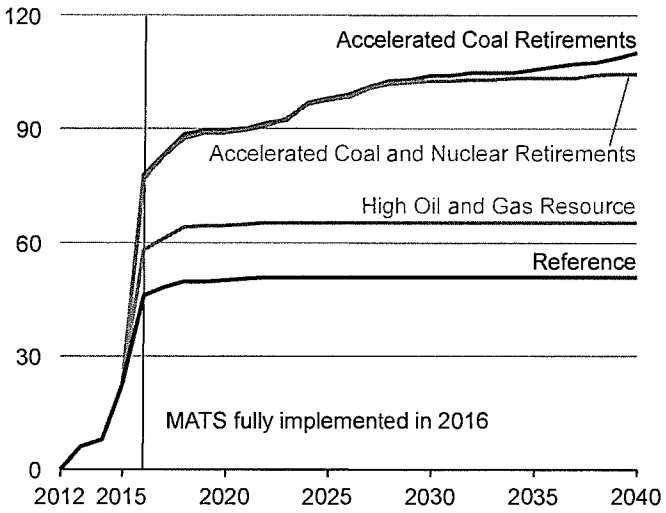
Accelerated Nuclear Retirements case

The Nuclear Regulatory Commission (NRC) has the authority to issue initial operating licenses for commercial nuclear power plants for a period of 40 years and then to extend them in 20-year increments. The NRC has already approved initial 20-year license extensions for more than 70% of the nuclear fleet, and the AEO2014 Reference case assumes that each plant will receive a first license extension unless its planned retirement has specifically been reported. The nuclear power industry currently is developing strategies to submit license applications for additional 20-year life extensions that would allow plants to continue operating beyond 60 years. The AEO2014 Reference case assumes that plants reaching 60 years of age between 2030 and 2040 will be granted a second life extension.

Nuclear power plants operate as baseload capacity. Although they are expensive to build and maintain, they have relatively low variable operating costs, which ensures that they are dispatched when available. While not affecting their dispatch order, increases in nonfuel O&M costs can have negative effects on the economics of nuclear power plants through lower profit margins. To avoid retirement for economic reasons, a plant must maintain a positive net present value over its operating lifetime. As with coal plants, annual O&M costs for nuclear power plants remain flat in the AEO2014 Reference case. However, recent data suggest that O&M costs for nuclear plants rose at an average annual rate of 4% over the 2008-12 period [*10*].

The Accelerated Nuclear Retirements case assumes that O&M costs for nuclear power plants grow by 3% per year through 2040; that all nuclear plants not retired for economic reasons are retired after 60 years of operation; and that no additional nuclear power plants are built after the 5.5 GW of capacity currently under construction is completed. This case reflects uncertainty regarding actions and costs associated with continued operation of the existing nuclear fleet.

Figure IF6-1. Cumulative retirements of coal-fired generating capacity in four cases, 2012-40 (gigawatts)



Accelerated Coal and Nuclear Retirements case

Large-scale simultaneous retirements of both coal-fired and nuclear capacity could have a significant effect on the electric power system. In order to assess that potential effect, the AEO2014 Accelerated Coal and Nuclear Retirements case combines the assumptions of the Accelerated Coal Retirements case and the Accelerated Nuclear Retirements case.

Results

Retirements

In the Accelerated Coal Retirements case, 110 GW of capacity, or 117% more than in the Reference case, is retired by 2040 (Figure IF6-1). In the Accelerated Coal and Nuclear Retirements case, coal retirement levels are similar to those in the Accelerated Coal Retirements case through 2030, with a slight leveling off toward the end of the projection, when some coal-fired capacity is needed to make up for the lost nuclear capacity.

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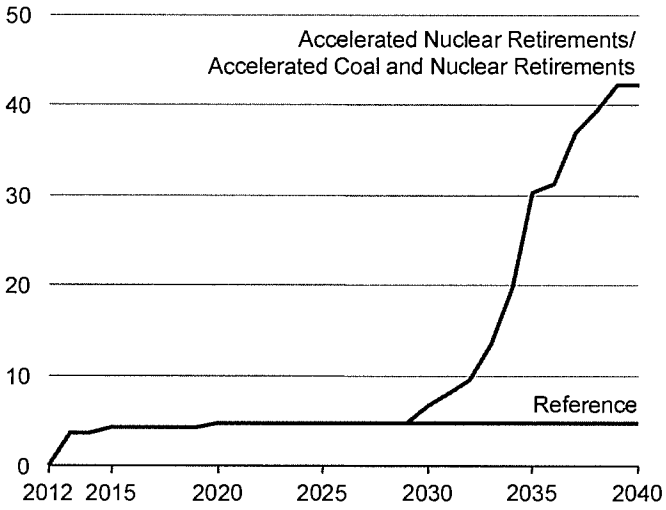
In the Accelerated Nuclear Retirements case, 42 GW of nuclear capacity is retired through 2040 (Figure IF6-2). However, other than retirements early in the projection, there is no significant reduction in nuclear capacity before the plants begin to reach their 60th year of operation, in 2029. The same retirement trajectory is repeated in the Accelerated Coal and Nuclear Retirements case.

There is no incremental increase in nuclear retirements in the Accelerated Nuclear Retirements, despite higher O&M costs. However, incremental retirements do occur in the Low Nuclear case, discussed in the Market Trends section of the AEO2014. The Low Nuclear case uses the same assumptions as the Accelerated Nuclear Retirements case, but also includes the resource assumptions from the High Oil and Gas Resource case that result in lower natural gas prices than in the Reference case. As a result, economic retirements of nuclear power plants that have not operated for 60 years do occur in the last decade of the projection in the Low Nuclear case, with nuclear capacity falling to 35 GW below the levels in the Accelerated Coal and Nuclear Retirements case.

Capacity additions

In order to replace capacity that is retired in the accelerated retirement cases, more total capacity (including capacity in the electric power sector, combined heat and power, and capacity in the end-use sectors) is added than in the Reference case. The new capacity mix consists almost entirely of natural gas and renewable energy sources (Figure IF6-3). Natural gas-fired combined-cycle units are favored because of their low fuel prices and relatively moderate capital costs.

Figure IF6-2. Cumulative retirements of nuclear generating capacity in three cases, 2012-40 (gigawatts)



Generation fuel mix

As existing coal and nuclear plants are retired, natural gas and renewables gain increasing shares of the generation mix (Figure IF6-4). The strength of this trend depends on how much nuclear and coal-fired capacity is retired.

Coal-fired generation in 2040 is lowest in the Accelerated Coal Retirements case, which results in the greatest total loss of coal-fired capacity. In all AEO2014 cases, including the Reference case, available coal-fired capacity operates as baseload generation throughout the projection. Therefore, removing coal capacity results in lower overall levels of generation. Coal-fired electricity generation in 2040 is 1% higher in the Accelerated Nuclear Retirements case than in the Reference case as a result of a small increase in coal-fired capacity installed at the end of the projection period.

Nuclear power plants also consistently operate as baseload generation, and their total generation varies with changes in capacity. In the Accelerated Nuclear Retirements and Accelerated Coal and Nuclear Retirements cases, nuclear

Figure IF6-3. Cumulative additions of electricity generating capacity by fuel in four cases, 2012-40 (gigawatts)

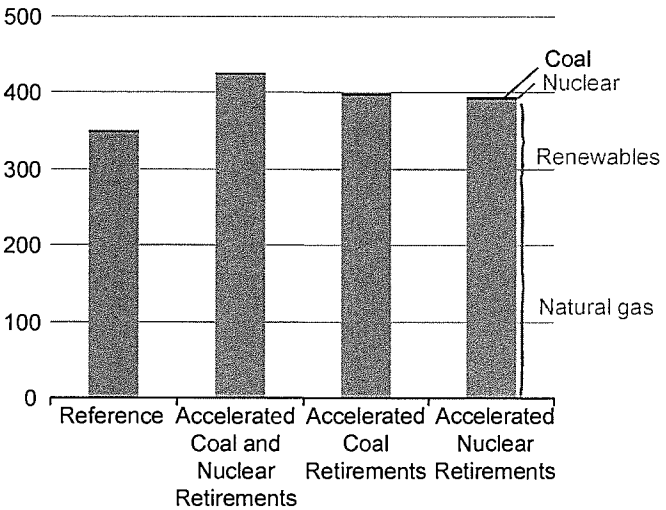
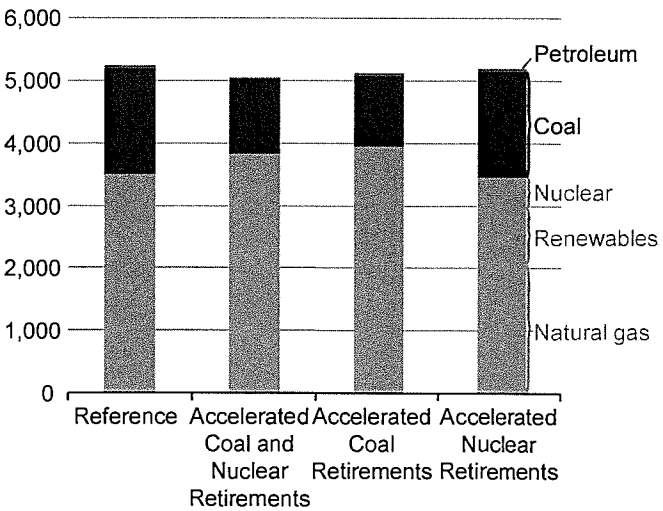


Figure IF6-4. Electricity generation by fuel in four cases, 2040 (billion kilowatthours)



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generation in 2040 is 40% lower than in the Reference case. In the Accelerated Coal Retirements case, nuclear electricity generation is 2% above the Reference case level in 2040.

Natural gas prices

In all the AEO2014 accelerated retirement cases, natural gas prices are higher in most years than in the Reference case as retirements of existing coal and nuclear capacity lead to both increased use of existing natural gas-fired plants and the development of new plants. The alternative cases with the largest increases in natural gas-fired generation also have the largest price increases. For example, the price of natural gas delivered to the electric power sector in 2040 in the Accelerated Coal and Nuclear Retirements case is 11% higher than the Reference case price (Figure IF6-5) [*11*].

Carbon dioxide emissions in the electric power sector

Coal and natural gas are the primary sources of CO_2 emissions from the electric power sector. Coal is the most significant contributor, emitting more than twice as much CO_2 per megawatthour (mWh) as a combined-cycle plant fueled by natural gas. Generation using nuclear power and renewables does not emit CO_2.

Because of the high CO_2 intensity of coal, scenarios that result in less coal-fired electricity generation also result in the most significant emissions reductions. Total electric power sector CO_2 emissions in the Accelerated Coal Retirements case are 20% below those in the Reference case in 2040 (Figure IF6-6). Emissions are slightly higher in the Accelerated Coal and Nuclear Retirements case, because some nuclear power generation is replaced by gas-fired generation; however, the effect of the coal-fired capacity retirements still keeps emissions 14% below the Reference case level in 2040. In the Accelerated Nuclear Retirements case, nuclear generation is 328 mWh below the Reference case level in 2040, while electric power sector CO_2 emissions are 85 million metric tons higher, reflecting an average increase of 0.26 metric tons CO_2 per mWh reduction in nuclear generation across the two scenarios. The estimated increase in CO_2 emissions per mWh of nuclear generation reduced, which is slightly below the estimated increase in CO_2 emissions per additional mWh of generation from advanced combined-cycle plants burning natural gas, reflects replacement generation from natural gas and renewables, together with some reduction in overall electricity demand as a result of higher end-user prices.

Retail electricity prices

Retail electricity prices vary in the accelerated retirement cases, because natural gas prices are a key determinant of wholesale electricity prices, which in turn are a significant component of retail electricity prices. Accordingly, the cases with the highest delivered natural gas prices also show the highest retail electricity prices (Figure IF6-7). In 2040, real retail electricity prices in the Accelerated Coal and Nuclear Retirements case are 12% higher than those in the Reference case.

Conclusions

Accelerated retirements of coal-fired and nuclear electricity generation capacity would cause natural gas and renewables to gain an increased share in the nation's electricity generation mix. Natural gas is most often the lowest-cost option for replacement capacity, while renewable generation grows, spurred by the increased economic competitiveness of solar and wind technologies toward the end of the projection period. The rising use of natural gas in the electric power sector results in price increases for both natural gas and electricity in all sectors relative to the Reference case (Table IF6-1).

Figure IF6-5. Delivered price of natural gas to the electric power sector in four cases, 2012, 2025, and 2040 (2012 dollars per million Btu)

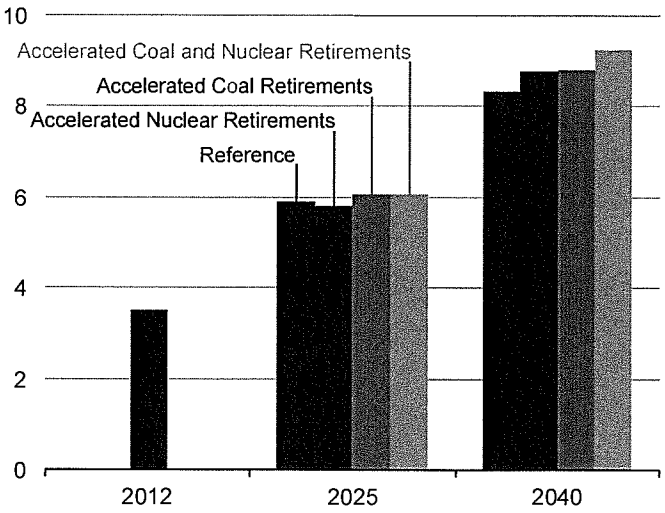

Figure IF6-6. Electric power sector carbon dioxide emissions in four cases, 2012-40 (million metric tons per year)

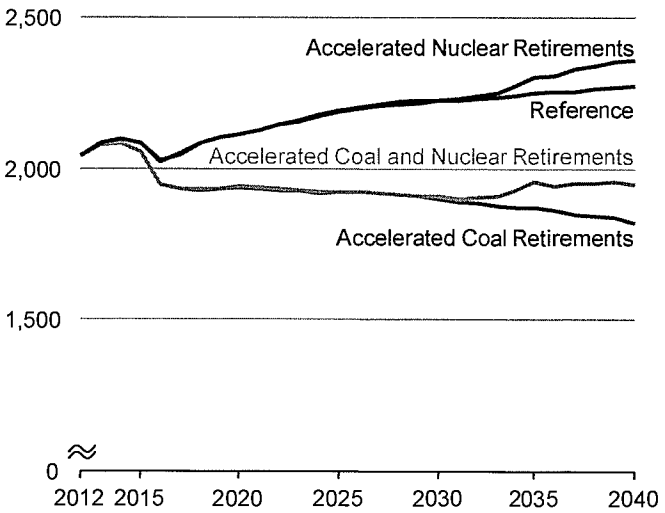

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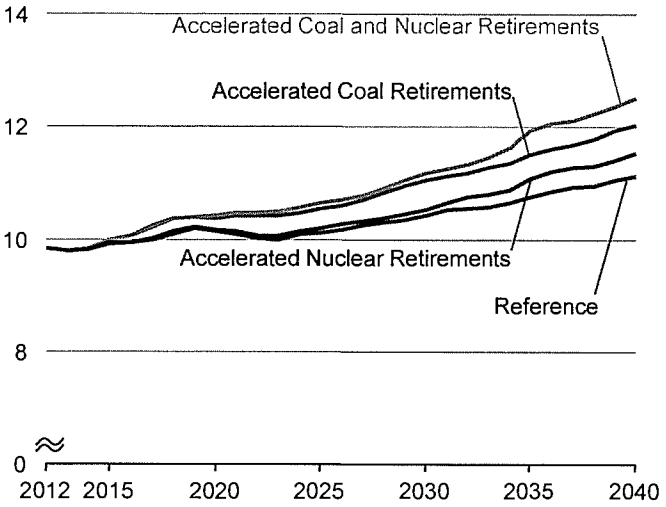
Figure IF6-7. Average retail electricity prices in four cases, 2012-40 (2012 cents per kilowatthour)



Effects on CO_2 emissions depend on the technology retired. Because a natural gas-fired combined-cycle plant emits less than half as much CO_2 as a plant fueled with pulverized coal, accelerated retirements of coal-fired plants result in lower CO_2 emissions compared with the Reference case. In contrast, because nuclear power plants emit no CO_2, accelerated retirements of nuclear power plants raise CO_2 emissions compared with the Reference case.

Table IF6-1. Average delivered natural gas prices, electricity prices, and carbon dioxide emissions in four cases, 2012, 2025, and 2040

Year and case	Average delivered natural gas price to power sector (2012 dollars per million Btu)	Retail electricity price (2012 cents per kilowatthour)	Electric power sector carbon dioxide emissions (million metric tons)
2012	3.44	9.8	2,039
2025			
Reference	5.76	10.1	2,194
Accelerated Coal Retirements	5.91	10.5	1,925
Accelerated Nuclear Retirements	5.69	10.2	2,188
Accelerated Coal and Nuclear Retirements	5.92	10.6	1,923
2040			
Reference	8.16	11.1	2,271
Accelerated Coal Retirements	8.60	12.0	1,821
Accelerated Nuclear Retirements	8.57	11.5	2,356
Accelerated Coal and Nuclear Retirements	9.03	12.5	1,946

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Endnotes for IF6

Links current as of April 2014

1. Entergy, "Entergy to close, decommission Vermont Yankee" (Press Release, August 27, 2013; accessed March 25, 2014), http://www.entergy.com/news_room/newsrelease.aspx?NR_ID=2769.
2. Exelon Corporation, "Exelon to retire Oyster Creek generating station in 2019" (Press Release, December 8, 2010; accessed March 25, 2014), http://www.exeloncorp.com/newsroom/pr_20101208_Nuclear_OysterCreekRetirement.aspx.
3. M. Wallace and G.D. Banks, *Restoring U.S. Leadership in Nuclear Energy* (Center for Strategic & International Studies, Washington, DC, June 2013), http://csis.org/publication/restoring-us-leadership-nuclear-energy.
4. The U.S. Energy Information Administration analysis assumes competitive economics for electric power capacity, in which variable costs determine dispatch, and fixed costs must also be paid by electric sales revenue to continue operation over the long term.
5. Capacity payments provide units with revenue for being available to run in order to ensure reliability. Capacity payments can account for a significant portion of revenue for peak load plants, which do not run often and require financial incentives to remain available for dispatch.
6. U.S. Energy Information Administration, "Dark spreads measure returns over fuel costs of coal-fired generation," *Today In Energy* (February 20, 2013), http://www.eia.gov/todayinenergy/detail.cfm?id=10051.
7. U.S. Energy Information Administration, "Electric generator dispatch depends on system demand and the relative cost of operation," *Today In Energy* (August 17, 2012), http://www.eia.gov/todayinenergy/detail.cfm?id=7590.
8. U.S. Energy Information Administration, "Assumptions to AEO2014: Electricity Market Module" (forthcoming), http://www.eia.gov/forecasts/aeo/assumptions/.
9. S. Ferris, "Hatfield's Ferry Power Station quietly closes for good," *Herald Standard* (Uniontown, PA, October 20, 2013), http://www.heraldstandard.com/new_today/hatfield-s-ferry-power-station-quietly-closes-for-good/article_cd0133e1-9adb-58c2-8f8d-66769de34835.html. Installing control equipment does not guarantee that a plant will remain economical to continue operating. Retirement of the Hatsfield's Ferry power station in Pennsylvania was announced after installation of a $650 million FGD scrubber system in 2009. However, in the AEO2014 Reference case most coal-fired power plants continue operating despite the regulatory hurdle of MATS in 2016.
10. Electric Utility Cost Group (EUCG), via Nuclear Energy Institute, "Annual briefing for the financial community" (February 13, 2014), http://www.nei.org/Issues-Policy/Economics/Financial-Analyst-Briefings/Nuclear-Energy-in-2014-Status-and-Outlook.
11. The 2025 average price of natural gas price delivered to the electric power sector in the Accelerated Nuclear Retirements case is slightly lower than the price in the Reference case due to a decline in LNG export capacity additions. The retirement of nuclear capacity in the Accelerated Nuclear Retirements case after 2030 causes an increase in demand from the electric power sector, resulting in higher natural gas prices, and the anticipation of higher prices reduces the economic competitiveness of LNG export facilities, lowering LNG export projections. This results in lower natural gas prices in the Accelerated Nuclear Retirements case between 2022 and 2032, because less natural gas is exported. Demand from the power sector does not change significantly from the Reference case until significant amounts of nuclear capacity are retired.

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Figure and table sources for IF6

Links current as of April 2014

Figure IF6-1. Cumulative retirements of coal-fired generating capacity in four cases, 2012-40. Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, HCCSTOM.D012314A, HCLONUC.D012314A, and HIGHRESOURCE.D112913B.

Figure IF6-2. Cumulative retirements of nuclear generating capacity in three cases, 2012-40. Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWNUC14.D012314B, and HCLONUC.D012314A.

Figure IF6-3. Cumulative additions of electricity generating capacity by fuel in four cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, HCLONUC.D012314A, HCCSTOM.D012314A, and LOWNUC14.D012314B.

Figure IF6-4. Electricity generation by fuel in four cases, 2040. Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, HCLONUC.D012314A, HCCSTOM.D012314A, and LOWNUC14.D012314B.

Figure IF6-5. Delivered price of natural gas to the electric power sector in four cases, 2012, 2025, and 2040. History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, HCLONUC.D012314A, HCCSTOM.D012314A, and LOWNUC14.D012314B.

Figure IF6-6. Electric power sector carbon dioxide emissions in four cases, 2012-40. Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, HCLONUC.D012314A, HCCSTOM.D012314A, and LOWNUC14.D012314B.

Figure IF6-7. Average retail electricity prices in four cases, 2012-40. Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, HCLONUC.D012314A, HCCSTOM.D012314A, and LOWNUC14.D012314B.

Table IF6-1. Average delivered natural gas prices, electricity prices, and carbon dioxide emissions in four cases, 2012, 2025, and 2040. History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, HCLONUC.D012314A, HCCSTOM.D012314A, and LOWNUC14.D012314B.

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IF7. Renewable electricity projections show growth under alternative assumptions in AEO2014

In the AEO2014 Reference case, renewable electricity generation grows by 69% from 2012 to 2040, including an increase of more than 140% in generation from nonhydropower renewable energy sources. Renewables are collectively the fastest-growing source of electricity generation in the projection, with annual growth rates that exceed the growth rate for natural gas-fired generation. However, because renewables start from a relatively low 12% market share of total generation, their contribution to U.S. total electricity generation is just 16% in 2040 in the Reference case, well below the natural gas and coal shares of 35% and 32%, respectively (Figure IF7-1).

The AEO2014 Reference case is based on current laws and policies, as well as on known technology and demographic trends. Projections of nonhydropower [1] renewable electricity generation are sensitive to assumptions about government policies and external market factors. Key uncertainties affecting projected growth include expiration of policies that affect financial incentives for deployment or operation of particular technologies, the costs and performance of the technologies, the costs of competing generation sources, and macroeconomic conditions that affect growth in electricity demand (including GDP growth).

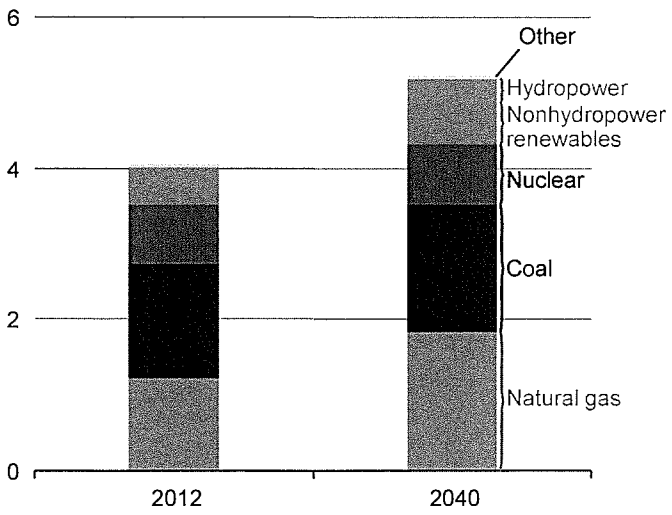
The renewable energy policy landscape is particularly dynamic compared to that of more-established energy sources, as new and existing policies continue to be created and adjusted at the federal, state, and local levels. In addition, policies that affect competing sources of generation, such as natural gas and coal, can have significant impacts on renewable generation projects. For example, placing an explicit or implicit value on carbon dioxide (CO_2) emissions would make the cost of operating fossil-fueled capacity higher, improving the relative economics of renewables.

From 2005 to 2012, nonhydropower renewable generation more than doubled, encouraged by policies such as federal tax credits and grants, state renewable portfolio standards (RPS), and a variety of other state and local policies such as rebates, tax incentives, financing assistance, net metering, and interconnection standards. For example, the federal production tax credit (PTC), which most recently applied to wind, geothermal, biomass, hydro, certain waste technologies, and marine energy projects under construction by the end of 2013, was first established by the Energy Policy Act of 1992. Since that time, the tax credit has been revised periodically—expiring several times and then subsequently being renewed. Most recently, the credit expired at the end of 2013 and has not been extended as of early 2014. Trade groups and renewable supporters continue to advocate for an extension to the 2013 deadline, but the AEO2014 Reference case assumes no such extension.

Assumptions about the cost and performance of renewable technologies also affect the projections, particularly as some renewable technologies become more economically competitive in some regions. Determination of future or even current technology costs can be a challenge. For example, in the case of solar photovoltaic (PV) technologies, there is enough variation among current projects in terms of geographic locations, technologies, developer experience, and regulatory frameworks that even the most carefully developed estimates will overstate actual costs for some projects and understate costs for others. While PV capital costs have declined over the past decade, there is continuing uncertainty about both the degree and pace of future cost declines.

Projections for generation with renewables are sensitive to the prices of competing generation sources and other market factors, particularly in later years of the projection period, when the projected trends in renewable generation are increasingly influenced by economic rather than policy factors. In some regions and projection years, renewable resources like wind or solar may represent the marginal source of capacity growth, which makes renewables sensitive to price swings in competing resources as well as to broader economic or market fluctuations. In order to address such uncertainties, AEO2014 includes alternative cases to provide insight regarding the direction and magnitude of sensitivities in the projections. Table IF7-1 shows key technology, policy, economic, and market uncertainties and shows how they are addressed in a selected group of AEO2014 alternative cases (described in more detail in Appendix E).

Figure IF7-1. Total U.S. electricity generation by energy source, 2012 and 2040 (billion kilowatthours)



The Low Renewable Technology Cost case assumes that renewable technology capital costs are 20% lower than in the Reference case. The No Sunset case assumes the extension of existing federal energy policies that contain sunset provisions—in particular the production and investment tax credits for certain renewable electricity generation technologies. The GHG25 case assumes a policy that applies a fee on carbon dioxide emissions (in 2012 dollars) starting at $25 per metric ton in 2015 and escalating by 5% per year to about $85 per metric ton in 2040. The High Oil and Gas Resource case adjusts oil and gas resource and productivity assumptions that result in natural gas prices to the electric power sector in 2040 that are 37% lower than in the Reference case. The Low Oil and Gas Resource case adjusts assumptions about oil and gas resources that result in natural gas prices to the electric power sector in 2040 that are 33%

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higher than in the Reference case. The High Economic Growth and Low Economic Growth cases assume higher and lower levels of real GDP growth from 2012 to 2040 than in the Reference case.

Figure IF7-2 shows projected total nonhydropower renewable generation from 2012 to 2040 in the selected alternative cases. The results vary significantly, particularly in the later years of the projection. For example, in the GHG25 case total nonhydropower renewable generation in 2040 is 83% higher than in the Reference case, and in the High Oil and Gas Resource case total nonhydropower renewable generation in 2040 is 12% lower than in the Reference case.

Some of the assumptions used in the AEO2014 alternative cases can lead to significant increases in long-term growth of renewable electricity generation. However, alternative cases with assumptions that are less favorable to renewables growth, such as the Low Economic Growth case (with slower electricity demand growth) and the High Oil and Gas Resource case (with lower natural gas prices) are unlikely to result in renewable projections that fall drastically below those in the Reference case—in large part because state renewable portfolio standards (RPS) effectively establish a floor for generation with renewables. RPS policies generally require that a minimum share of generation must come from renewable sources, and even with slow load growth or competition from low-cost alternative generation resources, renewable generation must be sufficient to meet the RPS target. On the other hand, as renewable generation sources become increasingly competitive after 2025, a favorable shift in assumptions may result in an impact that does not have a limit on the upper bound, allowing for stronger growth in renewable generation than is projected in the Reference case.

In addition, long-term projections are more sensitive to changes in assumptions than are near-term projections. Although the range of renewable generation in 2040 across the alternative cases is large, the 2025 projections for total renewable generation are within 15% of the Reference case in all the alternative cases except for the GHG25 case. Near-term growth in renewable generation is constrained by a combination of factors that generally hold across most sensitivity analyses: growth in electricity demand continues at a relatively low annual rate (less than 1% per year in the Reference case) compared with historical levels, and generating capacity required to meet demand and reserve requirements in many regions already exceeds near-term requirements at the start of the projection period. As a result, demand for new generating capacity of any type in the first decade of the projection is minimal in most regions. From 2012 to 2025, total generating capacity—including renewables, fossil fuels, and nuclear—increases by only 4%. However, as renewable technologies become more economically competitive, they capture a larger share of the growing market. In addition, even with low rates of electricity demand growth, the presence of a significant and growing fee on CO_2 emissions creates enough pressure early in the projection period to spur significant growth of renewable generation in the near term.

Alternative assumptions that lead to greater penetration of electricity markets by renewable energy sources—namely, those in the No Sunset, Low Renewable Technology Cost, GHG25, Low Oil and Gas Resource, and High Economic

Figure IF7-2. Nonhydropower renewable electricity generation in eight cases, 2005-40 (billion kilowatthours)

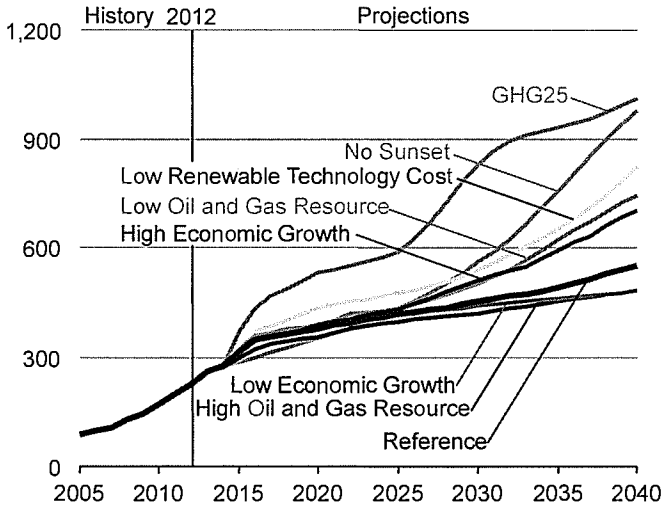

Table IF7-1. Sources of uncertainty and variation in AEO2014 projections for renewable electricity generation

Key uncertainties	Selected AEO2014 alternative cases	Uncertainties not addressed in AEO2014 alternative cases
Technology: Cost assumptions for renewable technologies.	Low Renewable Technology Cost	Breakthroughs in new or emerging renewable (e.g., wave/tide/ocean) or complementary (e.g., storage) technologies
Policy: Current policies may not expire as scheduled; future policies may impose direct or indirect fees on carbon dioxide emissions.	No Sunset GHG25 (carbon dioxide fee case)	Existing policies not explicitly modeled in AEO2014 that are more specific or geographically specialized (e.g., net metering, local rebate programs, and technology-specific set-asides in state RPS programs); other new policies that could be introduced
Macroeconomics and prices: Macroeconomic growth rates and natural gas prices.	High Oil and Gas Resource Low Oil and Gas Resource High Economic Growth Low Economic Growth	Competition from other fuels; sector- or region-specific economic factors; unexpected shifts in demand

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Growth cases—do not have proportionate effects on all renewable technologies (Figures IF7-3 through IF7-6). Generation from solar and wind installations generally increases by more compared with the Reference case than does generation from biomass, waste, and geothermal sources. Solar generation in 2040 in most of the alternative cases is more than double the Reference case level. Wind starts from a much larger installed capacity base, so the percentage growth in wind generation is lower than for solar, but in all five alternative cases wind generation in 2040 is at least 20% higher than projected in the Reference case.

Solar and wind energy are expected to remain the primary sources of renewable capacity growth. Although geothermal, waste, and biomass resources have some favorable characteristics compared to wind and solar, such as the ability to provide operator-dispatched power, each has significant limitations. The limitations include a limited resource base (geothermal, waste) or relatively high capital and/or fuel costs (biomass). Although wind and solar will continue to be capital-intensive technologies, they are expected to achieve cost reductions that—along with a larger resource base—result in higher growth than other renewables under favorable conditions (such as placement of an explicit or implicit value on CO_2 emissions, or high natural gas prices). However, solar and wind resources also vary in availability and quality by region, and generation facilities are likely to be concentrated in the more favorable regions.

Even in the alternative cases that result in higher levels of market penetration for renewable generation technologies, the results are limited by the selection of technologies currently modeled by the U.S. Energy Information Administration. The AEO2014 alternative cases cannot be used to evaluate potential technologies that are not characterized in the National Energy Modeling

Figure IF7-3. Electricity generation from wind power in eight cases, 2012, 2020, 2030, and 2040 (billion kilowatthours)

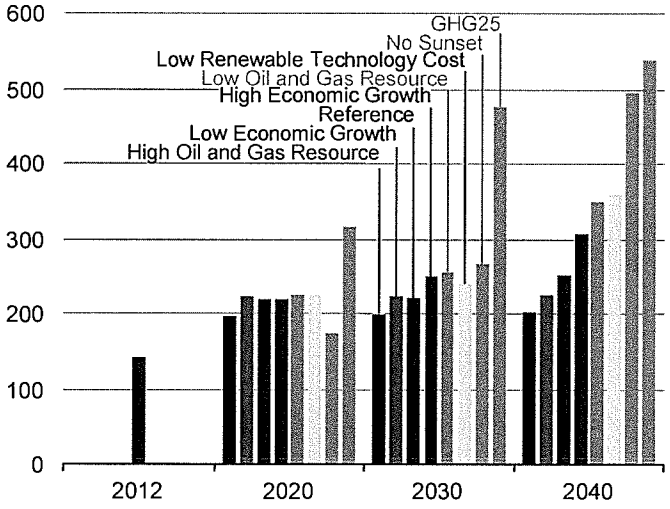


Figure IF7-4. Electricity generation from solar power in eight cases, 2012, 2020, 2030, and 2040 (billion kilowatthours)

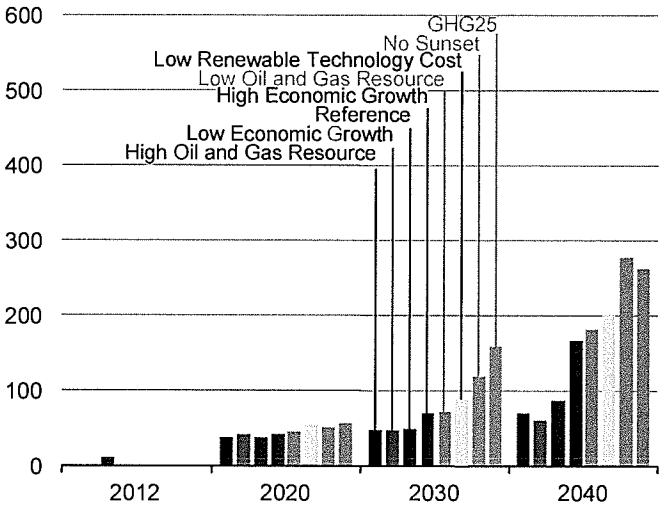


Figure IF7-5. Electricity generation from geothermal power in eight cases, 2012, 2020, 2030, and 2040 (billion kilowatthours)

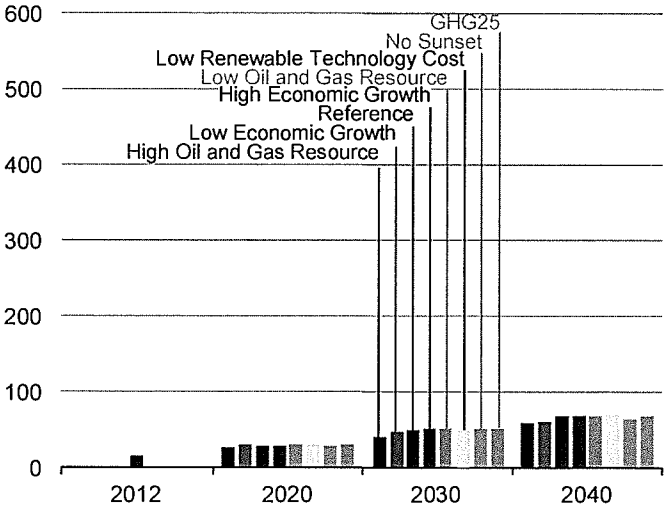
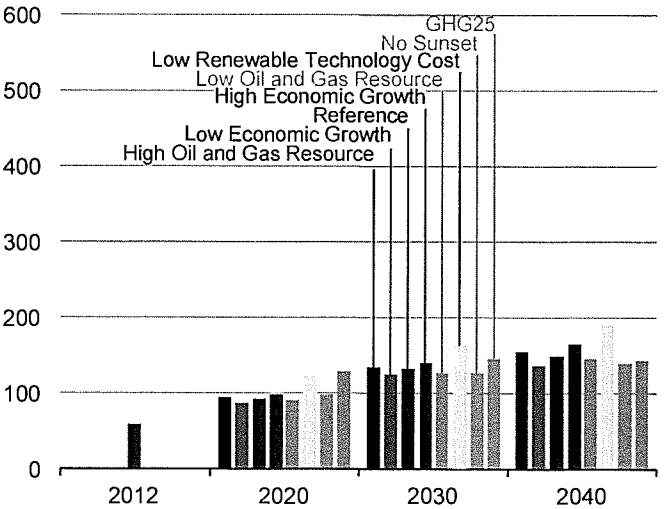


Figure IF7-6. Electricity generation from biomass and waste power in eight cases, 2012, 2020, 2030, and 2040 (billion kilowatthours)



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System. Some emerging renewable technologies not included in AEO2014 include engineered geothermal systems, marine hydrokinetics (such as wave energy), in-stream hydroelectric, and hybrid solar thermal combined cycle.

Similarly, no new electricity storage technologies are included in the projections. Electricity storage represents one of several options for accommodating high levels of intermittent generation from wind and solar resources. Because such technologies, other than pumped hydro storage, generally are either in early stages of development or not yet commercially established, impacts on electricity markets in the near- to mid-term period are difficult to model.

The AEO2014 alternative cases typically examine the effects of changing single assumptions within a moderate range of uncertainty, and they are not intended to be interpreted as bounding cases. For example, a compound case incorporating high natural gas prices, low renewable technology costs, and an explicit or implicit value for CO_2 emissions could be expected to result in additional renewable generation growth, although the impact would not necessarily be the sum of the results of the individual cases. The same could be true if any of the individual alternative cases were examined using different assumptions—for example, if renewable technology costs were assumed to be 50%, rather than 20%, below the costs used in the Reference case.

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Endnotes for IF7

Links current as of April 2014

1. Hydropower has resource-specific characteristics that separate it from other renewable energy sources. It is projected to remain close to current capacity and generation levels in the cases considered here.

Figure and table sources for IF7

Links current as of April 2014

Figure IF7-1. Total U.S. electricity generation by fuel, 2012 and 2040: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Table IF7-1. Sources of uncertainty and variation in AEO2014 projections for renewable electricity generation: U.S. Energy Information Administration.

Figure IF7-2. Nonhydropower renewable electricity generation in eight cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, CO2FEE25.D011614A, NOSUNSET.D121713A, LCR_2014.D120613A, LOWRESOURCE.D112913A, HIGHRESOURCE.D112913B, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

Figure IF7-3. Electricity generation from wind power in eight cases, 2012, 2020, 2030, and 2040: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, CO2FEE25.D011614A, NOSUNSET.D121713A, LCR_2014.D120613A, LOWRESOURCE.D112913A, HIGHRESOURCE.D112913B, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

Figure IF7-4. Electricity generation from solar power in eight cases, 2012, 2020, 2030, and 2040: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, CO2FEE25.D011614A, NOSUNSET.D121713A, LCR_2014.D120613A, LOWRESOURCE.D112913A, HIGHRESOURCE.D112913B, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

Figure IF7-5. Electricity generation from geothermal power in eight cases: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, CO2FEE25.D011614A, NOSUNSET.D121713A, LCR_2014.D120613A, LOWRESOURCE.D112913A, HIGHRESOURCE.D112913B, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

Figure IF7-6. Electricity generation from biomass and waste power in eight cases: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, CO2FEE25.D011614A, NOSUNSET.D121713A, LCR_2014.D120613A, LOWRESOURCE.D112913A, HIGHRESOURCE.D112913B, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

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IF8. Implications of low electricity demand growth

Although electricity demand fell in only three years between 1950 and 2007, it declined in four of the five years between 2008 and 2012. The largest drop occurred in 2009 (Figure IF8-1). One contributing factor was the steep economic downturn from late 2007 through 2009, which led to a large drop in electricity sales in the industrial sector. Other factors, such as efficiency improvements associated with new appliance standards in the buildings sectors and overall improvement in the efficiency of technologies powered by electricity, have slowed electricity demand growth and may contribute to slower growth in the future, even as the U.S. economy continues its recovery.

In the Reference case, which assumes no new efficiency standards beyond those already in place or announced as final for future implementation as of 2012, total electricity use grows by an average of less than 1% per year from 2012 to 2040. Demand grows across all sectors, with average annual increases in the industrial sector (0.9% per year) slightly higher than those in the residential and commercial sectors (0.7% and 0.8% per year, respectively). As a result of rising demand, 351 gigawatts (GW) of new electricity generating capacity is added from 2012 to 2040, electricity generation increases by 29%, and carbon dioxide (CO_2) emissions from the electric power sector increase by 11%.

To examine the energy implications of slower growth of electricity demand, AEO2014 includes a Low Electricity Demand case, in which annual electricity demand in 2040 is only slightly higher than the 2012 level of 3.8 trillion kilowatthours (kWh).

Low Electricity Demand case

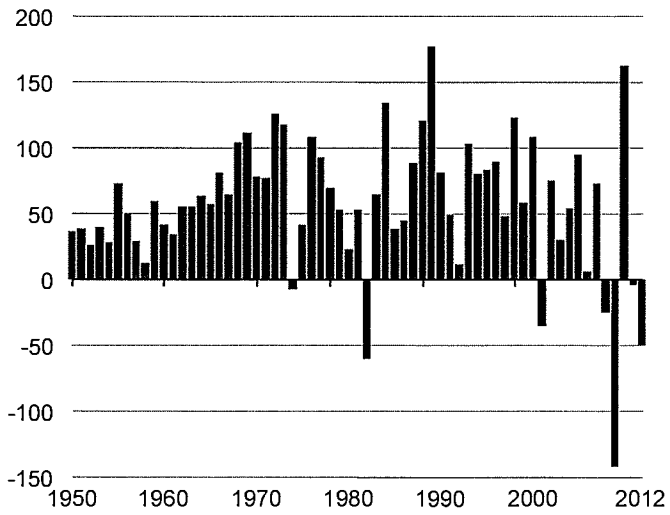
Electricity demand growth depends on economic growth, relative energy prices, and technology choices in the end-use sector, among other factors. Changes in electricity demand result in corresponding changes in electricity generation and the mix of technologies used to meet demand.

The Low Electricity Demand case was developed by assuming changes in technology choices and higher efficiency in the end-use sectors. To limit the number of competing influences, macroeconomic and fuel supply assumptions were unchanged from those in the Reference case. The goals for the Low Electricity Demand case were to identify a combination of technologies that would result in flat demand, and to examine the impacts of stagnant demand on future needs for electricity generation and supply.

The Low Electricity Demand case uses the assumptions incorporated in the Best Available Demand Technology case for both the residential and the commercial sectors, as described in Appendix E and the Market Trends section of this report. The Best Available Demand Technology case assumes that all future equipment purchases in the residential and commercial sectors will be made from a menu of technologies that includes only the most efficient models available in a particular year, regardless of cost. Building shell efficiencies also are assumed to improve relative to the Reference case, and distributed generation costs are assumed to decline much faster than in the Reference case. In addition to those assumptions, the Low Electricity Demand case assumes higher energy savings for electric motors in pumps, fans, and air compressors used in the industrial sector compared with the Reference case. Those adjustments reduce total electric power consumption by electric motors slightly less than 20% over the course of the projection. Although technically plausible, such a drop in electric motor energy usage may not represent a likely path for motor development.

As a result of changes across all end-use sectors in the Low Electricity Demand case, retail electricity sales in 2040 are roughly the same as in 2012. Industrial sales grow slightly from 2012 levels, but a decline in residential sales offsets that growth. Because the distributed generation assumptions in the buildings sector result in higher investment in end-use renewable capacity and generation relative to the Reference case, direct-use generation increases, and there is a 7% increase in total electricity consumption from 2012 to 2040, as compared with 29% in the Reference case (Figure IF8-2).

Figure IF8-1. Annual changes in U.S. electricity demand, 1950-2012 (billion kilowatthours)



Analysis results

Electricity generation capacity

In the Low Electricity Demand case, little new capacity is added in the power sector after planned capacity additions are completed (Figure IF8-3). A significant amount of renewable capacity is added in the end-use sectors as a result of the lower cost assumptions for distributed solar photovoltaics, and a smaller amount of renewable capacity (19% of total renewable additions) is added in the power sector to meet renewable portfolio standards. Total natural gas capacity added is only one-quarter of the amount in the AEO2014 Reference case. Even more so than in the Reference case, there are few new additions of coal or nuclear capacity beyond those already under construction.

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With lower demand for electricity, a total of 110 GW of older coal-fired generating capacity is retired between 2013 and 2040 in the Low Electricity Demand case, more than double the 51 GW retired in the Reference case (Figure IF8-4). Most of the retirements occur early in the projection, due to the timing of the Mercury and Air Toxics Standards (MATS), which require a decision to retire or retrofit coal plants to meet environmental standards by 2016. A total of 100 GW of oil- and gas-fired capacity is retired between 2013 and 2040 in the Low Electricity Demand case, compared with 40 GW in the Reference case.

Electricity generation

Electricity generation in 2040 is 17% lower in the Low Electricity Demand case than in the Reference case, with natural gas-fired generation 472 billion kWh lower and coal-fired generation 343 billion kWh lower. Figure IF8-5 shows total electricity generation from the electric power sector and the end-use sectors, with the contributions broken out for natural gas and renewable generation to display the relative levels of generation from the end-use sectors. As in the Reference case, natural gas-fired generation overtakes coal-fired generation by the end of the projection period, but overall shares for both fuels are lower than in the Reference case. In 2040, the coal share of total generation drops from 37% in 2012 to 32% in the Reference case, and to 31% in the Low Electricity Demand case. The natural gas share, which increases from 30% in 2012 to 35% in 2040 in the Reference case, grows to only 32% in 2040 in the Low Electricity Demand case. Because there is less need for new generating capacity, there is less opportunity for growth in natural gas-fired generation from new plants.

Nuclear electricity generation is slightly lower in the Low Electricity Demand case than in the Reference case, as a result of fewer new builds, but it provides a slightly higher share of total generation than in the Reference case. Renewable generation grows by 60% from 2012 to 2040 in the Low Electricity Demand case, slightly less than the 69% growth in the Reference case, as a large

Figure IF8-2. U.S. total electricity demand by sector in two cases, 2012 and 2040 (billion kilowatthours)

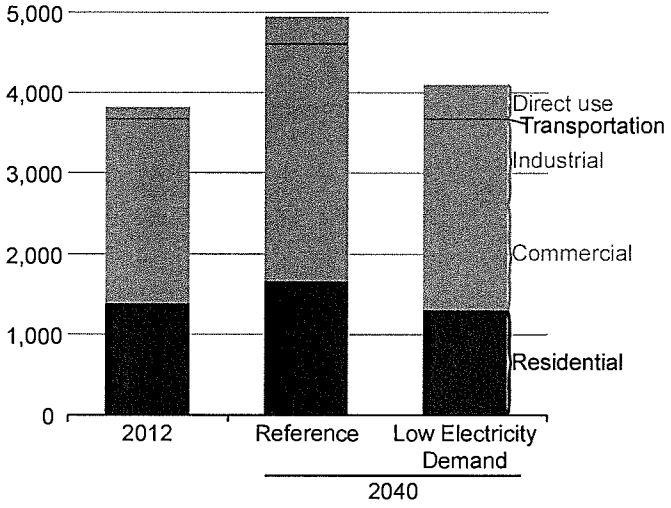


Figure IF8-3. Electricity capacity additions by fuel type in two cases, 2013-40 (gigawatts)

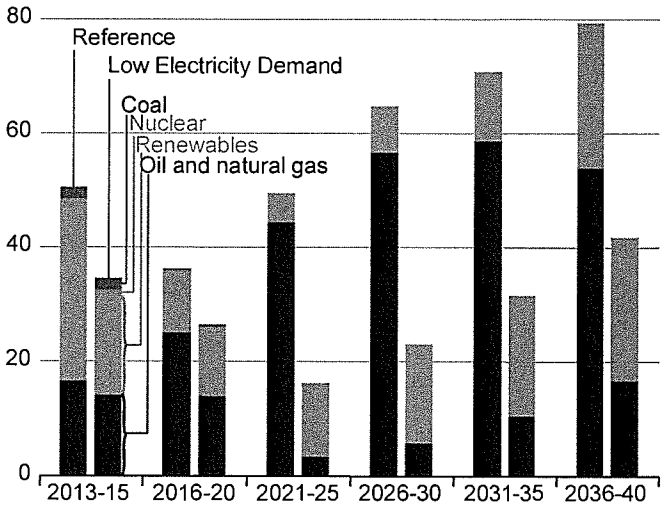


Figure IF8-4. Electric power sector cumulative retirements in two cases, 2013-40 (gigawatts)

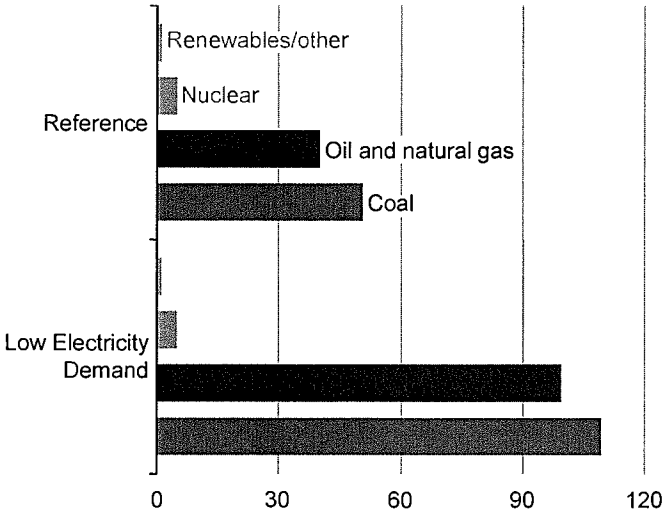
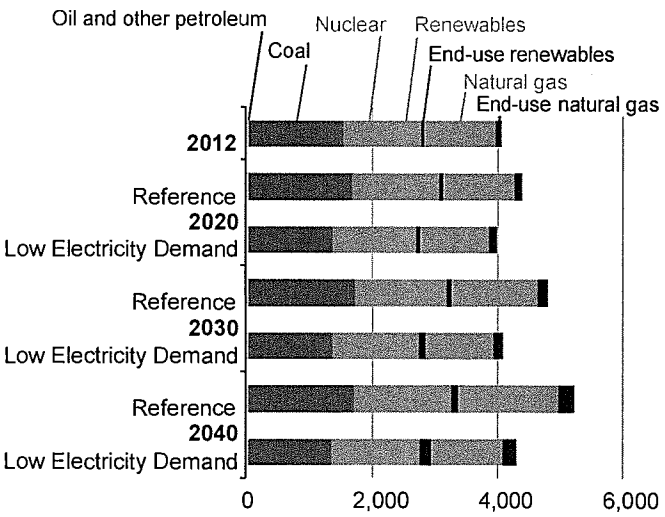


Figure IF8-5. Electricity generation in two cases, 2012-40 (billion kilowatthours)



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increase in end-use sector renewable generation offsets much of the decline in renewable generation in the electric power sector compared with the Reference case.

Emissions

The lower level of generation from fossil fuels in the Low Electricity Demand case results in lower greenhouse gas emissions. In 2020, power sector CO_2 emissions are 16% lower than in the Reference case, and in 2040 they are 22% lower (Figure IF8-6). Emissions of other pollutants (sulfur dioxide, nitrogen oxides, and mercury) are also lower than in the Reference case, in proportion to coal-fired generation. The additional retirements of coal-fired capacity in the Low Electricity Demand case begin to occur in 2016, when MATS takes effect. With lower demand and prices for electricity than in the Reference case, it is less economical to install retrofits to comply with the MATS standards. As a result, fewer environmental controls are added.

Regional impacts

The mix of fuels used to meet U.S. demand for electricity varies across the country, and the initial mix can affect regional projections in the different cases. In general, the West is more reliant on natural gas and renewable generation, the upper Midwest and Central parts of the country are more reliant on coal, the Northeast is more reliant on natural gas and nuclear power, and in the Mid-Atlantic and Southeast there is a mix of generation from coal, nuclear power, and natural gas.

Currently, most coal-fired capacity is installed in two North American Electric Reliability Corporation (NERC) regions: the SERC Reliability Corporation (SERC) region, which covers the Southeast region, and the Reliability First Corporation (RFC) region, which includes most of the Mid-Atlantic and Ohio Valley region [1] (Figure IF8-7). Most of the coal retirements in both the Reference case and the Low Electricity Demand case occur in those regions.

In the RFC region, retirements of coal-fired capacity in the Low Electricity Demand case are double those in the Reference case, and in the SERC region they are nearly triple those in the Reference case. The RFC and SERC regions also contain 67% of the country's current nuclear capacity. However, as in other regions, there are no additional retirements of nuclear capacity in the Low Electricity Demand case relative to the Reference case. As a result, nuclear generation levels are similar in the two cases, and they make up a higher share of the total generation when electricity demand is lower. In SERC, the coal share of total generation in 2040 declines from 38% in the Reference case to 34% in the Low Electricity Demand case, and the nuclear share grows from 23% in the Reference case to 28%. Similarly in the RFC region, the 2040 coal share drops from 44% in the Reference case to 40% in the Low Electricity Demand case, and the 2040 nuclear share rises from 21% to 26%. In both regions the natural gas share also declines slightly in the Low Electricity Demand case relative to the Reference case, because fewer new natural gas-fired power plants are built. Additional retirements of older oil and gas units have less effect on generation than do retirements of coal units, because the oil and gas units typically operate less frequently throughout the year.

In contrast, in regions where there may not be more economical baseload technologies available, coal continues to provide most of the generation needs in 2040, even when electricity demand is assumed to be flat. In the Midwest Reliability Organization (MRO) region, coal-fired plants provided 60% of total generation in 2012, and they still provide 52% in the Reference case and 55% in the Low Electricity Demand case in 2040. With few new natural gas-fired additions projected in the Low Electricity Demand case, coal-fired power plants continue to provide a large portion of the region's total electricity generation.

Figure IF8-6. Carbon dioxide emissions in the electric power sector in two cases, 2012-40 (million metric tons carbon dioxide)

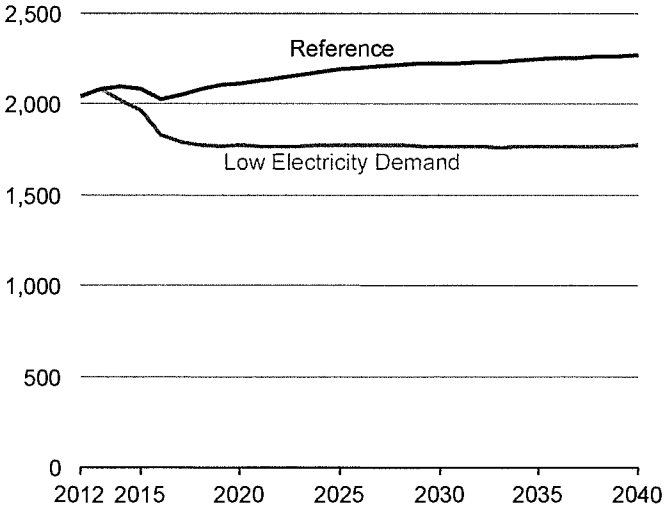
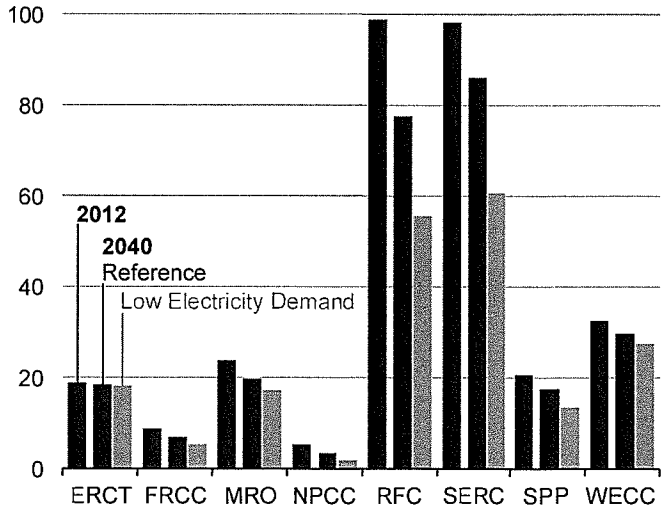


Figure IF8-7. Coal-fired generating capacity by NERC region in two cases, 2012 and 2040 (gigawatts)



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Endnotes for IF8

Links current as of April 2014

1. See Appendix F for a map of the Electricity Market Model (EMM) regions. For this discussion, results at the EMM level have been aggregated to the larger NERC regions on which they are based.

Figure sources for IF8

Links current as of April 2014

Figure IF8-1. Annual changes in U.S. electricity demand, 1950-2012: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013).

Figure IF8-2. U.S. total electricity demand by sector in two cases, 2012 and 2040: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A and FLAT.D010914A.

Figure IF8-3. Electricity capacity additions by fuel type in two cases, 2013-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A and FLAT.D010914A.

Figure IF8-4. Electric power sector cumulative retirements in two cases, 2013-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A and FLAT.D010914A.

Figure IF8-5. Electricity generation in two cases, 2012-40: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A and FLAT.D010914A.

Figure IF8-6. Carbon dioxide emissions in the electric power sector in two cases, 2012-40: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A and FLAT.D010914A.

Figure IF8-7. Coal-fired generating capacity by NERC region in two cases, 2012 and 2040: History: U.S. Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A and FLAT.D010914A.

012728

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Market trends

Projections by the U.S. Energy Information Administration (EIA) are not statements of what will happen but of what might happen, given the assumptions and methodologies used for any particular case. The Reference case projection is a business-as-usual estimate, given known market, demographic, and technological trends. Most cases in the *Annual Energy Outlook 2014* (AEO2014) generally assume that current laws and regulations are maintained throughout the projections. Such projections provide a baseline starting point that can be used to analyze policy initiatives. EIA explores the impacts of alternative assumptions in other cases with different macroeconomic growth rates, world oil prices, rates of technological progress, and policy changes.

While energy markets are complex, energy models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics are indicative of real-world tendencies rather than representations of specific outcomes.

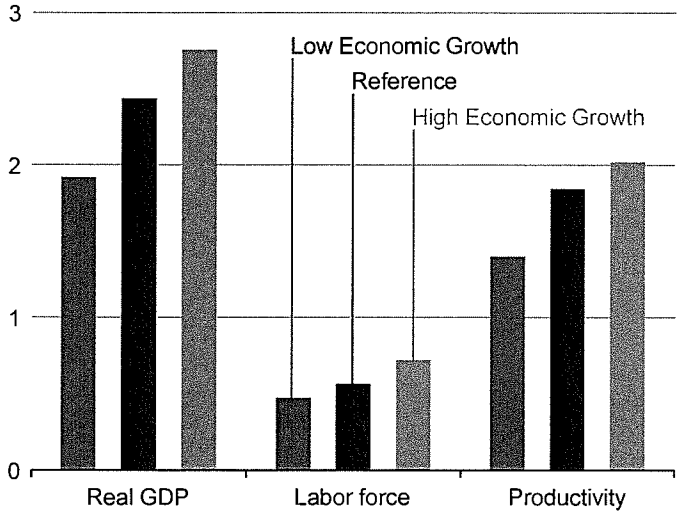
Energy market projections are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated. In addition, future developments in technologies, demographics, and resources cannot be foreseen with certainty. Many key uncertainties in the AEO2014 projections are addressed through alternative cases.

EIA has tried to make these projections as objective, reliable, and useful as possible. However, they should serve as an adjunct to, not as a substitute for, a complete and focused analysis of public policy initiatives.

012730

Growth in business fixed investment offsets slow growth in labor force

Figure MT-1. Average annual growth rates of real GDP, labor force, and productivity in three cases, 2012-40 (percent per year)



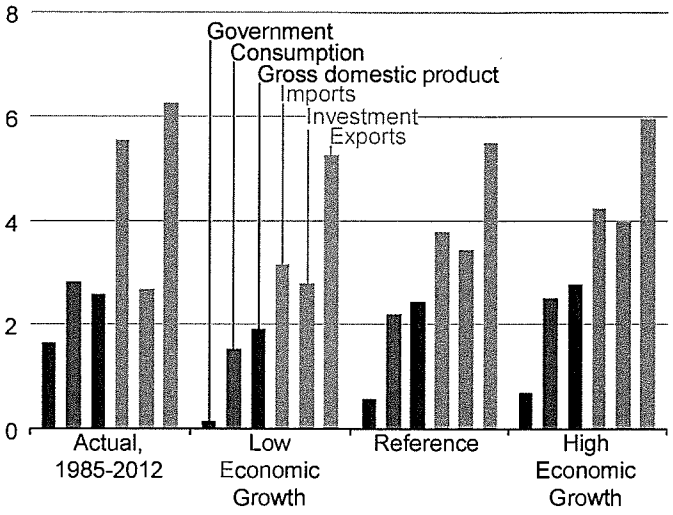
Growth in the output of the U.S. economy depends on increases in the labor force, growth of capital stock, and improvements in productivity. In the *Annual Energy Outlook 2014* (AEO2014) Reference case, U.S. labor force growth slows over the projection period as the baby boom generation starts to retire, but projected growth in business fixed investment and spending on research and development offsets the slowdown in labor force growth. Annual growth in real gross domestic product (GDP) averages 2.4%/year from 2012 to 2040 in the Reference case (Figure MT-1), 0.3 percentage point slower than the growth rate over the past 30 years. Slow long-run increases in the labor force indicate more moderate long-run employment growth, with total civilian employment rising by an average of 0.8%/year, from 134 million in 2012 to 169 million in 2040. The manufacturing share of total employment continues to decline, from 9% in 2012 to 7% in 2040.

Real consumption growth averages 2.2%/year in the Reference case. From 2012 to 2040, the share of GDP accounted for by personal consumption expenditures varies between 66% and 71%, and the share spent on services rises mainly as a result of increasing expenditures on health care. The share of GDP devoted to business fixed investment ranges from 10% to 16% of GDP through 2040.

Issues such as financial market reform, fiscal policies, and financial problems in Europe, among others, will affect both short-run and long-run growth, adding uncertainty to the projections.

Economic activity varies considerably across the economic growth cases

Figure MT-2. Average annual growth rates for real output and its major components in three cases, 2012-40 (percent per year)



AEO2014 presents three economic growth cases: Reference, High, and Low (Figure MT-2). The High Economic Growth case assumes higher growth and lower inflation, relative to the Reference Case, and the Low Economic Growth case assumes lower growth and higher inflation. The short-term outlook (five years) in each case represents current views of economic activity in the United States and the rest of the world, the impacts of fiscal and monetary policies, and potential risks to economic activity. The long-term outlook includes smooth economic growth and assumes no shocks to the economy.

Differences among the Reference, High, and Low Economic Growth cases reflect different expectations for growth in population (specifically, net immigration), labor force, capital stock, and productivity, which are above trend in the High Economic Growth case and below trend in the Low Economic Growth case. The average annual growth rate for real GDP from 2012 to 2040 in the Reference case is 2.4%, as compared with 2.8% in the High Economic Growth case and 1.9% in the Low Economic Growth case.

Figure MT-2 compares the average annual growth rates for output and its major components in each of the three cases. Compared with the 1985-to-2012 period, investment growth from 2012 to 2040 will be faster in all three cases, whereas consumption, government expenditures, imports, and exports will grow more slowly in all three cases. Opportunities for trade will expand in all three cases, resulting in real trade surpluses that continue to grow throughout the projection period.

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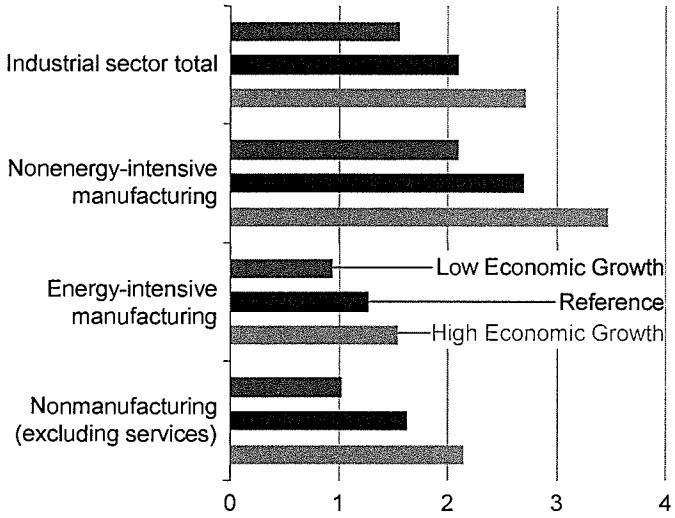
For energy-intensive industries, output growth is strong early, then slows after 2025

Figure MT-3. Average annual growth rates of shipments for the industrial sector and its components in three cases, 2012-40 (percent per year)



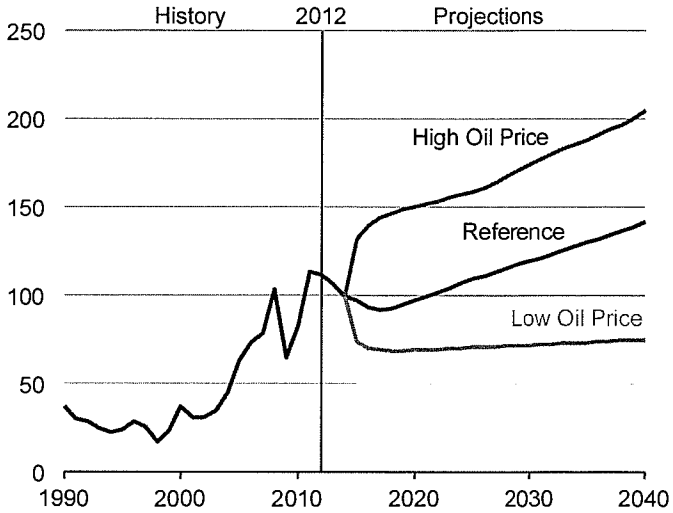
With a rapidly growing service sector and imports meeting a large share of demand for goods in recent decades, industrial sector shipments have expanded more slowly than the overall economy [1]. In the AEO2014 Reference case, real value of shipments for all goods and services [2] grows by 2.0% from 2012 to 2040, for the industrial sector by 2.1%/year, and for the service sector by 2.0%/year. Industrial sector manufacturing grows by 2.3%/year and nonmanufacturing by 1.6%/year (Figure MT-3).

The Reference case shows two distinct periods of growth, and the energy-intensive industries display the sharpest contrast between the periods. With increased shale gas production affecting U.S. competitiveness, growth in U.S. manufacturing output accelerates through 2025. From 2012 to 2025, real GDP grows by an average of 2.5%/year, and the industrial sector grows by 2.8%/year. After 2025, industrial output growth slows as a result of increased foreign competition and rising energy prices, with energy-intensive industries showing the largest slowdowns—from a 2012-25 average of 2.0%/year to a 2025-40 average of 0.7%/year. The 2012-40 output growth rates vary among industries, with iron and steel averaging 0.9%/year and the cement industry 2.5%/year.

Industrial production growth is strongly linked to exports, along with consumer demand and investment. Declining exchange rates, combined with modest escalation in unit labor costs, increase U.S. exports in the projection. From 2012 to 2040, real exports of goods and services increase by an average of 5.5%/year, while real imports of goods and services grow by an average of 3.8%/year.

Range of oil price cases represents uncertainty in world oil markets

Figure MT-4. North Sea Brent crude oil spot prices in three cases, 1990-2040 (2012 dollars per barrel)



In AEO2014 the North Sea Brent crude oil price is tracked as the main benchmark for world oil prices. In 2013, the West Texas Intermediate (WTI) crude oil price continued to trade at a discount relative to other world oil prices. With refineries running at high levels through August 2013, the discount narrowed as a result of new oil transportation infrastructure from the market center for WTI prices in Cushing, Oklahoma. The discount widened from September to December 2013, however, as lower 48 production continued to grow and refinery utilization returned to lower levels after the summer.

EIA developed three oil price cases—Reference, High, and Low—to examine how alternative price paths could affect energy markets (Figure MT-4). The AEO2014 price cases included varying assumptions about: (1) investment and production decisions by the Organization of the Petroleum Exporting Countries (OPEC), (2) development of tight oil and bitumen resources in non-OPEC countries (including the United States), and (3) demand growth in China, the Middle East, and other countries outside the Organization for Economic Cooperation and Development (non-OECD countries).

Relative to the Reference case, the Low Oil Price case assumes lower economic growth and thus lower liquids demand from non-OECD regions; and rising production from OPEC countries, which displaces relatively more expensive crude oil from non-OPEC producers. In the Low Oil Price case, OPEC supplies 51% of the world's liquid fuels in 2040, compared with 44% in the Reference case. In the High Oil Price case, assuming stronger demand growth and fewer resources developed in OPEC countries, the non-OECD countries account for 62% of world liquids use in 2040, compared with 60% in the Reference case and 57% in the Low Oil Price case. The OPEC share of world liquids production never exceeds 40% in the High Oil Price case.

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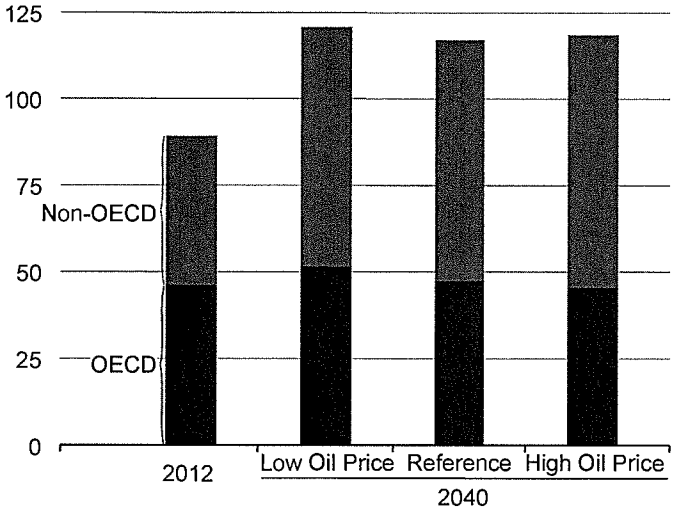
Trends in petroleum and other liquids markets are defined largely by the developing nations

Figure MT-5. World petroleum and other liquids consumption by region in three cases, 2012 and 2040 (million barrels per day)



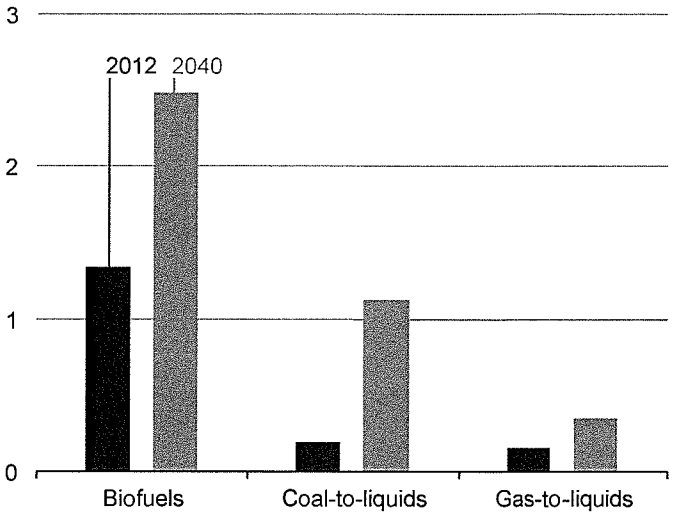
In the AEO2014 Reference, High Oil Price, and Low Oil Price cases, total world consumption of petroleum and other liquids in 2040 ranges from 117 to 121 million barrels per day (MMbbl/d) (Figure MT-5). The alternative oil price cases reflect shifts in both supply and demand. Although demand at the margin in the Organization for Economic Cooperation and Development (OECD) countries is influenced primarily by price, demand in non-OECD regions is driven primarily by rates of economic growth that are particularly uncertain. The AEO2014 High Oil Price case reflects a scenario in which strong economic growth in the emerging non-OECD nations increases the growth of their liquids demand and drives oil prices higher.

OECD petroleum and other liquids use grows in the Reference case to 47 MMbbl/d in 2040, while non-OECD use grows to 70 MMbbl/d. In the High Oil Price case, OECD petroleum and other liquids use in 2040 is lower than in the Reference case, at 45 MMbbl/d, but demand in the fast-growing non-OECD economies rises to 73 MMbbl/d. In the Low Oil Price case, OECD consumption grows to 51 MMbbl/d in 2040, and lower GDP growth in the non-OECD countries leads to slower growth in liquids demand, which reaches only 69 MMbbl/d in 2040. Non-OECD liquids demand would be even lower than projected in the Low Oil Price case, but low oil prices encourage more use of liquid fuels in the non-OECD nations in the long term.

The supply response also varies across the price cases. In the Low Oil Price case, OPEC's ability to manage its market share is weakened. Low prices have a negative impact on non-OPEC petroleum supply in comparison with the Reference case. In the High Oil Price case, OPEC restricts production, non-OPEC petroleum resources become more economical, and high oil prices make production of nonpetroleum liquids more economically attractive.

World production of liquid fuels from biomass, coal, and natural gas increases

Figure MT-6. World production of nonpetroleum liquids by type in the Reference case, 2012 and 2040 (million barrels per day)



Nonpetroleum liquids are a small but increasing source of total liquids supply in the AEO2014 Reference case. World production of nonpetroleum liquids—including biofuels, coal-to-liquids (CTL), and gas-to-liquids (GTL)—totaled 1.7 MMbbl/d, or 1.9% of total world liquids production, in 2012. In 2040, nonpetroleum liquids production, at 4.0 MMbbl/d, accounts for 3.4% of total world liquids production (Figure MT-6).

While world production of nonpetroleum liquids is spurred by sustained high prices, high prices alone are not expected to be sufficient to increase U.S. production of nonpetroleum liquids. As a result, no U.S. production of CTL or GTL is projected in the AEO2014 Reference case. U.S. biofuels production does grow in the projection, but only modestly, from 0.9 MMbbl/d in 2012 to 1.1 MMbbl/d in 2040.

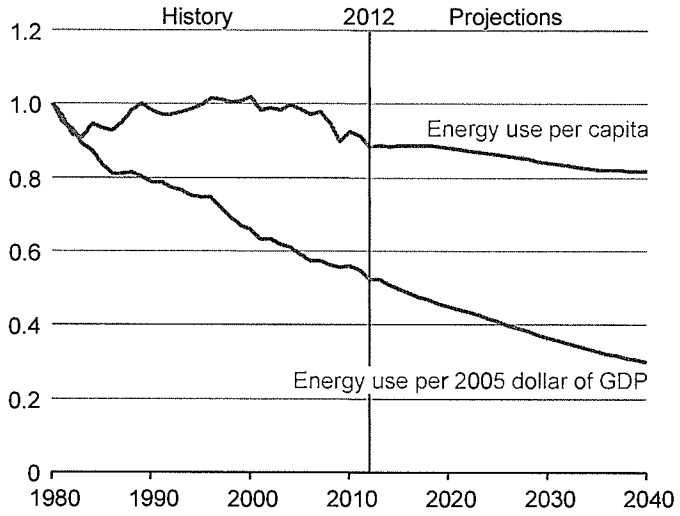
The U.S. share of world biofuels production shrinks in the AEO2014 Reference case from 66% in 2012 to 43% in 2040. Biofuels development relies heavily on country-specific programs or mandates and outlooks for transportation fuels. U.S. demand for transportation fuels declines, and without significant additional market penetration of fuels with high-percentage ethanol blends or of drop-in fuels, the possibilities for expanded biofuel production are limited.

Biofuels production accounts for the largest share of total world nonpetroleum liquids production throughout the projection, although its share falls to 63% in 2040 from 79% in 2012. In 2040, world biofuels production of 2.5 MMbbl/d is 68% larger than world production of CTL and GTL combined.

012733

In the United States, average energy use per person declines from 2012 to 2040

Figure MT-7. Energy use per capita and per dollar of gross domestic product in the Reference case, 1980-2040 (index, 1980 = 1)



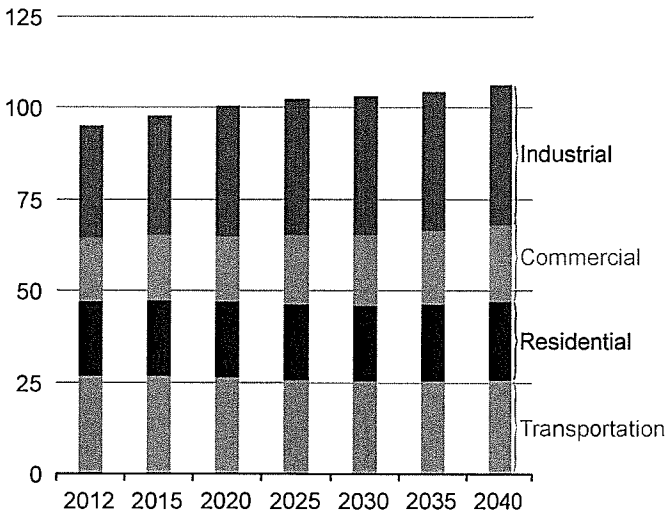
Population growth affects energy use through increases in housing, commercial floorspace, transportation, and economic activity. However, the structure and efficiency of the U.S. economy are changing in ways that can lower energy use. Changes in consumer behavior can also have an impact, such as changes in the rate of vehicle miles traveled (VMT) per licensed driver. U.S. population increases by 0.7%/year from 2012 to 2040; the economy, as measured by gross domestic product (GDP), increases at an average annual rate of 2.4%; and total energy consumption increases by 0.4%/year. As a result, energy intensity, measured both as energy use per person and as energy use per dollar of GDP, declines over the projection period (Figure MT-7).

The projected decline in energy use per capita is brought about largely by gains in appliance efficiency, a shift in production from cooler to warmer regions, and an increase in vehicle efficiency standards, combined with modest growth in travel per licensed driver. From 1970 through 2008, energy use dipped below 320 million British thermal units (Btu) per person for only a few years in the 1980s. In 2012, energy use per capita was about 302 million Btu. In the Reference case, energy use per capita declines to 279 million Btu per person in 2040—a level not seen since 1965.

Continual changes in the structure of the economy reduce energy use per dollar of GDP. Although the service industries' share of total shipments remains below the 2012 level of 78%, the manufacturing sector shifts about 1% of the output from energy-intensive industries to non-energy-intensive industries. Efficiency gains in the electric power sector also reduce overall energy intensity, as older, less-efficient generators are retired as a result of slower growth in electricity demand, changing dispatch economics related to rising fuel prices, and stricter environmental regulations.

Industrial and commercial sectors lead U.S. growth in primary energy use

Figure MT-8. Primary energy use by end-use sector in selected years in the Reference case, 2012-40 (quadrillion Btu)



Total primary energy consumption, including fuels for electricity generation, grows by 0.4%/year in the Reference case, to 106.3 quadrillion Btu in 2040 (Figure MT-8). The largest increase, 7.8 quadrillion Btu, is in the industrial sector, with increased use of natural gas in some industries (bulk chemicals, for example) as a result of low natural gas prices coinciding with rising shipments in those industries. In the industrial sector, which was more severely affected than the other end-use sectors by the 2007-09 economic downturn, energy consumption increases by 7.0 quadrillion Btu from 2008 to 2040.

The second-largest increase in total primary energy use, 3.3 quadrillion Btu from 2012 to 2040, is in the commercial sector. Even as standards for building shells and energy efficiency are tightened and commercial energy intensity (energy use per square foot) decreases by 0.4%/year from 2012 through 2040, energy use grows by 0.6%/year as annual growth in commercial floorspace averages 1.0%.

Primary energy use in the residential sector grows by 0.2%/year, or about 1.4 quadrillion Btu from 2012 to 2040. Energy use for space heating was down by almost 1 quadrillion Btu in 2012 because of an unusually warm heating season. In 2040, residential energy use is at 2011 levels, despite reduced energy use for space heating, lighting, and clothes washers, among other uses.

In the transportation sector, light-duty vehicle (LDV) energy use declines with the implementation of fuel economy standards. VMT remain flat (about 12,200 per licensed driver) in the near term, then begin to increase after 2025. From 2012 to 2040, total transportation sector energy use falls by more than 1 quadrillion Btu.

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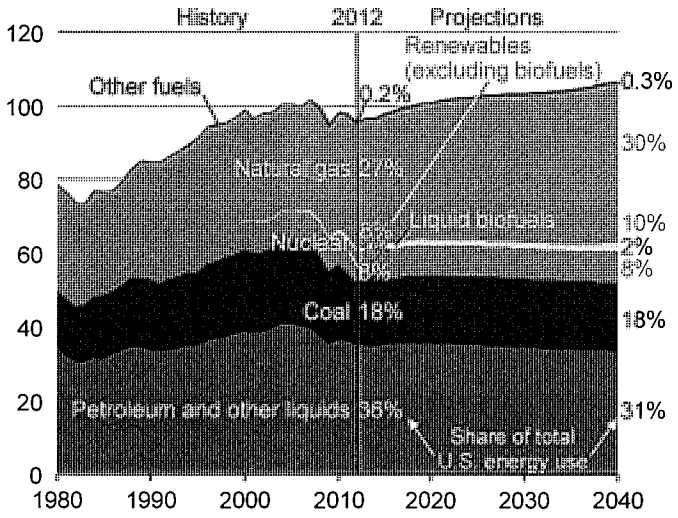
Renewables and natural gas lead rise in primary energy consumption

Figure MT-9. Primary energy use by fuel in the Reference case, 1980-2040 (quadrillion Btu)



The fossil fuel share of total energy use declines from 82% in 2012 to 80% in 2040 in the Reference case, while renewable energy use grows (Figure MT-9). The renewable share of total energy use (including biofuels) increases from 9% in 2012 to 12% in 2040 in response to the availability of federal tax credits for renewable electricity generation and capacity during the early years of the projection and in response to state renewable portfolio standard (RPS) programs. Biofuel use mandated by the Renewable Fuels Standard (RFS) accounts for a small part of the increase.

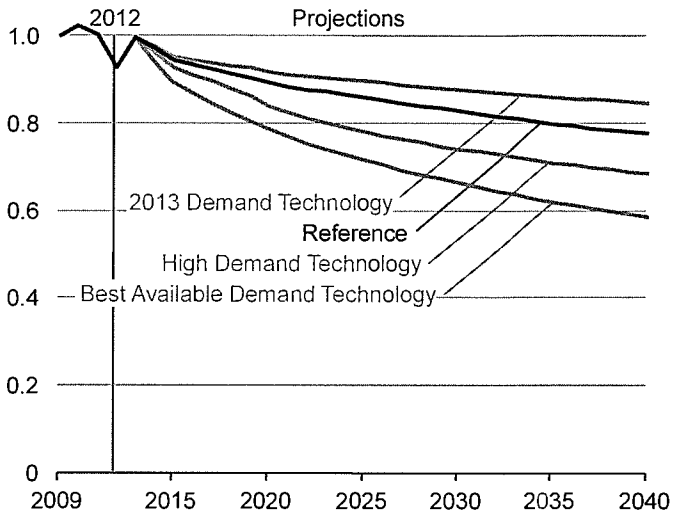
Natural gas consumption grows by about 0.8%/year from 2012 to 2040, led by increases in natural gas use for electricity generation and in the industrial sector. Growing production from tight shale keeps the price of natural gas to end users below 2005-08 levels through 2038.

Increases in vehicle fuel economy offset growth in transportation activity, resulting in a decline in the petroleum and other liquids share of fuel use while consumption of liquid biofuels increases. Biofuels, including E85, biodiesel blended into diesel, and ethanol blended into motor gasoline (up to 15%), account for 4% of all petroleum and other liquids consumption by energy content in 2040.

Coal consumption increases by an average of 0.3%/year from 2012 to 2040, remaining between the 2011 and 2012 levels through 2040. A small amount of coal-fired power plant capacity is added: a total of 2.2 gigawatts (GW) currently under construction and another 0.5 GW added after 2016 (including 0.3 GW with carbon sequestration capability). Coal-fired capacity retirements total 51 GW between 2012 and 2040, but the remaining coal-fired plants continue to be used extensively.

Residential energy intensity drops across a wide range of technology assumptions

Figure MT-10. Residential delivered energy intensity in four cases, 2009-40 (index, 2009 = 1)



In the AEO2014 Reference case, the intensity of residential energy demand, defined as annual energy use per household, declines by 16% between 2012 and 2040 (Figure MT-10). Energy use for lighting, space heating, and water heating accounts for most of the decline. While household energy intensity decreases, total delivered energy consumption in the residential sector increases by about 5%, with the number of homes growing by 26% over the period. More use of distributed generation, such as from rooftop solar panels, would further reduce delivered energy intensity, but it is not projected to have a large effect, because electricity from distributed generation sources accounts for a small percentage of total electricity use in households over the projection period.

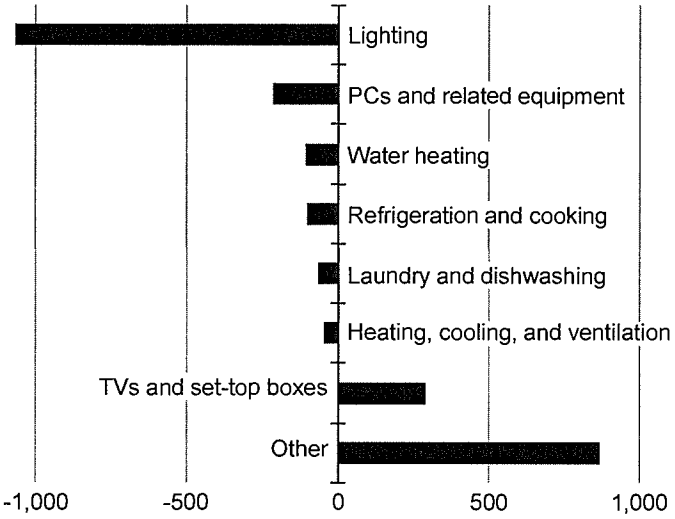
Three additional cases show the effects of different technology assumptions on residential energy intensity. The Best Available Demand Technology case limits purchases of new and replacement equipment by consumers to the most efficient models available at the time of purchase and assumes that the most energy-efficient specifications will be used in new home construction, which influences space heating and cooling demand. The High Demand Technology case assumes higher efficiency, earlier availability, lower cost, and more frequent energy-efficient purchases for some equipment than the Reference case. The 2013 Demand Technology case assumes no future improvement in efficiency for equipment or building shells beyond what is available in 2013.

From 2012 to 2040, household energy intensity declines by 37% in the Best Available Demand Technology case and by 26% in the High Demand Technology case. In the 2013 Demand Technology case, energy intensity is higher than in the Reference case but still declines by 9% from 2012 to 2040 as older, less-efficient appliances are replaced over time by 2013-vintage equipment.

012735

Electricity use per household declines from 2012 to 2040 in the Reference case

Figure MT-11. Change in residential electricity consumption for selected end uses in the Reference case, 2012-40 (kilowatthours per household)



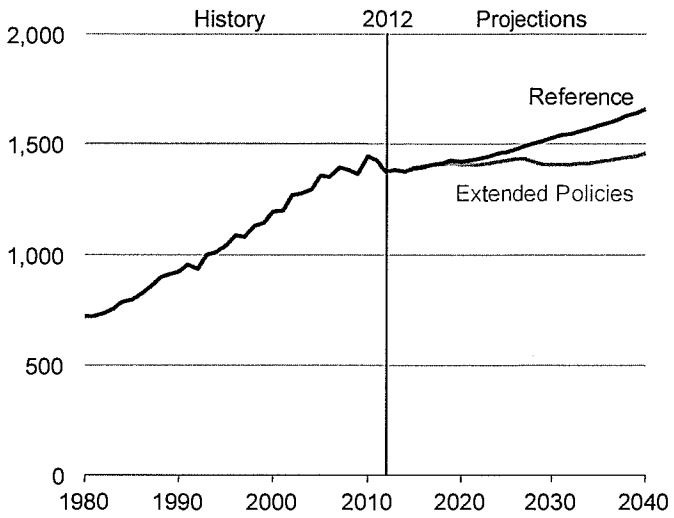
Annual electricity demand for the average household in the Reference case declines by 4%, from 12.1 megawatthours (MWh) in 2012 to 11.6 MWh in 2040. In 2012, the largest uses of electricity at the household level are space cooling, small devices and other minor electric end uses, and lighting. In 2040, electricity consumed for lighting per household is 65% lower, and electricity use for minor electric end uses and for space cooling rises by 33% and 17%, respectively (Figure MT-11). Regulations implementing lighting efficiency standards established by the Energy Independence and Security Act of 2007 (EISA2007) are a major factor in the replacement of incandescent bulbs with more efficient compact fluorescent lighting (CFL) and light-emitting diode (LED) lamps.

Although electricity consumption for most end uses declines on a per-household basis between 2012 and 2040, electricity consumption at the sectoral level increases for most end uses because of growth in the number of households. Most of the growth at the sectoral level comes from increasing market penetration of smaller electric devices, which have little coverage by efficiency standards, and by a growing need for cooling as the U.S. population shifts to warmer climates in the South.

From 2012 to 2040, residential electricity use grows by 21% as the fuel mix in the residential sector moves increasingly toward electricity. Petroleum and other liquids lose fuel share for every end-use service, and particularly for space heating, where both electricity and natural gas gain share. Natural gas loses fuel share in every end-use service except space heating, and it continues to account for more than half of the fuel consumed for space heating, water heating, and cooking through the projection. In 2040, overall natural gas use in the residential sector is 1% lower, and petroleum and other liquids use is 35% lower than in 2012.

Continuing efficiency gains restrain growth in residential electricity use

Figure MT-12. Residential electricity sales in two cases, 1980-2040 (billion kilowatthours)



In the AEO2014 Reference case, electricity is the only fuel for which demand increases in the residential sector from 2012 to 2040, in part as a result of population growth, regional population shifts, and temperature assumptions. Electricity is affected more than other fuels by the increased adoption of new and existing uses. In the Reference case, which includes only existing and announced standards and codes, residential electricity demand grows by 0.7%/year from 2012 to 2040 (Figure MT-12). In the Extended Policies case, which assumes additional rounds of appliance standards and building codes in the future, residential electricity use increases by 0.2%/year from 2012 to 2040. In contrast, residential electricity demand grew by an average of more than 2%/year over the previous 30 years.

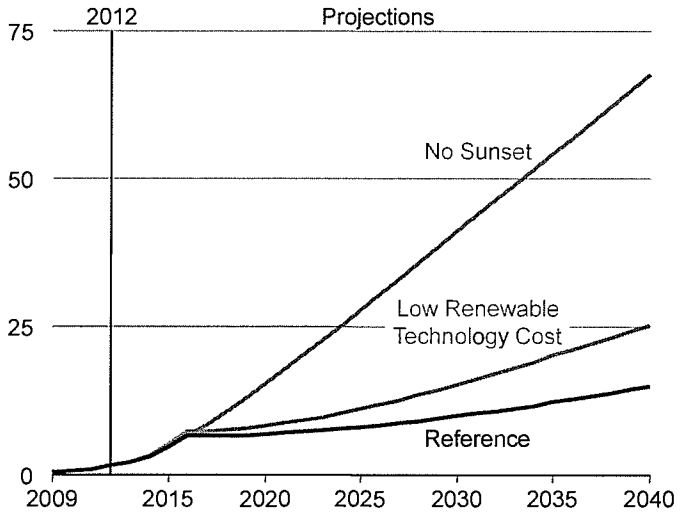
Most of the announced standards in the Reference case are scheduled to take effect in the near term. For instance, the Reference case includes changes in minimum efficiency levels for refrigerators and freezers in 2014 and for central air conditioners, air source heat pumps, and electric water heaters in 2015. The most distant standard assumed in the Reference case is the 2020 standard for general service lighting, which is a part of the second wave of congressionally-mandated standards from EISA2007.

Given the long lifetimes of most major residential equipment (10 to 30 years), it can take years for an appliance standard to affect the majority of installed equipment; but once the standard has been fully incorporated, electricity consumption tends to increase in line with the growth of housing stock (0.8%/year from 2012 to 2040)—as occurs around 2020 in the Reference case but not until 2035 in the Extended Policies case.

012736

Extending tax credits supports increased residential use of renewable energy sources

Figure MT-13. Residential distributed generation capacity in three cases, 2009-40 (gigawatts)



Electricity generation capacity from residential solar photovoltaic (PV) and wind technologies roughly doubled from 2010 to 2012. In the AEO2014 Reference case, it doubles again in both 2014 and 2016 before slowing considerably as a result of the planned expiration of the investment tax credit (ITC) after 2016. Without the tax credit available, almost two decades pass before annual additions to residential distributed generation capacity surpass 0.5 gigawatts (GW), as they have in recent years.

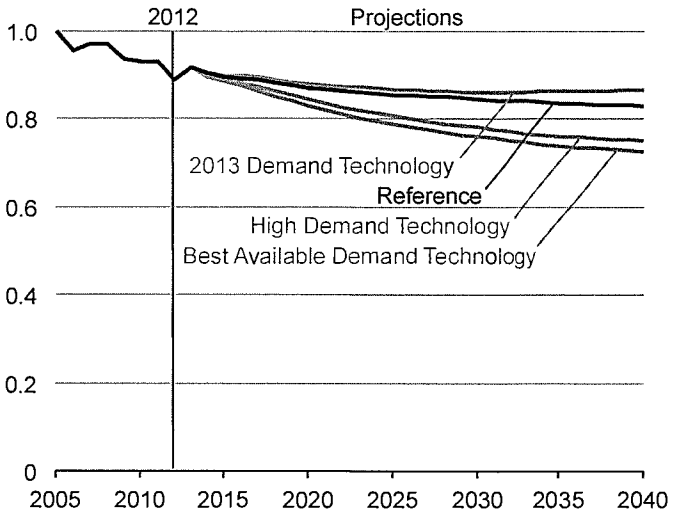
Two alternative cases present more optimistic scenarios for further growth in residential distributed generation, either by extending the tax credits or by lowering installed costs. With the ITC extended beyond its legislated 2016 expiration date in the No Sunset case, residential renewable capacity doubles twice from 2013 to 2019, again from 2019 to 2024, and again from 2024 to 2034. In 2040, more than 67 GW of solar and wind capacity is installed in the residential sector, as compared with less than 2 GW in 2012 (Figure MT-13).

The Low Renewable Technology Cost case includes the tax credit through 2016, as in the Reference case, but assumes lower installed costs than in the Reference case. Even in the Reference case, installed costs for renewable technologies decline from their present values. For example, solar PV installed costs fall from around $5,400 per kilowatt (kW) in 2012 to around $3,270 per kW in 2020 and around $2,900 per kW in 2040.

The Low Renewable Technology Cost case assumes an additional 20% reduction in installed costs after 2013, resulting in increased adoption of both solar PV and wind technologies for electricity generation, especially in locations with the combination of high electricity prices and sufficient renewable resources. By 2040, more than 25 GW of renewable capacity is installed, 10 GW more than in the Reference case.

Commercial sector energy intensity varies with technology improvements

Figure MT-14. Commercial delivered energy intensity in four cases, 2005-40 (index of energy use per square foot, 2005 = 1)



In the AEO2014 Reference case, commercial sector energy intensity, or delivered energy consumption per square foot of commercial floorspace, declines by an average of 0.3%/year from 2012 to 2040 (Figure MT-14). During this period, delivered electricity consumption grows by 0.7%/year despite 1.0% annual growth in commercial floorspace. Natural gas consumption also increases over the period despite increases in building shells and equipment efficiency.

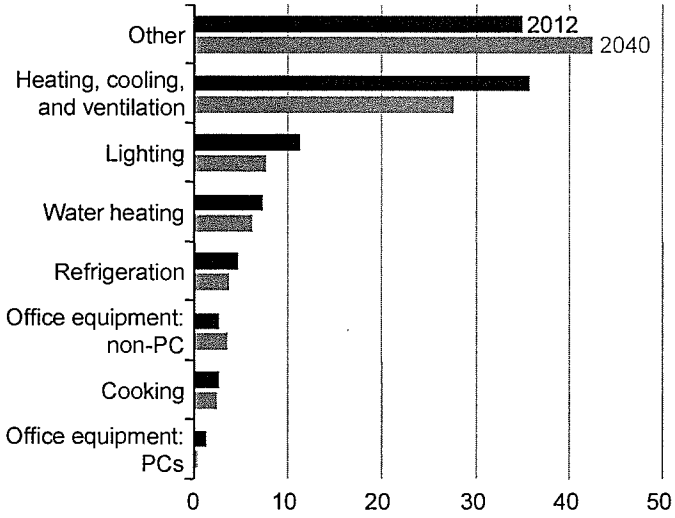
Improvements in major end-use equipment and distributed generation technologies help to slow the growth of delivered energy consumption in the commercial sector. Varying the rate of improvement in the 2013 Demand Technology, High Demand Technology, and Best Available Demand Technology cases shows a range in which equipment and building shell efficiency improvement, or lack thereof, could affect commercial energy consumption.

In the 2013 Demand Technology case, which restricts equipment and shell efficiencies to those available in 2013, energy intensity is reduced by 2.7% from 2012 to 2040, averaging 0.1%/year as equipment is replaced over time and as new buildings are constructed. In the High Demand Technology case, which assumes lower costs and higher efficiencies for commercial equipment and building shells and a 7% real discount rate, commercial energy intensity falls by 0.6%/year, or twice the rate in the Reference case. As a result, energy intensity is 15.8% lower in 2040 than in 2012. The Best Available Demand Technology case allows for even greater shell efficiency improvements than the High Demand Technology case, and also limits future technology choices to only the most efficient models of equipment in each year. As a result, commercial sector energy intensity declines by 0.7%/year on average, to 18.5% below the 2012 level in 2040.

012737

Energy use continues to shift from personal computing equipment to networked computing

Figure MT-15. Energy intensity of selected commercial end uses in the Reference case, 2012 and 2040 (thousand Btu per square foot)



Commercial energy intensity—the ratio of energy consumption to floorspace—decreases from 2012 to 2040 for most electric end uses in the Reference case, while commercial floorspace increases by 1.0% annually (Figure MT-15). Electricity accounted for 54.5% of commercial delivered energy use in 2012.

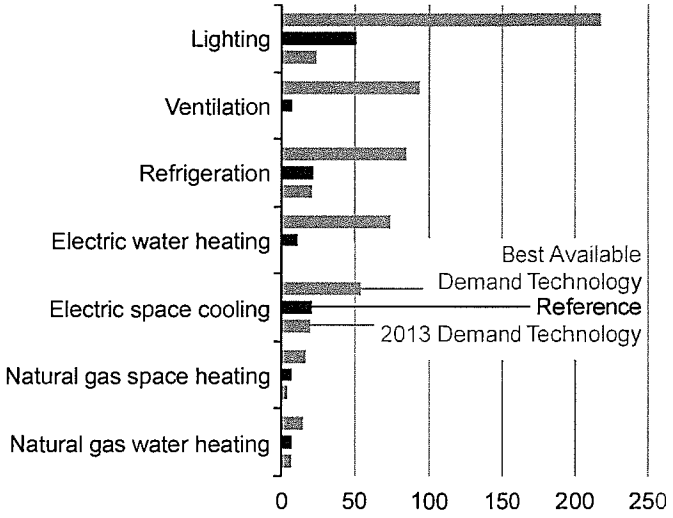
Electricity use for personal computers (PCs), including desktop and laptop computers and monitors, continues to decline. Reductions in processor power use, improvements in display backlighting, and a general shift from desktop to mobile computing devices all cause the energy consumption of PC office equipment to fall by 5.6% annually. With expanding use of web-based services increasing the role of servers in data centers, electricity use by non-PC office equipment grows by 2.0%/year in the Reference case.

Federal efficiency standards moderate energy consumption by major end-use equipment, such as space heating and cooling, water heating, lighting, and refrigeration. The Energy Independence and Security Act of 2007 (EISA2007) mandatory efficacy improvements for lighting continue to foster the adoption of advanced incandescent, fluorescent, and solid-state lighting technologies. As a result, the share of purchased electricity consumption used for lighting declines from 20.7% in 2012 to 14.7% in 2040.

The growing use of energy for miscellaneous electric loads, many of which are not currently subject to federal standards, leads to a 21.4% increase in energy intensity from 2012 to 2040 for other end uses in the Reference case. Miscellaneous electric loads in the commercial sector include medical equipment, video displays, and many other devices. Increases in the use of such devices and equipment can vary greatly by building type and service demand.

Efficiency gains for advanced technologies reduce commercial energy consumption growth

Figure MT-16. Efficiency gains for selected commercial equipment in three cases, 2040 (percent change from 2012 installed stock efficiency)



Behind the 0.3% average annual decline in delivered energy intensity in the commercial sector in the AEO2014 Reference case is a shift in the mix of end-use services, from core building services (space heating, space cooling, ventilation, water heating, lighting, cooking, and refrigeration) to other office equipment and electric services. Core end-use energy intensity falls by 0.9%/year from 2012 to 2040, and the intensity of other end uses increases by 0.6%/year on average.

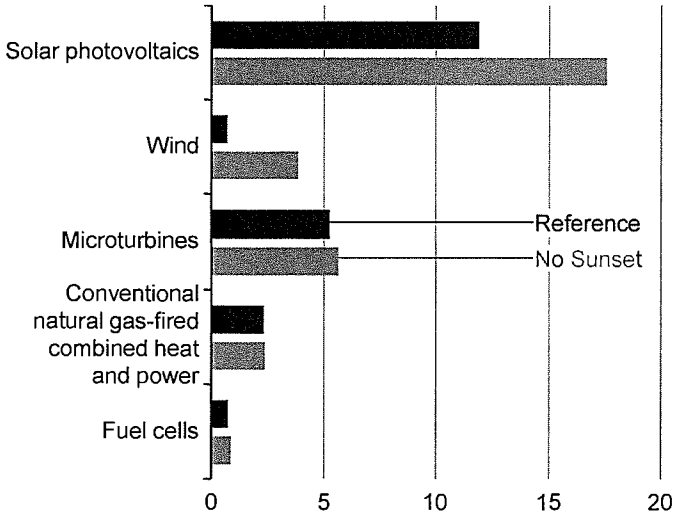
The largest energy efficiency improvements in the Reference case are for lighting, as a result of new standards and the penetration of LED technologies. PC office equipment is a close second to lighting, as a result of the shift toward network computing. Refrigeration, electric space cooling, and electric water heating also show significant efficiency gains (Figure MT-16).

The Best Available Demand Technology case demonstrates significant potential for further improvements—especially for electric equipment in the core end uses. In this case, core end-use intensity declines at more than twice the rate of the Reference case, and core delivered energy use in 2040 is 1.3 quadrillion Btu lower than in the Reference case. Lighting accounts for 35% of the additional delivered energy savings, resulting from both earlier and more widespread penetration of LED technologies than in the Reference case. Beyond lighting, the Best Available Technology case projects significant savings for variable air volume ventilation systems, high-efficiency chiller systems for space cooling, high-efficiency natural gas furnaces, and various advanced refrigeration technologies. Together with lighting, those end uses account for more than 90% of the energy savings relative to the Reference case, with delivered energy consumption in 2040 only 0.6 quadrillion Btu higher than in 2012 and delivered energy intensity declining by 0.7%/year.

012738

Renewable technologies drive more additions to distributed generation capacity

Figure MT-17. Additions to electricity generation capacity in the commercial sector in two cases, 2012-40 (gigawatts)



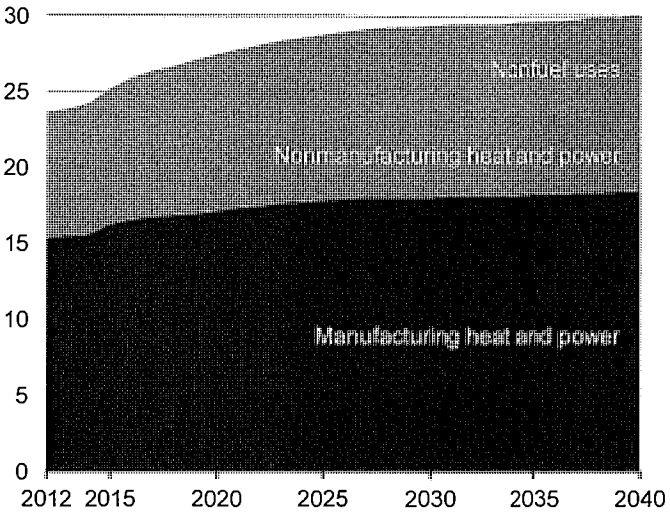
Renewable energy sources, chiefly solar photovoltaic and wind, continue to dominate new commercial distributed generation capacity in the AEO2014 Reference case, accounting for 62.3% of commercial capacity in 2040. Lower prices for photovoltaic inverters and panels, decreasing installation costs, federal investment tax credits, and state and utility rebates all contribute to growth in commercial photovoltaic capacity, which increases by 5.7%/year from 2012 to 2040 in the Reference case. The current 30% federal investment tax credit continues through 2016, after which it reverts to 10%. In the No Sunset case, with investment tax credits for all distributed generation technologies extended through 2040, photovoltaic capacity increases by an average of 7.0%/year.

Small-scale wind capacity grows by 14.2%/year from 2012 to 2040 in the No Sunset case, compared with 7.9%/year in the Reference case (Figure MT-17). As in the case of solar photovoltaic, additional federal and local incentives help to support the growth in commercial wind capacity. Commercial wind capacity accounts for 11.1% of the 35.7 gigawatts (GW) of total distributed generation capacity in 2040 in the No Sunset case, with photovoltaic capacity accounting for 58.1%.

Rising fuel prices offset the effects of the 10% investment tax credit on nonrenewable technologies for distributed generation. In the Reference case, microturbine capacity using natural gas grows by 15.3%/year on average, from 98.3 MW in 2012 to 5.4 GW in 2040, and its growth rate in the No Sunset case is only slightly higher, at 15.7%/year. The microturbine share of total distributed generation capacity in 2040 is 16.2% in the No Sunset case, compared with 20.4% in the Reference case. Fuel cell capacity grows by an average of 12.3%/year in the Reference case and 12.7%/year in the No Sunset case.

Growth in industrial energy consumption is slower than growth in shipments

Figure MT-18. Industrial energy consumption by application in the Reference case, 2012-40 (quadrillion Btu)



In the AEO2014 Reference case, manufacturing shipments increase by 87% from 2012 to 2040, while delivered energy consumption for heat and power in the manufacturing sector increases by only 19%. The continued decline in energy intensity of manufacturing is explained in part by continued improvement in the efficiency of industrial equipment as energy prices gradually increase, and by a shift in the share of shipments from energy-intensive manufacturing industries to non-energy-intensive industries. With growing foreign competition, shipments and energy use in many trade-exposed energy-intensive industries (bulk chemicals, petroleum refineries, iron and steel, and aluminum) begin declining around 2025. For less energy-intensive manufacturing industries (plastics, computers, machinery, and transportation), shipments continue to grow, capturing a larger share of total U.S. manufacturing output.

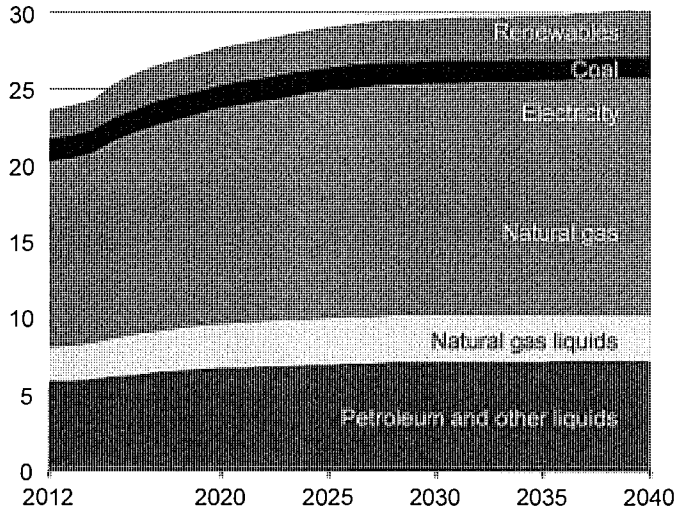
In the nonmanufacturing industries (agriculture, mining, and construction), energy intensity declines from 2012 to 2040, as shipments increase by 57% and as total delivered energy consumption increases by 41%. The decline in energy intensity is limited by the mining industry, where energy intensity increases as resource extraction moves into less productive areas.

U.S. manufacturing energy consumption for heat and power grows in the Reference case by an average of 1.1%/year from 2012 to 2025, and then slows to 0.2%/year from 2025 to 2040 (Figure MT-18). Nonmanufacturing energy consumption grows by an average of 1.9%/year from 2012 to 2025, and then slows to 0.6%/year from 2025 to 2040. Nonfuel energy use, principally bulk chemical feedstocks and asphalt, grows robustly at 2.6% annually from 2012 to 2025, largely as a result of rising bulk chemical shipments. After 2025, nonfuel energy use increases 0.1%/year, in parallel with bulk chemical shipments.

012739

Reliance on natural gas, natural gas liquids, and renewables rises as industrial energy use grows

Figure MT-19. Industrial energy consumption by fuel in the Reference case, 2012-40 (quadrillion Btu)



Total delivered energy consumption in the industrial sector increases by 28% (6.6 quadrillion British thermal units [Btu]) from 2012 to 2040 in the AEO2014 Reference case (Figure MT-19). Much of the growth is in natural gas use, which accounts for 34% of the total increase in energy consumption from 2012 to 2025 and 59% of the increase from 2025 to 2040, as a result of relatively low natural gas prices from steady increases in domestic natural gas production through 2040. The mix of industrial energy sources stays relatively constant, however, reflecting limited remaining capability for switching from other fuels to natural gas in most industries.

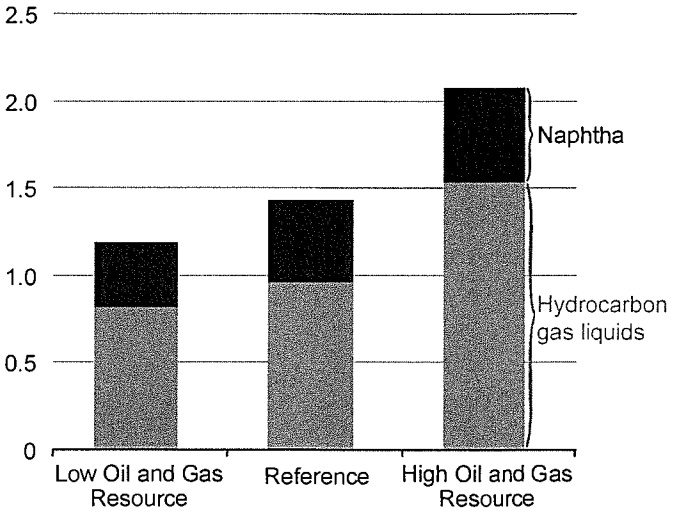
Renewable fuel consumption increases by 53% from 2012 to 2040, although as a percentage of total energy consumption, renewable fuels remain small, at 10% of total energy consumption in 2040. The paper industry remains the predominant user of renewable energy, accounting for roughly 66% of the energy consumed for heat and power in that industry.

Industrial consumption of hydrocarbon gas liquids (HGL) increases by 35% from 2012 to 2025, followed by a 5% decline from 2025 to 2040. HGL are consumed predominantly as feedstocks in the bulk chemicals industry, and smaller amounts (mostly propane) are consumed for process heat in other industries. Coal is the only industrial fuel that shows a consistent decline in consumption, from 6% of the total in 2012 to 5% in 2040.

Low natural gas prices and increased availability of biomass contribute to growth in the use of combined heat and power (CHP). Industrial CHP generation, excluding the refining industry, increases by 88%, from 111.3 billion kilowatthours (kWh) in 2012 to 208.9 billion kWh in 2040.

Bulk chemicals feedstock mix reflects both relative fuel prices and demand for chemicals

Figure MT-20. Change in liquid feedstock consumption in three cases, 2012-40 (quadrillion Btu)



Liquid feedstock consumption in the bulk chemicals industries is divided between heavy feedstock (petroleum-based naphtha and gasoil) and light feedstock (hydrocarbon gas liquids [HGL], primarily ethane and propane), according to their relative prices. Heavy feedstock prices follow the price of oil, and prices for HGL feedstock, a composite of propane and ethane prices, vary relative to both oil and natural gas prices. Ethane prices are also influenced by production of ethane from natural gas plant liquids and by demand for organic and resin chemicals.

Shipments in the bulk chemicals industries grow by 60% from 2012 to 2028 in the AEO2014 Reference case, followed by no growth after 2028. Growth in total liquid feedstock consumption follows a similar pattern.

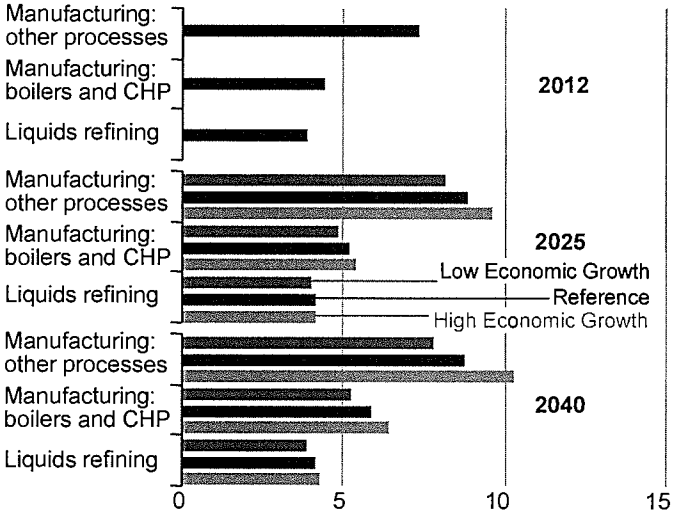
In the AEO2014 projections, the mix of feedstocks used to produce bulk chemicals varies with changes in supply assumptions. In the High Oil and Gas Resource case, natural gas prices in 2040 are 40% lower than in the Reference case, while crude oil prices are 12% lower. As a result, the HGL feedstock price in 2040 is 31% lower than in the Reference case, while the heavy feedstock price is only 18% lower. In the Low Oil and Gas Resource case, the HGL feedstock price in 2040 is 13% higher than in the Reference case, while the heavy feedstock price is only 3% higher.

The greater variation in feedstock prices in the High Oil and Gas Resource case leads to more change in the feedstock mix (Figure MT-20), with the use of light HGL feedstock growing faster than the use of heavy naphtha feedstock. In all the cases, consumption of heavy feedstock continues to grow from 2012 to 2040, because some chemicals, such as butadiene and aromatics, cannot be made in sufficient quantities to meet demand by cracking only HGL feedstocks.

012740

For manufacturing applications, heat and power use varies with economic assumptions

Figure MT-21. Heat and power consumption for refining and manufacturing applications in three cases, 2012, 2025, and 2040 (quadrillion Btu)



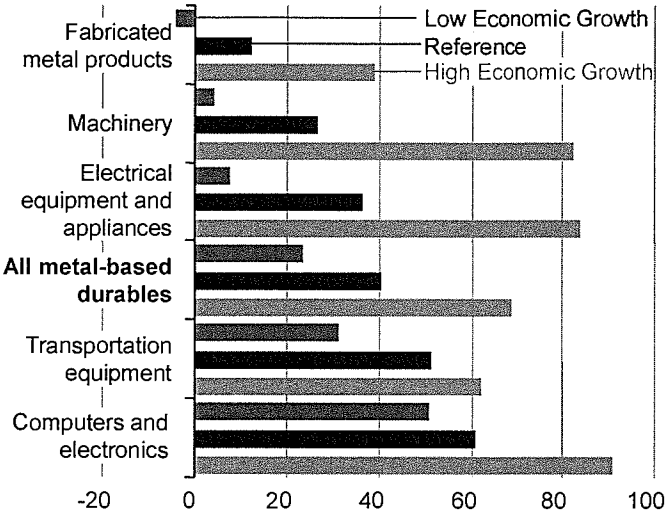
There are three principal uses of energy for heat and power in manufacturing: steam generation for process heat applications, direct-fired heat applications, and the use of electricity to drive machinery. Steam, produced in boilers and by CHP applications, accounted for 4.4 quadrillion Btu of the 14.8 quadrillion Btu of energy consumed for heat and power in the manufacturing sector in 2012. The remaining 10.4 quadrillion Btu of energy consumed for heat and power in manufacturing in 2012, consisting of fuels and purchased electricity, was used in applications such as motors, kilns, direct process heaters, and refining of liquid fuels. Energy for manufacturing can also be used to produce chemical feedstocks.

Demand for heat in the manufacturing sector is particularly sensitive to the rate of economic growth (Figure MT-21). In the Reference case, industrial energy use for boilers and CHP grows by 32% from 2012 to 2040, compared with 45% in the High Economic Growth case and 18% in the Low Economic Growth case.

The energy-intensive manufacturing industries account for a disproportionate amount of the energy used in boiler and CHP applications. The paper industry is the largest industrial user of boiler and CHP, which accounted for 1.6 quadrillion Btu, or roughly 80%, of total heat and power consumption in the paper industry in 2012. The paper industry also recovered 1.2 quadrillion Btu of renewable and waste fuels in 2012, specifically wood, pulping liquor, and municipal solid waste, all of which was consumed in recovery boilers. In addition, roughly half of the energy consumed for heat and power in the bulk chemicals industry in 2012 was used for boiler and CHP applications. Adoption of CHP in energy-intensive industries with stable base-steam demand offers significant potential for energy savings and cost reductions.

Energy consumption in the metal-based durables industries increases rapidly

Figure MT-22. Cumulative growth in energy consumption by metal-based durables industries in three cases, 2012-40 (percent)



Energy consumption in the metal-based durables industries increases at a rate that is more than twice the rate of growth in the energy-intensive industries, driven by higher growth in shipments relative to the energy-intensive industries. Energy consumption in the metal-based durables industries grows from 1.4 quadrillion Btu in 2012 to 2.0 quadrillion Btu in 2040 in the AEO2014 Reference case, compared with 1.7 quadrillion Btu in 2040 in the Low Economic Growth case and 2.4 quadrillion Btu in 2040 in the High Economic Growth case.

In each of the three cases, the energy intensity of metal-based durables industries declines from 2012 to 2040. Shipments grow more rapidly than energy use, as the industries' energy efficiency improves significantly over the period. Energy intensity in the metal-based durables industries declines by 1.5%/year from 2012 to 2040 in both the Reference and Low Economic Growth cases and by 1.7%/year in the High Economic Growth case.

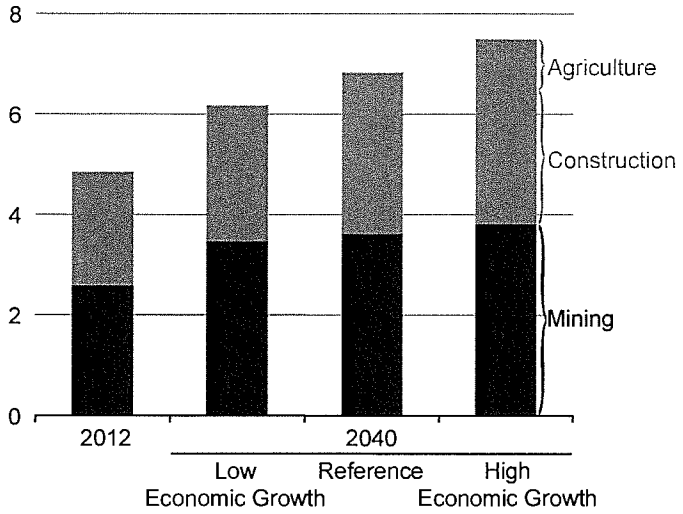
The mix of energy used in the metal-based durables industries differs significantly from that in the energy-intensive industries. With extensive use of machine drive, the metal-based durables industries use more electricity as a share of total energy consumption. Also, manufacturing in the metal-based durables industries uses energy for facility support activities, such as lighting and climate control.

Growth varies among specific segments of the metal-based durables industries (Figure MT-22). After 2025, shipments and energy use slow significantly in the fabricated metals and machinery segments but only slightly in other segments of the metal-based durables industries. The segment with the fastest growth in shipments and energy use is computers and electronic products.

012741

Nonmanufacturing energy intensity reductions are tempered by the mining industry

Figure MT-23. Delivered energy consumption by nonmanufacturing industries in three cases, 2012 and 2040 (quadrillion Btu)



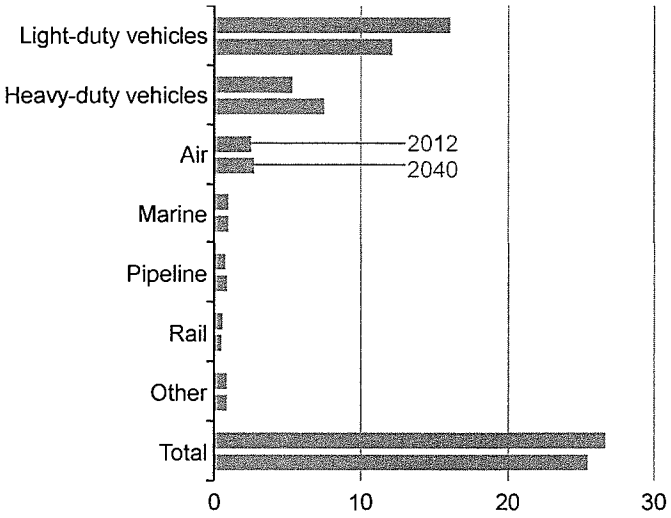
In 2040, nonmanufacturing industries account for $2.6 trillion (2005 dollars) in shipments in the AEO2014 Reference case—a 57% increase from 2012. From 2012 to 2040, total energy consumption in the nonmanufacturing subsector increases by 27% (1.3 quadrillion Btu) in the Low Economic Growth case, 41% (2.0 quadrillion Btu) in the Reference case, and 55% (2.6 quadrillion Btu) in the High Economic Growth case (Figure MT-23).

The nonmanufacturing subsector consists of the construction, agriculture, and mining industries. In the Reference case, it accounts for roughly 23% of total value of shipments and about 23% of total delivered energy consumed in the industrial sector in 2040. The mining industry is the most energy-intensive of the three industries, accounting for 53% of the energy consumed in the nonmanufacturing subsector in 2040 but only 20% of the value of shipments. In contrast, the construction industry accounts for 65% of the shipments in 2040 but only 33% of the energy consumed, and the agriculture sector accounts for 15% of the shipments and 14% of the energy consumed.

Overall, energy intensity declines in the nonmanufacturing subsector by 10% from 2012 to 2040 in the Reference case. Construction and agriculture both show a decline in energy intensity of 17% from 2012 to 2040, whereas the mining industry shows an increase in energy intensity of 26% over the same period. The energy intensity of mining increases as producers move into less-productive areas over time.

Transportation sector energy consumption declines in the Reference case

Figure MT-24. Delivered energy consumption for transportation by mode in the Reference case, 2012 and 2040 (quadrillion Btu)



Transportation sector energy consumption declines from 26.7 quadrillion Btu in 2012 to 25.5 quadrillion Btu in 2040 in the AEO2014 Reference case (Figure MT-24), differing markedly from the longer historic trend. Transportation energy consumption grew by an average of 1.3%/year from 1973 to 2007, when it totaled 29.1 quadrillion Btu [3]. The decline in transportation energy demand is the result of significantly less energy use by light-duty vehicles (LDVs), along with a small decline in energy use by rail, which together more than offset increased energy use by heavy-duty vehicles (HDVs), aircraft, marine vessels, and pipelines.

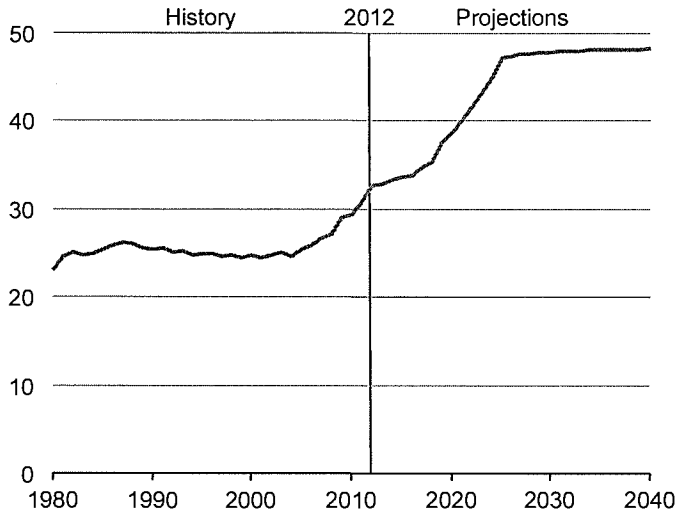
LDV energy demand falls sharply, from 16.0 quadrillion Btu in 2012 to 12.1 quadrillion Btu in 2040, as the result of higher fuel economy that more than offsets increases in LDV travel. Even with new standards for HDV fuel efficiency and greenhouse gas emissions starting in 2014, energy use by HDVs (including tractor trailers, buses, vocational vehicles, and heavy-duty pickup trucks and vans) increases the fastest among the transportation modes, from 5.3 quadrillion Btu in 2012 to 7.5 quadrillion Btu in 2040, as a result of increased demand for travel as economic output grows.

Aircraft energy consumption increases modestly, from 2.5 quadrillion Btu in 2012 to 2.7 quadrillion Btu in 2040, with growth in personal air travel mostly offset by gains in aircraft fuel efficiency. Energy consumption by marine vessels grows as increased international trade boosts demand for shipping and rising incomes increase demand for recreational boating. Pipeline energy use is tempered as increasing volumes of natural gas are produced closer to end-use markets, and energy consumption for rail travel declines slightly as the efficiency of rail improves more rapidly than travel demand increases.

012742

CAFE and greenhouse gas emissions standards boost light-duty vehicle fuel economy

Figure MT-25. Average fuel economy of new light-duty vehicles in the Reference case, 1980-2040
(miles per gallon)

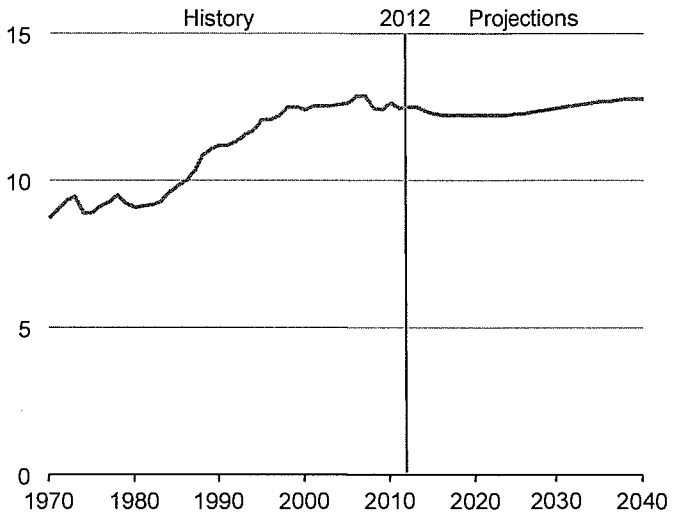


The 1978 introduction of corporate average fuel economy (CAFE) standards for LDVs increased the average fuel economy of these vehicles from 19.9 miles per gallon (mpg) in 1978 to 26.2 mpg in 1987. Despite technology improvements, however, as sales of light trucks increased from 17% of new LDV sales in 1980 to 53% in 2004 [4], fuel economy fell below 26 mpg in 1989 and did not rise above that level until 2007. From 2008 through 2012, LDV average fuel economy rose steadily from 27.1 mpg to 32.7 mpg, as a result of more stringent CAFE standards for light-duty trucks starting in model year 2008 and for passenger cars starting in model year 2011; CAFE and greenhouse gas (GHG) emissions standards for passenger cars and light-duty trucks starting in model year 2012; rising fuel prices; and a reduction in the sales share of light trucks.

The National Highway Traffic Safety Administration (NHTSA) and the U.S. Environmental Protection Agency (EPA) have jointly issued new GHG emissions and CAFE standards for model years 2012 through 2025 [5, 6], which are included in AEO2014. As a result, the fuel economy of new LDVs, measured in terms of their compliance values in CAFE testing [7], rises from 32.7 mpg in 2012 to 47.2 mpg in 2025 (Figure MT-25). The GHG emissions and CAFE standards are held roughly constant after 2025 in the Reference case, but fuel economy continues to rise, to 48.2 mpg in 2040, as new fuel-saving technologies are adopted. In 2040, passenger car fuel economy averages 55.6 mpg, and light-duty truck fuel economy averages 40.9 mpg.

Miles traveled per licensed driver remains below its historic high through 2040

Figure MT-26. Vehicle miles traveled per licensed driver in the Reference case, 1970-2040
(thousand miles)



Personal vehicle travel demand, measured as annual vehicle miles traveled (VMT) per licensed driver, declined from its historic high of 12,900 miles in 2007 to about 12,500 miles in 2012. In the AEO2014 Reference case, personal vehicle travel continues declining to 12,200 miles in 2020 before increasing to 12,800 miles in 2040—still below the 2007 level (Figure MT-26). Although motor gasoline prices, personal income, and vehicle fuel efficiency continue to influence personal vehicle travel, the major factors in the decline from 2013 through 2025 are changes in travel patterns by driver age and gender groups and changes in employment rates.

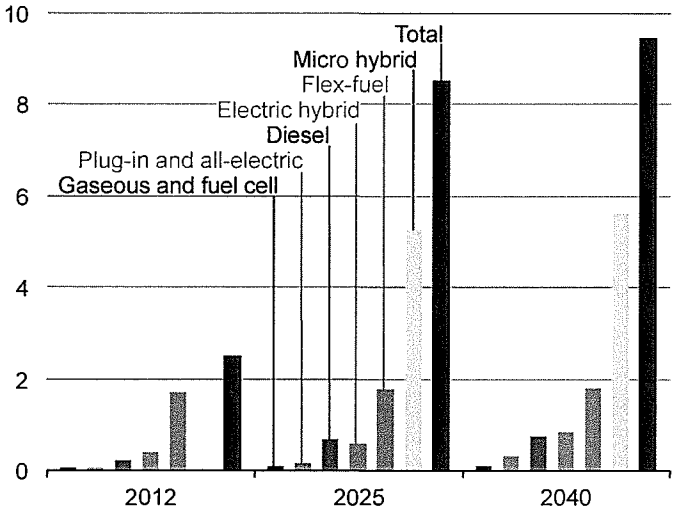
The number of licensed drivers grows by an average of 0.8%/year from 2012 to 2040, but declines in personal vehicle travel demand for some age groups cause an overall decline in VMT per licensed driver. The employment rate of the licensed driver population (the employed, nonfarm population ages 16 and over), which fell by 4 percentage points during the 2007-09 recession, does not rebound to pre-recession levels before 2040, tempering the projected growth in personal travel. Total light-duty VMT increase in the Reference case to 3.4 trillion in 2040—a 29% increase from 2012—as a result of 26% overall growth in the number of licensed drivers, from 213 million in 2012 to 269 million in 2040.

Although vehicle sales also grow through 2040, the number of vehicles per licensed driver drops from 1.12 in 2007 to 1.02 in 2040, limiting the availability of vehicles for travel. Motor gasoline prices fall from 2012 levels and do not exceed that level until 2035, while real personal disposable income per licensed driver increases by 55% through 2040. The changes in travel behavior and demographics more than offset the boost to personal travel provided by income growth and lower motor gasoline prices.

012743

Sales of vehicles using nongasoline technologies grow by nearly 400 percent from 2012 to 2040

Figure MT-27. Sales of light-duty vehicles using nongasoline technologies by type in the Reference case, 2012, 2025, and 2040 (million vehicles sold)



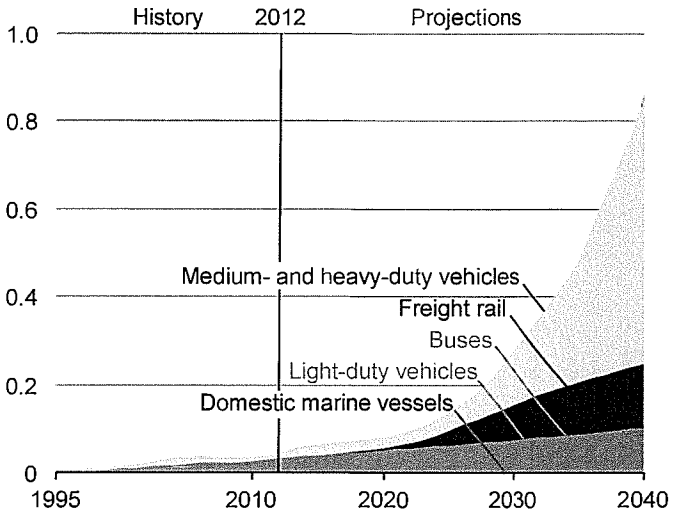
Light-duty vehicles (LDVs) that use diesel, alternative-fuel, hybrid-electric, or all-electric systems play a significant role in meeting more stringent GHG emissions and corporate average fuel economy (CAFE) standards in the AEO2014 Reference case, with sales increasing from 18% of all new LDV sales in 2012 to 55% in 2040. Micro hybrid vehicles, defined here as conventional gasoline vehicles with micro hybrid systems that manage engine operation at idle, represent 33% of new LDV sales in 2040 (Figure MT-27). Flex-fuel vehicles (FFVs), which can use blends of up to 85% ethanol, represent about 11% of all new LDV sales in 2040. Current incentives for manufacturers selling FFVs, which are available in the form of fuel economy credits earned for CAFE compliance, expire at the end of 2019. As a result, the FFV share of LDV sales rises through 2019 and then remains flat through the rest of the projection.

Sales of hybrid electric and all-electric vehicles that use stored electric energy for motive power grow substantially in the Reference case. Gasoline- and diesel-electric hybrid vehicles account for 5% of total LDV sales in 2040. Plug-in hybrid and all-electric vehicles account for 2% of total LDV sales and 3% of total sales of vehicles using diesel, alternative-fuel, hybrid, or all-electric systems.

The diesel vehicle share of total LDV sales remains roughly constant from 2012 to 2040 in the Reference case. Light-duty gaseous and fuel cell vehicles account for less than 1% of new vehicle sales because of limited fueling infrastructure and the high incremental costs of the vehicles.

Natural gas use for transportation fuel grows but still makes up a modest share of total use

Figure MT-28. Natural gas consumption in the transportation sector in the Reference case, 1995-2040 (quadrillion Btu)



The use of compressed natural gas (CNG) and liquefied natural gas (LNG) in LDVs, HDVs, locomotives, buses, and marine vessels grows from 43 trillion Btu in 2012 to 863 trillion Btu in 2040 in the Reference case (Figure MT-28). Still, CNG and LNG account for only 3% of total energy consumption in the transportation sector in 2040, similar to the amount of natural gas consumed in pipeline transport.

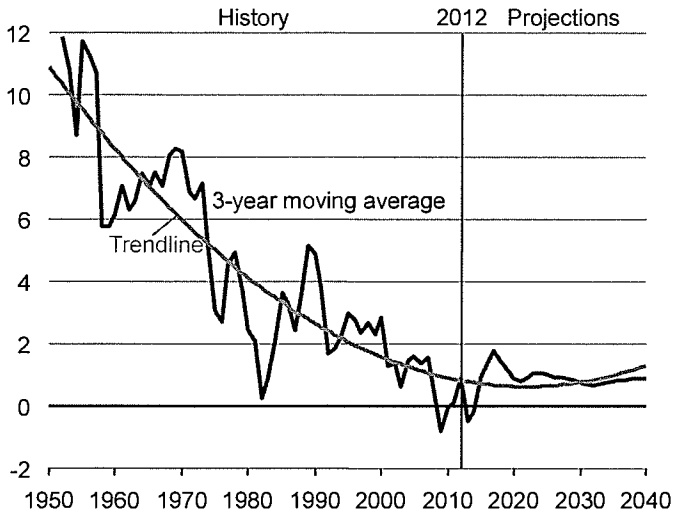
Medium-duty and heavy-duty vehicles—including tractor trailers, vocational vehicles, pickups, and vans with a gross vehicle weight rating (GVWR) of 10,001 pounds or more—become the largest consumers of CNG and LNG, increasing from 11 trillion Btu in 2012 to 613 trillion Btu in 2040 in the Reference case. The increase is spurred by relatively low natural gas prices. Initially, natural gas is consumed primarily by medium-duty trucks using CNG; but the vast majority of growth in natural gas consumption is for heavy-duty trucks (primarily tractor trailers) using LNG—a relatively high-mileage application in which the fuel cost savings of LNG offset the significant incremental capital cost of LNG vehicles.

LNG energy consumption by freight rail locomotives grows to 148 trillion Btu by 2040, when it accounts for 35% of total freight rail energy consumption, with fuel cost savings offsetting the incremental capital costs of LNG locomotives. CNG and LNG energy demand for buses grows from 13 trillion Btu in 2012 to 81 trillion Btu in 2040, primarily because of growth in CNG use for transit buses, which represents 28% of total energy consumption by buses in 2040. Use of CNG by LDVs and LNG by domestic marine vessels remains relatively minor, at 19.1 trillion Btu and 1.5 trillion Btu in 2040, or 2% and 0.2% of each mode's energy consumption, respectively.

012744

Growth in electricity use slows, but use still increases by 29% from 2012 to 2040

Figure MT-29. U.S. electricity demand growth in the Reference case, 1950-2040 (percent)



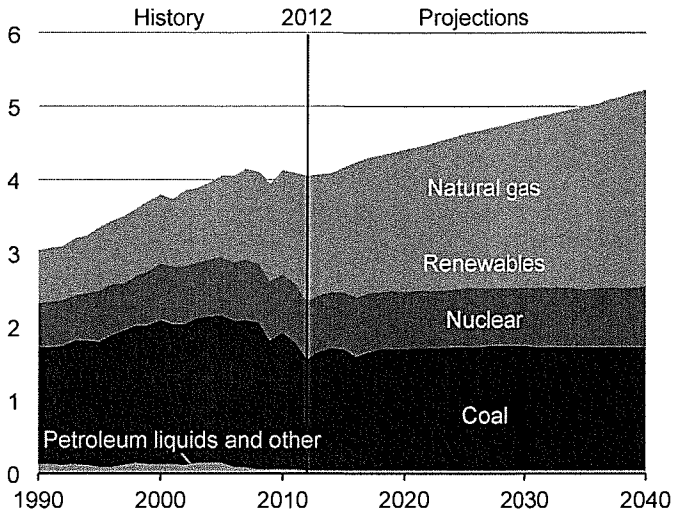
Growth of electricity demand (including retail sales and direct use) has slowed in each decade since the 1950s, from 9.8%/year from 1949 to 1959 to only 0.7%/year since 2000. In the AEO2014 Reference case, electricity demand growth remains relatively low, as rising demand for electric services is offset by efficiency gains from new appliance standards and investments in energy-efficient equipment (Figure MT-29). Total electricity demand grows by 29% (0.9%/year), from 3,826 billion kilowatthours (kWh) in 2012 to 4,954 billion kWh in 2040.

Retail electricity sales grow by 25% (0.8%/year) in the Reference case, from 3,686 billion kWh in 2012 to 4,623 billion kWh in 2040. Population shifts to warmer regions with greater cooling requirements affect both residential and commercial electricity sales. Residential electricity sales grow by 21%, to 1,657 billion kWh in 2040, with cooling needs offset by more efficient appliances and light bulbs. Electricity sales to the commercial sector rise by 27%, to 1,675 billion kWh in 2040, with continuous growth in demand for electrical devices and equipment. Sales to the industrial sector rise by 30%, initially in the primary metals and bulk chemical industries and later in the food, construction, and metal-based durables industries.

Electricity demand varies with different assumptions about economic growth, advances in energy-efficient technologies, and electricity prices. In the High Economic Growth case, electricity demand grows by 41% from 2012 to 2040, compared with 20% in the Low Economic Growth case and only 14% in the Best Available Demand Technology case. In the High Oil and Gas Resource Case, a 2% decline in electricity prices from 2012 to 2040, because of greater natural gas availability, results in demand growth of 35% over the same period. In contrast, in the Reference Case, electricity prices increase by 13% over the projection, while demand increases by 29%.

By 2035, natural gas surpasses coal as the largest source of U.S. electricity generation

Figure MT-30. Electricity generation by fuel in the Reference case, 1990-2040 (trillion kilowatthours)



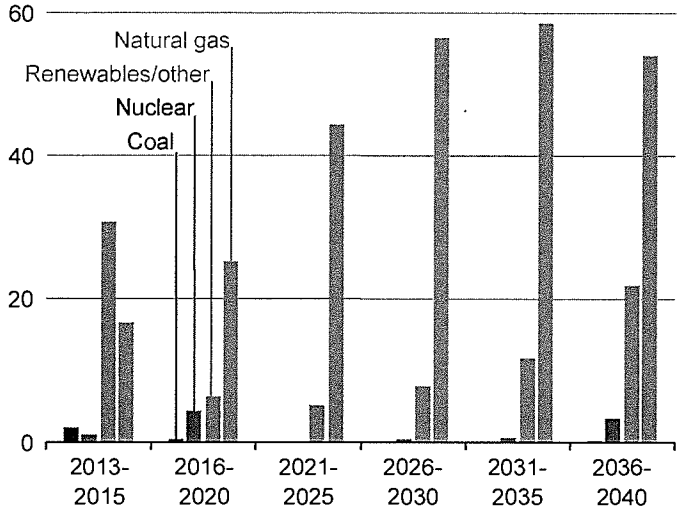
The share of electricity generated from natural gas grows steadily in the AEO2014 Reference case (Figure MT-30). The shift to natural gas occurs primarily as a result of its relatively low cost and coal-fired capacity retirements, although coal maintains the largest share of the generation mix through most of the projection. Changes in fuel mix are primarily a function of natural gas prices, which drive dispatch decisions for both coal and natural gas plants. Although a significant number of coal plants are retired early in the projection, the reduction in coal-fired generation is not proportional to the decline in capacity, because many of the coal plants projected to be retired currently operate at low capacity factors.

After 2020, increasing demand for electricity creates a need for new generating capacity, and natural gas plants account for more than 70% of all new capacity in the projection. As a result, the natural gas share of total electricity generation surpasses the coal share in 2035. Generation from nuclear power plants is relatively constant through 2040, increasing by an average of 0.2%/year, as 10 gigawatts (GW) of new capacity is brought online and 5 GW of older capacity is retired, and the nuclear share of total generation declines while the natural gas and renewable shares increase. Renewable generation grows by an average of 1.9%/year from 2012 through 2040 and makes up an increasing share of the generation mix in the Reference case. The non-hydropower share of total renewable generation increases from 45% in 2012 to 65% in 2040. The generation mix is sensitive to fuel prices and future policies and, therefore, varies significantly across the AEO2014 alternative cases.

012745

Most new capacity uses natural gas and renewables

Figure MT-31. Electricity generation capacity additions by fuel type, including combined heat and power, in the Reference case, 2013-40 (gigawatts)



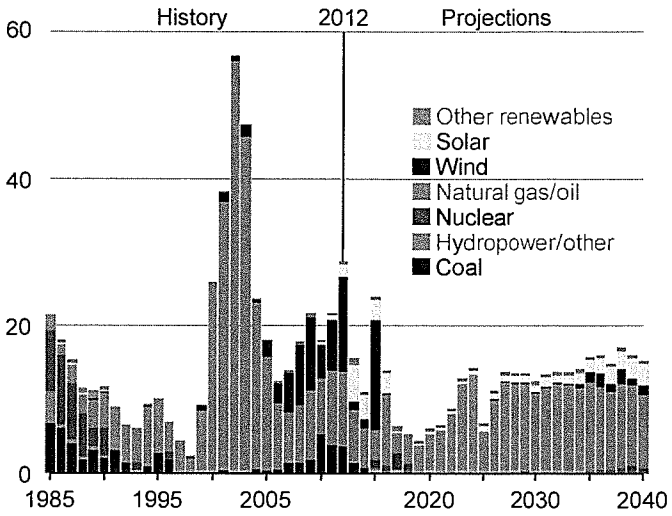
Decisions to add capacity, and the choice of fuel for new capacity, depend on a number of factors [8]. With growing electricity demand and the retirement of 97 GW of existing capacity, 351 GW of new generating capacity [9] is added in the AEO2014 Reference case from 2013 to 2040 (Figure MT-31).

Natural gas-fired plants account for 73% of capacity additions from 2013 to 2040 in the Reference case, compared with 24% for renewables, 3% for nuclear, and 1% for coal. Escalating construction costs have the largest impact on capital-intensive technologies, which include nuclear, coal, and renewables. However, federal tax incentives, nuclear loan guarantees, state energy programs, and rising prices for fossil fuels can increase the competitiveness of renewable and nuclear generating capacity. Federal and state environmental regulations also affect the use of fossil fuels, particularly coal, as does uncertainty about future limits on GHG emissions and other possible environmental programs (reflected in the Reference case by adding 3 percentage points to the cost of capital for new coal-fired capacity without carbon controls).

Uncertainty about demand growth and fuel prices also affects capacity planning. Capacity additions from 2013 to 2040 range from 263 GW in the Low Economic Growth case to 482 GW in the High Economic Growth case. In the Low Oil and Gas Resource case, with higher natural gas prices, new gas-fired capacity totals 181 GW, or 49% of total additions, from 2013 to 2040. In the High Oil and Gas Resource case, with natural gas prices that are lower than in the Reference case, 323 GW of new natural gas-fired capacity is added from 2013 to 2040, accounting for 83% of total new capacity.

Additions to power plant capacity slow after 2016 but accelerate beyond 2023

Figure MT-32. Additions to electricity generating capacity in the Reference case, 1985-2040 (gigawatts)



Past investments in electricity generation capacity have gone through boom-and-bust cycles, with periods of slow growth followed by rapid growth in response to changing expectations for future electricity demand and fuel prices, as well as changes in the industry, such as restructuring. A construction boom in the early 2000s saw capacity additions averaging 35 GW/year from 2000 to 2005, but the average dropped to 19 GW/year from 2006 to 2012 (Figure MT-32).

In the AEO2014 Reference case, capacity additions from 2013 to 2040 total 351 GW, including new plants in the power sector as well as end-use generators. Additions through 2016 average 16 GW/year, with 52% consisting of renewable plants built to take advantage of federal tax incentives and to meet state RFS. Eligibility rules for the wind production tax credit (PTC) allow new wind capacity coming online before 2016 to qualify, leading to a large increase just at the deadline.

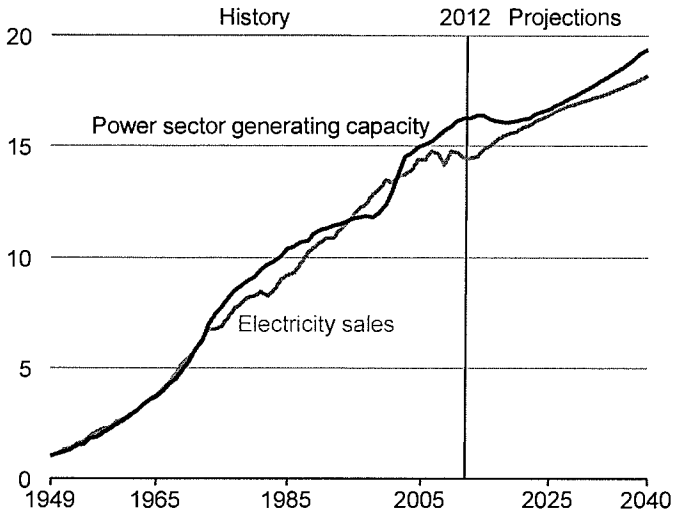
Annual capacity additions drop significantly after 2016 and remain below 9 GW/year until 2023, while existing capacity is adequate to meet relatively slow demand growth in most regions and satisfy renewable requirements under state standards. From 2025 to 2040, annual builds average 14 GW/year, as what was previously excess capacity is again needed. About 79% of the capacity added from 2025 to 2040 is fueled with natural gas, given higher construction costs for other types of capacity and uncertainty about the prospects for future limits on GHG emissions.

Uncertainty about electricity demand growth affects annual capacity additions. In the Low Economic Growth case, annual additions average 10 GW/year from 2025 to 2040; in the High Economic Growth case, they increase to an average of 20 GW/year over the same period.

012746

Growth in power generating capacity parallels rising sales of electricity

Figure MT-33. Electricity sales and power sector generating capacity in the Reference case, 1949-2040 (indices, 1949 = 1.0)



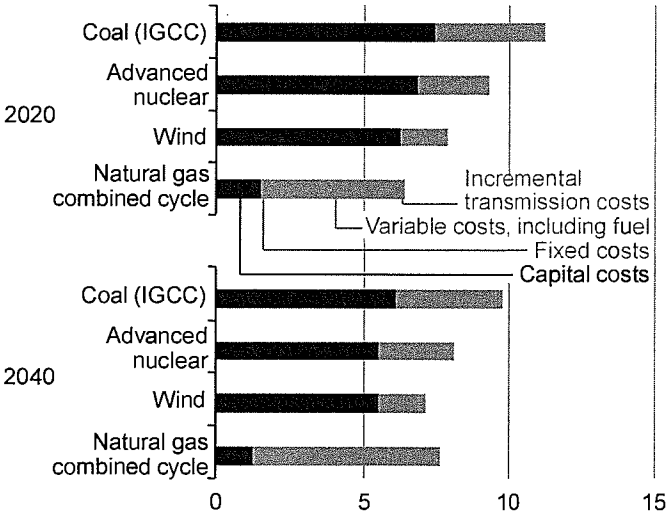
In the long term, growth in generating capacity parallels growth in electricity demand. However, unexpected shifts in demand or changes that affect capacity investment decisions can cause imbalances that may take years to work out. Capacity growth has outpaced demand since the 2007-09 economic recession that resulted in flat or declining demand. Low natural gas prices and tax incentives for renewable technologies have contributed to increases in those capacity types, even while most regions had sufficient capacity to serve load with an adequate reserve margin.

Figure MT-33 shows indexes summarizing relative changes in total power sector generating capacity and electricity sales. During the 1950s and 1960s, capacity and demand indexes tracked closely; but energy crises in the 1970s and 1980s slowed demand growth, with capacity additions outpacing demand for more than 10 years, as planned units continued to come online. Demand and capacity were aligned again in the mid-1990s, but in the late 1990s uncertainty about industry deregulation led to a downturn in capacity expansion, and another period of imbalance followed, with demand growth exceeding capacity growth.

In 2000, a boom in construction of new natural gas-fired plants brought capacity back into balance with demand, but capacity continued to grow, creating excess. Construction of new wind capacity also grew after 2000. Excess capacity remains in the early years of the AEO2014 Reference case, until retirements eventually bring capacity growth and demand growth back into balance after 2023. In the later years, total capacity grows at a rate slightly higher than demand growth, due in part to an increase in intermittent renewable capacity that does not contribute to meeting demand in the same proportion as dispatchable capacity.

Costs and regulatory uncertainties vary across options for new capacity

Figure MT-34. Average levelized electricity costs for new power plants, excluding subsidies, in the Reference case, 2020 and 2040 (2012 cents per kilowatthour)



Technology choices for new generating capacity are based largely on capital, operating, and transmission costs [*10*]. Coal, nuclear, and wind plants are capital-intensive (Figure MT-34), whereas operating (fuel) expenditures make up most of the costs for natural gas plants. Capital costs depend on such factors as equipment costs, interest rates, and capital cost recovery periods, which vary with technology. Fuel costs vary with operating efficiency, fuel price, and transportation costs.

Capital costs can decline over time as developers gain technology experience, with the largest rate of decline observed for new technologies. In the AEO2014 Reference case, the capital costs of new technologies are adjusted upward initially to compensate for the optimism inherent in early estimates of project costs, then they decline as project developers gain experience. The decline continues at a progressively slower rate as more units are built. Operating efficiencies also are assumed to improve over time, resulting in reduced variable costs unless increases in fuel costs exceed the savings from efficiency gains.

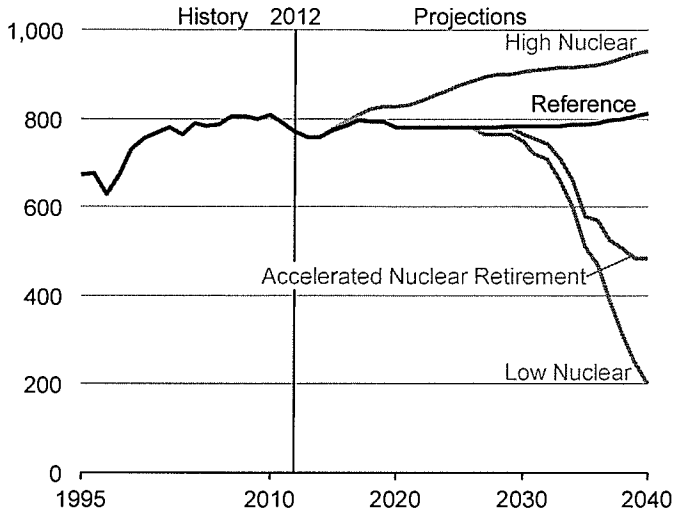
In addition to considerations of levelized costs [*11*], some technologies and fuels receive subsidies, such as production or investment tax credits. Also, new plants must satisfy local and federal emissions standards and be compatible with the utility's load profile to maximize revenue.

Regulatory uncertainty also affects capacity planning. Laws and regulations may require new coal plants to include carbon control and sequestration equipment, resulting in higher material, labor, and operating costs. Because nuclear and renewable power plants (including wind plants) do not emit greenhouse gases, their costs are not directly affected by these specific sources of regulatory uncertainty.

012747

Nuclear electricity generation varies with license renewals, uprates, and operating costs

Figure MT-35. Nuclear electricity generation in four cases, 1995-2040 (billion kilowatthours)



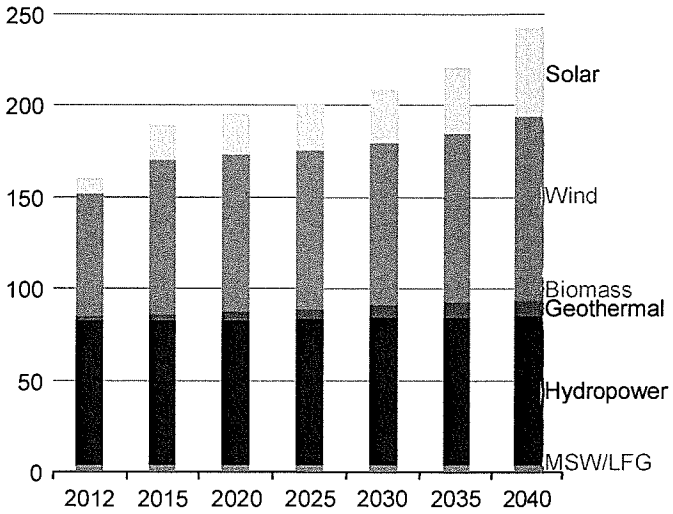
Projections of nuclear capacity and generation are influenced by assumptions about the potential for capacity uprates, new licensing requirements, future operating costs, and outside influences such as natural gas prices and incentives for other generating technologies. In the Reference case, nuclear capacity and generation remain relatively flat, with early retirements offset by new additions (Figure MT-35).

As discussed in AEO2014 Issues in focus, the Accelerated Nuclear Retirement case assumes no new nuclear builds beyond those currently under construction; that all existing units are retired by 60 years of age; and that nonfuel operating costs at existing nuclear plants increase by 3% annually, similar to recent rates. In this case, 42 gigawatts (GW) of nuclear capacity is retired, mostly from 2030 to 2040. The Low Nuclear case combines those assumptions with the High Oil and Gas Resource case and the No Sunset case. Lower natural gas prices make existing and new natural gas units more economical, and together with tax credits for newly added renewable capacity, they lower electricity market prices. With rising operating costs for nuclear plants and lower electricity prices, 77 GW of nuclear capacity is retired before 60 years of life. The retired nuclear capacity is replaced primarily by natural gas capacity, leading to a 6% increase in CO_2 emissions in the electric power sector in 2040.

The High Nuclear case assumes more uprates of existing units, adding 6.0 GW of capacity, and the addition of 12.6 GW of planned capacity through 2027. As a result, total nuclear generation in 2040 is 17% higher than in the Reference case, reducing the need for additional natural gas-fired generation.

Solar photovoltaics and wind dominate renewable capacity growth

Figure MT-36. Renewable electricity generating capacity by energy source, including end-use capacity in the Reference case, 2012-40 (gigawatts)



Total renewable generating capacity grows by 52% from 2012 to 2040 in the AEO2014 Reference case. Nonhydropower renewable capacity, particularly wind and solar, nearly doubles (Figure MT-36) and accounts for almost all of the growth in renewable capacity.

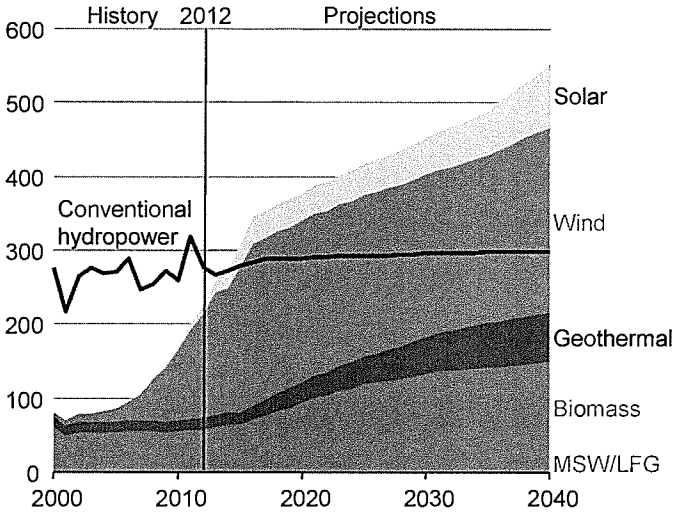
Solar power leads the growth in renewable capacity, increasing from less than 8 GW in 2012 to more than 48 GW in 2040. Wind capacity increases from less than 60 GW in 2012 to 87 GW in 2040, the second-largest amount of new renewable capacity. Although geothermal capacity more than triples and biomass capacity nearly doubles in the projection, combined they account for less than 15% of renewable capacity additions. Wind is the top source of nonhydropower renewable capacity in the projection, surpassing the hydropower share in 2036.

Renewable capacity growth is supported by a variety of federal and state policies, particularly state renewable portfolio standards (RPS) and federal tax credits. However, the impact of those policies is limited later in the projection period, because individual state renewable targets stop increasing by 2025, and projects must generally be online by 2016 to qualify for currently available federal tax credits. In addition, growth in electricity demand is modest and natural gas prices are relatively low after 2025. Renewable capacity grows by an average of 0.7%/year from 2020 to 2030, compared with 3.8%/year from 2010 to 2020. However, as natural gas prices rise over the projection period, renewable capacity becomes an increasingly cost-competitive option in some regions, and the total grows by an average of 1.5%/year overall from 2030 to 2040.

012748

Total generation from wind, solar, and other renewables surpasses hydropower

Figure MT-37. Renewable electricity generation by type, all sectors, in the Reference case, 2000-40 (billion kilowatthours)



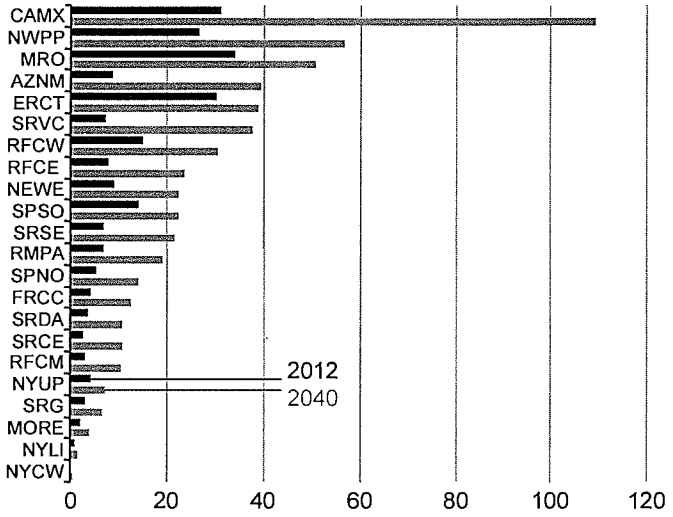
Total renewable electricity generation grows by 1.9%/year on average in the Reference case, from 502 billion kWh in 2012 to 851 billion kWh in 2040. Nonhydropower renewables, averaging 3.2%/year growth, account for nearly all of the growth, with their total surpassing hydropower (the previous leader of renewable generation) in 2014 and accounting for about two-thirds of all renewable generation in 2040 (Figure MT-37).

Solar energy is the fastest-growing source of renewable generation, increasing by 7.5%/year from 2012 to 2040, almost exclusively as a result of increased photovoltaic capacity in both the electric power (central-station) and end-use (customer-sited) sectors. Wind generation grows by an average of 2.0%/year but provides the largest absolute increase in renewable generation. From 2012 to 2016, wind power developers take advantage of the existing federal PTC, which requires plants to be under construction by the end of 2013 to qualify.

Geothermal power is the second-fastest-growing source of renewable electricity generation in the Reference case, increasing from less than 16 billion kWh in 2012 to 67 billion in 2040—a 5.4% average annual growth rate. Biomass generation also grows significantly, increasing by an average of 4.4%/year from 2012 to 2040, primarily as a result of increased use of co-firing technology in the electric power sector in the near- to mid-term. Co-firing is encouraged by state-level policies and increasing regional cost-competitiveness with coal. In the long run, the growth of biomass generation is supported by increased capacity at dedicated biomass plants in the electric power sector, as well as combined heat and power plants in the industrial sector.

California leads renewable electricity generation growth

Figure MT-38. Regional nonhydropower renewable electricity, including end-use generation, in the Reference case, 2012 and 2040 (billion kilowatthours)



In the AEO2014 Reference case, nonhydropower renewable generation increases from 2012 to 2040 in all modeled electricity regions (for a map of the regions and definition of acronyms, see Appendix F). Its growth is faster in some regions than in others, and the penetration in the generation mix and resulting increases in generation vary substantially among regions (Figure MT-38).

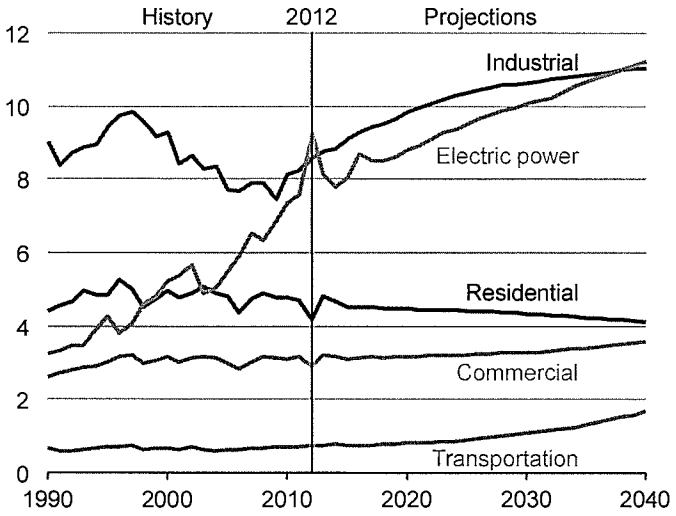
Regional growth in nonhydropower renewable generation is mainly driven by three factors: state RPS, availability of renewable energy resources, and cost competiveness with fossil fuel technologies. Factors such as electricity demand growth, non-RPS policies (such as net metering), and electricity prices also affect the rate of growth, which tends to be strongest in regions where a combination of factors is in place.

The WECC California (CAMX) region accounts for both the highest absolute level of nonhydropower renewable generation in 2040 and the largest growth from 2012 to 2040, which is supported by an aggressive RPS, availability of solar, wind, and geothermal resources, and relatively high electricity prices. The AZNM (Arizona, New Mexico, and Nevada) and SRVC (Virginia, North Carolina, and South Carolina) regions show the next-highest increases in nonhydropower renewable generation from 2012 to 2040. In the AZNM region, growth is supported by mandatory RPS standards, above-average electricity demand growth, and the availability of solar and wind resources. Although Virginia and South Carolina do not have mandatory policies in place, the SRVC region has robust biomass and solar resources and relatively high fossil fuel prices.

012749

Industrial and electric power sectors drive growth in U.S. natural gas consumption

Figure MT-39. Natural gas consumption by sector in the Reference case, 1990-2040 (trillion cubic feet)



U.S. total natural gas consumption grows from 25.6 trillion cubic feet (Tcf) in 2012 to 31.6 Tcf in 2040 in the AEO2014 Reference case. Natural gas use increases in all of the end-use sectors except residential (Figure MT-39). Natural gas use for residential space heating declines as a result of population shifts to warmer regions of the country and improvements in appliance efficiency.

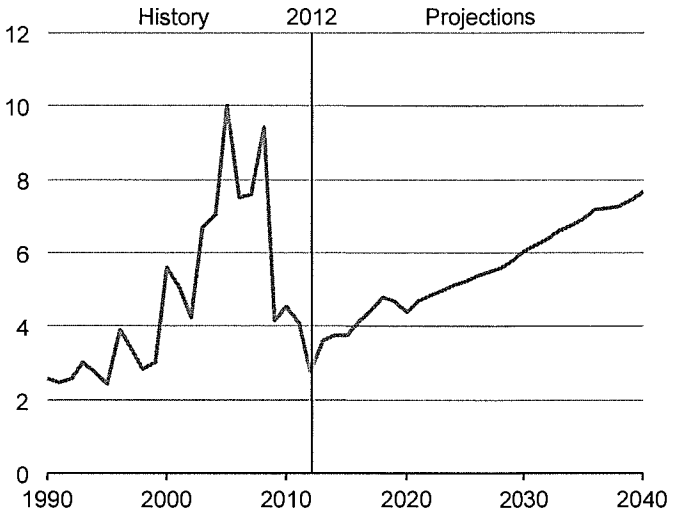
Consumption of natural gas for electric power generation grows by about 2 Tcf and makes up about 33% of the increase in total natural gas consumption by 2040. Relatively low natural gas prices make natural gas an attractive fuel for serving increased load. Natural gas is also the fuel most often used to replace older coal-fired generation as it is retired.

From 2012 to 2040, natural gas consumption in the industrial sector increases by 2.5 Tcf, an average of 0.9%/year, representing about 26% of the total increase in natural gas consumption. As industrial output grows, the energy-intensive industries take advantage of relatively low natural gas prices, particularly through 2028. After 2028, industrial sector consumption of natural gas continues to grow but at a somewhat slower rate, in response to rising prices.

Although transportation use currently accounts for only a small portion of total U.S. natural gas consumption, natural gas use by heavy-duty vehicles (HDVs), trains, and ships shows the largest percentage growth of any fuel in the projection. Consumption in the transportation sector, excluding natural gas use at compressor stations, grows from about 40 billion cubic feet (Bcf) in 2012 to 850 Bcf in 2040.

Natural gas prices rise with an expected increase in production costs

Figure MT-40. Annual average Henry Hub spot natural gas prices in the Reference case, 1990-2040 (2012 dollars per million Btu)



Average annual U.S. natural gas prices have remained relatively low over the past several years as a result of the availability of abundant domestic resources and the application of improved production technologies. To provide the supplies necessary to meet growth in natural gas consumption and a rise in exports in the AEO2014 Reference case, producers move into areas where the recovery of natural gas is more difficult and expensive, which leads to an increase in Henry Hub spot prices over the projection period. Henry Hub spot prices for natural gas increase by an average of 3.7%/year in the Reference case, from $2.75/million Btu (MMBtu) in 2012 to $7.65/MMBtu (2012 dollars) in 2040 (Figure MT-40).

Growth in demand for natural gas, largely from the electric power and industrial sectors and for liquefied natural gas (LNG) exports, results in upward pressure on prices, particularly in the 2015-18 period. Delivered prices to residential, commercial, industrial, and electric power consumers generally rise with Henry Hub prices in the projection, but the lower 48 average spot price increases at a slightly slower rate than the Henry Hub spot price, because regional production growth in areas that do not serve the Henry Hub is somewhat faster than growth in areas that supply the Henry Hub. In particular, dry gas production in the Marcellus shale play, which predominantly serves the Northeastern and Mid-Atlantic regions, grows from 1.9 Tcf in 2012 to 5.0 Tcf in 2022 in the Reference case, before declining to 4.6 Tcf in 2040. Total onshore production in the Northeast region grows on average by 3.2%/year, from 3.3 Tcf in 2012 to 8.1 Tcf in 2040, while combined onshore and offshore production in the Gulf region grows by 2.1%/year, from 7.3 Tcf in 2012 to 13.0 Tcf in 2040.

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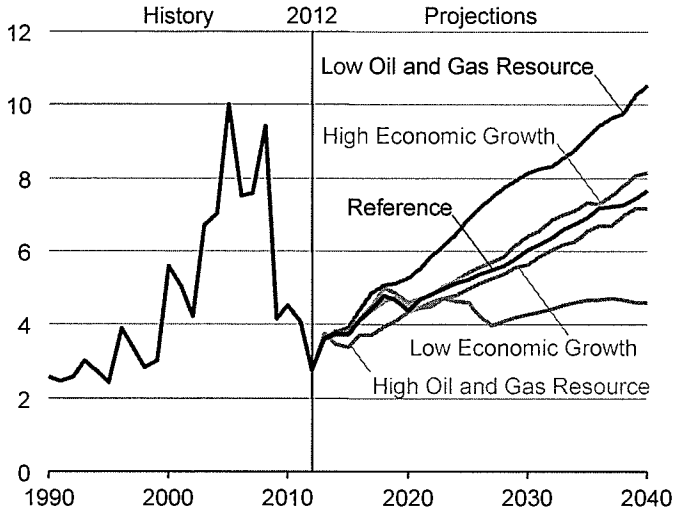
Natural gas prices depend on economic growth and resource recovery rates among other factors

Figure MT-41. Annual average Henry Hub spot prices for natural gas in five cases, 1990-2040 (2012 dollars per million Btu)



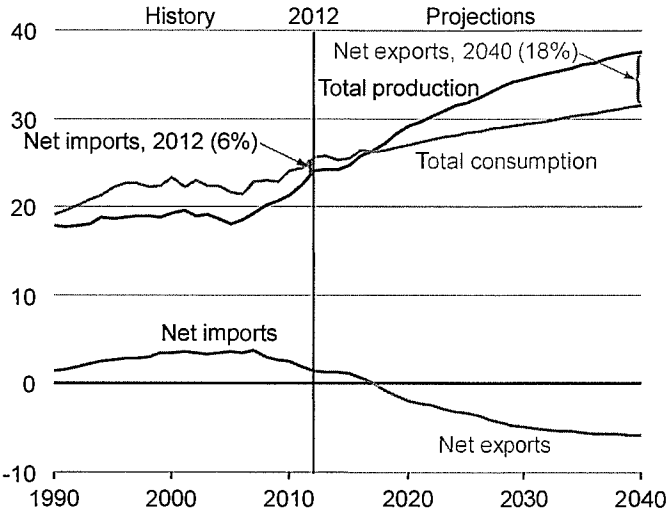
The projection of natural gas prices depends on many factors, including macroeconomic growth rates and expected rates of resource recovery from natural gas wells. Higher rates of economic growth lead to increased consumption of natural gas, primarily in response to their effects on housing starts, commercial floorspace, and industrial output. In the High Economic Growth case, higher levels of consumption result in more rapid increases both in depletion of natural gas resources and in the cost of developing new production, pushing natural gas prices higher. The converse is true in the Low Economic Growth case (Figure MT-41). In the High and Low Economic Growth cases, the price rises by 4.0%/year and 3.5%/year, respectively, compared with 3.7%/year in the Reference case.

The rate of resource recovery from oil and natural gas wells has a direct impact on the cost per unit of production and, in turn, prices. The High Oil and Gas Resource case assumes higher estimates for recoverable crude oil and natural gas resources in tight wells and shale formations and for offshore resources in the lower 48 states and Alaska than in the Reference case. The Low Oil and Gas Resource case assumes lower estimated ultimate recovery of natural gas from each shale well or tight well than in the Reference case. In the Low and High Oil and Gas Resource cases, Henry Hub spot natural gas prices increase by 4.9%/year and 1.8%/year, respectively. (An article in the Issues in focus section, "U.S. tight oil production: Alternative supply projections and an overview of EIA's analysis of well-level data aggregated to the county level," provides more information on the alternative resource cases.)

In both cases, there are mitigating effects that dampen the initial price response from the demand or supply shift. For example, lower natural gas prices lead to increases in natural gas exports and demand, which place some upward pressure on natural gas prices.

With production growing faster than use, the U.S. becomes a net exporter of natural gas

Figure MT-42. Total natural gas production, consumption, and imports in the Reference case, 1990-2040 (trillion cubic feet)



In the AEO2014 Reference case, natural gas production grows by an average rate of 1.6%/year from 2012 to 2040, more than double the 0.8% annual growth rate of total U.S. consumption over the period. The growth in production meets increasing demand and exports (liquefied natural gas [LNG] and pipeline exports), while also making up for a drop in natural gas imports. The United States becomes a net exporter of natural gas before 2020.

The development of shale gas resources spurs growth in natural gas production, with producers seeing higher prices as a result of growing demand, especially from both the industrial and electricity generation sectors. Growing LNG exports also support higher natural gas prices.

The United States transitions from being a net importer of 1.5 Tcf of natural gas in 2012 to a net exporter of 5.8 Tcf in 2040, with 88% of the rise in net exports (6.5 Tcf) occurring by 2030, followed by slower growth through 2040 (Figure MT-42).

Net LNG exports, primarily to Asia, increase by 3.5 Tcf from 2012 to 2030, then remain flat through 2040. Prospects for future LNG exports are uncertain, depending on many factors that are difficult to anticipate. The increase in net LNG exports to Asia through 2030 accounts for 55% of the rise in total net natural gas exports, with the remainder coming from decreased net pipeline imports from Canada and increased net pipeline exports to Mexico. Net pipeline imports from Canada drop from 2.0 Tcf in 2012 to 0.4 Tcf in 2030, mainly as a result of lower imports to the western United States. Imports from Canada increase to 0.7 Tcf in 2040, with higher imports into the northeastern United States. In contrast, net pipeline exports to Mexico grow steadily, from 0.6 Tcf in 2012 to 3.1 Tcf in 2040.

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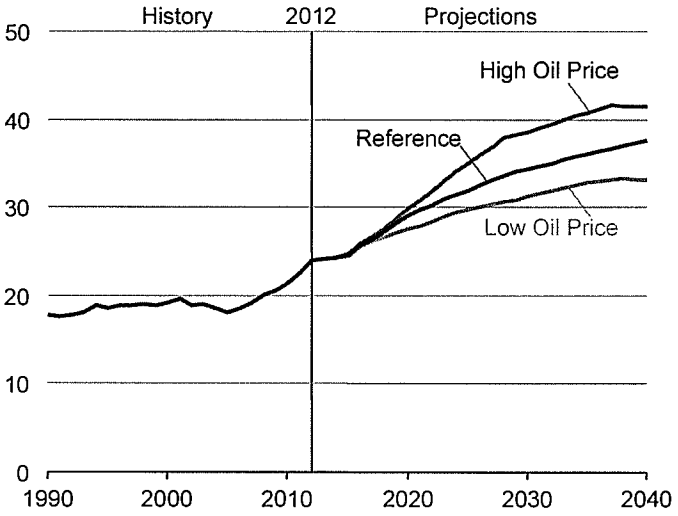
U.S. natural gas production, use, and exports all are affected by oil prices

Figure MT-43. U.S. natural gas production in three cases, 1990-2040 (trillion cubic feet per year)



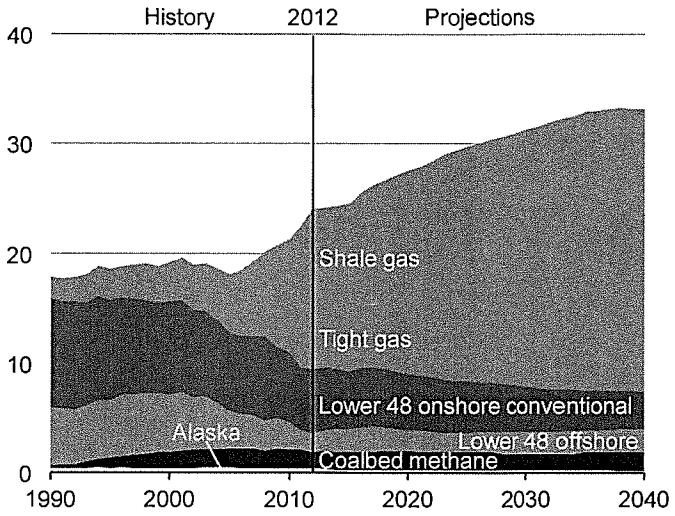
U.S. natural gas production is affected by crude oil prices primarily through changes in natural gas consumption and exports. Across the oil price cases, the largest changes in consumption are seen for natural gas consumed in transportation and natural gas exported as LNG.

The profitability of natural gas as a transportation fuel or as LNG for export depends primarily on the price differential between crude oil and natural gas. For example, in the Low Oil Price case, the average difference between oil prices and natural gas prices from 2012 through 2040 is about $7.70 per million Btu (MMBtu). With that low price differential, virtually no natural gas is consumed in the transportation sector, and little LNG is exported. In the High Oil Price case, in contrast, the average price difference is about $21.90/MMBtu, which provides substantial incentive for direct use of natural gas in transportation and for conversion to LNG for export.

Across the oil price cases, total natural gas production varies by 8.3 Tcf in 2040 (Figure MT-43), with changes in LNG exports accounting for 6.3 Tcf and changes in direct consumption for transportation accounting for 2.2 Tcf. The increase in LNG exports and transportation consumption is offset to some extent by lower natural gas consumption in other sectors, with spot prices for natural gas from 2012 to 2040 averaging about $0.70/MMBtu higher in the High Oil Price case than in the Low Oil Price case.

Shale gas provides the largest source of growth in U.S. natural gas supply

Figure MT-44. U.S. natural gas production by source in the Reference case, 1990-2040 (trillion cubic feet)



The 56% increase in total natural gas production from 2012 to 2040 in the AEO2014 Reference Case results from increased development of shale gas, tight gas, and offshore natural gas resources (Figure MT-44). Shale gas production is the largest contributor, growing by more than 10 Tcf, from 9.7 Tcf in 2012 to 19.8 Tcf in 2040. The shale gas share of total U.S. natural gas production increases from 40% in 2012 to 53% in 2040. Tight gas production and offshore gas production increase by 73% and 78%, respectively, from 2012 to 2040, but their shares of total production remain relatively constant.

From 2017 to 2022, U.S. offshore natural gas production declines by 0.3 Tcf, as offshore exploration and development activities are directed primarily toward oil resources in the Gulf of Mexico. Offshore natural gas production increases after 2022, growing to 2.9 Tcf in 2040, as natural gas prices rise.

Alaska's natural gas production also increases during the projection period, because of Alaska LNG exports to overseas customers, beginning in 2026 and increasing to 0.8 Tcf (2.2 Bcf/d) in 2029. Alaska's LNG exports level off at 0.8 Tcf per year over the last decade of the projec-tion. Alaska's total natural gas production in 2040 is 1.2 Tcf.

Although U.S. natural gas production rises throughout the projection, the mix of sources changes over time. Onshore nonassociated production (from sources other than tight gas, shale gas, and coalbed methane) declines from 3.9 Tcf in 2012 to 1.6 Tcf in 2040, and in 2040 it accounts for only about 4% of total domestic production, down from 16% in 2012.

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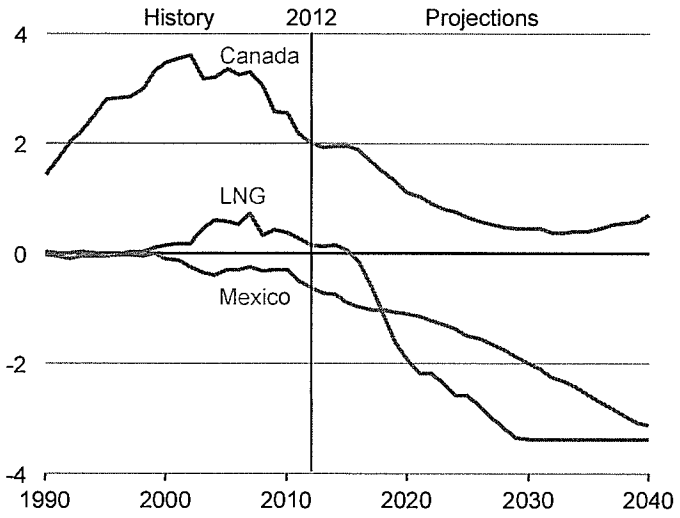
U.S. exports to North American and overseas gas markets increase as gas production rises

Figure MT-45. U.S. net imports of natural gas by source in the Reference case, 1990-2040 (trillion cubic feet)



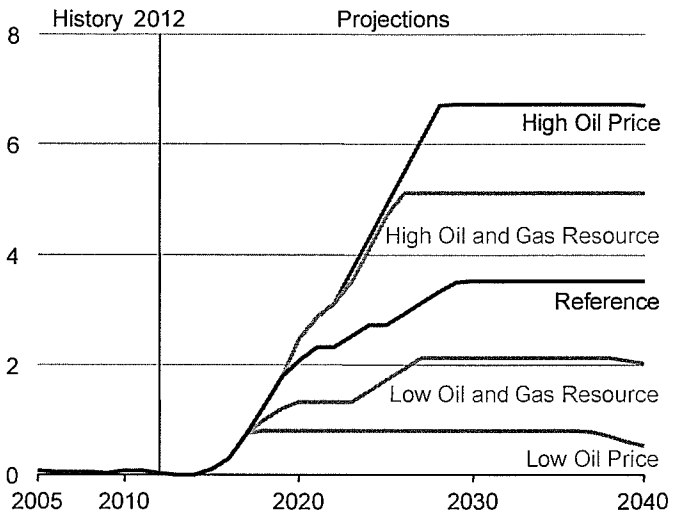
With relatively low natural gas prices in the AEO2014 Reference case, the United States becomes a net exporter of natural gas in 2018, with net exports growing to 5.8 Tcf in 2040. Most of the projected growth in exports consists of LNG exported to overseas markets. From 2012 to 2040, U.S. net exports of LNG increase by 3.5 Tcf (Figure MT-45), including 0.8 Tcf of LNG originating in south-central Alaska, with the remaining volumes originating from export terminals located along the Atlantic and Gulf coasts. In general, future U.S. LNG exports depend on a number of factors that are difficult to anticipate, including the speed and extent of price convergence in global natural gas markets, the extent to which natural gas competes with oil in U.S. and international gas markets, and the pace of natural gas supply growth outside the United States.

The next-largest growth market for U.S. natural gas exports is pipeline exports to Mexico, which increase from 0.6 Tcf in 2012 to 3.1 Tcf in 2040. The increase in exports to Mexico reflects a growing gap between Mexico's natural gas consumption and production. However, Mexico's recently enacted legislation to restructure its oil and gas industry could reduce the need for U.S. natural gas exports to Mexico in the future.

Net natural gas imports from Canada decline through 2033, when they reach a low point of about 0.4 Tcf. After 2033, higher natural gas prices in the lower 48 improve the economics of Canadian natural gas exports to the U.S. West Coast. In 2040, net U.S. imports of natural gas from Canada total about 0.7 Tcf.

LNG export growth depends on price and productivity assumptions

Figure MT-46. U.S. exports of liquefied natural gas in five cases, 2005-40 (trillion cubic feet)



In the AEO2014 Reference case, growing natural gas production from shale gas and tight oil formations supports an increase in U.S. exports of LNG and pipeline gas. Net exports of LNG increase by 3.5 Tcf from 2012 to 2040, representing 48% of the total increase in U.S. natural gas net exports over the period. The United States becomes a net LNG exporter in 2016, with gross exports reaching their peak level of 3.5 Tcf in 2030.

The United States is a net LNG exporter in all of the AEO2014 oil price and resource cases; however, LNG export levels vary significantly by case. In the High Oil Price case, where both global LNG demand and LNG prices are higher than in the Reference case, LNG exports increase to 6.7 Tcf in 2028 and remain at that level through 2040 (Figure MT-46). Conversely, in the Low Oil Price case, gross LNG exports increase to only 0.8 Tcf in 2018, where they remain through most of the projection period. The LNG export projections in AEO2014 are based on a generalized economic evaluation and do not reflect a specific evaluation or knowledge of decisions on pending LNG export applications.

In the High Oil and Gas Resource case, large production increases put downward pressure on U.S. natural gas prices, and as a result LNG exports climb to 5.1 Tcf after 2025. The Low Oil and Gas Resource case assumes lower natural gas production and higher domestic gas prices. Gross LNG exports in the Low Oil and Gas Resource case reach 2.1 Tcf by 2027.

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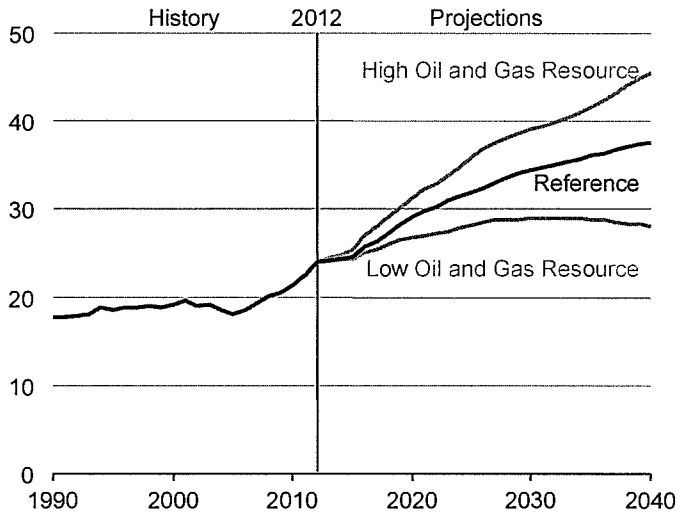
U.S. natural gas production rates depend on resource availability and production costs

Figure MT-47. U.S. natural gas production in three cases, 1990-2040 (trillion cubic feet per year)



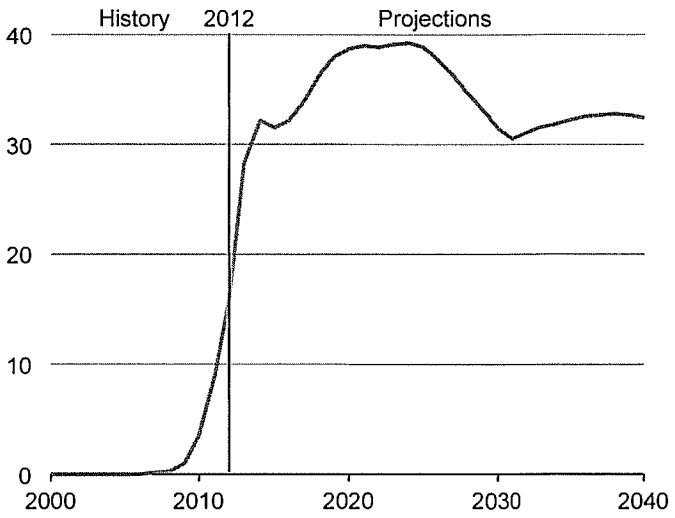
Prospects for production from tight oil and shale gas resources are uncertain, both because large portions of the formations have little or no production history, and because future technology could increase well productivity while reducing costs. The Low Oil and Gas Resource and High Oil and Gas Resource cases illustrate the potential impacts of changes in the Reference case assumptions regarding technology advances and the resource size and quality.

The High Oil and Gas Resource case assumes (1) higher estimates of onshore lower 48 tight oil, tight gas, and shale gas resources than in the Reference case, as a result of higher estimated ultimate recovery (EUR) per well and closer well spacing; (2) tight oil development in Alaska; (3) higher estimates of offshore resources in Alaska and the lower 48 states; and (4) higher rates of long-term technology improvement. In the High Resource case, higher well productivity reduces development and production costs per unit, resulting in more and earlier resource development than in the Reference case. With the greater abundance of less-expensive shale gas resources, cumulative shale gas production from 2012 through 2040 totals 540 Tcf, as compared with 442 Tcf in the Reference case. In the Reference case and the High Resource case, total natural gas production in 2040 grows to 37.5 Tcf and 45.5 Tcf per year, respectively.

In the Low Oil and Gas Resource case, which assumes lower tight oil, tight gas, and shale gas resources than in the Reference case, total natural gas production plateaus at just under 29 Tcf per year from 2027 through 2036, then declines to 28.1 Tcf in 2040 (Figure MT-47). Shale gas production peaks in 2030 at 13.1 Tcf and declines to 11.6 Tcf in 2040. From 2012 to 2040, cumulative shale gas production totals 341 Tcf in the Low Oil and Gas Resource case.

Marcellus shale gas production growth changes U.S. natural gas transportation patterns

Figure MT-48. Marcellus shale production share of total U.S. natural gas consumption east of the Mississippi River in the Reference case, 2000-40 (percent)



Historically, natural gas produced in Texas, Louisiana, Oklahoma, and the offshore Gulf of Mexico has been transported to markets east of the Mississippi River. In addition, significant volumes of natural gas have been transported from Canada and the Rocky Mountains to serve the same markets. However, the advent of large-scale natural gas production in the Marcellus shale formation, located in Appalachia, will alter natural gas transportation patterns east of the Mississippi River.

In the AEO2014 Reference Case, natural gas production from the Marcellus shale grows from 1.9 Tcf in 2012 to a peak production volume of about 5.0 Tcf per year from 2022 through 2025. Marcellus shale gas production could provide up to 39% of the natural gas needed to meet demand in markets east of the Mississippi River during that period—up from 16% in 2012. Although Marcellus gas production declines after 2024 in the Reference case, it still provides enough natural gas to meet at least 31% of the region's total demand for natural gas through 2040 (Figure MT-48).

Marcellus natural gas exceeds 100% of the demand projected for the New England and Mid-Atlantic Census Divisions from 2016 through 2040 in the Reference case, requiring transportation of some Marcellus gas to other markets. During the expected peak production period for the Marcellus shale, from 2022 through 2025, its total production exceeds natural gas consumption in the New England and Middle Atlantic regions by more than 1.0 Tcf over the period.

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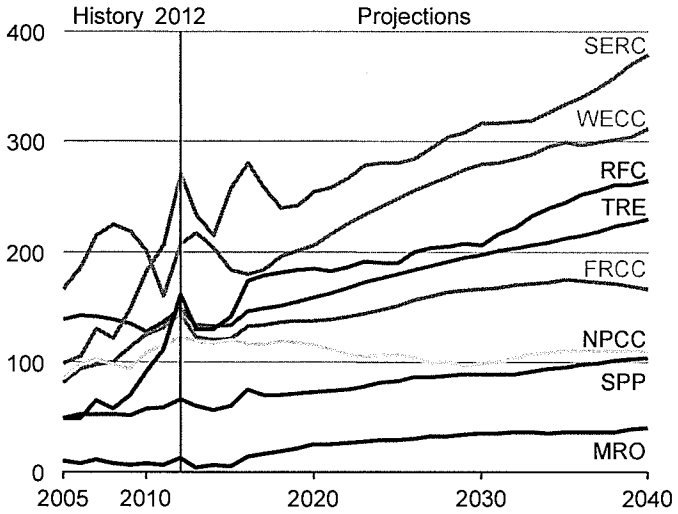
Natural gas-fired generation grows strongly in the electric power sector

Figure MT-49. Natural gas-fired generation in the electric power sector by NERC region in the Reference case, 2005-40 (billion kilowatthours)



Consumption of natural gas by the U.S. electric power sector grows by an average of 0.7%/year from 2012 to 2040 in the AEO2014 Reference case. That growth is equivalent to 42% of the total increase in electricity generation over the period. While the coal-fired share of total generation in the electric power sector declines from 39% in 2012 to 34% in 2040, the natural gas share rises from 29% to 33%.

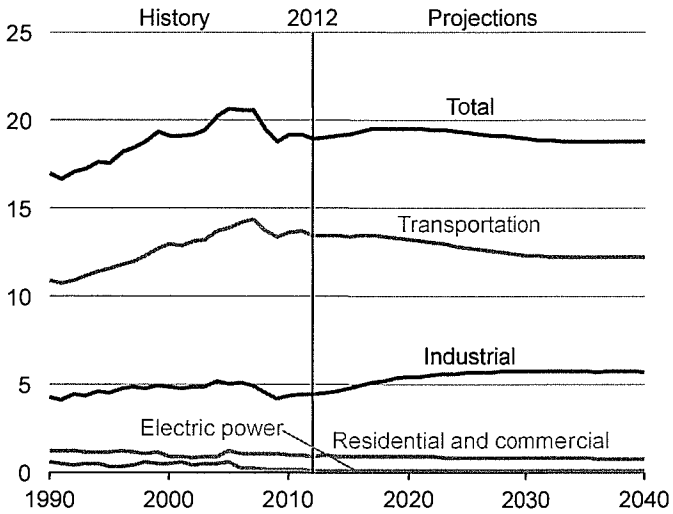
The increase in natural gas-fired generation is generally more pronounced in regions where coal-fired power plants are retired, including the SERC Reliability Corporation (SERC) and ReliabilityFirst Corporation (RFC) regions (Figure MT-49). The retirement of coal-fired capacity in the SERC region from 2012 to 2040, at 12.9 GW, is the country's second largest, and its increase in natural gas-fired generation over the same period, at 109 million MWh, is the largest. The largest decrease in coal-fired capacity (21.7 GW) is in the RFC region, which also has the third-largest increase in natural gas-fired generation, at 103 million MWh.

Two other regions with large increases in natural gas-fired generation in the Reference case are the Western Electricity Coordinating Council (WECC) and the Texas Reliability Entity (TRE). Those two regions do not have large retirements of coal-fired generation capacity, but they do have significant overall growth in electricity demand, most of which is met with natural gas-fired generation. WECC has the country's second-largest increase in natural gas-fired generation from 2012 to 2040 (105 million MWh), and TRE has the fourth-largest increase (81 million MWh).

In the RFC and TRE regions, natural gas-fired generation meets the vast majority of growth in electricity demand through 2040. Despite retirements of coal units, coal generation still meets a significant portion of demand in the SERC region. In the WECC region, renewables meet a significant portion of demand growth.

Led by transportation, petroleum and other liquids consumption declines

Figure MT-50. Consumption of petroleum and other liquids by sector in the Reference case, 1990-2040 (million barrels per day)



Consumption of petroleum and other liquids remains relatively flat in volumetric terms in the AEO2014 Reference case (Figure MT-50). While the transportation sector accounts for the largest share of total consumption throughout the projection, its share falls from 72% in 2013 to 65% in 2040, as a result of improvements in vehicle efficiency following the incorporation of corporate average fuel economy (CAFE) standards for both light-duty vehicles (LDVs) and heavy-duty vehicles (HDVs). In the industrial sector, consumption in the chemicals industry increases by 1.3 million barrels per day (MMbbl/d) from 2012 to 2040, largely reflecting higher volumes of hydrocarbon gas liquids as the sector benefits from increased U.S. production of natural gas. Consumption in all other industry segments decreases between 2012 and 2040.

Motor gasoline, ultra-low-sulfur diesel fuel, and jet fuel are the primary transportation fuels, all of which can include biofuels and may be supplemented by natural gas. Total motor gasoline consumption increases from 2012 to 2015 before dropping by approximately 2.1 MMbbl/d from 2015 to 2040 in the Reference case, while total diesel fuel consumption increases from 3.4 MMbbl/d in 2012 to 4.3 MMbbl/d in 2040, primarily for use in HDVs.

Both ethanol blending into gasoline and E85 consumption are essentially flat throughout the projection period, as a result of declining gasoline consumption and limited penetration of FFVs. The rapid rise of U.S. crude oil production, combined with the decline in motor gasoline demand and a modest increase in diesel fuel demand, reduces market opportunities for CTL and GTL technologies.

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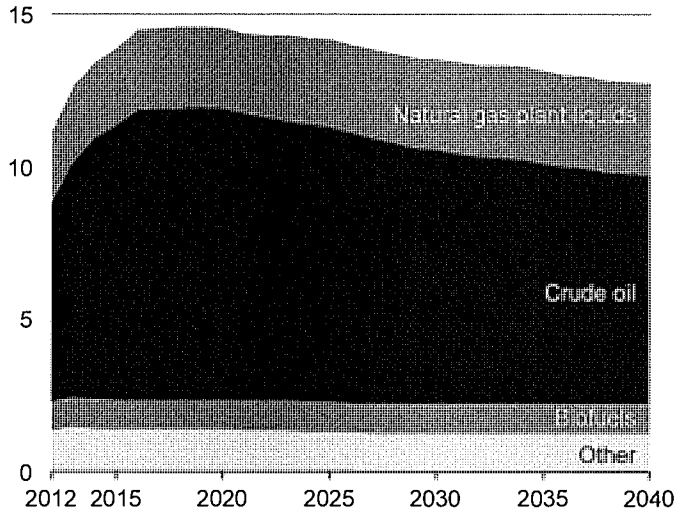
Crude oil leads initial growth in liquids supply, next-generation liquids grow slowly after 2020

Figure MT-51. U.S. production of petroleum and other liquids by source in the Reference case, 2012-40 (million barrels per day)



In the AEO2014 Reference case, petroleum and other liquids supply grows through 2019 as a result of increases in production of tight oil (including condensates) and natural gas plant liquids (NGPL) (Figure MT-51). Total liquids production grows from 11.1 MMbbl/d in 2012 to a peak of 14.6 MMbbl/d in 2019, then drops to 12.7 MMbbl/d in 2040—still above 2012 levels—as tight oil production declines.

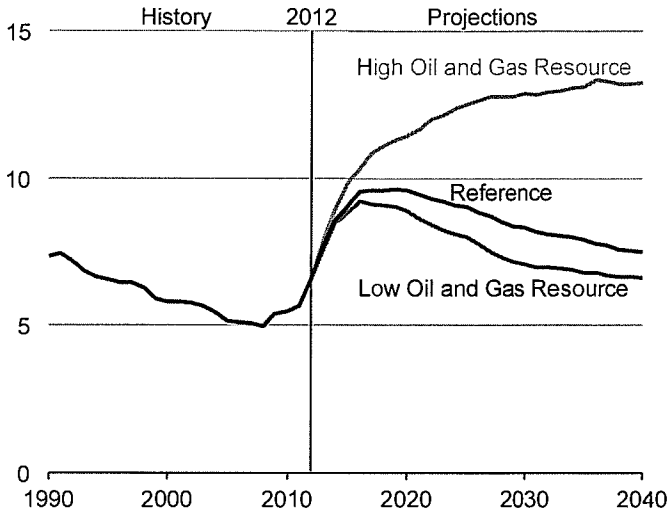
Production of hydrocarbon gas liquids (HGL) [12] increases throughout the projection. HGL is a new term introduced in the analysis to account for NGPL produced from natural gas processing plants and fractionators, and the liquefied refinery gases from crude oil in refineries. NGPL production increases from 2.4 MMbbl/d in 2012 to about 3.0 MMbbl/d in 2030, then remains level after 2030, as growth in natural gas production slows.

Domestic ethanol production remains relatively flat, as consumption of motor gasoline decreases and the penetration of ethanol is slowed by the limited availability of flex-fuel vehicles and retrofitted filling stations. Biodiesel production is also constant throughout the projection on the assumption that the U.S. Environmental Protection Agency (EPA) will indefinitely continue the current requirement of 1.28 billion gallons per year under the RFS.

Other biomass-to-liquids production, excluding ethanol and biodiesel, increases by 32,200 bbl/d from 2012 to 2040. However, neither gas-to-liquids (GTL) nor coal-to-liquids (CTL) contributes to domestic liquids production in the Reference case because of the risks associated with their high capital costs, long construction leadtimes, and the possibility that liquids from CTL facilities will not remain price-competitive with crude oil over the lifetimes of the facilities.

U.S. crude oil production rates depend on resource availability and production costs

Figure MT-52. Total U.S. crude oil production in three cases, 1990-2040 (million barrels per day)



Projections of U.S. tight oil production are uncertain, because large portions of the known formations have little or no production history, and because technology improvements could increase well productivity while reducing drilling, completion, and production costs. The High and Low Oil and Gas Resource cases illustrate the potential impacts of changes in the Reference case assumptions regarding technology advances and the resource size and quality.

The High Oil and Gas Resource case assumes more onshore lower 48 tight resources than in the Reference case, as a result of higher EUR per well and closer well spacing; tight oil development in Alaska; more offshore resources in Alaska and the lower 48 states; and more rapid technology improvements over the long term.

In the High Oil and Gas Resource case, higher well productivity reduces development and production costs per unit, resulting in more and earlier development of oil and gas resources than in the Reference case (Figure MT-52). U.S. crude oil production in the High Oil and Gas Resource case reaches 13.3 MMbbl/d in 2036, compared with an earlier and lower projected high point of 9.6 MMbbl/d in 2019 in the Reference case. Cumulative production in the High Oil and Gas Resource case is about 125 billion barrels—compared to about 90 billion barrels in the Reference case—from 2012 to 2040.

In the Low Oil and Gas Resource case, which assumes lower estimates of tight resources than in the Reference case, crude oil production plateaus at an earlier and lower projected high of 9.2 MMbbl/d in 2016 before declining. With production of tight oil continuing to decline through 2040 in the Low Oil and Gas Resource case, cumulative crude oil production from 2012 to 2040 is 10% lower than in the Reference case, at about 81 billion barrels.

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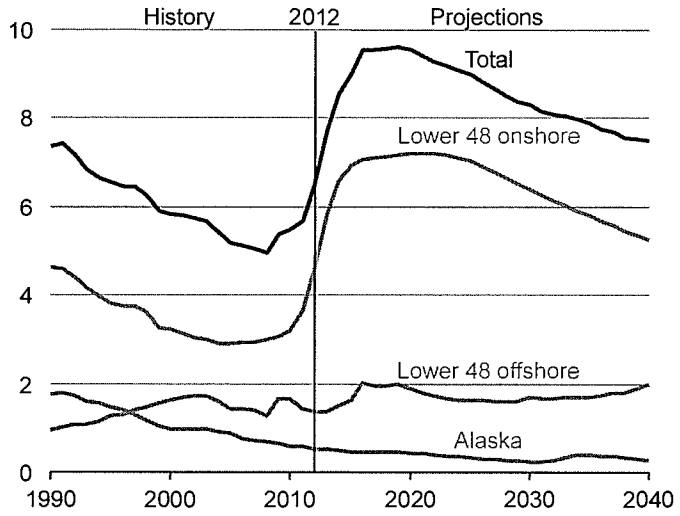
Lower 48 onshore tight oil development spurs increase in U.S. crude oil production

Figure MT-53. Domestic crude oil production by source in the Reference case, 1990-2040 (million barrels per day)



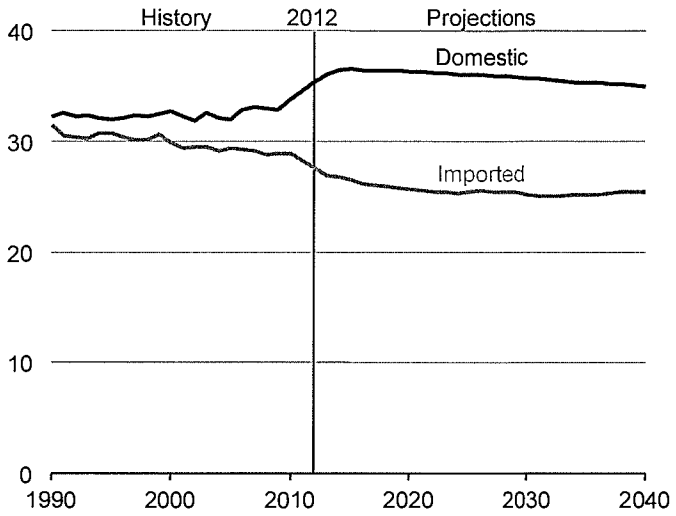
U.S. crude oil production grows from 2012 through 2019 in the Reference case, before peaking at more than 9.6 million barrels per day (MMbbl/d)—about 3.1 MMbbl/d above the 2012 total and close to the historical high of 9.6 MMbbl/d in 1970 (Figure MT-53). The growth in lower 48 onshore crude oil production is primarily a result of continued development of tight oil resources in the Bakken, Eagle Ford, and Permian Basin formations. Tight oil production increases to a peak of 4.8 MMbbl/d from 2018 through 2021 and then declines to about 3.2 MMbbl/d in 2040 (0.9 MMbbl/d higher than the 2012 total) as high-productivity areas, or sweet spots, are depleted. There is considerable uncertainty about the expected peak level of tight oil production, because ongoing exploration, appraisal, and development programs expand operator knowledge about producing reservoirs and could result in the identification of additional tight oil resources.

Crude oil production using carbon dioxide-enhanced oil recovery (CO_2-EOR) increases after 2017—when oil prices rise, and as output from the more profitable tight oil deposits begins declining and affordable anthropogenic sources of carbon dioxide (CO_2) become available—to 0.7 MMbbl/d in 2040. The rate of the increase is slower over the last five years, when production is limited by reservoir quality and CO_2 availability. From 2013 through 2040, cumulative crude oil production from CO_2-EOR projects totals 5.2 billion barrels.

Lower 48 offshore oil production varies between 1.4 MMbbl/d and 2.0 MMbbl/d over the projection period. Toward the end of the period, the pace of exploration and production activity quickens, and new large development projects, associated predominantly with discoveries in the deepwater and ultra-deepwater portions of the Gulf of Mexico, are brought on stream. New offshore oil production from the Alaska North Slope partially offsets the decline in production from onshore North Slope fields.

Domestic production of tight oil leads to lower imports of light sweet crude oil

Figure MT-54. Average API gravity of U.S. domestic and imported crude oil supplies in the Reference case, 1990-2040 (degrees API)



API gravity is a measure of the specific gravity, or relative density, of a liquid, as defined by the American Petroleum Institute. It is expressed in degrees, where a higher number indicates a lower density. Refineries generally process a mix of crude oils with a range of API gravities to optimize refinery operations. Over the past 15 years, the API gravity of crude oil processed in U.S. refineries has averaged between 30 and 32 degrees. As U.S. refiners run more domestic light crude oil produced from tight formations, they need less imported light crude to maintain an optimal API gravity. With increasing U.S. production of light crude oil in the AEO2014 Reference case, the average API gravity of crude oil imports declines from 27.6 degrees in 2012 to 25.6 degrees in 2040 (Figure MT-54).

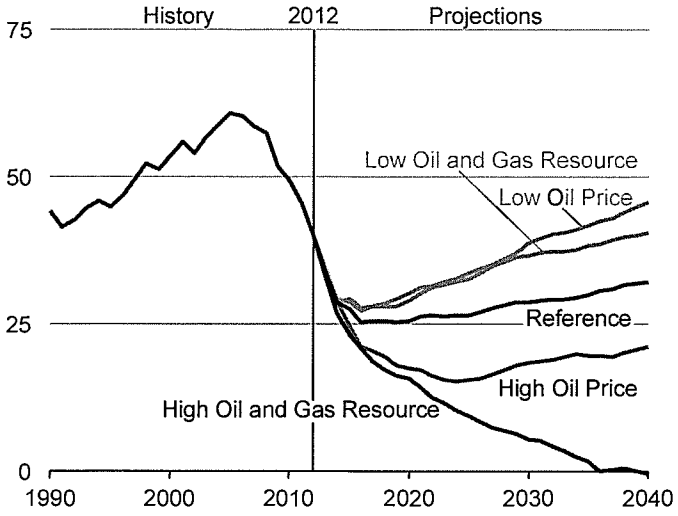
With total crude oil imports declining in the Reference case, imports of light crude oil are reduced, resulting in a heavier slate of imported crude oil. The growing share of heavier crude oil imports continues through 2025 before stabilizing. The increase in demand for diesel fuel in the Reference case, from 3.4 MMbbl/d in 2012 to 4.3 MMbbl/d in 2040, combined with a steady increase in exports of distillate fuel oil from 1.0 MMbbl/d to 1.1 MMbbl/d over the same period, increases the value of heavier crudes in U.S. refineries.

The large increase in domestic production of light crude oil and the increase in imports of heavier crude oils have prompted significant investments in the midstream infrastructure for crude oil, including pipelines that will bring higher quantities of light sweet and heavy sour crudes to petroleum refineries along the U.S. Gulf Coast. In addition, significant investments have been made to move crude oil by rail to refineries on the East Coast, West Coast, and Gulf Coast.

012757

Increasing U.S. oil supply reduces net imports of petroleum and other liquid fuels

Figure MT-55. Net import share of U.S. petroleum and other liquid fuels consumption in five cases, 1990-2040 (percent)



The net crude oil and product imports share of U.S. petroleum and other liquid fuels consumption grew from the mid-1980s to 2005 but has fallen steadily since 2005 (Figure MT-55). Because each barrel of U.S. crude oil production displaces a barrel of imported crude oil, the outlook for net petroleum and other liquid fuel imports in the High and Low Oil Price and High and Low Oil and Gas Resource cases depends on U.S. oil production.

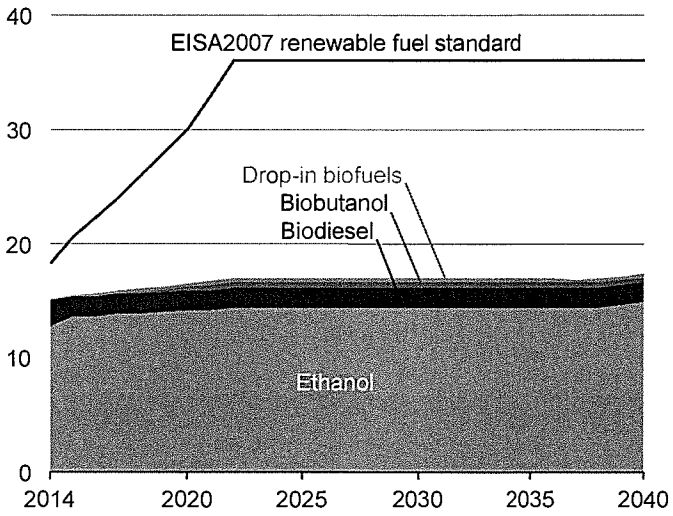
The net import share of U.S. petroleum and other liquid fuels consumption declines from 2012 through 2023 in the AEO2014 Reference case, largely because of projected growth in tight oil production. The net import share declines to 25% in 2019, coinciding with a peak in U.S. oil production of 9.6 MMbbl/d, then increases to 32% in 2040 after domestic oil production declines.

Higher oil prices encourage more rapid and extensive oil resource development. In the High Oil Price case, the share of domestic consumption accounted for by imports of petroleum and liquid fuels drops to 15% in 2023, then grows to 21% in 2040. The opposite occurs in the Low Oil Price case, with the petroleum and other liquids imports share of domestic consumption rising after 2016, to 46% in 2040.

In the High Oil and Gas Resource case, improvements in oil production technology beyond those in the Reference case, along with 1% annual growth in estimated ultimate recovery (EUR), lead to higher U.S. crude oil production. In 2036, U.S. crude production peaks at 13.3 MMbbl/d, and net U.S. imports of crude oil and petroleum products fall to virtually zero, where they remain through 2040. The Low Oil and Gas Resource case uses the same production technology assumptions as the Reference case but assumes a 50% lower EUR. As in the Low Price case, net imports begin to rise in 2016 and increase to 40% of U.S. consumption in 2040.

U.S. consumption of biofuels grows but does not approach EISA2007 applicable volumes

Figure MT-56. EISA2007 Renewable Fuels Standard credits earned by fuel type in the Reference case, 2012-40 (billion credits)



Consumption of biofuels grows in the AEO2014 Reference case but falls well short of the Energy Independence and Security Act of 2007 (EISA2007) RFS target [*13*] of 36 billion ethanol gallon equivalents in 2022 (Figure MT-56), largely because of a decline in gasoline consumption as a result of newly enacted corporate average fuel economy (CAFE) standards and updated expectations for sales of vehicles capable of using E85. Demand for motor gasoline ethanol blends (E10 and E15) falls from 8.7 MMbbl/d in 2012 to 7.9 MMbbl/d in 2022, while total biofuels consumption rises from 14 billion gallons to 16 billion ethanol gallons equivalent over the same period.

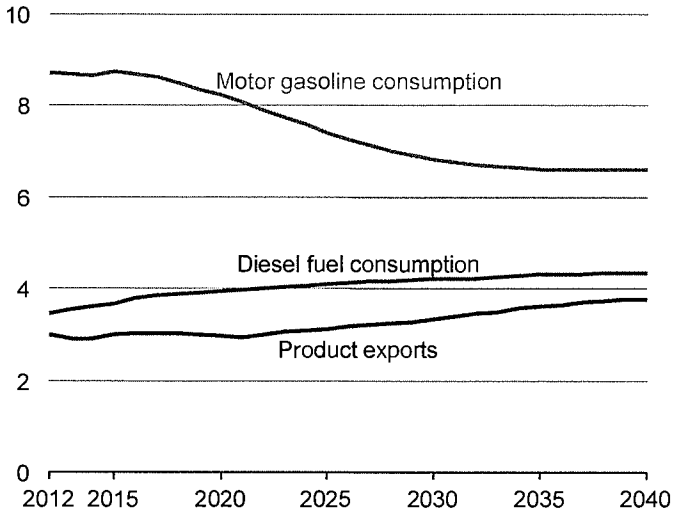
The current and projected vehicle fleets are not equipped to use ethanol's increased octane content relative to gasoline. As a result, the retail price of E85 must be less than 79% of the motor gasoline price for E85 to gain significant market share. In the Reference case, with the lowest ratio of E85 to gasoline prices at 77% in 2022, market penetration of E85 is modest, and the RFS program does not provide sufficient incentives to promote significant new ethanol production capacity.

In the Reference case, as gasoline demand continues to drop and E85 consumption levels off, total ethanol consumption grows to about 14 billion gallons in 2022 and remains there until late in the projection. Consumption of biodiesel falls in the near term, as production of drop-in biofuels grows. Domestic consumption of drop-in biofuels grows from 135 million ethanol gallons equivalent in 2014 to 316 million ethanol gallons equivalent in 2019. Biobutanol consumption rises after 2019, to about 516 million gallons in 2040.

012758

A variety of factors leads to a shift in consumption from motor gasoline to diesel fuel

Figure MT-57. Motor gasoline consumption, diesel fuel consumption, and petroleum product exports in the Reference case, 2012-40 (million barrels per day)



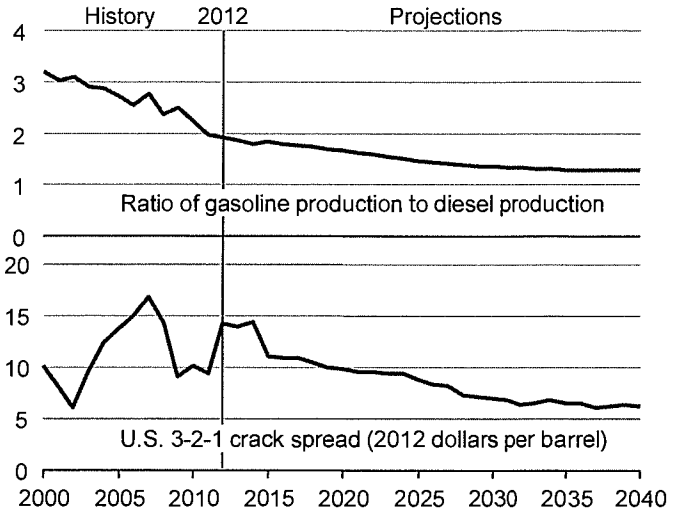
Based on the NHTSA and EPA GHG and CAFE standards, EIA projects that new light-duty vehicles (LDVs) will average approximately 47 mpg in 2025. These efficiency standards contribute to a decline in consumption of motor gasoline, while increases in vehicle miles traveled (VMT) and renewable fuel standards (RFS) lead to an increase in consumption of diesel fuel and ethanol in the Reference case. As a result of rising fuel economy standards, motor gasoline consumption by LDVs falls over the projection period while total VMT increase.

The decrease in gasoline consumption, combined with growth in diesel consumption, leads to a shift in refinery outputs and investments. Motor gasoline consumption and diesel fuel consumption trend in opposite directions in the Reference case, with consumption of diesel fuel increasing by approximately 0.9 MMbbl/d from 2012 to 2040, while finished motor gasoline consumption falls by 2.1 MMbbl/d (Figure MT-57). New refinery projects are expected to focus on shifting production from gasoline to distillate fuels to meet the growing demand for diesel.

As a result of refinery economics and slower growth in domestic demand, no new petroleum refinery crude unit capacity is built in the Reference case, except for plants already under construction in 2012. Further, the refining system has at least 2 MMbbl/d of excess crude oil capacity beginning in 2015. In addition to meeting domestic demand, refineries continue to export finished products to international markets throughout the projection. Beginning in 2016, gross exports of total finished petroleum products increase to 3.0 MMbbl/d for the first time, and in 2040 exceed 3.7 MMbbl/d (Figure MT-57). The United States became a net exporter of finished petroleum products in 2011, and in the Reference case, it remains a net exporter through 2040.

Shifts in demand for liquid fuels change petroleum refinery yields and crack spreads

Figure MT-58. U.S. refinery gasoline-to-diesel production ratio and crack spread in the Reference case, 2000-40



The transition to lower gasoline and higher diesel production has a significant effect on petroleum refinery operations in the AEO2014 Reference case, with the ratio of gasoline to diesel production declining from 1.8 in 2012 to below 1.3 in 2040 (Figure MT-58). In response to the drop in gasoline demand, refinery utilization of fluid catalytic cracking (FCC) units falls from 67% in 2012 to about 55% in 2040. In contrast, with diesel production increasing, installed distillate and gas oil hydrocracking capacity grows from about 2.2 MMbbl/d in 2012 to 2.9 MMbbl/d in 2040, indicating a shift from FCC feeds to hydrocrackers to maximize diesel production.

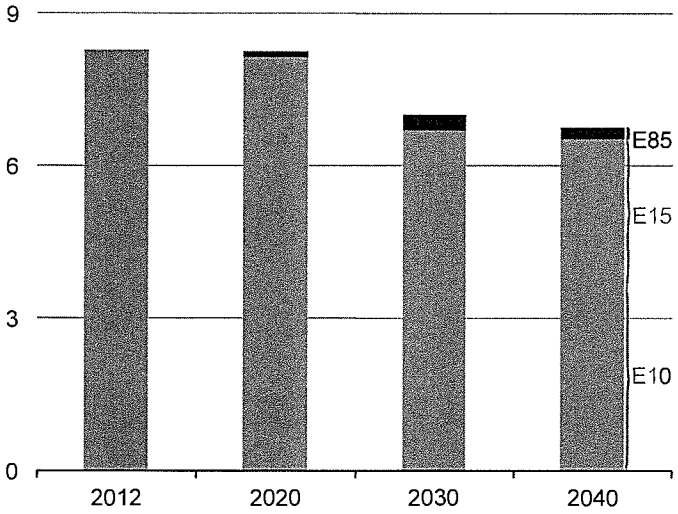
Refinery profitability is a function of crude input costs, processing costs, and market prices for the end products. Profitability often is estimated from the crack spread, which is the difference between the price of crude oil and the price of finished products—typically, gasoline and distillate fuel. The 3-2-1 crack spread estimates the profitability of processing three barrels of crude oil to produce two barrels of gasoline and one barrel of distillate. In the Reference case, the 3-2-1 crack spread (based on Brent crude oil prices) declines from $14/barrel in 2012 to about $6/barrel in 2040 (2012 dollars). In the current environment, the gross margin would vary with the differential between Brent and Gulf Coast light crude oil prices.

To relate the gross margin to refinery profitability, operating costs for specific refineries also must be deducted. As product demands shift, petroleum refineries may alter the ratio of gasoline to diesel production. A 5-3-2 crack spread estimates the profitability of processing five barrels of crude oil into three barrels of gasoline and two barrels of distillate, more consistent with the 1.3 gasoline-to-diesel production ratio after 2035.

012759

Consumption of biofuels blended into motor gasoline increases in response to RFS targets

Figure MT-59. Consumption of biofuels in motor gasoline blends in the Reference case, 2012-40 (million barrels per day)



In the AEO2014 Reference case, consumption of E15 motor gasoline (15% ethanol, 85% gasoline) and E85 motor gasoline (average 74% ethanol, 26% gasoline) increases at the expense of E10 motor gasoline (10% ethanol, 90% gasoline) (Figure MT-59). The shift depends on the level of RFS targets, infrastructure issues, the relative costs of E15 and biobutanol blends compared to E10 and E85, and the general market acceptability of manufacturers' automobile warranties.

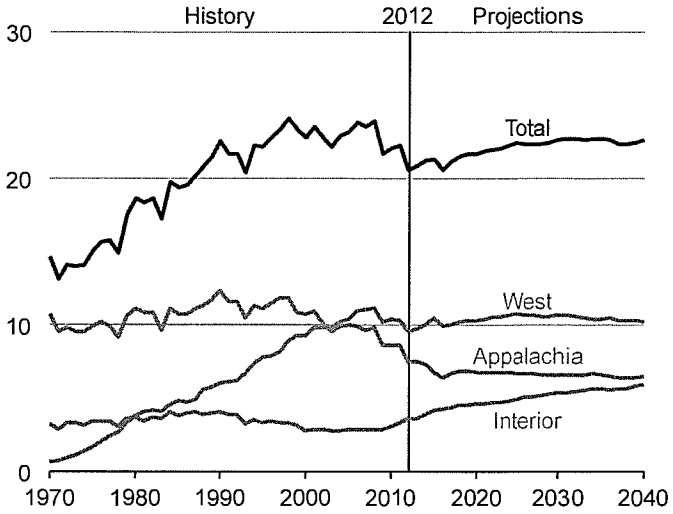
In response to RFS renewable fuel targets and market conditions, consumption of E15 increases in the Reference case, both in absolute terms and relative to E10 consumption. The growth of E15 consumption also displaces potential consumption of biobutanol blends, such as Bu16 (16% biobutanol, 84% gasoline).

Starting in about 2020, E15 slowly penetrates the motor gasoline market, as blend wall issues are assumed to be resolved over time [14]. In 2040, E15 makes up approximately 40% of the total motor gasoline market. Consumption of biobutanol-blended gasoline remains low, as it competes with E15 for market share. Although E85 is used in the motor gasoline market throughout the projection, its share of the market declines after 2032, when most cars are capable of using E15.

The increase in consumption of E15 in the Reference case is based on the assumption that consumers, refiners, and vehicle manufacturers will prefer E15 over E85 and biobutanol blends, and that infrastructure constraints will be resolved gradually over time. In addition to the biofuels blended into motor gasoline shown in Figure MT-59, the RFS also promotes consumption of other biofuels—such as biodiesel, renewable diesel, and renewable gasoline—that are not blended in fixed percentages with petroleum-based motor gasoline.

Coal production growth limited by competitive fuel prices and little new coal-fired capacity

Figure MT-60. Coal production by region in the Reference case, 1970-2040 (quadrillion Btu)



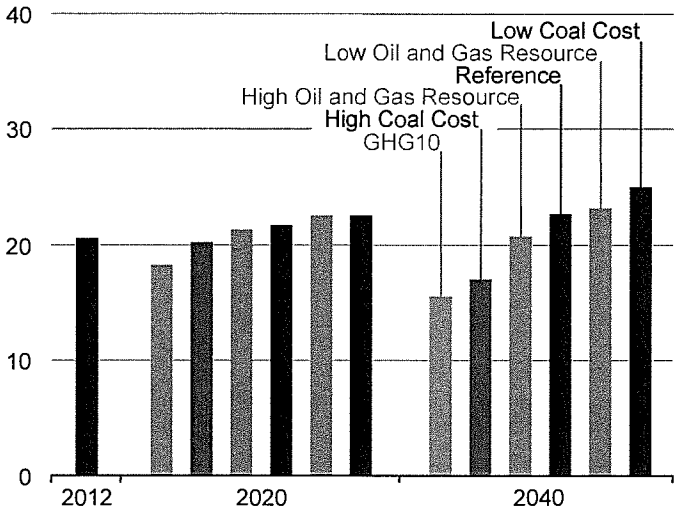
Coal production in 2012 was more than 7% below the 2011 total (Figure MT-60), mostly as a result of gas-on-coal competition. In the AEO2014 Reference case, coal production recovers briefly as natural gas prices rise before dropping to 2012 levels in 2016, as the need for electricity generators to comply with Mercury and Air Toxic Standards (MATS) leads to a wave of coal-fired capacity retirements. From 2016 to 2030, coal production increases gradually as growing electricity demand and rising natural gas prices spur the use of coal for power generation. After 2030, when existing coal units reach maximum utilization rates and virtually no new capacity is built, coal production stabilizes. Coal exports, which totaled 3.2 quadrillion Btu in 2012, remain at that level through 2020 and then increase to 3.8 quadrillion Btu in 2040. Overall, U.S. coal production grows by an average of 0.3%/year in the Reference case, from 20.6 quadrillion Btu in 2012 to 22.6 quadrillion Btu in 2040.

On a regional basis, strong production growth in the Interior region contrasts with generally stagnant production in Appalachia and the West. Interior coal production reaches new highs as scrubbers installed at existing coal-fired generating units allow them to burn the region's higher-sulfur coals with lower delivered costs. Western production grew steadily for decades but fell by 14% from 2008 to 2012 as a result of the recession and competition from natural gas. Western production increases slightly in the Reference case, tempered by slow growth in coal use for electricity generation and by competition from coal producers in the Interior region. Appalachian coal production declines by 14% from 2012 to 2016, as coal produced from the extensively mined, higher-cost reserves of Central Appalachia is supplanted by lower-cost coal from other regions.

012760

Outlook for U.S. coal production is affected by fuel price uncertainties

Figure MT-61. U.S. total coal production in six cases, 2012, 2020, and 2040 (quadrillion Btu)

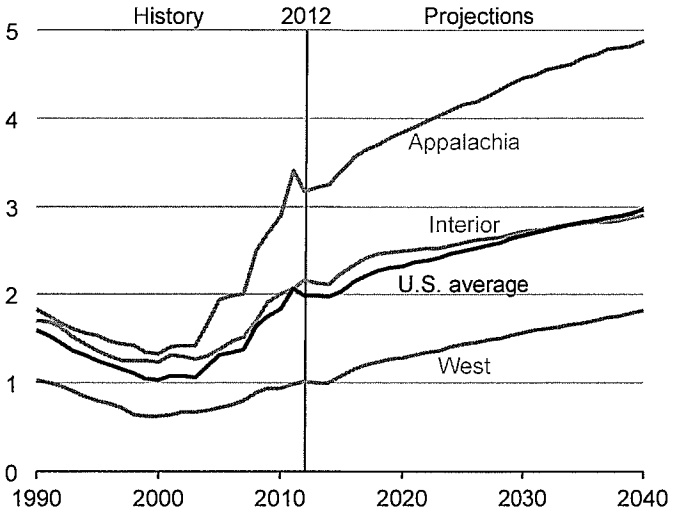


U.S. coal production varies across the AEO2014 cases, reflecting different assumptions about coal production and transportation costs, natural gas prices, and actions to limit greenhouse gas (GHG) emissions (Figure MT-61). In general, assumptions that reduce the competitiveness of coal versus natural gas lead to lower coal production. For example, relative to the Reference case, coal production is lower in both the High Coal Cost case (higher costs for coal mining and transportation) and the High Oil and Gas Resource case (lower costs for natural gas production). Similarly, actions to cut GHG emissions would also reduce the competiveness of coal because of its high carbon content. Conversely, lower coal prices in the Low Coal Cost case and higher natural gas prices in the Low Oil and Gas Resource case improve the competitiveness of coal and lead to higher levels of coal production.

Of the cases shown in Figure MT-61, the GHG10 case shows the largest decline in U.S. coal production, with an economy-wide CO_2 emissions price that rises to $34 per metric ton of CO_2 (2012 dollars) in 2040, leading to 32% lower coal production in 2040 compared with the Reference case. Production in the High Coal Cost and Low Coal Cost cases is 7% lower and 4% higher, respectively, than in the Reference case in 2020, evolving to 25% lower and 11% higher in 2040 as the gap between coal and natural gas prices widens. In addition to the GHG10 case, two more GHG scenarios were developed for AEO2014 (not shown in Figure MT-61)—the GHG25 case, with an economywide CO_2 allowance fee that increases to $85 per metric ton in 2040; and the GHG10 and Low Gas Prices case, with lower natural gas prices than in the Reference case. In the GHG25 case and the GHG10 and Low Gas Prices case, total coal production in 2040 is 73% and 53% lower, respectively, than in the Reference case.

Expected declines in mining productivity lead to further increases in average minemouth prices

Figure MT-62. Average annual minemouth coal prices by region in the Reference case, 1990-2040 (2012 dollars per million Btu)



In the AEO2014 Reference case, the average real minemouth price for U.S. coal increases by 1.4%/year, from $1.98/MMBtu in 2012 to $2.96/MMBtu in 2040, continuing the upward trend that began in 2000 (Figure MT-62). A key factor underlying the higher coal prices is an expected decline in coal mining productivity in most areas, but at slower rates than those seen between 2000 and 2011. The minemouth price fell slightly in 2012, primarily as a result of a 19% decline in the price of coking coal [15]. Steam coal prices also declined in 2012, but by less than 1%. In the High and Low Coal Cost cases developed for AEO2014, different assumptions about mining productivity lead to minemouth coal prices in 2040 that are 87% higher and 45% lower, respectively, than in the Reference case.

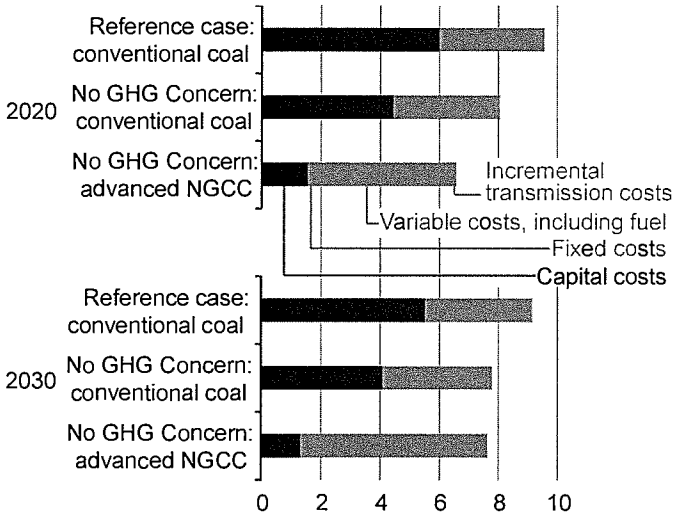
In the Appalachia region, the average minemouth coal price increases by 1.6%/year from 2012 to 2040, because of a decline in mine productivity. The higher price outlook in the region also reflects a larger share of total production for higher-value coking coal, resulting from a decline in shipments of steam coal to domestic markets. Recent increases in the average price of Appalachia coal, from $1.33/MMBtu in 2000 to $3.16/MMBtu in 2012, have reduced the ability of Appalachia coal to compete with coal from other regions.

In the Western region, the coal price grows by 2.1%/year from 2012 to 2040. An increase in stripping ratios at mines in Wyoming's Powder River Basin, which contributed to a 32% decrease in the basin's coal mining productivity from 2000 to 2012, continues to push mining costs higher. In the Interior region, with a more optimistic outlook for mine productivity, minemouth prices rise by 1.0%/year from 2012 to 2040. Increased output from large, highly productive longwall mines in the region supports expected improvements in productivity.

012761

Concerns about future GHG policies affect builds of new coal-fired generating capacity

Figure MT-63. Average levelized electricity costs for new coal and natural gas plants in two cases, 2020 and 2030 (2012 cents per kilowatthour)

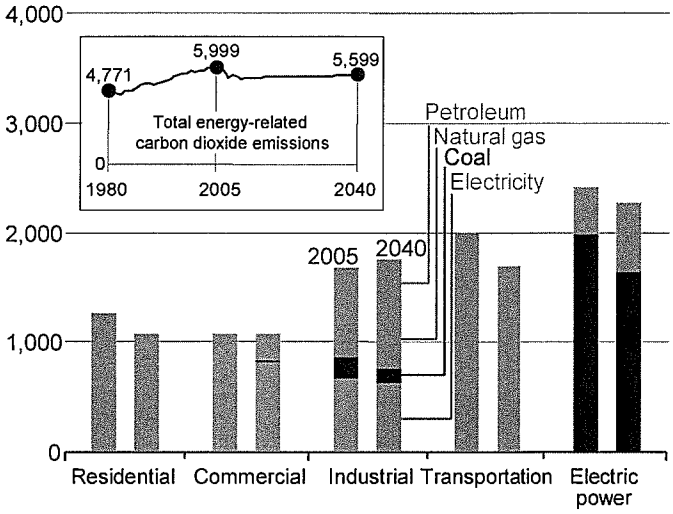


The cost of capital for investments in GHG-intensive technologies, such as new coal-fired and coal-to-liquids (CTL) plants without carbon capture and storage (CCS), is increased by 3 percentage points in the AEO2014 Reference case. This increase addresses the higher risk associated with those investments, given the potential for future restrictions on GHG emissions. The higher cost of capital is also applied to capital projects at existing coal-fired power plants (excluding CCS), such as retrofits to control emissions of mercury, acid gases, and particulates for compliance with MATS. The 3 percentage point adjustment is roughly equivalent in levelized cost terms to an emissions fee of $15/metric ton of CO_2 when investing in a new coal plant without CCS, and it increases the capital cost component for a new coal unit by approximately 1.5 cents/kWh. The No GHG Concern case assumes that the costs of capital for GHG-intensive technologies do not reflect the risk premium described above.

In the No GHG Concern case, estimated levelized costs for new coal- and natural gas-fired capacity begin to converge in the mid- to late-2020s (Figure MT-63) [16], leading to new coal-fired capacity builds in a number of regions. In comparison, virtually no new unplanned coal-fired capacity is added in the Reference case until nearly 2040. In the No GHG Concern case, 13 GW of new coal-fired capacity is added (including plants currently under construction), compared with fewer than 3 GW in the Reference case. As a consequence, additions of natural gas, nuclear, and renewable generating capacity all are slightly lower in the No GHG Concern case than in the Reference case, and total energy-related CO_2 emissions in 2040 are 54 million metric tons (1%) higher than in the Reference case. In the No GHG Concern case, the cost estimates for new coal-fired plants by region in 2030 range from 9% below to 11% above the national average—not including New England, where the cost estimate is 23% above the national average [17].

Energy-related carbon dioxide emissions remain below their 2005 level through 2040

Figure MT-64. U.S. energy-related carbon dioxide emissions by sector and fuel in the Reference case, 2005 and 2040 (million metric tons)



Energy-related CO_2 emissions in the AEO2014 Reference case decline by 0.2%/year on average from 2005 to 2040, as compared with an average increase of 0.9%/year from 1980 to 2005. Reasons for the decline include lower economic growth, increasing use of renewable technologies and fuels; automobile efficiency improvements; slower growth in electricity demand; and more use of natural gas, which is less carbon-intensive than other fossil fuels when combusted. Energy-related CO_2 emissions in 2020 are 8.7% below their 2005 level in the Reference case, and in 2040 they total 5,599 million metric tons (MMmt) and 400 MMmt (6.7%) below their 2005 level (Figure MT-64).

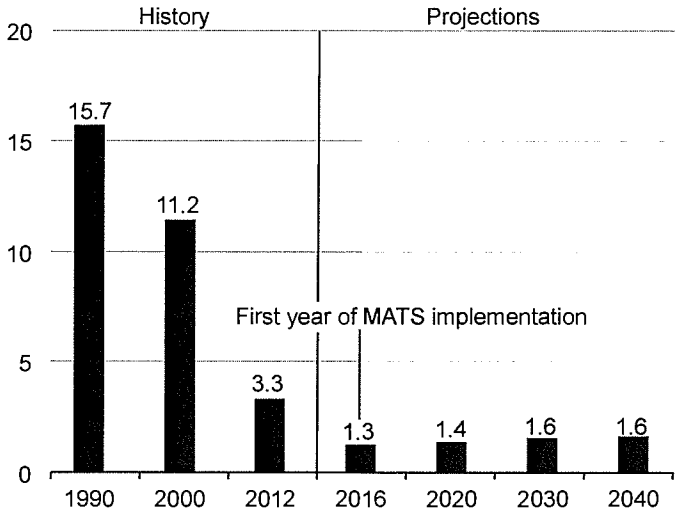
In the Reference case, petroleum remains the largest source of U.S. energy-related CO_2 emissions. However, its share of the total falls to 38% in 2040 from 44% in 2005. In 2040, CO_2 emissions from petroleum use, mainly in the transportation sector, are 509 MMmt below the 2005 level.

Emissions from coal, the second-largest source of energy-related CO_2 emissions, are 402 MMmt below the 2005 level in 2040 in the Reference case, and their share of total energy-related CO_2 emissions declines from 36% in 2005 to 32% in 2040. The natural gas share of energy-related CO_2 emissions increases from 20% in 2005 to 30% in 2040, as the use of natural gas to fuel electricity generation and industrial applications increases. Emissions levels are sensitive to assumptions about economic growth, fuel prices, technology costs, and policies that are explored in many of the alternative cases completed for AEO2014.

012762

Power plant emissions of sulfur dioxide are reduced by further environmental controls

Figure MT-65. Sulfur dioxide emissions from electricity generation in selected years in the Reference case, 1990-2040 (million short tons)



In the AEO2014 Reference case, sulfur dioxide (SO_2) emissions from the electric power sector increase slightly in the early years of the projection but fall rapidly in 2016, when the Mercury and Air Toxics Standards (MATS) [*18*] are fully implemented.

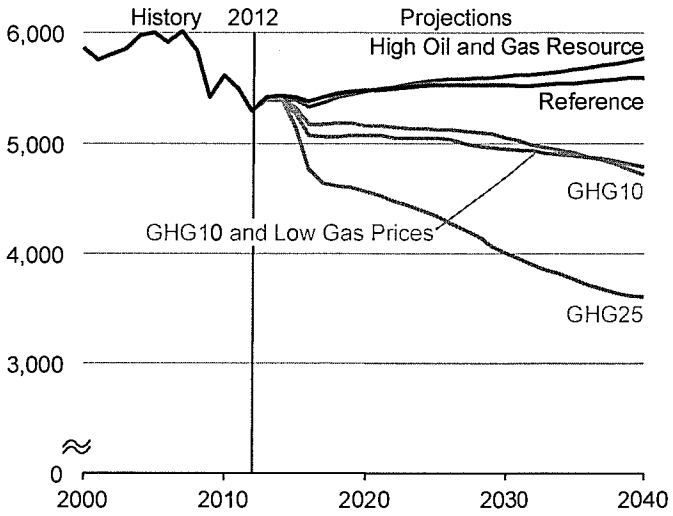
The Reference case assumes that all coal-fired power plants operating in the United States will be equipped with either flue gas desulfurization units (scrubbers) or dry sorbent injection (DSI) systems by 2016 to comply with the specific requirements of MATS. The emissions controls have the ancillary benefit of removing significant amounts of SO_2. For example, scrubbers remove more than 90% of SO_2 emissions from flue gas. DSI systems, when combined with fabric filters, remove approximately 70% of SO_2 emissions.

At the end of 2012, 64% of electric power sector coal-fired generating capacity in the United States already had either scrubbers or DSI systems installed. The Reference case assumes that by 2016, every operating coal plant in the United States larger than 25 megawatts has some type of control equipment, including approximately 31 GW of coal-fired capacity retrofitted with scrubbers and another 45 GW retrofitted with DSI systems.

After a 61% decrease from 2012 to 2016 (Figure MT-65), annual SO_2 emissions increase by 0.9%/year from 2016 to 2040, as total electricity generation from coal-fired power plants increases by 0.3%/year, and scrubbers and DSI equipment remove most (but not all) SO_2 from flue gas. As a result of MATS compliance, SO_2 emissions are reduced to a level below the cap specified in the Clean Air Interstate Rule (CAIR).

Energy-related carbon dioxide emissions are sensitive to potential policy changes

Figure MT-66. Energy-related carbon dioxide emissions in five cases, 2000-40 (million metric tons)



Although the AEO2014 Reference case assumes that current laws and regulations remain in effect through 2040, the potential impacts of future policies that would place an implicit or explicit value on CO_2 emissions are examined in two cases, starting at $10 (GHG10) and $25 (GHG25) per metric ton CO_2 in 2015 and rising by 5% per year thereafter. Because of uncertainty about the growing role of natural gas in the U.S. energy landscape and how it might affect efforts to reduce GHG emissions, the $10 fee case was run both with the Reference case and combined with the High Oil and Gas Resource case (GHG10 and Low Gas Prices) (Figure MT-66).

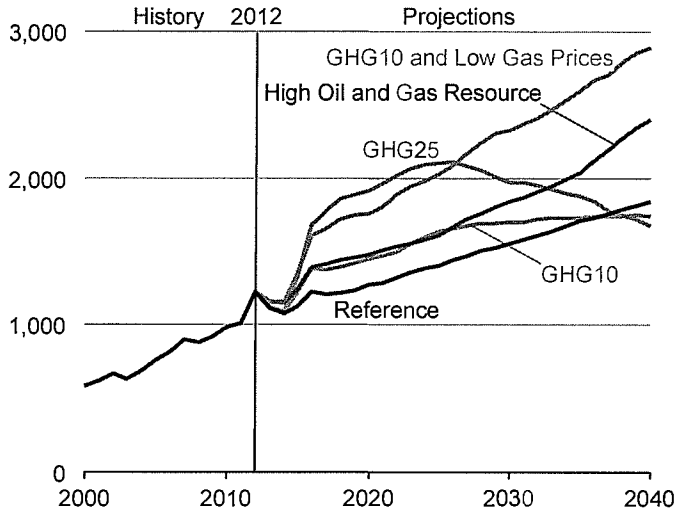
Emissions fees or other policies that place an explicit or implicit value on CO_2 emissions would encourage all energy producers and consumers to shift to lower-carbon or zero-carbon energy sources. Relative to 2005 emissions levels, energy-related CO_2 emissions are 15% and 28% lower in 2025 in the GHG10 and GHG25 cases using Reference case resources, respectively, and 22% and 40% lower in 2040. When combined with High Oil and Gas Resource assumptions, the CO_2 fees in the GHG10 case tend to lead to slightly greater emissions reductions in the near term and smaller reductions in the long term.

The alternative assumptions about natural gas resources have only small impacts on energy-related CO_2 emissions in the GHG10 and Low Gas Prices case. Although more abundant and less expensive natural gas in the High Oil and Gas Resource cases does lead to less coal use and more natural gas use, it also reduces the use of renewable and nuclear fuels and increases energy consumption overall. Shortly after 2020, the emissions reductions achieved by shifting from coal to natural gas are offset by the impacts of reduced use of renewables and nuclear power for electricity generation, and by higher overall levels of energy consumption.

012763

Carbon dioxide fees first favor, then discourage, natural gas-fired generation

Figure MT-67. Natural gas-fired electricity generation in five cases, 2000-40 (billion kilowatthours)



The role of natural gas in the CO_2 fee cases varies widely over time and also varies over the range of assumptions about natural gas resources. When CO_2 fees are assumed to be introduced in 2015 in both the GHG10 and GHG25 cases, natural gas-fired generation increases sharply during the first few years, and it continues to increase modestly over the next several years (Figure MT-67). Subsequently, the increases no longer occur, as more new nuclear and renewable plants are added. In the GHG10 case, natural gas-fired generation levels off around 2030. In the GHG25 case, the role of natural gas begins to decline after 2025.

After accounting for about 50% of all U.S. electricity generation for many years, coal's share has declined in recent years as a result of growing competition from efficient natural gas-fired plants with access to relatively low-cost natural gas. In the Reference case, the share of generation fueled by coal falls from 37% in 2012 to 32% in 2040. Coal's share falls even further in the GHG cases, to a range between 10% and 28% in 2025 and between 1% and 19% in 2040.

As the fee for CO_2 emissions increases over time, power companies reduce their use of coal and increase their use of natural gas, renewables, and nuclear. The nuclear and renewable shares of total generation increase in most of the GHG cases, particularly in the later years of the projections. In the Reference case, nuclear generation accounts for 17% of the total in 2025 and 16% in 2040. In the GHG cases, the nuclear share varies from 17% to 21% in 2025 and from 17% to 37% in 2040. In the Reference case, the renewable share of total generation increases from 15% in 2025 to 16% in 2040. The renewable share is generally higher in the GHG cases—between 17% and 20% in 2025 and between 18% and 27% in 2040.

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Endnotes for Market trends

Links current as of April 2014

1. The industrial sector includes manufacturing, agriculture, construction, and mining. The energy-intensive manufacturing sectors include food, paper, bulk chemicals, petroleum refining, glass, cement, steel, and aluminum.
2. Value of shipments includes both final and intermediate products.
3. S.C. Davis, S.W. Diegel, and R.G. Boundy, *Transportation Energy Databook: Edition 32,* ORNL-6989 (Oak Ridge, TN: July 2013), Chapter 2, Table 2.1, "U.S. Consumption of Total Energy by End-Use Sector, 1973-2012."
4. S.C. Davis, S.W. Diegel, and R.G. Boundy, *Transportation Energy Databook: Edition 32,* ORNL-6989 (Oak Ridge, TN: July 2013), Chapter 4, Table 4.6, "New Retail Sales of Trucks 10,000 Pounds GVWR and Less in the United States, 1970-2012."
5. U.S. Environmental Protection Agency and National High way Traffic Safety Administration, "Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; Final Rule," *Federal Register,* Vol. 75, No. 88 (Washington, DC: May 7, 2010), https://www.federalregister.gov/articles/2010/05/07/2010-8159/light-duty-vehicle-greenhouse-gas-emission-standards-and-corporate-average-fuel-economy-standards.
6. U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards; Final Rule," *Federal Register,* Vol. 77, No. 199 (Washington, DC: October 15, 2012), https://www.federalregister.gov/articles/2012/10/15/2012-21972/2017-and-later-model-year-light-duty-vehicle-greenhouse-gas-emissions-and-corporate-average-fuel.
7. LDV fuel economy includes alternative-fuel vehicles and banked credits towards compliance.
8. Factors that influence decisionmaking on capacity additions include electricity demand growth, the need to replace inefficient plants, the costs and operating efficiencies of different power generation options, fuel prices, state RPS programs, and the availability of federal tax credits for some technologies.
9. Unless otherwise noted, the term capacity in the discussion of electricity generation indicates utility, nonutility, and CHP capacity.
10. Costs are for the electric power sector only.
11. The levelized costs reflect the average of regional costs. For detailed discussion of levelized costs, see U.S. Energy Information Administration, "Levelized Cost of New Generation Resources in the Annual Energy Outlook 2014," http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.
12. HGL is a new term that accounts for similar fuels produced from both natural gas and petroleum through different processes. A description of the term HGL and how related terms are applied can be found at http://www.eia.gov/ngl/.
13. U.S. Environmental Protection Agency, "EPA Finalizes 2012 Renewable Fuel Standards," EPA-420-F-11-044 (Washington, DC: December 2011), http://www.epa.gov/otaq/fuels/renewablefuels/documents/420f11044.pdf.
14. U.S. Energy Information Administration, *This Week in Petroleum* (November 23, 2011), http://www.eia.gov/oog/info/twip/twiparch/2011/111123/twipprint.html.
15. Minemouth coal price estimates for coking coal (or premium metallurgical) and steam coal in 2012 dollars/short ton are provided in the AEO2014 Reference case "Supplemental Tables for Regional Detail," Table 140. These prices are converted to units of 2012 dollars/million Btu by using the production and price data from AEO2014 Supplemental Data Tables 139 and 140, the heat content data for total coal production from Supplemental Data Table 146, and an estimated heat content of 26.3 million Btu/short ton for U.S. coking coal production. For regional detail, see the AEO2014 Reference case "Supplemental Tables for Regional Detail," http://www.eia.gov/forecasts/aeo/tables_ref.cfm.
16. For detailed discussion of levelized costs, see U.S. Energy Information Administration, "Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2014," http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.
17. The levelized cost estimates shown in Figure MT-63 represent national averages.
18. U.S. Environmental Protection Agency, "Mercury and Air Toxics Standards," http://www.epa.gov/mats.

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Figure and table sources

Links current as of April 2014

Figure MT-1. Average annual growth rates of real GDP, labor force, and productivity in three cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

Figure MT-2. Average annual growth rates for real output and its major components in three cases, 2012-40: History: Bureau of Economic Analysis. Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

Figure MT-3. Annual growth rates of shipments for the industrial sector and its components in three cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

Figure MT-4. North Sea Brent crude oil spot prices in three cases, 1990-2040: History: U.S. Energy Information Administration, Petroleum & Other Liquids, Europe Bent Spot Price FOB, http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=RBRTE&f=D. Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWPRICE.D120613A, and HIGHPRICE.D120613A.

Figure MT-5. World petroleum and other liquids consumption by region in three cases, 2012 and 2040: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A LOWPRICE.D120613A, and HIGHPRICE.D120613A.

Figure MT-6. World production of nonpetroleum liquids by type, 2012 and 2040: Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-7. Energy use per capita and per dollar of gross domestic product in the Reference case, 1980-2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-8. Primary energy use by end-use sector in selected years in the Reference case, 2012-40: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-9. Primary energy use by fuel in the Reference case, 1980-2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-10. Residential delivered energy intensity in four cases, 2009-40: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, FROZTECH.D121813A, HIGHTECH.D121813A, and BESTTECH.D121813A.

Figure MT-11. Change in residential electricity consumption for selected end uses in the Reference case, 2012-40: Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-12. Residential electricity sales in two cases, 1980-2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A and EXTENDED.D022814A.

Figure MT-13. Residential distributed generation in three cases, 2012-40: Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A, NOSUNSET.D121713A, and LCR_2014.D120613A.

Figure MT-14. Commercial delivered energy intensity in four cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, FROZTECH.D121813A, HIGHTECH.D121813A, and BESTTECH.D121813A.

Figure MT-15. Energy intensity of selected commercial end uses in the Reference case, 2012 and 2040: Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-16. Efficiency gains for selected commercial equipment in three cases, 2040: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, FROZTECH.D121813A, and BESTTECH.D121813A.

Figure MT-17. Additions to electricity generation capacity in the commercial sector in two cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A and NOSUNSET.D121713A.

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Figure MT-18. Industrial delivered energy consumption by application in the Reference case, 2012-40: Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-19. Industrial energy consumption by fuel in the Reference case, 2012-40: Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-20. Change in liquid feedstock consumption in three cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure MT-21. Heat and power consumption for refining and manufacturing applications in three cases, 2012, 2025, and 2040: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

Figure MT-22. Cumulative growth in energy consumption by metal-based durables industries, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

Figure MT-23. Delivered energy consumption by nonmanufacturing industries in three cases, 2012 and 2040: Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

Figure MT-24. Delivered energy consumption for transportation by mode in the Reference case, 2012 and 2040: Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-25. Average fuel economy of new light-duty vehicles in the Reference case, 1980-2040: History: U.S. Department of Transportation, National Highway Traffic Safety Administration, *Summary of Fuel Economy Performance,* April 2013. www.nhtsa.gov/staticfiles/rulemaking/pdf/cafe/April_2013_Summary_Report.pdf. Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-26. Vehicle miles traveled per licensed driver in the Reference case, 1970-2040: History: U.S. Department of Transportation, Federal Highway Administration, *Highway Statistics 2011* (Washington, DC: 2013), http://www.fhwa.dot.gov/policyinformation/statistics/2011/. Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-27. Sales of light-duty vehicles using non-gasoline technologies by type in the Reference case, 2012, 2025, and 2040: Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-28. Natural gas consumption in the transportation sector in the Reference case, 1995-2040: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-29. U.S. electricity demand growth in the Reference case, 1950-2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-30. Electricity generation by fuel in the Reference case, 1990-2040: Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-31. Electricity generation capacity additions by fuel type, including combined heat and power, in the Reference case, 2013-40: Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-32. Additions to electricity generating capacity in the Reference case, 1985-2040: History: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report." Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-33. Electricity sales and power sector generating capacity in the Reference case, 1949-2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-34. Levelized electricity costs for new power plants, excluding subsidies, 2020 and 2040: Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-35. Nuclear electricity generation in four cases, 1995-2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, ALTLOWNUC14.D012314C, HINUC14.D120313A, and LOWNUC14.D012314B.

Figure MT-36. Renewable electricity generation capacity by energy source, including end-use capacity, 2012-40: Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

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Figure MT-37. Renewable electricity generation by type, all sectors, in the Reference case, 2000-40: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-38. Regional nonhydropower renewable electricity, including end-use generation, in the Reference case, 2012 and 2040: Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-39. Natural gas consumption by sector in the Reference case, 1990-2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-40. Annual average Henry Hub spot natural gas prices in the Reference case, 1990-2040: History: U.S. Energy Information Administration, *Natural Gas Annual 2012,* DOE/EIA-0131(2012) (Washington, DC, December 2013). Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-41. Annual average Henry Hub spot prices for natural gas in five cases, 1990-2040: History: U.S. Energy Information Administration, *Natural Gas Annual 2012,* DOE/EIA-0131(2012) (Washington, DC, December 2013). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWMACRO.D112913A, HIGHMACRO.D112913A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure MT-42. Total U.S. natural gas production, consumption, and imports in the Reference case, 1990-2040: History: U.S. Energy Information Administration, *Natural Gas Annual 2012,* DOE/EIA-0131(2012) (Washington, DC, December 2013). Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-43. Total U.S. natural gas production in three oil price cases, 1990-2040: History: U.S. Energy Information Administration, *Natural Gas Annual 2012,* DOE/EIA-0131(2012) (Washington, DC, December 2013). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWPRICE.D120613A, and HIGHPRICE.D120613A.

Figure MT-44. Natural gas production by source in the Reference case, 1990-2040: History: U.S. Energy Information Administration, *Natural Gas Annual 2012,* DOE/EIA-0131(2012) (Washington, DC, December 2013). Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-45. U.S. net imports of natural gas by source in the Reference case, 1990-2040: History: U.S. Energy Information Administration, *Natural Gas Annual 2011,* DOE/EIA-0131(2011) (Washington, DC, January 2013). Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-46. U.S. exports of liquefied natural gas in five cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, HIGHRESOURCE.D112913B, LOWPRICE.D120613A, and HIGHPRICE.D120613A.

Figure MT-47. U.S. natural gas production in three cases, 1990-2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure MT-48. Marcellus shale production share of total U.S. natural gas consumption east of the Mississippi River in the Reference case, 2000-40: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-49. Natural gas-fired electricity generation by NERC region in the Reference case, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-50. Consumption of petroleum and other liquids by sector in the Reference case, 1990-2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-51. U.S. production of petroleum and other liquids by source in the Reference case, 2012-40: Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-52. Total U.S. crude oil production in three cases, 1990-2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

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Figure MT-53. Domestic crude oil production by source in the Reference case, 1990-2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-54. Average API gravity of U.S. domestic and imported crude oil supplies in the Reference case, 1990-2040: History: U.S. Energy Information Administration, Crude Oil Input Qualities and Company Level Imports Archives, http://www.eia.gov/petroleum/imports/companylevel/archive/. Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-55. Net import share of U.S. petroleum and other liquids consumption in five cases, 1990-2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, HIGHRESOURCE.D112913B, LOWPRICE.D120613A, and HIGHPRICE.D120613A.

Figure MT-56. EISA2007 Renewable Fuels Standard credits earned by fuel type in the Reference case, 2012-40: Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-57. Motor gasoline consumption, diesel fuel consumption, and petroleum product exports in the Reference case, 2012-40: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-58. U.S. refinery gasoline-to-diesel production ratio and crack spread in the Reference case, 2000-40: History: Crack spread calculated from national average New York Harbor (NYH) RBOB prices and ULSD spot prices (2006-12) and No. 2 heating oil spot prices (2000-05), http://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm. 2000-12: Gasoline and diesel refinery production calculated from finished gasoline, motor gasoline blend components (net), and distillate fuel oil (15ppm and 15-500 ppm), http://www.eia.gov/dnav/pet/pet_pnp_refp2_dc_nus_mbblpd_a.htm and http://www.eia.gov/dnav/pet/pet_pnp_intp2_dc_nus_mbblpd_a.htm. Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-59. Consumption of biofuels in motor gasoline blends in the Reference case, 2012-40: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-60. Coal production by region in the Reference case, 1970-2040: History (short tons): 1970-1990: U.S. Energy Information Administration, *The U.S. Coal Industry, 1970-1990: Two Decades of Change,* DOE/EIA-0559 (Washington, DC, November 2002). 1991-2000: U.S. Energy Information Administration, Coal Industry Annual, DOE/EIA-0584 (various years). 2001-2012: U.S. Energy Information Administration, *Annual Coal Report 2012,* DOE/EIA-0584(2012) (Washington, DC, December 2013), and previous issues. History (conversion to quadrillion Btu): 1970-2012: Estimation Procedure: Estimates of average heat content by region and year are based on coal quality data collected through various energy surveys (see sources) and national-level estimates of U.S. coal production by year in units of quadrillion Btu, published in EIA's *Monthly Energy Review.* Sources: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09), Table 1.2; Form EIA-3, "Quarterly Coal Consumption and Quality Report, Manufacturing and Transformation/Processing Coal Plants and Commercial and Institutional Coal Users"; Form EIA-5, "Quarterly Coal Consumption and Quality Report, Coke Plants"; Form EIA-6A, "Coal Distribution Report"; Form EIA-7A, "Coal Production and Preparation Report"; Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report"; Form EIA-906, "Power Plant Report"; Form EIA-920, "Combined Heat and Power Plant Report"; Form EIA-923, "Power Plant Operations Report"; U.S. Department of Commerce, Bureau of the Census, "Monthly Report EM 545"; and Federal Energy Regulatory Commission, Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A. Note: For 1989-2040, coal production includes waste coal.

Figure MT-61. U.S. total coal production in six cases, 2012, 2020, and 2040: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LCCST14.D120413A, HCCST14.D120413A, LOWRESOURCE.D112913A, HIGHRESOURCE.D112913B, and CO2FEE10.D011614A. Note: Coal production includes waste coal.

Figure MT-62. Average annual minemouth coal prices by region in the Reference case, 1990-2040: History (dollars per short ton): 1990-2000: U.S. Energy Information Administration, *Coal Industry Annual,* DOE/EIA-0584 (various years). 2001-2012: U.S. Energy Information Administration, *Annual Coal Report 2012,* DOE/EIA-0584(2012) (Washington, DC, December 2013), and previous issues. History (conversion to dollars per million Btu): 1970-2012: Estimation Procedure: Estimates of average heat content by region and year based on coal quality data collected through various energy surveys (see sources) and national-level estimates of U.S. coal production by year in units of quadrillion Btu published in EIA's *Monthly Energy Review.* Sources: U.S. Energy Information Administration, *Monthly Energy Review,* DOE/EIA-0035(2013/09) (Washington, DC, September 2013), Table 1.2; Form EIA-3, "Quarterly Coal Consumption and Quality Report, Manufacturing and Transformation/Processing Coal Plants and Commercial and Institutional Coal Users"; Form EIA-5, "Quarterly Coal Consumption and Quality Report, Coke Plants"; Form EIA-6A, "Coal Distribution Report"; Form EIA-7A, "Coal Production and Preparation Report"; Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report"; Form EIA-906, "Power Plant Report"; Form EIA-920, "Combined Heat and Power Plant Report"; Form

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EIA-923, "Power Plant Operations Report"; U.S. Department of Commerce, Bureau of the Census, "Monthly Report EM 545"; and Federal Energy Regulatory Commission, Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A. Note: Includes reported prices for both open-market and captive mines.

Figure MT-63.Average levelized electricity costs for new coal and natural gas plants in two cases, 2020 and 2030: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A and NOGHGCONCERN.D120413A. Note: Costs for conventional coal reflect estimates for a supercritical pulverized coal plant that includes all advanced control technologies except for CCS. NGCC represents natural gas combined-cycle.

Figure MT-64. U.S. energy-related carbon dioxide emissions by sector and fuel in the Reference case, 2005 and 2040: History: U.S. Energy Information Administration, Monthly Energy Review, September 2013, DOE/EIA-0035(2013/09). Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-65. Sulfur dioxide emissions from electricity generation in the Reference case, 1990-2040: History: U.S. Environmental Protection Agency, Clean Air Markets Database, http://ampd.epa.gov/ampd/. Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-66. Energy-related carbon dioxide emissions in five cases, 2000-40: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, HIGHRESOURCE.D112913B, CO2FEE10.D011614A, CO2FEE25.D011614A, and CO2FEE10HR.D011614A.

Figure MT-67. Natural gas-fired electricity generation in five cases, 2000-40: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, HIGHRESOURCE.D112913B, CO2FEE10.D011614A, CO2FEE25.D011614A, and CO2FEE10HR.D011614A.

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Comparison with other projections

Energy Information Administration (EIA) and other contributors have endeavored to make these projections as objective, reliable, and useful as possible; however, they should serve as an adjunct to, not a substitute for, a complete and focused analysis of public policy initiatives. None of the EIA or any of the other contributors shall be responsible for any loss sustained due to reliance on the information included in this report.

IHS Global Insight (IHSGI) is the only organization available to the U.S. Energy Information Administration (EIA) that produces an energy projection with detail and a time horizon that are comparable to those in the *Annual Energy Outlook 2014* (AEO2014). Other organizations, however, address one or more aspects of the U.S. energy market. The most recent projection from IHSGI, as well as others that concentrate on economic growth, international oil prices, energy consumption, electricity, natural gas, petroleum, and coal, are compared here with the AEO2014 Reference case.

CP1. Economic growth

The range of projected economic growth in the outlooks included in the comparison tends to be wider over the first three years of the projection than over a longer period, because the group of variables—such as population, productivity, and labor force growth—that influence long-run economic growth is smaller than the group of variables that affect projections of short-run growth. The average annual rate of growth of real gross domestic product (GDP) from 2012 to 2015 ranges from 2.4% to 3.0% (Table CP1); while the 13-year annual average growth, from 2012 to 2025, ranges from 2.5% to 2.8%.

From 2012 to 2015, real GDP grows at a 2.6% average annual rate in the AEO2014 Reference case, lower than projected by the Office of Management and Budget (OMB), the Social Security Administration (SSA) (in *The 2013 Annual Report of the Board of Trustees of the Federal Old-Age and Survivors Insurance and Federal Disability Insurance Trust Funds*), and Oxford Economic Group (OEG), but higher than that projected by Interindustry Forecasting Project at the University of Maryland (INFORUM). The AEO2014 projection of GDP growth is similar to the average annual rate of 2.6% over the same period projected by IHSGI and the Congressional Budget Office (CBO) and by the International Energy Agency (IEA) in its November 2013 *World Energy Outlook* Current Policies Scenario.

The average annual GDP growth of 2.5% in the AEO2014 Reference case from 2012 to 2025 is in the low range of the outlooks, with IHSGI and ExxonMobil projecting similar growth, while OMB and INFORUM project slightly higher mid-term growth, at 2.6%/year. SSA and OEG project annual average growth of 2.7% from 2012 to 2025. IEA projects the highest midterm growth, at 2.8%/year from 2012 to 2025. The CBO projects the lowest annual GDP growth, averaging 2.4% from 2012 to 2025.

There are few public or private projections of GDP growth for the United States that extend to 2040. The AEO2014 Reference case projects 2.4% average annual GDP growth from 2012 to 2040, consistent with trends in labor force and productivity growth. SSA, IEA, ExxonMobil, and INFORUM also project GDP growth averaging 2.4%/year from 2012 to 2040, while IHSGI and OEG project higher rates of 2.5% and 2.6%/year, respectively, from 2012 to 2040.

CP2. Oil prices

In the AEO2014 Reference case, oil prices are represented by spot prices for North Sea Brent crude. Prices decline in the Reference case from $112/barrel in 2012 to about $109/barrel in 2025 and then rise slowly to $130/barrel in 2035 and $141/barrel in 2040 (Table CP2). In AEO2014, the North Sea Brent crude oil price is tracked as the main benchmark for world oil prices, because it reflects the marginal price paid by refineries for imported light, sweet crude oil (used to produce petroleum products for consumers) better than does the West Texas Intermediate (WTI) crude oil price. The WTI price continued to trade at a discount relative to other world oil prices in 2013. The discount narrowed through the end of the summer, as a result of new U.S. oil transportation infrastructure out of the market center for WTI prices in Cushing, Oklahoma, and refineries running at record levels. In 2012, the WTI and North Sea Brent prices differed by $18/barrel. In the AEO2014 Reference case, the gap closes to $2/barrel in 2020 and

Table CP1. Comparisons of average annual economic growth projections, 2012-40

	Average annual percentage growth rates			
Projection	2012-2015	2012-2025	2025-2040	2012-2040
AEO2014 (Reference case)	2.6	2.5	2.4	2.4
AEO2013 (Reference case)	2.6	2.6	2.4	2.5
IHSGI (May 2013)	2.6	2.5	2.4	2.5
OMB (January 2014)[a]	2.7	2.6	--	--
CBO (February 2014)[a]	2.6	2.5	--	--
INFORUM (November 2013)	2.4	2.6	2.3	2.4
Social Security Administration (August 2013)	3.0	2.7	2.2	2.4
IEA (2013)[b]	2.6	2.8	--	2.4
ExxonMobil	--	2.5	2.2	2.4
OEG (January 2013)	2.7	2.7	2.5	2.6

-- = not reported or not applicable.

[a]OMB and CBO projections end in 2024, and growth rates cited are for 2012-24. AEO projections end in 2040.

[b]IEA publishes U.S. growth rates for certain intervals: 2011-15 growth is 2.6%, 2011-20 growth is 2.8%, and 2011-35 growth is 2.4%.

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remains at that level throughout the projection period, following resolution of most of the transportation system constraints in the United States. In each of the other outlooks in the comparison, oil spot prices are based on either North Sea Brent or WTI prices, with the exception of IEA spot prices, which are based on the international average of crude oil import prices within the member countries of the Organization for Economic Cooperation and Development (OECD).

The range of oil price projections for both the near term and the long term reflects market volatility caused by persistent political instability in major producing countries in the developing world, as well as different assumptions about the future of the world economy. However, with the exception of Strategic Energy & Economic Research (SEER), the projections show oil prices rising over the entire projection period. The projections for 2025 range from $60/barrel to $117/barrel for WTI and from $64/barrel to $127/barrel for North Sea Brent. The projections for 2040 range from $52/barrel to $164/barrel for WTI and from $54/barrel to $171/barrel for North Sea Brent. The wide range underscores the uncertainty inherent in the projections. Again, with the exception of SEER, the spread of the projections is encompassed in the AEO2014 Low and High Oil Price cases, which range from $70/barrel to $159/barrel for Brent in 2025 and from $75/barrel to $204/barrel in 2040.

CP3. Total energy consumption

Four projections by other organizations—INFORUM, IHSGI, ExxonMobil, and IEA—include energy consumption by sector. To allow comparison with the IHSGI projection, the AEO2014 Reference case was adjusted to remove coal-to-liquids (CTL) heat and power, natural gas-to-liquids heat and power, biofuels heat and coproducts, and natural gas feedstock use. To allow comparison with the ExxonMobil projection, electricity consumption in each sector was removed from the AEO2014 Reference case. To allow comparison with the IEA projections, the AEO2014 Reference case projections for the residential and commercial sectors were combined to produce a buildings sector projection (Table CP3). The IEA projections have a base year of 2011 and extend only through 2035. ExxonMobil provided base year data for 2010.

Both IEA and ExxonMobil account for electricity generation with renewable energy at the electricity conversion rate of 3,412 Btu per kilowatthour rather than at a displaced fossil fuel heat rate used in the AEO and other projections, which lowers their estimates of total energy consumption. ExxonMobil also includes a cost for carbon dioxide (CO_2) emissions, which helps to explain the lower level of consumption in their outlook. Although the IEA's central case also includes a cost for CO_2 emissions, its Current Policies Scenario (which assumes that no new policies are added to those in place in mid-2013) is used for comparison in this analysis, because it corresponds better with the assumptions in the AEO2014 Reference case. In all years shown, ExxonMobil and IEA show lower total energy consumption in comparison with the AEO2014 Reference case. Total energy consumption is higher in all years of the IHSGI projection than in the AEO2014 Reference case but starts from a lower level.

The INFORUM projection of total energy consumption in 2040 is similar to the AEO2014 Reference case projection, but the INFORUM projection for the transportation sector is 1.5 quadrillion Btu higher than the AEO2014 projection, and the buildings sector is 0.6 quadrillion Btu higher. Those higher levels of energy consumption are offset by a 2.5 quadrillion Btu lower level of industrial sector consumption in the INFORUM projection. For the transportation sector, the INFORUM projection features strong growth in diesel fuel demand from 2011 to 2020 (more than 1.2 quadrillion Btu above the 2011 level). However, from 2020 to 2040, growth is less than one-half (0.6 quadrillion Btu) that in the earlier period. The INFORUM projection for motor gasoline is lower than the AEO2014 projection in 2020 but does not decline as quickly afterward. The INFORUM projection for the industrial sector is lower than the AEO2014 projection despite higher industrial output, implying greater efficiency improvement.

Table CP2. Comparisons of oil price projections, 2025, 2035, and 2040 (2012 dollars per barrel)

			Projections					
	2012		2025		2035		2040	
	WTI	Brent	WTI	Brent	WTI	Brent	WTI	Brent
AEO2014 (Reference case)	94.12	111.65	106.99	108.99	127.77	129.77	139.46	141.46
AEO2014 (Low Oil Price case)	94.12	111.65	68.40	70.40	71.40	73.40	72.90	74.90
AEO2014 (High Oil Price case)	94.12	111.65	156.62	158.62	185.92	187.92	202.24	204.24
AEO2013 (Reference case)	94.12	110.43	117.41	119.45	145.96	147.99	163.54	165.57
SEER	94.15	111.63	60.00	64.00	54.00	56.00	52.00	54.00
ArrowHead Economics	94.12	111.65	101.94	108.34	119.61	124.00	131.34	135.42
Energy Ventures Associates (EVA)	94.12	--	85.64	--	106.01	--	--	--
INFORUM	--	111.65	--	123.86	--	154.26	--	171.16
Energy Security Analysis (ESAI)	--	111.50	--	99.10	--	125.30	--	131.30
IEA (Current Policies Scenario)[a]	94.12	111.65	--	127.00	--	145.00	--	--

-- = not reported.

[a]IEA mixed crude oil import prices are based on OECD member country reporting.

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IHSGI projects significantly higher electricity consumption for all sectors than the AEO2014 Reference case, which helps to explain much of the difference in total energy consumption between the two projections. In the IHSGI projection, the electric power sector consumes 4.9 quadrillion Btu more energy in 2040 than in the AEO2014 Reference case. The greater use of electricity in the IHSGI projection, including 152 trillion Btu used in the transportation sector (more than double the amount in AEO2014), also results in higher electricity prices than in the AEO2014 Reference case.

Total energy consumption declines in the ExxonMobil projection, primarily as a result of the inclusion of a tax on CO_2 emissions, which is not considered in the AEO2014 Reference case. Energy consumption in the transportation sector declines from 2010 levels in the ExxonMobil projection, based on expected policy changes, efficiency improvements, and the penetration of new technologies.

Table CP3. Comparisons of energy consumption projections by sector, 2025, 2035, and 2040 (quadrillion Btu)

Sector	*AEO2014* Reference	INFORUM	IHSGI	ExxonMobil	IEA
	2012 (except where noted)[a]				
Residential	10.4	10.6	10.0	11.0[b]	--
Residential excluding electricity	5.7	5.9	5.4	5.0[b]	--
Commercial	8.3	8.3	8.2	8.0[b]	--
Commercial excluding electricity	3.8	3.8	3.7	4.0[b]	--
Buildings Sector	18.7	18.9	18.3	--	19.0[c]
Industrial	23.6	23.9	--	24.0[b]	23.5[c]
Industrial excluding electricity	20.3	20.5	--	20.0[b]	--
Losses[d]	0.5	--	--	--	--
Natural gas feedstocks	0.9	--	--	--	--
Industrial removing losses and feedstocks	22.2	--	21.8	--	--
Transportation	26.7	26.7	25.9	27.0[b]	23.4[c]
Electric Power	38.5	38.2	39.4	37.0[b]	36.3[c]
Less: electricity demand[e]	12.6	12.6	12.6	--	14.9[c]
Electric power losses	26.0	--	--	--	--
Total primary energy	**95.0**	**95.1**	--	**94.0**[b]	**86.9**[c]
Excluding losses[d] and feedstocks	**93.6**	--	**92.7**	--	--
	2025				
Residential	10.8	11.2	11.6	10.0	--
Residential excluding electricity	5.8	6.0	5.8	5.0	--
Commercial	9.1	9.2	9.4	9.0	--
Commercial excluding electricity	4.1	4.3	4.0	4.0	--
Buildings sector	19.9	20.4	21.0	--	--
Industrial	29.0	26.8	--	26.0	--
Industrial excluding electricity	24.8	22.8	--	21.0	--
Losses[d]	0.8	--	--	--	--
Natural gas feedstocks	1.1	--	--	--	--
Industrial removing losses and feedstocks	27.2	--	24.9	--	--
Transportation	25.6	26.7	27.6	26.0	--
Electric power	42.2	42.2	47.1	37.0	--
Less: electricity demand[e]	14.3	14.2	15.7	--	--
Electric power losses	27.9	--	--	--	--
Total primary energy	**102.5**	**101.9**	--	**93.0**	--
Excluding losses[d] and feedstocks	**100.6**	--	**105.0**	--	--

-- = not reported.
See notes at end of table.

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Total energy consumption in the IEA projection is higher in 2035 than in 2011 because of a 3.7 quadrillion Btu increase in buildings sector energy consumption, including a 3.1 quadrillion Btu increase in electricity consumption. IEA projects little change in energy use in the industrial sector from 2020 to 2035. Energy consumption in the transportation sector is projected to increase by 0.3 quadrillion Btu through 2020, decline by 0.3 quadrillion Btu from 2020 through 2030, and increase by 0.4 quadrillion Btu from 2030 to 2035. The increases from 2011 through 2020 and from 2030 through 2035 reflect growing biofuel use for transportation. The

Table CP3. Comparisons of energy consumption by sector projections, 2025, 2035, and 2040 (quadrillion Btu) (continued)

Sector	*AEO2014* Reference	INFORUM	IHSGI	ExxonMobil	IEA
			2035		
Residential	10.9	11.5	12.2	10.0	--
Residential excluding electricity	5.5	5.7	5.7	5.0	--
Commercial	9.7	9.8	10.1	9.0	--
Commercial excluding electricity	4.3	4.4	4.0	3.0	--
Buildings sector	20.6	21.3	22.3	--	22.7
Industrial	29.8	26.9	--	26.0	25.5
Industrial excluding electricity	25.5	23.1	--	20.0	--
Losses[d]	0.8	--	--	--	--
Natural gas feedstocks	1.0	--	--	--	--
Industrial removing losses and feedstocks	28.0	--	25.5	--	--
Transportation	25.1	26.4	27.6	25.0	23.7
Electric power	43.9	44.0	49.6	36.0	42.3
Less: electricity demand[e]	15.2	15.1	17.3	--	18.6
Electric power losses	28.7	--	--	--	--
Total primary energy	**104.3**	**103.5**	**--**	**90.0**	**95.3**
Excluding losses[d] and feedstocks	**102.5**	**--**	**107.8**	**--**	**--**
			2040		
Residential	10.9	11.7	12.6	10.0	--
Residential excluding electricity	5.3	5.6	5.7	5.0	--
Commercial	10.2	10.1	10.3	9.0	--
Commercial excluding electricity	4.5	4.4	4.1	3.0	--
Buildings sector	21.2	21.8	22.9	--	--
Industrial	30.2	27.7	--	25.0	--
Industrial excluding electricity	25.9	23.9	--	20.0	
Losses[d]	0.8	--	--	--	--
Natural gas feedstocks	1.0	--	--	--	--
Industrial removing losses and feedstocks	28.4	--	26.1	--	--
Transportation	25.5	27.0	27.8	24.0	--
Electric power	45.2	45.1	50.1	36.0	--
Less: electricity demand[e]	15.8	15.6	17.9	--	--
Electric power losses	29.4	--	--	--	--
Total primary energy	**106.3**	**106.0**	**--**	**88.0**	**--**
Excluding losses[d] and feedstocks	**104.5**	**--**	**108.9**	**--**	**--**

-- = not reported.

[a]Base year varies by projection or data for 2012 may differ based on coverage.

[b]ExxonMobil data are for 2010.

[c]IEA data are for 2011.

[d]Losses in CTL and biofuel production.

[e]Energy consumption in the sectors includes electricity demand purchases from the electric power sector, which are subtracted to avoid double counting in deriving total primary energy consumption.

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decline from 2020 through 2030 reflects a drop in petroleum use. The IEA projection for total energy consumption in 2035 is higher than the ExxonMobil projection but considerably lower than projected in the AEO2014 Reference case for both 2030 and 2035.

CP4. Electricity

Table CP4 compares summary results for electricity from the AEO2014 Reference case with projections from EVA, IHSGI, INFORUM, and ICF International, Incorporated (ICF). The AEO2014 Reference case, EVA, and INFORUM project modest growth in total electricity sales over the coming decades. The AEO2014 Reference case projects 4,178 billion kilowatthours (kWh) of total electricity sales in 2025. By comparison, IHSGI projects 4,600 billion kWh of total electricity sales in 2025, which is 10% higher than the AEO2014 Reference case projection, and higher than the EVA and INFORUM projections. The IHSGI projection for total electricity sales is also the highest among the projections in 2035 and 2040. Similarly, IHSGI's individual sector level sales projections are the highest among the projections in 2025, 2035 and 2040.

Table CP4. Comparisons of electricity projections, 2025, 2035, and 2040 (billion kilowatthours, except where noted)

Sector	2012	*AEO2014* Reference	EVA	IHSGI	INFORUM	ICF
				2025		
Average end-use price (2012 cents per kilowatthour)[a]	9.8	10.1	--	11.3	12.3	--
Residential	11.9	12.3	--	13.6	15.0	--
Commercial	10.1	10.4	--	11.7	12.7	--
Industrial	6.7	7.2	--	7.6	8.4	--
Total generation plus net imports	**4,102**	**4,658**	**4,324**	**5,108**	**--**	**4,772**
Coal	1,512	1,689	1,753	1,454	--	1,684
Petroleum	23	19	--	23	--	15
Natural gas[b]	1,239	1,419	1,150	1,848	--	1,505
Nuclear	769	779	846	875	--	811
Hydroelectric/other[c]	511	717	575	842	--	756
Solar	11	42	26	--	--	43
Wind	142	219	217	364	--	268
Net imports	47	35	--	66	--	--
Electricity sales[d]	3,686	4,178	4,067	4,600	4,141	--
Residential	1,375	1,467	1,428	1,703	1,508	--
Commercial/other[e]	1,331	1,459	1,420	1,621	1,460	--
Industrial	981	1,253	1,220	1,277	1,174	--
Capacity, including CHP (gigawatts)[f]	1,066	1,110	1,109	1,225	--	1,123
Coal	310	262	254	263	--	245
Oil and natural gas	471	527	539	567	--	541
Nuclear	102	98	104	110	--	103
Hydroelectric/other[g]	182	223	211	285	--	234
Solar	8	25	19	--	--	27
Wind	59	76	80	124	--	94
Cumulative capacity retirements from 2011 (gigawatts)[h]	--	87	--	98	--	104
Coal	--	51	--	51	--	66
Oil and natural gas	--	31	--	45	--	30
Nuclear	--	5	--	2	--	8
Hydroelectric/other[g]	--	1	--	--	--	1

-- = not reported.
See notes at end of table.

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The AEO2014 Reference case, IHSGI, and INFORUM provide projections for average electricity prices by sector for 2025, 2035, and 2040. On average, the lowest electricity price projections are in the AEO2014 Reference case, and the highest are in the INFORUM projection. The lowest prices by sector in 2025 are in the AEO2014 Reference case (12.3 cents/kWh for the residential sector, 10.4 cents/kWh for the commercial/other sector, and 7.2 cents/kWh for the industrial sector). The highest average electricity prices by sector in 2025 are in the INFORUM projection (15.0 cents/kWh for the residential sector, 12.7 cents/kWh for the commercial sector, and 8.4 cents/kWh for the industrial sector). The AEO2014 Reference case, IHSGI, and INFORUM reflect similar relative price patterns for 2035 and 2040.

The AEO2014 Reference case projects total U.S. generation plus imports of 4,658 billion kWh for 2025. By comparison, IHSGI projects 5,108 billion kWh of total U.S. generation plus imports for 2025, which is the highest among the projections reported. IHSGI's projections for total U.S. electricity generation plus imports continue to be the highest among the projections considered for 2035 and 2040.

Table CP4. Comparisons of electricity projections, 2025, 2035, and 2040 (billion kilowatthours, except where noted) (continued)

Sector	2012	*AEO2014* Reference	EVA	IHSGI	INFORUM	ICF
				2035		
Average end-use price (2012 cents per kilowatthour)[a]	9.8	10.7	--	11.9	16.1	--
Residential	11.9	12.9	--	14.4	19.3	--
Commercial	10.1	10.9	--	12.3	16.4	--
Industrial	6.7	7.8	--	8.0	10.9	--
Total generation plus net imports	**4,102**	**5,034**	**4,765**	**5,606**	**--**	**5,242**
Coal	1,512	1,679	1,661	1,203	--	1,609
Petroleum	23	19	--	22	--	4
Natural gas[b]	1,239	1,726	1,828	2,362	--	2,122
Nuclear	769	786	665	898	--	593
Hydroelectric/other[c]	511	793	611	1,066	--	913
Solar	11	61	34	--	--	49
Wind	142	227	241	513	--	397
Net imports	47	31	--	55	--	--
Electricity sales[d]	3,686	4,454	4,510	5,057	4,398	--
Residential	1,375	1,585	1,605	1,910	1,685	--
Commercial/other[e]	1,331	1,604	1,624	1,801	1,596	--
Industrial	981	1,265	1,281	1,347	1,117	--
Capacity, including CHP (gigawatts)[f]	1,066	1,237	1,215	1,385	--	1,266
Coal	310	262	231	227	--	244
Oil and natural gas	471	633	674	685	--	660
Nuclear	102	99	84	114	--	77
Hydroelectric/other[g]	182	243	227	360	--	286
Solar	8	36	25	--	--	32
Wind	59	80	89	169	--	138
Cumulative capacity retirements from 2011 (gigawatts)[h]	--	96	--	172	--	129
Coal	--	51	--	92	--	69
Oil and natural gas	--	40	--	70	--	30
Nuclear	--	5	--	11	--	29
Hydroelectric/other[g]	--	1	--	--	--	1

-- = not reported.
See notes at end of table.

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In the AEO2014 Reference case, generation from coal-fired plants is projected to exceed generation from natural-gas fired plants by 270 billion kWh in 2025. By comparison, in the IHSGI projection for 2025, total natural gas-fired generation is projected to exceed coal-fired generation by 394 billion kWh. IHSGI has previously projected that the total generation from natural gas-fired plants would exceed that for coal-fired plants in 2024 as a result of the assumed implementation of a carbon tax. In the AEO2014

Table CP4. Comparisons of electricity projections, 2025, 2035, and 2040 (billion kilowatthours, except where noted) (continued)

Sector	2012	*AEO2014* Reference	EVA	IHSGI	INFORUM	ICF
				2040		
Average end-use price (2012 cents per kilowatthour)[a]	9.8	11.1	--	12.1	19.1	--
Residential	11.9	13.3	--	14.5	22.8	--
Commercial	10.1	11.3	--	12.4	19.3	--
Industrial	6.7	8.2	--	8.1	12.8	--
Total generation plus net imports	**4,102**	**5,254**	**5,020**	**5,825**	**--**	**5,478**
Coal	1,512	1,675	1,477	944	--	1,483
Petroleum	23	19	--	20	--	4
Natural gas[b]	1,239	1,857	2,303	2,743	--	2,497
Nuclear	769	811	611	898	--	473
Hydroelectric/other[c]	511	857	628	1,165	--	1,021
Solar	11	86	35	--	--	50
Wind	142	250	254	573	--	491
Net imports	47	35	--	55	--	--
Electricity sales[d]	3,686	4,623	4,757	5,256	4,539	--
Residential	1,375	1,657	1,704	2,004	1,783	--
Commercial/other[e]	1,331	1,693	1,742	1,869	1,651	--
Industrial	981	1,273	1,310	1,384	1,105	--
Capacity, including CHP (gigawatts)[f]	1,066	1,316	1,273	1,448	--	1,344
Coal	310	262	202	176	--	243
Oil and natural gas	471	687	764	763	--	719
Nuclear	102	102	76	114	--	62
Hydroelectric/other[g]	182	265	231	395	--	319
Solar	8	48	25	--	--	32
Wind	59	87	93	189	--	169
Cumulative capacity retirements from 2011 (gigawatts)[h]	--	97	--	259	--	152
Coal	--	51	--	146	--	70
Oil and natural gas	--	40	--	102	--	30
Nuclear	--	5	--	11	--	50
Hydroelectric/other[g]	--	1	--	--	--	1

-- = not reported.

[a]Average end-use price includes the transportation sector.

[b]Includes supplemental gaseous fuels. For EVA, represents total oil and natural gas.

[c]Other includes conventional hydroelectric, pumped storage, geothermal, wood, wood waste, municipal waste, other biomass, solar and wind power, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, petroleum coke, and miscellaneous technologies.

[d]Electricity sales for EVA and INFORUM reflect the sum of the individual sector level sales.

[e]Other includes sales of electricity to government and other transportation services.

[f]EIA capacity is net summer capability, including CHP plants and end-use generators.

[g]Other includes conventional hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, wind, pumped storage, and fuel cells.

[h]Retirements for AEO2014 reflect the electric power sector only.

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Reference case, which is based on current laws and regulations and does not include a carbon tax, generation from natural gas-fired plants does not surpass generation from coal-fired plants until 2035.

There are varying outlooks for generation from U.S. nuclear power plants. Nuclear generation projections for the year 2025 range from a low of 779 billion kWh in the AEO2014 Reference case to a high of 875 billion kWh in the IHSGI projection. The AEO2014 Reference case reflects increasing U.S. nuclear generation, with increases to 786 billion kWh in 2035 and 811 billion kWh in 2040. In the IHSGI projection, nuclear generation increases to 898 billion kWh in 2035, and remains at 898 billion kWh in 2040. Both ICF and EVA project declines in nuclear generation through 2040.

Generation from nonhydroelectric renewable resources constitutes a significant portion of generation growth. However, the share of total generation from nonhydroelectric renewables varies across the projections. For instance, in 2035 the AEO2014 Reference case and EVA, respectively, show 5.8% and 5.8% shares of total generation from wind and solar, and IHSGI and ICF, respectively, show 9.2% and 8.5% shares from wind and solar. Part of this variation may be due to the adoption of different assumptions regarding the extension or enhancement of federal and state policies.

Total generating capacity by fuel in 2025 (including combined heat and power [CHP]) is fairly similar across the projections, ranging from 1,109 gigawatts (GW) in the EVA projection (the AEO2014 Reference case projects 1,110 gigawatts) to 1,225 GW in the IHSGI projection. IHSGI projects slightly more growth in total generating capacity, corresponding to their higher projections for both sales and generation.

Projections for capacity retirements vary widely over the 2012-40 period. Cumulative capacity retirements from 2013 through 2025 are closely aligned, ranging from a high of 104 GW in the ICF projection to 87 GW in the AEO2014 Reference case and 98 GW in the IHSGI projection. The majority of the retirements in the ICF, AEO2014 Reference case, and IHSGI projections from 2013 to 2025 are attributed to reductions in coal-fired capacity. Coal-fired capacity also represents the largest portion of cumulative retirements from 2013 to 2040. However, there is substantial variation in the projected timing of coal retirements. In the AEO2014 Reference case there are no incremental coal-fired capacity retirements from 2025 to 2035, but ICF and IHSGI project incremental coal-fired capacity retirements of 3 GW and 41 GW, respectively, over the same period. In general, the projected coal-fired capacity retirements are balanced by increases in natural gas- and oil-fired capacity (dominated by natural gas) and hydroelectric/other capacity (dominated by wind and solar).

CP5. Natural gas

The projections for natural gas consumption, production, imports, and prices differ significantly among the outlooks (Table CP5). The variations result, in large part, from differences in underlying assumptions. For example, the AEO2014 Reference case assumes that current laws and regulations remain unchanged through the projection period, whereas some of the other projections include assumptions about anticipated policy developments over the period. In particular, the AEO2014 Reference case does not incorporate any future changes in policy directed at carbon emissions or other environmental issues, while some of the other outlooks include explicit assumptions about policies aimed at reducing carbon emissions.

Production

All of the outlooks shown in Table CP5 (with the exception of ExxonMobil, which did not provide production data) project increases in natural gas production from 2012, when production totaled 24.1 trillion cubic feet (Tcf). EVA projects the largest production increase, to 38.3 Tcf in 2035, or 59% more than the 2012 level. EVA is followed closely by IHSGI, which projects 38.1 Tcf of natural gas production in 2035, a 58% increase over 2012 levels. ICF projects the third-highest production growth after EVA and IHSGI, at 37.4 Tcf in 2035. ICF, EVA, and IHSGI all project significantly larger increases in natural gas production before 2025 than in the later years.

The AEO2014 Reference case and BP, p.l.c. (BP) project relatively modest growth in natural gas production, particularly in the near term. The two projections show natural gas production increasing more rapidly, on average, from 2012 to 2025 than from 2025 to 2035. In the AEO2014 Reference case, natural gas production rises by 50% from 2012 to 2035, when total production is 36.1 Tcf. BP projects a production increase of 46% from 2012 to 35.1 Tcf in 2035.

INFORUM shows by far the lowest growth in natural gas production from 2012 through 2035, at 15%, with total production of 27.7 Tcf in 2035. INFORUM also projects relatively higher production growth from 2012 to 2025 than from 2025 to 2035.

Net imports/exports

The AEO2014 Reference case projects the strongest export growth over the 2012-35 period, attributable to exports via pipeline and as liquefied natural gas (LNG). The United States becomes a net LNG exporter by 2016 and an overall net exporter of natural gas by 2018. In 2035, the United States has net exports of 5.5 Tcf of natural gas, as a result of further growth in both LNG exports and net pipeline exports. U.S. exports of LNG from new liquefaction capacity surpass 2.0 Tcf in 2020 and increase to 3.5 Tcf in 2029. In addition, net pipeline exports increase to 2.2 Tcf in the AEO2014 Reference case, buoyed by higher net pipeline exports to Mexico and lower net pipeline imports from Canada.

All of the other projections show the United States becoming a net natural gas exporter by 2020, but they differ from AEO2014 in terms of export levels. Both EVA and IHSGI show net exports peaking early in the projection period but declining through 2035,

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with net exports in 2035 that are less than one-quarter of those in the AEO2014 Reference case. Both EVA and IHSGI show the domestic sector consuming a greater portion of U.S. natural gas production than in the AEO2014 Reference case. In the EVA and IHSGI projections, U.S. net natural gas exports in 2035 total 1.0 and 1.3 Tcf, respectively. Unlike IHSGI, the EVA projection of 3.2 Tcf of net LNG exports in 2035 is fairly close to the 3.4 Tcf in the AEO2014 Reference case in 2035. EVA differs from the Reference

Table CP5. Comparisons of natural gas projections, 2025, 2035, and 2040 (trillion cubic feet, except where noted)

Projection	2012	*AEO2014* Reference	IHSGI	EVA	ICF	BP[a]	ExxonMobil	INFORUM
					2025			
Dry gas production[b]	24.06	31.86	34.26	33.14	33.15	31.96	--	26.20
Net imports	**1.51**	**-3.41**	**-1.81**	**-2.34**	**-3.02**	**--**	**--**	**--**
Pipeline	1.37	-0.84	--	0.64	-0.80	--	--	--
LNG	0.15	-2.57	--	-2.99	-2.22	--	--	--
Consumption	**25.64**	**28.35**	**32.52**	**32.15**	**29.64**	**28.28**	**29.30[c]**	**24.84[c]**
Residential	4.17	4.40	4.60	5.09	5.04	--	8.00[d]	4.71
Commercial	2.90	3.22	3.24	3.55	3.11	--	--	3.38
Industrial[e]	7.14	8.41	7.96	9.56	7.96	--	9.00	7.82
Electric generators[f]	9.25	9.49	13.28	10.61	10.90	--	12.00	8.92
Others[g]	2.18	2.84	3.45	3.35	2.64	--	0.30	--
Henry Hub spot market price (2012 dollars per million Btu)	2.75	5.23	3.92	5.69	5.44[h]	--	--	--
End-use prices (2012 dollars per thousand cubic feet)								
Residential	10.69	12.75	11.37	--	--	--	--	--
Commercial	8.29	10.51	9.26	--	--	--	--	--
Industrial[i]	3.85	6.46	6.18	--	--	--	--	--
Electricity generation	3.51	5.88	4.60	--	--	--	--	--
					2035			
Dry gas production[b]	24.06	36.09	38.07	38.32	37.45	35.14	--	27.72
Net imports	**1.51**	**-5.53**	**-1.33**	**-1.04**	**-3.66**	**--**	**--**	**--**
Pipeline	1.37	-2.16	--	2.15	-1.47	--	--	--
LNG	**0.15**	-3.37	--	-3.19	-2.19	--	--	--
Consumption	**25.64**	**30.44**	**36.66**	**39.13**	**33.39**	**31.13**	**31.70[c]**	**25.19[c]**
Residential	4.17	4.23	4.56	5.07	5.00	--	7.00[d]	4.53
Commercial	2.90	3.40	3.33	3.62	2.93	--	--	3.51
Industrial[e]	7.14	8.59	7.55	10.56	8.19	--	9.00	7.80
Electric generators[f]	9.25	10.67	16.17	15.76	14.28	--	15.00	9.36
Others[g]	2.18	3.54	5.06	4.14	3.00	--	0.70	--
Henry Hub spot market price (2012 dollars per million Btu)	2.75	6.92	4.42	6.46	6.89[h]	--	--	--
End-use prices (2012 dollars per thousand cubic feet)								
Residential	10.69	14.93	11.88	--	--	--	--	--
Commercial	8.29	12.22	9.79	--	--	--	--	--
Industrial[i]	3.85	7.93	6.69	--	--	--	--	--
Electricity generation	3.51	7.45	5.13	--	--	--	--	--

-- = not reported.
See notes at end of table.

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case in that it projects net pipeline imports of natural gas into the United States after 2020, rather than net pipeline exports, with gross natural gas pipeline imports into the United States more than tripling between 2025 and 2035.

In the ICF projection, the United States becomes a net exporter of both pipeline gas and LNG by 2025, and remains so through 2035. The increase in net exports in the ICF projection, to 3.7 Tcf in 2035, is significantly larger than projected by EVA and IHSGI but significantly smaller than projected in the AEO2014 Reference case. The AEO2014 and ICF production and price projections are similar to each other, but the ICF projection shows less natural gas going to other countries and more consumed at home.

Consumption

In the AEO2014 Reference case, total domestic natural gas consumption increases by 19% from 2012 to 2035 when it totals 30.4 Tcf, which is the lowest projected increase in total consumption among the comparable projections. Although the INFORUM projection shows lower volumes, they are not comparable since they are missing natural gas consumed for lease and plant operations and as a pipeline fuel. The 4.8 Tcf increase in total domestic consumption in the AEO2014 Reference case is also 32% less than the projected 7.0 Tcf increase in natural gas net exports, whereas IHSGI, EVA, and ICF all show domestic consumption growth exceeding net export growth through 2035. The AEO2014 Reference case projects more rapid growth in industrial consumption from 2012 to 2035 (20%, to a total of 8.6 Tcf in 2035) than in power sector consumption (15%, to 10.7 Tcf in 2035). Some of the variation in electric sector consumption may be the result of different assumptions about potential fees on carbon emissions, which are not included in the AEO2014 Reference case.

Table CP5. Comparisons of natural gas projections, 2025, 2035, and 2040 (trillion cubic feet, except where noted) (continued)

Projection	2012	*AEO2014* Reference	IHSGI	EVA	ICF	BP[a]	ExxonMobil	INFORUM
					2040			
Dry gas production[b]	24.06	37.54	40.80	--	--	--	--	31.58
Net imports	**1.51**	**-5.80**	**-0.90**	**-1.13**	--	--	--	--
Pipeline	1.37	-2.43	--	2.06	--	--	--	--
LNG	0.15	-3.37	--	-3.19	--	--	--	--
Consumption	**25.64**	**31.63**	**39.83**	**40.99**	--	--	**31.00[c]**	**24.86[c]**
Residential	4.17	4.12	4.56	5.06	--	--	7.00[d]	4.43
Commercial	2.90	3.57	3.38	3.63	--	--	--	3.58
Industrial[e]	7.14	8.68	7.39	11.09	--	--	8.00	7.84
Electric generators[f]	9.25	11.23	18.43	16.90	--	--	15.00	9.01
Others[g]	2.18	4.03	6.07	4.30	--	--	1.00	--
Henry Hub spot market price (2012 dollars per million Btu)	2.75	7.65	4.54	--	--	--	--	--
End-use prices (2012 dollars per thousand cubic feet)								
Residential	10.69	16.33	12.00	--	--	--	--	--
Commercial	8.29	13.37	9.91	--	--	--	--	--
Industrial[i]	3.85	8.78	6.81	--	--	--	--	--
Electricity generation	3.51	8.34	5.26	--	--	--	--	--

-- = not reported.

[a]Projections for total consumption and production are for all of North America. Consumption by type provided only on a worldwide level. The conversion factor used is 1 million metric tons of oil equivalent = 39.2 billion cubic feet of natural gas.

[b]Does not include supplemental fuels.

[c]Does not include lease, plant, and pipeline fuel.

[d]Natural gas consumed in the residential and commercial sectors.

[e]Includes consumption for industrial CHP plants and a small number of industrial electricity-only plants, and natural gas-to-liquids heat/power and production; excludes consumption by nonutility generators.

[f]Includes consumption of energy by electricity-only and CHP plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes electric utilities, small power producers, and exempt wholesale generators.

[g]Includes lease, plant, and pipeline fuel and fuel consumed in natural gas vehicles.

[h]Converted to 2012 dollars using EIA's GDP deflator.

[i]The IHSGI 2012 industrial natural gas price is $4.84 per million Btu.

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IHSGI, EVA, and ICF show higher projections for total natural gas consumption in 2035 than in the AEO2014 Reference case, with consumption in the electric power sector accounting for a larger share of total U.S. consumption than other sectors. IHSGI shows the largest increase in electric power sector consumption through 2035, at 75%, with 2035 consumption totaling 16.2 Tcf. EVA shows a 70% increase, to 15.8 Tcf in 2035.

EVA differs from IHSGI in that it shows industrial consumption growing to 10.6 Tcf in 2035 (the highest level among the projections), whereas IHSGI shows relatively flat consumption in the industrial sector. EVA also differs from IHSGI in its projection for the electric power sector, which shows most growth occurring after 2025, whereas the IHSGI projection shows most of the growth in electric power sector natural gas use occurring before 2025. Like EVA and the AEO2014 Reference case, ICF projects most growth in electric power sector natural gas consumption occurring after 2025. ICF projects 54% growth in power sector natural gas use, to 14.3 Tcf in 2035, which is less than projected by IHSGI and EVA but significantly more than in the AEO2014 Reference case. The AEO2014 projection for natural gas consumption in the electric power sector is lower than the others, but its projection for industrial sector natural gas consumption in 2035 is exceeded only by EVA and ExxonMobil.

ExxonMobil projects electric power sector natural gas consumption growth of 62% to 15.0 Tcf in 2035. Like EVA and ICF, ExxonMobil shows most of the growth occurring after 2025. ExxonMobil also projects strong growth for natural gas consumption in the industrial sector, to 9.0 Tcf in 2035. Although the BP projection shows lower production growth than AEO2014 through 2035, it shows higher growth in domestic natural gas consumption, presumably as a result of lower net exports. Only INFORUM projects lower consumption growth than the AEO2014 Reference case through 2035. In the INFORUM projection, delivered (excluding lease, plant, and pipeline fuel) U.S. natural gas consumption totals 25.2 Tcf in 2035—less than the 2012 total.

Prices

Only four of the outlooks included in Table CP5 provide projections for Henry Hub natural gas spot prices. Prices from IHSGI are significantly lower than those in the AEO2014 Reference case, EVA, and ICF projections, particularly in the later years. IHSGI projects a Henry Hub price of $4.42 in 2035, in 2012 dollars/million Btu (MMBtu). All the other projections are well over $6/MMBtu, even though the IHSGI production level is one of the highest. Through 2025, the AEO2014 Reference case has the second lowest projected Henry Hub prices after IHSGI; however, it has the highest projected 2035 spot price, at $6.92/MMBtu in real 2012 dollars, followed by EVA and ICF, at $6.46 and $6.89/MMBtu, respectively.

In the AEO2014 Reference case, commercial, residential, electric power, and industrial natural gas prices all rise from 2012 to 2035 by between $3.93 and $4.24/thousand cubic feet (Mcf) in real 2012 dollars. IHSGI is the only other outlook that projects natural gas prices by sector, and like the IHSGI Henry Hub price projection, they are far lower than those in the AEO2014 Reference case. IHSGI projects price increases from 2012 to 2035 ranging from $1.19/Mcf in the residential sector to $2.84/Mcf in the industrial sector, with the commercial and electric power sectors increasing by $1.50 and $1.61/Mcf, respectively.

CP6. Petroleum and other liquid fuels

In the AEO2014 Reference case, the North Sea Brent crude oil spot price (in 2012 dollars) declines from about $112/barrel in 2012 to $109/barrel in 2025 before rising to $130/barrel in 2035 and $141/barrel in 2040 (Table CP6). North Sea Brent crude oil spot prices increase steadily in the INFORUM projection, rising from $124/barrel in 2025 to $154/barrel in 2035. In the AEO2014 Reference case, the U.S. imported refiner acquisition cost (IRAC) for crude oil (in 2012 dollars) declines to about $100/barrel in 2025, then increases to $120/barrel in 2035 and $131/barrel in 2040. IRAC prices in the IEA projection are higher, ranging from $112/barrel in 2025 to $140/barrel in 2035. BP, EVA, ExxonMobil, and IHSGI did not report projections of North Sea Brent or IRAC crude oil prices.

In the AEO2014 Reference Case, domestic crude oil production increases from about 6.5 million barrels/day (MMbbl/d) in 2012 to a peak of 9.6 MMbbl/d in 2019 before falling to 9.0 MMbbl/d in 2025, about 7.9 MMbbl/d in 2035, and 7.5 MMbbl/d in 2040. Overall, the production level in 2035 is more than 21% higher than in 2012. The INFORUM projection shows a considerable increase in production, to 8.8 MMbbl/d in 2035. The EVA projection shows an even steeper increase, with crude oil production reaching 11.8 MMbbl/d in 2025 before falling slightly to 11.5 MMbbl/d in 2035. Both the IHSGI and ExxonMobil projections are considerably below the AEO2014 Reference case, with domestic crude oil production in 2035 at 7.2 MMbbl/d and 4.6 MMbbl/d, respectively.

With rapid growth in U.S. crude oil production, net imports fall in the AEO2014 Reference case and in the other projections. In the AEO2014 Reference case, total net imports of crude oil and products fall from 7.5 MMbbl/d in 2012 to a low of 5.0 MMbbl/d in 2025 before increasing to 5.9 MMbbl/d in 2040. In the IHSGI projection, total net imports are slightly higher in 2025 at 6.0 MMbbl/d and rise slightly to 6.2 MMbbl/d in 2040 as a result of growing net exports of products. The BP projection shows total net imports falling to 3.7 MMbbl/d in 2025, whereas the INFORUM projection shows total net imports increasing from 6.9 MMbbl/d in 2025 to 7.0 MMbbl/d in 2035.

Biofuel production increases to about 1.0 MMbbl/d in 2025 and then remains at roughly that level through 2040 in the AEO2014 Reference case. In the BP projection, biofuel production, on an energy-equivalent basis, increases to 1.1 MMbbl/d in 2025. The IHSGI projection is slightly higher, at 1.2 MMbbl/d in 2025. BP does not show biofuel production in 2035. IHSGI shows biofuel

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production falling slightly to 1.1 MMbbl/d in 2035 and remaining near that level in 2040. Biofuels production is not explicitly included in the projections by EVA, INFORUM, IEA, and ExxonMobil.

Prices for diesel fuel increase through 2040 in the AEO2014 projection, while gasoline prices are lower in both 2025 and 2035 compared to 2012. INFORUM projects increases in both gasoline and diesel prices through 2035, with the gasoline price nearly equaling the diesel price in 2035. IHSGI projects falling gasoline and diesel fuel prices, with gasoline prices nearly $0.70/gallon lower and diesel fuel prices more than $1.16/gallon lower in 2040 than projected in the AEO2014 Reference case. The BP, EVA, IEA, and ExxonMobil projections do not include delivered fuel prices.

CP7. Coal

The AEO2014 Reference case generally projects the highest levels of total coal production, consumption, exports, and prices in comparison with the coal outlooks available from EVA, ICF, IHSGI, and BP (Table CP7). One key exception is INFORUM, whose projections of coal production, consumption, and exports are consistently higher than the AEO2014 projections. The IEA's *World Energy Outlook 2013* Current Policies case projections for coal consumption also are slightly higher than the AEO2014 projections, but only one year of the projection, 2035, is available for comparison.

The detailed assumptions that underlie the various projections are not generally available to EIA, although there are some important known differences that contribute to the range of outlooks. For example, the AEO2014 Reference case assumes current laws and regulations, whereas other projections reflect alternative policy outcomes affecting the coal sector, particularly with respect to the price of carbon emissions. Although not shown in Table CP7, ExxonMobil projects a larger decline in U.S. coal consumption than any other group. The ExxonMobil outlook, which features a fee on CO^2 emissions that rises to $80/metric ton (2013 dollars) in 2040, shows U.S. coal consumption declining from 17 quadrillion Btu in 2012 to 6 quadrillion Btu in 2040, an amount that is approximately 70% below the AEO2014 Reference case outlook for 2040 [*1*]. IHSGI, which has the second-lowest projection for coal consumption, assumes a CO^2 cap-and-trade program for the electricity sector that begins in 2021 and features a CO^2 allowance price that increases to $20/metric ton (2012 dollars) in 2040 [*2*]. EVA and ICF include a carbon pollution standard for

Table CP6. Comparisons of petroleum and other liquids projections, 2025, 2035, and 2040 (million barrels per day, except where noted)

Projection	2012	*AEO2014* Reference	BP[a,b]	EVA	INFORUM[c]	IEA[b]	ExxonMobil[c]	IHSGI
					2025			
U.S. refiner imported acquisition cost of crude oil (2012 dollars per barrel)	101.10	100.01	--	--	112.14	--	--	--
Brent spot price (2012 dollars per barrel)	111.65	108.99	--	--	123.86	127.00	--	--
U.S. WTI crude oil price (2012 dollars per barrel)	94.12	106.99	--	--	--	--	--	94.35
Domestic production	**8.89**	**11.88**	**12.57**	**15.30**	--	--	--	**11.12**
Crude oil	6.49	9.00	--	11.79	8.28	--	4.60	7.54
Alaska	0.53	0.33	--	0.34	--	--	--	--
Natural gas liquids	2.40	2.87	--	3.51	--	--	--	3.58
Total net imports	**7.52**	**5.05**	**3.74**	--	**6.95**	--	--	**5.99**
Crude oil	8.43	6.05	--	--	6.92	--	--	7.77
Products	-0.92	-1.01	--	--	0.03	--	--	-1.78
Petroleum and other liquids consumption	18.49	19.27	17.69	--	18.64	--	19.04	19.82
Net petroleum import share of liquids supplied (percent)	40	26	21	--	--	--	--	30
Biofuel production	0.91	0.97	1.14	--	--	--	--	1.16
Transportation product prices (2012 dollars per gallon)								
Gasoline	3.69	3.29	--	--	4.04	--	--	3.27
Diesel	3.95	3.98	--	--	4.30	--	--	3.60

-- = not reported.
See notes at end of table.

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new plants. ICF also includes a carbon cap-and-trade program beginning in 2023. EVA, ICF, and IHSGI assume the implementation of new regulations for cooling water intake and coal combustion residuals. Because those policies are not current law, the AEO2014 Reference case excludes them, which contributes to the lower coal consumption projections in many of the other outlooks relative to AEO2014. Variation among the assumptions about growth in energy demand and other fuel prices, particularly for natural gas, also contribute to the differences.

Although the AEO2014 Reference case projection for total coal consumption is somewhat lower than the INFORUM and IEA projections, the other outlooks offer more pessimistic projections. IHSGI is the most pessimistic, with coal consumption 30% and 44% lower in 2035 and 2040, respectively, than in the AEO2014 Reference case. Lower natural gas prices (37% lower in 2040 than in the AEO2014 Reference case) and a CO^2 allowance price assumption for the power sector are key reasons for lower coal consumption in the IHSGI projection. In the EVA outlook, coal consumption in 2035 is only 2% less than in the AEO2014 Reference case; in the ICF outlook it is 14% lower. From 2035 to 2040, the differences between the EVA and ICF projections and the AEO2014 Reference case widen: in the EVA outlook, coal consumption in 2040 is 16% below the AEO2014 Reference case projection, and in the ICF outlook it is 21% lower than in the AEO2014 Reference case. The BP outlook for total coal consumption is 9% lower than the AEO2014 Reference case in 2025 and 19% lower in 2035, whereas the INFORUM outlook is 25% (247 million tons) higher in 2035 and 32% (315 million tons) higher in 2040 than projected in the AEO2014 Reference case.

The electricity sector is the predominant consumer of coal and the primary source of differences among the projections, due to differing assumptions about regulations and the economics of coal versus other fuels over time. Because the power sector accounts for more than 90% of total U.S. coal consumption, the variations in the projections for electricity sector coal consumption across the different groups primarily mirror those for total coal consumption. In 2025, the projected levels of electricity sector coal consumption for the three groups that supplied projections for all three comparison years (EVA, ICF, and IHSGI) range from 16% less to 2% more than in AEO2014. The range widens to between 30% below and 0% difference in 2035 and 44% below to 16% below in 2040, with IHGSI representing the lower end of the range and EVA the upper end. Electricity sector coal use in the EVA projection aligns most closely with the AEO2014 projection, although the two diverge after 2035, with EVA projecting a decline

Table CP6. Comparisons of petroleum and other liquids projections, 2025, 2035, and 2040 (million barrels per day, except where noted) (continued)

Projection	2012	*AEO2014* Reference	BP[a,b]	EVA	INFORUM[c]	IEA[b]	ExxonMobil[c]	IHSGI
					2035			
U.S. refiner imported acquisition cost of crude oil (2012 dollars per barrel)	101.10	119.80	--	--	139.67	--	--	--
Brent spot price (2012 dollars per barrel)	111.65	129.77	--	--	154.26	145.00	--	--
U.S. WTI crude oil price (2012 dollars per barrel)	94.12	127.77	--	--	--	--	--	95.66
Domestic production	**8.89**	**10.92**	**11.99**	**15.24**	**--**	**--**	**--**	**10.84**
Crude oil	6.49	7.87	--	11.46	8.76	--	4.60	7.16
Alaska	0.53	0.38	--	0.00	--	--	--	--
Natural gas liquids	2.40	3.05	--	3.78	--	--	--	3.68
Total net imports	**7.52**	**5.54**	**--**	**--**	**7.00**	**--**	**--**	**6.13**
Crude oil	8.43	7.15	--	--	7.26	--	--	7.39
Products	-0.92	-1.61	--	--	-0.26	--	--	-1.26
Petroleum and other liquids consumption	18.49	18.76	--	--	18.06	16.33	18.53	19.55
Net petroleum import share of liquids supplied (percent)	40	30	--	--	--	--	--	31
Biofuel production	0.91	0.97	--	--	--	--	--	1.09
Transportation product prices (2012 dollars per gallon)								
Gasoline	3.69	3.65	--	--	4.70	--	--	3.22
Diesel	3.95	4.47	--	--	4.77	--	--	3.59

-- = not reported.
See notes at end of table.

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in coal use for electricity generation during this period and EIA projecting a stable outlook. IEA's projection for power sector coal consumption is available only for 2035 and is 7% higher than the AEO2014 Reference case. BP's projections are available only for 2025 and 2035; the 2035 projection is 17% lower than the AEO2014 Reference case projection. INFORUM, which has the highest projections for total coal consumption, did not supply projections for electricity sector coal use.

Projections of coal-fired generating capacity in Table CP4 underlie the projections for electricity sector coal consumption. For the most part, coal-fired generating capacity in the AEO2014, EVA, ICF, and IHSGI projections align with their respective levels of projected electricity sector coal consumption. The AEO2014 Reference case shows the highest level of coal-fired generating capacity in 2040 and IHSGI the lowest. In the AEO2014 Reference case, coal-fired generating capacity in the electric power sector declines from 307 GW in 2012 to 258 GW in 2040. ICF, EVA, and IHSGI project 243 GW, 202 GW, and 176 GW of coal-fired generating capacity, respectively, in 2040. In the AEO2014 Reference case, the 48-GW decline in coal-fired generating capacity from 2012 to 2040 is the net result of 51 GW of cumulative retirements and 3 GW of additions. IHSGI projects 146 GW of cumulative coal-fired generating capacity retirements from 2012 to 2040 and 10 GW of coal-fired capacity additions.

In all the projections, coal consumption in the end-use sectors is low in comparison with the electric power sector; however, there are some significant differences. The largest variations occur in the projections for the other industrial/buildings sector, where the AEO2014 projection is generally higher than the projections from the other groups, with the exception of INFORUM. While the AEO2014 Reference case shows a relatively flat outlook for coal consumption in the other industrial/buildings sector after rebounding from a low of 45 million tons in 2012, the other projections generally show significant declines from 2012 to 2025, with steady consumption levels thereafter. In 2040, the projections for coal consumption in the other industrial/buildings sector provided by EVA, ICF, and IHSGI range from a low of 7 million tons (ICF) to a high of 33 million tons (EVA), and all are considerably lower than the AEO2014 projection of 52 million tons.

The projections for coal consumption at coke plants are similar to AEO2014, which shows a slight decline in coking coal consumption, from 21 million tons in 2012 to 18 million tons in 2040. The largest deviation from AEO2014 is in the ICF projection, which shows

Table CP6. Comparisons of petroleum and other liquids projections, 2025, 2035, and 2040 (million barrels per day, except where noted) (continued)

Projection	2012	*AEO2014* Reference	BP[a,b]	EVA	INFORUM[c]	IEA[b]	ExxonMobil[c]	IHSGI
					2040			
U.S. refiner imported acquisition cost of crude oil (2012 dollars per barrel)	101.10	130.80	--	--	154.97	--	--	--
Brent spot price (2012 dollars per barrel)	111.65	141.46	--	--	171.16	--	--	--
U.S. WTI crude oil price (2012 dollars per barrel)	94.12	139.46	--	--	--	--	--	95.63
Domestic production	**8.89**	**10.46**	--	--	--	--	--	**10.88**
Crude oil	6.49	7.48	--	--	10.35	--	4.30	7.16
Alaska	0.53	0.26	--	--	--	--	--	--
Natural gas liquids	2.40	2.98	--	--	--	--	--	3.72
Total net imports	**7.52**	**5.93**	--	--	**6.80**	--	--	**6.16**
Crude oil	8.43	7.74	--	--	7.47	--	--	7.02
Products	-0.92	-1.82	--	--	-0.66	--	--	-0.86
Petroleum and other liquids consumption	18.49	18.73	--	--	18.16	--	17.96	19.56
Net petroleum import share of liquids supplied (percent)	40	32	--	--	--	--	--	32
Biofuel production	0.91	0.97	--	--	--	--	--	1.05
Transportation product prices (2012 dollars per gallon)								
Gasoline	3.69	3.90	--	--	5.14	--	--	3.20
Diesel	3.95	4.73	--	--	5.08	--	--	3.57

-- = not reported.

[a]BP production data converted from million tonnes of oil equivalent at 8.067817 bbl/MTOE.

[b]BP and IEA demand data converted from million tonnes of oil equivalent at 8.162674 bbl/MTOE.

[c]INFORUM and ExxonMobil liquids demand data converted from quadrillion Btu to barrels at 187.84572 million barrels per quadrillion Btu.

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coal consumption at coke plants declining to 10 million tons in 2040. INFORUM, which provided projections only for total end-use sector coal consumption, shows slightly higher levels of coal use in these sectors than AEO2014 for all comparison years. ICF is the only group projecting any production of coal-based synthetic liquids, with coal consumption at coal-to-liquids plants increasing to 6 million tons in 2025 and 14 million tons in 2040.

For coal production, differences in the projections are primarily the result of differences in the outlooks for coal consumption and net exports (which basically equal total coal production when added together) [3]. Because the AEO2014 projections for net coal exports are generally similar to those from other groups, the percent differences in the projected levels of coal production between the AEO2014 Reference case and those from other groups generally align with the percent differences in the projections for coal consumption. The most substantial deviation is in the ICF outlook for 2040, where the ICF projection for coal production is 12% less than the AEO2014 Reference case, and the outlook for coal consumption is 21% less. ICF's projection for coal production in 2040 is supported by a relatively strong outlook for net coal exports at 205 million tons, which is 28% higher than in AEO2014.

Coal production by region is available in the AEO2014, EVA, and ICF projections. For the most part, the EVA and ICF projections of regional coal production are less than in AEO2014. This is consistent with the generally lower projections for total coal production in the EVA and ICF outlooks. Although the shares of coal production by region remain relatively constant in AEO2014, with coal production east of the Mississippi River accounting for between 40% and 42% of total coal production in all years, the EVA projection shows the region's share of total U.S. coal production fall from 42% in 2012 to 35% in 2040, and ICF projects an increase to 49% in 2040.

In the AEO2014 Reference case, exports increase gradually from 126 million tons in 2012 to 160 million tons in 2035 and remain flat through 2040, maintaining 12% to 14% shares of total U.S. coal production over time. The EVA projection shows exports growing modestly, to 135 million tons in 2025, then remaining flat through 2040 and maintaining a share of total U.S. production similar to that in the AEO2014 projection. Exports in the IHSGI outlook are similar to those in the AEO2014 Reference case, but the share of total U.S. production in 2040 is much higher, at 22%, because of a projected significant reduction in total U.S. production. After a modest decrease from 2012 to 2025, the ICF projection shows exports recover more than in the other projections—to 206 million tons, or 21% of total U.S. coal production. Exports in the INFORUM outlook are similar to those in the ICF projection for 2040, although they represent only 13% of their stronger expected total U.S. coal production.

Table CP7. Comparisons of coal projections, 2025, 2035, and 2040 (million short tons, except where noted)

		AEO2014 Reference case		Other projections					
Projection	2012	(million short tons)	(quadrillion Btu)	EVA[a]	ICF[b]	IHSGI[c]	INFORUM	IEA[d]	BP[d]
				(million short tons)				(quadrillion Btu)	
		2025							
Production	**1,016**	**1,114**	**22.36**	**1,111**	**1,005**	**970**	**1,253**	--	**18.9**
East of the Mississippi	423	446	--	435	377	--	--	--	--
West of the Mississippi	593	668	--	676	628	--	--	--	--
Consumption									
Electric power	825	919	17.41	937	867	771	--	--	16.4
Coke plants	21	22	0.58	21	12	19	--	--	--
Coal-to-liquids	--	--	--	--	6	--	--	--	--
Other industrial/buildings	45	51	1.63[e]	36	8	38	1.69[e]	--	--
Total consumption (quadrillion Btu)	**17.34**	--	**19.03**	--		**16.41**	--	--	**17.3**
Total consumption (million short tons)	**891**	**993**	--	**994**	**893**	**828**	**1,117[f]**	--	--
Net coal exports	**118**	**135**	**3.27**	--	**110**	**142**	**136**	--	**1.6[g]**
Exports	126	136	--	135	111	144	140	--	--
Imports	8	2	--	--	1	2	4	--	--
Minemouth price									
2012 dollars per ton	39.94	49.67	--	--	31.94	--	44.93	--	--
2012 dollars per Btu	1.98	2.49	--	--	1.60	--	2.26	--	--
Average delivered price to electricity generators									
2012 dollars per ton	46.13	52.56	--	--	42.33	50.77	--	--	--
2012 dollars per Btu	2.39	2.77	--	--	2.17	2.59	--	--	--

-- = not reported.
See notes at end of table.

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In the AEO2014, ICF, and IHSGI projections, coal imports decline from 8 million tons in 2012 to 2 million tons or less in 2025 and remain at that level through 2040. INFORUM projects an initial decline in coal imports, to 4 million tons in 2025, followed by an increase to 34 million tons in 2040. EVA, IEA, and BP did not provide projections for coal imports.

Only AEO2014, ICF, and INFORUM provide projections of minemouth coal prices. All three show prices increasing from 2025 through 2040. The AEO2014 Reference case projects the highest mine prices in every comparison year, with the average price rising from about $40/ton in 2012 to $59/ton in 2040. The ICF outlook has the lowest projections, with prices declining initially to about $32/ton in 2025 and increasing thereafter to $37/ton in 2040. In the INFORUM projection, average minemouth coal prices increase to $52/ton in 2040.

Projections for the average delivered price of coal to the electricity sector are available only from AEO2014, ICF, and IHSGI. Similarly to the projections for minemouth coal prices, AEO2014 projects the highest delivered coal prices in every comparison year. In the AEO2014 Reference case, the delivered price of coal to the power sector increases from about $46/ton in 2012 to $61/ton in 2040. By comparison, the ICF price projections are the lowest in each year, with a 2040 projection of $44/ton, or 27% less than in the AEO2014 Reference case. In the IHSGI projection, the delivered price of coal to the power sector increases to $52/ton in 2040, or 15% below the AEO2014 Reference case projection.

Table CP7. Comparisons of coal projections, 2025, 2035, and 2040 (million short tons, except where noted) (continued)

		AEO2014 Reference case		Other projections					
Projection	2012	(million short tons)	(quadrillion Btu)	EVA[a]	ICF[b]	IHSGI[c]	INFORUM	IEA[d]	BP[d]
				(million short tons)				(quadrillion Btu)	
				2035					
Production	1,016	1,126	22.68	1,084	1,004	837	1,386	--	16.3
East of the Mississippi	423	471	--	414	427	--	--	--	--
West of the Mississippi	593	655	--	670	577	--	--	--	--
Consumption									
Electric power	825	915	17.32	910	820	637	--	18.57	14.4
Coke plants	21	19	0.50	21	11	18	--	--	--
Coal-to-liquids	--	--	--	--	11	--	--	--	--
Other industrial/buildings	45	51	1.54[e]	34	7	33	1.61[e]	--	--
Total consumption (quadrillion Btu)	17.34	--	18.82	--		13.56	--	20.87	15.2
Total consumption (million short tons)	891	985	--	965	849	688	1,232[f]	--	--
Net coal exports	118	158	3.76	--	153	151	154	--	1.1[g]
Exports	126	160	--	137	154	153	173	--	--
Imports	8	2	--	--	1	2	20	--	--
Minemouth price									
2012 dollars per ton	39.94	56.37	--	--	33.55	--	50.10	--	--
2012 dollars per Btu	1.98	2.82	--	--	1.66	--	2.52	--	--
Average delivered price to electricity generators									
2012 dollars per ton	46.13	57.76	--	--	42.92	52.93	--	--	--
2012 dollars per Btu	2.39	3.05	--	--	2.19	2.72	--	--	--

-- = not reported.
See notes at end of table.

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Table CP7. Comparisons of coal projections, 2025, 2035, and 2040 (million short tons, except where noted) (continued)

Projection	2012	*AEO2014* Reference case (million short tons)	*AEO2014* Reference case (quadrillion Btu)	Other projections: EVA[a]	ICF[b]	IHSGI[c]	INFORUM	IEA[d]	BP[d]
				(million short tons)				(quadrillion Btu)	
				2040					
Production	1,016	1,121	22.61	938	981	703	1,451	--	--
East of the Mississippi	423	475	--	331	481	--	--	--	--
West of the Mississippi	593	645	--	607	500	--	--	--	--
Consumption									
Electric power	825	909	17.27	764	742	506	--	--	--
Coke plants	21	18	0.47	22	10	17	--	--	--
Coal-to-liquids	--		--	--	14	--	--	--	--
Other industrial/buildings	45	52	1.53[e]	33	7	30	1.66[e]	--	--
Total consumption (quadrillion Btu)	**17.34**	--	**18.75**	--	--	**10.75**	--	--	--
Total consumption (million short tons)	**891**	**979**	--	**819**	**773**	**553**	**1,294[f]**	--	--
Net coal exports (million short tons)	**118**	**160**	**3.76**	--	**205**	**154**	**157**	--	--
Exports	126	161	--	137	206	156	191	--	--
Imports	8	1	--	--	1	2	34	--	--
Minemouth price									
2012 dollars per ton	39.94	59.16	--	--	36.58	--	52.20	--	--
2012 dollars per Btu	1.98	2.96	--	--	1.76	--	2.63	--	--
Average delivered price to electricity generators									
2012 dollars per ton	46.13	60.61	--	--	43.96	51.76	--	--	--
2012 dollars per Btu	2.39	3.19	--	--	2.22	2.71	--	--	--

-- = not reported.

[a]Regulations known to be accounted for in the EVA projections include MATS, carbon pollution standard for new plants, regulations for cooling-water intake structures under Section 316(b) of the Clean Water Act, and regulations for coal combustion residuals under authority of the Resource Conservation and Recovery Act.

[b]Regulations known to be accounted for in the ICF projections include MATS for mercury (Hg), hydrochloric acid (HCl), and filterable particulate matter (fPM) requirements starting in 2016, Phase I and II for CAIR followed by a more stringent CAIR replacement in 2018 to address 2012 National Ambient Air Quality Standards (NAAQS) for PM2.5, carbon pollution standard for new plants, entrainments requirements for cooling water intake structures beginning in 2025, coal combustion residual requirements under subtitle D starting in 2018, and a federal carbon cap-and-trade program starting in 2023.

[c]The IHSGI projections include a CO2 cap-and-trade program for the electricity sector that begins in 2021 and a CO2 allowance price that increases to $20 per metric ton (2012 dollars) in 2040.

[d]For IEA and BP, data were converted to quadrillion Btu from million metric tons of oil equivalent using a conversion factor of 39.683 million Btu per metric ton of oil equivalent.

[e]Reported in quadrillion Btu and represents coal consumed in both the other industrial/buildings sector and at coke plants. This was done to facilitate comparison between the AEO2014 and INFORUM projections, because INFORUM provided projections only for total end-use coal consumption.

[f]Total coal consumption for the INFORUM projection equals (production - exports + imports).

[g]Net coal exports for the BP projection equals (production - consumption).

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Endnotes for Comparison with other projections

Links current as of April 2014

1. ExxonMobil Corporation, "The Outlook for Energy: A View to 2040" (Irving, TX, 2013), http://cdn.exxonmobil.com/~/media/Reports/Outlook%20For%20Energy/2014/2014-Outlook-for-Energy.pdf; and W. Colton, "The Outlook for Energy: A View to 2040" (Irving, TX, December 12, 2013), http://cdn.exxonmobil.com/~/media/Reports/Outlook%20For%20Energy/2014/ExxonMobil_2014_Outlook-for-Energy_Rollout_Presentation.pdf.
2. E-mail on February 10, 2014 from Margaret Rhodes of IHS Global Insight.
3. For the AEO2014 Reference case, waste coal is counted as part of overall coal consumption but is not counted as part of coal production. Rather, waste coal is considered to be a separate source of coal supply. As a result, the AEO2014 Reference case projection of coal production in tons equals coal consumption plus net exports minus waste coal.

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Table sources

Links current as of April 2014

Table CP1. Comparisons of average annual economic growth projections, 2012-40: AEO2014 (Reference case): AEO2014 National Energy Modeling System, run REF2014.D102413A. AEO2013 (Reference case): AEO2013 National Energy Modeling System, run REF2013.D102312A. IHSGI: IHS Global Insight, 30-year U.S. Economic Forecast (Lexington, MA, October 2013), http://www.ihs.com/products/global-insight/index.aspx (subscription site). OMB: Office of Management and Budget, Budget of the United States Government, Fiscal Year 2015 (Washington, DC, January 2014), http://www.whitehouse.gov/sites/default/files/omb/budget/fy2015/assets/budget.pdf. CBO: Congressional Budget Office, *The Budget and Economic Outlook: 2014 to 2024* (Washington, DC, February 2014), http://www.cbo.gov/publication/45010. INFORUM: *INFORUM AEO2012 Reference Case, Lift (Long-term Interindustry Forecasting Tool) Model* (College Park, MD, January 2014), http://inforumweb.umd.edu/services/models/lift.html. SSA: Social Security Administration, OASDI Trustees Report, *The Long-Range Economic Assumptions for the 2013 Trustees Report* (U.S. Government Printing Office, Washington, DC, May 2013), http://www.ssa.gov/oact/tr/2013/2013_Long-Range_Economic_Assumptions.pdf. IEA (2013): International Energy Agency, *World Energy Outlook 2013* (Paris, France, November 2013), http://www.iea.org/Textbase/nppdf/stud/13/weo2013.pdf. ExxonMobil: *ExxonMobil 2014 The Outlook for Energy: A View to 2040* (Irving, TX, 2013), http://www.exxonmobil.com/Corporate/energy_outlook.aspx. OEG: Oxford Economics, Ltd., 2014 Long Term Forecast (Oxford, United Kingdom, January 2014), http://www.OxfordEconomics.com (subscription site).

Table CP2. Comparisons of oil price projections, 2025, 2035, and 2040: AEO2014 (Reference case): AEO2014 National Energy Modeling System, run REF2014.D102413A. AEO2014 (Low Oil Price case): AEO2014 National Energy Modeling System, run LOWPRICE.D120613. AEO2014 (High Oil Price case): AEO2014 National Energy Modeling System, run HIGHPRICE.D120613A. AEO2013 (Reference case): AEO2013 National Energy Modeling System, run REF2013.D102312A. Energy SEER: Strategic Energy & Economic Research, Inc., e-mail from Michael Lynch (Amherst, MA, January 2014). ArrowHead Economics: ArrowHead Economics LLC, e-mail from Dale Nesbitt (Los Altos Hills, CA, January 2014), www.arrowheadeconomics.com. EVA: Energy Ventures Analysis, Inc., e-mail from Anthony Petruzzo, January 17, 2014. INFORUM: *INFORUM AEO2012 Reference Case, Lift (Long-term Interindustry Forecasting Tool) Model* (College Park, MD, January 2014), http://inforumweb.umd.edu/services/models/lift.html. ESAI: Energy Security Analysis, Inc., e-mail from Sarah Emerson (Wakefield, MA, March 2014), www.esai.com. IEA (Current Policies Scenario): International Energy Agency, *World Energy Outlook 2013* (Paris, France, November 2013), http://www.iea.org/Textbase/nppdf/stud/13/weo2013.pdf.

Table CP3. Comparisons of energy consumption projections by sector, 2025, 2035, and 2040: AEO2014 (Reference case): AEO2014 National Energy Modeling System, run REF2014.D102413A. INFORUM: *INFORUM AEO2012 Reference Case, Lift (Long-term Interindustry Forecasting Tool) Model* (College Park, MD, January 2014), http://inforumweb.umd.edu/services/models/lift.html. IHSGI: IHS Global Insight, 30-year U.S. Economic Forecast (Lexington, MA, October 2013), http://www.ihs.com/products/global-insight/index.aspx (subscription site). ExxonMobil: *ExxonMobil 2014 The Outlook for Energy: A View to 2040* (Irving, TX, 2013), http://www.exxonmobil.com/Corporate/energy_outlook.aspx. IEA (Current Policies Scenario): International Energy Agency, *World Energy Outlook 2013* (Paris, France, November 2013), http://www.iea.org/Textbase/nppdf/stud/13/weo2013.pdf.

Table CP4. Comparisons of electricity projections, 2025, 2035, and 2040: AEO2014 (Reference case): AEO2014 National Energy Modeling System, run REF2014.D102413A. EVA: Energy Ventures Analysis, Inc., e-mail from Anthony Petruzzo, January 17, 2014. IHSGI: IHS Global Insight, 30-year U.S. Economic Forecast (Lexington, MA, October 2013), http://www.ihs.com/products/global-insight/index.aspx (subscription site). INFORUM: *INFORUM AEO2012 Reference Case, Lift (Long-term Interindustry Forecasting Tool) Model* (College Park, MD, January 2014), http://inforumweb.umd.edu/services/models/lift.html. ICF: *ICF International Integrated Energy Outlook Q1 2014*, ICF Integrated Planning Model (IPM) and Gas Market Model (GMM) (Fairfax, VA, 1st Quarter 2014.

Table CP5. Comparisons of natural gas projections, 2025, 2035, and 2040: AEO2014 (Reference case): AEO2014 National Energy Modeling System, run REF2014.D102413A. IHSGI: IHS Global Insight, 30-year U.S. Economic Forecast (Lexington, MA, October 2013), http://www.ihs.com/products/global-insight/index.aspx (subscription site). EVA: Energy Ventures Analysis, Inc., e-mail from Anthony Petruzzo, January 17, 2014. ICF: *ICF International Integrated Energy Outlook Q1 2014*, ICF Integrated Planning Model (IPM) and Gas Market Model (GMM) (Fairfax, VA, 1st Quarter 2014. BP: BP, p.l.c., e-mail from Mark J. Finley, January 17, 2014. ExxonMobil: *ExxonMobil 2014 The Outlook for Energy: A View to 2040* (Irving, TX, 2013), http://www.exxonmobil.com/Corporate/energy_outlook.aspx. INFORUM: *INFORUM AEO2012 Reference Case, Lift (Long-term Interindustry Forecasting Tool) Model* (College Park, MD, January 2014), http://inforumweb.umd.edu/services/models/lift.html.

Table CP6. Comparisons of petroleum and other liquids projections, 2025, 2035, and 2040: AEO2014 (Reference case): AEO2014 National Energy Modeling System, run REF2014.D102413A. BP: BP, p.l.c., e-mail from Mark J. Finley, January 17, 2014. EVA: Energy Ventures Analysis, Inc., e-mail from Anthony Petruzzo, January 17, 2014. INFORUM: *INFORUM AEO2012 Reference Case, Lift (Long-term Interindustry Forecasting Tool) Model* (College Park, MD, January 2014), http://inforumweb.umd.edu/services/models/lift.html. IEA (Current Policies Scenario): International Energy Agency, *World Energy Outlook 2013* (Paris, France, November 2013), http://www.iea.org/Textbase/nppdf/stud/13/weo2013.pdf. ExxonMobil: *ExxonMobil 2014 The Outlook for Energy: A View to 2040* (Irving, TX, 2013), http://www.exxonmobil.com/Corporate/energy_outlook.aspx. IHSGI: IHS Global Insight, 30-year U.S. Economic Forecast (Lexington, MA, October 2013), http://www.ihs.com/products/global-insight/index.aspx (subscription site).

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Table CP7. Comparisons of coal projections, 2025, 2035, and 2040: AEO2014 (Reference case): AEO2014 National Energy Modeling System, run REF2014.D102413A. EVA: Energy Ventures Analysis, Inc., e-mail from Anthony Petruzzo, January 17, 2014. ICF: *ICF International Integrated Energy Outlook Q1 2014,* ICF Integrated Planning Model (IPM) and Gas Market Model (GMM) (Fairfax, VA, 1st Quarter 2014. IHSGI: IHS Global Insight, 30-year U.S. Economic Forecast (Lexington, MA, October 2013), http://www.ihs.com/products/global-insight/index.aspx (subscription site). INFORUM: *INFORUM AEO2012 Reference Case, Lift (Long-term Interindustry Forecasting Tool) Model* (College Park, MD, January 2014), http://inforumweb.umd.edu/services/models/lift.html. IEA (Current Policies Scenario): International Energy Agency, *World Energy Outlook 2013* (Paris, France, November 2013), http://www.iea.org/Textbase/nppdf/stud/13/weo2013.pdf. BP: BP, p.l.c., e-mail from Mark J. Finley, January 17, 2014.

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List of acronyms

AB 32	California Assembly Bill 32, the Global Warming Solutions Act of 2006
AC	Alternating current
ACP	Alternative compliance payment
AEO	Annual Energy Outlook
AEO2012	Annual Energy Outlook 2012
AEO2013	Annual Energy Outlook 2013
AEO2014	Annual Energy Outlook 2014
ARRA2009	American Recovery and Reinvestment Act of 2009
AZNM	Arizona, New Mexico, and Nevada
Bcf	Billion cubic feet
BP	BP, p.l.c.
BTL	Biomass-to-liquids
BNSF	Burlington Northern Santa Fe
BWRs	Boiling water reactors
Btu	British thermal units
BEA	Bureau of Economic Analysis
Bu16	Biobutanol blends with 16% biobutanol and 84% gasoline
CAFE	Corporate average fuel economy
CAIR	Clean Air Interstate Rule
CAMX	WECC California
CBO	Congressional Budget Office
CBTL	Coal- and biomass-to-liquids
CCS	Carbon capture and storage
CEUS	Central and Eastern United States
CFL	Compact fluorescent lighting
CHP	Combined heat and power
CMM	Coal Market Module
CNG	Compressed natural gas
COL	Combined operating license
CO_2	Carbon dioxide
CO_2-EOR	Carbon dioxide-enhanced oil recovery
CSAPR	Cross-State Air Pollution Rule
CTL	Coal-to-liquids
DC	Direct current
DG	Distributed generation
DOE	U.S. Department of Energy
DSI	Dry sorbent injection
E10	Motor gasoline blend containing up to 10 percent ethanol
E15	Motor gasoline blend containing up to 15 percent ethanol
E85	Motor fuel containing up to 85 percent ethanol
EIA	U.S. Energy Information Administration
ESICA	Energy Savings and Industrial Competitiveness Act of 2013
EIEA2008	Energy Improvement and Extension Act of 2008
EISA2007	Energy Independence and Security Act of 2007
EPACT2005	Energy Policy Act of 2005
EPRI	Electric Power Research Institute
EMM	Electricity Market Module
EPA	U.S. Environmental Protection Agency
EPACT2005	Energy Policy Act of 2005
ESAI	Energy Security Analysis
EUR	Estimated ultimate recovery
EVA	Energy Ventures Analysis
FCC	Fluid catalytic cracking
FEMA	Federal Emergency Management Administration
FFV	Flex-fuel vehicle
FGD	Flue gas desulfurization (scrubbers)
FRA	Federal Railroad Administration
Gal	Gallons
GDP	Gross domestic product
GHG	Greenhouse gas
GTL	Gas-to-liquids
GVWR	Gross vehicle weight rating
GW	Gigawatts
HDV	Heavy-duty vehicle
HGL	Hydrocarbon gas liquids
Hg	Mercury
HPDI	High-pressure direct injection
ICF	ICF International, Incorporated
IDM	Industrial Demand Module
IEA	International Energy Agency
IEM	International Energy Module
IGCC	Integrated gasification combined cycle
IHSGI	IHS Global Insight, Inc.
INFORUM	Interindustry Forecasting Project at the University of Maryland
INPO	Institute for Nuclear Power Operations
IRAC	U.S. imported refiner acquisition cost
ITC	Investment tax credit
KW	Kilowatt
kWh	Kilowatthours
LCFS	Low Carbon Fuel Standard
LDV	Light-duty vehicle
LED	Light-emitting diode
LFG	Landfill gas
LFMM	Liquid Fuels Market Module
LNG	Liquefied natural gas
MACT	Maximum achievable control technology
Mcf	Thousand cubic feet
MW	Megawatts
MWh	Megawatthours
MATS	Mercury and Air Toxics Standards
MAM	Macroeconomic Activity Module
Mpg	Miles per gallon
MMbbl/d	Million barrels per day
MMBtu	Million British thermal units
MRO	Midwest Reliability Organization
MMmt	Million metric tons
MY	Model year
MSW	Municipal solid waste
NAICS	North American Industry Classification System
NEMS	National Energy Modeling System
NERC	North American Electric Reliability Corporation
NGCC	Natural gas combined-cycle
NGPL	Natural gas plant liquids
NGTDM	Natural Gas Transmission and Distribution Module
NHTSA	National Highway Traffic Safety Administration
NIPA	National Income and Product Accounts
NO_x	Nitrogen oxides
NRC	U.S. Nuclear Regulatory Commission
O&M	Operations and maintenance
OECD	Organization for Economic Cooperation and Development

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List of acronyms (continued)

OEG	Oxford Economics Group
OMB	Office of Management and Budget
OPEC	Organization of the Petroleum Exporting Countries
PADDs	Petroleum Administration for Defense Districts
PCs	Personal computers
PTC	Production tax credit
PV	Solar photovoltaic
RGGI	Regional Greenhouse Gas Initiative
RFM	Renewable Fuels Module
RFS	Renewable fuel standard
RPS	Renewable portfolio standard
R&D	Research and development
RFC	ReliabilityFirst Corporation
RTO	Regional Transmission Organization
SEER	Strategic Energy & Economic Research
SERC	SERC Reliability Corporation
SO_2	Sulfur dioxide
SSA	Social Security Administration
SRVC	Virginia, North Carolina, and South Carolina
STEO	Short-Term Energy Outlook
TRE	Texas Reliability Entity
Tcf	Trillion cubic feet
VMT	Vehicle miles traveled
WECC	Western Electricity Coordinating Council
WTI	West Texas Intermediate
WUS	Western United States

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Appendix A

Reference case

Table A1. Total energy supply, disposition, and price summary

(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Production								
Crude oil and lease condensate	12.20	13.87	20.36	19.19	17.71	16.81	16.00	0.5%
Natural gas plant liquids	3.11	3.21	3.54	3.84	3.98	4.08	3.99	0.8%
Dry natural gas	23.04	24.59	29.73	32.57	35.19	36.89	38.37	1.6%
Coal[1]	22.22	20.60	21.70	22.36	22.61	22.68	22.61	0.3%
Nuclear / uranium[2]	8.26	8.05	8.15	8.15	8.18	8.23	8.49	0.2%
Hydropower	3.11	2.67	2.81	2.84	2.87	2.89	2.90	0.3%
Biomass[3]	3.90	3.78	4.66	5.08	5.29	5.44	5.61	1.4%
Other renewable energy[4]	1.70	1.97	3.01	3.09	3.23	3.44	3.89	2.5%
Other[5]	0.80	0.41	0.24	0.24	0.24	0.24	0.24	-2.0%
Total	**78.35**	**79.15**	**94.19**	**97.36**	**99.30**	**100.70**	**102.09**	**0.9%**
Imports								
Crude oil	19.52	18.57	13.15	13.70	15.00	16.12	17.43	-0.2%
Petroleum and other liquids[6]	5.21	4.26	4.21	4.20	4.08	4.00	3.93	-0.3%
Natural gas[7]	3.56	3.21	2.39	2.04	2.01	2.06	2.28	-1.2%
Other imports[8]	0.43	0.36	0.17	0.15	0.12	0.11	0.10	-4.5%
Total	**28.71**	**26.40**	**19.92**	**20.09**	**21.22**	**22.29**	**23.73**	**-0.4%**
Exports								
Petroleum and other liquids[9]	5.95	6.29	6.30	6.48	6.91	7.40	7.70	0.7%
Natural gas[10]	1.52	1.63	4.30	5.45	6.96	7.60	8.09	5.9%
Coal	2.75	3.22	3.13	3.31	3.55	3.81	3.79	0.6%
Total	**10.22**	**11.14**	**13.73**	**15.24**	**17.42**	**18.81**	**19.58**	**2.0%**
Discrepancy[11]	**-0.27**	**-0.61**	**-0.35**	**-0.24**	**-0.17**	**-0.11**	**-0.07**	**- -**
Consumption								
Petroleum and other liquids[12]	36.56	35.87	36.86	36.28	35.65	35.37	35.35	-0.1%
Natural gas	24.91	26.20	27.65	28.97	30.03	31.10	32.32	0.8%
Coal[13]	19.62	17.34	18.56	19.03	19.01	18.82	18.75	0.3%
Nuclear / uranium[2]	8.26	8.05	8.15	8.15	8.18	8.23	8.49	0.2%
Hydropower	3.11	2.67	2.81	2.84	2.87	2.89	2.90	0.3%
Biomass[14]	2.60	2.53	3.35	3.74	3.95	4.10	4.26	1.9%
Other renewable energy[4]	1.70	1.97	3.01	3.09	3.23	3.44	3.89	2.5%
Other[15]	0.35	0.39	0.34	0.35	0.35	0.33	0.35	-0.4%
Total	**97.11**	**95.02**	**100.73**	**102.45**	**103.27**	**104.28**	**106.31**	**0.4%**
Prices (2012 dollars per unit)								
Crude oil spot prices (dollars per barrel)								
Brent	113.24	111.65	96.57	108.99	118.99	129.77	141.46	0.8%
West Texas Intermediate	96.55	94.12	94.57	106.99	116.99	127.77	139.46	1.4%
Natural gas at Henry Hub (dollars per million Btu)	4.07	2.75	4.38	5.23	6.03	6.92	7.65	3.7%
Coal (dollars per ton)								
at the minemouth[16]	41.74	39.94	46.52	49.67	53.15	56.37	59.16	1.4%
Coal (dollars per million Btu)								
at the minemouth[16]	2.07	1.98	2.33	2.49	2.67	2.82	2.96	1.4%
Average end-use[17]	2.61	2.60	2.85	3.02	3.17	3.29	3.43	1.0%
Average electricity (cents per kilowatthour)	10.1	9.8	10.1	10.1	10.4	10.7	11.1	0.4%

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Table A1. Total energy supply, disposition, and price summary (continued)

(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Prices (nominal dollars per unit)								
Crude oil spot prices (dollars per barrel)								
Brent	111.26	111.65	109.37	134.25	160.19	193.27	234.53	2.7%
West Texas Intermediate	94.86	94.12	107.11	131.78	157.49	190.30	231.22	3.3%
Natural gas at Henry Hub (dollars per million Btu)	4.00	2.75	4.96	6.45	8.12	10.31	12.69	5.6%
Coal (dollars per ton)								
at the minemouth[16]	41.01	39.94	52.69	61.18	71.55	83.96	98.08	3.3%
Coal (dollars per million Btu)								
at the minemouth[16]	2.04	1.98	2.63	3.07	3.59	4.21	4.91	3.3%
Average end-use[17]	2.56	2.60	3.23	3.72	4.27	4.90	5.68	2.8%
Average electricity (cents per kilowatthour)	9.9	9.8	11.5	12.5	14.0	16.0	18.5	2.3%

[1]Includes waste coal.
[2]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[3]Includes grid-connected electricity from wood and wood waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[4]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy data.
[5]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[6]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[7]Includes imports of liquefied natural gas that are later re-exported.
[8]Includes coal, coal coke (net), and electricity (net). Excludes imports of fuel used in nuclear power plants.
[9]Includes crude oil, petroleum products, ethanol, and biodiesel.
[10]Includes re-exported liquefied natural gas.
[11]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[12]Estimated consumption. Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids and crude oil consumed as a fuel. Refer to Table A17 for detailed renewable liquid fuels consumption.
[13]Excludes coal converted to coal-based synthetic liquids and natural gas.
[14]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[15]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[16]Includes reported prices for both open market and captive mines. Prices weighted by production, which differs from average minemouth prices published in EIA data reports where it is weighted by reported sales.
[17]Prices weighted by consumption; weighted average excludes export free-alongside-ship (f.a.s.) prices.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 natural gas supply values: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2011*, DOE/EIA-0131(2011) (Washington, DC, December 2012). 2012 natural gas supply values: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2013/06) (Washington, DC, June 2013). 2011 and 2012 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2012*, DOE/EIA-0584(2012) (Washington, DC, December 2013). 2012 petroleum supply values and 2011 crude oil and lease condensate production: EIA, *Petroleum Supply Annual 2012*, DOE/EIA-0340(2012)/1 (Washington, DC, September 2013). Other 2011 petroleum supply values: EIA, *Petroleum Supply Annual 2011*, DOE/EIA-0340(2011)/1 (Washington, DC, August 2012). 2011 and 2012 crude oil spot prices and natural gas spot price at Henry Hub: Thomson Reuters. Other 2011 and 2012 coal values: *Quarterly Coal Report, October-December 2012*, DOE/EIA-0121(2012/4Q) (Washington, DC, March 2013). Other 2011 and 2012 values: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). **Projections:** EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

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Table A2. Energy consumption by sector and source

(quadrillion Btu per year, unless otherwise noted)

Sector and source	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Energy consumption								
Residential								
Propane	0.51	0.51	0.42	0.40	0.38	0.36	0.35	-1.3%
Kerosene	0.02	0.01	0.00	0.00	0.00	0.00	0.00	-2.5%
Distillate fuel oil	0.53	0.51	0.46	0.41	0.37	0.34	0.31	-1.7%
Petroleum and other liquids subtotal	1.05	1.02	0.89	0.82	0.75	0.70	0.66	-1.5%
Natural gas	4.82	4.26	4.56	4.50	4.43	4.32	4.21	0.0%
Renewable energy[1]	0.54	0.45	0.46	0.45	0.44	0.43	0.42	-0.3%
Electricity	4.85	4.69	4.84	5.00	5.21	5.41	5.65	0.7%
Delivered energy	**11.26**	**10.42**	**10.74**	**10.77**	**10.83**	**10.86**	**10.94**	**0.2%**
Electricity related losses	10.13	9.68	9.64	9.81	10.00	10.22	10.55	0.3%
Total	**21.39**	**20.10**	**20.38**	**20.58**	**20.83**	**21.09**	**21.48**	**0.2%**
Commercial								
Propane	0.15	0.15	0.16	0.16	0.17	0.17	0.18	0.7%
Motor gasoline[2]	0.05	0.05	0.04	0.05	0.05	0.05	0.05	0.6%
Kerosene	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.8%
Distillate fuel oil	0.42	0.40	0.40	0.39	0.38	0.37	0.37	-0.3%
Residual fuel oil	0.05	0.04	0.08	0.08	0.08	0.08	0.08	2.4%
Petroleum and other liquids subtotal	0.67	0.63	0.68	0.68	0.67	0.67	0.68	0.2%
Natural gas	3.22	2.96	3.23	3.29	3.35	3.48	3.65	0.7%
Coal	0.06	0.04	0.04	0.04	0.04	0.04	0.04	0.0%
Renewable energy[3]	0.11	0.13	0.13	0.13	0.13	0.13	0.13	0.0%
Electricity	4.53	4.52	4.69	4.94	5.18	5.42	5.72	0.8%
Delivered energy	**8.60**	**8.29**	**8.78**	**9.08**	**9.38**	**9.75**	**10.22**	**0.7%**
Electricity related losses	9.46	9.32	9.34	9.69	9.94	10.24	10.66	0.5%
Total	**18.05**	**17.61**	**18.12**	**18.77**	**19.32**	**19.99**	**20.88**	**0.6%**
Industrial[4]								
Liquefied petroleum gases and other[5]	2.25	2.25	2.90	3.05	3.05	2.97	2.90	0.9%
Motor gasoline[2]	0.26	0.26	0.30	0.30	0.30	0.29	0.29	0.4%
Distillate fuel oil	1.24	1.20	1.40	1.41	1.41	1.41	1.42	0.6%
Residual fuel oil	0.13	0.10	0.14	0.14	0.15	0.15	0.15	1.4%
Petrochemical feedstocks	0.88	0.75	1.27	1.52	1.62	1.62	1.59	2.7%
Other petroleum[6]	3.36	3.50	3.56	3.53	3.58	3.63	3.75	0.2%
Petroleum and other liquids subtotal	8.13	8.06	9.56	9.95	10.10	10.08	10.10	0.8%
Natural gas	7.06	7.29	8.26	8.59	8.71	8.78	8.87	0.7%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and plant fuel[7]	1.35	1.45	1.77	1.99	2.16	2.29	2.41	1.8%
Natural gas subtotal	8.41	8.75	10.04	10.58	10.87	11.07	11.28	0.9%
Metallurgical coal	0.56	0.55	0.58	0.58	0.55	0.50	0.47	-0.5%
Other industrial coal	0.95	0.93	0.99	1.00	1.00	1.00	1.01	0.3%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Net coal coke imports	0.01	0.00	0.00	-0.01	-0.03	-0.05	-0.05	- -
Coal subtotal	1.53	1.48	1.57	1.57	1.52	1.45	1.44	-0.1%
Biofuels heat and coproducts	0.46	0.52	0.76	0.79	0.79	0.79	0.79	1.5%
Renewable energy[8]	1.49	1.48	1.74	1.88	2.01	2.13	2.28	1.6%
Electricity	3.38	3.35	4.04	4.27	4.33	4.32	4.34	0.9%
Delivered energy	**23.40**	**23.63**	**27.71**	**29.05**	**29.62**	**29.84**	**30.22**	**0.9%**
Electricity related losses	7.06	6.91	8.05	8.38	8.33	8.16	8.10	0.6%
Total	**30.46**	**30.54**	**35.76**	**37.43**	**37.94**	**38.00**	**38.33**	**0.8%**

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Table A2. Energy consumption by sector and source (continued)

(quadrillion Btu per year, unless otherwise noted)

Sector and source	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Transportation								
Propane	0.05	0.05	0.05	0.05	0.06	0.06	0.07	1.1%
Motor gasoline[2]	16.37	16.33	15.00	13.69	12.69	12.24	12.09	-1.1%
of which: E85[9]	0.00	0.01	0.19	0.38	0.46	0.43	0.33	11.9%
Jet fuel[10]	3.01	3.00	3.08	3.14	3.20	3.24	3.28	0.3%
Distillate fuel oil[11]	6.04	5.82	6.70	7.04	7.25	7.44	7.54	0.9%
Residual fuel oil	0.78	0.58	0.58	0.59	0.59	0.60	0.60	0.2%
Other petroleum[12]	0.16	0.15	0.15	0.15	0.15	0.15	0.15	0.1%
Petroleum and other liquids subtotal	26.40	25.93	25.55	24.66	23.94	23.73	23.73	-0.3%
Pipeline fuel natural gas	0.70	0.73	0.74	0.76	0.82	0.83	0.85	0.5%
Compressed / liquefied natural gas	0.04	0.04	0.08	0.14	0.28	0.48	0.86	11.3%
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electricity	0.02	0.02	0.03	0.04	0.04	0.05	0.06	3.6%
Delivered energy	**27.16**	**26.72**	**26.40**	**25.60**	**25.08**	**25.10**	**25.50**	**-0.2%**
Electricity related losses	0.05	0.05	0.06	0.07	0.08	0.10	0.12	3.2%
Total	**27.21**	**26.77**	**26.47**	**25.67**	**25.17**	**25.20**	**25.62**	**-0.2%**
Delivered energy consumption for all sectors								
Liquefied petroleum gases and other[5]	2.95	2.96	3.53	3.67	3.65	3.56	3.49	0.6%
Motor gasoline[2]	16.67	16.64	15.34	14.04	13.04	12.59	12.44	-1.0%
of which: E85[9]	0.00	0.01	0.19	0.38	0.46	0.43	0.33	11.9%
Jet fuel[10]	3.01	3.00	3.08	3.14	3.20	3.24	3.28	0.3%
Kerosene	0.03	0.01	0.01	0.01	0.01	0.01	0.01	0.9%
Distillate fuel oil	8.23	7.93	8.95	9.24	9.41	9.56	9.63	0.7%
Residual fuel oil	0.97	0.72	0.80	0.81	0.82	0.82	0.83	0.5%
Petrochemical feedstocks	0.88	0.75	1.27	1.52	1.62	1.62	1.59	2.7%
Other petroleum[13]	3.52	3.64	3.70	3.68	3.73	3.78	3.89	0.2%
Petroleum and other liquids subtotal	36.25	35.64	36.68	36.10	35.47	35.18	35.17	0.0%
Natural gas	15.14	14.56	16.14	16.52	16.77	17.07	17.59	0.7%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and plant fuel[7]	1.35	1.45	1.77	1.99	2.16	2.29	2.41	1.8%
Pipeline fuel natural gas	0.70	0.73	0.74	0.76	0.82	0.83	0.85	0.5%
Natural gas subtotal	17.19	16.74	18.65	19.28	19.75	20.19	20.84	0.8%
Metallurgical coal	0.56	0.55	0.58	0.58	0.55	0.50	0.47	-0.5%
Other coal	1.01	0.98	1.03	1.04	1.04	1.04	1.05	0.3%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Net coal coke imports	0.01	0.00	0.00	-0.01	-0.03	-0.05	-0.05	- -
Coal subtotal	1.59	1.53	1.61	1.62	1.56	1.50	1.48	-0.1%
Biofuels heat and coproducts	0.46	0.52	0.76	0.79	0.79	0.79	0.79	1.5%
Renewable energy[14]	2.14	2.06	2.33	2.47	2.58	2.70	2.83	1.1%
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electricity	12.79	12.58	13.60	14.26	14.76	15.20	15.77	0.8%
Delivered energy	**70.42**	**69.07**	**73.63**	**74.50**	**74.91**	**75.56**	**76.88**	**0.4%**
Electricity related losses	26.69	25.95	27.10	27.95	28.35	28.73	29.43	0.5%
Total	**97.11**	**95.02**	**100.73**	**102.45**	**103.27**	**104.28**	**106.31**	**0.4%**
Electric power[15]								
Distillate fuel oil	0.06	0.05	0.09	0.09	0.09	0.09	0.09	1.8%
Residual fuel oil	0.25	0.18	0.09	0.09	0.09	0.10	0.10	-2.1%
Petroleum and other liquids subtotal	0.32	0.23	0.18	0.18	0.18	0.18	0.19	-0.8%
Natural gas	7.72	9.46	9.00	9.69	10.28	10.91	11.48	0.7%
Steam coal	18.03	15.82	16.95	17.41	17.44	17.32	17.27	0.3%
Nuclear / uranium[16]	8.26	8.05	8.15	8.15	8.18	8.23	8.49	0.2%
Renewable energy[17]	4.80	4.59	6.08	6.42	6.68	6.95	7.44	1.7%
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.0%
Electricity imports	0.13	0.16	0.11	0.12	0.12	0.10	0.12	-1.1%
Total	**39.49**	**38.53**	**40.70**	**42.21**	**43.12**	**43.92**	**45.20**	**0.6%**

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Table A2. Energy consumption by sector and source (continued)

(quadrillion Btu per year, unless otherwise noted)

Sector and source	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Total energy consumption								
Liquefied petroleum gases and other[5]	2.95	2.96	3.53	3.67	3.65	3.56	3.49	0.6%
Motor gasoline[2]	16.67	16.64	15.34	14.04	13.04	12.59	12.44	-1.0%
of which: E85[9]	0.00	0.01	0.19	0.38	0.46	0.43	0.33	11.9%
Jet fuel[10]	3.01	3.00	3.08	3.14	3.20	3.24	3.28	0.3%
Kerosene	0.03	0.01	0.01	0.01	0.01	0.01	0.01	0.9%
Distillate fuel oil	8.29	7.98	9.03	9.33	9.50	9.64	9.72	0.7%
Residual fuel oil	1.22	0.90	0.89	0.90	0.91	0.92	0.93	0.1%
Petrochemical feedstocks	0.88	0.75	1.27	1.52	1.62	1.62	1.59	2.7%
Other petroleum[13]	3.52	3.64	3.70	3.68	3.73	3.78	3.89	0.2%
Petroleum and other liquids subtotal	36.56	35.87	36.86	36.28	35.65	35.37	35.35	-0.1%
Natural gas	22.86	24.02	25.14	26.22	27.05	27.97	29.07	0.7%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and plant fuel[7]	1.35	1.45	1.77	1.99	2.16	2.29	2.41	1.8%
Pipeline fuel natural gas	0.70	0.73	0.74	0.76	0.82	0.83	0.85	0.5%
Natural gas subtotal	24.91	26.20	27.65	28.97	30.03	31.10	32.32	0.8%
Metallurgical coal	0.56	0.55	0.58	0.58	0.55	0.50	0.47	-0.5%
Other coal	19.05	16.79	17.98	18.45	18.49	18.36	18.32	0.3%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Net coal coke imports	0.01	0.00	0.00	-0.01	-0.03	-0.05	-0.05	- -
Coal subtotal	19.62	17.34	18.56	19.03	19.01	18.82	18.75	0.3%
Nuclear / uranium[16]	8.26	8.05	8.15	8.15	8.18	8.23	8.49	0.2%
Biofuels heat and coproducts	0.46	0.52	0.76	0.79	0.79	0.79	0.79	1.5%
Renewable energy[18]	6.95	6.65	8.40	8.88	9.26	9.65	10.27	1.6%
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.0%
Electricity imports	0.13	0.16	0.11	0.12	0.12	0.10	0.12	-1.1%
Total	**97.11**	**95.02**	**100.73**	**102.45**	**103.27**	**104.28**	**106.31**	**0.4%**
Energy use and related statistics								
Delivered energy use	70.42	69.07	73.63	74.50	74.91	75.56	76.88	0.4%
Total energy use	97.11	95.02	100.73	102.45	103.27	104.28	106.31	0.4%
Ethanol consumed in motor gasoline and E85	1.09	1.09	1.22	1.25	1.25	1.25	1.29	0.6%
Population (millions)	312.32	314.58	334.47	346.98	359.03	370.19	380.53	0.7%
Gross domestic product (billion 2005 dollars)	13,299	13,593	16,753	18,769	21,139	23,751	26,670	2.4%
Carbon dioxide emissions (million metric tons)	5,498.1	5,289.9	5,475.9	5,526.2	5,526.9	5,545.7	5,599.1	0.2%

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal water heating, and electricity generation from wind and solar photovoltaic sources.
[2]Includes ethanol and ethers blended into gasoline.
[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal water heating and electricity generation from wind and solar photovoltaic sources.
[4]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[5]Includes ethane, natural gasoline, and refinery olefins.
[6]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[7]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[8]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol in motor gasoline.
[9]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[10]Includes only kerosene type.
[11]Diesel fuel for on- and off- road use.
[12]Includes aviation gasoline and lubricants.
[13]Includes aviation gasoline, petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[14]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[15]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[16]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[17]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[18]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
Btu = British thermal unit.
- - = Not applicable.
Note: Includes estimated consumption for petroleum and other liquids. Totals may not equal sum of components due to independent rounding. Data for 2011 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 and 2012 consumption based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2011 and 2012 population and gross domestic product: IHS Global Insight Industry and Employment models, May 2013. 2011 and 2012 carbon dioxide emissions and emission factors: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). Projections: EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

012800

Table A3. Energy prices by sector and source

(2012 dollars per million Btu, unless otherwise noted)

Sector and source	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Residential								
Propane	25.28	24.12	23.79	24.86	25.75	26.84	27.64	0.5%
Distillate fuel oil	26.93	27.30	24.67	26.95	28.60	30.57	32.64	0.6%
Natural gas	10.98	10.46	11.59	12.48	13.50	14.61	15.98	1.5%
Electricity	34.95	34.83	36.15	36.14	36.98	37.82	38.83	0.4%
Commercial								
Propane	22.20	20.75	20.33	21.66	22.79	24.14	25.17	0.7%
Distillate fuel oil	26.43	26.81	21.77	24.01	25.66	27.69	29.72	0.4%
Residual fuel oil	19.41	22.84	14.40	16.13	17.92	19.36	20.99	-0.3%
Natural gas	8.96	8.11	9.49	10.29	11.19	11.95	13.08	1.7%
Electricity	30.53	29.55	30.80	30.55	31.26	31.98	33.01	0.4%
Industrial[1]								
Propane	22.63	21.09	20.64	22.06	23.27	24.73	25.84	0.7%
Distillate fuel oil	27.04	27.41	22.22	24.45	26.11	27.97	29.92	0.3%
Residual fuel oil	19.17	20.90	14.88	16.65	18.29	19.79	21.48	0.1%
Natural gas[2]	5.09	3.77	5.79	6.32	6.99	7.76	8.59	3.0%
Metallurgical coal	7.13	7.25	8.43	8.95	9.51	9.93	10.20	1.2%
Other industrial coal	3.31	3.24	3.59	3.73	3.88	4.03	4.19	0.9%
Coal to liquids	--	--	--	--	--	--	--	--
Electricity	20.35	19.50	20.77	21.08	21.99	22.91	24.05	0.8%
Transportation								
Propane	26.29	25.14	24.85	25.92	26.81	28.01	28.82	0.5%
E85[3]	44.13	35.06	25.61	27.53	27.91	30.68	35.49	0.0%
Motor gasoline[4]	30.32	30.68	25.59	27.37	28.54	30.40	32.67	0.2%
Jet fuel[5]	23.02	22.99	19.47	21.96	23.71	25.83	28.07	0.7%
Diesel fuel (distillate fuel oil)[6]	28.37	28.80	26.80	29.02	30.68	32.60	34.53	0.7%
Residual fuel oil	18.05	20.07	12.46	14.16	15.50	16.94	18.55	-0.3%
Natural gas[7]	15.90	14.64	15.62	15.57	16.63	18.09	19.67	1.1%
Electricity	34.00	31.43	29.86	30.09	31.68	32.65	34.19	0.3%
Electric power[8]								
Distillate fuel oil	23.79	24.12	20.66	22.94	24.65	26.68	28.81	0.6%
Residual fuel oil	15.94	20.68	13.86	15.59	17.14	18.74	20.42	0.0%
Natural gas	4.88	3.44	5.07	5.76	6.49	7.29	8.16	3.1%
Steam coal	2.42	2.39	2.61	2.77	2.93	3.05	3.19	1.0%
Average price to all users[9]								
Propane	24.39	23.24	22.54	23.68	24.66	25.89	26.79	0.5%
E85[3]	44.13	35.06	25.61	27.53	27.91	30.68	35.49	0.0%
Motor gasoline[4]	30.18	30.44	25.58	27.37	28.53	30.40	32.67	0.3%
Jet fuel[5]	23.02	22.99	19.47	21.96	23.71	25.83	28.07	0.7%
Distillate fuel oil	27.95	28.36	25.70	27.98	29.67	31.58	33.54	0.6%
Residual fuel oil	17.80	20.41	13.15	14.88	16.32	17.79	19.42	-0.2%
Natural gas	6.83	5.38	7.09	7.72	8.49	9.33	10.38	2.4%
Metallurgical coal	7.13	7.25	8.43	8.95	9.51	9.93	10.20	1.2%
Other coal	2.48	2.44	2.67	2.83	2.98	3.11	3.25	1.0%
Coal to liquids	--	--	--	--	--	--	--	--
Electricity	29.52	28.85	29.72	29.67	30.56	31.49	32.63	0.4%
Non-renewable energy expenditures by sector (billion 2012 dollars)								
Residential	249.85	234.06	249.25	258.12	272.82	287.79	306.56	1.0%
Commercial	183.94	173.25	189.44	200.39	215.91	232.66	255.39	1.4%
Industrial[1]	232.59	213.75	279.45	315.89	343.02	365.43	390.91	2.2%
Transportation	757.76	755.09	632.05	653.92	667.67	711.27	772.91	0.1%
Total non-renewable expenditures	1,424.14	1,376.15	1,350.18	1,428.32	1,499.43	1,597.14	1,725.77	0.8%
Transportation renewable expenditures	0.12	0.50	4.89	10.53	12.96	13.30	11.80	11.9%
Total expenditures	**1,424.26**	**1,376.66**	**1,355.07**	**1,438.85**	**1,512.39**	**1,610.44**	**1,737.56**	**0.8%**

012801

Table A3. Energy prices by sector and source (continued)

(nominal dollars per million Btu, unless otherwise noted)

Sector and source	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Residential								
Propane	24.83	24.12	26.94	30.63	34.67	39.98	45.83	2.3%
Distillate fuel oil	26.46	27.30	27.94	33.19	38.50	45.53	54.12	2.5%
Natural gas	10.79	10.46	13.13	15.37	18.18	21.75	26.49	3.4%
Electricity	34.34	34.83	40.94	44.52	49.78	56.33	64.39	2.2%
Commercial								
Propane	21.81	20.75	23.02	26.69	30.68	35.95	41.74	2.5%
Distillate fuel oil	25.97	26.81	24.66	29.57	34.54	41.24	49.27	2.2%
Residual fuel oil	19.07	22.84	16.31	19.87	24.12	28.84	34.80	1.5%
Natural gas	8.80	8.11	10.75	12.67	15.07	17.80	21.68	3.6%
Electricity	30.00	29.55	34.88	37.63	42.08	47.64	54.73	2.2%
Industrial[1]								
Propane	22.24	21.09	23.38	27.18	31.32	36.84	42.83	2.6%
Distillate fuel oil	26.56	27.41	25.17	30.12	35.15	41.66	49.61	2.1%
Residual fuel oil	18.84	20.90	16.85	20.51	24.62	29.47	35.61	1.9%
Natural gas[2]	5.00	3.77	6.56	7.79	9.41	11.55	14.25	4.9%
Metallurgical coal	7.01	7.25	9.55	11.03	12.81	14.80	16.91	3.1%
Other industrial coal	3.25	3.24	4.07	4.59	5.23	6.00	6.95	2.8%
Coal to liquids	--	--	--	--	--	--	--	--
Electricity	19.99	19.50	23.52	25.96	29.60	34.13	39.88	2.6%
Transportation								
Propane	25.83	25.14	28.14	31.93	36.09	41.71	47.79	2.3%
E85[3]	43.36	35.06	29.00	33.92	37.57	45.69	58.85	1.9%
Motor gasoline[4]	29.79	30.68	28.98	33.72	38.42	45.28	54.17	2.1%
Jet fuel[5]	22.61	22.99	22.06	27.05	31.91	38.47	46.53	2.5%
Diesel fuel (distillate fuel oil)[6]	27.87	28.80	30.35	35.75	41.30	48.56	57.25	2.5%
Residual fuel oil	17.73	20.07	14.11	17.44	20.86	25.23	30.76	1.5%
Natural gas[7]	15.62	14.64	17.69	19.18	22.38	26.95	32.61	2.9%
Electricity	33.40	31.43	33.82	37.07	42.65	48.63	56.68	2.1%
Electric power[8]								
Distillate fuel oil	23.37	24.12	23.40	28.26	33.18	39.74	47.77	2.5%
Residual fuel oil	15.67	20.68	15.70	19.21	23.08	27.92	33.86	1.8%
Natural gas	4.80	3.44	5.75	7.09	8.74	10.85	13.53	5.0%
Steam coal	2.38	2.39	2.96	3.42	3.94	4.54	5.29	2.9%

012802

Table A3. Energy prices by sector and source (continued)

(nominal dollars per million Btu, unless otherwise noted)

Sector and source	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Average price to all users[9]								
Propane	23.96	23.24	25.53	29.17	33.20	38.55	44.42	2.3%
E85[3]	43.36	35.06	29.00	33.92	37.57	45.69	58.85	1.9%
Motor gasoline[4]	29.66	30.44	28.98	33.71	38.41	45.28	54.17	2.1%
Jet fuel[5]	22.61	22.99	22.06	27.05	31.91	38.47	46.53	2.5%
Distillate fuel oil	27.46	28.36	29.11	34.46	39.94	47.04	55.61	2.4%
Residual fuel oil	17.49	20.41	14.90	18.32	21.97	26.49	32.20	1.6%
Natural gas	6.71	5.38	8.04	9.51	11.43	13.90	17.22	4.2%
Metallurgical coal	7.01	7.25	9.55	11.03	12.81	14.80	16.91	3.1%
Other coal	2.43	2.44	3.03	3.49	4.02	4.63	5.39	2.9%
Coal to liquids	--	--	--	--	--	--	--	--
Electricity	29.01	28.85	33.66	36.55	41.13	46.90	54.11	2.3%
Non-renewable energy expenditures by sector (billion nominal dollars)								
Residential	245.47	234.06	282.30	317.94	367.27	428.63	508.27	2.8%
Commercial	180.72	173.25	214.56	246.83	290.65	346.52	423.44	3.2%
Industrial[1]	228.52	213.75	316.50	389.11	461.77	544.27	648.12	4.0%
Transportation	744.51	755.09	715.87	805.47	898.80	1,059.37	1,281.47	1.9%
Total non-renewable expenditures	1,399.23	1,376.15	1,529.23	1,759.34	2,018.49	2,378.79	2,861.30	2.6%
Transportation renewable expenditures	0.12	0.50	5.54	12.97	17.45	19.81	19.56	14.0%
Total expenditures	**1,399.35**	**1,376.66**	**1,534.77**	**1,772.32**	**2,035.94**	**2,398.59**	**2,880.86**	**2.7%**

[1]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[2]Excludes use for lease and plant fuel.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[5]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Natural gas used as fuel in motor vehicles, trains, and ships. Price includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[8]Includes electricity-only and combined heat and power plants that have a regulatory status.
[9]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
- - = Not applicable.
Note: Data for 2011 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 and 2012 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2013/08) (Washington, DC, August 2013). 2011 residential, commercial, and industrial natural gas delivered prices: EIA, *Natural Gas Annual 2011*, DOE/EIA-0131(2011) (Washington, DC, December 2012). 2012 residential, commercial, and industrial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2013/06) (Washington, DC, June 2013). 2011 transportation sector natural gas delivered prices are based on: EIA, *Natural Gas Annual 2011*, DOE/EIA-0131(2011) (Washington, DC, December 2012) and estimated State taxes, Federal taxes, and dispensing costs or charges. 2012 transportation sector natural gas delivered prices are model results. 2011 and 2012 electric power sector distillate and residual fuel oil prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2011 and 2012 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2012 and April 2013, Table 4.2, and EIA, *State Energy Data Report 2011*, DOE/EIA-0214(2011) (Washington, DC, June 2013). 2011 and 2012 coal prices based on: EIA, *Quarterly Coal Report, October-December 2012*, DOE/EIA-0121(2012/4Q) (Washington, DC, March 2013) and EIA, AEO2014 National Energy Modeling System run REF2014.D102413A. 2011 and 2012 electricity prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2011 and 2012 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report.
Projections: EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

012803

Table A4. Residential sector key indicators and consumption

(quadrillion Btu per year, unless otherwise noted)

Key indicators and consumption	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Key indicators								
Households (millions)								
Single-family	78.99	79.28	85.71	89.73	93.56	96.99	100.37	0.8%
Multifamily	28.13	28.24	30.55	32.18	33.98	35.82	37.61	1.0%
Mobile homes	6.58	6.41	5.70	5.46	5.29	5.14	5.03	-0.9%
Total	**113.70**	**113.93**	**121.96**	**127.38**	**132.83**	**137.95**	**143.01**	**0.8%**
Average house square footage	**1,662**	**1,670**	**1,736**	**1,771**	**1,802**	**1,831**	**1,858**	**0.4%**
Energy intensity								
(million Btu per household)								
Delivered energy consumption	99.0	91.5	88.1	84.6	81.5	78.7	76.5	-0.6%
Total energy consumption	188.2	176.4	167.1	161.6	156.8	152.8	150.2	-0.6%
(thousand Btu per square foot)								
Delivered energy consumption	59.6	54.8	50.7	47.8	45.2	43.0	41.2	-1.0%
Total energy consumption	113.2	105.6	96.3	91.2	87.0	83.5	80.9	-1.0%
Delivered energy consumption by fuel								
Purchased electricity								
Space heating	0.37	0.29	0.35	0.35	0.34	0.33	0.32	0.4%
Space cooling	0.83	0.85	0.89	0.98	1.07	1.16	1.25	1.4%
Water heating	0.44	0.45	0.47	0.49	0.50	0.50	0.51	0.5%
Refrigeration	0.38	0.38	0.38	0.38	0.38	0.40	0.41	0.3%
Cooking	0.11	0.11	0.12	0.12	0.13	0.14	0.15	1.1%
Clothes dryers	0.20	0.20	0.21	0.22	0.23	0.24	0.25	0.8%
Freezers	0.08	0.08	0.08	0.08	0.08	0.08	0.08	-0.1%
Lighting	0.64	0.64	0.44	0.39	0.35	0.30	0.28	-2.9%
Clothes washers[1]	0.03	0.03	0.03	0.02	0.02	0.02	0.02	-1.2%
Dishwashers[1]	0.10	0.10	0.10	0.10	0.10	0.11	0.12	0.6%
Televisions and related equipment[2]	0.33	0.33	0.33	0.33	0.35	0.37	0.39	0.5%
Computers and related equipment[3]	0.13	0.12	0.10	0.08	0.07	0.06	0.05	-3.0%
Furnace fans and boiler circulation pumps	0.12	0.09	0.12	0.12	0.12	0.12	0.12	0.8%
Other uses[4]	1.11	1.02	1.24	1.34	1.46	1.58	1.70	1.9%
Delivered energy	**4.85**	**4.69**	**4.84**	**5.00**	**5.21**	**5.41**	**5.65**	**0.7%**
Natural gas								
Space heating	3.09	2.51	2.82	2.76	2.69	2.62	2.54	0.0%
Space cooling	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-0.6%
Water heating	1.20	1.22	1.21	1.22	1.22	1.19	1.16	-0.2%
Cooking	0.21	0.21	0.21	0.21	0.21	0.22	0.22	0.2%
Clothes dryers	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.7%
Other uses[5]	0.25	0.25	0.24	0.23	0.22	0.22	0.21	-0.6%
Delivered energy	**4.82**	**4.26**	**4.56**	**4.50**	**4.43**	**4.32**	**4.21**	**0.0%**
Distillate fuel oil								
Space heating	0.46	0.44	0.42	0.38	0.34	0.31	0.29	-1.5%
Water heating	0.06	0.06	0.03	0.03	0.02	0.02	0.02	-4.4%
Other uses[6]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-0.6%
Delivered energy	**0.53**	**0.51**	**0.46**	**0.41**	**0.37**	**0.34**	**0.31**	**-1.7%**
Propane								
Space heating	0.37	0.37	0.30	0.28	0.26	0.25	0.24	-1.6%
Water heating	0.07	0.07	0.05	0.04	0.04	0.03	0.03	-3.3%
Cooking	0.03	0.03	0.03	0.03	0.02	0.02	0.02	-0.9%
Other uses[6]	0.04	0.04	0.05	0.05	0.05	0.06	0.06	1.5%
Delivered energy	**0.51**	**0.51**	**0.42**	**0.40**	**0.38**	**0.36**	**0.35**	**-1.3%**
Marketed renewables (wood)[7]	0.54	0.45	0.46	0.45	0.44	0.43	0.42	-0.3%
Kerosene	0.02	0.01	0.00	0.00	0.00	0.00	0.00	-2.5%

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Table A4. Residential sector key indicators and consumption (continued)

(quadrillion Btu per year, unless otherwise noted)

Key indicators and consumption	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Delivered energy consumption by end use								
Space heating	4.84	4.07	4.36	4.22	4.09	3.95	3.81	-0.2%
Space cooling	0.85	0.88	0.91	1.00	1.09	1.18	1.27	1.3%
Water heating	1.77	1.79	1.77	1.78	1.78	1.74	1.71	-0.2%
Refrigeration	0.38	0.38	0.38	0.38	0.38	0.40	0.41	0.3%
Cooking	0.34	0.34	0.35	0.36	0.37	0.38	0.39	0.4%
Clothes dryers	0.25	0.25	0.27	0.28	0.29	0.30	0.31	0.8%
Freezers	0.08	0.08	0.08	0.08	0.08	0.08	0.08	-0.1%
Lighting	0.64	0.64	0.44	0.39	0.35	0.30	0.28	-2.9%
Clothes washers[1]	0.03	0.03	0.03	0.02	0.02	0.02	0.02	-1.2%
Dishwashers[1]	0.10	0.10	0.10	0.10	0.10	0.11	0.12	0.6%
Televisions and related equipment[2]	0.33	0.33	0.33	0.33	0.35	0.37	0.39	0.5%
Computers and related equipment[3]	0.13	0.12	0.10	0.08	0.07	0.06	0.05	-3.0%
Furnace fans and boiler circulation pumps	0.12	0.09	0.12	0.12	0.12	0.12	0.12	0.8%
Other uses[8]	1.40	1.31	1.53	1.63	1.74	1.86	1.98	1.5%
Delivered energy	**11.26**	**10.42**	**10.74**	**10.77**	**10.83**	**10.86**	**10.94**	**0.2%**
Electricity related losses	**10.13**	**9.68**	**9.64**	**9.81**	**10.00**	**10.22**	**10.55**	**0.3%**
Total energy consumption by end use								
Space heating	5.63	4.66	5.05	4.90	4.74	4.57	4.41	-0.2%
Space cooling	2.58	2.64	2.68	2.91	3.14	3.37	3.61	1.1%
Water heating	2.68	2.71	2.71	2.74	2.74	2.69	2.65	-0.1%
Refrigeration	1.17	1.16	1.12	1.12	1.12	1.15	1.19	0.1%
Cooking	0.56	0.56	0.59	0.60	0.62	0.64	0.66	0.6%
Clothes dryers	0.66	0.66	0.69	0.71	0.73	0.76	0.78	0.6%
Freezers	0.25	0.25	0.24	0.23	0.23	0.22	0.23	-0.3%
Lighting	1.97	1.95	1.31	1.16	1.02	0.86	0.79	-3.2%
Clothes washers[1]	0.10	0.10	0.08	0.07	0.06	0.06	0.06	-1.4%
Dishwashers[1]	0.31	0.31	0.29	0.29	0.30	0.32	0.34	0.4%
Televisions and related equipment[2]	1.03	1.02	0.98	0.99	1.02	1.07	1.11	0.3%
Computers and related equipment[3]	0.39	0.38	0.29	0.25	0.21	0.18	0.15	-3.3%
Furnace fans and boiler circulation pumps	0.36	0.29	0.34	0.34	0.34	0.34	0.34	0.6%
Other uses[8]	3.71	3.42	4.01	4.27	4.55	4.84	5.16	1.5%
Total	**21.39**	**20.10**	**20.38**	**20.58**	**20.83**	**21.09**	**21.48**	**0.2%**
Nonmarketed renewables[9]								
Geothermal heat pumps	0.01	0.01	0.02	0.02	0.02	0.02	0.03	3.2%
Solar hot water heating	0.00	0.01	0.01	0.01	0.01	0.01	0.01	2.4%
Solar photovoltaic	0.02	0.02	0.10	0.12	0.14	0.18	0.22	8.3%
Wind	0.00	0.00	0.01	0.01	0.01	0.01	0.01	9.1%
Total	**0.03**	**0.04**	**0.14**	**0.16**	**0.19**	**0.23**	**0.27**	**6.9%**
Heating degree days[10]	**4,258**	**3,712**	**4,015**	**3,945**	**3,877**	**3,810**	**3,745**	**0.0%**
Cooling degree days[10]	**1,481**	**1,514**	**1,488**	**1,530**	**1,572**	**1,614**	**1,656**	**0.3%**

[1]Does not include water heating portion of load.
[2]Includes televisions, set-top boxes, home theater systems, DVD players, and video game consoles.
[3]Includes desktop and laptop computers, monitors, and networking equipment.
[4]Includes small electric devices, heating elements, and motors not listed above. Electric vehicles are included in the transportation sector.
[5]Includes such appliances as outdoor grills, exterior lights, pool heaters, spa heaters, and backup electricity generators.
[6]Includes such appliances as pool heaters, spa heaters, and backup electricity generators.
[7]Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 2009*.
[8]Includes small electric devices, heating elements, outdoor grills, exterior lights, pool heaters, spa heaters, backup electricity generators, and motors not listed above. Electric vehicles are included in the transportation sector.
[9]Consumption determined by using the fossil fuel equivalent of 9,716 Btu per kilowatthour.
[10]See Table A5 for regional detail.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 and 2012 consumption based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2011 and 2012 degree days based on state-level data from the National Oceanic and Atmospheric Administration's Climatic Data Center and Climate Prediction Center. **Projections:** EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

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Table A5. Commercial sector key indicators and consumption
(quadrillion Btu per year, unless otherwise noted)

Key indicators and consumption	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Key indicators								
Total floorspace (billion square feet)								
Surviving	80.2	80.8	87.1	91.9	96.2	100.8	106.5	1.0%
New additions	1.5	1.6	2.1	2.0	2.0	2.3	2.4	1.6%
Total	**81.7**	**82.4**	**89.1**	**93.9**	**98.2**	**103.1**	**108.9**	**1.0%**
Energy consumption intensity (thousand Btu per square foot)								
Delivered energy consumption	105.2	100.7	98.5	96.7	95.6	94.6	93.9	-0.3%
Electricity related losses	115.7	113.2	104.8	103.1	101.3	99.4	98.0	-0.5%
Total energy consumption	220.9	213.8	203.3	199.9	196.9	194.0	191.8	-0.4%
Delivered energy consumption by fuel								
Purchased electricity								
Space heating[1]	0.17	0.15	0.16	0.16	0.15	0.15	0.14	-0.1%
Space cooling[1]	0.55	0.55	0.51	0.53	0.53	0.55	0.57	0.1%
Water heating[1]	0.09	0.09	0.09	0.09	0.09	0.08	0.08	-0.4%
Ventilation	0.51	0.52	0.55	0.57	0.59	0.60	0.62	0.6%
Cooking	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-0.3%
Lighting	0.96	0.94	0.88	0.88	0.87	0.85	0.84	-0.4%
Refrigeration	0.39	0.38	0.37	0.37	0.38	0.39	0.41	0.2%
Office equipment (PC)	0.13	0.12	0.07	0.05	0.04	0.03	0.02	-5.6%
Office equipment (non-PC)	0.22	0.22	0.24	0.27	0.31	0.35	0.38	2.0%
Other uses[2]	1.50	1.53	1.80	2.00	2.20	2.41	2.63	2.0%
Delivered energy	**4.53**	**4.52**	**4.69**	**4.94**	**5.18**	**5.42**	**5.72**	**0.8%**
Natural gas								
Space heating[1]	1.72	1.54	1.71	1.68	1.64	1.59	1.54	0.0%
Space cooling[1]	0.04	0.04	0.04	0.04	0.04	0.04	0.04	-0.7%
Water heating[1]	0.47	0.48	0.50	0.51	0.52	0.52	0.53	0.3%
Cooking	0.19	0.20	0.21	0.22	0.23	0.23	0.24	0.7%
Other uses[3]	0.81	0.70	0.78	0.84	0.94	1.09	1.30	2.2%
Delivered energy	**3.22**	**2.96**	**3.23**	**3.29**	**3.35**	**3.48**	**3.65**	**0.7%**
Distillate fuel oil								
Space heating[1]	0.15	0.13	0.14	0.13	0.12	0.11	0.11	-0.8%
Water heating[1]	0.03	0.03	0.04	0.05	0.05	0.06	0.06	2.5%
Other uses[4]	0.23	0.24	0.21	0.21	0.21	0.20	0.20	-0.7%
Delivered energy	**0.42**	**0.40**	**0.40**	**0.39**	**0.38**	**0.37**	**0.37**	**-0.3%**
Marketed renewables (biomass)	0.11	0.13	0.13	0.13	0.13	0.13	0.13	0.0%
Other fuels[5]	0.31	0.28	0.33	0.33	0.34	0.35	0.36	0.9%
Delivered energy consumption by end use								
Space heating[1]	2.04	1.82	2.01	1.97	1.91	1.85	1.79	-0.1%
Space cooling[1]	0.59	0.60	0.55	0.56	0.57	0.58	0.60	0.0%
Water heating[1]	0.59	0.60	0.63	0.65	0.66	0.66	0.67	0.4%
Ventilation	0.51	0.52	0.55	0.57	0.59	0.60	0.62	0.6%
Cooking	0.21	0.22	0.23	0.24	0.25	0.26	0.26	0.6%
Lighting	0.96	0.94	0.88	0.88	0.87	0.85	0.84	-0.4%
Refrigeration	0.39	0.38	0.37	0.37	0.38	0.39	0.41	0.2%
Office equipment (PC)	0.13	0.12	0.07	0.05	0.04	0.03	0.02	-5.6%
Office equipment (non-PC)	0.22	0.22	0.24	0.27	0.31	0.35	0.38	2.0%
Other uses[6]	2.96	2.88	3.26	3.52	3.81	4.18	4.62	1.7%
Delivered energy	**8.60**	**8.29**	**8.78**	**9.08**	**9.38**	**9.75**	**10.22**	**0.7%**

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Table A5. Commercial sector key indicators and consumption (continued)
(quadrillion Btu per year, unless otherwise noted)

Key indicators and consumption	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Electricity related losses	**9.46**	**9.32**	**9.34**	**9.69**	**9.94**	**10.24**	**10.66**	**0.5%**
Total energy consumption by end use								
Space heating[1]	2.40	2.13	2.33	2.28	2.20	2.13	2.06	-0.1%
Space cooling[1]	1.73	1.74	1.57	1.59	1.60	1.62	1.66	-0.2%
Water heating[1]	0.78	0.80	0.81	0.82	0.83	0.82	0.82	0.1%
Ventilation	1.58	1.58	1.64	1.69	1.71	1.73	1.77	0.4%
Cooking	0.26	0.27	0.28	0.28	0.29	0.30	0.30	0.4%
Lighting	2.95	2.87	2.63	2.60	2.54	2.45	2.41	-0.6%
Refrigeration	1.20	1.17	1.10	1.10	1.11	1.13	1.16	0.0%
Office equipment (PC)	0.39	0.35	0.20	0.15	0.11	0.08	0.07	-5.8%
Office equipment (non-PC)	0.69	0.67	0.72	0.80	0.90	1.00	1.10	1.8%
Other uses[6]	6.08	6.04	6.85	7.45	8.04	8.73	9.54	1.6%
Total	**18.05**	**17.61**	**18.12**	**18.77**	**19.32**	**19.99**	**20.88**	**0.6%**
Nonmarketed renewable fuels[7]								
Solar thermal	0.08	0.08	0.09	0.09	0.09	0.10	0.11	1.0%
Solar photovoltaic	0.03	0.05	0.10	0.12	0.15	0.19	0.24	5.9%
Wind	0.00	0.00	0.00	0.00	0.00	0.01	0.01	8.3%
Total	**0.11**	**0.13**	**0.18**	**0.21**	**0.24**	**0.29**	**0.35**	**3.7%**
Heating degree days								
New England	6,082	5,541	6,045	5,975	5,905	5,835	5,763	0.1%
Middle Atlantic	5,405	4,886	5,307	5,229	5,152	5,076	5,000	0.1%
East North Central	6,163	5,350	5,933	5,867	5,801	5,735	5,669	0.2%
West North Central	6,635	5,537	6,226	6,170	6,112	6,053	5,992	0.3%
South Atlantic	2,568	2,297	2,588	2,551	2,516	2,481	2,448	0.2%
East South Central	3,358	2,896	3,258	3,218	3,177	3,135	3,093	0.2%
West South Central	2,145	1,683	1,924	1,870	1,815	1,761	1,707	0.1%
Mountain	5,223	4,445	4,660	4,586	4,508	4,428	4,347	-0.1%
Pacific	3,532	3,150	3,244	3,267	3,290	3,314	3,339	0.2%
United States	**4,258**	**3,712**	**4,015**	**3,945**	**3,877**	**3,810**	**3,745**	**0.0%**
Cooling degree days								
New England	568	592	565	583	601	620	638	0.3%
Middle Atlantic	885	863	848	875	903	929	956	0.4%
East North Central	855	982	825	835	846	856	867	-0.4%
West North Central	1,064	1,231	1,024	1,032	1,041	1,051	1,061	-0.5%
South Atlantic	2,267	2,184	2,208	2,244	2,280	2,316	2,350	0.3%
East South Central	1,740	1,780	1,795	1,829	1,863	1,897	1,931	0.3%
West South Central	3,067	2,903	2,880	2,948	3,017	3,086	3,155	0.3%
Mountain	1,506	1,664	1,661	1,719	1,779	1,841	1,905	0.5%
Pacific	767	917	860	861	861	861	861	-0.2%
United States	**1,481**	**1,514**	**1,488**	**1,530**	**1,572**	**1,614**	**1,656**	**0.3%**

[1]Includes fuel consumption for district services.
[2]Includes (but is not limited to) miscellaneous uses such as transformers, medical imaging and other medical equipment, elevators, escalators, off-road electric vehicles, laboratory fume hoods, laundry equipment, coffee brewers, and water services.
[3]Includes miscellaneous uses, such as pumps, emergency generators, combined heat and power in commercial buildings, and manufacturing performed in commercial buildings.
[4]Includes miscellaneous uses, such as cooking, emergency generators, and combined heat and power in commercial buildings.
[5]Includes residual fuel oil, propane, coal, motor gasoline, and kerosene.
[6]Includes (but is not limited to) miscellaneous uses such as transformers, medical imaging and other medical equipment, elevators, escalators, off-road electric vehicles, laboratory fume hoods, laundry equipment, coffee brewers, water services, pumps, emergency generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, propane, coal, motor gasoline, kerosene, and marketed renewable fuels (biomass).
[7]Consumption determined by using the fossil fuel equivalent of 9,716 Btu per kilowatthour.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 and 2012 consumption based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2011 and 2012 degree days based on state-level data from the National Oceanic and Atmospheric Administration's Climatic Data Center and Climate Prediction Center. **Projections:** EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

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Table A6. Industrial sector key indicators and consumption

Shipments, prices, and consumption	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Key indicators								
Value of shipments (billion 2005 dollars)								
Manufacturing	4,370	4,525	5,735	6,467	7,148	7,784	8,443	2.3%
Agriculture, mining, and construction	1,556	1,623	2,226	2,311	2,389	2,457	2,551	1.6%
Total	**5,926**	**6,147**	**7,960**	**8,778**	**9,537**	**10,241**	**10,994**	**2.1%**
Energy prices								
(2012 dollars per million Btu)								
Propane	22.63	21.09	20.64	22.06	23.27	24.73	25.84	0.7%
Motor gasoline	23.19	17.52	25.56	27.34	28.51	30.36	32.62	2.2%
Distillate fuel oil	27.04	27.41	22.22	24.45	26.11	27.97	29.92	0.3%
Residual fuel oil	19.17	20.90	14.88	16.65	18.29	19.79	21.48	0.1%
Asphalt and road oil	10.13	10.11	10.85	12.26	13.38	14.60	15.80	1.6%
Natural gas heat and power	4.80	3.43	5.59	6.11	6.79	7.58	8.43	3.3%
Natural gas feedstocks	5.41	4.16	6.01	6.55	7.21	7.96	8.78	2.7%
Metallurgical coal	7.13	7.25	8.43	8.95	9.51	9.93	10.20	1.2%
Other industrial coal	3.31	3.24	3.59	3.73	3.88	4.03	4.19	0.9%
Coal to liquids	--	--	--	--	--	--	--	--
Electricity	20.35	19.50	20.77	21.08	21.99	22.91	24.05	0.8%
(nominal dollars per million Btu)								
Propane	22.24	21.09	23.38	27.18	31.32	36.84	42.83	2.6%
Motor gasoline	22.79	17.52	28.95	33.68	38.37	45.22	54.08	4.1%
Distillate fuel oil	26.56	27.41	25.17	30.12	35.15	41.66	49.61	2.1%
Residual fuel oil	18.84	20.90	16.85	20.51	24.62	29.47	35.61	1.9%
Asphalt and road oil	9.95	10.11	12.29	15.10	18.02	21.75	26.20	3.5%
Natural gas heat and power	4.72	3.43	6.33	7.53	9.14	11.29	13.98	5.1%
Natural gas feedstocks	5.32	4.16	6.81	8.07	9.70	11.86	14.56	4.6%
Metallurgical coal	7.01	7.25	9.55	11.03	12.81	14.80	16.91	3.1%
Other industrial coal	3.25	3.24	4.07	4.59	5.23	6.00	6.95	2.8%
Coal to liquids	--	--	--	--	--	--	--	--
Electricity	19.99	19.50	23.52	25.96	29.60	34.13	39.88	2.6%
Energy consumption (quadrillion Btu)[1]								
Industrial consumption excluding refining								
Propane heat and power	0.13	0.08	0.15	0.16	0.16	0.15	0.15	2.2%
Liquefied petroleum gas and other feedstocks[2]	2.12	2.16	2.75	2.89	2.89	2.81	2.75	0.9%
Motor gasoline	0.26	0.26	0.30	0.30	0.30	0.29	0.29	0.4%
Distillate fuel oil	1.24	1.19	1.40	1.41	1.41	1.41	1.42	0.6%
Residual fuel oil	0.13	0.10	0.14	0.14	0.15	0.15	0.15	1.5%
Petrochemical feedstocks	0.88	0.75	1.27	1.52	1.62	1.62	1.59	2.7%
Petroleum coke	0.12	0.15	0.16	0.16	0.16	0.15	0.16	0.1%
Asphalt and road oil	0.86	0.83	1.13	1.16	1.21	1.26	1.32	1.7%
Miscellaneous petroleum[3]	0.45	0.56	0.47	0.51	0.54	0.55	0.57	0.0%
Petroleum and other liquids subtotal	6.18	6.09	7.76	8.25	8.43	8.41	8.41	1.2%
Natural gas heat and power	5.14	5.22	5.79	6.05	6.18	6.26	6.35	0.7%
Natural gas feedstocks	0.53	0.58	0.68	0.71	0.70	0.69	0.68	0.5%
Lease and plant fuel[4]	1.35	1.45	1.77	1.99	2.16	2.29	2.41	1.8%
Natural gas subtotal	7.03	7.25	8.25	8.74	9.04	9.24	9.43	0.9%
Metallurgical coal and coke[5]	0.58	0.55	0.58	0.57	0.52	0.46	0.42	-0.9%
Other industrial coal	0.95	0.93	0.99	1.00	1.00	1.00	1.01	0.3%
Coal subtotal	1.52	1.48	1.57	1.57	1.52	1.45	1.44	-0.1%
Renewables[6]	1.49	1.48	1.74	1.88	2.01	2.13	2.28	1.6%
Purchased electricity	3.18	3.15	3.87	4.11	4.17	4.16	4.18	1.0%
Delivered energy	**19.40**	**19.45**	**23.18**	**24.56**	**25.17**	**25.39**	**25.73**	**1.0%**
Electricity related losses	6.64	6.50	7.71	8.06	8.02	7.86	7.80	0.7%
Total	**26.04**	**25.95**	**30.90**	**32.61**	**33.19**	**33.25**	**33.53**	**0.9%**

012808

Table A6. Industrial sector key indicators and consumption (continued)

Shipments, prices, and consumption	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Refining consumption								
Liquefied petroleum gas heat and power[2]	0.00	0.01	0.00	0.00	0.00	0.00	0.00	- -
Distillate fuel oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Residual fuel oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Petroleum coke	0.53	0.54	0.45	0.41	0.40	0.39	0.40	-1.1%
Still gas	1.40	1.41	1.35	1.29	1.28	1.28	1.30	-0.3%
Miscellaneous petroleum[3]	0.01	0.01	0.00	0.00	0.00	0.00	0.00	- -
Petroleum and other liquids subtotal	1.95	1.97	1.80	1.70	1.67	1.67	1.69	-0.5%
Natural gas heat and power	1.09	1.19	1.43	1.48	1.47	1.47	1.48	0.8%
Natural gas feedstocks	0.29	0.30	0.36	0.36	0.36	0.36	0.36	0.6%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural gas subtotal	1.38	1.50	1.79	1.84	1.83	1.83	1.85	0.8%
Other industrial coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Coal subtotal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Biofuels heat and coproducts	0.46	0.52	0.76	0.79	0.79	0.79	0.79	1.5%
Purchased electricity	0.20	0.20	0.17	0.17	0.16	0.16	0.16	-0.7%
Delivered energy	**4.00**	**4.18**	**4.52**	**4.49**	**4.45**	**4.45**	**4.49**	**0.3%**
Electricity related losses	0.42	0.40	0.34	0.32	0.31	0.30	0.30	-1.0%
Total	**4.42**	**4.59**	**4.86**	**4.82**	**4.76**	**4.76**	**4.79**	**0.2%**
Total industrial sector consumption								
Liquefied petroleum gas heat and power[2]	0.13	0.09	0.15	0.16	0.16	0.15	0.15	1.9%
Liquefied petroleum gas and other feedstocks[2]	2.12	2.16	2.75	2.89	2.89	2.81	2.75	0.9%
Motor gasoline	0.26	0.26	0.30	0.30	0.30	0.29	0.29	0.4%
Distillate fuel oil	1.24	1.20	1.40	1.41	1.41	1.41	1.42	0.6%
Residual fuel oil	0.13	0.10	0.14	0.14	0.15	0.15	0.15	1.4%
Petrochemical feedstocks	0.88	0.75	1.27	1.52	1.62	1.62	1.59	2.7%
Petroleum coke	0.65	0.69	0.61	0.57	0.56	0.55	0.56	-0.8%
Asphalt and road oil	0.86	0.83	1.13	1.16	1.21	1.26	1.32	1.7%
Still gas	1.40	1.41	1.35	1.29	1.28	1.28	1.30	-0.3%
Miscellaneous petroleum[3]	0.46	0.57	0.47	0.51	0.54	0.55	0.57	0.0%
Petroleum and other liquids subtotal	8.13	8.06	9.56	9.95	10.10	10.08	10.10	0.8%
Natural gas heat and power	6.24	6.41	7.23	7.52	7.65	7.74	7.83	0.7%
Natural gas feedstocks	0.82	0.88	1.04	1.07	1.06	1.05	1.04	0.6%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and plant fuel[4]	1.35	1.45	1.77	1.99	2.16	2.29	2.41	1.8%
Natural gas subtotal	8.41	8.75	10.04	10.58	10.87	11.07	11.28	0.9%
Metallurgical coal and coke[5]	0.58	0.55	0.58	0.57	0.52	0.46	0.42	-0.9%
Other industrial coal	0.95	0.93	0.99	1.00	1.00	1.00	1.01	0.3%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Coal subtotal	1.53	1.48	1.57	1.57	1.52	1.45	1.44	-0.1%
Biofuels heat and coproducts	0.46	0.52	0.76	0.79	0.79	0.79	0.79	1.5%
Renewables[6]	1.49	1.48	1.74	1.88	2.01	2.13	2.28	1.6%
Purchased electricity	3.38	3.35	4.04	4.27	4.33	4.32	4.34	0.9%
Delivered energy	**23.40**	**23.63**	**27.71**	**29.05**	**29.62**	**29.84**	**30.22**	**0.9%**
Electricity related losses	7.06	6.91	8.05	8.38	8.33	8.16	8.10	0.6%
Total	**30.46**	**30.54**	**35.76**	**37.43**	**37.94**	**38.00**	**38.33**	**0.8%**

012809

Table A6. Industrial sector key indicators and consumption (continued)

Key indicators and consumption	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Energy consumption per dollar of shipments (thousand Btu per 2005 dollar)								
Petroleum and other liquids	1.37	1.31	1.20	1.13	1.06	0.98	0.92	-1.3%
Natural gas	1.42	1.42	1.26	1.21	1.14	1.08	1.03	-1.2%
Coal	0.26	0.24	0.20	0.18	0.16	0.14	0.13	-2.2%
Renewable fuels[5]	0.33	0.33	0.31	0.30	0.29	0.29	0.28	-0.5%
Purchased electricity	0.57	0.54	0.51	0.49	0.45	0.42	0.40	-1.1%
Delivered energy	**3.95**	**3.84**	**3.48**	**3.31**	**3.11**	**2.91**	**2.75**	**-1.2%**
Industrial combined heat and power[1]								
Capacity (gigawatts)	25.51	26.95	31.11	34.21	38.48	43.27	46.16	1.9%
Generation (billion kilowatthours)	140.20	143.79	169.54	185.50	207.81	233.21	249.22	2.0%

[1]Includes combined heat and power plants that have a regulatory status, and small on-site generating systems.
[2]Includes ethane, natural gasoline, and refinery olefins.
[3]Includes lubricants and miscellaneous petroleum products.
[4]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[5]Includes net coal coke imports.
[6]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources.
Btu = British thermal unit.
- - = Not applicable.

Note: Includes estimated consumption for petroleum and other liquids. Totals may not equal sum of components due to independent rounding. Data for 2011 and 2012 are model results and may differ from official EIA data reports.

Sources: 2011 and 2012 prices for motor gasoline and distillate fuel oil are based on: U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2013/08) (Washington, DC, August 2013). 2011 and 2012 petrochemical feedstock and asphalt and road oil prices are based on: EIA, *State Energy Data Report 2011*, DOE/EIA-0214(2011) (Washington, DC, June 2013). 2011 and 2012 coal prices are based on: EIA, *Quarterly Coal Report, October-December 2012*, DOE/EIA-0121(2012/4Q) (Washington, DC, March 2013) and EIA, AEO2014 National Energy Modeling System run REF2014.D102413A. 2011 and 2012 electricity prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2011 natural gas prices: EIA, *Natural Gas Annual 2011*, DOE/EIA-0131(2011) (Washington, DC, December 2012) and EIA, Office of Energy Analysis. 2012 natural gas prices: *Natural Gas Monthly*, DOE/EIA-0130(2013/06) (Washington, DC, June 2013) and EIA, Office of Energy Analysis. 2011 refining consumption values are based on: *Petroleum Supply Annual 2011*, DOE/EIA-0340(2011)/1 (Washington, DC, August 2012). 2012 refining consumption based on: *Petroleum Supply Annual 2012*, DOE/EIA-0340(2012)/1 (Washington, DC, September 2013). Other 2011 and 2012 consumption values are based on: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2011 and 2012 shipments: IHS Global Insight, Global Insight Industry model, May 2013. **Projections:** EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

012810

Table A7. Transportation sector key indicators and delivered energy consumption

Key indicators and consumption	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Key indicators								
Travel indicators								
(billion vehicle miles traveled)								
Light-duty vehicles less than 8,501 pounds	2,623	2,662	2,851	2,977	3,138	3,303	3,434	0.9%
Commercial light trucks[1]	62	63	76	83	90	96	103	1.8%
Freight trucks greater than 10,000 pounds	252	245	310	339	362	385	411	1.9%
(billion seat miles available)								
Air	982	990	1,064	1,101	1,135	1,165	1,199	0.7%
(billion ton miles traveled)								
Rail	1,746	1,729	1,624	1,721	1,738	1,737	1,736	0.0%
Domestic shipping	447	378	390	378	369	367	371	-0.1%
Energy efficiency indicators								
(miles per gallon)								
New light-duty vehicle CAFE standard[2]	27.6	29.4	36.6	46.4	46.6	46.7	46.8	1.7%
New car[2]	30.7	33.4	43.7	54.3	54.3	54.3	54.3	1.8%
New light truck[2]	24.6	25.7	30.9	39.5	39.5	39.5	39.5	1.5%
Compliance new light-duty vehicle[3]	32.4	32.7	38.6	47.2	47.8	48.1	48.2	1.4%
New car[3]	36.7	37.1	44.2	54.9	55.4	55.6	55.6	1.5%
New light truck[3]	28.5	28.7	33.7	40.3	40.8	40.9	40.9	1.3%
Tested new light-duty vehicle[4]	31.2	31.7	38.6	47.2	47.8	48.0	48.2	1.5%
New car[4]	35.7	36.3	44.2	54.9	55.4	55.5	55.6	1.5%
New light truck[4]	27.3	27.5	33.7	40.3	40.7	40.9	40.8	1.4%
On-road new light-duty vehicle[5]	25.2	25.6	31.2	38.1	38.6	38.8	38.9	1.5%
New car[5]	29.2	29.7	36.1	44.8	45.2	45.4	45.4	1.5%
New light truck[5]	21.8	22.0	27.0	32.2	32.6	32.7	32.7	1.4%
Light-duty stock[6]	21.2	21.5	25.1	28.7	32.6	35.4	37.2	2.0%
New commercial light truck[1]	18.1	18.1	20.9	24.2	24.5	24.6	24.6	1.1%
Stock commercial light truck[1]	14.9	15.2	18.0	20.4	22.5	23.9	24.5	1.7%
Freight truck	6.7	6.7	7.3	7.5	7.7	7.8	7.8	0.5%
(seat miles per gallon)								
Aircraft	62.3	62.4	63.9	65.2	67.0	69.2	71.5	0.5%
(ton miles per thousand Btu)								
Rail	3.4	3.4	3.6	3.8	3.9	4.1	4.2	0.7%
Domestic shipping	4.6	4.7	5.0	5.2	5.4	5.6	5.8	0.8%
Energy use by mode (quadrillion Btu)								
Light-duty vehicles	15.52	15.49	14.24	13.01	12.09	11.70	11.58	-1.0%
Commercial light trucks[1]	0.52	0.52	0.53	0.51	0.50	0.50	0.53	0.0%
Bus transportation	0.24	0.24	0.25	0.26	0.27	0.28	0.29	0.7%
Freight trucks	5.19	5.02	5.87	6.19	6.47	6.80	7.23	1.3%
Rail, passenger	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.9%
Rail, freight	0.51	0.48	0.45	0.46	0.45	0.43	0.42	-0.5%
Shipping, domestic	0.11	0.10	0.09	0.09	0.08	0.08	0.08	-0.8%
Shipping, international	0.77	0.58	0.59	0.59	0.60	0.61	0.61	0.2%
Recreational boats	0.24	0.24	0.25	0.26	0.27	0.28	0.28	0.6%
Air	2.46	2.47	2.60	2.65	2.69	2.69	2.70	0.3%
Military use	0.74	0.70	0.64	0.65	0.68	0.72	0.77	0.3%
Lubricants	0.13	0.12	0.12	0.12	0.12	0.12	0.12	0.1%
Pipeline fuel	0.70	0.73	0.74	0.76	0.82	0.83	0.85	0.5%
Total	**27.17**	**26.74**	**26.41**	**25.61**	**25.09**	**25.11**	**25.51**	**-0.2%**

012811

Table A7. Transportation sector key indicators and delivered energy consumption (continued)

Key indicators and consumption	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Energy use by mode (million barrels per day oil equivalent)								
Light-duty vehicles	8.42	8.41	7.76	7.13	6.65	6.44	6.38	-1.0%
Commercial light trucks[1]	0.27	0.27	0.27	0.26	0.26	0.26	0.27	0.0%
Bus transportation	0.12	0.11	0.12	0.13	0.13	0.13	0.14	0.7%
Freight trucks	2.50	2.42	2.83	2.98	3.12	3.28	3.48	1.3%
Rail, passenger	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.9%
Rail, freight	0.24	0.23	0.21	0.22	0.21	0.21	0.20	-0.5%
Shipping, domestic	0.05	0.05	0.04	0.04	0.04	0.04	0.04	-0.8%
Shipping, international	0.34	0.25	0.26	0.26	0.26	0.27	0.27	0.2%
Recreational boats	0.13	0.13	0.14	0.14	0.15	0.15	0.15	0.6%
Air	1.19	1.20	1.26	1.28	1.30	1.30	1.31	0.3%
Military use	0.35	0.34	0.31	0.31	0.33	0.35	0.37	0.3%
Lubricants	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.1%
Pipeline fuel	0.33	0.35	0.35	0.36	0.39	0.39	0.40	0.5%
Total	**14.03**	**13.84**	**13.63**	**13.20**	**12.92**	**12.90**	**13.09**	**-0.2%**

[1]Commercial trucks 8,501 to 10,000 pounds gross vehicle weight rating.
[2]CAFE standard based on projected new vehicle sales.
[3]Includes CAFE credits for alternative fueled vehicle sales and credit banking.
[4]Environmental Protection Agency rated miles per gallon.
[5]Tested new vehicle efficiency revised for on-road performance.
[6]Combined"on-the-road" estimate for all cars and light trucks.
CAFE = Corporate average fuel economy.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 and 2012: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013); EIA, Alternatives to Traditional Transportation Fuels 2009 (Part II - User and Fuel Data), April 2011; Federal Highway Administration, *Highway Statistics 2010* (Washington, DC, February 2012); Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 32* (Oak Ridge, TN, July 2013); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, October 2012); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey," EC02TV (Washington, DC, December 2004); EIA, U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2010/2009* (Washington, DC, December 2010); and United States Department of Defense, Defense Fuel Supply Center, Factbook (January, 2010). **Projections:** EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

012812

Table A8. Electricity supply, disposition, prices, and emissions
(billion kilowatthours, unless otherwise noted)

Supply, disposition, prices, and emissions	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Generation by fuel type								
Electric power sector[1]								
Power only[2]								
Coal	1,692	1,478	1,606	1,650	1,652	1,640	1,635	0.4%
Petroleum	26	18	15	16	15	15	16	-0.5%
Natural gas[3]	804	1,000	1,020	1,135	1,256	1,374	1,471	1.4%
Nuclear power	790	769	779	779	782	786	811	0.2%
Pumped storage/other[4]	1	3	3	3	3	3	3	0.2%
Renewable sources[5]	476	459	600	634	660	686	735	1.7%
Distributed generation (natural gas)	0	0	1	2	2	3	4	- -
Total	**3,790**	**3,727**	**4,025**	**4,217**	**4,370**	**4,508**	**4,675**	**0.8%**
Combined heat and power[6]								
Coal	26	20	26	26	26	26	26	0.9%
Petroleum	2	2	1	1	1	1	1	-3.6%
Natural gas	121	133	134	135	135	134	134	0.0%
Renewable sources	5	5	8	8	8	8	8	1.9%
Total	**157**	**163**	**168**	**169**	**170**	**169**	**169**	**0.1%**
Total electric power sector generation	**3,946**	**3,890**	**4,193**	**4,386**	**4,540**	**4,677**	**4,844**	**0.8%**
Less direct use	12	13	14	14	14	14	14	0.3%
Net available to the grid	**3,935**	**3,877**	**4,179**	**4,373**	**4,526**	**4,663**	**4,830**	**0.8%**
End-use sector[7]								
Coal	15	13	13	13	13	13	13	0.0%
Petroleum	2	3	3	3	3	3	3	-0.4%
Natural gas	88	95	112	130	159	197	231	3.2%
Other gaseous fuels[8]	11	11	18	18	18	18	18	1.8%
Renewable sources[9]	36	39	60	69	80	93	108	3.7%
Other[10]	4	3	3	3	3	3	3	0.0%
Total end-use sector generation	**156**	**165**	**209**	**236**	**276**	**327**	**375**	**3.0%**
Less direct use	115	127	169	193	228	274	317	3.3%
Total sales to the grid	**41**	**38**	**41**	**43**	**47**	**53**	**58**	**1.5%**
Total electricity generation by fuel								
Coal	1,733	1,512	1,646	1,689	1,692	1,679	1,675	0.4%
Petroleum	30	23	18	19	19	19	19	-0.7%
Natural gas	1,014	1,228	1,268	1,401	1,552	1,708	1,839	1.5%
Nuclear power	790	769	779	779	782	786	811	0.2%
Renewable sources[5,9]	517	502	667	711	748	787	851	1.9%
Other[11]	19	19	24	24	24	24	24	0.7%
Total electricity generation	**4,103**	**4,054**	**4,402**	**4,622**	**4,815**	**5,004**	**5,219**	**0.9%**
Net generation to the grid	**3,976**	**3,915**	**4,220**	**4,416**	**4,573**	**4,716**	**4,888**	**0.8%**
Net imports	**37**	**47**	**33**	**35**	**35**	**31**	**35**	**-1.1%**
Electricity sales by sector								
Residential	1,423	1,375	1,418	1,467	1,526	1,585	1,657	0.7%
Commercial	1,328	1,324	1,374	1,448	1,517	1,588	1,675	0.8%
Industrial	991	981	1,184	1,253	1,270	1,265	1,273	0.9%
Transportation	7	7	9	10	13	15	18	3.6%
Total	**3,749**	**3,686**	**3,986**	**4,178**	**4,327**	**4,454**	**4,623**	**0.8%**
Direct use	127	139	182	206	242	288	331	3.1%
Total electricity use	**3,875**	**3,826**	**4,168**	**4,385**	**4,569**	**4,742**	**4,954**	**0.9%**

012813

Table A8. Electricity supply, disposition, prices, and emissions (continued)
(billion kilowatthours, unless otherwise noted)

Supply, disposition, prices, and emissions	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
End-use prices								
(2012 cents per kilowatthour)								
Residential	11.9	11.9	12.3	12.3	12.6	12.9	13.3	0.4%
Commercial	10.4	10.1	10.5	10.4	10.7	10.9	11.3	0.4%
Industrial	6.9	6.7	7.1	7.2	7.5	7.8	8.2	0.8%
Transportation	11.6	10.7	10.2	10.3	10.8	11.1	11.7	0.3%
All sectors average	**10.1**	**9.8**	**10.1**	**10.1**	**10.4**	**10.7**	**11.1**	**0.4%**
(nominal cents per kilowatthour)								
Residential	11.7	11.9	14.0	15.2	17.0	19.2	22.0	2.2%
Commercial	10.2	10.1	11.9	12.8	14.4	16.3	18.7	2.2%
Industrial	6.8	6.7	8.0	8.9	10.1	11.6	13.6	2.6%
Transportation	11.4	10.7	11.5	12.6	14.6	16.6	19.3	2.1%
All sectors average	**9.9**	**9.8**	**11.5**	**12.5**	**14.0**	**16.0**	**18.5**	**2.3%**
Prices by service category								
(2012 cents per kilowatthour)								
Generation	5.9	5.7	6.4	6.5	6.8	7.1	7.5	1.0%
Transmission	1.1	1.1	1.1	1.1	1.1	1.1	1.1	0.2%
Distribution	3.1	3.1	2.7	2.6	2.6	2.6	2.6	-0.6%
(nominal cents per kilowatthour)								
Generation	5.8	5.7	7.2	8.0	9.2	10.6	12.4	2.8%
Transmission	1.0	1.1	1.2	1.3	1.5	1.6	1.8	2.0%
Distribution	3.1	3.1	3.1	3.2	3.5	3.8	4.3	1.2%
Electric power sector emissions[1]								
Sulfur dioxide (million short tons)	4.57	3.34	1.38	1.54	1.58	1.59	1.61	-2.6%
Nitrogen oxide (million short tons)	1.94	1.68	1.48	1.56	1.59	1.60	1.60	-0.2%
Mercury (short tons)	30.75	26.35	6.51	6.60	6.69	6.72	6.81	-4.7%

[1]Includes electricity-only and combined heat and power plants that have a regulatory status.
[2]Includes plants that only produce electricity and that have a regulatory status.
[3]Includes electricity generation from fuel cells.
[4]Includes non-biogenic municipal waste. The U.S. Energy Information Administration estimates that in 2012 approximately 7 billion kilowatthours of electricity were generated from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See U.S. Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy*, (Washington, DC, May 2007).
[5]Includes conventional hydroelectric, geothermal, wood, wood waste, biogenic municipal waste, landfill gas, other biomass, solar, and wind power.
[6]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report North American Industry Classification System code 22 or that have a regulatory status).
[7]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors that have a non-regulatory status; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[8]Includes refinery gas and still gas.
[9]Includes conventional hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, and wind power.
[10]Includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
[11]Includes pumped storage, non-biogenic municipal waste, refinery gas, still gas, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 and 2012 electric power sector generation; sales to the grid; net imports; electricity sales; and electricity end-use prices: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013), and supporting databases. 2011 and 2012 emissions: U.S. Environmental Protection Agency, Clean Air Markets Database. 2011 and 2012 electricity prices by service category: EIA, AEO2014 National Energy Modeling System run REF2014.D102413A. **Projections:** EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

012814

Table A9. Electricity generating capacity
(gigawatts)

Net summer capacity[1]	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Electric power sector[2]								
Power only[3]								
Coal	307.9	301.9	254.9	254.0	254.0	254.0	254.1	-0.6%
Oil and natural gas steam[4]	103.4	99.2	84.9	77.2	70.9	68.7	68.5	-1.3%
Combined cycle	178.8	186.2	205.1	224.1	259.6	291.0	316.2	1.9%
Combustion turbine/diesel	135.4	136.4	146.3	166.1	180.6	199.5	220.4	1.7%
Nuclear power[5]	101.5	102.1	97.8	97.8	98.2	98.8	102.0	0.0%
Pumped storage	22.3	22.4	22.4	22.4	22.4	22.4	22.4	0.0%
Fuel cells	0.0	0.0	0.1	0.1	0.1	0.1	0.1	1.9%
Renewable sources[6]	133.0	147.6	173.1	175.0	178.2	184.2	199.2	1.1%
Distributed generation (natural gas)[7]	0.0	0.0	1.6	3.3	4.6	6.2	8.9	--
Total	**982.4**	**996.0**	**986.1**	**1,020.0**	**1,068.6**	**1,124.7**	**1,191.7**	**0.6%**
Combined heat and power[8]								
Coal	4.8	4.7	4.4	4.4	4.4	4.4	4.3	-0.3%
Oil and natural gas steam[4]	1.1	1.1	1.1	1.1	1.1	1.1	1.1	0.0%
Combined cycle	25.6	25.7	26.0	26.0	26.0	26.0	26.0	0.0%
Combustion turbine/diesel	3.3	3.3	3.3	3.3	3.3	3.3	3.3	0.0%
Renewable sources[6]	1.3	1.3	1.4	1.4	1.4	1.4	1.4	0.1%
Total	**36.1**	**36.1**	**36.2**	**36.2**	**36.2**	**36.2**	**36.1**	**0.0%**
Cumulative planned additions[9]								
Coal	--	--	2.2	2.2	2.2	2.2	2.2	--
Oil and natural gas steam[4]	--	--	0.0	0.0	0.0	0.0	0.0	--
Combined cycle	--	--	9.7	9.7	9.7	9.7	9.7	--
Combustion turbine/diesel	--	--	3.7	3.7	3.7	3.7	3.7	--
Nuclear power	--	--	5.5	5.5	5.5	5.5	5.5	--
Pumped storage	--	--	0.0	0.0	0.0	0.0	0.0	--
Fuel cells	--	--	0.0	0.0	0.0	0.0	0.0	--
Renewable sources[6]	--	--	9.0	9.0	9.0	9.0	9.0	--
Distributed generation[7]	--	--	0.0	0.0	0.0	0.0	0.0	--
Total	--	--	**30.1**	**30.1**	**30.1**	**30.1**	**30.1**	--
Cumulative unplanned additions[9]								
Coal	--	--	0.3	0.3	0.3	0.3	0.5	--
Oil and natural gas steam[4]	--	--	0.0	0.0	0.0	0.0	0.0	--
Combined cycle	--	--	9.8	28.8	64.3	95.7	120.9	--
Combustion turbine/diesel	--	--	14.1	34.5	49.2	68.5	89.4	--
Nuclear power	--	--	0.0	0.0	0.3	0.9	4.2	--
Pumped storage	--	--	0.0	0.0	0.0	0.0	0.0	--
Fuel cells	--	--	0.0	0.0	0.0	0.0	0.0	--
Renewable sources[6]	--	--	17.4	19.3	22.5	28.5	43.5	--
Distributed generation[7]	--	--	1.6	3.3	4.6	6.2	8.9	--
Total	--	--	**43.2**	**86.3**	**141.4**	**200.2**	**267.4**	--
Cumulative electric power sector additions[9]	--	--	**73.3**	**116.4**	**171.5**	**230.3**	**297.5**	--
Cumulative retirements[10]								
Coal	--	--	49.9	50.7	50.7	50.7	50.8	--
Oil and natural gas steam[4]	--	--	14.4	22.1	28.3	30.6	30.8	--
Combined cycle	--	--	0.3	0.3	0.3	0.3	0.3	--
Combustion turbine/diesel	--	--	7.8	8.5	8.7	9.1	9.2	--
Nuclear power	--	--	4.8	4.8	4.8	4.8	4.8	--
Pumped storage	--	--	0.0	0.0	0.0	0.0	0.0	--
Fuel cells	--	--	0.0	0.0	0.0	0.0	0.0	--
Renewable sources[6]	--	--	0.9	0.9	0.9	0.9	0.9	--
Total	--	--	**78.0**	**87.3**	**93.8**	**96.4**	**96.7**	--
Total electric power sector capacity	**1,018.5**	**1,032.0**	**1,022.2**	**1,056.2**	**1,104.8**	**1,160.9**	**1,227.8**	**0.6%**

012815

Table A9. Electricity generating capacity (continued)
(gigawatts)

Net summer capacity[1]	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
End-use generators[11]								
Coal	3.6	3.4	3.4	3.4	3.4	3.4	3.4	0.0%
Petroleum	0.7	0.9	0.9	0.9	0.9	0.9	0.9	-0.3%
Natural gas	14.9	16.3	19.2	22.3	27.3	33.7	38.9	3.2%
Other gaseous fuels[12]	2.0	2.1	2.8	2.8	2.8	2.8	2.8	1.0%
Renewable sources[6]	8.6	10.5	20.5	23.8	28.5	34.3	41.3	5.0%
Other[13]	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.1%
Total	**30.2**	**33.8**	**47.2**	**53.7**	**63.4**	**75.6**	**87.7**	**3.5%**
Cumulative capacity additions[9]	- -	- -	**13.5**	**20.0**	**29.7**	**41.8**	**53.9**	- -

[1]Net summer capacity is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
[2]Includes electricity-only and combined heat and power plants that have a regulatory status.
[3]Includes plants that only produce electricity and that have a regulatory status. Includes capacity increases (uprates) at existing units.
[4]Includes oil-, gas-, and dual-fired capacity.
[5]Nuclear capacity includes 0.7 gigawatts of uprates and 5.7 gigawatts of derates through 2020.
[6]Includes conventional hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
[7]Primarily peak load capacity fueled by natural gas.
[8]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report North American Industry Classification System code 22 or that have a regulatory status).
[9]Cumulative additions after December 31, 2012.
[10]Cumulative retirements after December 31, 2012.
[11]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors that have a non-regulatory status; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[12]Includes refinery gas and still gas.
[13]Includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 and 2012 capacity and projected planned additions: U.S. Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). **Projections:** EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

012816

Table A10. Electricity trade

(billion kilowatthours, unless otherwise noted)

Electricity trade	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Interregional electricity trade								
Gross domestic sales								
Firm power	161.5	155.8	129.7	65.9	27.6	27.6	27.6	-6.0%
Economy	157.3	174.0	134.7	141.4	194.5	164.9	182.6	0.2%
Total	**318.8**	**329.9**	**264.4**	**207.3**	**222.1**	**192.5**	**210.2**	**-1.6%**
Gross domestic sales (million 2012 dollars)								
Firm power	10,069.9	9,716.3	8,088.6	4,109.8	1,722.5	1,722.5	1,722.5	-6.0%
Economy	7,446.1	6,053.8	6,421.1	7,674.7	11,497.7	10,617.5	12,851.8	2.7%
Total	**17,516.0**	**15,770.1**	**14,509.7**	**11,784.5**	**13,220.2**	**12,340.0**	**14,574.2**	**-0.3%**
International electricity trade								
Imports from Canada and Mexico								
Firm power	15.0	15.9	20.4	16.4	14.0	14.0	14.0	-0.5%
Economy	37.4	43.1	27.9	34.2	35.4	31.0	35.0	-0.7%
Total	**52.4**	**59.0**	**48.3**	**50.6**	**49.3**	**44.9**	**49.0**	**-0.7%**
Exports to Canada and Mexico								
Firm power	2.6	2.7	1.5	0.5	0.0	0.0	0.0	- -
Economy	12.8	8.8	13.9	14.6	14.6	14.3	14.3	1.8%
Total	**15.4**	**11.5**	**15.3**	**15.1**	**14.6**	**14.3**	**14.3**	**0.8%**

- - = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2011 and 2012 are model results and may differ from official EIA data reports. Firm power sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy sales are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions.

Sources: 2011 and 2012 interregional firm electricity trade data: 2012 seasonal reliability assessments from North American Electric Reliability Council regional entities and Independent System Operators. 2011 and 2012 interregional economy electricity trade are model results. 2011 and 2012 Mexican electricity trade data: U.S. Energy Information Administration (EIA), *Electric Power Annual 2011*, DOE/EIA-0348(2011) (Washington, DC, January 2013). 2011 Canadian international electricity trade data: National Energy Board, *Electricity Exports and Imports Statistics, 2011*. 2012 Canadian international electricity trade data: National Energy Board, *Electricity Exports and Imports Statistics, 2012*. **Projections:** EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

012817

Table A11. Petroleum and other liquids supply and disposition
(million barrels per day, unless otherwise noted)

Supply and disposition	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Crude oil								
Domestic crude production[1]	5.66	6.49	9.55	9.00	8.30	7.87	7.48	0.5%
Alaska	0.57	0.53	0.44	0.33	0.24	0.38	0.26	-2.5%
Lower 48 states	5.09	5.96	9.12	8.68	8.06	7.49	7.22	0.7%
Net imports	8.89	8.43	5.79	6.05	6.64	7.15	7.74	-0.3%
Gross imports	8.94	8.49	5.94	6.18	6.77	7.27	7.87	-0.3%
Exports	0.05	0.06	0.15	0.13	0.13	0.12	0.12	2.6%
Other crude supply[2]	0.27	0.09	0.00	0.00	0.00	0.00	0.00	--
Total crude supply	**14.81**	**15.01**	**15.34**	**15.06**	**14.94**	**15.02**	**15.22**	**0.0%**
Other petroleum supply	**0.85**	**0.10**	**0.23**	**-0.01**	**-0.34**	**-0.67**	**-0.86**	--
Net product imports	-0.25	-0.92	-0.86	-1.01	-1.29	-1.61	-1.82	--
Gross refined product imports[3]	1.15	0.85	0.98	1.06	1.06	1.08	1.10	0.9%
Unfinished oil imports	0.69	0.60	0.52	0.50	0.49	0.47	0.45	-1.0%
Blending component imports	0.72	0.62	0.62	0.55	0.50	0.45	0.40	-1.5%
Exports	2.81	2.98	2.97	3.12	3.33	3.61	3.76	0.8%
Refinery processing gain[4]	1.08	1.08	1.08	1.00	0.96	0.94	0.95	-0.4%
Product stock withdrawal	0.03	-0.06	0.00	0.00	0.00	0.00	0.00	--
Other non-petroleum supply	**3.27**	**3.48**	**3.96**	**4.21**	**4.32**	**4.40**	**4.36**	**0.8%**
Supply from renewable sources	0.87	0.89	1.01	1.04	1.04	1.04	1.07	0.7%
Ethanol	0.82	0.83	0.90	0.92	0.91	0.91	0.95	0.5%
Domestic production	0.89	0.84	0.84	0.85	0.86	0.85	0.86	0.1%
Net imports	-0.07	-0.02	0.06	0.06	0.06	0.06	0.08	--
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	--
Biodiesel	0.06	0.06	0.09	0.09	0.09	0.09	0.09	--
Domestic production	0.06	0.06	0.08	0.08	0.08	0.08	0.08	0.7%
Net imports	0.00	0.00	0.01	0.01	0.01	0.01	0.01	--
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	--
Other biomass-derived liquids[5]	0.00	0.00	0.03	0.04	0.04	0.04	0.03	--
Domestic production	0.00	0.00	0.03	0.04	0.04	0.04	0.03	--
Net imports	0.00	0.00	0.00	0.00	0.00	0.00	0.00	--
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	--
Liquids from gas	2.22	2.40	2.65	2.87	2.98	3.05	2.98	0.8%
Natural gas plant liquids	2.22	2.40	2.65	2.87	2.98	3.05	2.98	0.8%
Gas-to-liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	--
Liquids from coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	--
Other[6]	0.18	0.19	0.30	0.30	0.30	0.31	0.31	1.8%
Total primary supply[7]	**18.94**	**18.59**	**19.52**	**19.26**	**18.93**	**18.75**	**18.72**	**0.0%**
Product supplied								
by fuel								
Liquefied petroleum gases and other[8]	2.30	2.32	2.73	2.84	2.84	2.78	2.73	0.6%
Motor gasoline[9]	8.75	8.71	8.35	7.67	7.15	6.91	6.84	-0.9%
of which: E85[10]	0.00	0.01	0.13	0.26	0.32	0.30	0.23	11.9%
Jet fuel[11]	1.43	1.40	1.49	1.52	1.55	1.57	1.59	0.5%
Distillate fuel oil[12]	3.90	3.74	4.30	4.44	4.52	4.59	4.62	0.8%
of which: Diesel	3.51	3.45	3.94	4.11	4.21	4.30	4.34	0.8%
Residual fuel oil	0.46	0.35	0.39	0.39	0.40	0.40	0.40	0.6%
Other[13]	2.08	1.97	2.28	2.40	2.49	2.51	2.55	0.9%
by sector								
Residential and commercial	0.97	0.94	0.88	0.84	0.81	0.78	0.76	-0.8%
Industrial[14]	4.45	4.42	5.37	5.64	5.72	5.70	5.68	0.9%
Transportation	13.65	13.44	13.19	12.71	12.32	12.20	12.20	-0.3%
Electric power[15]	0.14	0.10	0.08	0.08	0.08	0.08	0.08	-0.7%
Total	**18.92**	**18.49**	**19.53**	**19.27**	**18.94**	**18.76**	**18.73**	**0.0%**
Discrepancy[16]	0.02	0.11	-0.01	-0.01	-0.01	-0.01	-0.01	--

012818

Table A11. Petroleum and other liquids supply and disposition (continued)

(million barrels per day, unless otherwise noted)

Supply and disposition	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Domestic refinery distillation capacity[17]	17.7	17.3	18.1	18.1	18.1	18.1	18.1	0.2%
Capacity utilization rate (percent)[18]	86.0	89.0	84.6	83.1	82.4	82.9	84.0	-0.2%
Net import share of product supplied (percent)	45.2	40.3	25.6	26.6	28.6	29.9	32.2	-0.8%
Net expenditures for imported crude oil and petroleum products (billion 2012 dollars)	494.73	313.70	198.85	234.27	278.60	327.33	385.39	0.7%

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude product supplied.
[3]Includes other hydrocarbons and alcohols.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes pyrolysis oils, biomass-derived Fischer-Tropsch liquids, and renewable feedstocks used for the on-site production of diesel and gasoline.
[6]Includes domestic sources of other blending components, other hydrocarbons, and ethers.
[7]Total crude supply plus other petroleum supply plus other non-petroleum supply.
[8]Includes ethane, natural gasoline, and refinery olefins.
[9]Includes ethanol and ethers blended into gasoline.
[10]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[11]Includes only kerosene type.
[12]Includes distillate fuel oil from petroleum and biomass feedstocks.
[13]Includes kerosene, aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, methanol, and miscellaneous petroleum products.
[14]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[15]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[16]Balancing item. Includes unaccounted for supply, losses, and gains.
[17]End-of-year operable capacity.
[18]Rate is calculated by dividing the gross annual input to atmospheric crude oil distillation units by their operable refining capacity in barrels per calendar day.
- - = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2011 and 2012 are model results and may differ from official EIA data reports.

Sources: 2011 and 2012 product supplied based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). Other 2011 data: EIA, *Petroleum Supply Annual 2011*, DOE/EIA-0340(2011)/1 (Washington, DC, August 2012). Other 2012 data: EIA, *Petroleum Supply Annual 2012*, DOE/EIA-0340(2012)/1 (Washington, DC, September 2013). Projections: EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

012819

Table A12. Petroleum and other liquids prices

(2012 dollars per gallon, unless otherwise noted)

Sector and fuel	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Crude oil prices (2012 dollars per barrel)								
Brent spot	113.24	111.65	96.57	108.99	118.99	129.77	141.46	0.8%
West Texas Intermediate spot	96.55	94.12	94.57	106.99	116.99	127.77	139.46	1.4%
Average imported refiners acquisition cost[1]	104.47	101.10	88.07	100.01	109.22	119.80	130.80	0.9%
Delivered sector product prices								
Residential								
Propane	2.31	2.20	2.17	2.27	2.35	2.45	2.52	0.5%
Distillate fuel oil	3.73	3.79	3.42	3.74	3.97	4.24	4.53	0.6%
Commercial								
Distillate fuel oil	3.64	3.70	3.00	3.31	3.54	3.82	4.10	0.4%
Residual fuel oil	2.91	3.42	2.16	2.41	2.68	2.90	3.14	-0.3%
Residual fuel oil (2012 dollars per barrel)	122.01	143.59	90.53	101.42	112.66	121.75	131.97	-0.3%
Industrial[2]								
Propane	2.07	1.93	1.89	2.02	2.13	2.26	2.36	0.7%
Distillate fuel oil	3.71	3.76	3.05	3.36	3.58	3.84	4.11	0.3%
Residual fuel oil	2.87	3.13	2.23	2.49	2.74	2.96	3.22	0.1%
Residual fuel oil (2012 dollars per barrel)	120.55	131.40	93.56	104.67	115.00	124.42	135.04	0.1%
Transportation								
Propane	2.40	2.30	2.27	2.37	2.45	2.56	2.63	0.5%
Ethanol (E85)[3]	4.19	3.33	2.43	2.62	2.65	2.92	3.37	0.0%
Ethanol wholesale price	2.58	2.58	2.66	2.61	2.52	2.43	2.65	0.1%
Motor gasoline[4]	3.65	3.69	3.08	3.29	3.43	3.65	3.90	0.2%
Jet fuel[5]	3.11	3.10	2.63	2.96	3.20	3.49	3.79	0.7%
Diesel fuel (distillate fuel oil)[6]	3.89	3.95	3.67	3.98	4.20	4.47	4.73	0.7%
Residual fuel oil	2.70	3.00	1.86	2.12	2.32	2.54	2.78	-0.3%
Residual fuel oil (2012 dollars per barrel)	113.46	126.17	78.31	89.03	97.43	106.50	116.65	-0.3%
Electric power[7]								
Distillate fuel oil	3.30	3.35	2.87	3.18	3.42	3.70	4.00	0.6%
Residual fuel oil	2.39	3.10	2.07	2.33	2.57	2.81	3.06	0.0%
Residual fuel oil (2012 dollars per barrel)	100.25	130.00	87.12	98.04	107.77	117.85	128.40	0.0%
Average prices, all sectors[8]								
Propane	2.23	2.12	2.06	2.16	2.25	2.36	2.45	0.5%
Motor gasoline[4]	3.63	3.66	3.08	3.29	3.43	3.65	3.90	0.2%
Jet fuel[5]	3.11	3.10	2.63	2.96	3.20	3.49	3.79	0.7%
Distillate fuel oil	3.83	3.89	3.53	3.84	4.07	4.33	4.60	0.6%
Residual fuel oil	2.66	3.05	1.97	2.23	2.44	2.66	2.91	-0.2%
Residual fuel oil (2012 dollars per barrel)	111.89	128.30	82.69	93.53	102.60	111.83	122.12	-0.2%
Average	**3.28**	**3.28**	**2.80**	**3.02**	**3.19**	**3.43**	**3.69**	**0.4%**

012820

Table A12. Petroleum and other liquids prices (continued)

(nominal dollars per gallon, unless otherwise noted)

Sector and fuel	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Crude oil spot prices (nominal dollars per barrel)								
Brent spot	111.26	111.65	109.37	134.25	160.19	193.27	234.53	2.7%
West Texas Intermediate spot	94.86	94.12	107.11	131.78	157.49	190.30	231.22	3.3%
Average imported refiners acquisition cost[1]	102.64	101.10	99.75	123.19	147.02	178.43	216.87	2.8%
Delivered sector product prices								
Residential								
Propane	2.27	2.20	2.46	2.80	3.17	3.65	4.19	2.3%
Distillate fuel oil	3.67	3.79	3.88	4.60	5.34	6.31	7.51	2.5%
Commercial								
Distillate fuel oil	3.58	3.70	3.40	4.08	4.76	5.69	6.79	2.2%
Residual fuel oil	2.85	3.42	2.44	2.97	3.61	4.32	5.21	1.5%
Residual fuel oil (nominal dollars per barrel)	119.88	143.59	102.54	124.92	151.65	181.33	218.81	1.5%
Industrial[2]								
Propane	2.03	1.93	2.14	2.48	2.86	3.36	3.91	2.6%
Distillate fuel oil	3.65	3.76	3.46	4.13	4.82	5.72	6.81	2.1%
Residual fuel oil	2.82	3.13	2.52	3.07	3.69	4.41	5.33	1.9%
Residual fuel oil (nominal dollars per barrel)	118.44	131.40	105.96	128.93	154.81	185.30	223.89	1.9%
Transportation								
Propane	2.36	2.30	2.57	2.92	3.30	3.81	4.36	2.3%
Ethanol (E85)[3]	4.11	3.33	2.76	3.22	3.57	4.34	5.59	1.9%
Ethanol wholesale price	2.54	2.58	3.02	3.21	3.39	3.63	4.39	1.9%
Motor gasoline[4]	3.58	3.69	3.49	4.05	4.61	5.43	6.47	2.0%
Jet fuel[5]	3.05	3.10	2.98	3.65	4.31	5.19	6.28	2.5%
Diesel fuel (distillate fuel oil)[6]	3.82	3.95	4.16	4.90	5.66	6.65	7.84	2.5%
Residual fuel oil	2.65	3.00	2.11	2.61	3.12	3.78	4.60	1.5%
Residual fuel oil (nominal dollars per barrel)	111.48	126.17	88.69	109.66	131.15	158.62	193.40	1.5%
Electric power[7]								
Distillate fuel oil	3.24	3.35	3.25	3.92	4.60	5.51	6.62	2.5%
Residual fuel oil	2.35	3.10	2.35	2.88	3.45	4.18	5.07	1.8%
Residual fuel oil (nominal dollars per barrel)	98.49	130.00	98.67	120.77	145.08	175.52	212.89	1.8%
Average prices, all sectors[8]								
Propane	2.19	2.12	2.33	2.66	3.03	3.52	4.06	2.3%
Motor gasoline[4]	3.57	3.66	3.49	4.05	4.61	5.43	6.47	2.1%
Jet fuel[5]	3.05	3.10	2.98	3.65	4.31	5.19	6.28	2.5%
Distillate fuel oil	3.77	3.89	3.99	4.73	5.48	6.45	7.63	2.4%
Residual fuel oil	2.62	3.05	2.23	2.74	3.29	3.97	4.82	1.6%
Residual fuel oil (nominal dollars per barrel)	109.93	128.30	93.65	115.20	138.12	166.56	202.47	1.6%
Average	**3.22**	**3.28**	**3.17**	**3.72**	**4.30**	**5.11**	**6.11**	**2.2%**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[5]Includes only kerosene type.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Includes electricity-only and combined heat and power plants that have a regulatory status.
[8]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2011 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 and 2012 Brent and West Texas Intermediate crude oil spot prices: Thomson Reuters. 2011 and 2012 average imported crude oil cost: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2011 and 2012 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, *Petroleum Marketing Monthly*, DOE/EIA-0380(2013/08) (Washington, DC, August 2013). 2011 and 2012 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2011 and 2012 electric power prices based on: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2011 and 2012 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. 2011 and 2012 wholesale ethanol prices derived from Bloomberg U.S. average rack price. **Projections:** EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

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Table A13. Natural gas supply, disposition, and prices
(trillion cubic feet per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Supply								
Dry gas production[1]	22.55	24.06	29.09	31.86	34.43	36.09	37.54	1.6%
Supplemental natural gas[2]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.1%
Net imports	1.96	1.51	-1.93	-3.41	-4.94	-5.53	-5.80	- -
Pipeline[3]	1.68	1.37	0.00	-0.84	-1.57	-2.16	-2.43	- -
Liquefied natural gas	0.28	0.15	-1.93	-2.57	-3.37	-3.37	-3.37	- -
Total supply	**24.57**	**25.64**	**27.23**	**28.52**	**29.56**	**30.63**	**31.81**	**0.8%**
Consumption by sector								
Residential	4.71	4.17	4.46	4.40	4.33	4.23	4.12	0.0%
Commercial	3.16	2.90	3.16	3.22	3.28	3.40	3.57	0.7%
Industrial[4]	6.90	7.14	8.09	8.41	8.52	8.59	8.68	0.7%
Natural-gas-to-liquids heat and power[5]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural gas to liquids production[6]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electric power[7]	7.56	9.25	8.81	9.49	10.06	10.67	11.23	0.7%
Transportation[8]	0.04	0.04	0.08	0.14	0.28	0.48	0.85	11.3%
Pipeline fuel	0.68	0.72	0.73	0.75	0.80	0.82	0.83	0.5%
Lease and plant fuel[9]	1.32	1.42	1.74	1.95	2.11	2.24	2.35	1.8%
Total consumption	**24.38**	**25.64**	**27.06**	**28.35**	**29.39**	**30.44**	**31.63**	**0.8%**
Discrepancy[10]	**0.19**	**0.00**	**0.17**	**0.17**	**0.17**	**0.19**	**0.18**	**- -**
Natural gas spot price at Henry Hub								
(2012 dollars per million Btu)	**4.07**	**2.75**	**4.38**	**5.23**	**6.03**	**6.92**	**7.65**	**3.7%**
(nominal dollars per million Btu)	**4.00**	**2.75**	**4.96**	**6.45**	**8.12**	**10.31**	**12.69**	**5.6%**
Delivered natural gas prices								
(2012 dollars per thousand cubic feet)								
Residential	11.22	10.69	11.85	12.75	13.80	14.93	16.33	1.5%
Commercial	9.16	8.29	9.70	10.51	11.44	12.22	13.37	1.7%
Industrial[4]	5.21	3.85	5.92	6.46	7.14	7.93	8.78	3.0%
Electric power[7]	4.98	3.51	5.19	5.88	6.64	7.45	8.34	3.1%
Transportation[11]	16.25	14.96	15.96	15.91	16.99	18.49	20.10	1.1%
Average[12]	**6.98**	**5.50**	**7.25**	**7.89**	**8.68**	**9.54**	**10.61**	**2.4%**
(nominal dollars per thousand cubic feet)								
Residential	11.02	10.69	13.42	15.70	18.58	22.23	27.07	3.4%
Commercial	9.00	8.29	10.99	12.95	15.40	18.20	22.16	3.6%
Industrial[4]	5.11	3.85	6.70	7.96	9.62	11.81	14.56	4.9%
Electric power[7]	4.90	3.51	5.87	7.25	8.93	11.09	13.82	5.0%
Transportation[11]	15.97	14.96	18.08	19.60	22.87	27.54	33.33	2.9%
Average[12]	**6.86**	**5.50**	**8.21**	**9.71**	**11.68**	**14.21**	**17.59**	**4.2%**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida, as well as gas from Canada and Mexico.
[4]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[5]Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted.
[6]Includes any natural gas converted into liquid fuel.
[7]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[8]Natural gas used as fuel in motor vehicles, trains, and ships.
[9]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[10]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2011 and 2012 values include net storage injections.
[11]Natural gas used as fuel in motor vehicles, trains, and ships. Price includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[12]Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
- - = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2011 and 2012 are model results and may differ from official EIA data reports.

Sources: 2011 supply values; lease, plant, and pipeline fuel consumption; and residential, commercial, and industrial delivered prices: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2011*, DOE/EIA-0131(2011) (Washington, DC, December 2012). 2012 supply values; lease, plant, and pipeline fuel consumption; and residential, commercial, and industrial delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2013/06) (Washington, DC, June 2013). Other 2011 and 2012 consumption based on: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2011 and 2012 natural gas spot price at Henry Hub: Thomson Reuters. 2011 and 2012 electric power prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2012 and April 2013, Table 4.2, and EIA, *State Energy Data Report 2011*, DOE/EIA-0214(2011) (Washington, DC, June 2013). 2011 transportation sector delivered prices are based on: EIA, *Natural Gas Annual 2011*, DOE/EIA-0131(2011) (Washington, DC, December 2012) and estimated state taxes, federal taxes, and dispensing costs or charges. 2012 transportation sector delivered prices are model results. **Projections:** EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

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Table A14. Oil and gas supply

Production and supply	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Crude oil								
Lower 48 average wellhead price[1] (2012 dollars per barrel)	**98.12**	**94.94**	**92.93**	**104.90**	**114.69**	**125.59**	**137.63**	**1.3%**
Production (million barrels per day)[2]								
United States total	5.66	6.49	9.55	9.00	8.30	7.87	7.48	0.5%
Lower 48 onshore	3.66	4.60	7.21	7.04	6.38	5.79	5.23	0.5%
Tight oil[3]	1.31	2.25	4.79	4.54	4.17	3.69	3.20	1.3%
Carbon dioxide enhanced oil recovery	0.28	0.28	0.36	0.47	0.58	0.66	0.74	3.6%
Other	2.07	2.07	2.06	2.03	1.63	1.44	1.29	-1.7%
Lower 48 offshore	1.43	1.37	1.90	1.64	1.68	1.70	1.99	1.4%
Alaska	0.57	0.53	0.44	0.33	0.24	0.38	0.26	-2.5%
Lower 48 end of year reserves[2] (billion barrels)	**25.10**	**24.71**	**31.78**	**33.01**	**34.42**	**34.58**	**35.45**	**1.3%**
Natural gas plant liquids production (million barrels per day)								
United States total	2.22	2.40	2.65	2.87	2.98	3.05	2.98	0.8%
Lower 48 onshore	0.00	2.31	2.42	2.66	2.75	2.81	2.71	0.6%
Lower 48 offshore	0.15	0.14	0.20	0.19	0.22	0.22	0.26	2.3%
Alaska	0.05	0.05	0.03	0.02	0.01	0.02	0.02	-4.1%
Natural gas								
Natural gas spot price at Henry Hub (2012 dollars per million Btu)	4.07	2.75	4.38	5.23	6.03	6.92	7.65	3.7%
Dry production (trillion cubic feet)[4]								
United States total	22.55	24.06	29.09	31.86	34.43	36.09	37.54	1.6%
Lower 48 onshore	20.35	22.07	26.65	29.52	30.82	32.46	33.43	1.5%
Associated-dissolved[5]	1.67	2.06	2.65	2.60	2.25	2.06	1.91	-0.3%
Non-associated	18.68	20.02	24.00	26.92	28.57	30.39	31.52	1.6%
Tight gas	5.01	4.86	6.48	7.06	8.06	8.53	8.41	2.0%
Shale gas	7.94	9.72	13.33	15.99	16.92	18.50	19.82	2.6%
Coalbed methane	1.73	1.58	1.66	1.61	1.61	1.64	1.71	0.3%
Other	4.00	3.86	2.53	2.25	1.98	1.72	1.58	-3.1%
Lower 48 offshore	1.86	1.66	2.16	2.09	2.42	2.46	2.95	2.1%
Associated-dissolved[5]	0.51	0.48	0.68	0.56	0.58	0.59	0.71	1.4%
Non-associated	1.35	1.18	1.48	1.53	1.84	1.87	2.24	2.3%
Alaska	0.33	0.33	0.28	0.26	1.19	1.17	1.17	4.6%
Lower 48 end of year dry reserves[4] (trillion cubic feet)	**324.64**	**320.09**	**352.47**	**368.52**	**382.58**	**393.60**	**402.59**	**0.8%**
Supplemental gas supplies (trillion cubic feet)[6]	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.1%**
Total lower 48 wells drilled (thousands)	**41.81**	**42.49**	**50.46**	**60.06**	**59.28**	**61.73**	**61.57**	**1.3%**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Tight oil represents resources in low-permeability reservoirs, including shale and chalk formations. The specific plays included in the tight oil category are Bakken/Three Forks/Sanish, Eagle Ford, Woodford, Austin Chalk, Spraberry, Niobrara, Avalon/Bone Springs, and Monterey.
[4]Marketed production (wet) minus extraction losses.
[5]Gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).
[6]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 and 2012 crude oil lower 48 average wellhead price: U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2013/08) (Washington, DC, August 2013). 2011 and 2012 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: EIA, *Petroleum Supply Annual 2012*, DOE/EIA-0340(2012)/1 (Washington, DC, September 2013). 2011 U.S. crude oil and natural gas reserves: EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(2010) (Washington, DC, August 2012). 2011 Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Annual 2011*, DOE/EIA-0131(2011) (Washington, DC, December 2012). 2011 and 2012 natural gas spot price at Henry Hub: Thomson Reuters. 2012 Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2013/06) (Washington, DC, June 2013). Other 2011 and 2012 values: EIA, Office of Energy Analysis. **Projections:** EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

012823

Table A15. Coal supply, disposition, and prices

(million short tons per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Production[1]								
Appalachia	337	293	261	259	253	253	247	-0.6%
Interior	171	180	228	244	266	279	289	1.7%
West	588	543	587	611	607	594	584	0.3%
East of the Mississippi	456	423	438	446	459	471	475	0.4%
West of the Mississippi	639	593	639	668	668	655	645	0.3%
Total	**1,096**	**1,016**	**1,077**	**1,114**	**1,127**	**1,126**	**1,121**	**0.3%**
Waste coal supplied[2]	**13**	**11**	**14**	**14**	**15**	**17**	**19**	**1.9%**
Net imports								
Imports[3]	11	8	2	2	1	2	1	-6.6%
Exports	107	126	128	136	148	160	161	0.9%
Total	**-96**	**-118**	**-126**	**-135**	**-147**	**-158**	**-160**	**1.1%**
Total supply[4]	**1,013**	**909**	**965**	**993**	**995**	**985**	**979**	**0.3%**
Consumption by sector								
Commercial and institutional	3	2	2	2	2	2	2	-0.1%
Coke plants	21	21	22	22	21	19	18	-0.5%
Other industrial[5]	46	43	49	49	49	49	50	0.5%
Coal-to-liquids heat and power	0	0	0	0	0	0	0	--
Coal to liquids production	0	0	0	0	0	0	0	--
Electric power[6]	932	825	892	919	923	915	909	0.3%
Total	**1,003**	**891**	**965**	**993**	**995**	**985**	**979**	**0.3%**
Discrepancy and stock change[7]	**10**	**19**	**0**	**0**	**0**	**0**	**0**	**--**
Average minemouth price[8]								
(2012 dollars per short ton)	41.74	39.94	46.52	49.67	53.15	56.37	59.16	1.4%
(2012 dollars per million Btu)	2.07	1.98	2.33	2.49	2.67	2.82	2.96	1.4%
Delivered prices[9]								
(2012 dollars per short ton)								
Commercial and institutional	93.58	90.76	95.19	97.75	101.39	104.53	108.37	0.6%
Coke plants	187.72	190.55	221.01	234.75	249.43	260.42	267.23	1.2%
Other industrial[5]	71.87	70.32	76.39	79.29	82.64	85.75	89.22	0.9%
Coal to liquids	--	--	--	--	--	--	--	--
Electric power[6]								
(2012 dollars per short ton)	47.06	46.13	49.63	52.56	55.32	57.76	60.61	1.0%
(2012 dollars per million Btu)	2.42	2.39	2.61	2.77	2.93	3.05	3.19	1.0%
Average	**51.36**	**50.85**	**54.99**	**58.06**	**60.85**	**63.22**	**65.97**	**0.9%**
Exports[10]	151.51	118.43	136.76	142.74	145.97	148.56	150.13	0.9%

012824

Table A15. Coal supply, disposition, and prices (continued)

(million short tons per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Average minemouth price[8]								
(nominal dollars per short ton)	41.01	39.94	52.69	61.18	71.55	83.96	98.08	3.3%
(nominal dollars per million Btu)	2.04	1.98	2.63	3.07	3.59	4.21	4.91	3.3%
Delivered prices[9]								
(nominal dollars per short ton)								
Commercial and institutional	91.94	90.76	107.81	120.40	136.49	155.69	179.68	2.5%
Coke plants	184.44	190.55	250.32	289.16	335.77	387.86	443.06	3.1%
Other industrial[5]	70.61	70.32	86.52	97.66	111.25	127.72	147.92	2.7%
Coal to liquids	--	--	--	--	--	--	--	--
Electric power[6]								
(nominal dollars per short ton)	46.24	46.13	56.21	64.74	74.47	86.03	100.48	2.8%
(nominal dollars per million Btu)	2.38	2.39	2.96	3.42	3.94	4.54	5.29	2.9%
Average	**50.46**	**50.85**	**62.28**	**71.52**	**81.91**	**94.16**	**109.37**	**2.8%**
Exports[10]	148.86	118.43	154.90	175.82	196.51	221.27	248.92	2.7%

[1]Includes anthracite, bituminous coal, subbituminous coal, and lignite.
[2]Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
[3]Excludes imports to Puerto Rico and the U.S. Virgin Islands.
[4]Production plus waste coal supplied plus net imports.
[5]Includes consumption for combined heat and power plants that have a non-regulatory status, and small on-site generating systems. Excludes all coal use in the coal-to-liquids process.
[6]Includes all electricity-only and combined heat and power plants that have a regulatory status.
[7]Balancing item: the sum of production, net imports, and waste coal supplied minus total consumption.
[8]Includes reported prices for both open market and captive mines. Prices weighted by production, which differs from average minemouth prices published in EIA data reports where it is weighted by reported sales.
[9]Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship prices.
[10]Free-alongside-ship price at U.S. port of exit.
-- = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 and 2012 data based on: U.S. Energy Information Administration (EIA), *Annual Coal Report 2012*, DOE/EIA-0584(2012) (Washington, DC, December 2013); EIA, *Quarterly Coal Report, October-December 2012*, DOE/EIA-0121(2012/4Q) (Washington, DC, March 2013); and EIA, AEO2014 National Energy Modeling System run REF2014.D102413A. **Projections:** EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

012825

Table A16. Renewable energy generating capacity and generation
(gigawatts, unless otherwise noted)

Net summer capacity and generation	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Electric power sector[1]								
Net summer capacity								
Conventional hydropower	77.96	78.10	78.41	79.10	79.75	80.07	80.35	0.1%
Geothermal[2]	2.45	2.58	4.02	5.15	6.58	7.99	8.80	4.5%
Municipal waste[3]	3.45	3.57	3.63	3.63	3.63	3.63	3.63	0.1%
Wood and other biomass[4]	2.56	2.70	3.14	3.14	3.14	3.17	3.46	0.9%
Solar thermal	0.48	0.48	1.73	1.73	1.73	1.73	1.73	4.7%
Solar photovoltaic[5]	1.05	2.49	7.90	7.96	8.62	10.33	17.07	7.1%
Wind	46.33	59.01	75.59	75.62	76.12	78.61	85.48	1.3%
Offshore wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	--
Total electric power sector capacity	**134.28**	**148.92**	**174.43**	**176.32**	**179.56**	**185.54**	**200.52**	**1.1%**
Generation (billion kilowatthours)								
Conventional hydropower	316.65	273.89	287.67	291.17	294.35	296.14	297.34	0.3%
Geothermal[2]	15.32	15.56	28.24	37.44	49.04	60.60	67.26	5.4%
Biogenic municipal waste[6]	16.20	16.79	19.05	18.19	18.15	18.66	19.21	0.5%
Wood and other biomass	10.73	11.04	36.71	58.87	67.50	70.39	72.22	6.9%
Dedicated plants	9.55	9.84	15.31	15.95	16.17	16.80	18.99	2.4%
Cofiring	1.19	1.20	21.40	42.92	51.33	53.59	53.23	14.5%
Solar thermal	0.81	0.90	3.52	3.53	3.53	3.53	3.53	5.0%
Solar photovoltaic[5]	0.92	3.25	14.54	14.65	16.07	19.86	35.24	8.9%
Wind	120.12	141.87	217.53	217.62	219.06	225.11	248.02	2.0%
Offshore wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	--
Total electric power sector generation	**480.74**	**463.29**	**607.26**	**641.47**	**667.71**	**694.30**	**742.82**	**1.7%**
End-use sectors[7]								
Net summer capacity								
Conventional hydropower	0.33	0.29	0.29	0.29	0.29	0.29	0.29	0.0%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	--
Municipal waste[8]	0.37	0.47	0.47	0.47	0.47	0.47	0.47	0.0%
Biomass	4.85	4.89	6.27	7.17	7.95	8.74	9.62	2.4%
Solar photovoltaic[5]	2.89	4.71	12.75	15.18	18.93	23.73	29.47	6.8%
Wind	0.14	0.15	0.70	0.74	0.90	1.09	1.42	8.3%
Total end-use sector capacity	**8.58**	**10.51**	**20.48**	**23.84**	**28.53**	**34.31**	**41.26**	**5.0%**
Generation (billion kilowatthours)								
Conventional hydropower	1.82	1.38	1.38	1.38	1.38	1.38	1.38	0.0%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	--
Municipal waste[8]	2.91	3.65	3.63	3.63	3.63	3.63	3.63	0.0%
Biomass	26.69	26.53	34.10	39.18	43.75	48.37	53.50	2.5%
Solar photovoltaic[5]	4.51	7.35	19.91	23.92	30.09	38.00	47.46	6.9%
Wind	0.18	0.20	0.96	1.03	1.25	1.53	2.01	8.6%
Total end-use sector generation	**36.11**	**39.11**	**59.98**	**69.14**	**80.10**	**92.91**	**107.99**	**3.7%**

012826

Table A16. Renewable energy generating capacity and generation (continued)
(gigawatts, unless otherwise noted)

Net summer capacity and generation	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Total, all sectors								
Net summer capacity								
Conventional hydropower	78.29	78.39	78.70	79.39	80.03	80.36	80.63	0.1%
Geothermal	2.45	2.58	4.02	5.15	6.58	7.99	8.80	4.5%
Municipal waste	3.82	4.04	4.10	4.10	4.10	4.10	4.10	0.1%
Wood and other biomass[4]	7.42	7.59	9.41	10.30	11.08	11.91	13.08	2.0%
Solar[5]	4.42	7.68	22.38	24.86	29.27	35.78	48.26	6.8%
Wind	46.47	59.16	76.29	76.37	77.02	79.70	86.91	1.4%
Total capacity, all sectors	**142.86**	**159.43**	**194.91**	**200.17**	**208.09**	**219.85**	**241.78**	**1.5%**
Generation (billion kilowatthours)								
Conventional hydropower	318.47	275.27	289.05	292.55	295.73	297.52	298.72	0.3%
Geothermal	15.32	15.56	28.24	37.44	49.04	60.60	67.26	5.4%
Municipal waste	19.11	20.44	22.68	21.82	21.78	22.29	22.84	0.4%
Wood and other biomass	37.42	37.57	70.81	98.06	111.25	118.76	125.72	4.4%
Solar[5]	6.24	11.50	37.98	42.09	49.69	61.40	86.23	7.5%
Wind	120.30	142.06	218.49	218.64	220.32	226.65	250.03	2.0%
Total generation, all sectors	**516.85**	**502.41**	**667.24**	**710.61**	**747.81**	**787.22**	**850.80**	**1.9%**

[1]Includes electricity-only and combined heat and power plants that have a regulatory status.
[2]Includes both hydrothermal resources (hot water and steam) and near-field enhanced geothermal systems (EGS). Near-field EGS potential occurs on known hydrothermal sites, however this potential requires the addition of external fluids for electricity generation and is only available after 2025.
[3]Includes municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[4]Facilities co-firing biomass and coal are classified as coal.
[5]Does not include off-grid photovoltaics (PV). Based on annual PV shipments from 1989 through 2012, EIA estimates that as much as 274 megawatts of remote electricity generation PV applications (i.e., off-grid power systems) were in service in 2012, plus an additional 573 megawatts in communications, transportation, and assorted other non-grid-connected, specialized applications. See U.S. Energy Information Administration, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012), Table 10.9 (annual PV shipments, 1989-2010), and Table 12 (U.S. photovoltaic module shipments by end use, sector, and type) in U.S. Energy Information Administration, *Solar Photovoltaic Cell/Module Shipments Report, 2011* (Washington, DC, September 2012) and U.S. Energy Information Administration, *Solar Photovoltaic Cell/Module Shipments Report, 2012* (Washington, DC, December 2013). The approach used to develop the estimate, based on shipment data, provides an upper estimate of the size of the PV stock, including both grid-based and off-grid PV. It will overestimate the size of the stock, because shipments include a substantial number of units that are exported, and each year some of the PV units installed earlier will be retired from service or abandoned.
[6]Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. Only biogenic municipal waste is included. The U.S. Energy Information Administration estimates that in 2012 approximately 7 billion kilowatthours of electricity were generated from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See U.S. Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy* (Washington, DC, May 2007).
[7]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors that have a non-regulatory status; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[8]Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 and 2012 capacity: U.S. Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). 2011 and 2012 generation: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). Projections: EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

012827

Table A17. Renewable energy consumption by sector and source
(quadrillion Btu per year)

Sector and source	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Marketed renewable energy[1]								
Residential (wood)	**0.54**	**0.45**	**0.46**	**0.45**	**0.44**	**0.43**	**0.42**	**-0.3%**
Commercial (biomass)	**0.11**	**0.13**	**0.13**	**0.13**	**0.13**	**0.13**	**0.13**	**0.0%**
Industrial[2]	**1.95**	**2.00**	**2.50**	**2.67**	**2.79**	**2.92**	**3.07**	**1.5%**
Conventional hydroelectric	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.0%
Municipal waste[3]	0.17	0.19	0.20	0.20	0.20	0.20	0.20	0.2%
Biomass	1.30	1.28	1.53	1.67	1.80	1.92	2.07	1.7%
Biofuels heat and coproducts	0.46	0.52	0.76	0.79	0.79	0.79	0.79	1.5%
Transportation	**1.21**	**1.22**	**1.42**	**1.45**	**1.45**	**1.45**	**1.49**	**0.7%**
Ethanol used in E85[4]	0.00	0.01	0.13	0.25	0.31	0.29	0.22	11.9%
Ethanol used in gasoline blending	1.09	1.09	1.07	0.97	0.91	0.93	1.04	-0.2%
Biodiesel used in distillate blending	0.12	0.12	0.17	0.17	0.17	0.17	0.17	1.5%
Biobutanol	0.00	0.00	0.03	0.04	0.04	0.04	0.03	- -
Liquids from biomass	0.00	0.00	0.01	0.01	0.01	0.01	0.01	- -
Renewable diesel and gasoline[5]	0.00	0.00	0.01	0.01	0.01	0.01	0.01	- -
Electric power[6]	**4.80**	**4.59**	**6.08**	**6.42**	**6.68**	**6.95**	**7.44**	**1.7%**
Conventional hydroelectric	3.09	2.66	2.79	2.83	2.86	2.88	2.89	0.3%
Geothermal	0.15	0.15	0.28	0.36	0.48	0.59	0.65	5.4%
Biogenic municipal waste[7]	0.19	0.21	0.25	0.23	0.23	0.24	0.25	0.6%
Biomass	0.18	0.15	0.47	0.70	0.79	0.83	0.86	6.5%
Dedicated plants	0.16	0.16	0.24	0.25	0.26	0.27	0.30	2.3%
Cofiring	0.03	-0.01	0.23	0.45	0.54	0.56	0.56	- -
Solar thermal	0.01	0.01	0.03	0.03	0.03	0.03	0.03	5.0%
Solar photovoltaic	0.01	0.03	0.14	0.14	0.16	0.19	0.34	8.9%
Wind	1.17	1.38	2.11	2.11	2.13	2.19	2.41	2.0%
Total marketed renewable energy	**8.62**	**8.39**	**10.58**	**11.12**	**11.50**	**11.89**	**12.54**	**1.4%**
Sources of ethanol								
from corn and other starch	1.18	1.12	1.11	1.12	1.12	1.12	1.13	0.0%
from cellulose	0.00	0.00	0.01	0.02	0.02	0.02	0.02	- -
Net imports	-0.09	-0.02	0.07	0.08	0.08	0.08	0.11	- -
Total	**1.09**	**1.10**	**1.19**	**1.22**	**1.22**	**1.22**	**1.26**	**0.5%**

012828

Table A17. Renewable energy consumption by sector and source (continued)

(quadrillion Btu per year)

Sector and source	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Nonmarketed renewable energy[8]								
Selected consumption								
Residential	**0.03**	**0.04**	**0.14**	**0.16**	**0.19**	**0.23**	**0.27**	**6.9%**
Solar hot water heating	0.00	0.01	0.01	0.01	0.01	0.01	0.01	2.4%
Geothermal heat pumps	0.01	0.01	0.02	0.02	0.02	0.02	0.03	3.2%
Solar photovoltaic	0.02	0.02	0.10	0.12	0.14	0.18	0.22	8.3%
Wind	0.00	0.00	0.01	0.01	0.01	0.01	0.01	9.1%
Commercial	**0.11**	**0.13**	**0.18**	**0.21**	**0.24**	**0.29**	**0.35**	**3.7%**
Solar thermal	0.08	0.08	0.09	0.09	0.09	0.10	0.11	1.0%
Solar photovoltaic	0.03	0.05	0.10	0.12	0.15	0.19	0.24	5.9%
Wind	0.00	0.00	0.00	0.00	0.00	0.01	0.01	8.3%

[1]Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table A2. Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, geothermal, solar, and wind. Consumption at hydroelectric, geothermal, solar, and wind facilities is determined by using the fossil fuel equivalent of 9,716 Btu per kilowatthour.
[2]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[3]Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[4]Excludes motor gasoline component of E85.
[5]Renewable feedstocks for the on-site production of diesel and gasoline.
[6]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[7]Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. Only biogenic municipal waste is included. The U.S. Energy Information Administration estimates that in 2012 approximately 0.3 quadrillion Btus were consumed from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See U.S. Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy* (Washington, DC, May 2007).
[8]Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The U.S. Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.
- - = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 and 2012 ethanol: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2011 and 2012 electric power sector: EIA, Form EIA-860, "Annual Electric Generator Report" (preliminary). Other 2011 and 2012 values: EIA, Office of Energy Analysis. **Projections:** EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

012829

Table A18. Energy-related carbon dioxide emissions by sector and source
(million metric tons, unless otherwise noted)

Sector and source	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Residential								
Petroleum	72	69	60	55	51	48	45	-1.6%
Natural gas	255	226	242	239	235	229	223	0.0%
Electricity[1]	824	760	751	770	785	800	814	0.2%
Total residential	**1,150**	**1,056**	**1,054**	**1,064**	**1,071**	**1,077**	**1,082**	**0.1%**
Commercial								
Petroleum	47	45	49	48	48	48	48	0.2%
Natural gas	171	157	172	174	178	185	194	0.7%
Coal	6	4	4	4	4	4	4	0.0%
Electricity[1]	769	732	728	760	781	801	823	0.4%
Total commercial	**992**	**939**	**952**	**987**	**1,011**	**1,038**	**1,069**	**0.5%**
Industrial[2]								
Petroleum	347	350	395	402	405	404	406	0.5%
Natural gas[3]	432	449	512	540	556	567	578	0.9%
Coal	148	139	152	152	147	140	139	0.0%
Electricity[1]	574	543	628	658	654	638	625	0.5%
Total industrial	**1,501**	**1,480**	**1,688**	**1,752**	**1,761**	**1,750**	**1,748**	**0.6%**
Transportation								
Petroleum[4]	1,812	1,771	1,734	1,669	1,618	1,603	1,600	-0.4%
Natural gas[5]	39	41	44	48	58	70	91	2.9%
Electricity[1]	4	4	5	6	7	8	9	3.1%
Total transportation	**1,854**	**1,815**	**1,782**	**1,723**	**1,683**	**1,681**	**1,700**	**-0.2%**
Electric power[6]								
Petroleum	27	19	13	14	14	14	14	-1.0%
Natural gas	409	494	478	514	545	578	608	0.7%
Coal	1,723	1,514	1,609	1,654	1,656	1,643	1,637	0.3%
Other[7]	12	12	12	12	12	12	12	0.0%
Total electric power	**2,171**	**2,039**	**2,112**	**2,194**	**2,227**	**2,247**	**2,271**	**0.4%**
Total by fuel								
Petroleum[4]	2,304	2,254	2,252	2,188	2,136	2,117	2,113	-0.2%
Natural gas	1,306	1,366	1,447	1,516	1,572	1,629	1,694	0.8%
Coal	1,876	1,657	1,766	1,810	1,807	1,788	1,780	0.3%
Other[7]	12	12	12	12	12	12	12	0.0%
Total	**5,498**	**5,290**	**5,476**	**5,526**	**5,527**	**5,546**	**5,599**	**0.2%**
Carbon dioxide emissions (tons per person)	**17.6**	**16.8**	**16.4**	**15.9**	**15.4**	**15.0**	**14.7**	**-0.5%**

[1]Emissions from the electric power sector are distributed to the end-use sectors.
[2]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[3]Includes lease and plant fuel.
[4]This includes carbon dioxide from international bunker fuels, both civilian and military, which are excluded from the accounting of carbon dioxide emissions under the United Nations convention. From 1990 through 2012, international bunker fuels accounted for 90 to 126 million metric tons annually.
[5]Includes pipeline fuel natural gas and natural gas used as fuel in motor vehicles, trains, and ships.
[6]Includes electricity-only and combined heat and power plants that have a regulatory status.
[7]Includes emissions from geothermal power and nonbiogenic emissions from municipal waste.

Note: By convention, the direct emissions from biogenic energy sources are excluded from energy-related carbon dioxide emissions. The release of carbon from these sources is assumed to be balanced by the uptake of carbon when the feedstock is grown, resulting in zero net emissions over some period of time. If, however, increased use of biomass energy results in a decline in terrestrial carbon stocks, a net positive release of carbon may occur. See "Energy-Related Carbon Dioxide Emissions by End Use" for the emissions from biogenic energy sources as an indication of the potential net release of carbon dioxide in the absence of offsetting sequestration. Totals may not equal sum of components due to independent rounding. Data for 2011 and 2012 are model results and may differ from official EIA data reports.

Sources: 2011 and 2012 emissions and emission factors: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0384(2013/09) (Washington, DC, September 2013). 2011 emissions: EIA, *Monthly Energy Review*, DOE/EIA-0035(2011/10) (Washington, DC, October 2011). 2012 emissions and emission factors: EIA, *Monthly Energy Review*, DOE/EIA-0035(2012/08) (Washington, DC, August 2012). **Projections:** EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

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Table A19. Energy-related carbon dioxide emissions by end use
(million metric tons)

Sector and end use	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Residential								
Space heating	285.2	235.7	254.0	245.4	236.2	226.7	217.3	-0.3%
Space cooling	141.5	139.7	139.1	151.3	162.1	172.5	181.4	0.9%
Water heating	146.6	145.2	143.4	144.9	144.1	140.7	137.0	-0.2%
Refrigeration	64.1	61.5	58.3	58.0	57.9	58.7	59.6	-0.1%
Cooking	30.8	30.1	31.0	31.9	32.7	33.5	34.1	0.4%
Clothes dryers	36.3	35.1	35.7	36.9	37.8	38.8	39.5	0.4%
Freezers	13.5	13.0	12.4	12.1	11.8	11.5	11.3	-0.5%
Lighting	108.3	103.0	67.7	60.1	52.8	44.2	39.8	-3.3%
Clothes washers[1]	5.4	5.1	4.0	3.4	3.2	3.2	3.2	-1.6%
Dishwashers[1]	16.9	16.2	15.2	15.0	15.7	16.5	17.2	0.2%
Televisions and related equipment[2]	56.7	54.0	50.8	51.5	52.8	54.9	55.9	0.1%
Computers and related equipment[3]	21.7	20.2	15.2	12.9	10.8	9.2	7.6	-3.4%
Furnace fans and boiler circulation pumps	20.0	15.3	17.9	17.9	17.8	17.5	17.0	0.4%
Other uses[4]	203.6	181.4	209.0	222.8	235.9	248.7	260.7	1.3%
Discrepancy[5]	-0.4	0.3	0.0	0.0	0.0	0.0	0.0	- -
Total residential	**1,150.4**	**1,055.9**	**1,053.7**	**1,064.2**	**1,071.5**	**1,076.6**	**1,081.7**	**0.1%**
Commercial								
Space heating[6]	131.4	115.4	125.8	122.9	118.7	114.6	110.2	-0.2%
Space cooling[6]	95.2	92.1	81.5	82.9	82.6	82.9	83.4	-0.4%
Water heating[6]	42.7	42.8	43.5	44.4	44.5	44.3	44.1	0.1%
Ventilation	86.7	83.8	85.1	87.9	88.3	88.5	88.8	0.2%
Cooking	14.1	14.2	14.5	14.9	15.3	15.6	15.9	0.4%
Lighting	162.2	151.8	136.3	135.4	131.3	125.3	121.2	-0.8%
Refrigeration	65.7	62.0	57.0	57.1	57.2	57.8	58.4	-0.2%
Office equipment (PC)	21.3	18.7	10.5	7.8	5.7	4.3	3.4	-6.0%
Office equipment (non-PC)	37.8	35.3	37.3	41.7	46.5	51.1	55.1	1.6%
Other uses[7]	335.4	322.6	360.6	392.2	420.7	453.4	488.2	1.5%
Total commercial	**992.3**	**938.6**	**952.2**	**987.2**	**1,010.8**	**1,037.9**	**1,068.7**	**0.5%**
Industrial[8]								
Manufacturing								
Refining								-0.2%
Food products	252.4	257.5	254.7	248.9	245.1	244.6	246.7	0.9%
Paper products	96.4	96.8	106.4	111.9	116.2	119.8	123.7	0.1%
Bulk chemicals	74.5	71.0	69.9	70.9	70.9	71.6	73.2	0.5%
Glass	254.8	247.7	295.6	313.5	310.4	295.8	282.2	0.2%
Cement and lime	15.5	15.4	16.1	16.3	17.1	16.7	16.1	1.8%
Iron and steel	29.0	29.1	42.2	43.6	45.0	45.7	47.3	-0.4%
Aluminum	126.9	124.8	136.5	142.4	133.7	120.9	110.4	-0.8%
Fabricated metal products	45.3	45.6	50.3	54.2	49.7	41.2	36.3	0.4%
Machinery	37.8	38.2	42.3	44.3	43.8	43.0	42.2	0.9%
Computers and electronics	21.4	21.8	25.0	27.1	28.2	28.2	28.2	1.3%
Transportation equipment	46.3	46.4	50.5	57.4	61.7	64.6	65.8	1.4%
Electrical equipment	41.7	44.3	50.5	53.2	58.2	62.1	65.0	1.1%
Wood products	8.3	8.2	9.1	9.9	10.5	10.9	11.1	0.5%
Plastics	15.6	15.4	20.7	20.3	19.4	18.2	17.5	0.4%
Balance of manufacturing	39.7	38.7	42.4	44.3	44.6	44.0	43.6	0.9%
Total manufacturing	159.7	154.0	166.2	174.3	179.4	185.8	195.5	**0.4%**
Nonmanufacturing	**1,265.2**	**1,254.9**	**1,378.4**	**1,432.6**	**1,433.9**	**1,413.3**	**1,404.8**	
Agriculture								0.6%
Construction	71.0	65.5	75.7	76.7	77.3	77.4	77.7	1.5%
Mining	59.7	61.0	81.1	83.9	86.6	88.7	91.7	0.0%
Total nonmanufacturing	100.5	101.0	113.3	111.5	107.4	103.9	100.1	**0.6%**
Discrepancy[5]	**231.1**	**227.5**	**270.1**	**272.1**	**271.3**	**270.0**	**269.5**	- -
Total industrial	4.9	-2.6	39.1	47.5	56.2	66.6	74.1	**0.6%**

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Table A19. Energy-related carbon dioxide emissions by end use (continued)
(million metric tons)

Sector and end use	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Transportation								
Light-duty vehicles	1,037.7	1,030.7	934.9	845.5	780.7	753.9	743.8	-1.2%
Commercial light trucks[9]	35.9	35.6	36.1	34.9	34.1	34.4	35.6	0.0%
Bus transportation	16.8	16.1	16.0	16.1	16.0	15.9	15.8	-0.1%
Freight trucks	369.7	357.7	415.3	438.4	457.1	478.1	502.2	1.2%
Rail, passenger	5.5	5.4	5.6	5.9	6.1	6.2	6.5	0.7%
Rail, freight	36.9	34.7	31.7	32.0	30.5	28.8	27.2	-0.9%
Shipping, domestic	8.1	7.0	6.8	6.3	5.9	5.6	5.5	-0.9%
Shipping, international	60.0	45.3	46.0	46.6	47.1	47.5	47.9	0.2%
Recreational boats	16.1	16.1	17.0	17.7	18.2	18.6	18.8	0.6%
Air	174.4	175.2	184.1	188.1	190.3	190.8	191.4	0.3%
Military use	52.5	50.1	45.4	46.1	48.6	51.4	54.4	0.3%
Lubricants	5.0	4.4	4.5	4.5	4.5	4.5	4.6	0.1%
Pipeline fuel	37.1	38.8	39.3	40.6	43.5	44.3	44.9	0.5%
Discrepancy[5]	-1.4	-1.7	-0.4	0.1	0.6	1.2	1.7	- -
Total transportation	**1,854.1**	**1,815.4**	**1,782.4**	**1,722.6**	**1,683.2**	**1,681.3**	**1,700.4**	**-0.2%**
Biogenic energy combustion[10]								
Biomass	200.6	188.7	242.7	277.4	297.0	311.1	326.0	2.0%
Electric power sector	17.3	13.7	44.0	65.6	74.5	77.9	80.3	6.5%
Other sectors	183.3	175.0	198.7	211.8	222.5	233.2	245.7	1.2%
Biogenic waste	17.6	19.1	22.5	21.1	21.1	21.9	22.8	0.6%
Biofuels heat and coproducts	43.3	48.6	71.6	73.8	73.9	73.8	73.8	1.5%
Ethanol	74.8	75.5	81.6	83.3	83.3	83.2	86.1	0.5%
Biodiesel	8.5	8.4	12.6	12.5	12.5	12.7	12.7	1.5%
Liquids from biomass	0.0	0.0	1.0	1.0	1.0	1.0	1.0	- -
Renewable diesel and gasoline	0.0	0.0	0.9	0.9	0.9	0.9	0.9	- -
Total	**344.8**	**340.3**	**432.9**	**470.1**	**489.7**	**504.6**	**523.3**	**1.5%**

[1]Does not include water heating portion of load.
[2]Includes televisions, set-top boxes, home theater systems, DVD players, and video game consoles.
[3]Includes desktop and laptop computers, monitors, and networking equipment.
[4]Includes small electric devices, heating elements, outdoor grills, exterior lights, pool heaters, spa heaters, backup electricity generators, and motors not listed above. Electric vehicles are included in the transportation sector.
[5]Represents differences between total emissions by end-use and total emissions by fuel as reported in Table A18. Emissions by fuel may reflect benchmarking and other modeling adjustments to energy use and the associated emissions that are not assigned to specific end uses.
[6]Includes emissions related to fuel consumption for district services.
[7]Includes (but is not limited to) miscellaneous uses such as transformers, medical imaging and other medical equipment, elevators, escalators, off-road electric vehicles, laboratory fume hoods, laundry equipment, coffee brewers, water services, pumps, emergency generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, propane, coal, motor gasoline, kerosene, and marketed renewable fuels (biomass).
[8]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[9]Commercial trucks 8,501 to 10,000 pounds gross vehicle weight rating.
[10]By convention, the direct emissions from biogenic energy sources are excluded from energy-related carbon dioxide emissions. The release of carbon from these sources is assumed to be balanced by the uptake of carbon when the feedstock is grown, resulting in zero net emissions over some period of time. If, however, increased use of biomass energy results in a decline in terrestrial carbon stocks, a net positive release of carbon may occur. Accordingly, the emissions from biogenic energy sources are reported here as an indication of the potential net release of carbon dioxide in the absence of offsetting sequestration.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 and 2012 emissions and emission factors: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). **Projections:** EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

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Table A20. Macroeconomic indicators

(billion 2005 chain-weighted dollars, unless otherwise noted)

Indicators	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Real gross domestic product	**13,299**	**13,593**	**16,753**	**18,769**	**21,139**	**23,751**	**26,670**	**2.4%**
Components of real gross domestic product								
Real consumption	9,429	9,603	11,592	12,773	14,220	15,828	17,635	2.2%
Real investment	1,744	1,914	2,876	3,269	3,740	4,274	4,925	3.4%
Real government spending	2,524	2,481	2,443	2,495	2,623	2,754	2,917	0.6%
Real exports	1,777	1,837	2,863	3,857	5,056	6,516	8,186	5.5%
Real imports	2,185	2,238	2,925	3,453	4,213	5,167	6,328	3.8%
Energy intensity (thousand Btu per 2005 dollar of GDP)								
Delivered energy	5.29	5.08	4.40	3.97	3.54	3.18	2.88	-2.0%
Total energy	7.30	6.99	6.01	5.46	4.89	4.39	3.99	-2.0%
Price indices								
GDP chain-type price index (2005=1.000)	1.134	1.154	1.307	1.421	1.553	1.719	1.913	1.8%
Consumer price index (1982-4=1.00)								
All-urban	2.25	2.30	2.63	2.90	3.20	3.59	4.05	2.1%
Energy commodities and services	2.44	2.46	2.55	2.91	3.33	3.86	4.56	2.2%
Wholesale price index (1982=1.00)								
All commodities	2.01	2.02	2.22	2.40	2.62	2.89	3.21	1.7%
Fuel and power	2.16	2.12	2.42	2.82	3.30	3.92	4.73	2.9%
Metals and metal products	2.26	2.20	2.43	2.56	2.77	2.99	3.22	1.4%
Industrial commodities excluding energy	1.93	1.94	2.14	2.26	2.41	2.59	2.78	1.3%
Interest rates (percent, nominal)								
Federal funds rate	0.10	0.14	3.85	3.99	4.14	4.20	4.22	- -
10-year treasury note	2.79	1.80	4.14	4.24	4.36	4.45	4.52	- -
AA utility bond rate	4.78	3.83	6.60	6.74	6.88	7.05	7.22	- -
Value of shipments (billion 2005 dollars)								
Non-industrial and service sectors	21,240	21,359	26,033	28,947	31,782	34,480	37,135	2.0%
Total industrial	5,926	6,147	7,960	8,778	9,537	10,241	10,994	2.1%
Agriculture, mining, and construction	1,556	1,623	2,226	2,311	2,389	2,457	2,551	1.6%
Manufacturing	4,370	4,525	5,735	6,467	7,148	7,784	8,443	2.3%
Energy-intensive	1,599	1,616	1,931	2,081	2,171	2,238	2,303	1.3%
Non-energy-intensive	2,772	2,909	3,803	4,386	4,977	5,547	6,140	2.7%
Total shipments	**27,166**	**27,506**	**33,994**	**37,725**	**41,319**	**44,721**	**48,129**	**2.0%**
Population and employment (millions)								
Population, with armed forces overseas	312.3	314.6	334.5	347.0	359.0	370.2	380.5	0.7%
Population, aged 16 and over	247.0	249.2	266.7	277.2	287.6	297.9	307.3	0.8%
Population, over age 65	41.7	43.4	56.2	65.3	73.0	77.5	79.8	2.2%
Employment, nonfarm	131.5	133.7	148.4	152.2	158.6	163.7	169.2	0.8%
Employment, manufacturing	11.7	11.9	12.8	12.9	12.5	11.8	11.0	-0.3%
Key labor indicators								
Labor force (millions)	153.6	155.0	163.5	166.9	170.9	175.8	181.2	0.6%
Nonfarm labor productivity (2005=1.00)	1.10	1.11	1.25	1.39	1.53	1.68	1.85	1.8%
Unemployment rate (percent)	8.93	8.08	5.49	5.29	5.10	5.08	5.12	- -
Key indicators for energy demand								
Real disposable personal income	10,150	10,304	12,710	14,162	15,926	17,749	19,724	2.3%
Housing starts (millions)	0.66	0.84	1.75	1.72	1.71	1.67	1.66	2.5%
Commercial floorspace (billion square feet)	81.7	82.4	89.1	93.9	98.2	103.1	108.9	1.0%
Unit sales of light-duty vehicles (millions)	12.73	14.43	16.23	16.55	17.23	17.45	17.93	0.8%

GDP = Gross domestic product.
Btu = British thermal unit.
- - = Not applicable.
Sources: 2011 and 2012: IHS Global Insight, Global Insight Industry and Employment models, May 2013. **Projections:** U.S. Energy Information Administration, AEO2014 National Energy Modeling System run REF2014.D102413A.

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Table A21. International petroleum and other liquids supply, disposition, and prices

(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Crude oil spot prices								
(2012 dollars per barrel)								
Brent	113.24	111.65	96.57	108.99	118.99	129.77	141.46	0.8%
West Texas Intermediate	96.55	94.12	94.57	106.99	116.99	127.77	139.46	1.4%
(nominal dollars per barrel)								
Brent	111.26	111.65	109.37	134.25	160.19	193.27	234.53	2.7%
West Texas Intermediate	94.86	94.12	107.11	131.78	157.49	190.30	231.22	3.3%
Petroleum and other liquids consumption[1]								
OECD								
United States (50 states)	18.65	18.21	19.23	18.97	18.63	18.46	18.42	0.0%
United States territories	0.25	0.25	0.29	0.31	0.33	0.35	0.37	1.5%
Canada	2.25	2.26	2.24	2.17	2.18	2.22	2.30	0.1%
Mexico and Chile	2.45	2.51	2.71	2.85	3.08	3.33	3.63	1.3%
OECD Europe[2]	14.81	14.21	13.85	13.83	13.94	14.12	14.32	0.0%
Japan	4.51	4.75	4.50	4.38	4.29	4.19	4.05	-0.6%
South Korea	2.62	2.65	2.76	2.67	2.68	2.71	2.76	0.2%
Australia and New Zealand	1.24	1.28	1.23	1.19	1.21	1.25	1.30	0.0%
Total OECD consumption	**46.79**	**46.13**	**46.82**	**46.37**	**46.37**	**46.63**	**47.15**	**0.1%**
Non-OECD								
Russia	3.12	3.20	3.55	3.64	3.81	3.91	3.92	0.7%
Other Europe and Eurasia[3]	1.91	1.99	2.32	2.43	2.62	2.82	3.08	1.6%
China	9.94	10.36	13.91	15.70	17.04	18.72	20.48	2.5%
India	3.47	3.68	4.50	5.19	6.11	7.14	8.33	3.0%
Other Asia[4]	7.15	6.97	7.99	8.60	9.35	10.21	11.16	1.7%
Middle East	7.60	7.67	8.81	8.85	9.22	9.75	10.38	1.1%
Africa	3.40	3.47	3.70	3.84	4.03	4.28	4.58	1.0%
Brazil	2.74	2.83	3.12	3.10	3.32	3.52	3.85	1.1%
Other Central and South America	2.76	2.77	3.29	3.51	3.76	3.97	4.13	1.4%
Total non-OECD consumption	**42.10**	**42.94**	**51.19**	**54.84**	**59.24**	**64.32**	**69.90**	**1.8%**
Total consumption	**88.88**	**89.07**	**98.01**	**101.21**	**105.61**	**110.96**	**117.05**	**1.0%**
Petroleum and other liquids production								
OPEC[5]								
Middle East	25.50	25.84	28.28	29.62	32.35	35.77	38.85	1.5%
North Africa	2.37	3.36	3.19	3.20	3.43	3.75	3.96	0.6%
West Africa	4.39	4.40	4.99	5.13	5.26	5.39	5.52	0.8%
South America	2.99	2.99	3.10	3.03	3.01	3.10	3.31	0.4%
Total OPEC production	**35.25**	**36.59**	**39.57**	**40.97**	**44.04**	**48.00**	**51.64**	**1.2%**
Non-OPEC								
OECD								
United States (50 states)	10.11	10.84	14.25	13.86	13.23	12.86	12.42	0.5%
Canada	3.71	4.00	5.10	5.61	5.92	6.12	6.21	1.6%
Mexico and Chile	2.99	2.97	2.13	1.97	2.11	2.18	2.27	-1.0%
OECD Europe[2]	4.20	3.93	3.26	2.94	2.78	2.98	3.63	-0.3%
Japan and South Korea	0.18	0.18	0.16	0.17	0.18	0.18	0.19	0.2%
Australia and New Zealand	0.58	0.57	0.54	0.53	0.56	0.80	0.92	1.7%
Total OECD production	**21.77**	**22.48**	**25.44**	**25.07**	**24.78**	**25.11**	**25.64**	**0.5%**
Non-OECD								
Russia	10.24	10.40	10.74	10.93	11.44	12.01	11.68	0.4%
Other Europe and Eurasia[3]	3.26	3.19	3.73	4.35	4.44	4.62	5.44	1.9%
China	4.32	4.37	4.91	5.35	5.50	5.59	5.62	0.9%
Other Asia[4]	3.81	3.82	3.63	3.42	3.20	3.03	3.31	-0.5%
Middle East	1.51	1.31	0.98	0.86	0.77	0.67	0.71	-2.2%
Africa	2.67	2.34	2.61	2.63	2.57	2.52	2.91	0.8%
Brazil	2.53	2.49	4.00	5.14	6.36	6.81	7.03	3.8%
Other Central and South America	2.16	2.16	2.38	2.42	2.44	2.56	3.06	1.3%
Total non-OECD production	**30.51**	**30.08**	**32.98**	**35.11**	**36.73**	**37.83**	**39.75**	**1.0%**
Total petroleum and other liquids production	**87.53**	**89.15**	**97.99**	**101.15**	**105.55**	**110.94**	**117.03**	**1.0%**
OPEC market share (percent)	40.3	41.0	40.4	40.5	41.7	43.3	44.1	- -

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Table A21. International petroleum and other liquids supply, disposition, and prices (continued)

(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Selected world production subtotals:								
Petroleum								
Crude oil and equivalents[6]	74.37	75.78	82.35	84.40	87.58	91.09	96.56	0.9%
Tight oil	1.36	2.40	5.81	6.43	6.88	7.17	7.28	4.0%
Bitumen[7]	1.74	1.94	3.00	3.52	3.95	4.21	4.26	2.8%
Refinery processing gain[8]	2.37	2.37	2.26	2.33	2.52	2.71	2.86	0.7%
Liquids from renewable sources[9]	1.31	1.34	1.68	1.89	2.09	2.28	2.48	2.2%
Liquids from coal[10]	0.18	0.19	0.40	0.65	0.91	1.12	1.12	6.6%
Liquids from natural gas	8.73	9.21	10.78	11.61	12.19	12.88	13.29	1.3%
Natural gas plant liquids	8.61	9.05	10.46	11.26	11.84	12.53	12.93	1.3%
Gas-to-liquids[11]	0.12	0.16	0.31	0.35	0.35	0.35	0.35	2.9%
Liquids from kerogen[12]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.6%
Petroleum production[13]								
OPEC[5]								
Middle East	25.44	25.74	28.07	29.38	32.10	35.52	38.61	1.5%
North Africa	2.37	3.36	3.19	3.20	3.43	3.75	3.96	0.6%
West Africa	4.39	4.40	4.96	5.09	5.22	5.35	5.49	0.8%
South America	2.99	2.99	3.10	3.03	3.01	3.10	3.31	0.4%
Total OPEC production	**35.20**	**36.50**	**39.33**	**40.70**	**43.77**	**47.73**	**51.37**	**1.2%**
Non-OPEC								
OECD								
United States (50 states)	9.25	10.00	13.28	12.87	12.24	11.87	11.42	0.5%
Canada	3.69	3.97	5.08	5.58	5.88	6.08	6.17	1.6%
Mexico and Chile	2.99	2.97	2.13	1.97	2.11	2.18	2.27	-1.0%
OECD Europe[2]	3.98	3.71	3.03	2.70	2.53	2.71	3.35	-0.4%
Japan and South Korea	0.17	0.17	0.15	0.16	0.17	0.18	0.18	0.1%
Australia and New Zealand	0.58	0.56	0.53	0.52	0.55	0.79	0.91	1.7%
Total OECD production	**20.65**	**21.39**	**24.21**	**23.80**	**23.49**	**23.80**	**24.30**	**0.5%**
Non-OECD								
Russia	10.24	10.40	10.74	10.93	11.44	12.01	11.68	0.4%
Other Europe and Eurasia[3]	3.26	3.19	3.73	4.34	4.44	4.62	5.43	1.9%
China	4.28	4.32	4.77	4.98	4.82	4.69	4.72	0.3%
Other Asia[4]	3.74	3.75	3.51	3.22	2.99	2.82	3.10	-0.7%
Middle East	1.51	1.31	0.98	0.86	0.77	0.67	0.71	-2.2%
Africa	2.45	2.13	2.28	2.29	2.22	2.17	2.55	0.6%
Brazil	2.25	2.20	3.50	4.55	5.65	5.96	6.00	3.6%
Other Central and South America	2.08	2.06	2.30	2.34	2.36	2.47	2.97	1.3%
Total non-OECD production	**29.81**	**29.35**	**31.81**	**33.51**	**34.69**	**35.40**	**37.15**	**0.8%**
Total petroleum production[13]	**85.66**	**87.24**	**95.34**	**98.01**	**101.95**	**106.94**	**112.82**	**0.9%**
OPEC market share (percent)	41.1	41.8	41.2	41.5	42.9	44.6	45.5	- -

[1]Estimated consumption. Includes both OPEC and non-OPEC consumers in the regional breakdown.
[2]OECD Europe - Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.
[3]Other Europe and Eurasia = Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Macedonia, Malta, Moldova, Montenegro, Romania, Serbia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan.
[4]Other Asia = Afghanistan, Bangladesh, Bhutan, Brunei, Cambodia (Kampuchea), Fiji, French Polynesia, Guam, Hong Kong, India (for production), Indonesia, Kiribati, Laos, Malaysia, Macau, Maldives, Mongolia, Myanmar (Burma), Nauru, Nepal, New Caledonia, Niue, North Korea, Pakistan, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Taiwan, Thailand, Tonga, Vanuatu, and Vietnam.
[5]OPEC = Organization of the Petroleum Exporting Countries - Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[6]Includes crude oil, lease condensate, tight oil (shale oil), extra-heavy oil, and bitumen (oil sands).
[7]Includes diluted and upgraded/synthetic bitumen (syncrude).
[8]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[9]Includes liquids produced from energy crops.
[10]Includes liquids converted from coal via the Fischer-Tropsch coal-to-liquids process.
[11]Includes liquids converted from natural gas via the Fischer-Tropsch gas-to-liquids process.
[12]Includes liquids produced from kerogen (oil shale, not to be confused with tight oil (shale oil)).
[13]Includes production of crude oil (including lease condensate, tight oil (shale oil), extra-heavy oil, and bitumen (oil sands)), natural gas plant liquids, refinery gains, and other hydrogen and hydrocarbons for refinery feedstocks.
OECD = Organization for Economic Cooperation and Development.
- - = Not applicable.
Note: Ethanol is represented in motor gasoline equivalent barrels. Totals may not equal sum of components due to independent rounding. Data for 2011 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 and 2012 Brent and West Texas Intermediate crude oil spot prices: Thomson Reuters. 2011 quantities derived from: Energy Information Administration (EIA), International Energy Statistics database as of September 2013. 2012 quantities and projections: EIA, AEO2014 National Energy Modeling System run REF2014.D102413A and EIA, Generate World Oil Balance Model.

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Appendix B

Economic growth case comparisons

Table B1. Total energy supply, disposition, and price summary

(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2012	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Production										
Crude oil and lease condensate	13.87	20.31	20.36	20.39	17.40	17.71	17.82	16.04	16.00	16.40
Natural gas plant liquids	3.21	3.53	3.54	3.55	3.92	3.98	4.09	3.92	3.99	4.05
Dry natural gas	24.59	29.02	29.73	30.59	33.37	35.19	36.94	36.09	38.37	40.33
Coal[1]	20.60	21.18	21.70	22.24	21.67	22.61	23.28	21.67	22.61	23.50
Nuclear / uranium[2]	8.05	8.15	8.15	8.15	8.15	8.18	8.30	8.15	8.49	9.65
Hydropower	2.67	2.84	2.81	2.83	2.84	2.87	2.90	2.86	2.90	2.92
Biomass[3]	3.78	4.52	4.66	4.77	5.02	5.29	5.48	5.24	5.61	6.02
Other renewable energy[4]	1.97	3.09	3.01	3.04	3.25	3.23	3.71	3.42	3.89	5.13
Other[5]	0.41	0.24	0.24	0.23	0.24	0.24	0.23	0.24	0.24	0.23
Total	**79.15**	**92.88**	**94.19**	**95.80**	**95.87**	**99.30**	**102.74**	**97.63**	**102.09**	**108.23**
Imports										
Crude oil	18.57	12.31	13.15	14.08	12.98	15.00	16.49	14.11	17.43	19.26
Petroleum and other liquids[6]	4.26	4.20	4.21	4.25	4.06	4.08	4.12	3.92	3.93	4.45
Natural gas[7]	3.21	2.38	2.39	2.46	1.87	2.01	2.12	2.21	2.28	2.41
Other imports[8]	0.36	0.14	0.17	0.16	0.11	0.12	0.12	0.09	0.10	0.19
Total	**26.40**	**19.03**	**19.92**	**20.95**	**19.02**	**21.22**	**22.84**	**20.34**	**23.73**	**26.30**
Exports										
Petroleum and other liquids[9]	6.29	6.32	6.30	6.29	6.85	6.91	7.00	7.63	7.70	7.75
Natural gas[10]	1.63	4.49	4.30	4.28	6.96	6.96	6.93	8.26	8.09	7.90
Coal	3.22	3.13	3.13	3.11	3.53	3.55	3.57	3.77	3.79	3.73
Total	**11.14**	**13.95**	**13.73**	**13.68**	**17.35**	**17.42**	**17.50**	**19.66**	**19.58**	**19.38**
Discrepancy[11]	**-0.61**	**-0.35**	**-0.35**	**-0.30**	**-0.17**	**-0.17**	**-0.15**	**-0.03**	**-0.07**	**-0.07**
Consumption										
Petroleum and other liquids[12]	35.87	35.93	36.86	37.82	33.28	35.65	37.27	32.04	35.35	38.13
Natural gas	26.20	26.73	27.65	28.60	28.08	30.03	31.92	29.78	32.32	34.62
Coal[13]	17.34	18.01	18.56	19.11	18.08	19.01	19.66	17.83	18.75	19.75
Nuclear / uranium[2]	8.05	8.15	8.15	8.15	8.15	8.18	8.30	8.15	8.49	9.65
Hydropower	2.67	2.84	2.81	2.83	2.84	2.87	2.90	2.86	2.90	2.92
Biomass[14]	2.53	3.22	3.35	3.46	3.69	3.95	4.13	3.92	4.26	4.63
Other renewable energy[4]	1.97	3.09	3.01	3.04	3.25	3.23	3.71	3.42	3.89	5.13
Other[15]	0.39	0.34	0.34	0.34	0.33	0.35	0.35	0.34	0.35	0.38
Total	**95.02**	**98.31**	**100.73**	**103.36**	**97.71**	**103.27**	**108.23**	**98.34**	**106.31**	**115.22**
Prices (2012 dollars per unit)										
Crude oil spot prices (dollars per barrel)										
Brent	111.65	95.51	96.57	97.79	116.23	118.99	121.23	136.52	141.46	145.21
West Texas Intermediate	94.12	93.53	94.57	95.77	114.28	116.99	119.19	134.59	139.46	143.15
Natural gas at Henry Hub (dollars per million Btu)	2.75	4.51	4.38	4.59	5.65	6.03	6.39	7.19	7.65	8.15
Coal (dollars per ton) at the minemouth[16]	39.94	46.31	46.52	46.68	52.85	53.15	53.94	58.57	59.16	60.20
Coal (dollars per million Btu)										
at the minemouth[16]	1.98	2.32	2.33	2.34	2.66	2.67	2.71	2.94	2.96	3.02
Average end-use[17]	2.60	2.83	2.85	2.89	3.13	3.17	3.23	3.38	3.43	3.54
Average electricity (cents per kilowatthour)	9.8	10.1	10.1	10.1	10.3	10.4	10.6	10.8	11.1	11.6

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Table B1. Total energy supply, disposition, and price summary (continued)

(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2012	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Prices (nominal dollars per unit)										
Crude oil spot prices (dollars per barrel)										
Brent	111.65	114.20	109.37	108.50	195.53	160.19	154.87	335.90	234.53	222.72
West Texas Intermediate	94.12	111.84	107.11	106.25	192.24	157.49	152.27	331.15	231.22	219.57
Natural gas at Henry Hub (dollars per million Btu)	2.75	5.40	4.96	5.10	9.50	8.12	8.16	17.69	12.69	12.49
Coal (dollars per ton)										
at the minemouth[16]	39.94	55.37	52.69	51.79	88.91	71.55	68.91	144.11	98.08	92.34
Coal (dollars per million Btu)										
at the minemouth[16]	1.98	2.77	2.63	2.59	4.47	3.59	3.46	7.23	4.91	4.63
Average end-use[17]	2.60	3.38	3.23	3.21	5.27	4.27	4.13	8.31	5.68	5.43
Average electricity (cents per kilowatthour)	9.8	12.1	11.5	11.2	17.4	14.0	13.6	26.6	18.5	17.7

[1]Includes waste coal.
[2]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[3]Includes grid-connected electricity from wood and wood waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[4]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy data.
[5]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[6]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[7]Includes imports of liquefied natural gas that are later re-exported.
[8]Includes coal, coal coke (net), and electricity (net). Excludes imports of fuel used in nuclear power plants.
[9]Includes crude oil, petroleum products, ethanol, and biodiesel.
[10]Includes re-exported liquefied natural gas.
[11]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[12]Estimated consumption. Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids and crude oil consumed as a fuel. Refer to Table A17 for detailed renewable liquid fuels consumption.
[13]Excludes coal converted to coal-based synthetic liquids and natural gas.
[14]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[15]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[16]Includes reported prices for both open market and captive mines. Prices weighted by production, which differs from average minemouth prices published in EIA data reports where it is weighted by reported sales.
[17]Prices weighted by consumption; weighted average excludes export free-alongside-ship (f.a.s.) prices.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 are model results and may differ from official EIA data reports.
Sources: 2012 natural gas supply values: U.S. Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2013/06) (Washington, DC, June 2013). 2012 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2012*, DOE/EIA-0584(2012) (Washington, DC, December 2013). 2012 petroleum supply values: EIA, *Petroleum Supply Annual 2012*, DOE/EIA-0340(2012)/1 (Washington, DC, September 2013). 2012 crude oil spot prices and natural gas spot price at Henry Hub: Thomson Reuters. Other 2012 coal values: *Quarterly Coal Report, October-December 2012*, DOE/EIA-0121(2012/4Q) (Washington, DC, March 2013). Other 2012 values: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). **Projections:** EIA, AEO2014 National Energy Modeling System runs LOWMACRO.D112913A, REF2014.D102413A, and HIGHMACRO.D112913A.

012837

Table B2. Energy consumption by sector and source

(quadrillion Btu per year, unless otherwise noted)

Sector and source	2012	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Energy consumption										
Residential										
Propane	0.51	0.42	0.42	0.43	0.37	0.38	0.40	0.33	0.35	0.38
Kerosene	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Distillate fuel oil	0.51	0.46	0.46	0.46	0.37	0.37	0.37	0.31	0.31	0.31
Petroleum and other liquids subtotal	1.02	0.88	0.89	0.89	0.74	0.75	0.77	0.64	0.66	0.69
Natural gas	4.26	4.50	4.56	4.61	4.25	4.43	4.64	3.91	4.21	4.55
Renewable energy[1]	0.45	0.45	0.46	0.47	0.43	0.44	0.45	0.40	0.42	0.44
Electricity	4.69	4.73	4.84	4.99	4.86	5.21	5.61	5.07	5.65	6.31
Delivered energy	**10.42**	**10.56**	**10.74**	**10.96**	**10.28**	**10.83**	**11.48**	**10.01**	**10.94**	**11.99**
Electricity related losses	9.68	9.43	9.64	9.85	9.53	10.00	10.61	9.60	10.55	11.71
Total	**20.10**	**19.99**	**20.38**	**20.81**	**19.81**	**20.83**	**22.09**	**19.62**	**21.48**	**23.70**
Commercial										
Propane	0.15	0.16	0.16	0.16	0.17	0.17	0.17	0.17	0.18	0.18
Motor gasoline[2]	0.05	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.06
Kerosene	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Distillate fuel oil	0.40	0.40	0.40	0.39	0.38	0.38	0.38	0.37	0.37	0.37
Residual fuel oil	0.04	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Petroleum and other liquids subtotal	0.63	0.68	0.68	0.68	0.67	0.67	0.68	0.67	0.68	0.68
Natural gas	2.96	3.22	3.23	3.22	3.33	3.35	3.37	3.60	3.65	3.70
Coal	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Renewable energy[3]	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Electricity	4.52	4.68	4.69	4.71	5.11	5.18	5.24	5.60	5.72	5.81
Delivered energy	**8.29**	**8.75**	**8.78**	**8.80**	**9.29**	**9.38**	**9.46**	**10.05**	**10.22**	**10.38**
Electricity related losses	9.32	9.34	9.34	9.31	10.01	9.94	9.91	10.61	10.66	10.80
Total	**17.61**	**18.09**	**18.12**	**18.11**	**19.30**	**19.32**	**19.38**	**20.66**	**20.88**	**21.17**
Industrial[4]										
Liquefied petroleum gases and other[5]	2.25	2.85	2.90	2.93	2.95	3.05	3.06	2.82	2.90	2.93
Motor gasoline[2]	0.26	0.29	0.30	0.31	0.28	0.30	0.31	0.27	0.29	0.31
Distillate fuel oil	1.20	1.32	1.40	1.48	1.28	1.41	1.52	1.28	1.42	1.56
Residual fuel oil	0.10	0.14	0.14	0.15	0.13	0.15	0.16	0.13	0.15	0.17
Petrochemical feedstocks	0.75	1.22	1.27	1.31	1.47	1.62	1.68	1.49	1.59	1.67
Other petroleum[6]	3.50	3.35	3.56	3.80	3.17	3.58	3.91	3.22	3.75	4.19
Petroleum and other liquids subtotal	8.06	9.17	9.56	9.97	9.29	10.10	10.64	9.21	10.10	10.82
Natural gas	7.29	7.99	8.26	8.50	8.10	8.71	9.20	8.11	8.87	9.73
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and plant fuel[7]	1.45	1.77	1.77	1.81	2.07	2.16	2.25	2.30	2.41	2.52
Natural gas subtotal	8.75	9.75	10.04	10.31	10.17	10.87	11.44	10.41	11.28	12.25
Metallurgical coal	0.55	0.54	0.58	0.65	0.49	0.55	0.65	0.41	0.47	0.64
Other industrial coal	0.93	0.95	0.99	1.04	0.92	1.00	1.10	0.92	1.01	1.20
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net coal coke imports	0.00	0.00	0.00	0.01	-0.02	-0.03	-0.03	-0.04	-0.05	-0.06
Coal subtotal	1.48	1.50	1.57	1.70	1.38	1.52	1.72	1.28	1.44	1.78
Biofuels heat and coproducts	0.52	0.76	0.76	0.76	0.78	0.79	0.79	0.77	0.79	0.81
Renewable energy[8]	1.48	1.65	1.74	1.82	1.81	2.01	2.14	2.03	2.28	2.50
Electricity	3.35	3.83	4.04	4.32	3.91	4.33	4.76	3.87	4.34	5.01
Delivered energy	**23.63**	**26.67**	**27.71**	**28.87**	**27.35**	**29.62**	**31.49**	**27.58**	**30.22**	**33.17**
Electricity related losses	6.91	7.65	8.05	8.53	7.66	8.33	8.99	7.33	8.10	9.31
Total	**30.54**	**34.32**	**35.76**	**37.40**	**35.02**	**37.94**	**40.48**	**34.90**	**38.33**	**42.47**

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Table B2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2012	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Transportation										
Propane	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.07	0.08
Motor gasoline[2]	16.33	14.85	15.00	15.05	11.99	12.69	12.87	10.81	12.09	12.59
of which: E85[9]	0.01	0.19	0.19	0.18	0.54	0.46	0.42	0.47	0.33	0.34
Jet fuel[10]	3.00	3.06	3.08	3.10	3.15	3.20	3.25	3.19	3.28	3.37
Distillate fuel oil[11]	5.82	6.35	6.70	7.17	6.48	7.25	8.07	6.53	7.54	8.94
Residual fuel oil	0.58	0.58	0.58	0.58	0.59	0.59	0.59	0.60	0.60	0.61
Other petroleum[12]	0.15	0.14	0.15	0.15	0.14	0.15	0.15	0.14	0.15	0.15
Petroleum and other liquids subtotal	25.93	25.02	25.55	26.10	22.40	23.94	24.99	21.34	23.73	25.74
Pipeline fuel natural gas	0.73	0.72	0.74	0.76	0.78	0.82	0.86	0.80	0.85	0.89
Compressed / liquefied natural gas	0.04	0.08	0.08	0.08	0.28	0.28	0.30	0.86	0.86	1.05
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.02	0.03	0.03	0.03	0.04	0.04	0.04	0.06	0.06	0.06
Delivered energy	**26.72**	**25.85**	**26.40**	**26.98**	**23.50**	**25.08**	**26.20**	**23.05**	**25.50**	**27.75**
Electricity related losses	0.05	0.06	0.06	0.06	0.08	0.08	0.08	0.11	0.12	0.12
Total	**26.77**	**25.92**	**26.47**	**27.04**	**23.58**	**25.17**	**26.28**	**23.16**	**25.62**	**27.87**
Delivered energy consumption for all sectors										
Liquefied petroleum gases and other[5]	2.96	3.47	3.53	3.56	3.54	3.65	3.69	3.38	3.49	3.57
Motor gasoline[2]	16.64	15.18	15.34	15.40	12.31	13.04	13.22	11.13	12.44	12.96
of which: E85[9]	0.01	0.19	0.19	0.18	0.54	0.46	0.42	0.47	0.33	0.34
Jet fuel[10]	3.00	3.06	3.08	3.10	3.15	3.20	3.25	3.19	3.28	3.37
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate fuel oil	7.93	8.52	8.95	9.51	8.51	9.41	10.34	8.49	9.63	11.17
Residual fuel oil	0.72	0.80	0.80	0.82	0.80	0.82	0.83	0.81	0.83	0.85
Petrochemical feedstocks	0.75	1.22	1.27	1.31	1.47	1.62	1.68	1.49	1.59	1.67
Other petroleum[13]	3.64	3.49	3.70	3.94	3.31	3.73	4.06	3.36	3.89	4.34
Petroleum and other liquids subtotal	35.64	35.76	36.68	37.64	33.10	35.47	37.09	31.86	35.17	37.93
Natural gas	14.56	15.78	16.14	16.42	15.97	16.77	17.51	16.47	17.59	19.04
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and plant fuel[7]	1.45	1.77	1.77	1.81	2.07	2.16	2.25	2.30	2.41	2.52
Pipeline natural gas	0.73	0.72	0.74	0.76	0.78	0.82	0.86	0.80	0.85	0.89
Natural gas subtotal	16.74	18.27	18.65	19.00	18.81	19.75	20.61	19.56	20.84	22.44
Metallurgical coal	0.55	0.54	0.58	0.65	0.49	0.55	0.65	0.41	0.47	0.64
Other coal	0.98	0.99	1.03	1.09	0.97	1.04	1.14	0.96	1.05	1.25
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net coal coke imports	0.00	0.00	0.00	0.01	-0.02	-0.03	-0.03	-0.04	-0.05	-0.06
Coal subtotal	1.53	1.54	1.61	1.74	1.43	1.56	1.76	1.33	1.48	1.83
Biofuels heat and coproducts	0.52	0.76	0.76	0.76	0.78	0.79	0.79	0.77	0.79	0.81
Renewable energy[14]	2.06	2.24	2.33	2.41	2.38	2.58	2.72	2.56	2.83	3.07
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	12.58	13.27	13.60	14.05	13.93	14.76	15.65	14.60	15.77	17.20
Delivered energy	**69.07**	**71.83**	**73.63**	**75.61**	**70.43**	**74.91**	**78.63**	**70.69**	**76.88**	**83.28**
Electricity related losses	25.95	26.48	27.10	27.75	27.28	28.35	29.60	27.65	29.43	31.93
Total	**95.02**	**98.31**	**100.73**	**103.36**	**97.71**	**103.27**	**108.23**	**98.34**	**106.31**	**115.22**
Electric power[15]										
Distillate fuel oil	0.05	0.09	0.09	0.09	0.09	0.09	0.09	0.08	0.09	0.09
Residual fuel oil	0.18	0.09	0.09	0.09	0.09	0.09	0.10	0.09	0.10	0.11
Petroleum and other liquids subtotal	0.23	0.17	0.18	0.18	0.17	0.18	0.19	0.18	0.19	0.20
Natural gas	9.46	8.47	9.00	9.60	9.27	10.28	11.31	10.21	11.48	12.18
Steam coal	15.82	16.48	16.95	17.36	16.65	17.44	17.90	16.51	17.27	17.93
Nuclear / uranium[16]	8.05	8.15	8.15	8.15	8.15	8.18	8.30	8.15	8.49	9.65
Renewable energy[17]	4.59	6.14	6.08	6.16	6.63	6.68	7.22	6.87	7.44	8.81
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Electricity imports	0.16	0.11	0.11	0.11	0.11	0.12	0.12	0.11	0.12	0.15
Total	**38.53**	**39.75**	**40.70**	**41.80**	**41.21**	**43.12**	**45.25**	**42.25**	**45.20**	**49.13**

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Table B2. Energy consumption by sector and source (continued)

(quadrillion Btu per year, unless otherwise noted)

Sector and source	2012	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Total energy consumption										
Liquefied petroleum gases and other[5]	2.96	3.47	3.53	3.56	3.54	3.65	3.69	3.38	3.49	3.57
Motor gasoline[2]	16.64	15.18	15.34	15.40	12.31	13.04	13.22	11.13	12.44	12.96
of which: E85[9]	0.01	0.19	0.19	0.18	0.54	0.46	0.42	0.47	0.33	0.34
Jet fuel[10]	3.00	3.06	3.08	3.10	3.15	3.20	3.25	3.19	3.28	3.37
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate fuel oil	7.98	8.61	9.03	9.60	8.59	9.50	10.43	8.57	9.72	11.26
Residual fuel oil	0.90	0.89	0.89	0.91	0.89	0.91	0.93	0.90	0.93	0.96
Petrochemical feedstocks	0.75	1.22	1.27	1.31	1.47	1.62	1.68	1.49	1.59	1.67
Other petroleum[13]	3.64	3.49	3.70	3.94	3.31	3.73	4.06	3.36	3.89	4.34
Petroleum and other liquids subtotal	35.87	35.93	36.86	37.82	33.28	35.65	37.27	32.04	35.35	38.13
Natural gas	24.02	24.25	25.14	26.03	25.23	27.05	28.82	26.68	29.07	31.21
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and plant fuel[7]	1.45	1.77	1.77	1.81	2.07	2.16	2.25	2.30	2.41	2.52
Pipeline natural gas	0.73	0.72	0.74	0.76	0.78	0.82	0.86	0.80	0.85	0.89
Natural gas subtotal	26.20	26.73	27.65	28.60	28.08	30.03	31.92	29.78	32.32	34.62
Metallurgical coal	0.55	0.54	0.58	0.65	0.49	0.55	0.65	0.41	0.47	0.64
Other coal	16.79	17.47	17.98	18.45	17.62	18.49	19.04	17.47	18.32	19.18
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net coal coke imports	0.00	0.00	0.00	0.01	-0.02	-0.03	-0.03	-0.04	-0.05	-0.06
Coal subtotal	17.34	18.01	18.56	19.11	18.08	19.01	19.66	17.83	18.75	19.75
Nuclear / uranium[16]	8.05	8.15	8.15	8.15	8.15	8.18	8.30	8.15	8.49	9.65
Biofuels heat and coproducts	0.52	0.76	0.76	0.76	0.78	0.79	0.79	0.77	0.79	0.81
Renewable energy[18]	6.65	8.38	8.40	8.58	9.00	9.26	9.95	9.43	10.27	11.88
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Electricity imports	0.16	0.11	0.11	0.11	0.11	0.12	0.12	0.11	0.12	0.15
Total	**95.02**	**98.31**	**100.73**	**103.36**	**97.71**	**103.27**	**108.23**	**98.34**	**106.31**	**115.22**
Energy use and related statistics										
Delivered energy use	69.07	71.83	73.63	75.61	70.43	74.91	78.63	70.69	76.88	83.28
Total energy use	95.02	98.31	100.73	103.36	97.71	103.27	108.23	98.34	106.31	115.22
Ethanol consumed in motor gasoline and E85	1.09	1.21	1.22	1.22	1.25	1.25	1.25	1.25	1.29	1.34
Population (millions)	314.58	332.91	334.47	336.27	354.64	359.03	364.05	372.79	380.53	389.40
Gross domestic product (billion 2005 dollars)	13,593	15,918	16,753	17,594	18,910	21,139	22,725	23,158	26,670	29,154
Carbon dioxide emissions (million metric tons)	5,290	5,327	5,476	5,633	5,195	5,527	5,778	5,170	5,599	5,972

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal water heating, and electricity generation from wind and solar photovoltaic sources.
[2]Includes ethanol and ethers blended into gasoline.
[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal water heating and electricity generation from wind and solar photovoltaic sources.
[4]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[5]Includes ethane, natural gasoline, and refinery olefins.
[6]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[7]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[8]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol in motor gasoline.
[9]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[10]Includes only kerosene type.
[11]Diesel fuel for on- and off- road use.
[12]Includes aviation gasoline and lubricants.
[13]Includes aviation gasoline, petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[14]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[15]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[16]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[17]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[18]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
Btu = British thermal unit.
Note: Includes estimated consumption for petroleum and other liquids. Totals may not equal sum of components due to independent rounding. Data for 2012 are model results and may differ from official EIA data reports.
Sources: 2012 consumption based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2012 population and gross domestic product: IHS Global Insight Industry and Employment models, May 2013. 2012 carbon dioxide emissions and emission factors: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). **Projections:** EIA, AEO2014 National Energy Modeling System runs LOWMACRO.D112913A, REF2014.D102413A, and HIGHMACRO.D112913A.

012840

Table B3. Energy prices by sector and source

(2012 dollars per million Btu, unless otherwise noted)

Sector and source	2012	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Residential										
Propane	24.12	23.76	23.79	24.21	25.45	25.75	26.02	27.09	27.64	27.99
Distillate fuel oil	27.30	24.26	24.67	25.12	27.69	28.60	29.24	31.27	32.64	33.97
Natural gas	10.46	11.58	11.59	12.22	12.92	13.50	14.06	14.90	15.98	17.10
Electricity	34.83	36.20	36.15	36.03	36.93	36.98	37.33	38.37	38.83	39.81
Commercial										
Propane	20.75	20.29	20.33	20.81	22.40	22.79	23.13	24.51	25.17	25.62
Distillate fuel oil	26.81	21.40	21.77	22.47	24.90	25.66	26.23	28.31	29.72	31.07
Residual fuel oil	22.84	14.19	14.40	14.52	17.39	17.92	18.26	20.36	20.99	21.89
Natural gas	8.11	9.50	9.49	9.96	10.72	11.19	11.62	12.26	13.08	13.94
Electricity	29.55	30.42	30.80	30.98	30.65	31.26	32.26	31.56	33.01	34.76
Industrial[1]										
Propane	21.09	20.60	20.64	21.14	22.86	23.27	23.64	25.10	25.84	26.32
Distillate fuel oil	27.41	21.86	22.22	22.77	25.46	26.11	26.65	28.77	29.92	31.25
Residual fuel oil	20.90	14.67	14.88	15.03	17.82	18.29	18.61	20.80	21.48	22.37
Natural gas[2]	3.77	5.84	5.79	6.08	6.57	6.99	7.37	8.11	8.59	9.25
Metallurgical coal	7.25	8.48	8.43	8.42	9.57	9.51	9.57	10.21	10.20	10.43
Other industrial coal	3.24	3.58	3.59	3.61	3.86	3.88	3.95	4.16	4.19	4.26
Coal to liquids	--	--	--	--	--	--	--	--	--	--
Electricity	19.50	20.54	20.77	20.98	21.45	21.99	22.77	22.94	24.05	25.45
Transportation										
Propane	25.14	24.82	24.85	25.45	26.51	26.81	27.08	28.14	28.82	29.20
E85[3]	35.06	25.36	25.61	27.09	25.63	27.91	29.07	29.82	35.49	36.50
Motor gasoline[4]	30.68	25.48	25.59	26.22	27.98	28.54	28.90	30.76	32.67	33.65
Jet fuel[5]	22.99	19.12	19.47	19.95	22.89	23.71	24.33	26.92	28.07	29.36
Diesel fuel (distillate fuel oil)[6]	28.80	26.44	26.80	27.38	30.07	30.68	31.22	33.34	34.53	35.85
Residual fuel oil	20.07	12.26	12.46	12.67	15.08	15.50	15.83	17.91	18.55	19.41
Natural gas[7]	14.64	15.44	15.62	16.41	15.95	16.63	17.25	18.26	19.67	20.83
Electricity	31.43	29.38	29.86	30.23	31.08	31.68	32.54	32.45	34.19	35.88
Electric power[8]										
Distillate fuel oil	24.12	20.27	20.66	21.19	23.77	24.65	25.25	27.39	28.81	30.14
Residual fuel oil	20.68	13.65	13.86	13.98	16.72	17.14	17.46	19.76	20.42	21.32
Natural gas	3.44	5.06	5.07	5.37	6.04	6.49	6.89	7.63	8.16	8.78
Steam coal	2.39	2.59	2.61	2.64	2.90	2.93	2.95	3.16	3.19	3.24
Average price to all users[9]										
Propane	23.24	22.51	22.54	23.02	24.30	24.66	25.00	26.12	26.79	27.24
E85[3]	35.06	25.36	25.61	27.09	25.63	27.91	29.07	29.82	35.49	36.50
Motor gasoline[4]	30.44	25.48	25.58	26.22	27.97	28.53	28.90	30.76	32.67	33.64
Jet fuel[5]	22.99	19.12	19.47	19.95	22.89	23.71	24.33	26.92	28.07	29.36
Distillate fuel oil	28.36	25.33	25.70	26.30	28.99	29.67	30.24	32.32	33.54	34.94
Residual fuel oil	20.41	12.95	13.15	13.36	15.85	16.32	16.68	18.74	19.42	20.34
Natural gas	5.38	7.15	7.09	7.42	8.10	8.49	8.86	9.81	10.38	11.16
Metallurgical coal	7.25	8.48	8.43	8.42	9.57	9.51	9.57	10.21	10.20	10.43
Other coal	2.44	2.66	2.67	2.70	2.96	2.98	3.02	3.22	3.25	3.31
Coal to liquids	--	--	--	--	--	--	--	--	--	--
Electricity	28.85	29.62	29.72	29.70	30.26	30.56	31.20	31.65	32.63	33.90
Non-renewable energy expenditures by sector (billion 2012 dollars)										
Residential	234.06	244.36	249.25	258.05	254.20	272.82	296.05	271.38	306.56	350.21
Commercial	173.25	187.07	189.44	192.88	208.45	215.91	225.21	239.06	255.39	273.61
Industrial[1]	213.75	265.70	279.45	299.80	306.22	343.02	376.63	342.35	390.91	450.69
Transportation	755.09	613.11	632.05	662.34	606.78	667.67	711.94	655.67	772.91	874.31
Total non-renewable expenditures	1,376.15	1,310.24	1,350.18	1,413.07	1,375.65	1,499.43	1,609.82	1,508.46	1,725.77	1,948.83
Transportation renewable expenditures	0.50	4.86	4.89	4.77	13.77	12.96	12.35	14.14	11.80	12.43
Total expenditures	**1,376.66**	**1,315.10**	**1,355.07**	**1,417.84**	**1,389.42**	**1,512.39**	**1,622.18**	**1,522.61**	**1,737.56**	**1,961.26**

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Table B3. Energy prices by sector and source (continued)

(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2012	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Residential										
Propane	24.12	28.41	26.94	26.86	42.82	34.67	33.24	66.64	45.83	42.93
Distillate fuel oil	27.30	29.00	27.94	27.87	46.59	38.50	37.35	76.92	54.12	52.10
Natural gas	10.46	13.84	13.13	13.56	21.74	18.18	17.97	36.65	26.49	26.23
Electricity	34.83	43.29	40.94	39.97	62.12	49.78	47.70	94.41	64.39	61.06
Commercial										
Propane	20.75	24.26	23.02	23.08	37.69	30.68	29.55	60.30	41.74	39.29
Distillate fuel oil	26.81	25.59	24.66	24.93	41.89	34.54	33.51	69.64	49.27	47.65
Residual fuel oil	22.84	16.97	16.31	16.11	29.25	24.12	23.33	50.10	34.80	33.58
Natural gas	8.11	11.36	10.75	11.06	18.03	15.07	14.84	30.16	21.68	21.38
Electricity	29.55	36.38	34.88	34.37	51.56	42.08	41.21	77.65	54.73	53.32
Industrial[1]										
Propane	21.09	24.64	23.38	23.45	38.45	31.32	30.20	61.77	42.83	40.37
Distillate fuel oil	27.41	26.14	25.17	25.26	42.83	35.15	34.04	70.79	49.61	47.93
Residual fuel oil	20.90	17.55	16.85	16.68	29.98	24.62	23.77	51.17	35.61	34.32
Natural gas[2]	3.77	6.98	6.56	6.75	11.06	9.41	9.41	19.96	14.25	14.19
Metallurgical coal	7.25	10.14	9.55	9.34	16.10	12.81	12.22	25.13	16.91	16.00
Other industrial coal	3.24	4.28	4.07	4.00	6.50	5.23	5.05	10.22	6.95	6.54
Coal to liquids	--	--	--	--	--	--	--	--	--	--
Electricity	19.50	24.56	23.52	23.28	36.09	29.60	29.09	56.45	39.88	39.03
Transportation										
Propane	25.14	29.68	28.14	28.23	44.59	36.09	34.60	69.24	47.79	44.78
E85[3]	35.06	30.32	29.00	30.05	43.12	37.57	37.14	73.38	58.85	55.99
Motor gasoline[4]	30.68	30.46	28.98	29.09	47.06	38.42	36.92	75.69	54.17	51.61
Jet fuel[5]	22.99	22.87	22.06	22.14	38.51	31.91	31.08	66.24	46.53	45.04
Diesel fuel (distillate fuel oil)[6]	28.80	31.62	30.35	30.38	50.59	41.30	39.89	82.02	57.25	54.99
Residual fuel oil	20.07	14.66	14.11	14.05	25.37	20.86	20.23	44.06	30.76	29.77
Natural gas[7]	14.64	18.46	17.69	18.21	26.83	22.38	22.04	44.93	32.61	31.95
Electricity	31.43	35.13	33.82	33.54	52.29	42.65	41.56	79.83	56.68	55.04
Electric power[8]										
Distillate fuel oil	24.12	24.23	23.40	23.51	39.98	33.18	32.26	67.38	47.77	46.22
Residual fuel oil	20.68	16.33	15.70	15.51	28.13	23.08	22.30	48.61	33.86	32.70
Natural gas	3.44	6.05	5.75	5.96	10.16	8.74	8.80	18.76	13.53	13.47
Steam coal	2.39	3.10	2.96	2.93	4.88	3.94	3.77	7.78	5.29	4.97

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Table B3. Energy prices by sector and source (continued)

(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2012	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Average price to all users[9]										
Propane	23.24	26.91	25.53	25.54	40.88	33.20	31.93	64.27	44.42	41.78
E85[3]	35.06	30.32	29.00	30.05	43.12	37.57	37.14	73.38	58.85	55.99
Motor gasoline[4]	30.44	30.46	28.98	29.09	47.06	38.41	36.92	75.68	54.17	51.60
Jet fuel[5]	22.99	22.87	22.06	22.14	38.51	31.91	31.08	66.24	46.53	45.04
Distillate fuel oil	28.36	30.29	29.11	29.18	48.78	39.94	38.63	79.52	55.61	53.60
Residual fuel oil	20.41	15.48	14.90	14.82	26.67	21.97	21.31	46.10	32.20	31.20
Natural gas	5.38	8.55	8.04	8.23	13.62	11.43	11.32	24.13	17.22	17.12
Metallurgical coal	7.25	10.14	9.55	9.34	16.10	12.81	12.22	25.13	16.91	16.00
Other coal	2.44	3.17	3.03	2.99	4.97	4.02	3.86	7.92	5.39	5.08
Coal to liquids	--	--	--	--	--	--	--	--	--	--
Electricity	28.85	35.42	33.66	32.95	50.90	41.13	39.85	77.86	54.11	52.00
Non-renewable energy expenditures by sector (billion nominal dollars)										
Residential	234.06	292.19	282.30	286.31	427.62	367.27	378.21	667.71	508.27	537.16
Commercial	173.25	223.69	214.56	214.01	350.66	290.65	287.71	588.19	423.44	419.68
Industrial[1]	213.75	317.71	316.50	332.63	515.14	461.77	481.15	842.31	648.12	691.29
Transportation	755.09	733.13	715.87	734.87	1,020.75	898.80	909.52	1,613.19	1,281.47	1,341.05
Total non-renewable expenditures	1,376.15	1,566.72	1,529.23	1,567.81	2,314.17	2,018.49	2,056.59	3,711.39	2,861.30	2,989.19
Transportation renewable expenditures	0.50	5.81	5.54	5.29	23.16	17.45	15.78	34.80	19.56	19.06
Total expenditures	**1,376.66**	**1,572.53**	**1,534.77**	**1,573.10**	**2,337.33**	**2,035.94**	**2,072.36**	**3,746.19**	**2,880.86**	**3,008.25**

[1]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[2]Excludes use for lease and plant fuel.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[5]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Natural gas used as fuel in motor vehicles, trains, and ships. Price includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[8]Includes electricity-only and combined heat and power plants that have a regulatory status.
[9]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
- - = Not applicable.
Note: Data for 2012 are model results and may differ from official EIA data reports.
Sources: 2012 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2013/08) (Washington, DC, August 2013). 2012 residential, commercial, and industrial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2013/06) (Washington, DC, June 2013). 2012 transportation sector natural gas delivered prices are model results. 2012 electric power sector distillate and residual fuel oil prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2012 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2012 and April 2013, Table 4.2, and EIA, *State Energy Data Report 2011*, DOE/EIA-0214(2011) (Washington, DC, June 2013). 2012 coal prices based on: EIA, *Quarterly Coal Report, October-December 2012*, DOE/EIA-0121(2012/4Q) (Washington, DC, March 2013) and EIA, AEO2014 National Energy Modeling System run REF2014.D102413A. 2012 electricity prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2012 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. **Projections:** EIA, AEO2014 National Energy Modeling System runs LOWMACRO.D112913A, REF2014.D102413A, and HIGHMACRO.D112913A.

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Table B4. Macroeconomic indicators

(billion 2005 chain-weighted dollars, unless otherwise noted)

Indicators	2012	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Real gross domestic product	**13,593**	**15,918**	**16,753**	**17,594**	**18,910**	**21,139**	**22,725**	**23,158**	**26,670**	**29,154**
Components of real gross domestic product										
Real consumption	9,603	11,020	11,592	12,118	12,576	14,220	15,309	14,671	17,635	19,162
Real investment	1,914	2,554	2,876	3,256	3,174	3,740	4,288	4,137	4,925	5,702
Real government spending	2,481	2,374	2,443	2,505	2,425	2,623	2,708	2,587	2,917	3,005
Real exports	1,837	2,778	2,863	2,962	4,703	5,056	5,438	7,707	8,186	9,273
Real imports	2,238	2,738	2,925	3,127	3,746	4,213	4,667	5,339	6,328	7,128
Energy intensity (thousand Btu per 2005 dollar of GDP)										
Delivered energy	5.08	4.51	4.40	4.30	3.72	3.54	3.46	3.05	2.88	2.86
Total energy	6.99	6.18	6.01	5.87	5.17	4.89	4.76	4.25	3.99	3.95
Price indices										
GDP chain-type price index (2005=1.000)	1.154	1.380	1.307	1.280	1.941	1.553	1.474	2.839	1.913	1.770
Consumer price index (1982-4=1.00)										
All-urban	2.30	2.77	2.63	2.58	3.99	3.20	3.04	6.01	4.05	3.76
Energy commodities and services	2.46	2.68	2.55	2.54	4.08	3.33	3.21	6.51	4.56	4.39
Wholesale price index (1982=1.00)										
All commodities	2.02	2.35	2.22	2.20	3.28	2.62	2.51	4.79	3.21	3.06
Fuel and power	2.12	2.54	2.42	2.41	4.00	3.30	3.23	6.72	4.73	4.61
Metals and metal products	2.20	2.54	2.43	2.51	3.41	2.77	2.75	4.67	3.22	3.28
Industrial commodities excluding energy	1.94	2.27	2.14	2.13	3.07	2.41	2.30	4.27	2.78	2.64
Interest rates (percent, nominal)										
Federal funds rate	0.14	5.28	3.85	3.40	7.03	4.14	3.63	7.45	4.22	3.85
10-year treasury note	1.80	6.02	4.14	3.61	7.26	4.36	3.83	7.84	4.52	4.05
AA utility bond rate	3.83	8.91	6.60	5.59	10.42	6.88	5.99	11.30	7.22	6.35
Value of shipments (billion 2005 dollars)										
Non-industrial and service sectors	21,359	24,672	26,033	27,492	28,252	31,782	34,301	31,742	37,135	40,577
Total industrial	6,147	7,439	7,960	8,614	8,400	9,537	10,672	9,475	10,994	12,985
Agriculture, mining, and construction	1,623	2,011	2,226	2,470	2,040	2,389	2,717	2,159	2,551	2,945
Manufacturing	4,525	5,428	5,735	6,144	6,360	7,148	7,955	7,315	8,443	10,041
Energy-intensive	1,616	1,861	1,931	2,012	2,003	2,171	2,292	2,105	2,303	2,484
Non-energy-intensive	2,909	3,567	3,803	4,131	4,358	4,977	5,663	5,210	6,140	7,557
Total shipments	**27,506**	**32,111**	**33,994**	**36,105**	**36,651**	**41,319**	**44,973**	**41,217**	**48,129**	**53,563**
Population and employment (millions)										
Population, with armed forces overseas	314.6	332.9	334.5	336.3	354.6	359.0	364.1	372.8	380.5	389.4
Population, aged 16 and over	249.2	265.6	266.7	268.0	284.4	287.6	291.4	301.4	307.3	314.0
Population, over age 65	43.4	56.2	56.2	56.3	72.7	73.0	73.3	79.1	79.8	80.6
Employment, nonfarm	133.7	145.4	148.4	153.5	155.0	158.6	166.4	163.0	169.2	178.4
Employment, manufacturing	11.9	12.2	12.8	13.7	11.1	12.5	13.9	9.5	11.0	13.1
Key labor indicators										
Labor force (millions)	155.0	162.4	163.5	165.0	168.3	170.9	174.7	176.9	181.2	189.8
Non-farm labor productivity (1992=1.00)	1.11	1.21	1.25	1.27	1.41	1.53	1.58	1.64	1.85	1.94
Unemployment rate (percent)	8.08	5.87	5.49	5.07	5.38	5.10	4.80	5.27	5.12	4.72
Key indicators for energy demand										
Real disposable personal income	10,304	12,212	12,710	13,204	14,681	15,926	16,752	17,688	19,724	20,650
Housing starts (millions)	0.84	1.25	1.75	2.38	1.09	1.71	2.50	1.02	1.66	2.59
Commercial floorspace (billion square feet)	82.4	88.6	89.1	89.8	96.5	98.2	100.0	105.6	108.9	112.3
Unit sales of light-duty vehicles (millions)	14.43	15.16	16.23	17.06	15.49	17.23	17.93	15.27	17.93	19.42

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 2012: IHS Global Insight, Global Insight Industry and Employment models, May 2013. **Projections:** U.S. Energy Information Administration, AEO2014 National Energy Modeling System runs LOWMACRO.D112913A, REF2014.D102413A, and HIGHMACRO.D112913A.

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Appendix C

Price case comparisons

Table C1. Total energy supply, disposition, and price summary

(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2012	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Production										
Crude oil and lease condensate	13.87	19.06	20.36	22.76	14.60	17.71	19.80	12.41	16.00	17.55
Natural gas plant liquids	3.21	3.47	3.54	3.62	3.80	3.98	4.18	3.69	3.99	4.17
Dry natural gas	24.59	28.18	29.73	30.60	31.92	35.19	39.44	33.89	38.37	42.37
Coal[1]	20.60	21.75	21.70	21.30	22.70	22.61	22.32	23.08	22.61	23.23
Nuclear / uranium[2]	8.05	8.15	8.15	8.15	8.16	8.18	8.22	8.41	8.49	9.37
Hydropower	2.67	2.80	2.81	2.80	2.86	2.87	2.88	2.90	2.90	2.92
Biomass[3]	3.78	4.52	4.66	4.74	5.16	5.29	5.31	5.52	5.61	5.63
Other renewable energy[4]	1.97	2.98	3.01	3.07	3.22	3.23	3.32	3.94	3.89	4.50
Other[5]	0.41	0.27	0.24	0.23	0.29	0.24	0.23	0.29	0.24	0.23
Total	**79.15**	**91.20**	**94.19**	**97.28**	**92.71**	**99.30**	**105.70**	**94.13**	**102.09**	**109.96**
Imports										
Crude oil	18.57	15.06	13.15	9.40	19.49	15.00	10.61	22.99	17.43	12.69
Petroleum and other liquids[6]	4.26	4.74	4.21	3.72	4.99	4.08	3.29	5.58	3.93	3.00
Natural gas[7]	3.21	2.37	2.39	2.46	1.95	2.01	1.95	2.34	2.28	2.12
Other imports[8]	0.36	0.14	0.17	0.57	0.12	0.12	0.16	0.09	0.10	0.27
Total	**26.40**	**22.31**	**19.92**	**16.16**	**26.55**	**21.22**	**16.01**	**31.00**	**23.73**	**18.08**
Exports										
Petroleum and other liquids[9]	6.29	6.51	6.30	5.93	7.39	6.91	6.54	8.09	7.70	7.26
Natural gas[10]	1.63	3.04	4.30	4.69	4.34	6.96	9.92	5.33	8.09	10.89
Coal	3.22	3.14	3.13	3.10	3.61	3.55	3.29	4.15	3.79	3.33
Total	**11.14**	**12.69**	**13.73**	**13.72**	**15.34**	**17.42**	**19.74**	**17.57**	**19.58**	**21.48**
Discrepancy[11]	**-0.61**	**-0.28**	**-0.35**	**-0.34**	**-0.12**	**-0.17**	**-0.16**	**0.06**	**-0.07**	**-0.14**
Consumption										
Petroleum and other liquids[12]	35.87	37.64	36.86	35.44	37.19	35.65	33.13	38.16	35.35	32.69
Natural gas	26.20	27.36	27.65	28.20	29.36	30.03	31.24	30.66	32.32	32.98
Coal[13]	17.34	18.58	18.56	18.60	19.03	19.01	19.02	18.84	18.75	19.58
Nuclear / uranium[2]	8.05	8.15	8.15	8.15	8.16	8.18	8.22	8.41	8.49	9.37
Hydropower	2.67	2.80	2.81	2.80	2.86	2.87	2.88	2.90	2.90	2.92
Biomass[14]	2.53	3.24	3.35	3.45	3.87	3.95	3.98	4.24	4.26	4.28
Other renewable energy[4]	1.97	2.98	3.01	3.07	3.22	3.23	3.32	3.94	3.89	4.50
Other[15]	0.39	0.34	0.34	0.34	0.35	0.35	0.35	0.35	0.35	0.39
Total	**95.02**	**101.10**	**100.73**	**100.06**	**104.04**	**103.27**	**102.14**	**107.49**	**106.31**	**106.71**
Prices (2012 dollars per unit)										
Crude oil spot prices (dollars per barrel)										
Brent	111.65	68.90	96.57	150.28	71.90	118.99	173.69	74.90	141.46	204.24
West Texas Intermediate	94.12	66.90	94.57	148.28	69.90	116.99	171.69	72.90	139.46	202.24
Natural gas at Henry Hub (dollars per million Btu)	2.75	4.35	4.38	4.73	5.75	6.03	6.88	7.43	7.65	8.34
Coal (dollars per ton) at the minemouth[16]	39.94	45.43	46.52	48.49	51.20	53.15	55.00	56.67	59.16	60.51
Coal (dollars per million Btu)										
at the minemouth[16]	1.98	2.27	2.33	2.42	2.58	2.67	2.75	2.85	2.96	3.04
Average end-use[17]	2.60	2.76	2.85	2.99	3.03	3.17	3.30	3.25	3.43	3.60
Average electricity (cents per kilowatthour)	9.8	10.1	10.1	10.3	10.4	10.4	10.7	11.1	11.1	11.7

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Table C1. Total energy supply, disposition, and price summary (continued)

(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2012	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Prices (nominal dollars per unit)										
Crude oil spot prices (dollars per barrel)										
Brent	111.65	77.64	109.37	171.98	94.64	160.19	243.19	119.51	234.53	351.41
West Texas Intermediate	94.12	75.39	107.11	169.69	92.01	157.49	240.39	116.32	231.22	347.97
Natural gas at Henry Hub (dollars per million Btu)	2.75	4.90	4.96	5.41	7.57	8.12	9.64	11.86	12.69	14.34
Coal (dollars per ton)										
at the minemouth[16]	39.94	51.20	52.69	55.49	67.39	71.55	77.01	90.42	98.08	104.11
Coal (dollars per million Btu)										
at the minemouth[16]	1.98	2.56	2.63	2.77	3.40	3.59	3.86	4.54	4.91	5.23
Average end-use[17]	2.60	3.11	3.23	3.42	3.99	4.27	4.63	5.18	5.68	6.20
Average electricity (cents per kilowatthour)	9.8	11.3	11.5	11.8	13.6	14.0	15.0	17.6	18.5	20.1

[1]Includes waste coal.
[2]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[3]Includes grid-connected electricity from wood and wood waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[4]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy data.
[5]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[6]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[7]Includes imports of liquefied natural gas that are later re-exported.
[8]Includes coal, coal coke (net), and electricity (net). Excludes imports of fuel used in nuclear power plants.
[9]Includes crude oil, petroleum products, ethanol, and biodiesel.
[10]Includes re-exported liquefied natural gas.
[11]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[12]Estimated consumption. Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids and crude oil consumed as a fuel. Refer to Table A17 for detailed renewable liquid fuels consumption.
[13]Excludes coal converted to coal-based synthetic liquids and natural gas.
[14]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[15]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[16]Includes reported prices for both open market and captive mines. Prices weighted by production, which differs from average minemouth prices published in EIA data reports where it is weighted by reported sales.
[17]Prices weighted by consumption; weighted average excludes export free-alongside-ship (f.a.s.) prices.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 are model results and may differ from official EIA data reports.
Sources: 2012 natural gas supply values: U.S. Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2013/06) (Washington, DC, June 2013). 2012 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2012*, DOE/EIA-0584(2012) (Washington, DC, December 2013). 2012 petroleum supply values: EIA, *Petroleum Supply Annual 2012*, DOE/EIA-0340(2012)/1 (Washington, DC, September 2013). 2012 crude oil spot prices and natural gas spot price at Henry Hub: Thomson Reuters. Other 2012 coal values: *Quarterly Coal Report, October-December 2012*, DOE/EIA-0121(2012/4Q) (Washington, DC, March 2013). Other 2012 values: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). **Projections:** EIA, AEO2014 National Energy Modeling System runs LOWPRICE.D120613A, REF2014.D102413A, and HIGHPRICE.D120613A.

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Table C2. Energy consumption by sector and source

(quadrillion Btu per year, unless otherwise noted)

Sector and source	2012	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Energy consumption										
Residential										
Propane	0.51	0.43	0.42	0.42	0.39	0.38	0.37	0.36	0.35	0.34
Kerosene	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Distillate fuel oil	0.51	0.48	0.46	0.43	0.40	0.37	0.35	0.34	0.31	0.29
Petroleum and other liquids subtotal	1.02	0.91	0.89	0.85	0.79	0.75	0.72	0.70	0.66	0.63
Natural gas	4.26	4.57	4.56	4.54	4.44	4.43	4.39	4.22	4.21	4.16
Renewable energy[1]	0.45	0.41	0.46	0.55	0.37	0.44	0.51	0.33	0.42	0.48
Electricity	4.69	4.86	4.84	4.81	5.23	5.21	5.16	5.69	5.65	5.57
Delivered energy	**10.42**	**10.75**	**10.74**	**10.75**	**10.82**	**10.83**	**10.78**	**10.95**	**10.94**	**10.85**
Electricity related losses	9.68	9.67	9.64	9.59	10.05	10.00	9.96	10.61	10.55	10.60
Total	**20.10**	**20.42**	**20.38**	**20.34**	**20.88**	**20.83**	**20.75**	**21.56**	**21.48**	**21.45**
Commercial										
Propane	0.15	0.17	0.16	0.15	0.18	0.17	0.16	0.19	0.18	0.17
Motor gasoline[2]	0.05	0.05	0.04	0.04	0.05	0.05	0.05	0.06	0.05	0.05
Kerosene	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00
Distillate fuel oil	0.40	0.43	0.40	0.35	0.42	0.38	0.33	0.43	0.37	0.32
Residual fuel oil	0.04	0.09	0.08	0.06	0.10	0.08	0.06	0.10	0.08	0.06
Petroleum and other liquids subtotal	0.63	0.74	0.68	0.61	0.76	0.67	0.60	0.79	0.68	0.60
Natural gas	2.96	3.25	3.23	3.22	3.36	3.35	3.32	3.66	3.65	3.59
Coal	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Renewable energy[3]	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Electricity	4.52	4.70	4.69	4.67	5.19	5.18	5.14	5.74	5.72	5.66
Delivered energy	**8.29**	**8.86**	**8.78**	**8.68**	**9.48**	**9.38**	**9.24**	**10.36**	**10.22**	**10.02**
Electricity related losses	9.32	9.35	9.34	9.32	9.97	9.94	9.93	10.70	10.66	10.75
Total	**17.61**	**18.21**	**18.12**	**18.00**	**19.46**	**19.32**	**19.17**	**21.06**	**20.88**	**20.78**
Industrial[4]										
Liquefied petroleum gases and other[5]	2.25	2.86	2.90	2.97	2.87	3.05	3.18	2.79	2.90	3.10
Motor gasoline[2]	0.26	0.30	0.30	0.30	0.29	0.30	0.29	0.30	0.29	0.29
Distillate fuel oil	1.20	1.40	1.40	1.38	1.42	1.41	1.36	1.45	1.42	1.36
Residual fuel oil	0.10	0.17	0.14	0.12	0.19	0.15	0.13	0.21	0.15	0.13
Petrochemical feedstocks	0.75	1.27	1.27	1.27	1.58	1.62	1.62	1.49	1.59	1.70
Other petroleum[6]	3.50	3.67	3.56	3.38	3.83	3.58	3.34	4.10	3.75	3.46
Petroleum and other liquids subtotal	8.06	9.66	9.56	9.43	10.19	10.10	9.92	10.33	10.10	10.04
Natural gas	7.29	8.11	8.26	8.40	8.54	8.71	8.57	8.49	8.87	8.74
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.40
Lease and plant fuel[7]	1.45	1.57	1.77	1.90	1.77	2.16	2.84	1.83	2.41	3.11
Natural gas subtotal	8.75	9.69	10.04	10.29	10.32	10.87	11.42	10.32	11.28	12.26
Metallurgical coal	0.55	0.57	0.58	0.59	0.55	0.55	0.53	0.49	0.47	0.46
Other industrial coal	0.93	0.98	0.99	0.99	0.99	1.00	1.00	1.00	1.01	1.02
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.56
Net coal coke imports	0.00	0.00	0.00	0.01	-0.03	-0.03	-0.03	-0.05	-0.05	-0.04
Coal subtotal	1.48	1.56	1.57	1.59	1.51	1.52	1.51	1.44	1.44	2.01
Biofuels heat and coproducts	0.52	0.76	0.76	0.75	0.79	0.79	0.78	0.78	0.79	0.78
Renewable energy[8]	1.48	1.74	1.74	1.74	2.05	2.01	1.93	2.38	2.28	2.20
Electricity	3.35	4.02	4.04	4.09	4.31	4.33	4.27	4.34	4.34	4.33
Delivered energy	**23.63**	**27.43**	**27.71**	**27.90**	**29.18**	**29.62**	**29.82**	**29.59**	**30.22**	**31.61**
Electricity related losses	6.91	8.01	8.05	8.16	8.30	8.33	8.25	8.10	8.10	8.22
Total	**30.54**	**35.44**	**35.76**	**36.05**	**37.48**	**37.94**	**38.07**	**37.69**	**38.33**	**39.83**

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Table C2. Energy consumption by sector and source (continued)

(quadrillion Btu per year, unless otherwise noted)

Sector and source	2012	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil Price
Transportation										
Propane	0.05	0.04	0.05	0.06	0.05	0.06	0.07	0.05	0.07	0.08
Motor gasoline[2]	16.33	15.61	15.00	14.05	13.81	12.69	11.52	13.69	12.09	10.88
of which: E85[9]	0.01	0.13	0.19	0.29	0.30	0.46	0.59	0.27	0.33	0.56
Jet fuel[10]	3.00	3.08	3.08	3.07	3.20	3.20	3.19	3.29	3.28	3.27
Distillate fuel oil[11]	5.82	6.69	6.70	6.47	7.47	7.25	6.18	8.36	7.54	6.24
Residual fuel oil	0.58	0.58	0.58	0.58	0.59	0.59	0.59	0.60	0.60	0.60
Other petroleum[12]	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Petroleum and other liquids subtotal	25.93	26.15	25.55	24.38	25.27	23.94	21.70	26.14	23.73	21.22
Pipeline fuel natural gas	0.73	0.71	0.74	0.76	0.76	0.82	0.86	0.78	0.85	0.89
Compressed / liquefied natural gas	0.04	0.07	0.08	0.43	0.08	0.28	1.44	0.10	0.86	2.32
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.02	0.03	0.03	0.03	0.04	0.04	0.05	0.05	0.06	0.07
Delivered energy	**26.72**	**26.97**	**26.40**	**25.60**	**26.16**	**25.08**	**24.05**	**27.08**	**25.50**	**24.51**
Electricity related losses	0.05	0.06	0.06	0.07	0.08	0.08	0.09	0.10	0.12	0.14
Total	**26.77**	**27.03**	**26.47**	**25.66**	**26.23**	**25.17**	**24.15**	**27.18**	**25.62**	**24.65**
Delivered energy consumption for all sectors										
Liquefied petroleum gases and other[5]	2.96	3.50	3.53	3.60	3.49	3.65	3.77	3.39	3.49	3.68
Motor gasoline[2]	16.64	15.95	15.34	14.39	14.16	13.04	11.85	14.05	12.44	11.22
of which: E85[9]	0.01	0.13	0.19	0.29	0.30	0.46	0.59	0.27	0.33	0.56
Jet fuel[10]	3.00	3.08	3.08	3.07	3.20	3.20	3.19	3.29	3.28	3.27
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate fuel oil	7.93	9.00	8.95	8.64	9.71	9.41	8.23	10.58	9.63	8.21
Residual fuel oil	0.72	0.85	0.80	0.77	0.88	0.82	0.78	0.92	0.83	0.80
Petrochemical feedstocks	0.75	1.27	1.27	1.27	1.58	1.62	1.62	1.49	1.59	1.70
Other petroleum[13]	3.64	3.81	3.70	3.52	3.97	3.73	3.48	4.24	3.89	3.61
Petroleum and other liquids subtotal	35.64	37.46	36.68	35.27	37.00	35.47	32.94	37.97	35.17	32.50
Natural gas	14.56	16.00	16.14	16.59	16.43	16.77	17.72	16.47	17.59	18.81
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.40
Lease and plant fuel[7]	1.45	1.57	1.77	1.90	1.77	2.16	2.84	1.83	2.41	3.11
Pipeline natural gas	0.73	0.71	0.74	0.76	0.76	0.82	0.86	0.78	0.85	0.89
Natural gas subtotal	16.74	18.28	18.65	19.24	18.96	19.75	21.42	19.08	20.84	23.21
Metallurgical coal	0.55	0.57	0.58	0.59	0.55	0.55	0.53	0.49	0.47	0.46
Other coal	0.98	1.03	1.03	1.04	1.03	1.04	1.05	1.04	1.05	1.07
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.56
Net coal coke imports	0.00	0.00	0.00	0.01	-0.03	-0.03	-0.03	-0.05	-0.05	-0.04
Coal subtotal	1.53	1.60	1.61	1.64	1.55	1.56	1.55	1.48	1.48	2.05
Biofuels heat and coproducts	0.52	0.76	0.76	0.75	0.79	0.79	0.78	0.78	0.79	0.78
Renewable energy[14]	2.06	2.28	2.33	2.42	2.56	2.58	2.58	2.84	2.83	2.82
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	12.58	13.61	13.60	13.60	14.77	14.76	14.62	15.83	15.77	15.63
Delivered energy	**69.07**	**74.00**	**73.63**	**72.93**	**75.64**	**74.91**	**73.89**	**77.98**	**76.88**	**76.99**
Electricity related losses	25.95	27.10	27.10	27.13	28.40	28.35	28.25	29.51	29.43	29.71
Total	**95.02**	**101.10**	**100.73**	**100.06**	**104.04**	**103.27**	**102.14**	**107.49**	**106.31**	**106.71**
Electric power[15]										
Distillate fuel oil	0.05	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Residual fuel oil	0.18	0.09	0.09	0.09	0.09	0.09	0.09	0.11	0.10	0.10
Petroleum and other liquids subtotal	0.23	0.18	0.18	0.18	0.18	0.18	0.18	0.19	0.19	0.19
Natural gas	9.46	9.08	9.00	8.96	10.40	10.28	9.81	11.58	11.48	9.76
Steam coal	15.82	16.98	16.95	16.96	17.48	17.44	17.47	17.37	17.27	17.53
Nuclear / uranium[16]	8.05	8.15	8.15	8.15	8.16	8.18	8.22	8.41	8.49	9.37
Renewable energy[17]	4.59	5.98	6.08	6.15	6.60	6.68	6.83	7.45	7.44	8.11
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Electricity imports	0.16	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.16
Total	**38.53**	**40.71**	**40.70**	**40.74**	**43.16**	**43.12**	**42.87**	**45.34**	**45.20**	**45.34**

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Table C2. Energy consumption by sector and source (continued)

(quadrillion Btu per year, unless otherwise noted)

Sector and source	2012	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Total energy consumption										
Liquefied petroleum gases and other[5]	2.96	3.50	3.53	3.60	3.49	3.65	3.77	3.39	3.49	3.68
Motor gasoline[2]	16.64	15.95	15.34	14.39	14.16	13.04	11.85	14.05	12.44	11.22
of which: E85[9]	0.01	0.13	0.19	0.29	0.30	0.46	0.59	0.27	0.33	0.56
Jet fuel[10]	3.00	3.08	3.08	3.07	3.20	3.20	3.19	3.29	3.28	3.27
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate fuel oil	7.98	9.09	9.03	8.73	9.79	9.50	8.31	10.66	9.72	8.29
Residual fuel oil	0.90	0.94	0.89	0.86	0.98	0.91	0.88	1.03	0.93	0.90
Petrochemical feedstocks	0.75	1.27	1.27	1.27	1.58	1.62	1.62	1.49	1.59	1.70
Other petroleum[13]	3.64	3.81	3.70	3.52	3.97	3.73	3.48	4.24	3.89	3.61
Petroleum and other liquids subtotal	35.87	37.64	36.86	35.44	37.19	35.65	33.13	38.16	35.35	32.69
Natural gas	24.02	25.07	25.14	25.55	26.82	27.05	27.53	28.05	29.07	28.58
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.40
Lease and plant fuel[7]	1.45	1.57	1.77	1.90	1.77	2.16	2.84	1.83	2.41	3.11
Pipeline natural gas	0.73	0.71	0.74	0.76	0.76	0.82	0.86	0.78	0.85	0.89
Natural gas subtotal	26.20	27.36	27.65	28.20	29.36	30.03	31.24	30.66	32.32	32.98
Metallurgical coal	0.55	0.57	0.58	0.59	0.55	0.55	0.53	0.49	0.47	0.46
Other coal	16.79	18.01	17.98	18.00	18.51	18.49	18.52	18.41	18.32	18.59
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.56
Net coal coke imports	0.00	0.00	0.00	0.01	-0.03	-0.03	-0.03	-0.05	-0.05	-0.04
Coal subtotal	17.34	18.58	18.56	18.60	19.03	19.01	19.02	18.84	18.75	19.58
Nuclear / uranium[16]	8.05	8.15	8.15	8.15	8.16	8.18	8.22	8.41	8.49	9.37
Biofuels heat and coproducts	0.52	0.76	0.76	0.75	0.79	0.79	0.78	0.78	0.79	0.78
Renewable energy[18]	6.65	8.26	8.40	8.57	9.16	9.26	9.41	10.29	10.27	10.93
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Electricity imports	0.16	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.16
Total	**95.02**	**101.10**	**100.73**	**100.06**	**104.04**	**103.27**	**102.14**	**107.49**	**106.31**	**106.71**
Energy use and related statistics										
Delivered energy use	69.07	74.00	73.63	72.93	75.64	74.91	73.89	77.98	76.88	76.99
Total energy use	95.02	101.10	100.73	100.06	104.04	103.27	102.14	107.49	106.31	106.71
Ethanol consumed in motor gasoline and E85	1.09	1.22	1.22	1.21	1.25	1.25	1.24	1.25	1.29	1.31
Population (millions)	314.58	334.47	334.47	334.47	359.03	359.03	359.03	380.53	380.53	380.53
Gross domestic product (billion 2005 dollars).	13,593	16,739	16,753	16,812	21,150	21,139	21,100	26,725	26,670	26,772
Carbon dioxide emissions (million metric tons)	5,290	5,523	5,476	5,401	5,621	5,527	5,401	5,746	5,599	5,475

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal water heating, and electricity generation from wind and solar photovoltaic sources.
[2]Includes ethanol and ethers blended into gasoline.
[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal water heating and electricity generation from wind and solar photovoltaic sources.
[4]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[5]Includes ethane, natural gasoline, and refinery olefins.
[6]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[7]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[8]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol in motor gasoline.
[9]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[10]Includes only kerosene type.
[11]Diesel fuel for on- and off- road use.
[12]Includes aviation gasoline and lubricants.
[13]Includes aviation gasoline, petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[14]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[15]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[16]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[17]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[18]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
Btu = British thermal unit.
Note: Includes estimated consumption for petroleum and other liquids. Totals may not equal sum of components due to independent rounding. Data for 2012 are model results and may differ from official EIA data reports.
Sources: 2012 consumption based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE-EIA-0035(2013/09) (Washington, DC, September 2013). 2012 population and gross domestic product: IHS Global Insight Industry and Employment models, May 2013. 2012 carbon dioxide emissions and emission factors: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). **Projections:** EIA, AEO2014 National Energy Modeling System runs LOWPRICE.D120613A, REF2014.D102413A, and HIGHPRICE.D120613A.

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Table C3. Energy prices by sector and source

(2012 dollars per million Btu, unless otherwise noted)

Sector and source	2012	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil Price
Residential										
Propane	24.12	22.39	23.79	25.81	23.38	25.75	28.16	24.24	27.64	29.79
Distillate fuel oil	27.30	19.42	24.67	34.47	20.14	28.60	38.28	20.70	32.64	43.67
Natural gas	10.46	11.58	11.59	11.91	13.32	13.50	14.02	15.76	15.98	17.01
Electricity	34.83	35.80	36.15	36.73	36.70	36.98	37.81	38.53	38.83	40.50
Commercial										
Propane	20.75	18.60	20.33	22.87	19.78	22.79	25.93	20.80	25.17	28.11
Distillate fuel oil	26.81	16.64	21.77	31.50	17.38	25.66	35.27	17.87	29.72	40.58
Residual fuel oil	22.84	10.41	14.40	22.09	11.17	17.92	25.57	11.73	20.99	30.45
Natural gas	8.11	9.45	9.49	9.79	10.95	11.19	11.62	12.85	13.08	14.20
Electricity	29.55	30.53	30.80	31.28	31.07	31.26	31.98	32.82	33.01	34.56
Industrial[1]										
Propane	21.09	18.85	20.64	23.33	20.23	23.27	26.61	21.65	25.84	28.95
Distillate fuel oil	27.41	17.04	22.22	31.89	17.72	26.11	35.68	18.11	29.92	40.96
Residual fuel oil	20.90	10.84	14.88	22.60	11.54	18.29	25.97	12.15	21.48	30.80
Natural gas[2]	3.77	5.70	5.79	6.11	6.70	6.99	7.67	8.48	8.59	9.53
Metallurgical coal	7.25	8.34	8.43	8.60	9.38	9.51	9.65	10.05	10.20	10.38
Other industrial coal	3.24	3.51	3.59	3.72	3.76	3.88	4.04	4.02	4.19	4.36
Coal to liquids	--	--	--	--	--	--	--	--	--	3.16
Electricity	19.50	20.54	20.77	21.17	21.75	21.99	22.71	23.86	24.05	25.41
Transportation										
Propane	25.14	23.49	24.85	26.88	24.52	26.81	29.22	25.43	28.82	30.84
E85[3]	35.06	22.62	25.61	33.07	24.13	27.91	34.30	26.08	35.49	40.38
Motor gasoline[4]	30.68	21.22	25.59	34.56	21.23	28.54	37.08	21.79	32.67	42.21
Jet fuel[5]	22.99	14.26	19.47	29.11	15.29	23.71	32.98	16.09	28.07	38.74
Diesel fuel (distillate fuel oil)[6]	28.80	21.63	26.80	36.44	22.33	30.68	40.19	22.73	34.53	45.47
Residual fuel oil	20.07	8.73	12.46	19.50	9.40	15.50	22.49	10.00	18.55	26.71
Natural gas[7]	14.64	16.00	15.62	18.62	16.68	16.63	19.78	17.80	19.67	21.46
Electricity	31.43	29.74	29.86	30.17	31.41	31.68	32.47	33.74	34.19	36.24
Electric power[8]										
Distillate fuel oil	24.12	15.46	20.66	30.47	16.25	24.65	34.31	16.86	28.81	39.77
Residual fuel oil	20.68	9.88	13.86	21.50	10.48	17.14	24.95	10.78	20.42	29.76
Natural gas	3.44	5.00	5.07	5.35	6.20	6.49	7.05	8.05	8.16	8.98
Steam coal	2.39	2.52	2.61	2.75	2.79	2.93	3.06	3.00	3.19	3.40
Average price to all users[9]										
Propane	23.24	20.99	22.54	24.84	21.99	24.66	27.45	22.80	26.79	29.34
E85[3]	35.06	22.62	25.61	33.07	24.13	27.91	34.30	26.08	35.49	40.38
Motor gasoline[4]	30.44	21.22	25.58	34.56	21.22	28.53	37.08	21.78	32.67	42.21
Jet fuel[5]	22.99	14.26	19.47	29.11	15.29	23.71	32.98	16.09	28.07	38.74
Distillate fuel oil	28.36	20.51	25.70	35.36	21.30	29.67	39.14	21.79	33.54	44.42
Residual fuel oil	20.41	9.39	13.15	20.34	10.10	16.32	23.48	10.70	19.42	27.91
Natural gas	5.38	7.03	7.09	7.55	8.16	8.49	9.57	10.00	10.38	11.96
Metallurgical coal	7.25	8.34	8.43	8.60	9.38	9.51	9.65	10.05	10.20	10.38
Other coal	2.44	2.59	2.67	2.81	2.85	2.98	3.12	3.07	3.25	3.46
Coal to liquids	--	--	--	--	--	--	--	--	--	3.16
Electricity	28.85	29.46	29.72	30.17	30.34	30.56	31.33	32.42	32.63	34.15
Non-renewable energy expenditures by sector (billion 2012 dollars)										
Residential	234.06	245.83	249.25	256.46	268.11	272.82	280.40	301.65	306.56	319.45
Commercial	173.25	186.48	189.44	195.36	211.31	215.91	222.46	249.84	255.39	268.38
Industrial[1]	213.75	249.82	279.45	335.52	285.52	343.02	407.85	312.95	390.91	479.52
Transportation	755.09	527.76	632.05	827.37	514.23	667.67	809.67	548.77	772.91	923.38
Total non-renewable expenditures	1,376.15	1,209.88	1,350.18	1,614.71	1,279.17	1,499.43	1,720.37	1,413.21	1,725.77	1,990.73
Transportation renewable expenditures	0.50	2.85	4.89	9.50	7.27	12.96	20.25	7.05	11.80	22.66
Total expenditures	**1,376.66**	**1,212.74**	**1,355.07**	**1,624.21**	**1,286.44**	**1,512.39**	**1,740.62**	**1,420.26**	**1,737.56**	**2,013.39**

012851

Table C3. Energy prices by sector and source (continued)

(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2012	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Residential										
Propane	24.12	25.22	26.94	29.54	30.77	34.67	39.43	38.67	45.83	51.25
Distillate fuel oil	27.30	21.89	27.94	39.45	26.51	38.50	53.60	33.02	54.12	75.14
Natural gas	10.46	13.05	13.13	13.62	17.53	18.18	19.62	25.15	26.49	29.27
Electricity	34.83	40.34	40.94	42.04	48.31	49.78	52.93	61.48	64.39	69.68
Commercial										
Propane	20.75	20.97	23.02	26.17	26.04	30.68	36.31	33.19	41.74	48.37
Distillate fuel oil	26.81	18.75	24.66	36.05	22.87	34.54	49.38	28.51	49.27	69.82
Residual fuel oil	22.84	11.73	16.31	25.27	14.70	24.12	35.80	18.71	34.80	52.39
Natural gas	8.11	10.65	10.75	11.20	14.42	15.07	16.27	20.51	21.68	24.43
Electricity	29.55	34.40	34.88	35.80	40.89	42.08	44.78	52.37	54.73	59.46
Industrial[1]										
Propane	21.09	21.24	23.38	26.70	26.63	31.32	37.26	34.54	42.83	49.82
Distillate fuel oil	27.41	19.20	25.17	36.50	23.33	35.15	49.96	28.89	49.61	70.48
Residual fuel oil	20.90	12.21	16.85	25.87	15.19	24.62	36.36	19.39	35.61	52.99
Natural gas[2]	3.77	6.42	6.56	7.00	8.82	9.41	10.73	13.53	14.25	16.40
Metallurgical coal	7.25	9.40	9.55	9.84	12.35	12.81	13.51	16.04	16.91	17.87
Other industrial coal	3.24	3.95	4.07	4.26	4.94	5.23	5.66	6.42	6.95	7.51
Coal to liquids	--	--	--	--	--	--	--	--	--	5.44
Electricity	19.50	23.14	23.52	24.23	28.63	29.60	31.80	38.07	39.88	43.73
Transportation										
Propane	25.14	26.48	28.14	30.75	32.27	36.09	40.91	40.57	47.79	53.06
E85[3]	35.06	25.49	29.00	37.84	31.77	37.57	48.02	41.61	58.85	69.48
Motor gasoline[4]	30.68	23.91	28.98	39.55	27.94	38.42	51.91	34.76	54.17	72.63
Jet fuel[5]	22.99	16.07	22.06	33.32	20.12	31.91	46.18	25.67	46.53	66.66
Diesel fuel (distillate fuel oil)[6]	28.80	24.38	30.35	41.70	29.39	41.30	56.27	36.26	57.25	78.23
Residual fuel oil	20.07	9.84	14.11	22.31	12.37	20.86	31.48	15.95	30.76	45.96
Natural gas[7]	14.64	18.03	17.69	21.31	21.95	22.38	27.69	28.40	32.61	36.92
Electricity	31.43	33.51	33.82	34.52	41.34	42.65	45.46	53.83	56.68	62.36
Electric power[8]										
Distillate fuel oil	24.12	17.42	23.40	34.87	21.40	33.18	48.04	26.91	47.77	68.43
Residual fuel oil	20.68	11.13	15.70	24.60	13.79	23.08	34.94	17.19	33.86	51.21
Natural gas	3.44	5.63	5.75	6.12	8.16	8.74	9.87	12.84	13.53	15.46
Steam coal	2.39	2.84	2.96	3.14	3.67	3.94	4.29	4.79	5.29	5.84

012852

Table C3. Energy prices by sector and source (continued)

(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2012	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Average price to all users[9]										
Propane	23.24	23.65	25.53	28.42	28.95	33.20	38.44	36.38	44.42	50.48
E85[3]	35.06	25.49	29.00	37.84	31.77	37.57	48.02	41.61	58.85	69.48
Motor gasoline[4]	30.44	23.91	28.98	39.55	27.94	38.41	51.91	34.76	54.17	72.62
Jet fuel[5]	22.99	16.07	22.06	33.32	20.12	31.91	46.18	25.67	46.53	66.66
Distillate fuel oil	28.36	23.12	29.11	40.47	28.04	39.94	54.81	34.77	55.61	76.43
Residual fuel oil	20.41	10.58	14.90	23.27	13.30	21.97	32.87	17.07	32.20	48.03
Natural gas	5.38	7.92	8.04	8.64	10.75	11.43	13.40	15.96	17.22	20.57
Metallurgical coal	7.25	9.40	9.55	9.84	12.35	12.81	13.51	16.04	16.91	17.87
Other coal	2.44	2.91	3.03	3.21	3.75	4.02	4.37	4.89	5.39	5.94
Coal to liquids	--	--	--	--	--	--	--	--	--	5.44
Electricity	28.85	33.19	33.66	34.52	39.94	41.13	43.87	51.73	54.11	58.76
Non-renewable energy expenditures by sector (billion nominal dollars)										
Residential	234.06	277.02	282.30	293.48	352.89	367.27	392.59	481.30	508.27	549.64
Commercial	173.25	210.13	214.56	223.56	278.14	290.65	311.47	398.63	423.44	461.77
Industrial[1]	213.75	281.51	316.50	383.95	375.82	461.77	571.03	499.33	648.12	825.06
Transportation	755.09	594.71	715.87	946.80	676.84	898.80	1,133.62	875.60	1,281.47	1,588.74
Total non-renewable expenditures	1,376.15	1,363.37	1,529.23	1,847.79	1,683.69	2,018.49	2,408.71	2,254.86	2,861.30	3,425.20
Transportation renewable expenditures	0.50	3.21	5.54	10.87	9.57	17.45	28.36	11.24	19.56	38.98
Total expenditures	**1,376.66**	**1,366.59**	**1,534.77**	**1,858.66**	**1,693.26**	**2,035.94**	**2,437.07**	**2,266.10**	**2,880.86**	**3,464.18**

[1]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[2]Excludes use for lease and plant fuel.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[5]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Natural gas used as fuel in motor vehicles, trains, and ships. Price includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[8]Includes electricity-only and combined heat and power plants that have a regulatory status.
[9]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
-- = Not applicable.
Note: Data for 2012 are model results and may differ from official EIA data reports.
Sources: 2012 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2013/08) (Washington, DC, August 2013). 2012 residential, commercial, and industrial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2013/06) (Washington, DC, June 2013). 2012 transportation sector natural gas delivered prices are model results. 2012 electric power sector distillate and residual fuel oil prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2012 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2012 and April 2013, Table 4.2, and EIA, *State Energy Data Report 2011*, DOE/EIA-0214(2011) (Washington, DC, June 2013). 2012 coal prices based on: EIA, *Quarterly Coal Report, October-December 2012*, DOE/EIA-0121(2012/4Q) (Washington, DC, March 2013) and EIA, AEO2014 National Energy Modeling System run REF2014.D102413A. 2012 electricity prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2012 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. **Projections:** EIA, AEO2014 National Energy Modeling System runs LOWPRICE.D120613A, REF2014.D102413A, and HIGHPRICE.D120613A.

012853

Table C4. Petroleum and other liquids supply and disposition

(million barrels per day, unless otherwise noted)

Supply and disposition	2012	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil Price
Crude oil										
Domestic crude production[1]	6.49	8.95	9.55	10.69	6.85	8.30	9.28	5.81	7.48	8.21
Alaska	0.53	0.44	0.44	0.44	0.00	0.24	0.55	0.00	0.26	0.40
Lower 48 states	5.96	8.51	9.12	10.25	6.85	8.06	8.73	5.81	7.22	7.81
Net imports	8.43	6.65	5.79	4.09	8.65	6.64	4.66	10.26	7.74	5.61
Gross imports	8.49	6.80	5.94	4.25	8.78	6.77	4.79	10.38	7.87	5.73
Exports	0.06	0.15	0.15	0.15	0.13	0.13	0.13	0.12	0.12	0.12
Other crude supply[2]	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total crude supply	**15.01**	**15.59**	**15.34**	**14.78**	**15.50**	**14.94**	**13.94**	**16.07**	**15.22**	**13.81**
Other petroleum supply	**0.10**	**0.41**	**0.23**	**0.06**	**-0.05**	**-0.34**	**-0.65**	**-0.12**	**-0.86**	**-1.20**
Net product imports	-0.92	-0.70	-0.86	-0.92	-1.11	-1.29	-1.49	-1.18	-1.82	-2.04
Gross refined product imports[3]	0.85	1.10	0.98	0.92	1.27	1.06	0.88	1.52	1.10	0.89
Unfinished oil imports	0.60	0.59	0.52	0.43	0.62	0.49	0.37	0.62	0.45	0.31
Blending component imports	0.62	0.68	0.62	0.52	0.60	0.50	0.40	0.62	0.40	0.31
Exports	2.98	3.08	2.97	2.79	3.60	3.33	3.14	3.95	3.76	3.54
Refinery processing gain[4]	1.08	1.11	1.08	0.97	1.05	0.96	0.84	1.06	0.95	0.83
Product stock withdrawal	-0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other non-petroleum supply	**3.48**	**3.90**	**3.96**	**4.00**	**4.19**	**4.32**	**4.43**	**4.11**	**4.36**	**4.88**
Supply from renewable sources	0.89	1.01	1.01	1.01	1.03	1.04	1.03	1.04	1.07	1.09
Ethanol	0.83	0.90	0.90	0.88	0.89	0.91	0.90	0.92	0.95	0.97
Domestic production	0.84	0.85	0.84	0.81	0.84	0.86	0.83	0.86	0.86	0.86
Net imports	-0.02	0.05	0.06	0.07	0.05	0.06	0.07	0.06	0.08	0.11
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biodiesel	0.06	0.07	0.09	0.09	0.06	0.09	0.09	0.06	0.09	0.10
Domestic production	0.06	0.06	0.08	0.08	0.05	0.08	0.08	0.05	0.08	0.08
Net imports	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other biomass-derived liquids[5]	0.00	0.04	0.03	0.04	0.08	0.04	0.05	0.06	0.03	0.02
Domestic production	0.00	0.04	0.03	0.04	0.08	0.04	0.05	0.06	0.03	0.02
Net imports	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquids from gas	2.40	2.60	2.65	2.71	2.85	2.98	3.12	2.76	2.98	3.32
Natural gas plant liquids	2.40	2.60	2.65	2.71	2.85	2.98	3.12	2.76	2.98	3.11
Gas-to-liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.20
Liquids from coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.20
Other[6]	0.19	0.29	0.30	0.28	0.31	0.30	0.28	0.31	0.31	0.27
Total primary supply[7]	**18.59**	**19.90**	**19.52**	**18.84**	**19.64**	**18.93**	**17.72**	**20.06**	**18.72**	**17.49**
Product supplied										
by fuel										
Liquefied petroleum gases and other[8]	2.32	2.70	2.73	2.79	2.71	2.84	2.94	2.63	2.73	2.88
Motor gasoline[9]	8.71	8.67	8.35	7.85	7.73	7.15	6.52	7.67	6.84	6.20
of which: E85[10]	0.01	0.09	0.13	0.20	0.21	0.32	0.41	0.19	0.23	0.39
Jet fuel[11]	1.40	1.49	1.49	1.49	1.55	1.55	1.55	1.59	1.59	1.59
Distillate fuel oil[12]	3.74	4.32	4.30	4.15	4.66	4.52	3.95	5.07	4.62	3.95
of which: Diesel	3.45	3.95	3.94	3.82	4.33	4.21	3.67	4.76	4.34	3.69
Residual fuel oil	0.35	0.41	0.39	0.37	0.43	0.40	0.38	0.45	0.40	0.39
Other[13]	1.97	2.32	2.28	2.20	2.57	2.49	2.38	2.64	2.55	2.49
by sector										
Residential and commercial	0.94	0.92	0.88	0.83	0.87	0.81	0.76	0.84	0.76	0.71
Industrial[14]	4.42	5.39	5.37	5.35	5.69	5.72	5.69	5.70	5.68	5.74
Transportation	13.44	13.51	13.19	12.59	13.01	12.32	11.20	13.42	12.20	10.96
Electric power[15]	0.10	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.08	0.08
Total	**18.49**	**19.91**	**19.53**	**18.84**	**19.65**	**18.94**	**17.73**	**20.06**	**18.73**	**17.50**
Discrepancy[16]	0.11	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	0.00	-0.01	-0.01

012854

Table C4. Petroleum and other liquids supply and disposition (continued)

(million barrels per day, unless otherwise noted)

Supply and disposition	2012	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Domestic refinery distillation capacity[17]	17.3	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1
Capacity utilization rate (percent)[18]	89.0	86.0	84.6	81.5	85.5	82.4	76.9	88.6	84.0	76.2
Net import share of product supplied (percent)	40.3	30.2	25.6	17.3	38.8	28.6	18.3	45.6	32.2	21.1
Net expenditures for imported crude oil and petroleum products (billion 2012 dollars)	313.70	160.27	198.85	226.18	214.45	278.60	290.21	264.46	385.39	408.21

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude product supplied.
[3]Includes other hydrocarbons and alcohols.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes pyrolysis oils, biomass-derived Fischer-Tropsch liquids, and renewable feedstocks used for the on-site production of diesel and gasoline.
[6]Includes domestic sources of other blending components, other hydrocarbons, and ethers.
[7]Total crude supply plus other petroleum supply plus other non-petroleum supply.
[8]Includes ethane, natural gasoline, and refinery olefins.
[9]Includes ethanol and ethers blended into gasoline.
[10]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[11]Includes only kerosene type.
[12]Includes distillate fuel oil from petroleum and biomass feedstocks.
[13]Includes Kerosene, aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, methanol, and miscellaneous petroleum products.
[14]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[15]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[16]Balancing item. Includes unaccounted for supply, losses, and gains.
[17]End-of-year operable capacity.
[18]Rate is calculated by dividing the gross annual input to atmospheric crude oil distillation units by their operable refining capacity in barrels per calendar day.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 are model results and may differ from official EIA data reports.
Sources: 2012 product supplied based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). Other 2012 data: EIA, *Petroleum Supply Annual 2012*, DOE/EIA-0340(2012)/1 (Washington, DC, September 2013). **Projections:** EIA, AEO2014 National Energy Modeling System runs LOWPRICE.D120613A, REF2014.D102413A, and HIGHPRICE.D120613A.

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Table C5. Petroleum and other liquids prices

(2012 dollars per gallon, unless otherwise noted)

Sector and fuel	2012	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Crude oil prices (2012 dollars per barrel)										
Brent spot	111.65	68.90	96.57	150.28	71.90	118.99	173.69	74.90	141.46	204.24
West Texas Intermediate spot	94.12	66.90	94.57	148.28	69.90	116.99	171.69	72.90	139.46	202.24
Average imported refiners acquisition cost[1]	101.10	61.93	88.07	139.34	64.73	109.22	160.61	67.84	130.80	190.62
Delivered sector product prices										
Residential										
Propane	2.20	2.04	2.17	2.36	2.14	2.35	2.57	2.21	2.52	2.72
Distillate fuel oil	3.79	2.69	3.42	4.78	2.79	3.97	5.31	2.87	4.53	6.06
Commercial										
Distillate fuel oil	3.70	2.29	3.00	4.34	2.40	3.54	4.86	2.46	4.10	5.59
Residual fuel oil	3.42	1.56	2.16	3.31	1.67	2.68	3.83	1.76	3.14	4.56
Residual fuel oil (2012 dollars per barrel)	143.59	65.46	90.53	138.85	70.23	112.66	160.76	73.73	131.97	191.43
Industrial[2]										
Propane	1.93	1.72	1.89	2.13	1.85	2.13	2.43	1.98	2.36	2.64
Distillate fuel oil	3.76	2.34	3.05	4.38	2.43	3.58	4.90	2.49	4.11	5.62
Residual fuel oil	3.13	1.62	2.23	3.38	1.73	2.74	3.89	1.82	3.22	4.61
Residual fuel oil (2012 dollars per barrel)	131.40	68.13	93.56	142.11	72.54	115.00	163.27	76.40	135.04	193.63
Transportation										
Propane	2.30	2.15	2.27	2.45	2.24	2.45	2.67	2.32	2.63	2.82
Ethanol (E85)[3]	3.33	2.15	2.43	3.14	2.29	2.65	3.26	2.48	3.37	3.84
Ethanol wholesale price	2.58	2.58	2.66	2.81	2.50	2.52	2.63	2.34	2.65	2.80
Motor gasoline[4]	3.69	2.55	3.08	4.16	2.55	3.43	4.45	2.61	3.90	5.04
Jet fuel[5]	3.10	1.93	2.63	3.93	2.06	3.20	4.45	2.17	3.79	5.23
Diesel fuel (distillate fuel oil)[6]	3.95	2.96	3.67	4.99	3.06	4.20	5.51	3.11	4.73	6.23
Residual fuel oil	3.00	1.31	1.86	2.92	1.41	2.32	3.37	1.50	2.78	4.00
Residual fuel oil (2012 dollars per barrel)	126.17	54.90	78.31	122.57	59.10	97.43	141.38	62.85	116.65	167.94
Electric power[7]										
Distillate fuel oil	3.35	2.14	2.87	4.23	2.25	3.42	4.76	2.34	4.00	5.52
Residual fuel oil	3.10	1.48	2.07	3.22	1.57	2.57	3.74	1.61	3.06	4.45
Residual fuel oil (2012 dollars per barrel)	130.00	62.10	87.12	135.14	65.87	107.77	156.88	67.74	128.40	187.11
Average prices, all sectors[8]										
Propane	2.12	1.92	2.06	2.27	2.01	2.25	2.51	2.08	2.45	2.68
Motor gasoline[4]	3.66	2.55	3.08	4.16	2.55	3.43	4.45	2.61	3.90	5.04
Jet fuel[5]	3.10	1.93	2.63	3.93	2.06	3.20	4.45	2.17	3.79	5.23
Distillate fuel oil	3.89	2.81	3.53	4.85	2.92	4.07	5.37	2.99	4.60	6.09
Residual fuel oil	3.05	1.41	1.97	3.04	1.51	2.44	3.51	1.60	2.91	4.18
Residual fuel oil (2012 dollars per barrel)	128.30	59.05	82.69	127.85	63.52	102.60	147.61	67.25	122.12	175.49
Average	**3.28**	**2.27**	**2.80**	**3.81**	**2.32**	**3.19**	**4.17**	**2.42**	**3.69**	**4.79**

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Table C5. Petroleum and other liquids prices (continued)

(nominal dollars per gallon, unless otherwise noted)

Sector and fuel	2012	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Crude oil prices (nominal dollars per barrel)										
Brent spot	111.65	77.64	109.37	171.98	94.64	160.19	243.19	119.51	234.53	351.41
West Texas Intermediate spot	94.12	75.39	107.11	169.69	92.01	157.49	240.39	116.32	231.22	347.97
Average imported refiners acquisition cost[1]	101.10	69.79	99.75	159.45	85.20	147.02	224.87	108.25	216.87	327.97
Delivered sector product prices										
Residential										
Propane	2.20	2.30	2.46	2.70	2.81	3.17	3.60	3.53	4.19	4.68
Distillate fuel oil	3.79	3.04	3.88	5.47	3.68	5.34	7.43	4.58	7.51	10.42
Commercial										
Distillate fuel oil	3.70	2.59	3.40	4.97	3.15	4.76	6.81	3.93	6.79	9.63
Residual fuel oil	3.42	1.76	2.44	3.78	2.20	3.61	5.36	2.80	5.21	7.84
Industrial[2]										
Propane	1.93	1.94	2.14	2.44	2.43	2.86	3.40	3.15	3.91	4.55
Distillate fuel oil	3.76	2.64	3.46	5.01	3.20	4.82	6.86	3.97	6.81	9.67
Residual fuel oil	3.13	1.83	2.52	3.87	2.27	3.69	5.44	2.90	5.33	7.93
Transportation										
Propane	2.30	2.42	2.57	2.81	2.95	3.30	3.74	3.71	4.36	4.85
Ethanol (E85)[3]	3.33	2.42	2.76	3.60	3.02	3.57	4.56	3.96	5.59	6.60
Ethanol wholesale price	2.58	2.91	3.02	3.22	3.29	3.39	3.68	3.73	4.39	4.82
Motor gasoline[4]	3.69	2.88	3.49	4.76	3.36	4.61	6.23	4.17	6.47	8.68
Jet fuel[5]	3.10	2.17	2.98	4.50	2.72	4.31	6.23	3.47	6.28	9.00
Diesel fuel (distillate fuel oil)[6]	3.95	3.34	4.16	5.71	4.03	5.66	7.71	4.97	7.84	10.72
Residual fuel oil	3.00	1.47	2.11	3.34	1.85	3.12	4.71	2.39	4.60	6.88
Electric power[7]										
Distillate fuel oil	3.35	2.42	3.25	4.84	2.97	4.60	6.66	3.73	6.62	9.49
Residual fuel oil	3.10	1.67	2.35	3.68	2.06	3.45	5.23	2.57	5.07	7.67
Average prices, all sectors[8]										
Propane	2.12	2.16	2.33	2.60	2.64	3.03	3.51	3.32	4.06	4.61
Motor gasoline[4]	3.66	2.88	3.49	4.76	3.36	4.61	6.23	4.17	6.47	8.67
Jet fuel[5]	3.10	2.17	2.98	4.50	2.72	4.31	6.23	3.47	6.28	9.00
Distillate fuel oil	3.89	3.17	3.99	5.55	3.85	5.48	7.52	4.77	7.63	10.48
Residual fuel oil (nominal dollars per barrel)	128.30	66.54	93.65	146.31	83.60	138.12	206.68	107.31	202.47	301.95
Average	**3.28**	**2.56**	**3.17**	**4.36**	**3.05**	**4.30**	**5.84**	**3.85**	**6.11**	**8.24**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[5]Includes only kerosene type.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Includes electricity-only and combined heat and power plants that have a regulatory status.
[8]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2012 are model results and may differ from official EIA data reports.
Sources: 2012 Brent and West Texas Intermediate crude oil spot prices: Thomson Reuters. 2012 average imported crude oil cost: Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035Monthly Energy Review. 2012 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, *Petroleum Marketing Monthly*, DOE/EIA-0380(2013/08) (Washington, DC, August 2013). 2012 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2012 electric power prices based on: *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2012 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. 2012 wholesale ethanol prices derived from Bloomberg U.S. average rack price. **Projections:** EIA, AEO2014 National Energy Modeling System runs LOWPRICE.D120613A, REF2014.D102413A, and HIGHPRICE.D120613A.

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Table C6. International petroleum and other liquids supply, disposition, and prices

(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	2012	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Crude oil spot prices										
(2012 dollars per barrel)										
Brent	111.65	68.90	96.57	150.28	71.90	118.99	173.69	74.90	141.46	204.24
West Texas Intermediate	94.12	66.90	94.57	148.28	69.90	116.99	171.69	72.90	139.46	202.24
(nominal dollars per barrel)										
Brent	111.65	77.64	109.37	171.98	94.64	160.19	243.19	119.51	234.53	351.41
West Texas Intermediate	94.12	75.39	107.11	169.69	92.01	157.49	240.39	116.32	231.22	347.97
Petroleum and other liquids consumption[1]										
OECD										
United States (50 states)	18.21	19.61	19.23	18.55	19.35	18.63	17.43	19.76	18.42	17.18
United States territories	0.25	0.31	0.29	0.28	0.35	0.33	0.32	0.39	0.37	0.36
Canada	2.26	2.35	2.24	2.15	2.36	2.18	2.13	2.46	2.30	2.31
Mexico and Chile	2.51	2.78	2.71	2.61	3.32	3.08	3.02	4.00	3.63	3.60
OECD Europe[2]	14.21	14.47	13.85	13.30	15.06	13.94	13.49	15.80	14.32	13.93
Japan	4.75	4.75	4.50	4.28	4.69	4.29	4.13	4.49	4.05	3.90
South Korea	2.65	2.74	2.76	2.65	2.97	2.68	2.58	3.18	2.76	2.68
Australia and New Zealand	1.28	1.22	1.23	1.18	1.28	1.21	1.19	1.40	1.30	1.28
Total OECD consumption	**46.13**	**48.23**	**46.82**	**45.01**	**49.39**	**46.37**	**44.30**	**51.47**	**47.15**	**45.22**
Non-OECD										
Russia	3.20	3.77	3.55	3.43	4.14	3.81	3.72	4.29	3.92	3.85
Other Europe and Eurasia[3]	1.99	2.52	2.32	2.25	2.88	2.62	2.54	3.45	3.08	3.00
China	10.36	13.90	13.91	13.63	16.49	17.04	17.73	18.78	20.48	22.98
India	3.68	4.58	4.50	4.38	6.52	6.11	6.19	8.89	8.33	8.94
Other Asia[4]	6.97	8.14	7.99	7.71	9.47	9.35	9.28	11.01	11.16	11.36
Middle East	7.67	8.64	8.81	8.54	9.15	9.22	9.22	10.00	10.38	10.74
Africa	3.47	3.79	3.70	3.55	4.16	4.03	3.93	4.52	4.58	4.54
Brazil	2.83	3.18	3.12	2.96	3.50	3.32	3.25	3.88	3.85	3.94
Other Central and South America	2.77	3.53	3.29	3.16	3.95	3.76	3.62	4.38	4.13	4.00
Total non-OECD consumption	**42.94**	**52.06**	**51.19**	**49.60**	**60.26**	**59.24**	**59.48**	**69.20**	**69.90**	**73.35**
Total consumption	**89.07**	**100.29**	**98.01**	**94.61**	**109.65**	**105.61**	**103.78**	**120.68**	**117.05**	**118.57**
Petroleum and other liquids production										
OPEC[5]										
Middle East	25.84	29.62	28.28	23.24	35.30	32.35	27.29	44.28	38.85	32.84
North Africa	3.36	3.74	3.19	2.95	3.99	3.43	3.25	4.62	3.96	3.69
West Africa	4.40	5.79	4.99	4.71	6.46	5.26	5.15	7.06	5.52	5.38
South America	2.99	3.56	3.10	2.98	4.13	3.01	2.98	5.10	3.31	3.24
Total OPEC production	**36.59**	**42.71**	**39.57**	**33.88**	**49.87**	**44.04**	**38.68**	**61.06**	**51.64**	**45.15**
Non-OPEC										
OECD										
United States (50 states)	10.84	13.63	14.25	15.30	11.73	13.23	14.19	10.63	12.42	13.52
Canada	4.00	5.18	5.10	6.00	6.15	5.92	7.24	5.77	6.21	7.81
Mexico and Chile	2.97	1.93	2.13	1.92	1.75	2.11	1.95	1.68	2.27	2.15
OECD Europe[2]	3.93	3.24	3.26	3.24	2.86	2.78	2.73	3.74	3.63	3.72
Japan and South Korea	0.18	0.18	0.16	0.17	0.20	0.18	0.18	0.21	0.19	0.19
Australia and New Zealand	0.57	0.53	0.54	0.52	0.56	0.56	0.55	0.83	0.92	0.93
Total OECD production	**22.48**	**24.69**	**25.44**	**27.15**	**23.25**	**24.78**	**26.84**	**22.85**	**25.64**	**28.31**
Non-OECD										
Russia	10.40	10.22	10.74	10.76	10.81	11.44	11.41	10.86	11.68	11.98
Other Europe and Eurasia[3]	3.19	3.86	3.73	3.89	4.02	4.44	4.50	3.56	5.44	5.54
China	4.37	4.49	4.91	4.56	5.51	5.50	5.80	5.63	5.62	8.43
Other Asia[4]	3.82	3.41	3.63	3.41	3.04	3.20	2.96	3.10	3.31	3.11
Middle East	1.31	1.19	0.98	1.18	1.07	0.77	1.03	0.95	0.71	0.95
Africa	2.34	2.91	2.61	2.95	2.97	2.57	2.96	3.32	2.91	3.41
Brazil	2.49	4.81	4.00	4.80	7.03	6.36	7.46	6.65	7.03	8.95
Other Central and South America	2.16	2.23	2.38	2.26	2.32	2.44	2.32	2.90	3.06	3.00
Total non-OECD production	**30.08**	**33.13**	**32.98**	**33.81**	**36.77**	**36.73**	**38.43**	**36.97**	**39.75**	**45.37**
Total petroleum and other liquids production	**89.15**	**100.53**	**97.99**	**94.84**	**109.89**	**105.55**	**103.95**	**120.89**	**117.03**	**118.83**
OPEC market share (percent)	41.0	42.5	40.4	35.7	45.4	41.7	37.2	50.5	44.1	38.0

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Table C6. International petroleum and other liquids supply, disposition, and prices (continued)

(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	2012	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Selected world production subtotals:										
Petroleum										
Crude oil and equivalents[6]	75.78	85.10	82.35	79.06	91.71	87.58	85.40	99.82	96.56	95.06
Tight oil	2.40	5.28	5.81	6.78	5.79	6.88	7.42	6.04	7.28	9.00
Bitumen[7]	1.94	3.18	3.00	3.87	4.29	3.95	5.19	3.99	4.26	5.71
Refinery processing gain[8]	2.37	2.40	2.26	2.11	2.70	2.52	2.32	3.00	2.86	2.52
Liquids from renewable sources[9]	1.34	1.83	1.68	1.91	2.79	2.09	2.52	4.10	2.48	4.21
Liquids from coal[10]	0.19	0.36	0.40	0.53	0.82	0.91	1.15	0.98	1.12	2.78
Liquids from natural gas	9.21	10.36	10.78	10.76	11.56	12.19	12.39	12.37	13.29	13.56
Natural gas plant liquids	9.05	10.06	10.46	10.47	11.24	11.84	12.07	12.05	12.93	13.10
Gas-to-liquids[11]	0.16	0.30	0.31	0.29	0.32	0.35	0.32	0.31	0.35	0.46
Liquids from kerogen[12]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Petroleum production[13]										
OPEC[5]										
Middle East	25.74	29.42	28.07	23.06	35.07	32.10	27.07	44.06	38.61	32.62
North Africa	3.36	3.74	3.19	2.95	3.99	3.43	3.25	4.62	3.96	3.69
West Africa	4.40	5.76	4.96	4.68	6.42	5.22	5.12	7.03	5.49	5.35
South America	2.99	3.56	3.10	2.98	4.13	3.01	2.98	5.10	3.31	3.24
Total OPEC production	**36.50**	**42.48**	**39.33**	**33.67**	**49.62**	**43.77**	**38.44**	**60.81**	**51.37**	**44.90**
Non-OPEC										
OECD										
United States (50 states)	10.00	12.66	13.28	14.37	10.75	12.24	13.24	9.64	11.42	12.15
Canada	3.97	5.15	5.08	5.97	6.09	5.88	7.19	5.69	6.17	7.73
Mexico and Chile	2.97	1.93	2.13	1.92	1.75	2.11	1.95	1.68	2.27	2.15
OECD Europe[2]	3.71	3.02	3.03	3.00	2.55	2.53	2.45	3.31	3.35	3.27
Japan and South Korea	0.17	0.18	0.15	0.16	0.19	0.17	0.17	0.19	0.18	0.18
Australia and New Zealand	0.56	0.52	0.53	0.51	0.54	0.55	0.54	0.81	0.91	0.91
Total OECD production	**21.39**	**23.46**	**24.21**	**25.93**	**21.87**	**23.49**	**25.55**	**21.32**	**24.30**	**26.39**
Non-OECD										
Russia	10.40	10.22	10.74	10.76	10.81	11.44	11.41	10.86	11.68	11.98
Other Europe and Eurasia[3]	3.19	3.85	3.73	3.89	4.01	4.44	4.49	3.55	5.43	5.53
China	4.32	4.35	4.77	4.27	4.76	4.82	4.83	4.60	4.72	6.04
Other Asia[4]	3.75	3.29	3.51	3.27	2.82	2.99	2.73	2.85	3.10	2.82
Middle East	1.31	1.19	0.98	1.18	1.07	0.77	1.03	0.95	0.71	0.95
Africa	2.13	2.61	2.28	2.61	2.66	2.22	2.58	3.02	2.55	3.01
Brazil	2.20	4.19	3.50	4.13	5.88	5.65	6.46	4.53	6.00	6.78
Other Central and South America	2.06	2.15	2.30	2.18	2.21	2.36	2.22	2.74	2.97	2.84
Total non-OECD production	**29.35**	**31.85**	**31.81**	**32.29**	**34.22**	**34.69**	**35.76**	**33.10**	**37.15**	**39.94**
Total petroleum production[13]	**87.24**	**97.79**	**95.34**	**91.90**	**105.71**	**101.95**	**99.75**	**115.23**	**112.82**	**111.23**
OPEC market share (percent)	41.8	43.4	41.2	36.6	46.9	42.9	38.5	52.8	45.5	40.4

[1]Estimated consumption. Includes both OPEC and non-OPEC consumers in the regional breakdown.
[2]OECD Europe - Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.
[3]Other Europe and Eurasia = Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Macedonia, Malta, Moldova, Montenegro, Romania, Serbia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan.
[4]Other Asia = Afghanistan, Bangladesh, Bhutan, Brunei, Cambodia (Kampuchea), Fiji, French Polynesia, Guam, Hong Kong, India (for production), Indonesia, Kiribati, Laos, Malaysia, Macau, Maldives, Mongolia, Myanmar (Burma), Nauru, Nepal, New Caledonia, Niue, North Korea, Pakistan, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Taiwan, Thailand, Tonga, Vanuatu, and Vietnam.
[5]OPEC = Organization of the Petroleum Exporting Countries - Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[6]Includes crude oil, lease condensate, tight oil (shale oil), extra-heavy oil, and bitumen (oil sands).
[7]Includes diluted and upgraded/synthetic bitumen (syncrude).
[8]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[9]Includes liquids produced from energy crops.
[10]Includes liquids converted from coal via the Fischer-Tropsch coal-to-liquids process.
[11]Includes liquids converted from natural gas via the Fischer-Tropsch natural-gas-to-liquids process.
[12]Includes liquids produced from kerogen (oil shale, not to be confused with tight oil (shale oil)).
[13]Includes production of crude oil (including lease condensate, tight oil (shale oil), extra-heavy oil, and bitumen (oil sands)), natural gas plant liquids, refinery gains, and other hydrogen and hydrocarbons for refinery feedstocks.
OECD = Organization for Economic Cooperation and Development.
Note: Ethanol is represented in motor gasoline equivalent barrels. Totals may not equal sum of components due to independent rounding. Data for 2012 are model results and may differ from official EIA data reports.
Sources: 2012 Brent and West Texas Intermediate crude oil spot prices: Thomson Reuters. **2012 quantities and projections:** Energy Information Administration (EIA), AEO2014 National Energy Modeling System runs LOWPRICE.D120613A, REF2014.D102413A, and HIGHPRICE.D120613A and EIA, Generate World Oil Balance Model.

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Appendix D

Results from side cases

Table D1. Key results for demand sector technology cases

Consumption, emissions, combined heat and power capacity and generation	2012	2020				2030			
		2013 Demand Technology	Reference	High Demand Technology	Best Available Demand Technology	2013 Demand Technology	Reference	High Demand Technology	Best Available Demand Technology
Energy consumption (quadrillion Btu)									
Residential									
Liquid fuels and other petroleum[1]	1.02	0.91	0.89	0.86	0.83	0.79	0.75	0.70	0.66
Natural gas	4.26	4.65	4.56	4.33	4.04	4.63	4.43	4.06	3.51
Renewable energy[2]	0.45	0.48	0.46	0.44	0.43	0.50	0.44	0.41	0.38
Electricity	4.69	5.00	4.84	4.47	4.15	5.56	5.21	4.53	4.13
Total residential	**10.42**	**11.04**	**10.74**	**10.10**	**9.45**	**11.48**	**10.83**	**9.70**	**8.68**
Nonmarketed renewables, residential	0.04	0.11	0.14	0.15	0.16	0.12	0.19	0.28	0.40
Commercial									
Liquid fuels and other petroleum[3]	0.63	0.68	0.68	0.67	0.67	0.67	0.67	0.65	0.65
Natural gas	2.96	3.23	3.23	3.20	3.20	3.32	3.35	3.34	3.31
Coal	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Renewable energy[4]	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Electricity	4.52	4.77	4.69	4.44	4.31	5.38	5.18	4.49	4.28
Total commercial	**8.29**	**8.86**	**8.78**	**8.50**	**8.35**	**9.55**	**9.38**	**8.66**	**8.42**
Nonmarketed renewables, commercial	0.13	0.18	0.18	0.22	0.23	0.20	0.24	0.35	0.43
Industrial[5]									
Liquefied petroleum gases and other[6]	2.25	2.91	2.90	2.88	2.91	3.07	3.05	3.04	3.07
Distillate fuel oil	1.20	1.46	1.40	1.36	1.38	1.54	1.41	1.35	1.39
Petrochemical feedstocks	0.75	1.29	1.27	1.27	1.28	1.65	1.62	1.60	1.63
Other petroleum[7]	3.86	4.12	4.00	3.92	3.99	4.26	4.02	3.92	4.03
Liquid fuels and other petroleum	8.06	9.77	9.56	9.43	9.56	10.53	10.10	9.92	10.12
Natural gas	8.75	10.41	10.04	10.07	10.04	11.70	10.87	10.89	10.90
Coal	1.48	1.62	1.57	1.54	1.58	1.64	1.52	1.46	1.57
Renewable energy[8]	2.00	2.47	2.50	2.54	2.51	2.72	2.79	2.94	2.82
Electricity	3.35	4.14	4.04	3.99	4.08	4.57	4.33	4.27	4.47
Total industrial	**23.63**	**28.42**	**27.71**	**27.57**	**27.77**	**31.17**	**29.62**	**29.47**	**29.88**
Transportation									
Motor gasoline[9]	16.33	14.99	15.00	14.88	15.00	12.64	12.69	12.54	12.71
of which: E85[10]	0.01	0.18	0.19	0.20	0.19	0.45	0.46	0.48	0.47
Jet fuel	3.00	3.08	3.08	3.06	3.08	3.20	3.20	3.16	3.20
Distillate fuel oil	5.82	6.70	6.70	6.58	6.68	7.20	7.25	7.08	7.32
Other petroleum[11]	0.77	0.78	0.78	0.77	0.78	0.80	0.80	0.79	0.80
Liquid fuels and other petroleum	25.93	25.55	25.55	25.30	25.53	23.84	23.94	23.57	24.04
Pipeline fuel natural gas	0.73	0.76	0.74	0.72	0.71	0.86	0.82	0.77	0.76
Compressed / liquefied natural gas	0.04	0.08	0.08	0.08	0.08	0.28	0.28	0.21	0.30
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.02	0.03	0.03	0.03	0.03	0.04	0.04	0.05	0.04
Total transportation	**26.72**	**26.42**	**26.40**	**26.13**	**26.36**	**25.02**	**25.08**	**24.59**	**25.14**
Electric power[12]									
Distillate and residual fuel oil	0.23	0.18	0.18	0.17	0.16	0.19	0.18	0.17	0.16
Natural gas	9.46	9.32	9.00	8.29	8.28	11.35	10.28	8.42	8.54
Steam coal	15.82	17.42	16.95	16.16	15.05	17.81	17.44	16.43	15.11
Nuclear / uranium[13]	8.05	8.15	8.15	8.15	8.15	8.20	8.18	8.15	8.15
Renewable energy[14]	4.59	6.15	6.08	5.69	5.55	7.17	6.68	6.18	6.02
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Net electricity imports	0.16	0.11	0.11	0.11	0.11	0.12	0.12	0.09	0.09
Total electric power	**38.53**	**41.56**	**40.70**	**38.81**	**37.54**	**45.07**	**43.12**	**39.68**	**38.30**
Total energy consumption									
Liquid fuels and other petroleum	35.87	37.09	36.86	36.42	36.76	36.02	35.65	35.01	35.63
Natural gas	26.20	28.45	27.65	26.69	26.35	32.14	30.03	27.68	27.31
Steam coal	17.34	19.08	18.56	17.74	16.67	19.50	19.01	17.93	16.73
Nuclear / uranium[13]	8.05	8.15	8.15	8.15	8.15	8.20	8.18	8.15	8.15
Renewable energy[15]	7.17	9.24	9.17	8.81	8.63	10.52	10.05	9.66	9.36
Other[16]	0.39	0.34	0.34	0.34	0.34	0.35	0.35	0.32	0.32
Total energy consumption	**95.02**	**102.35**	**100.73**	**98.16**	**96.90**	**106.74**	**103.27**	**98.76**	**97.50**

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2040				Annual Growth 2012-2040 (percent)			
2013 Demand Technology	Reference	High Demand Technology	Best Available Demand Technology	2013 Demand Technology	Reference	High Demand Technology	Best Available Demand Technology
0.72	0.66	0.60	0.55	-1.2%	-1.5%	-1.9%	-2.2%
4.54	4.21	3.75	3.02	0.2%	0.0%	-0.5%	-1.2%
0.50	0.42	0.36	0.33	0.4%	-0.3%	-0.8%	-1.2%
6.15	5.65	4.92	4.36	1.0%	0.7%	0.2%	-0.3%
11.91	**10.94**	**9.64**	**8.26**	**0.5%**	**0.2%**	**-0.3%**	**-0.8%**
0.13	0.27	0.48	0.79	4.3%	6.9%	9.1%	11.1%
0.68	0.68	0.65	0.65	0.2%	0.2%	0.1%	0.1%
3.53	3.65	3.69	3.63	0.6%	0.7%	0.8%	0.7%
0.04	0.04	0.04	0.04	0.0%	0.0%	0.0%	0.0%
0.13	0.13	0.13	0.13	0.0%	0.0%	0.0%	0.0%
6.27	5.72	4.71	4.48	1.2%	0.8%	0.2%	0.0%
10.66	**10.22**	**9.24**	**8.93**	**0.9%**	**0.7%**	**0.4%**	**0.3%**
0.23	0.35	0.59	0.75	2.2%	3.7%	5.6%	6.5%
2.95	2.90	2.88	2.91	1.0%	0.9%	0.9%	0.9%
1.61	1.42	1.36	1.39	1.1%	0.6%	0.4%	0.5%
1.65	1.59	1.57	1.60	2.9%	2.7%	2.7%	2.7%
4.53	4.19	4.08	4.19	0.6%	0.3%	0.2%	0.3%
10.74	10.10	9.89	10.10	1.0%	0.8%	0.7%	0.8%
12.47	11.28	11.24	11.27	1.3%	0.9%	0.9%	0.9%
1.62	1.44	1.38	1.51	0.3%	-0.1%	-0.3%	0.1%
2.92	3.07	3.32	3.09	1.4%	1.5%	1.8%	1.6%
4.78	4.34	4.24	4.51	1.3%	0.9%	0.8%	1.1%
32.53	**30.22**	**30.06**	**30.47**	**1.1%**	**0.9%**	**0.9%**	**0.9%**
12.05	12.09	12.07	12.18	-1.1%	-1.1%	-1.1%	-1.0%
0.34	0.33	0.35	0.35	11.9%	11.9%	12.0%	12.1%
3.28	3.28	3.17	3.28	0.3%	0.3%	0.2%	0.3%
7.51	7.54	7.55	7.63	0.9%	0.9%	0.9%	1.0%
0.82	0.82	0.81	0.82	0.2%	0.2%	0.2%	0.2%
23.66	23.73	23.61	23.91	-0.3%	-0.3%	-0.3%	-0.3%
0.89	0.85	0.77	0.77	0.7%	0.5%	0.2%	0.2%
0.79	0.86	0.54	0.95	11.0%	11.3%	9.5%	11.7%
0.00	0.00	0.00	0.00	--	--	--	--
0.06	0.06	0.07	0.06	3.6%	3.6%	3.9%	3.6%
25.41	**25.50**	**24.99**	**25.70**	**-0.2%**	**-0.2%**	**-0.2%**	**-0.1%**
0.20	0.19	0.17	0.16	-0.5%	-0.8%	-1.1%	-1.3%
12.38	11.48	9.08	9.24	1.0%	0.7%	-0.1%	-0.1%
17.75	17.27	16.35	15.05	0.4%	0.3%	0.1%	-0.2%
9.32	8.49	8.25	8.15	0.5%	0.2%	0.1%	0.0%
9.30	7.44	6.51	6.33	2.6%	1.7%	1.3%	1.2%
0.23	0.23	0.23	0.23	0.0%	0.0%	0.0%	0.0%
0.14	0.12	0.10	0.10	-0.4%	-1.1%	-1.6%	-1.8%
49.32	**45.20**	**40.69**	**39.26**	**0.9%**	**0.6%**	**0.2%**	**0.1%**
36.00	35.35	34.91	35.37	0.0%	-0.1%	-0.1%	-0.1%
34.61	32.32	29.08	28.88	1.0%	0.8%	0.4%	0.3%
19.41	18.75	17.77	16.60	0.4%	0.3%	0.1%	-0.2%
9.32	8.49	8.25	8.15	0.5%	0.2%	0.1%	0.0%
12.86	11.05	10.32	9.88	2.1%	1.6%	1.3%	1.2%
0.37	0.35	0.33	0.33	-0.1%	-0.4%	-0.5%	-0.6%
112.56	**106.31**	**100.67**	**99.21**	**0.6%**	**0.4%**	**0.2%**	**0.2%**

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Table D1. Key results for demand sector technology cases (continued)

Consumption, emissions, combined heat and power capacity and generation	2012	2020				2030			
		2013 Demand Technology	Reference	High Demand Technology	Best Available Demand Technology	2013 Demand Technology	Reference	High Demand Technology	Best Available Demand Technology
Carbon dioxide emissions (million metric tons)									
by sector									
Residential	295	308	302	288	271	300	286	263	231
Commercial	206	224	224	222	222	228	230	228	226
Industrial[5]	937	1,094	1,060	1,054	1,061	1,183	1,107	1,097	1,114
Transportation	1,812	1,779	1,777	1,759	1,775	1,672	1,677	1,644	1,681
Electric power[12]	2,039	2,174	2,112	2,000	1,892	2,318	2,227	2,031	1,911
by fuel									
Petroleum[17]	2,254	2,263	2,252	2,226	2,244	2,152	2,136	2,098	2,133
Natural gas	1,366	1,489	1,447	1,396	1,378	1,684	1,572	1,448	1,428
Coal	1,657	1,815	1,766	1,688	1,586	1,854	1,807	1,705	1,590
Other[18]	12	12	12	12	12	12	12	12	12
Total carbon dioxide emissions	**5,290**	**5,579**	**5,476**	**5,322**	**5,220**	**5,702**	**5,527**	**5,263**	**5,163**
Residential delivered energy intensity (million Btu per household)	91.5	90.5	88.1	82.8	77.5	86.4	81.5	73.0	65.3
Commercial delivered energy intensity (thousand Btu per square foot)	100.7	99.4	98.5	95.3	93.7	97.3	95.6	88.2	85.8
Industrial delivered energy intensity (thousand Btu per 2005 dollar)	3.84	3.57	3.48	3.46	3.48	3.29	3.11	3.06	3.09
Residential sector net summer capacity (megawatts)									
Natural gas	0	0	0	0	0	0	0	0	0
Solar photovoltaic	1,553	5,330	6,327	6,867	7,904	5,638	9,364	14,807	22,999
Wind	55	186	590	644	737	186	590	644	737
Residential sector electricity generation (billion kilowatthours)									
Natural gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar photovoltaic	2.48	8.29	9.96	10.81	12.47	8.80	14.92	23.67	36.77
Wind	0.07	0.26	0.82	0.89	1.00	0.26	0.82	0.89	1.00
Commercial sector net summer capacity (megawatts)									
Natural gas	1,041	1,638	1,770	2,132	2,177	3,085	4,206	5,921	5,959
Solar photovoltaic	3,155	6,205	6,417	6,731	7,566	7,170	9,561	12,978	18,279
Wind	97	104	109	108	109	160	307	309	303
Commercial sector electricity generation (billion kilowatthours)									
Natural gas	7.57	11.91	12.87	15.50	15.83	22.43	30.59	43.07	43.35
Solar photovoltaic	4.86	9.53	9.94	10.46	11.80	11.07	15.16	20.63	28.99
Wind	0.12	0.13	0.14	0.14	0.14	0.22	0.43	0.43	0.43

[1]Includes propane, kerosene, and distillate fuel oil.
[2]Includes wood used for residential heating. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[3]Includes propane, motor gasoline (including ethanol and ethers), kerosene, distillate fuel oil, and residual fuel oil.
[4]Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[5]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[6]Includes ethane, natural gasoline, and refinery olefins.
[7]Includes motor gasoline (including ethanol and ethers), residual fuel oil, petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[8]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol.
[9]Includes ethanol and ethers blended into gasoline.
[10]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[11]Includes propane, residual fuel oil, aviation gasoline, and lubricants.
[12]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[13]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[14]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[16]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[17]This includes carbon dioxide from international bunker fuels, both civilian and military, which are excluded from the accounting of carbon dioxide emissions under the United Nations convention. From 1990 through 2012, international bunker fuels accounted for 90 to 126 million metric tons annually.
[18]Includes emissions from geothermal power and emissions from non-biogenic municipal waste.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 are model results and may differ from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2014 National Energy Modeling System, runs FROZTECH.D121813A, REF2014.D102413A, HIGHTECH.D121813A, and BESTTECH.D121813A.

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2040				Annual Growth 2012-2040 (percent)			
2013 Demand Technology	Reference	High Demand Technology	Best Available Demand Technology	2013 Demand Technology	Reference	High Demand Technology	Best Available Demand Technology
289	268	240	197	-0.1%	-0.4%	-0.7%	-1.4%
240	246	246	242	0.5%	0.6%	0.6%	0.6%
1,235	1,123	1,110	1,128	1.0%	0.6%	0.6%	0.7%
1,685	1,691	1,660	1,703	-0.3%	-0.2%	-0.3%	-0.2%
2,361	2,271	2,057	1,941	0.5%	0.4%	0.0%	-0.2%
2,145	2,113	2,090	2,113	-0.2%	-0.2%	-0.3%	-0.2%
1,811	1,694	1,523	1,512	1.0%	0.8%	0.4%	0.4%
1,842	1,780	1,687	1,576	0.4%	0.3%	0.1%	-0.2%
12	12	12	12	0.0%	0.0%	0.0%	0.0%
5,810	**5,599**	**5,313**	**5,213**	**0.3%**	**0.2%**	**0.0%**	**-0.1%**
83.3	76.5	67.4	57.7	-0.3%	-0.6%	-1.1%	-1.6%
97.9	93.9	84.8	82.0	-0.1%	-0.3%	-0.6%	-0.7%
2.98	2.75	2.71	2.73	-0.9%	-1.2%	-1.2%	-1.2%
1	1	1	1	--	--	--	--
6,283	14,366	27,180	47,373	5.1%	8.3%	10.8%	13.0%
186	610	667	794	4.4%	8.9%	9.3%	10.0%
0.00	0.00	0.00	0.00	--	--	--	--
9.82	23.12	43.67	75.94	5.0%	8.3%	10.8%	13.0%
0.26	0.85	0.92	1.09	4.6%	9.1%	9.4%	10.0%
5,691	9,752	14,094	13,792	6.3%	8.3%	9.7%	9.6%
9,341	15,094	23,123	33,742	4.0%	5.7%	7.4%	8.8%
396	814	944	1,114	5.2%	7.9%	8.5%	9.1%
41.40	70.94	102.53	100.33	6.3%	8.3%	9.7%	9.6%
14.54	24.33	36.99	53.91	4.0%	5.9%	7.5%	9.0%
0.56	1.16	1.34	1.57	5.6%	8.3%	8.9%	9.5%

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Table D2. Key results for policy extension cases

Consumption, emissions, electricity generating capacity and generation, and prices	2012	2020			2030			2040		
		Reference	No Sunset	Extended Policies	Reference	No Sunset	Extended Policies	Reference	No Sunset	Extended Policies
Energy consumption (quadrillion Btu)										
Residential										
Liquid fuels and other petroleum[1]	1.02	0.89	0.88	0.89	0.75	0.75	0.75	0.66	0.66	0.65
Natural gas	4.26	4.56	4.52	4.54	4.43	4.34	4.24	4.21	4.07	3.89
Renewable energy[2]	0.45	0.46	0.46	0.46	0.44	0.44	0.44	0.42	0.41	0.41
Electricity	4.69	4.84	4.79	4.79	5.21	5.02	4.80	5.65	5.36	4.96
Total residential	**10.42**	**10.74**	**10.65**	**10.67**	**10.83**	**10.55**	**10.22**	**10.94**	**10.50**	**9.91**
Commercial										
Liquid fuels and other petroleum[3]	0.63	0.68	0.68	0.68	0.67	0.67	0.67	0.68	0.68	0.67
Natural gas	2.96	3.23	3.23	3.22	3.35	3.38	3.35	3.65	3.72	3.65
Coal	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Renewable energy[4]	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Electricity	4.52	4.69	4.69	4.68	5.18	5.16	5.10	5.72	5.69	5.62
Total commercial	**8.29**	**8.78**	**8.78**	**8.76**	**9.38**	**9.39**	**9.29**	**10.22**	**10.27**	**10.11**
Industrial[5]										
Liquid fuels and other petroleum[6]	8.06	9.56	9.56	9.55	10.10	10.13	10.06	10.10	10.15	9.94
Natural gas	8.75	10.04	10.03	10.05	10.87	10.94	10.93	11.28	11.42	11.36
Coal	1.48	1.57	1.56	1.56	1.52	1.53	1.53	1.44	1.46	1.46
Renewable energy[7]	2.00	2.50	2.50	2.49	2.79	2.81	2.80	3.07	3.08	3.07
Electricity	3.35	4.04	4.04	4.03	4.33	4.35	4.35	4.34	4.38	4.37
Total industrial	**23.63**	**27.71**	**27.68**	**27.68**	**29.62**	**29.76**	**29.68**	**30.22**	**30.49**	**30.19**
Transportation										
Liquid fuels and other petroleum[8]	25.93	25.55	25.54	25.51	23.94	23.96	23.56	23.73	23.80	22.33
Pipeline fuel natural gas	0.73	0.74	0.74	0.75	0.82	0.81	0.80	0.85	0.80	0.80
Compressed / liquefied natural gas	0.04	0.08	0.08	0.08	0.28	0.28	0.26	0.86	0.91	0.94
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.02	0.03	0.03	0.03	0.04	0.04	0.05	0.06	0.06	0.12
Total transportation	**26.72**	**26.40**	**26.40**	**26.37**	**25.08**	**25.10**	**24.68**	**25.50**	**25.58**	**24.19**
Electric power[9]										
Distillate and residual fuel oil	0.23	0.18	0.18	0.18	0.18	0.18	0.18	0.19	0.18	0.18
Natural gas	9.46	9.00	9.26	9.26	10.28	9.76	9.54	11.48	9.11	8.88
Steam coal	15.82	16.95	16.77	16.75	17.44	17.23	17.10	17.27	17.13	16.99
Nuclear / uranium[10]	8.05	8.15	8.15	8.15	8.18	8.15	8.15	8.49	8.15	8.15
Renewable energy[11]	4.59	6.08	5.73	5.71	6.68	7.21	6.86	7.44	10.62	9.81
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Net electricity imports	0.16	0.11	0.11	0.11	0.12	0.11	0.10	0.12	0.11	0.10
Total electric power	**38.53**	**40.70**	**40.43**	**40.37**	**43.12**	**42.88**	**42.15**	**45.20**	**45.53**	**44.34**
Total energy consumption										
Liquid fuels and other petroleum	35.87	36.86	36.84	36.80	35.65	35.70	35.21	35.35	35.47	33.76
Natural gas	26.20	27.65	27.87	27.89	30.03	29.52	29.12	32.32	30.03	29.51
Steam coal	17.34	18.56	18.38	18.35	19.01	18.81	18.67	18.75	18.63	18.49
Nuclear / uranium[10]	8.05	8.15	8.15	8.15	8.18	8.15	8.15	8.49	8.15	8.15
Renewable energy[12]	7.17	9.17	8.81	8.79	10.05	10.59	10.23	11.05	14.25	13.42
Other[13]	0.39	0.34	0.34	0.34	0.35	0.34	0.33	0.35	0.34	0.33
Total energy consumption	**95.02**	**100.73**	**100.39**	**100.32**	**103.27**	**103.11**	**101.72**	**106.31**	**106.88**	**103.67**
Carbon dioxide emissions (million metric tons)										
by sector										
Residential	295	302	300	301	286	281	275	268	260	250
Commercial	206	224	224	223	230	231	229	246	250	245
Industrial[5]	937	1,060	1,059	1,060	1,107	1,113	1,108	1,123	1,134	1,116
Transportation	1,812	1,777	1,776	1,775	1,677	1,676	1,648	1,691	1,694	1,595
Electric power[9]	2,039	2,112	2,109	2,106	2,227	2,179	2,155	2,271	2,132	2,107
by fuel										
Petroleum[14]	2,254	2,252	2,249	2,249	2,136	2,135	2,104	2,113	2,117	2,001
Natural gas	1,366	1,447	1,459	1,460	1,572	1,545	1,524	1,694	1,573	1,545
Coal	1,657	1,766	1,748	1,746	1,807	1,788	1,775	1,780	1,768	1,755
Other[15]	12	12	12	12	12	12	12	12	12	12
Total carbon dioxide emissions	**5,290**	**5,476**	**5,468**	**5,466**	**5,527**	**5,480**	**5,415**	**5,599**	**5,469**	**5,313**

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Table D2. Key results for policy extension cases (continued)

Consumption, emissions, electricity generating capacity and generation, and prices	2012	2020			2030			2040		
		Reference	No Sunset	Extended Policies	Reference	No Sunset	Extended Policies	Reference	No Sunset	Extended Policies
Electricity generating capacity (gigawatts)	**1,066**	**1,069**	**1,056**	**1,053**	**1,168**	**1,184**	**1,156**	**1,316**	**1,414**	**1,350**
Electric power sector[9]	1,032	1,022	1,000	996	1,105	1,084	1,055	1,228	1,262	1,198
Coal	307	259	255	253	258	254	252	258	254	252
Oil and natural gas steam	100	86	84	82	72	70	65	70	67	62
Combined-cycle	212	231	231	233	286	262	261	342	287	281
Combustion turbine / diesel	140	150	148	147	184	173	164	224	208	186
Nuclear / uranium	102	98	98	98	98	98	98	102	98	98
Pumped storage	22	22	22	22	22	22	22	22	22	22
Renewable sources	149	174	161	161	180	203	191	201	321	292
of which: Solar	3	10	9	9	10	19	17	19	66	58
of which: Wind	59	76	62	62	76	90	80	85	159	138
Distributed generation	0	2	1	1	5	3	2	9	5	4
Residential and commercial sectors	7	16	25	25	25	60	60	41	103	103
of which: Natural gas	1	2	2	2	4	5	4	10	10	10
of which: Solar photovoltaic	5	13	21	21	19	49	49	29	81	81
of which: Wind	0	1	1	2	1	5	5	1	11	11
Industrial sector[5]	27	31	32	32	39	40	41	46	49	49
of which: Natural gas	15	17	18	18	23	25	25	29	32	32
Cumulative capacity additions (gigawatts)	**0**	**87**	**80**	**81**	**201**	**224**	**203**	**351**	**458**	**401**
Cumulative capacity retirements (gigawatts)	**0**	**78**	**85**	**89**	**94**	**101**	**108**	**97**	**105**	**111**
Generation by fuel (billion kilowatthours)	**4,054**	**4,402**	**4,400**	**4,399**	**4,815**	**4,819**	**4,742**	**5,219**	**5,243**	**5,116**
Electric power sector[9]	3,890	4,193	4,175	4,173	4,540	4,479	4,400	4,844	4,753	4,628
Coal	1,499	1,632	1,616	1,614	1,678	1,660	1,647	1,661	1,649	1,637
Petroleum	20	16	16	16	16	16	16	16	16	16
Natural gas	1,133	1,155	1,189	1,191	1,391	1,296	1,266	1,605	1,231	1,199
Nuclear / uranium	769	779	779	779	782	779	779	811	779	779
Pumped storage / other	6	3	3	3	3	3	3	3	3	3
Renewable sources	463	607	571	569	668	723	687	743	1,072	992
of which: Wood and other biomass	11	37	43	42	68	60	59	72	64	65
of which: Solar	4	18	17	17	20	40	35	39	147	129
of which: Wind	142	218	172	172	219	258	229	248	480	417
Distributed generation	0	1	1	1	2	2	2	4	3	2
Residential and commercial sectors	20	38	53	53	66	123	123	125	225	222
of which: Natural gas	8	13	13	13	31	33	33	71	75	73
of which: Solar photovoltaic	7	20	33	33	30	79	79	47	129	129
of which: Wind	0	1	2	2	1	7	7	2	15	15
Industrial sector[5]	145	171	172	173	209	216	218	251	265	266
of which: Natural gas	88	99	101	102	128	135	137	160	174	175
Delivered natural gas prices (2012 dollars per thousand cubic feet)										
Residential	10.69	11.85	11.89	11.98	13.80	13.65	13.62	16.33	15.62	15.77
Commercial	8.29	9.70	9.73	9.83	11.44	11.25	11.11	13.37	12.65	12.56
Industrial[5]	3.85	5.92	5.94	6.06	7.14	6.96	6.81	8.78	8.28	8.23
Electric power[9]	3.51	5.19	5.21	5.32	6.64	6.43	6.27	8.34	7.70	7.65
Average electricity price (2012 cents per kilowatthour)	9.8	10.1	10.1	10.1	10.4	10.3	10.2	11.1	10.7	10.6

[1]Includes propane, kerosene, and distillate fuel oil.
[2]Includes wood used for residential heating. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[3]Includes propane, motor gasoline (including ethanol and ethers), kerosene, distillate fuel oil, and residual fuel oil.
[4]Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[5]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[6]Includes motor gasoline (including ethanol and ethers), residual fuel oil, petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[7]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol.
[8]Includes propane, motor gasoline, ethanol and ethers, jet fuel, distillate fuel oil, residual fuel oil, aviation gasoline, and lubricants.
[9]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[10]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[11]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources.
[12]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[13]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[14]This includes carbon dioxide from international bunker fuels, both civilian and military, which are excluded from the accounting of carbon dioxide emissions under the United Nations convention. From 1990 through 2012, international bunker fuels accounted for 90 to 126 million metric tons annually.
[15]Includes emissions from geothermal power and emissions from non-biogenic municipal waste.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 are model results and may differ from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2014 National Energy Modeling System, runs REF2014.D102413A, NOSUNSET.D121713A, and EXTENDED.D022814A.

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Table D3. Key results for accelerated power plant retirement and nuclear plant cases

(gigawatts, unless otherwise noted)

Net summer capacity, generation, emissions, and fuel prices	2012	2040					
		High Nuclear	Reference	Accelerated Coal Retirements	Accelerated Nuclear Retirements	Accelerated Coal and Nuclear Retirements	Low Nuclear
Capacity							
Coal steam	306.6	258.3	258.4	198.8	260.0	204.7	239.1
Oil and natural gas steam	100.4	70.5	69.6	65.3	67.4	64.7	75.2
Combined cycle	211.9	331.5	342.2	383.9	373.7	406.9	406.1
Combustion turbine / diesel	139.8	221.9	223.7	221.1	223.5	220.7	229.4
Nuclear / uranium	102.1	119.7	102.0	104.1	60.4	60.4	25.2
Pumped storage	22.4	22.4	22.4	22.4	22.4	22.4	22.4
Fuel cells	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Renewable sources	148.9	199.4	200.5	202.1	213.9	211.6	200.8
Distributed generation	0.0	9.1	8.9	6.0	8.9	5.5	12.6
Combined heat and power[1]	33.8	86.4	87.7	95.3	89.8	97.5	152.5
Total	**1,065.8**	**1,319.4**	**1,315.6**	**1,299.1**	**1,319.8**	**1,294.4**	**1,363.3**
Cumulative additions							
Coal steam	0.0	2.6	2.6	2.5	4.2	2.5	2.5
Oil and natural gas steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined cycle	0.0	119.9	130.6	172.3	162.1	195.3	194.5
Combustion turbine / diesel	0.0	91.4	93.2	90.8	93.1	90.6	99.0
Nuclear / uranium	0.0	16.4	9.7	11.8	5.5	5.5	5.5
Pumped storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable sources	0.0	51.4	52.5	54.1	65.8	63.5	52.8
Distributed generation	0.0	9.1	8.9	6.0	8.9	5.5	12.6
Combined heat and power[1]	0.0	52.6	53.9	61.5	56.0	63.8	118.7
Total	**0.0**	**343.5**	**351.5**	**399.1**	**395.8**	**426.8**	**485.6**
Cumulative retirements	**0.0**	**95.9**	**96.7**	**160.8**	**136.8**	**193.2**	**183.2**
Generation by fuel (billion kilowatthours)							
Coal	1,499	1,659	1,661	1,118	1,672	1,178	1,504
Petroleum	20	16	16	14	16	15	16
Natural gas	1,133	1,493	1,605	1,922	1,834	2,114	2,413
Nuclear / uranium	769	951	811	827	483	483	201
Pumped storage / other	6	3	3	3	3	3	3
Renewable sources	463	739	743	820	782	849	727
Distributed generation	0	4	4	3	5	3	34
Combined heat and power[1]	165	371	375	404	383	412	505
Total	**4,054**	**5,238**	**5,219**	**5,111**	**5,178**	**5,056**	**5,404**
Carbon dioxide emissions by the electric power sector (million metric tons)[2]							
Petroleum	19	14	14	13	14	13	14
Natural gas	494	570	608	714	684	780	914
Coal	1,514	1,635	1,637	1,082	1,646	1,142	1,479
Other[3]	12	12	12	12	12	12	12
Total	**2,039**	**2,231**	**2,271**	**1,821**	**2,356**	**1,946**	**2,418**
Prices to the electric power sector[2] (2012 dollars per million Btu)							
Petroleum	21.46	24.25	24.30	23.83	24.29	23.91	21.23
Natural gas	3.44	7.87	8.16	8.60	8.57	9.03	5.43
Coal	2.39	3.18	3.19	5.14	3.20	5.20	3.01
Average electricity price (2012 cents per kilowatthour)	**9.8**	**11.0**	**11.1**	**12.0**	**11.5**	**12.5**	**9.9**

[1]Includes combined heat and power plants and electricity-only plants in commercial and industrial sectors that have a non-regulatory status. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[2]Includes electricity-only and combined heat and power plants that have a regulatory status.
[3]Includes emissions from geothermal power and nonbiogenic emissions from municipal solid waste.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 are model results and may differ from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2014 National Energy Modeling System runs HINUC14.D120313A, REF2014.D102413A, HCCSTOM.D012314A, LOWNUC14.D012314B, HCLONUC.D012314A, and ALTLOWNUC14.D012314C.

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Table D4. Key results for renewable technology case

Capacity, generation, and emissions	2012	2020		2030		2040	
		Reference	Low Renewable Technology Cost	Reference	Low Renewable Technology Cost	Reference	Low Renewable Technology Cost
Net summer capacity (gigawatts)							
Electric power sector[1]							
Conventional hydropower	78.10	78.41	79.55	79.75	80.50	80.35	82.00
Geothermal[2]	2.58	4.02	4.28	6.58	6.66	8.80	9.07
Municipal waste[3]	3.57	3.63	3.63	3.63	3.63	3.63	3.63
Wood and other biomass[4]	2.70	3.14	3.14	3.14	3.26	3.46	4.56
Solar thermal	0.48	1.73	1.73	1.73	1.73	1.73	1.73
Solar photovoltaic[5]	2.49	7.90	14.63	8.62	20.83	17.07	56.34
Wind	59.01	75.59	77.27	76.12	82.63	85.48	119.92
Total	**148.92**	**174.43**	**184.23**	**179.56**	**199.24**	**200.52**	**277.26**
End-use sector[6]							
Conventional hydropower	0.29	0.29	0.29	0.29	0.29	0.29	0.29
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal waste[7]	0.47	0.47	0.47	0.47	0.47	0.47	0.47
Wood and other biomass	4.89	6.27	6.92	7.95	9.86	9.62	13.35
Solar photovoltaic[5]	4.71	12.75	13.89	18.93	25.65	29.47	43.27
Wind	0.15	0.70	1.21	0.90	1.70	1.42	3.38
Total	**10.51**	**20.48**	**22.77**	**28.53**	**37.97**	**41.26**	**60.75**
Generation (billion kilowatthours)							
Electric power sector[1]							
Coal	1,499	1,632	1,602	1,678	1,656	1,661	1,644
Petroleum	20	16	16	16	16	16	17
Natural gas	1,133	1,155	1,132	1,391	1,337	1,605	1,405
Total fossil	**2,651**	**2,803**	**2,750**	**3,085**	**3,009**	**3,282**	**3,066**
Conventional hydropower	273.89	287.67	293.48	294.35	297.83	297.34	303.30
Geothermal	15.56	28.24	30.34	49.04	49.86	67.26	69.62
Municipal waste[8]	16.79	19.05	18.67	18.15	18.53	19.21	19.12
Wood and other biomass[4]	11.04	36.71	63.30	67.50	85.07	72.22	93.42
Dedicated plants	9.84	15.31	15.86	16.17	17.43	18.99	27.03
Cofiring	1.20	21.40	47.44	51.33	67.64	53.23	66.39
Solar thermal	0.90	3.52	3.52	3.53	3.53	3.53	3.53
Solar photovoltaic[5]	3.25	14.54	30.06	16.07	44.82	35.24	128.36
Wind	141.87	217.53	223.15	219.06	237.99	248.02	354.74
Total renewable	**463.29**	**607.26**	**662.52**	**667.71**	**737.62**	**742.82**	**972.09**
End-use sector[6]							
Total fossil	**112**	**128**	**128**	**175**	**173**	**247**	**247**
Conventional hydropower	1.38	1.38	1.38	1.38	1.38	1.38	1.38
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal waste[7]	3.65	3.63	3.63	3.63	3.63	3.63	3.63
Wood and other biomass	26.53	34.10	37.75	43.75	54.79	53.50	75.17
Solar photovoltaic[5]	7.35	19.91	21.75	30.09	40.94	47.46	69.49
Wind	0.20	0.96	1.62	1.25	2.33	2.01	4.67
Total renewable	**39.11**	**59.98**	**66.13**	**80.10**	**103.07**	**107.99**	**154.34**

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Table D4. Key results for renewable technology case (continued)

Capacity, generation, and emissions	2012	2020		2030		2040	
		Reference	Low Renewable Technology Cost	Reference	Low Renewable Technology Cost	Reference	Low Renewable Technology Cost
Carbon dioxide emissions by the electric power sector (million metric tons)[1]							
Coal	1,514	1,609	1,580	1,656	1,634	1,637	1,621
Petroleum	19	13	13	14	14	14	14
Natural gas	494	478	469	545	530	608	541
Other [9]	12	12	12	12	12	12	12
Total	**2,039**	**2,112**	**2,073**	**2,227**	**2,189**	**2,271**	**2,188**

[1]Includes electricity-only and combined heat and power plants that have a regulatory status.
[2]Includes both hydrothermal resources (hot water and steam) and near-field enhanced geothermal systems (EGS). Near-field EGS potential occurs on known hydrothermal sites, however this potential requires the addition of external fluids for electricity generation and is only available after 2025.
[3]Includes all municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[4]Facilities co-firing biomass and coal are classified as coal.
[5]Does not include off-grid photovoltaics (PV). Based on annual PV shipments from 1989 through 2012, EIA estimates that as much as 274 megawatts of remote electricity generation PV applications (i.e., off-grid power systems) were in service in 2012, plus an additional 573 megawatts in communications, transportation, and assorted other non-grid-connected, specialized applications. See U.S. Energy Information Administration, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012), Table 10.9 (annual PV shipments, 1989-2010), and Table 12 (U.S. photovoltaic module shipments by end use, sector, and type) in U.S. Energy Information Administration, *Solar Photovoltaic Cell/Module Shipments Report, 2011* (Washington, DC, September 2012) and U.S. Energy Information Administration, *Solar Photovoltaic Cell/Module Shipments Report, 2012* (Washington, DC, December 2013). The approach used to develop the estimate, based on shipment data, provides an upper estimate of the size of the PV stock, including both grid-based and off-grid PV. It will overestimate the size of the stock, because shipments include a substantial number of units that are exported, and each year some of the PV units installed earlier will be retired from service or abandoned.
[6]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors that have a non-regulatory status. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[7]Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[8]Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. Only biogenic municipal waste is included. The U.S. Energy Information Administration estimates that in 2012 approximately 7 billion kilowatthours of electricity were generated from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See U.S. Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy* (Washington, DC, May 2007).
[9]Includes emissions from geothermal power and nonbiogenic emissions from municipal solid waste.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 are model results and may differ from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2014 National Energy Modeling System runs REF2014.D102413A, and LCR_2014.D120613A.

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Table D5. Key results for enviornmental cases

Net summer capacity, generation, emissions, fuel prices, and coal production	2012	2030					2040				
		Reference	GHG10	GHG25	High Oil and Gas Resource	GHG10 and Low Gas Prices	Reference	GHG10	GHG25	High Oil and Gas Resource	GHG10 and Low Gas Prices
Capacity (gigawatts)											
Coal steam	306.6	258.4	208.4	52.6	243.8	163.2	258.4	176.7	19.1	243.8	127.4
Oil and natural gas steam	100.4	72.1	64.8	42.4	81.2	65.9	69.6	55.2	31.2	79.8	60.4
Combined cycle	211.9	285.6	313.4	381.6	294.4	372.6	342.2	365.4	420.7	382.3	477.5
Combustion turbine / diesel	139.8	184.0	178.8	185.8	202.4	191.1	223.7	206.1	179.4	241.2	218.4
Nuclear / uranium	102.1	98.2	101.3	142.1	97.8	97.8	102.0	141.8	231.6	97.8	111.0
Pumped storage	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4
Renewable sources	148.9	179.6	200.5	312.6	170.1	183.5	200.5	279.8	363.1	177.4	227.5
Distributed generation	0.0	4.6	1.5	0.3	7.6	2.4	8.9	2.9	0.3	17.8	4.8
Combined heat and power[1]	33.8	63.4	67.1	75.5	64.0	67.6	87.7	96.4	109.3	86.9	95.2
Total	**1,065.8**	**1,168.2**	**1,158.4**	**1,215.2**	**1,183.7**	**1,166.5**	**1,315.6**	**1,346.6**	**1,377.3**	**1,349.5**	**1,344.4**
Cumulative additions (gigawatts)											
Coal steam	0.0	2.5	2.5	2.5	2.5	2.5	2.6	2.5	2.5	2.5	2.5
Combined cycle	0.0	74.0	101.8	170.0	82.8	160.9	130.6	153.8	209.1	170.7	265.9
Combustion turbine / diesel	0.0	53.0	48.3	59.8	70.7	60.1	93.2	77.2	75.2	110.0	88.2
Nuclear / uranium	0.0	5.8	9.0	49.8	5.5	5.5	9.7	49.4	139.3	5.5	18.7
Renewable sources	0.0	31.6	52.5	164.6	22.1	35.5	52.5	131.8	215.1	29.4	79.5
Distributed generation	0.0	4.6	1.5	0.3	7.6	2.4	8.9	2.9	0.3	17.8	4.8
Combined heat and power[1]	0.0	29.7	33.4	41.7	30.2	33.8	53.9	62.6	75.6	53.2	61.4
Total	**0.0**	**201.1**	**249.0**	**488.6**	**221.4**	**300.8**	**351.5**	**480.2**	**717.2**	**389.1**	**520.9**
Cumulative retirements (gigawatts)	**0.0**	**93.8**	**151.4**	**334.1**	**98.5**	**195.2**	**96.7**	**194.5**	**400.6**	**100.4**	**237.3**
Generation by fuel (billion kilowatthours)											
Coal	1,499	1,678	1,255	241	1,544	834	1,661	964	48	1,445	460
Petroleum	20	16	15	10	16	13	16	14	9	16	12
Natural gas	1,133	1,391	1,531	1,780	1,647	2,148	1,605	1,489	1,405	2,108	2,623
Nuclear / uranium	769	782	802	1,114	779	779	811	1,116	1,819	779	879
Pumped storage / other	6	3	3	3	3	3	3	3	3	3	3
Renewable sources	463	668	794	1,044	631	717	743	1,074	1,185	672	847
Distributed generation	0	2	1	0	22	1	4	1	0	48	2
Combined heat and power[1]	165	276	287	313	283	295	375	400	432	385	411
Total	**4,054**	**4,815**	**4,689**	**4,505**	**4,924**	**4,791**	**5,219**	**5,060**	**4,902**	**5,456**	**5,237**
Retrofits (gigawatts)											
Scrubber	0.00	31.99	23.25	22.94	28.71	23.03	31.99	23.25	22.94	28.71	23.03
Nitrogen oxide controls											
Combustion	0.00	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78
Selective catalytic reduction post-combustion	0.00	10.33	11.11	11.71	10.29	10.25	10.33	11.97	11.71	10.29	10.68
Selective non-catalytic reduction post-combustion	0.00	3.04	3.04	3.04	3.04	3.04	3.04	4.49	3.04	3.04	3.78
Emissions by the electric power sector[2]											
Sulfur dioxide (million short tons)	3.34	1.58	1.09	0.24	1.37	0.67	1.61	0.84	0.03	1.32	0.38
Nitrogen oxides (million short tons)	1.68	1.59	1.16	0.37	1.44	0.78	1.60	0.94	0.24	1.39	0.55
Mercury (short tons)	26.35	6.69	4.90	1.15	6.07	3.24	6.81	3.90	0.28	5.91	1.90
Carbon dioxide emissions (million metric tons)											
by sector											
Residential	295	286	282	277	291	288	268	264	257	277	271
Commercial	206	230	224	219	239	234	246	240	233	263	254
Industrial[3]	937	1,107	1,086	1,073	1,151	1,121	1,123	1,102	1,078	1,206	1,171
Transportation	1,812	1,677	1,647	1,606	1,723	1,686	1,691	1,651	1,604	1,767	1,714
Electric power[2]	2,039	2,227	1,810	826	2,201	1,620	2,271	1,446	419	2,254	1,372
by fuel											
Petroleum[4]	2,254	2,136	2,094	2,040	2,192	2,141	2,113	2,060	2,000	2,208	2,143
Natural gas	1,366	1,572	1,589	1,592	1,730	1,851	1,694	1,595	1,412	1,981	2,066
Coal	1,657	1,807	1,354	358	1,671	944	1,780	1,036	168	1,565	562
Other[5]	12	12	12	12	12	12	12	12	12	12	12
Total carbon dioxide emissions	**5,290**	**5,527**	**5,049**	**4,001**	**5,605**	**4,949**	**5,599**	**4,703**	**3,591**	**5,767**	**4,782**

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Table D5. Key results for enviornmental cases (continued)

Net summer capacity, generation, emissions, fuel prices, and coal production	2012	2030					2040				
		Reference	GHG10	GHG25	High Oil and Gas Resource	GHG10 and Low Gas Prices	Reference	GHG10	GHG25	High Oil and Gas Resource	GHG10 and Low Gas Prices
Energy consumption (quadrillion Btu)											
Liquid fuels and other petroleum[6]	35.87	35.65	35.01	34.28	36.59	35.87	35.35	34.57	33.72	37.20	36.16
Natural gas	26.20	30.03	30.56	31.99	33.02	35.53	32.32	31.07	30.36	37.86	39.93
Coal[7]	17.34	19.01	14.50	3.95	17.57	10.07	18.75	11.41	1.96	16.49	6.15
Nuclear / uranium[8]	8.05	8.18	8.40	11.66	8.15	8.15	8.49	11.68	19.03	8.15	9.20
Hydropower	2.67	2.87	2.91	2.93	2.83	2.87	2.90	2.98	2.95	2.84	2.94
Biomass[9]	2.53	3.95	4.61	4.13	3.96	4.32	4.26	5.29	4.33	4.37	4.53
Other renewable energy[10]	1.97	3.23	3.76	6.69	2.91	3.32	3.89	6.03	8.15	3.21	4.62
Other[11]	0.39	0.35	0.35	0.42	0.33	0.34	0.35	0.36	0.45	0.30	0.32
Total consumption	**95.02**	**103.27**	**100.10**	**96.05**	**105.37**	**100.47**	**106.31**	**103.40**	**100.95**	**110.43**	**103.85**
Prices to the electric power sector[2] (2012 dollars per million Btu)											
Natural gas	3.44	6.49	7.70	9.34	5.02	6.07	8.16	9.57	12.38	5.17	7.31
Coal	2.39	2.93	4.74	7.14	2.78	4.45	3.19	6.08	10.27	2.97	5.62
Average energy prices to all users (2012 dollars per million Btu)											
Propane	23.24	24.66	26.03	27.85	22.48	23.99	26.79	28.59	31.75	24.04	26.10
E85[12]	35.06	27.91	28.85	30.40	26.18	26.72	35.49	35.93	37.64	33.33	33.92
Motor gasoline[13]	30.44	28.53	29.95	32.02	26.09	27.32	32.67	34.65	37.85	29.18	30.82
Jet fuel[14]	22.99	23.71	25.09	27.10	20.82	22.07	28.07	30.28	33.46	24.10	26.52
Distillate fuel oil	28.36	29.67	31.06	33.10	27.15	28.40	33.54	35.61	38.90	30.19	32.20
Residual fuel oil	20.41	16.32	17.79	19.83	14.79	16.07	19.42	21.81	25.28	17.18	19.54
Natural gas	5.38	8.49	9.62	11.07	6.88	7.65	10.38	11.86	14.65	7.06	8.92
Metallurgical coal	7.25	9.51	11.60	14.45	9.42	11.49	10.20	13.52	18.91	10.05	13.35
Other coal	2.44	2.98	4.82	7.46	2.85	4.56	3.25	6.18	11.26	3.04	5.84
Electricity	28.85	30.56	33.64	38.27	28.56	31.42	32.63	36.54	39.72	28.40	32.93
Average electricity price (2012 cents per kilowatthour)	**9.8**	**10.4**	**11.5**	**13.1**	**9.7**	**10.7**	**11.1**	**12.5**	**13.6**	**9.7**	**11.2**

[1]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors that have a non-regulatory status. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[2]Includes electricity-only and combined heat and power plants that have a regulatory status.
[3]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[4]This includes carbon dioxide from international bunker fuels, both civilian and military, which are excluded from the accounting of carbon dioxide emissions under the United Nations convention. From 1990 through 2012, international bunker fuels accounted for 90 to 126 million metric tons annually.
[5]Includes emissions from geothermal power and emissions from non-biogenic municipal waste.
[6]Estimated consumption. Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids and crude oil consumed as a fuel. Refer to Table A17 for detailed renewable liquid fuels consumption.
[7]Excludes coal converted to coal-based synthetic liquids and natural gas.
[8]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[9]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[10]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy.
[11]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[12]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[13]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[14]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
GHG = Greenhouse gas.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 are model results and may differ from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2014 National Energy Modeling System runs REF2014.D102413A, CO2FEE10.D011614A, CO2FEE25.D011614A, HIGHRESOURCE.D112913B, CO2FEE10HR.D011614A.

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Table D6. Key results for low electricity demand case

(gigawatts, unless otherwise noted)

Net summer capacity, generation, emissions, and fuel prices	2012	2020		2030		2040	
		Reference	Low Electricity Demand	Reference	Low Electricity Demand	Reference	Low Electricity Demand
Total electricity sales (billion kilowatthours)	**3,686**	**3,986**	**3,580**	**4,327**	**3,604**	**4,623**	**3,690**
Average electricity price (2012 cents per kilowatthour)	**9.8**	**10.1**	**9.9**	**10.4**	**9.9**	**11.1**	**10.1**
Capacity							
Coal steam	306.6	259.2	199.9	258.4	199.6	258.4	199.6
Oil and natural gas steam	100.4	86.0	65.8	72.1	37.9	69.6	32.5
Combined cycle	211.9	231.0	229.4	285.6	230.6	342.2	242.1
Combustion turbine / diesel	139.8	149.7	133.8	184.0	119.6	223.7	120.8
Nuclear / uranium	102.1	97.8	97.8	98.2	97.8	102.0	97.8
Pumped storage	22.4	22.4	22.4	22.4	22.4	22.4	22.4
Fuel cells	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Renewable sources	148.9	174.4	159.4	179.6	162.5	200.5	166.7
Distributed generation	0.0	1.6	0.2	4.6	0.2	8.9	0.5
Combined heat and power[1]	33.8	47.2	50.1	63.4	84.6	87.7	137.2
Total	**1,065.8**	**1,069.5**	**958.7**	**1,168.2**	**955.2**	**1,315.6**	**1,019.7**
Cumulative additions							
Coal steam	0.0	2.5	2.5	2.5	2.5	2.6	2.5
Oil and natural gas steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined cycle	0.0	19.4	17.8	74.0	19.0	130.6	30.5
Combustion turbine / diesel	0.0	17.8	7.4	53.0	8.1	93.2	12.5
Nuclear / uranium	0.0	5.5	5.5	5.8	5.5	9.7	5.5
Pumped storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable sources	0.0	26.4	11.4	31.6	14.5	52.5	18.7
Distributed generation	0.0	1.6	0.2	4.6	0.2	8.9	0.5
Combined heat and power[1]	0.0	13.5	16.3	29.7	50.8	53.9	103.4
Total	**0.0**	**86.7**	**61.0**	**201.1**	**100.6**	**351.5**	**173.6**
Cumulative retirements	**0.0**	**78.0**	**163.2**	**93.8**	**206.3**	**96.7**	**214.7**
Generation by fuel (billion kilowatthours)							
Coal	1,499	1,632	1,322	1,678	1,335	1,661	1,318
Petroleum	20	16	14	16	13	16	14
Natural gas	1,133	1,155	1,096	1,391	1,076	1,605	1,138
Nuclear / uranium	769	779	779	782	779	811	779
Pumped storage / other	6	3	3	3	3	3	3
Renewable sources	463	607	546	668	577	743	612
Distributed generation	0	1	0	2	0	4	0
Total electric power sector generation[2]	**3,890**	**4,193**	**3,760**	**4,540**	**3,783**	**4,844**	**3,865**
Combined heat and power[1]	165	209	215	276	309	375	457
Total electricity generation	**4,054**	**4,402**	**3,974**	**4,815**	**4,092**	**5,219**	**4,321**
Carbon dioxide emissions by the electric power sector (million metric tons)[2]							
Petroleum	19	13	12	14	12	14	12
Natural gas	494	478	453	545	438	608	456
Coal	1,514	1,609	1,296	1,656	1,308	1,637	1,292
Other[3]	12	12	12	12	12	12	12
Total	**2,039**	**2,112**	**1,772**	**2,227**	**1,770**	**2,271**	**1,771**
Prices to the electric power sector[2] (2012 dollars per million Btu)							
Petroleum	21.46	17.28	17.08	20.80	20.69	24.30	24.06
Natural gas	3.44	5.07	5.02	6.49	5.95	8.16	7.33
Coal	2.39	2.61	2.43	2.93	2.69	3.19	2.93

[1]Includes combined heat and power plants and electricity-only plants in commercial and industrial sectors that have a non-regulatory status. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[2]Includes electricity-only and combined heat and power plants that have a regulatory status.
[3]Includes emissions from geothermal power and nonbiogenic emissions from municipal solid waste.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 are model results and may differ from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2014 National Energy Modeling System runs REF2014.D102413A, and FLAT.D010914A.

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Table D7. Natural gas supply and disposition, oil and gas resource cases

(trillion cubic feet per year, unless otherwise noted)

Supply, disposition, and prices	2012	2020			2030			2040		
		Low Oil and Gas Resource	Reference	High Oil and Gas Resource	Low Oil and Gas Resource	Reference	High Oil and Gas Resource	Low Oil and Gas Resource	Reference	High Oil and Gas Resource
Henry Hub spot price										
(2012 dollars per million Btu)	2.75	5.28	4.38	4.34	8.15	6.03	4.25	10.53	7.65	4.58
(2012 dollars per thousand cubic feet)	2.81	5.39	4.47	4.44	8.33	6.17	4.35	10.76	7.82	4.68
Dry gas production[1]	**24.06**	**26.77**	**29.09**	**31.29**	**28.99**	**34.43**	**39.07**	**28.07**	**37.54**	**45.51**
Lower 48 onshore	22.07	24.30	26.65	28.61	25.28	30.82	36.29	23.59	33.43	42.41
Associated-dissolved[2]	2.06	2.47	2.65	3.09	2.04	2.25	3.43	1.69	1.91	2.99
Non-associated	20.02	21.83	24.00	25.52	23.25	28.57	32.86	21.89	31.52	39.42
Tight gas	4.86	5.99	6.48	6.54	6.31	8.06	7.62	6.55	8.41	9.51
Shale gas	9.72	11.53	13.33	14.79	13.10	16.92	21.85	11.59	19.82	26.95
Coalbed methane	1.58	1.73	1.66	1.59	1.86	1.61	1.43	2.15	1.71	1.40
Other	3.86	2.57	2.53	2.60	1.97	1.98	1.96	1.59	1.58	1.56
Lower 48 offshore	1.66	2.19	2.16	2.40	2.53	2.42	2.52	3.32	2.95	2.81
Associated-dissolved[2]	0.48	0.68	0.68	0.77	0.61	0.58	0.60	0.78	0.71	0.69
Non-associated	1.18	1.51	1.48	1.64	1.92	1.84	1.92	2.53	2.24	2.13
Alaska	0.33	0.28	0.28	0.28	1.18	1.19	0.27	1.17	1.17	0.28
Supplemental natural gas[3]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net imports	**1.51**	**-0.99**	**-1.93**	**-2.18**	**-2.66**	**-4.94**	**-6.66**	**-2.21**	**-5.80**	**-8.30**
Pipeline[4]	1.37	0.18	0.00	0.15	-0.69	-1.57	-1.69	-0.35	-2.43	-3.33
Liquefied natural gas	0.15	-1.17	-1.93	-2.33	-1.97	-3.37	-4.97	-1.86	-3.37	-4.97
Total supply	**25.64**	**25.84**	**27.23**	**29.18**	**26.39**	**29.56**	**32.48**	**25.92**	**31.81**	**37.27**
Consumption by sector										
Residential	4.17	4.42	4.46	4.52	4.20	4.33	4.41	3.98	4.12	4.28
Commercial	2.90	3.10	3.16	3.27	3.09	3.28	3.41	3.35	3.57	3.85
Industrial[5]	7.14	8.00	8.09	8.20	8.11	8.52	8.79	8.24	8.68	9.22
Natural-gas-to-liquids heat and power[6]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural gas to liquids production[7]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electric power[8]	9.25	7.82	8.81	10.33	8.19	10.06	12.10	7.31	11.23	14.99
Transportation[9]	0.04	0.08	0.08	0.08	0.21	0.28	0.22	0.48	0.85	0.76
Pipeline fuel	0.72	0.67	0.73	0.74	0.71	0.80	0.89	0.71	0.83	0.98
Lease and plant fuel[10]	1.42	1.59	1.74	1.86	1.71	2.11	2.50	1.69	2.35	2.98
Total	**25.64**	**25.68**	**27.06**	**29.01**	**26.23**	**29.39**	**32.31**	**25.76**	**31.63**	**37.05**
Discrepancy[11]	0.00	0.17	0.17	0.17	0.17	0.17	0.17	0.16	0.18	0.21
Lower 48 end of year dry reserves[1]	**320.09**	**334.75**	**352.47**	**388.50**	**342.80**	**382.58**	**427.94**	**347.18**	**402.59**	**492.37**

[1]Marketed production (wet) minus extraction losses.
[2]Gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).
[3]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[4]Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida, as well as gas from Canada and Mexico.
[5]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[6]Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted.
[7]Includes any natural gas converted into liquid fuel.
[8]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[9]Natural gas used as fuel in motor vehicles, trains, and ships.
[10]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[11]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2012 values include net storage injections.

Note: Totals may not equal sum of components due to independent rounding. Data for 2012 are model results and may differ from official EIA data reports.

Sources: 2012 supply values; lease, plant, and pipeline fuel consumption: U.S. Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2013/06) (Washington, DC, June 2013). Other 2012 consumption based on: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2012 natural gas price at Henry Hub based on daily spot prices published in Natural Gas Intelligence. **Projections:** EIA, AEO2014 National Energy Modeling System runs LOWRESOURCE.D112913A, REF2014.D102413A, and HIGHRESOURCE.D112913B.

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Table D8. Liquid fuels supply and disposition, oil and gas resource case

(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	2012	2020			2030			2040		
		Low Oil and Gas Resource	Reference	High Oil and Gas Resource	Low Oil and Gas Resource	Reference	High Oil and Gas Resource	Low Oil and Gas Resource	Reference	High Oil and Gas Resource
Crude oil prices (2012 dollars per barrel)										
Brent spot	111.65	98.61	96.57	91.58	122.90	118.99	106.55	145.02	141.46	124.74
West Texas Intermediate spot	94.12	96.56	94.57	89.69	120.83	116.99	104.76	142.96	139.46	122.97
Imported crude oil[1]	101.10	90.10	88.07	82.58	113.23	109.22	96.67	133.65	130.80	113.71
Crude oil supply										
Domestic production[2]	6.49	8.85	9.55	11.41	7.05	8.30	12.85	6.61	7.48	13.22
Alaska	0.53	0.44	0.44	0.49	0.24	0.24	0.69	0.31	0.26	1.00
Lower 48 States	5.96	8.42	9.12	10.93	6.81	8.06	12.16	6.30	7.22	12.22
Net imports	8.43	6.49	5.79	3.95	7.82	6.64	2.33	8.71	7.74	2.38
Gross imports	8.49	6.64	5.94	4.10	7.95	6.77	2.46	8.84	7.87	2.51
Exports	0.06	0.15	0.15	0.15	0.13	0.13	0.13	0.12	0.12	0.12
Other crude oil supply[3]	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total crude oil supply	**15.01**	**15.35**	**15.34**	**15.36**	**14.88**	**14.94**	**15.17**	**15.32**	**15.22**	**15.60**
Other petroleum supply	**0.10**	**0.15**	**0.23**	**0.10**	**-0.08**	**-0.34**	**-0.46**	**-0.34**	**-0.86**	**-1.74**
Net product imports	-0.92	-0.94	-0.86	-0.92	-1.07	-1.29	-1.32	-1.34	-1.82	-2.55
Gross refined product imports[4]	0.85	0.94	0.98	1.12	1.02	1.06	1.26	1.19	1.10	1.08
Unfinished oil imports	0.60	0.52	0.52	0.52	0.49	0.49	0.49	0.45	0.45	0.45
Blending component imports	0.62	0.62	0.62	0.61	0.50	0.50	0.49	0.40	0.40	0.38
Exports	2.98	3.02	2.97	3.18	3.08	3.33	3.56	3.38	3.76	4.46
Refinery processing gain[5]	1.08	1.10	1.08	1.02	0.99	0.96	0.86	0.99	0.95	0.82
Product stock withdrawal	-0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other non-petroleum supply	**3.48**	**3.99**	**3.96**	**4.34**	**3.85**	**4.32**	**4.77**	**3.55**	**4.36**	**5.99**
Supply from renewable sources	0.89	1.01	1.01	1.02	1.04	1.04	1.04	1.06	1.07	1.08
Ethanol	0.83	0.89	0.90	0.90	0.92	0.91	0.92	0.96	0.95	0.96
Domestic production	0.84	0.83	0.84	0.84	0.85	0.86	0.87	0.87	0.86	0.89
Net imports	-0.02	0.06	0.06	0.06	0.07	0.06	0.05	0.08	0.08	0.07
Biodiesel	0.06	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Domestic production	0.06	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Net imports	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Other biomass-derived liquids[6]	0.00	0.03	0.03	0.03	0.03	0.04	0.03	0.01	0.03	0.03
Liquids from gas	2.40	2.68	2.65	3.05	2.50	2.98	3.44	2.17	2.98	4.62
Natural gas plant liquids	2.40	2.68	2.65	3.05	2.50	2.98	3.44	2.17	2.98	4.62
Gas-to-liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquids from coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other[7]	0.19	0.30	0.30	0.27	0.31	0.30	0.29	0.32	0.31	0.29
Total primary supply[8]	**18.59**	**19.49**	**19.52**	**19.80**	**18.64**	**18.93**	**19.48**	**18.52**	**18.72**	**19.85**
Net import share of product supplied (percent)	40.3	28.8	25.6	15.7	36.6	28.6	5.5	40.3	32.2	-0.4
Net expenditures for imports of crude oil and petroleum products (billion 2012 dollars)	313.70	226.68	198.85	131.35	337.87	278.60	94.87	441.03	385.39	112.60
Lower 48 end of year reserves[2] (billion barrels)	**24.71**	**29.22**	**31.78**	**37.19**	**29.86**	**34.42**	**47.13**	**32.56**	**35.45**	**48.12**

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Table D8. Liquid fuels supply and disposition, oil and gas resource case (continued)

(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	2012	2020			2030			2040		
		Low Oil and Gas Resource	Reference	High Oil and Gas Resource	Low Oil and Gas Resource	Reference	High Oil and Gas Resource	Low Oil and Gas Resource	Reference	High Oil and Gas Resource
Refined petroleum product prices to the transportation sector (2012 dollars per gallon)										
Propane	2.30	2.33	2.27	2.20	2.54	2.45	2.27	2.68	2.63	2.42
Ethanol (E85)[9]	3.33	2.46	2.43	2.36	2.68	2.65	2.49	3.36	3.37	3.17
Ethanol wholesale price	2.58	2.71	2.66	2.64	2.62	2.52	2.41	2.64	2.65	2.54
Motor gasoline[10]	3.69	3.11	3.08	2.96	3.50	3.43	3.13	3.92	3.90	3.49
Jet fuel[11]	3.10	2.68	2.63	2.49	3.32	3.20	2.81	3.89	3.79	3.25
Distillate fuel oil[12]	3.95	3.72	3.67	3.54	4.32	4.20	3.85	4.79	4.73	4.26
Residual fuel oil	3.00	1.90	1.86	1.78	2.41	2.32	2.13	2.86	2.78	2.47
Residual fuel oil (2012 dollars per barrel)	126.17	79.86	78.31	74.64	101.27	97.43	89.26	120.14	116.65	103.86

[1]Weighted average price delivered to U.S. refiners.
[2]Includes lease condensate.
[3]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude product supplied.
[4]Includes other hydrocarbons and alcohol.
[5]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[6]Includes pyrolysis oils, biomass-derived Fischer-Tropsch liquids, and renewable feedstocks used for the on-site production of diesel and gasoline.
[7]Includes domestic sources of other blending components, other hydrocarbons, and ethers.
[8]Total crude supply plus other petroleum supply plus other non-petroleum supply.
[9]E85 refers to a blend of 85 pecent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[10]Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
[11]Includes only kerosene-type.
[12]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 are model results and may differ from official EIA data reports.
Sources: 2012 product supplied data and imported crude oil price based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2012 crude oil spot prices: Thomson Reuters. 2012 transportation sector prices based on: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report". 2012 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. 2012 wholesale ethanol prices derived from Bloomberg U.S. average rack price. Other 2012 data: EIA, *Petroleum Supply Annual 2012*, DOE/EIA-0340(2012)/1 (Washington, DC, September 2013). **Projections:** EIA, AEO2014 National Energy Modeling System runs LOWRESOURCE.D112913A, REF2014.D102413A, and HIGHRESOURCE.D112913B.

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Table D9. Key transportation results, oil and gas resource cases

Consumption and indicators	2012	2020			2030			2040		
		Low Oil and Gas Resource	Reference	High Oil and Gas Resource	Low Oil and Gas Resource	Reference	High Oil and Gas Resource	Low Oil and Gas Resource	Reference	High Oil and Gas Resource
Level of travel										
(billion vehicle miles traveled)										
Light-duty vehicles less than 8,501 pounds.	2,662	2,846	2,851	2,869	3,118	3,138	3,201	3,422	3,434	3,529
Commercial light trucks[1]	63	76	76	77	88	90	91	101	103	106
Freight trucks greater than 10,000 pounds..	245	308	310	317	351	362	377	398	411	437
(billion seat miles available)										
Air	990	1,064	1,064	1,065	1,135	1,135	1,135	1,199	1,199	1,199
(billion ton miles traveled)										
Rail	1,729	1,675	1,624	1,581	1,761	1,738	1,688	1,763	1,736	1,647
Domestic shipping	378	386	390	406	356	369	403	360	371	419
Energy efficiency indicators										
(miles per gallon)										
Tested new light-duty vehicle[2]	31.7	38.7	38.6	38.5	47.9	47.8	47.4	48.1	48.2	47.7
New car[2]	36.3	44.2	44.2	44.2	55.2	55.4	55.2	55.4	55.6	55.3
New light truck[2]	27.5	33.7	33.7	33.6	40.8	40.7	40.6	40.9	40.8	40.7
On-road new light-duty vehicle[3]	25.6	31.2	31.2	31.1	38.7	38.6	38.3	38.9	38.9	38.5
New car[3]	29.7	36.1	36.1	36.1	45.1	45.2	45.1	45.2	45.4	45.2
New light truck[3]	22.0	27.0	27.0	26.9	32.7	32.6	32.5	32.7	32.7	32.6
Light-duty stock[4]	21.5	25.1	25.1	25.1	32.6	32.6	32.4	37.2	37.2	36.9
New commercial light truck[1]	18.1	20.9	20.9	20.8	24.5	24.5	24.4	24.6	24.6	24.5
Stock commercial light truck[1]	15.2	18.0	18.0	18.0	22.5	22.5	22.5	24.5	24.5	24.4
Freight truck	6.7	7.3	7.3	7.3	7.7	7.7	7.7	7.8	7.8	7.8
(seat miles per gallon)										
Aircraft	62.4	63.9	63.9	63.9	67.0	67.0	67.0	71.5	71.5	71.6
(ton miles per thousand Btu)										
Rail	3.4	3.6	3.6	3.6	3.9	3.9	3.9	4.2	4.2	4.2
Domestic shipping	4.7	5.0	5.0	5.0	5.4	5.4	5.4	5.8	5.8	5.8
Energy use by mode (quadrillion Btu)										
Light-duty vehicles	15.49	14.21	14.24	14.34	12.00	12.09	12.38	11.53	11.58	12.00
Commercial light trucks[1]	0.52	0.53	0.53	0.53	0.49	0.50	0.51	0.52	0.53	0.54
Bus transportation	0.24	0.25	0.25	0.25	0.27	0.27	0.27	0.29	0.29	0.29
Freight trucks	5.02	5.83	5.87	6.00	6.26	6.47	6.73	6.97	7.23	7.71
Rail, passenger	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06
Rail, freight	0.48	0.46	0.45	0.43	0.45	0.45	0.43	0.43	0.42	0.40
Shipping, domestic	0.10	0.09	0.09	0.10	0.08	0.08	0.09	0.07	0.08	0.09
Shipping, international	0.58	0.59	0.59	0.59	0.60	0.60	0.60	0.61	0.61	0.61
Recreational boats	0.24	0.25	0.25	0.26	0.27	0.27	0.28	0.28	0.28	0.29
Air	2.47	2.60	2.60	2.60	2.68	2.69	2.69	2.70	2.70	2.70
Military use	0.70	0.64	0.64	0.64	0.68	0.68	0.68	0.77	0.77	0.77
Lubricants	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Pipeline fuel	0.73	0.69	0.74	0.75	0.72	0.82	0.91	0.72	0.85	1.00
Total	**26.74**	**26.31**	**26.41**	**26.66**	**24.69**	**25.09**	**25.75**	**25.07**	**25.51**	**26.59**

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Table D9. Key transportation results, oil and gas resource cases (continued)

Consumption and indicators	2012	2020			2030			2040		
		Low Oil and Gas Resource	Reference	High Oil and Gas Resource	Low Oil and Gas Resource	Reference	High Oil and Gas Resource	Low Oil and Gas Resource	Reference	High Oil and Gas Resource
Energy use by fuel (quadrillion Btu)										
Propane	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.07	0.07	0.07
Motor gasoline[5]	16.33	14.97	15.00	15.11	12.59	12.69	13.02	12.04	12.09	12.56
of which: E85[6]	0.01	0.19	0.19	0.18	0.49	0.46	0.43	0.34	0.33	0.29
Jet fuel[7]	3.00	3.08	3.08	3.08	3.20	3.20	3.20	3.28	3.28	3.28
Distillate fuel oil[8]	5.82	6.67	6.70	6.81	7.12	7.25	7.55	7.65	7.54	8.08
Residual fuel oil	0.58	0.58	0.58	0.58	0.59	0.59	0.59	0.60	0.60	0.60
Other petroleum[9]	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Liquid fuels and other petroleum	25.93	25.50	25.55	25.78	23.70	23.94	24.57	23.79	23.73	24.74
Pipeline fuel natural gas	0.73	0.69	0.74	0.75	0.72	0.82	0.91	0.72	0.85	1.00
Compressed/liquefied natural gas	0.04	0.08	0.08	0.08	0.21	0.28	0.22	0.48	0.86	0.77
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.02	0.03	0.03	0.03	0.04	0.04	0.04	0.06	0.06	0.06
Delivered energy	**26.72**	**26.30**	**26.40**	**26.65**	**24.69**	**25.08**	**25.74**	**25.06**	**25.50**	**26.58**
Electricity related losses	0.05	0.06	0.06	0.06	0.09	0.08	0.08	0.12	0.12	0.11
Total	**26.77**	**26.36**	**26.47**	**26.71**	**24.77**	**25.17**	**25.82**	**25.18**	**25.62**	**26.68**

[1]Commercial trucks 8,501 to 10,000 pounds gross vehicle weight rating.
[2]Environmental Protection Agency rated miles per gallon.
[3]Tested new vehicle efficiency revised for on-road performance.
[4]Combined "on-the-road" estimate for all cars and light trucks.
[5]Includes ethanol and ethers blended into gasoline.
[6]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[7]Includes only kerosene type.
[8]Diesel fuel for on- and off- road use.
[9]Includes aviation gasoline and lubricants.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 are model results and may differ from official EIA data reports.
Source: 2012 consumption based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0384(2013/09) (Washington, DC, September 2013). Other 2012 data: Federal Highway Administration, *Highway Statistics 2010* (Washington, DC, February 2012); Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 31* (Oak Ridge, TN, July 2012); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, October 28, 2010); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey", EC02TV (Washington, DC, December 2004); EIA, Alternatives to Traditional Transportation Fuels 2009 (Part II – User and Fuel Data), April 2011; EIA, *State Energy Data Report 2011*, DOE/EIA-0214(2011) (Washington, DC, June 2013); U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2010-2009* (Washington, DC, December 2010); and United States Department of Defense, Defense Fuel Supply Center, Factbook (January, 2010). **Projections:** EIA, AEO2014 National Energy Modeling System runs LOWRESOURCE.D112913A, REF2014.D102413A, and HIGHRESOURCE.D112913B.

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Table D10. Key transportation results, vehicle miles traveled cases

Consumption and indicators	2012	2020			2030			2040		
		Low VMT	Reference	High VMT	Low VMT	Reference	High VMT	Low VMT	Reference	High VMT
Level of travel										
(billion vehicle miles traveled)										
Light-duty vehicles less than 8,501 pounds.	2,662	2,752	2,851	2,954	2,772	3,138	3,301	2,793	3,434	3,624
Commercial light trucks[1]	63	75	76	77	86	90	91	97	103	105
Freight trucks greater than 10,000 pounds..	245	310	310	310	362	362	362	410	411	411
(billion seat miles available)										
Air	990	1,064	1,064	1,064	1,135	1,135	1,135	1,199	1,199	1,199
(billion ton miles traveled)										
Rail	1,729	1,624	1,624	1,620	1,736	1,738	1,736	1,738	1,736	1,737
Domestic shipping	378	390	390	390	368	369	369	370	371	371
Vehicles miles traveled per licensed driver (thousand miles)	12.5	11.8	12.2	12.7	11.0	12.5	13.1	10.4	12.8	13.5
Licensed drivers (millions)	213.1	233.5	233.5	233.5	252.0	252.0	252.0	268.6	268.6	268.6
Energy efficiency indicators										
(miles per gallon)										
Tested new light-duty vehicle[2]	31.7	38.6	38.6	38.7	47.8	47.8	47.9	48.0	48.2	48.2
New car[2]	36.3	44.2	44.2	44.2	55.4	55.4	55.2	55.5	55.6	55.4
New light truck[2]	27.5	33.7	33.7	33.7	40.9	40.7	40.9	40.9	40.8	40.9
On-road new light-duty vehicle[3]	25.6	31.2	31.2	31.3	38.6	38.6	38.7	38.8	38.9	39.0
New car[3]	29.7	36.1	36.1	36.1	45.2	45.2	45.1	45.3	45.4	45.3
New light truck[3]	22.0	27.0	27.0	27.0	32.7	32.6	32.7	32.8	32.7	32.8
Light-duty stock[4]	21.5	25.1	25.1	25.1	32.6	32.6	32.6	37.2	37.2	37.3
New commercial light truck[1]	18.1	20.9	20.9	20.9	24.6	24.5	24.6	24.7	24.6	24.7
Stock commercial light truck[1]	15.2	18.0	18.0	18.0	22.6	22.5	22.6	24.6	24.5	24.6
Freight truck	6.7	7.3	7.3	7.3	7.7	7.7	7.7	7.8	7.8	7.8
(seat miles per gallon)										
Aircraft	62.4	63.9	63.9	63.9	67.0	67.0	67.0	71.5	71.5	71.5
(ton miles per thousand Btu)										
Rail	3.4	3.6	3.6	3.6	3.9	3.9	3.9	4.2	4.2	4.2
Domestic shipping	4.7	5.0	5.0	5.0	5.4	5.4	5.4	5.8	5.8	5.8
Energy use by mode (quadrillion Btu)										
Light-duty vehicles	15.49	13.74	14.24	14.75	10.66	12.09	12.71	9.42	11.58	12.21
Commercial light trucks[1]	0.52	0.52	0.53	0.54	0.48	0.50	0.51	0.49	0.53	0.53
Bus transportation	0.24	0.25	0.25	0.25	0.27	0.27	0.27	0.29	0.29	0.29
Freight trucks	5.02	5.87	5.87	5.87	6.46	6.47	6.47	7.22	7.23	7.24
Rail, passenger	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06
Rail, freight	0.48	0.45	0.45	0.45	0.45	0.45	0.45	0.42	0.42	0.42
Shipping, domestic	0.10	0.09	0.09	0.09	0.08	0.08	0.08	0.08	0.08	0.08
Shipping, international	0.58	0.59	0.59	0.59	0.60	0.60	0.60	0.61	0.61	0.61
Recreational boats	0.24	0.25	0.25	0.25	0.27	0.27	0.27	0.29	0.28	0.28
Air	2.47	2.60	2.60	2.60	2.68	2.69	2.69	2.70	2.70	2.70
Military use	0.70	0.64	0.64	0.64	0.68	0.68	0.68	0.77	0.77	0.77
Lubricants	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Pipeline fuel	0.73	0.74	0.74	0.74	0.81	0.82	0.82	0.84	0.85	0.84
Total	**26.74**	**25.91**	**26.41**	**26.94**	**23.63**	**25.09**	**25.72**	**23.31**	**25.51**	**26.15**
Energy use by fuel (quadrillion Btu)										
Propane	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.07	0.07
Motor gasoline[5]	16.33	14.51	15.00	15.50	11.31	12.69	13.28	10.04	12.09	12.68
of which: E85[6]	0.01	0.21	0.19	0.15	0.56	0.46	0.39	0.49	0.33	0.34
Jet fuel[7]	3.00	3.08	3.08	3.08	3.20	3.20	3.20	3.28	3.28	3.28
Distillate fuel oil[8]	5.82	6.68	6.70	6.71	7.18	7.25	7.27	7.41	7.54	7.58
Residual fuel oil	0.58	0.58	0.58	0.58	0.59	0.59	0.59	0.60	0.60	0.60
Other petroleum[9]	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Liquid fuels and other petroleum	25.93	25.05	25.55	26.07	22.48	23.94	24.55	21.54	23.73	24.37
Pipeline fuel natural gas	0.73	0.74	0.74	0.74	0.81	0.82	0.82	0.84	0.85	0.84
Compressed/liquefied natural gas	0.04	0.08	0.08	0.08	0.28	0.28	0.29	0.86	0.86	0.86
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.02	0.03	0.03	0.03	0.04	0.04	0.04	0.05	0.06	0.06
Delivered energy	**26.72**	**25.90**	**26.40**	**26.93**	**23.62**	**25.08**	**25.71**	**23.30**	**25.50**	**26.14**

012879

Table D10. Key transportation results, vehicle miles traveled cases (continued)

Consumption and indicators	2012	2020			2030			2040		
		Low VMT	Reference	High VMT	Low VMT	Reference	High VMT	Low VMT	Reference	High VMT
Carbon dioxide emissions in the transportation sector (million metric tons)										
Petroleum[10]	1,771	1,701	1,734	1,769	1,521	1,618	1,662	1,451	1,600	1,642
Natural gas[11]	41	44	44	44	58	58	59	91	91	91
Total	**1,812**	**1,745**	**1,777**	**1,812**	**1,579**	**1,677**	**1,721**	**1,542**	**1,691**	**1,733**

[1]Commercial trucks 8,501 to 10,000 pounds gross vehicle weight rating.
[2]Environmental Protection Agency rated miles per gallon.
[3]Tested new vehicle efficiency revised for on-road performance.
[4]Combined "on-the-road" estimate for all cars and light trucks.
[5]Includes ethanol and ethers blended into gasoline.
[6]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[7]Includes only kerosene type.
[8]Diesel fuel for on- and off- road use.
[9]Includes aviation gasoline and lubricants.
[10]This includes carbon dioxide from international bunker fuels, both civilian and military, which are excluded from the accounting of carbon dioxide emissions under the United Nations convention. From 1990 through 2012, international bunker fuels accounted for 90 to 126 million metric tons annually.
[11]Include pipeline fuel natural gas and natural gas used as fuel in motor vehicles, trains, and ships.
VMT = Vehicle miles traveled.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 are model results and may differ from official EIA data reports.
Source: 2012 consumption based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0384(2013/09) (Washington, DC, September 2013). Other 2012 data: Federal Highway Administration, *Highway Statistics 2010* (Washington, DC, February 2012); Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 31* (Oak Ridge, TN, July 2012); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, October 28, 2010); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey", EC02TV (Washington, DC, December 2004); EIA, Alternatives to Traditional Transportation Fuels 2009 (Part II – User and Fuel Data), April 2011; EIA, *State Energy Data Report 2011*, DOE/EIA-0214(2011) (Washington, DC, June 2013); U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2010-2009* (Washington, DC, December 2010); and United States Department of Defense, Defense Fuel Supply Center, Factbook (January, 2010). **Projections:** EIA, AEO2014 National Energy Modeling System runs LOWVMT.D020314B, REF2014.D102413A, and HIGHVMT.D020314D.

012880

Table D11. Key transportation results, rail liquefied natural gas cases

Consumption and indicators	2012	2020			2030			2040		
		Low Rail LNG	Reference	High Rail LNG	Low Rail LNG	Reference	High Rail LNG	Low Rail LNG	Reference	High Rail LNG
Rail travel										
(billion ton miles traveled)	1,729	1,622	1,624	1,622	1,742	1,738	1,739	1,734	1,736	1,737
Rail efficiency										
(ton miles per thousand Btu)	3.4	3.6	3.6	3.6	3.9	3.9	3.9	4.2	4.2	4.2
Energy use by mode (quadrillion Btu)										
Light-duty vehicles	15.49	14.24	14.24	14.24	12.09	12.09	12.09	11.58	11.58	11.59
Commercial light trucks[1]	0.52	0.53	0.53	0.53	0.50	0.50	0.50	0.53	0.53	0.53
Bus transportation	0.24	0.25	0.25	0.25	0.27	0.27	0.27	0.29	0.29	0.29
Freight trucks	5.02	5.87	5.87	5.87	6.47	6.47	6.47	7.24	7.23	7.23
Rail, passenger	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06
Rail, freight	0.48	0.45	0.45	0.45	0.45	0.45	0.44	0.41	0.42	0.41
Distillate fuel oil	0.48	0.44	0.44	0.42	0.41	0.37	0.21	0.35	0.27	0.02
Liquefied natural gas	0.00	0.00	0.00	0.02	0.04	0.08	0.24	0.06	0.15	0.39
Shipping, domestic	0.10	0.09	0.09	0.09	0.08	0.08	0.08	0.08	0.08	0.08
Shipping, international	0.58	0.59	0.59	0.59	0.60	0.60	0.60	0.61	0.61	0.61
Recreational boats	0.24	0.25	0.25	0.25	0.27	0.27	0.27	0.28	0.28	0.28
Air	2.47	2.60	2.60	2.60	2.69	2.69	2.69	2.70	2.70	2.70
Military use	0.70	0.64	0.64	0.64	0.68	0.68	0.68	0.77	0.77	0.76
Lubricants	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Pipeline fuel	0.73	0.74	0.74	0.74	0.83	0.82	0.83	0.85	0.85	0.85
Total	**26.74**	**26.41**	**26.41**	**26.41**	**25.10**	**25.09**	**25.10**	**25.51**	**25.51**	**25.51**
Energy use by fuel (quadrillion Btu)										
Propane	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.07	0.07	0.07
Motor gasoline[2]	16.33	15.00	15.00	15.00	12.69	12.69	12.69	12.09	12.09	12.09
of which: E85[3]	0.01	0.19	0.19	0.19	0.46	0.46	0.46	0.33	0.33	0.34
Jet fuel[4]	3.00	3.08	3.08	3.08	3.20	3.20	3.20	3.28	3.28	3.28
Distillate fuel oil[5]	5.82	6.70	6.70	6.68	7.29	7.25	7.09	7.61	7.54	7.32
Residual fuel oil	0.58	0.58	0.58	0.58	0.59	0.59	0.59	0.60	0.60	0.60
Other petroleum[6]	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Liquid fuels and other petroleum	25.93	25.55	25.55	25.53	23.98	23.94	23.78	23.79	23.73	23.51
Pipeline fuel natural gas	0.73	0.74	0.74	0.74	0.83	0.82	0.83	0.85	0.85	0.85
Compressed/liquefied natural gas	0.04	0.08	0.08	0.10	0.24	0.28	0.44	0.79	0.86	1.07
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.02	0.03	0.03	0.03	0.04	0.04	0.04	0.06	0.06	0.06
Delivered energy	**26.72**	**26.40**	**26.40**	**26.40**	**25.09**	**25.08**	**25.09**	**25.50**	**25.50**	**25.51**
Carbon dioxide emissions in the transportation sector (million metric tons)										
Petroleum[7]	1,771	1,734	1,734	1,732	1,621	1,618	1,607	1,605	1,600	1,585
Natural gas[8]	41	44	44	45	57	58	67	87	91	103
Total	**1,812**	**1,778**	**1,777**	**1,777**	**1,678**	**1,677**	**1,674**	**1,693**	**1,691**	**1,687**

[1]Commercial trucks 8,501 to 10,000 pounds gross vehicle weight rating.
[2]Includes ethanol and ethers blended into gasoline.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Includes only kerosene type.
[5]Diesel fuel for on- and off- road use.
[6]Includes aviation gasoline and lubricants.
[7]This includes carbon dioxide from international bunker fuels, both civilian and military, which are excluded from the accounting of carbon dioxide emissions under the United Nations convention. From 1990 through 2012, international bunker fuels accounted for 90 to 126 million metric tons annually.
[8]Includes pipeline fuel natural gas and natural gas used as fuel in motor vehicles, trains, and ships.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 are model results and may differ from official EIA data reports.
Source: 2012 consumption based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0384(2013/09) (Washington, DC, September 2013). Other 2012 data: Federal Highway Administration, *Highway Statistics 2010* (Washington, DC, February 2012); Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 31* (Oak Ridge, TN, July 2012); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, October 28, 2010); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey", EC02TV (Washington, DC, December 2004); EIA, Alternatives to Traditional Transportation Fuels 2009 (Part II – User and Fuel Data), April 2011; EIA, *State Energy Data Report 2011*, DOE/EIA-0214(2011) (Washington, DC, June 2013); U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2010-2009* (Washington, DC, December 2010); and United States Department of Defense, Defense Fuel Supply Center, Factbook (January, 2010). **Projections:** EIA, AEO2014 National Energy Modeling System runs RLNGLOW20.D012914C, REF2014.D102413A, and RLNGHIGH20.D012914C.

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Table D12. Key results for energy savings and industrial competitiveness act case

(quadrillion Btu per year, unless otherwise noted)

Consumption, emissions	2012	2020		2030		2040	
		Reference	ESICA	Reference	ESICA	Reference	ESICA
Energy consumption							
Residential	**10.42**	**10.74**	**10.70**	**10.83**	**10.71**	**10.94**	**10.78**
Propane, kerosene, and distillate fuel oil	1.02	0.89	0.88	0.75	0.75	0.66	0.66
Natural gas	4.26	4.56	4.52	4.43	4.35	4.21	4.10
Renewable energy[1]	0.45	0.46	0.46	0.44	0.44	0.42	0.41
Electricity	4.69	4.84	4.83	5.21	5.18	5.65	5.62
Commercial	**8.29**	**8.78**	**8.76**	**9.38**	**9.31**	**10.22**	**10.14**
Liquid fuels and other petroleum[2]	0.63	0.68	0.68	0.67	0.67	0.68	0.67
Natural gas	2.96	3.23	3.22	3.35	3.31	3.65	3.59
Coal	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Renewable energy[3]	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Electricity	4.52	4.69	4.68	5.18	5.16	5.72	5.70
Industrial[4]	**23.63**	**27.71**	**27.71**	**29.62**	**29.59**	**30.22**	**30.19**
Liquid fuels and other petroleum[5]	8.06	9.56	9.55	10.10	10.08	10.10	10.07
Natural gas	8.75	10.04	10.04	10.87	10.86	11.28	11.27
Coal	1.48	1.57	1.57	1.52	1.52	1.44	1.44
Renewable energy[6]	2.00	2.50	2.50	2.79	2.79	3.07	3.07
Electricity	3.35	4.04	4.04	4.33	4.33	4.34	4.35
Transportation	**26.72**	**26.40**	**26.40**	**25.08**	**25.08**	**25.50**	**25.50**
Liquid fuels and other petroleum[7]	25.93	25.55	25.55	23.94	23.94	23.73	23.73
Pipeline fuel natural gas	0.73	0.74	0.74	0.82	0.81	0.85	0.84
Compressed / liquefied natural gas	0.04	0.08	0.08	0.28	0.28	0.86	0.86
Electricity and liquid hydrogen	0.02	0.03	0.03	0.05	0.05	0.07	0.07
Electric power[8]	**38.53**	**40.70**	**40.66**	**43.12**	**43.04**	**45.20**	**45.08**
Natural gas	9.46	9.00	8.99	10.28	10.23	11.48	11.33
Steam coal	15.82	16.95	16.95	17.44	17.43	17.27	17.27
Nuclear / uranium[9]	8.05	8.15	8.15	8.18	8.18	8.49	8.56
Renewable energy[10]	4.59	6.08	6.06	6.68	6.68	7.44	7.41
Other[11]	0.62	0.52	0.52	0.53	0.53	0.53	0.52
Total energy consumption	**95.02**	**100.73**	**100.63**	**103.27**	**103.02**	**106.31**	**105.97**
Carbon dioxide emissions (million metric tons)							
by sector							
Residential	295	302	300	286	281	268	262
Commercial	206	224	223	230	227	246	242
Industrial[4]	937	1,060	1,059	1,107	1,106	1,123	1,121
Transportation	1,812	1,777	1,777	1,677	1,676	1,691	1,691
Electric power[8]	2,039	2,112	2,111	2,227	2,223	2,271	2,263
by fuel							
Petroleum[12]	2,254	2,252	2,251	2,136	2,134	2,113	2,111
Natural gas	1,366	1,447	1,443	1,572	1,563	1,694	1,676
Coal	1,657	1,766	1,766	1,807	1,805	1,780	1,780
Other[13]	12	12	12	12	12	12	12
Total carbon dioxide emissions	**5,290**	**5,476**	**5,472**	**5,527**	**5,513**	**5,599**	**5,579**

[1]Includes wood used for residential heating. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[2]Includes propane, motor gasoline, ethanol and ethers, kerosene, distillate fuel oil, and residual fuel oil.
[3]Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[4]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[5]Includes ethane, natural gasoline, refinery olefins, liquefied petroleum gases, motor gasoline, ethanol and ethers, distillate fuel oil, residual fuel oil, petrochemical feedstocks, petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol.
[7]Includes propane, motor gasoline, ethanol and ethers, jet fuel, distillate fuel oil, residual fuel oil, aviation gasoline, and lubricants.
[8]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[9]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[10]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[11]Includes distillate fuel oil, residual fuel oil, non-biogenic municipal waste, and net electricity imports.
[12]This includes carbon dioxide from international bunker fuels, both civilian and military, which are excluded from the accounting of carbon dioxide emissions under the United Nations convention. From 1990 through 2012, international bunker fuels accounted for 90 to 126 million metric tons annually.
[13]Includes emissions from geothermal power and emissions from non-biogenic municipal waste.
ESICA = Energy Savings and Industrial Competitiveness Act.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 are model results and may differ from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2014 National Energy Modeling System, runs REF2014.D102413A, and ESICA.D021014A.

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Table D13. Key results for no greenhouse gas concern case

(million short tons per year, unless otherwise noted)

Supply, disposition, prices, and electricity generating capacity additions	2012	2020		2030		2040	
		Reference	No GHG Concern	Reference	No GHG Concern	Reference	No GHG Concern
Production[1]	1,016	1,077	1,084	1,127	1,136	1,121	1,159
Appalachia	293	261	262	253	255	247	252
Interior	180	228	231	266	268	289	310
West	543	587	591	607	613	584	597
Waste coal supplied[2]	11	14	14	15	15	19	20
Net imports[3]	-118	-126	-126	-147	-147	-160	-160
Total supply[4]	**909**	**965**	**971**	**995**	**1,004**	**979**	**1,020**
Consumption by sector							
Commercial and institutional	2	2	2	2	2	2	2
Coke plants	21	22	22	21	21	18	18
Other industrial[5]	43	49	49	49	49	50	50
Coal-to-liquids	0	0	0	0	0	0	0
Electric power[6]	825	892	898	923	931	909	950
Total coal consumption	**891**	**965**	**971**	**995**	**1,004**	**979**	**1,020**
Average minemouth price[7]							
(2012 dollars per short ton)	39.94	46.52	46.53	53.15	53.15	59.16	59.33
(2012 dollars per million Btu)	1.98	2.33	2.33	2.67	2.67	2.96	2.98
Delivered prices[8]							
(2012 dollars per short ton)							
Commercial and institutional	90.76	95.19	95.30	101.39	102.33	108.37	109.02
Coke plants	190.55	221.01	221.03	249.43	249.52	267.23	267.29
Other industrial[5]	70.32	76.39	76.44	82.64	83.42	89.22	90.11
Coal to liquids	--	--	--	--	--	--	--
Electric power[6]	46.13	49.63	49.71	55.32	55.37	60.61	61.20
Average	**50.85**	**54.99**	**55.04**	**60.85**	**60.90**	**65.97**	**66.35**
Electric power (2012 dollars per million Btu)[6]	2.39	2.61	2.62	2.93	2.93	3.19	3.23
Exports[9]	118.43	136.76	136.75	145.97	146.13	150.13	150.56
Electricity generating capacity (gigawatts)							
Cumulative capacity additions[10]							
Coal	0.0	2.5	2.5	2.5	4.1	2.6	13.0
Conventional with scrubber	0.0	1.0	1.0	1.0	2.6	1.1	11.5
IGCC without sequestration	0.0	0.6	0.6	0.6	0.6	0.6	0.6
IGCC with sequestration	0.0	0.9	0.9	0.9	0.9	0.9	0.9
End-use generators[11]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural gas	0.0	41.7	40.6	142.6	139.3	255.2	246.4
Nuclear / uranium	0.0	5.5	5.5	5.8	5.5	9.7	7.2
Renewables[12]	0.0	36.4	36.5	49.6	49.3	83.3	77.7
Other	0.0	0.6	0.6	0.6	0.6	0.6	0.6
Total cumulative additions	**0.0**	**86.7**	**85.7**	**201.1**	**198.9**	**351.5**	**344.9**
Cumulative coal capacity retirements[13]	0.0	49.9	48.5	50.7	49.3	50.8	49.4
Total coal capacity	310.0	262.6	264.0	261.8	264.8	261.8	273.6
Liquids from coal (million barrels per day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00

[1]Includes anthracite, bituminous coal, subbituminous coal, and lignite.
[2]Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
[3]Excludes imports to Puerto Rico and the U.S. Virgin Islands.
[4]Production plus waste coal supplied plus net imports.
[5]Includes consumption for combined heat and power plants that have a non-regulatory status, and small on-site generating systems. Excludes all coal use in the coal-to-liquids process.
[6]Includes all electricity-only and combined heat and power plants that have a regulatory status.
[7]Includes reported prices for both open market and captive mines. Prices weighted by production, which differs from average minemouth prices published in EIA data reports where it is weighted by reported sales.
[8]Prices weighted by consumption tonnage; weighted average excludes export free-alongside-ship prices.
[9]Free-alongside-ship price at U.S. port of exit.
[10]Cumulative additions after December 31, 2012. Includes all additions of electricity only and combined heat and power plants projected for the electric power, industrial, and commercial sectors.
[11]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors that have a non-regulatory status. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[12]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
[13]Cumulative retirements after December 31, 2012. Includes retirements of electricity-only and combined heat and power plants that have a regulatory status.
-- = Not applicable.
Btu = British thermal unit.
GHG = Greenhouse gas.
IGCC = Integrated coal-gasification combined cycle.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 are model results and may differ from official EIA data reports.
Sources: 2012 data based on: U.S. Energy Information Administration (EIA), *Annual Coal Report 2012*, DOE/EIA-0584(2012) (Washington, DC, December 2013); EIA, *Quarterly Coal Report, October-December 2012*, DOE/EIA-0121(2012/4Q) (Washington, DC, March 2013); and EIA, AEO2014 National Energy Modeling System run REF2014.D102413A. **Projections:** EIA, AEO2014 National Energy Modeling System runs REF2014.D102413A and NOGHGCONCERN.D120413A.

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Table D14. Key results and assumptions for coal cost cases

(million short tons per year, unless otherwise noted)

Supply, disposition, prices, electricity generating capacity, and costs	2012	2020			2040			Annual growth 2012-2040 (percent)		
		Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost
Production[1]	1,016	1,122	1,077	1,003	1,244	1,121	814	0.7%	0.3%	-0.8%
Appalachia	293	271	261	247	293	247	200	0.0%	-0.6%	-1.4%
Interior	180	230	228	225	268	289	253	1.4%	1.7%	1.2%
West	543	622	587	530	683	584	360	0.8%	0.3%	-1.5%
Waste coal supplied[2]	11	11	14	15	11	19	27	0.1%	1.9%	3.2%
Net imports[3]	-118	-127	-126	-122	-201	-160	-69	1.9%	1.1%	-1.9%
Total supply[4]	**909**	**1,006**	**965**	**895**	**1,054**	**979**	**771**	**0.5%**	**0.3%**	**-0.6%**
Consumption by sector										
Commercial and institutional	2	2	2	2	2	2	2	0.0%	-0.1%	-0.2%
Coke plants	21	22	22	22	18	18	17	-0.4%	-0.5%	-0.6%
Other industrial[5]	43	49	49	49	51	50	49	0.6%	0.5%	0.4%
Coal-to-liquids	0	0	0	0	0	0	0	--	--	--
Electric power[6]	825	933	892	822	983	909	705	0.6%	0.3%	-0.6%
Total coal use	**891**	**1,006**	**965**	**895**	**1,054**	**979**	**773**	**0.6%**	**0.3%**	**-0.5%**
Average minemouth price[7]										
(2012 dollars per short ton)	39.94	39.46	46.52	55.11	32.29	59.16	113.47	-0.8%	1.4%	3.8%
(2012 dollars per million Btu)	1.98	1.97	2.33	2.76	1.61	2.96	5.54	-0.7%	1.4%	3.7%
Delivered prices[8]										
(2012 dollars per short ton)										
Commercial and institutional	90.76	86.19	95.19	105.18	70.73	108.37	165.32	-0.9%	0.6%	2.2%
Coke plants	190.55	197.05	221.01	248.69	170.56	267.23	428.62	-0.4%	1.2%	2.9%
Other industrial[5]	70.32	68.17	76.39	85.17	55.92	89.22	141.81	-0.8%	0.9%	2.5%
Coal to liquids	--	--	--	--	--	--	--	--	--	--
Electric power[6]										
(2012 dollars per short ton)	46.13	44.13	49.63	55.83	35.89	60.61	105.06	-0.9%	1.0%	3.0%
(2012 dollars per million Btu)	2.39	2.31	2.61	2.95	1.89	3.19	5.36	-0.8%	1.0%	2.9%
Average	**50.85**	**48.76**	**54.99**	**62.22**	**39.28**	**65.97**	**114.80**	**-0.9%**	**0.9%**	**3.0%**
Exports[9]	118.43	120.29	136.76	155.84	96.59	150.13	250.91	-0.7%	0.9%	2.7%
Electricity generating capacity (gigawatts)										
Capacity										
Coal	310.0	269.1	262.6	244.2	274.0	261.8	243.3	-0.4%	-0.6%	-0.9%
Conventional	306.2	263.8	257.3	238.9	268.7	256.5	238.0	0.0	0.0	0.0
IGCC without sequestration	0.4	1.0	1.0	1.0	1.0	1.0	1.0	0.0	0.0	0.0
IGCC with sequestration	0.0	0.9	0.9	0.9	0.9	0.9	0.9	--	--	--
End-use generators[10]	3.4	3.4	3.4	3.4	3.4	3.4	3.4	0.0%	0.0%	0.0%
Natural gas	367.9	397.3	401.5	410.7	609.5	613.7	622.8	1.8%	1.8%	1.9%
Nuclear / uranium	102.1	97.8	97.8	97.8	100.5	102.0	101.4	-0.1%	0.0%	0.0%
Renewables[11]	159.4	195.1	194.9	196.0	248.0	241.8	239.0	1.6%	1.5%	1.5%
Other	126.3	112.6	112.6	111.4	96.8	96.2	94.7	-0.9%	-1.0%	-1.0%
Total capacity	**1,065.8**	**1,072.0**	**1,069.5**	**1,060.2**	**1,328.9**	**1,315.6**	**1,301.3**	**0.8%**	**0.8%**	**0.7%**
Cumulative capacity additions[12]										
Coal	0.0	2.5	2.5	2.5	8.2	2.6	2.5	--	--	--
Conventional with scrubber	0.0	1.0	1.0	1.0	6.8	1.1	1.0	--	--	--
IGCC without sequestration	0.0	0.6	0.6	0.6	0.6	0.6	0.6	--	--	--
IGCC with sequestration	0.0	0.9	0.9	0.9	0.9	0.9	0.9	--	--	--
End-use generators[10]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	--	--	--
Natural gas	0.0	37.5	41.7	51.1	251.0	255.2	264.3	--	--	--
Nuclear / uranium	0.0	5.5	5.5	5.5	8.2	9.7	9.1	--	--	--
Renewables[11]	0.0	36.6	36.4	37.5	89.5	83.3	80.5	--	--	--
Other	0.0	0.6	0.6	0.6	0.6	0.6	0.6	--	--	--
Total cumulative additions	**0.0**	**82.7**	**86.7**	**97.2**	**357.6**	**351.5**	**357.1**	**--**	**--**	**--**
Cumulative capacity retirements[13]										
Coal	0.0	43.4	49.9	68.3	44.2	50.8	69.2	--	--	--
Natural gas	0.0	8.1	8.1	8.3	9.4	9.4	9.5	--	--	--
Nuclear / uranium	0.0	4.8	4.8	4.8	4.8	4.8	4.8	--	--	--
Renewables[11]	0.0	0.9	0.9	0.9	0.9	0.9	0.9	--	--	--
Other	0.0	14.3	14.4	15.6	30.1	30.8	32.2	--	--	--
Total cumulative retirements	**0.0**	**71.5**	**78.0**	**97.9**	**89.5**	**96.7**	**116.6**	**--**	**--**	**--**
Liquids from coal (million barrels per day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	--	--	--

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Table D14. Key results and assumptions for coal cost cases (continued)

(million short tons per year, unless otherwise noted)

Supply, disposition, prices, electricity generating capacity, and costs	2012	2020			2040			Annual growth 2012-2040 (percent)		
		Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost
Cost indices										
(constant dollar index, 2012=1.000)										
Transportation rate multipliers										
Eastern railroads	1.000	0.960	1.022	1.090	0.760	1.008	1.260	-1.0%	0.0%	0.8%
Western railroads	1.000	0.940	1.005	1.070	0.750	0.996	1.250	-1.0%	0.0%	0.8%
Mine equipment costs										
Underground	1.000	0.932	1.000	1.072	0.762	1.000	1.308	-1.0%	0.0%	1.0%
Surface	1.000	0.932	1.000	1.072	0.762	1.000	1.308	-1.0%	0.0%	1.0%
Other mine supply costs										
East of the Mississippi: all mines	1.000	0.932	1.000	1.072	0.762	1.000	1.308	-1.0%	0.0%	1.0%
West of the Mississippi: underground	1.000	0.932	1.000	1.072	0.762	1.000	1.308	-1.0%	0.0%	1.0%
West of the Mississippi: surface	1.000	0.932	1.000	1.072	0.762	1.000	1.308	-1.0%	0.0%	1.0%
Coal mining labor productivity (short tons per miner per hour)	5.19	5.52	4.64	3.85	6.89	3.68	1.68	1.0%	-1.2%	-4.0%
Average coal miner wage (2012 dollars per year)	80,450	87,295	93,666	100,431	79,835	104,525	136,440	0.0%	0.9%	1.9%

[1]Includes anthracite, bituminous coal, subbituminous coal, and lignite.
[2]Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
[3]Excludes imports to Puerto Rico and the U.S. Virgin Islands.
[4]Production plus waste coal supplied plus net imports.
[5]Includes consumption for combined heat and power plants that have a non-regulatory status, and small on-site generating systems. Excludes all coal use in the coal to liquids process.
[6]Includes all electricity-only and combined heat and power plants that have a regulatory status.
[7]Includes reported prices for both open market and captive mines. Prices weighted by production, which differs from average minemouth prices published in EIA data reports where it is weighted by reported sales.
[8]Prices weighted by consumption tonnage; weighted average excludes export free-alongside-ship prices.
[9]Free-alongside-ship price at U.S. port of exit.
[10]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors that have a non-regulatory status. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[11]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
[12]Cumulative additions after December 31, 2012. Includes all additions of electricity-only and combined heat and power plants projected for the electric power, industrial, and commercial sectors.
[13]Cumulative retirements after December 31, 2012. Includes retirements of electricity-only and combined heat and power plants that have a regulatory status.
- - = Not applicable.
Btu = British thermal unit.
IGCC = Integrated coal-gasification combined cycle.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 are model results and may differ from official EIA data reports.
Sources: 2012 data based on: U.S. Energy Information Administration (EIA), *Annual Coal Report 2012*, DOE/EIA-0584(2012) (Washington, DC, December 2013); EIA, *Quarterly Coal Report, October-December 2012*, DOE/EIA-0121(2012/4Q) (Washington, DC, March 2013); U.S. Department of Labor, Bureau of Labor Statistics, Quarterly Census of Employment and Wages: Coal Mining, Series ID: ENUUS0005052121; and EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.
Projections: EIA, AEO2014 National Energy Modeling System runs LCCST14.D120413A, REF2014.D102413A, and HCCST14.D120413A.

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Appendix E

NEMS overview and brief description of cases

The National Energy Modeling System

Projections in the *Annual Energy Outlook 2014* (AEO2014) are generated using the National Energy Modeling System (NEMS) [1], developed and maintained by the Office of Energy Analysis of the U.S. Energy Information Administration (EIA). In addition to its use in developing the *Annual Energy Outlook* (AEO) projections, NEMS is used to complete analytical studies for the U.S. Congress, the Executive Office of the President, other offices within the U.S. Department of Energy (DOE), and other federal agencies. NEMS is also used by nongovernment groups, such as the Electric Power Research Institute, Duke University, and Georgia Institute of Technology. In addition, AEO projections are used by analysts and planners in other government agencies and nongovernmental organizations.

The projections in NEMS are developed with the use of a market-based approach, subject to regulations and standards. For each fuel and consuming sector, NEMS balances energy supply and demand, accounting for economic competition across the various energy fuels and sources. The time horizon of NEMS extends to 2040. To represent regional differences in energy markets, the component modules of NEMS function at the regional level: the 9 Census divisions for the end-use demand modules; production regions specific to oil, natural gas, and coal supply and distribution; 22 regions and subregions of the North American Electric Reliability Corporation for electricity; and 9 refining regions that are a subset of the 5 Petroleum Administration for Defense Districts (PADDs).

NEMS is organized and implemented as a modular system. The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. The modular design also permits the use of the methodology and level of detail most appropriate for each energy sector. NEMS executes each of the component modules to solve for prices of energy delivered to end users and the quantities consumed, by product, region, and sector. The delivered fuel prices encompass all activities necessary to produce, import, and transport fuels to end users. The information flows also include such areas as economic activity, domestic production, and international petroleum supply. NEMS calls each supply, conversion, and end-use demand module in sequence until the delivered prices of energy and the quantities demanded have converged within tolerance, thereby achieving an economic equilibrium of supply and demand in the consuming sectors. A solution is reached for each year from 2013 through 2040. Other variables, such as petroleum product imports, crude oil imports, and several macroeconomic indicators, also are evaluated for convergence.

Each NEMS component represents the effects and costs of legislation and environmental regulations that affect each sector. NEMS accounts for all energy-related carbon dioxide (CO_2) emissions, as well as emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_X), and mercury from the electricity generation sector.

The version of NEMS used for AEO2014 generally represents current legislation and environmental regulations, including recent government actions for which implementing regulations were available as of October 31, 2013, as discussed in the Legislation and Regulations section of the AEO. The potential effects of proposed federal and state legislation, regulations, or standards—or of sections of legislation that have been enacted but require funds or implementing regulations that have not been provided or specified—are not reflected in NEMS. Many of the pending provisions are examined, however, in alternative cases included in AEO2014 or in other analysis completed by EIA.

In general, the historical data presented with AEO2014 projections are based on various EIA publications [2]; however, data were taken from multiple sources. Historical numbers are presented for comparison only and may be estimates. Source documents should be consulted for the official data values. Footnotes to AEO2014 appendix tables indicate the definitions and sources of historical data.

Where possible AEO2014, which was developed during the summer of 2013, presents information for 2013 and 2014 that is consistent with the short-term projections from EIA's September 2013 *Short-Term Energy Outlook* (STEO) [3]. EIA's views regarding energy use over the 2013 through 2015 period are reported in monthly STEO updates [4], which should be considered to supersede information reported for those years in AEO2014.

Component modules

The component modules of NEMS represent the individual supply, demand, and conversion sectors of domestic energy markets and also include international and macroeconomic modules. In general, the modules interact through values representing prices or expenditures for energy delivered to the consuming sectors and the quantities of end-use energy consumption.

Macroeconomic Activity Module

The Macroeconomic Activity Module (MAM) provides a set of macroeconomic drivers to the energy modules and receives energy-related indicators from the NEMS energy components as part of the macroeconomic feedback mechanism within NEMS. Key macroeconomic variables used in the energy modules include gross domestic product (GDP), disposable income, values of industrial shipments, new housing starts, sales of new light-duty vehicles (LDVs), interest rates, and employment. Key energy indicators fed back to the MAM include aggregate energy prices and quantities. The MAM uses the following models from IHS

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Global Insight: Macroeconomic Model of the U.S. Economy, National Industrial Output model, and National Employment by Industry Model. In addition, EIA has constructed a Regional Economic, Industrial Output and Employment by Industry model to project regional economic drivers, and a Commercial Floorspace model to project 13 floorspace types in the nine Census divisions. The accounting framework for industrial value of shipments uses the North American Industry Classification System (NAICS).

International Energy Module

The International Energy Module (IEM) uses assumptions of economic growth and expectations of future U.S. and world petroleum and other liquids production and consumption, by year, to project the interaction of U.S. and international petroleum and other liquids markets. This module provides a world crude-like liquids supply curve and generates a worldwide oil supply/demand balance for each year of the projection period. The supply-curve calculations are based on historical market data and a world oil supply/demand balance, which is developed from reduced-form models of international petroleum and other liquids supply and demand, current investment trends in exploration and development, and long-term resource economics by country and territory. The oil production estimates include both petroleum and other liquids supply recovery technologies. The IEM also provides, for each year of the projection period, endogenous assumptions for petroleum products for import and export in the United States. The IEM, through interaction with the rest of NEMS, changes North Sea Brent and West Texas Intermediate (WTI) prices in response to changes in expected production and consumption of crude-like liquids in the United States.

Residential and Commercial Demand Modules

The Residential Demand Module projects energy consumption in the residential sector by Census division, housing type, and end use, based on delivered energy prices, the menu of equipment available, the availability of renewable sources of energy, and changes in the housing stock. The Commercial Demand Module projects energy consumption in the commercial sector by Census division, building type, and category of end use, based on delivered prices of energy, the menu of available equipment, availability of renewable sources of energy, and changes in commercial floorspace.

Both modules estimate the equipment stock for the major end-use services, incorporating assessments of advanced technologies, representations of renewable energy technologies, and the effects of both building shell and appliance standards. The modules also include projections of distributed generation. The Commercial Demand Module also incorporates combined heat and power (CHP) technology. Both modules incorporate projections of heating and cooling degree-days by Census division, based on a 30-year historical trend and on state-level population projections. The Residential Demand Module projects an increase in the average square footage of both new construction and existing structures, based on trends in new construction and remodeling.

Industrial Demand Module

The Industrial Demand Module (IDM) projects the consumption of energy for heat and power, as well as the consumption of feedstocks and raw materials in each of 21 industry groups, subject to the delivered prices of energy and macroeconomic estimates of employment and the value of shipments for each industry. As noted in the description of MAM, the representation of industrial activity in NEMS is based on the NAICS. The industries are classified into three groups—energy-intensive manufacturing, non-energy-intensive manufacturing, and nonmanufacturing. Seven of eight energy-intensive manufacturing industries are modeled in the IDM, including energy-consuming components for boiler/steam/cogeneration, buildings, and process/assembly use of energy. Energy demand for petroleum and other liquids refining (the other energy-intensive manufacturing industry) is modeled in the Liquid Fuels Market Module (LFMM) as described below, but the projected consumption is reported under the industrial totals.

There are several updates and upgrades in the representations of select industries. AEO2014 includes an upgraded representation for the glass industry. Instead of assuming that technological development for a particular process occurs on a predetermined or exogenous path based on engineering judgment, these upgrades allow technological change in the glass industry to be modeled endogenously, using a more detailed process flow representation. The upgrade allows for explicit technological change, and therefore energy intensity, to respond to economic, regulatory, and other conditions. The combined cement and lime industries and aluminum industry were upgraded to process flow models in previous AEOs. The iron and steel and paper industries will be similarly upgraded in future AEOs.

Model input data associated with energy intensity were aligned with the Manufacturing Energy Consumption Survey 2010 data. In the bulk chemicals model, behavior of naphtha and ethane prices was modified to better respond to oil price cases. The cement model was modified to include multichannel burners that add flexibility for fuel mix, allowing the use of significant amounts of secondary fuels, such as alternative solid fuels including tires, plastics, wood, and waste. The model also includes more rapid penetration of energy-efficient grinding. In the food industry, shipments were categorized in more detail, to grain and oil seed milling, dairy, animal slaughter, and all other. Changes also were made to the nonmanufacturing data approach. Census, U.S. Department of Agriculture, and EIA's Fuel Oil Kerosene Sales data were used to improve projections of petroleum product and natural gas consumption in agriculture, construction, and mining. CHP use is now differentiated by region and industry, based on EIA's updated historical data.

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Transportation Demand Module

The Transportation Demand Module projects consumption of energy by mode and fuel—including petroleum products, electricity, methanol, ethanol, compressed natural gas (CNG), liquefied natural gas (LNG), and hydrogen—in the transportation sector, subject to delivered energy prices, macroeconomic variables such as GDP, and other factors such as technology adoption and consumer behavior. The Transportation Demand Module includes legislation and regulations—such as the Energy Policy Act of 2005 (EPACT2005), the Energy Improvement and Extension Act of 2008 (EIEA2008), and the American Recovery and Reinvestment Act of 2009 (ARRA2009)—which contain tax credits for the purchase of alternatively fueled vehicles. Representations of LDV corporate average fuel economy (CAFE) and greenhouse gas (GHG) emissions standards, heavy-duty vehicle (HDV) fuel consumption and GHG emissions standards, and biofuels consumption reflect standards enacted by the National Highway Traffic Safety Administration (NHTSA) and the U.S. Environmental Protection Agency (EPA), as well as provisions in the Energy Independence and Security Act of 2007 (EISA2007).

The air transportation component of the Transportation Demand Module represents air travel in domestic and foreign markets and includes the industry practice of parking aircraft in both domestic and international markets to reduce operating costs, as well as the movement of aging aircraft from passenger to cargo markets. For passenger travel and air freight shipments, the module represents regional fuel use and travel demand for three aircraft types: regional, narrow-body, and wide-body. An infrastructure constraint, which is also modeled, can potentially limit overall growth in passenger and freight air travel to levels commensurate with industry-projected infrastructure expansion and capacity growth.

The Transportation Demand Module projects energy consumption for freight and passenger rail and marine vessels by mode and fuel, subject to macroeconomic variables such as the value and type of industrial shipments. Freight ton-miles and efficiency also are projected in the model.

Electricity Market Module

There are three primary submodules of the Electricity Market Module (EMM)—capacity planning, fuel dispatching, and finance and pricing. The capacity expansion submodule uses the stock of existing generation capacity, known environmental regulations, the expected cost and performance of future generation capacity, expected fuel prices, expected financial parameters, and expected electricity demand to project the optimal mix of new generation capacity that should be added in future years. The fuel dispatching submodule uses the existing stock of generation equipment types, their operation and maintenance costs and performance, fuel prices to the electricity sector, electricity demand, and all applicable environmental regulations to determine the least-cost way to meet that demand. This submodule also determines transmission and pricing of electricity. The finance and pricing submodule uses capital costs, fuel costs, macroeconomic parameters, environmental regulations, and load shapes to estimate generation costs for each technology.

All specifically identified options promulgated by EPA for compliance with the Clean Air Act Amendments of 1990 are explicitly represented in the capacity expansion and dispatch decisions. All financial incentives for power generation expansion and dispatch specifically identified in EPACT2005 have been implemented. Several states, primarily in the Northeast, have enacted air emission regulations for CO_2 that affect the electricity generation sector, and those regulations are represented in AEO2014. The AEO2014 Reference case also imposes a limit on CO_2 emissions for specific covered sectors, including the electric power sector in California as represented in California Assembly Bill 32, the Global Warming Solutions Act of 2006 (AB 32). The AEO2014 Reference case leaves the Clean Air Interstate Rule (CAIR) in effect after the court vacated the Cross-State Air Pollution Rule in August 2012. CAIR incorporates a cap-and-trade program for annual emissions of SO_2 and annual and seasonal emissions of NO_X from fossil fuel power plants. Reductions in hazardous air pollutant emissions from coal- and oil-fired steam electric power plants also are reflected through the inclusion of the Mercury and Air Toxics Standards for power plants, finalized by EPA on December 16, 2011.

Although currently there is no federal legislation in place that restricts GHG emissions, regulators and the investment community have continued to push energy companies to invest in technologies that are less GHG-intensive. The trend is captured in the AEO2014 Reference case through a 3-percentage-point increase in the cost of capital when evaluating investments in new coal-fired power plants, new coal-to-liquids (CTL) plants without carbon capture and storage (CCS), and pollution control retrofits.

Renewable Fuels Module

The Renewable Fuels Module (RFM) includes submodules representing renewable resource supply and technology input information for central-station, grid-connected electricity generation technologies, including conventional hydroelectricity, biomass (dedicated biomass plants and co-firing in existing coal plants), geothermal, landfill gas, solar thermal electricity, solar photovoltaics (PV), and both onshore and offshore wind energy. The RFM contains renewable resource supply estimates representing the regional opportunities for renewable energy development. Investment tax credits (ITCs) for renewable fuels are incorporated, as currently enacted, including a permanent 10% ITC for business investment in solar energy (thermal nonpower uses as well as power uses) and geothermal power (available only to those projects not accepting the production tax credit [PTC] for geothermal power). In addition, the module reflects the increase in the ITC to 30% for solar energy systems installed before January 1, 2017. The extension of the credit to individual homeowners under EIEA2008 is reflected in the Residential and Commercial Demand Modules.

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PTCs for wind, geothermal, landfill gas, and some types of hydroelectric and biomass-fueled plants also are represented. They provide a credit of up to 2.3 cents/kilowatthour (kWh) for electricity produced in the first 10 years of plant operation. For AEO2014, EIA represents the expiration of the PTC that occurred at the end of 2013. However, because the expiration date reflects an under-construction versus in-service deadline, the effective modeled eligibility deadline is extended to new wind and landfill gas plants coming online by the end of 2015, and to other eligible plants coming online by the end of 2016. AEO2014 also accounts for new renewable energy capacity resulting from state renewable portfolio standard programs, mandates, and goals, as described in Assumptions to the Annual Energy Outlook 2014 [5].

Oil and Gas Supply Module

The Oil and Gas Supply Module represents domestic crude oil and natural gas supply within an integrated framework that captures the interrelationships among the various sources of supply—onshore, offshore, and Alaska—by all production techniques, including natural gas recovery from coalbeds and low-permeability geologic formations. The framework analyzes cash flow and profitability to compute investment and drilling for each of the supply sources, based on the prices for crude oil and natural gas, the domestic recoverable resource base, and the state of technology. Oil and natural gas production activities are modeled for 12 supply regions, including six onshore, three offshore, and in three Alaska regions.

The Onshore Lower 48 Oil and Gas Supply Submodule evaluates the economics of future exploration and development projects for crude oil and natural gas plays. Crude oil resources include structurally reservoired resources (i.e., conventional) as well as highly fractured continuous zones, such as the Austin Chalk and Bakken shale formations. Production potential from advanced secondary recovery techniques (such as infill drilling, horizontal continuity, and horizontal profile) and enhanced oil recovery (such as CO_2 flooding, steam flooding, polymer flooding, and profile modification) are explicitly represented. Natural gas resources include high-permeability carbonate and sandstone, tight gas, shale gas, and coalbed methane.

Domestic crude oil production volumes are used as inputs to the LFMM for conversion and blending into refined petroleum products. Supply curves for natural gas are used as inputs to the Natural Gas Transmission and Distribution Module (NGTDM) for determining natural gas wellhead prices and domestic production.

Natural Gas Transmission and Distribution Module

The NGTDM represents the transmission, distribution, and pricing of natural gas, subject to end-use demand for natural gas and the availability of domestic natural gas and natural gas traded on the international market. The module balances natural gas supply and demand, tracks the flows of natural gas, and determines the associated capacity expansion requirements in an aggregate pipeline network, connecting domestic and limited foreign supply sources with 12 lower 48 states regions. The 12 lower 48 states regions align with the nine Census divisions, with three subdivided, and Alaska handled separately. The flow of natural gas is determined for both a peak and off-peak period in the year, assuming a historically based seasonal distribution of natural gas demand. Key components of pipeline and distributor tariffs are included in separate pricing algorithms. The primary outputs of the module are delivered natural gas prices by region and sector, supply prices, and realized domestic natural gas production. The module also projects natural gas pipeline imports and exports to Canada and Mexico, as well as LNG imports and exports.

Liquid Fuels Market Module

The LFMM projects prices of petroleum products, crude oil and product import/export activity, and domestic refinery operations, subject to demand for petroleum products, availability and price of imported petroleum, environmental regulations, and domestic production of crude oil, natural gas liquids, and biofuels—ethanol, biodiesel, biomass-to-liquids (BTL), CTL, gas-to-liquids (GTL), and coal-and-biomass-to-liquids (CBTL). Costs, performance, and first dates of commercial availability for the advanced liquid fuels technologies [6] are reviewed and updated annually.

The module represents refining activities in eight U.S. regions, and a new Maritime Canada/Caribbean refining region (created to represent short-haul international refineries that predominantly serve U.S. markets). In order to better represent policy, import/export patterns, and biofuels production, the eight U.S. regions are defined by subdividing three of the five U.S. PADDs. All nine refining regions are defined below:

Region 1. PADD I - East Coast
Region 2. PADD II - Interior
Region 3. PADD II - Great Lakes
Region 4. PADD III - Gulf Coast
Region 5. PADD III - Interior
Region 6. PADD IV - Mountain
Region 7. PADD V - California
Region 8. PADD V - Other
Region 9. Maritime Canada/Caribbean.

The LFMM models the costs of automotive fuels, such as conventional and reformulated gasoline, and includes production of biofuels for blending in gasoline and diesel. Fuel ethanol and biodiesel are included in the LFMM because they are commonly

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blended into petroleum products. The module allows ethanol blending into gasoline at 10% by volume (E10), 15% by volume (E15) in states that lack explicit language capping ethanol volume or oxygen content, and up to 85% by volume (E85) for use in flex-fuel vehicles. The module also includes a 16% by volume biobutanol/gasoline blend. Crude oil and refinery product imports are represented by supply curves defined by the NEMS IEM. Products also can be imported from refining region nine (Maritime Canada/Caribbean). Refinery product exports are represented by demand curves, also provided by the IEM.

Capacity expansion of refinery process units and nonpetroleum liquid fuels production facilities is also modeled in the LFMM. The model uses current liquid fuels production capacity, the cost and performance of each production unit, expected fuel and feedstock costs, expected financial parameters, expected liquid fuels demand, and relevant environmental policies to project the optimal mix of new capacity that should be added in the future.

The LFMM includes representation of the renewable fuels standard (RFS) specified in EISA2007, which mandates the use of 36 billion gallons of ethanol equivalent renewable fuel by 2022. Both domestic and imported biofuels count toward the RFS. Domestic ethanol production is modeled for three feedstock categories: corn, cellulosic plant materials, and advanced feedstock materials. Starch-based ethanol plants are numerous (more than 175 are now in operation, with a total maximum sustainable nameplate capacity of more than 13 billion gallons annually), and are based on a well-known technology that converts starch and sugar into ethanol. Ethanol from cellulosic sources is a new technology with only a few small pilot plants in operation. Ethanol from advanced feedstocks—produced at ethanol refineries that ferment and distill grains other than corn, and reduce GHG emissions by at least 50%—is another new technology modeled in the LFMM. The LFMM also has the capability to produce biobutanol from a retrofitted corn ethanol facility, if economically competitive.

Fuels produced by Fischer-Tropsch synthesis and through a pyrolysis process are also modeled in the LFMM, based on their economics compared with competing feedstocks and products. The five processes modeled are CTL, CBTL, GTL, BTL, and pyrolysis.

Two California-specific policies are also represented in the LFMM: the low carbon fuel standard (LCFS) and the AB 32 cap-and-trade program. The LCFS requires the carbon intensity (amount of greenhouse gases/unit of energy) of transportation fuels sold for use in California to decrease according to a schedule published by the California Air Resources Board. California's AB 32 cap-and-trade program is established to help California achieve its goal of reducing CO_2 emissions to 1990 levels by 2020. Working with other NEMS modules (IDM, EMM, and Emissions Policy Module), the LFMM provides emissions allowances and actual emissions of CO_2 from California refineries, and NEMS provides the mechanism (carbon price) to trade allowances such that the total CO_2 emissions cap is met.

Coal Market Module

The Coal Market Module (CMM) simulates mining, transportation, and pricing of coal, subject to end-use demand for coal differentiated by heat and sulfur content. U.S. coal production is represented in the CMM by 41 separate supply curves—differentiated by region, mine type, coal rank, and sulfur content. The coal supply curves respond to mining capacity, capacity utilization of mines, labor productivity, and factor input costs (mining equipment, mining labor, and fuel requirements). Projections of U.S. coal distribution are determined by minimizing the cost of coal supplied, given coal demands by region and sector; environmental restrictions; and accounting for minemouth prices, transportation costs, and coal supply contracts. Over the projection horizon, coal transportation costs in the CMM vary in response to changes in the cost of rail investments.

The CMM produces projections of U.S. steam and metallurgical coal exports and imports in the context of world coal trade, determining the pattern of world coal trade flows that minimizes production and transportation costs while meeting a specified set of regional coal import demands, subject to constraints on export capacities and trade flows. The international coal market component of the module computes trade in two types of coal (steam and metallurgical) for 17 export regions and 20 import regions. U.S. coal production and distribution are computed for 14 supply regions and 16 demand regions.

Annual Energy Outlook 2014 cases

Table E1 provides a summary of the cases produced as part of AEO2014. For each case, the table gives the name used in AEO2014, a brief description of the major assumptions underlying the projections, and a reference to the pages in the body of the report and in this appendix where the case is discussed. The text sections following Table E1 describe the various cases in more detail. The Reference case assumptions for each sector are described in Assumptions to the Annual Energy Outlook 2014 [7]. Regional results and other details of the projections are available at http://www.eia.gov/forecasts/aeo/tables_ref.cfm#supplement.

Macroeconomic growth cases

In addition to the AEO2014 Reference case, Low Economic Growth and High Economic Growth cases were developed to reflect the uncertainty in projections of economic growth. The alternative cases are intended to show the effects of alternative growth assumptions on energy market projections. The cases are described as follows:

- In the Reference case, population grows by 0.7%/year, nonfarm employment by 0.8%/year, and labor productivity by 1.8%/year from 2012 to 2040. Economic output as measured by real GDP increases by 2.4%/year from 2012 through 2040, and growth in real disposable income per capita averages 1.7%/year.

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Table E1. Summary of the AEO2014 cases

Case name	Description	Reference in text	Reference in Appendix E
Reference	Real GDP grows at an average annual rate of 2.4% from 2012 to 2040. Crude oil prices rise to about $141/barrel (2012 dollars) in 2040. Complete projection tables in Appendix A.	--	--
Low Economic Growth	Real GDP grows at an average annual rate of 1.9% from 2012 to 2040. Other energy market assumptions are the same as in the Reference case. Partial projection tables in Appendix B.	p. MT-2	p. E-8
High Economic Growth	Real GDP grows at an average annual rate of 2.8% from 2012 to 2040. Other energy market assumptions are the same as in the Reference case. Partial projection tables in Appendix B.	p. MT-2	p. E-9
Low Oil Price	Low prices result from a combination of low demand for petroleum and other liquids in the non-Organization for Economic Cooperative Development (non-OECD) nations and higher global supply. Lower demand is measured by lower economic growth relative to the Reference case. On the supply side, the Organization of the Petroleum Exporting Countries (OPEC) increases its market share to 51%, and the costs of other liquids production technologies are lower than in the Reference case. Light, sweet crude oil prices fall to $70/barrel in 2017 and rise slowly to $75/barrel in 2040. Partial projection tables in Appendix C.	p. MT-3	p. E-9
High Oil Price	High prices result from a combination of higher demand for liquid fuels in non-OECD nations and lower global supply. Higher demand is measured by higher economic growth relative to the Reference case. OPEC market share averages 37% throughout the projection. Non-OPEC petroleum production expands more slowly in the short to middle term relative to the Reference case. Crude oil prices rise to $204/barrel (2012 dollars) in 2040. Partial projection tables in Appendix C.	p. MT-3	p. E-9
No Sunset	Begins with the Reference case and assumes extension of all existing tax credits and policies that contain sunset provisions, except those requiring additional funding (e.g., loan guarantee programs) and those that involve extensive regulatory analysis, such as CAFE improvements and periodic updates of efficiency standards. Also includes extension of the $1.01/gallon ethanol subsidy and $1.00/gallon biodiesel subsidy to the end of the projection period. Partial projection tables in Appendix D.	p. IF-3	p. E-10
Extended Policies	Begins with the No Sunset case but excludes extension of the ethanol and biofuel subsidies that were included in the No Sunset case. Assumes an increase in the capacity limitations on the ITC for CHP and extension of the program. The case includes additional rounds of efficiency standards for residential and commercial products, as well as new standards for products not yet covered; adds multiple rounds of national building codes by 2026; and increases LDV and HDV fuel economy standards in the transportation sector. Partial projection tables in Appendix D.	p. IF-3	p. E-10
High Rail LNG	Assumes a higher LNG locomotive penetration rate into motive stock such that 100% of locomotives are LNG capable by 2037. Partial projection tables in Appendix D.	p. IF-18	p. E-11
Low Rail LNG	Assumes a lower LNG locomotive penetration rate into motive stock, at a 1.0 average annual turnover rate for dual-fuel engines that can use up to 80% LNG. Partial projection tables in Appendix D.	p. IF-18	p. E-11
High VMT	Assumes higher licensing rates and travel demand for specific age and gender cohorts. Vehicle miles traveled per licensed driver in 2012 is 3% higher than in the Reference case, increasing to 7% higher in 2027, and then declining to 3% above the Reference case in 2040. Partial projection tables in Appendix D.	p. IF-22	p. E-11
Low VMT	Assumes lower licensing rates and travel demand for specific age and gender cohorts. Vehicle miles traveled per licensed driver is 5% lower than in the Reference case for the full projection. Licensing rates stay constant at 2011 levels or decline from 2011 to 2040, specific to gender, age, and census division categories. Partial projection tables in Appendix D.	p. IF-22	p. E-11

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Table E1. Summary of the AEO2014 cases (continued)

Case name	Description	Reference in text	Reference in Appendix E
Accelerated Nuclear Retirements	Assumes that all nuclear plants are limited to a 60-year life, uprates are limited to the 0.7 gigawatts (GW) that have been reported to EIA, and no new additions beyond those planned in the Reference case. Nonfuel operating costs for existing nuclear plants are assumed to increase by 3%/year after 2013. Partial projection tables in Appendix D.	p. IF-35	p. E-11
Accelerated Coal Retirements	Begins with the AEO2014 High Coal Cost case assumptions and also assumes that nonfuel operating costs for existing coal plants increase by 3%/year after 2013. Partial projection tables in Appendix D.	p. IF-35	p. E-12
Accelerated Nuclear and Coal Retirements	Combines the assumptions in the Accelerated Nuclear Retirements and Accelerated Coal Retirements cases. Partial projection tables in Appendix D.	p. IF-35	p. E-12
Electricity: Low Nuclear	Begins with the Accelerated Nuclear Retirements case and combines with assumptions in the High Oil and Gas Resource and the No Sunset cases. Partial projection tables in Appendix D.	p. MT-19	p. E-12
Electricity: High Nuclear	Assumes that all nuclear plants are life-extended beyond 60 years (except for 4.8 GW of announced retirement), and a total of 6.0 GW of uprates. New plants include those under construction and plants that have a scheduled U.S. Nuclear Regulatory Commission (NRC) or Atomic Safety and Licensing Board hearing. Partial projection tables in Appendix D.	p. MT-19	p. E-12
Renewable Fuels: Low Renewable Technology Cost	Capital costs for new nonhydro renewable generating technologies are 20% lower than Reference case levels through 2040, and biomass feedstocks are 20% less expensive for a given resource quantity. Capital costs for new ethanol, biodiesel, pyrolysis, and other BTL production technologies are 20% lower than Reference case levels through 2040, and the industrial sector assumes a higher rate of recovery for biomass byproducts from industrial processes. Partial projection tables in Appendix D.	p. MT-8	p. E-12
Oil and Gas: Low Oil and Gas Resource	Estimated ultimate recovery per shale gas, tight gas, and tight oil well is 50% lower than in the Reference case. All other resource assumptions remain the same as in the Reference case. Partial projection tables in Appendix D.	p. IF-12	p. E-12
Oil and Gas: High Oil and Gas Resource	Estimated ultimate recovery per shale gas, tight gas, and tight oil well is 50% higher and well spacing is 50% lower (or the number of wells left to be drilled is 100% higher) than in the Reference case. In addition, tight oil resources are added to reflect new plays or the expansion of known tight oil plays and the estimated ultimate recovery for tight and shale wells increases 1%/year to reflect additional technological improvement. Also includes kerogen development, tight oil resources in Alaska, and 50% higher undiscovered resources in the offshore lower 48 states and Alaska than in the Reference case. Partial projection tables in Appendix D.	p. IF-12	p. E-13
Coal: Low Coal Cost	Regional productivity growth rates for coal mining are approximately 2.3 percentage points per year higher than in the Reference case, and coal miner wages, mine equipment costs, and coal transportation rates are lower than in the Reference case, falling to about 25% below the Reference case in 2040. The price change for non-U.S. export supplies is assumed to be roughly 10% less than the price change projected for U.S. coal exports. Partial projection tables in Appendix D.	p. MT-32	p. E-13
Coal: High Coal Cost	Regional productivity growth rates for coal mining are approximately 2.3 percentage points per year lower than in the Reference case, and coal miner wages, mine equipment costs, and coal transportation rates are higher than in the Reference case, ranging between 24% and 31% above the Reference case in 2040. The price change for non-U.S. export supplies is assumed to be roughly 10% less than the price change projected for U.S. coal exports. Partial projection tables in Appendix D.	p. MT-32	p. E-13
Integrated 2013 Demand Technology	Referred to in the text as 2013 Demand Technology. Assumes that future equipment purchases in the residential and commercial sectors are based only on the range of equipment available in 2013. Commercial and existing residential building shell efficiency is held constant at 2013 levels. Energy efficiency of new industrial plant and equipment is held constant at the 2014 level over the projection period. Partial projection tables in Appendix D.	p. MT-6	p. E-9

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Table E1. Summary of the AEO2014 cases (continued)

Case name	Description	Reference in text	Reference in Appendix E
Integrated Best Available Demand Technology	Referred to in the text as Best Available Demand Technology. Assumes that all future equipment purchases in the residential and commercial sectors are made from a menu of technologies that includes only the most efficient models available in a particular year, regardless of cost. All residential building shells for new construction are assumed to be code compliant and built to the most efficient specifications after 2013, and existing residential shells have twice the improvement of the Reference case. New and existing commercial building shell efficiencies improve 50% more than in the Reference case by 2040. Industrial and transportation sector assumptions are the same as in the Reference case. Partial projection tables in Appendix D.	p. MT-6	p. E-9
Integrated High Demand Technology	Referred to in the text as High Demand Technology. Assumes earlier availability, lower costs, and higher efficiencies for more advanced residential and commercial equipment. For new residential construction, building code compliance is assumed to improve after 2013, and building shell efficiencies are assumed to meet ENERGY STAR requirements by 2023. Existing residential building shells exhibit 50% more improvement than in the Reference case after 2013. New and existing commercial building shells are assumed to improve 25% more than in the Reference case by 2040. Industrial sector assumes earlier availability, lower costs, and higher efficiency for more advanced equipment and a more rapid rate of improvement in the recovery of biomass byproducts from industrial processes. In the transportation sector, the characteristics of conventional and alternative-fuel LDVs reflect more optimistic assumptions about incremental improvements in fuel economy and costs, as well as battery electric vehicle costs. Freight trucks are assumed to see more rapid improvement in fuel efficiency. More optimistic assumptions for fuel efficiency improvements are also made for the air, rail, and shipping sectors. Partial projection tables in Appendix D.	p. MT-6	p. E-9
Energy Savings and Industrial Competitiveness Act	Begins with the Reference case and assumes passage of the energy efficiency provisions in S. 1392, including appropriation of funds at the levels authorized in the bill. Key provisions modeled include improved national building codes for new homes and commercial buildings and a rebate program for advanced industrial motor systems, assuming the bill's passage in 2014. For new residential construction, building shell efficiencies are assumed to improve by 15% relative to IECC2009 by 2020, and building code compliance is assumed to improve. New commercial building shells are assumed to be 30% more efficient than ASHRAE 90.1-2004 by 2020. Partial projection tables in Appendix D.	p. IF-6	--
Low Electricity Demand	This case was developed to explore the effects on the electric power sector if growth in sales to the grid remained relatively low. Begins with the Best Available Demand Technology case, which lowers demand in the building sectors, and also assumes greater improvement in industrial motor efficiency. Partial projection tables in Appendix D.	p. IF-46	p. E-12
No GHG Concern	No GHG emissions reduction policy is enacted, and market investment decisions are not altered in anticipation of such a policy. Partial projection tables in Appendix D.	p. MT-33	p. E-14
GHG10	Applies a price for CO2 emissions throughout the economy, starting at $10/metric ton in 2015 and rising by 5%/year through 2040. Partial projection tables in Appendix D.	p. MT-34	p. E-14
GHG25	Applies a price for CO2 emissions throughout the economy, starting at $25/metric ton in 2015 and rising by 5%/year through 2040. Partial projection tables in Appendix D.	p. MT-34	p. E-14
GHG10 and Low Gas Prices	Combines GHG10 and High Oil and Gas Resource cases. Partial projection tables in Appendix D.	p. MT-34	p. E-14

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- The Low Economic Growth case assumes lower growth rates for population (0.6%/year) and labor productivity (1.4%/year), resulting in lower nonfarm employment (0.7%/year), higher prices and interest rates, and lower growth in industrial output. In the Low Economic Growth case, economic output as measured by real GDP increases by 1.9%/year from 2012 through 2040, and growth in real disposable income per capita averages 1.3%/year.
- The High Economic Growth case assumes higher growth rates for population (0.8%/year) and labor productivity (2.0%/year), resulting in higher nonfarm employment (1.0%/year). With higher productivity gains and employment growth, inflation and interest rates are lower than in the Reference case, and consequently economic output grows at a higher rate (2.8%/year) than in the Reference case (2.4%). Disposable income per capita grows by 1.7%/year, the same as in the Reference case.

Oil price cases

The benchmark oil price is the price for Brent crude oil, which better reflects the marginal price paid by refineries for imported light, sweet crude oil used to produce petroleum products for consumers. EIA continues to report the WTI price and the Imported Refiner Acquisition Cost.

The historical record shows substantial variability in oil prices, and there is arguably even more uncertainty about future prices in the long term. AEO2014 considers three oil price cases (Reference, Low Oil Price, and High Oil Price) to allow an assessment of alternative views on the future course of oil prices.

The Low and High Oil Price cases reflect a wide range of potential price paths, resulting primarily from variation in demand for petroleum and other liquid fuels in non-OECD countries due to different levels of economic growth. The Low and High Oil Price cases also reflect different assumptions about decisions by members of OPEC regarding the preferred rate of oil production and about the future finding and development costs and accessibility of non-OPEC oil resources.

- In the Reference case, real oil prices (in 2012 dollars) rise from $112/barrel in 2012 to $141/barrel in 2040. The Reference case represents EIA's current judgment regarding exploration and development costs and accessibility of oil resources. Compared with AEO2013, EIA sees increasing production from non-OPEC countries, particularly the United States. However, EIA also assumes that OPEC producers will choose to maintain their share of the market and will schedule investments in incremental production capacity so that OPEC oil production will represent between 39% and 44% of the world's total petroleum and other liquids production over the projection period.
- In the Low Oil Price case, crude oil prices fall to $70/barrel (2012 dollars) in 2016, remain below $70/barrel through 2023, and stay below $75/barrel through 2040. The low price results from lower costs of production and lower demand from China and the Middle East compared with the Reference case. Crude oil production from across OPEC rises throughout the projection period in this case, displacing more expensive crude projected in the Reference case (including from the United States). Correspondingly, OPEC's market share of petroleum rises steadily from 40% through 2015 to almost 53% in 2040. In addition, in this case, bitumen production in Canada and renewable fuels from Brazil and the United States see decreases in costs, leading to increased production. This keeps the OPEC market share to between 39% and 50% of the total liquids market. With the exceptions of China and the Middle East, which see reduced economic growth in this case, the lower prices generally lead to higher demand than projected in the Reference case.
- In the High Oil Price case, oil prices reach about $205/barrel (2012 dollars) in 2040. The high prices result primarily from higher costs of petroleum supply. Fewer structurally reservoired crude oil supplies are developed than in the Reference case, leading to increased development of more costly resources, including tight oil and bitumen. Higher prices also lead to significant increases in renewable liquid fuels and coal-to-liquid products as compared with the Reference case. In this case, OPEC's share of world liquids production never exceeds the high of 40% that it reaches in 2013 and drops as low as 36%. The higher supply costs depress demand globally through 2028, but stronger growth in non-OECD countries than is projected in the Reference case leads to higher demand than in the Reference case, starting in these countries in 2029, and starting globally in 2037.

Buildings sector cases

In addition to the AEO2014 Reference case, three technology-focused cases using the NEMS Demand Modules were developed to examine the effects of changes in technology. Residential sector assumptions for the technology-focused cases are as follows:

- The Integrated 2013 Demand Technology case assumes that all future residential equipment purchases are limited to the range of equipment available in 2013. Existing building shell efficiencies are assumed to be fixed at 2013 levels (no further improvements). For new construction, building shell assumptions are the same as in the Reference case.
- The Integrated High Demand Technology case assumes that residential advanced equipment is available earlier, at lower costs, and/or at higher efficiencies [8]. Existing building shell efficiencies exhibit 50% more improvement than in the Reference case after 2013. For new construction, building code compliance is assumed to improve after 2013, and building shell efficiencies are assumed to meet ENERGY STAR requirements by 2023. Consumers evaluate investments in energy efficiency at a 7% real discount rate.
- The Integrated Best Available Demand Technology case assumes that all future residential equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year for each technology class,

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regardless of cost. Existing building shell efficiencies have twice the improvement of the Reference case after 2013. For new construction, 100% compliance with building codes is assumed, and building shell efficiencies are assumed to meet the criteria for the most efficient components after 2013. Consumers evaluate investments in energy efficiency at a 7% real discount rate.

Commercial sector assumptions for the technology-focused cases are as follows:

- The Integrated 2013 Demand Technology case assumes that all future commercial equipment purchases are limited to the range of equipment available in 2013. Building shell efficiencies are assumed to be fixed at 2013 levels.
- The Integrated High Demand Technology case assumes that commercial advanced equipment is available earlier, at lower costs, and/or with higher efficiencies than in the Reference case. Energy efficiency investments are evaluated at a 7% real discount rate. For new and existing buildings in 2040, building shell efficiencies are assumed to show 25% more improvement than in the Reference case.
- The Integrated Best Available Demand Technology case assumes that all future commercial equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year for each technology class, regardless of cost. Energy efficiency investments are evaluated at a 7% real discount rate. For new and existing buildings in 2040, building shell efficiencies are assumed to show 50% more improvement than in the Reference case.

The Residential and Commercial Demand Modules of NEMS were also used to complete the Low Renewable Technology Cost case, which is discussed in more detail in the renewable fuels cases section. In combination with assumptions for electricity generation from renewable fuels in the electric power sector and industrial sector, this sensitivity case analyzes the impacts of changes in generating technologies that use renewable fuels and in the availability of renewable energy sources. For the Residential and Commercial Demand Modules:

- The Low Renewable Technology Cost case assumes greater improvements in residential and commercial PV and wind systems than in the Reference case. The assumptions for capital cost estimates are 20% below Reference case assumptions from 2014 through 2040.

The No Sunset and Extended Policies cases described below in the cross-cutting integrated cases discussion also include assumptions in the Residential and Commercial Demand Modules of NEMS. The Extended Policies case builds on the No Sunset case and adds multiple rounds of appliance standards and building codes as described below.

- The No Sunset case assumes that selected federal policies with sunset provisions will be extended indefinitely rather than allowed to sunset as the law currently prescribes. For the residential sector, these extensions include personal tax credits for PV installations, solar water heaters, small wind turbines, and geothermal heat pumps, as well as tax credits for energy-efficient homes and selected residential appliances. For the commercial sector, business ITC for PV installations, solar water heaters, small wind turbines, geothermal heat pumps, and CHP are extended to the end of the projection. The business tax credit for solar technologies remains at the current 30% level without reverting to 10% as scheduled.
- The Extended Policies case includes updates to federal appliance standards, as prescribed by the timeline in DOE's multiyear plan, and introduces new standards for products currently not covered by DOE. Efficiency levels for the updated residential appliance standards are based on current ENERGY STAR guidelines. End-use technologies eligible for No Sunset incentives are not subject to new standards. Efficiency levels for updated commercial equipment standards are based on the technology menu from the AEO2014 Reference case and purchasing specifications for federal agencies designated by the Federal Energy Management Program. The case also adds two additional rounds of improved national building codes with full implementation in 2023 and 2029.

Industrial sector cases

In addition to the AEO2014 Reference case, two technology-focused cases developed using the IDM of NEMS examine the effects of less rapid and more rapid technology change and adoption. The energy intensity changes discussed in this section exclude the refining industry, which is modeled separately from the IDM in the LFMM. Different assumptions for the IDM were also used as part of the Integrated Low Renewable Technology Cost case, No Sunset case, and Extended Policies case, but each is structured on a set of the initial industrial assumptions used for the Integrated 2013 Demand Technology case and Integrated High Demand Technology case. For the industrial sector, assumptions for the two technology-focused cases are as follows:

- For the Integrated 2013 Demand Technology case, the energy efficiency of new industrial plant and equipment is held constant at the 2014 level over the projection period. Changes in aggregate energy intensity may result both from changing equipment and production efficiency and from changing the composition of output within an individual industry. Because all AEO2014 side cases are integrated runs, potential feedback effects from energy market interactions are captured. Therefore, the level and composition of overall industrial output varies from the Reference case, and any change in energy intensity in the two technology side cases is attributable to process and efficiency changes and increased use of CHP, as well as changes in the level and composition of overall industrial output.
- For the Integrated High Demand Technology case, the IDM assumes earlier availability, lower costs, and higher efficiency for more advanced equipment [9] and a more rapid rate of improvement in the recovery of biomass byproducts from industrial

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processes—i.e., 0.7%/year as compared with 0.4%/year in the Reference case. The same assumption is incorporated in the Low Renewable Technology Cost case, which focuses on electricity generation. Although the choice of the 0.7% annual rate of improvement in byproduct recovery is an assumption in the High Demand Technology case, it is based on the expectation of higher recovery rates and substantially increased use of CHP in that case. Due to integration with other NEMS modules, potential feedback effects from energy market interactions are captured.

The No Sunset and Extended Policies cases described below in the cross-cutting integrated cases discussion also include assumptions in the IDM of NEMS. The Extended Policies case builds on the No Sunset case and modifies selected industrial assumptions as follows:

- The No Sunset case and Extended Policies case include an assumption for CHP that extends the existing ITC for industrial CHP through the end of the projection period. Additionally, the Extended Policies case includes an increase in the capacity limitations on the ITC by increasing the cap on CHP equipment from 15 megawatts (MW) to 25 MW and eliminating the system-wide cap of 50 MW. These assumptions are based on the proposals made in H.R. 2750 and H.R. 2784 of the 112th Congress.

Transportation sector cases

In addition to the AEO2014 Reference case, the NEMS Transportation Demand Module was used as part of six AEO2014 side cases.

The Transportation Demand Module was used to examine the effects of advanced technology costs and efficiency improvement for technology adoption and vehicle fuel economy as part of the Integrated High Demand Technology case. For the Integrated High Demand Technology case, the characteristics of conventional and alternative-fuel LDVs reflect more optimistic assumptions about incremental improvements in fuel economy and costs, including battery electric systems. In the freight truck sector, the Integrated High Demand Technology case assumes more rapid incremental improvement in fuel efficiency. More optimistic assumptions for fuel efficiency improvements are also made for the air, rail, and shipping sectors.

The Transportation Demand Module was used to examine the effects of an extension to the LDV GHG Emissions and CAFE Standards beyond 2025 as part of the Extended Policies case. The joint EPA and NHTSA CAFE Standards were increased after 2025, at an average annual rate of 1.3% through 2040, reaching a combined average LDV fuel economy compliance of 55.7 miles/gallon in 2040. As part of the Extended Policies case, the Transportation Demand Module was also used to examine the effects of extending and enhancing the HDV fuel consumption and GHG emissions standards through 2040. The regulations are currently specified for model year (MY) 2014 to MY 2018. The Extended Policies case includes a modest increase in fuel consumption and GHG emissions standards for 13 HDV vehicle size classes.

Assumptions in the NEMS Transportation Demand Module were modified for the High Vehicle Miles Traveled (VMT) and Low VMT cases. These cases examine the effects of changes to licensing rates and VMT on the LDV transportation sector. The High VMT case includes assumptions for increases in VMT per licensed driver for the five VMT age cohorts. VMT per licensed driver is 3% higher than in the Reference case in 2012, increases to 7% above the Reference case in 2027, and decreases back to 3% above the Reference case by 2040. The Low VMT case includes assumptions for a decline in licensed drivers for the 13 gender/age cohorts, as well as decreases in VMT per licensed driver for the five VMT age groups. VMT per licensed driver are 5% lower than in the Reference case for the entire projection, and the licensing rates either stay constant at 2011 levels for all age cohorts or decline as portrayed in the Reference case.

The Transportation Demand Module was also used to examine the effect of varying LNG locomotive penetration in the freight rail sector. The High Rail LNG case allows for LNG locomotives to penetrate the rail sector fully by 2037. The Low Rail LNG case incorporates dual-fuel engines that utilize LNG up to 80%, with an LNG locomotive penetration rate at 1.0% of the average annual stock turnover.

Electricity sector cases

In addition to the Reference case, several integrated cases with alternative electric power assumptions were developed to support discussions in the Market Trends and Issues in Focus sections of AEO2014. Three alternative cases were run to examine the impacts on the electric power sector of potentially large retirements of baseload coal and nuclear plants. In recent years, a combination of low natural gas prices, high retrofit or repair costs, and uncertainty about environmental legislation have led to an increase in announced retirements of coal and nuclear plants. The Issues in Focus article, "Implications of accelerated power plant retirements," discusses the factors influencing those retirement decisions, using the analysis cases to illustrate potential impacts. Two additional cases for nuclear power plants were developed to address uncertainties about the operating lives of existing reactors and the potential for new nuclear capacity and for capacity uprates at existing plants.

A final case combines technology and efficiency improvements across the end-use demand sectors to create a case that projects relatively low growth in total electricity consumption. The Issues in Focus article, "Implications of low electricity demand growth," analyzes the impacts on power sector capacity and generation requirements under a scenario of low demand growth.

Accelerated Retirement cases

- The Accelerated Nuclear Retirement case assumes that reactors will not receive second license renewals, so that all existing nuclear plants are retired within 60 years after beginning operation. The 4.8 GW of announced retirements remain as in the

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Reference case, along with the decrease of 5.7 GW of nuclear capacity by 2020 to reflect plants at risk of early closure in specific regions. In the Reference case, after 2020, existing plants are assumed to run as long as they continue to be economic, implicitly assuming that a second 20-year license renewal will occur for most plants that reach 60 years of operation before 2040. In the Accelerated Nuclear Retirement case, an additional 37 GW of nuclear capacity is retired by 2040. The Accelerated Nuclear Retirement case also assumes that no new nuclear capacity is added throughout the projection, excluding capacity already planned and under construction. It assumes that only those capacity uprates already reported to EIA (0.7 GW) are completed, as in the Reference case, and that nonfuel operating costs at existing nuclear plants increase by 3%/year after 2013.

- The Accelerated Coal Retirement case includes the assumptions used for the High Coal Cost case, including lower productivity and higher costs associated with mining and coal transportation rates. In 2040, delivered coal prices are more than 60% higher in the Accelerated Coal Retirement case than in the Reference case. This case also assumes that non-fuel operating costs at existing coal plants increase by 3%/year after 2013.
- The Accelerated Coal and Nuclear Retirement case combines the assumptions of the Accelerated Coal Retirement and Accelerated Nuclear Retirement cases.

Nuclear cases

- The Low Nuclear case combines the Accelerated Nuclear Retirement case with the High Oil and Gas Resource case and the No Sunset case. This combines more pessimistic assumptions for nuclear costs and lifetimes with more favorable conditions for natural gas-fired and renewable technologies, so that the impacts on the power sector can be viewed under an outlook where output from nuclear power is greatly reduced.
- The High Nuclear case was run to provide a more optimistic outlook, with all nuclear power plant licenses renewed and all plants continuing to operate economically beyond 60 years (excluding the 4.8 GW of announced retirements). The High Nuclear case also assumes that additional planned nuclear capacity is completed, based on combined license applications (COL) issued by the NRC and whether an Atomic Safety and Licensing Board hearing has been scheduled for a COL. The High Nuclear case assumes 12.6 GW of planned capacity additions, as compared with 5.5 GW of planned capacity additions assumed in the Reference case. Finally, the High Nuclear case assumes a total of 6.0 GW of uprates at existing plants, reflecting an assumption that most plants with remaining uprate potential will elect to perform such uprates.

Low Electricity Demand case

- The Low Electricity Demand case uses the assumptions in the Best Available Demand Technology case for the residential and commercial sectors. In addition, input values for the industrial sector motor model are adjusted to increase system savings values for pumps, fans, and air compressors relative to the Reference case. This adjustment lowers total motor electricity consumption by slightly less than 20%. Although technically plausible, this decrease in motor adjustment is not intended to be a likely representation of motor development. As a result of these changes across the end-use sectors, retail sales in 2040 in this case are roughly the same as in 2012.

Renewable fuels cases

In addition to the AEO2014 Reference case, EIA developed a case with alternative assumptions about renewable generation technologies and policies to examine the effects of more aggressive improvement in the costs of renewable technologies.

- In the Low Renewable Technology Cost case, the capital costs of new non-hydro renewable generating technologies are assumed to be 20% below Reference case assumptions from 2014 through 2040. In general, lower costs are represented by reducing the capital costs of new plant construction. Biomass fuel supplies also are assumed to be 20% less expensive than in the Reference case for the same resource quantities. Assumptions for other generating technologies are unchanged from those in the Reference case. In the Low Renewable Technology Cost case, the rate of improvement in recovery of biomass byproducts from industrial processes also is increased. Capital costs for new ethanol, biodiesel, pyrolysis, and other BTL production technologies also are 20% lower than Reference case levels through 2040.
- In the No Sunset case and the Extended Policies case, expiring federal tax credits targeting renewable electricity are assumed to be permanently extended. This applies to the PTC, which is a tax credit of 2.3 cents/kWh (adjusted annually for inflation) available for the first 10 years of production by new generators using wind, geothermal, and certain biomass fuels, or a tax credit of 1.1 cents/kWh available for the first 10 years of production by new generators using geothermal energy, certain hydroelectric technologies, and biomass fuels not eligible for the full credit of 2.3 cents/kWh. The extension also applies to the 30% ITC for new generators using solar energy, which may also be claimed in lieu of the PTC for eligible technologies.

Oil and natural gas supply cases

The sensitivity of the AEO2014 projections to changes in assumptions regarding technically recoverable domestic crude oil and natural gas resources is examined in two cases. These cases do not represent a confidence interval for future domestic oil and natural gas supply, but rather provide a framework to examine the effects of higher and lower domestic supply on energy demand, imports, and prices. Assumptions associated with these cases are described below.

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- In the Low Oil and Gas Resource case, the estimated ultimate recovery per tight oil, tight gas, or shale gas well is assumed to be 50% lower than in the Reference case, increasing the per-unit cost of developing the resource. The total unproved technically recoverable resource of crude oil is decreased to 180 billion barrels, and the natural gas resource is decreased to 1,480 trillion cubic feet (Tcf), as compared with unproved resource estimates of 209 billion barrels of crude oil and 1,932 Tcf of natural gas as of January 1, 2012, in the Reference case.
- In the High Oil and Gas Resource case, the resource assumptions are adjusted to allow a continued increase in domestic crude oil production, to more than 13 million barrels per day (MMbbl/d) in 2040 compared with 7.5 MMbbl/d in the Reference case. This case includes: (1) 50% higher estimated ultimate recovery per tight oil, tight gas, or shale gas well, with 50% lower acre spacing (minimum 40 acres) than in the Reference case, as well as additional unidentified tight oil resources to reflect the possibility that additional layers or new areas of low-permeability zones will be identified and developed; (2) diminishing returns on the estimated ultimate recovery once drilling levels in a county exceed the number of potential wells assumed in the Reference case to reflect well interference at greater drilling density; (3) additional 1% annual increase in the estimated ultimate recovery for tight oil, tight gas, and shale gas wells due to faster technological improvement; (4) kerogen development reaching 135,000 barrels/day in 2024; (5) tight oil development in Alaska, increasing the total Alaska technically recoverable resource by 1.9 billion barrels; and (6) 50% higher technically recoverable undiscovered resources in Alaska and the offshore lower 48 states than in the Reference case. Additionally, a few offshore Alaska fields are assumed to be discovered and developed earlier than in the Reference case. The total unproved technically recoverable resource of crude oil increases to 401 billion barrels, and the natural gas resource increases to 3,349 Tcf as compared with unproved resource estimates of 209 billion barrels of crude oil and 1,932 Tcf of natural gas in the Reference case as of the start of 2012.

Liquids market cases

The Liquid Fuels Market Module of NEMS was used (with other NEMS models) to complete the Low Renewable Technology Cost case, which is discussed in more detail in the renewable fuels cases section. In addition to the 20% reduction in nonhydro renewable generating technologies, 20% reduction in biomass feedstock costs, and higher rate of recovery for biomass byproducts from industrial processes, the LFMM assumes capital costs for new ethanol, biodiesel, pyrolysis, and other BTL technologies are 20% lower than reference case levels through 2040.

Some assumptions in the LFMM were changed to support the No Sunset case by extending the ethanol and biodiesel subsidies beyond their current end dates (2013). This assumption was excluded from the Extended Policies case.

Coal market cases

Two alternative coal cost cases examine the impacts on U.S. coal supply, demand, distribution, and prices that result from alternative assumptions about mining productivity, labor costs, mine equipment costs, coal transportation rates, and costs of non-U.S. coal supplies to international markets. The alternative productivity and cost assumptions are applied in every year from 2014 through 2040. For the coal cost cases, adjustments to the Reference case assumptions for coal mining productivity are based on variation in the average annual productivity growth of 2.4 percentage points observed since 2000 for mines in Wyoming's Powder River Basin and 2.3 percentage points for other coal-producing regions. Transportation rates are lowered (in the Low Coal Cost case) or raised (in the High Coal Cost case) from Reference case levels to achieve a 25% change in rates relative to the Reference case in 2040. In both the High and Low Coal Cost cases, price trends for non-U.S. coal export supplies (e.g., coal exported to international markets from ports in Australia or Southern Africa, a NEMS-defined region that includes South Africa, Mozambique, and Botswana) are assumed to be similar, but price changes are approximately 10% less than the price changes projected for U.S. coal exports. The Low and High Coal Cost cases represent fully integrated NEMS runs, with feedback from the macroeconomic activity, international, supply, conversion, and end-use demand modules.

- In the Low Coal Cost case, the average annual growth rates for coal mining productivity are higher than those in the Reference case and are applied at the supply curve level. As an example, the average annual productivity growth rate for Wyoming's Southern Powder River Basin supply curve is increased from -1.5% in the Reference case for the years 2014 through 2040 to 0.9% in the Low Coal Cost case. Coal miner wages, mine equipment costs, and other mine supply costs all are assumed to be about 24% lower in 2040 in real terms in the Low Coal Cost case than in the Reference case. Coal transportation rates, excluding the impact of fuel surcharges, are assumed to be 25% lower in 2040. In the international coal market, the price change for non-U.S. export supplies is assumed to be roughly 10% less than the price change projected for U.S. coal exports.
- In the High Coal Cost case, the average annual productivity growth rates for coal mining are lower than those in the Reference case and are applied as described in the Low Coal Cost case. Coal miner wages, mine equipment costs, and other mine supply costs in 2040 are assumed to be about 31% higher than in the Reference case, and coal transportation rates in 2040 are assumed to be 25% higher. In the international coal market, the price change for non-U.S. export supplies is assumed to be roughly 10% less than the price change projected for U.S. coal exports.

Additional data on productivity, wage, mine equipment cost, and coal transportation rate assumptions for the Reference and alternative coal cost cases are included in Appendix D.

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Cross-cutting integrated cases

A series of cross-cutting integrated cases are used in AEO2014 to analyze specific cases with broader sectoral impacts. For example, three integrated technology progress cases analyze the effects of faster and slower technology improvement in the demand sectors (partially described in the sector-specific sections above). In addition, four cases were run with alternative assumptions about expectations for future regulation of GHG emissions.

Integrated technology cases

In the demand sectors (residential, commercial, industrial, and transportation), technology improvement typically means greater efficiency and/or reduced technology cost. Three alternative demand technology cases—Integrated 2013 Demand Technology, Integrated Best Available Demand Technology, and Integrated High Demand Technology—are used in AEO2014 to examine the potential effects of variation in the rate of technology improvement in the end-use demand sectors, independent of any offsetting effects of variations in technology improvement in the supply/conversion sectors. Assumptions for each end-use sector are described in the sector-specific sections above.

No Sunset case

In addition to the AEO2014 Reference case, a No Sunset case was run, assuming the extension of all existing tax credits and policies that contain sunset provisions, except those requiring additional funding (e.g., loan guarantee programs) and those that involve extensive regulatory analysis, such as CAFE improvements and periodic updates of efficiency standards. The No Sunset case also includes extension of the $1.01/gallon ethanol subsidy and $1.00/gallon biodiesel subsidy to the end of the projection period. Specific assumptions for each end-use sector and for renewables are described in the sector-specific sections above.

Extended Policies case

The Extended Policies case begins with the No Sunset case described above but excludes extension of the ethanol and biofuel subsidies included in the No Sunset case, because the RFS program already included in the AEO2014 Reference case tends to determine the levels of ethanol and biodiesel use. The Extended Policies case assumes an increase in the capacity limitations on the ITC and extension of the program. It includes additional rounds of federal efficiency standards for residential and commercial products, as well as new standards for products not yet covered; adds multiple rounds of national building codes by 2029; and increases LDV and HDV fuel economy standards in the transportation sector. Specific assumptions for each end-use sector and for renewables are described in the sector-specific sections above.

Greenhouse gas cases

Given concerns about climate change and possible future policy actions to limit GHG emissions, regulators and the investment community are beginning to push energy companies to invest in technologies that are less GHG-intensive. To reflect the market's current reaction to potential future GHG regulation, a 3-percentage-point increase in the cost of capital is assumed for investments in new coal-fired power and CTL plants without CCS and for all capital investment projects (excluding CCS) at existing coal-fired power plants in the Reference case and all other AEO2014 cases except the No GHG Concern case, GHG10 case, GHG25 case, and GHG10 and Low Gas Prices case. Those assumptions affect cost evaluations for the construction of new capacity but not the actual operating costs when a new plant begins operation.

The four alternative GHG cases are used to provide a range of potential outcomes, from no concern about future GHG legislation to the imposition of a specific economywide carbon emissions price, as well as an examination of the impact of a combination of a specific economywide carbon emission price and low natural gas price. AEO2014 includes three economywide CO_2 price cases—two levels of carbon prices and one case combined with an alternative natural gas price projection. In the GHG10 case and the GHG10 and Low Gas Prices case, the price of carbon emissions is set at $10/metric ton of CO_2 in 2015. In the GHG25 case, the price is set at $25/metric ton of CO_2 in 2015. In all cases, the price begins to rise in 2016 at 5%/year. The GHG10 case and the GHG25 case use the Reference case assumptions regarding oil and natural gas resource availability. The GHG10 and Low Gas Prices case uses the assumptions from the High Oil and Gas Resource case, as described above in the Oil and natural gas supply section. The GHG cases are intended to measure the sensitivity of the AEO2014 projections to a range of implicit or explicit valuations of CO_2 emissions. At the time AEO2014 was completed, no legislation including a GHG price was pending; however, the EPA is developing technology-based CO_2 standards for new coal-fired power plants. In the GHG cases for AEO2014, no assumptions are made with regard to offsets, policies to promote CCS, or specific policies to mitigate impacts in selected sectors.

The No GHG Concern case was run without any adjustment for concern about potential GHG regulations (without the 3-percentage point increase in the cost of capital). In the No GHG Concern case, the same cost of capital is used to evaluate all new capacity builds, regardless of type.

012901

Endnotes for Appendix E

Links current as of April 2014

1. U.S. Energy Information Administration, *The National Energy Modeling System: An Overview 2009*, DOE/EIA-0581(2009) (Washington, DC, October 2009), http://www.eia.gov/oiaf/aeo/overview.
2. Selected EIA publications used for data sources include *Monthly Energy Review, Natural Gas Annual, Natural Gas Monthly, Electric Power Monthly, Electric Power Annual, Annual Coal Report, Petroleum Supply Annual,* and *Quarterly Coal Report,* as well as EIA surveys.
3. U.S. Energy Information Administration, *Short-Term Energy Outlook September 2013* (Washington, DC, September 2013), http://www.eia.gov/forecasts/steo/archives/Sep13.pdf. Portions of the preliminary information were also used to initialize the NEMS Liquids Fuels Market Module projection.
4. U.S. Energy Information Administration, *Short-Term Energy Outlook* (Washington, DC, January 2014), http://www.eia.gov/forecasts/steo/outlook.cfm.
5. U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2014,* DOE/EIA-0554(2014) (Washington, DC, April 2014), http://www.eia.gov/forecasts/aeo/assumptions.
6. Alternative technologies for other liquids include all biofuels technologies plus CTL and GTL.
7. U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2014,* DOE/EIA-0554(2014) (Washington, DC, April 2014), http://www.eia.gov/forecasts/aeo/assumptions.
8. High technology assumptions for the buildings sector are based on U.S. Energy Information Administration, *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Case* (Navigant Consulting, Inc. with SAIC, September 2011), and *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Case* (Navigant Consulting, Inc. with SAIC, November 2012).
9. These assumptions are based in part on U.S. Energy Information Administration, *Industrial Technology and Data Analysis Supporting the NEMS Industrial Model* (FOCIS Associates, October 2005).

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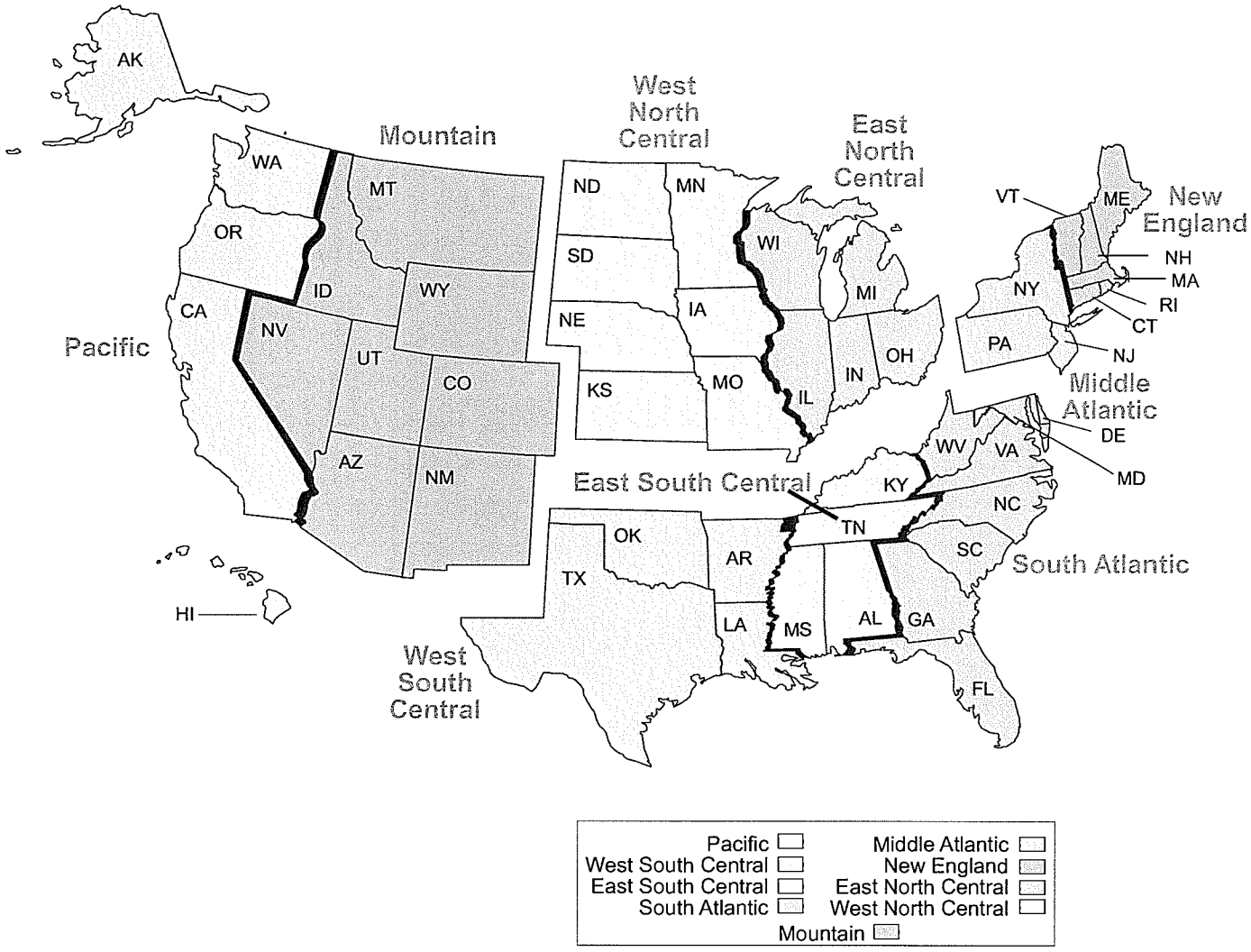
Appendix F

Regional Maps

Figure F1. United States Census Divisions



Source: U.S. Energy Information Administration, Office of Energy Analysis.

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Figure F1. United States Census Divisions (continued)

Division 1
New England

Connecticut
Maine
Massachusetts
New Hampshire
Rhode Island
Vermont

Division 2
Middle Atlantic

New Jersey
New York
Pennsylvania

Division 3
East North Central

Illinois
Indiana
Michigan
Ohio
Wisconsin

Division 4
West North Central

Iowa
Kansas
Minnesota
Missouri
Nebraska
North Dakota
South Dakota

Division 5
South Atlantic

Delaware
District of Columbia
Florida
Georgia
Maryland
North Carolina
South Carolina
Virginia
West Virginia

Division 6
East South Central

Alabama
Kentucky
Mississippi
Tennessee

Division 7
West South Central

Arkansas
Louisiana
Oklahoma
Texas

Division 8
Mountain

Arizona
Colorado
Idaho
Montana
Nevada
New Mexico
Utah
Wyoming

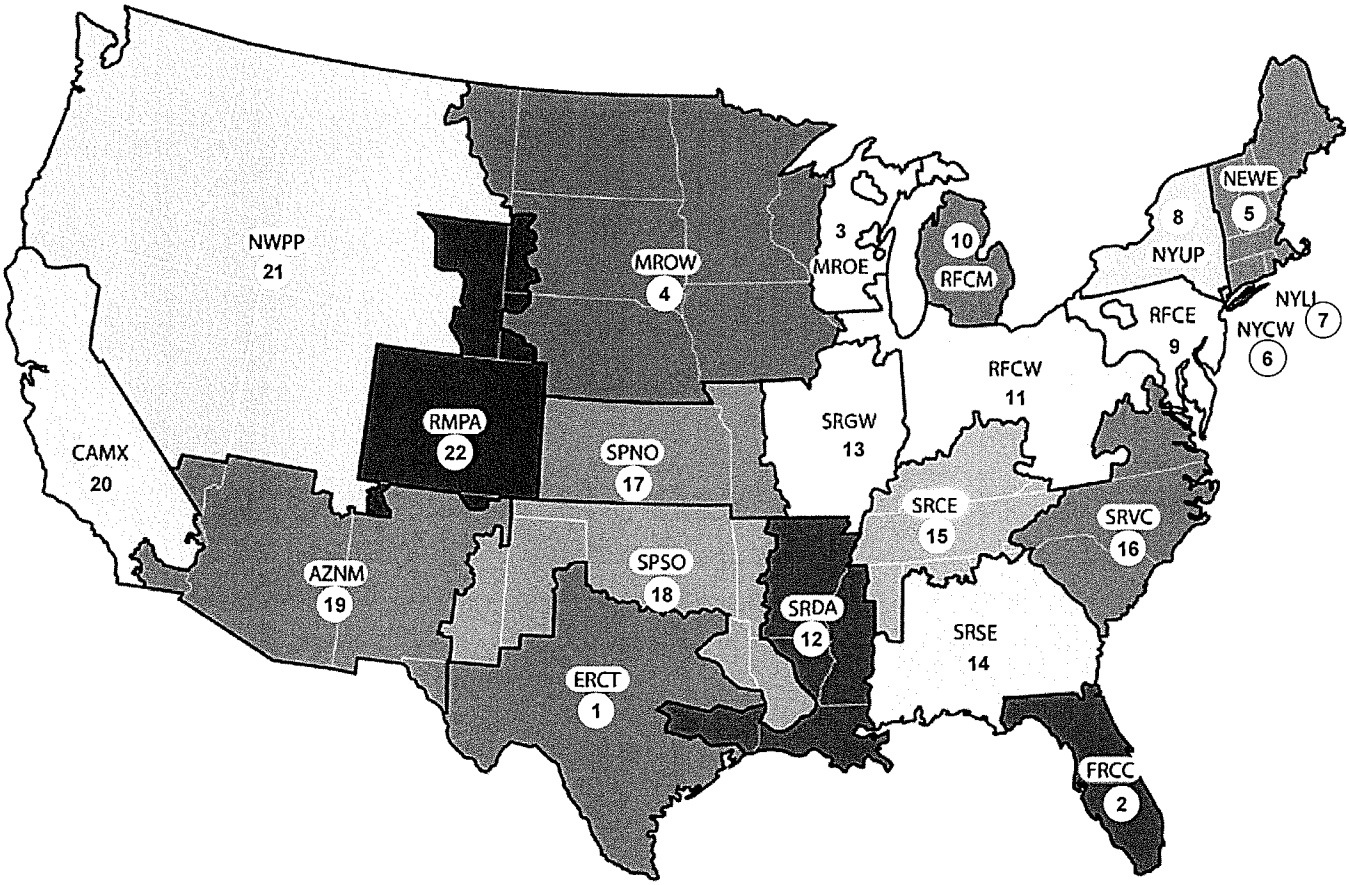
Division 9
Pacific

Alaska
California
Hawaii
Oregon
Washington

Source: U.S. Energy Information Administration, Office of Energy Analysis.

012905

Figure F2. Electricity market module regions



1.	ERCT	TRE All	12.	SRDA	SERC Delta
2.	FRCC	FRCC All	13.	SRGW	SERC Gateway
3.	MROE	MRO East	14.	SRSE	SERC Southeastern
4.	MROW	MRO West	15.	SRCE	SERC Central
5.	NEWE	NPCC New England	16.	SRVC	SERC VACAR
6.	NYCW	NPCC NYC/Westchester	17.	SPNO	SPP North
7.	NYLI	NPCC Long Island	18.	SPSO	SPP South
8.	NYUP	NPCC Upstate NY	19.	AZNM	WECC Southwest
9.	RFCE	RFC East	20.	CAMX	WECC California
10.	RFCM	RFC Michigan	21.	NWPP	WECC Northwest
11.	RFCW	RFC West	22.	RMPA	WECC Rockies

Source: U.S. Energy Information Administration, Office of Energy Analysis.

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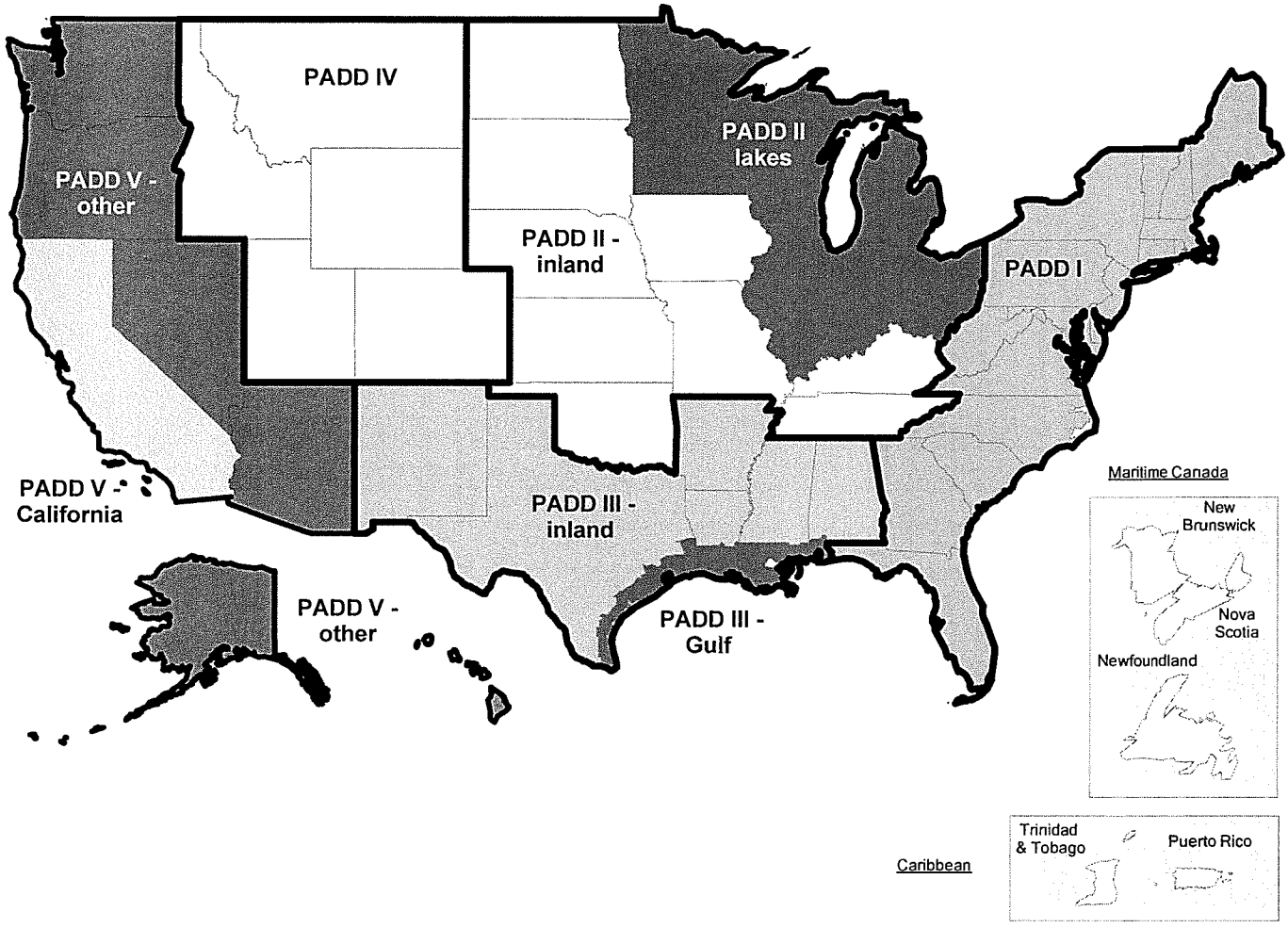
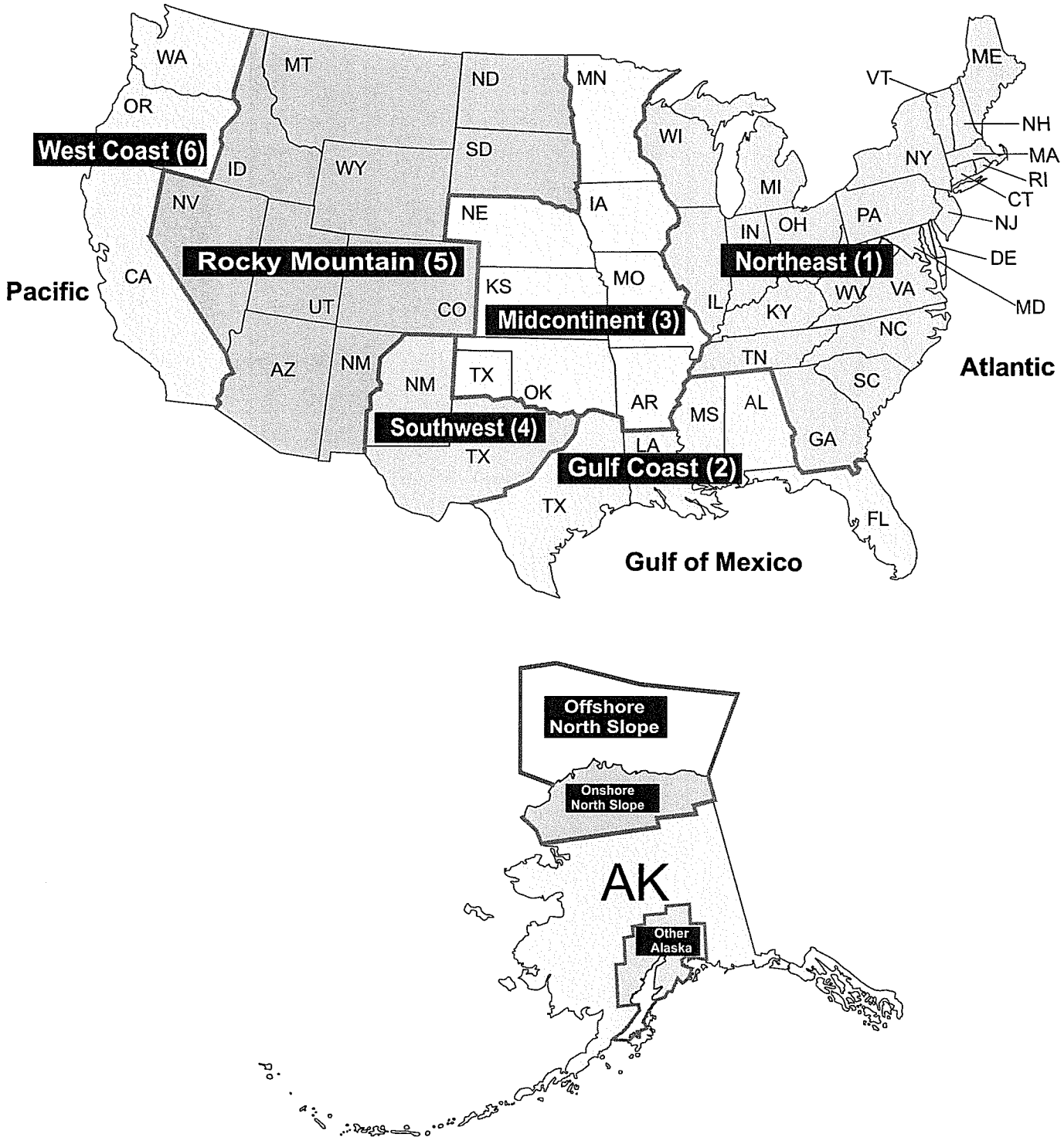
Figure F3. Liquid fuels market module regions



Source: U.S. Energy Information Administration, Office of Energy Analysis.

012907

Figure F4. Oil and gas supply model regions



Source: U.S. Energy Information Administration, Office of Energy Analysis.

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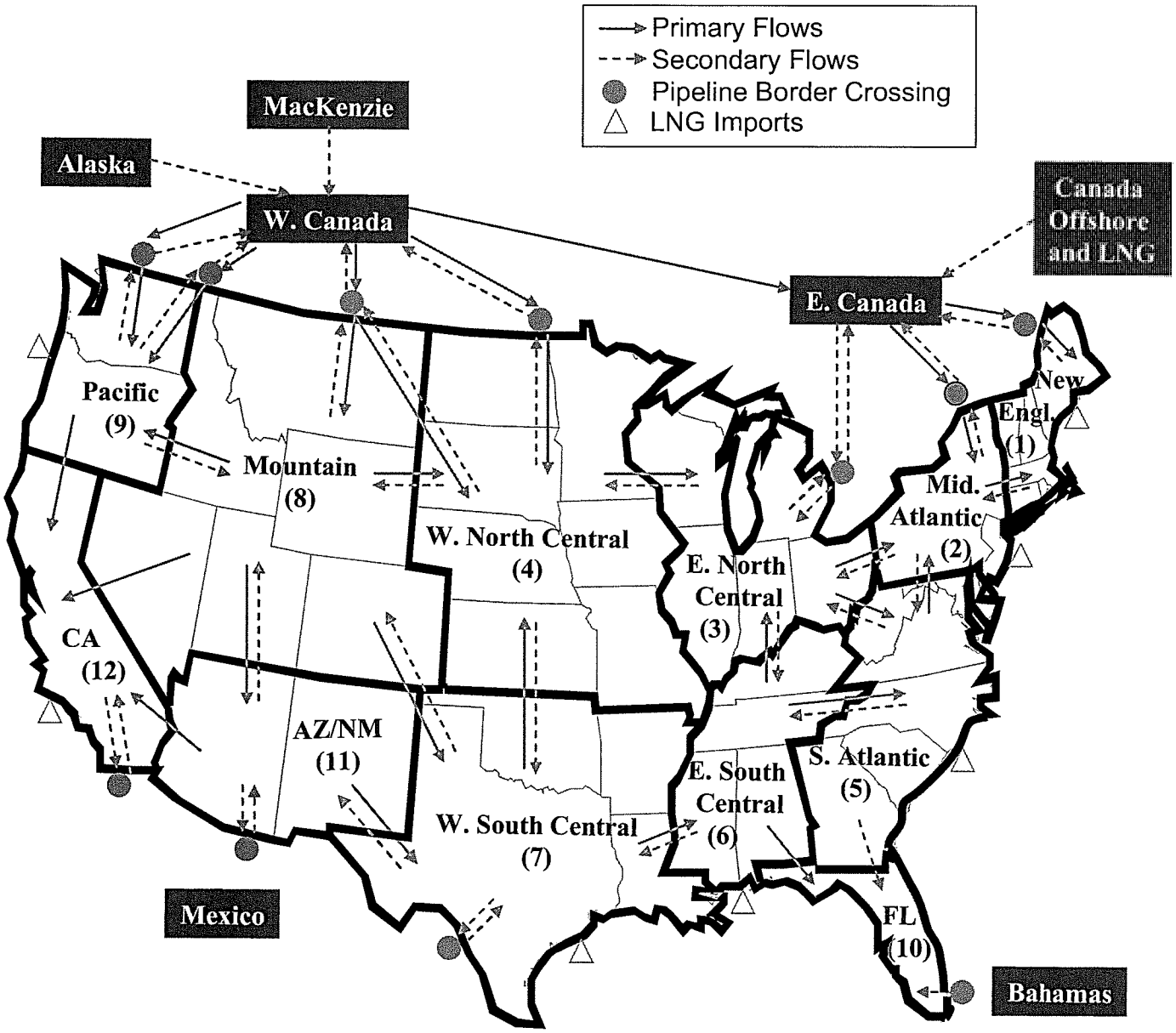
Figure F5. Natural gas transmission and distribution model regions



Source: U.S. Energy Information Administration, Office of Energy Analysis.

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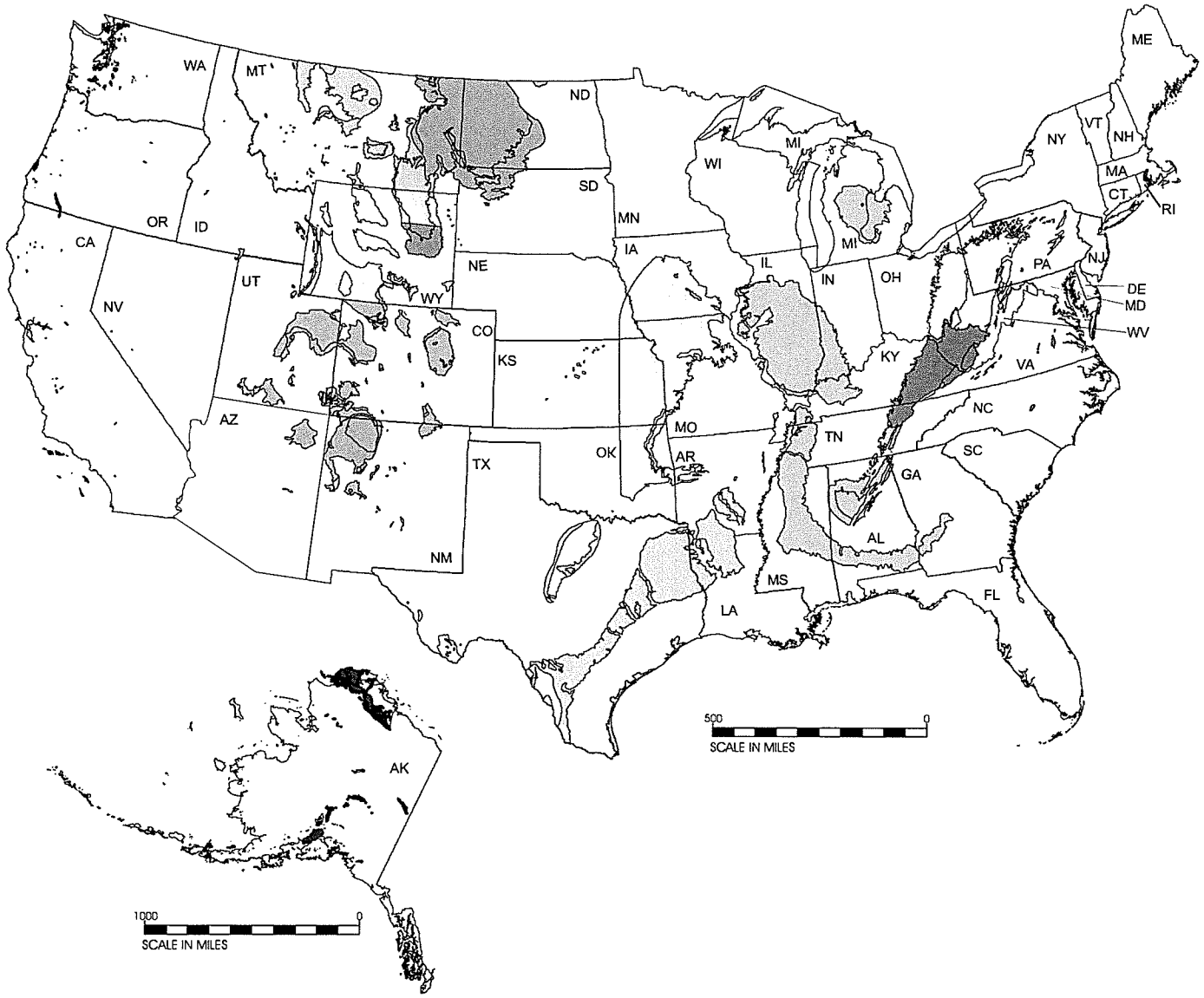
Figure F6. Coal supply regions



APPALACHIA
- Northern Appalachia
- Central Appalachia
- Southern Appalachia

INTERIOR
- Eastern Interior
- Western Interior
- Gulf Lignite

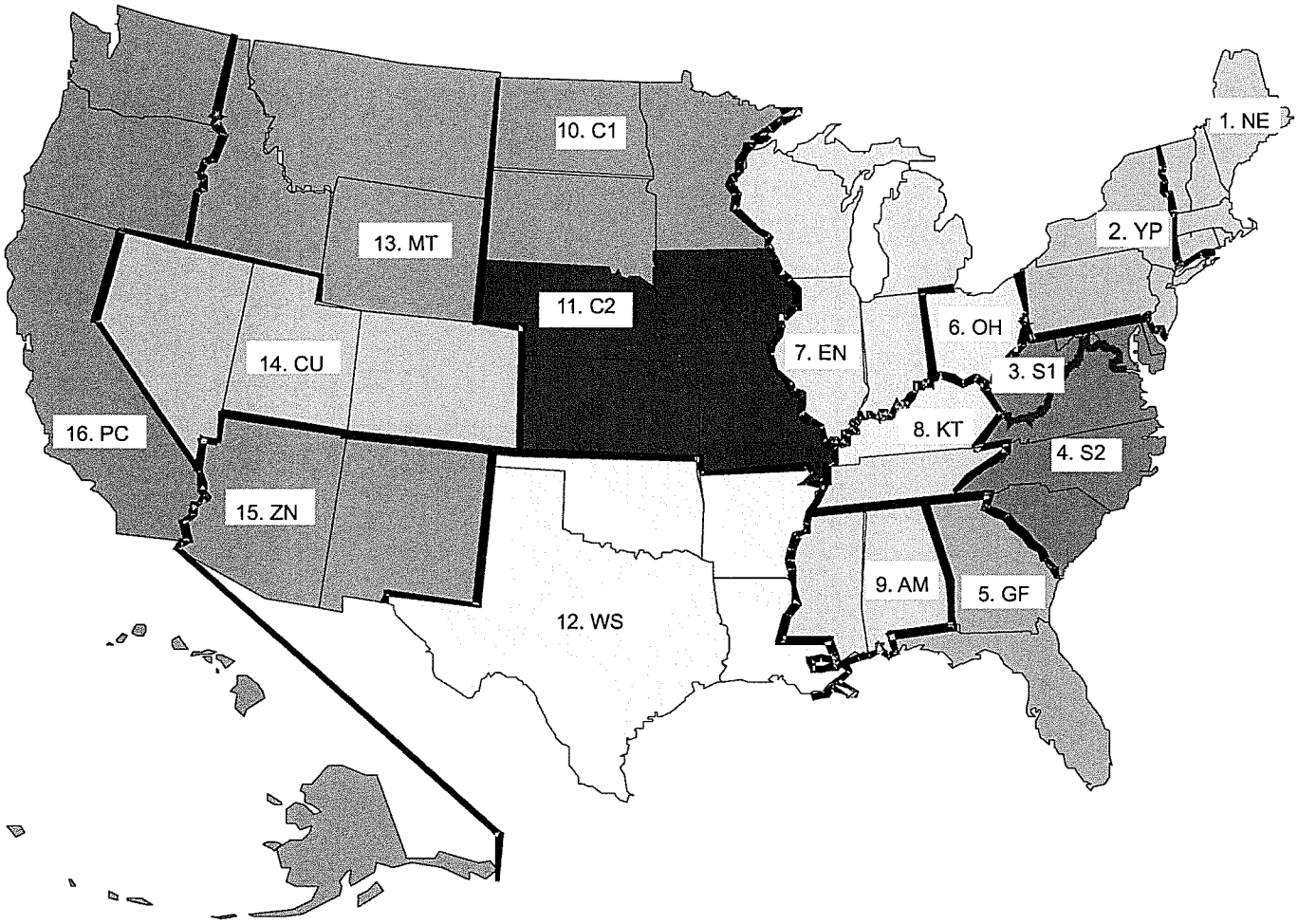
NORTHERN GREAT PLAINS
- Dakota Lignite
- Western Montana
- Wyoming, Northern Powder River Basin
- Wyoming, Southern Powder River Basin
- Western Wyoming

OTHER WEST
- Rocky Mountain
- Southwest
- Northwest

Source: U.S. Energy Information Administration, Office of Energy Analysis.

012910

Figure F7. Coal demand regions



Region Code	Region Content
1. NE	CT,MA,ME,NH,RI,VT
2. YP	NY,PA,NJ
3. S1	WV,MD,DC,DE
4. S2	VA,NC,SC
5. GF	GA,FL
6. OH	OH
7. EN	IN,IL,MI,WI
8. KT	KY,TN

Region Code	Region Content
9. AM	AL,MS
10. C1	MN,ND,SD
11. C2	IA,NE,MO,KS
12. WS	TX,LA,OK,AR
13. MT	MT,WY,ID
14. CU	CO,UT,NV
15. ZN	AZ,NM
16. PC	AK,HI,WA,OR,CA

Source: U.S. Energy Information Administration, Office of Energy Analysis.

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Appendix G

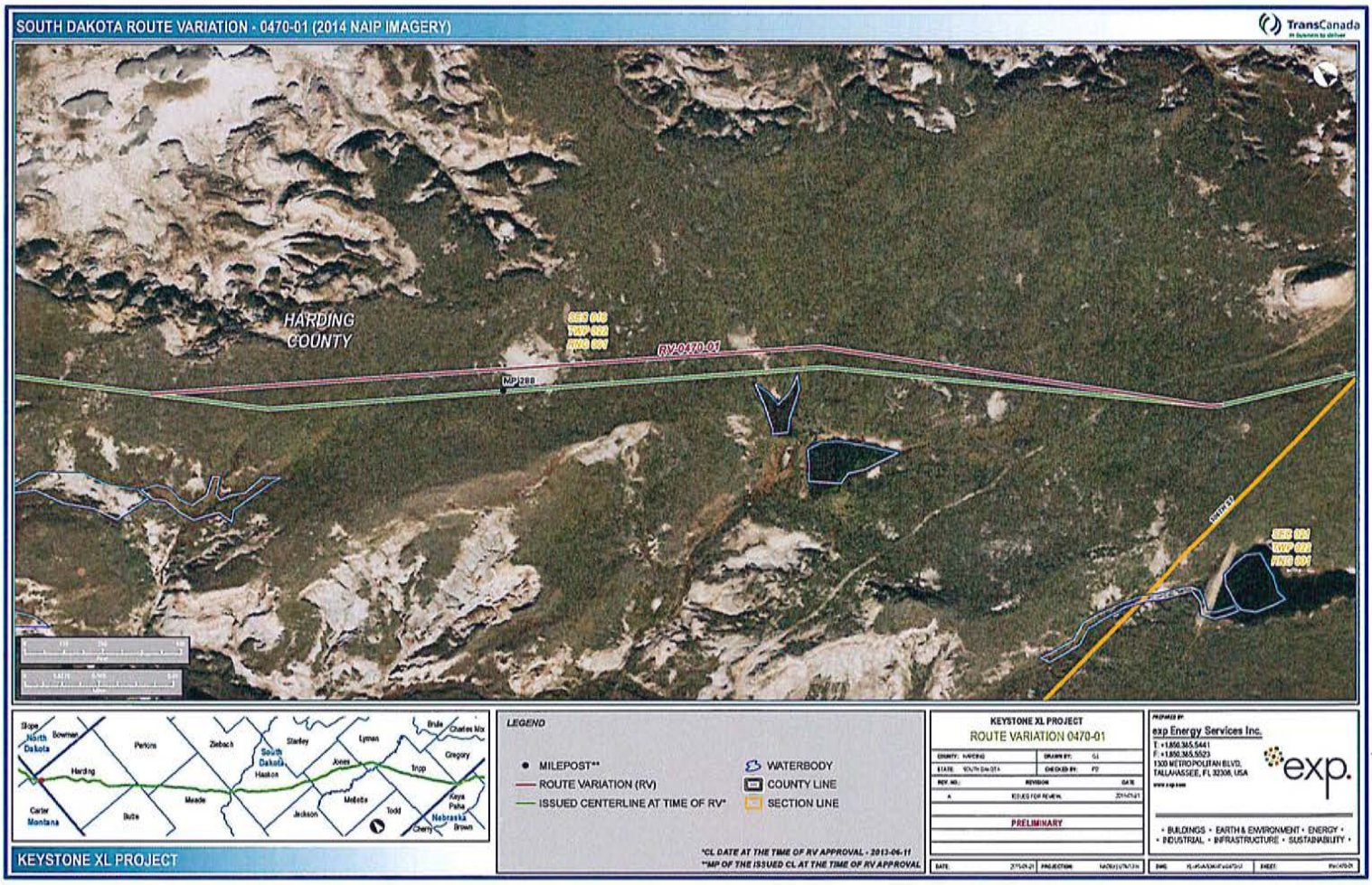
Conversion factors

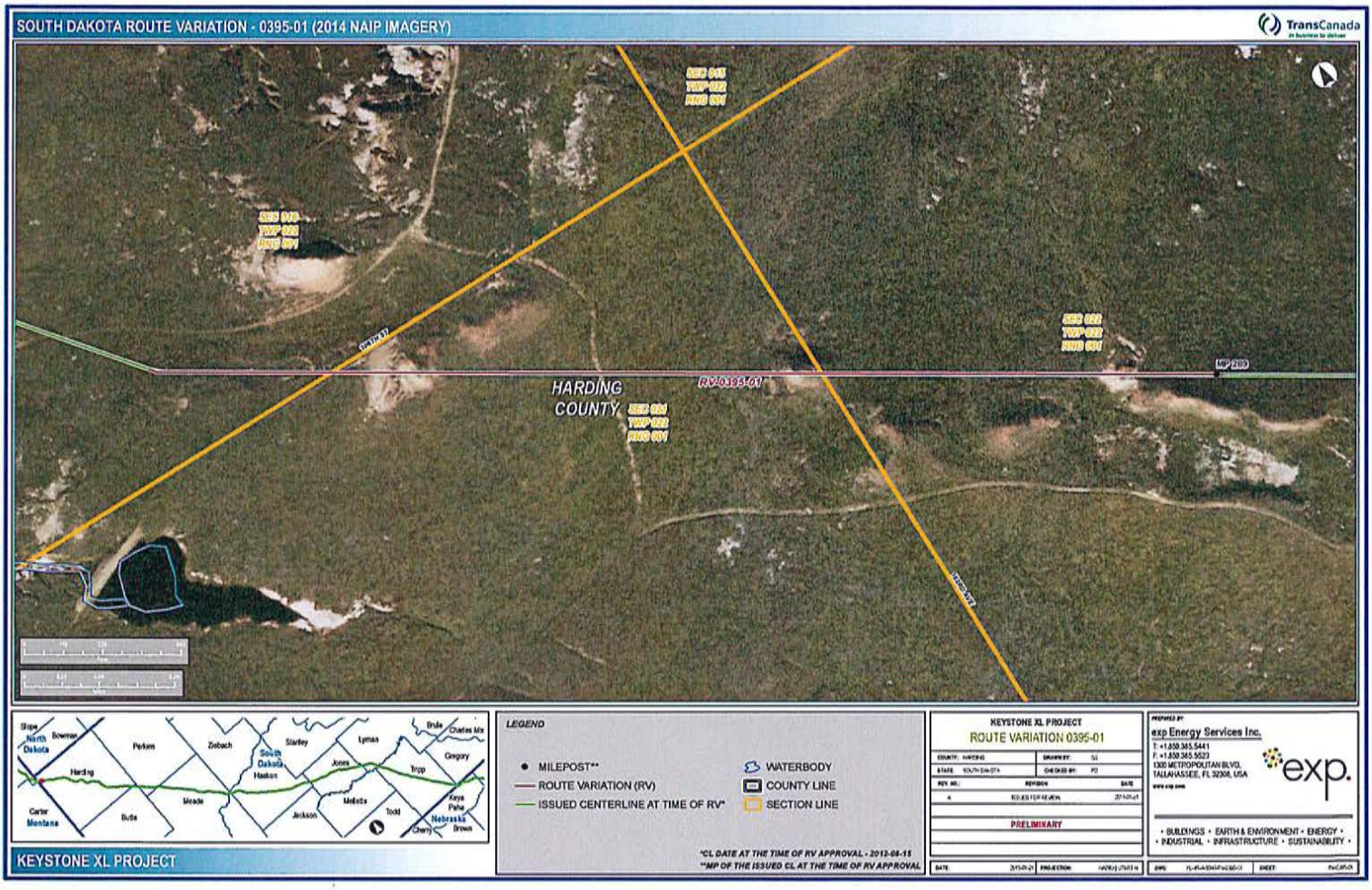
Table G1. Heat contents

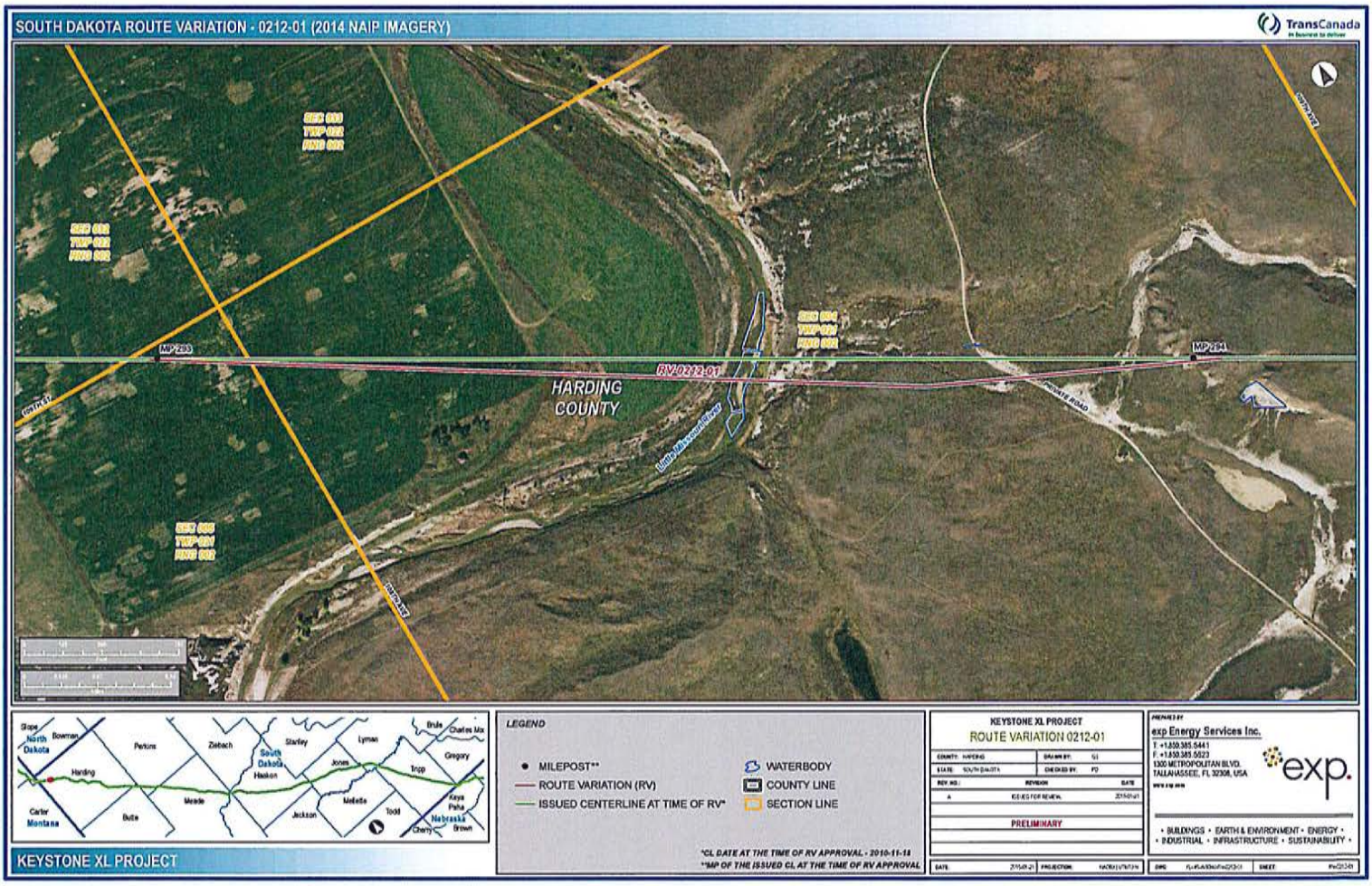
Fuel	Units	Approximate heat content
Coal[1]		
Production	million Btu per short ton	20.142
Consumption	million Btu per short ton	19.622
Coke plants	million Btu per short ton	26.304
Industrial	million Btu per short ton	22.999
Residential and commercial	million Btu per short ton	21.122
Electric power sector	million Btu per short ton	19.176
Imports	million Btu per short ton	25.132
Exports	million Btu per short ton	25.606
Coal coke	million Btu per short ton	24.800
Crude oil[1]		
Production	million Btu per barrel	5.850
Imports	million Btu per barrel	5.992
Petroleum products and other liquids		
Consumption[1]	million Btu per barrel	5.316
Motor gasoline[1]	million Btu per barrel	5.047
Jet fuel	million Btu per barrel	5.670
Distillate fuel oil[1]	million Btu per barrel	5.761
Diesel fuel[1]	million Btu per barrel	5.757
Residual fuel oil	million Btu per barrel	6.287
Liquefied petroleum gases and other[1,2]	million Btu per barrel	3.550
Kerosene	million Btu per barrel	5.670
Petrochemical feedstocks[1]	million Btu per barrel	5.066
Unfinished oils[1]	million Btu per barrel	6.098
Imports[1]	million Btu per barrel	5.548
Exports[1]	million Btu per barrel	5.584
Ethanol[3]	million Btu per barrel	3.560
Biodiesel	million Btu per barrel	5.359
Natural gas plant liquids[1]		
Production	million Btu per barrel	3.667
Natural gas[1]		
Production, dry	Btu per cubic foot	1,022
Consumption	Btu per cubic foot	1,022
End-use sectors	Btu per cubic foot	1,022
Electric power sector	Btu per cubic foot	1,022
Imports	Btu per cubic foot	1,025
Exports	Btu per cubic foot	1,009
Electricity consumption	Btu per kilowatthour	3,412

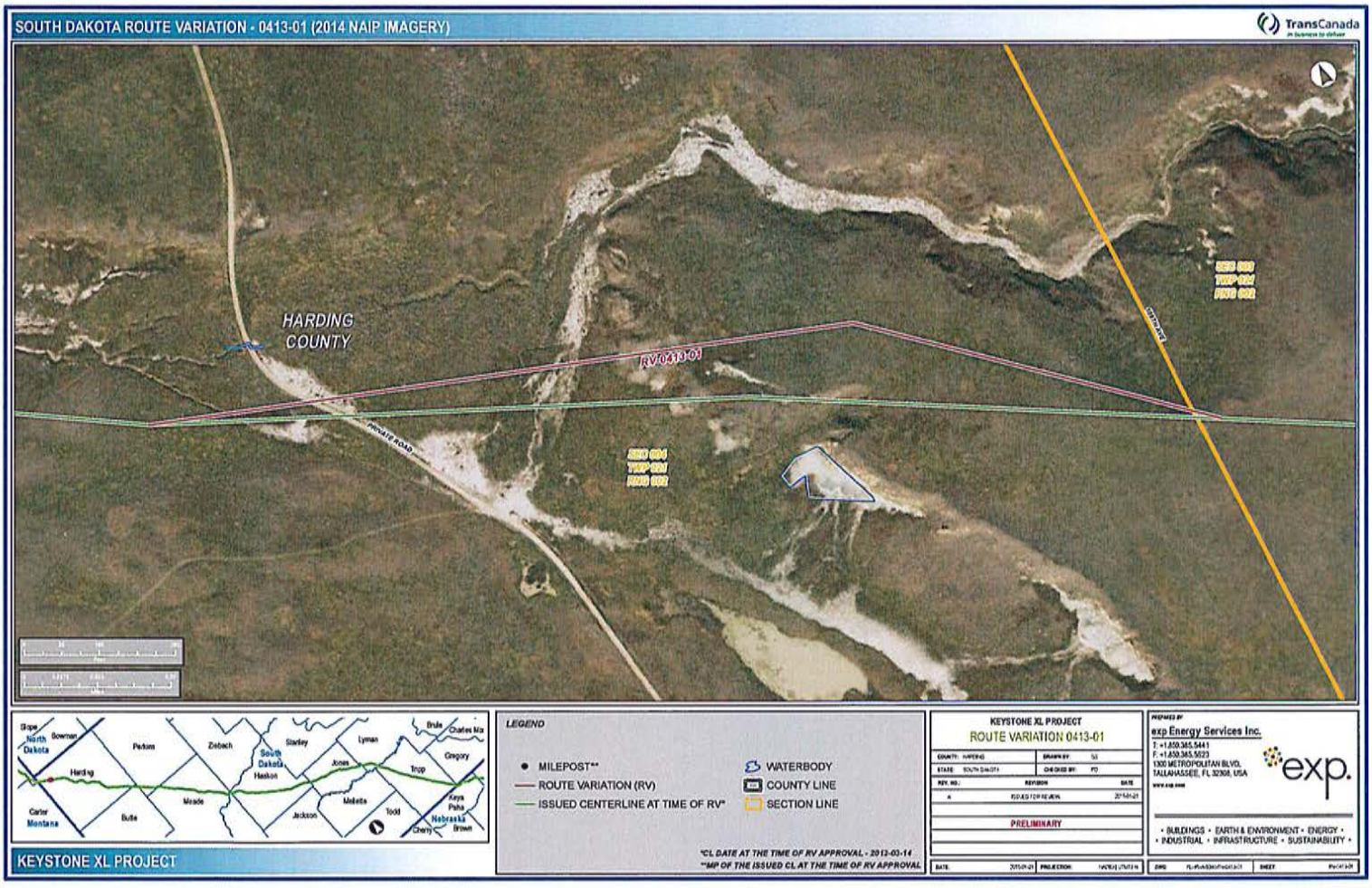
[1]Conversion factor varies from year to year. The value shown is for 2012.
[2]Includes ethane, natural gasoline, and refinery olefins.
[3]Includes denaturant.
Btu = British thermal unit.
Sources: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013), and EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

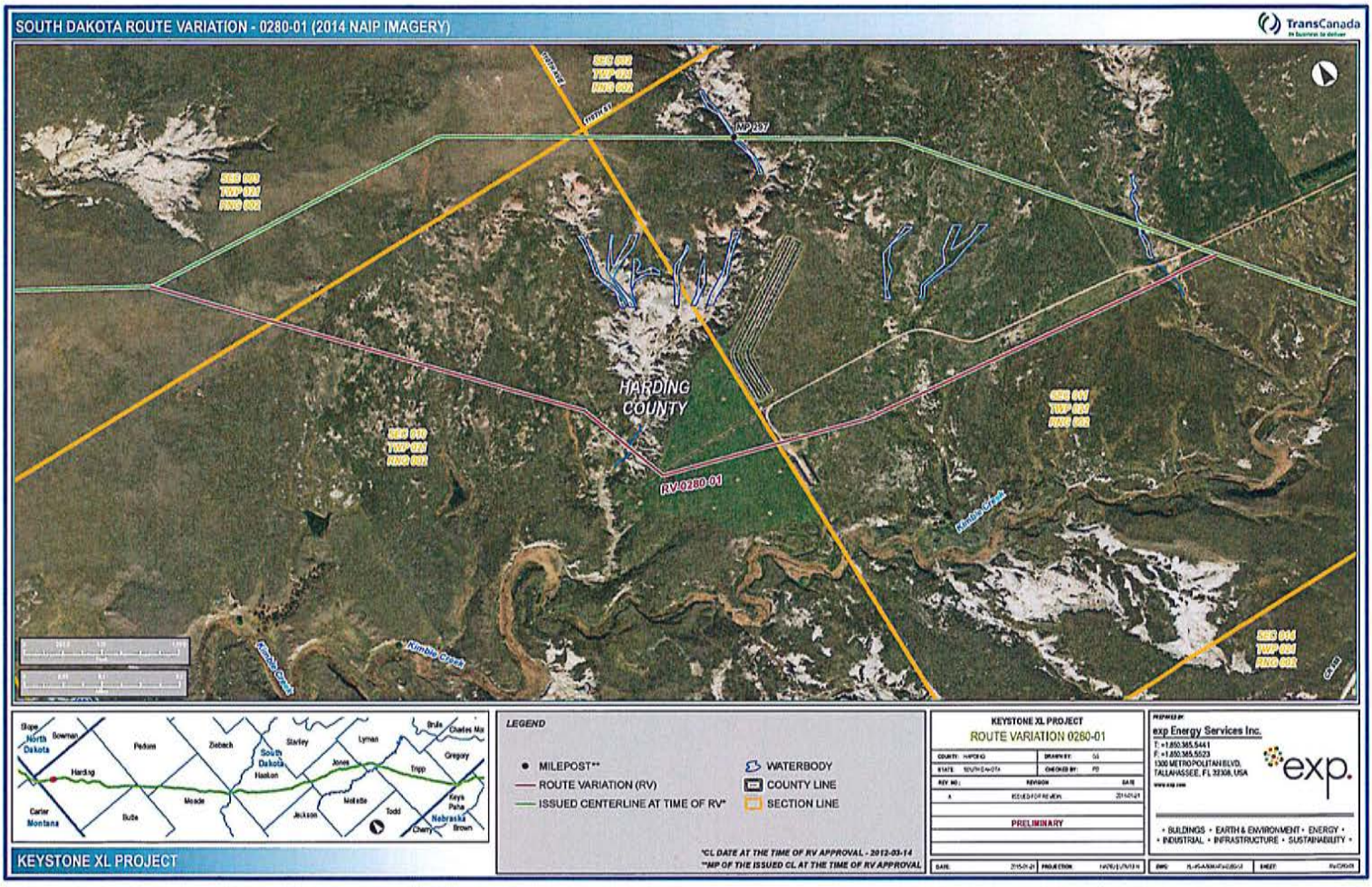
012912

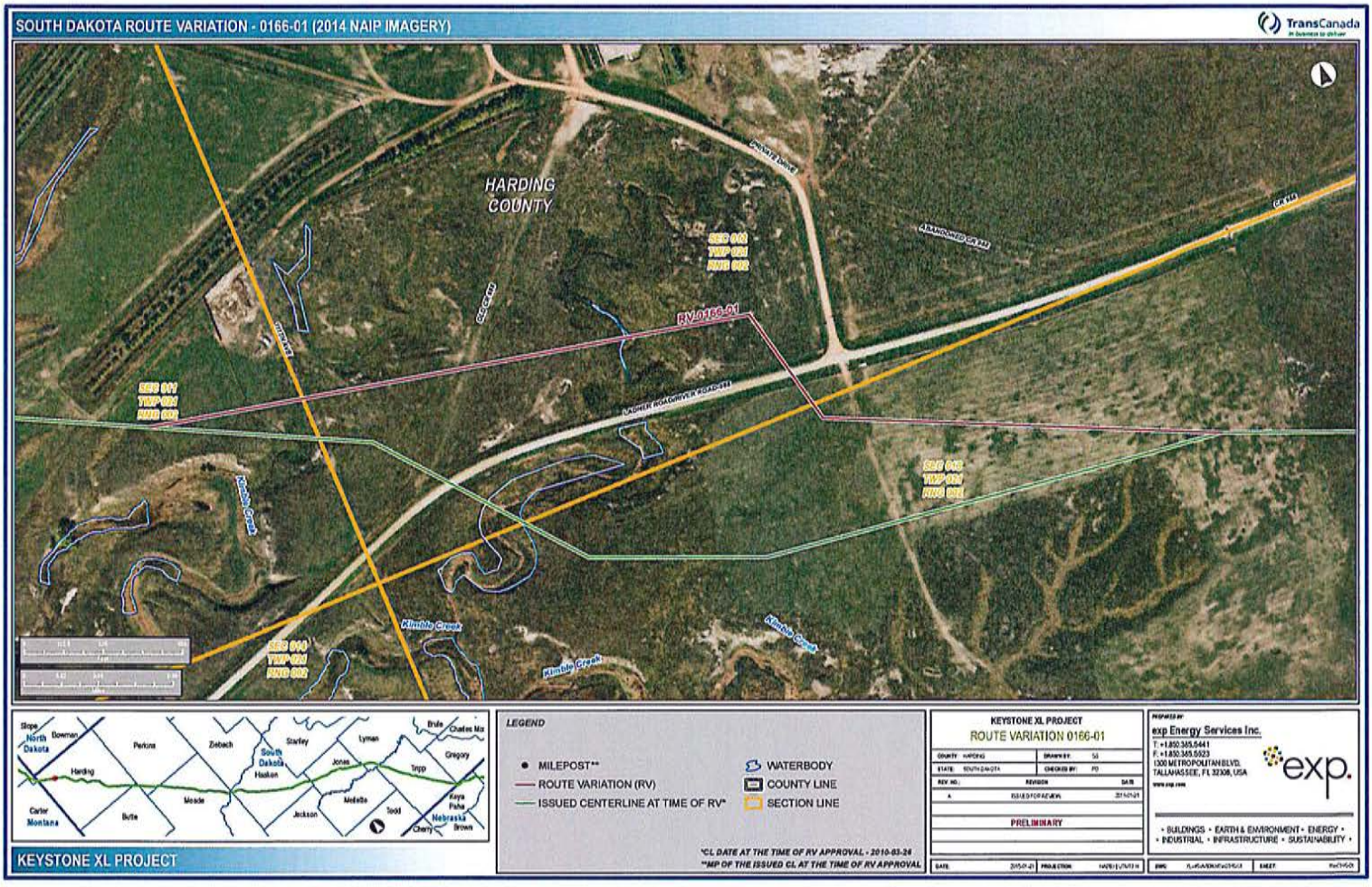

SOUTH DAKOTA ROUTE VARIATION - 0470-01 (2014 NAIP IMAGERY)
TransCanada
HARDING COUNTY
RV-0470-01
MP 288
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-06-11
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0470-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

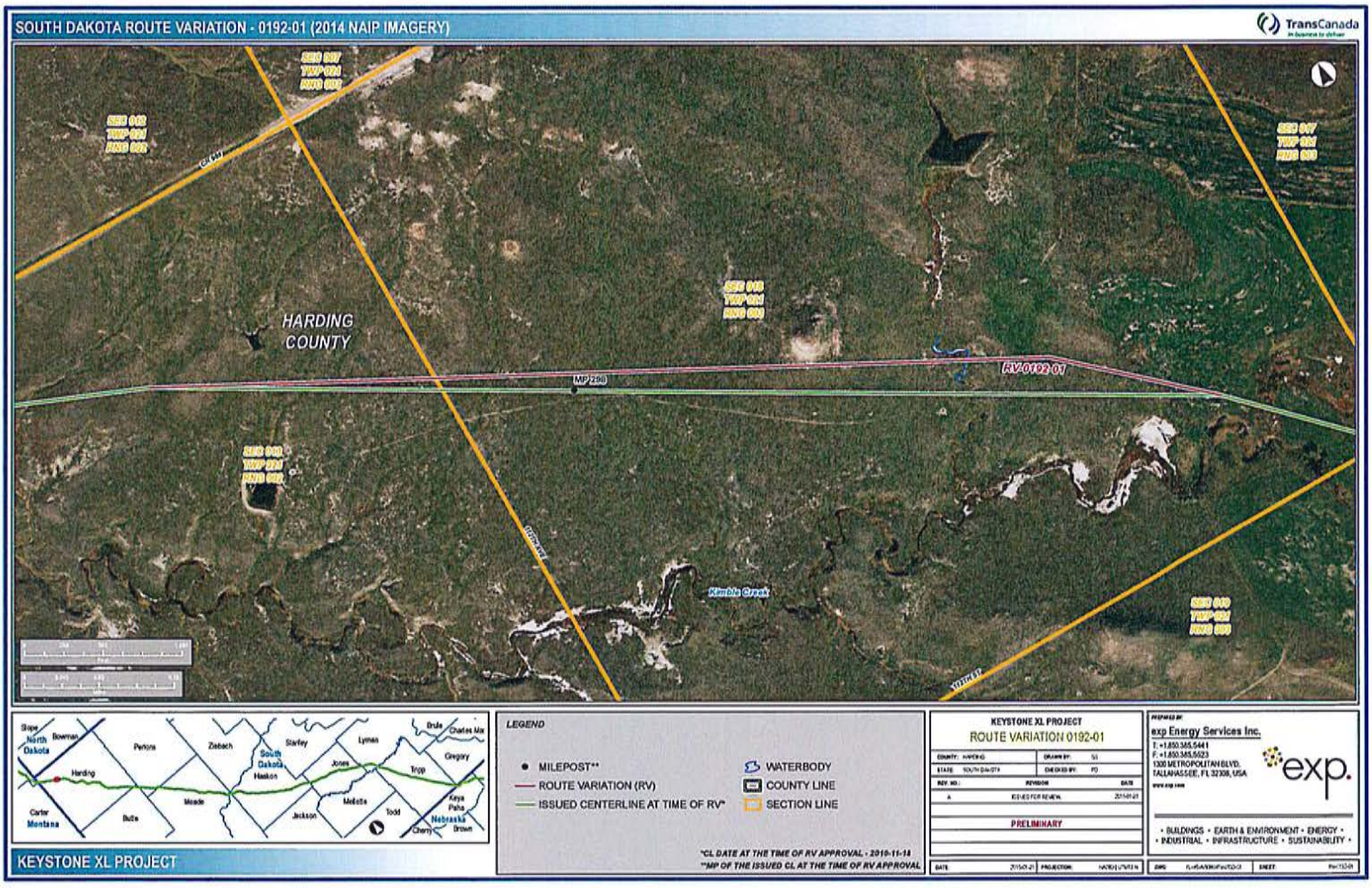

SOUTH DAKOTA ROUTE VARIATION - 0395-01 (2014 NAIP IMAGERY)
TransCanada
SEC 013
TWP 022
RNG 01W
SEC 012
TWP 022
RNG 01W
SEC 007
TWP 022
RNG 01E
HARDING
COUNTY
RV-0395-01
MP 2087
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-08-15
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0395-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD,
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
KEYSTONE XL PROJECT

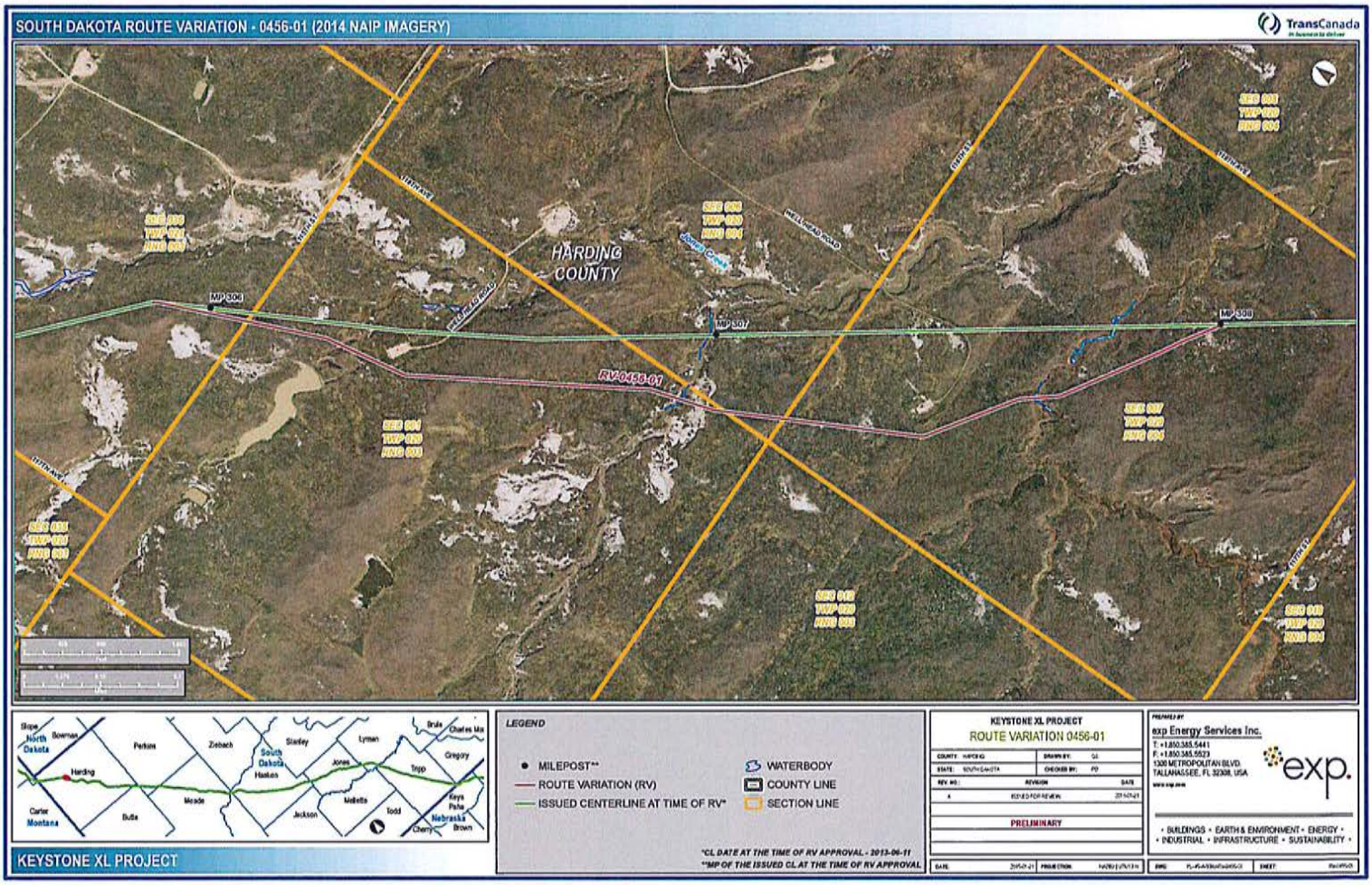

SOUTH DAKOTA ROUTE VARIATION - 0212-01 (2014 NAIP IMAGERY)
TransCanada
SEC 035
TWP 022
RNG 002
SEC 034
TWP 022
RNG 001
SEC 003
TWP 021
RNG 002
SEC 004
TWP 021
RNG 001
MP 208
MP 204
RV-0212-01
HARDING
COUNTY
PRIVATE ROAD
SOUTH DAKOTA
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2010-11-16
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0212-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

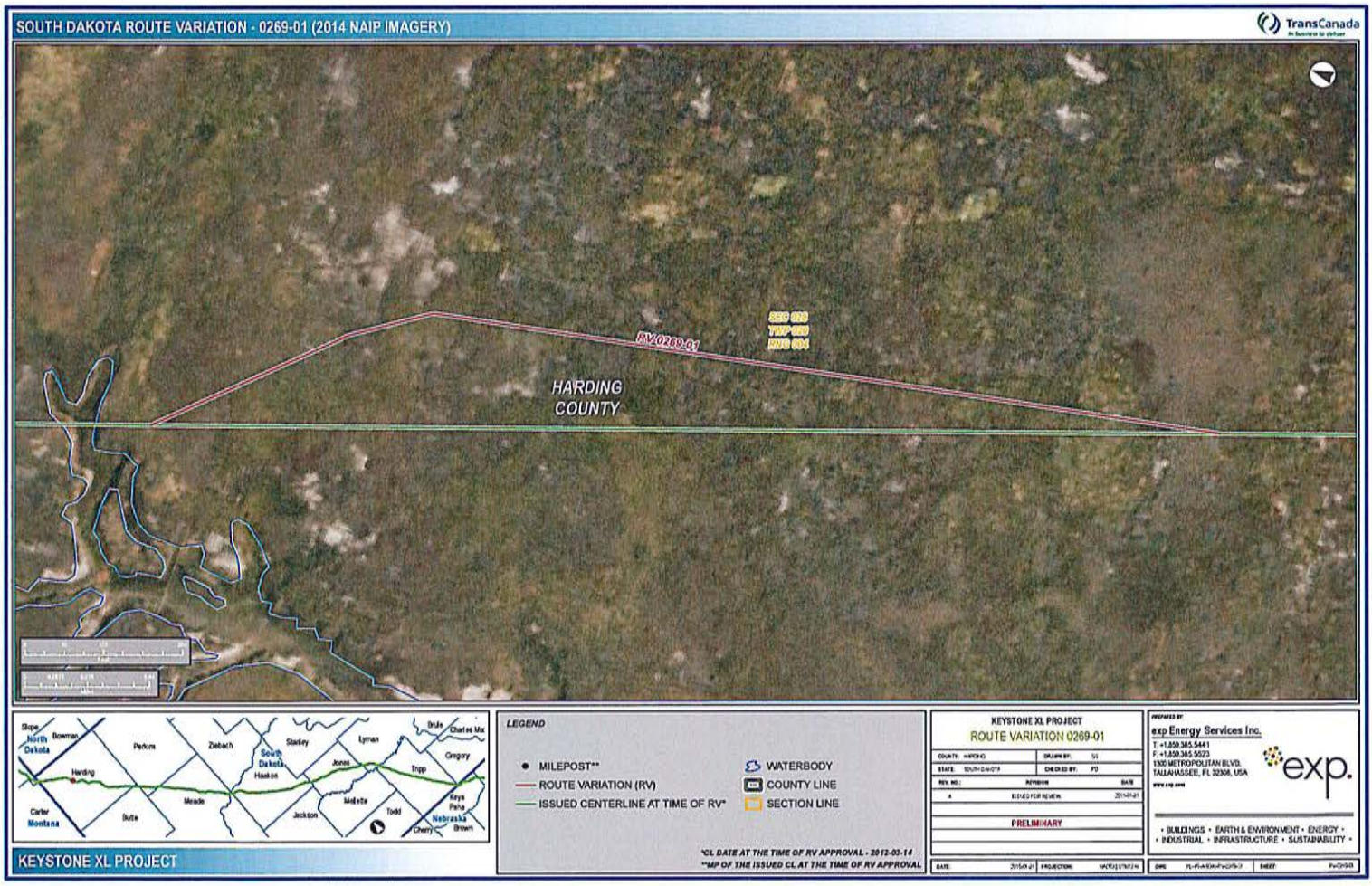

SOUTH DAKOTA ROUTE VARIATION - 0413-01 (2014 NAIP IMAGERY)
TransCanada
HARDING COUNTY
RV 0413-01
PERKINS ROAD
MEADE
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-03-14
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0413-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5023
1300 METROPOLITAN BLVD,
TALLAHASSEE, FL 32308, USA
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

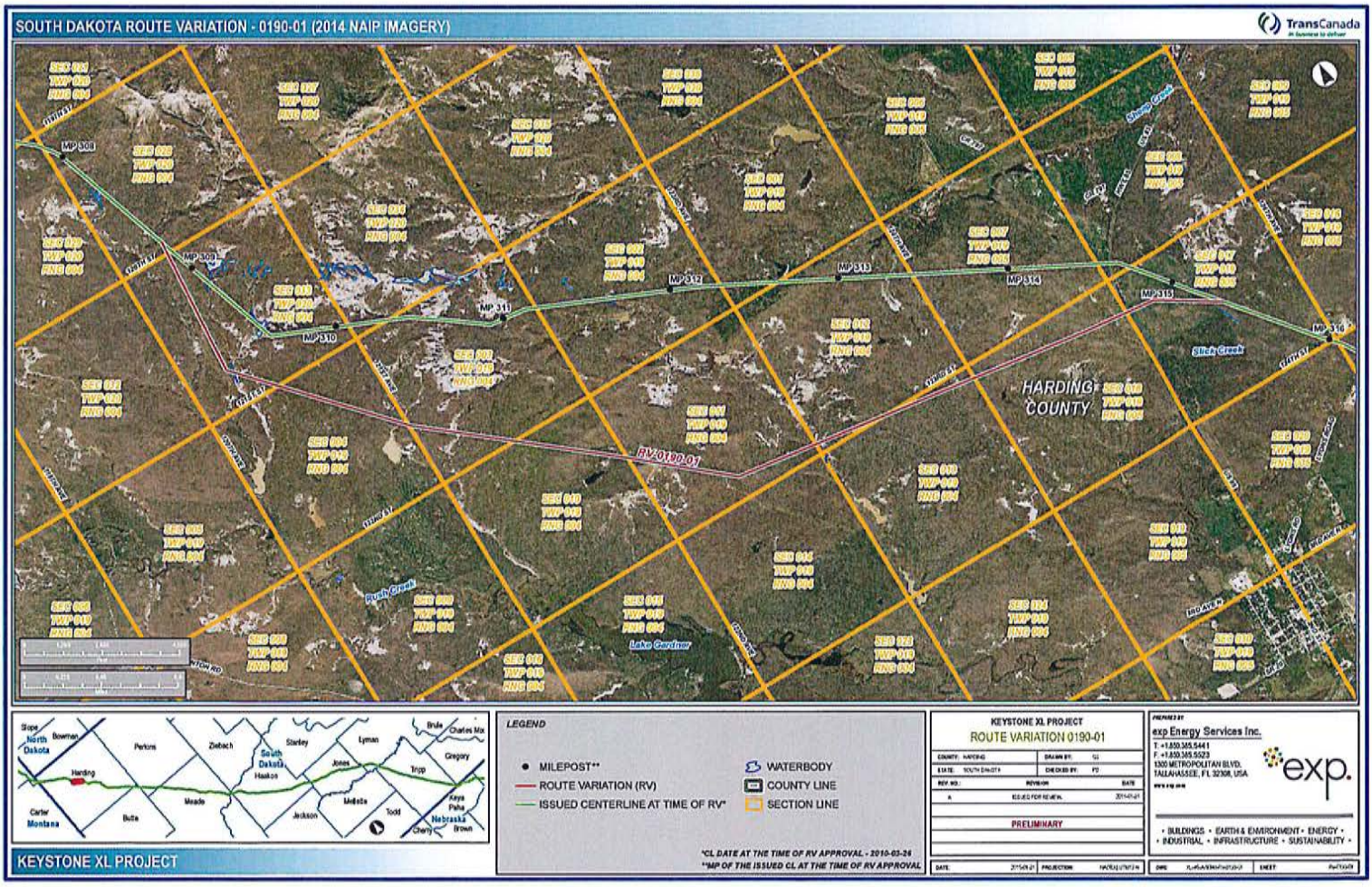

SOUTH DAKOTA ROUTE VARIATION - 0280-01 (2014 NAIP IMAGERY)
TransCanada
HARDING COUNTY
RV 0280-01
MP 297
Rhoda Creek
Rimbey Creek
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2012-03-14
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0280-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

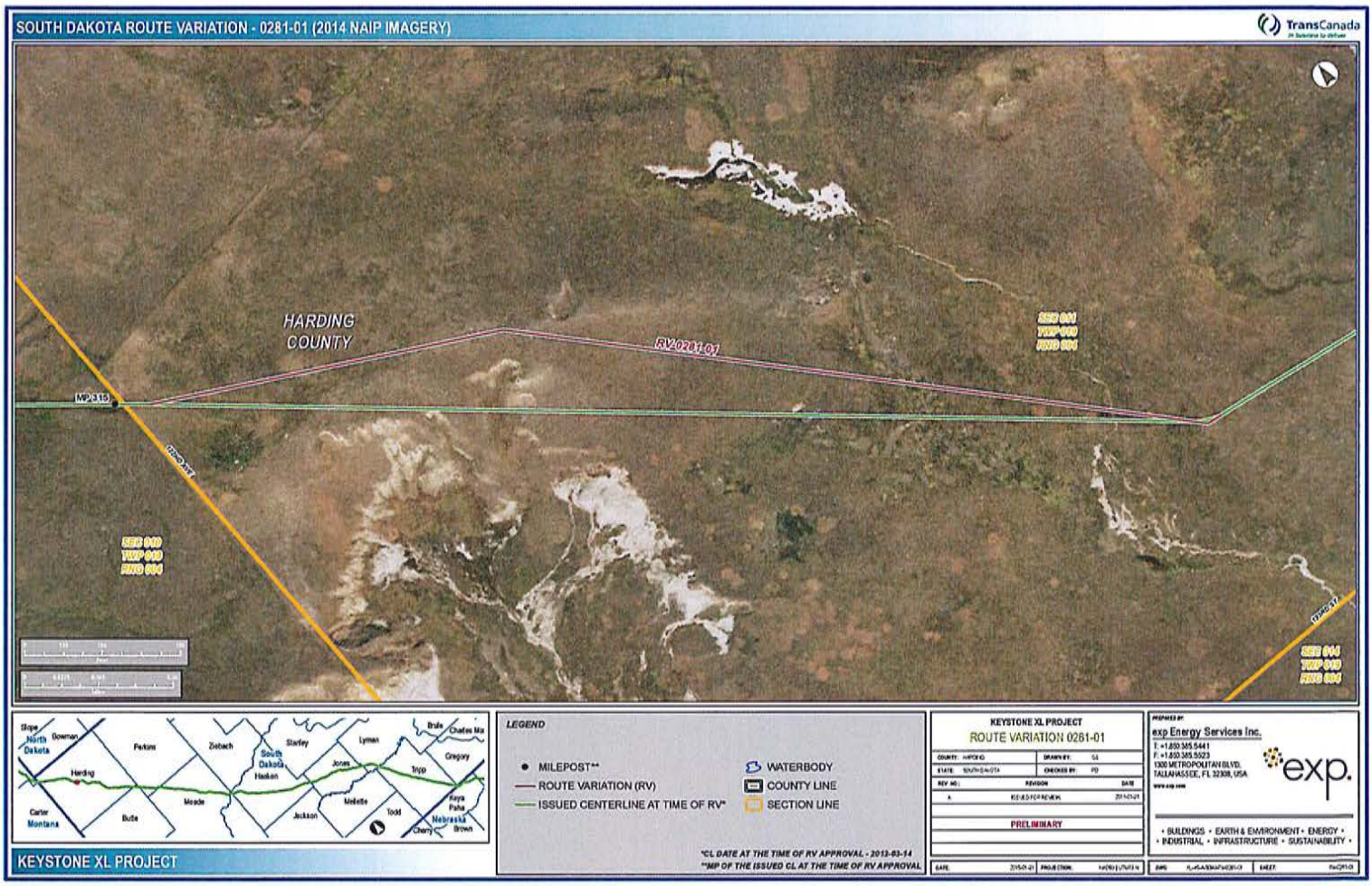

SOUTH DAKOTA ROUTE VARIATION - 0166-01 (2014 NAIP IMAGERY)
TransCanada
HARDING COUNTY
RV-0166-01
Kimble Creek
Kimble Creek
Kimble Creek
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2010-03-24
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0166-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
KEYSTONE XL PROJECT

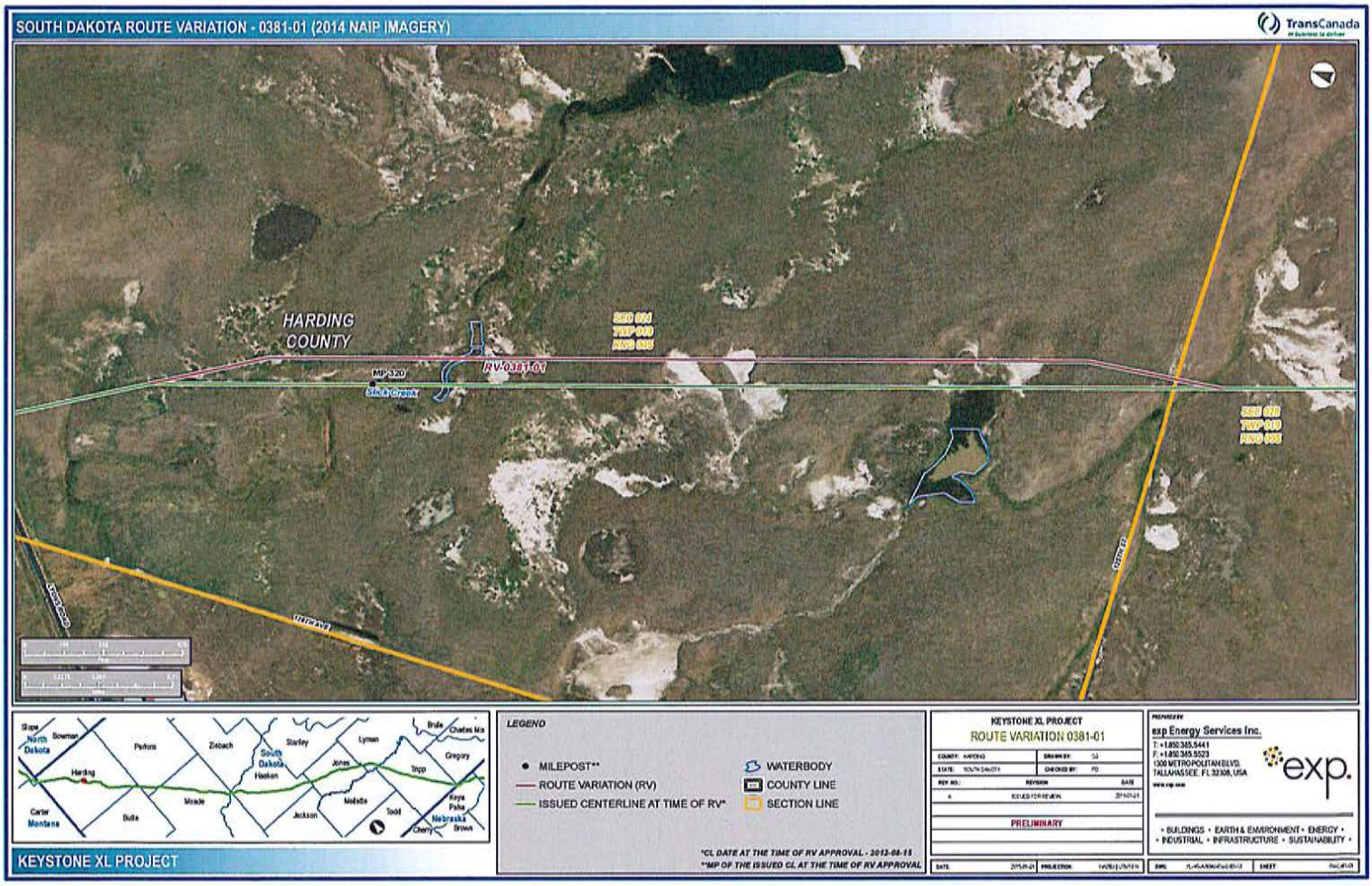

SOUTH DAKOTA ROUTE VARIATION - 0192-01 (2014 NAIP IMAGERY)
TransCanada
HARDING COUNTY
MP 290
RV 0192-01
Kimble Creek
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2010-11-14
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0192-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
KEYSTONE XL PROJECT

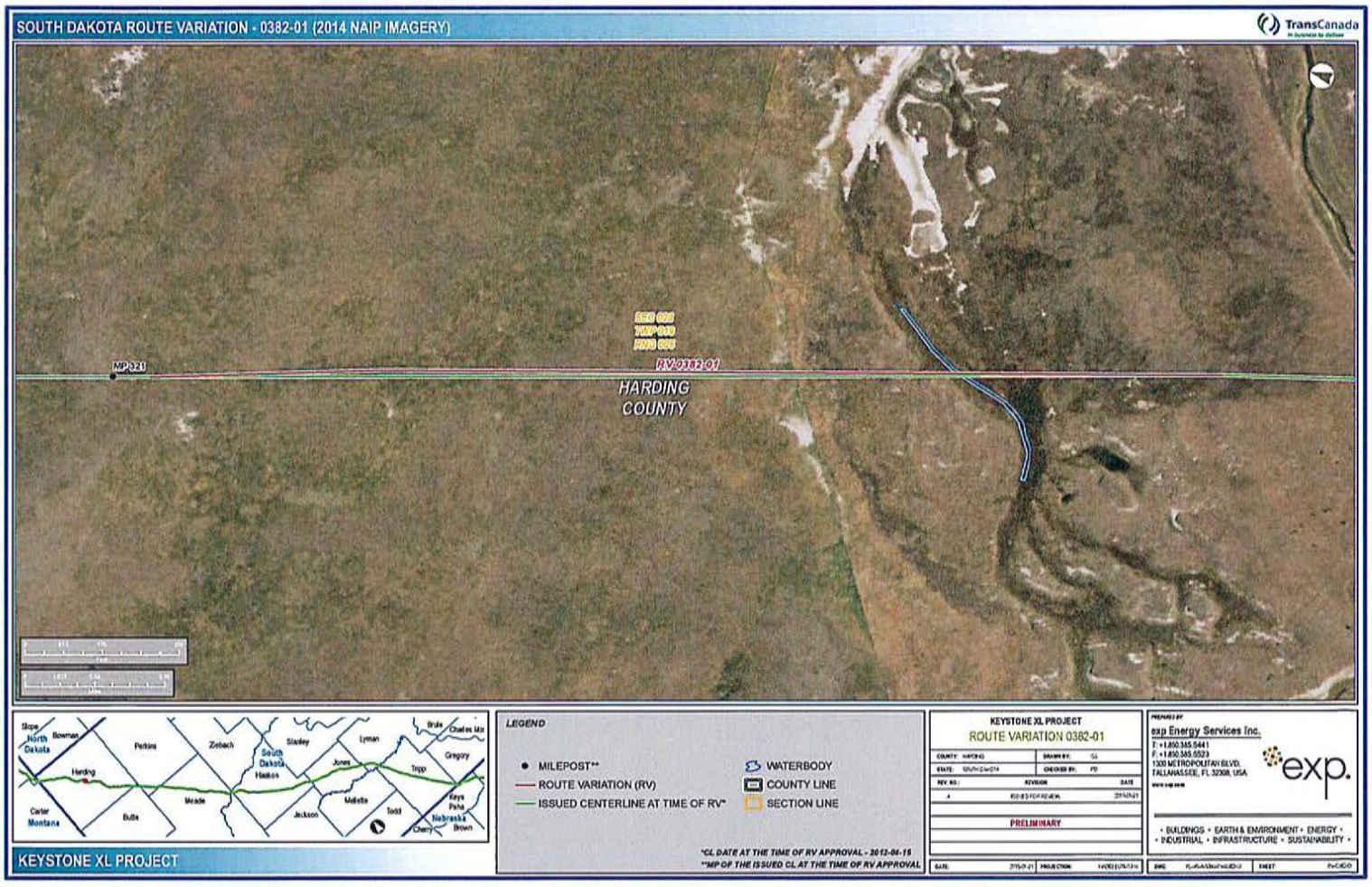

SOUTH DAKOTA ROUTE VARIATION - 0456-01 (2014 NAIP IMAGERY)
TransCanada
HARDING COUNTY
MP 506
MP 507
MP 508
RV 0456-01
HIGHWAY 85
HIGHWAY 20
HIGHWAY 79
HIGHWAY 212
WELLHEAD ROAD
PETE CREEK ROAD
SEC 000
TWP 000
RNG 000
Slope
Bowman
North Dakota
Perkins
Ziebach
South Dakota
Stanley
Lyman
Jones
Harding
Haakon
Tripp
Brule
Charles Mix
Gregory
Meade
Butte
Carter
Montana
Jackson
Mellette
Todd
Keya Paha
Nebraska
Brown
Cherry
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-06-11
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0456-01
PRELIMINARY
PREPARED BY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

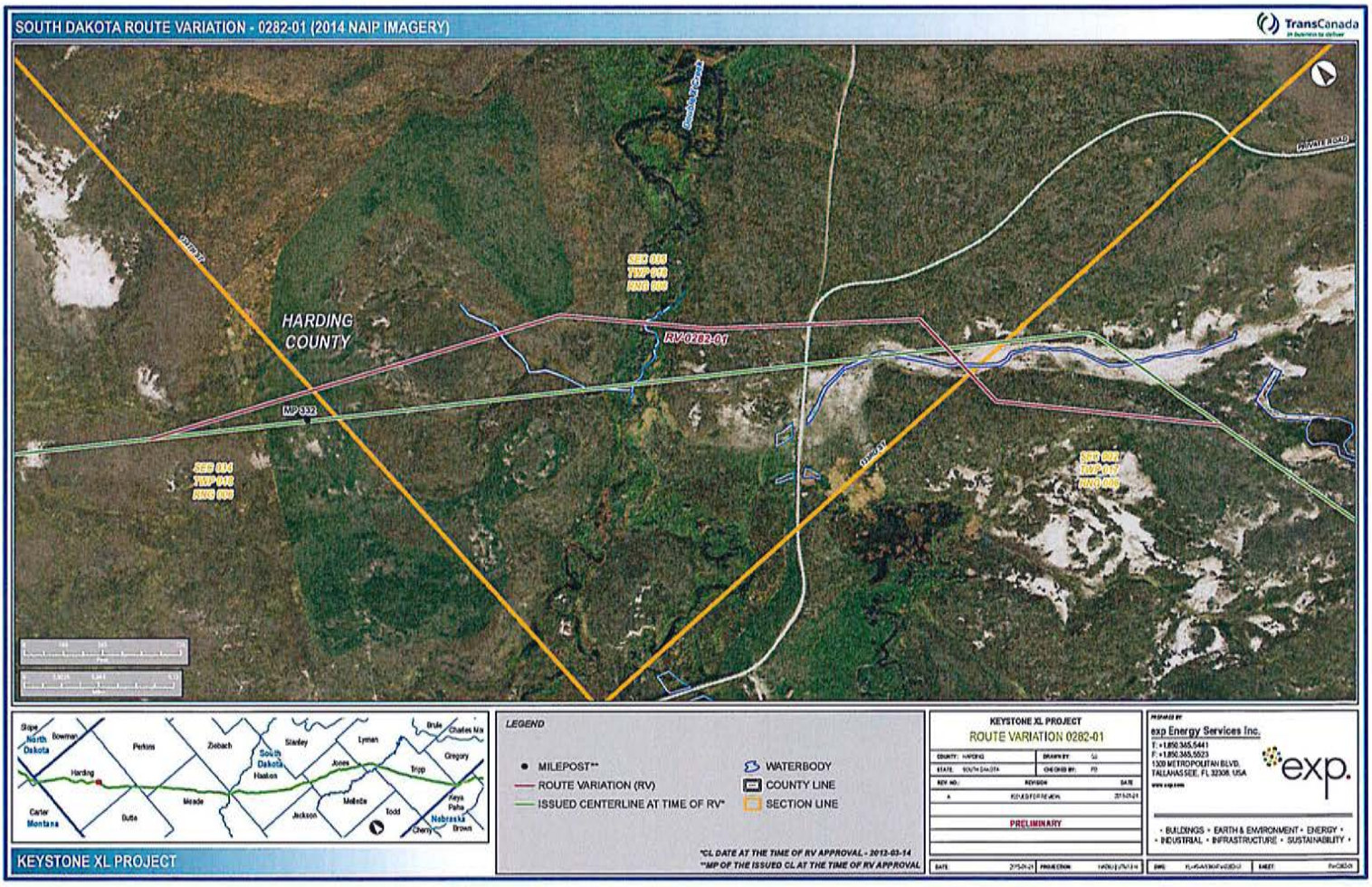

SOUTH DAKOTA ROUTE VARIATION - 0269-01 (2014 NAIP IMAGERY)
TransCanada
RV 0269-01
SEC 036
TWP 020
RNG 004
HARDING
COUNTY
Slope
Bowman
North Dakota
Perkins
Ziebach
Stanley
Lyman
Brule
Charles Mix
South Dakota
Haakon
Jones
Gregory
Tripp
Harding
Carter
Montana
Butte
Meade
Jackson
Mellette
Todd
Keya Paha
Nebraska
Brown
Cherry
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2012-03-14
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0269-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

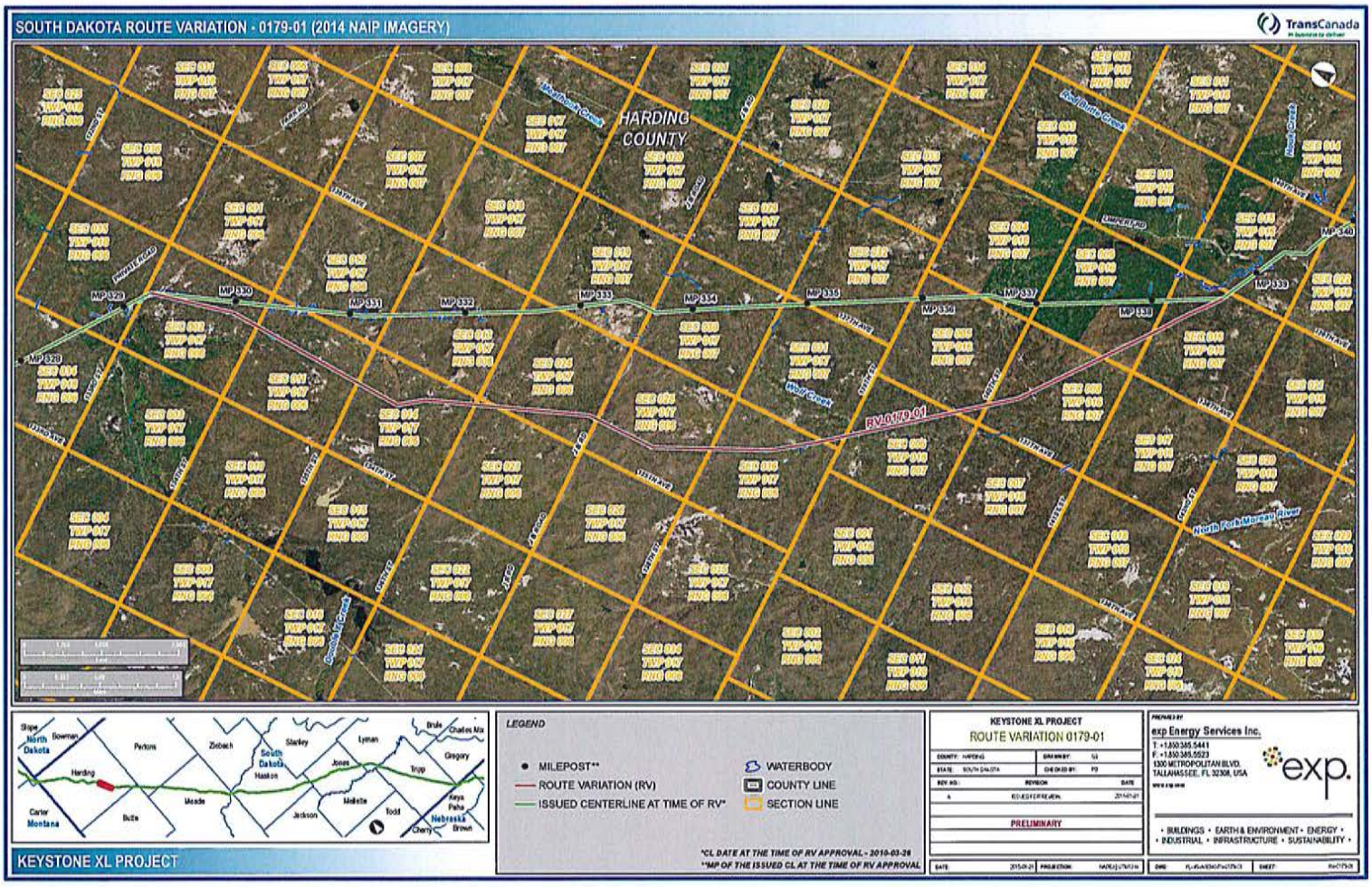

SOUTH DAKOTA ROUTE VARIATION - 0190-01 (2014 NAIP IMAGERY)
TransCanada
MP 308
MP 309
MP 310
MP 311
MP 312
MP 313
MP 314
MP 315
MP 316
HARDING COUNTY
RV-0190-01
Slick Creek
Rush Creek
Lake Gardner
Slope
North Dakota
Bowman
Perkins
Ziebach
South Dakota
Harding
Butte
Meade
Carter
Montana
Starley
Haakon
Jones
Lyman
Jackson
Mellette
Todd
Tripp
Gregory
Brule
Charles Mix
Keya Paha
Nebraska
Brown
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2010-03-26
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0190-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •


SOUTH DAKOTA ROUTE VARIATION - 0281-01 (2014 NAIP IMAGERY)
TransCanada
HARDING COUNTY
RV-0281-01
MP 315
SEC 001
TWP 019
RNG 004
SEC 010
TWP 019
RNG 004
SEC 011
TWP 019
RNG 004
Slope
North Dakota
Bowman
Perkins
Zebach
Harding
South Dakota
Haakon
Stanley
Jones
Lyman
Tripp
Brule
Charles Mix
Gregory
Carter
Montana
Butte
Meade
Jackson
Mellette
Todd
Keya Paha
Nebraska
Brown
Cherry
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-03-14
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0281-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •


SOUTH DAKOTA ROUTE VARIATION - 0381-01 (2014 NAIP IMAGERY)
TransCanada
HARDING COUNTY
MP 320
RV-0381-01
Slick Creek
HARDING CO
HARDING CO
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-08-15
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0381-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
KEYSTONE XL PROJECT


SOUTH DAKOTA ROUTE VARIATION - 0382-01 (2014 NAIP IMAGERY)
TransCanada
SEC 026
TWP 019
RNG 005
MP 021
RV-0382-01
HARDING
COUNTY
Slope
North Dakota
Bowman
Perkins
Ziebach
South Dakota
Harding
Meade
Butte
Carter
Montana
Stanley
Haakon
Jackson
Jones
Lyman
Mellette
Todd
Tripp
Brule
Charles Mix
Gregory
Keya Paha
Nebraska
Brown
Cherry
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2012-06-15
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0382-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •


SOUTH DAKOTA ROUTE VARIATION - 0282-01 (2014 NAIP IMAGERY)
TransCanada
HARDING COUNTY
RV-0282-01
MP 332
PRIVATE ROAD
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-03-14
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0282-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1309 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
KEYSTONE XL PROJECT


SOUTH DAKOTA ROUTE VARIATION - 0179-01 (2014 NAIP IMAGERY)
TransCanada
HARDING COUNTY
MP 329
MP 330
MP 331
MP 332
MP 333
MP 334
MP 335
MP 336
MP 337
MP 338
MP 339
MP 340
RV 0179-01
Wolf Creek
North Fork Moreau River
Slope
Bowman
North Dakota
Perkins
Ziebach
Stanley
Lyman
Brule
Charles Mix
Gregory
Tripp
Harding
South Dakota
Haakon
Jones
Mellette
Todd
Keya Paha
Nebraska
Brown
Carter
Montana
Butte
Meade
Jackson
Cherry
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2010-03-26
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0179-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
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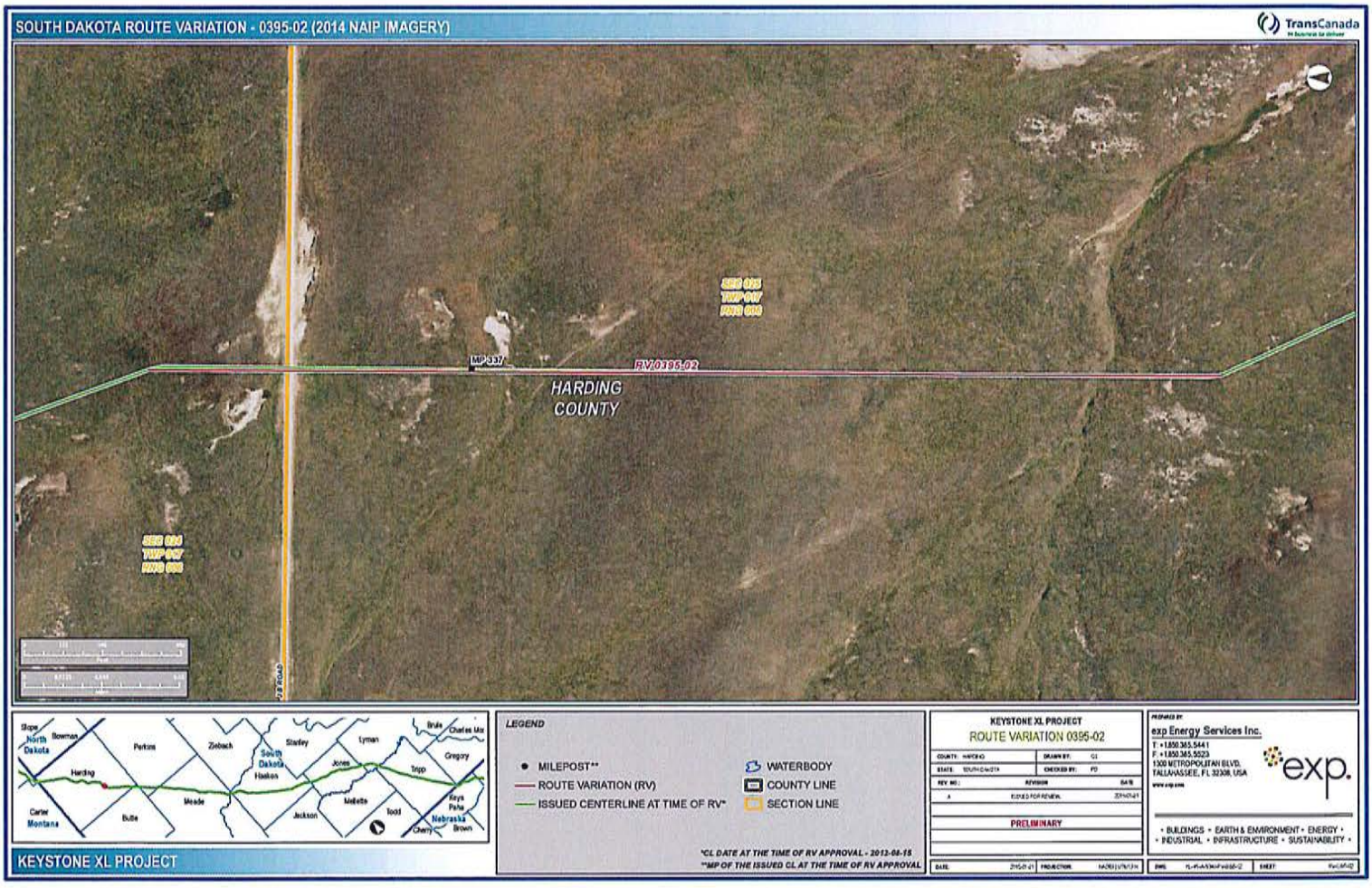
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •


SOUTH DAKOTA ROUTE VARIATION - 0395-02 (2014 NAIP IMAGERY)
TransCanada
SEC 035
TWP 04N
RNG 04E
MP 937
RV 0395-02
HARDING
COUNTY
SEC 004
TWP 03N
RNG 04E
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2012-06-15
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0395-02
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
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1300 METROPOLITAN BLVD.
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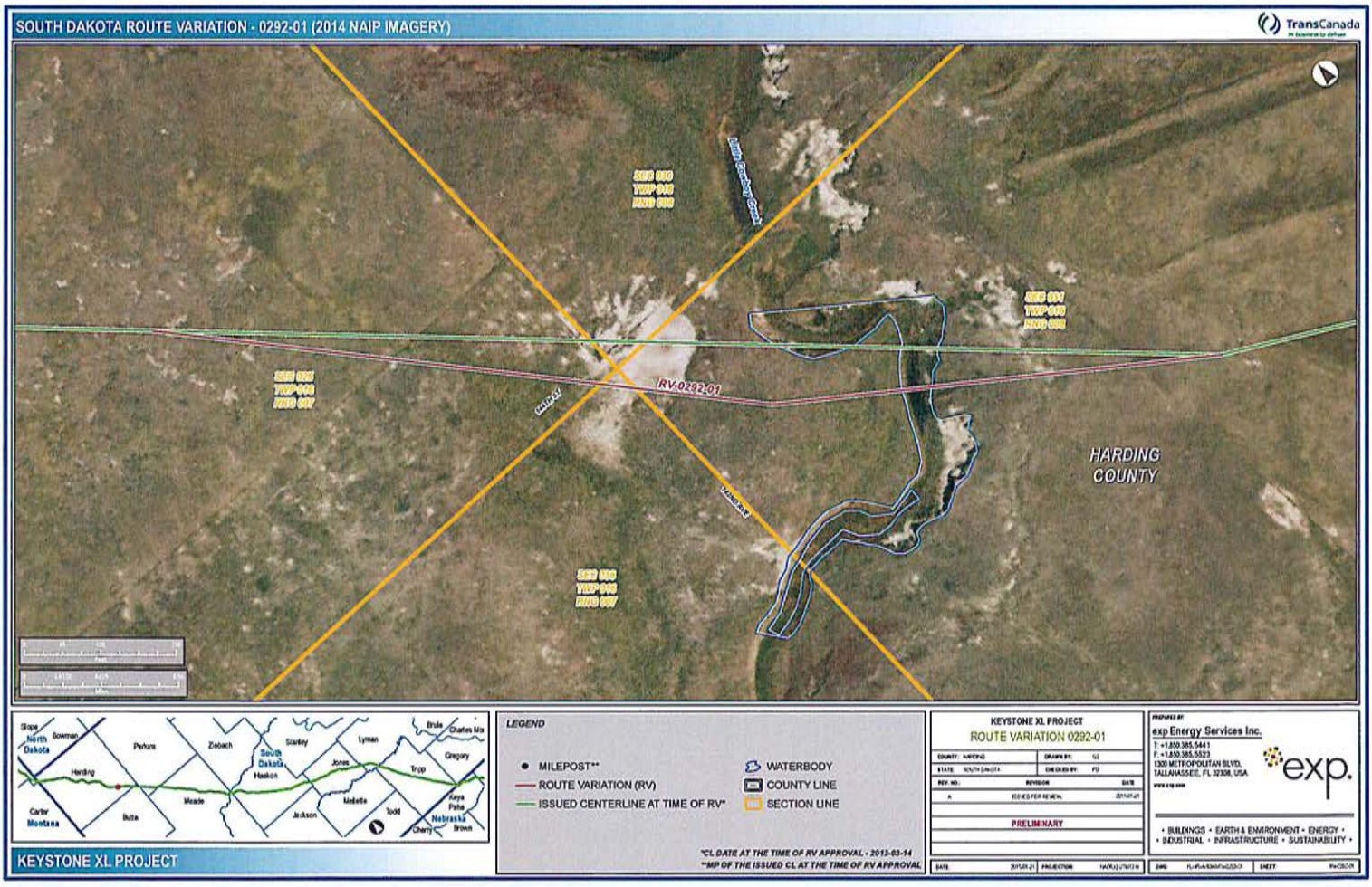
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
KEYSTONE XL PROJECT


SOUTH DAKOTA ROUTE VARIATION - 0292-01 (2014 NAIP IMAGERY)
TransCanada
RV-0292-01
HARDING COUNTY
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-03-14
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0292-01
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exp Energy Services Inc.
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F: +1.850.385.5023
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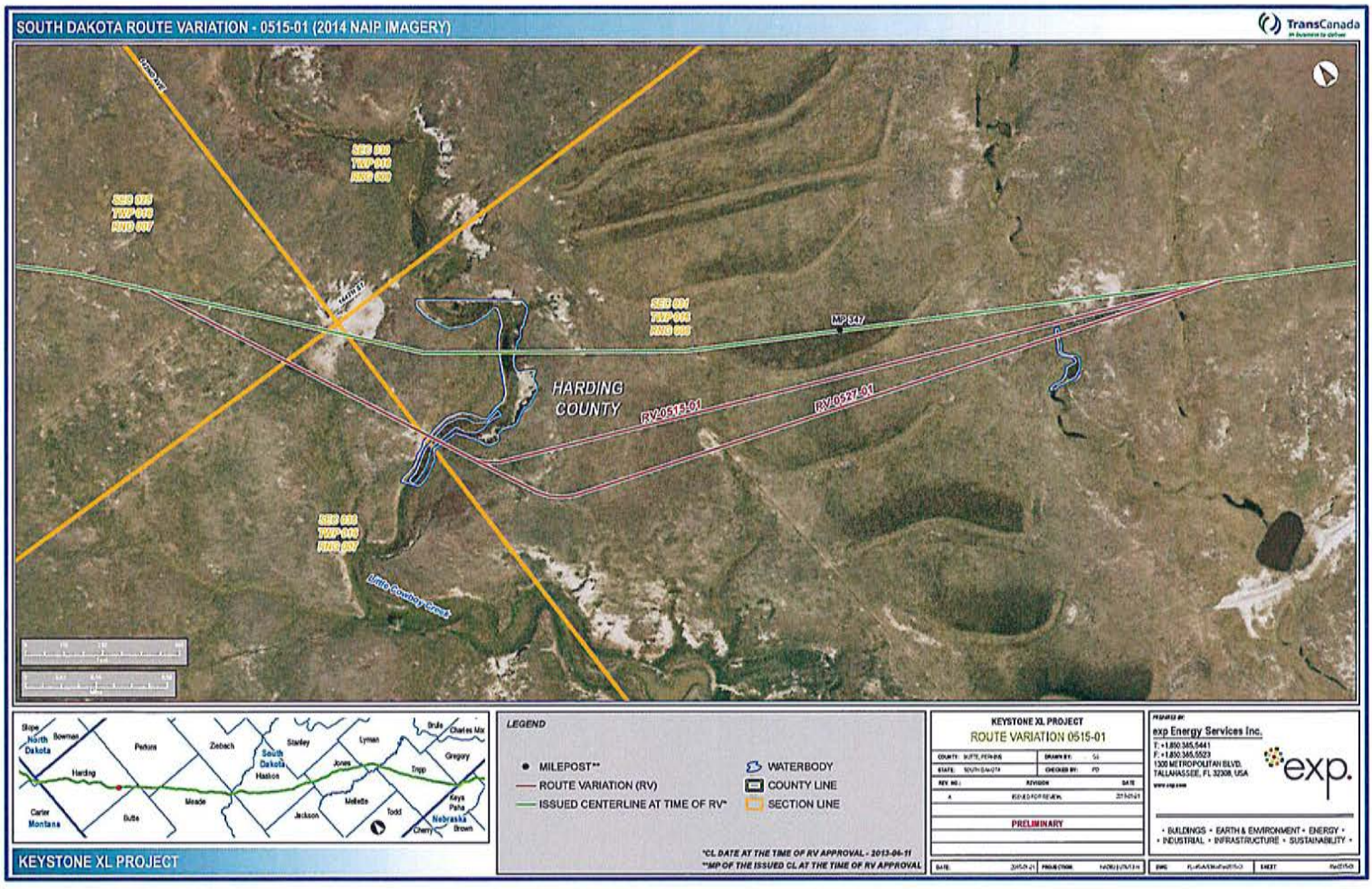
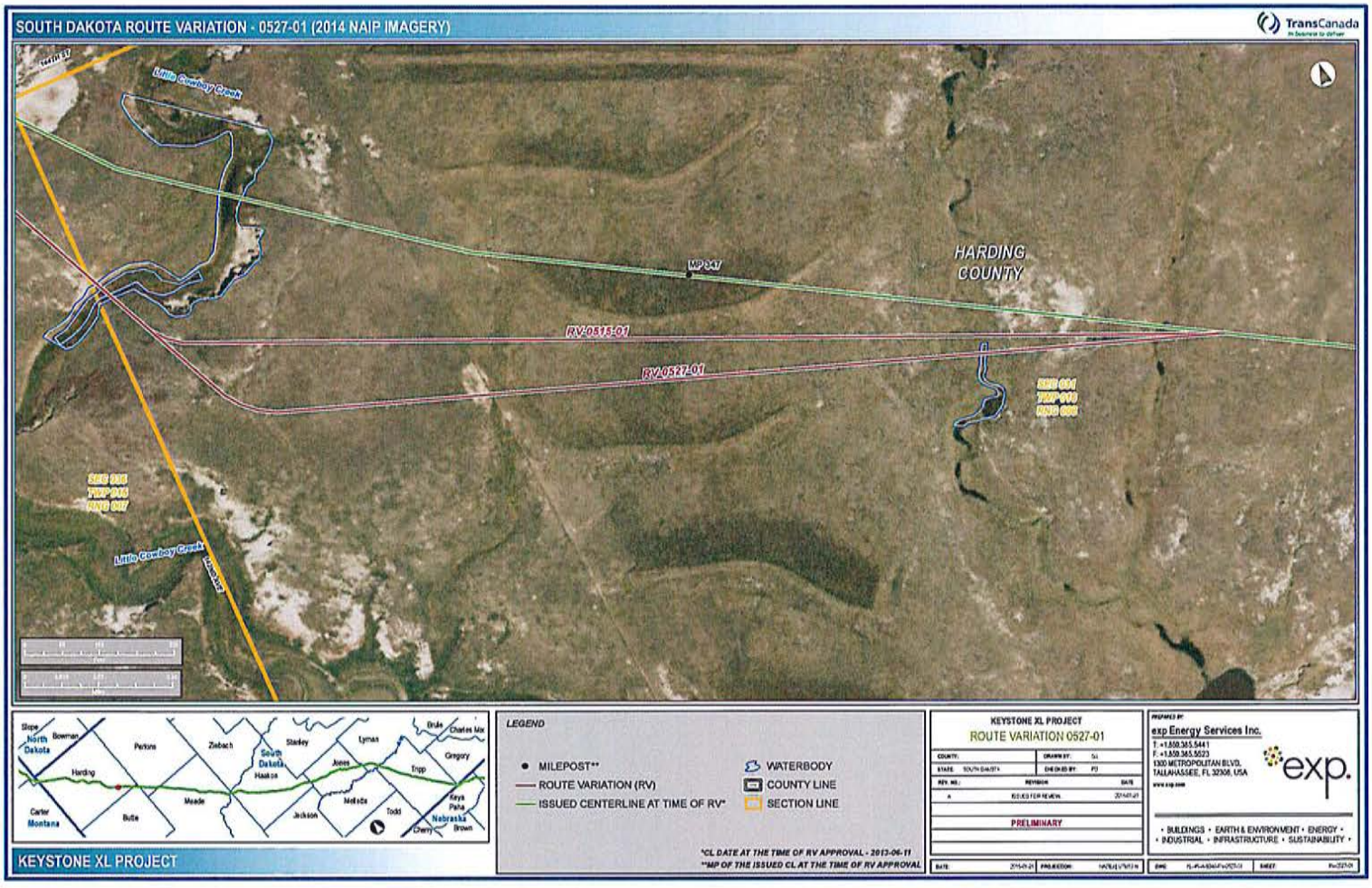
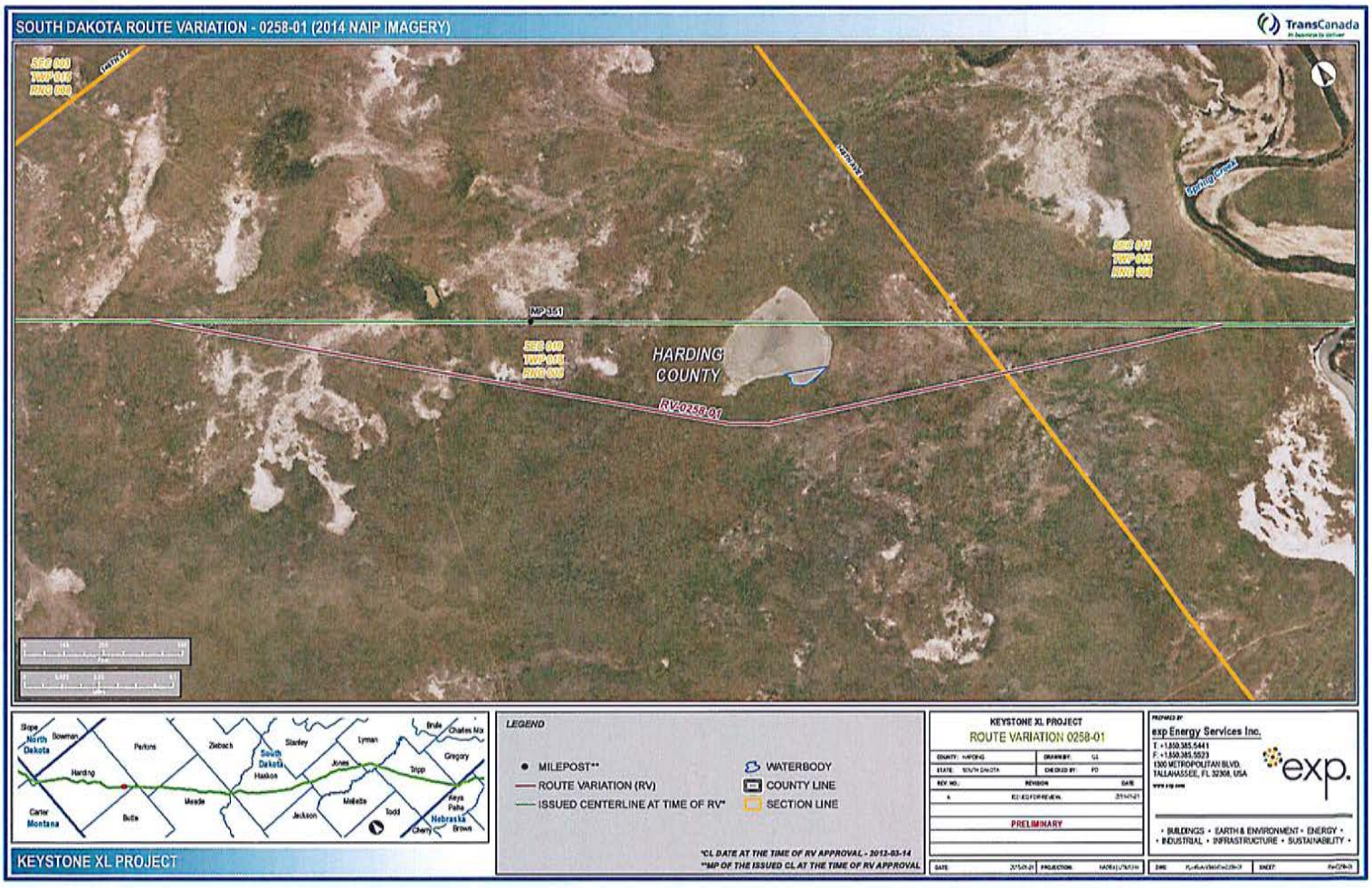
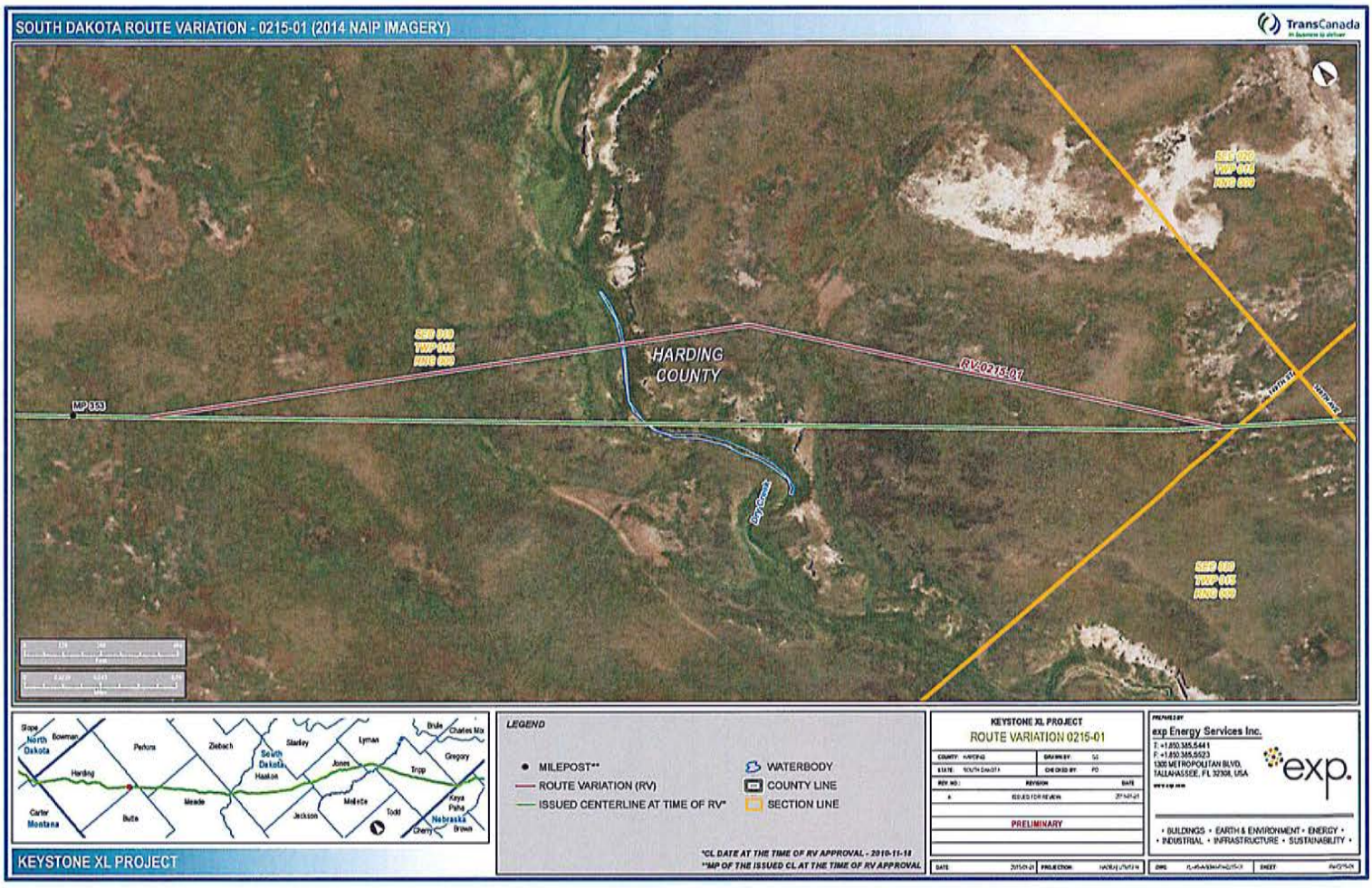
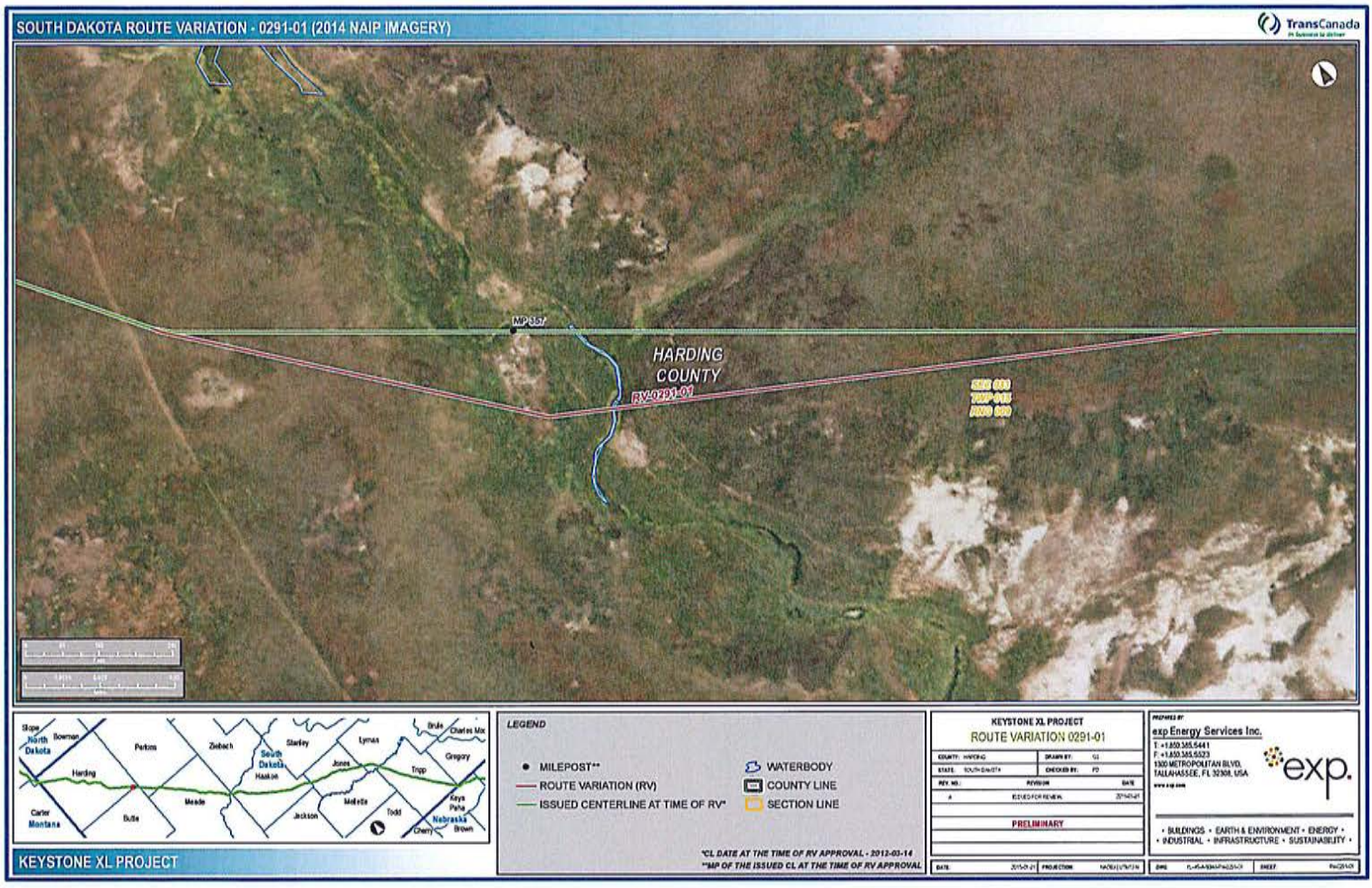
TALLAHASSEE, FL 32308, USA
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
KEYSTONE XL PROJECT

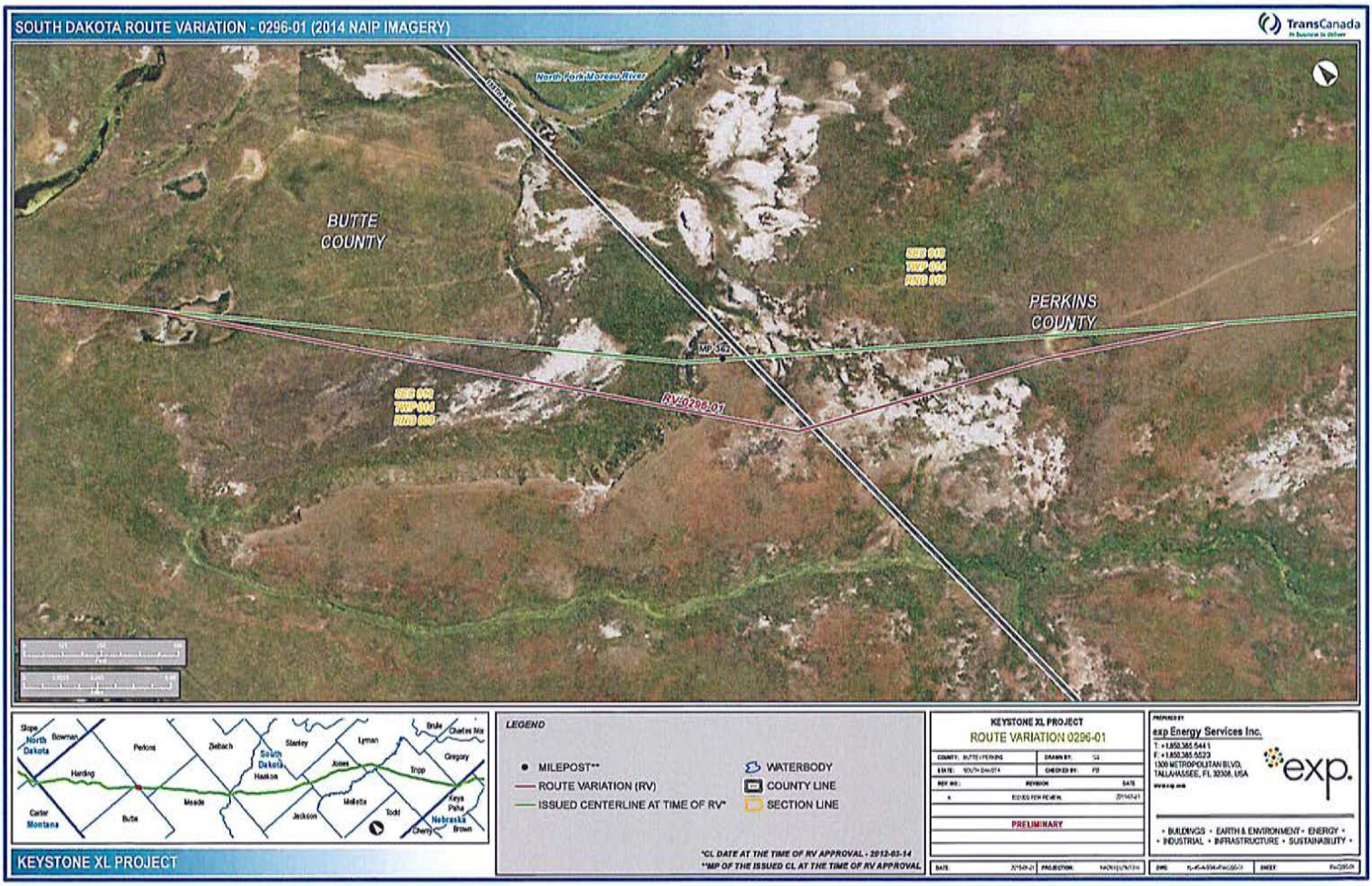

SOUTH DAKOTA ROUTE VARIATION - 0515-01 (2014 NAIP IMAGERY)
TransCanada
HARDING COUNTY
RV-0515-01
RV-0527-01
MP 547
Little Cowboy Creek
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-06-11
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0515-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY
KEYSTONE XL PROJECT

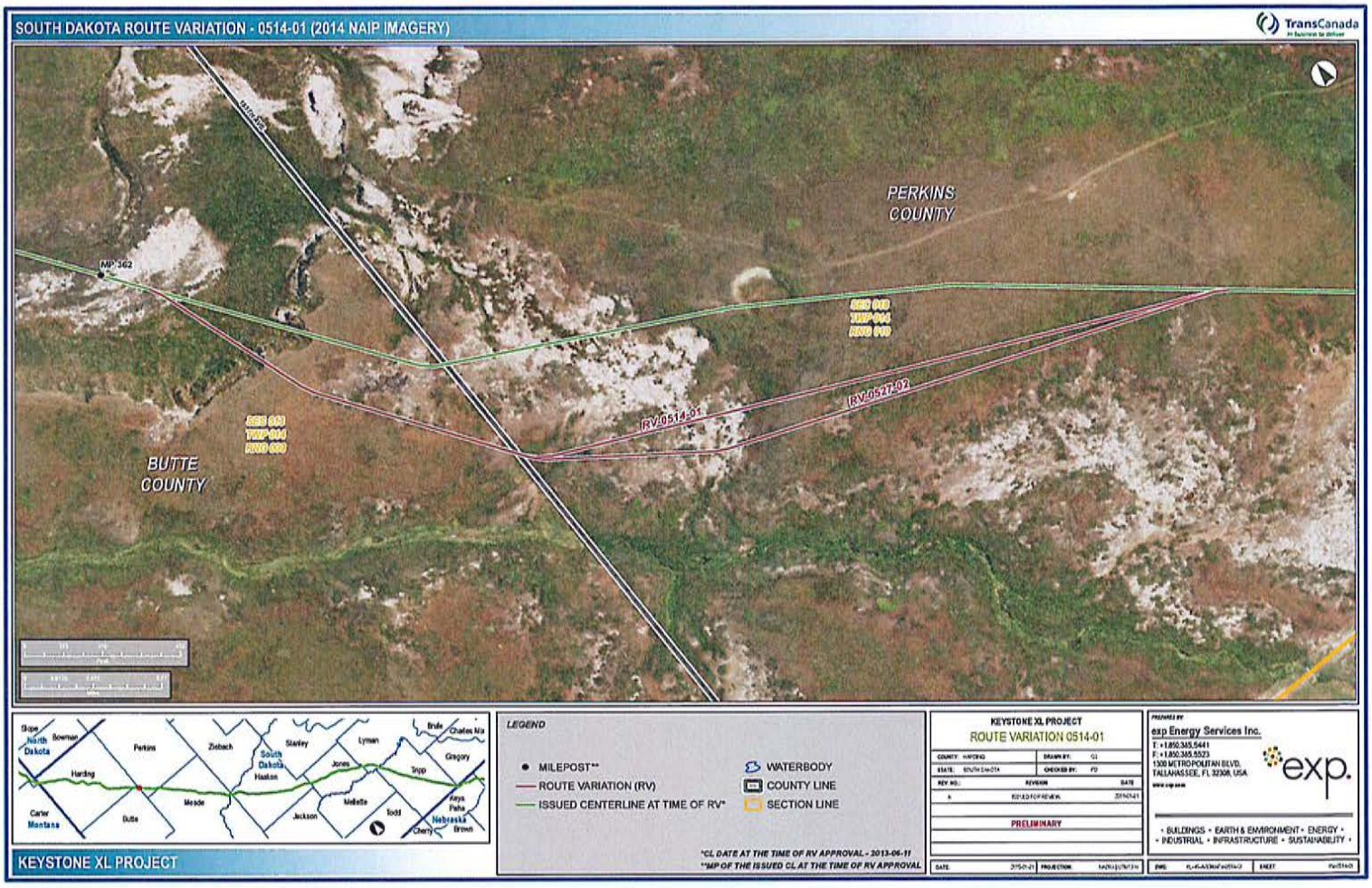

SOUTH DAKOTA ROUTE VARIATION - 0527-01 (2014 NAIP IMAGERY)
TransCanada
North ST
Little Cowboy Creek
MP 047
HARDING COUNTY
RV-0515-01
RV-0527-01
SEC 036
TWP 015
RNG 007
Little Cowboy Creek
Slope
North Dakota
Bowman
Perkins
Ziebach
Stanley
Lyman
Brule
Charles Mix
South Dakota
Harding
Haakon
Jones
Tripp
Gregory
Carter
Montana
Butte
Meade
Jackson
Mellette
Todd
Keya Paha
Nebraska
Brown
Cherry
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-06-11
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0527-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

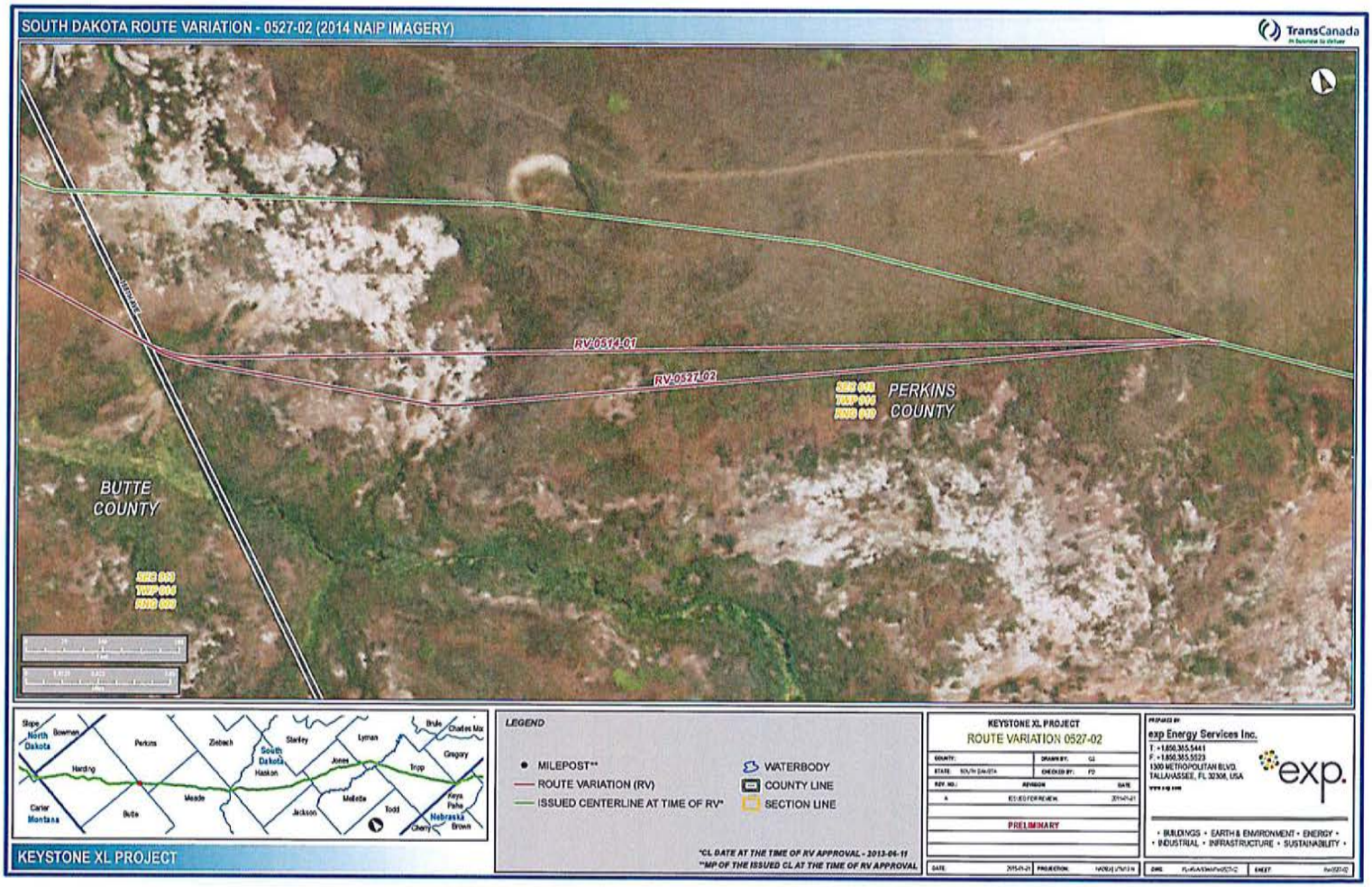

SOUTH DAKOTA ROUTE VARIATION - 0258-01 (2014 NAIP IMAGERY)
TransCanada
SEC 000
TWP 015
RNG 000
MP 351
SEC 000
TWP 015
RNG 000
HARDING
COUNTY
RV-0258-01
SEC 000
TWP 015
RNG 000
Spring Creek
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2012-03-14
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0258-01
PRELIMINARY
KEYSTONE XL PROJECT
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1320 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

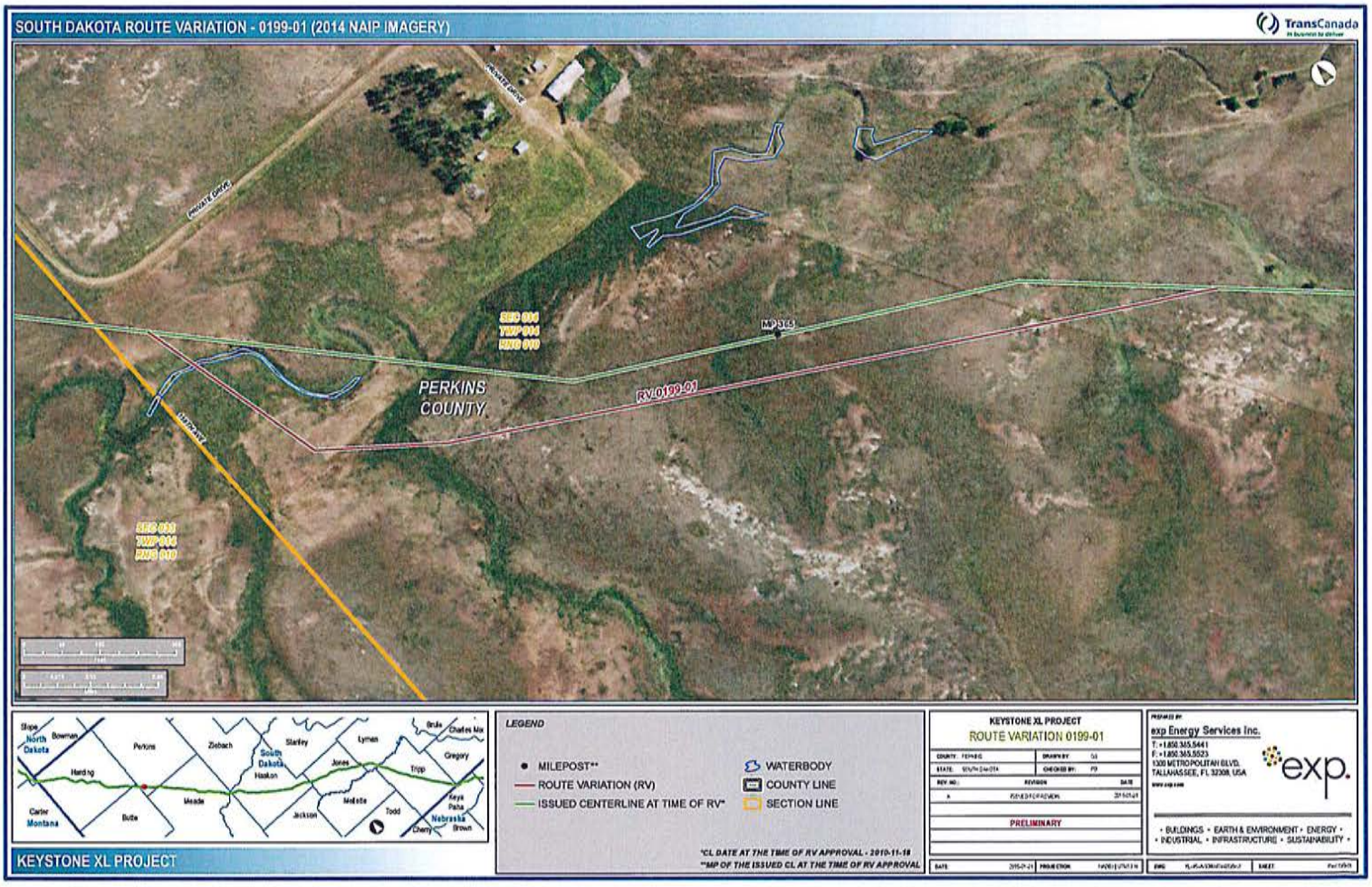

SOUTH DAKOTA ROUTE VARIATION - 0215-01 (2014 NAIP IMAGERY)
TransCanada
HARDING COUNTY
RV-0215-01
MP 333
Slope
Bowman
North Dakota
Perkins
Ziebach
Dewey
Stanley
Lyman
Brule
Charles Mix
Harding
South Dakota
Haakon
Jones
Gregory
Tripp
Meade
Mellette
Todd
Keya Paha
Carter
Montana
Butte
Jackson
Nebraska
Brown
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2010-11-10
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0215-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

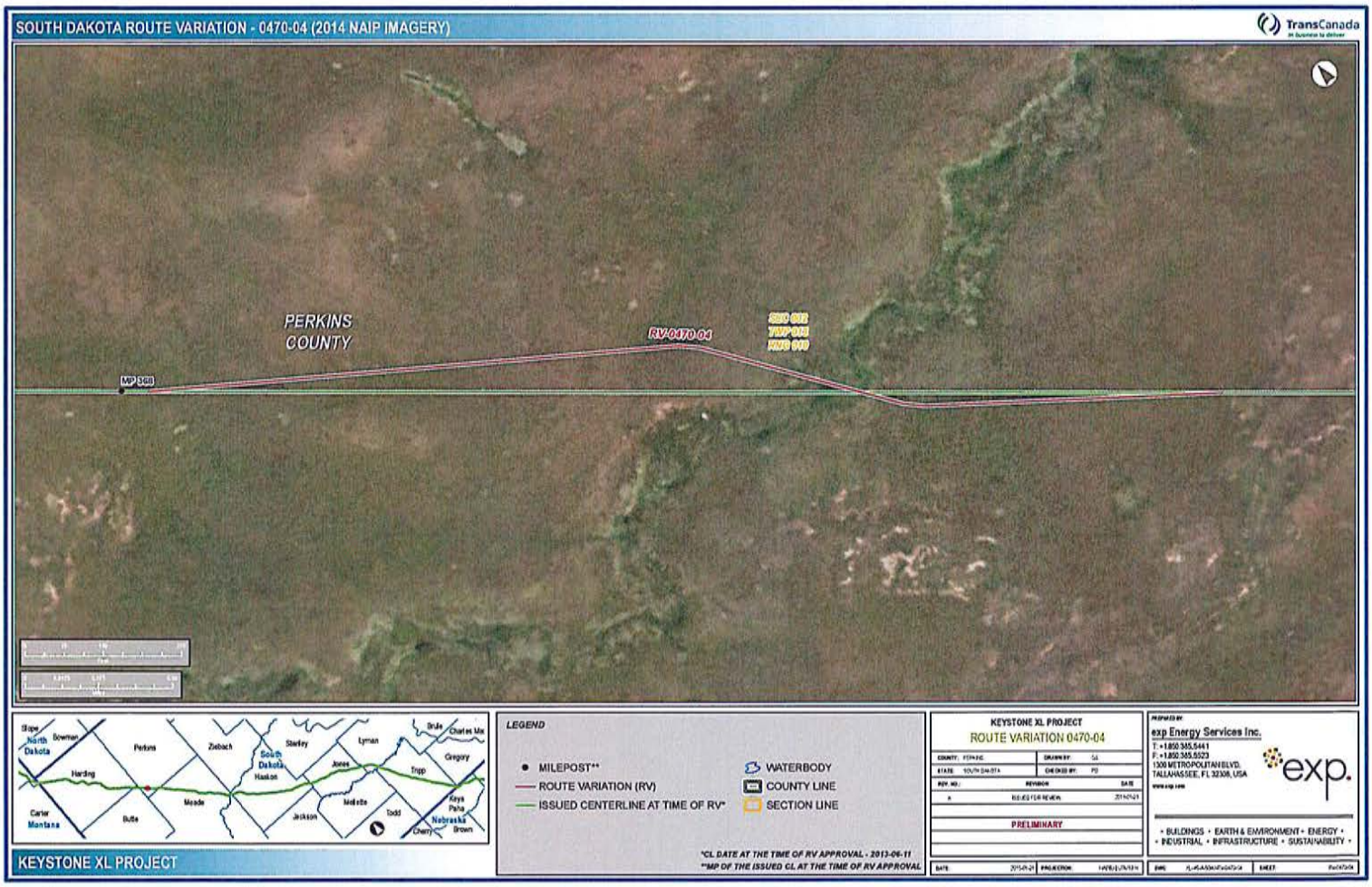

SOUTH DAKOTA ROUTE VARIATION - 0291-01 (2014 NAIP IMAGERY)
TransCanada
MP 357
HARDING
COUNTY
RV-0291-01
Slope
Bowman
North Dakota
Perkins
Ziebach
Dewey
Corson
Harding
Meade
Butte
Carter
Montana
Stanley
South Dakota
Haakon
Jones
Lyman
Brule
Charles Mix
Gregory
Tripp
Mellette
Todd
Jackson
Keya Paha
Nebraska
Brown
Cherry
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2012-03-14
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0291-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1330 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

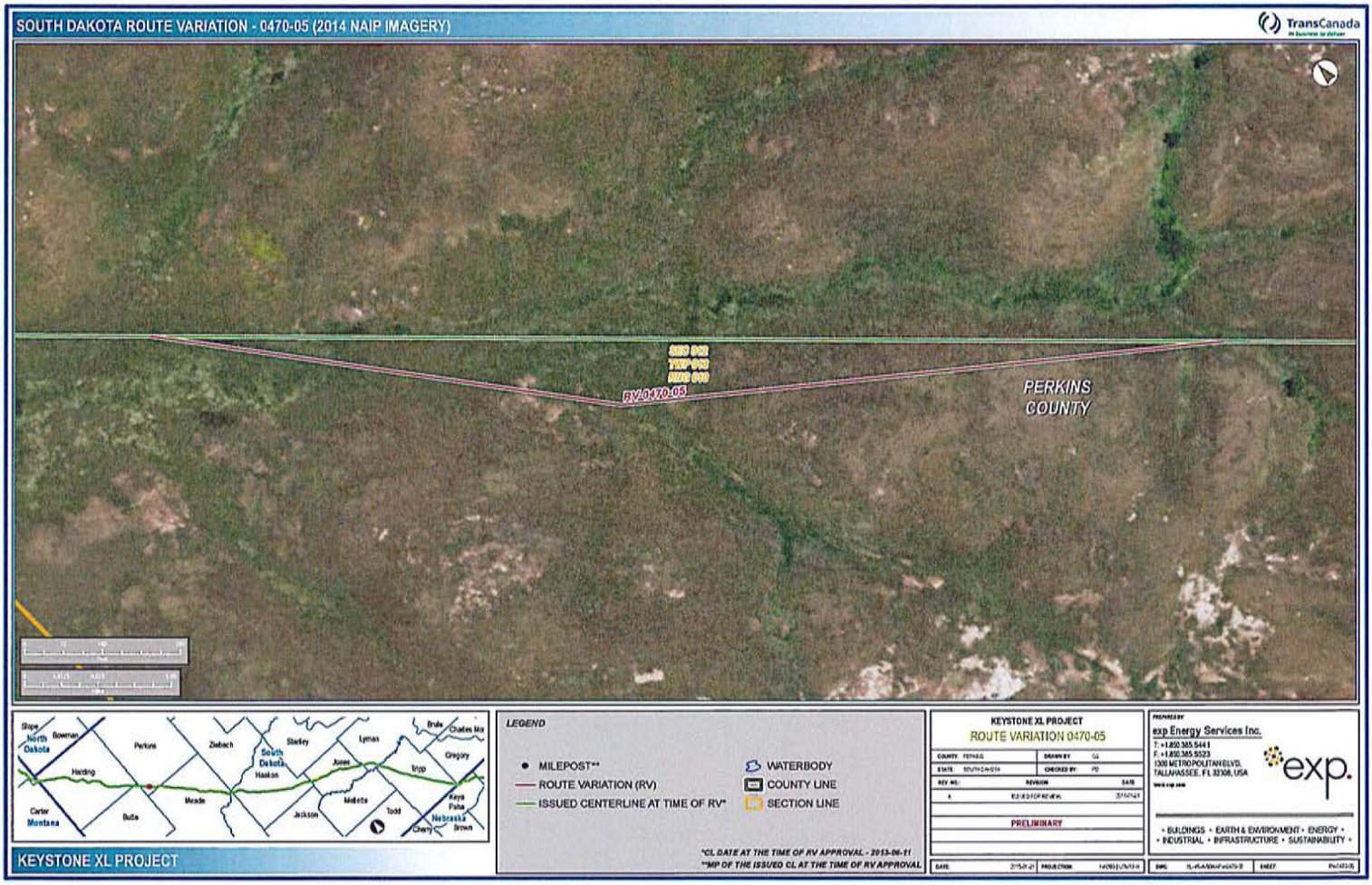

SOUTH DAKOTA ROUTE VARIATION - 0296-01 (2014 NAIP IMAGERY)
TransCanada
North Fork Moreau River
BUTTE COUNTY
PERKINS COUNTY
SEC 002
TWP 014
RNG 008
SEC 002
TWP 014
RNG 009
MP 382
RV-0296-01
Slope
North Dakota
Bowman
Perkins
Zeibach
Stanley
Lyman
Brule
Charles Mix
Harding
South Dakota
Haakon
Jones
Tripp
Gregory
Carter
Montana
Butte
Meade
Jackson
Mellette
Todd
Keya Paha
Nebraska
Brown
Cherry
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-03-14
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0296-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

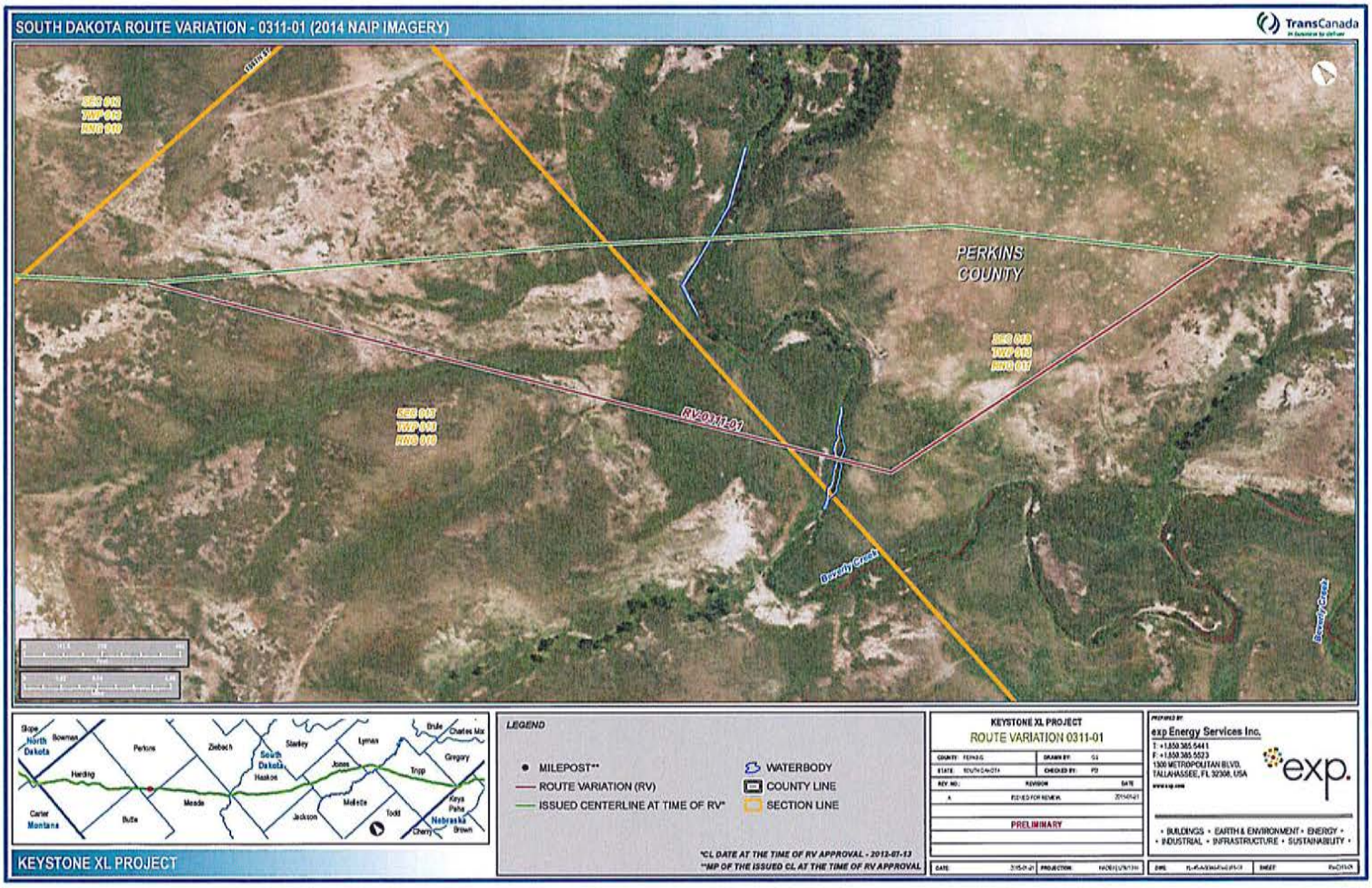

SOUTH DAKOTA ROUTE VARIATION - 0514-01 (2014 NAIP IMAGERY)
TransCanada
PERKINS COUNTY
BUTTE COUNTY
MP 362
RV-0514-01
RV-0527-02
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-06-11
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
KEYSTONE XL PROJECT
ROUTE VARIATION 0514-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

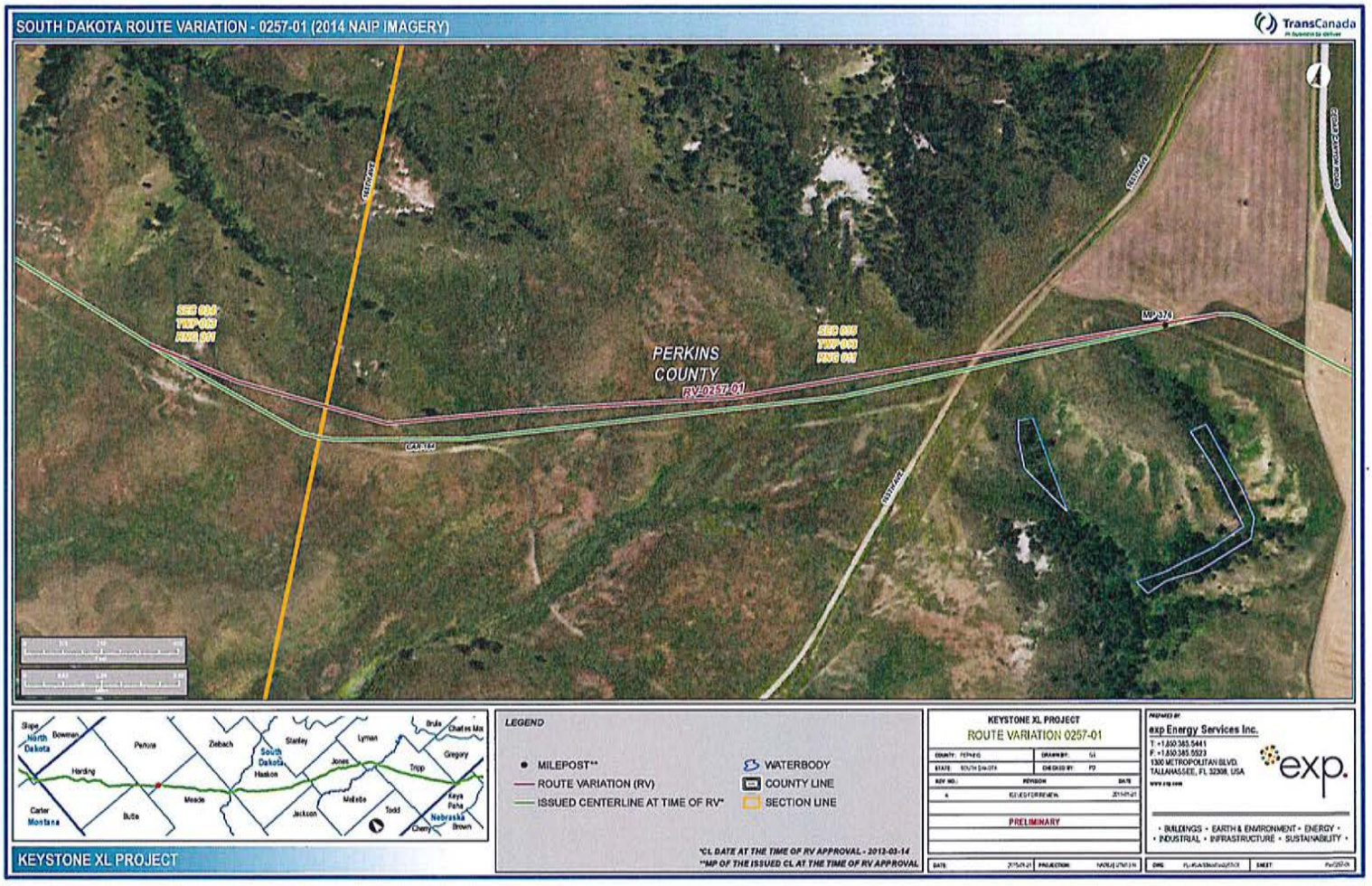

SOUTH DAKOTA ROUTE VARIATION - 0527-02 (2014 NAIP IMAGERY)
TransCanada
RV-0514-01
RV-0527-02
PERKINS COUNTY
BUTTE COUNTY
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-06-11
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0527-02
PRELIMINARY
KEYSTONE XL PROJECT
exp Energy Services Inc.
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

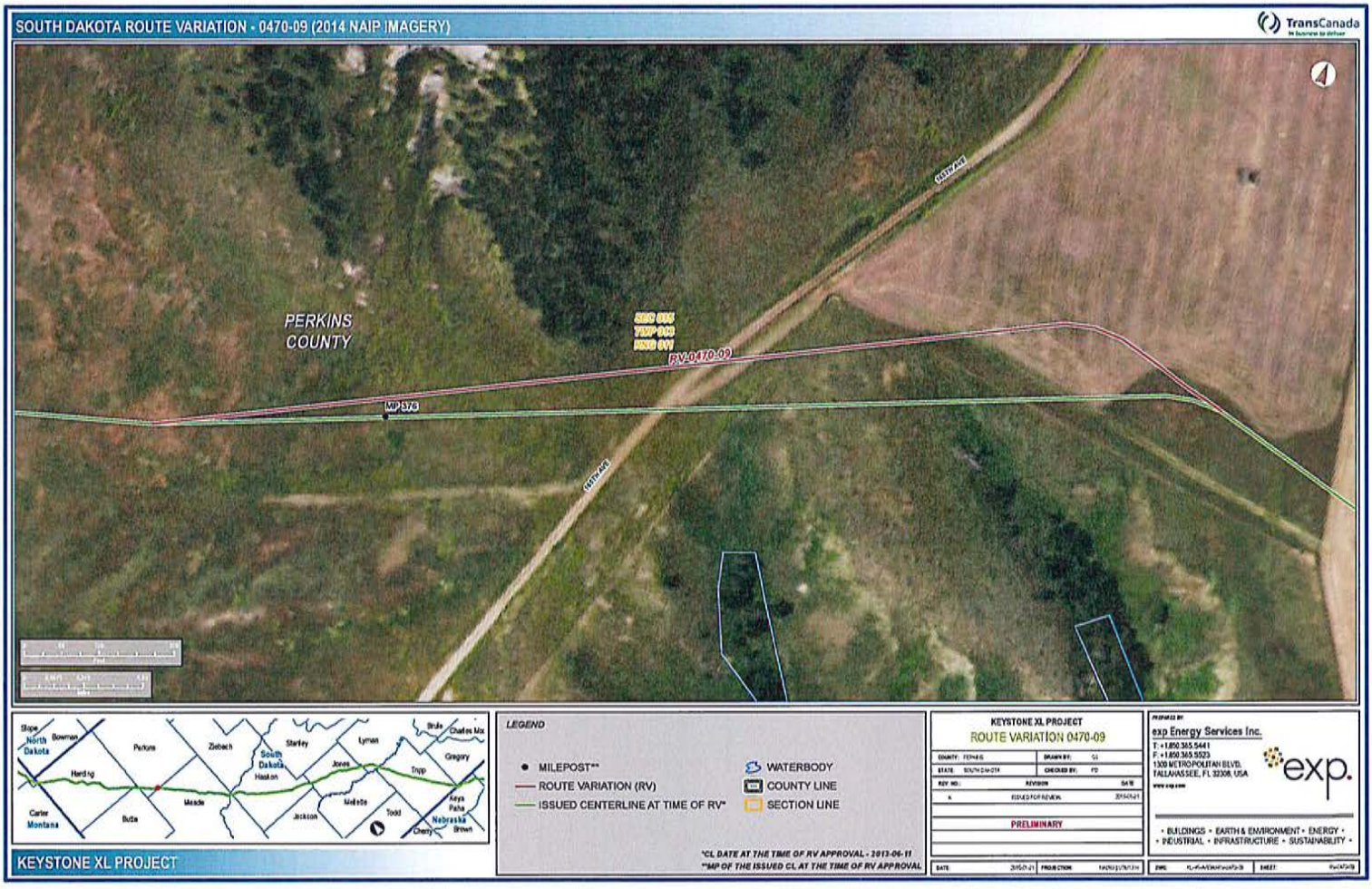

SOUTH DAKOTA ROUTE VARIATION - 0199-01 (2014 NAIP IMAGERY)
TransCanada
PERKINS COUNTY
RV.0199-01
SEC 030
TWP 014
RNG 010
MP 916
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2010-11-18
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0199-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1309 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
KEYSTONE XL PROJECT

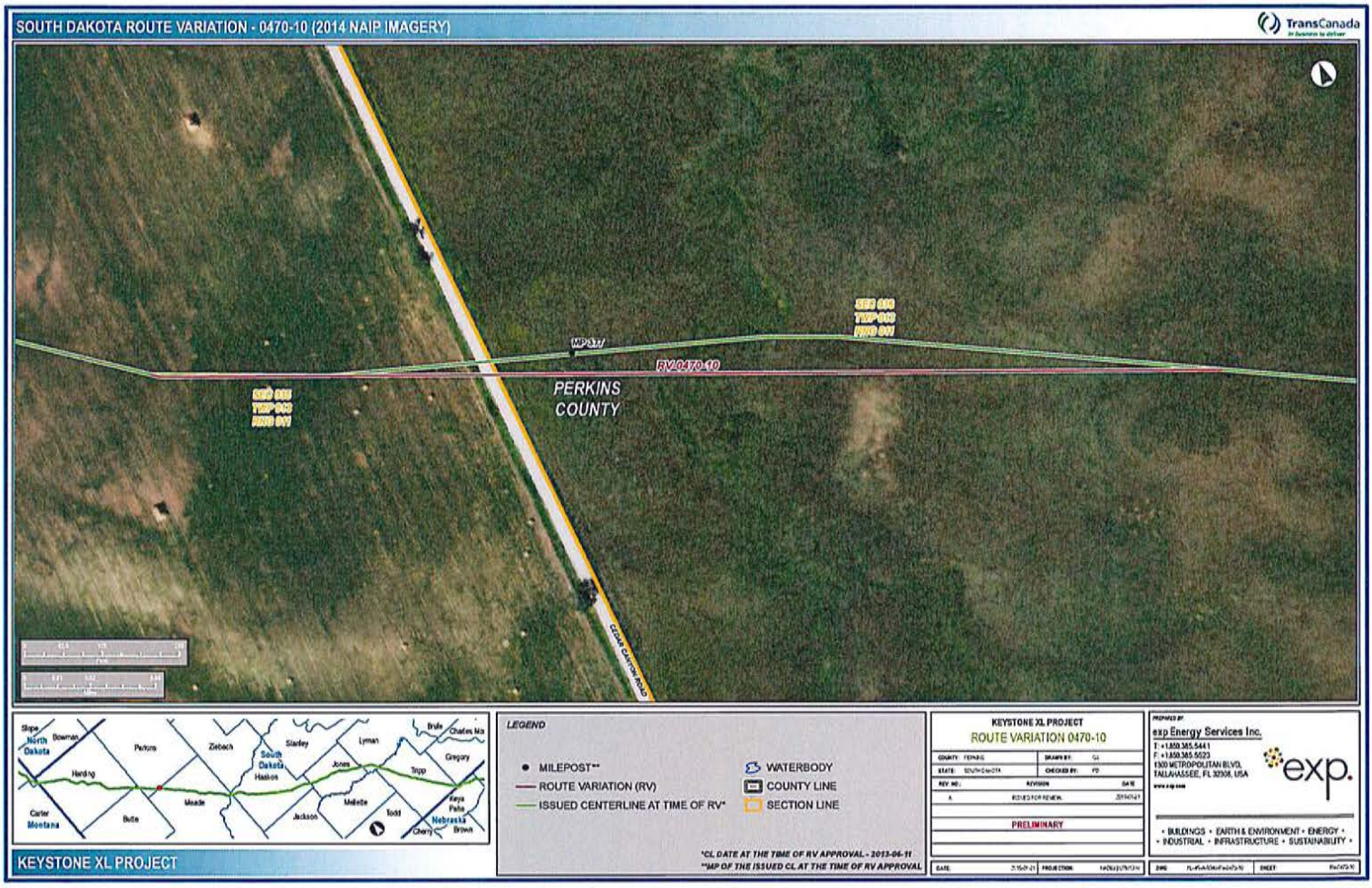

SOUTH DAKOTA ROUTE VARIATION - 0470-04 (2014 NAIP IMAGERY)
TransCanada
PERKINS
COUNTY
RV-0470-04
MP 398
Slope
North Dakota
Bowman
Perkins
Ziebach
South Dakota
Harding
Butte
Carter
Montana
Meade
Stanley
Haakon
Jackson
Lyman
Jones
Mellette
Todd
Brule
Charles Mix
Gregory
Tripp
Keya Paha
Nebraska
Brown
Cherry
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-06-11
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0470-04
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

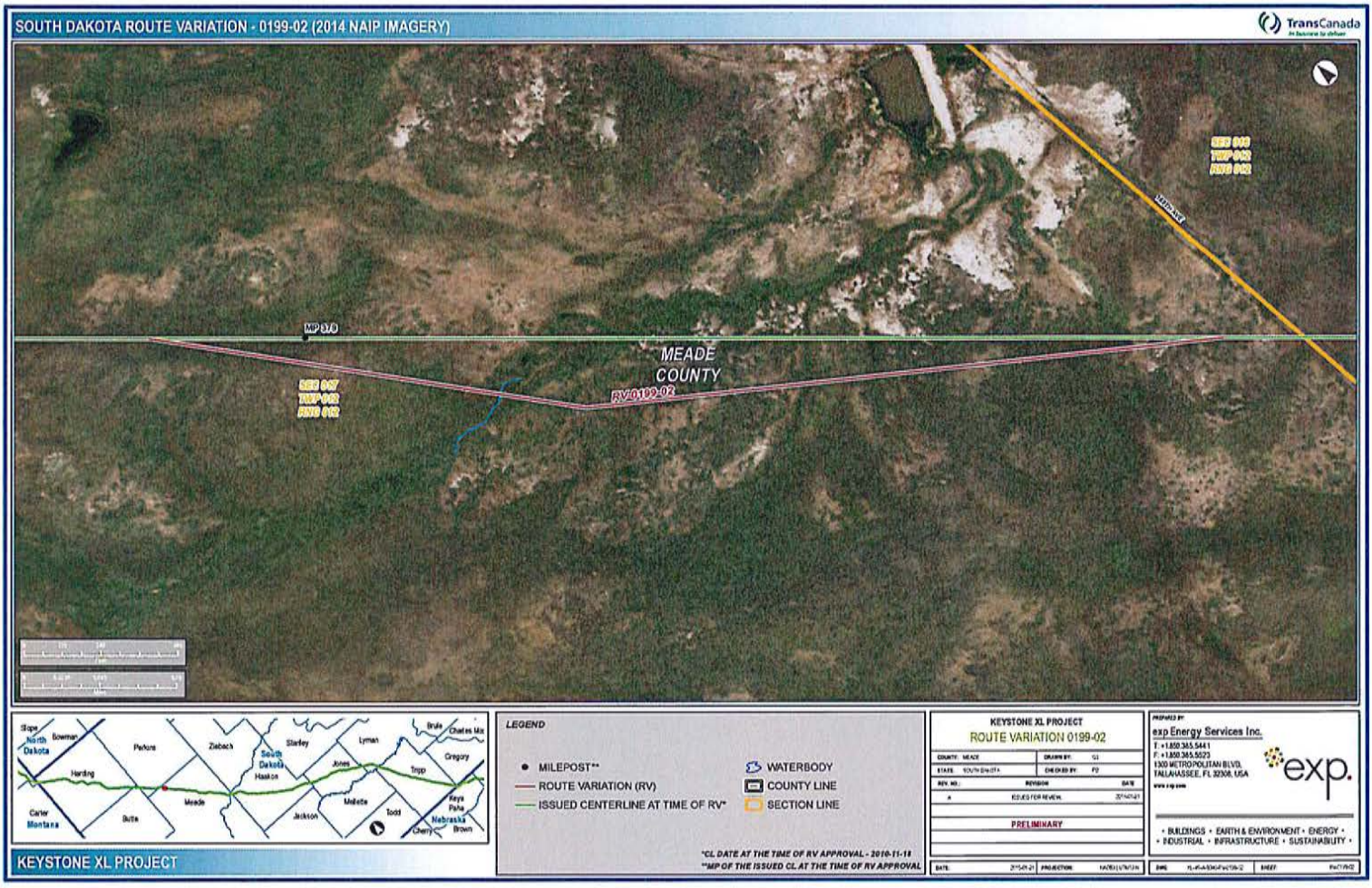

SOUTH DAKOTA ROUTE VARIATION - 0470-05 (2014 NAIP IMAGERY)
TransCanada
RV-0470-05
PERKINS
COUNTY
Slope
Bowman
North Dakota
Perkins
Ziebach
South Dakota
Haakon
Stanley
Lyman
Jones
Brule
Charles Mix
Gregory
Tripp
Harding
Meade
Butte
Carter
Montana
Jackson
Mellette
Todd
Fall River
Custer
Pennington
Shannon
Bennett
Mellette
Todd
Tripp
Gregory
Charles Mix
Douglas
Hutchinson
Bon Homme
Yankton
Nebraska
Knox
Cedar
Dixon
Dakota
Dixon
Thurston
Wayne
Pierce
Cuming
Stanton
Madison
Antelope
Boone
Platte
Colfax
Nance
Merrick
Hamilton
Polk
York
Fillmore
Saline
Adams
Clay
Webster
Nuckolls
Thayer
Jefferson
Gage
Johnson
Nemaha
Pawnee
Richardson
Otoe
Cass
Lancaster
Saunders
Sarpy
Douglas
Washington
Burt
Monona
Harrison
Shelby
Pottawattamie
Mills
Fremont
Page
Montgomery
Adams
Taylor
Ringgold
Union
Clarke
Lucas
Monroe
Wayne
Appanoose
Davis
Van Buren
Lee
Jefferson
Henry
Des Moines
Louisa
Muscatine
Scott
Clinton
Jackson
Dubuque
Iowa
Johnson
Cedar
Jones
Linn
Benton
Tama
Poweshiek
Iowa
Keya Paha
Brown
Cherry
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-06-11
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
KEYSTONE XL PROJECT
ROUTE VARIATION 0470-05
COUNTY: PERKINS
DRAWN BY: GS
STATE: SOUTH DAKOTA
CHECKED BY: PD
REV NO:
REVISION
DATE
A
ISSUED FOR REVIEW
2015/04/21
PRELIMINARY
DATE: 2015-07-21
PROJECTION:
SHEET:
PREPARED BY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

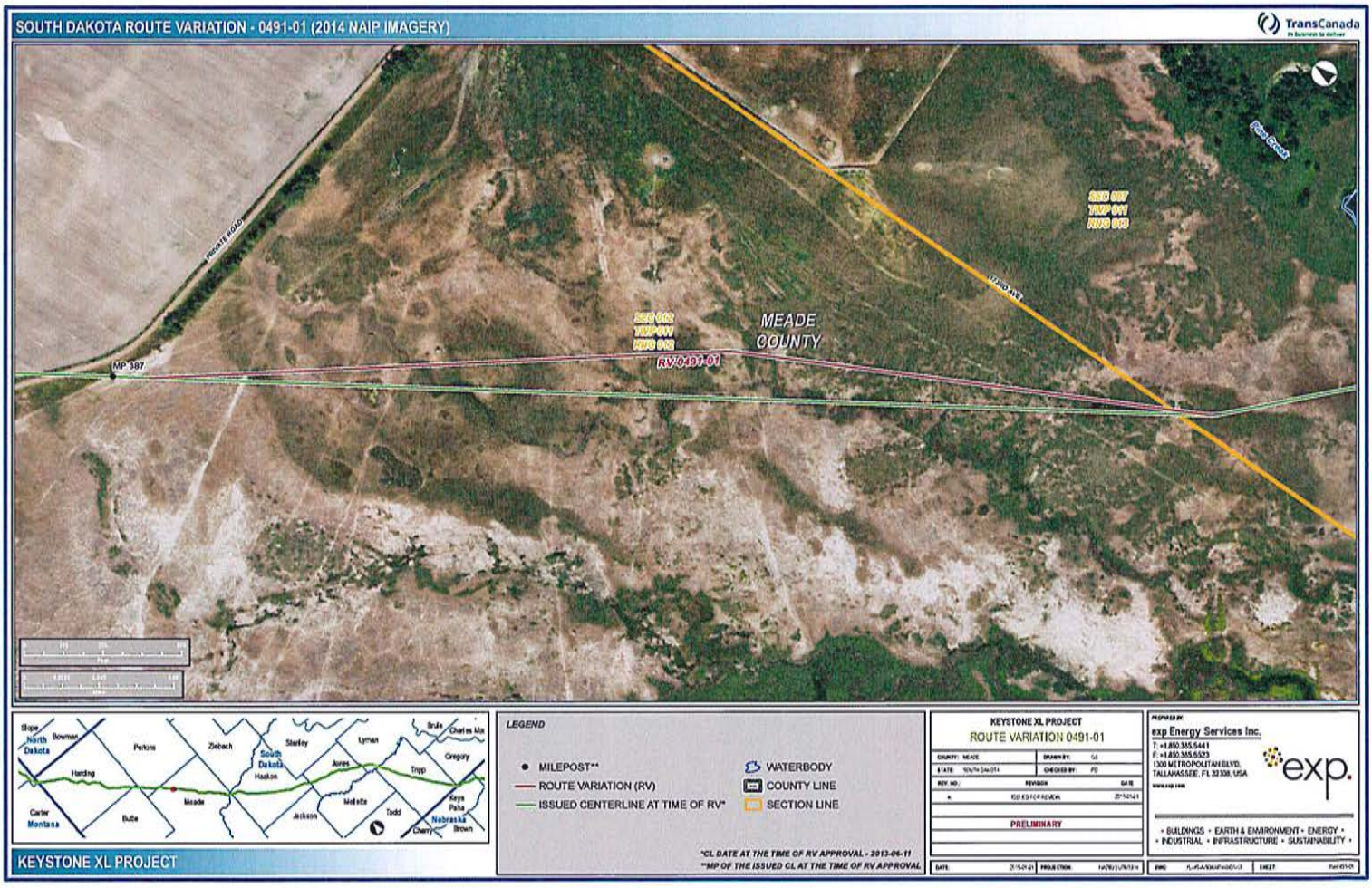

SOUTH DAKOTA ROUTE VARIATION - 0311-01 (2014 NAIP IMAGERY)
TransCanada
PERKINS COUNTY
RV-0311-01
Beverly Creek
Beverly Creek
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-07-13
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0311-01
PRELIMINARY
exp Energy Services Inc.
KEYSTONE XL PROJECT

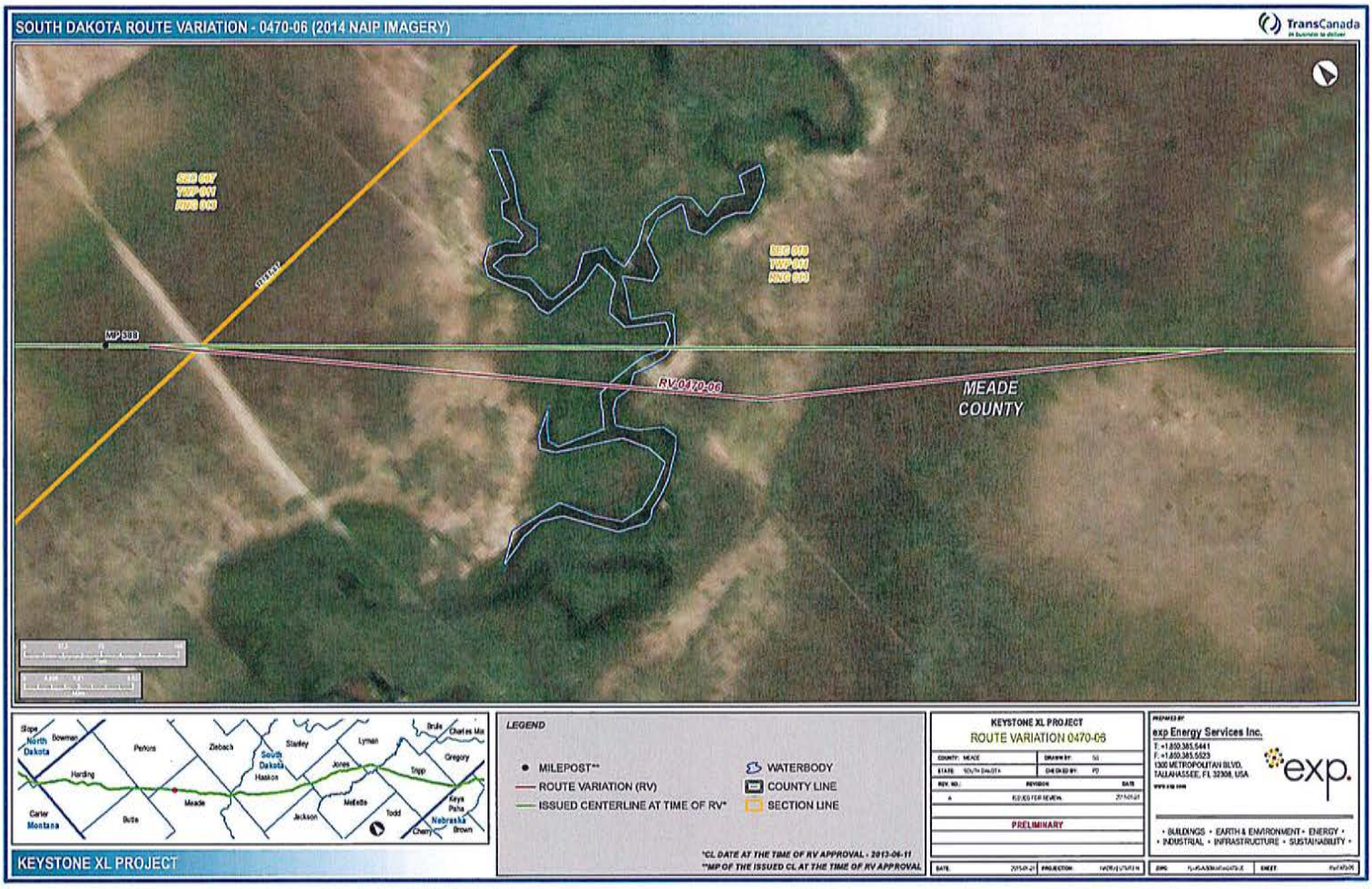

SOUTH DAKOTA ROUTE VARIATION - 0257-01 (2014 NAIP IMAGERY)
TransCanada
PERKINS
COUNTY
RV-0257-01
MP 320
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-03-14
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0257-01
PRELIMINARY
KEYSTONE XL PROJECT
exp Energy Services Inc.
T +1.850.385.5441
F +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •


SOUTH DAKOTA ROUTE VARIATION - 0470-09 (2014 NAIP IMAGERY)
TransCanada
PERKINS COUNTY
RV-0470-09
MP 578
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-06-11
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0470-09
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1309 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •


SOUTH DAKOTA ROUTE VARIATION - 0470-10 (2014 NAIP IMAGERY)
TransCanada
MP 277
RV 0470-10
PERKINS
COUNTY
GEDNA CANYON ROAD
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-06-11
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0470-10
PRELIMINARY
KEYSTONE XL PROJECT
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1500 METROPOLITAN BLVD,
TALLAHASSEE, FL 32308, USA
www.exp.com
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •


SOUTH DAKOTA ROUTE VARIATION - 0199-02 (2014 NAIP IMAGERY)
TransCanada
MP 0.0
MEADE
COUNTY
RV 0199-02
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2010-11-18
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0199-02
PRELIMINARY
exp Energy Services Inc.
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •


SOUTH DAKOTA ROUTE VARIATION - 0491-01 (2014 NAIP IMAGERY)
TransCanada
MEADE COUNTY
RV 0491-01
MP 387
PRIVATE ROAD
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-06-11
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0491-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.6523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •


SOUTH DAKOTA ROUTE VARIATION - 0470-06 (2014 NAIP IMAGERY)
TransCanada
MP 980
RV 0470-06
MEADE
COUNTY
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-06-11
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0470-06
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
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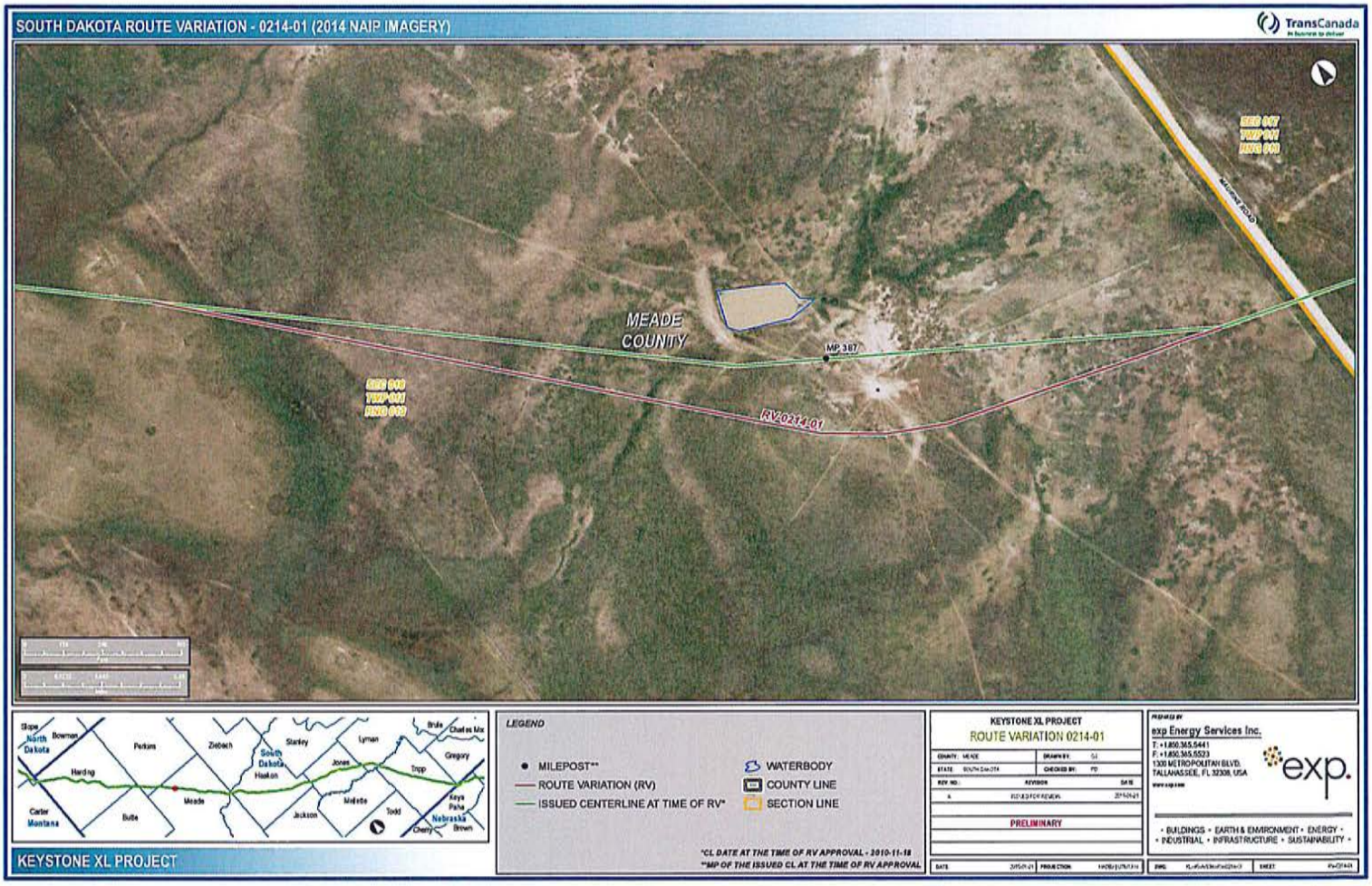
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
KEYSTONE XL PROJECT


SOUTH DAKOTA ROUTE VARIATION - 0214-01 (2014 NAIP IMAGERY)
TransCanada
MEADE COUNTY
MP 387
RV 0214-01
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2010-11-18
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0214-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
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exp.
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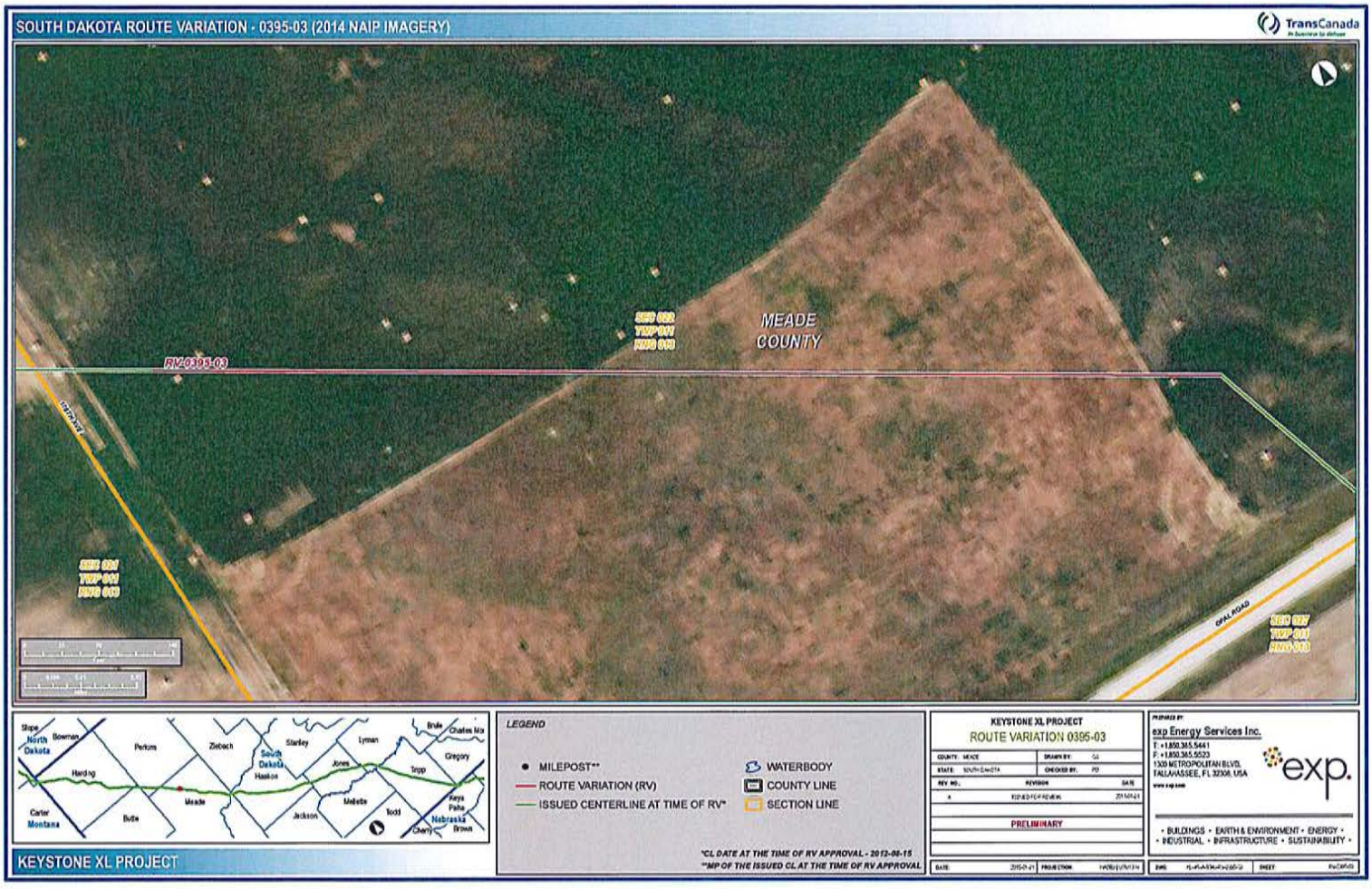
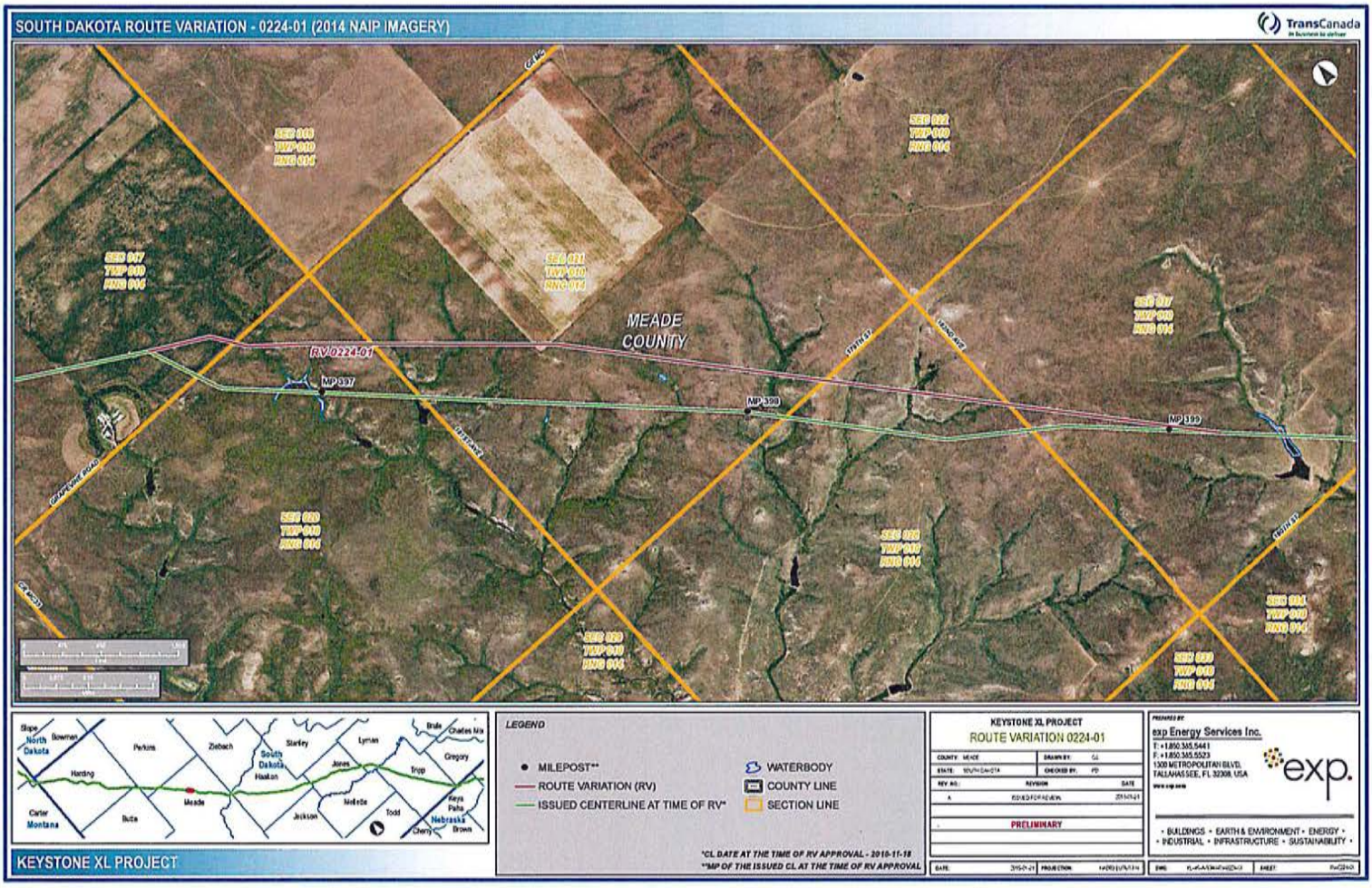
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •


SOUTH DAKOTA ROUTE VARIATION - 0395-03 (2014 NAIP IMAGERY)
TransCanada
MEADE COUNTY
RV-0395-03
OPAL ROAD
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2012-08-15
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0395-03
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1309 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
KEYSTONE XL PROJECT


SOUTH DAKOTA ROUTE VARIATION - 0224-01 (2014 NAIP IMAGERY)
TransCanada
MEADE COUNTY
RV 0224-01
MP 397
MP 398
MP 399
SEC 007 TWP 010 RNG 014
SEC 008 TWP 010 RNG 014
SEC 017 TWP 010 RNG 014
SEC 018 TWP 010 RNG 014
SEC 019 TWP 010 RNG 014
SEC 020 TWP 010 RNG 014
SEC 029 TWP 010 RNG 014
SEC 030 TWP 010 RNG 014
SEC 031 TWP 010 RNG 014
SEC 032 TWP 010 RNG 014
CR 1013
CR 1015
CR 1017
CR 1019
CR 1021
Slope
Bowman
North Dakota
Perkins
Ziebach
South Dakota
Stanley
Lyman
Brule
Charles Mix
Gregory
Tripp
Jones
Haakon
Harding
Meade
Butte
Carter
Montana
Jackson
Mellette
Todd
Keya Paha
Nebraska
Brown
Cherry
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2010-11-18
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0224-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
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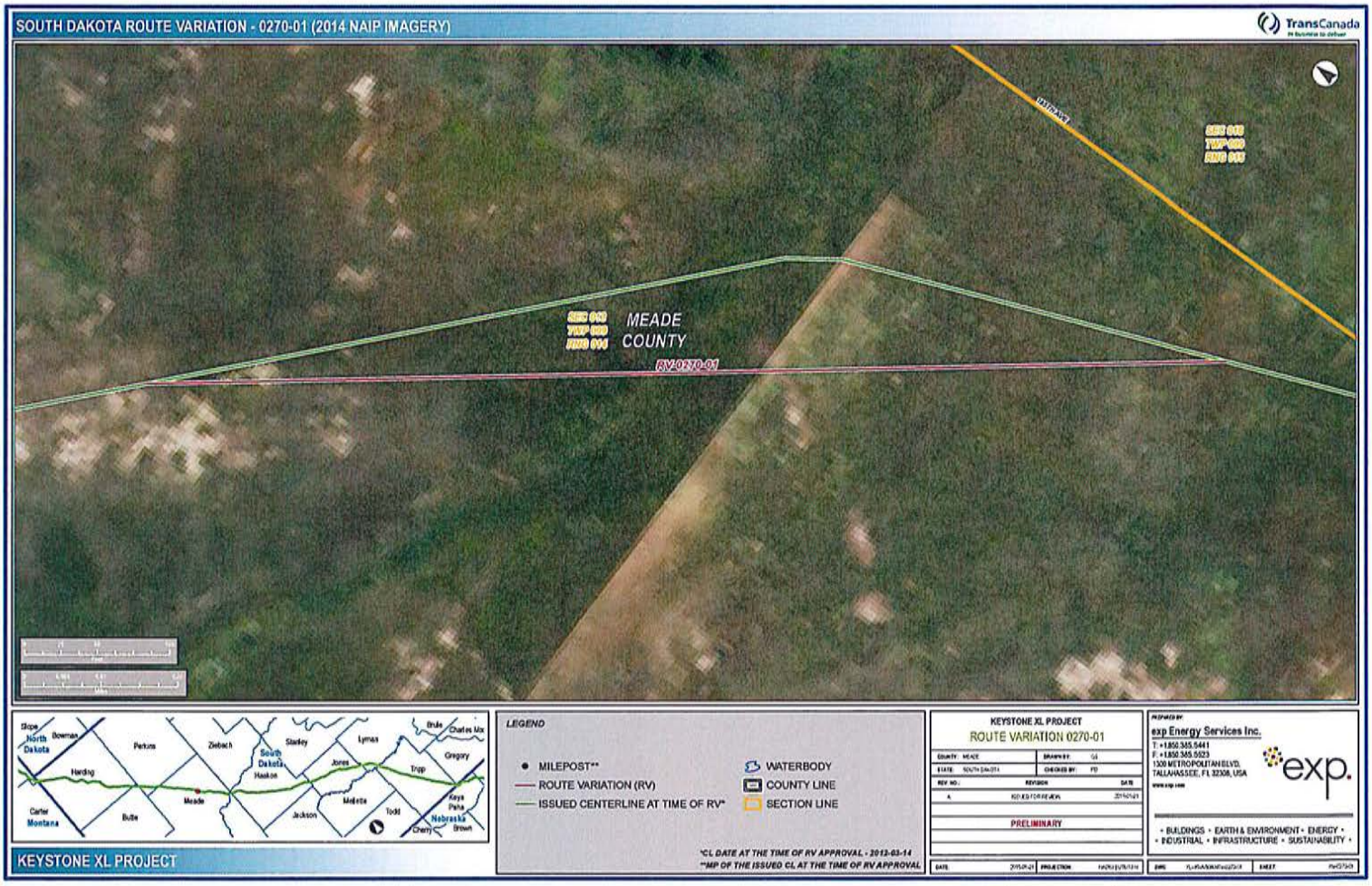
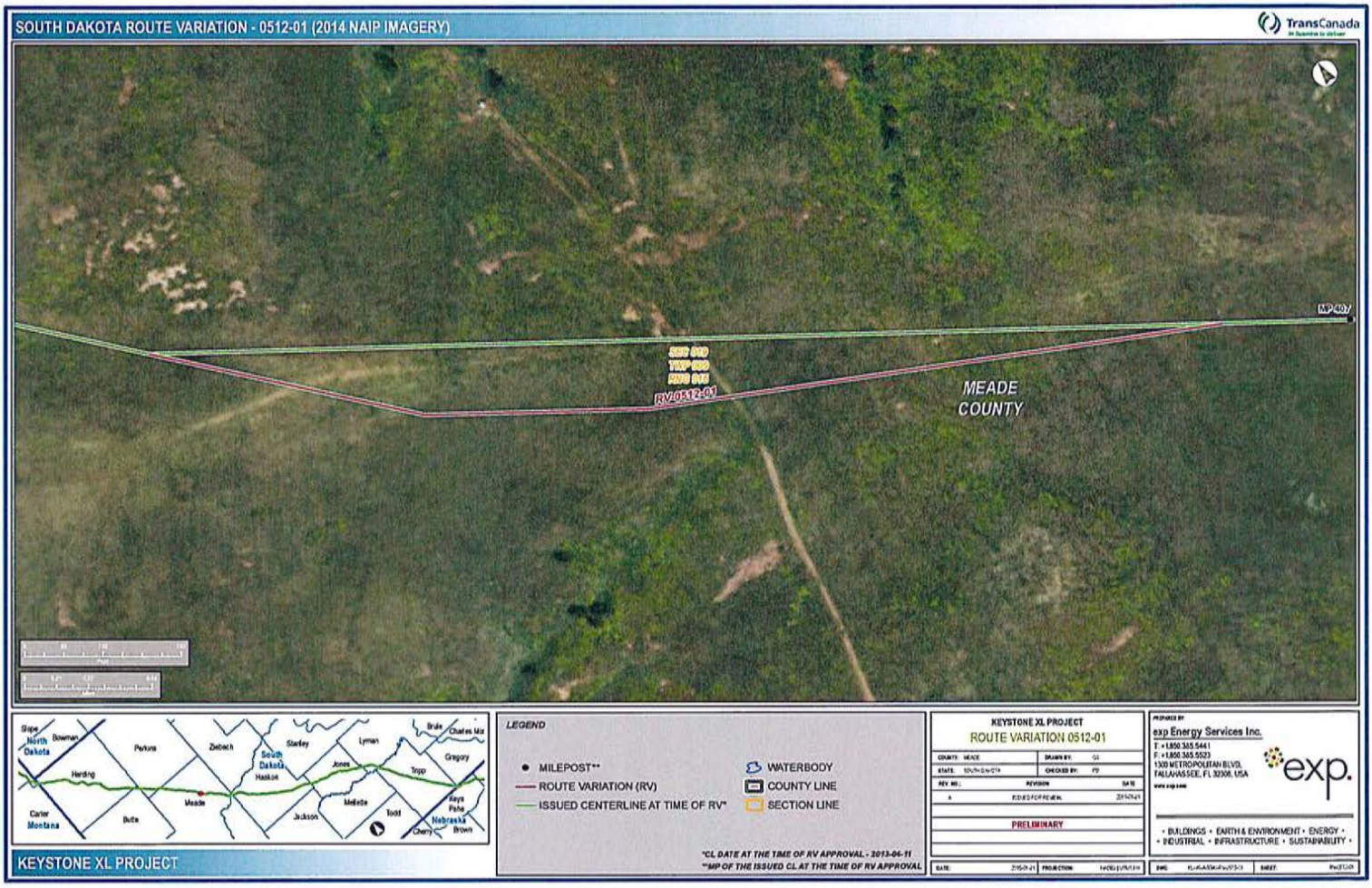
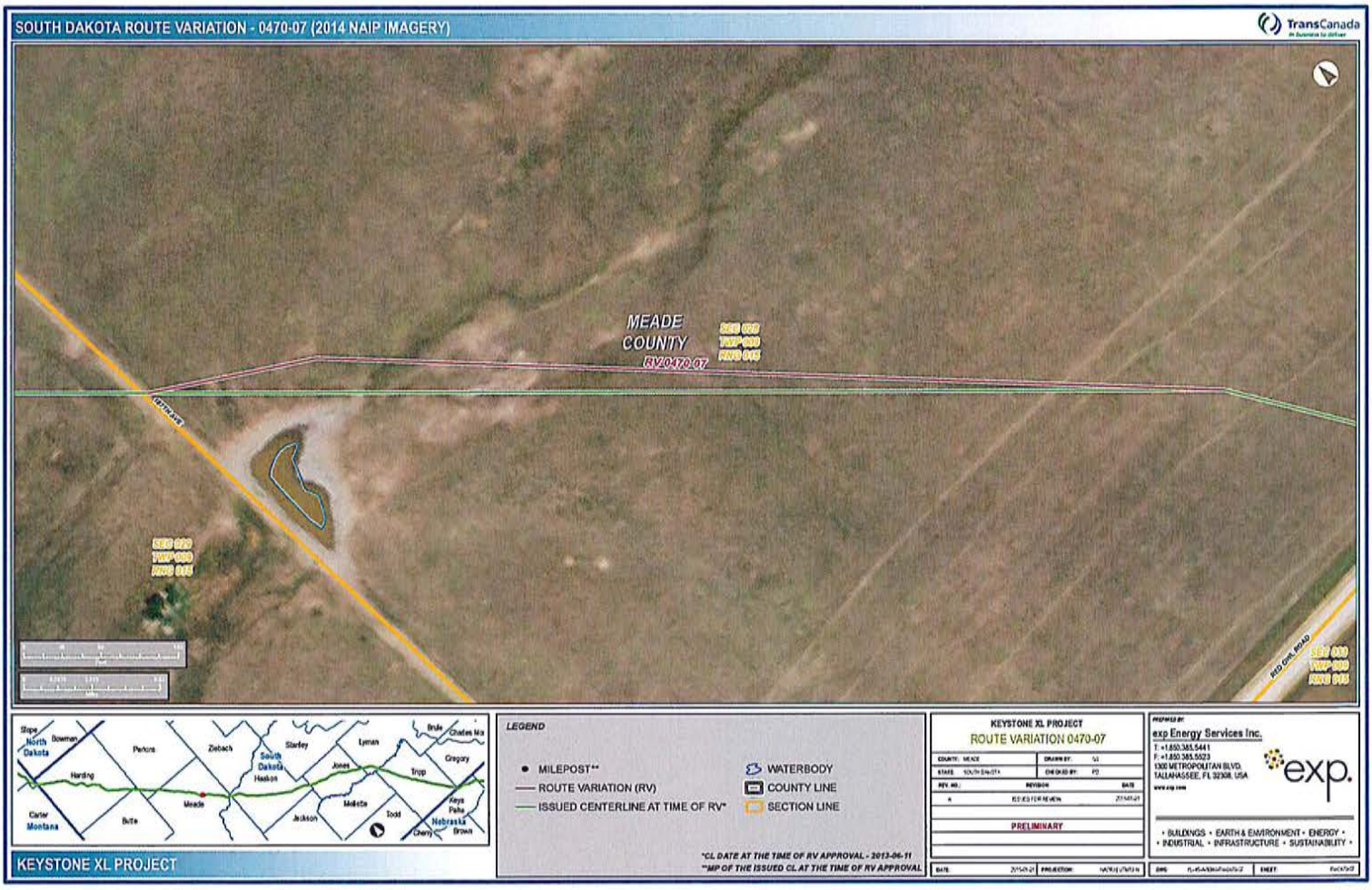
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
KEYSTONE XL PROJECT


SOUTH DAKOTA ROUTE VARIATION - 0270-01 (2014 NAIP IMAGERY)
TransCanada
MEADE
COUNTY
RV 0270-01
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-03-14
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0270-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
KEYSTONE XL PROJECT


SOUTH DAKOTA ROUTE VARIATION - 0512-01 (2014 NAIP IMAGERY)
TransCanada
MP 407
RV 0512-01
MEADE
COUNTY
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-06-11
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0512-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1309 METROPOLITAN BLVD,
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •


SOUTH DAKOTA ROUTE VARIATION - 0470-07 (2014 NAIP IMAGERY)
TransCanada
MEADE
COUNTY
RV.0470.07
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-06-11
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
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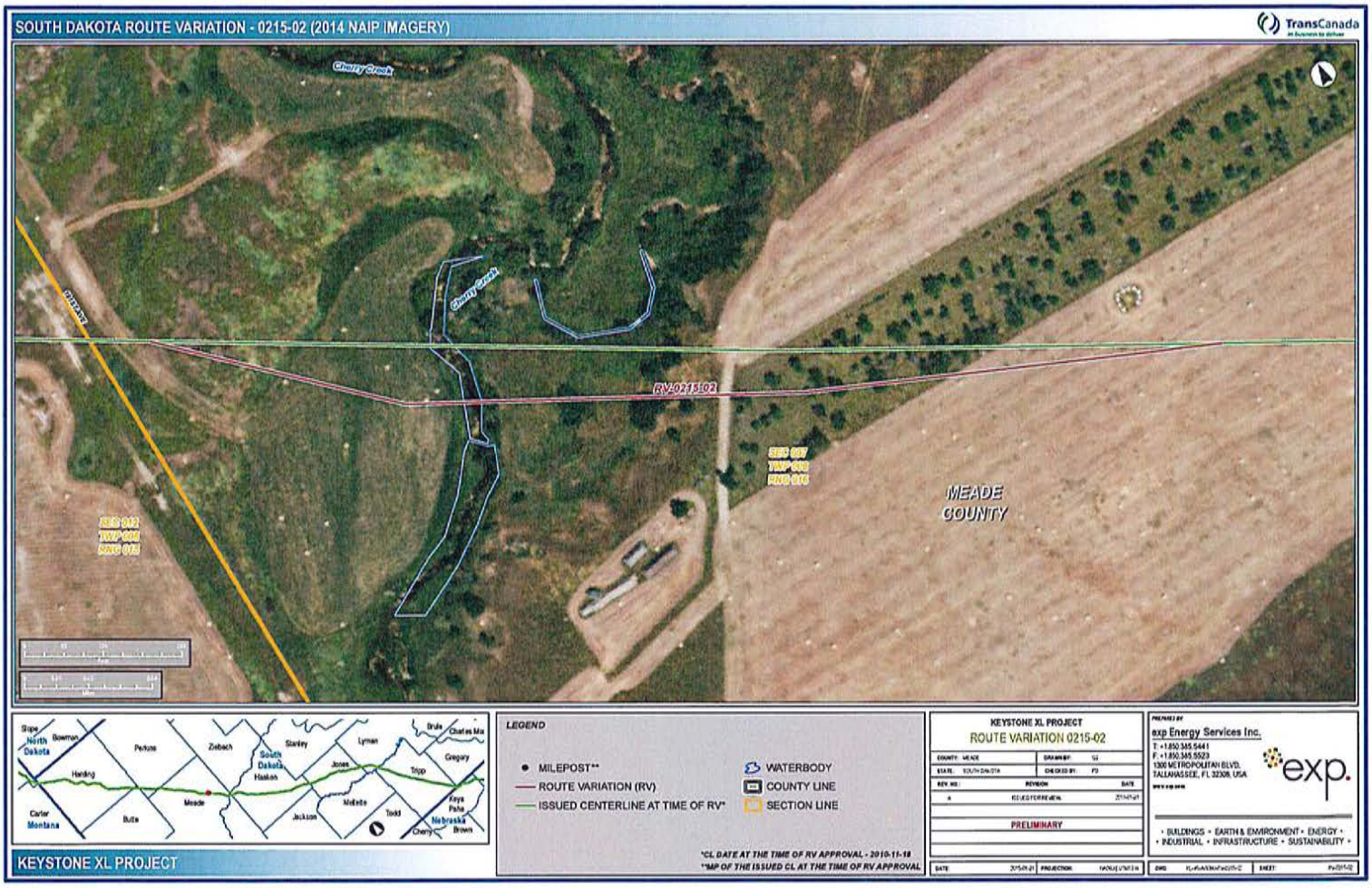
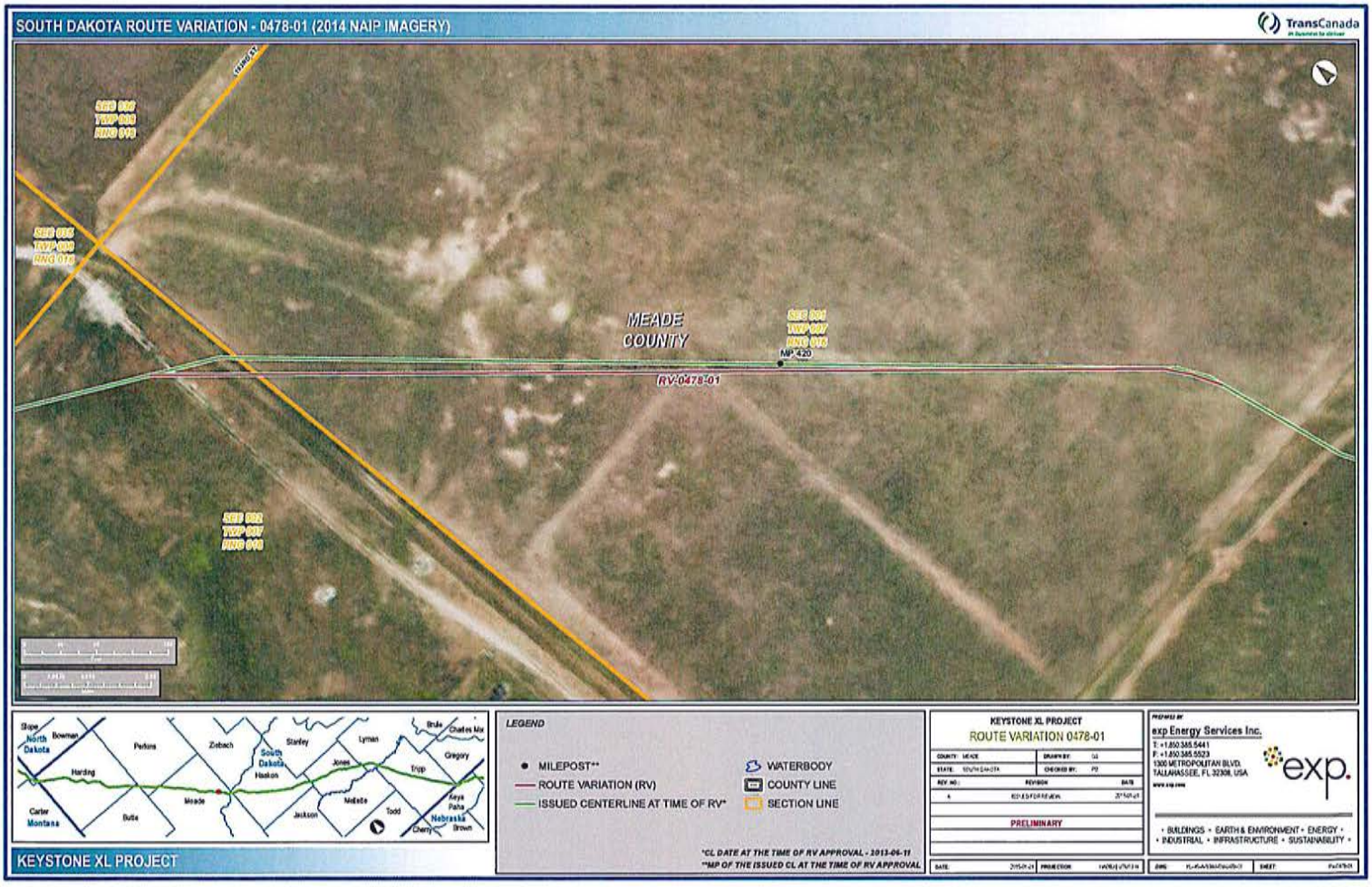
PRELIMINARY
exp Energy Services Inc.
exp.
KEYSTONE XL PROJECT


SOUTH DAKOTA ROUTE VARIATION - 0215-02 (2014 NAIP IMAGERY)
TransCanada
Cherry Creek
Cherry Creek
RV-0215-02
MEADE
COUNTY
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2010-11-18
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0215-02
PRELIMINARY
exp Energy Services Inc.
KEYSTONE XL PROJECT


SOUTH DAKOTA ROUTE VARIATION - 0478-01 (2014 NAIP IMAGERY)
TransCanada
MEADE COUNTY
MP 420
RV-0478-01
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-06-11
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0478-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
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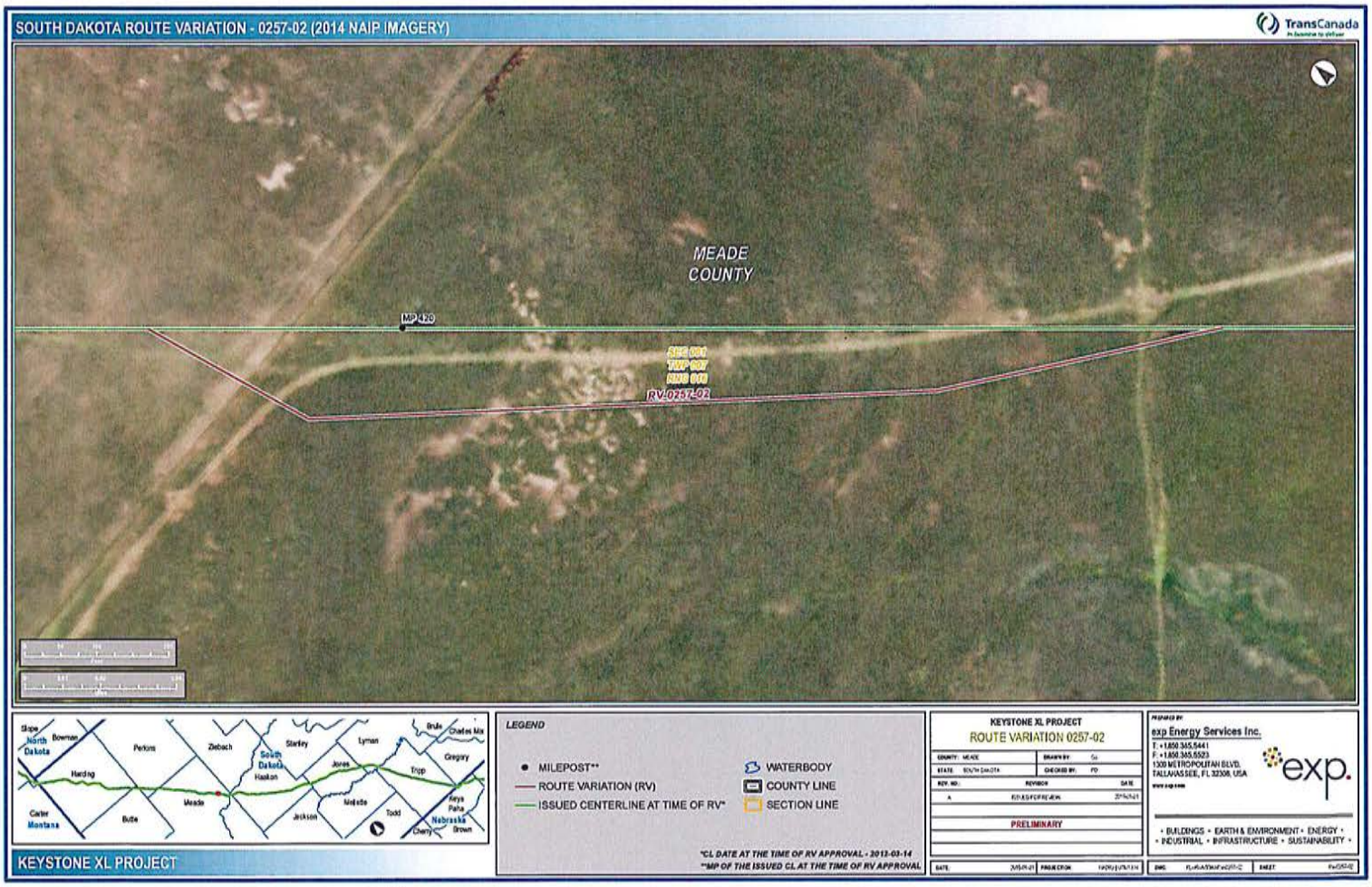
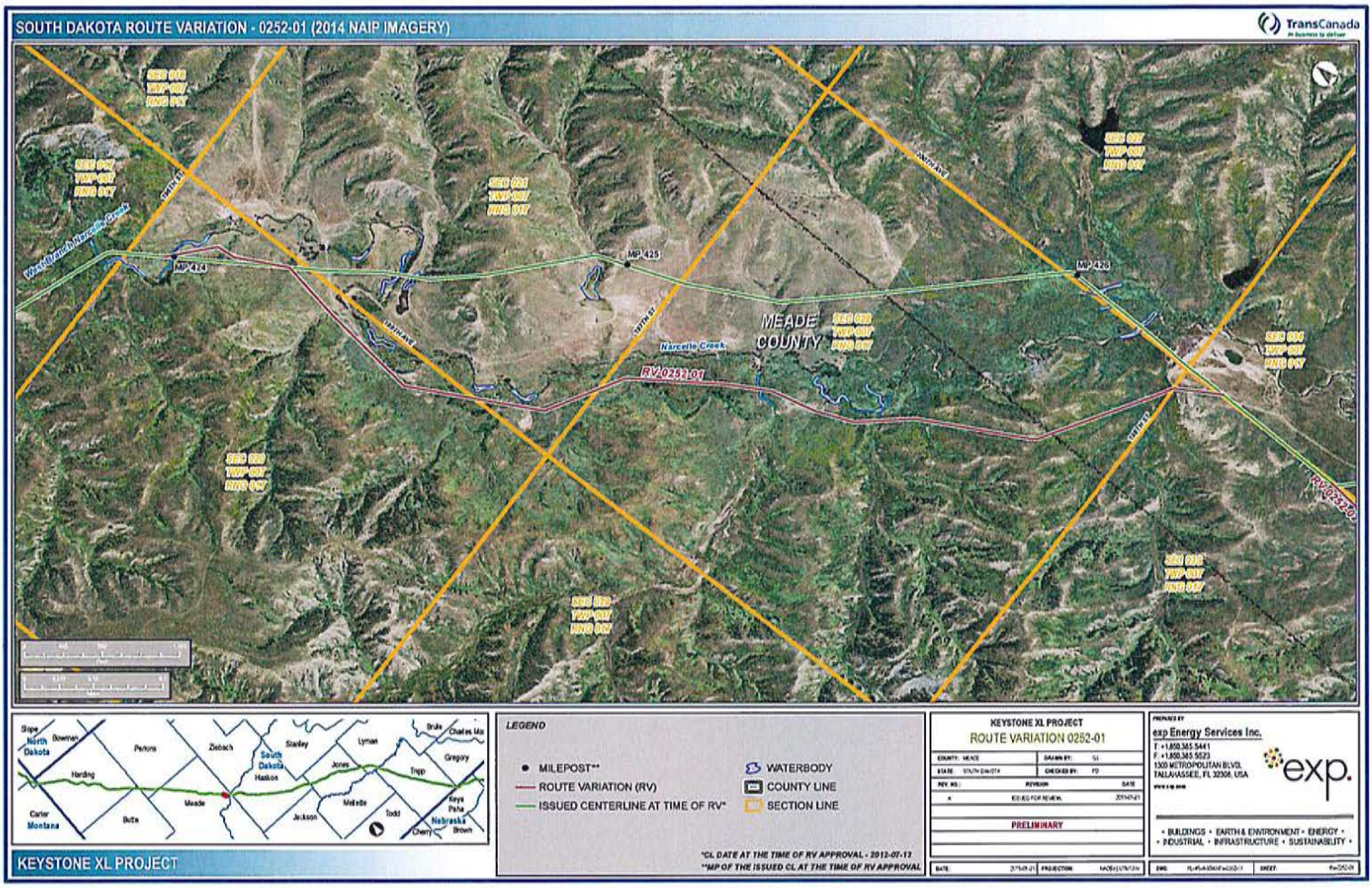
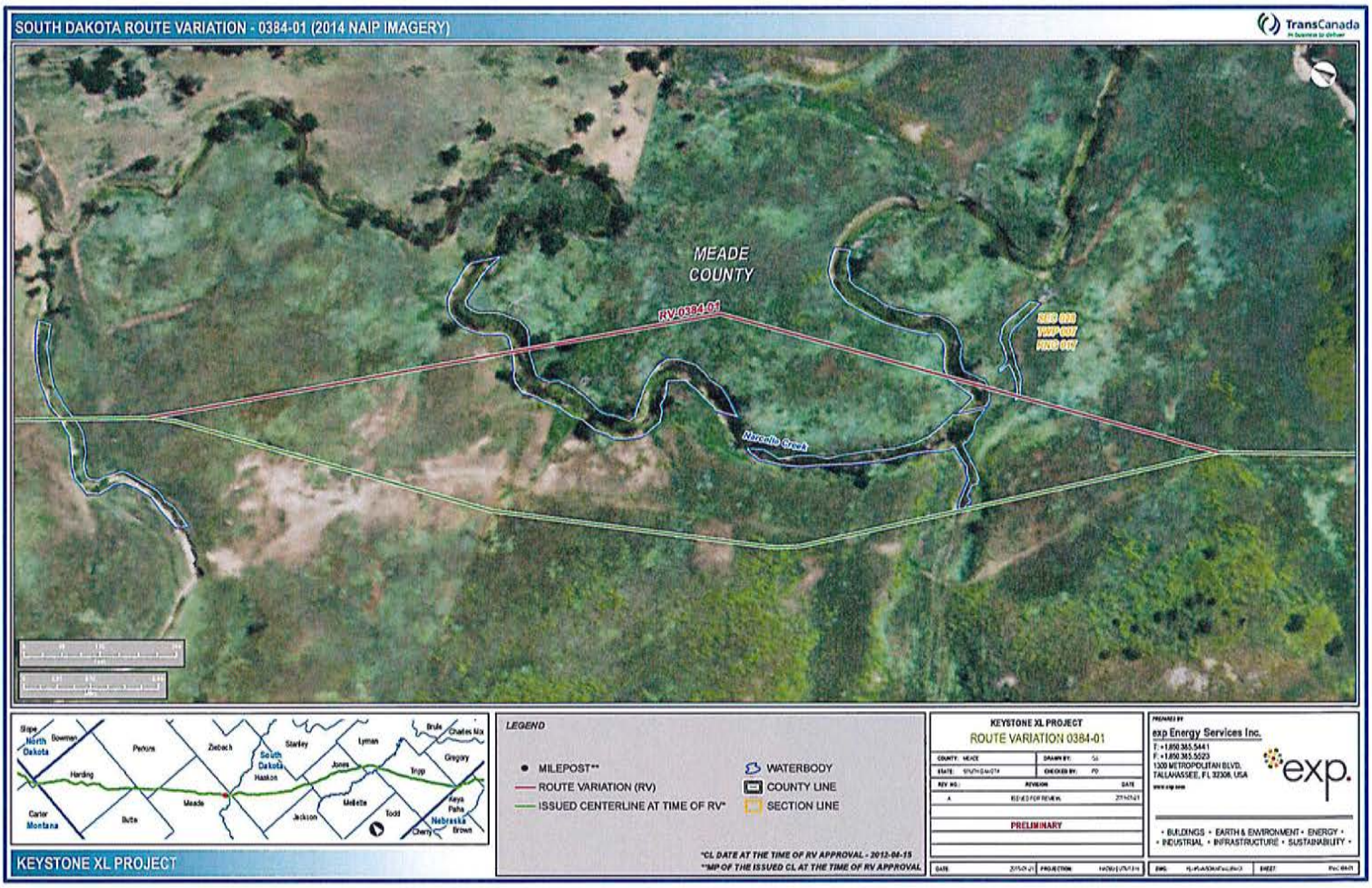
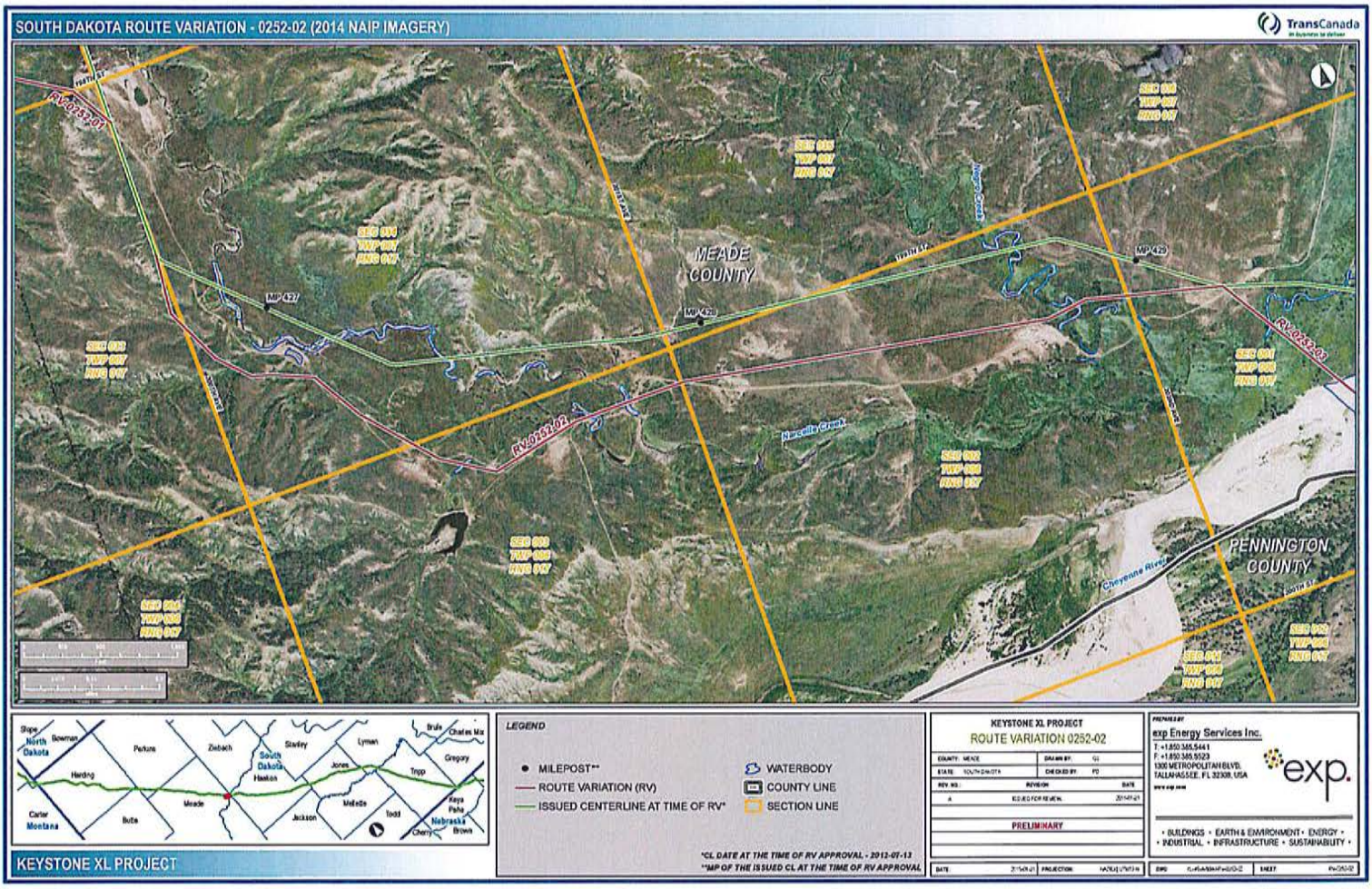
KEYSTONE XL PROJECT


SOUTH DAKOTA ROUTE VARIATION - 0257-02 (2014 NAIP IMAGERY)
TransCanada
MEADE
COUNTY
MP 426
RV-0257-02
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-03-14
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0257-02
PRELIMINARY
exp Energy Services Inc.
KEYSTONE XL PROJECT


SOUTH DAKOTA ROUTE VARIATION - 0252-01 (2014 NAIP IMAGERY)
TransCanada
MP 424
MP 425
MP 426
MEADE COUNTY
Narcelle Creek
RV 0252-01
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2012-07-13
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0252-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1309 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
KEYSTONE XL PROJECT


SOUTH DAKOTA ROUTE VARIATION - 0384-01 (2014 NAIP IMAGERY)
TransCanada
MEADE
COUNTY
RV-0384-01
Nuremlo Creek
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2012-08-15
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0384-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1320 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
KEYSTONE XL PROJECT


SOUTH DAKOTA ROUTE VARIATION - 0252-02 (2014 NAIP IMAGERY)
TransCanada
RV-0252-01
MEADE COUNTY
MP 427
MP 428
RV-0252-02
RV-0252-03
Newell Creek
PENNINGTON COUNTY
Cheyenne River
Slope
Bowman
North Dakota
Perkins
Ziebach
South Dakota
Stanley
Haakon
Lyman
Jones
Brule
Charles Mix
Gregory
Tripp
Harding
Carter
Montana
Butte
Meade
Jackson
Mellette
Todd
Keya Paha
Nebraska
Brown
Cherry
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2012-07-13
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0252-02
COUNTY: MEADE
DRAWN BY: GJ
STATE: SOUTH DAKOTA
CHECKED BY: PD
REV NO.
REVISION
DATE
A
ISSUED FOR REVIEW
2014-04-21
PRELIMINARY
DATE: 2014-04-21
PROJECTION: NAD83 UTM 14N
PREPARED BY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
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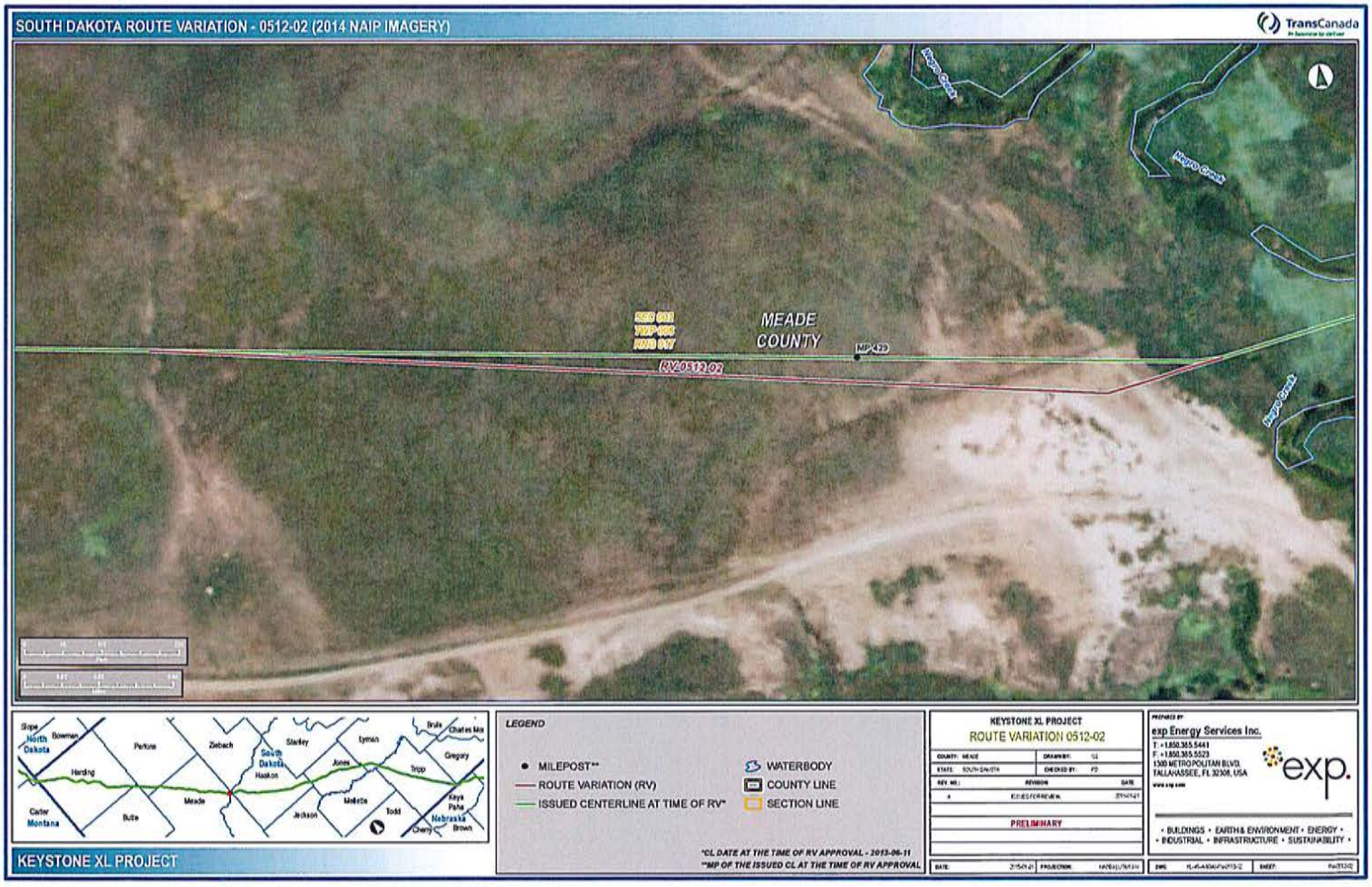
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
DWG
SHEET
RV-0252-02


SOUTH DAKOTA ROUTE VARIATION - 0512-02 (2014 NAIP IMAGERY)
TransCanada
MEADE COUNTY
MP 439
RV 0512-02
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-06-11
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0512-02
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1500 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
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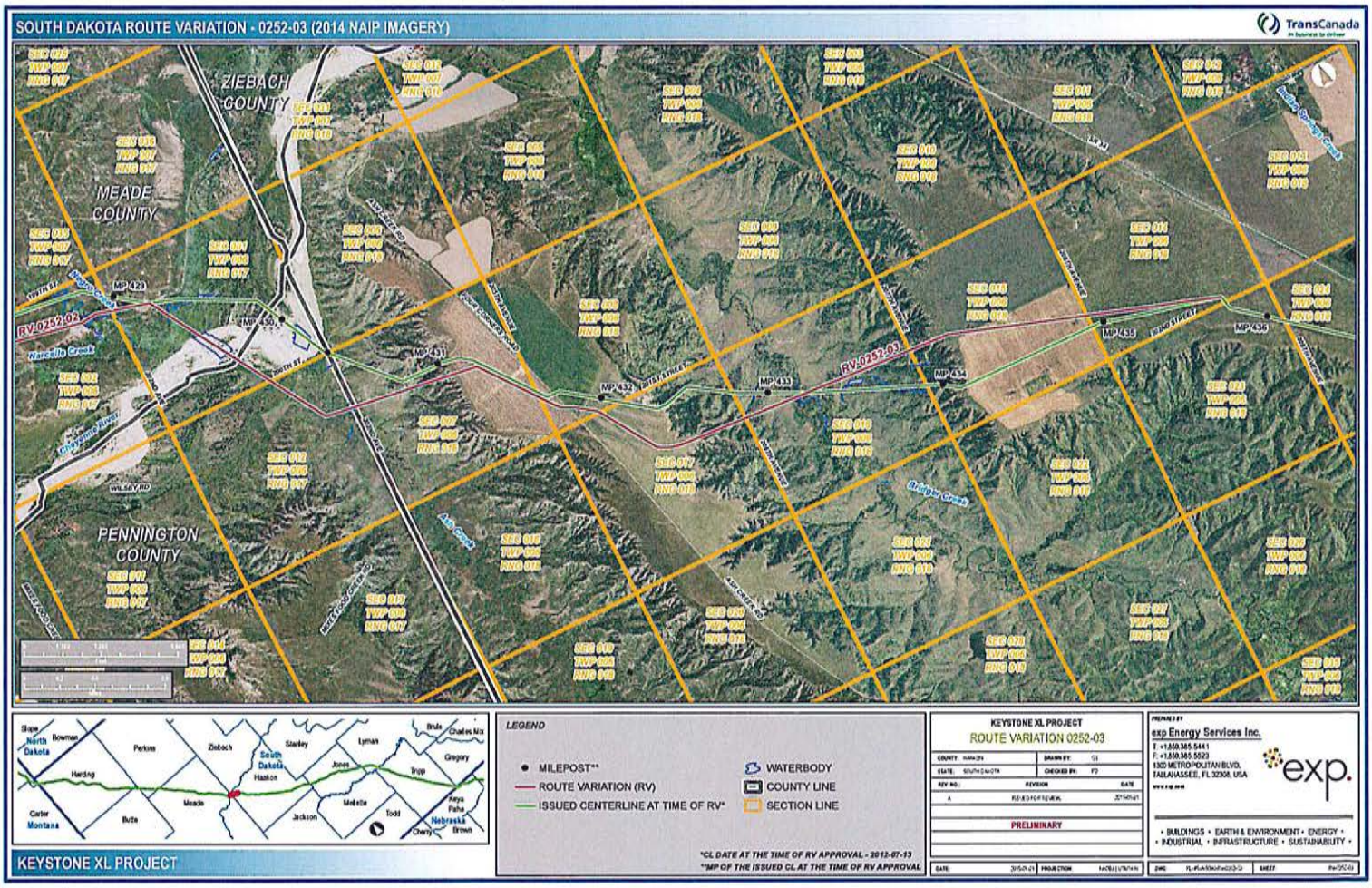
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
KEYSTONE XL PROJECT


SOUTH DAKOTA ROUTE VARIATION - 0252-03 (2014 NAIP IMAGERY)
TransCanada
ZIEBACH COUNTY
MEADE COUNTY
PENNINGTON COUNTY
RV 0252-02
RV 0252-03
MP 429
MP 430
MP 431
MP 432
MP 433
MP 434
MP 435
MP 436
Marcotte Creek
Cottonwood River
Bridger Creek
Ash Creek
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2012-07-13
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0252-03
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1320 METROPOLITAN BLVD,
TALLAHASSEE, FL 32308, USA
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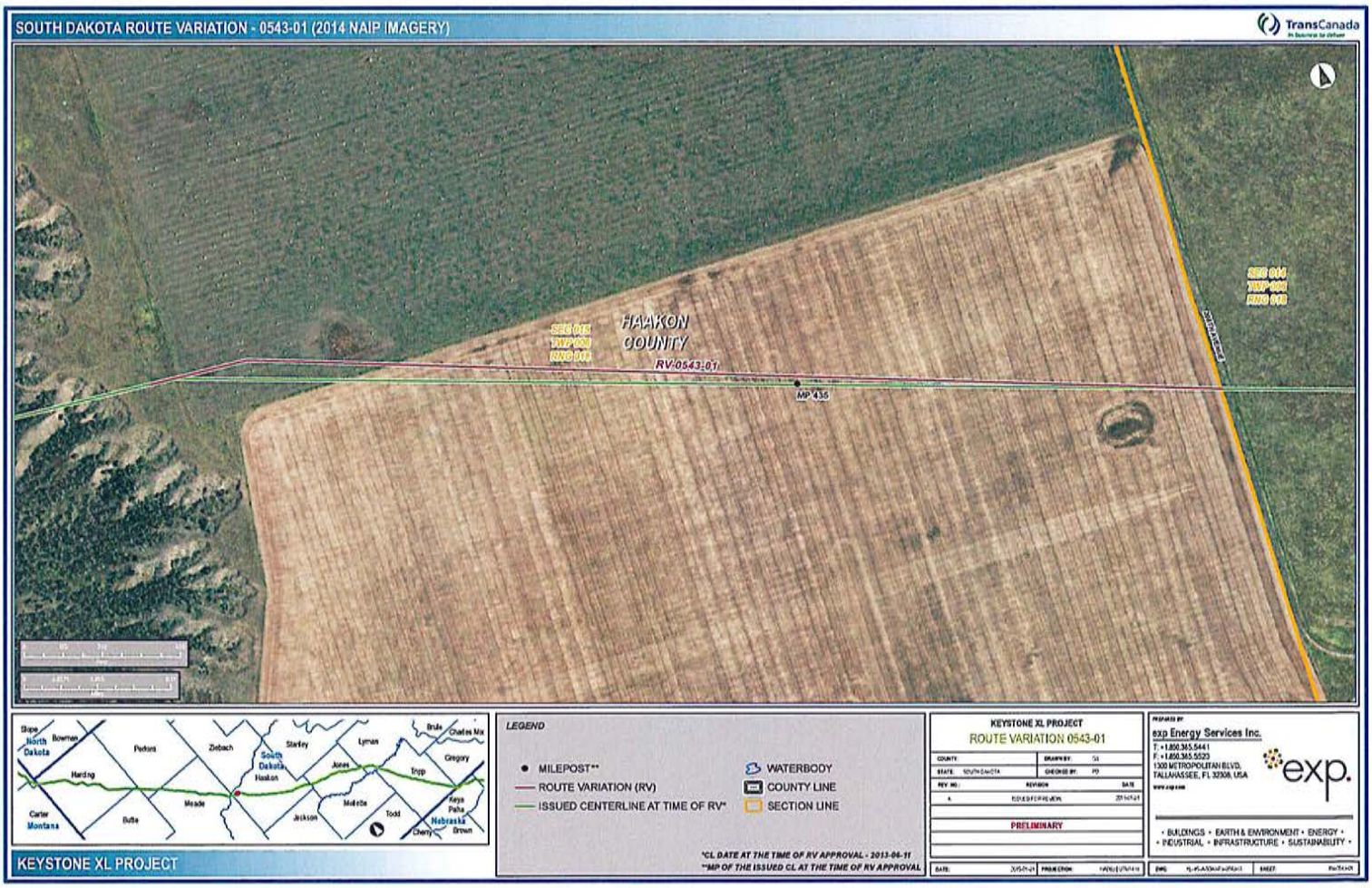
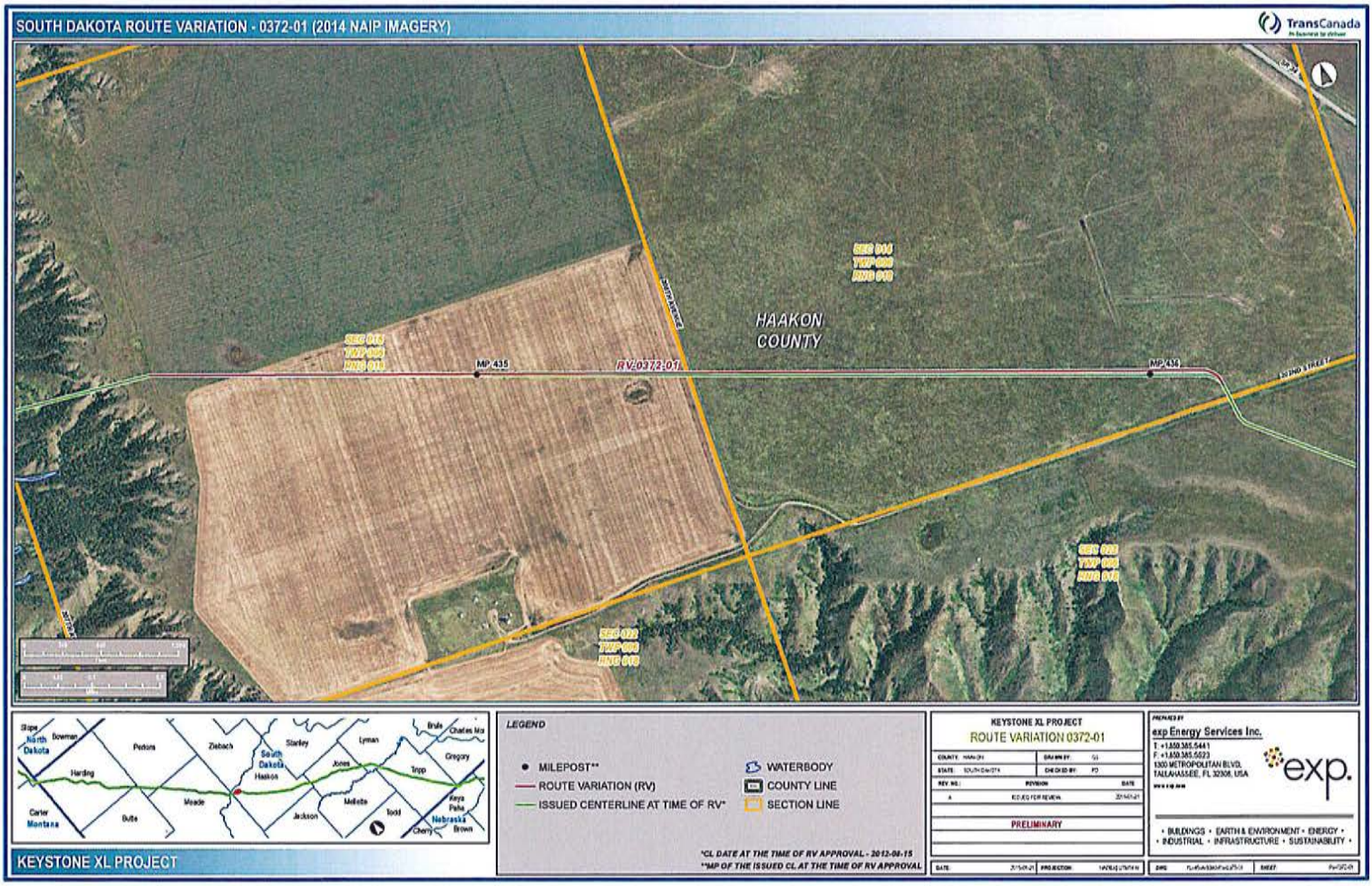
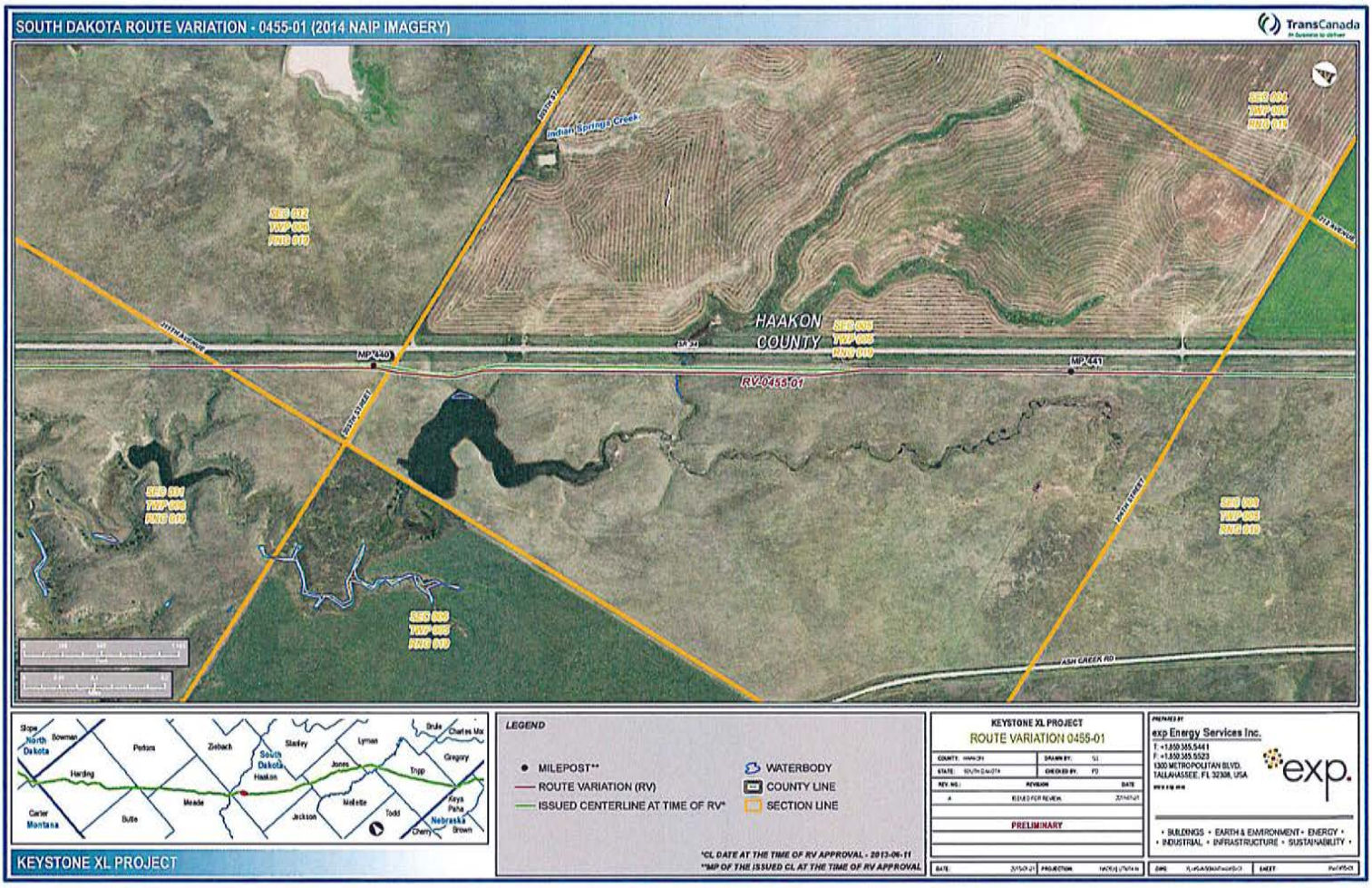
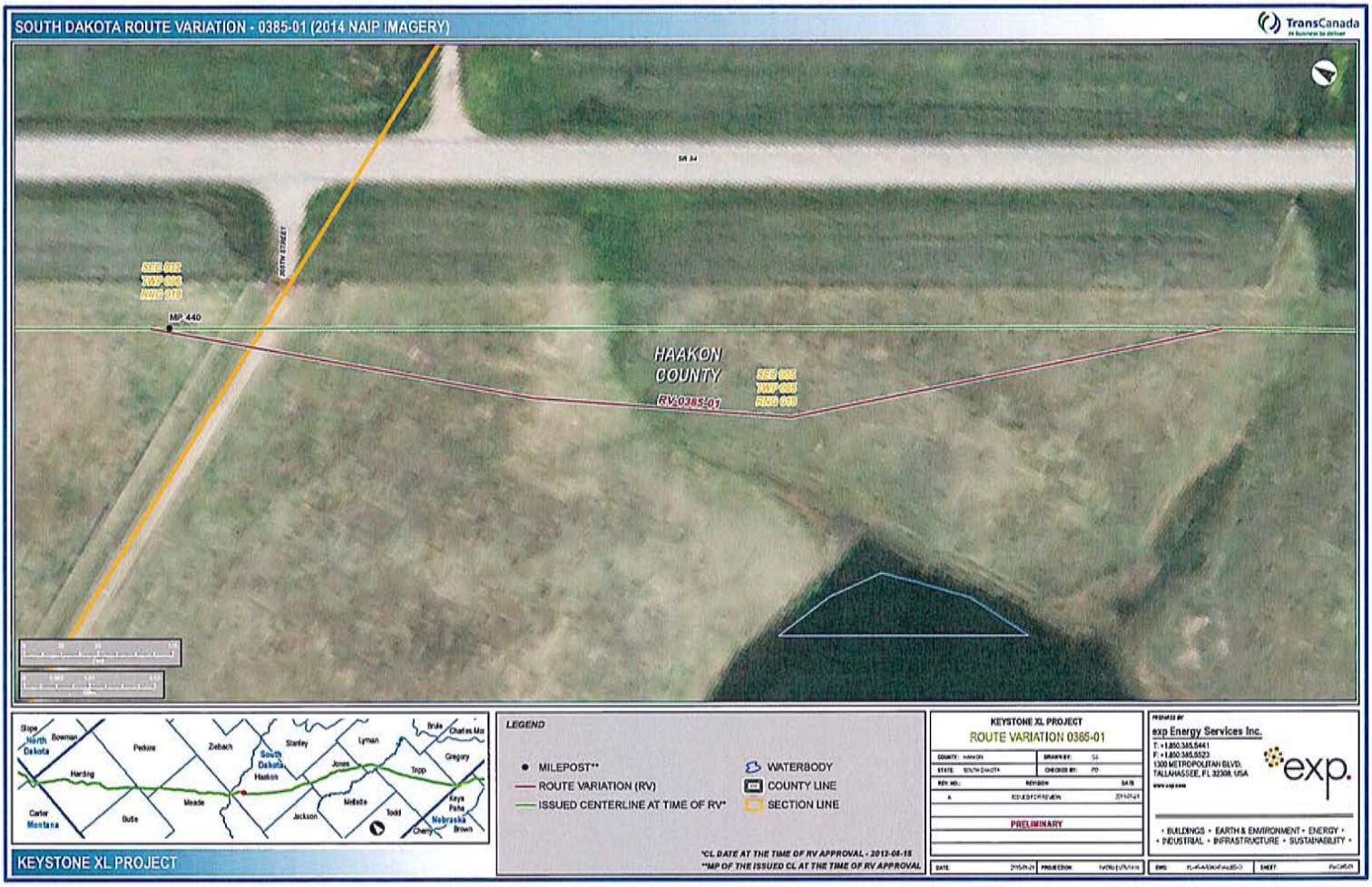
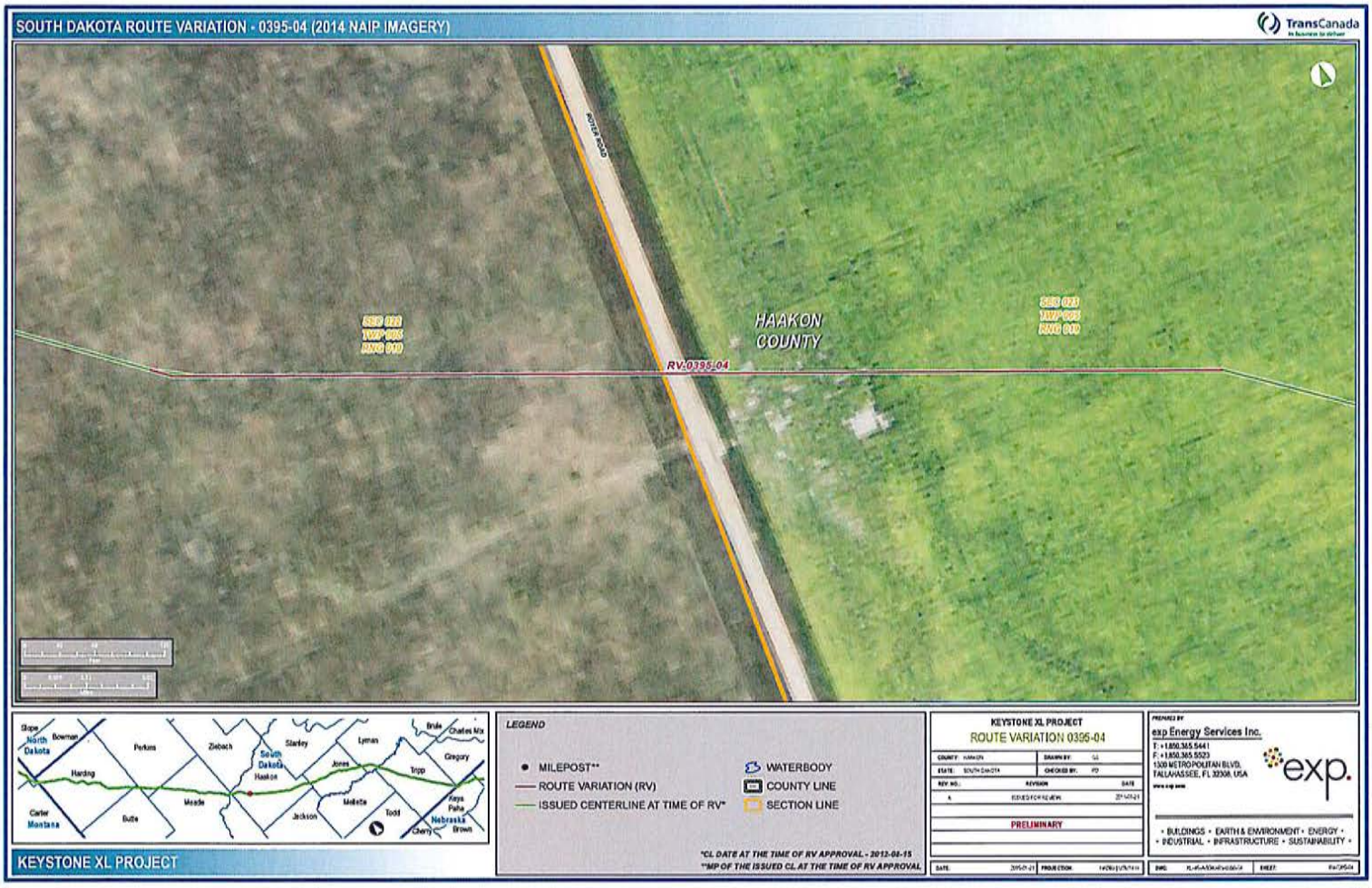
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
KEYSTONE XL PROJECT

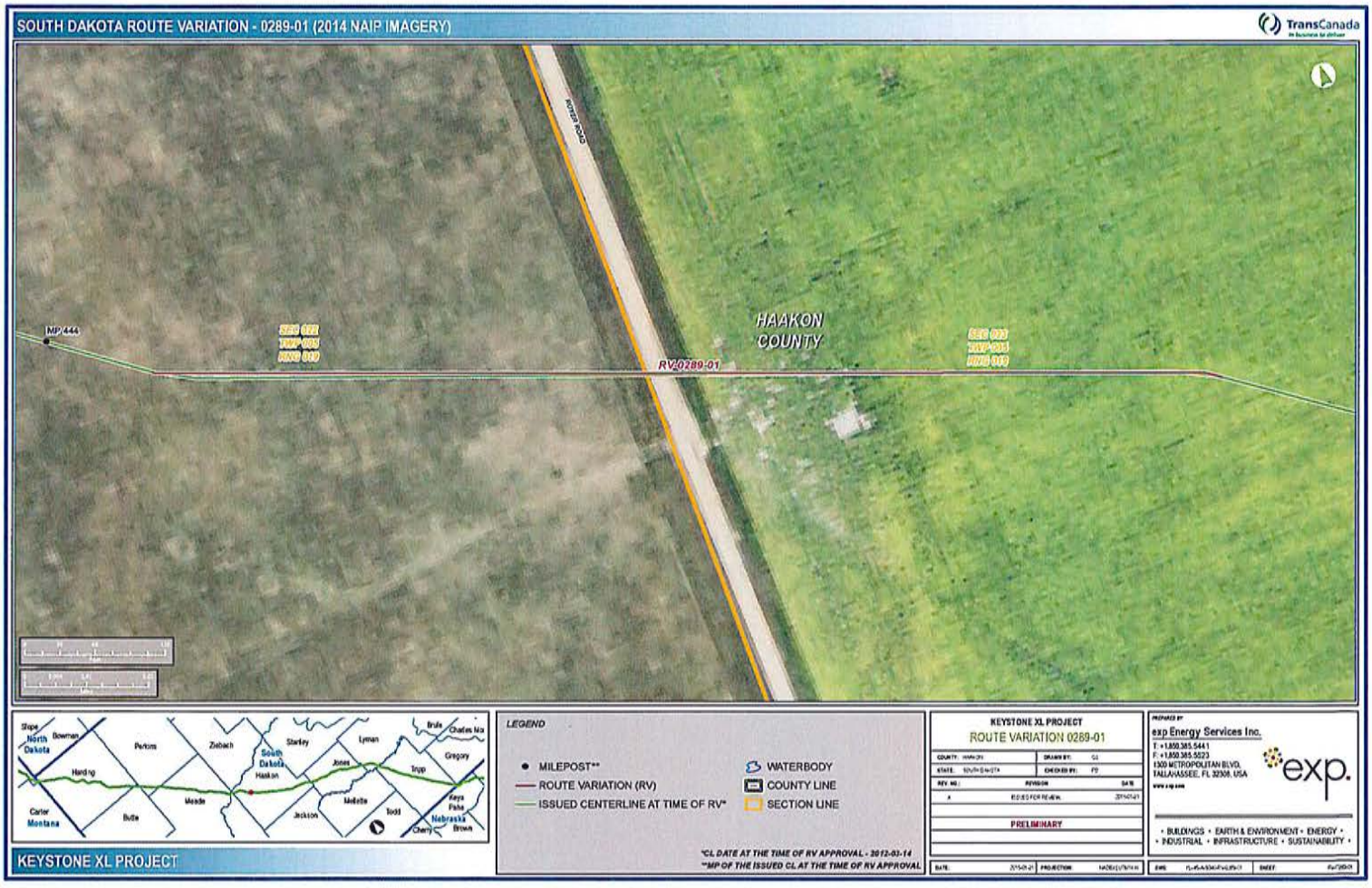

SOUTH DAKOTA ROUTE VARIATION - 0543-01 (2014 NAIP IMAGERY)
TransCanada
HAAKON COUNTY
RV-0543-01
MP 436
SEC 015
TWP 05N
RNG 01E
SEC 011
TWP 05N
RNG 01E
SOUTH DAKOTA
NORTH DAKOTA
Slope
Bowman
Perkins
Ziebach
Stanley
Lyman
Brule
Charles Mix
Gregory
Harding
South Dakota
Haakon
Jones
Tripp
Carter
Montana
Butte
Meade
Jackson
Mellette
Todd
Keya Paha
Nebraska
Brown
Cherry
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-06-11
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0543-01
PRELIMINARY
exp Energy Services Inc.
T: +1.800.365.5441
F: +1.800.365.5520
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

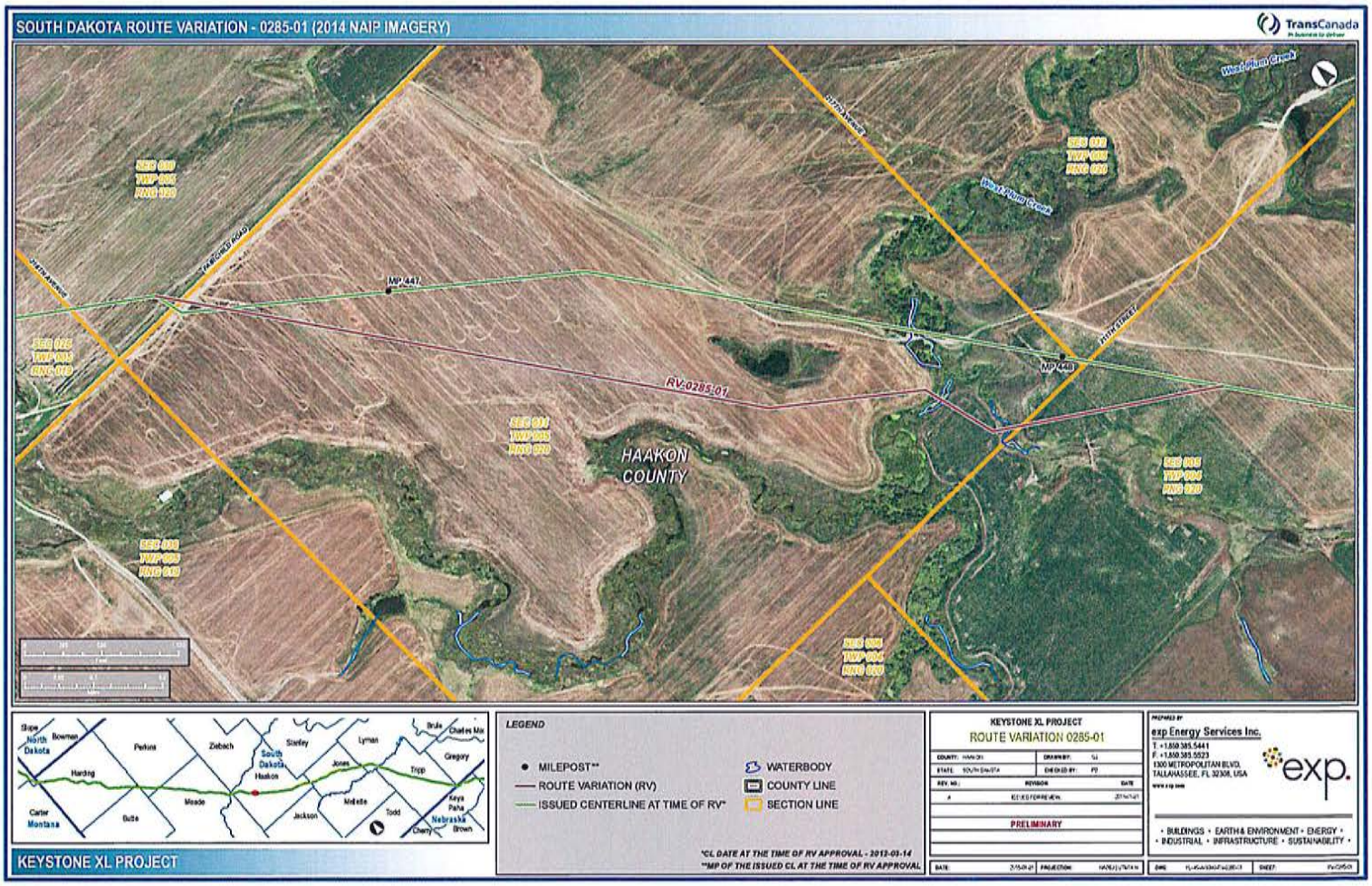

SOUTH DAKOTA ROUTE VARIATION - 0372-01 (2014 NAIP IMAGERY)
TransCanada
HAAKON COUNTY
MP 435
RV-0372-01
MP 435
435TH STREET
SEC 013
TWP 003
RNG 018
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2012-08-15
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0372-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD,
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

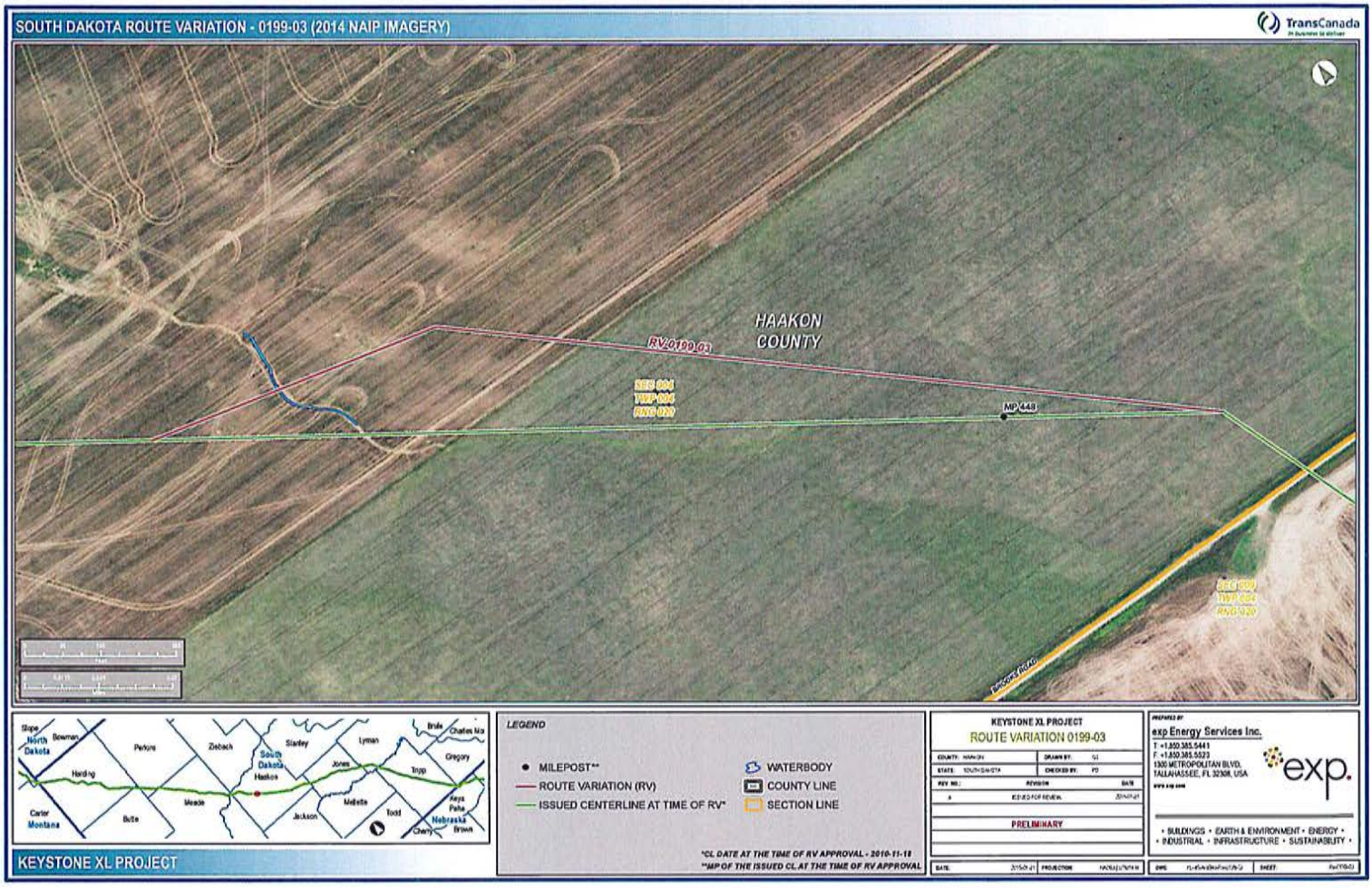

SOUTH DAKOTA ROUTE VARIATION - 0455-01 (2014 NAIP IMAGERY)
TransCanada
Indian Springs Creek
HAAKON COUNTY
MP 440
MP 441
RV-0455-01
ASH CREEK RD
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-06-11
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0455-01
PRELIMINARY
exp Energy Services Inc.
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
KEYSTONE XL PROJECT

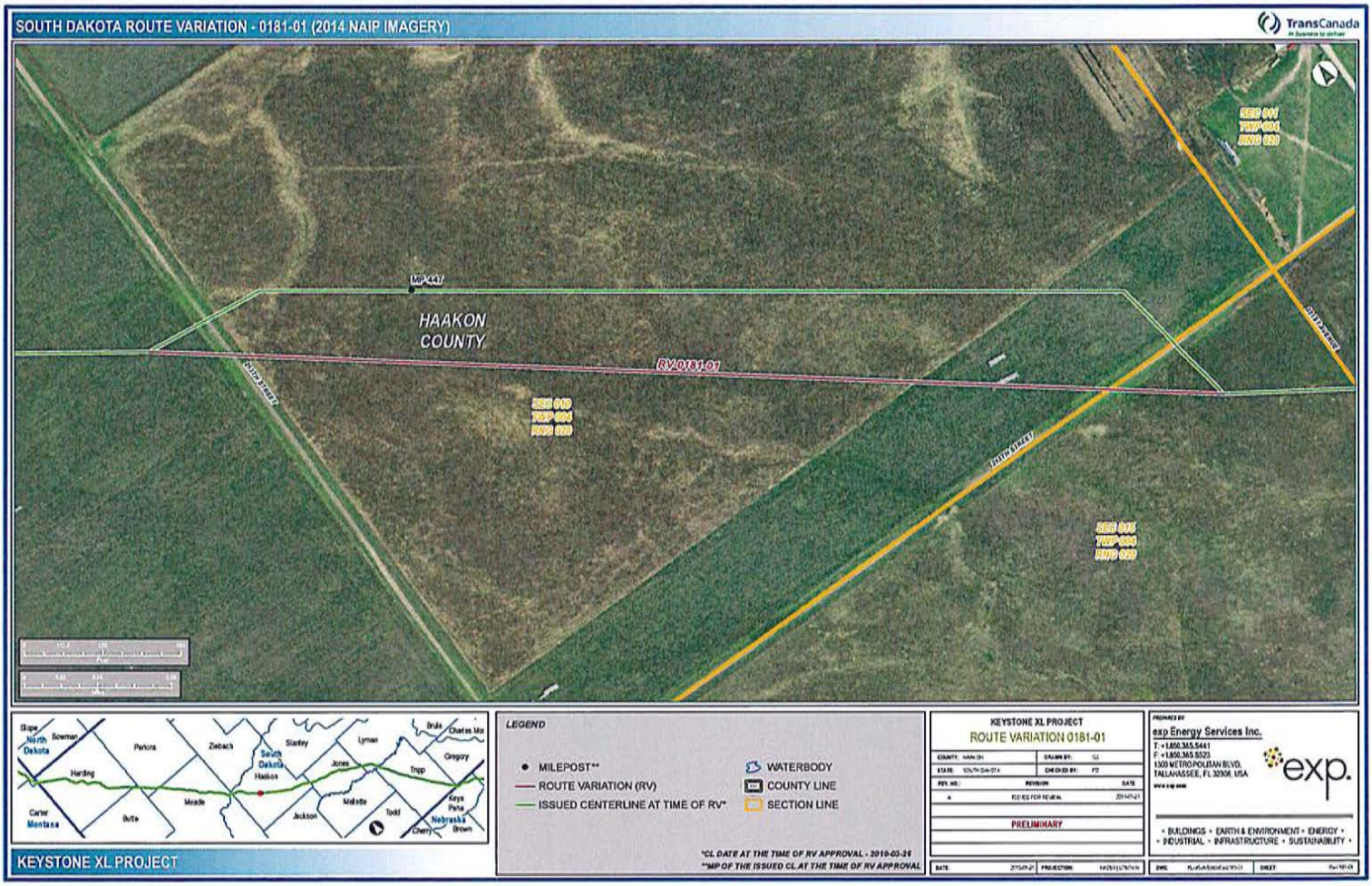

SOUTH DAKOTA ROUTE VARIATION - 0385-01 (2014 NAIP IMAGERY)
TransCanada
SR 34
SEC 002
TWP 002
RNG 019
MP 440
HAAKON
COUNTY
RV-0385-01
SEC 035
TWP 003
RNG 019
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-08-15
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0385-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
KEYSTONE XL PROJECT

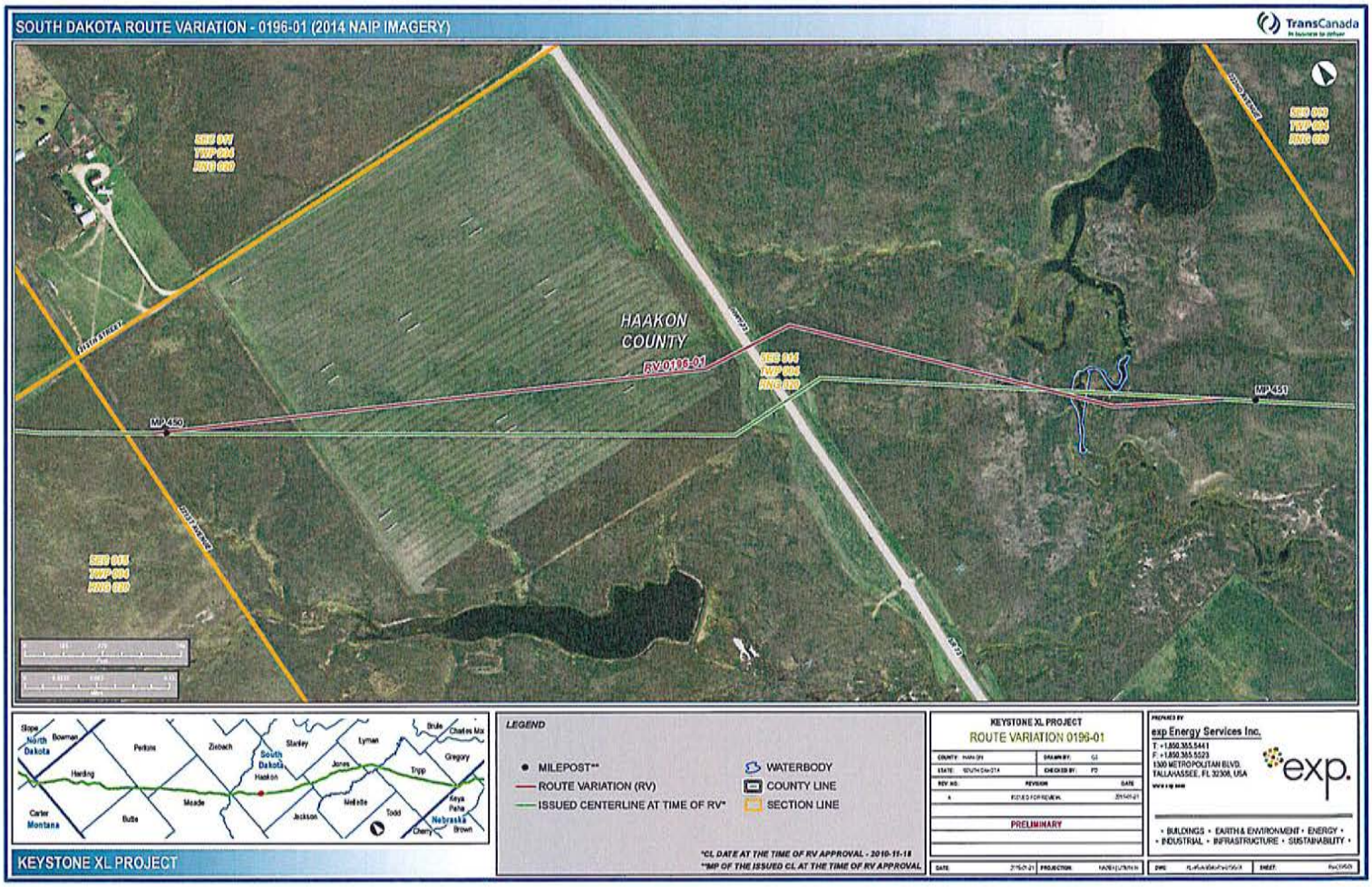

SOUTH DAKOTA ROUTE VARIATION - 0395-04 (2014 NAIP IMAGERY)
TransCanada
ROTER ROAD
HAAKON COUNTY
RV-0395-04
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2012-08-15
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
KEYSTONE XL PROJECT
ROUTE VARIATION 0395-04
PRELIMINARY
PREPARED BY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1309 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

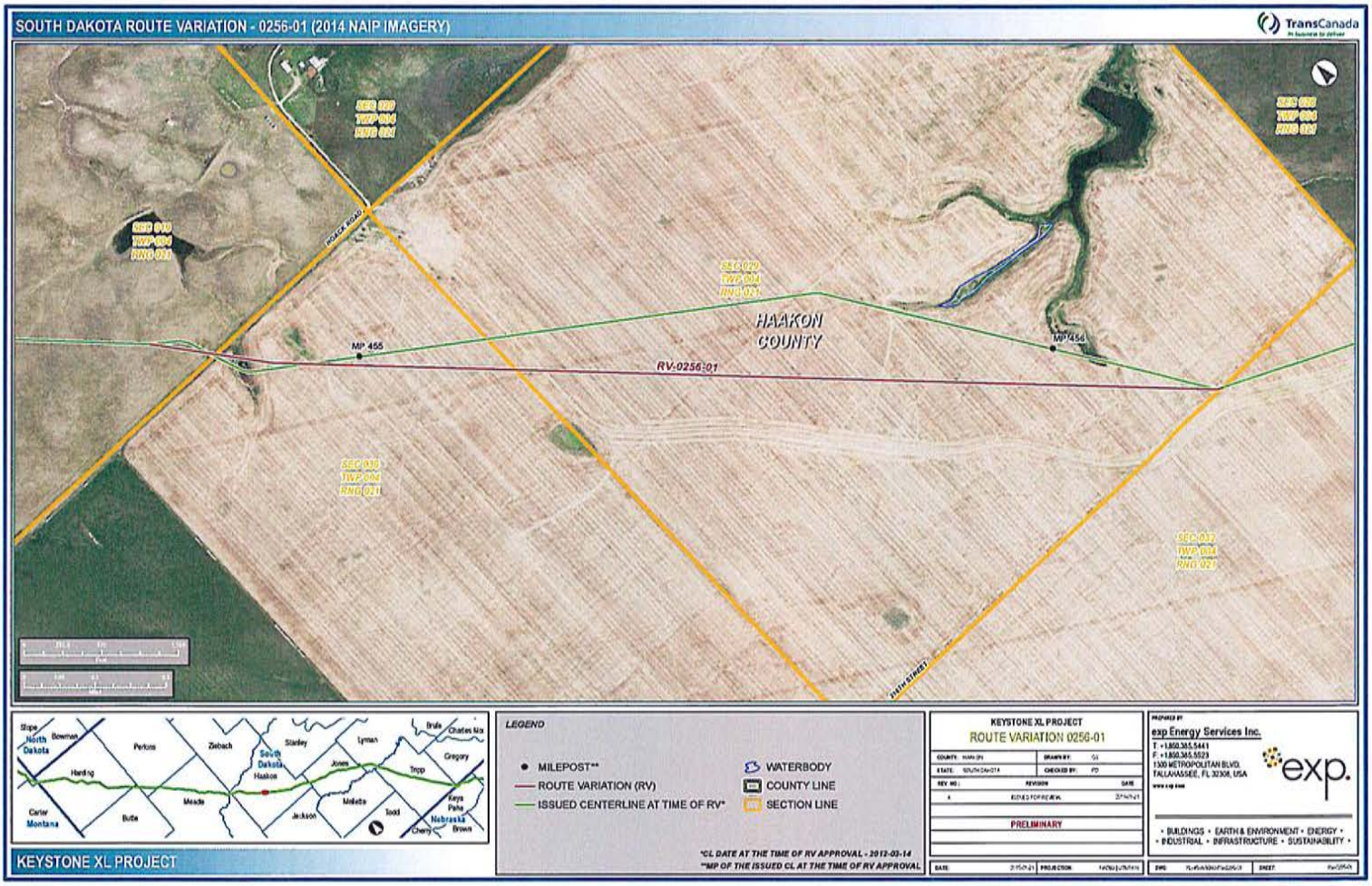

SOUTH DAKOTA ROUTE VARIATION - 0289-01 (2014 NAIP IMAGERY)
TransCanada
ROSER ROAD
HAAKON COUNTY
MP 444
RV-0289-01
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2012-03-14
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
KEYSTONE XL PROJECT
ROUTE VARIATION 0289-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1309 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

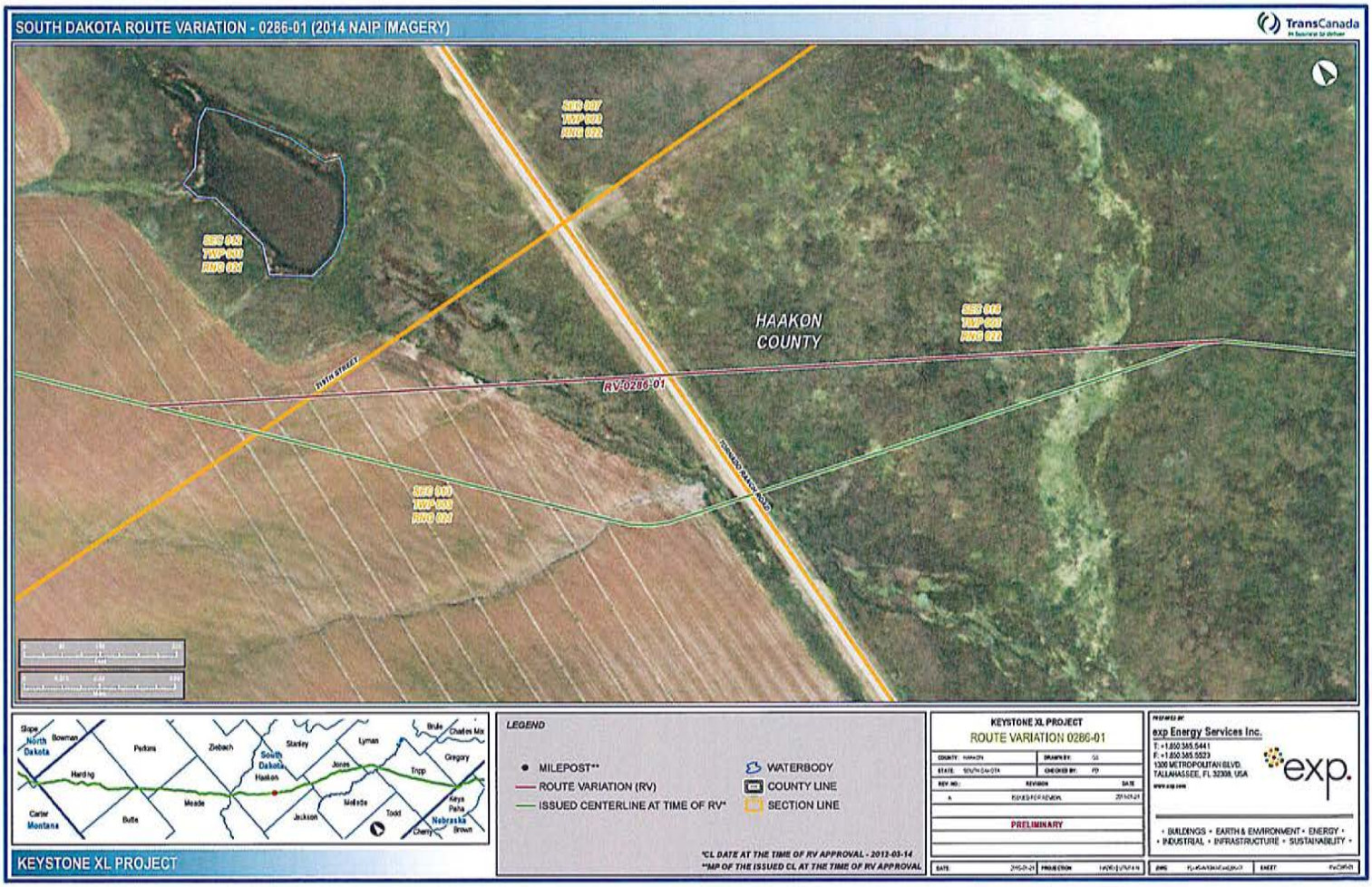

SOUTH DAKOTA ROUTE VARIATION - 0285-01 (2014 NAIP IMAGERY)
TransCanada
West White Creek
MP 447
MP 448
RV-0285-01
HAAKON COUNTY
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2012-03-14
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0285-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.383.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH& ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
KEYSTONE XL PROJECT

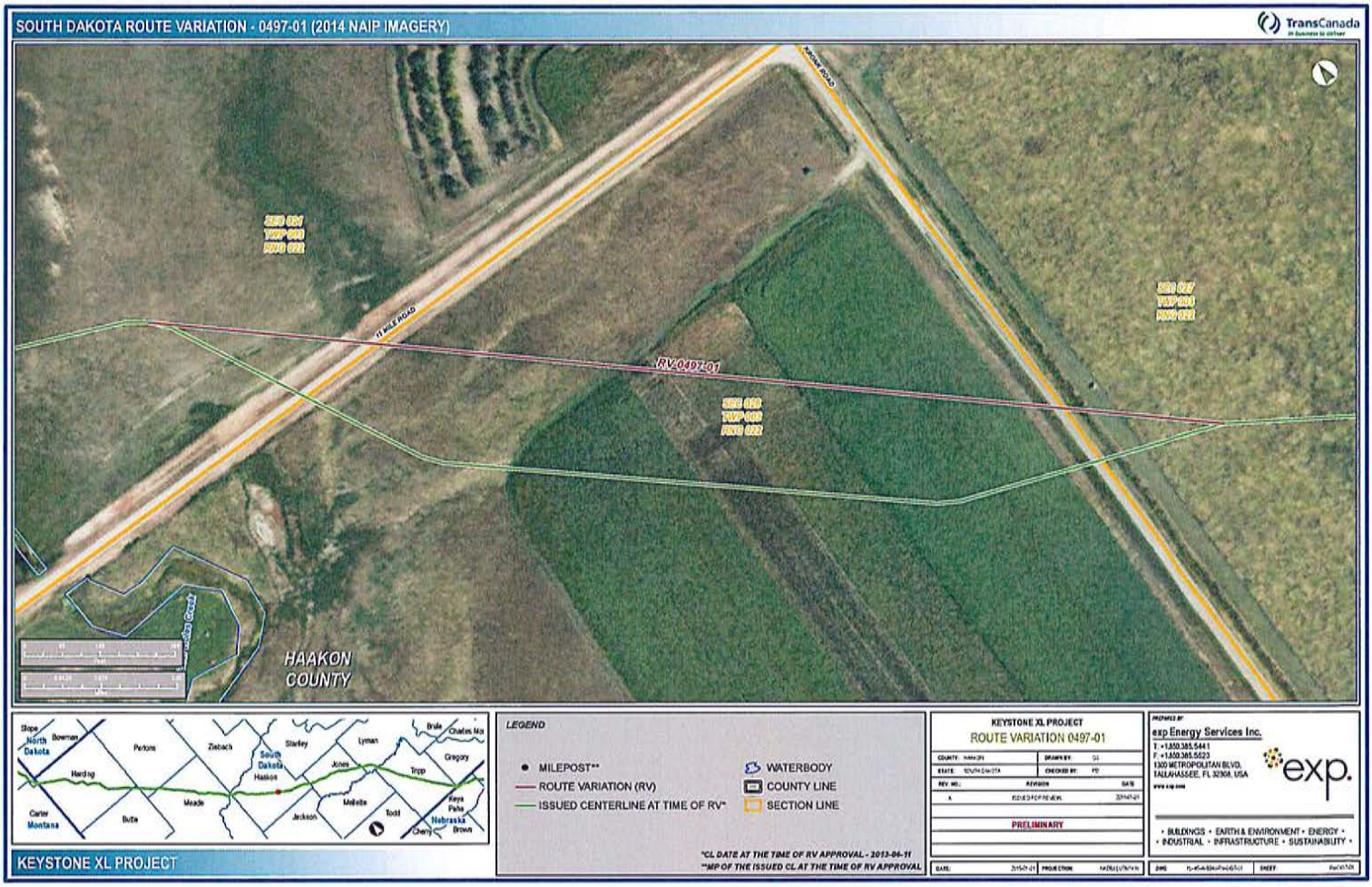

SOUTH DAKOTA ROUTE VARIATION - 0199-03 (2014 NAIP IMAGERY)
TransCanada
HAAKON
COUNTY
RV.0199.03
MP 448
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2010-11-18
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0199-03
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD,
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

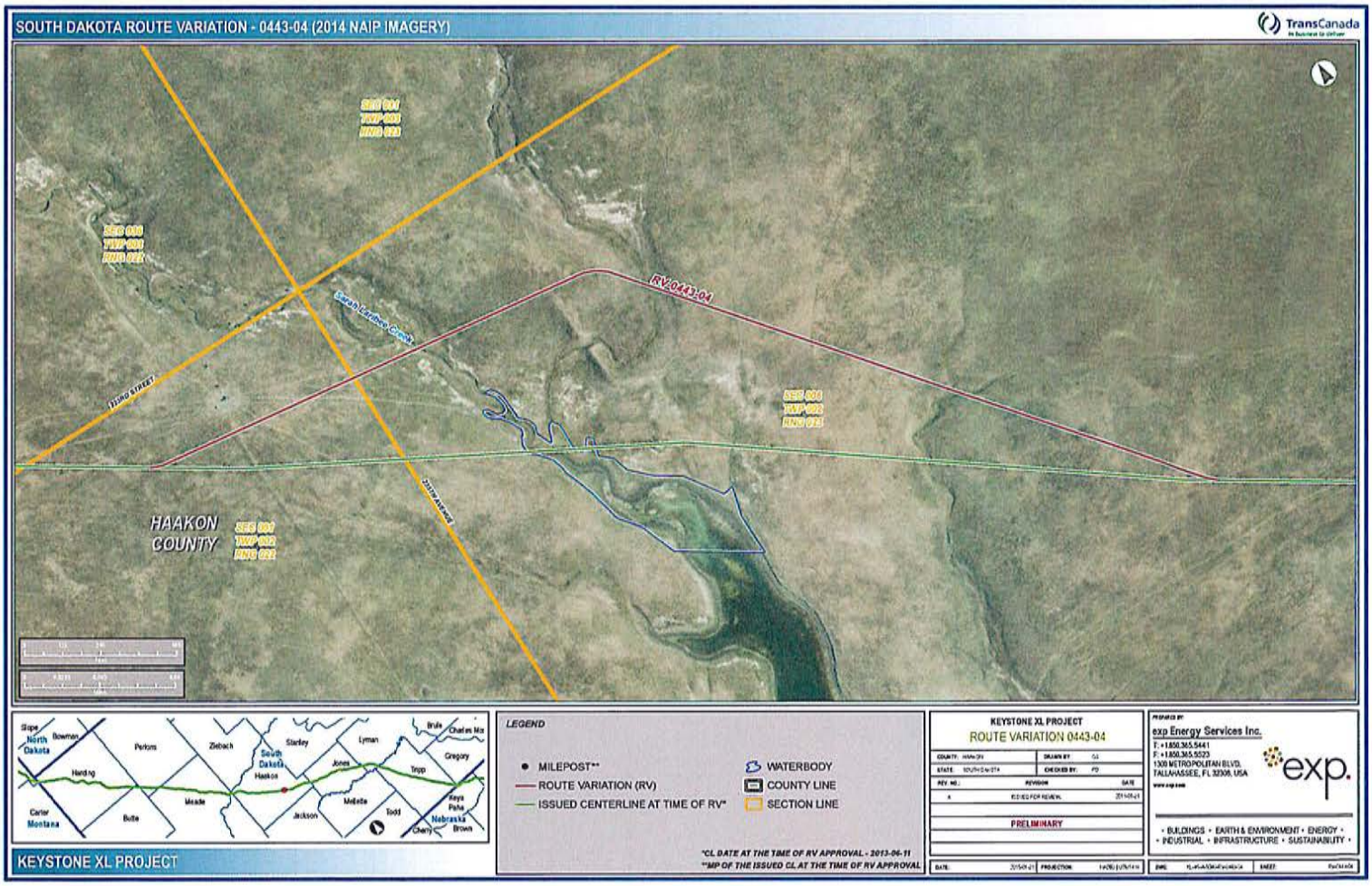

SOUTH DAKOTA ROUTE VARIATION - 0181-01 (2014 NAIP IMAGERY)
TransCanada
MP 447
HAAKON COUNTY
RV 0181-01
SEC 01
TWP 004
RNG 020
SEC 06
TWP 004
RNG 019
SEC 01
TWP 004
RNG 020
SOUTH STREET
EASTWARD
EASTWARD STREET
Slope
North Dakota
Bowman
Perkins
Ziebach
South Dakota
Haakon
Stanley
Lyman
Brule
Charles Mix
Gregory
Tripp
Jones
Harding
Meade
Butte
Carter
Montana
Mellette
Todd
Jackson
Keya Paha
Nebraska
Brown
Cherry
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2016-03-24
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0181-01
PRELIMINARY
PREPARED BY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5920
1500 METROPOLITAN BLVD,
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

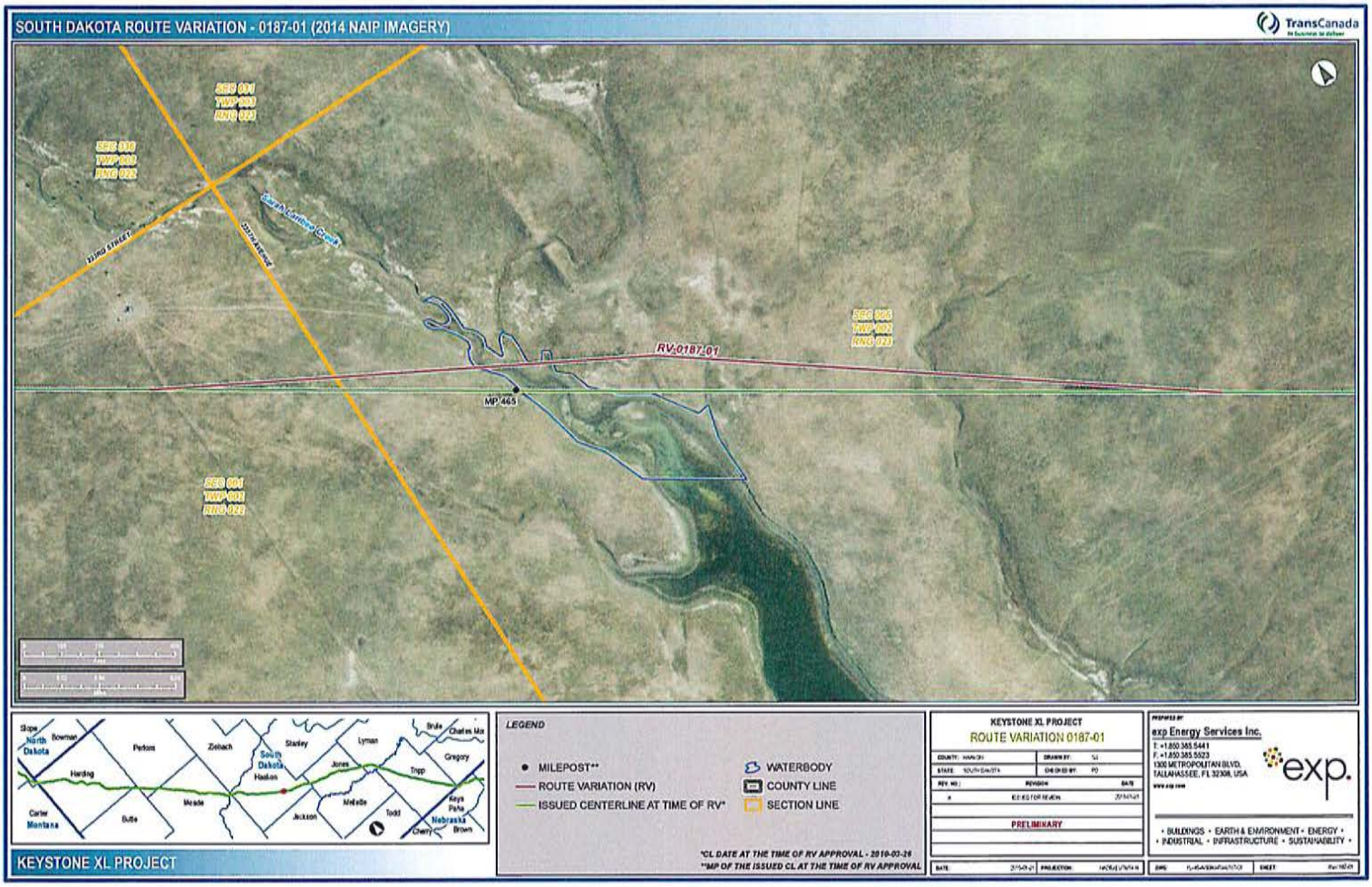

SOUTH DAKOTA ROUTE VARIATION - 0196-01 (2014 NAIP IMAGERY)
TransCanada
HAAKON COUNTY
RV-0196-01
MP 450
MP 451
SEC 01
TWP 01S
RNG 01E
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2010-11-18
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0196-01
PRELIMINARY
exp Energy Services Inc.
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
KEYSTONE XL PROJECT

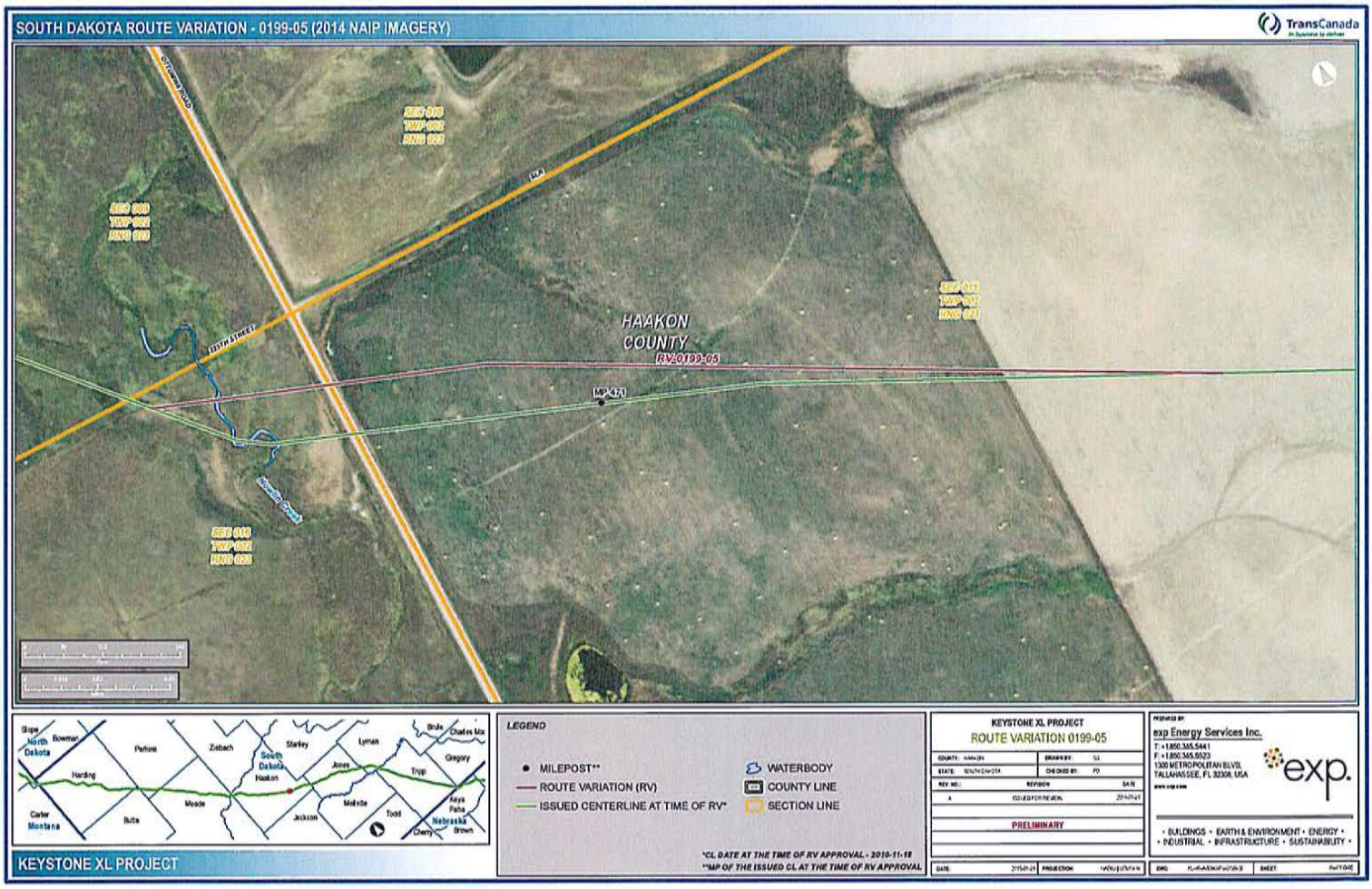

SOUTH DAKOTA ROUTE VARIATION - 0256-01 (2014 NAIP IMAGERY)
TransCanada
SEC 029
TWP 004
RNG 021
HAAKON
COUNTY
MP 455
MP 456
RV-0256-01
SEC 030
TWP 004
RNG 021
SEC 032
TWP 004
RNG 021
POLICE ROAD
SIXTH STREET
Slope
North Dakota
Bowman
Perkins
Ziebach
Stanley
Lyman
Brule
Charles Mix
Gregory
South Dakota
Haakon
Jones
Tripp
Harding
Meade
Butte
Carter
Montana
Millette
Todd
Jackson
Keya Paha
Nebraska
Brown
Cherry
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2012-03-14
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0256-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5920
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

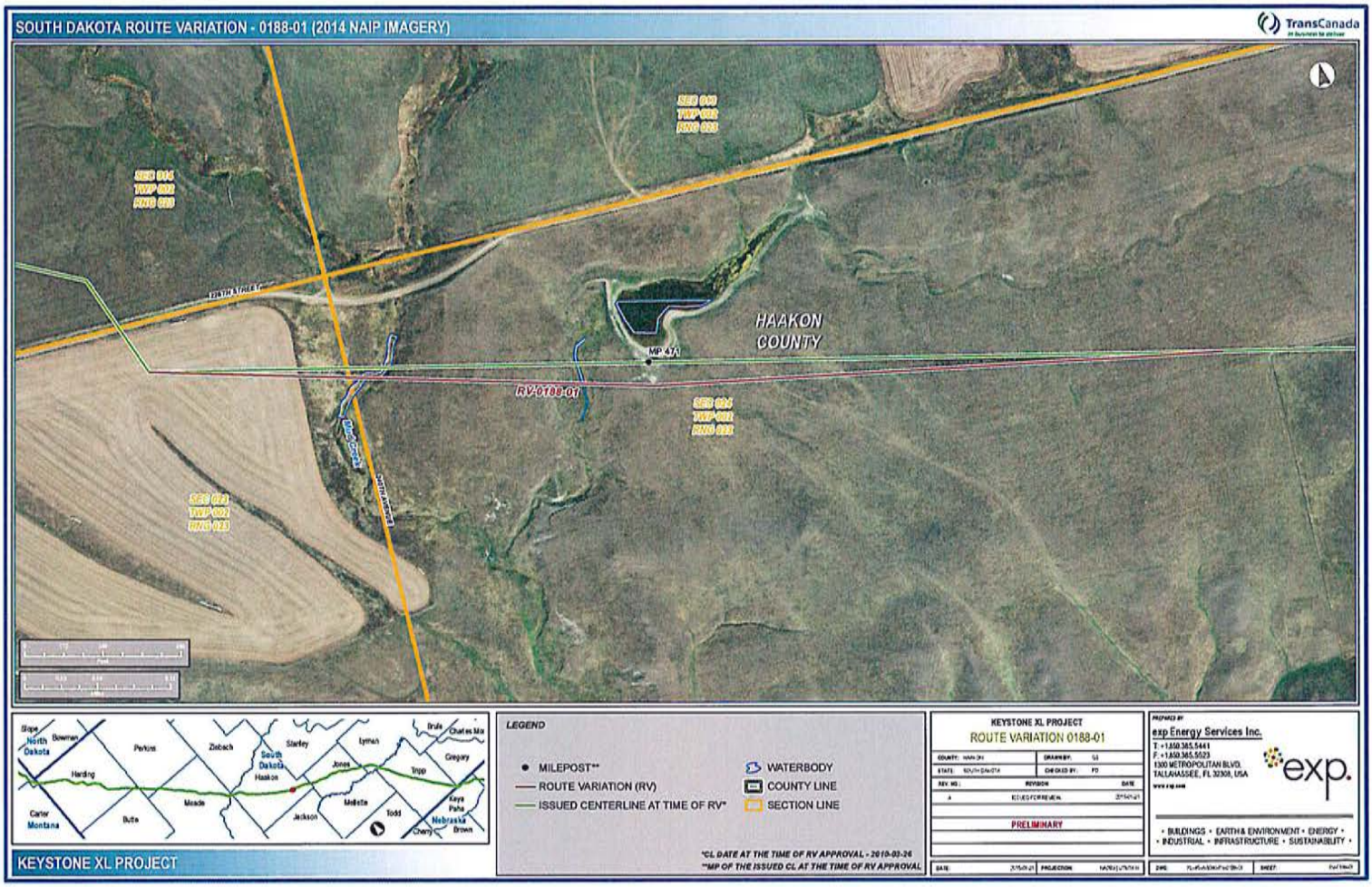

SOUTH DAKOTA ROUTE VARIATION - 0286-01 (2014 NAIP IMAGERY)
TransCanada
HAAKON COUNTY
RV-0286-01
SOUTH STREET
CHEYENNE CROSSING ROAD
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2012-03-14
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0286-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
KEYSTONE XL PROJECT

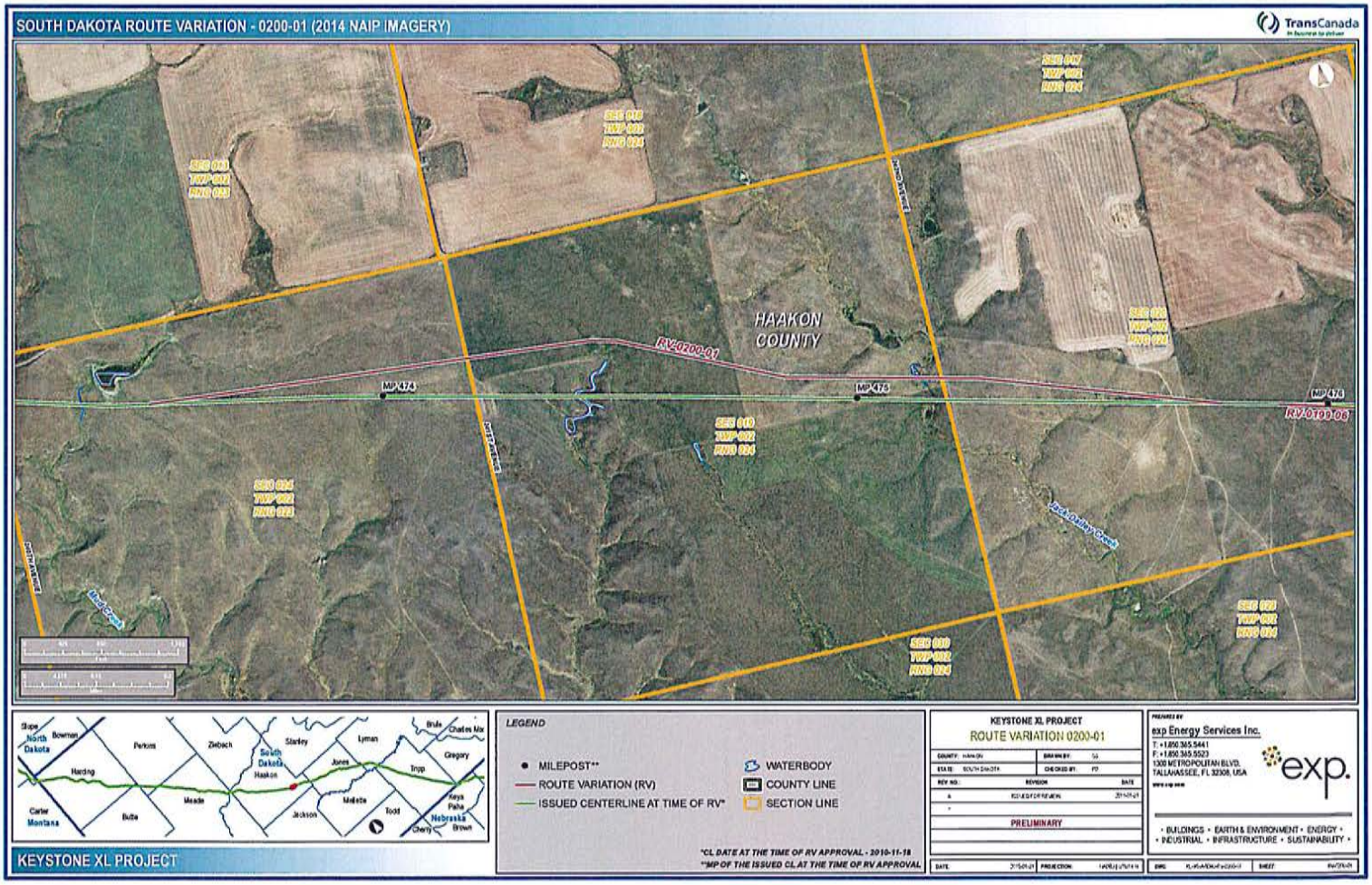

SOUTH DAKOTA ROUTE VARIATION - 0497-01 (2014 NAIP IMAGERY)
TransCanada
BROOKS ROAD
11 MILE ROAD
RV-0497-01
HAAKON COUNTY
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-06-11
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0497-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1320 METROPOLITAN BLVD,
TALLAHASSEE, FL 32308, USA
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
KEYSTONE XL PROJECT

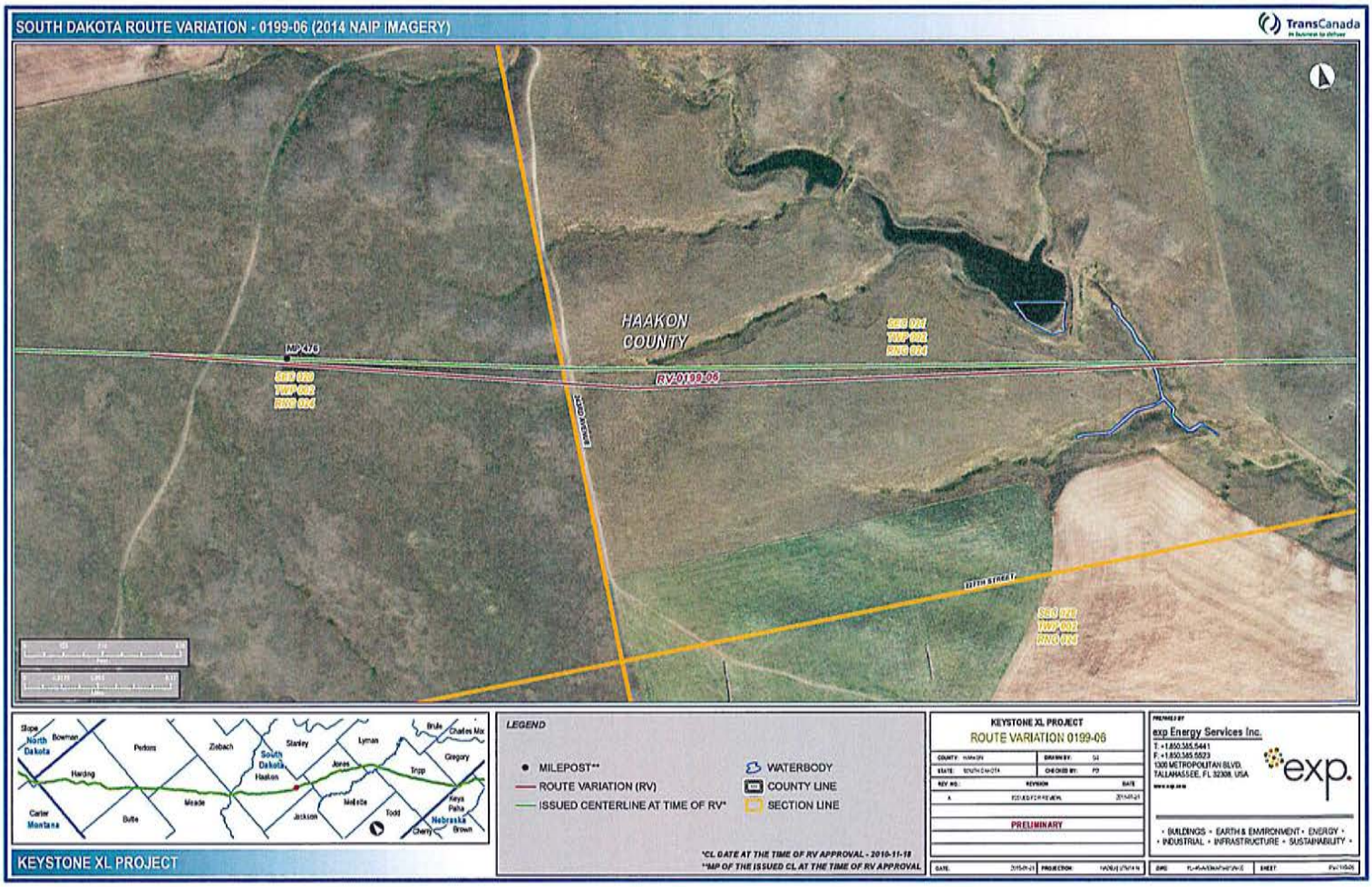

SOUTH DAKOTA ROUTE VARIATION - 0443-04 (2014 NAIP IMAGERY)
TransCanada
RV-0443-04
HAAKON COUNTY
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-06-11
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0443-04
PRELIMINARY
KEYSTONE XL PROJECT
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5020
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

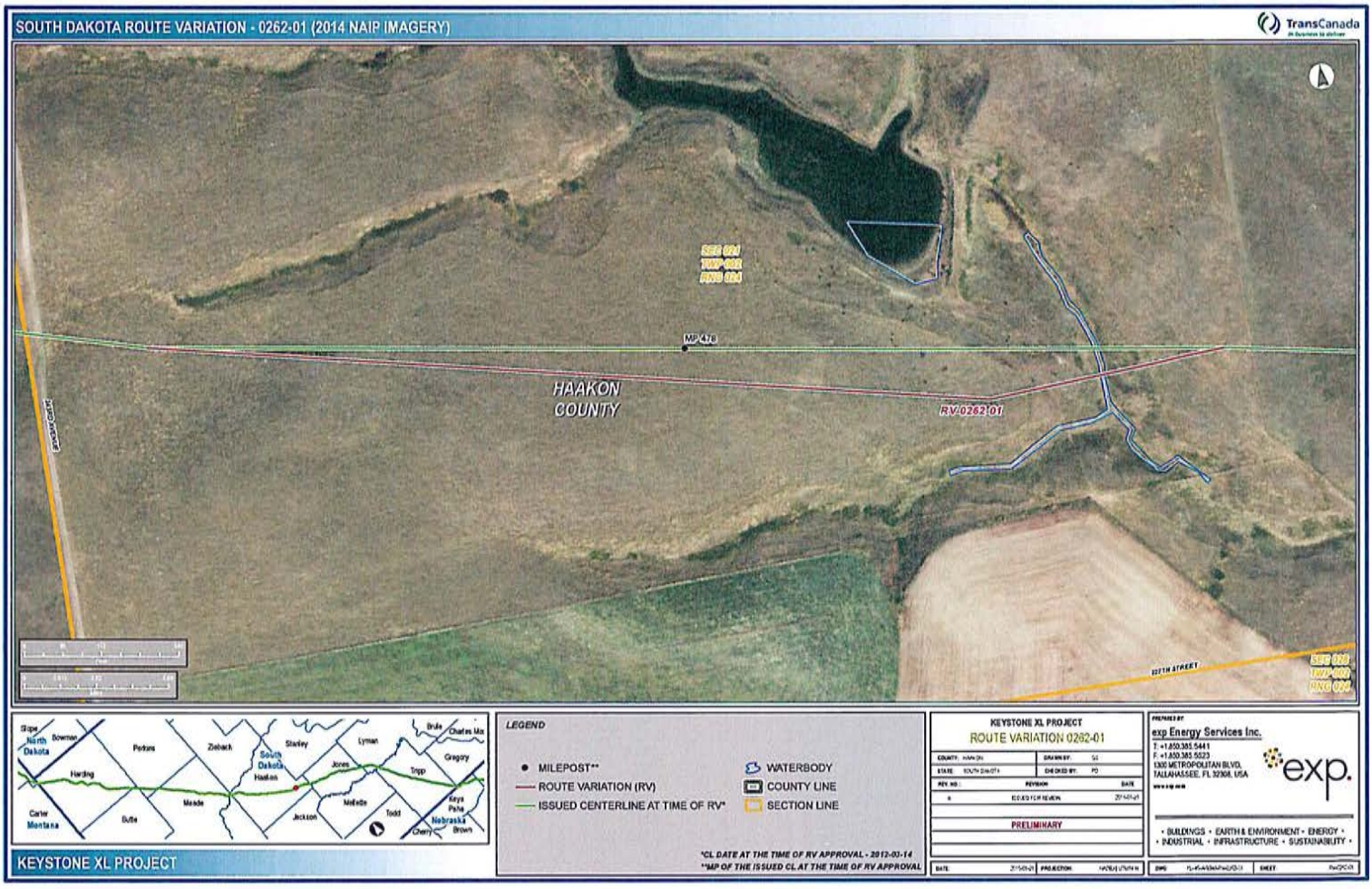

SOUTH DAKOTA ROUTE VARIATION - 0187-01 (2014 NAIP IMAGERY)
TransCanada
SEC 001
TWP 002
RNG 003
SEC 036
TWP 003
RNG 002
312ND STREET
323RD AVENUE
Sarah Lambert Creek
RV-0187-01
MP 465
SEC 006
TWP 002
RNG 003
SEC 001
TWP 002
RNG 002
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2010-03-26
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0187-01
PRELIMINARY
KEYSTONE XL PROJECT
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

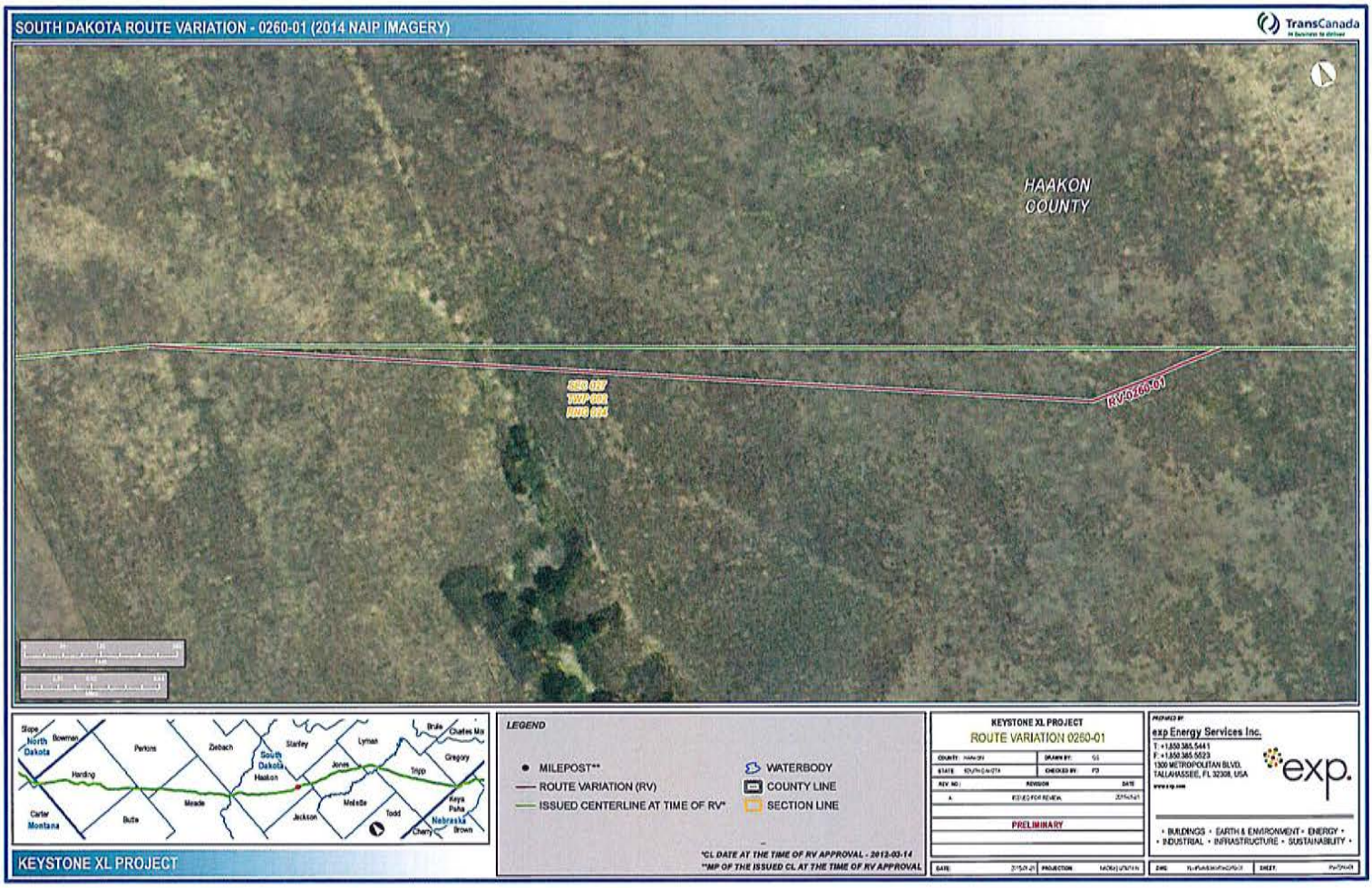

SOUTH DAKOTA ROUTE VARIATION - 0199-05 (2014 NAIP IMAGERY)
TransCanada
HAAKON
COUNTY
RV.0199-05
MP 471
133TH STREET
SEC 010
TWP 002
RNG 023
SEC 015
TWP 002
RNG 023
SEC 016
TWP 002
RNG 023
SEC 015
TWP 001
RNG 023
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2010-11-18
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0199-05
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1320 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

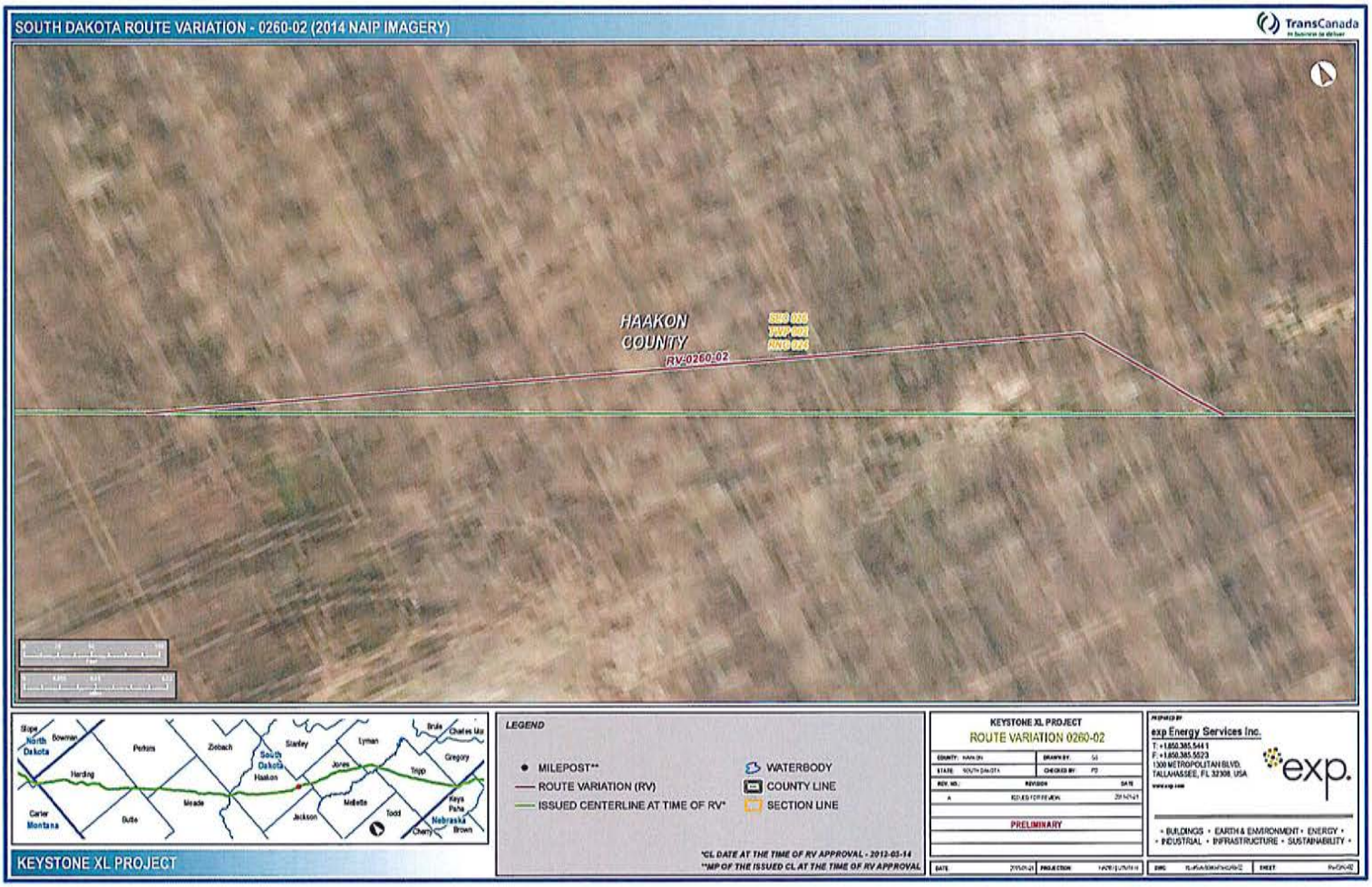

SOUTH DAKOTA ROUTE VARIATION - 0188-01 (2014 NAIP IMAGERY)
TransCanada
SEC 009
TWP 002
RNG 023
SEC 015
TWP 002
RNG 023
126TH STREET
HAAKON
COUNTY
MP 47N
RV-0188-01
SEC 015
TWP 002
RNG 023
White River
SEC 021
TWP 002
RNG 023
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2010-03-26
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0188-01
PRELIMINARY
KEYSTONE XL PROJECT
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH& ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

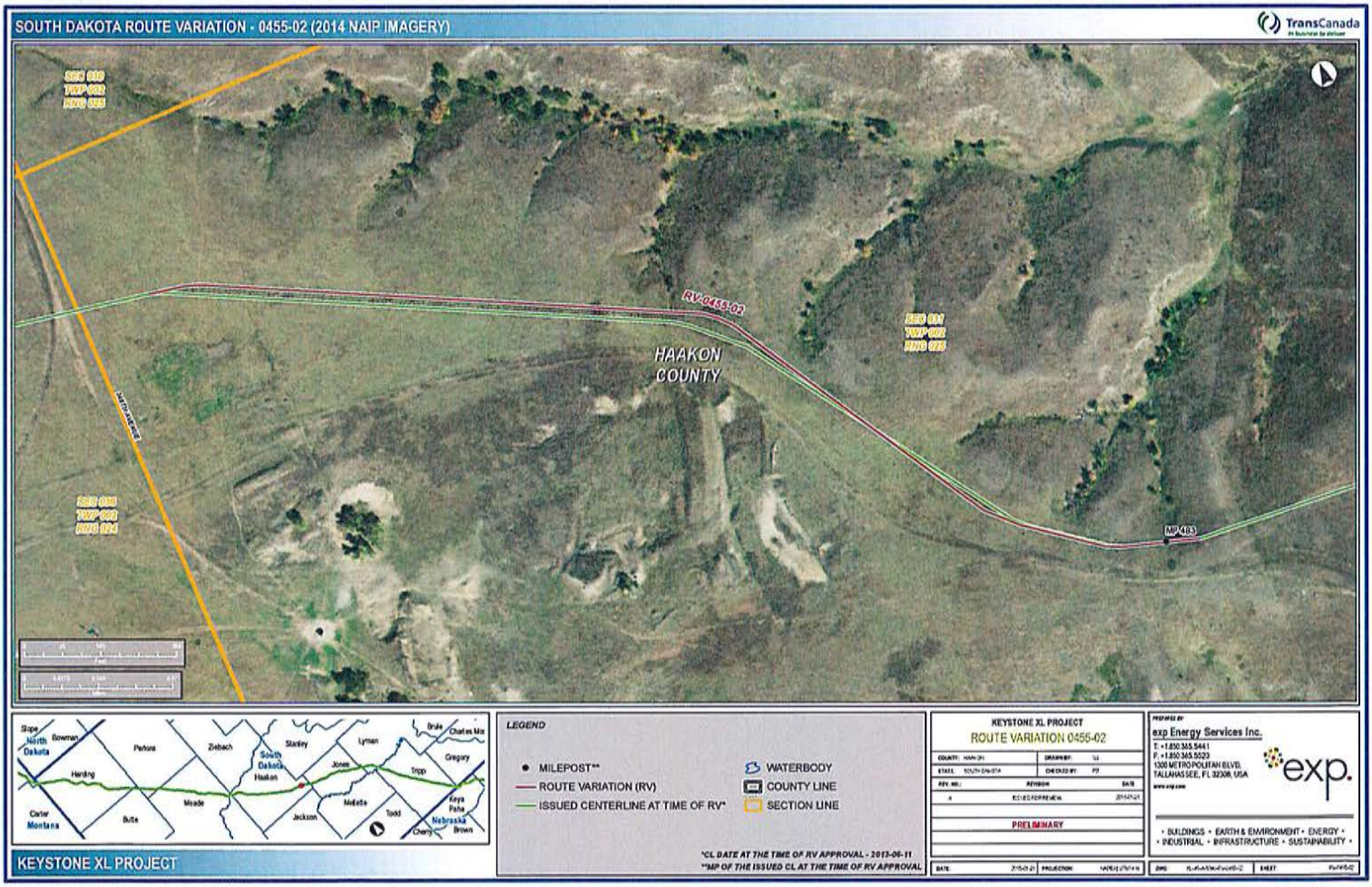

SOUTH DAKOTA ROUTE VARIATION - 0200-01 (2014 NAIP IMAGERY)
TransCanada
HAAKON COUNTY
RV-0200-01
RV-0199-08
MP 474
MP 475
MP 476
SEC 001 TWP 002 RNG 023
SEC 006 TWP 002 RNG 024
SEC 007 TWP 002 RNG 024
SEC 008 TWP 002 RNG 024
SEC 009 TWP 002 RNG 024
SEC 010 TWP 002 RNG 024
SEC 016 TWP 002 RNG 024
SEC 017 TWP 002 RNG 024
SEC 020 TWP 002 RNG 024
SEC 021 TWP 002 RNG 024
Slope
North Dakota
Bowman
Perkins
Ziebach
South Dakota
Haakon
Stanley
Lyman
Jones
Tripp
Brule
Charles Mix
Gregory
Harding
Meade
Butte
Carter
Montana
Mellette
Todd
Jackson
Keya Paha
Nebraska
Cherry
Brown
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2010-11-18
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0200-01
PRELIMINARY
PREPARED BY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

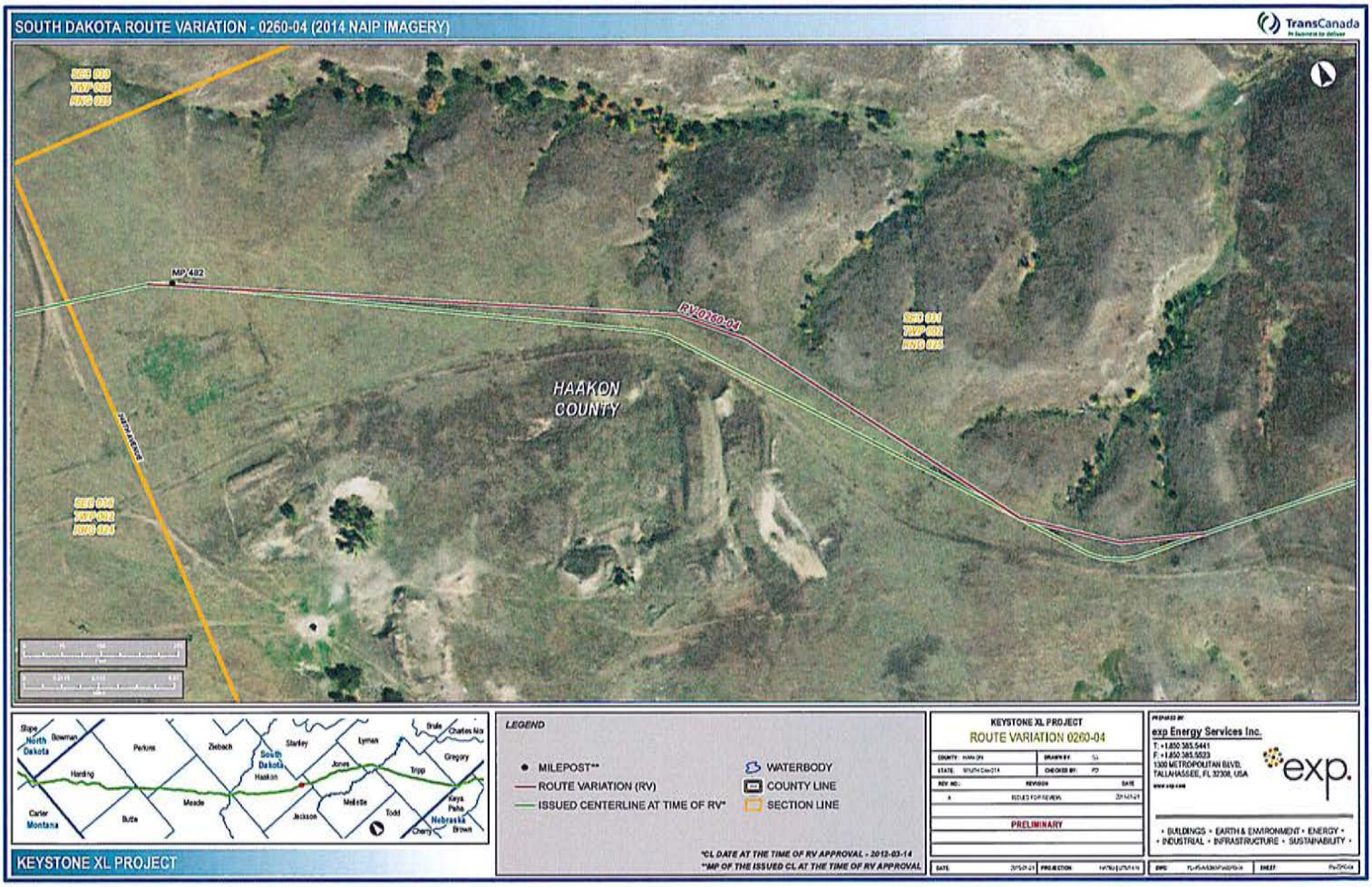

SOUTH DAKOTA ROUTE VARIATION - 0199-06 (2014 NAIP IMAGERY)
TransCanada
HAAKON
COUNTY
MP 436
RV-0199-06
SEC 07
TWP 002
RNG 014
SEC 01
TWP 002
RNG 013
SEC 12
TWP 002
RNG 014
SEC 06
TWP 002
RNG 014
SOUTH STREET
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2010-11-18
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0199-06
PRELIMINARY
KEYSTONE XL PROJECT
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5823
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •


SOUTH DAKOTA ROUTE VARIATION - 0262-01 (2014 NAIP IMAGERY)
TransCanada
SEC 08
TWP 03S
RNG 08E
MP 478
HAAKON
COUNTY
RV 0262-01
SOUTH DAKOTA
NEBRASKA
SEC 08
TWP 03S
RNG 08E
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2012-03-14
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0262-01
PRELIMINARY
KEYSTONE XL PROJECT
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5023
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •


SOUTH DAKOTA ROUTE VARIATION - 0260-01 (2014 NAIP IMAGERY)
TransCanada
HAAKON COUNTY
RV 0260-01
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-03-14
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0260-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
KEYSTONE XL PROJECT


SOUTH DAKOTA ROUTE VARIATION - 0260-02 (2014 NAIP IMAGERY)
TransCanada
HAAKON
COUNTY
RV-0260-02
SEC 035
TWP 001
RNG 024
Slope
North Dakota
Bowman
Perkins
Zeibach
South Dakota
Haakon
Stanley
Lyman
Jones
Brule
Charles Mix
Gregory
Tripp
Harding
Carter
Montana
Butte
Meade
Jackson
Mellette
Todd
Keya Paha
Nebraska
Brown
Cherry
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2012-03-14
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0260-02
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5023
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308 USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •


SOUTH DAKOTA ROUTE VARIATION - 0455-02 (2014 NAIP IMAGERY)
TransCanada
RV-0455-02
HAAKON COUNTY
MP 483
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-06-11
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0455-02
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5020
1309 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •


SOUTH DAKOTA ROUTE VARIATION - 0260-04 (2014 NAIP IMAGERY)
TransCanada
SEC 030
TWP 02S
RNG 02E
MP 482
RV-0260-04
SEC 031
TWP 02S
RNG 02E
HAAKON
COUNTY
SEC 002
TWP 03S
RNG 02E
Slope
North Dakota
Bowman
Perkins
Ziebach
Stanley
Lyman
Brule
Charles Mix
Gregory
Harding
South Dakota
Haakon
Jones
Tripp
Carter
Montana
Butte
Meade
Jackson
Mellette
Todd
Keya Paha
Nebraska
Brown
Cherry
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2012-03-14
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0260-04
PRELIMINARY
exp Energy Services Inc.
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
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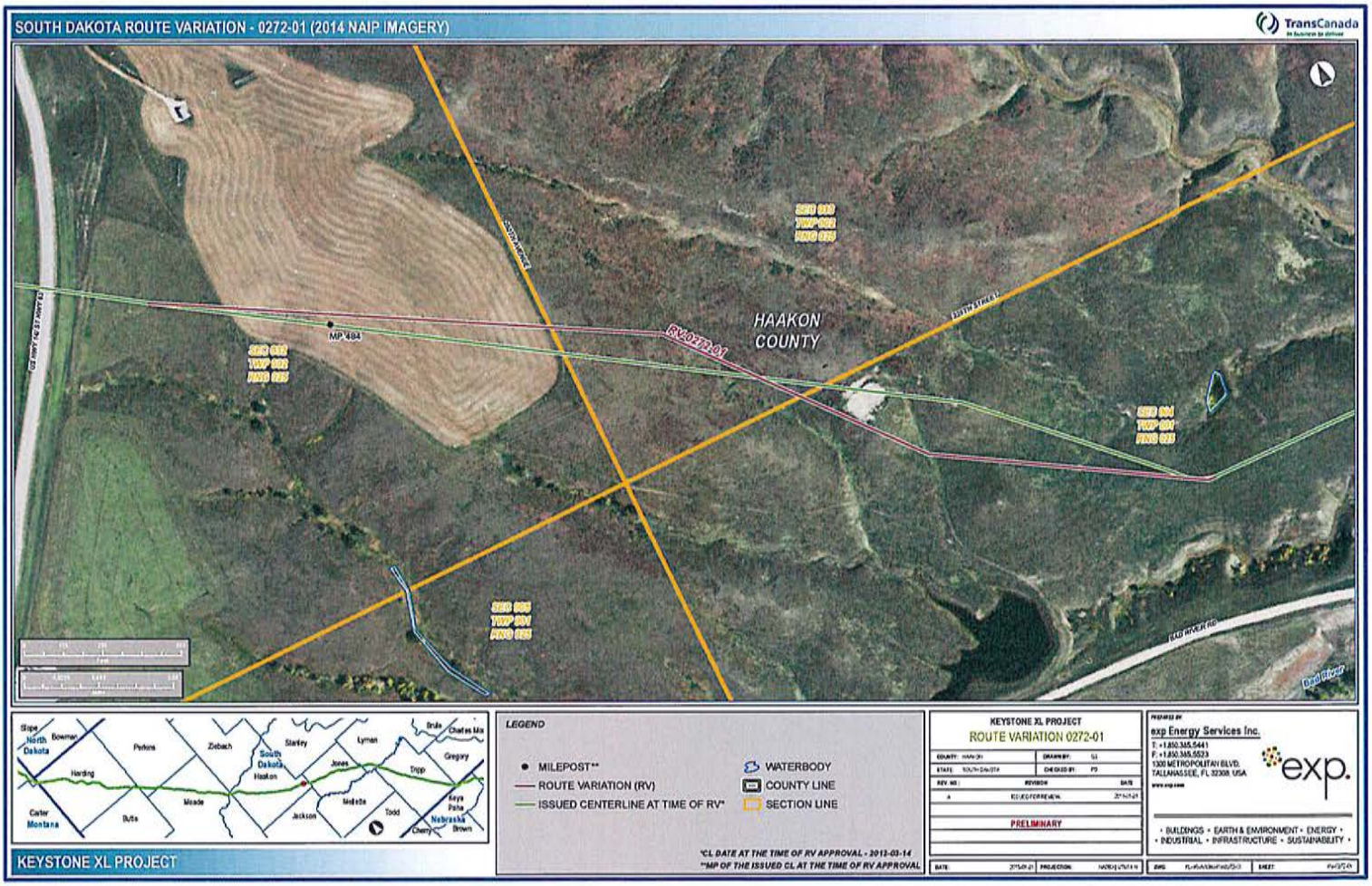
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •


SOUTH DAKOTA ROUTE VARIATION - 0272-01 (2014 NAIP IMAGERY)
TransCanada
HAAKON COUNTY
MP 484
RV-0272-01
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-03-14
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0272-01
PRELIMINARY
KEYSTONE XL PROJECT
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308 USA
www.exp.com
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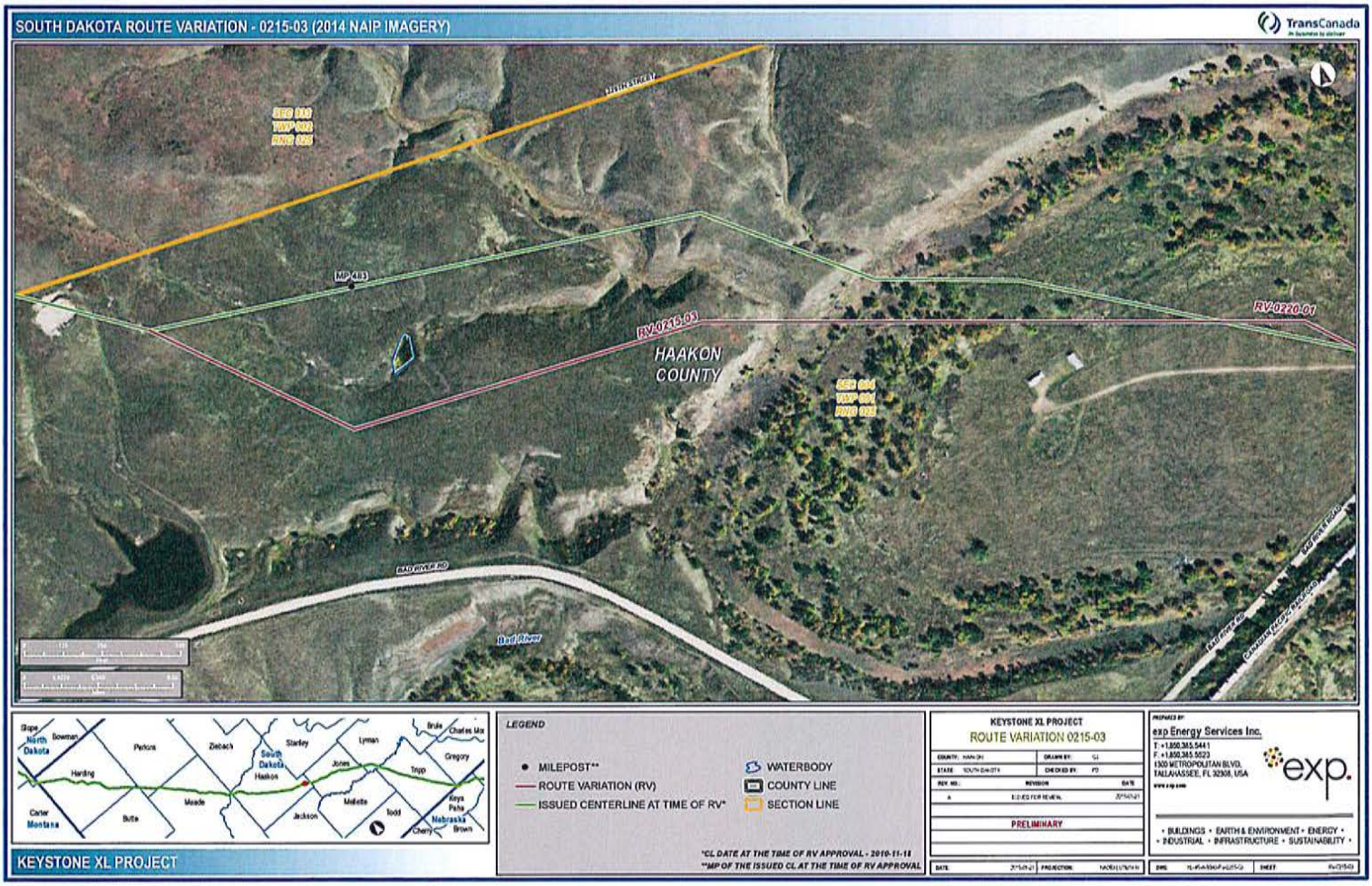
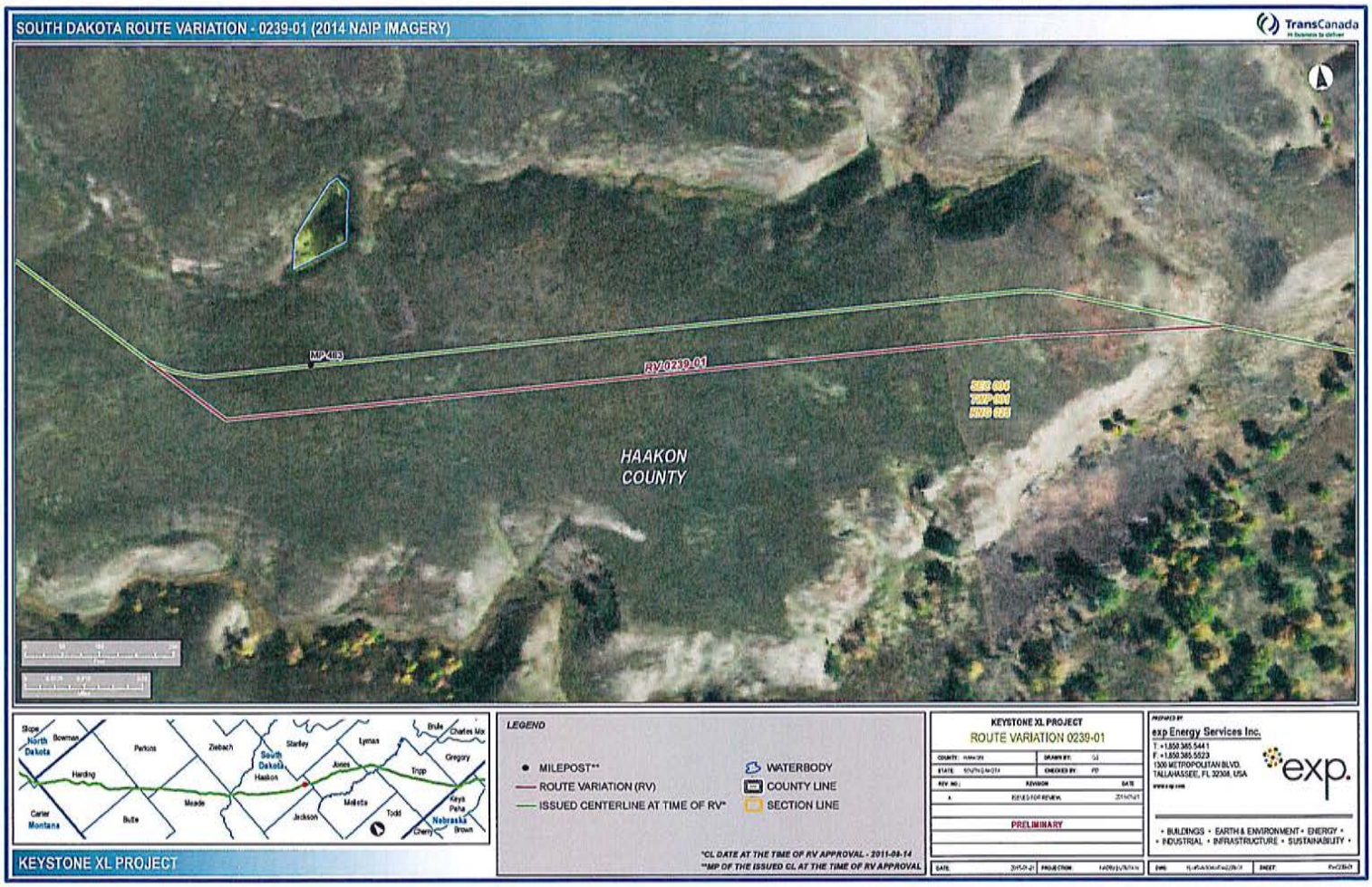
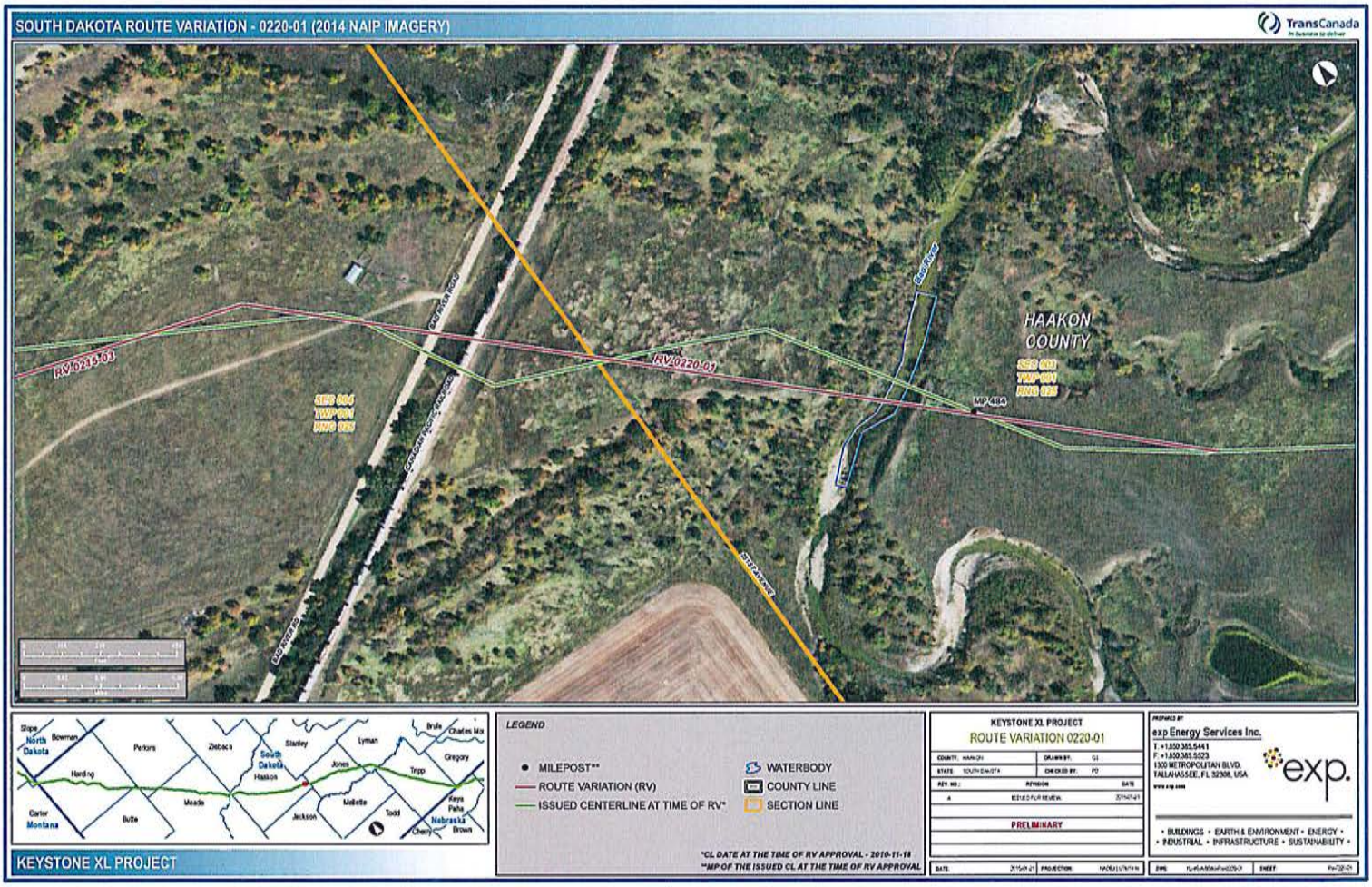
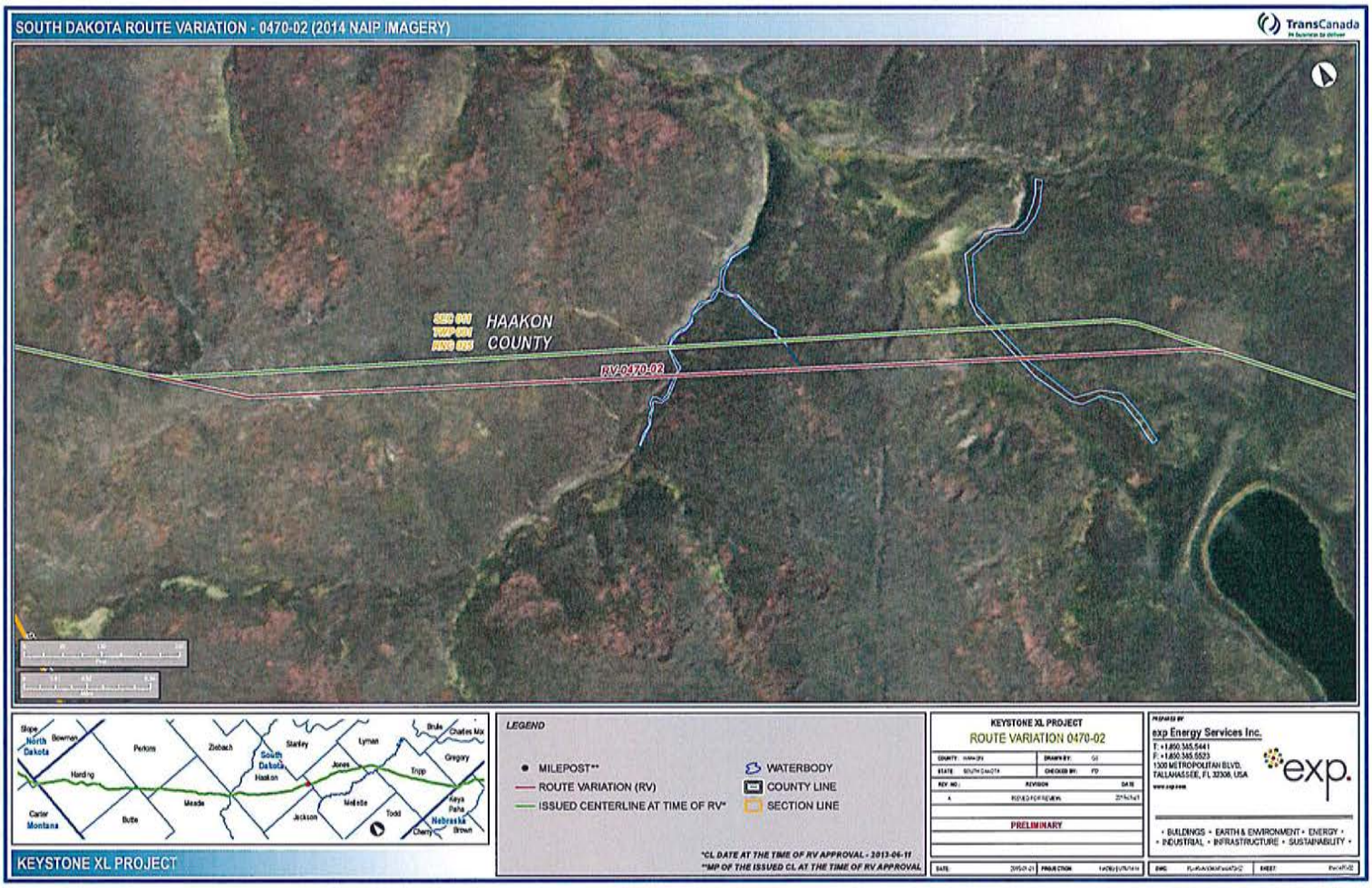
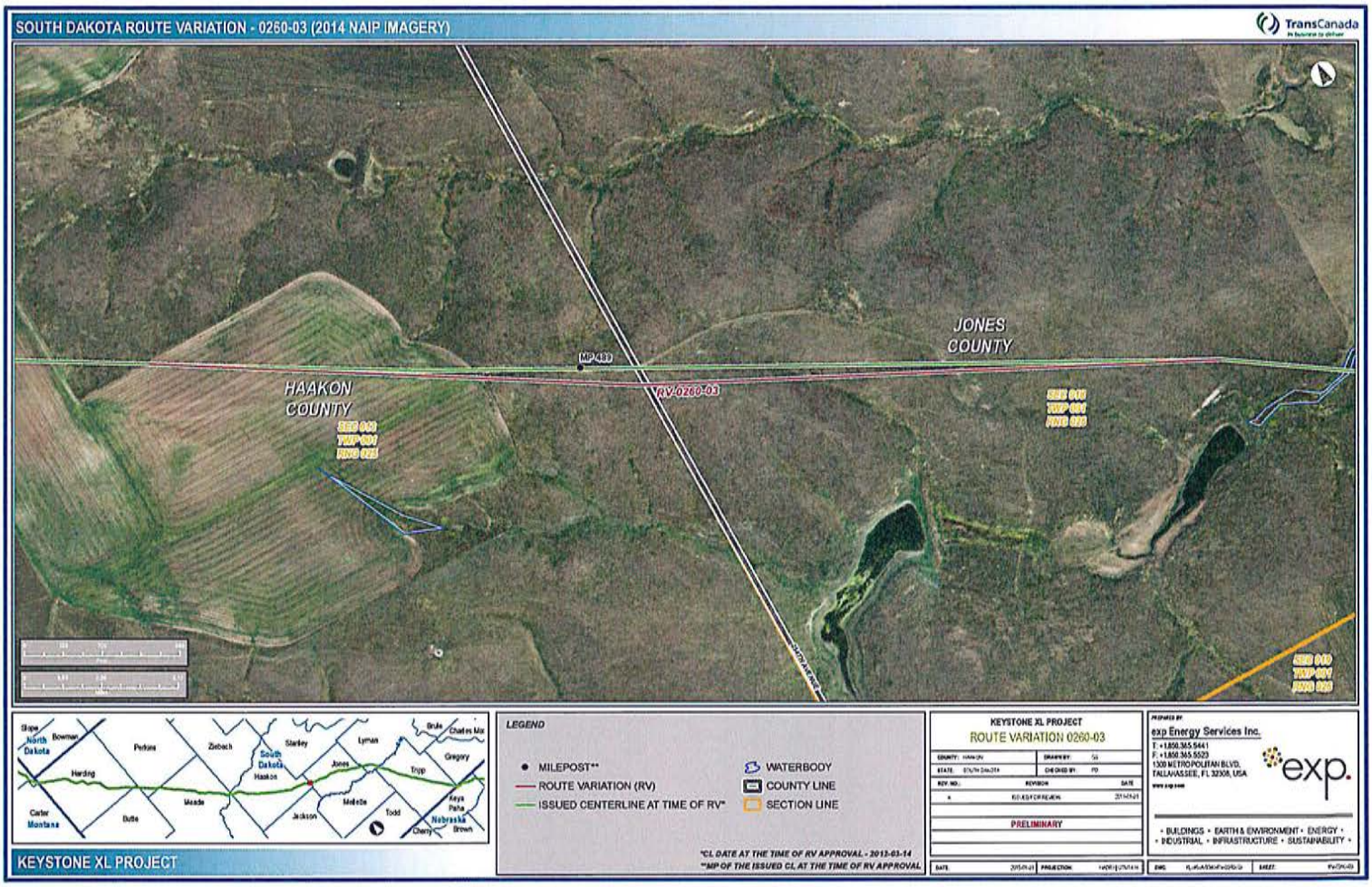
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

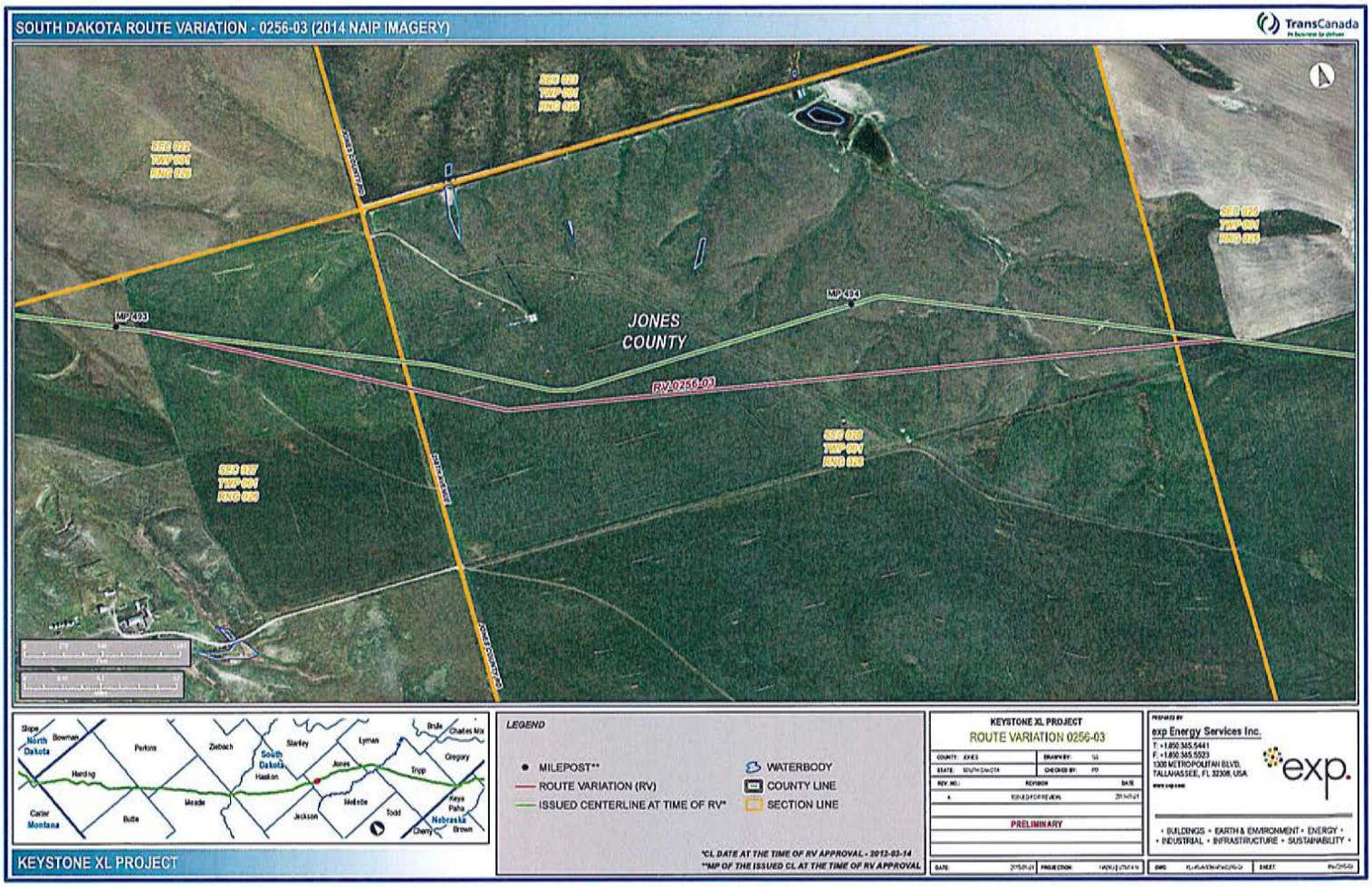

SOUTH DAKOTA ROUTE VARIATION - 0215-03 (2014 NAIP IMAGERY)
TransCanada
MP 483
RV-0215-03
RV-0220-01
HAAKON
COUNTY
BAD RIVER RD
Bad River
Slope
North Dakota
Bowman
Perkins
Ziebach
Stanley
Lyman
Brule
Charles Mix
Gregory
South Dakota
Haakon
Jones
Tripp
Harding
Carter
Montana
Butte
Meade
Jackson
Mellette
Todd
Keya Paha
Nebraska
Brown
Cherry
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2010-11-18
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0215-03
PRELIMINARY
KEYSTONE XL PROJECT
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5023
1500 METROPOLITAN BLVD,
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

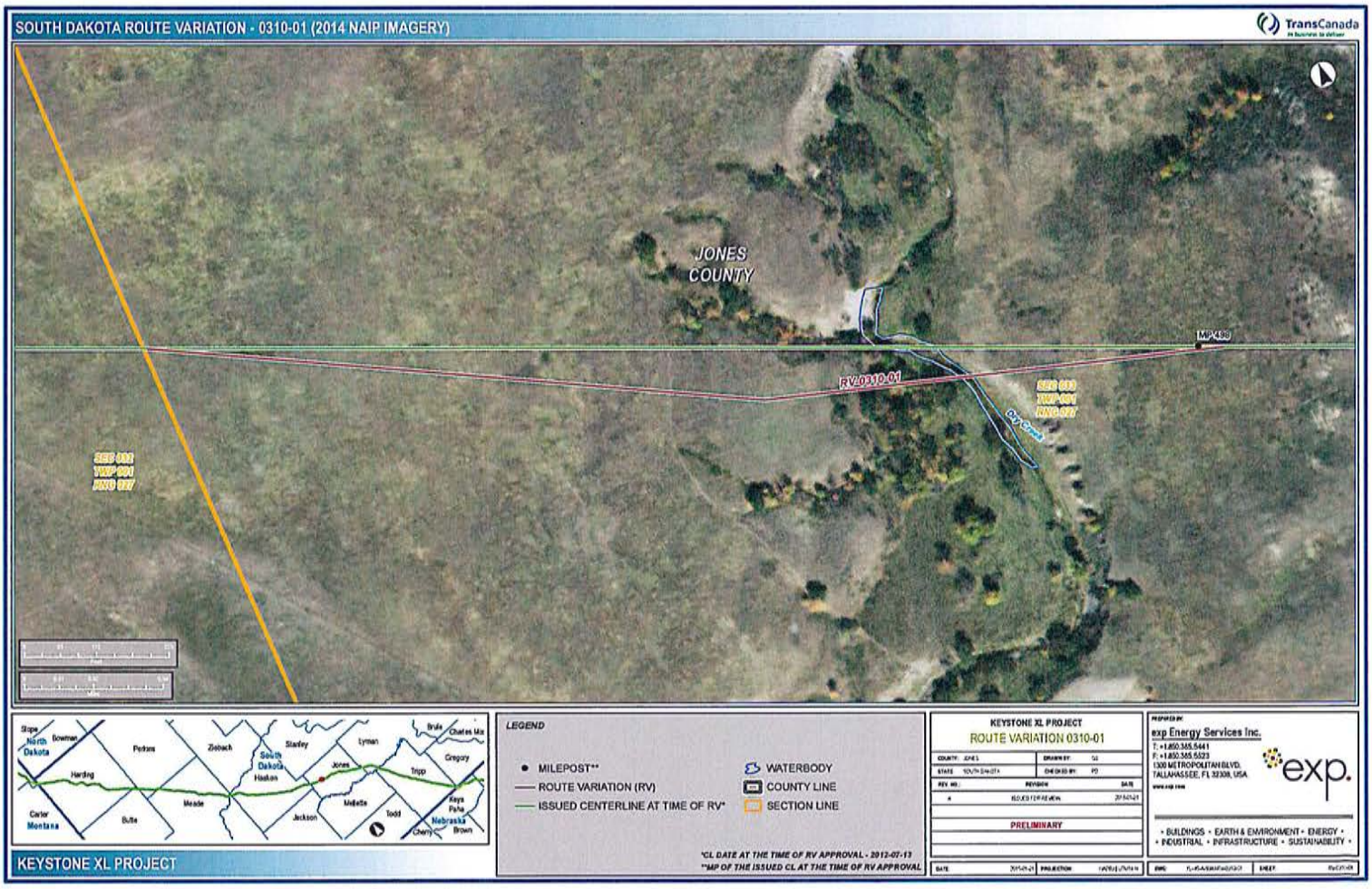

SOUTH DAKOTA ROUTE VARIATION - 0239-01 (2014 NAIP IMAGERY)
TransCanada
MP 418
RV 0239-01
HAAKON
COUNTY
Slope
North Dakota
Bowman
Perkins
Ziebach
Dewey
Corson
Walworth
Potter
Sully
Hughes
Stanley
Lyman
Brule
Charles Mix
Gregory
South Dakota
Haakon
Jones
Tripp
Harding
Meade
Butte
Jackson
Mellette
Todd
Keya Paha
Nebraska
Brown
Cherry
Carter
Montana
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2011-09-14
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0239-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

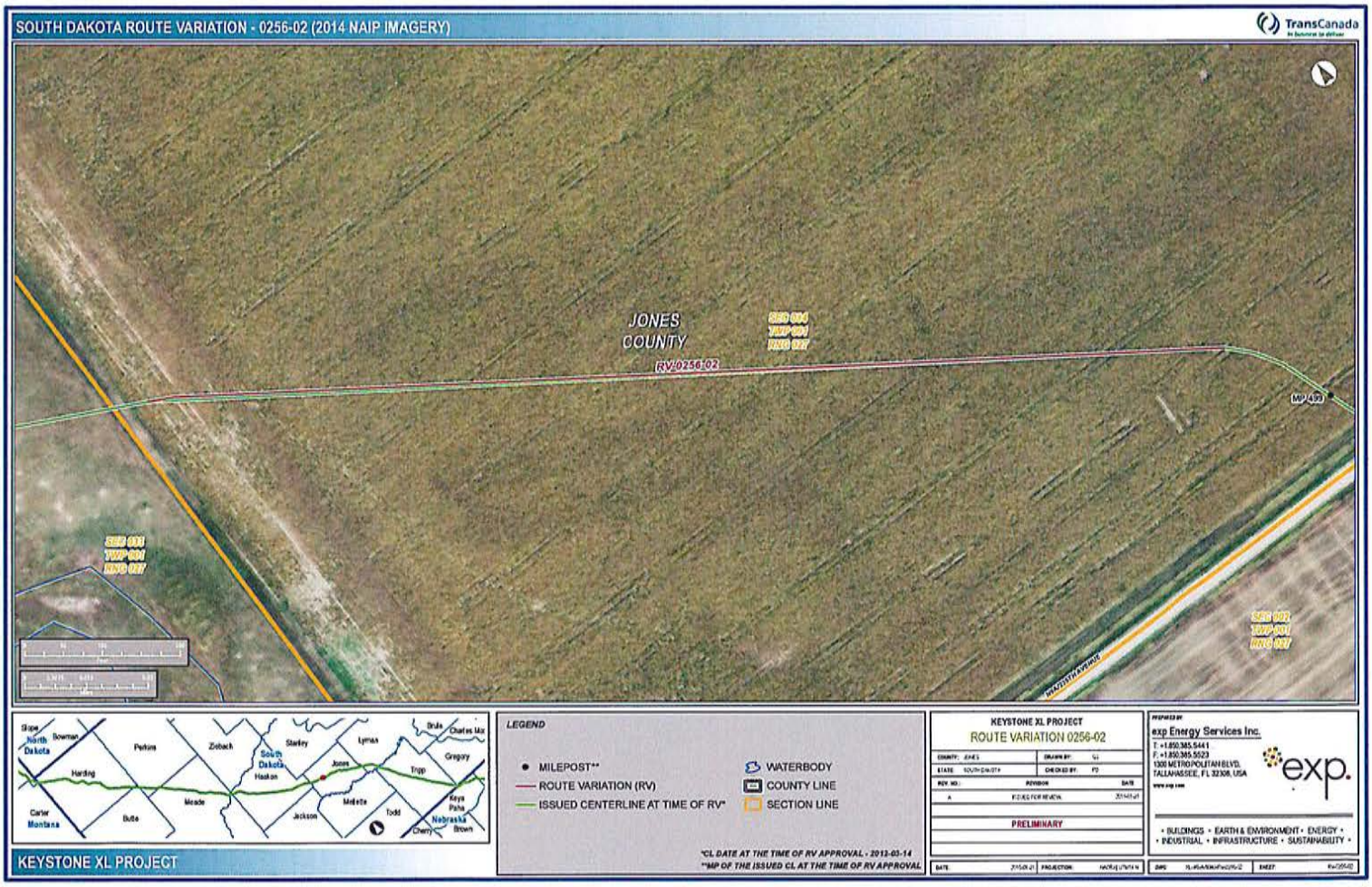

SOUTH DAKOTA ROUTE VARIATION - 0220-01 (2014 NAIP IMAGERY)
TransCanada
HAAKON COUNTY
RV 0213-03
RV 0220-01
MP 484
SEC 003
TWP 001
RNG 026
Slope
North Dakota
Bowman
Perkins
Ziebach
Stanley
Lyman
Brule
Charles Mix
Gregory
Harding
South Dakota
Haakon
Jones
Tripp
Carter
Montana
Butte
Meade
Jackson
Mellette
Todd
Tripp
Keya Paha
Nebraska
Brown
Cherry
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2010-11-19
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0220-01
PRELIMINARY
PREPARED BY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1500 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

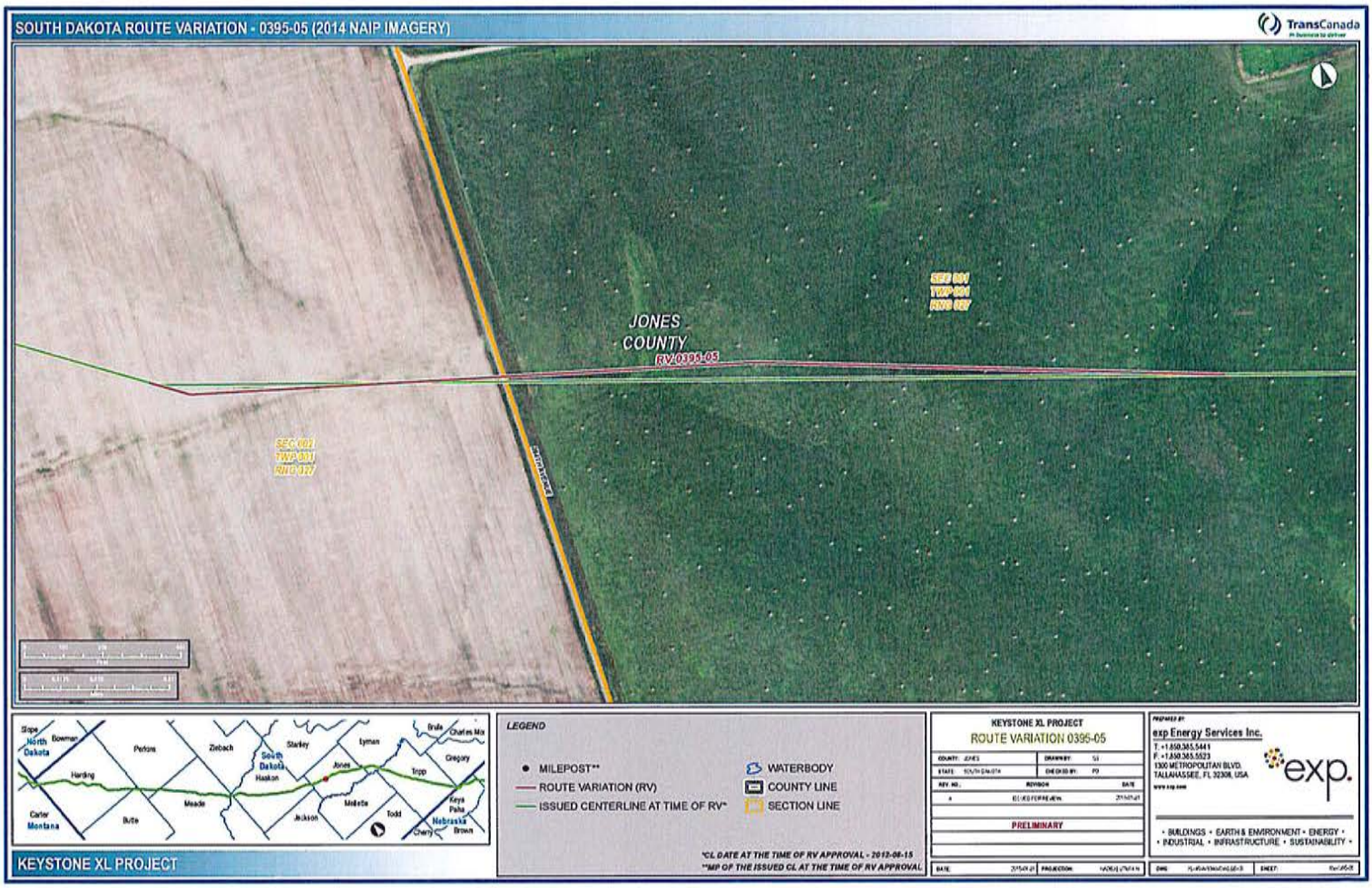

SOUTH DAKOTA ROUTE VARIATION - 0470-02 (2014 NAIP IMAGERY)
TransCanada
HAAKON
COUNTY
RV-0470-02
Slope
Bowman
North Dakota
Perkins
Ziebach
Stanley
Lyman
Brule
Charles Mix
Gregory
Harding
South Dakota
Haakon
Jones
Tripp
Carter
Montana
Butte
Meade
Jackson
Mellette
Todd
Keya Paha
Nebraska
Brown
Cherry
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-06-11
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0470-02
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

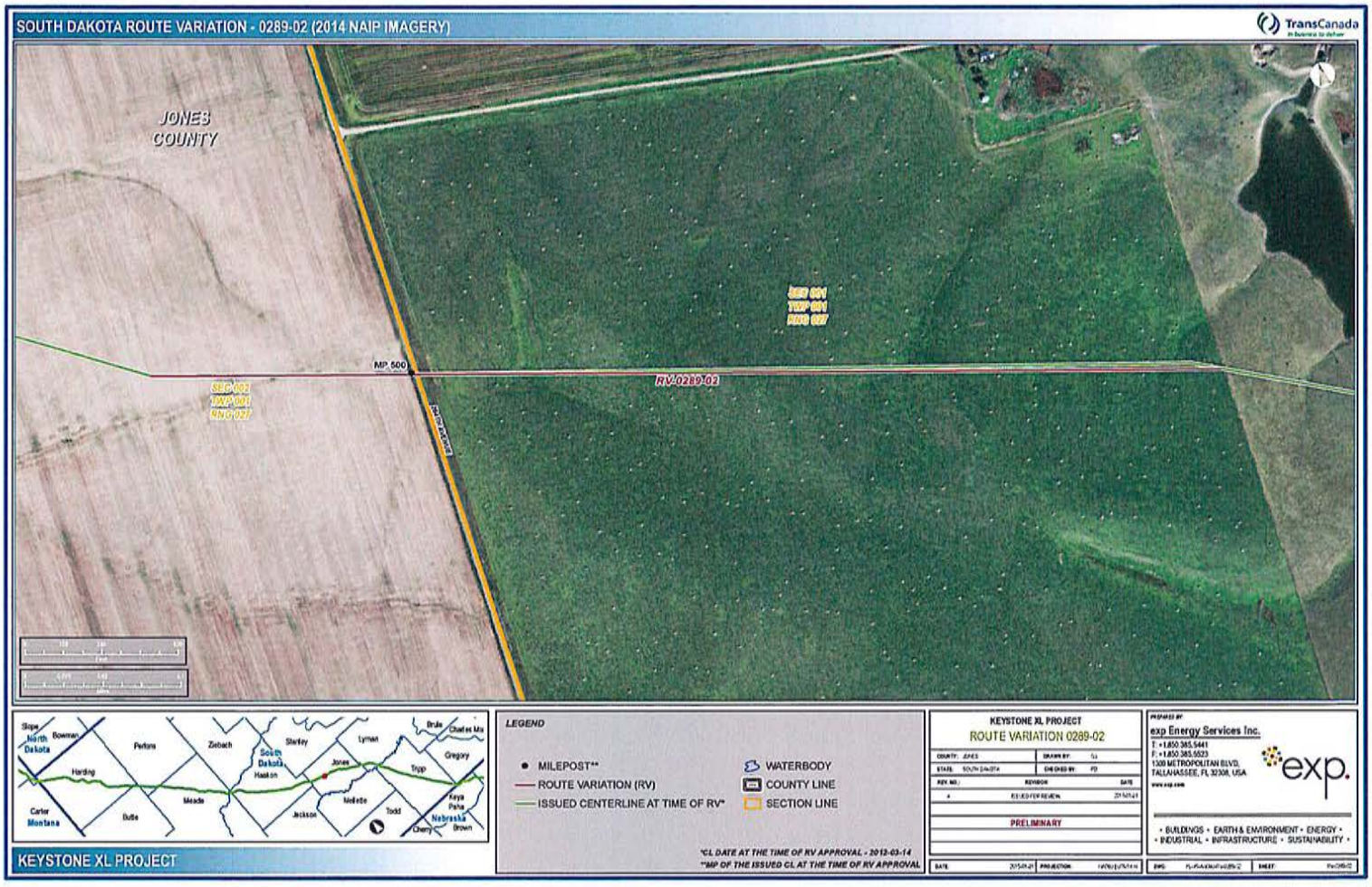

SOUTH DAKOTA ROUTE VARIATION - 0260-03 (2014 NAIP IMAGERY)
TransCanada
JONES COUNTY
HAAKON COUNTY
MP 439
RV-0260-03
SEC 010
TWP 001
RNG 028
SEC 003
TWP 001
RNG 025
SOUTH DAKOTA
NEBRASKA
Slope
Bowman
North Dakota
Perkins
Ziebach
South Dakota
Haakon
Stanley
Jones
Lyman
Brule
Charles Mix
Gregory
Tripp
Harding
Meade
Butte
Carter
Montana
Mellette
Todd
Jackson
Keya Paha
Nebraska
Brown
Cherry
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-03-14
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0260-03
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1309 METROPOLITAN BLVD,
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
KEYSTONE XL PROJECT

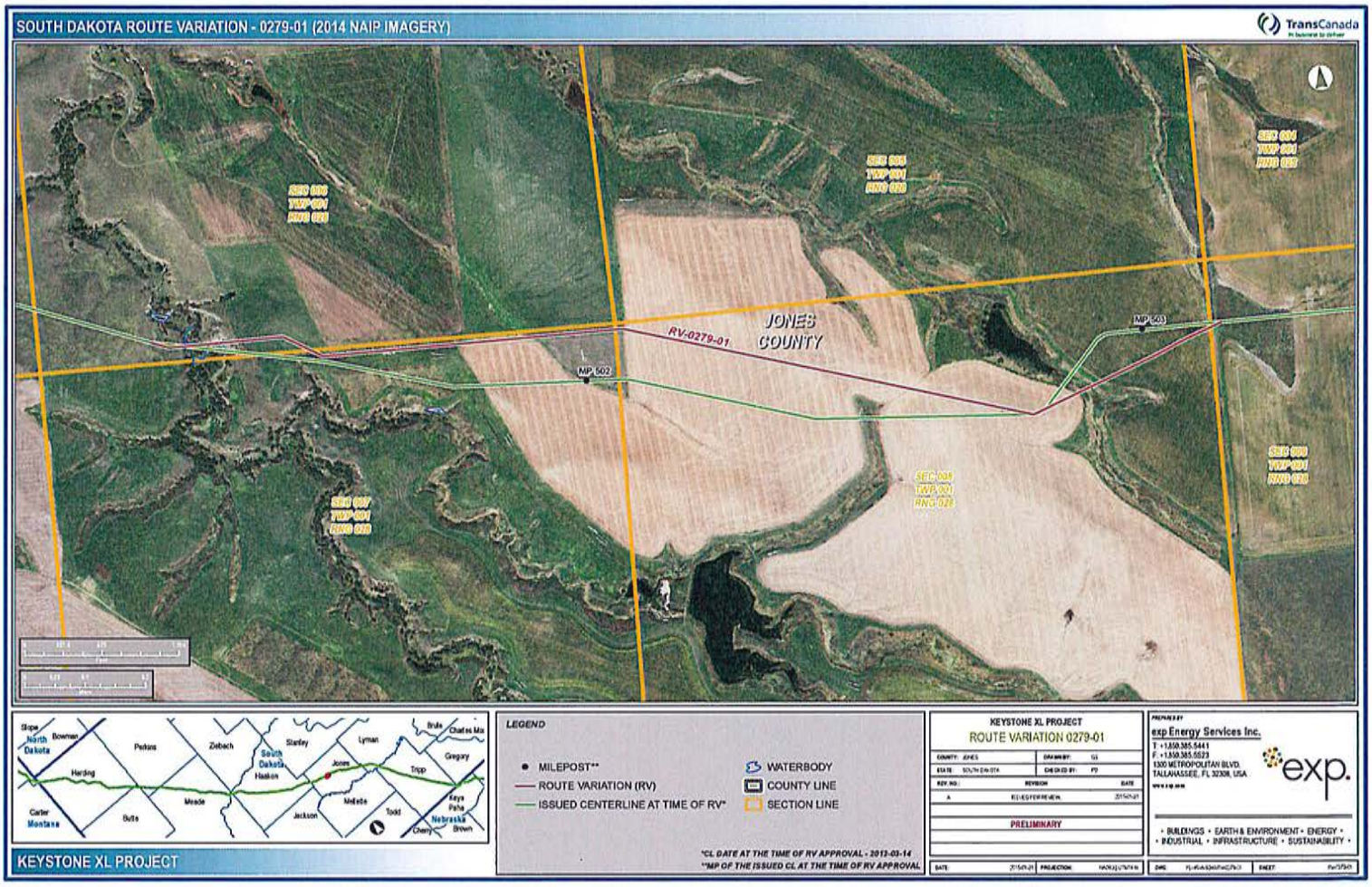

SOUTH DAKOTA ROUTE VARIATION - 0256-03 (2014 NAIP IMAGERY)
TransCanada
JONES COUNTY
MP 493
MP 494
RV 0256-03
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-03-14
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0256-03
PRELIMINARY
KEYSTONE XL PROJECT
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

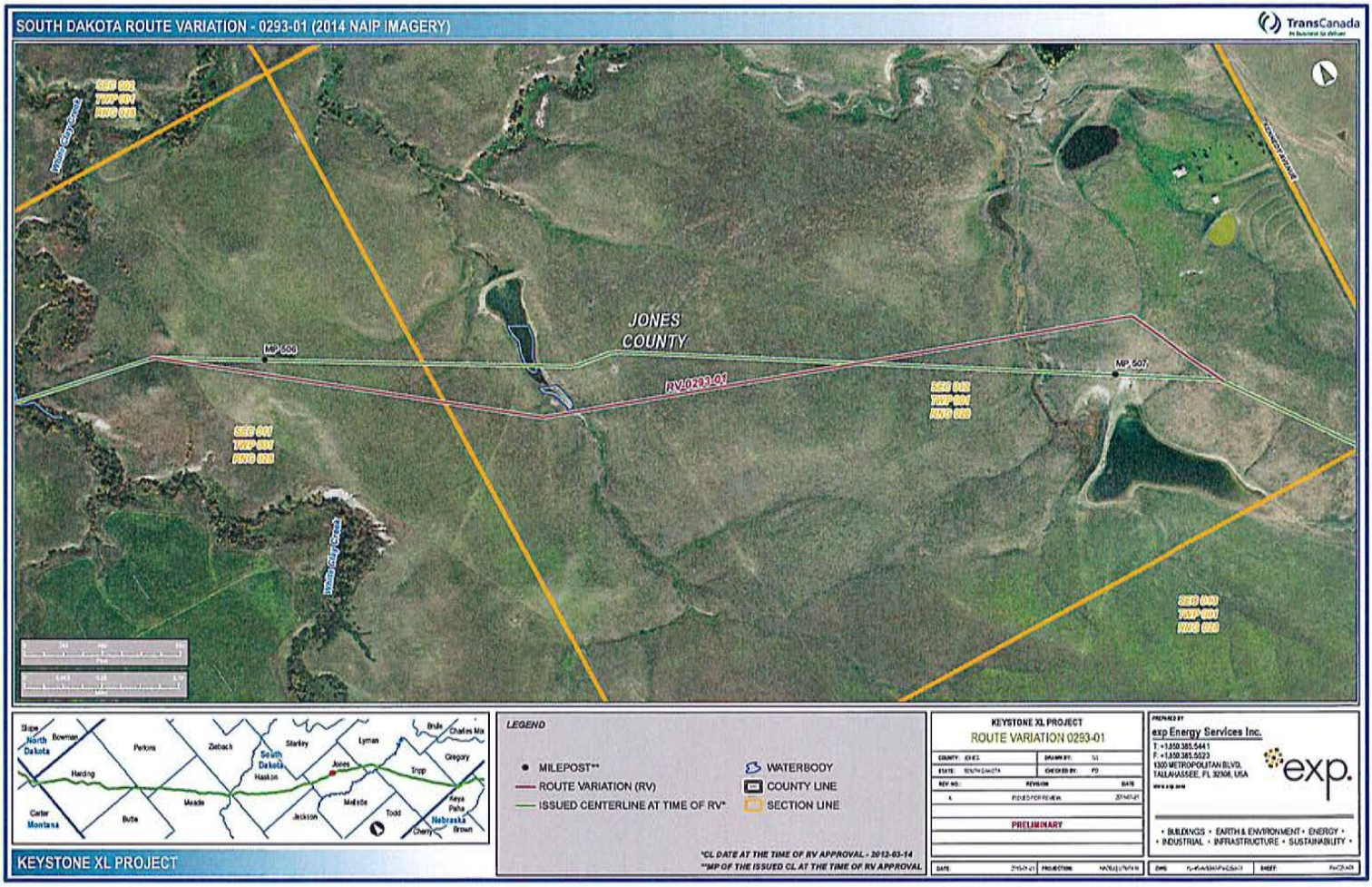

SOUTH DAKOTA ROUTE VARIATION - 0310-01 (2014 NAIP IMAGERY)
TransCanada
JONES COUNTY
MP 490
RV-0310-01
SEC 033
TWP 001
RNG 027
Dry Creek
SEC 033
TWP 001
RNG 027
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2012-07-13
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0310-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
KEYSTONE XL PROJECT

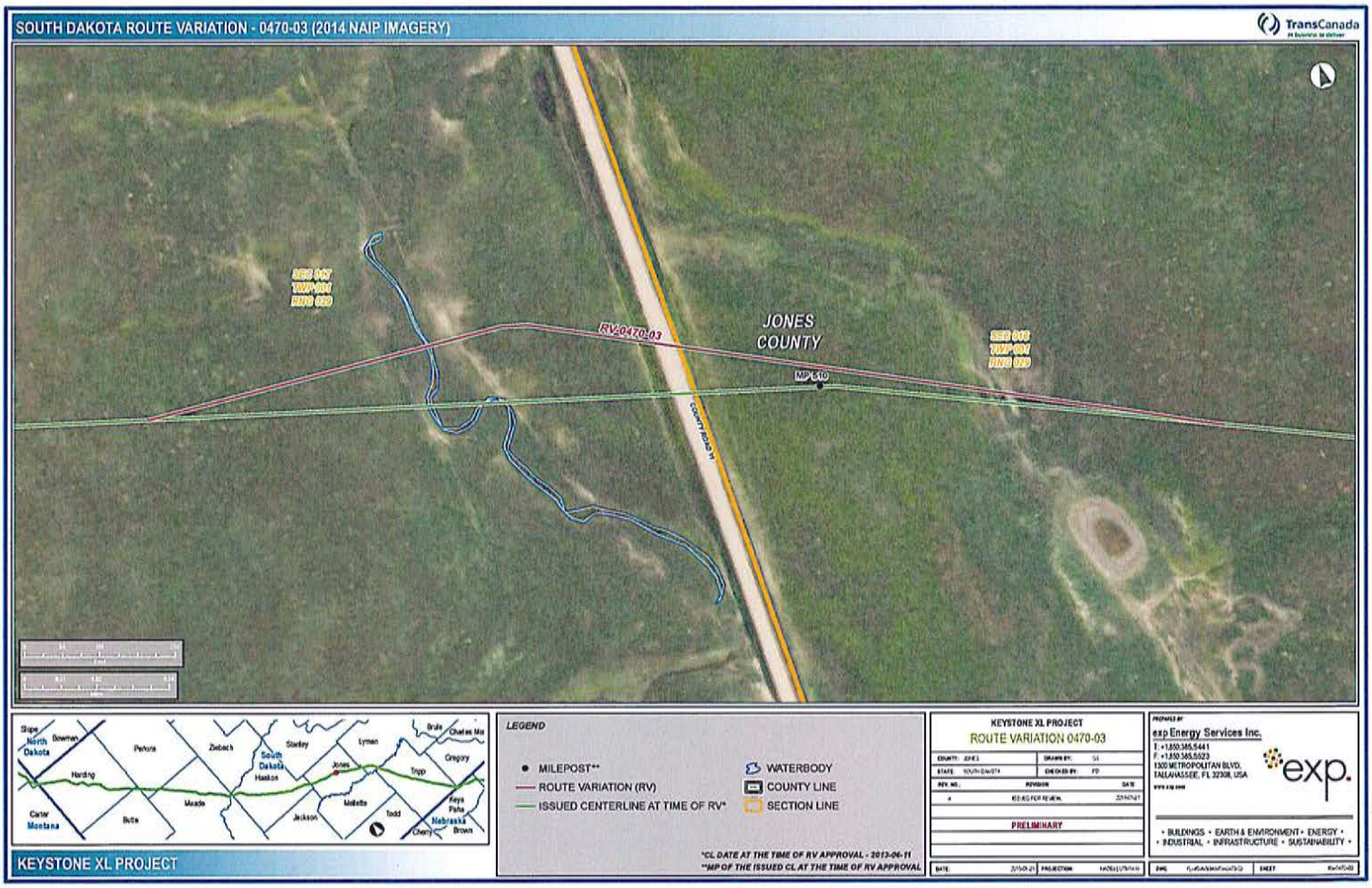

SOUTH DAKOTA ROUTE VARIATION - 0256-02 (2014 NAIP IMAGERY)
TransCanada
JONES COUNTY
RV-0256-02
MP 439
SEC 004 TWP 001 RNG 027
SEC 003 TWP 001 RNG 027
SEC 002 TWP 001 RNG 027
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-03-14
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0256-02
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
+ BUILDINGS + EARTH & ENVIRONMENT + ENERGY +
+ INDUSTRIAL + INFRASTRUCTURE + SUSTAINABILITY +

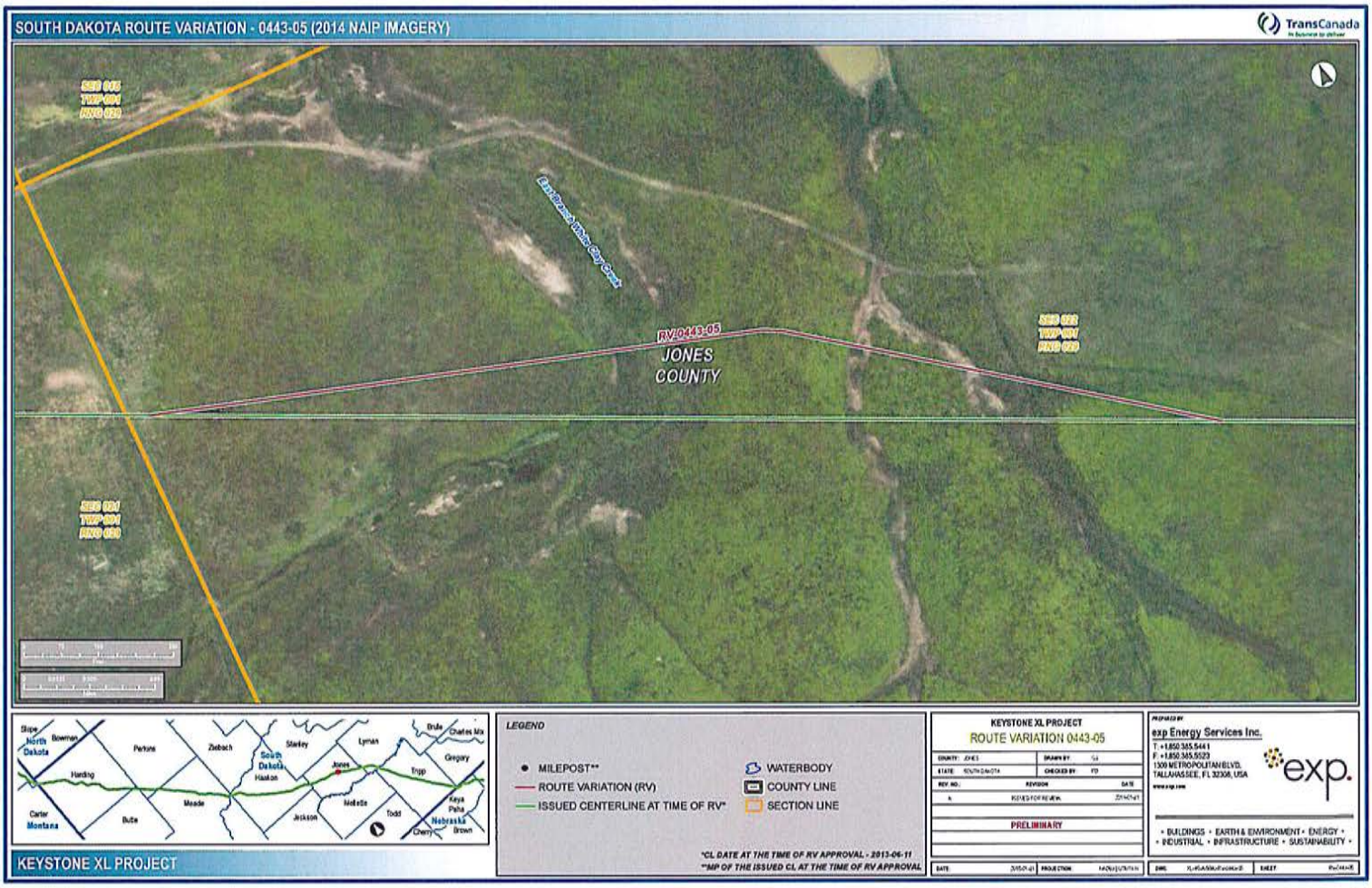

SOUTH DAKOTA ROUTE VARIATION - 0395-05 (2014 NAIP IMAGERY)
TransCanada
JONES
COUNTY
RV 0395-05
SEC 001
TWP 001
RNG 027
SEC 001
TWP 001
RNG 027
SHORTCUT
Slope
North Dakota
Bowman
Perkins
Ziebach
Stanley
Lyman
Brule
Charles Mix
Gregory
Tripp
Jones
Haakon
South Dakota
Harding
Meade
Butte
Carter
Montana
Jackson
Mellette
Todd
Keya Paha
Nebraska
Brown
Cherry
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2012-08-15
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0395-05
PRELIMINARY
KEYSTONE XL PROJECT
exp Energy Services Inc.
T. +1.850.385.5441
F. +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

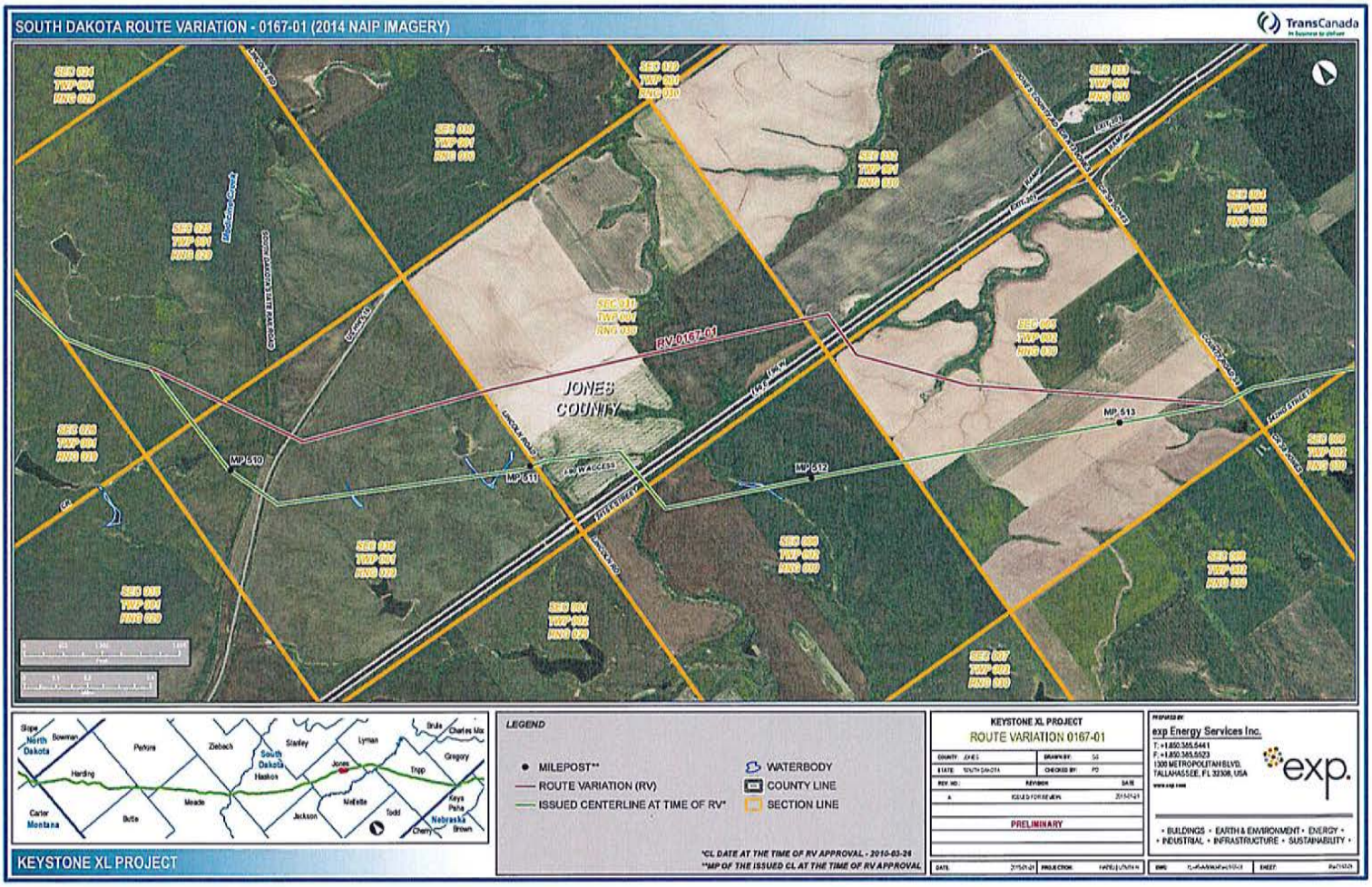

SOUTH DAKOTA ROUTE VARIATION - 0289-02 (2014 NAIP IMAGERY)
TransCanada
JONES COUNTY
SEC 001
TWP 001
RNG 027
MP 500
RV-0289-02
SEC 002
TWP 001
RNG 027
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2012-03-14
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0289-02
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1309 METROPOLITAN BLVD,
TALLAHASSEE, FL 32308, USA
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
KEYSTONE XL PROJECT

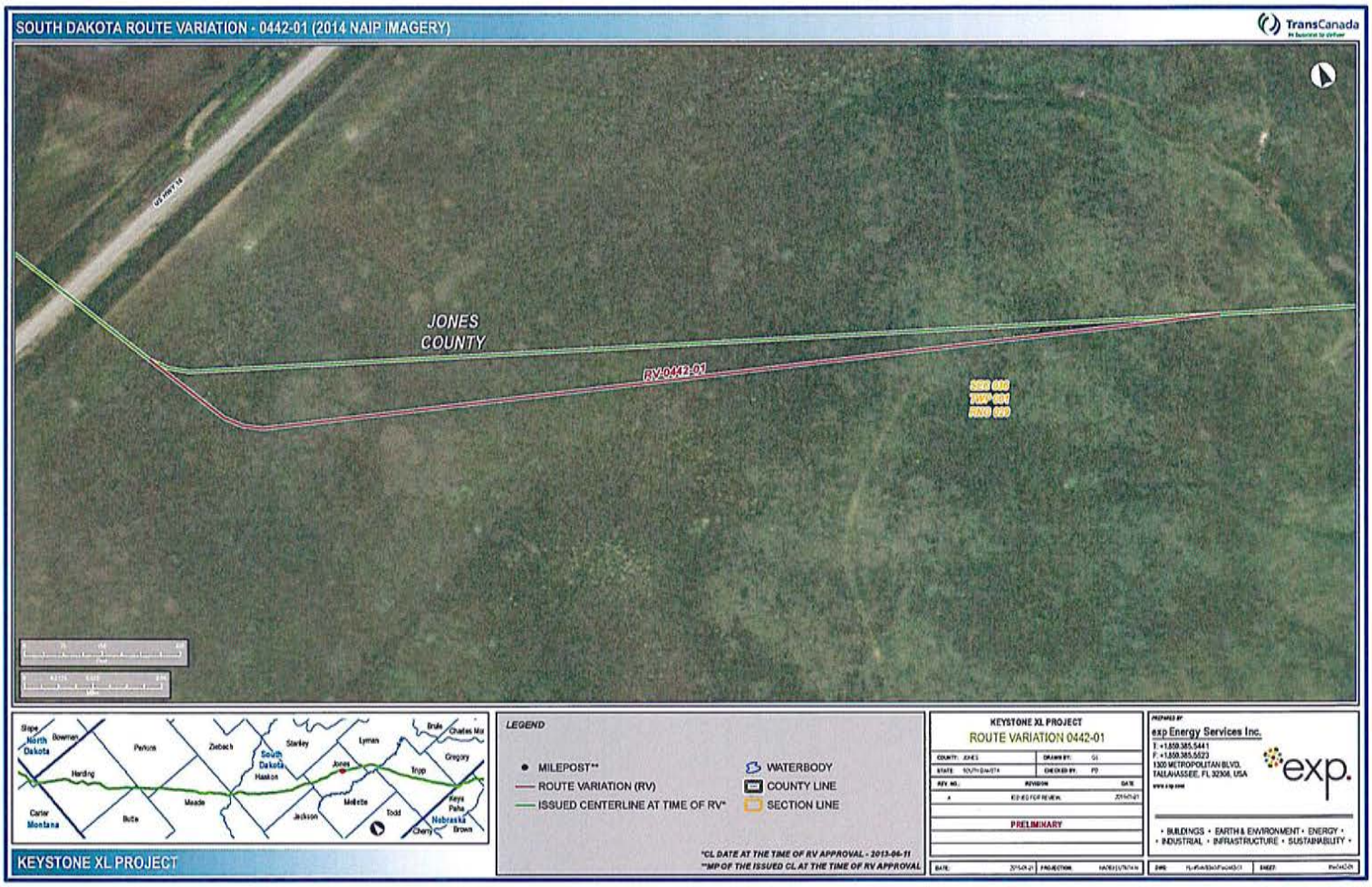

SOUTH DAKOTA ROUTE VARIATION - 0279-01 (2014 NAIP IMAGERY)
TransCanada
JONES COUNTY
RV-0279-01
MP 502
MP 503
SEC 006 TWP 001 RNG 028
SEC 005 TWP 001 RNG 028
SEC 004 TWP 001 RNG 028
SEC 007 TWP 001 RNG 028
SEC 008 TWP 001 RNG 028
SEC 009 TWP 001 RNG 028
Slope
Bowman
North Dakota
Perkins
Ziebach
Stanley
Lyman
Brule
Charles Mix
South Dakota
Harding
Haakon
Jones
Tripp
Gregory
Carter
Montana
Butte
Meade
Jackson
Mellette
Todd
Keya Paha
Nebraska
Cherry
Brown
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-03-14
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0279-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

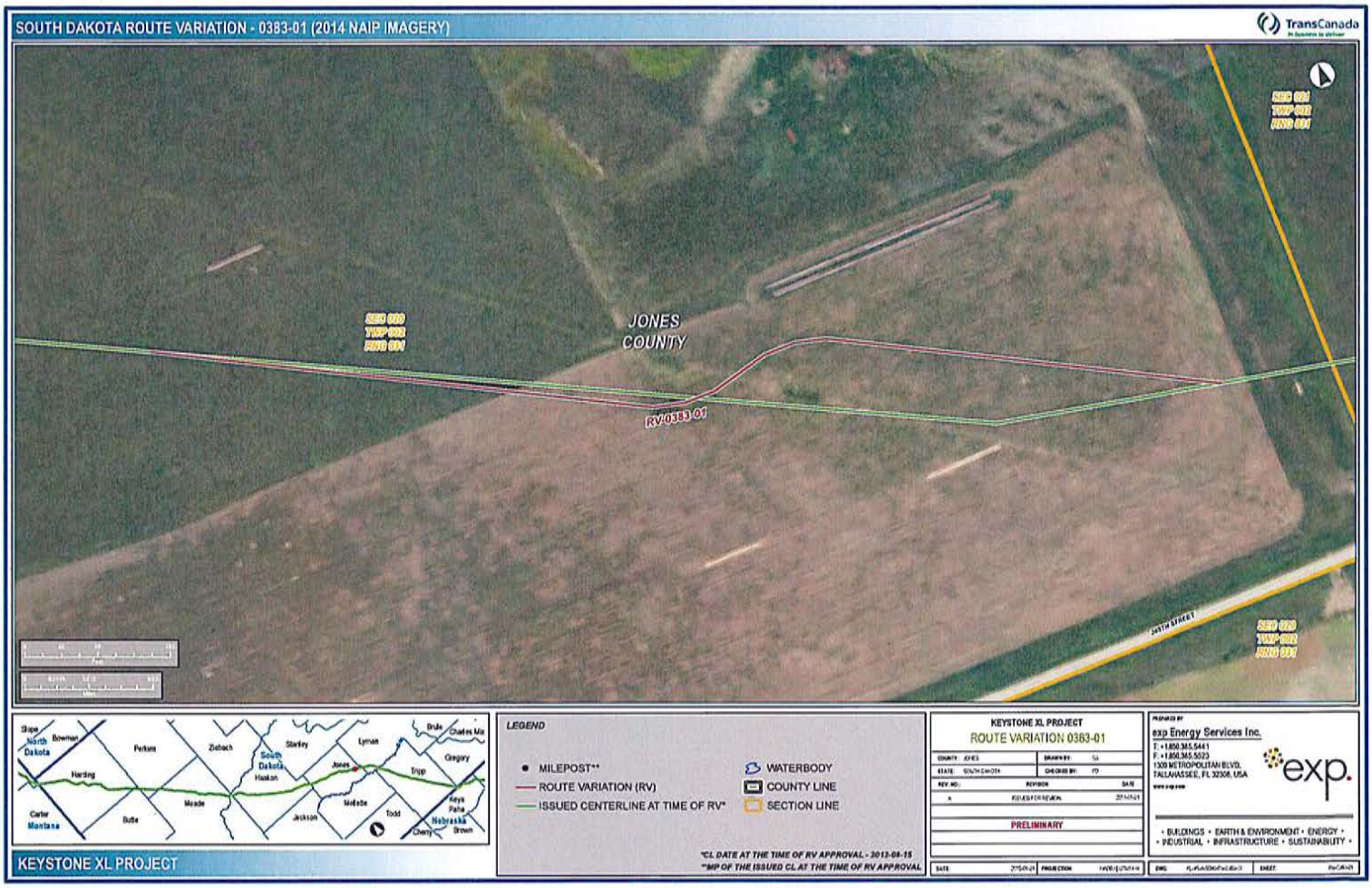

SOUTH DAKOTA ROUTE VARIATION - 0293-01 (2014 NAIP IMAGERY)
TransCanada
JONES COUNTY
MP 506
MP 507
RV:0293-01
SEC 002 TWP 001 RNG 028
SEC 001 TWP 001 RNG 028
SEC 011 TWP 001 RNG 028
White Clay Creek
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2012-03-14
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0293-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5023
1320 METROPOLITAN BLVD,
TALLAHASSEE, FL 32308, USA
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
KEYSTONE XL PROJECT

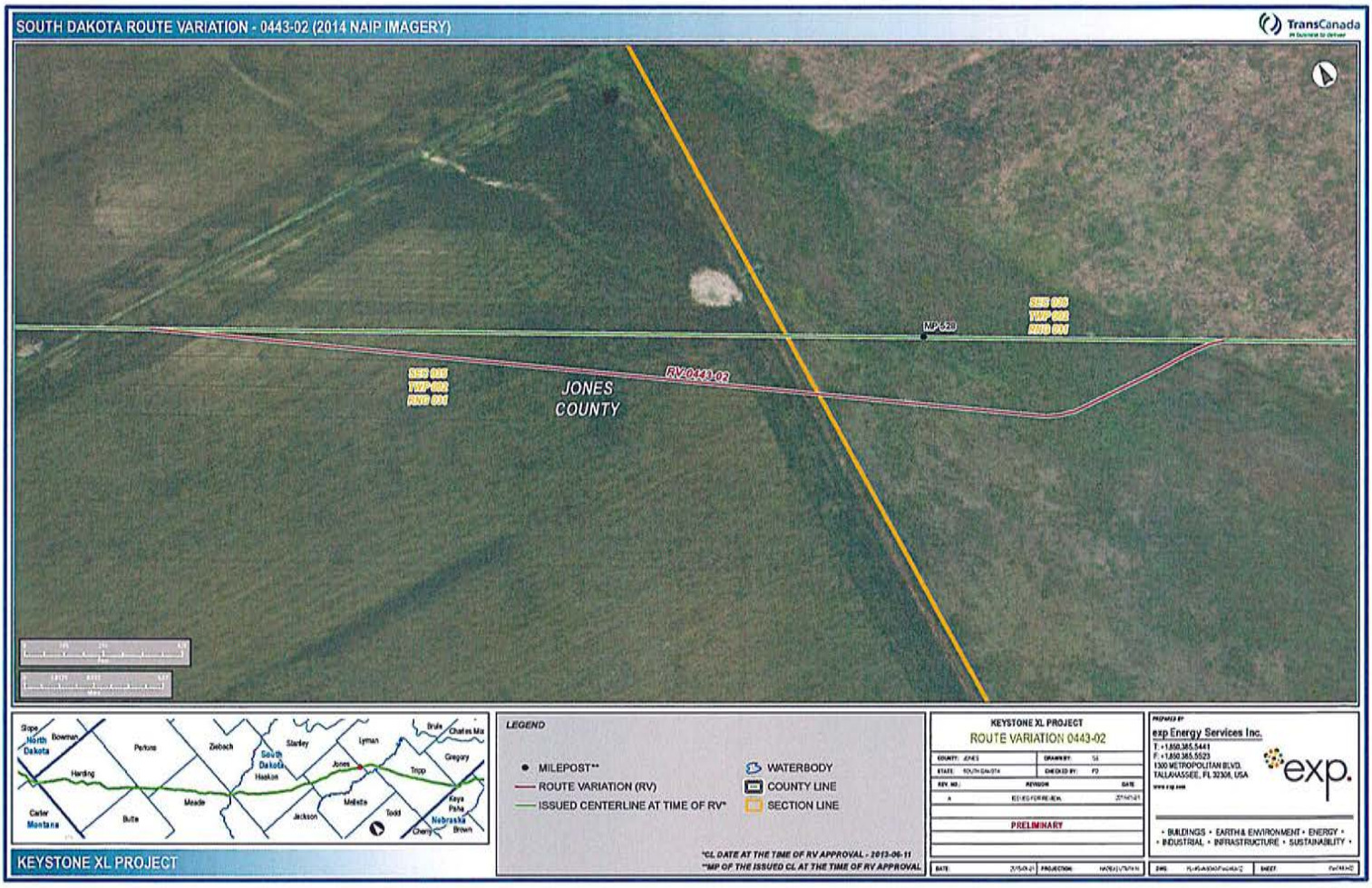

SOUTH DAKOTA ROUTE VARIATION - 0470-03 (2014 NAIP IMAGERY)
TransCanada
SEC 047
TWP 00N
RNG 00E
RV-0470-03
JONES
COUNTY
MP 510
SEC 005
TWP 00N
RNG 00E
County Road 1
Slope
North Dakota
Bowman
Perkins
Zeibach
Stanley
Lyman
Brule
Charles Mix
Gregory
Harding
South Dakota
Haakon
Jones
Tripp
Carter
Montana
Butte
Meade
Jackson
Mellette
Todd
Keya Paha
Nebraska
Brown
Cherry
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-06-11
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0470-03
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1320 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

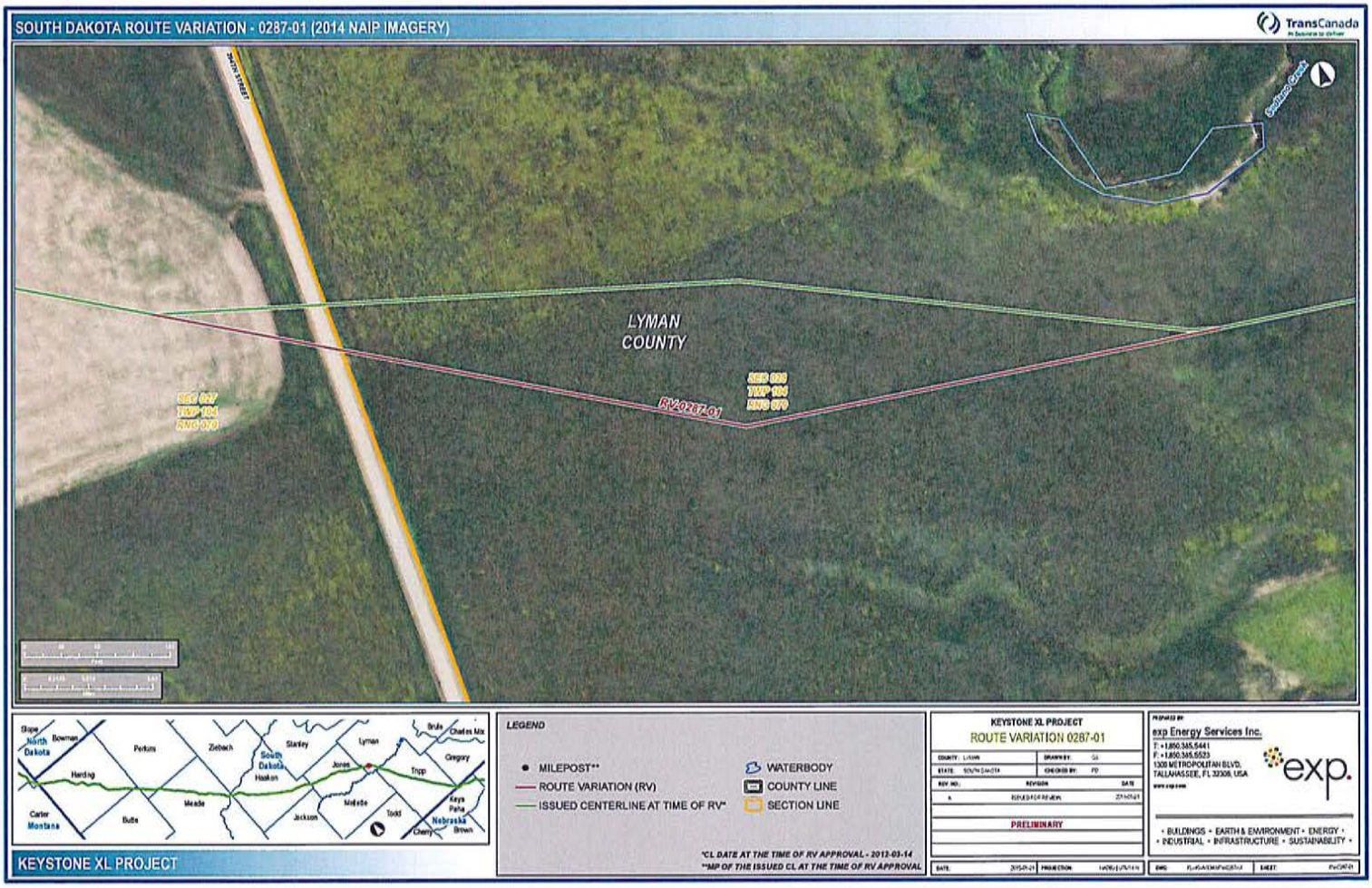

SOUTH DAKOTA ROUTE VARIATION - 0443-05 (2014 NAIP IMAGERY)
TransCanada
RV 0443-05
JONES
COUNTY
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-06-11
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0443-05
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
+ BUILDINGS + EARTH & ENVIRONMENT + ENERGY +
+ INDUSTRIAL + INFRASTRUCTURE + SUSTAINABILITY +
KEYSTONE XL PROJECT

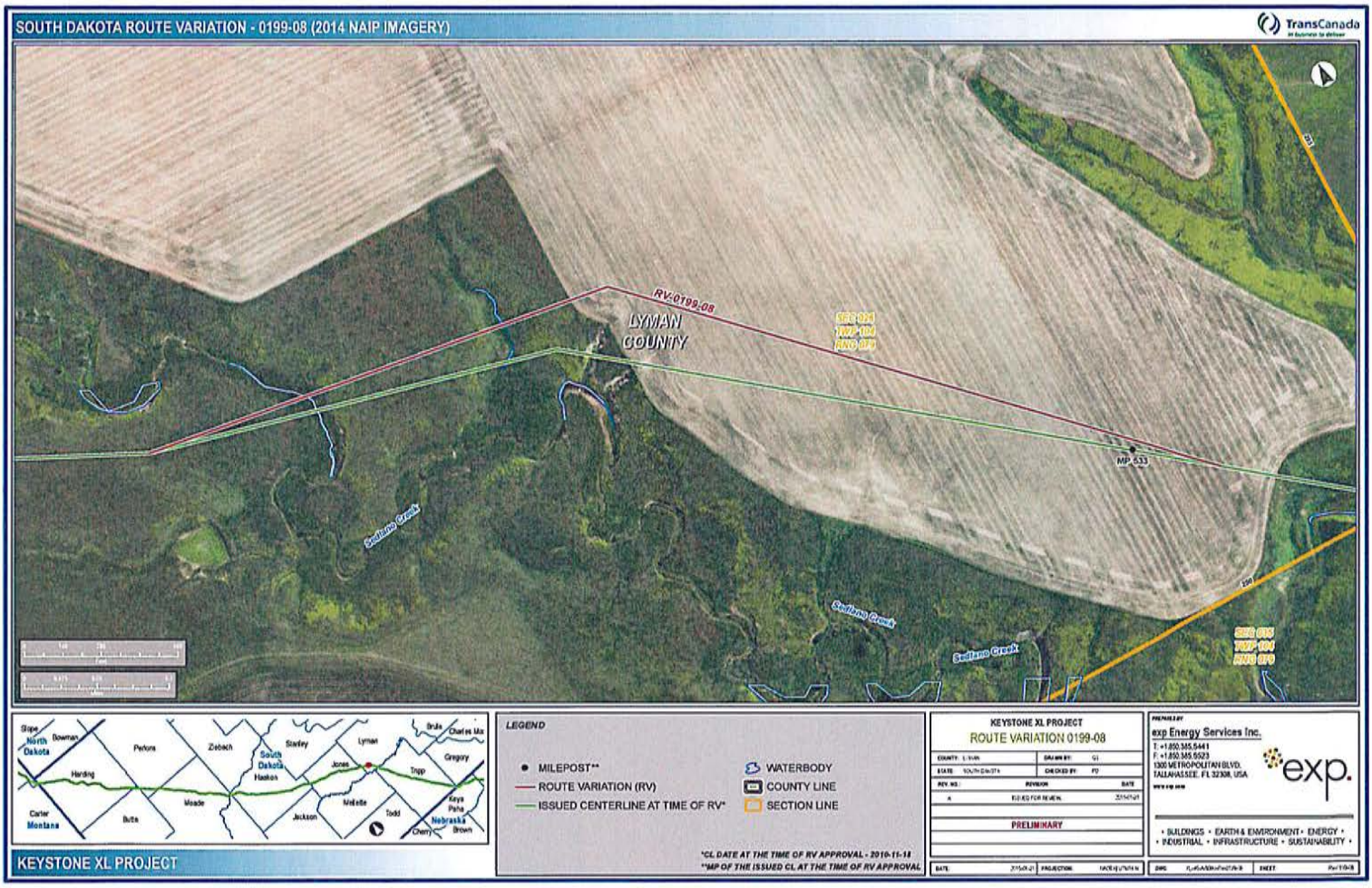

SOUTH DAKOTA ROUTE VARIATION - 0167-01 (2014 NAIP IMAGERY)
TransCanada
RV-0167-01
JONES COUNTY
MP 510
MP 511
MP 512
MP 513
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2010-03-24
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0167-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
KEYSTONE XL PROJECT

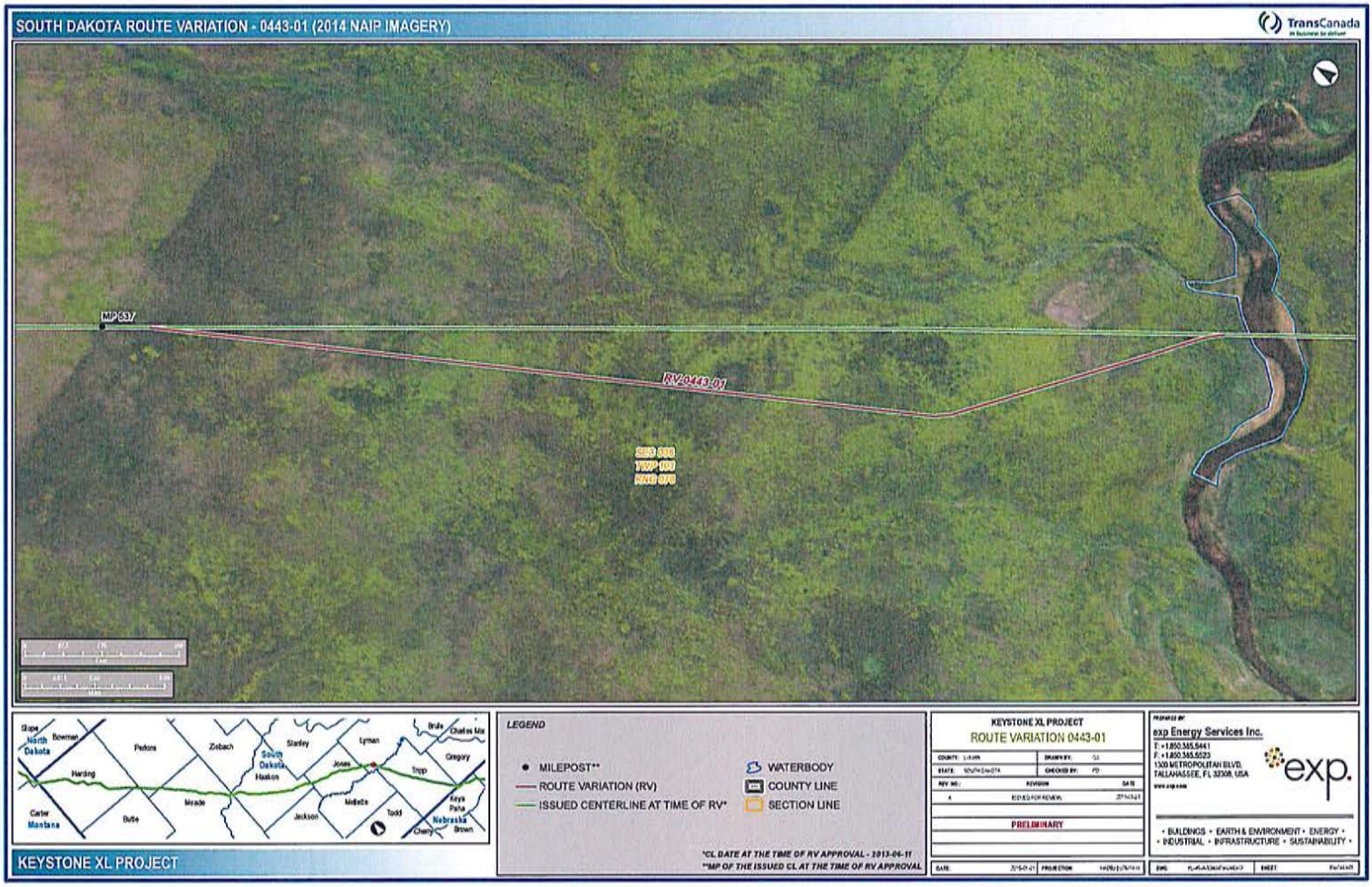

SOUTH DAKOTA ROUTE VARIATION - 0442-01 (2014 NAIP IMAGERY)
TransCanada
JONES COUNTY
RV0442-01
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-06-11
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0442-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1320 METROPOLITAN BLVD,
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

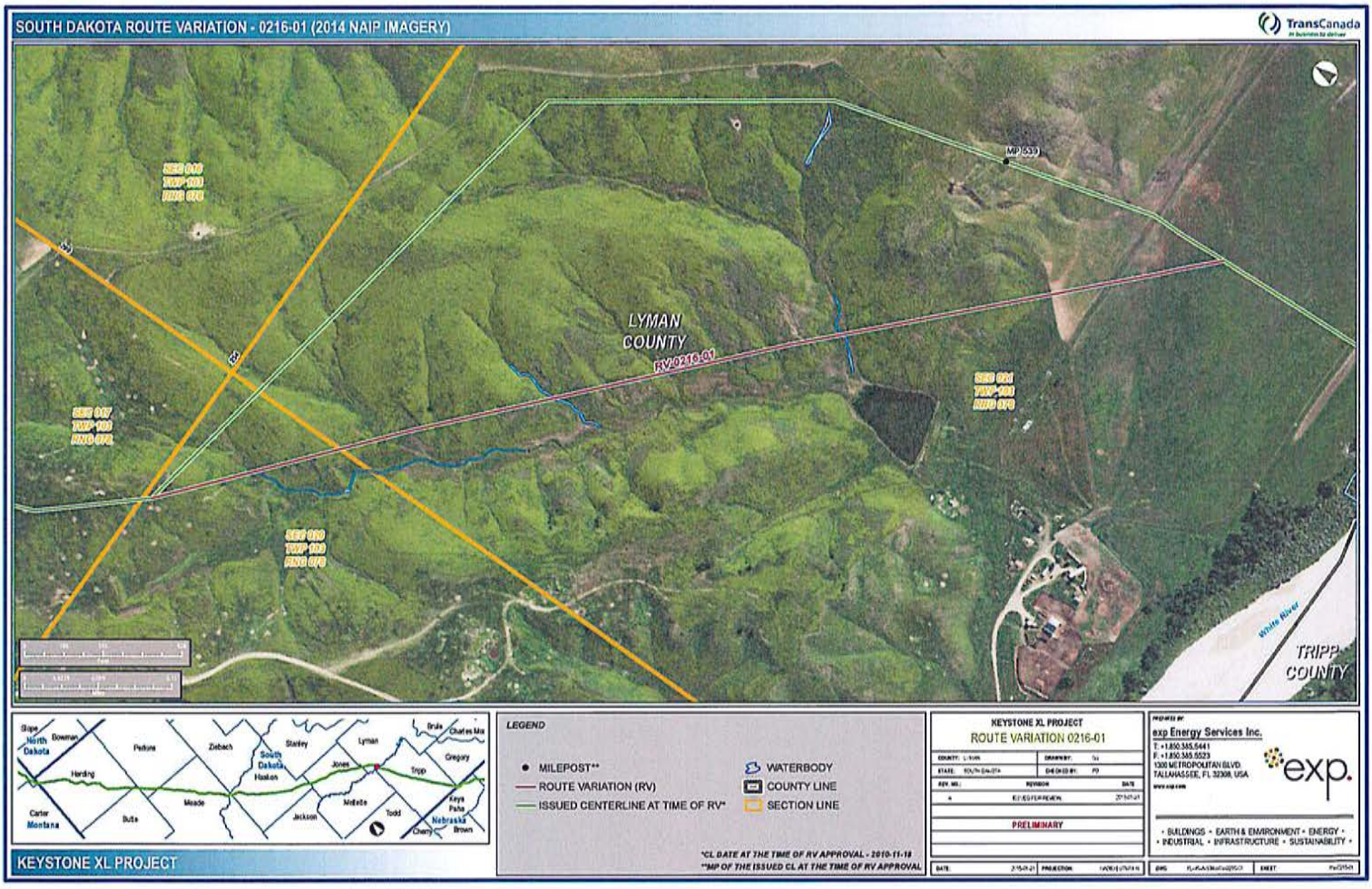

SOUTH DAKOTA ROUTE VARIATION - 0383-01 (2014 NAIP IMAGERY)
TransCanada
JONES COUNTY
RV 0383-01
SEC 010
TWP 002
RNG 001
SOUTH STREET
Slope
North Dakota
Bowman
Perkins
Ziebach
Dewey
Corson
Harding
Butte
Meade
Stanley
South Dakota
Haakon
Jones
Lyman
Brule
Charles Mix
Gregory
Tripp
Mellette
Todd
Jackson
Keya Paha
Nebraska
Brown
Cherry
Carter
Montana
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-08-15
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0383-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5023
1309 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
KEYSTONE XL PROJECT

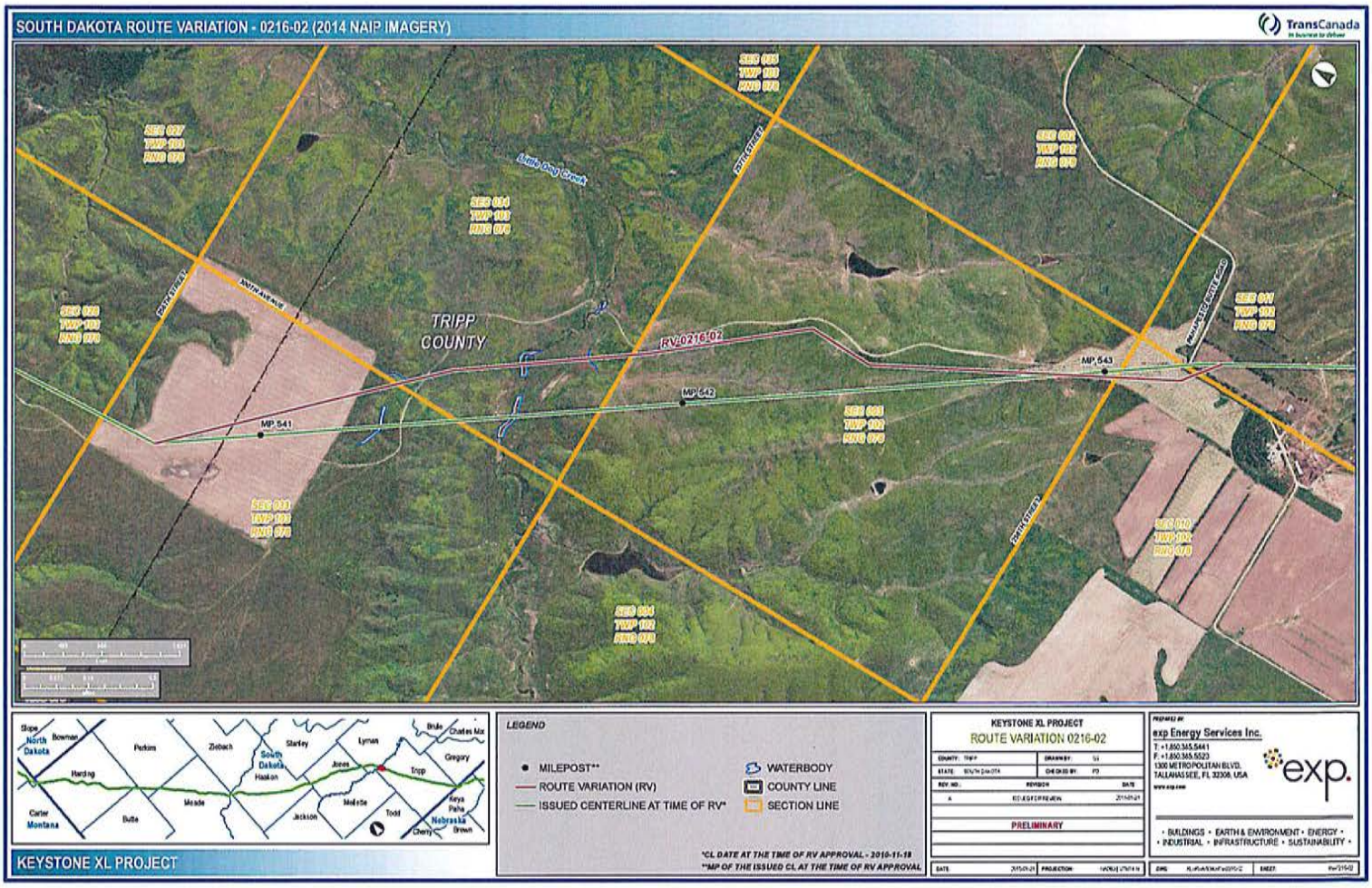

SOUTH DAKOTA ROUTE VARIATION - 0443-02 (2014 NAIP IMAGERY)
TransCanada
MP 620
SEC 005
TWP 002
RNG 001
RV 0443-02
JONES
COUNTY
SEC 005
TWP 002
RNG 001
Slope
North Dakota
Bowman
Perkins
Ziebach
Stanley
Lyman
Brule
Charles Mix
Gregory
South Dakota
Harding
Haakon
Jones
Tripp
Carter
Montana
Butte
Meade
Jackson
Mellette
Todd
Keya Paha
Nebraska
Cherry
Brown
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-06-11
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0443-02
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

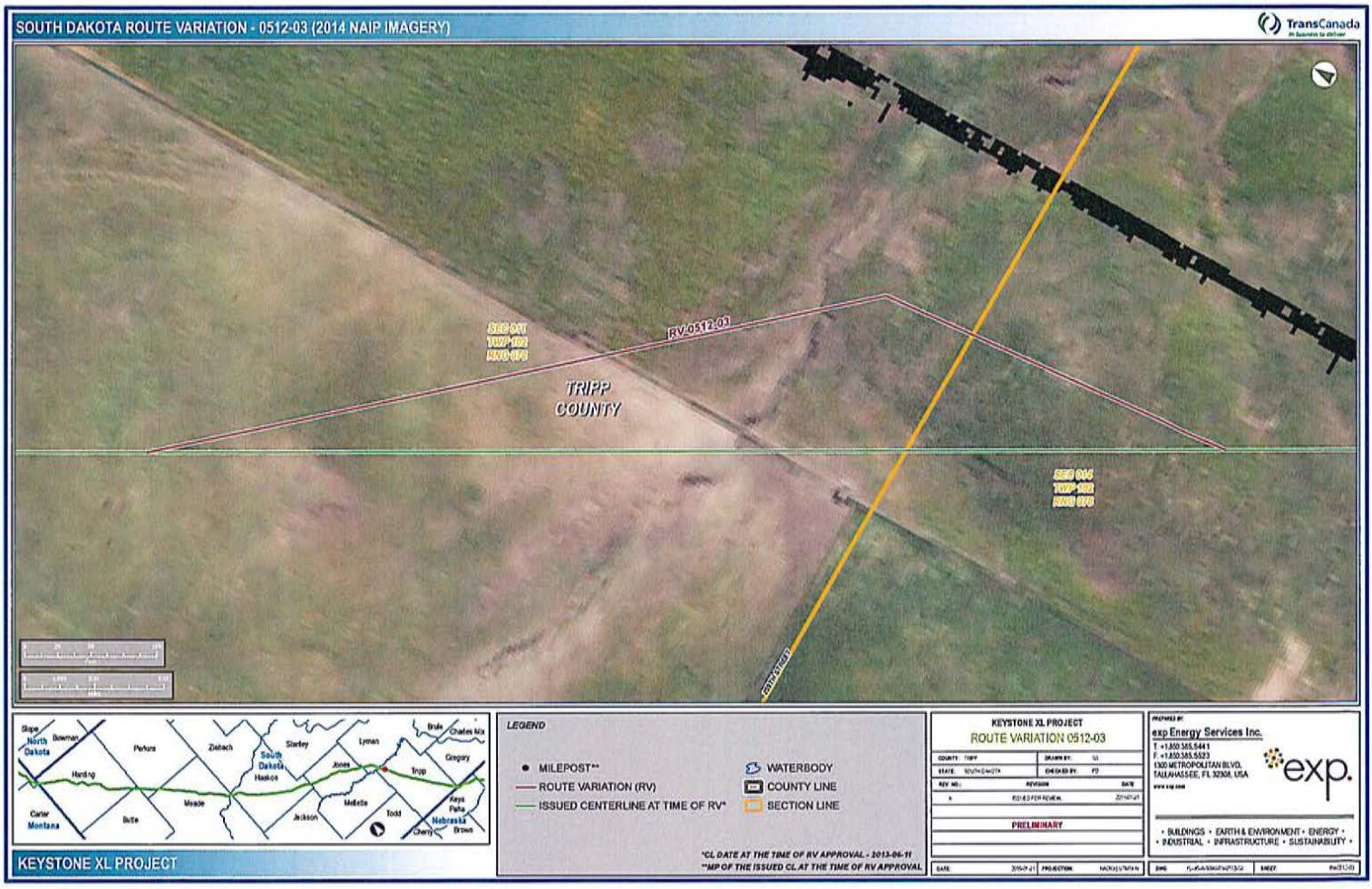

SOUTH DAKOTA ROUTE VARIATION - 0287-01 (2014 NAIP IMAGERY)
TransCanada
LYMAN
COUNTY
RV0287-01
SEC 017
TWP 104
RNG 079
SEC 018
TWP 104
RNG 079
Slippe
North Dakota
Bowman
Perkins
Ziebach
Stanley
Lyman
Brule
Charles Mix
South Dakota
Haakon
Jones
Gregory
Tripp
Harding
Meade
Mellette
Todd
Keya Paha
Nebraska
Brown
Carter
Montana
Butte
Jackson
Cherry
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2012-03-14
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0287-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1309 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

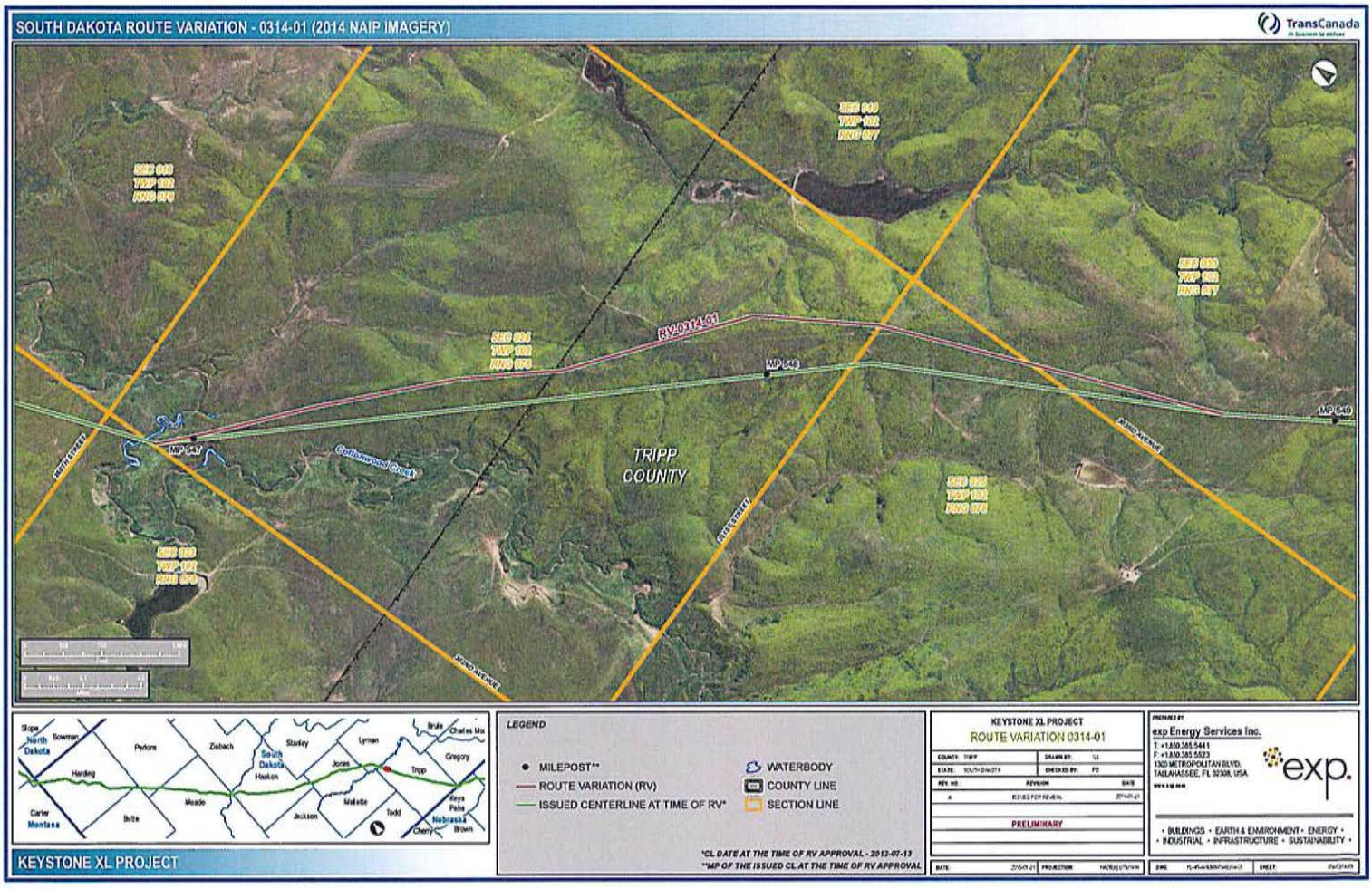

SOUTH DAKOTA ROUTE VARIATION - 0199-08 (2014 NAIP IMAGERY)
TransCanada
RV-0199-08
LYMAN
COUNTY
MP 633
Sedlacek Creek
Sedlacek Creek
Sedlacek Creek
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2010-11-18
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0199-08
PRELIMINARY
exp Energy Services Inc.
exp.
KEYSTONE XL PROJECT

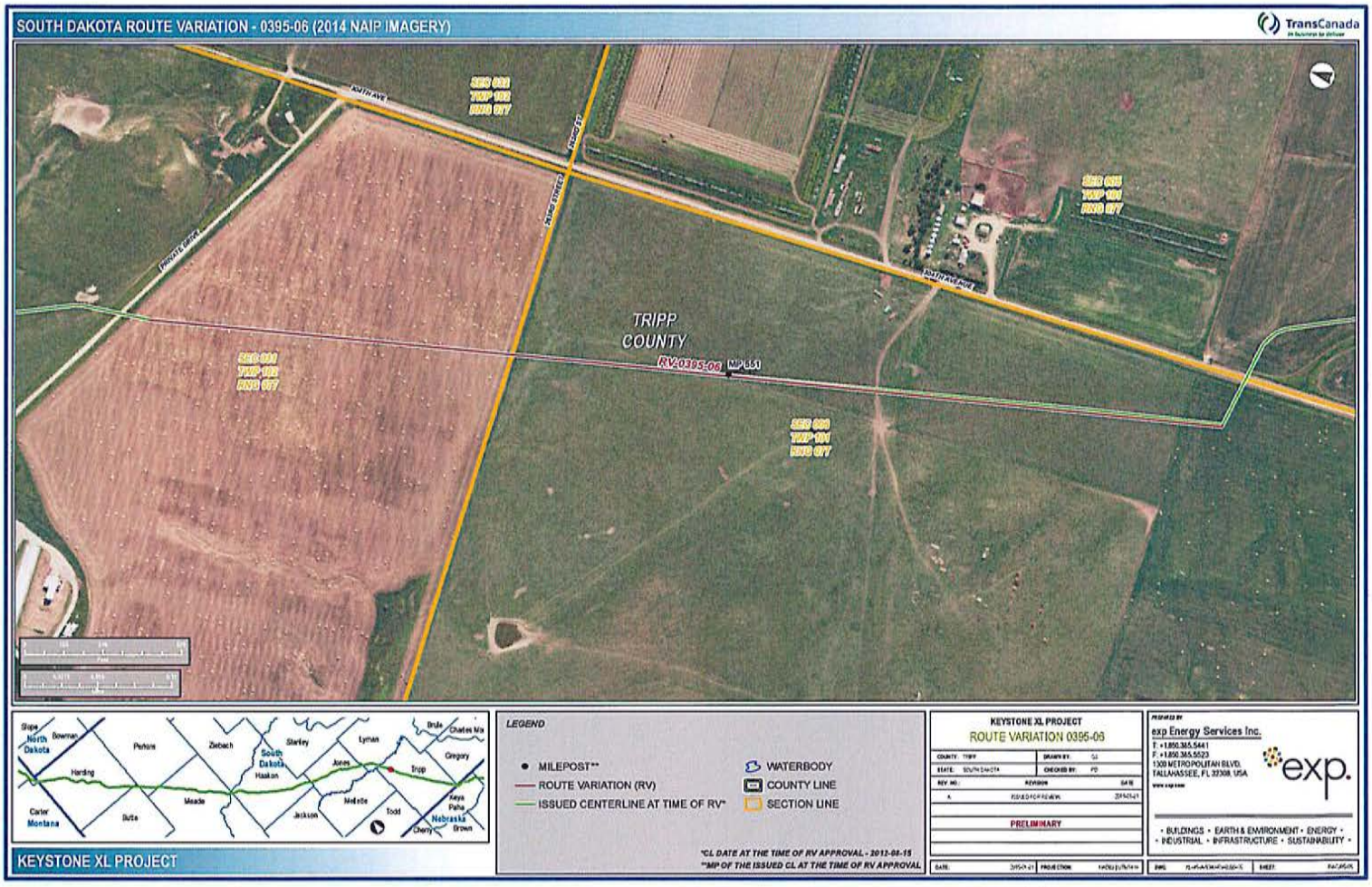

SOUTH DAKOTA ROUTE VARIATION - 0443-01 (2014 NAIP IMAGERY)
TransCanada
MP 637
RV-0443-01
SEC 000
TWP 000
RNG 000
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-06-11
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0443-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5533
1500 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
KEYSTONE XL PROJECT

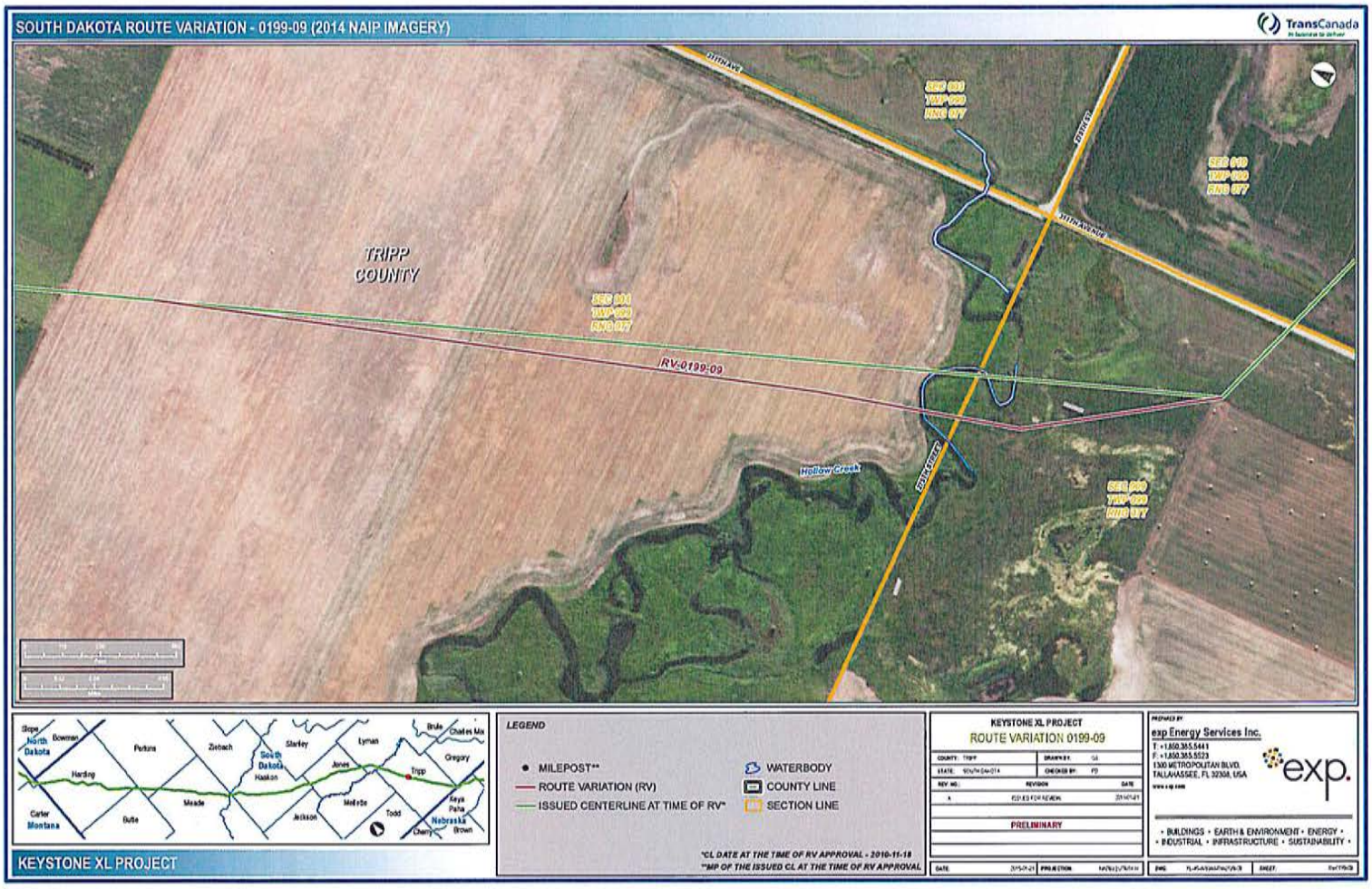

SOUTH DAKOTA ROUTE VARIATION - 0216-01 (2014 NAIP IMAGERY)
TransCanada
MP 639
LYMAN
COUNTY
RV 0216-01
TRIPP
COUNTY
White River
SEC 018
TWP 100
RNG 076
SEC 017
TWP 100
RNG 075
SEC 020
TWP 100
RNG 076
SEC 021
TWP 100
RNG 076
Slope
North Dakota
Bowman
Perkins
Ziebach
South Dakota
Harding
Stanley
Haakon
Lyman
Jones
Tripp
Gregory
Brule
Charles Mix
Carter
Montana
Butte
Meade
Jackson
Mellette
Todd
Keya Paha
Nebraska
Cherry
Brown
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2010-11-18
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0216-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

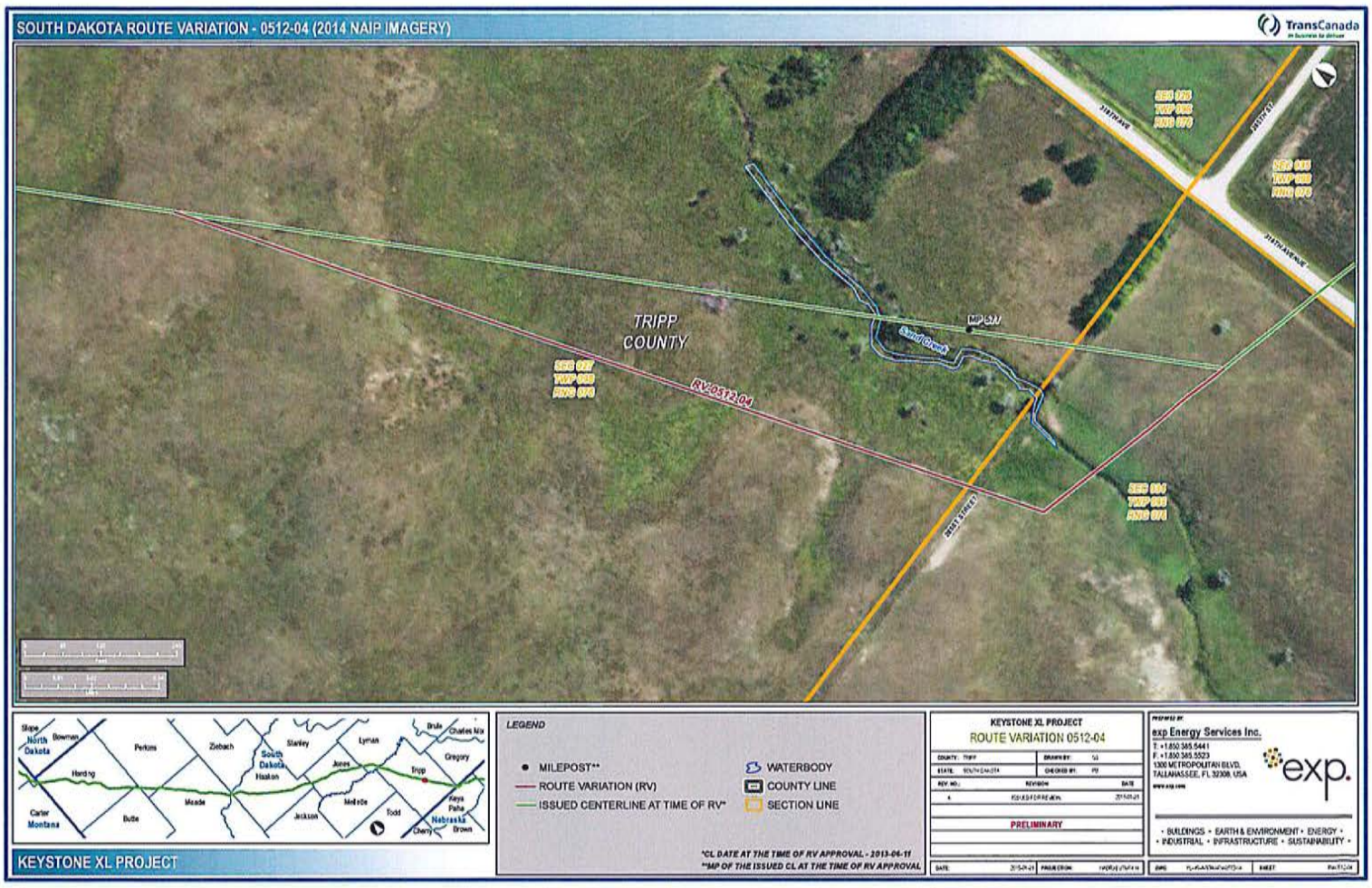

SOUTH DAKOTA ROUTE VARIATION - 0216-02 (2014 NAIP IMAGERY)
TransCanada
TRIPP COUNTY
RV-0216-02
MP 541
MP 542
MP 543
Little Dog Creek
PATH STREET
SOUTH AVENUE
MARMOUTH-BILLINGS ROAD
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2010-11-18
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0216-02
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
KEYSTONE XL PROJECT

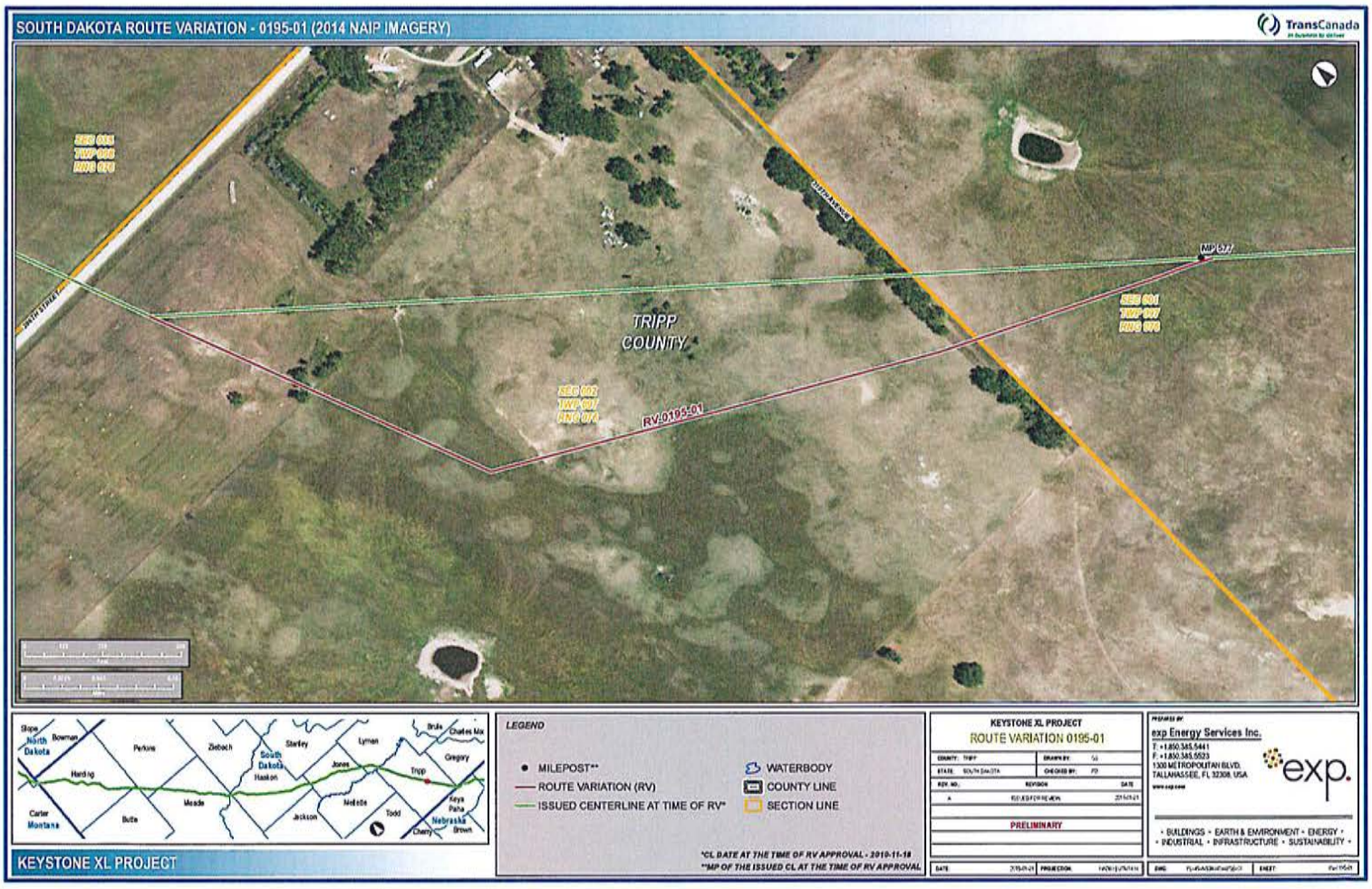

SOUTH DAKOTA ROUTE VARIATION - 0512-03 (2014 NAIP IMAGERY)
TransCanada
RV-0512-03
TRIPP
COUNTY
SEC 017
TWP 102
RNG 074
SEC 016
TWP 102
RNG 074
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-06-11
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0512-03
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD,
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •

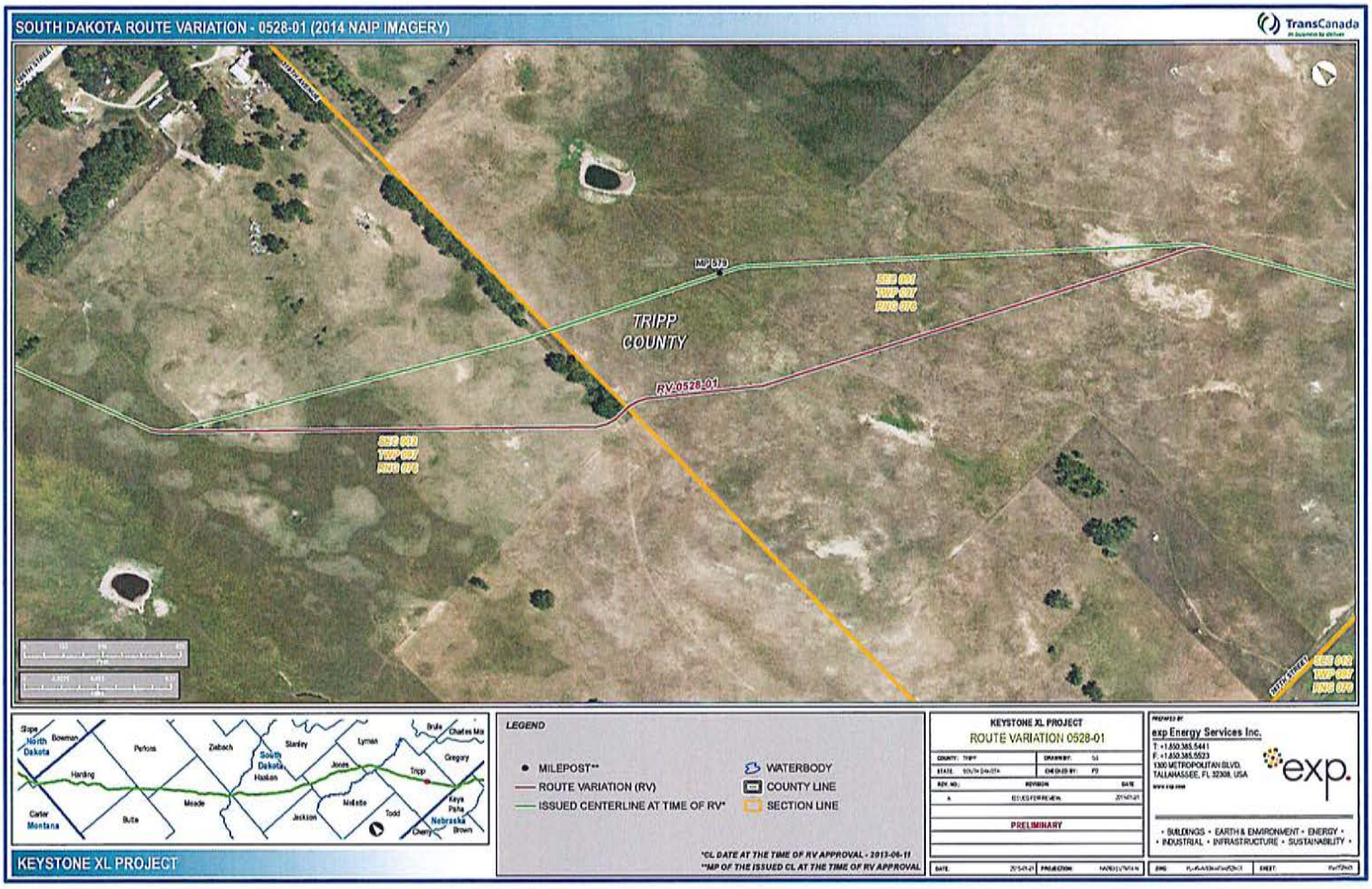

SOUTH DAKOTA ROUTE VARIATION - 0314-01 (2014 NAIP IMAGERY)
TransCanada
SEC 010 TWP 102 RNG 074
SEC 011 TWP 102 RNG 073
SEC 012 TWP 102 RNG 074
SEC 013 TWP 101 RNG 074
RV-0314-01
MP 547
MP 548
MP 549
TRIPP COUNTY
Cottonwood Creek
NORTH STREET
SOUTH STREET
232ND AVENUE
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2012-07-13
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0314-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •


SOUTH DAKOTA ROUTE VARIATION - 0395-06 (2014 NAIP IMAGERY)
TransCanada
SEC 001
TWP 101
RNG 077
257th Ave
Road 21
Road 23
Prairie Center
TRIPP
COUNTY
RV-0395-06
MP 55.1
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2012-08-15
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0395-06
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1309 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
KEYSTONE XL PROJECT


SOUTH DAKOTA ROUTE VARIATION - 0199-09 (2014 NAIP IMAGERY)
TransCanada
TRIPP COUNTY
RV-0199-09
Hollow Creek
SEC 001 TWP 099 RNG 077
SEC 012 TWP 099 RNG 077
SEC 036 TWP 099 RNG 077
SEC 036 TWP 099 RNG 077
SEC 001 TWP 099 RNG 077
BIRCH AVE
FOX CT
MILWAUKEE
DAKOTA RIDGE
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2010-11-18
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0199-09
PRELIMINARY
KEYSTONE XL PROJECT
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •


SOUTH DAKOTA ROUTE VARIATION - 0512-04 (2014 NAIP IMAGERY)
TransCanada
TRIPP
COUNTY
RV-0512-04
MP 5M
Sand Creek
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-04-11
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0512-04
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •


SOUTH DAKOTA ROUTE VARIATION - 0195-01 (2014 NAIP IMAGERY)
TransCanada
SEC 005
TWP 095
RNG 074
MP 037
TRIPP
COUNTY
SEC 001
TWP 037
RNG 075
SEC 007
TWP 037
RNG 074
RV-0195-01
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2019-11-18
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0195-01
PRELIMINARY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
KEYSTONE XL PROJECT


SOUTH DAKOTA ROUTE VARIATION - 0528-01 (2014 NAIP IMAGERY)
TransCanada
MP 079
SEC 001
TWP 097
RNG 076
TRIPP
COUNTY
RV-0528-01
SEC 002
TWP 097
RNG 076
SEC 012
TWP 097
RNG 076
Slope
North Dakota
Bowman
Perkins
Ziebach
South Dakota
Stanley
Lyman
Brule
Charles Mix
Gregory
Harding
Haakon
Jones
Tripp
Carter
Montana
Butte
Meade
Jackson
Mellette
Todd
Keya Paha
Nebraska
Cherry
Brown
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-06-11
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0528-01
PRELIMINARY
exp Energy Services Inc.
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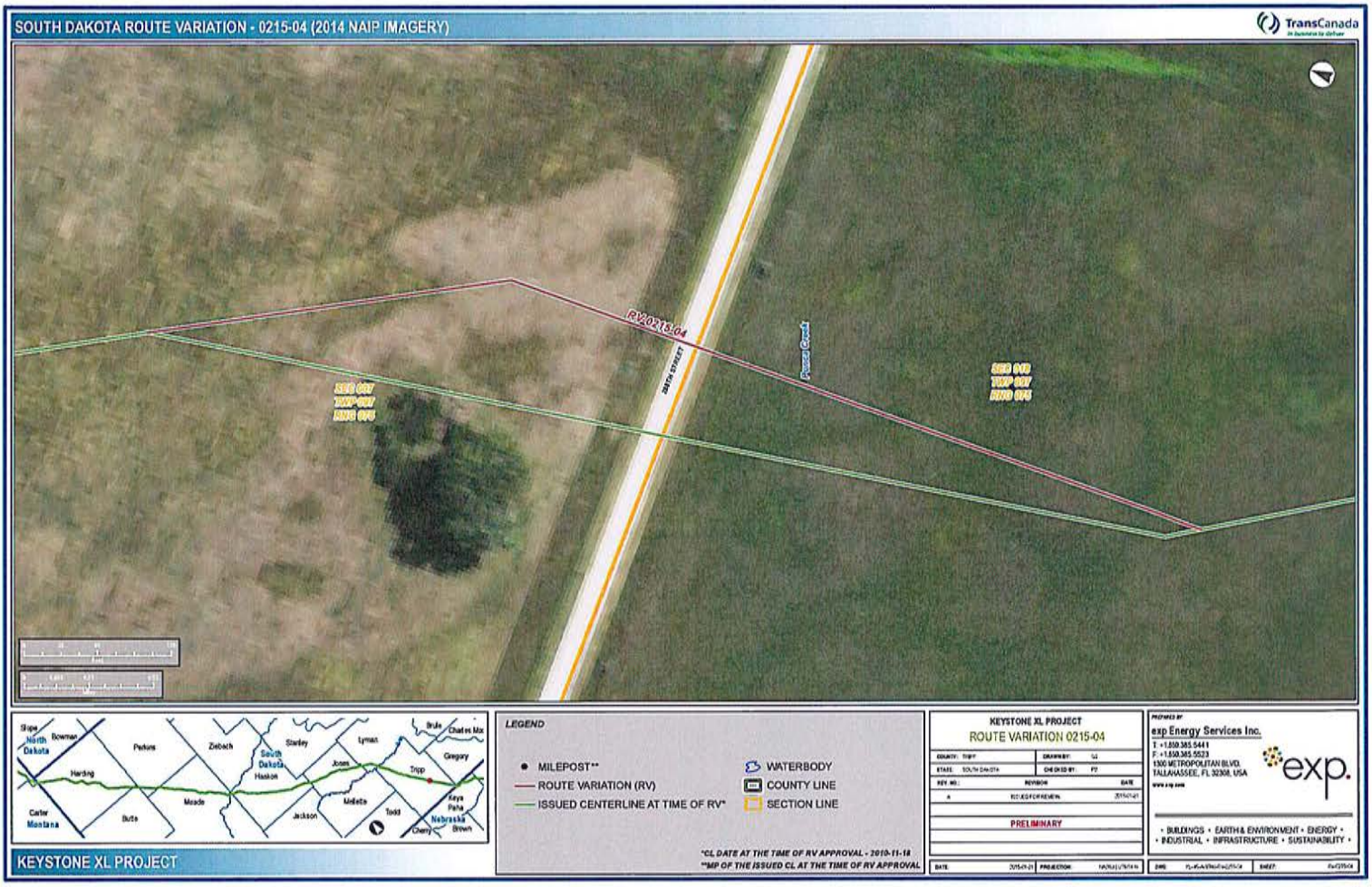
SOUTH DAKOTA ROUTE VARIATION - 0215-04 (2014 NAIP IMAGERY)
TransCanada
RV-0215-04
307th STREET
Pierre Creek
SEC 01T
TWP 00T
RNG 04T
SEC 01T
TWP 00T
RNG 04T
Slope
North Dakota
Bowman
Perkins
Ziebach
South Dakota
Harding
Haakon
Stanley
Jones
Lyman
Tripp
Brule
Charles Mix
Gregory
Carter
Montana
Butte
Meade
Jackson
Mellette
Todd
Keya Paha
Nebraska
Cherry
Brown
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2010-11-18
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0215-04
PRELIMINARY
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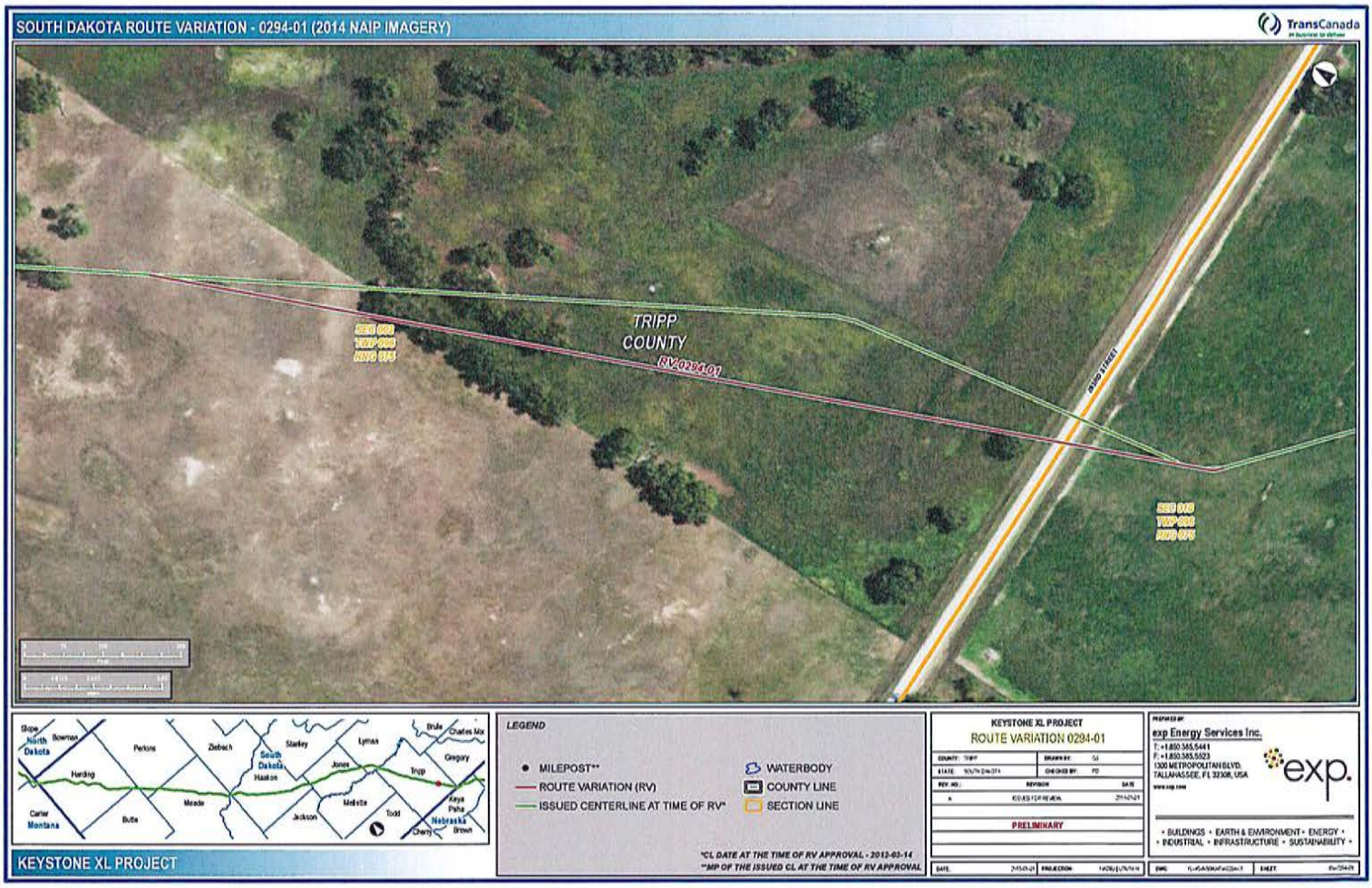
SOUTH DAKOTA ROUTE VARIATION - 0294-01 (2014 NAIP IMAGERY)
TransCanada
TRIPP
COUNTY
RV0294-01
SEC 008
TWP 095
RNG 074
SEC 018
TWP 095
RNG 074
850TH STREET
Slope
Bowman
North Dakota
Perkins
Ziebach
Stanley
Lyman
Brule
Charles Mix
South Dakota
Haakon
Jones
Gregory
Tripp
Harding
Meade
Mellette
Todd
Keya Paha
Carter
Montana
Butte
Jackson
Nebraska
Cherry
Brown
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-03-14
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0294-01
PRELIMINARY
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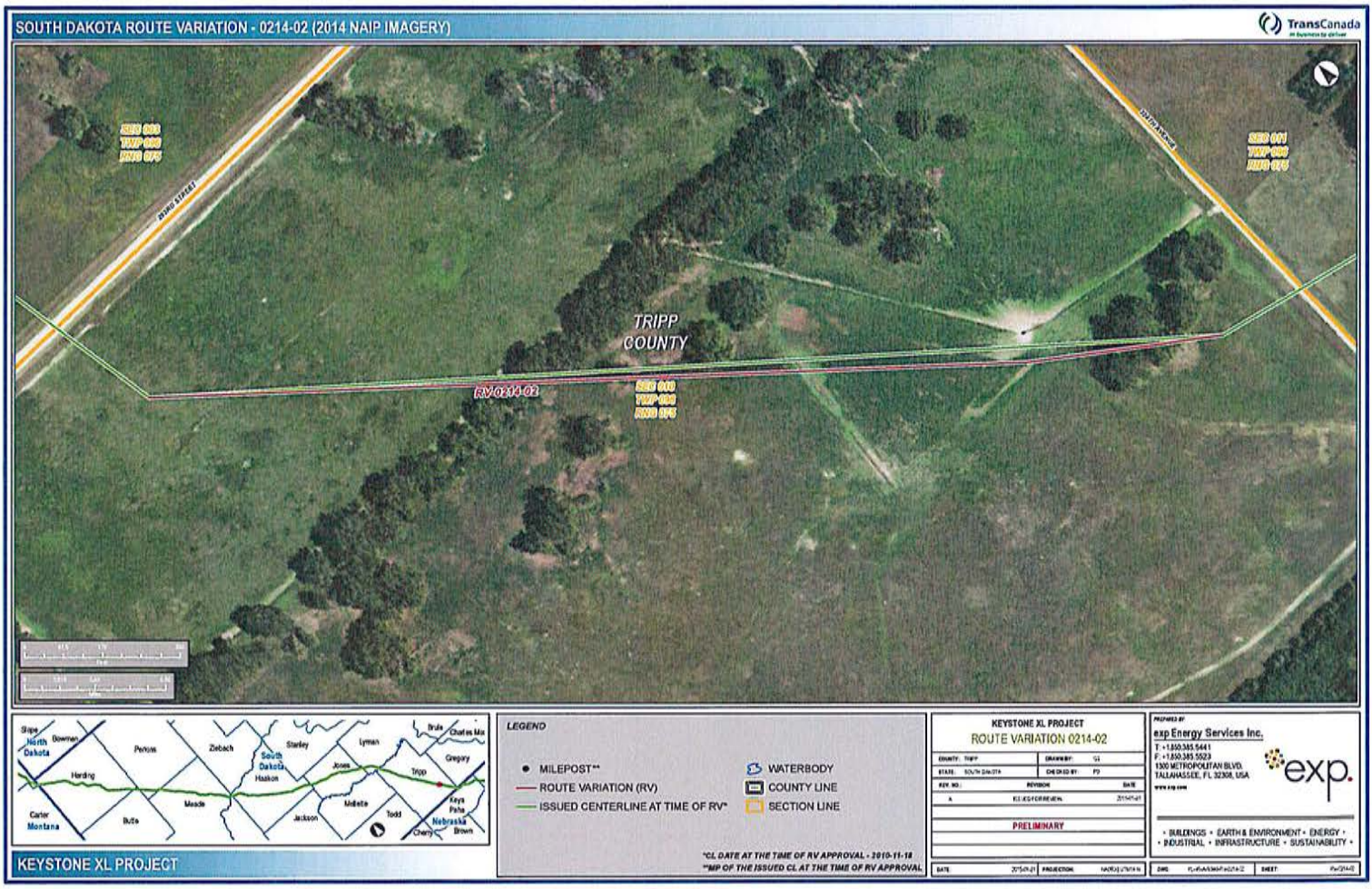
SOUTH DAKOTA ROUTE VARIATION - 0214-02 (2014 NAIP IMAGERY)
TransCanada
SEC 000
TWP 000
RNG 075
HWY 18 EAST
SEC 001
TWP 000
RNG 074
TRIPP
COUNTY
RV 0214-02
SEC 000
TWP 000
RNG 075
Slope
North Dakota
Bowman
Perkins
Ziebach
Stanley
Lyman
Butte
Charles Mix
Gregory
South Dakota
Haakon
Jones
Tripp
Harding
Carter
Montana
Meade
Butte
Jackson
Mellette
Todd
Keya Paha
Nebraska
Cherry
Brown
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2010-11-18
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0214-02
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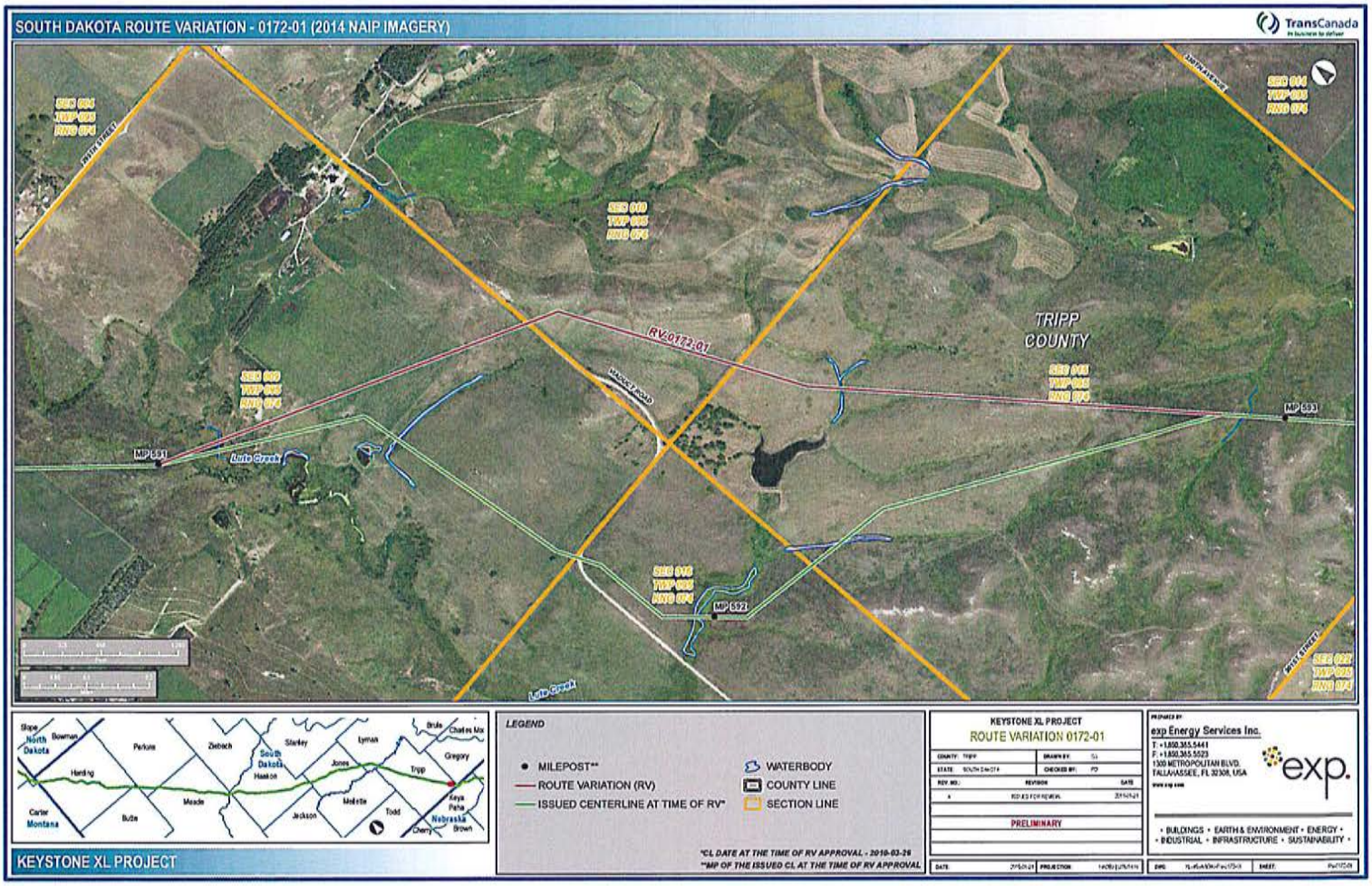
SOUTH DAKOTA ROUTE VARIATION - 0172-01 (2014 NAIP IMAGERY)
TransCanada
TRIPP COUNTY
RV-0172-01
MP 591
MP 592
MP 593
Little Creek
Little Creek
MINNEKAHTA AVENUE
PARKER AVENUE
MAGNOLIA ROAD
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2010-03-26
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
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ROUTE VARIATION 0172-01
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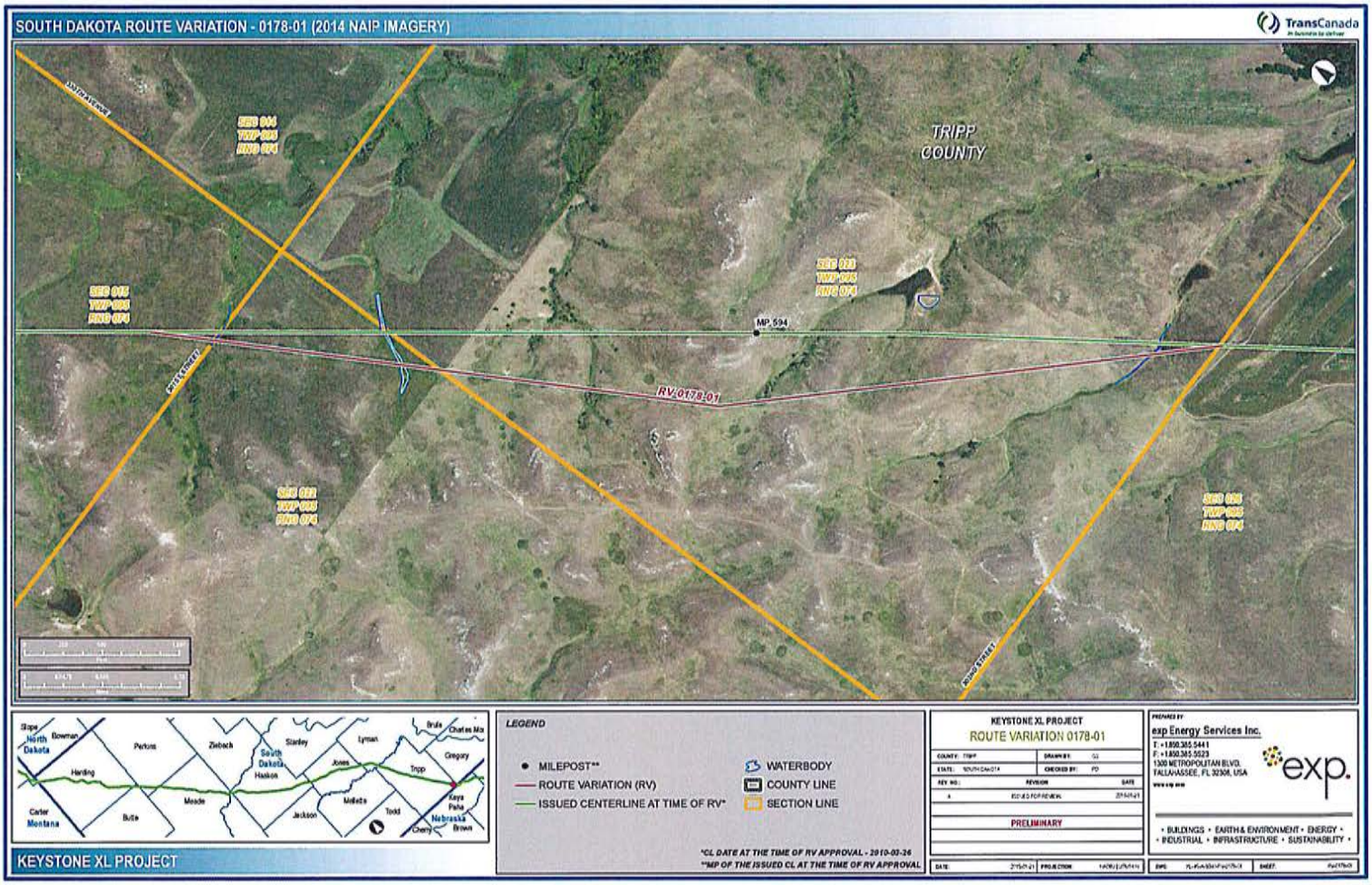
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •


SOUTH DAKOTA ROUTE VARIATION - 0178-01 (2014 NAIP IMAGERY)
TransCanada
TRIPP COUNTY
MP 594
RV 0178-01
PATH CREEK
RUSH STREET
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2010-03-26
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0178-01
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F: +1.850.385.5023
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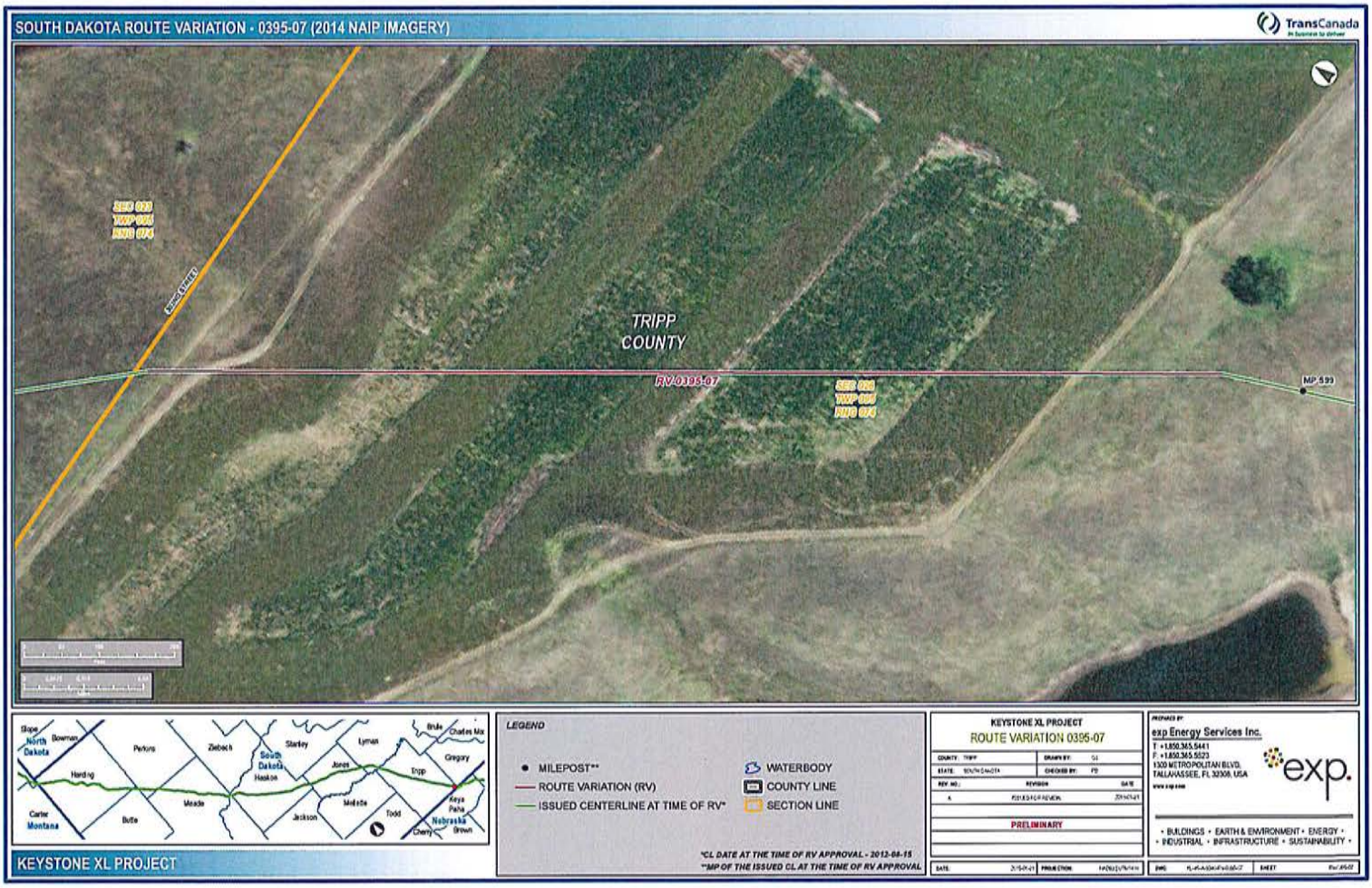
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TransCanada
TRIPP
COUNTY
RV 0395-07
MP 599
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2012-08-15
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
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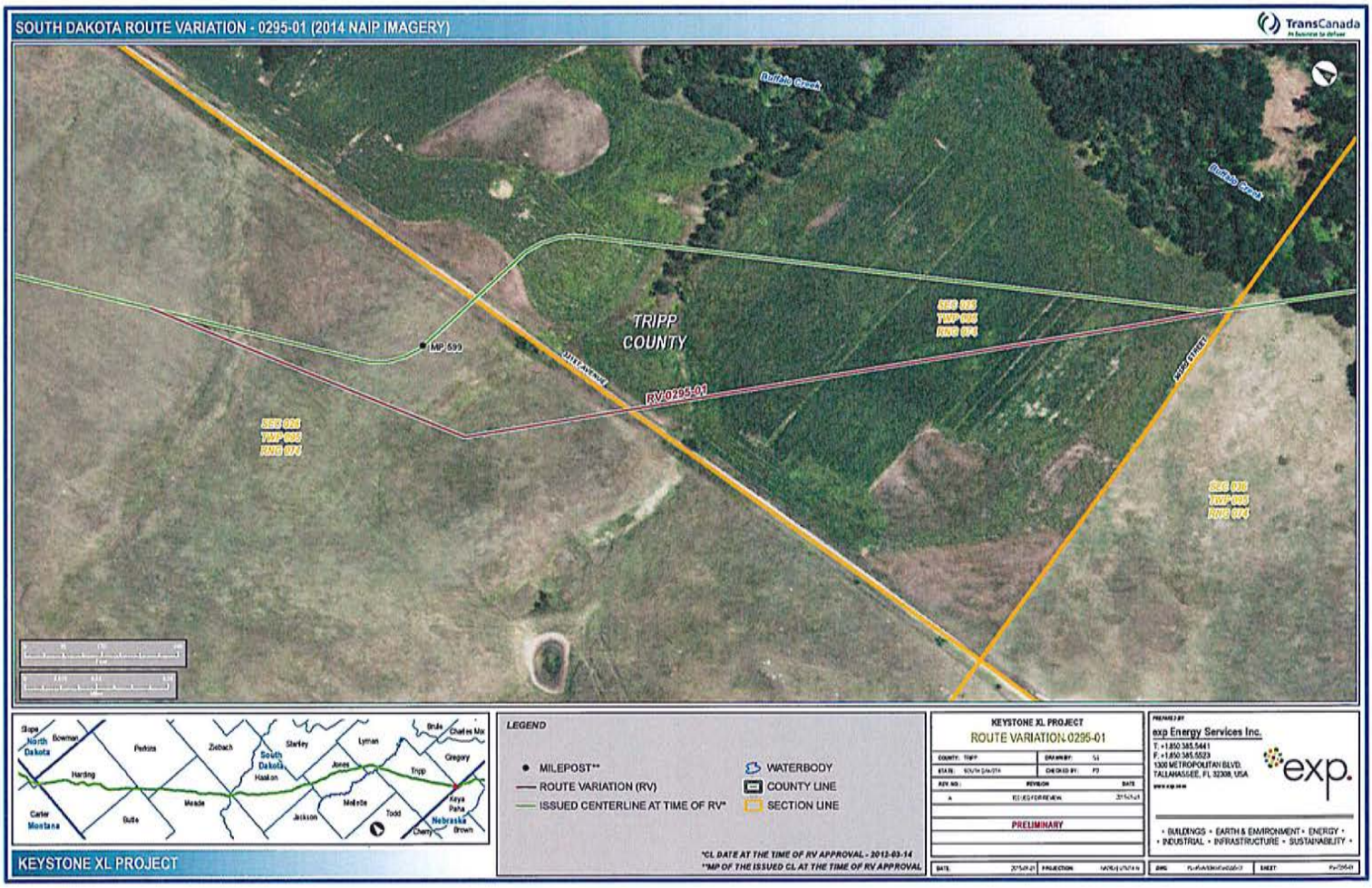
ROUTE VARIATION 0395-07
PRELIMINARY
exp Energy Services Inc.
KEYSTONE XL PROJECT


SOUTH DAKOTA ROUTE VARIATION - 0295-01 (2014 NAIP IMAGERY)
TransCanada
Buffalo Creek
Buffalo Creek
TRIPP
COUNTY
MP 599
RV 0295-01
SEC 036
TWP 095
RNG 074
SEC 036
TWP 095
RNG 074
SEC 036
TWP 095
RNG 074
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2012-03-14
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0295-01
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South Dakota Route Variations

Route Variation Number	State	County	Reason
0166-01	SD	Harding	Route variation to minimize constructability and safety concerns with current County Road 988 crossing.
0167-01	SD	Jones	Route variation to minimize constructability and safety concerns with current Interstate 90, Hwy 16 and State Railroad crossings.
0172-01	SD	Tripp	Route variation to minimize landowner impacts and reduce crossing of varying terrain features.
0178-01	SD	Tripp	Route variation to minimize constructability and safety concerns with current Interstate 90, Hwy 16 and State Railroad crossings.
0179-01	SD	Harding	Route variation to avoid endangered species.
0181-01	SD	Haakon	Route variation to remove unnecessary points of inflection in the route and reduce the route length.
0187-01	SD	Haakon	Route variation per landowner request and to avoid crossing a pond.
0188-01	SD	Haakon	Route variation per landowner request to minimze construction impacts to a pond.
0190-01	SD	Harding	Route variation to avoid paleontological features.
0192-01	SD	Harding	Route variation to minimize multiple crossing of a waterline.
0195-01	SD	Tripp	Route variation per landowner requests to avoid a row of trees and minimize landowner impacts.
0196-01	SD	Haakon	Route variation to minimimize crossing length of Hwy 73 and constructability concerns.
0199-01	SD	Perkins	Route variation to minimize multiple creek crossings.
0199-02	SD	Meade	Route variation to minimize multiple creek crossings and avoid paralling drainage feature.
0199-03	SD	Haakon	Route variation to avoid paralling drainage feature.
0199-05	SD	Haakon	Route variation to minimize creek crossings and adjust for better constructability of creek crossing.
0199-06	SD	Haakon	Route variation to avoid drainage feature and eliminate construction impacts to the levee.
0199-08	SD	Lyman	Route variation to avoid drainage features.
0199-09	SD	Tripp	Route variation to minimize multiple creek crossings.
0200-01	SD	Haakon	Route variation to minimize creek crossings, adjust for better constructability of creek crossing and minimize construction impacts to a pond.
0212-01	SD	Harding	Route variation to accommodate HDD design for the Little Missouri River.
0214-01	SD	Meade	Route variation to avoid a well and levee.
0214-02	SD	Tripp	Route variation to avoid a well and impacts to a fence.
0215-01	SD	Harding	Route variation to avoid varying terrain features.
0215-02	SD	Meade	Route variation to avoid paralling a creek.
0215-03	SD	Haakon	Route variation to avoid sudden terrain change.
0215-04	SD	Tripp	Route variation to avoid road crossing within a wetland area.
0216-01	SD	Lyman	Route variation to minimize side slope construction.
0216-02	SD	Tripp	Route variation to minimize side slope construction.
0220-01	SD	Haakon	Route variation to accommodate HDD design for the Bad River.
0224-01	SD	Meade	Route variation to minimize multiple creek crossings.
0239-01	SD	Haakon	Route variation to avoid sudden terrain change.
0252-01	SD	Meade	Route variation to avoid ridge lines, varying terrain and sudden terrain changes.
0252-02	SD	Meade	Route variation to avoid ridge lines, varying terrain and sudden terrain changes.
0252-03	SD	Haakon	Route variation to accommodate HDD design for the Cheyenne River.
0256-01	SD	Haakon	Route variation to remove unnecessary points of inflection in the route and reduce the route length.
0256-02	SD	Haakon	Route variation to accommodate a road crossing.
0256-03	SD	Jones	Route variation to minimize the route length.
0257-01	SD	Perkins	Route variation to avoid construction foot print impacts paralleling a road.
0257-02	SD	Meade	Route variation to avoid route and construction foot print impacts paralleling a road.
0258-01	SD	Harding	Route variation to avoid crossing a pond.
0260-01	SD	Haakon	Route variation to accommodate waterline crossings.
0260-02	SD	Haakon	Route variation to accommodate waterline crossings.
0260-03	SD	Haakon	Route variation to avoid construction foot print on waterline.
0260-04	SD	Haakon	Route variation to avoid crossing waterlines.
0262-01	SD	Haakon	Route variation to increase seperation of route and pond spillway due to constructability and avoid potential future concerns.
0269-01	SD	Harding	Route variation to avoid cultural site.

013024

South Dakota Route Variations

Route Variation Number	State	County	Reason
0270-01	SD	Meade	Route variation to avoid constuction foot print impacts to cattle guard and fence.
0272-01	SD	Haakon	Route variation to minimize side slope construction and varying terrain.
0279-01	SD	Jones	Route variation to remove unnecessary points of inflection in the route and reduce the route length.
0280-01	SD	Harding	Route variation to avoid varying terrain and sudden terrain changes.
0281-01	SD	Harding	Route variation to avoid side slope construction.
0282-01	SD	Harding	Route variation to minimize drainage crossings and avoid paralleling a drainage.
0285-01	SD	Haakon	Route variation to accommodate road and creek crossings.
0286-01	SD	Haakon	Route variation to remove unnecessary points of inflection in the route, reduce the route length and better valve location.
0287-01	SD	Lyman	Route variation to accommodate road crossing and better valve location.
0289-01	SD	Haakon	Route variation to accommodate pump station design.
0289-02	SD	Jones	Route variation to accommodate pump station design.
0291-01	SD	Harding	Route variation to avoid paralleling and minimize multiple creek crossings.
0292-01	SD	Harding	Route variation to avoid paralleling a creek.
0293-01	SD	Jones	Route variation to avoid construction impacts to a pond and levee. Also, minimize varying terrain features.
0294-01	SD	Tripp	Route variation to avoid a well and construction foot print impacts to a fence surrounding a historical site.
0295-01	SD	Tripp	Route variation to avoid a drainage crossing and accommodate a road crossing.
0296-01	SD	Butte / Perkins	Route variation to avoid terrain feature.
0310-01	SD	Jones	Route variation to avoid paralleling a drainage and increase seperation at a washout at a creek crossing.
0311-01	SD	Perkins	Route variation to avoid a cultural site and accommodate a creek crossing.
0314-01	SD	Tripp	Route variation to avoid side slope construction and sudden terrain changes.
0372-01	SD	Haakon	Route variation to accommodate valve placement.
0381-01	SD	Harding	Route variation to avoid crossing a pond.
0382-01	SD	Harding	Route variation to minimize construction foot print on adjacent landowner property.
0384-01	SD	Meade	Route variation to avoid impacts to adjacent property.
0383-01	SD	Jones	Route variation to accommodate waterline crossing.
0385-01	SD	Haakon	Route variation to minimize multiple crossing of a waterline.
0395-01	SD	Harding	Route variation to accommodate pump station design.
0395-02	SD	Harding	Route variation to accommodate pump station design.
0395-03	SD	Meade	Route variation to accommodate pump station design.
0395-04	SD	Haakon	Route variation to accommodate pump station design.
0395-05	SD	Jones	Route variation to accommodate pump station design.
0395-06	SD	Tripp	Route variation to accommodate pump station design.
0395-07	SD	Tripp	Route variation to accommodate pump station design.
0413-01	SD	Harding	Route variation to avoid washouts and sudden terrain changes.
0442-01	SD	Jones	Route variation to accommodate waterline crossing.
0443-01	SD	Lyman	Route variation to avoid paralleling a creek.
0443-02	SD	Jones	Route variation to avoid paralleling a creek.
0443-04	SD	Haakon	Route variation to avoid waterbody crossing.
0443-05	SD	Jones	Route variation to avoid paralleling a creek.
0455-01	SD	Haakon	Route variation to increase parallel seperation of route and waterline.
0455-02	SD	Haakon	Route variation to increase parallel seperation of route and waterline.
0456-01	SD	Harding	Route variation to avoid an oil well.
0470-01	SD	Harding	Route variation to avoid creek crossing.
0470-02	SD	Haakon	Route variation to minimize multiple creek crossings.
0470-03	SD	Jones	Route variation to minimize multiple creek crossings.
0470-04	SD	Perkins	Route variation to avoid paralleling a creek.
0470-05	SD	Perkins	Route variation to avoid paralleling a creek.
0470-06	SD	Meade	Route variation to accommodate creek crossing.
0470-07	SD	Meade	Route variation to avoid a pond.
0470-09	SD	Perkins	Route variation to avoid ravine.
0470-10	SD	Perkins	Route variation to avoid paralleling a creek.

South Dakota Route Variations

Route Variation Number	State	County	Reason
0478-01	SD	Meade	Route variation to accommodate road crossing.
0491-01	SD	Meade	Route variation to avoid drainage.
0497-01	SD	Haakon	Route variation to accommodate road crossing.
0512-01	SD	Meade	Route variation to avoid any well impacts.
0512-02	SD	Meade	Route variation to avoid any well impacts.
0512-03	SD	Tripp	Route variation to avoid any well impacts.
0512-04	SD	Tripp	Route variation to avoid any well impacts.
0514-01	SD	Butte	Route variation to avoid cultural site.
0515-01	SD	Harding	Route variation to avoid cultural site.
0527-01	SD	Harding	Route variation to avoid cultural site.
0527-02	SD	Perkins	Route variation to avoid cultural site.
0528-01	SD	Tripp	Route variation to avoid swampy low lying area near a pond.
0543-01	SD	various	Route variation to accommodate HDD designs.

Harding Pump Station

The Harding Pump Station is located in Harding County in South Dakota. The proposed site equipment will initially consist of three (3) pumps and motors, a VFD building, an ESD building and an HV substation. A future planned upgrade to the facility will consist of an additional one (1) pump and motor added to the site. The noise impact assessment was prepared for the 3/5 pump case for consistency with the other stations and to determine the noise impact of a maximum of 5 total pumps on this site.

There are no residences within 1 mile of the site location and thus four hypothetical receptors have been set at 1 mile in each of the cardinal directions from the site. The predicted sound pressure levels at these theoretical nearest sensitive receptors (NSRs) from the proposed pump station, under Scenarios 1 and 2 are presented in Table 1 and Table 2 below, respectively.

Table 1: Predicted Sound Pressure Levels – Scenario 1 (3 Pumps and Motors)

Receptor ID	Location (from TCPL Site Fence Line)	Predicted Facility Sound Level (L_{eq}, dBA)
R1	1 mile North	39
R2	1 mile East	34
R3	1 mile South	34
R$	1 mile West	35

Table 2: Predicted Sound Pressure Levels – Scenario 2 (5 Pumps and Motors)

Receptor ID	Location (from TCPL Site Fence Line)	Predicted Facility Sound Level (L_{eq}, dBA)
R1	1 mile North	43
R2	1 mile East	39
R3	1 mile South	39
R$	1 mile West	39

The predicted levels at each of the NSRs are below the levels as recommended in the US EPA environmental noise guidelines under both the initial Scenario 1 conditions and the future Scenario 2 expansion.

Buffalo Pump Station

The Buffalo Pump Station is located near Buffalo, South Dakota, in Harding County. The proposed site equipment will initially consist of two (2) pumps and motors, a VFD building, an ESD building and an HV substation. A future planned upgrade to the facility will consist of an additional two (2) pumps and motors added to the site. However, the noise impact assessment was prepared for the 3/5 pump case for consistency with the other stations and to determine the noise impact of a maximum of 5 total pumps on this site.

The predicted sound pressure levels at the nearest sensitive receptors (NSRs) from the proposed pump station under Scenarios 1 and 2 are presented in Table 1 and Table 2 below, respectively.

Table 1: Predicted Sound Pressure Levels – Scenario 1 (3 Pumps and Motors)

Receptor ID	Location (from TCPL Site Fence Line)	Predicted Facility Sound Level (L_{eq}, dBA)
R1	1 mile North	33
R2	1 mile East	35
R3	1 mile South	34
R4	1 mile West	33

Table 2: Predicted Sound Pressure Levels – Scenario 2 (5 Pumps and Motors)

Receptor ID	Location (from TCPL Site Fence Line)	Predicted Facility Sound Level (L_{eq}, dBA)
R1	1 mile North	37
R2	1 mile East	39
R3	1 mile South	39
R4	1 mile West	38

The predicted levels at each of the NSRs are below the levels as recommended in the US EPA environmental noise guidelines under both the initial Scenario 1 conditions and the future Scenario 2 expansion.

Faith Pump Station

The Faith Pump Station is located 4 miles west of Opal, South Dakota, in Meade County. The proposed site equipment will initially consist of three (3) pumps and motors, a VFD building, an ESD building and an HV substation. A future planned upgrade to the facility will consist of an additional two (2) pumps and motors added to the site. However, the noise impact assessment was prepared for the 3/5 pump case for consistency with the other stations and to determine the noise impact of a maximum of 5 total pumps on this site.

The predicted sound pressure levels at the nearest sensitive receptors (NSRs) from the proposed pump station, under Scenarios 1 and 2 are presented in Table 1 and Table 2 below, respectively.

Table 1: Predicted Sound Pressure Levels – Scenario 1 (3 Pumps and Motors)

Receptor ID	Location (from TCPL Site Fence Line)	Predicted Facility Sound Level (L_{eq}, dBA)
R1	4480 ft Northeast	37
R2	4420 ft Northeast	37

Table 2: Predicted Sound Pressure Levels – Scenario 2 (5 Pumps and Motors)

Receptor ID	Location (from TCPL Site Fence Line)	Predicted Facility Sound Level (L_{eq}, dBA)
R1	4480 ft Northeast	41
R2	4420 ft Northeast	41

The predicted levels at each of the NSRs are below the levels as recommended in the US EPA environmental noise guidelines under both the initial Scenario 1 conditions and the future Scenario 2 expansion.

Haakon Pump Station

The Haakon Pump Station is located near Hartley, South Dakota, in Haakon County. The proposed site equipment will initially consist of two (2) pumps and motors, a VFD building, an ESD building and an HV substation, modeled under Scenario 1. A future planned upgrade to the facility will consist of an additional two (2) pumps and motors added to the site. However, the noise impact assessment was prepared for the 3/5 pump case for consistency with the other stations and to determine the noise impact of a maximum of 5 total pumps on this site.

The predicted sound pressure levels at the nearest sensitive receptors (NSRs) from the proposed TCPL pump station, under Scenarios 1 and 2 are presented in Table 1 and Table 2 below, respectively.

Table 1: Predicted Sound Pressure Levels – Scenario 1 (3 Pumps and Motors)

Receptor ID	Location (from TCPL Site Fence Line)	Predicted Facility Sound Level (L_{eq}, dBA)
R1	1 mile North	34
R2	1 mile East	34
R3	1 mile South	35
R4	1 mile West	34

Table 2: Predicted Sound Pressure Levels – Scenario 2 (5 Pumps and Motors)

Receptor ID	Location (from TCPL Site Fence Line)	Predicted Facility Sound Level (L_{eq}, dBA)
R1	1 mile North	39
R2	1 mile East	39
R3	1 mile South	39
R4	1 mile West	39

The predicted levels at each of the NSRs are below the levels as recommended in the US EPA environmental noise guidelines under both the initial Scenario 1 conditions and the future Scenario 2 expansion.

Murdo Pump Station

The Murdo Pump Station is located near Okaton, South Dakota, in Jones County. The proposed site equipment will initially consist of three (3) pumps and motors, a VFD building, an ESD building and an HV substation. A future planned upgrade to the facility will consist of an additional two (2) pumps and motors added to the site. However, the noise impact assessment was prepared for the 3/5 pump case for consistency with the other stations and to determine the noise impact of a maximum of 5 total pumps on this site.

The predicted sound pressure levels at the nearest sensitive receptors (NSRs) from the proposed pump station, under Scenarios 1 and 2 are presented in Table 1 and Table 2 below, respectively.

Table 1: Predicted Sound Pressure Levels – Scenario 1 (3 Pumps and Motors)

Receptor ID	Location (from TCPL Site Fence Line)	Predicted Facility Sound Level (L_{eq}, dBA)
R1	2350 ft Northeast	44
R2	3800 ft Northwest	40

Table 2: Predicted Sound Pressure Levels – Scenario 2 (5 Pumps and Motors)

Receptor ID	Location (from TCPL Site Fence Line)	Predicted Facility Sound Level (L_{eq}, dBA)
R1	2350 ft Northeast	48
R2	3800 ft Northwest	45

The predicted levels at each of the NSRs are below the levels as recommended in the US EPA environmental noise guidelines under both the initial Scenario 1 conditions and the future Scenario 2 expansion.

Winner Pump Station

The Winner Pump Station is located near Winner, South Dakota, in Tripp County. The proposed site equipment will initially consist of three (3) pumps and motors, a VFD building, an ESD building and an HV substation, modeled under Scenario 1. A future planned upgrade to the facility will consist of an additional two (2) pumps and motors added to the site. However, the noise impact assessment was prepared for the 3/5 pump case for consistency with the other stations and to determine the noise impact of a maximum of 5 total pumps on this site.

The predicted sound pressure levels at the nearest sensitive receptors (NSRs) from the proposed pump station, under Scenarios 1 and 2 are presented in Table 1 and Table 2 below, respectively.

Table 1: Predicted Sound Pressure Levels – Scenario 1 (3 Pumps and Motors)

Receptor ID	Location (from TCPL Site Fence Line)	Predicted Facility Sound Level (L_{eq}, dBA)
R1	1200 ft North	55
R2	1260 ft Southeast	54
R3	4500 ft Southwest	36

Table 2: Predicted Sound Pressure Levels – Scenario 2 (5 Pumps and Motors)

Receptor ID	Location (from TCPL Site Fence Line)	Predicted Facility Sound Level (L_{eq}, dBA)
R1	1200 ft North	59
R2	1260 ft Southeast	58
R3	4500 ft Southwest	41

The predicted levels at R1 and R2 are above the levels as recommended in the US EPA environmental noise guidelines under both the initial Scenario 1 conditions and the future Scenario 2 expansion. Noise mitigation has been recommended to reduce the overall predicted sound level of the facility to be within the EPA guidelines for only Scenario 1 conditions. Additional noise mitigation necessary for Scenario 2 compliance will be developed and presented when the Scenario 2 upgrade to the facility is confirmed. The predicted sound pressure levels at the receptors with noise mitigation applied to the site are presented in Table 3 below,

Table 3: Predicted Sound Pressure Levels – Scenario 1 with Noise Mitigation

Receptor ID	Location (from TCPL Site Fence Line)	Predicted Facility Sound Level (L_{eq}, dBA)
R1	1200 ft North	45
R2	1260 ft Southeast	45
R3	4500 ft Southwest	28

Colome Pump Station

The Colome Pump Station is located near Colome, South Dakota, in Tripp County. The proposed site equipment will initially consist of three (3) pumps and motors, a VFD building, an ESD building and an HV substation, modeled under Scenario 1. A future planned upgrade to the facility will consist of an additional two (2) pumps and motors added to the site. However, the noise impact assessment was prepared for the 3/5 pump case for consistency with the other stations and to determine the noise impact of a maximum of 5 total pumps on this site.

The predicted sound pressure levels at the nearest sensitive receptor (NSR) from the proposed TCPL pump station, under Scenarios 1 and 2 are presented in Table 1 and Table 2 below, respectively.

Table 1: Predicted Sound Pressure Levels – Scenario 1 (3 Pumps and Motors)

Receptor ID	Location (from TCPL Site Fence Line)	Predicted Facility Sound Level (L_{eq}, dBA)
R1	1280 ft East	48

Table 2: Predicted Sound Pressure Levels – Scenario 2 (5 Pumps and Motors)

Receptor ID	Location (from TCPL Site Fence Line)	Predicted Facility Sound Level (L_{eq}, dBA)
R1	1280 ft East	53

The predicted levels at R1 is below levels as recommended in the US EPA environmental noise guidelines under the initial Scenario 1 conditions but above the recommended levels under the future Scenario 2 expansion. Noise mitigation for Scenario 2 compliance will be developed and presented when the Scenario 2 upgrade to the facility is confirmed.

TransCanada-Keystone XL Steele City

Contact Record

Date/Time: **06.07.2010**	Meeting Phone Conversation E-Mail (attach) *(highlight)*

Agency/Organization(s):	Natural Resources Conservation Service (NRCS), South Dakota State Office

Person(s) Involved:	NRCS: Kent Cooley (Soil scientist), Stan Boltz (State Range Scientist) WESTECH: Lisa Larsen, Corey Baker

Notes: WESTECH requested a meeting with the SD NRCS State Office to solicit comments on the Keystone XL CON/REC Units and revegetation mixes. The meeting was held in Rapid City, SD at the NRCS Office. CON/REC Units were previously sent to SB and KC electronically for their review. LL and CB described the project, explained how CON/REC Units were created and provided background on formulation of seed mixes. SB and KC repeatedly expressed surprise over the level of thoroughness and scope of reclamation planning.

Both SB and KC agreed that forbs are not needed in the mixes based on the fact that they tend to reestablish well on their own. Seed rates were satisfactory for a Critical Area planting. SB suggested a few changes to species composition and varieties (see attached CON/REC Units with track changes).

CB and LL questioned SB and KC about landowner communications, regarding reclamation issues per the SD PUC conditions. They recommended the following ideas to disseminate information to landowners:

- County Conservation Districts (meetings, printed materials)
- FSA Newsletter
- Town meetings
- Internet
- TransCanada letter/Land Agents

KC wondered if it would be possible to utilize the pipeline trench to characterize soils for NRCS soils surveys.

Is follow up required?	Yes - send revisions using track changes (attached). Clarify if trench can be utilized to characterize soils. Contact during reclamation to be on-site to observe.

Commitments made:	See attached CON/REC Units changes

Recorded by:	Lisa Larsen and Corey Baker, WESTECH

013035

RSVP Roster

2011 - SD, Buffalo - First Responder Training Program (Dinner)

2/1/2011 5:30:00 PM

RSVP ID	Web Code	Signin #	RSVP (28)	CPS	Audience	Company	Title	Name
1	E6EB-RPQM	1	1		Emergency Officials	BUFFALO FIRE DEPT	FIRE CHIEF	JOHN HELMS
2	EAXH-2HA	NL	2		Public Officials	HARDING COUNTY	STATE'S ATTORNEY	ROBERT A. HAIVALA
3	E6EB-RLQK	DNN	12		Emergency Officials	HARDING COUNTY AMBULANCE SERVICE	EMT TRAINING OFFICER	ANNETTE SLABA
4	E6EB-RMQS	1	1		Emergency Officials	HARDING COUNTY EMERGENCY MANAGEMENT	MANAGER	KATHY GLINES
5	E6EB-RKQM		2		Emergency Officials	HARDING COUNTY SHERIFF OFFICE	SHERIFF	WILLIAM CLARKSON
6	EE2J-4GFV	1	2		Sponsors	MONTANA-DAKOTA UTILITIES		TOBY BORDEWYK
7	EC4F-ZKM	1	1		Sponsors	PLAINS PIPELINE		DANIEL HOLLI
8	EAMK-LRPB		2		Local Public Officials	SOUTH DAKOTA DEPT OF TRNSPRTN	MANAGER	
9	EDYR-23C	111	3		Sponsors	TRANSCANADA	AREA MANAGER - WEST RIVER	VIRGIL PFENNIG
10	EAXH-3MAE	1111	2		Sponsors	WILLISTON BASIN INTERSTATE PIPELINE	SAFETY AWARENESS COORDINATOR	DON JOHNSON

11 1 sponsor Steve Wilkerson

Paradigm
222 S. Ridge Rd.
Wichita, KS 67209
877-477-1165

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RSVP Signature Form

Meeting City, ST: Buffalo, SD. Meeting TIme: 2-1-11 1730.

RSVP ID	Print Your Company Name	Print Your Name
11	Robert L. Soto	Roadster.
10	WILLISTON BASIN INT. PIPELINE	DON JOHNSON
07	Plains Pipeline	Daniel Holli
—	[illegible]	[illegible]
09	Trans Canada	Virgil Pfennig
02	Robert Johnson Harding Co	Robert Johnson
02	Harding County	Charles Verhulst
04	Kathy Glines - Harding Co.	Em
03	Laura Johnson - EMT	Laura Johnson
03	Bill Johnson	EMT
03	Lynnette Stugelmeyer	EMT
01	TROY STUGELMEYER	FIRE
03	Julia Davis	EMT / State's Attorney Office
03	Annette Slaba	EMT
02	Ray Ford Anderson	Harding County
09	Kirsten Torgerson	TransCanada
09	[illegible]	" "
10	Kay Latham	EMT
10	Darwin Latham	EMT & VFD Fire Chief
10	Tim Glines	
6	Bruce Springgymath	MOU
6	Toby Bordewyk	MOU

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RSVP Roster

2011 - SD, Mitchell - First Responder Training Program (Lunch)

2/7/2011 11:30:00 AM

RSVP ID	Web Code	SignIn #	RSVP (46)	CPS	Audience	Company	Title	Name
1	E6EC-4TQN		2		Local Public Officials	COUNTY COURTHOUSE	COMMISSIONER	PAT MARONEY
2	E6EC-4LQK	//	2		Emergency Officials	DAVISON COUNTY SHERIFFS OFFICE	SHERIFF	DAVID MILES
3	EDYJ-QMF		1		Emergency Officials	GREGORY AMBULANCE	DIRECTOR	CHERYL CLARK
4	EDYJ-M4FR		1		Emergency Officials	GREGORY AMBULANCE SERVICE	DIRECTOR	CHERYL CLARK
5	E6EC-7WQS	///	4		Emergency Officials	HANSON COUNTY DISASTER & EMERGENCY SERVICES	MANAGER	KEVIN KAYSER
6	E6EC-3BQE	/	3		Emergency Officials	HANSON COUNTY LOCAL EMERGENCY PLANNING COMMITTEE	LEPC COORDINATOR	RAY THOMAS
7	EAA4-AGHM	///	2		Local Public Officials	MARION (CITY OF)	MAYOR	RON GLOBKE
8	EDFH-8TH		0		Sponsors	MIDAMERICAN ENERGY	SR. GAS ENGINEER	RON DAKE
9	E6EC-2AQM	//	1		Emergency Officials	MINER COUNTY SHERIFFS OFFICE	SHERIFF	LANNY KLINKHAMMER
10	E9BK-2LUB	///	16		Local Public Officials	MITCHELL CITY WATER TREATMENT	MANAGER	
11	E6EC-4HQK	////	1		Emergency Officials	MITCHELL DEPT OF PUBLIC SFTY	CHIEF	LYNDON OVERWEG
12	EDWQ-VBC	/	1		Sponsors	NORTHERN NATURAL GAS COMPANY	TEAM LEADER	MIKE GARRY
13	EDJ4-KL8	////	2		Emergency Officials	NORTHWESTERN ENERGY	ENGINEER	JAMIE HAJEK
14	EDYJ-QKF	///	2		Sponsors	NORTHWESTERN ENERGY	SAFETY	JAMES WILKENS
15	EE6L-HYV		2		Others	NORTHWESTERN ENERGY	DISTRICT SUPT	TERRY MEYER
16	EAYF-WYQ	//	1		Sponsors	NUSTAR ENERGY LP	PIPELINE SAFETY COORDINATOR	TROY STYER
17	EE6N-NKU2	/	1		Sponsors	TRANSCANADA KEYSTONE PIPELINE		ROB LATIMER

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18	EAA6-3VHB	4	Local Public Officials	TRANSPORTATION DEPT

IIII

19 F Sponsor Paradigm 222 S. Ridge Rd. Wichita KS 67209 877-427-1162. Steve Roberts

20 1 CO Davison Co. Sheriff Dept. 1015 S. Miller Mitchell SD 57301. 605-995-8630 David Miles

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RSVP Signature Form

Meeting City, ST: Mitchell, SD Meeting Time: 2-9-11 1130hrs

RSVP ID	Print Your Company Name	Print Your Name
10	City of Mitchell Wastewater	Loren Skinner
10	City of Mitchell Wastewater	Ryan Nussbaum
10	City of Mitch Water	Rick Vanderheiden
10	City of Mitchell Water	Dave Grosz
09	Miner Co. Hwy Dpt.	Ron Krempges
11	City of Mitchell Engineering	Corey Beyer
11	CITY OF MITCHELL ENGINEERING	RYAN MUCK
11	City of Mitchell Engineering	Terry Johnson
18	DOT Tyndall Dot	Jacque Humpal
18	DOT Yankton DOT	Steve Baxter
18	DOT Yankton	Tony Hirschman
18	DOT Menno DOT	John Huber John Huber
11	City of Mitchell	

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RSVP Signature Form

Meeting City, ST: Mitchell, SD Meeting Time: 2-24-11 1130am

RSVP ID	Print Your Company Name	Print Your Name
14	Transcanada - Keystone	Jeremy Dangel
07	Morris E Dorf	Martin E Dorf
19	Avadisan	Robert L. Soden
13	Northwestern Energy	James Wilkens
09	Miner County	PAT MARONEY
23	NorthWestern Energy	Ken Schoenfelder
19	NorthWestern Energy	Craig Fergen
14	Northwestern Energy	Jamie Hajek
14	NWE	
12	Northern Natural Gas	Alvin Madrid
16	Nustar Energy	Ron Kleinsasser
16	NuStar Energy	Curt Grafing
05	Hanson Co LEPC	Jan Nebelsick
05	Hanson Co hepo.	Bay Thomas
13	NorthwesternEnergy	Allan Hale
02	Davison Co Sheriff	David Miles Sheriff
20	Davison co. sheriff	Tim Reitzel Deputy sheriff
06	Hanson Co EM	Kevin Kayser EM
10	City of Mitchell	Jon Vermeulen
10	City of Mitchell	Kerry Plooster
10	City of Mitchell	
16	City of Mitchell	Tyler Veurink
05	Hanson County	Carl Nordvedt
10	City of mitchell water	Kirby Larson
10	City of Mitchell Water	Brian Wendelboe
13	NorthWestern Energy	Melissa Barnett
02	Howard Udurter-Fire Dept.	Nathan Kizer
10	Cityofmitchell water	Tylor Peterson
07	Cityof Marion Water	Josh Picek
07	City of Marion	Dustin Sutzle

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RSVP Roster

2011 - SD, Pierre - First Responder Training Program (Dinner)

1/31/2011 5:30:00 PM

RSVP ID	Web Code	SignIn #	RSVP (46)	CPS	Audience	Company	Title	Name
1	E6EC-98QK		2		Emergency Officials	COLOME VOLUNTEER FIRE DEPT	FIRE CHIEF	GLENN SEALEY
2	E6EC-FRQN		3		Local Public Officials	COUNTY COURTHOUSE	COMMISSIONER	NICHOLAS KONST
3	E6EC-92QK	11	2		Emergency Officials	CROW CREEK SIOUX AMBULANCE SERVICE	DIRECTOR	THOMAS THOMPSON
4	E6EC-KLQM		1		Emergency Officials	HYDE COUNTY SHERIFF DEPT	SHERIFF	MIKE VOLEK
5	E6EC-9JQM		1		Emergency Officials	JONES COUNTY SHERIFFS DEPT	SHERIFF	FRED KOESTER
6	E6EC-DRQM		1		Emergency Officials	MIDLAND VOLUNTEER FIRE DEPT	FIRE CHIEF	RUBIN VOLMUR JR
7	EBWG-2BN		2		Sponsors	MONTANA DAKOTA UTILITIES		BO SECREST
8	EAYF-WXQ		1		Sponsors	NUSTAR ENERGY LP	PIPELINE SAFETY COORDINATOR	TROY STYER
9	E6EC-FBQI	IIII	8		Emergency Officials	PIERRE FIRE DEPT	FIRE CHIEF	WILLIAM ALEXANDER
10	EDYJ-JQFB	IIIIIII	15		Local Public Officials	SD STATE ELECTRICAL COMMISSION	EXEC DIRECTOR	
11	E6EC-FDQK	I	1		Emergency Officials	SD STATE FIRE MARSHALS OFFICE	STATE FIRE MARSHAL	ALLEN CHRISTIE
12	EDJN-UDV	III	3		Sponsors	SOUTH DAKOTA INRASTATE PIPELINE CO	VICE PRESIDENT	GORDON WOODS
13	E8H6-3B7B	11	3		Local Public Officials	SOUTH DAKOTA PUBLIC UTILITIES COMMISSION	PIPELINE SAFETY PROGRAM MANAGER	NATHAN SOLEM
14	E6EC-ECQM		1		Emergency Officials	STANLEY COUNTY LAW ENFORCEMENT OFFICE	SHERIFF	BRAD RATHBUN
15	EDYR-4QC	111	3		Sponsors	TRANSCANADA	AREA MANAGER - WEST RIVER	VIRGIL PFENNIG

16

11 PD

HAAKON. Gouts
22488 Dusty Ridge
Midland, SD 57552
605. 843-2267

Gous SNOOK

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Pre-Meeting RSVP Signature Form

Meeting City, ST: Pierre, SD. Meeting Date/Time: 1-31-11 1230pm

Print Your Name	NO ABBREVIATING! "PLEASE" Print Your Agency/Company Name	TT#	RSVP#
Ed Briggs	Haakon Co. Comm.	702	16
Brad Like	Fording Electric SDEC	706	10
Paul Arnould	Pierre Fire Department	707	09
Craig Brookmueller	State of SD	711	12
Tyler Menzel	John Hoffman Electric	713	10
Ian Paul	Pierre Fire Dept	715	09
Jack Estes	Crow Creek Sioux Ambulance	716	03
Roland Hawk	" " "	717	03
Sweena Boe	Dakota Electric	720	10
Kirsten Torgerson	Transcanada	722	15
[illegible]	SDEC	—	10
Kara Semmler	PUC		13

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Pre-Meeting RSVP Signature Form

Meeting City, ST: Pierre, SD. Meeting Date/Time: 1-3/11 - 1230am.

Print Your Name	NO ABBREVIATING! "PLEASE" Print Your Agency/Company Name	TT#	RSVP#
Bruce Earland	S.D. Intrastate Pipeline Co.		12
Virgil PFennig	TRANSCANADA		15
R. Bud Andersen	" "		15
PAUL TITZE	STATE OF S.D. (SDEC)	701	12
Gordon Woods	South DAKOTA INTRA PL.		12
Gary Snook	Hanson County Commission	703	16
Brent Schoulte	Schoulte Electric (SDEC)	704	10
John Hoffman	John Hoffman Electric (SDEC)	705	10
Bill Alexander	Pierre FD	708	09
Leon Ellis	Pierre FD	709	09
Monty Kenwathy	FF Pierre	710	10
Joshua Williams	Pierre, SD / SDPUC	712	12
Duane Messing	Pierre SD Todds Electric	714	10
Buddy Cronin	Nystrom Electric Pierre	718	10
Nathan Solem	South Dakota Public Utilities Com	719	13
PATRICIA SNYDER	PIERRE FIRE DEPT	721	09
Bill Newlon	Pierre Fire Dept	723	09
Glenda Marks	SD Fire Marshal's Office	724	11
Williams SHAWN	Todds Electric	726	10

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RSVP Roster

2011 - SD, Rapid City - First Responder Training Program (Lunch)

2/2/2011 11:30:00 AM

RSVP ID	Web Code	SignIn #	RSVP (59)	CPS	Audience	Company	Title	Name
1	E6EC-M2QM		4		Local Public Officials	BOX ELDER (CITY OF)	PLANNING DIRECTOR	MICHAEL MCMAHON
2	E6EC-NDQK		4		Emergency Officials	BOX ELDER POLICE DEPT	CHIEF	TIM RYAN
3	E6EC-NXQK		2		Emergency Officials	ELLSWORTH AFB FIRE DEPT	FIRE CHIEF	DAVID OLSEN
4	E6EC-LZQM		1		Emergency Officials	FAITH FIRE DEPT	FIRE CHIEF	JUSTIN HAINES
5	EDJN-TNVB		1		Emergency Officials	MEADE COUNTY EMERGENCY MGMT	MANAGER	KATHIE GRANT
6	EDJN-UUVV		3		Sponsors	MONTANA-DAKOTA UTILITIES		TOBY BORDEWYK
7	E6EC-NQQK		2		Emergency Officials	NORTH HAINES FIRE DEPT	SECRETARY	JAMES W. RUSSELL, JR.
8	E6EC-QCQN		2		Local Public Officials	PC EMERGENCY MANAGEMENT	DIRECTOR	ANTHONY CARBAJAL
9	E6EC-Q9QN		5		Local Public Officials	PENNINGTON COUNTY	HIGHWAY SUPERINTENDENT	HIENE JUNGE
10	EAC8-6RGM		3		Local Public Officials	PHILIP (CITY OF)	MAYOR	JOHN HART
11	EC4F-ZJM		1		Sponsors	PLAINS PIPELINE		DANIEL HOLLI
12	E6EC-PBQR		4		Emergency Officials	RAPID CITY DEPT OF FIRE-EMS SERVICES	FIRE PREVENTION	RICH BRODERICK
13	E6EC-N4QI		14		Emergency Officials	RAPID CITY FIRE DEPT	FIRE OFFICIAL	MARK ENRIGHT
14	E6EC-NKQM		1		Emergency Officials	RAPID CITY POLICE DEPT	POLICE LIEUTENANT	PETER RAGNONE
15	E6EC-MNQM		2		Emergency Officials	SD HIGHWAY PATROL-RAPID CITY DISTRICT 3	OFFICER IN CHARGE	CPT. KEVIN KARLEY
16	E6EC-N3QK		6		Emergency Officials	WHISPERING PINES VOLUNTEER FIRE DEPT	CHIEF	STEPHEN KEEGAN
17	EALA-W3EE		1		Sponsors	WILLISTON BASIN INTERSTATE PIPELINE	SAFETY AWARENESS COORDINATOR	DON JOHNSON

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18	EBGL-TW7E		2		Sponsors	WILLISTON BASIN INTERSTATE PIPELINE	SAFETY AWARENESS COORDINATOR	DON JOHNSON
19	EALA-W4E		1		Emergency Officials	WILLISTON BASIN INTERSTATE PIPELINE CO	AREA REP	BOB HENDRICKSON

20 1 Sponsor Paddock 222 S. Ridge Rd. Wichita KS 67209. 877-422-4162 Dale Witherson.

21 11 Sponsor Black Hills Power. 409 Deadwood Ave. Rapid City SD. 605-742-8448

22 1 PO HAAKON County Hwy. PO Box 156. Philip, SD 57567. 605-859-2472. Kenny Neville.

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RSVP Signature Form

Meeting City, ST: Rapid City, SD. Meeting Time: 8-2-11 1130CT

	RSVP ID	Print Your Company Name	Print Your Name
22	~~77~~ 79	Haakon Co Hgy Supt	Kenny Neville
	06	MDU	Ron Blum
	17	WBI Pipeline Co.	Bob Hendrickson
	06	MDU	Casey Williamson
	10	City of Philip/Philip Fire	Matt Reckling
	07	North Haines Vol Fire Dept	Jim Russell
	01	CITY OF BOX ELDER	AL TODD
	14	RAPID CITY POLICE	Peter Ragnone
	16	WPVFD	Craig Fairey
	09	Pennington Co. Hwy	Mike Sotterer
	21	Black Hills Power (BH Corp)	[illegible]
	16	WPVFD	Jerry EATON
	03	Ellsworth FES	Dean J. Stetson II
	01	City of Box Elder PD	Tully Jackson
	09	Pen. Co. Highway	MARK A. Schock
	13	Rapid City Fire Dept	Jack Tomac
13	~~76~~	WDT Fire Science	Mark Menning
13	~~76~~	" " "	Marshall Keefe
13	~~76~~	" " "	Michael Seiler
	16	Whispering Pines	Ken Orrock
	13	Rapid City FD.	Mark Enright
	13	WDT Fire Science	MARCIN LEWANDOWSKI
	15	SDHP	RICK MILLER
	16	JUSTEN LOVE	WPVFD
	12	Anthony CARBAJAL	RCPCEM
	12	Alexa White	RCPCEM
	02	Boxelder Police Dept.	Kate Ackerson
	02	Box Elder P.D.	Timothy Ryon

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RSVP Signature Form

Meeting City, ST: ~~Rapid City~~, SD Meeting Time: 2-2-11 1130AD

RSVP ID	Print Your Company Name	Print Your Name
20	Robert L. Cobb	Paradigm
11	Plains Pipeline	Daniel Holl
17	Williston Basin Int. Pipeline	Don Johnson
21	Black Hills Power	~~Frank~~ Hawk
09	~~Pen~~ Pennington County Hwy Dept	Glenn Bintliff
09	Pennington County Hwy Dept	Duane Anderson
07	North Haines VFD	Monty Bullock
05	Meade County Emy Mgmt	Kathie Grant
16	Whispering Pines VFD	Stephen Keegan
16	Whispering Pines VFD	Bruce Jensen
10	Philip Vol Fire Dept	Cody Garner
10	Philip Fire Dept	Marty Gartner
09	Penn. Co. Hwy	Mike Casjens
01	City of Box Elder	Michael McMahon
09	Pennington Co. Highway	Chris Wiek
03	Ellsworth AFB FD	Dave Olsen
01	City of Box Elder	Paul Schmidt
13	City of Rapid City Fire Dept.	Dan Janecek
13	WDT Fire Science	Mitch Hove
13	WDT Fire	Tanner Waltz
13	" "	Dustin Wenzel
13	" "	Cody Allen
13	WDT Fire	Kurt Carlson
15	SDAP	Kevin Karley
02	Boxelder PD	Chris Misselt
13	Rapid City Fire Dept	Tim Weaver
11	Plains Pipeline	Clayton Miller
11	Plains Pipe line	Mark Johring
02	Box Elder P.D	Jason Dubois

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RSVP Roster

2011 - SD, Spearfish - First Responder Training Program (Dinner)

2/2/2011 5:30:00 PM

RSVP ID	Web Code	Signin #	RSVP (21)	CPS	Audience	Company	Title	Name
1	E6ED-CMPR	IIII	4		Emergency Officials	BUTTE COUNTY AMBULANCE SERVICE	DIRECTOR	JANIE STEVENS
2	E6ED-CEPK	III	1		Emergency Officials	LAWRENCE COUNTY EMERGENCY MANAGEMENT	DIRECTOR	PAUL THOMSON
3	E6ED-C8PS	I	2		Emergency Officials	LAWRENCE COUNTY PUBLIC SAFETY ANSWERING POINT	911 COORDINATOR	TOM SANDVICK
4	EDJN-UFV	III	3		Sponsors	MONTANA-DAKOTA UTILITIES		TOBY BORDEWYK
5	EC4F-ZLM		1		Sponsors	PLAINS PIPELINE		DANIEL HOLLI
6	E6ED-DMPK	I	1		Emergency Officials	SOUTH DAKOTA NATIONAL GUARD	OPERATIONS SGT	BLAINE ANDERSON
7	E6ED-EGPM	II	2		Local Public Officials	SPEARFISH (CITY OF)	PLANNING DIRECTOR	JAYNA WATSON
8	E6ED-CQPM	II	2		Emergency Officials	STURGIS VOLUNTEER FIRE DEPT	FIRE CHIEF	RON KOAN
9	E6ED-EVPM		2		Emergency Officials	WHITEWOOD POLICE DEPT	POLICE CHIEF	JERRY DAVIDSON
10	EBGM-PL6E	I	1		Sponsors	WILLISTON BASIN INTERSTATE PIPELINE	SAFETY AWARENESS COORDINATOR	DON JOHNSON
11	EAXH-2NA		2		Others	WILLISTON BASIN INTERSTATE PIPELINE COMPANY	COMPRESSOR STATION SUPERVISOR	DAVID S BROWN

12 11 Sponsor. Black Hills Power P.O. Box 1400 Rapid City, SD 57709. 605-721-2287 Sheila Suurmeier.

13 1 Sponsor. Paradigm 222 S Ridge Wichita, KS 67209. 877-472-1162 Steve Roberts.

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013049

RSVP Signature Form

Meeting City, ST: Spearfish, SD. Meeting TIme: 2-2-11 1800 MT

RSVP ID	Print Your Company Name	Print Your Name
10	WILLISTON BASIN PIPELINE CO.	DON JOHNSON
12	Black Hills Power	FRANK HAUK
12	Black Hills Power - Black Hills Corp.	Sheila Suurmeier
13	Landowner	Robert L. Sode
09	Spearfish Volunteer Fire	Dalton Baker
02	Lawrence County Emergency Mgmt	Rene' Larson
02	Lawrence County Sheriff's Office	Sue Black
07	Spearfish Volunteer Fire Dept	
01	Belle Fourche Ambulance	Janice Stein
01	Belle Fourche Ambulance	Sharon K. Klok
01	Belle Fourche Ambulance	Kendall Stevens
01	" " "	
03	~~Tom Sandvick~~ Lawrence County	Tom Sandvick
06	Wm Blaine Anderson SDNG	Wm Blaine Anderson
02	Lawrence County Emergency Mangmt	
08	SVFD	Ethan A Berk
4	MDU	Bruce Spyngynatyk
4	MDU	Russell Gmuzik
4	MDU	Toby Bordewyk
1	WBI	DAVID S BROWN
08	SVFD	PAUL PANKONIN

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RSVP Roster

2012 - SD, Buffalo - First Responder Training Program (Dinner)

2/1/2012 5:30:00 PM

RSVP ID	Web Code	SignIn #	RSVP (29)	Audience	Company	Title	Name	City
1	H7BX-CXHN	0	1	Local Public Officials	County Courthouse	Commissioner	Matt Debow	BUFFALO, SD
2	H7BX-D2HN	1	1	Local Public Officials	County Courthouse	States Attorney	Robert Haivala	BUFFALO, SD
3	H7BX-D6HK	5	3	Local Public Officials	County Courthouse	Emergency Manager	Kathy Glines	BUFFALO, SD
4	H7BX-D7HK	2	3	Local Public Officials	County Courthouse	Commissioner	Charles Verhulst	BUFFALO, SD
5	H7BX-DAHK	2	2	Local Public Officials	County Courthouse	Register Of Deeds	Sue Litzel	BUFFALO, SD
6	H7BV-7VJK	10	8	Emergency Officials	Harding Cnty Ambulance Svc	Emt Training Officer	Annette Slaba	BUFFALO, SD
7	H7BV-7UJS	0	3	Emergency Officials	Harding County Emergency Mgmt	Manager	Kathy Glines	BUFFALO, SD
8	H7BV-3ZJK	1	2	Emergency Officials	Lemmon Fire Dept	Fire Chief	Chad Bumgarten	LEMMON, SD
9	H7BV-7ZJI	2	2	Emergency Officials	Ludlow Volunteer Fire Dept	Supervisor	Dale W Turbiville	BUFFALO, SD

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Sponsor Sign-In Sheet

2012 - SD, Buffalo - First Responder Training Program (Dinner)

2/1/2012 5:30:00 PM

RSVP ID	Web Code	Sign In #	RSVP (3)	Audience	Company & Contact	Attendee 1 Name & Signature	Attendee 2 Name & Signature	Attendee 3 Name & Signature
1	H7BX-MZH	1	1	Sponsors	PARADIGM LIAISON SERVICES Roberts, Steve			
2	HCKQ-UK6	1	1	Sponsors	PLAINS PIPELINE Dan Holli	Dan Holli		
3	H7BX-N2H	0	1	Sponsors	SOUTH DAKOTA PIPELINE ASSOCIATION (PAPA) Styer, Troy			
4	H7BV-7MJK	1	1	Sponsors	WILLISTON BASIN INTERSTATE PIPELINE CO. David Brown	DON JOHNSON		
		3						
5		2		Sponsors	TransCanada	See pg 2		
6		2		Sponsors	Montana-Dakota Utilities Co.			
		7						

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* Sponsor PL Co.

Meeting City, ST: Buffalo, SD

Non-RSVP Registration Form
Meeting Type:
ER - Contractor - Combo

Meeting Time: 530 pm

	Department / Agency Name	Title	Name	Address City, St Zip	Phone / Fax	Email address
*	Trans Canada	Area Manager	Virgil Pfennig	Omaha, NE	P: 402 F: 492-7469	Virgil_Pfennig@transcanada.com
*	TRANSCANADA	Relations Stakeholder	Bud Andersen	Whitehall, MT	P: 775-771-0851 F: 406-287-995x	budzaewesternenergy.com
Non RSVP	~~Fox Wilson~~ TDService	TDService EMS	Tom Wilson	Buffalo SD	P: 605-848-1336 F:	t_wilson328@hotmail.com TT 903
	Continental Res Buffalo Res	Prod. Foreman	Tim Glines	Buffalo SD	P: 605-375-3187 F: TT 911	tglines@contres
	Reva	Firefighter	Kent Wilkinson	Reva SD	P: 605 569 9156 F:	TT 920
*	Montana-Dakota Utilities	Dirt Mgr	Scott Gannaway	~~Sp~~ Spearfish, SD	P: 605-355-4053 F: 605-645-2655	Scott.gannaway@mdu.com
*	MDU	Foreman	Bruce Spryncznatyk	Spearfish	P: 605-642-3049 F: 605-484-5007	Bruce.Spryncznatyk@mdu.com
					P: F:	
					P: F:	
					P: F:	
					P: F:	
					P: F:	
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					P: F:	

Instructor: _____

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Attendee Sign-in Sheet

Meeting City, St: Buffalo, SD

Meeting Type: ER - Contractor - Combo

Meeting Time: 5:30 AM / PM

TT#	Full Name (Please Print Clearly)	Title	Department / Agency / Company Name	RSVP ID (Internal Use)
901	Print: ALLISON WEAKLAND Sign: Allison Weakland	EMT	HARDING CO. AMBULANCE	6
904	Print: Robert Haivala Sign:	ITCSA.		2
907	Print: Dale Turbiville Sign: Dale Turbiville	Ludlow (Supervisor) Fire	Ludlow Fire	9
909	Print: Kathy Glines Sign: Kathy Glines	Harding Co. Em	Harding County, SD	3
912	Print: Carol Helms Sign: Carol Helms		Harding County	3
914	Print: Brian Teller Sign: Brian Teller	Harding County EMT	Harding County	6
915	Print: Annette Sisla Sign: Annette Sisla	Harding Co. EMT	Harding County Ambulance	6
917	Print: Lila Teigen Sign: Lila Teigen	HC EMTA	HC Ambulance	6
918	Print: Alvin Fabris Sign: Alvin Fabris	HC EMT	HC Ambulance	6
922	Print: Rachelle Phillips Sign: Rachelle Phillips	Deputy Director of Equalization for Harding County	Equalization Office Harding County	3
924	Print: Chad Baumgarten Sign: Chad Baumgarten	Lemmon Chief Fire Dept		8
926	Print: Ann Palfrey Sign: Ann Palfrey	Harding Co EMT		6
	Print: Sign:			
	Print: Sign:			
	Print: Sign:			
	Print: Sign:			

Instructor: _____

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Attendee Sign-in Sheet

Meeting City, St: Buffalo, SD

Meeting Type: ER - Contractor - Combo

Meeting Time: 5:30 AM / PM

TT#	Full Name (Please Print Clearly)	Title	Department / Agency / Company Name	RSVP ID (Internal Use)
	Print: ~~Text Text~~ E Sign:			
902	Print: Matt Weiland Sign:	EMT	Harding County Ambulance	6
905	Print: Laurie Leibel Sign:	EMT	Harding County Ambulance	6
906	Print: Brent Elmore Sign:	VFD, EMT	HardingCountx	6
908	Print: Bay Shinabarger Sign:	VFD, FF	Ludlow	9
910	Print: John Helms Sign:	Lead worker ~~VFD~~ + SD DOT	BVFD + SDDOT	3
913	Print: Matthew K. DeBow Sign:	Commissioner,	Harding County Commissioners.	4
916	Print: Michelle Rotenberger Sign:	HC EMS	HC EMS Ludlow, SD	6
919	Print: Milton Douglas Sign:	VSO	Buffalo, SD	5
921	Print: Scott Phillips Sign:	WDS	B + Harding SD	3
923	Print: Sue Litzel Sign:	HC.	Buffalo S.D.	5
925	Print: Charles Verhulst Sign:	Harding County Comm.	Harding County	4
	Print: Sign:			
	Print: Sign:			
	Print: Sign:			
	Print: Sign:			

Instructor: _____

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RSVP Roster

2012 - SD, Hot Springs - First Responder Training Program (Lunch)

1/30/2012 11:30:00 AM

RSVP ID	Web Code	SignIn #	RSVP (34)	Audience	Company	Title	Name	City
1	H7BV-9DJR	2	2	Emergency Officials	Cascade Fire Dept	Fire Chief	Tim Lamont	HOT SPRINGS, SD
2	H7BX-FFHN	0	4	Local Public Officials	County Courthouse	Commission Chair	Michael Ortner	HOT SPRINGS, SD
3	H7BX-DMHM	2	2	Local Public Officials	Custer (City Of)	Mayor	Harold Stickney	CUSTER, SD
4	H7BV-89JM	2	2	Emergency Officials	Custer County Sheriffs Office	Sheriff	Rick Wheeler	CUSTER, SD
5	H7BV-8UJK	0	2	Emergency Officials	Fairburn Fire Dist	Fire Chief	Clyde Gorsuch	FAIRBURN, SD
6	HAXQ-HYRK	3	1	Emergency Officials - Additional Responders	Fall River County Emergency Management	Asst Emergency Mgr	Andy Timmins	HOT SPRINGS, SD
7	H7BV-97JM	1	2	Emergency Officials	Fall River County Jail-Sheriff Office	Sheriff	Jeffrey Tarrell	HOT SPRINGS, SD
8	H7BV-8YJK	1	3	Emergency Officials	Hermosa Police Dept	Police Chief	James Daggett	HERMOSA, SD
9	H7BX-FVHM	4	2	Local Public Officials	Hot Springs (City Of)	Water Director	Gene Weisser	HOT SPRINGS, SD
10	H7BV-A3JK	3	4	Emergency Officials	Oral Vol Fire Dept	Chief	Russ Sanders	ORAL, SD
11	H7BV-AFJM	1	1	Emergency Officials	Smithwick Fire Dept	Fire Chief	Pete Kindred	SMITHWICK, SD
12	H7BV-6FJK	0	1	Emergency Officials	Williston Basin Interstate Pipeline Co.	Emergency Official	Bob Hendrickson	RAPID CITY, SD

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Sponsor Sign-In Sheet

2012 - SD, Hot Springs - First Responder Training Program (Lunch)
1/30/2012 11:30:00 AM

RSVP ID	Web Code	Sign In #	RSVP (8)	Audience	Company & Contact	Attendee 1 Name & Signature	Attendee 2 Name & Signature	Attendee 3 Name & Signature
1	HD9V-CMY	1	1	Sponsors	Black Hills Power Frank A. Hauk	Frank Hauk Frank A. Hauk		
2	HEWT-4AV	Ø	1	Sponsors	Montana-Dakota Utilities Co Ron Blum			
3	H7BX-MZH	1	1	Sponsors	PARADIGM LIAISON SERVICES Roberts, Steve			
4	HCKQ-UK6	4	4	Sponsors	PLAINS PIPELINE Dan Holli	Dan Holli Daniel Holli	Howard Selkenrick Dan Lillien	E. Clayton Miller E. Clayton Miller
5	H7BX-N2H	Ø	1	Sponsors	SOUTH DAKOTA PIPELINE ASSOCIATION (PAPA) Styer, Troy			
		6	8					

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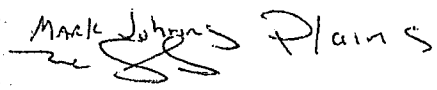
Attendee 4
Name & Signature



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Attendee Sign-in Sheet

Meeting City, St: Hot Springs SD

Meeting Type: ER - Contractor - Combo

Meeting Time: 11:30 AM / PM

TT#	Full Name (Please Print Clearly)	Title	Department / Agency / Company Name	RSVP ID (Internal Use)
901	Print: John Sidos Sign: John Sidos	Fire chief	Smithwick VFD	11
902	Print: Sign: Norm Kadwill	FR County Hazmat	Hot Springs SD	06
903	Print: Mick Jennigers Sign: Mick Jennigers	Oral FD	Oral, SD	10
904	Print: Richard S Wright Sign: R.S. Wright	Oral, FD	Oral, SD	10
908	Print: Kirk Johnson Sign: Kirk Johnson	Water Dept. City of	City of Custer	3
912	Print: Andrew Bosch Sign: Andrew Bosch	City of Hot Springs	City of HS.	9
914	Print: Marc Lamphere Sign: Marc Lamphere	Training officer ~~Cascade VFD~~	Cascade VFD.	1
916	Print: Charles Fadness Sign: Charles Fadness	EMT	HSAS	9
921	Print: Bill Schleining Sign: Bill A. Schleining	Custer Co SO	Custer, SO	4
	Print: Rose Fadness Sign: Rose Fadness	EMT	HSAS	9
	Print: Sign:			
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Instructor: _____

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Attendee Sign-in Sheet

Meeting City, St: Hot Springs SD

Meeting Type: ER - Contractor - Combo

Meeting Time: 11:30 AM / PM

TT#	Full Name (Please Print Clearly)	Title	Department / Agency / Company Name	RSVP ID (Internal Use)
905	Print: Jason Hamilton Sign:	Oral FD	Oral SD	10
906	Print: Lee M. Jones Sign:	DW500	Stat. of South Dakota	
907	Print: John Davies Sign: J. Davies	Oelrichs FD ~~RETIRED~~ " SD. STATE		
908	Print: Bill Mueller Jr Sign:	Water Operators	City of Custer	3
910	Print: Rick Matsamas Sign:	City of Oelrichs Water Attendant	City of Oelrichs	
911	Print: Stephanie Akers Sign:	City of Hot Springs Water & Wastewater Supt	City of HS	9
913	Print: Randy Seiler Sign: Randy Seiler	Hwy Supt Fall River Co		6
915	Print: Jim Degeest Sign:	County Sheriff Town Marshal	Hermosa S.D.	8
917	Print: SASON MARCH Sign:	Deputy	FRCSO	7
918	Print: John Nash Sign:	VFD	Cascade	1
919	Print: ANDY TITTLES Sign:	ASST EMS-Man	FALL River Co	6
920	Print: Rick Wheeler Sign: Rick Wheeler	Sheriff	Custer Co.	4
	Print: Sign:			
	Print: Sign:			
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Instructor: _____

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RSVP Roster

2012 - SD, Mitchell - First Responder Training Program (Lunch)

2/8/2012 11:30:00 AM

RSVP ID	Web Code	SignIn #	RSVP (66)	Audience	Company	Title	Name	City
1	H7BW-6DJM	2	2	Local Public Officials	Alexandria (City Of)	Water Director	Dennis Boggs	ALEXANDRIA, SD
2	H7BU-NRKM	3	3	Emergency Officials	Alexandria Fire Dept	Fire Chief	Donny Huberse	ALEXANDRIA, SD
3	H7BU-RVKK	1	2	Emergency Officials	Aurora County	Director Of Emergency Management	David Baker	PLANKINTON, SD
4	H7BW-7QJM	1	1	Local Public Officials	Canova (City Of)	Utilities Director	William Perrine	CANOVA, SD
5	HA2R-JVDK	1	2	Emergency Officials - Additional Responders	Davison Cnty Sheriffs Ofc	Chief Deputy	Steve Brink	MITCHELL, SD
6	H7BU-NMKK	0	1	Emergency Officials	Davison County Cert	Director	Allan Miller	MITCHELL, SD
7	H7BW-4GJM	0	4	Local Public Officials	Davison County Health Department	Health Official	Connie Fergen	MITCHELL, SD
8	H7BU-NLKK	1	3	Emergency Officials	Davison County Sheriffs Dept	Sheriff	David Miles	MITCHELL, SD
9	H7BU-NTKK	1	8	Emergency Officials	Hanson County, Sd Lepc	Emergency Official	Kevin J Kayser	ALEXANDRIA, SD
10	H7BU-NPKE	1	8	Emergency Officials	Hanson County, Sd Local Emergency Planning Committee	Lepc Coordinator	Ray Thomas	ALEXANDRIA, SD
11	H7BW-4MJM	0	1	Local Public Officials	Mitchell (City Of)	Building Official	John Hegg	MITCHELL, SD
12	HAYV-JJ9M	5	6	Local Public Officials - Additional Responders	Mitchell (City Of)	Public Works Secretary	Sheila Loecker	MITCHELL, SD
13	HAYV-JN9M	7	7	Local Public Officials - Additional Responders	Mitchell (City Of)	Public Works Secretary	Sheila Loecker	MITCHELL, SD
14	H7BW-4HJI	1	2	Local Public Officials	Mitchell Street & Sanitation	Sanitation Official	Ron Olson	MITCHELL, SD
15	HCLD-V8R	0	1	Local Public Officials - Additional Responders	Northwestern	Dot Coordinator	Melissa Baruth	HURON , SD
16	HEWL-YRX	0	2	Excavators	Nustar Energy Lp	Manager Of Operations	Bruce Myers	yankton, sd
17	H7BU-NNKR	2	2	Emergency Officials	Rosedale Fire Dept	Fire Chief	Moses Waldner	MITCHELL, SD
18	HB7V-K88M	2	2	Emergency Officials - Additional Responders	Spencer Fire Dept	Fire Chief	Don Rieck	SPENCER, SD
19	H7BV-LUJI	4	4	Local Public Officials	Transportation Dept	Transportation Official	Rob Hansen	SALEM, SD
20	H7BX-4QHM	2	2	Local Public Officials	Winner (City Of)	Water Director	Danny Ayers	WINNER, SD

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Sponsor Sign-In Sheet

2012 - SD, Mitchell - First Responder Training Program (Lunch)
2/8/2012 11:30:00 AM

RSVP ID	Web Code	Sign In #	RSVP (3)	Audience	Company & Contact	Attendee 1 Name & Signature	Attendee 2 Name & Signature	Attendee 3 Name & Signature	Attendee 4 Name & Signature
1	HCLF-LDR	1	1	Sponsors	NORTHERN NATURAL GAS COMPANY Alvin Madrid	Alvin Madrid			
2	H7BX-MZH	1	1	Sponsors	PARADIGM LIAISON SERVICES Roberts, Steve				
3	H7BX-N2H	1	1	Sponsors	SOUTH DAKOTA PIPELINE ASSOCIATION (PAPA) Styer, Troy	Troy Styer			

013062

Sponsor Sign-In Sheet

RSVP ID	Web Code	Sign In #	RSVP ()	Audience	Company & Contact	Attendee 1 Name & Signature	Attendee 2 Name & Signature	Attendee 3 Name & Signature
4		1			TransCanada 989-619-0123	Dan Sirois		
5		1			Nustar Energy 605-996-2361	Herb Albin		
6		4			NW Energy 605-928-7608		Allan Hale	Melissa Brandt
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Attendee Sign-in Sheet

Meeting City, St: Mitchell, SD

Meeting Type: (ER) - Contractor - Combo

Meeting Time: 11:30 (AM) PM

TT#	Full Name (Please Print Clearly)	Title	Department / Agency / Company Name	RSVP ID Internal Use
928	Print: Nick Ehrich Sign:		Alexandria Fire Dept	2
931	Print: Charles Goldammer Sign:	Supervisor	Mitchell SD. DOT	19
933	Print: Don Rieck Sign:	Chief	Spencer Fire	18
934	Print: John Ruden Sign:	Asst chief	Spencer Fire	18
936	Print: Marius Laursen Sign:	Fire Marshal	Mitchell Fire	
	Print: Paul Morris Sign:	Asst Fire chief	Mitchell Fire	
939	Print: Kelly Haggart Sign:	Asst. fire chief	Alex Fire	2
942	Print: Russel Weinberger Sign:	Co Hwy Supt	Davison County Hwy Dept.	
943	Print: JERRY R. FISCHER Sign:	DAVISON CO. COMMISSIONER	DAVISON COUNTY	
944	Print: Darrel Rekow-ST Sign:	Fire Fighter First Responder	Alex Fire	2
945	Print: David Bartels Sign:	Aurora County	EM	3
	Print: Sign:			
	Print: Sign:			
	Print: Sign:			
	Print: Sign:			
	Print: Sign:			

Instructor:

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Attendee Sign-in Sheet

Meeting City, St: Mitchell, SD

Meeting Type: (ER) - Contractor - Combo

Meeting Time: 11:30 AM / PM

TT#	Full Name (Please Print Clearly)	Title	Department / Agency / Company Name	RSVP ID (Internal Use)
905	Print: Loren Skinner Sign:	City of Mitchell	waste water	13
909	Print: Kevin Tiefz Sign:	Mitchell	DOT	19
910	Print: Rob Hansen Sign:	Mitchell		19
913	Print: Steve Brink Sign:	Davison Co S.O	Dav. Co S.O.	8
915	Print: Moses Waldner Sign:	Rosedale FD	Rosedale FD	17
917	Print: Calvin Cerv Sign:	Park water Sewer Water SD Supervisor	City of Winner	20
919	Print: Andy Menzie Sign:	Traffic Specialist City of Mitchell Traffic	City of Mitchell Traffic	
921	Print: Corey Beyer Sign:	Engineering City of mitchell	City of mitchell	13
924	Print: Sign:	city of mitchell	water	12
926	Print: Thomas Schuman Sign:	City of mitchell	water	12
927	Print: Tyler Peterson Sign:	city of mitchell	water	12
929	Print: Denny Boggs Sign:	City of Alexandria		1
930	Print: Robert Jungwirth Sign:	city of Alexandria		1
932	Print: Greg Nelson Sign:	Deputy Sheriff	Hanson Co	
935	Print: Lyndon Overweg Sign:	Chief of Public Safety	Mitchell Public Safety	
938	Print: Dave Miles Sign:	Dav. Co Sheriff		5

Instructor:

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Attendee Sign-in Sheet

Meeting City, St: Mitchell, SD

Meeting Type: (ER) - Contractor - Combo

Meeting Time: 11:30 AM / PM

TT#	Full Name (Please Print Clearly)	Title	Department / Agency / Company Name	RSVP ID (Internal Use)
901	Print: Bill Peering Sign: Bill Peering	Division Manager	Town & Country	4
902	Print: Tom Schroeder Sign: Tom Schroeder	ambulance	White Lake SD	
903	Print: Jon Vermeulen Sign:	City of mitchell	mitchell SD	13
904	Print: Eugene Wagaman Sign: EWC	city of mitchell	Mitchell SD	13
906	Print: John D. Hegg Sign: John D Hegg	"Com"	Mitchell SD	13
907	Print: Jeff Lanning Sign: JLM	Code Enf.	Mitchell SD	13
908	Print: Brent Huffman Sign: Brent Huffman	DOT	mitchell SD	19
911	Print: Ray Thomas Sign: Ray Thomas	Hanson Co L.E.P.C.	Wheat, SD	10
912	Print: Casey Tegethoff Sign: Casey Tegethoff	Hanson CO SD	Alexandria, SD	9
914	Print: Mark Waldner Sign: Mark Waldner	Hanson Co. S.D.	" "	17
916	Print: Danny Ayers Sign: Danny Ayers	City of Winner	winner SD.	20
918	Print: Dick W & W Sign:	City of Mitchell Traffic D.W		
920	Print: RYAN MUCK Sign:	CITY OF MITCHELL PUBLIC WORKS		13
922	Print: Brian Wunderlee Sign:	City of Mitchell W.W.		12
923	Print: Rick Vanderschaaf Sign:	city of Mitchell water		12
925	Print: Ron Olson Sign: Ron Olson	City of mitchell Street & Sanitation		14

Instructor: Dynum

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Attendee Sign-in Sheet

Meeting City, St: Mitchell, SD

Meeting Type: (ER) - Contractor - Combo

Meeting Time: 11 :30 (AM) PM

TT#	Full Name (Please Print Clearly)	Title	Department / Agency / Company Name	RSVP ID (Internal Use)
943	Print: Kevin Kaysser Sign: Kevin Kaysser	Hanson Sup	Hanson Corrections	
941	Print: Jim Montgomery Sign: Jim Montgomery	Davison Co EM	Davison Co Emergency Management	
	Print: Sign:			
	Print: Sign:			
	Print: Sign:			
	Print: Sign:			
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RSVP Roster

2012 - SD, Pierre - First Responder Training Program (Dinner)

2/2/2012 5:30:00 PM

RSVP ID	Web Code	SignIn #	RSVP (62)	Audience	Company	Title	Name	City
1	H7BU-XKKK	1	1	Emergency Officials	American Medical Response-Pierre	Director	Kandace Kritz	PIERRE, SD
2	H7BV-4VJM	1	1	Emergency Officials	Dewey County Jail-Sheriffs Dept	Sheriff	Les Mayer	TIMBER LAKE, SD
3	H7BV-3HJM	1	1	Emergency Officials	Dupree Fire Dept	Fire Chief	Robert Menzel	DUPREE, SD
4	H7BU-Y9KI	2	2	Emergency Officials	Hughes County Emergency/Disaster	Emergency Official		PIERRE, SD
5	HEWY-NQRK	0	4	Emergency Officials - Additional Responders	Lower Brule Ambulance Service	Training Coordinator	Doug Todd	LOWER BRULE, SD
6	H7BV-2CJK	3	4	Emergency Officials	Lyman County Ambulance Service	Director	Karen Willis	PRESHO, SD
7	H7BW-ZQJM	2	2	Local Public Officials	Midland (Town Of)	Utilities Director	Reuben Vollmer Jr	MIDLAND, SD
8	H7BU-XMKK	4	6	Emergency Officials	Pierre Fire Dept	Chief	William Alexander	PIERRE, SD
9	H7BU-XZKI	1	1	Emergency Officials	Pierre Police Chief	Police Chief	Brandon Bloit	PIERRE, SD
10	H7BW-VNJI	5	5	Local Public Officials	Pierre Utilities	Utilities Official	Brad Palmer	PIERRE, SD
11	HEWT-DDVI	0	1	Local Public Officials - Additional Responders	Rosebud Natural Resources	Biologist	Emily Boyd-Valandra	ROSEBUD, SD
12	H7BU-XQKK	1	1	Emergency Officials	Sd State Fire Marshals Ofc	State Fire Marshal	Allen Christie	PIERRE, SD
13	H7BU-XAKK	1	1	Emergency Officials	Selby Police Dept	Police Chief	David Tonstad	SELBY, SD
14	H7BU-Y2KE	1	2	Emergency Officials	South Dakota Emergency Response Commission	Chair South Dakota Serc	Robert Mcgrath	PIERRE, SD
15	HEWZ-8JR	0	3	Excavators	South Dakota Intrastate Pipeline Co.	Vp/Coo	Gordon Woods	Pierre, SD
16	H7BW-VYJK	5	5	Local Public Officials	South Dakota Public Utilities Commission	Pipeline Safety Program Manager	Nathan Solem	PIERRE, SD
17	H7BU-YRJM	1	1	Emergency Officials	Stanley County Law Enforcement Office	Sheriff	Brad Rathbun	FORT PIERRE, SD
18	H7BV-TGJL	0	1	Local Public Officials	State Legislature	State Representative	Honorable Manny J. Steele	SIOUX FALLS, SD
19	H7BW-THJL	0	1	Local Public Officials	State Legislature	State Representative	Honorable James W. Bolin	PIERRE, SD
20	H7BW-UCJL	0	1	Local Public Officials	State Legislature	State Representative	Honorable Mark K. Willadsen	PIERRE, SD
21	H7BW-ULJL	0	1	Local Public Officials	State Legislature	State Representative	Honorable Patrick A. Kirschman	PIERRE, SD
22	H7BW-UMJL	0	1	Local Public Officials	State Legislature	State Representative	Honorable Patty Miller	PIERRE, SD
23	H7BW-UPJL	0	2	Local Public Officials	State Legislature	State Representative	Honorable Phil Jensen	PIERRE, SD
24	H7BW-VCJL	0	1	Local Public Officials	State Legislature	State Representative	Honorable Thomas Jones	PIERRE, SD
25	H7BW-VHJL	0	2	Local Public Officials	State Legislature	State Senator	Honorable Tom Hansen	PIERRE, SD
26	H7BV-2WJK	2	2	Emergency Officials	Tripp County Sheriff Office	Sheriff	Clifford Schroeder	WINNER, SD
27	H7BW-PKJM	1	1	Local Public Officials	Walworth County Offices	Zoning Administrator	Roger Walker	SELBY, SD
28	H7BV-2VJK	4	5	Emergency Officials	Winner Fire Dept	Fire Chief	Walter Harter	WINNER, SD
29	H7BV-3GJM	0	1	Emergency Officials	Ziebach County Sheriffs Dept	Sheriff	Robert Menzel	DUPREE, SD
		36	60					

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Sponsor Sign-In Sheet

2012 - SD, Pierre - First Responder Training Program (Dinner)
2/2/2012 5:30:00 PM

RSVP ID	Web Code	Sign In #	RSVP (2)	Audience	Company & Contact	Attendee 1 Name & Signature	Attendee 2 Name & Signature	Attendee 3 Name & Signature
1	H7BX-MZH		1	Sponsors	PARADIGM LIAISON SERVICES Roberts, Steve			
2	H7BX-N2H	/	1	Sponsors	SOUTH DAKOTA PIPELINE ASSOCIATION (PAPA) Styer, Troy	Troy Styer		

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Sponsor Sign-In Sheet

RSVP ID	Web Code	Sign In #	RSVP ()	Audience	Company & Contact	Attendee 1 Name & Signature	Attendee 2 Name & Signature	Attendee 3 Name & Signature
5		1			South Dakota Interstate Pipeline	Gordon Woods		
6		1			South Dakota Interstate Pipeline	Bruce Eastgard		
7		1			[illegible] Canada	Virgil Peters		
8		1			South Dakota Interstate Pipeline	Bob Thompson		
9		1			TransCanada	Bud Anderson		
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Attendee Sign-in Sheet

Meeting City, St: Pierre, SD

Meeting Type: ER - Contractor - Combo

Meeting Time: 5:30 AM / PM

TT#	Full Name (Please Print Clearly)	Title	Department / Agency / Company Name	RSVP ID (Internal Use)
	Print: Clifford Schroeder Sign:	Sheriff	Tripp Co. Sheriff's Office	26
905	Print: Robert Menzel Sign: Robert Menzel	FD Chief	Dupree VFD	3
907	Print: Sean Kruger Sign:	Captain	Pierre VFD	8
909	Print: Reuben Sign:	Fire Chief	Midland VFD	7
911	Print: Shawn Hussey Sign:	Crew Leader	City of Pierre Water	10
913	Print: Greg Swanson Sign:	Chief Deputy	Stanley Co. Sheriffs office	17
916	Print: Dave Cole Sign: David Cole	EMS	Lyman Co Amb	6
915	Print: Jennifer Leichtman Sign:	EMT	N/A	6
918	Print: Glenda Marks Sign:	Fire Marshal's office	Fire Marshals office	12
920	Print: Mike Compton Sign:	Sheriff	Hughes County	4
922	Print: Brad Palmer Sign:	Utilities Director	City of Pierre	10
924	Print: Joshua Williams Sign:	Pipeline Safety Engineer with	SDPUC	16
928	Print: Ken McCREADY Sign:	with	Winner Fire Dep.	28
930	Print: Patricia Kinney Sign:	Environmental Program Scientist	SD DENR - SERC	14
934	Print: Kristie Fiegen Sign: Kristie Fiegen	Commissioner PUC	SD PUC	16
	Print: Sign:			

Instructor: _____

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Attendee Sign-in Sheet

Meeting City, St: _____, _____

Meeting Type:
ER - Contractor - Combo

Meeting Time: ____:____ AM / PM

TT#	Full Name (Please Print Clearly)	Title	Department / Agency / Company Name	RSVP ID (Internal Use)
929	Print: Kara Semmler Sign:	Staff attorney	SD PUC	16
931	Print: John Meyer Sign:		Winner Fire Dept	28
932	Print: Ron Sprenkle Sign:		Winner Fire Dept	28
933	Print: Scott Ernest Sign:		Winner Fire Dept.	28
935	Print: Nathan Solem Sign:	Pipeline Safety Program Manager	SDPUC	16
936	Print: Gary Hanson Sign:	Commissioner	PUC	16
	Print: Mark E. Venner Sign:	Stat Rep Dist 24		
	Print: Sign:			
	Print: Sign:			
	Print: Sign:			
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Instructor: _____

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Attendee Sign-in Sheet

Meeting City, St: Pierre, SD

Meeting Type: ER - Contractor - Combo

Meeting Time: 5:30 AM / PM

TT#	Full Name (Please Print Clearly)	Title	Department / Agency / Company Name	RSVP ID (Internal Use)
901	Print: Donald Kneeht Sign:	Police chief	SELBY PD	13
902	Print: TODD STIEHL Sign:	DEPUTY SHERIFF	TRIPP Co. SO.	26
904	Print: Roger R Walker Sign:	Zoning	walworth CO	27
906	Print: LES MAYER Sign:	Sheriff	Dewey Co SO	2
~~907~~	~~Print: Bob Thomsen~~ ~~Sign:~~	~~Electrician Manager~~		
908	Print: Randy Nemec Sign:	~~A~~ 1st Captain	Midland SD Fire Dept	7
910	Print: Travis Jones Sign:		Pierre Water Dept	10
912	Print: Kerry SSmith Sign:	Crew leader Street	City of Pierre Street	10
914	Print: Tim Anderson Sign:	EMT	Lyman Co Kennedy SD	6
917	Print: PATRICK SNYDER Sign:	1ST ASST Chief	Pierre FIRE	8
919	Print: Ian Paul Sign:	Dep Chief	Pierre Fire	8
921	Print: Bill Alexander Sign:	Chief	Pierre fire	8
923	Print: LYNN PATTON Sign:	OPERATIONS MANAGER	City of Pierre	10
925	Print: Rob Kinse Sign:	HSCEP	Hughes County	4
926	Print: KANDACE KAITZ Sign:	AMR OPS SUP	AMR	1
927	Print: Bryan Wade Sign:	Sgt.	Pierre PD	9

Instructor: _____

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RSVP Roster

2012 - SD, Rapid City - First Responder Training Program (Lunch)

1/31/2012 11:30:00 AM

RSVP ID	Web Code	SignIn #	RSVP (36)	Audience	Company	Title	Name	City
1	H7BU-ZHJM	0	2	Emergency Officials	Bennett County Sheriff Dept	Sheriff	Lindell Adair	MARTIN, SD
2	H7BV-7RJK	3	5	Emergency Officials	Box Elder Police Dept	Police Chief	John Keegan	BOX ELDER, SD
3	H7BX-CQHK	3	5	Local Public Officials	City Of Box Elder	Planning Director	Michael Mcmahon	BOX ELDER, SD
4	HEWM-DEXR	1	1	Emergency Officials - Additional Responders	Division Emergeny Management-South Dakota Dept Of Mil	Hazardous Materials Coordinator	Bob Van Winsen	PIERRE, SD
5	H7BV-6ZJK	2	2	Emergency Officials	Ellsworth Afb Fire Dept	Fire Chief	David Olsen	ELLSWORTH AFB, SD
6	H7BU-YZJK	0	1	Emergency Officials	Jackson County Sheriff Dept	Sheriff	Ray Clements Jr.	KADOKA, SD
7	H7BX-ARHN	1	1	Local Public Officials	Pennington County	Commissioner	Ken Davis	RAPID CITY, SD
8	H7BV-4YJI	1	1	Emergency Officials	Pennington County Sheriff	Sherriff	Kevin Thorn	RAPID CITY, SD
9	H7BX-B7HM	1	1	Local Public Officials	Rapid City (City Of)	Planning Director	Marcia Elkins	RAPID CITY, SD
10	HEWT-GXUK	3	3	Emergency Officials - Additional Responders	Rapid City Fire Dept	Capt/Haz Mat Team Leader	Matt Culberson	RAPID CITY, SD
11	HAB4-R2MK	1	1	Emergency Officials - Additional Responders	South Dakota Highway Patrol	Lieutenant	David Berkley	RAPID CITY, SD
12	H7BV-6TJK	5	4	Emergency Officials	Whispering Pines Volunteer Fire Dept	Fire Chief	Stephen Keegan	RAPID CITY, SD
13	H7BV-6FJK	0	2	Emergency Officials	Williston Basin Interstate Pipeline Co.	Emergency Official	Bob Hendrickson	RAPID CITY, SD
		21						
			29					

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Sponsor Sign-In Sheet

2012 - SD, Rapid City - First Responder Training Program (Lunch)

1/31/2012 11:30:00 AM

RSVP ID	Web Code	Sign In #	RSVP (7)	Audience	Company & Contact	Attendee 1 Name & Signature	Attendee 2 Name & Signature	Attendee 3 Name & Signature
1	HD9V-CMY	1	1	Sponsors	Black Hills Power Frank A. Hauk	Frank Hauk		
2	H7BX-M2H	1	1	Sponsors	PARADIGM LIAISON SERVICES Roberts, Steve			
3	HCKQ-UK6	4	4	Sponsors	PLAINS PIPELINE Dan Holli	Daniel Holli		
4	H7BX-N2H	0	1	Sponsors	SOUTH DAKOTA PIPELINE ASSOCIATION (PAPA) Styer, Troy			
5		2		"	Williston Basin Interstate Pl			
6		2		"	Montana-Dakota Utilities Co	See pg 2		

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2012 - SD, Rapid City 1/31/12 Lunch

Sponsor Sign-In Sheet

RSVP ID	Web Code	Sign In #	RSVP ()	Audience	Company & Contact	Attendee 1 Name & Signature	Attendee 2 Name & Signature	Attendee 3 Name & Signature
5		2		Sponsor	WILLISTON BASIN INTERSTATE PIPELINE	DON JOHNSON	Bob Hendrickson Bob Oestreich	
6		2		Sponsor	Montana-Dakota Utilities	Ron Blum	Wade Jurgens	
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18								

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Attendee Sign-in Sheet

Meeting City, St: Rapid City, SD

Meeting Type: ER - Contractor - Combo

Meeting Time: 11:30 AM / PM

TT#	Full Name (Please Print Clearly)	Title	Department / Agency / Company Name	RSVP ID (Internal Use)
901	Print: Bob Van Winsen Sign:	Haz Mat Coordinator	Office of Emergency Mngmt State of SD	4
902	Print: Craig Feurey Sign:	WBVFD Ellsworth AFB	Firefighter Utes	12
903	Print: Gary Klatko Sign:	Wh. Spring Pines VFD	Firefighter	12
904	Print: Chris Misselt Sign:	Sgt Box Elder PD		2
905	Print: Matt Gibbons Sign:	Capt - Haz Mat RCFD	RC Fire Dept	10
907	Print: Eric O'Connor Sign:	Firefighter RCFD	RC Fire Dept	10
909	Print: Lon Schattgen Sign:	Building Inspector City of Rapid City	Community Planning	9
912	Print: Dave Olsen Sign:	Fire Chief	Ellsworth AFB Fire Dept.	5
915	Print: Jason Walter Sign:	Sergeant	Box Elder P.D.	2
914	Print: Michael McMahon Sign:	Planner	Box Elder	3
918	Print: David Berkley Sign:	Lt	SDHP	11
919	Print: Stephen Keegan Sign:	Asst. Fire Chief	Whispering Pines Vol. Fire Dept.	12
929	Print: DENNIS GORTON Sign:	FIRE ADM	Pennington County Fire	7
	Print: Sign:			
	Print: Sign:			
	Print: Sign:			

Instructor: _____

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Attendee Sign-in Sheet

Meeting City, St: Rapid City, SD

Meeting Type: ER - Contractor - Combo

Meeting Time: 11:30 AM / PM

TT#	Full Name (Please Print Clearly)	Title	Department / Agency / Company Name	RSVP ID (Internal Use)
906	Print: Jim FRYBARGER Sign:	HAZ-MAT Tech FIREFIGHTER	RCFD	10
908	Print: ALFRED DIAL Sign:	MAYOR	City OF Box Elder	3
910	Print: Corey Brudnak Ken Sign:	Captain	Pennington County Sheriff	8
911	Print: DEAN STEVENS Sign:	A/C Flt	Ellsworth AFB.	5
914	Print: Timothy Ryan Sign:	BERO/Chief	Box Elder Police	2
	Print: AL TODD Sign:	PW DIRECTOR	BOX ELDER	3
917	Print: Bruce Jensen Sign:	CHIEF	WPFD	12
920	Print: Craig Hansen Sign:		WPFD	12
	Print: Sign:			
	Print: Sign:			
	Print: Sign:			
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	Print: Sign:			

Instructor: _____

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RSVP Roster

2012 - SD, Spearfish - First Responder Training Program (Dinner)

1/31/2012 5:30:00 PM

RSVP ID	Web Code	SignIn #	RSVP (25)	Audience	Company	Title	Name	City
1	H7BV-7KJR	4	6	Emergency Officials	Belle Fourche Fire Dept	Fire Chief	Mark Hespe	BELLE FOURCHE, SD
2	H7BX-C8HK	1	2	Local Public Officials	Bureau Of Land Management - South Dakota Field Office	Field Manager	Marian Atkins	BELLE FOURCHE, SD
3	H7BV-8FJK	2	3	Emergency Officials	Lawrence Cnty Sheriffs Ofc	911 Coordinator	Tom Sandvick	DEADWOOD, SD
4	H7BX-GFHM	2	4	Local Public Officials	Lead (City Of)	City Manager	Mike Stahl	LEAD, SD
5	H7BX-J6HM	2	2	Local Public Officials	Meade County Government Office	Planning Director	Kirk Chaffee	STURGIS, SD
6	HDTQ-WJHR	1	1	Emergency Officials - Additional Responders	Saint Onge Fire Dept	Fire Chief	Woody Hover	SAINT ONGE, SD
7	H9RC-ZWKM	1	1	Local Public Officials - Additional Responders	Spearfish (City Of)	Water/Wastewater Utilities Superintendent	Robert Glenn	SPEARFISH, SD
8	H7BV-6FJK	0	2	Emergency Officials	Williston Basin Interstate Pipeline Co.	Emergency Official	Bob Hendrickson	RAPID CITY, SD
		13	21					

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Sponsor Sign-In Sheet

2012 - SD, Spearfish - First Responder Training Program (Dinner)

1/31/2012 5:30:00 PM

RSVP ID	Web Code	Sign In #	RSVP (4)	Audience	Company & Contact	Attendee 1 Name & Signature	Attendee 2 Name & Signature	Attendee 3 Name & Signature
1	HD9V-CMY	1	1	Sponsors	Black Hills Power Frank A. Hauk	Frank Hauk Frank A Hauk		
2	H7BX-MZH	1	1	Sponsors	PARADIGM LIAISON SERVICES Roberts, Steve			
3	HCKQ-UK6	1	1	Sponsors	PLAINS PIPELINE Dan Holli	Dan Holli Dan Holli		
4	H7BX-N2H	0	1	Sponsors	SOUTH DAKOTA PIPELINE ASSOCIATION (PAPA) Styer, Troy			
5		2		"	Williston Basin Interstate P.L. Co			
6		3		"	Montana-Dakota Utilities Co			
		8	4					

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Sponsor Sign-In Sheet

RSVP ID	Web Code	Sign In #	RSVP ()	Audience	Company & Contact	Attendee 1 Name & Signature	Attendee 2 Name & Signature	Attendee 3 Name & Signature
5		2		Sponsor	WBIP	Don Johnson	David Brown	
6		3		Sponsor	Montana-Dakota Utilities	Scott Simonsen	Bruce Spiegelberg	Ron Blum
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Attendee Sign-in Sheet

Meeting City, St: Spearfish, SD

Meeting Type: ER - Contractor - Combo

Meeting Time: 5:30 AM / PM

TT#	Full Name (Please Print Clearly)	Title	Department / Agency / Company Name	RSVP ID Internal Use
902	Print: Shelley Dragoo Sign: Shelley Dragoo	Telecommunicator	Lawrence County Sheriff's Office	3
903	Print: Robert Colton Sign:	Worker/Sworn Supervisor	City of Spearfish	7
905	Print: Jerilyn Rich Sign:	Owner	JBL, LLC Meade County	5
907	Print: Ryan Reeves Sign:	Lieutenant	Belle Fourche Fire Dept	1
909	Print: Chuck Carter Sign:	Deputy Chief	Lead Volunteer Fire Dept	4
912	Print: Fritz Carlson Sign:	Assistant Chief	Belle Fourche VFD	1
	Print: Sign:			
	Print: Sign:			
	Print: Sign:			
	Print: Sign:			
	Print: Sign:			
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Instructor: _____

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Attendee Sign-in Sheet

Meeting City, St: Spearfish, SD

Meeting Type: ER - Contractor - Combo

Meeting Time: 5:30 AM / (PM)

TT#	Full Name (Please Print Clearly)	Title	Department / Agency / Company Name	RSVP ID (Internal Use)
901	Print: MARIAN F HAMILTON Sign: Marian F Hamilton	Dispatcher	Lawrence County Sheriff's office	3
904	Print: BILL RICH Sign:	Planning Dir. 911	Meade County EM Dept	5
906	Print: Woody Hover Sign:	Fire Chief	ST. ONGE VFD	6
908	Print: Mike Stahl Sign: mystahl	City Admin LVFD	LVFD	4
910	Print: Russell Pigors Sign: Russell Pigors	Physical Scientist	Bureau of Land Mgt.	2
911	Print: Mark D. Hespe Sign: Mark D. Hespe	Belle Fourche Fire Chief	Belle Fourche Fire Dept	1
913	Print: Thomas Jankord Sign: Thomas Jankord	Belle Fourche FD Captain	BFVFD	1
	Print: Sign:			
	Print: Sign:			
	Print: Sign:			
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Instructor: _____

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RSVP Roster

2013 - SD, Belle Fourche - Safety Awareness Training Program (Dinner)
1/29/2013 5:30:00 PM

RSVP ID	Web Code	SignIn #	RSVP (44)	Audience	Company	Title	Name	City
1	L6X2-BT7		2	Emergency Officials	Belle Fourche Ambulance Service	Belle Fourche Ambulance Crew Members	Michelle Schmidt	BELLE FOURCHE, SD
2	KV4V-UF3K		1	Emergency Officials - Additional Responders	Belle Fourche Vfd	Firefighter	Thomas Jankord	BELLE FOURCHE, SD
3	KV4Z-EDYK		10	Emergency Officials	Belle Fourche Vfd	Fire Chief		BELLE FOURCHE, SD
4	KV4Z-DXYN		1	Public Officials	Butte County	Commissioner, District 3	Steve Smeenk	BELLE FOURCHE, SD
5	KV4Z-EAYM		5	Emergency Officials	Butte County Government Office	Emergency Services Director	Percy Bekken	BELLE FOURCHE, SD
6	KV4Z-E7YM		4	Emergency Officials	Butte County Sheriffs Office	Sheriff	Fred Lamphere	BELLE FOURCHE, SD
7	KV4Z-MYYI		3	Public Officials	Butte-Meade Sanitary Water	Manager	Merri Stapp	NEWELL, SD
8	KV4Z-JBYK		1	Emergency Officials	Lawrence County Ema	Administration Emergency Management	P. René Larson	DEADWOOD, SD
9	KV4Z-QYYI		1	Public Officials	Lawrence County Housing	Maintenance	Tyler Bush	STURGIS, SD
10	KV4Z-JCYE		1	Emergency Officials	Lawrence County Sd Lepc	Director	Paul Thomson	DEADWOOD, SD
11	KV4Z-HKYK		2	Emergency Officials	Lawrence County Sheriffs Office	911 Coordinator	Tom Sandvick	DEADWOOD, SD
12	L2MN-XLMM		2	Public Officials - Additional Responders	Meade County Offices	Planning/Engineering/Gis	Bill Rich	STURGIS, SD
13	KV4Z-PHYK		1	Emergency Officials	South Dakota National Guard	Operations Sgt	Sfc Wm. Blaine Anderson	SPEARFISH, SD
14	KV4Z-REYR		6	Emergency Officials	Sturgis Fire & Ems	Chief	Tom Trigg	STURGIS, SD
15	KV4Z-CGYK		2	Emergency Officials	Wildland Fire Suppression Div	Manager	Jay Esperance	RAPID CITY, SD
16	KV4Z-ELYK		2	Emergency Officials	Williston Basin Interstate Pipeline County	Emergency Official	David Brown	BELLE FOURCHE, SD

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Sponsor Sign-In Sheet

2013 - SD, Belle Fourche - Safety Awareness Training Program (Dinner)
1/29/2013 5:30:00 PM

RSVP ID	Web Code	Sign In #	RSVP (8)	Audience	Company & Contact	Attendee 1 Name & Signature	Attendee 2 Name & Signature	Attendee 3 Name & Signature	Attendee 4 Name & Signature
1	L4R7-2WP		1	Sponsors	BASIN ELECTRIC POWER COOPERATIVE Tony Skonhovd				
2	L4R7-36P		1	Sponsors	BLACK HILLS POWER, INC Frank Hauk	Frank Hauk			
3	L4RK-DYH		1	Sponsors	MONTANA DAKOTA UTILITIES ~~Paul Phillips~~	Toby Bordeaux	Bruce Stoltenberg	Jason Swanson	
4	L4RT-Z2D		2	Sponsors	NORTHERN BORDER PIPELINE - TRANSCANADA KEYSTONE Robert Lattimer	Virgil Ferris			
5	KV4Z-T9X		1	Sponsors	NUSTAR PIPELINE OPERATING PARTNERSHIP L.P. Troy Styer				
6	L4RU-26D			Sponsors	PLAINS - ROCKYMOUNTAIN PRODUCTS Daniel Holli	Daniel Holli			
7	L67N-VVE		1	Sponsors	SOUTH DAKOTA PIPELINE ASSOCIATION (PAPA) Troy Styer				
8	L4RU-2XD		1	Sponsors	WILLISTON BASIN INTERSTATE PIPELINE COMPANY Don Johnson	Don Johnson	Dave Brown	Brandon Hatling	

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Attendee Sign-In Sheet

2013 - SD, Belle Fourche - Safety Awareness Training Program (Dinner)
1/29/2013 5:30:00 PM - Instructor: Randy Leach

29	TT	Name and Job Title	Signature	Department or Company	For Internal Use Only
	##	*Johnathan L. Doe* *Fire Chief*	*Johnathan L Doe*	*Anytown Fire Dept*	
31	1223	Name: Ray Black Job Title: Batt chief	Ray Black	South Dakota wildland Fire	
32	1213	Name: Laurie Greeley Job Title: Dispatcher- Lawrence Co	Laurie Greeley	LAWRENCE CO SD	
33	1228	Name: Butte Meade Winter Job Title: Operator		Newell	
34	218	Name: Jenny Kirk Job Title:		Meade County	
35	1252	Name: James Smit Job Title: Building Inspector		Belle Fourche	
36	1227	Name: Steve Smeenk Job Title: Butte Co Commissioner	Steve Smeenk	Newell	
37	1205	Name: Mark Hespe Job Title: Belle Fourche Fire Chief	Mark D. Hespe	Belle Fourche Fire Dept	
38	1214	Name: Jared Johnson Job Title:	Jared Johnson	Belle fourche Dept.	
39	1274	Name: GARY BRUNNER Job Title: Deputy Sheriff	Gary Brunner	Butte co. sheriff office	
40	1216	Name: MARTHA WIERZBICKI Job Title: BUTTE CO EM	Martha Wierzbicki	BUTTE COUNTY DIRECTOR of EMERGENCY MANAGEMENT	
41	12 21	Name: SCOTT JONES Job Title: LT BFPD		BELLE FOURCHE POLICE	
42	12 42	Name: Dallas Ford Job Title: Butte Co. Dispatch Supervisor	Dallas Ford	Butte Co. Dispatch	
43		Name: Job Title:			
44		Name: Job Title:			

Instructor Signature:

Attendee Sign-In Sheet

2013 - SD, Belle Fourche - Safety Awareness Training Program (Dinner)
1/29/2013 5:30:00 PM - Instructor: Randy Leach

	TT	Name and Job Title	Signature	Department or Company	For Internal Use Only
	##	*Johnathan L. Doe* *Fire Chief*	*Johnathan L Doe*	*Anytown Fire Dept*	
16	1228	Name: Rene Larson Job Title: Administration		Law Co EM	
17	1244	Name: Cody Griffee Job Title: Division Chief		SD Wildland Fire	
18	1235	Name: Peggy Steffen Job Title: 911 Telecommunicator		Lawrence Co SD	
19		Name: Don Hewitt Job Title: Operator		Butte Meade Water	
20	1234	Name: BILL Rich Job Title: Cols 911		Meade County SD	
21	1204	Name: Blaine Anderson Job Title: SD National Guard		842nd Engineer Company Belle Fourche/Spearfish/Sturgis	
22	1215	Name: Kenneth Ellerton Job Title: Belle firefighter		Belle Fourche Vol. Fire Dept.	
23	1238	Name: Tristan Clements Job Title: Deputy Sheriff		BCSO	
24	1246	Name: Thomas Jinkord Job Title: BFVFD		Belle Fourche VFD	
25		Name: Job Title:			
26		Name: Job Title:			
27		Name: Job Title:			
28		Name: Job Title:			
29		Name: Job Title:			
30		Name: Job Title:			

Instructor Signature: Randy Leach

Attendee Sign-In Sheet

2013 - SD, Belle Fourche - Safety Awareness Training Program (Dinner)
1/29/2013 5:30:00 PM - Instructor: Randy Leach

#	TT	Name and Job Title	Signature	Department or Company	For Internal Use Only
	##	*Johnathan L. Doe* *Fire Chief*	*Johnathan L Doe*	*Anytown Fire Dept*	
1	1247	Name: James Kari Job Title: Maintnance	James Kari	Newell	
2	1217	Name: Paul Thomson Job Title: LC Emergency Manage	Paul Thomson	Lawrence County	
3	1254	Name: Fred L. Wells Job Title: VALE FIRE DEPT		VALE	
4	1248	Name: Fred Lamphere Job Title: Sheriff	Fred L. Lamphere	Butte County	
5		Name: Job Title:			
6		Name: Job Title:			
7		Name: Job Title:			
8		Name: Job Title:			
9		Name: Job Title:			
10		Name: Job Title:			
11		Name: Job Title:			
12		Name: Job Title:			
13		Name: Job Title:			
14		Name: Job Title:			
15		Name: Job Title:			

Instructor Signature: Randy Leach

RSVP Roster

2013 - SD, Hot Springs - First Responder Training Program (Lunch)
1/28/2013 11:30:00 AM

RSVP ID	Web Code	SignIn #	RSVP (27)	Audience	Company	Title	Name	City
1	KV4Z-HCYE	/	2	Emergency Officials	Custer County Sd Lepc	Director	Mike Carter	CUSTER, SD
2	KV4V-UT3K	//	2	Emergency Officials - Additional Responders	Custer County Sheriffs Dept	Deputy	Bill Schleining	CUSTER, SD
3	KV4Z-GGYR	/	1	Emergency Officials	Custer Vfd	Fire Chief	Joel Behlings	CUSTER, SD
4	KV4Z-JYYK	//	3	Emergency Officials	Fairburn Fire Dist	Chief	Clyde Gorsuch	FAIRBURN, SD
5	KV4V-VB3K		1	Emergency Officials - Additional Responders	Fall River County Ema	Asst Emergency Mgr	Andy Timmins	HOT SPRINGS, SD
6	KV4Z-L8YK		1	Emergency Officials	Fall River County Ema	Manager	Franklin W Maynard	HOT SPRINGS, SD
7	KV4W-2G3K	/	1	Public Officials - Additional Responders	Fall River County Highway Dept	Hwy Supt	Randy Seiler	HOT SPRINGS, SD
8	KV4V-V23K	///	3	Emergency Officials - Additional Responders	Fall River County Sheriff's Dept	Deputy	Jason March	HOT SPRINGS, SD
9	KV4Z-LQYK		3	Public Officials	Hot Springs Usda Service Center			HOT SPRINGS, SD
10	KV4V-VA3K	////	6	Emergency Officials - Additional Responders	Oral Vfd	Firefighter	Richard Wright	ORAL, SD
11	KV4Z-LEYS		1	Emergency Officials	Shannon County Cema	Director	Frank Maynard	HOT SPRINGS, SD
12	KV4Z-PFYR	/	1	Emergency Officials	Smithwick Fire Dept	Fire Chief	Pete Kindred	SMITHWICK, SD
13	KV4V-V73K	//	2	Emergency Officials - Additional Responders	South Dakota Wildland Fire	Div Chief	Les Madsen	HOT SPRINGS, SD

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Sponsor Sign-In Sheet

2013 - SD, Hot Springs - First Responder Training Program (Lunch)
1/28/2013 11:30:00 AM

RSVP ID	Web Code	Sign In #	RSVP (10)	Audience	Company & Contact	Attendee 1 Name & Signature	Attendee 2 Name & Signature	Attendee 3 Name & Signature	Attendee 4 Name & Signature
1	L4R7-36P		1	Sponsors	BLACK HILLS POWER, INC Frank Hauk	FRANK Hauk X Frank Hauk			
2	KV4Z-T9X		1	Sponsors	NUSTAR PIPELINE OPERATING PARTNERSHIP L.P. Troy Styer				
3	L4RU-26D		6	Sponsors	PLAINS - ROCKYMOUNTAIN PRODUCTS Daniel Holli	Daniel Holli X Daniel Holli	MARK Johnson X	Howard Sellenrick X	
4	L67N-VVE		1	Sponsors	SOUTH DAKOTA PIPELINE ASSOCIATION (PAPA) Troy Styer				
5	L4RU-2XD		1	Sponsors	WILLISTON BASIN INTERSTATE PIPELINE COMPANY Don Johnson	Don Johnson X			

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Attendee Sign-In Sheet

2013 - SD, Hot Springs - First Responder Training Program (Lunch)
1/28/2013 11:30:00 AM - Instructor: Randy Leach

27	TT	Name and Job Title	Signature	Department or Company	For Internal Use Only
	##	*Johnathan L. Doe* *Fire Chief*	*Johnathan L Doe*	*Anytown Fire Dept*	
1	1247	Name: Julie Tomlinson Job Title: District Manager	Julie Tomlinson	Fall River Conservation District	
2	1248	Name: Dick Klepper Job Title: C.R. manager	Dick Klepper	Fall River Cons. Dist.	
3	1230	Name: Margaret Stewart Job Title: South Shore Rep.	Margaret Stewart	South Shore Rep.	
4	1244	Name: Steve Neugebauer Job Title:	Steve Neugebauer	Oral VFD	10
5	1216	Name: Keith Neugebauer Job Title:	Keith Neugebauer	Oral VFD	10
6	1219	Name: Moritz Espy Job Title:	Moritz Espy	Fairburn VFD	4
7	1229	Name: Jason Damire Job Title:	Jason Damire	Oral VFD	10
8	1252	Name: Steve Esser Job Title: AFMO	Steve Esser	SD Dept. of Ag Wildland Fire Division	13
9	1242	Name: Randy Seiler Job Title: Hwy Supt	Randy Seiler	Hwy Dept.	7
10	1243	Name: Stacey Martin Job Title: GIS Coordinator	Stacey Martin	Fall River County Courthouse	
11	1213	Name: R.S. Wright Job Title: Dam tender	R.S. Wright	Oral VFD	10
12	1218	Name: Joel Behlings Job Title: Fire Chief Custer VSD	Joel Behlings	Custer VFD	3
13	1228	Name: Scott Davis Job Title: Deputy Sheriff	WA	Fall River Co S.O.	8
14	1207	Name: Andy Timmins Job Title: Asst Emer Mgr		" "	8
15		Name: Job Title:			

Instructor Signature:

Attendee Sign-In Sheet

2013 - SD, Hot Springs - First Responder Training Program (Lunch)
1/28/2013 11:30:00 AM - Instructor: Randy Leach

#	TT	Name and Job Title	Signature	Department or Company	For Internal Use Only
	##	*Johnathan L. Doe* *Fire Chief*	*Johnathan L Doe*	*Anytown Fire Dept*	
16	1223	Name: Arc Sic Catland Job Title: ;		VRC L fall river comm	
17	1225	Name: Doug Stewart Job Title:		South Shore Public official	
18	1215	Name: Mick Jennings Job Title: Sec/Treas		Oral Fire Dept	10
19	1254	Name: Nina Steinmetz Job Title: W/P Fall River		Weed Pest Fall River Supervisor	
20	12/1	Name: Clyde Gorsuch Job Title: ~~Fairburn Fire~~ Chief		Fairburn Fire Department	4
21	12 46	Name: John Sides Job Title: FRSO - SVFD		SMITHWICK VFD	12
22	12 21	Name: Mike Carter Job Title: Custer Co Emer Serv		Custer EMFD	1
23	X 2	Name: Lee Madsen Job Title: Division Chief SDSH Dakota		state of south Dakota	13
24	12 49	Name: Jason MARCH Job Title: Deputy		Fall River Co Sheriffs office HSVFD	8
25	12 05	Name: Bill Schaining Job Title: Deputy		Custer Co. Sheriffs Office	2
26	12 04	Name: Rick Whaley Job Title: Sheriff		Custer Co Sheriff Dept.	2
27		Name: Job Title:			
28		Name: Job Title:			
29		Name: Job Title:			
30		Name: Job Title:			

Instructor Signature:

RSVP Roster

2013 - SD, Rapid City - First Responder Training Program (Lunch)
1/29/2013 11:30:00 AM

RSVP ID	Web Code	SignIn #	RSVP (45)	Audience	Company	Title	Name	City
1	KV4Z-CFYK		2	Emergency Officials	Black Hills Life Flight	Flight Rn/Paramedic	Kimberly Bagby	RAPID CITY, SD
2	KV4V-XT3K		4	Emergency Officials - Additional Responders	Box Elder Police Dept	Chief	Jason Dubbs	BOX ELDER, SD
3	KV4Z-EUYK	III	4	Emergency Officials	Box Elder Police Dept	Police Chief		BOX ELDER, SD
4	KV4Z-EZYK	III	5	Public Officials	City Of Box Elder	Planning Director	Michael Mcmahon	BOX ELDER, SD
5	KV4Z-4VYM	I	4	Public Officials	Faith (City Of)	Mayor	Glen Haines	FAITH, SD
6	KV4Z-QNYE	I	2	Emergency Officials	Meade County Sd Lepc	Director	Angella Sutton	STURGIS, SD
7	KV4Z-NCYR		2	Emergency Officials	New Underwood Fire Dept	Fire Chief	Ron Raclcky	NEW UNDERWOOD, SD
8	L23A-E7EK	I	1	Emergency Officials - Additional Responders	Pennington County Sheriff		Jay Evenson	RAPID CITY, SD
9	KV4V-Y33K		3	Emergency Officials - Additional Responders	Rapid City Fire Dept	Fire Chief	Mike Maltaverne	RAPID CITY, SD
10	KV4Z-A3YK	II	3	Emergency Officials	Rapid City Fire Dept	Captain	Rich Broderick	RAPID CITY, SD
11	KV4Z-C6YK		1	Public Officials	Rapid City Usda Service Center	Soil Conservation Tech.	Paul Fulton	RAPID CITY, SD
12	KV4Z-D9YK	II	2	Emergency Officials	South Dakota Highway Patrol	District Commander	Kevin Karley	RAPID CITY, SD
13	L6XQ-R7R	I	1	Emergency Officials	South Dakota Office Of Emergency Manoement	Regional Coordinator Office Of Emergency Management	Brent Kolstad	RAPID CITY, SD
14	L23A-B6EK	III	2	Emergency Officials - Additional Responders	South Dakota Wildland Fire Division	Division Chief	Ray Bubb	RAPID CITY, SD
15	KV4V-Y43K	II	1	Emergency Officials - Additional Responders	Whispering Pines Vfd	Firefighter/Emt	R Craig Fairey	RAPID CITY, SD
16	KV4V-Y63K		6	Emergency Officials - Additional Responders	Whispering Pines Vfd	Asst Fire Chief	Stephen Keegan	RAPID CITY, SD
17	KV4Z-CGYK		1	Emergency Officials	Wildland Fire Suppression Div	Manager	Jay Esperance	RAPID CITY, SD
18	KV4Z-BGYK		1	Emergency Officials	Williston Basin Interstate Pipeline County	Emergency Official	Bob Hendrickson	RAPID CITY, SD

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Sponsor Sign-In Sheet

2013 - SD, Rapid City - First Responder Training Program (Lunch)
1/29/2013 11:30:00 AM

RSVP ID	Web Code	Sign In #	RSVP (12)	Audience	Company & Contact	Attendee 1 Name & Signature	Attendee 2 Name & Signature	Attendee 3 Name & Signature	Attendee 4 Name & Signature
1	L4R7-36P		2	Sponsors	BLACK HILLS POWER, INC Frank Hauk	Frank Hauk X	R. Kevin Hall X		
2	L4RK-DYH		1	Sponsors	MONTANA DAKOTA UTILITIES Paul Riely	Ron Blum X			
3	KV4Z-T9X		1	Sponsors	NUSTAR PIPELINE OPERATING PARTNERSHIP L.P. Troy Styer				
4	L4RU-26D		6	Sponsors	PLAINS - ROCKYMOUNTAIN PRODUCTS Daniel Holli	Daniel Holli X	X	X	X
5	L67N-VVE		1	Sponsors	SOUTH DAKOTA PIPELINE ASSOCIATION (PAPA) Troy Styer				
6	L4RU-2XD		1	Sponsors	WILLISTON BASIN INTERSTATE PIPELINE COMPANY Don Johnson	D. N. Johnson X	Bob Hendrickson X		

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Attendee Sign-In Sheet

2013 - SD, Rapid City - First Responder Training Program (Lunch)
1/29/2013 11:30:00 AM - Instructor: Randy Leach

	TT	Name and Job Title	Signature	Department or Company	For Internal Use Only
	##	*Johnathan L. Doe* *Fire Chief*	*Johnathan L Doe*	*Anytown Fire Dept*	
31	1246	Name: Kimberly Bayley Job Title: Flight RN/Medic		BHLF (Black Hills Life Flight)	
32	1243	Name: Jeremy Wella Job Title: Fire Fighter		Whispering Pines VFD	15
33	1254	Name: William Potter Job Title: FF/Hazmat	William Potter	RCFD	10
34	12 15	Name: Micki Haines Job Title: Admin Officer	Micki Haines	Faith Fire Dept.	
35	1247	Name: Kate Ackerson Job Title: Office Manager		Box Elder PD	3
36	12 19	Name: Fred Hulm Job Title: Faith Fire Dept		Faith S.D.	
37	1207	Name: William A Reishus Job Title: Rapid City Fire Lt.		Rapid City S.D.	10
38	12 25	Name: Angella Sutton Job Title: Emergency Manager		Meade County	6
39	1213	Name: Brent Kolstad Job Title: SD OEM	Brent Kolstad	State of SD	13
40	1218	Name: Paul Fulton Job Title: Soil conservation tech		USDA - NRCS	
41	12	Name: CASEY GLINES Job Title: SDWFS/AFMO		SDWFS	14
42	12 05	Name: Ray Bibb Job Title: Division Chief		SD. Wildland Fire	14
43	1238	Name: Cody Champion Job Title: EMT		Champion Towing & Sales	
44	12 14	Name: Rob Holso Job Title: WPUFD		WPUFD	15
45	1250	Name: Kevin Kinney Job Title: Sgt. SDHP		SD Highway Patrol	12

Instructor Signature:

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Attendee Sign-In Sheet

2013 - SD, Rapid City - First Responder Training Program (Lunch)
1/29/2013 11:30:00 AM - Instructor: Randy Leach

#	TT	Name and Job Title	Signature	Department or Company	For Internal Use Only
	##	*Johnathan L. Doe* *Fire Chief*	*Johnathan L Doe*	*Anytown Fire Dept*	
16	1247	Name: Randy Bagby Job Title: Volunteer 1st Responder	Randy Bagby	Search & Rescue	
17	1244	Name: Lt. Chris Misselt Job Title: Box Elder PD		Box Elder PD	3
18	1223	Name: Brandon Harvet Job Title: Box Elder PD		Box Elder PD	3
19	1211	Name: Scott Gray Job Title: Volunteer/Asst. Chief		Faith Fire Dept	
20	1252	Name: Esperance Jay Job Title: Director Wildlandfire		State of SD	14
21	1230	Name: Jay Evenson Job Title: Captain/Deputy		Pennington Co. Sheriffs office	8
22	1204	Name: AL TODD Job Title: PW DIRECTOR		CITY OF BOX ELDER	4
23		Name: Job Title:			
24		Name: Job Title:			
25		Name: Job Title:			
26		Name: Job Title:			
27		Name: Job Title:			
28		Name: Job Title:			
29		Name: Job Title:			
30		Name: Job Title:			

Instructor Signature:

Attendee Sign-In Sheet

2013 - SD, Rapid City - First Responder Training Program (Lunch)
1/29/2013 11:30:00 AM - Instructor: Randy Leach

#	TT	Name and Job Title	Signature	Department or Company	For Internal Use Only
	##	*Johnathan L. Doe* *Fire Chief*	*Johnathan L Doe*	*Anytown Fire Dept*	
1	1228	Name: Jim Hewin Job Title: Mayor		City of Dull	5
2		Name: Job Title:			
3	1248	Name: Jason Dubbs Job Title: Chief		City of Box Elder	4
4	1229	Name: Michael McMahon Job Title: Planning Coordinator		City of Box Elder	4
5	1217	Name: RICK MILLER Job Title: LIEUTENANT		SD HIGHWAY PATROL	12
6		Name: LARRY JANES Job Title:		SD One Call	X
7		Name: Job Title:			
8		Name: Job Title:			
9		Name: Job Title:			
10		Name: Job Title:			
11		Name: Job Title:			
12		Name: Job Title:			
13		Name: Job Title:			
14		Name: Job Title:			
15		Name: Job Title:			

Instructor Signature:

RSVP Roster

2013 - SD, Winner - Safety Awareness Training Program (Dinner)
1/21/2013 5:30:00 PM

RSVP ID	Web Code	SignIn #	RSVP (35)	Audience	Company	Title	Name	City
1	KV4Y-NTYK	𝍸	10	Emergency Officials	Colome Vfd	Fire Chief	Glenn Sealey	COLOME, SD
2	KV4Y-PYYM		2	Public Officials	Gregory (City Of)	Mayor	Wade Juracek	GREGORY, SD
3	KV4Y-YYYI	//	2	Public Officials	South Dakota Transportation	Manager	Doug Shermanon	WINNER, SD
4	KV4Y-YLYK	(||	3	Emergency Officials	Tripp County Ema	Emergency Management	Shawn Pettit	WINNER, SD
5	KV4Y-YKYK	//	2	Emergency Officials	Tripp County Sheriff Office	Sheriff	Clifford Schroeder	WINNER, SD
6	KV4V-YC3K		1	Emergency Officials - Additional Responders	Winner Fire Dept	Firefighter	John Meyer	WINNER, SD
7	KV4Y-YJYK	𝍸 ||||	6	Emergency Officials	Winner Fire Dept	Chief	Darin Nelson	WINNER, SD
8	KV4Y-Z3YM		3	Emergency Officials	Winner Police Dept	Police Chief	Paul Schueth	WINNER, SD
9	KV4Y-ZVYM	𝍸	6	Emergency Officials	Wood Fire Dept	Fire Chief	Kenny Osterbur	WOOD, SD

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Sponsor Sign-In Sheet

2013 - SD, Winner - Safety Awareness Training Program (Dinner)
1/21/2013 5:30:00 PM

RSVP ID	Web Code	Sign In #	RSVP (2)	Audience	Company & Contact	Attendee 1 Name & Signature	Attendee 2 Name & Signature	Attendee 3 Name & Signature	Attendee 4 Name & Signature
1	KV4Z-T9X		1	Sponsors	NUSTAR PIPELINE OPERATING PARTNERSHIP L.P. Troy Styer				
2	L67N-VVE		1	Sponsors	SOUTH DAKOTA PIPELINE ASSOCIATION (PAPA) Troy Styer				
		////	U		TRANSCANADA KEYSTONE	ROB LATIMER	KELLY PFAFF	VIRGIL PEINOVICH	TAIT KNUTSON

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Attendee Sign-In Sheet

2013 - SD, Winner - Safety Awareness Training Program (Dinner)
1/21/2013 5:30:00 PM - Instructor: Randy Leach

	TT	Name and Job Title	Signature	Department or Company	For Internal Use Only
	##	*Johnathan L. Doe* *Fire Chief*	*Johnathan L Doe*	*Anytown Fire Dept*	
31	23	Name: John S Meyer Job Title:		Winner Fire Dept	7
32	23	Name: Brad Whitley Job Title: Winner Fire Dept		Winner FD	7
33	1221	Name: Glenn Sealey Job Title: Colome VFD Chief	Glenn Sealey	Colome VFD	1
34	1218	Name: Bill Massingale Job Title: Wood VFD	Bill Massingale	Wood VFD	9
35	1216	Name: Kenny Osterhaus Job Title: Wood Fire chief	Kenny Osterhaus	Wood VFD	9
36	1215	Name: Wade Tucker Job Title: Wood Fire Dep	Wade Tucker	Wood, S.D.	9
37	1211	Name: Richard Frazier Job Title: Winner Fire Dept.		Winner, SD	7
38	1209	Name: Darin Nelson Job Title: Winner Fire Chief		Winner SD	7
39	1207	Name: Paul Eitel Job Title: Colome Fire Dept		Colome, SD	1
40	03	Name: Gary Brown Job Title: EMT		Winner SD	7
41	12 03	Name: CAROL BROWN Job Title: EMT	Carol Brown	Winner SD	7
42	1201	Name: Ken Jorgensen Job Title: Fire Fighter/EMT		Colome	1
43	1249	Name: Wayne Mallett Job Title: Firefighter		Colome VFD	1
44	1244	Name: Wade Tucker Job Title: Editor Wade Ihl		Winner Advocate	X
45	1244	Name: Travis Schwandt Job Title: Deputy Sheriff		Tripp Co SO.	5

Instructor Signature: Randy Leach

Attendee Sign-In Sheet

2013 - SD, Winner - Safety Awareness Training Program (Dinner)
1/21/2013 5:30:00 PM - Instructor: Randy Leach

35	TT	Name and Job Title	Signature	Department or Company	For Internal Use Only
	##	*Johnathan L. Doe* *Fire Chief*	*Johnathan L Doe*	*Anytown Fire Dept*	
1	1243	Name: Shawn Petty Job Title: EM / Deputy Sheri		Tr. PP County	4
2	1242	Name: Debby Engel Job Title: Emt Tripp Co.		tripp County	4
3	1241	Name: Lucy Attebery Job Title: EMT		Tripp County	4
4	1240	Name: Danny Brunmeier Job Title: Winner Fire		WFD	7
5		Name: Job Title:			
6		Name: Job Title:			
7		Name: Job Title:			
8		Name: Job Title:			
9		Name: Job Title:			
10		Name: Job Title:			
11		Name: Job Title:			
12		Name: Job Title:			
13		Name: Job Title:			
14		Name: Job Title:			
15		Name: Job Title:			

Instructor Signature:

Attendee Sign-In Sheet

2013 - SD, Winner - Safety Awareness Training Program (Dinner)
1/21/2013 5:30:00 PM - Instructor: Randy Leach

	TT	Name and Job Title	Signature	Department or Company	For Internal Use Only
	##	*Johnathan L. Doe* *Fire Chief*	*Johnathan L Doe*	*Anytown Fire Dept*	
16	1222	Name: Rocky Faldalen Job Title: Assistant Fire Chief	Rocky Fa	Winner	7
17	1220	Name: John Hofeldt Job Title: Assistant Chief		Colome	1
18	1219	Name: Mark Leibrich Job Title: Water Tech		City of Winner	
19	1217	Name: Dan Meyers Job Title: Rancher		Wood Fire Dept.	9
20	1214	Name: Duane Earll Job Title: Rancher		Wood Fire Dept.	9
21	1213	Name: Matt Vobr Job Title: SD DOT - CVFD		Colome	1
22	1212	Name: Ray Olson Job Title: LMW-SDDOT		Winner. SD	3
23	1208	Name: Gregg Ulmer Job Title: Hwy Supervisor		DOT Winner SD.	3
24	1206	Name: Christine Dvorak Job Title: Volunteer EMT / DSS		Tripp Cty Ambulance	
25	1205	Name: Bev Vaughn Job Title: Tripp Co Ambulance Director		Tripp Co Ambulance	
26	1202	Name: Daniel McMurtrey Job Title: Welder		Winner	
27	1250	Name: Clifford Schroeder Job Title: Sheriff Tripp Co.		Tripp Co. S.O.	5
28		Name: TODD MOSER Job Title: WINNER FIRE DEPT		TRIPP County	7
29	1247	Name: Maxine Urban Job Title: Lyman Co Amb EMT	Maxine ~~Urban~~ Urban	Presho SD.	
30	1245	Name: Amanda Comp Job Title: Lyman Co. Amb. EMT		Presho SD	

Instructor Signature:

RSVP Roster

2013 - SD, Pierre - First Responder Training Program (Dinner)
1/22/2013 5:30:00 PM

RSVP ID	Web Code	SignIn #	RSVP (49)	Audience	Company	Title	Name	City
1	KV4Y-MYYR	11	4	Emergency Officials	Blunt Rural Fire Dept	Fire Chief	Justin Hinkley	BLUNT, SD
2	KV4Y-MEYK		1	Emergency Officials	Central South Dakota Communications - Psap	Communications Super	Edie Jenniges	PIERRE, SD
3	KV4Z-8PYS		2	Emergency Officials	Dewey County Cema	Manager	Ted Schweitzer	TIMBER LAKE, SD
4	KV4Y-MCYS	1	3	Emergency Officials	Hughes County Cema	Director	Rob Fines	PIERRE, SD
5	KV4Y-M8YK		1	Emergency Officials	Hughes County Sheriffs Dept	Sheriff	Mike Leidholt	PIERRE, SD
6	KV4V-X33K		1	Emergency Officials - Additional Responders	Lyman County Ambulance Service	Emt	Jennifer Leichtnam	PRESHO, SD
7	KV4V-VH3K	1	4	Emergency Officials - Additional Responders	Midland Vfd	First Captain	Randy Nemec	MIDLAND, SD
8	KV4Y-V3YM	1	2	Public Officials	Murdo (City Of)	City Council		MURDO, SD
9	KV4V-WH3K		1	Emergency Officials - Additional Responders	Pierre Fire Dept	Assistant Chief	Sean Kruger	PIERRE, SD
10	KV4Y-LVYK		6	Emergency Officials	Pierre Fire Dept	Fire Chief	William Alexander	PIERRE, SD
11	KV4Y-M9YR	1	1	Emergency Officials	Pierre Police Dept	Captain	Elton Blemaster	PIERRE, SD
12	KV4W-2Z3K	1111	5	Public Officials - Additional Responders	Pierre Utilities	Operations Manager	Lynn Patton	PIERRE, SD
13	KV4Y-X4YR	1111	4	Emergency Officials	Reliance Fire Dept	Fire Chief	Dale Luif	RELIANCE, SD
14	KV4V-WE3K	1	1	Emergency Officials - Additional Responders	Sd State Fire Marshals Ofc	Senior Secretary	Glenda Marks	PIERRE, SD
15	KV4Y-FXYK		1	Emergency Officials	Sd State Fire Marshals Office	Deputy State Fire Marshal	Jason Dallagrana	PIERRE, SD
16	KZPM-7YQE	1	1	Emergency Officials - Additional Responders	South Dakota Emergency Response Commission		Trish Kindt	PIERRE, SD
17	KV4Y-PEYN		2	Public Officials	Stanley County	Sheriff	Bradley Rathbun	FORT PIERRE, SD
18	KV4Y-PTYM	11	2	Emergency Officials	Stanley County Law Enforcement Office	Sheriff	Brad Rathbun	FORT PIERRE, SD
19	KV4Y-GXYL	1	1	Public Officials	State Legislature	State Representative	Honorable James W. Bolin	PIERRE, SD
20	KV4Z-BUYL	1	1	Public Officials	State Legislature	House Majority Whip	Honorable Jacqueline Sly	RAPID CITY, SD
21	KV4Y-VPYN		1	Public Officials	Sully County	Commission Chair, District 1	William Floyd	ONIDA, SD
22	KV4Z-4MYI		4	Emergency Officials	Walter Miner Police Dept	Officer In Charge	Burton In The Woods	EAGLE BUTTE, SD

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Sponsor Sign-In Sheet

2013 - SD, Pierre - First Responder Training Program (Dinner)
1/22/2013 5:30:00 PM

RSVP ID	Web Code	Sign In #	RSVP (?)	Audience	Company & Contact	Attendee 1 Name & Signature	Attendee 2 Name & Signature	Attendee 3 Name & Signature	Attendee 4 Name & Signature
1	L4RK-DYH		1	Sponsors	MONTANA DAKOTA UTILITIES Paul Riely	Bo Secrest ✓	Ricky Schatz ✓		
2	L4RT-Z2D		1	Sponsors	NORTHERN BORDER PIPELINE - TRANSCANADA KEYSTONE Robert Latimer				
3	KV4Z-T9X		2	Sponsors	NUSTAR PIPELINE OPERATING PARTNERSHIP L.P. Troy Styer				
4	L4RU-2PD		2	Sponsors	SOUTH DAKOTA INTRASTATE PIPELINE Gordon Woods	Bruce England ✓	Gordon Woods ✓		
5	L67N-VVE		1	Sponsors	SOUTH DAKOTA PIPELINE ASSOCIATION (PAPA) Troy Styer				

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Attendee Sign-In Sheet

2013 - SD, Pierre - First Responder Training Program (Dinner)
1/22/2013 5:30:00 PM - Instructor: Randy Leach

#	TT	Name and Job Title	Signature	Department or Company	For Internal Use Only
	##	*Johnathan L. Doe* *Fire Chief*	*Johnathan L Doe*	*Anytown Fire Dept*	
16	12 11	Name: Jerry Hathaway Job Title: STREET SUPT	Jerry Hathaway	Murdo Fire Dept	8
17	12 23	Name: Gerard Yeager Job Title: Farm	Gerard Yeager	Blunt Fire Dept	1
18	12 12	Name: Glenda Marks Job Title:		State Fire Marshal's Office	14
19	12 14	Name: Reuben B Villmer JR Job Title: Fire Chief	Reuben B Villmer JR	Midland Fire Dept	7
20	12 18	Name: Steve Daly Job Title:	Steve Daly	Midland Fire Dept.	9
21	12 01	Name: Elton Blemaster Job Title: CAPTAIN	Elton Blemaster	PIERRE FD	11
22	12 21	Name: Trish Kindt Job Title: Scientist	Patricia Kindt	SD DENR Pierre	16
23	FC 13	Name: Jeff Monroe Job Title:		Senate District 24	✓
24	KSO	Name: Doyle Lulf Job Title: Chief	Doyle Lulf	Reliance Fire Dept	13
25		Name: Job Title:			
26		Name: Job Title:			
27		Name: Job Title:			
28		Name: Job Title:			
29		Name: Job Title:			
30		Name: Job Title:			

Instructor Signature: Randy Leach

Attendee Sign-In Sheet

2013 - SD, Pierre - First Responder Training Program (Dinner)
1/22/2013 5:30:00 PM - Instructor: Randy Leach

#	TT	Name and Job Title	Signature	Department or Company	For Internal Use Only
	##	*Johnathan L. Doe* *Fire Chief*	*Johnathan L Doe*	*Anytown Fire Dept*	
1	5	Name: Clint Lancerman Job Title: Fire Fighter	Clint Lancerman	Midland S.D.	7
2	12	Name: Perry Anderson Job Title: Heavy Equip operator	Perry Anderson	Pierre, S.D.	12
3	12/44	Name: Brent Hoffer Job Title: Fire fighter		Reliance, SD	13
4		Name: Job Title:			
5		Name: Job Title:			
6		Name: Job Title:			
7		Name: Job Title:			
8		Name: Job Title:			
9		Name: Job Title:			
10		Name: Job Title:			
11		Name: Job Title:			
12		Name: Job Title:			
13		Name: Job Title:			
14		Name: Job Title:			
15		Name: Job Title:			

Instructor Signature:

Attendee Sign-In Sheet

2013 - SD, Pierre - First Responder Training Program (Dinner)
1/22/2013 5:30:00 PM - Instructor: Randy Leach

	TT	Name and Job Title	Signature	Department or Company	For Internal Use Only
	##	*Johnathan L. Doe* *Fire Chief*	*Johnathan L Doe*	*Anytown Fire Dept*	
31	1224	Name: Rodney Luckhurst Job Title: Operator	Rodney Luckhurst	Waste Water City of Pierre	12
32	1248	Name: Ray Eriksen Job Title: W/W Supt.	Ray Eriksen	Murdo Fire Dept.	7
33	1222	Name: Ronnie Reding Job Title: Blunt Fire	Ronnie Reding	Blunt Fire Dept	1
34	1215	Name: Dane Brewer Job Title: Water Supt.	Dane Brewer	City of Pierre	12
35	1216	Name: Randy Nemec Job Title: Asst Chief	Randy Nemec	Midland Fire Dept	7
36	1209	Name: LAWRENCE STROPPEL Job Title: UTILITY OPER.	Lawrence Stroppel	MIDLAND FIRE DEPT.	7
37	1202	Name: Rob Fines Job Title: EM Director	Rob Fines	Hughs/Stanley Co Emergency Management	4
38	1241	Name: Greg Swanson Job Title: Chief Deputy Stanley Co.	Greg Swanson	Stanley County Sheriffs Office Ft. Pierre SD	18
39	1201	Name: Brad Rothbun Job Title: Sheriff Stanley Co.	Brad Rothbun	Stanley co. Sheriff	18
40	1220	Name: Brad Palmer Job Title: Utilities Director	Brad Palmer	City of Pierre	12
41	1249	Name: JACQUELINE JLY Job Title: Representative	Jacqueline Jly	State of SD - Dist. 23	20
42	1219	Name: Adam Schindler Job Title: Firefighter	Adam Schindler	Reliance Fire Dept	13
43	1206	Name: Jim Bolin Job Title: State Leg.	J. Bolin	Canton - Rep. Dist #16	19
44	1205	Name: LYNN PATTON Job Title: OPS Manager City Pier	L Patton	OPS Manager	12
45	1246	Name: Michael Hoffer Job Title: Fire Fighter	Michael Hoffer	Reliance fire dept.	13

Instructor Signature: Randy Leach

RSVP Roster

2014 - SD, Belle Fourche - First Responder Training Program (Dinner)
County Cluster: Butte, Harding, Lawrence, Meade, Pennington

RSVP ID	Web Code	CAP SUR	RSVP (49)	TT#	Audience	Company	Title	Name	City
1	NF6Y-D7DK		4		Emergency Officials	BELLE FOURCHE AMBULANCE SVC	BELLE FOURCHE AMBULANCE DIRECTOR	MISTY PECK	BELLE FOURCHE, SD
2	NF6Y-E4DK	THL	8		Emergency Officials - Additional Responders	BELLE FOURCHE FIRE DEPT	ASSISTANT CHIEF	THOMAS JANKORD	BELLE FOURCHE, SD
3	NKVB-RKAI		1		Public Officials - Additional Responders	BOX ELDER WATER DEPT	OPERATOR	JEFF MCGOUGH	BOX ELDER, SD
4	NKVB-RLAI		1		Public Officials - Additional Responders	BOX ELDER WATER DEPT	SUPERINTENDANT	ALLEN STEIER	BOX ELDER, SD
5	NKVB-RMAI		1		Public Officials - Additional Responders	BOX ELDER WATER DEPT	OPERATOR	TULLY JACKSON	BOX ELDER, SD
6	NKVB-RNAI		1		Public Officials - Additional Responders	BOX ELDER WATER DEPT	OPERATOR	MIKE LEMLEY	BOX ELDER, SD
7	NKVB-RPAI		1		Public Officials - Additional Responders	BOX ELDER WATER DEPT	OPERATOR	MICHAEL STARR	BOX ELDER, SD
8	NKVB-ROAI		1		Public Officials - Additional Responders	BOX ELDER WATER DEPT	OPERATOR	CHARLES HAGEN	BOX ELDER, SD
9	NKVB-RRAI		1		Public Officials - Additional Responders	BOX ELDER WATER DEPT	OPERATOR	TOM HILT	BOX ELDER, SD
10	NKVB-RTAI		1		Public Officials - Additional Responders	BOX ELDER WATER DEPT	OPERATOR	ROGER OLSON	BOX ELDER, SD
11	NRQK-TBKN	\	1		Public Officials - Additional Responders	BUTTE COUNTY	DEPUTY SHERIFF	TRISTAN CLEMENTS	BELLE FOURCHE, SD
12	NRQK-TCKN	\	1		Public Officials - Additional Responders	BUTTE COUNTY	CIVIL DEPUTY	DEBRA JANKORD	BELLE FOURCHE, SD
13	NRQK-WPKN	\	1		Public Officials - Additional Responders	BUTTE COUNTY	DEPUTY SHERIFF	CJ HUNTER	BELLE FOURCHE, SD
14	NF6Y-U9DP		1		Emergency Officials	BUTTE COUNTY DISPATCH CENTER - PSAP	DISPATCHER	DALLAS FORD	BELLE FOURCHE, SD
15	NF6Y-DWDN	\	1		Public Officials	BUTTE COUNTY SHERIFFS OFFICE	DEPUTY SHERIFF	GARY BRUNNER	BELLE FOURCHE, SD
16	NF6Y-JRDK	\	1		Emergency Officials	DEADWOOD FIRE DEPT	FIRE CHIEF	KEN HAWKI	DEADWOOD, SD
17	NF6Y-KADK	\	1		Emergency Officials	LAWRENCE COUNTY EMA	EXEC DIRECTOR	PAUL THOMSON	DEADWOOD, SD
18	NF6Y-K4DK	\	1		Emergency Officials	LAWRENCE COUNTY EMERGENCY SVCS	EMERGENCY SERVICES DIRECTOR	RENE LARSON	DEADWOOD, SD
19	NFDB-6YBP	\	1		Emergency Officials - Additional Responders	LAWRENCE COUNTY SHERIFFS OFFICE - PSAP	TELECOMMUNICATOR	ANDREW IVERSON	DEADWOOD, SD
20	NFDC-LC7P	\	1		Emergency Officials - Additional Responders	LAWRENCE COUNTY SHERIFFS OFFICE - PSAP		RICK WHITE	DEADWOOD, SD
21	NF6Y-NGDK	\	1		Public Officials	LEAD (CITY OF)	CITY MANAGER	MIKE STAHL	LEAD, SD
22	NRM6-HZCK	\	1		Emergency Officials - Additional Responders	LEAD FIRE DEPT	ASSISTANT CHIEF	FRED RAUBACH	LEAD, SD
23	NF6Y-RBDK	\	2		Public Officials - Additional Responders	MEADE COUNTY GOVERNMENT OFFICE	DEPUTY PLANNING DIRECTOR/911 COORDINATOR	BILL RICH	STURGIS, SD

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24	NLRE-4NMK	\	1	Public Officials - Additional Responders	MEADE COUNTY GOVERNMENT OFFICE	ENVIRONMENTAL MANAGER	JERILYN K	STURGIS, SD
25	NF6Y-CDDK		1	Emergency Officials	RAPID VALLEY VFD	FIRE CHIEF	TIM KOBES	RAPID CITY, SD
26	NF6Y-OHDK	\	1	Emergency Officials	SOUTH DAKOTA NATIONAL GUARD	OPERATIONS SERGEANT	WM BLAINE ANDERSON	SPEARFISH, SD
27	NF6Y-BZDK	\	1	Emergency Officials - Additional Responders	SOUTH DAKOTA WILDLAND FIRE DIV	BATALLION CHIEF	RAY BLACK	RAPID CITY, SD
28	NF6Y-C2DK	\	1	Emergency Officials - Additional Responders	SOUTH DAKOTA WILDLAND FIRE DIV	DIV CHIEF	CODY GRIFFEE	RAPID CITY, SD
29	NF6Y-OCDK	\	2	Emergency Officials	ST ONGE FIRE DEPT	FIRE CHIEF	WOODY HOVER	SAINT ONGE, SD
30	NRJV-A8GM	\	1	Emergency Officials - Additional Responders	STURGIS VFD	CHIEF	TOM TRIGG	STURGIS, SD
31	NRQJ-ZOKM	\	1	Emergency Officials - Additional Responders	STURGIS VFD	FIREFIGHTER	BOB KUSSER	STURGIS, SD
32	NRQJ-ZRKM	\	1	Emergency Officials - Additional Responders	STURGIS VFD	FIREFIGHTER	CHRIS GRUBLE	STURGIS, SD
33	NRQJ-ZTKM	\	1	Emergency Officials - Additional Responders	STURGIS VFD	ASST CHIEF	BRENT LYONS	STURGIS, SD
34	NRQJ-ZUKM	\	1	Emergency Officials - Additional Responders	STURGIS VFD	CAPTAIN	SCOTT LENSGRAV	STURGIS, SD
35	NRQJ-ZVKM	\	1	Emergency Officials - Additional Responders	STURGIS VFD	TRAINING OFFICER	RON ROTH	STURGIS, SD
36	NRQJ-ZWKM	\	1	Emergency Officials - Additional Responders	STURGIS VFD	FIREFIGHTER	CINDY SWENBY	STURGIS, SD
37	NRM3-9DD		1	Excavators	WBI ENERGY TRANSMISSION	COMPRESSOR STATION SUPERVISOR	DAVID BROWN	BELLE FOURCHE, SD

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Sponsor Sign-In Sheet

2014 - SD, Belle Fourche - First Responder Training Program (Dinner)
1/28/2014 5:30:00 PM

County Cluster: Butte, Harding, Lawrence, Meade, Pennington

Web Code	RSVP (5)	Company	Attendee 1-Name, Signature, & Email	Attendee 2-Name, Signature, & Email
NRL9-JPQ	1	BLACK HILLS POWER	Print: Sign: E-Mail: Print:	Print: Sign: E-Mail: Print:
NRMH-DW7	3	MONTANA DAKOTA UTILITIES	Sign: E-Mail: Print:	Sign: E-Mail: Print:
NK2E-9VR	1	NUSTAR ENERGY	Sign: E-Mail:	Sign: E-Mail:

1 WBI Energy — David Brown — David.Brown@WBIEnergy — X

MDU — Marc Lewis — X

BHP — Frank Hawk — X

MDU — Dale Schu[illegible] — X

MDU — Bruce Spry[illegible] — X

MDU — Toby Bordewyk — X

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Attendee Sign-In Sheet

2014 - SD, Belle Fourche - First Responder Training Program (Dinner)
1/28/2014 5:30:00 PM - Instructor: Randy Leach

County Cluster: Butte, Harding, Lawrence, Meade, Pennington

#	TT	Printed Name	Signature	Department or Company	Title	For Internal Use Only
	##	*Johnathan L. Doe*	*Johnathan L Doe*	*Anytown Fire Dept*	*Fire Fighter*	
1	1302	Rene Larson	Rene Larson	L.C. EM Mann	administration	18
2	1303	Jerilyn Rich		JBL LLC	Consultant Env. Mgr	24
3	1305	Bill Rd		Meade Co	Deputy Director of Emergency Services	23
4	1308	Ray Black	Ray Black	SDWFS Lead South Dakota Wildland Fire	Engine Boss	27
5	1310	Thomas Jankord	Thomas Jankord	Belle Fourche Fire Dept	Assistant Chief	2
6	1312	FRED RAUBACH	Fred Raubach	LEAD FIRE Dept.	DEPUTY CHIEF	22
7	1314	Cody Griffee		South Dakota Wildland Fire	Division Chief	28
8	1317	Debra Jankord	Debra Jankord	Butte County Sheriff's Office	Civil Deputy	12
9	1319	Charles Hunter		Butte County SO	Deputy Sheriff	13
10	1323	Tom Trigg	Tom Trigg	Sturgis Fire	Fire chief	30
11	1324	Scott Lensegrav		Sturgis fire	Captain	34
12	1329	Ron Roth		STURGIS VFD	TRAINING OFFICER	35
13						
14						

Instructor Signature:

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Attendee Sign-In Sheet

2014 - SD, Belle Fourche - First Responder Training Program (Dinner)
1/28/2014 5:30:00 PM - Instructor: Randy Leach

County Cluster: Butte, Harding, Lawrence, Meade, Pennington

#	TT	Printed Name	Signature	Department or Company	Title	For Internal Use Only
	##	*Johnathan L. Doe*	*Johnathan L Doe*	*Anytown Fire Dept*	*Fire Fighter*	
15	1304	Rick White		Lawrence Co. S.O.	Telecommunicator	20
16	1306	Ken Hawki		Law Co EM DWD FIRE	Firefighter	16
17	~~1307~~	Marc Lewis		MDU	Sponsor Engr	X
18	1315	Steve Shuck		Rocky Mtn Team A	FACL	
19	1320	Woody Hover		ST. ONGE VFD	Fire Chief	29
20	1321	Ryan Reeves		BFVFD	Asst Chief	2
21	1324	Chris Grabl		Sturgis Volunteer Fire Dept	Fire Fighter EMR	32
22	1325	Landy Swenby		Sturgis VFD	Firefighter	36
23	1330	Tristan Clements	Tristan Clements	BCSO	Deputy	11
24	1331	Andy Anderson		BFVFD	FF	2
25	1332	Rick Edson		BFVFD	FF	2
26						
27						
28						

Instructor Signature:

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Attendee Sign-In Sheet

2014 - SD, Belle Fourche - First Responder Training Program (Dinner)
1/28/2014 5:30:00 PM - Instructor: Randy Leach

County Cluster: Butte, Harding, Lawrence, Meade, Pennington

#	TT	Printed Name	Signature	Department or Company	Title	For Internal Use Only
	##	Johnathan L. Doe	Johnathan L Doe	Anytown Fire Dept	Fire Fighter	
29	1308	GARY Brunner	Gary Brunner	Butte County Sheriff	Deputy	15
30	1309	Wm Blaine Anderson	Wm Blaine Anderson	842ND EN CO SD National Goard	operations Sergeant	26
31	1311	MIKE STAHL	Mike Stahl	LEAD VFD LAW CTY SAR	CAPT.	21
32	1313	Paul Thomson	Paul Thomson	LCEM	EM	17
33	[illegible]	Dale Schmidt	Dale Schmidt	MDU	Sponsor	X
34	1316	Kip Marshall	Kip Marshall	BFVFD	Chief	2
35	1318	Nicholas Loper	Nicholas Loper	BFVFD	Fire Fighter	2
36	1322	Andrew Iverson	Andrew Iverson	LCSO	Dispatch	19
37	1325	Brent Lyons	Brent Lyons	Sturgis VFD	Ast Chief	33
38	1327	Bob Kusser	Bob Kusser	Sturgis VFD	Firefighter	31
39						
40						
41						
42						

Instructor Signature: Randy Leach

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RSVP Roster

2014 - SD, Buffalo - First Responder Training Program (Dinner)
County Cluster: Butte, Corson, Harding, Meade, Perkins, Ziebach

RSVP ID	Web Code	CAP SUR	RSVP (53)	TT#	Audience	Company	Title	Name	City
1	NF6Y-33DR		1		Emergency Officials	BISON AMBULANCE SVC	MGR	BECKY KRAUSE	BISON, SD
2	NRMZ-O9DR	\	1		Emergency Officials - Additional Responders	BISON AMBULANCE SVC	EMT	HEIDI STEVENS	BISON, SD
3	NRMZ-OADR	\	1		Emergency Officials - Additional Responders	BISON AMBULANCE SVC	EMT	BARBIE SERR	BISON, SD
4	NF6Y-FHDM	\	1		Public Officials	BUFFALO TOWN BOARD	PRESIDENT	TIM GLINES	BUFFALO, SD
5	NNQY-2RN	\	1		Public Officials	CAMP CROOK VFD	SEC/TREAS	JEAN TENNANT	CAMP CROOK, SD
6	NQTL-NGMN	\	1		Public Officials - Additional Responders	CAMP CROOK VFD	CHIEF	GEORGE DAVIS	CAMP CROOK, SD
7	NQTL-NHMN		1		Public Officials - Additional Responders	CAMP CROOK VFD	FIREFIGHTER	DOUG DAVIS	CAMP CROOK, SD
8	NQTL-NJMN	\	1		Public Officials - Additional Responders	CAMP CROOK VFD	FIREFIGHTER	RON TURBIVILLE	CAMP CROOK, SD
9	NQTL-NKMN	\	1		Public Officials - Additional Responders	CAMP CROOK VFD	FIREFIGHTER	TROY BRENCE	CAMP CROOK, SD
10	NQTL-NLMN	\	1		Public Officials - Additional Responders	CAMP CROOK VFD	FIREFIGHTER	RON DINGFELDER	CAMP CROOK, SD
11	NF6Y-F7DK	\	3		Public Officials	COUNTY COURTHOUSE	COMMISSIONER	CHARLES VERHULST	BUFFALO, SD
12	NF6Y-4YDK		1		Emergency Officials	FAITH POLICE DEPT	POLICE CHIEF	ARLEN FRANKFURTH	FAITH, SD
13	NF6Y-FFDN		1		Public Officials	HARDING COUNTY	SHERIFF	WILLIAM CLARKSON	BUFFALO, SD
14	NJZT-UU4N	\	1		Public Officials - Additional Responders	HARDING COUNTY	COMMISSIONER DISTRICT 1	DEB BROWN	BUFFALO, SD
15	NJZU-4C4K		1		Emergency Officials - Additional Responders	HARDING COUNTY	RECORDER	SUE LITZEL	BUFFALO, SD
16	NF6Y-EXDK	\	2		Emergency Officials - Additional Responders	HARDING COUNTY AMBULANCE SVC	EMT-DIRECTOR OF EQUALIZATION	LILA TEIGEN	BUFFALO, SD
17	NF6Y-FQDK	\	1		Emergency Officials - Additional Responders	HARDING COUNTY AMBULANCE SVC	EMT	MICHELLE ROTENBERGER	BUFFALO, SD
18	NF6Y-FTDK		2		Emergency Officials - Additional Responders	HARDING COUNTY AMBULANCE SVC	MRS.	LAURIE ELMORE	BUFFALO, SD
19	NF6Y-G6DK	\	4		Emergency Officials - Additional Responders	HARDING COUNTY AMBULANCE SVC	PRESIDENT	DARWIN LATHAM	BUFFALO, SD
20	NF6Y-G8DK		12		Emergency Officials	HARDING COUNTY AMBULANCE SVC	TRAINING OFFICER	ANNETTE SLABA	BUFFALO, SD
21	NF6Y-FGDS	\	1		Emergency Officials	HARDING COUNTY EMA	MANAGER	KATHY GLINES	BUFFALO, SD
22	NNT6-YX4L	\	1		Public Officials - Additional Responders	HARDING COUNTY HWY DEPT	LABORER	BC STRUBLE	BUFFALO, SD
23	NRM3-37DI		1		Public Officials - Additional Responders	HARDING COUNTY HWY DEPT	ROAD WORKER	ROCKY STRAGLEN	BUFFALO, SD

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24	NRM3-38DI		1	Public Officials - Additional Responders	HARDING COUNTY HWY DEPT	ROAD WORKER	JET HARMLEY	BUFFALO, SD
25	NRM3-39DI		1	Public Officials - Additional Responders	HARDING COUNTY HWY DEPT	ROAD WORKER	JUSTA WITT	BUFFALO, SD
26	NF6Y-GUDK		1	Emergency Officials	HARDING VFD	FIRE CHIEF	ANDREW THOMPSON	BUFFALO, SD
27	NRM2-YZDK		1	Emergency Officials - Additional Responders	HARDING VFD	ASST CHIEF	SHANNAN SECREST	BUFFALO, SD
28	NRM2-Z2DK		1	Emergency Officials - Additional Responders	HARDING VFD	FIREFIGHTER	ASHLEY SECREST	BUFFALO, SD
29	NF6Y-EWDK		2	Public Officials - Additional Responders	TD SERVICES	REP	TOM WILSON	BUFFALO, SD
30	NF6Y-GZDK		1	Public Officials	US LAND MANAGEMENT BUREAU	LAND OFFICIAL	JASON DONAHEY	CAMP CROOK, SD
31	NF6Y-GYDK		2	Emergency Officials - Additional Responders	USDA FS CNF SIOUX RANGER DIST	FORESTRY TECHNICIAN FUELS/FIRE	BRENT ELMORE	CAMP CROOK, SD
32	NF6Y-BBDK		1	Emergency Officials	WBI ENERGY TRANSMISSION	SR AREA REP	BOB HENDRICKSON	RAPID CITY, SD
33	NF6Y-THDM		1	Emergency Officials	WBI ENERGY TRANSMISSION	SR AREA REP	BOB HENDRICKSON	RAPID CITY, SD

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Sponsor Sign-In Sheet

2014 - SD, Buffalo - First Responder Training Program (Dinner)
1/27/2014 5:30:00 PM

County Cluster: Butte, Corson, Harding, Meade, Perkins, Ziebach

Web Code	RSVP (4)	Company	Attendee 1-Name, Signature, & Email	Attendee 2-Name, Signature, & Email
NRMH-DW7	3	MONTANA DAKOTA UTILITIES	Print: Sign: E-Mail:	Print: Sign: E-Mail:
NK2E-9VR	1	NUSTAR ENERGY	Print: Sign: E-Mail:	Print: Sign: E-Mail:

Trans Canada Virgil Pfenny
virgil_pfenny@transcanada.com

Plains Pipeline Daniel Holli
Daniel Holli
djholli@paalp.com

WBI Energy Bob Hendrickson
robert.hendrickson@wbienergy.com

Montana Dakota Utilities Jason Swanson
jason.swanson@mdu.com

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Attendee Sign-In Sheet

2014 - SD, Buffalo - First Responder Training Program (Dinner)
1/27/2014 5:30:00 PM - Instructor: Randy Leach

County Cluster: Butte, Corson, Harding, Meade, Perkins, Ziebach

53	TT	Printed Name	Signature	Department or Company	Title	For Internal Use Only
	##	Johnathan L. Doe	Johnathan L Doe	Anytown Fire Dept	Fire Fighter	
1	1302	Terry Brence	TROY BRENCE	BRENCE TRUCKIN	CAMPCREEK VFD	9
2	1304	Kathy Glines	Kathy Glines	Harding Co. Em. Mgmt	Emer Mgmt	21
3	1307	GEORGE DAVIS	George Davis	CAMP CREEK	FIRE CHIEF	6
4	1310	Andrew Thompson	Andrew Thompson	Harding Vol. F.D	Fire Chief	20
5	1318	Jason Latham		Harding County Emt	EMT	20
6	1326	Maxine Rasmussen	Maxine Rasmussen	HC EMT	EMT	20
7	1322	Benjamin Padden		HC EMT	EMT	20
8	1327	Doug Jerde		Reva F.D.		
9	1330	Michelle Rotenberger	M Rotenberger	HC. EMT	EMT	17
10	1333	Tom Wilson		Bullbull/170 Service		29
11	1334	Jeanne Tennant	Jeanne Tennant	Camp Creek - EMT	EMT	5
12	1337	Alvin Fabris	Alvin Fabris	Reva Fire + EMT	fire fighter/ EMT	
13	1338	Carol Giannonatti	Carol Giannonatti	HC-EMT	EMT	20
14	1339	Kelly Padden		Hc-EMT	EMT Fire Fighter	20

Instructor Signature:

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Attendee Sign-In Sheet

2014 - SD, Buffalo - First Responder Training Program (Dinner)
1/27/2014 5:30:00 PM - Instructor: Randy Leach

County Cluster: Butte, Corson, Harding, Meade, Perkins, Ziebach

53	TT	Printed Name	Signature	Department or Company	Title	For Internal Use Only
	**	*Johnathan L. Doe*	*Johnathan L Doe*	*Anytown Fire Dept*	*Fire Fighter*	
15	13-3	Ron Dingfelder	Ronald Dingfelder	Camp Crook VFD		10
16	13-5	Tim Glines	Tim Glines	Buffalo SD	President	4
17	1306	Chet Helms	Chet Holmes	Buffalo SD		
18	1308	Linda Mohagen	Linda Mohagen	Harding Co. EMS		20
19	1311	Ronald Turbiville	Ronald Turbiville	Camp Crook VFD		8
20	1312	Shannon Secrest	Shannon Secrest	Harding VFD	assistant Chief	27
21	1315	John Helms	John Helms	SDDOT + EVOC		
22	1317	Annette Slota	Annette Slota	Harding Co EMT	EMT	20
23	1324	Darwin Latham	Darwin Latham	HC EMT	President HCEMTA	19
24	1325	Laurie Elmore	Laurie Elmore	HC EMT	EMT	20
25	1320	Brent Elmore	Brent Elmore	Camp Crook VFD, USDAFS	Fire Fighter	31
26	1321	Spring Padden	Spring Padden	HC EMT LVFD	EMT	20
27	1323	Deb Brown	Deb Brown	HC Commissioner	Commissioner	14
28	1328	Charles Verhulst	Charles Verhulst	HC Commissioner		11

Instructor Signature

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Attendee Sign-In Sheet

2014 - SD, Buffalo - First Responder Training Program (Dinner)
1/27/2014 5:30:00 PM - Instructor: Randy Leach

County Cluster: Butte, Corson, Harding, Meade, Perkins, Ziebach

	TT	Printed Name	Signature	Department or Company	Title	For Internal Use Only
	##	Johnathan L. Doe	Johnathan L Doe	Anytown Fire Dept	Fire Fighter	
29	1309	Henry Mohagen	Henry Mohagen	Harding Co	Fire Dept 1st responder	20
30	1313	AshleySecrest	AshleySecrest	Harding VFD	Firefighter	28
31	1314	Justa Witt	~~Justa Witt~~	Harding Co.	Hwy Dept.	25
32	1316	BC STRUBLE	BC Struble	HARDING CO HWY DEPT	EQUIP OP.	22
33	1319	Kay Latham	Kay Latham	HC AMB.	EMT	20
34	1329	Jason Donahey	Jason Donahey	miles City BLM	Fire Operations Supervisor	30
35	1332	Troy Stingelmeyer		TO Services LLC Blue Bull LLC	mgmt partner	
36	1336	Austin Tenold	Austin	Sorum Reva VFD	Asst chief	
37	1340	HeidiStevens	HeidiStevens	Bison Amb	EMT	2
38	1341	Barbara Sorr	BarbaraASorr	Bison Ambulance	EMT	3
39	342	Nick Stevens	Nick Stevens	Bison Ambulance		
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Instructor Signature: Randy Leach

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Attendee Sign-In Sheet

2014 - SD, Buffalo - First Responder Training Program (Dinner)
1/27/2014 5:30:00 PM - Instructor: Randy Leach

County Cluster: Butte, Corson, Harding, Meade, Perkins, Ziebach

	TT	Printed Name	Signature	Department or Company	Title	For Internal Use Only
	##	*Johnathan L. Doe*	*Johnathan L Doe*	*Anytown Fire Dept*	*Fire Fighter*	
43	1331	Lila Teigen	Lila Teigen	HCEMS	EMT Director of Eg.	10
44	1335	Anne Marie Bruenzo	AD	HCEMS		20
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Instructor Signature: Randy Leach

RSVP Roster

2014 - SD, Pierre - First Responder Training Program (Lunch)

County Cluster: Bennett, Buffalo, Dewey, Faulk, Haakon, Hand, Hughes, Hyde, Jackson, Jones, Lyman, Mellette, Potter, Stanley, Sully, Todd, Ziebach

RSVP ID	Web Code	CAP SUR	RSVP (41)	TT#	Audience	Company	Title	Name	City
1	NF6X-FGEI	\	1		Emergency Officials	FEDERAL BUREAU OF INVESTIGATION	ACTING SUPERVISOR	MIKE RALEIGH	PIERRE, SD
2	NF6X-M8EK	\	1		Emergency Officials	HUGHES COUNTY EMA	EMERGENCY SERVICES DIRECTOR	ROBERT FINES	PIERRE, SD
3	NJZU-2R4K	\	1		Emergency Officials - Additional Responders	HUGHES COUNTY EMA	ASST EMERGENCY MANAGEMENT	MIKE HARMON	PIERRE, SD
4	NJZU-2T4K	\	1		Emergency Officials - Additional Responders	HUGHES COUNTY EMA	ASST EMERGENCY MANAGEMENT	SANDY CRONIN	PIERRE, SD
5	NF6X-GHEN	\	1		Public Officials	HUGHES COUNTY PLANNING & ZONING	DIRECTOR	RICHARD HAHN	PIERRE, SD
6	NJZT-WE4K	\	1		Emergency Officials - Additional Responders	HUGHES COUNTY SHERIFFS DEPT	DEPUTY SHERIFF	DARIN JOHNSON	PIERRE, SD
7	NF6X-UGDS	\	2		Emergency Officials	JONES COUNTY EMA	DIRECTOR	ANGIE KINSLEY	MURDO, SD
8	NF6X-UZDM	\	1		Emergency Officials	ONIDA FIRE DEPT & AMBULANCE	FIRE CHIEF	BRIAN RING	ONIDA, SD
9	NF6X-FLEM	\	12		Public Officials	PIERRE (CITY OF)	PUBLIC INFORMATION OFFICER	LYNN PATTON	PIERRE, SD
10	NF6X-FNEM	\	1		Public Officials	PIERRE (CITY OF)	CITY ENGINEER	KYLE KURTH	PIERRE, SD
11	NNMH-8OEM		1		Public Officials - Additional Responders	PIERRE (CITY OF)	SR ENGINEERING TECH	DEREK GRAY	PIERRE, SD
12	NNMH-8REM	\	1		Public Officials - Additional Responders	PIERRE (CITY OF)	ENGINEERING TECH	PAUL HERTEL	PIERRE, SD
13	NNMH-8TEM	\	1		Public Officials - Additional Responders	PIERRE (CITY OF)	BLDG OFFICIAL	KIRBY WELCH	PIERRE, SD
14	NF6X-F9EK	\	1		Emergency Officials - Additional Responders	PIERRE FIRE DEPT	CAPTAIN	PATRICK SNYDER	PIERRE, SD
15	NRM3-2JDM	\	1		Emergency Officials - Additional Responders	PIERRE FIRE DEPT - MAIN FIRE STATION	CAPTAIN	BYRON COAUWE	PIERRE, SD
16	NF6Y-UJDP	\	1		Emergency Officials	PIERRE POLICE DEPARTMENT - PSAP	COMMUNICATIONS SUPERVISOR	CINDY GROSS	PIERRE, SD
17	NF6X-M8EK	\	1		Emergency Officials	PIERRE POLICE DEPT	CAPTAIN	ELTON BLEMASTER	PIERRE, SD
18	NF6X-LDEK	\	6		Public Officials	PIERRE UTILITIES	UTILITIES DIR	BRAD PALMER	PIERRE, SD
19	NRJU-4WGK	\	1		Emergency Officials - Additional Responders	SOUTH DAKOTA DENR	ENVIRONMENTAL SCIENTIST	BARBARA FRIEDEMAN	PIERRE, SD
20	NRJU-4YGK	\	1		Emergency Officials - Additional Responders	SOUTH DAKOTA DENR	ENVIRONMENTAL ENGINEER	MARK MCINTIRE	PIERRE, SD
21	NRJU-8BGK	\	1		Emergency Officials - Additional Responders	SOUTH DAKOTA DENR	ENVIRONMENTAL SCIENTIST	KELSEY NEWLING	PIERRE, SD
22	NHHU-JBPK	\	1		Public Officials - Additional Responders	SOUTH DAKOTA PUBLIC UTILITIES COMMISSION	PIPELINE SAFETY PROGRAM MANAGER	MARY ZANTER	PIERRE, SD
23	NF6X-PEEN	\	1		Public Officials	STANLEY COUNTY	SHERIFF	BRADLEY RATHBUN	FORT PIERRE, SD

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24	NRJU-UVGN	\	1	Public Officials - Additional Responders	STANLEY COUNTY	CHIEF DEPUTY	GREG SWANSON	FORT PIERRE, SD

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Sponsor Sign-In Sheet

2014 - SD, Pierre - First Responder Training Program (Lunch)
1/22/2014 11:30:00 AM
County Cluster: Bennett, Buffalo, Dewey, Faulk, Haakon, Hand, Hughes, Hyde, Jackson, Jones, Lyman, Mellette, Potter, Stanley, Sully, Todd, Ziebach

Web Code	RSVP (4)	Company	Attendee 1-Name, Signature, & Email	Attendee 2-Name, Signature, & Email
			Print:	Print:
NK2E-9VR	1	NUSTAR ENERGY	Sign:	Sign:
			E-Mail:	E-Mail:
			Print:	Print:
NQRZ-ZEW	3	SOUTH DAKOTA INTRASTATE PIPELINE CO	Sign:	Sign:
			E-Mail:	E-Mail:

MONTANA - DAKOTA UTILITIES
Ricky Schatz
ricky.schatz@mdu.com

TransCanada
Virgil Pfennig
virgil_pfennig@transcanada.com

Montana-Dakota Utilities
Mitchel Voller
Mitch.voller@mdu.com

SDIP
Gordon Woods
gordon@sdipco.com

SDIP
Bob Thomason
bob@sdipco.com

SDIP
Bruce Easland
Bruce@sdipco.com

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Attendee Sign-In Sheet

2014 - SD, Pierre - First Responder Training Program (Lunch)
1/22/2014 11:30:00 AM - Instructor: Randy Leach

County Cluster: Bennett, Buffalo, Dewey, Faulk, Haakon, Hand, Hughes, Hyde, Jackson, Jones, Lyman, Mellette, Potter, Stanley, Sully, Todd, Ziebach

#	TT	Printed Name	Signature	Department or Company	Title	For Internal Use Only
	##	*Johnathan L. Doe*	*Johnathan L Doe*	*Anytown Fire Dept*	*Fire Fighter*	
1	1302	Kelsey Newling	Kelsey Newling	South Dakota Dept. of Env. Natural Resources	Env. Scientist	21
2	1309	Sandy Gronewald	Sandy Gronewald	Hughes/Stanley Co EM Mgmt Dir.	EM	4
3	1310	Rob Fines	Rob Fines	Hughes/Stanley County		2
4	1311	Paul Hertel	Paul Hert	City of Pierre		12
5	1313	Caleb Kusser		city of Pierre		9
6	1316	Shawn Hussy	Shawn Hussy	City of Pierre		9
7	1324	Mark McIntire	Mark McIntire	SD DENR	Engineer	20
8	1327	Brad Rathbun	Brad Rathbun	Stanley Co. Sheriff		23
9	1328	John M. Raleigh	John M. Raleigh	FBI		1
10	1330	Brian Ring	Brian Ring	ONIDA Fire Dept.	a.d.s.	8
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Instructor Signature:

Attendee Sign-In Sheet

2014 - SD, Pierre - First Responder Training Program (Lunch)
1/22/2014 11:30:00 AM - Instructor: Randy Leach

County Cluster: Bennett, Buffalo, Dewey, Faulk, Haakon, Hand, Hughes, Hyde, Jackson, Jones, Lyman, Mellette, Potter, Stanley, Sully, Todd, Ziebach

	TT	Printed Name	Signature	Department or Company	Title	For Internal Use Only
	**	*Johnathan L. Doe*	*Johnathan L Doe*	*Anytown Fire Dept*	*Fire Fighter*	
15		Mark Johnson		TRANSCANADA	SPONSOR	X
16	1304	PATRICK SNYDER		PIERRE FIRE	CAPT.	14
17	1303	Angie Kinsley		Jones County Emergency	Manager	7
18	1306	Kyle Kurth		City of Pierre	Staff Engineer	10
19	1307	Mike Harmon		Hughes Co EM	EM	3
20	1309	Byron Carlson		Pierre Rural FD	Captain	15
21	1312	KEVIN GOLDSMITH		CITY OF PIERRE	WWTP	9
22	1314	Kirby Welch		City of Pierre	Building Insp.	13
23	1317	Glenda Martin		SD Fire Marshal's Office		
24	1319	RICK HAHN		Hughes Co	PLANNING + ZONING	5
25	1320	Darin Johnsen		Hughes Co. S.O.	Deputy	6
26	1321	ELTON BLEMASTER		PIERRE POLICE	CAPTAIN	17
27	1325	LYNN PATTON		City of Pierre	Operations	9
28	1329	Boise Hillman		PUC	Pipeline Inspect	

Instructor Signature:

Attendee Sign-In Sheet

2014 - SD, Pierre - First Responder Training Program (Lunch)
1/22/2014 11:30:00 AM - Instructor: Randy Leach

County Cluster: Bennett, Buffalo, Dewey, Faulk, Haakon, Hand, Hughes, Hyde, Jackson, Jones, Lyman, Mellette, Potter, Stanley, Sully, Todd, Ziebach

	TT	Printed Name	Signature	Department or Company	Title	For Internal Use Only
	##	*Johnathan L. Doe*	*Johnathan L Doe*	*Anytown Fire Dept*	*Fire Fighter*	
29	1 5	Debra Byrd	Debra Byrd	Jones Co. Treas.	Treas.	7
30	1 3 1 5	Dane Brewer	Dane Brewer	City of Pierre	Water	18
31	1 3 1 8	Bill Floyd	William Floyd	Sully Co. Comm	Commissioner	
32	1 3 2 2	Cindy Gross	Cindy Gross	Pierre PD, Dispatch Center	911-Dispatcher	10
33	1 3 2 3	Barb Friedman	Barbara Friedman			19
34	1 3 2 6	Greg Swearson	Greg Swearson	Stanley Co. Sheriff	Chief Deputy	24
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Instructor Signature: Randy Leach

Attendee Sign-In Sheet

2014 - SD, Pierre - First Responder Training Program (Lunch)
1/22/2014 11:30:00 AM - Instructor: Randy Leach

County Cluster: Bennett, Buffalo, Dewey, Faulk, Haakon, Hand, Hughes, Hyde, Jackson, Jones, Lyman, Mellette, Potter, Stanley, Sully, Todd, Ziebach

#	TT	Printed Name	Signature	Department or Company	Title	For Internal Use Only
	##	*Johnathan L. Doe*	*Johnathan L Doe*	*Anytown Fire Dept*	*Fire Fighter*	
43		Kristie Fiegen		PUC		FB23
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Instructor Signature:

RSVP Roster

2014 - SD, Rapid City - First Responder Training Program (Lunch)

County Cluster: Bennett, Butte, Custer, Haakon, Jackson, Lawrence, Meade, Pennington, Perkins, Shannon, Ziebach

RSVP ID	Web Code	CAP SUR	RSVP (53)	TT#	Audience	Company	Title	Name	City
1	NF6Y-EMDM		1		Emergency Officials	BOX ELDER POLICE DEPT	POLICE CHIEF	JASON DUBBS	BOX ELDER, SD
2	NJCQ-UB8M		1		Emergency Officials - Additional Responders	BOX ELDER POLICE DEPT	LIEUTENANT	CHRIS MISSELT	BOX ELDER, SD
3	NJCQ-UC8M		1		Emergency Officials - Additional Responders	BOX ELDER POLICE DEPT	SERGEANT	GUNNAR GRASS	BOX ELDER, SD
4	NJCQ-UD8M		1		Emergency Officials - Additional Responders	BOX ELDER POLICE DEPT	OFC MGR	KATE ACKERSON	BOX ELDER, SD
5	NF6Y-EVDI		8		Public Officials	BOX ELDER WATER DEPT	MANAGER	AL TODD	BOX ELDER, SD
6	NF6Y-H8DK		2		Emergency Officials	CUSTER VFD	FIRE CHIEF	JOEL BEHLINGS	CUSTER, SD
7	NF6Y-CRDK		1		Emergency Officials	ELLSWORTH AFB AMBULANCE SVC	DIRECTOR	STEVEN HENRY	ELLSWORTH AFB, SD
8	NF6Y-CNDK		1		Emergency Officials - Additional Responders	ELLSWORTH AFB FIRE DEPT	ASST CHIEF HAZMAT HEALTH & SAFETY	DEAN STETSON	ELLSWORTH AFB, SD
9	NF6Y-CPDK		1		Emergency Officials	ELLSWORTH AFB FIRE DEPT	CHIEF	DAVE OLSEN	ELLSWORTH AFB, SD
10	NF6X-VNDK		1		Emergency Officials	HAAKON COUNTY SHERIFFS DEPT	SHERIFF	FRED KOESTER	PHILIP, SD
11	NF6Y-JUDK		1		Emergency Officials	LEAD DEADWOOD REGIONAL HOSPITAL AMB	EMS DIRECTOR	ROY GOBEN	DEADWOOD, SD
12	NF6Y-RHDK		2		Emergency Officials	MEADE COUNTY EMA	EMERGENCY SERVICES DIRECTOR	ANGELA SUTTON	STURGIS, SD
13	NF6Y-P3DM		1		Emergency Officials	NEW UNDERWOOD FIRE DEPT	CHIEF	RON RACICKY	NEW UNDERWOOD, SD
14	NF6Y-CTDK		3		Emergency Officials	NORTH HAINES FIRE DEPT	CHIEF	JASON WHITE	RAPID CITY, SD
15	NF6Y-A4DK		1		Emergency Officials	PENNINGTON COUNTY EMA	DIRECTOR	DUSTIN WILLETT	RAPID CITY, SD
16	NRM3-9PDM		1		Emergency Officials - Additional Responders	RAPID CITY DEPT OF FIRE & EMS	LIEUTENANT	MIKE WRIGHT	RAPID CITY, SD
17	NF6Y-9UDK		1		Emergency Officials - Additional Responders	RAPID CITY FIRE DEPT	LIEUTENANT	WILLIAM POTTER	RAPID CITY, SD
18	NRM6-8KCK		5		Emergency Officials - Additional Responders	RAPID CITY FIRE DEPT	CAPTAIN	JOE TJADEN	RAPID CITY, SD
19	NRMH-EY6M		1		Public Officials - Additional Responders	RAPID CITY PUBLIC WORKS ENGINEERING	DEVELOPMENT REVEIW GROUP COORDINATOR	TED JOHNSON	RAPID CITY, SD
20	NRNX-LLEM		1		Public Officials - Additional Responders	RAPID CITY PUBLIC WORKS ENGINEERING	ENGINEERING PROJ ADMIN	PAUL FAIMAN	RAPID CITY, SD
21	NRNX-LMEM		1		Public Officials - Additional Responders	RAPID CITY PUBLIC WORKS ENGINEERING	ENGINEERING PROJ ENGINEER	NICOLE LECY	RAPID CITY, SD
22	NRNX-LNEM		1		Public Officials - Additional Responders	RAPID CITY PUBLIC WORKS ENGINEERING	STORMWATER SPECIALIST	RICK SCHURGER	RAPID CITY, SD
23	NF6Y-CJDK		1		Emergency Officials	SOUTH DAKOTA OEM	REGIONAL COORDINATOR	BRENT KOLSTAD	RAPID CITY, SD

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24	NF6Y-C3DK	I	3	Emergency Officials - Additional Responders	SOUTH DAKOTA WILDLAND FIRE DIV	AFMO	CASEY GLINES	RAPID CITY, SD
25	NF6Y-BBDK		1	Emergency Officials	WBI ENERGY TRANSMISSION	SR AREA REP	BOB HENDRICKSON	RAPID CITY, SD
26	NF6Y-THDM		1	Emergency Officials	WBI ENERGY TRANSMISSION	SR AREA REP	BOB HENDRICKSON	RAPID CITY, SD
27	NF6Y-C6DK	I	1	Emergency Officials - Additional Responders	WHISPERING PINES VFD	FIREFIGHTER-EMT	R CRAIG FAIREY	RAPID CITY, SD
28	NF6Y-C7DK	III	9	Emergency Officials - Additional Resoonders	WHISPERING PINES VFD	ASSISTANT CHIEF	JEREMY WALLA	RAPID CITY, SD

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Sponsor Sign-In Sheet

2014 - SD, Rapid City - First Responder Training Program (Lunch)
1/29/2014 11:30:00 AM

County Cluster: Bennett, Butte, Custer, Haakon, Jackson, Lawrence, Meade, Pennington, Perkins, Shannon, Ziebach

Web Code	RSVP (7)	Company	Attendee 1-Name, Signature, & Email	Attendee 2-Name, Signature, & Email
NRL9-JPQ	1	BLACK HILLS POWER	Print: Sign: E-Mail:	Print: Sign: E-Mail:
NRMH-CM7	2	MAGELLAN PIPELINE COMPANY LP	Print: Mark Johrin Sign: E-Mail: Mark.Johrin@magellanlp.com	Print: Ryan Anderson Sign: E-Mail: Ryan.Anderson@magellanlp.com
NRLY-PQE	3	MONTANA-DAKOTA UTILITIES CO	Print: Wade Jutila Sign: E-Mail: Wade.Jutila@MDU.com	Print: Sign: E-Mail:
NK2E-9VR	1	NUSTAR ENERGY	Print: Sign: E-Mail:	Print: Sign: E-Mail:

TransCanada Virgil Affeldt
Virgil_affeldt@transcanada.com

WBI Energy Bob Hendrickson
robert.hendrickson@wbienergy.com

MDU Ron Blum
ron.blum@mdu.com

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Attendee Sign-In Sheet

2014 - SD, Rapid City - First Responder Training Program (Lunch)
1/29/2014 11:30:00 AM - Instructor: Randy Leach

County Cluster: Bennett, Butte, Custer, Haakon, Jackson, Lawrence, Meade, Pennington, Perkins, Shannon, Ziebach

SS	TT	Printed Name	Signature	Department or Company	Title	For Internal Use Only
	##	Johnathan L. Doe	Johnathan L Doe	Anytown Fire Dept	Fire Fighter	
1	1307	Brent Kolstad	Brt Kolstad	SD OEM	EM	23
2	1303	Joel Behlings	JBeh	Custer VFD	Chief	10
3	1306	Dwight Slovek	Dwight Slovek	Hisaposcante Foreman		
4	1309	William Potter	William Potter	RCFD	LT	17
5	1312	Paul Fatheree	Paul Fatheree	City - Rapid		20
6	1315	Angella Sutton	A/M	Meade Co EM	EM	12
7	1319	Luke Neville		Haakon County		
8	1322	Joe Milbo	Joe Milbo	Haakon County	CTY	
9	1328	DAN Hodge	Dan Hodge	North Haines VFD	FPS	14
10	1330	Ryan Jager	Ryan Jager	Black Hawk VFD	Capt.	
11	1336	Tim Bussell		RC/PC HAMERT	Tech/Spec.	
12	1342	Kate Ackerson	Kate	Box Elder PD	Office Manager	4
13	1344	Ron Racicky	Ron Racicky	New Underwood	Chief	13
14	1345	Stephen Keegan	Steph P Keegan	Whispering Pines VFD Custer VFD	Captain	28

Instructor Signature:

Attendee Sign-In Sheet

2014 - SD, Rapid City - First Responder Training Program (Lunch)
1/29/2014 11:30:00 AM - Instructor: Randy Leach

County Cluster: Bennett, Butte, Custer, Haakon, Jackson, Lawrence, Meade, Pennington, Perkins, Shannon, Ziebach

53	TT	Printed Name	Signature	Department or Company	Title	For Internal Use Only
	##	Johnathan L. Doe	Johnathan L Doe	Anytown Fire Dept	Fire Fighter	
15	1304	Timothy D. Parsons		Custer VFD	Safety Officer	0
16	1307	David Johannsen	David Johannsen	Haakon County Hwy	Heavy Equipment Operator	4
17	1310	Steven L Henry		Ellsworth AFB Ambulance Services	EMT	7
18	1313	Ted Johnson		City Rapid City	Engineer	19
19	1316	Dave Smith		City of Sturgis	Emergency Management	
20	1318	Monty Bollock		SD Wildland Fire	Fire Fighter	
21	1323	Roy Warner		Haakon Con	City	
22	1324	Casey Warren		Rapid Valley FD	Asst. Chief	
23	1326	Craig Fairley		Whispering Pines VFD	Firefighter EMT	27
24	1329	Richard Small		North Haines	Fire Fighter	14
25	1332	Troy Carling		Black Hawk VFD	Chief	
26	1335	Alan Johnson		Rapid City FD	Firefighter	18
27	1338	Dean Stetson		Ellsworth FD	Asst Chief	9
28	1340	Chris Misselt		Box Elder PD	Lt	2

Instructor Signature:

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Attendee Sign-In Sheet

2014 - SD, Rapid City - First Responder Training Program (Lunch)
1/29/2014 11:30:00 AM - Instructor: Randy Leach

County Cluster: Bennett, Butte, Custer, Haakon, Jackson, Lawrence, Meade, Pennington, Perkins, Shannon, Ziebach

	TT	Printed Name	Signature	Department or Company	Title	For Internal Use Only
	##	*Johnathan L. Doe*	*Johnathan L Doe*	*Anytown Fire Dept*	*Fire Fighter*	
29	1305	Fred Kreshe		Haakon Co Sheriff office	Sheriff	10
30	1308	Richard Baye		Haakon Co Hwy dept		
31	1311	Nicole Lecy		City of Rapid City	Engineer	21
32	1314	Kris James		MDU	Engineer	X
33	1317	Casey Gloves		SDWF	Firefighter	24
34	1319	Kenny Neville		Haakon CO		
35	1321	Lee Turnbull		Haakon CO		
36	1325	TIM KUBAS		RAPID VALLEY FIRE	FIRE CHIEF	
37	1327	RICK SCHUETER		CITY OF RAPID CITY		22
38	1330	Michael L McRidon		FBI	Special Agent	
39	1331	Alan McMillin		Black Hawk VFD	Lt.	
40	1334	JON BURTON		RCFD	LT.	18
41	1337	Matt Kellner		RCFD	FF/II	18
42	1339	Joe Tyler		RAPID VALLEY FD RAPID CITY FD	HM CAPT	18

Instructor Signature:

Attendee Sign-In Sheet

2014 - SD, Rapid City - First Responder Training Program (Lunch)
1/29/2014 11:30:00 AM - Instructor: Randy Leach

County Cluster: Bennett, Butte, Custer, Haakon, Jackson, Lawrence, Meade, Pennington, Perkins, Shannon, Ziebach

	TT	Printed Name	Signature	Department or Company	Title	For Internal Use Only
	##	*Johnathan L. Doe*	*Johnathan L Doe*	*Anytown Fire Dept*	*Fire Fighter*	
43	1341	Jason Dubbs		Box Elder P.D.	Chief	1
44	1343	Curtis Grass		Box Elder PD	Sgt	3
46	1347	Dustin Willatt		Pennington Co. EM	Emergency Manager	15
46	1346	Bruce Jensen		Whispering Pines VFD	Asst Chief	24
47	1348	Dave Olsen		Ellsworth FD	Fire Chief	9
48	1349	Jeremy Walla		Whispering Pines VFD	Asst Chief	24
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Instructor Signature:

RSVP Roster

2014 - SD, Winner - First Responder Training Program (Dinner)
County Cluster: Bennett, Brule, Buffalo, Hand, Hyde, Jones, Mellette, Todd

RSVP ID	Web Code	CAP SUR	RSVP (30)	TT#	Audience	Company	Title	Name	City
1	NJZU-6P4		1		Excavators	ATTEBERRY CONST INC	OWNER	LEE ATTBEERRY	COLOME, SD
2	NRM6-B7C	1111	8		Emergency Officials	COLOME VFD & RESCUE	FIRE CHIEF	GLENN SEALEY	COLOME, SD
3	NJZU-2U4		1		Excavators	TRANSCANADA - KEYSTONE XL	COMMUNITY RELATIONS ADVISOR	MARK JOHNSON	OMAHA, NE
4	NJZU-674H	\	1		Emergency Officials - Additional Responders	TRIPP COUNTY AMBULANCE SVC	EMT	MARLAJEAN WATERS	WINNER, SD
5	NJZU-6K4H	\	1		Emergency Officials - Additional Responders	TRIPP COUNTY AMBULANCE SVC	EMT	LUCY ATTEBERRY	WINNER, SD
6	NKVC-2CAH	\	1		Emergency Officials - Additional Responders	TRIPP COUNTY AMBULANCE SVC	EMT	WENDY SCHMALTZ	WINNER, SD
7	NRJU-T4GH		1		Emergency Officials - Additional Responders	TRIPP COUNTY AMBULANCE SVC	EMT	SISSY OREL	WINNER, SD
8	NRJU-T6GH	\	1		Emergency Officials - Additional Responders	TRIPP COUNTY AMBULANCE SVC	EMT	GARRY BROWN	WINNER, SD
9	NRJU-T7GH		1		Emergency Officials - Additional Responders	TRIPP COUNTY AMBULANCE SVC	EMT	WALTER HARTER	WINNER, SD
10	NRM6-8HCH	\	1		Emergency Officials - Additional Responders	TRIPP COUNTY AMBULANCE SVC	EMT	DEBBIE ENGEL	WINNER, SD
11	NJA9-CCFH	\	1		Emergency Officials - Additional Responders	TRIPP COUNTY OEM	EMERGENCY MANAGER	SHAWN PETTIT	WINNER, SD
12	NJZU-6L4H		1		Emergency Officials - Additional Responders	TRIPP COUNTY OEM	FIREFIGHTER	KURT ATTEBERRY	WINNER, SD
13	NJA4-N7H	\	1		Emergency Officials	TRIPP COUNTY SHERIFF OFC	SHERIFF	CLIFFORD SCHROEDER	WINNER, SD
14	NJA8-CAGH	\	1		Emergency Officials - Additional Responders	TRIPP COUNTY SHERIFF OFC	DEPUTY	TODD STIEHL	WINNER, SD
15	NJA8-CBGH	\	1		Emergency Officials - Additional Responders	TRIPP COUNTY SHERIFF OFC	DEPUTY	DALLAS ANDERSON	WINNER, SD
16	NF6Y-V3DP	\	1		Emergency Officials	WINNER POLICE DEPARTMENT - PSAP	9-1-1 DIRECTOR/CHIEF	PAUL SCHUETH	WINNER, SD
17	NLNQ-UGXP	\	1		Emergency Officials - Additional Responders	WINNER POLICE DEPARTMENT - PSAP	ASST CHIEF	TRENT SINCLAIR	WINNER, SD
18	NLNQ-UHXP	\	1		Emergency Officials - Additional Responders	WINNER POLICE DEPARTMENT - PSAP	COMM SUPERVISOR	DEB BICE	WINNER, SD
19	NLNQ-UJXP		1		Emergency Officials - Additional Responders	WINNER POLICE DEPARTMENT - PSAP	ASST COMM SUPERVISOR	ANDREA PTACEK	WINNER, SD
20	NF6X-ZTDM		1		Emergency Officials	WITTEN VFD	FIRE CHIEF	DOUG BEST	WITTEN, SD
21	NRJU-7ZGM	\	1		Emergency Officials - Additional Responders	WITTEN VFD	TRAINER	JIM UNDERHILL	WITTEN, SD
22	NRJU-73GM	\	1		Emergency Officials - Additional Responders	WITTEN VFD	FIREFIGHTER	ISAAC COLE	WITTEN, SD
23	NRJU-74GM		1		Emergency Officials - Additional Responders	WITTEN VFD	FIREFIGHTER	MELVIN HARTER	WITTEN, SD

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Sponsor Sign-In Sheet

2014 - SD, Winner - First Responder Training Program (Dinner)
1/21/2014 5:30:00 PM

County Cluster: Bennett, Brule, Buffalo, Hand, Hyde, Jones, Mellette, Todd

Web Code	RSVP (1)	Company	Attendee 1-Name, Signature, & Email	Attendee 2-Name, Signature, & Email
NK2E-9VR	1	NUSTAR ENERGY		
		Trans Canada	Virgil Pfennig virgil-pfennig@transcanada.com	
		Transcanada	Kelly Pfaff kelly-pfaff@transcanada.com	

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Attendee Sign-In Sheet

2014 - SD, Winner - First Responder Training Program (Dinner)
1/21/2014 5:30:00 PM - Instructor: Randy Leach

County Cluster: Bennett, Brule, Buffalo, Hand, Hyde, Jones, Mellette, Todd

	TT	Printed Name	Signature	Department or Company	Title	For Internal Use Only
	##	*Johnathan L. Doe*	*Johnathan L Doe*	*Anytown Fire Dept*	*Fire Fighter*	
15	1303	Todd Hauf	Todd Hauf	city of Colome	MAyor	X
16	1306	JAMES UNDERHILL	James Underhill	WITTEN	TRAING OFFICER	21
17	1308	Kurtis Hatcher		colome	Firefighter	2
18	1311	Deb Bice	Deb Bice	Winner P.D.	Communication Supervisor	18
19	1313	Lucy Hatchery		Tripp Ambulance		5
20	1315	Dallas Anderson		TC Sheriffs office	Deputy	15
21	1318	Shawn Pettit		TrippCo EM	emergency Manager	11
22	1320	Matt Vobr	Matt Vobr	Colome FD	Firefighter	2
23	1322	Wayne Hofeldt		Colome VFD	FirFighte	2
24	1323	Debby Engel		Tripp County	Emt	10
25	1325	Gary Brown	Gary Brown	tripp county Amb	EMT	8
26						
27						
28						

Instructor Signature:

Attendee Sign-In Sheet

2014 - SD, Winner - First Responder Training Program (Dinner)
1/21/2014 5:30:00 PM - Instructor: Randy Leach

County Cluster: Bennett, Brule, Buffalo, Hand, Hyde, Jones, Mellette, Todd

	TT	Printed Name	Signature	Department or Company	Title	For Internal Use Only
	##	Johnathan L. Doe	Johnathan L Doe	Anytown Fire Dept	Fire Fighter	
1	1302	Glenn Sealey	Glenn Sealey	Colome VFD	Chief	2
X 2	1304	Brad Whitley	Brad Whitley	Winner Fire Dept	Firefighter	
3	1305	Isaac Cole		witten VFD	fier fighter	22
4	1307	Ray Olson	Ray Olson	S.D. DOT	LEAH MAINT. WORKER	
5	1309	Brittany Kahler	Brittany Kahler	Colome Fire		2
6	1310	Paul Schuett	Paul Schuett	Winner Police Dept	Chief of Police	10
X 7	1312	Trent Sinclair		Winner Police Dept	Asst. Chief of Police	17
8	1314	John Hofeldt	John Hofeldt	Colome Fire Dept	Asst Chief	2
9	1316	Gregg Ulmer	Gregg Ulmer	SDDOT	Maint Super	
10	1317	Clifford Schroeder		Tripp Co. Sheriff	Sheriff	13
11	1319	TODD STIEHL	Todd Stiehl	TRIPP CO SO	DEPUTY	14
12	1321	Ethan Vobr	Ethan Vobr	Colome F.D.	Fire fighter	2
13	1324	Ken Jorgensen	Ken Jorgensen	Colome VFD	Fire Fighter EMT	2
14						

Instructor Signature: Randy Leach

Attendee Sign-In Sheet

2014 - SD, Winner - First Responder Training Program (Dinner)
1/21/2014 5:30:00 PM - Instructor: Randy Leach
County Cluster: Bennett, Brule, Buffalo, Hand, Hyde, Jones, Mellette, Todd

	TT	Printed Name	Signature	Department or Company	Title	For Internal Use Only
	##	*Johnathan L. Doe*	*Johnathan L Doe*	*Anytown Fire Dept*	*Fire Fighter*	
29	1351	MaryLajean Waters	MaryLajean Waters	Tripp Co EMS		
30	1326 [redacted]	Wendy Schmaltz	Wendy Schmaltz	Tripp Co EMS	EMT	
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Instructor Signature:

TransCanada Keystone Pipeline, LP
South Dakota Property Taxes
Tax Years 2011 - 2013

Attachment: BN-Int59

Tax Year / Year of Payment	2013 / 2014	2012 / 2013	2011 / 2012	2010 / 2011	2009 / 2010	
County						**Total**
Beadle County Treasurer	481,173	500,931	484,184	318,178	12,264	1,796,731
Brookings County Treasurer	2,200	1,430	1,289	815		5,734
Butte County Treasurer *	732	671				1,403
Clark County Treasurer	472,587	398,157	372,013	359,646		1,602,403
Day County Treasurer	579,830	494,120	448,391	464,958	307,424	2,294,723
Haakon County Treasurer *	33	22	22			77
Hanson County Treasurer	184,180	152,425	138,847	152,109		627,561
Harding County Treasurer *	135	140	99			375
Hutchinson County Treasurer	604,009	518,362	461,516	424,505	7,007	2,015,399
Jones County Treasurer *	34	32	31			98
Kingsbury County Treasurer	257,392	224,234	203,991	169,585		855,201
Marshall County Treasurer	353,389	305,527	271,177	286,611	316,713	1,533,417
McCook County Treasurer	163,775	136,149	129,241	139,426		568,591
Meade County Treasurer *	300	290	291			881
Miner County Treasurer	526,953	452,323	409,046	391,047	3,042	1,782,412
Tripp County Treasurer *	1,053	938	447			2,439
Yankton County Treasurer	309,181	251,379	225,512	247,966	6,744	1,040,782
	3,936,956	3,437,130	3,146,097	2,954,846	653,194	14,128,224

Per Docket HP07-001, TransCanada had originally estimated that the first full year of operations would produce a property tax liability of $6.5 Million state-wide. An estimate by county was not provided.

* These payments represent the property taxes on land currently owned at proposed Keystone XL pump station sites.

TransCanada Keystone Pipeline, LP
South Dakota Property Taxes
Tax Years 2011 - 2013

Attachment: S-F107_08

Tax Year / Year of Payment	2013 / 2014	2012 / 2013	2011 / 2012	2010 / 2011	2009 / 2010	Total
County						
Beadle County Treasurer	481,173	500,931	484,184	318,178	12,264	1,796,731
Brookings County Treasurer	2,200	1,430	1,289	815		5,734
Butte County Treasurer *	732	671				1,403
Clark County Treasurer	472,587	398,157	372,013	359,646		1,602,403
Day County Treasurer	579,830	494,120	448,391	464,958	307,424	2,294,723
Haakon County Treasurer *	33	22	22			77
Hanson County Treasurer	184,180	152,425	138,847	152,109		627,561
Harding County Treasurer *	135	140	99			375
Hutchinson County Treasurer	604,009	518,362	461,516	424,505	7,007	2,015,399
Jones County Treasurer *	34	32	31			98
Kingsbury County Treasurer	257,392	224,234	203,991	169,585		855,201
Marshall County Treasurer	353,389	305,527	271,177	286,611	316,713	1,533,417
McCook County Treasurer	163,775	136,149	129,241	139,426		568,591
Meade County Treasurer *	300	290	291			881
Miner County Treasurer	526,953	452,323	409,046	391,047	3,042	1,782,412
Tripp County Treasurer *	1,053	938	447			2,439
Yankton County Treasurer	309,181	251,379	225,512	247,966	6,744	1,040,782
	3,936,956	3,437,130	3,146,097	2,954,846	653,194	14,128,224

* These payments represent the property taxes on land currently owned at proposed Keystone XL pump station sites.

TransCanada Keystone Pipeline, LP
South Dakota Property Taxes
Tax Years 2011 - 2013

Attachment: DRA-Int84

Tax Year / Year of Payment	2013 / 2014	2012 / 2013	2011 / 2012	2010 / 2011	2009 / 2010	
County						**Total**
Beadle County Treasurer	481,173	500,931	484,184	318,178	12,264	1,796,731
Brookings County Treasurer	2,200	1,430	1,289	815		5,734
Butte County Treasurer *	732	671				1,403
Clark County Treasurer	472,587	398,157	372,013	359,646		1,602,403
Day County Treasurer	579,830	494,120	448,391	464,958	307,424	2,294,723
Haakon County Treasurer *	33	22	22			77
Hanson County Treasurer	184,180	152,425	138,847	152,109		627,561
Harding County Treasurer *	135	140	99			375
Hutchinson County Treasurer	604,009	518,362	461,516	424,505	7,007	2,015,399
Jones County Treasurer *	34	32	31			98
Kingsbury County Treasurer	257,392	224,234	203,991	169,585		855,201
Marshall County Treasurer	353,389	305,527	271,177	286,611	316,713	1,533,417
McCook County Treasurer	163,775	136,149	129,241	139,426		568,591
Meade County Treasurer *	300	290	291			881
Miner County Treasurer	526,953	452,323	409,046	391,047	3,042	1,782,412
Tripp County Treasurer *	1,053	938	447			2,439
Yankton County Treasurer	309,181	251,379	225,512	247,966	6,744	1,040,782
	3,936,956	3,437,130	3,146,097	2,954,846	653,194	14,128,224

Per Docket HP07-001, TransCanada had originally estimated that the first full year of operations would produce a property tax liability of $6.5 Million state-wide. An estimate by county was not provided.

* These payments represent the property taxes on land currently owned at proposed Keystone XL pump station sites.

TransCanada Keystone Pipeline, LP
South Dakota Property Taxes
Tax Years 2011 - 2013

Attachment: IEN-Int106

Tax Year / Year of Payment	2013 / 2014	2012 / 2013	2011 / 2012	2010 / 2011	2009 / 2010	
County						**Total**
Beadle County Treasurer	481,173	500,931	484,184	318,178	12,264	1,796,731
Brookings County Treasurer	2,200	1,430	1,289	815		5,734
Butte County Treasurer *	732	671				1,403
Clark County Treasurer	472,587	398,157	372,013	359,646		1,602,403
Day County Treasurer	579,830	494,120	448,391	464,958	307,424	2,294,723
Haakon County Treasurer *	33	22	22			77
Hanson County Treasurer	184,180	152,425	138,847	152,109		627,561
Harding County Treasurer *	135	140	99			375
Hutchinson County Treasurer	604,009	518,362	461,516	424,505	7,007	2,015,399
Jones County Treasurer *	34	32	31			98
Kingsbury County Treasurer	257,392	224,234	203,991	169,585		855,201
Marshall County Treasurer	353,389	305,527	271,177	286,611	316,713	1,533,417
McCook County Treasurer	163,775	136,149	129,241	139,426		568,591
Meade County Treasurer *	300	290	291			881
Miner County Treasurer	526,953	452,323	409,046	391,047	3,042	1,782,412
Tripp County Treasurer *	1,053	938	447			2,439
Yankton County Treasurer	309,181	251,379	225,512	247,966	6,744	1,040,782
	3,936,956	3,437,130	3,146,097	2,954,846	653,194	14,128,224

* These payments represent the property taxes on land currently owned at proposed Keystone XL pump station sites.

TransCanada Keystone Pipeline, LP
South Dakota Property Taxes
Tax Years 2011 - 2013

Attachment: IEN-Int87

Tax Year / Year of Payment	2013 / 2014	2012 / 2013	2011 / 2012	2010 / 2011	2009 / 2010	
County						**Total**
Beadle County Treasurer	481,173	500,931	484,184	318,178	12,264	1,796,731
Brookings County Treasurer	2,200	1,430	1,289	815		5,734
Butte County Treasurer *	732	671				1,403
Clark County Treasurer	472,587	398,157	372,013	359,646		1,602,403
Day County Treasurer	579,830	494,120	448,391	464,958	307,424	2,294,723
Haakon County Treasurer *	33	22	22			77
Hanson County Treasurer	184,180	152,425	138,847	152,109		627,561
Harding County Treasurer *	135	140	99			375
Hutchinson County Treasurer	604,009	518,362	461,516	424,505	7,007	2,015,399
Jones County Treasurer *	34	32	31			98
Kingsbury County Treasurer	257,392	224,234	203,991	169,585		855,201
Marshall County Treasurer	353,389	305,527	271,177	286,611	316,713	1,533,417
McCook County Treasurer	163,775	136,149	129,241	139,426		568,591
Meade County Treasurer *	300	290	291			881
Miner County Treasurer	526,953	452,323	409,046	391,047	3,042	1,782,412
Tripp County Treasurer *	1,053	938	447			2,439
Yankton County Treasurer	309,181	251,379	225,512	247,966	6,744	1,040,782
	3,936,956	3,437,130	3,146,097	2,954,846	653,194	14,128,224

* These payments represent the property taxes on land currently owned at proposed Keystone XL pump station sites.

TransCanada Keystone Pipeline, LP
South Dakota Property Taxes
Tax Years 2011 - 2013

Attachment: S-107

Tax Year / Year of Payment	2012 / 2013	2011 / 2012	2010 / 2011	
County				**Total**
Beadle County Treasurer	500,931	484,184	318,178	1,303,293
Brookings County Treasurer	1,430	1,289	815	3,534
Butte County Treasurer *	671			671
Clark County Treasurer	398,157	372,013	359,646	1,129,816
Day County Treasurer	494,120	448,391	464,958	1,407,469
Haakon County Treasurer *	22	22		44
Hanson County Treasurer	152,425	138,847	152,109	443,381
Harding County Treasurer *	140	99		240
Hutchinson County Treasurer	518,362	461,516	424,505	1,404,383
Jones County Treasurer *	32	31		63
Kingsbury County Treasurer	224,234	203,991	169,585	597,810
Marshall County Treasurer	305,527	271,177	286,611	863,315
McCook County Treasurer	136,149	129,241	139,426	404,816
Meade County Treasurer *	290	291		581
Miner County Treasurer	452,323	409,046	391,047	1,252,416
Tripp County Treasurer *	938	447		1,385
Yankton County Treasurer	251,379	225,512	247,966	724,857
	3,437,130	3,146,097	2,954,846	14,128,224

Per Docket HP07-001, TransCanada had originally estimated that the first full year of operations would produce a property tax liability of $6.5 Million state-wide. An estimate by county was not provided.

* These payments represent the property taxes on land currently owned at proposed Keystone XL pump station sites.

Year	Reference ID	Date	Facility	State	Substance	Volume	Unit	Description	
2010		2010-may-21	Carpenter PS	South Dakota	Crude	5	gallon	Failure of a 1½" below ground fitting connected to the mainline isolation valve.	
2010		2010-jun-23	Rosewell PS	South Dakota	Crude	100	gallon	during maintenance from a small fitting attached to the sump pump	
2010		2010-aug-10	Freeman PS	South Dakota	Crude	2	gallon	Failure of a 1" fitting attached to the pig trap receiver.	
2010		2010-aug-19	Hartington PS	Nebraska	Crude	10	gallon	Failure of ½" above ground fitting.	
2011	209437	2011-Jan-05	Ferney PS	South Dakota	Crude	5	gallon	Pump #2 casing and unit piping was found to be covered with a film of oil. Unit was isolated for further investigation on source of oil. Containment and remediation procedures implemented	
2011	209521	2011-Jan-07	Severance _2_1 valve	Kansas	Crude	5	gallon	Downstream 6 inch riser on remote main line block valve developed a small leak around the valve packing. Oil was cleaned up on pipe and absorbent materials applied to valve and associated piping. Initial remediation actions were implemented and site was stabilized for the evening	
2011	209562	2011-Jan-08	Freeman PS	South Dakota	Crude	1	gallon	OIL WAS DISCOVERED COMING OUT OF THE INSULATION OF THE PUMP BODY DRAIN VALVE ON THE OUTBOARD SIDE OF UNIT 4 AT FREEMAN PUMP/PIG STATION. UPON REMOVING THE INSULATION IT WAS DISCOVERED THAT THE INSDE VALVE OF THE TWO DRAIN VALVES WAS LEAKING FROM THE UPSTREAM SIDE.	
2011	210062	2011-Jan-26	Hope PS	Kansas	Crude	1.5	gallon	During Sump Commissioning a valve was opened to fill the sump tank. As the tank was being filled it was noticed that oil was backing up on the pump seal flush drains. Oil ran out of Unit 1 pump seal chamber onto the pump base and weeped over the front end of the base. Oil ran out of Unit 2 pump seal chambers onto the pump base and was contained. Oil backed up into the seal chambers on Unit 3 but not onto the base. We shut down the sump filling and identified the leak source and began clean up allowing the seal chambers to drain out we isolated the seal flush lines to continue the sump commissioning	
2011	210233	2011-Jan-30	Turney PS	Missouri	Crude	10	gallon	Outboard seal on Pump #2 failed resulting in approximately 10 gallons of oil being discharged on the ground, the pump, pump base and associated piping. Unit was isolated for further investigation and clean up. Containment and remediation procedures implemented	
2011	210615	2011-Feb-09	Hope PS	Kansas	Crude	4	gallon	On Final inspection before leaving the pump station I discovered oil on the pump skid of Unit 3 at Hope PS. Discovering the (pump suction side drain line) root valve to have oil on the pump side of the body. The amount of oil looks to be about 3 1/2 to 4 gallons with about 1 1/2 gallons leaving the pump skid.	
2011	210697	2011-Feb-11	David City PS	Nebraska	Crude	75	gallon	after repacing mechanical seal on outboard of unit 3 at david city a start was put in unit. unit went down on a hi hi on outboard pressure transmiter. a technician then tried to bleed the transmiter of oil. there was no oil in the transmiter to bleed. the unit was reset and another start was put in the unit. the unit ran for 1 minute and the outboard seal failed releasing oil	
2011	210803	2011-Feb-15	Hope PS	Kansas	Crude	2	gallon	Found oil underneath Hope Pump Unit 1 leaking from the discharge drain valve on the pump 1" bleed valve. This amounted to approximately 1 1/2 gallons of crude oil on the pump skid. Isolated the Unit pump and looking around the site discovered a 3" ball valve on Unit 1 suction side drain valve to have a small leak of crude oil from the bonnet and bolted body area not the piping flanges. Station Inlet first 3" drain valve to also have a leak from the bonnet area of the valve. This amounted to approximately 1 quart of crude oil on the site rock below the valve.	
2011	210951	2011-Feb-17	Rock PS	Kansas	Crude	4.5	gallon	A Station drain valve was discovered leaking oil from the bolted body connection.	
2011	211479	2011-Mar-09	Luvern PS	Nebraska	Crude	2	gallon	A leak occurred on the thermal relief pipe loop around the pump suction valve. The leak was at the downstream gasketed flange of the thermal relief device. Aproximately 2 gallons of oil in the immediate vacinity of the suction valve. surface rock and snow was wetted with oil	
2011	211685	2011-Mar-16	Seneca PS	Kansas	Crude	504	gallon	Technician was dispatched to site to investgate SDL on Pump #4. Pump and unit piping were found to be covered in oil. Unit was isolated to investigate source of oil.	
2011	212568	2011-Apr-11	Turney PS	Missouri	Crude	4	cups	Discovered leak out of the vent on mainline block valve at Turney station injected grease in the emergency fitting removed vent and installed 3/4" valve in place of vent	

2011	219941	2011-Apr-26	Ludden PS	North Dakota	Crude	4	cups	Ludden station, discharge relief valve, 3/4" nipple leaking oil. 1" piping has seen vibration, possibly causing leak.	
2011	220020	2011-Apr-28	Rock 2A Valve	Kansas	Crude	2	gallon	clouding of the rock around the inlet side blow down valve stinger. observed crude oil residue and oily rock just below the immediate grade. Reviewed the area valves and flanges but no signs of leaks.	
2011	220309	2011-May-07	Ludden PS	North Dakota	Crude	16800	gallon	Oil release at Ludden pump station. Line shutdown after indication of station pressure loss and call from PDL.	
2011	220877	2011-May-25	Rosewell PS	South Dakota	Crude	2	gallon	Roswell station, A4 suction pressure transmitter, 1/2 inch nipple leaking where threaded into manifold	
2011	220963	2011-May-28	Severance PS	Kansas	Crude	10	gallon	Oil release at Severance pump station. Station was ESD and isolated	
2011	222206	2011-Jul-06	Turney PS	Kansas	Crude	0.5	gallon	At the start of a planned excavation around the 3 valve cluster at Turney PS a sheen of oil and droplets were witnessed in the excavation.	
2011	222237	2011-Jul-07	Seneca PS	Kansas	Crude	7	gallon	On site to remove NP pump for retrim job. While draining down pump failed to open a valve to facilitate draining of pump piping. When crew cracked flange it allowed remaining oil to leak onto skid with approx. 3 reaching the ground (total of 7 gal.) before it could be contained.	
2011	223197	2011-Aug-02	Turney PS	Kansas	Crude	5	teaspoons	Technician noticed small amount of oil (less than 2 tablespoons) had seeped from a gasket on the station discharge piping and dripped on the rocks below.	
2011	223728	2011-Aug-12	Burns PS	Kansas	Crude	2	cups	Will draining water off the valve yoke at Burns Station on MOV 0204 the valve packing had leaked 2qt of crude oil into the yoke	
2011	225968	2011-Mar-11	St Paul PS	Missouri	Crude	1	teaspoons	While performing facility check at St Paul Pump Station Unit 2 (A2-MPM-02) small oil stain on skid below discharge pump flange. crude oil has been weeping from Pump flange side. New Gasket installed	
2011	229220	2011-Dec-06	Edinburg PS	North Dakota	Crude	4	cups	While inspecting the Rexa control valve, small amont of oil on the ground below less than a quart	
2012	232758	2012-Mar-26	Rosewell PS	South Dakota	Crude	10	teaspoons	while doing routine morning walk around. crude oil on one of the vents of the discharge piping between the rexa and the check valve. seeping at certain harmonics from a threaded connection on the vent fabrication. A	
2012	234766	2012-May-15	Cushing	Oklahoma	Crude	0.05	gallon	During a Routine Inspection of the Cushing Meter Station, the technician found that the upstream flange on the Pressure Control Valve was weeping oil onto the support for the valve. The volume of oil is minimal and has not left the base of the support. replace the gasket on the upstream side of the PCV.	
2012	236179	2012-Jun-18	Seneca PS	Kansas	Crude	10	gallon	While bringing A4 back into service after bracing work there was a small amount of oil released onto the pump and skid. It is suspected that the release was due to oil backing up in the drain line and then coming up out the seal covers. All oil was recovered and station was returned to normal operations	
2012	236542	2012-Jun-25	Carpenter PS	South Dakota	Crude Oil	4	cups	While performing a facility inspection at Carpenter pump station a leak was discovered on unit 4 suction pressure transmitter. Unit was placed in local and isolation valve was closed to stop fitting from dripping product. approximately 1 quart of oil had leaked onto ground. Oil was cleaned up and oily rock was placed into 55 gallon drum for disposal. Ralston fitting appeared to be OK but was replaced anyway then unit was turned back over to OCC.	
2012	237402	2012-Jul-13	Carpenter PS	South Dakota	Crude	6	cups	OCC called stating that we had a seal Inboard seal HI HI pressure on unit 3 at Carpenter. Once onsite discovery that approximately 1 ½ quarts of oil had leaked out and was totally contained on the pump skid. Oil was cleaned up and rags were placed in waste drums. Unit was placed into Local removing it from service until seal is replaced.	
2012	238538	2012-Aug-08	FREMA + 12 Valve	South Dakota	Crude	4	cups	Vapor detection contractor was conducting testing on the valve body drain line through the use of their patented innoculent.	
2012	238893	2012-Aug-15	Patoka	Illinois	Crude	3	gallon	After completing Vibration testing noticed oil on the relief skid between the upstream hand valve and the M&J relieif valva south run. Isolated south run drained piping to sump. cleaned up piping and picked up some stained rock.	
2012	241758	2012-Oct-10	Cushing	Oklahoma	Crude	2	gallon	Technician was doing a walk through of the facility, noticed a small amount of oil on MLV 104 and on the ground around it. Upon further investigation it was determined the the oil had came out of the condensate weep hole on the stem of the valve when the valve was opened to flow through Cushing.	
2013	254716	2013-Apr-23	Cushing	Oklahoma	Crude	5	gallon	During maintenance activity on meter bank2 meter. Approximate amount spilled is three to five gallons	

2013	256402	2013-May-13	Ponca City PS	Oklahoma	Crude			During the US Keystone Sulzer Pump Drain removal project at Ponca City, Oklahoma, crews discovered a broken small bore clamp on Temperature Transmitter 101 & 102. These clamps were installed as part of the Bracing Reliability Program.	
2013	258211	2013-Jun-06	Edinburg PS	North Dakota	Crude	1	gallon	While starting pump 4 noticed oil coming from out board seal area. Called OCC and ESDed the pump about 1 gallon of crude came out of outboard seal area.	
2013		2013 Dec 20	Winnsboro	Texas	Crude	3	Ounces	Today during line filling of the Winnsboro Pump station a leak occurred on the threaded body bleed of a manual drain valve on the station discharge piping. Approximately 3 ounces leaked out. The leak was corrected by tightening the body bleed fitting and cleanup performed immediately. It was discovered during inspection of piping during the line fill operations.	
2014		2014 Jan 07	Bryan PS	Oklahoma	Crude	0.5	Gallon	a minor leak was discovered. The pump station was wet commissioned on December 30, 2013 and the leak was not present when the facility was checked on January 6, 2014. A construction crew on site to complete punch list items discovered the approximately ½ gallon leak coming from a screwed body type 1 ½ inch valve. This valve is a body drain valve used to drain the gate valve body on the NPS 30 pig launcher valve. The screwed valve was tightened to stop the leak and cleanup commenced.	
2014		2014 Jan 24	Cromwell PS	Oklahoma	Crude	2	Teaspoons	On January 24th 2014 a drip was discovered on the 1 ½ " body bleed valve at the Cromwell Pump Station 3-valve cluster. The estimated volume released was two teaspoons. All impacted gravel was picked up and placed in a containment bucket. The valve was tightened and is scheduled for replacement	
2014		2014 Mar 19	Nederland	Texas	Crude	5	Gallon	Technician discovered a grease fitting dripping on a drain valve, at Nederland Delivery terminal. The 2" valve is the meter case isolation valve for draining meter #2300, meter bank #1	
2014		2014 Mar 26	Nederland	Texas	Crude	1	Cup	Less than one cup oil was found seeping from packing gland FE-2320. This was realized on close of day walk around a 18:57 hrs Completed clean up 21:19 hrs.	
2014		2014 Mar 27	Nederland	Texas	Crude	1	Cup	leak was found on meter (that is not in-service). Estimate leakage is around one cup or less released. The oil was seeping from the O-ring or gasket on the meter vent.	
2014		2014 Apr 12	Cushing 01A valve	Oklahoma	Crude	1	Pint	small release at Cushing 01A. The oil escaped from around the indicator on one of the two riser valves. A small amount of oil ran down the side of the valve, riser and on the gravel.	
2014		2014 Apr 15	Nederland	Texas	Crude	1	Ounce	Techs discovered a small release today Delta - 04A/downstream riser valve. The release came from around the stem on the needle valve assembly, below the pressure transmitter. The jam nut was found backed off and the stem packing nut was loose, allowing the oil to release around the valve stem	
2014		2014 Jun 03	Cushing	Oklahoma	Crude	0.5	Gallon	a small release was notice at the downstream flange of PCV-7218 (Approximately .5 gallon). Product appeared to be relieving at the flange through the gasket. Most of the product was contained on the concrete support for this valve. A small amount ran down the side to the ground.	
2014		2014 Jun 23	Cushing	Oklahoma	Crude	2	Gallons	a minor release at Cushing Terminal during wet commissioning activities.	
2014		2014 Jun 26	Ponca City PS	Oklahoma	Crude	3	Gallons	mechanical failure occurred on Ponca City Pump Station Unit #3 outboard. Approximately 3 gallons of crude oil escaped onto the pump skid. No oil hit the ground.	
2014	12499	2014 Jul 07	Nederland	Texas	Crude	1	Gallon	a small crude oil release at Nederland Delivery Terminal. The oil escaped from a meter run control valve on Meter Bank #1, run #4. The oil has ran down the valve, below the meter bank and onto the gravel/soil below.	
2014	2657	2014 Jul 09	Bryan PS	Oklahoma	Crude	1	Pint	small crude oil release at Bryan Pump Station on MOV 103. The oil escaped from around the threads of a loose grease fitting and ran down the valve, onto the soil below.	

2014	12819	2014 Jul 09	Nederland	Texas	Crude	<1	Gallon	small crude oil release at Nederland Delivery Terminal, on MOV 2201; pig receiver trap bypass valve. It appears the stem packing was leaking inside the valve stem cover and recent heavy rains floated the oil out of the valve stem cover. The oil ran down the side of the valve, with a very small amount dripping onto the soil below.	
2014	14270	2014 Jul 24	Nederland	Texas	Crude	1.5	Barrels	Nederland Tank Terminal, Valve 2201, a bypass valve on the mainline receiver pig trap. OCC was contacted and closed an upstream mainline valve to stop the leak.	
2014	14885	2014 Jul 29	Bryan PS	Oklahoma	Crude	20	Gallons	technician was performing an annual PM at Bryan pump station in Oklahoma on the sump tank levels which includes the rising of the level to test alarm set points, approximately 20 gallons estimated of oil was released out of unit #1 due to back up in the sump piping and the unit drain valve not being closed during the test.	
2014	15770	2014 Aug 10	Nederland	Texas	Crude	1	Ounce	Nederland MOV-2205, a 36 inch ball valve inlet to meter bank 2. The amount released is less than one ounce. Due to the location of the release being downstream of the pig receiver	
2014	15907	2014 Aug 12	Lufkin	Texas	Crude	4	Ounces	During Pigging Operations at Lufkin Pump Station, a small amount of Light Crude Oil constituting 3-4 ounces was released onto the soil immediately below the PIG Launcher Trap Closure Door. Pigging project team was in the process of the loading a PIG into the Receiver Trap. Construction team had laid plastic down underneath the Closure Door and the Catch Basin was positioned atop the plastic. Following the PIG Trap Drain and LO/TO Isolation, the Door was cracked open to let residual oil near the door fall into the Basin and be sucked up by a vacuum truck. The minor turbulence of the flow from the bottom of the door splashed some oil back behind onto the plastic sheeting. A small hole was torn in the plastic by the hook-up valve stem on the end of the Catch Basin. The oil made its' was thru the hole and onto the ground.	
2014	17307	2014 Aug 26	Ferney PS	South Dakota	Crude	5	Ounces	6" discharge riser, 6" valve, button head grease fitting leaked 5 OZ oil on pipe, and ground.	
2014	17183	2014 Aug 27	Cushing	Oklahoma	Crude	4	Ounces	Approx 4 ounces of crude oil seeped from a flange within the prover piping at Cushing Delivery Terminal. The oil escaped from the upstream flange of MOV control valve 2293.	
2014	17312	2014 Aug 27	Centralia PS		Crude	2	Gallons	While working on unit three the inboard on unit 4 leaked enough oil past the mechanical seal to fill the piping from the closed seal drain valve to the bootom of the seal housing and spilled approx. 8 quarts of oil on the skid. Oil did not reach the ground.	
2014	18358	2014 Sep 15	Cushing	Oklahoma	Crude	4	Ounces	The PSV on MOV 7291 had a plug that was not tight,and it caused a minor leak (4.oz) onto valve below. No oil touched the ground. The leak was stopped by tightening the plug	
2014	18440	2014 Sep 15	Saint Paul PS	Missouri	Crude	1	Ounce	during a weekly inspection technician noticed a small oil streak coming from the high point vent on top of unit 3 suction piping	
2014	18789	2014 Sep 18	Niagra PS	North Dakota	Crude	0.5	Gallons	During station reload, Immediately upon noticing oil coming out from seal cover the seal drain was opened and oil going on to skid was stopped.	
2014	19869	2014 Oct 2	Lucas Terminal	Texas	Crude	3	Gallons	During morning inspection of Meter bank 2, a small leak coming from the packing gland on the top of the meter. Approximately 3 gallon of crude oil leaked onto the ground.	
2014	21695	2014 Oct 29	Lufkin PS	Texas	Crude	0.5	Gallons	a release of approximately one-half gallons of crude occurred at a discharge Pressure Transmitter stainless flex pipe, which released at the bottom end of the loop;	
2014	22385	2014 Nov 10	Nederland	Texas	Crude	<1	Cup	found oil on top of meter. No oil on the ground. One cup oil speep on equipment.	
2015	25799	2015 Jan 02	Middletown PS	Missouri	Crude	3	Cups	During Weekly inspection a very small amount of oil was noticed on the station bypass valve. Further inspection revealed the oil was coming from the stem extension vent. Approximatly 3 cups of oil was on the ground.	
2015	26018	2015 Jan 08	Salisbury PS	Missouri	Crude	0.5	Cups	1/2 cup of oil discovered under flange at Salisbury pump station on flange on MOV 0203.	

2015	26404	2015 Jan 13	Cushing	Oklahoma	Crude	4	Gallons	During routine inspections it was discover MOV 204 had leaked oil onto the valve and surrounding piping. It was estimated 4.5 gallons was present with less than .5 on the ground.	
2015	26690	2015 Jan 16	Cushing	Oklahoma	Crude	2	Ounces	2 inch drain ball valve experienced a leak from the valve body due to losen bolts on body of valve. Valve dripped approximately 2 oz of crude on the rocks below. Valve was not actively leaking when found.	

Year	Reference ID	Date	Facility	Substance
2010	200202	7-Jul-10	Pump Stn 25 (Portage La Prairie)	Crude
2010	200206	7-Jul-10	Pump Stn 25 (Portage La Prairie) + 25 km	Crude
2010	200363	10-Jul-10	Pump Stn 22 (Crandall) + 26.4 km	Crude
2010	200363	10-Jul-10	Pump Stn 22 (Crandall) + 39.7 km	Crude
2010	200363	10-Jul-10	Pump Stn 21 (Moosomin) + 31.8 km	Crude
2010	200363	10-Jul-10	Pump Stn 21 (Moosomin) + 42.5 km	Crude
2010	200400	12-Jul-10	Hardisty Terminal	Crude
2010	200793	16-Jul-10	Elm Creek Pigging Stn	Crude
2010	200795	16-Jul-10	Elm Creek Pigging Stn	Crude
2010	200798	16-Jul-10	Elm Creek Pigging Stn	Crude
2010	200891	19-Jul-10	Pump Stn 25 (Portage La Prairie)	Crude
2010	200963	20-Jul-10	Pump Stn 21 (Moosomin) + 30 km	Crude
2010	201342	26-Jul-10	Hardisty Terminal	Crude
2010	201709	27-Jul-10	Pump Stn 17 (Regina)	Crude
2010	203569	26-Aug-10	Pump Stn 7 (Monitor)	Crude
2010	206857	20-Oct-10	Pump Stn 25 (Portage La Prairie) + 9.9 km	Crude
2010	207727	8-Nov-10	Pump Stn 26 (Carmen)	Crude
2010	207980	12-Nov-10	Pump Station 18 (Kendal)	Crude
2010	208257	20-Nov-10	Pump Stn 11 (Cabri)	Crude
2010	208287	19-Nov-10	Pump Stn 6 (Lakesend)	Crude
2010	208332	22-Nov-10	Hardisty Terminal	Crude
2010	208514	30-Nov-10	Pump Stn 15 (Caron)	Crude
2010	208869	9-Dec-10	Pump Stn 17 (Regina)	Crude
2010	208914	10-Dec-10	Pump Stn 19 (Grenfell)	Crude
2010	209179	18-Dec-10	Pump Stn 9 (Bindloss)	Crude
2010	209184	18-Dec-20	Pump Stn 19 (Grenfell)	Crude
2010	209217	20-Dec-10	Pump Stn 14 (Chaplin)	Crude
2010	209246	21-Dec-10	Pump Station 17 (Regina)	Crude
2011	209466	6-Jan-11	Hardisty Terminal	Crude
2011	209519	7-Jan-11	Pump Station 18 (Kendal)	Crude
2011	210390	28-Jan-11	Hardisty Terminal	Crude
2011	210386	2-Feb-11	Hardisty Terminal	Crude
2011	210658	10-Feb-11	Pump Station 22 (Crandall)	Crude
2011	210462	9-Mar-11	Hardisty Terminal	Crude
2011	210464	9-Mar-11	Pump Station 10 (Liebenthal)	Crude
2011	212155	22-Mar-11	Pump Station 24 (Wellwood)	Crude
2011	212093	23-Mar-11	Pump Station 8 (Oyen)	Crude
2011	212094	23-Mar-11	Pump Station 8 (Oyen)	Crude
2011	212193	30-Mar-11	Pump Station 8 (Oyen)	Crude
2011	220515	13-May-11	Hardisty Terminal	Crude
2011	220538	15-May-11	Pump Station 15 (Caron)	Crude
2011	220571	16-May-11	Pump Station 20 (Whitewood)	Crude
2011	220640	17-May-11	Hardisty Terminal	Crude
2011	220922	26-May-11	Pump Station 9 (Bindloss)	Crude
2011	221265	5-Jun-11	Pump Station 17 (Regina)	Crude
2011	221270	7-Jun-11	Hardisty Terminal	Crude
2011	221381	9-Jun-11	Pump Stn 19 (Grenfell)	Crude
2011	223157	1-Aug-11	Hardisty Terminal	Crude
2011	223171	2-Aug-11	Pump Station 12 (Stewart Valley)	Crude
2011	223326	3-Aug-11	Pump Station 15 (Caron)	Crude
2011	223415	5-Aug-11	Pump Station 8 (Oyen)	Crude
2011	223448	7-Aug-11	Pump Station 8 (Oyen)	Crude

2011	223450	7-Aug-11	Pump Stn 6 (Lakesend)	Crude
2011	223472	7-Aug-11	Pump Station 20 (Whitewood)	Crude
2011	223530	9-Aug-11	Pump Station 11 (Cabri)	Crude
2011	224694	6-Sep-11	Hardisty Terminal	Crude
2011	224866	11-Sep-11	Pump Station 12 (Stewart Valley)	Crude
2011	225081	15-Sep-11	Pump Station 16 (Belle Plaine)	Crude
2011	225843	30-Sep-11	Pump Station 9 (Bindloss)	Crude
2011	226139	13-Oct-11	Pump Station 9 (Bindloss)	Crude
2011	226619	25-Oct-11	Pump Station 16 (Belle Plaine)	Crude
2011	227194	8-Nov-11	Hardisty Terminal	Crude
2011	227227	9-Nov-11	Hardisty Terminal	Crude
2011	227690	21-Nov-11	Hardisty Terminal	Crude
2011	227849	25-Nov-11	Burstall Control Valve/Pigging Station	Crude
2011	228047	30-Nov-11	Elm Creek Pigging Station	Crude
2011	228540	12-Dec-11	Hardisty Terminal	Crude
2011	228822	12-Dec-11	Pump Station 21 (Moosomin)	Crude
2011	229075	22-Dec-11	Pump Station 16 (Belle Plaine)	Crude
2011	229190	30-Dec-11	Hardisty Terminal	Crude
2012	229303	5-Jan-12	Pump Station 13 (Herbert)	Crude
2012	229382	9-Jan-12	Hardisty Terminal	Crude
2012	229384	9-Jan-12	Elm Creek Pigging Station	Crude
2012	230096	24-Jan-12	Pump Station 16 (Belle Plaine)	Crude
2012	230577	3-Feb-12	Pump Station 21 (Mossomin)	Crude
2012	231183	16-Feb-12	Pump Station 24 (Wellwood)	Crude
2012	231361	21-Feb-12	Pump Station 8 (Oyen)	Crude
2012	232166	9-Mar-12	Pump Station 16 (Belle Plaine)	Crude
2012	232266	12-Mar-12	Pump Station 15 (Caron)	Crude
2012	232304	13-Mar-12	Hardisty Terminal	Crude
2012	232335	14-Mar-12	Portage La Prairie (PS 25) + 9.9 km	Crude
2012	232412	15-Mar-12	Stewart Valley (PS 12) + 31.2 km	Crude
2012	232516	19-Mar-12	Chaplin Pump Station (PS 14) + 32.8 km	Crude
2012	232517	19-Mar-12	Belle Plaine Pump Station (PS 16) + 6.4 km	Crude
2012	232518	19-Mar-12	Belle Plaine Pump Station (PS 16) + 33.1 km	Crude
2012	232519	19-Mar-12	Regina Pump Station (PS 17) + 26.4 km	Crude
2012	232520	19-Mar-12	Kendal Pump Station (PS 18) + 8.2 km	Crude
2012	232521	19-Mar-12	Kendal Pump Station (PS 18) + 32.8 km	Crude
2012	232552	20-Mar-12	Grenfell Pump Station (PS 19) + 26.2 km	Crude
2012	232554	20-Mar-12	Whitewood Pump Station (PS 20) + 24.7 km	Crude
2012	232641	20-Mar-12	Hardisty Terminal	Crude
2012	232807	27-Mar-12	Pump Station 17 (Regina)	Crude
2012	233236	9-Apr-12	Hardisty Terminal	Crude
2012	233337	12-Apr-12	Pump Station 15 (Caron)	Crude
2012	233389	13-Apr-12	Pump Station 17 (Regina)	Crude
2012	233400	13-Apr-12	Pump Station 22 (Crandall)	Crude
2012	233459	16-Apr-12	Pump Station 15 (Caron)	Crude
2012	233533	17-Apr-12	Hardisty Terminal	Crude
2012	235221	28-May-12	Pump Station PS 25 (Portage La Prairie)	Crude
2012	235242	29-May-12	Hardisty Terminal	Crude
2012	235401	31-May-12	Pump Station 15 (Caron)	Crude
2012	235599	5-Jun-12	Pump Station 21 (Moosomin)	Crude
2012	235890	11-Jun-12	Pump Station 15 (Caron)	Crude
2012	235917	12-Jun-12	Hardisty Terminal	Crude
2012	235968	12-Jun-12	Hardisty Terminal	Crude
2012	235968	12-Jun-12	Hardisty Terminal	Crude
2012	236186	18-Jun-12	Pump Station 19 (Grenfell)	Crude

2012	237375	12-Jul-12	Hardisty Terminal	Crude
2012	238775	14-Aug-12	Hardisty Terminal	Crude
2012	242789	25-Oct-12	Hardisty Terminal	Crude
2012	243627	13-Nov-12	Pump Station 6 (Lakesend)	Crude
2012	244020	20-Nov-12	Hardisty Terminal	Crude
2012	244020	20-Nov-12	Hardisty Terminal	Crude
2012	244020	20-Nov-12	Hardisty Terminal	Crude
2013	246824	10-Jan-13	Grenfell Pump Station 19	Crude
2013	247846	24-Jan-13	Belle Plaine Pump Station 16	Crude
2013	248429	1-Feb-13	Hardisty Terminal	Crude
2013	249250	11-Feb-13	Whitewood Pump Station 20	Crude
2013	252227	20-Mar-13	Hardisty Interconnects	Crude
2013	253639	9-Apr-13	Carman Pump Station 26	Crude
2013	255059	26-Apr-13	Hardisty Terminal	Crude
2013	257282	24-May-13	Hardisty Terminal	Crude
2013	260408	26-Jun-13	Hardisty Terminal	Crude
2013	259849	2-Jul-13	Monitor Pump Station 7	Crude
2013	259937	2-Jul-13	Hardisty Terminal	Crude
2013	260161	6-Jul-13	Caron Pump Station 15	Crude
2013	260507	10-Jul-13	Grenfell Pump Station 19	Crude
2013	266865	17-Sep-13	Lakesend Pump Station 6	Crude
2013	268880	6-Oct-13	Hakett Pump Station 27	Crude
2013	271558	29-Oct-13	Hardisty Terminal	Crude
2013	272095	6-Nov-13	Kendall Pump Station 18	Crude
2013	273490	24-Nov-13	Chaplain Pump Station 14	Crude
2013	274596	5-Dec-13	Cabri Pump Station 11	Crude
2013	275632	19-Dec-13	Hardisty Interconnects	Crude
2014	917	30-Jan-14	Hardisty Terminal	Crude
2014	1970	18-Feb-14	Kendall Pump Station 18	Crude
2014	3598	17-Mar-14	Hardisty Terminal	Crude
2014	5129	8-Apr-14	Portage La Prairie-Carman OP/L / ID: 3111	Crude
2014	5614	15-Apr-14	Oyen Pump Station	Crude
2014	7565	12-May-14	Hardisty Terminal	Crude
2014	9078	2-Jun-14	Carman Pump Station 26	Crude
2014	9204	3-Jun-14	Hardisty Terminal	Crude
2014	10849	19-Jun-14	Hardisty Terminal	Crude

Volume	Unit	Comments
0.01	Litres	Body Bleed Leak
0.01	Litres	Body Bleed Leak
0.5	Litres	Body Bleed Leak
	Litres	Body Bleed Leak
	Litres	Body Bleed Leak
	Litres	Body Bleed Leak
10	Litres	Spray during water draw operation
1	Litres	Drain Line Leak
0.5	Litres	Body Bleed Leak
0.5	Litres	Body Bleed Leak
0.01	Litres	Body Bleed Leak
1	Litres	Body Bleed Leak
1	Litres	Valve Stem leak
0.1	Litres	Loose threaded PSV
20	Litres	Release during bypass line removal
0.25	Litres	Threaded Pleeco fitting leak
0.01	Litres	Valve Stem Leak
0.01	Litres	Leak from the valve stem o-ring on Pump #3
1	Litres	Seal Failure
0.5	Litres	Body Bleed Leak
200	Litres	Line pressure caused thermal relief to open into sump with subsequent sump overflow
0.25	Litres	Leak on Coupling end from a 1/2 SS drain pipe on Pump #1
0.02	Litres	Drain Pipe Leak under Pump #1
0.11	Litres	Leaks on Drive-end & Non-drive end (Pump #1) and Drive-end (Pump #2)
0.1	Litres	Swagelok fitting Leak on pump
0.02	Litres	Swagelok fitting Leak on pressure transmitter
0.5	Litres	Bearing Housing Leak
0.005	Litres	Swagelok fitting Leak on Drain Pipe on Pump
22.7	Litres	Valve stem packing leak on Valve MOV-2040
0.01	Litres	Leak from the valve stem o-ring on Pump #3
0.47	Litres	Threaded connection between pressure transmitter and pipe
1	Litres	Valve stem packing leak on Valve MOV-2040
1	Litres	Unit 1 & 2 leaks into pump housing drain area
2	Litres	Valve stem packing leak on Valve MOV-2040
0.25	Litres	Fitting leak at end of closed body vent valve
2	Litres	Leak from undersized drain line below pump
2	Litres	Bearing isolator leaking on non-drive end of pump 5
2	Litres	Bearing isolator leaking on non-drive end of pump 4
0.5	Litres	Missing case temperature thermowell
40	Litres	Valve stem packing leak on Valve MOV-2040
10	Litres	Failed gauge on the pig receiver
0.005	Litres	Body bleed leak on #2 discharge valve
2	Litres	Valve stem packing leak on Valve MOV-2030
0.01	Litres	Improper tubing installation
0.02	Litres	Leak on suction side valve riser
0.01	Litres	Cracked weld on NPS 3/4 pipe below the MP#4 pump
0.01	Litres	Seepage of unit 2 pressure transmitter flange gasket
4	Litres	Packing stem leak on MOV-2231
40	Litres	Mechanical seal failure resulted in a release of 100 litres
1	Litres	Leak from cracked NPS 1 cam lock fitting
0.1	Litres	High nitrogen purge cause oil to overspray secondary containment
0.24	Litres	Premature removal of injection line while reflooding the station

0.35	Litres	Release from 1/4" vent line while plico valve was marginally open
5	Litres	Loose hose sprayed oil during refilling operation
4	Litres	High point vent hose end came out of sump
250	Litres	Stem packing leak on MOV 2014
0.05	Litres	Unit #2 body bleed nipple thread leak
2	Litres	Leak on the non-drive end of the pump skid
0.01	Litres	Weeping PSV after removing its bracing
0.2	Litres	Grease fitting ball check did not hold after re-lubrication
0.5	Litres	Body bleed leak on station suction MOV 101
0.06	Litres	Oil dripping from NPS 10 flange on the BP-03 recycle line
0.01	Litres	4 of 6 NPS 3/4 valves on NPS 2 bypass are weeping
3	Litres	Stem packing leak on MOV-2211
0.6	Litres	NPS 4 drain valve oil release because of missing NPS 1/4 plug
0.25	Litres	Receiver Barrel Door Dripped Oil onto concrete
0.1	Litres	Stem packing leak on MOV-2211 and MOV-2231
0.005	Litres	Pig launcher door seal leak
40	Litres	Lube Line Units Valves failed to seal
0.01	Litres	Stem packing leak on MOV-2281
0.01	Litres	Threading plug is leaking
3	Litres	Packing leak on Gibson Inlet Valve
0.25	Litres	Oil leaking from bottom of pig launcher door
0.5	Litres	Outboard pump seal failure
30	Litres	Leak from pig receiver door
0.5	Litres	Oil seeping from discharge piping connection
5	Litres	Oil seeping from drain line connector
0.1	Litres	Oil seeping from pleco plug
0.02	Litres	Trace oil seeping Unit A3 IB pump seal leakage housing
6	Litres	Gibsons Valve stem packing leak
0.25	Litres	Leaking blowdown valve
0.13	Litres	Leaking blowdown valve
0.5	Litres	Leaking blowdown valve
0.25	Litres	Leaking blowdown valve
0.25	Litres	Leaking blowdown valve
0.5	Litres	Leaking blowdown valve
0.25	Litres	Leaking blowdown valve
0.5	Litres	Leaking blowdown valve
0.5	Litres	Leaking blowdown valve
0.25	Litres	Leaking blowdown valve
2	Litres	Booster Pump # 3 Seal Leak
0.05	Litres	Loose fitting on NPS 4 drain line
2	Litres	Stem packing leak on MOV-2281
136	Litres	Oil from pig receiver overflowed the catch tray
0.2	Litres	leaks on three sulzer pump drive end drains
0.1	Litres	Stem leak fro NPS 1/2 swagelok valve
0.2	Litres	Trace oil leaking from NPS 2 drain pipe mod
0.25	Litres	Oil leaked flange due to thermal expansion
2	Litres	Stem seal vent leak
4	Litres	Valve packing leak on MOV-2040
0.01	Litres	Leak on launcher kicker valve #2
0.002	Litres	Body bleed leak on Unit A3 suction valve
0.01	Litres	Valve stem leak on MOV-203
2	Litres	Valve packing leak on MOV-2291
1.5	Litres	Valve packing leak on MOV-2521
1.5	Litres	Valve packing leak on MOV-2522
0.002	Litres	MLV 1011 - leak on NPS 1/2 pipe nipple

0.06	Litres	Oil Mist on Suction line to Mainline Pumps
0.5	Litres	Valve packing leak on MOV-2042
1	Litres	Accidental valve opening prior to full isolation
9	Litres	Both seal housings on LKSND #5 overflowed
1	Litres	Check vlave cover leaks on boosters 2
1	Litres	Check vlave cover leaks on boosters 3
1	Litres	Check vlave cover leaks on boosters 3
0.01	Litres	Valve stem leak
0.02	Litres	Leaking outboard seal
1	Litres	Valve stem leak due to thermal expansion
0.125	Litres	Injection pump discharge piping thread leak
3.78	Litres	Suction header maintenance leak
1000	Litres	Inboard and outboard seal failure on Unit #3
19	Litres	Oily water spillage during water draw callibration
19	Litres	Unpressurized leak on the pump discharge flange
7.6	Litres	Body bleed pleco plug located at the bottom of the valve.
0.05	Litres	Minor crude oil leak on 1 inch threaded fitting.
2000	Litres	Oil Release during tie-in preparation between Hardisty A and Hardisty B
0.125	Litres	Leak from the threaded base of the injection skid PSV.
0.1	Litres	1/2 swagelock fitting on the tubing on unit #1 MOV 1011 suction valve
0.5	Litres	Leak from inboard seal housing
0.05	Litres	Pin hole leak in the weld on a 90 degree NPS 1 fitting
0.001	Litres	Loose bolt on flow meter allowed oil to seep from the meter body
0.5	Litres	Leak from A2 inboard pump
0.015	Litres	Leak from stem
1	Litres	Suction Valve Thermal Relief Leak
1	Litres	Leak from gate valve body relief on MOV 2010
15	Litres	Plug leak
0.5	Litres	Seal on pump 3 failed
0.5	Litres	Leak path through the mounting base o-ring on 3 of 4 vertical pumps
5	Litres	Body bleed leak from a cracked valve under the launcher
0.1	Litres	Removal of boroscope while cleaning sump drain system
50	Litres	Leak from a loosening union
0.25	Litres	Body bleed leak from "Pieco" Mainline bypass valve MOV-0102.
0.015	Litres	Drip on pump #5 base
0.05	Litres	Drip on pump skid no. 1

Keystone Pipeline Project

Rocks?

Contact Summary Report

Tract No. ML-SD-HA-0840.0000 Directly Affected __X__ **Adjacent** _____

Legal Description E2NW4 - SEC. 25 - TWP. T-103-N - RGE. R-57-W

Additional Legal Information: Hanson County, SD

Landowner(s): Glorius B Heitzman

Address: 43013 244th Street City/Town: Spencer

County: _____ Township: _____ State: SD Zip Code: 57374

Telephone: Home :(605) 246-2472 Business : 605-941-3830

Tenant(s): N/A

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

4-17-2012 I met with Calvin and the contractor. We viewed the ROW. Contractor devised plan to fix the ROW. Calvin said to check with him when they are going to fix it as he may till the whole field and turn it into cropground. He also said he does not want the pasture fixed but may ask for Keystone to pay him to fertilize and spray for weeds.

17

Eric Munz

Land Representative

4-17-2012

Date

From: Joshua Thompson [mailto:joshua_thompson@transcanada.com]
Sent: Thursday, October 20, 2011 5:03 PM
To: TINA HALL
Subject: ML-SD-HA-0840 Calvin Heitzman

Tina,

I just finished speaking with Mr. Heitzman and he complained about not being compensated for several things during construction. He said he had to buy more feed for his cattle, and then the rock was removed from his property and then the quarry is trying to sell it back to him even though he wanted to keep the rock.

Could we pass this on to Eric and have him see if we owe them anymore compensation. His number is 605-941-3830.

Thanks,

Joshua Thompson
Land Representative, U.S. Land Management

Calvin Heitzman, representing Keystone tract numbers ML-SD-HA-0840 and 0842, has contacted Josh complaining about items he says he was not compensated for. A copy of the settlement agreement for 0840 (0842 is the same) is attached for reference. He is wanting compensation for feed for his cattle, and for rock that he says he wanted to keep. My understanding of the settlement agreement is that it covers all damages related to the construction and installation of the pipeline, including crops such as hay. If Mr. Heitzman had to buy hay for his cattle, I believe that is already covered in the settlement agreement. Regarding the rock, if he had ever filled out a construction conditions agreement requesting the rock, then he might have a valid claim, but he did not. I have contact reports where the land agent attempted to meet with him multiple times but he always set he did not have the time. The land agent finally mailed it to him so he could fill it out, but he never did. Can you confirm that Mr. Heitzman's damages were covered by the settlement agreement and there is nothing more owed to him? Please advise.
Thanks,
Tina

Tina Hall
TransCanada Keystone Pipeline Project
Land Manager - Phase I and Phase II
Ellis & Associates, Inc.
10525 Ambassador Drive, Suite 202
Kansas City, MO 64153
Office: 816-559-7770
Cell: 847-922-1734
Fax: 816-891-3410

From: Joshua Thompson [mailto:joshua_thompson@transcanada.com]
Sent: Thursday, October 20, 2011 5:03 PM
To: TINA HALL
Subject: ML-SD-HA-0840 Calvin Heitzman

Tina,

I just finished speaking with Mr. Heitzman and he complained about not being compensated for several things during construction. He said he had to buy more feed for his cattle, and then the rock was removed from his property and then the quarry is trying to sell it back to him even though he wanted to keep the rock.

Could we pass this on to Eric and have him see if we owe them anymore compensation. His number is 605-941-3830.

Thanks,

Joshua Thompson
Land Representative, U.S. Land Management
TransCanada
402-214-2082

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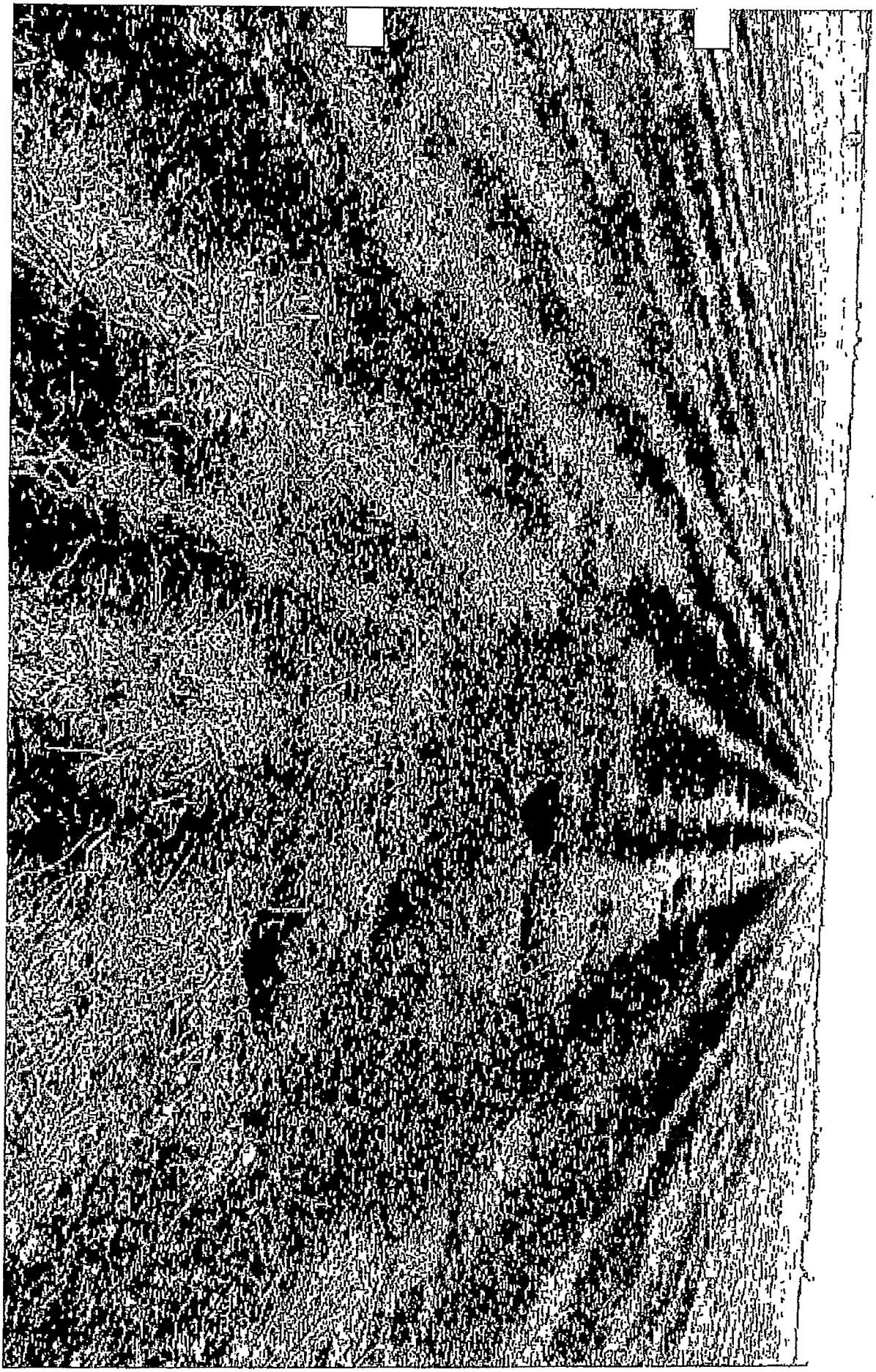


Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-HA-0839.0000 **Directly Affected** __X__ **Adjacent** _____

Legal Description Pt W2 - SEC. 24 - TWP. T-103-N - RGE. R-57-W

Additional Legal Information: Hanson County, SD

Landowner(s): Debra M Heitzman

Address: 42908 253rd Street City/Town: Spencer

County: _____ Township: _____ State: SD Zip Code: 57374

Telephone: Home :(605) 246-2498 Business : 605-941-3830

Tenant(s): Calvin Heitzman

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

COMMENTS:

Talked to Calvin Heitzman. He told me about the debrie damage to his tractor tire last year. I asked if he still had the receipts for the tire and labor. I asked he send them to me and I would take care of this. He said he would.

Patrick Fuller
Land Representative

4/23/14
Date

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-HA-0840.0000 **Directly Affected** __X__ **Adjacent** _____

Legal Description E2NW4 - SEC. 25 - TWP. T-103-N - RGE. R-57-W

Additional Legal Information: Hanson County, SD

Landowner(s): Glorius B Heitzman

Address: 43013 244th Street City/Town: Spencer

County: _____ Township: _____ State: SD Zip Code: 57374

Telephone: Home :(605) 246-2472 Business : 605-941-3830

Tenant(s): N/A

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

Called Calvin and informed him the crew will out there today to remove the matting and silt fence the construction crew left behind.

Patrick Fuller
Land Representative

7/16/14
Date

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-HA-0840.0000 **Directly Affected** __X__ **Adjacent** _____

Legal Description E2NW4 - SEC. 25 - TWP. T-103-N - RGE. R-57-W

Additional Legal Information: Hanson County, SD

Landowner(s): Glorius B Heitzman

Address: 43013 244th Street City/Town: Spencer

County: _____ Township: _____ State: SD Zip Code: 57374

Telephone: Home :(605) 246-2472 Business : 605-941-3830

Tenant(s): N/A

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

Talked to Calvin and he asked that we call him to meet so he can so us the areas he knows are an issue.

Patrick Fuller
Land Representative

7/15/14
Date

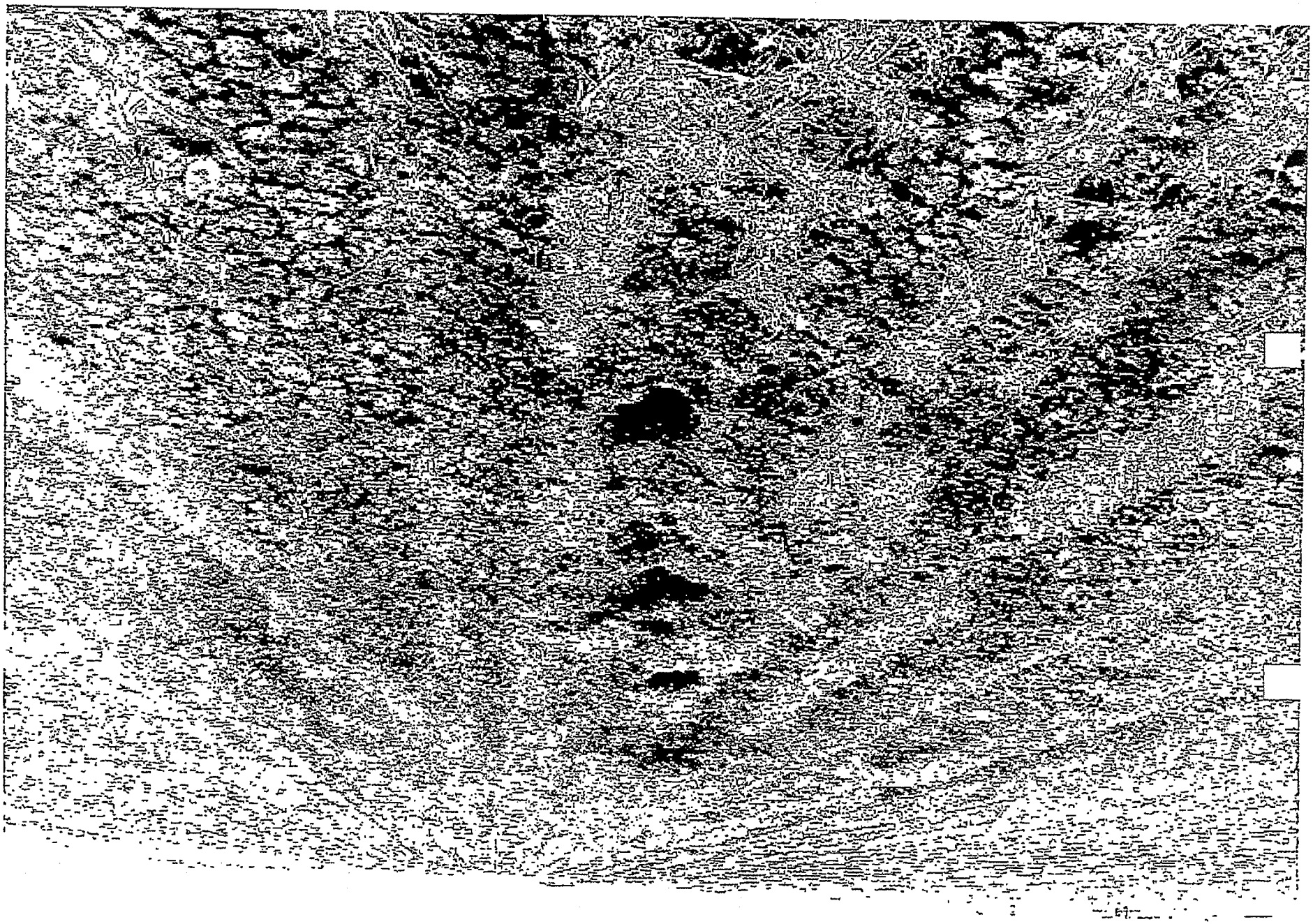
Felicia Webb

From: eric munz [northernmn2001@yahoo.com]
Sent: Monday, May 13, 2013 1:58 PM
To: Felicia Webb
Subject: Fw: Sibson 0795 & 0796
Attachments: Sibson-1.jpg; Sibson-2.jpg; Sibson-3.jpg

Eric Munz
Sr. Land Agent - Keystone Pipeline
605-461-8568
northernmn2001@yahoo.com
----- Forwarded Message -----
From: eric munz <northernmn2001@yahoo.com>
To: "frankmaddox@yahoo.com" <frankmaddox@yahoo.com>; "joshua_thompson@transcanada.com" <joshua_thompson@transcanada.com>; "heath_morton@transcanada.com" <heath_morton@transcanada.com>; "kdaustin@donellis-associates.com" <kdaustin@donellis-associates.com>
Sent: Saturday, May 11, 2013 8:31 AM
Subject: Sibson 0795 & 0796

Frank, Sue Sibson sent pics of holes in ROW. These are new issues. Jason had indicated the walk through will end just below the Sibson Property. Their neighbors have called and said they have issues on 0798.0001 & 0799. Do we want to include these areas as well? I will be happy to accompany Jason and crew if these tracts will be included on the walk through. I'm sure the Sibsons will appreciate some attention sooner than later.

Eric Munz
Sr. Land Agent - Keystone Pipeline
605-461-8568
northernmn2001@yahoo.com



Sincerely,
Mike and Sue Sibson

No virus found in this incoming message.
Checked by AVG - www.avg.com
Version: 9.0.829 / Virus Database: 271.1.1/2955 - Release Date: 06/22/10 01:36:00

No virus found in this incoming message.
Checked by AVG - www.avg.com
Version: 9.0.829 / Virus Database: 271.1.1/2960 - Release Date: 06/24/10 01:35:00

--
Sarah Metcalf
South Dakota Liaison Officer
Keystone Pipeline
110 3rd Street SW, Ste. #104
Huron, SD 57350
1-888-375-1370
(605) 228-4736 cell
SDLiaison@keystone.trow.com

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--
Sarah Metcalf
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110 3rd Street SW, Ste. #104
Huron, SD 57350
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SDLiaison@keystone.trow.com

--
Sarah Metcalf
South Dakota Liaison Officer
Keystone Pipeline
110 3rd Street SW, Ste. #104

7/23/2010

Dusty

From: Sue Sibson <suesibson@alliancewildblue.com>
To: Johnson, Dustin (PUC)
Sent: Fri Jun 25 08:33:18 2010
Subject: RE: Invitation

Dear Dusty Johnson:
If you want, Sarah along that is fine. Sarah was already here on June 1 at our request to look at the easement area.
Thanks
Sue and Mike

From: Dustin.Johnson@state.sd.us [mailto:Dustin.Johnson@state.sd.us]
Sent: Thursday, June 24, 2010 3:07 PM
To: suesibson@alliancewildblue.com
Subject: Re: Invitation

Can I have Sarah Metcalf along? If things aren't as they should be, I'd like to be able to ask her right then and there why that is.

Dusty

From: Sue Sibson <suesibson@alliancewildblue.com>
To: Johnson, Dustin (PUC)
Sent: Wed Jun 23 09:39:46 2010
Subject: RE: Invitation

Good Morning Dusty:

July 14 will work for us. You can let us know what time when the day gets closer.
Thanks
Sue and Mike

From: Dustin.Johnson@state.sd.us [mailto:Dustin.Johnson@state.sd.us]
Sent: Tuesday, June 22, 2010 4:52 PM
To: suesibson@alliancewildblue.com
Subject: Re: Invitation

Wednesday, July 14?

From: Sue Sibson <suesibson@alliancewildblue.com>
To: Johnson, Dustin (PUC)
Sent: Tue Jun 22 09:24:52 2010
Subject: Invitation

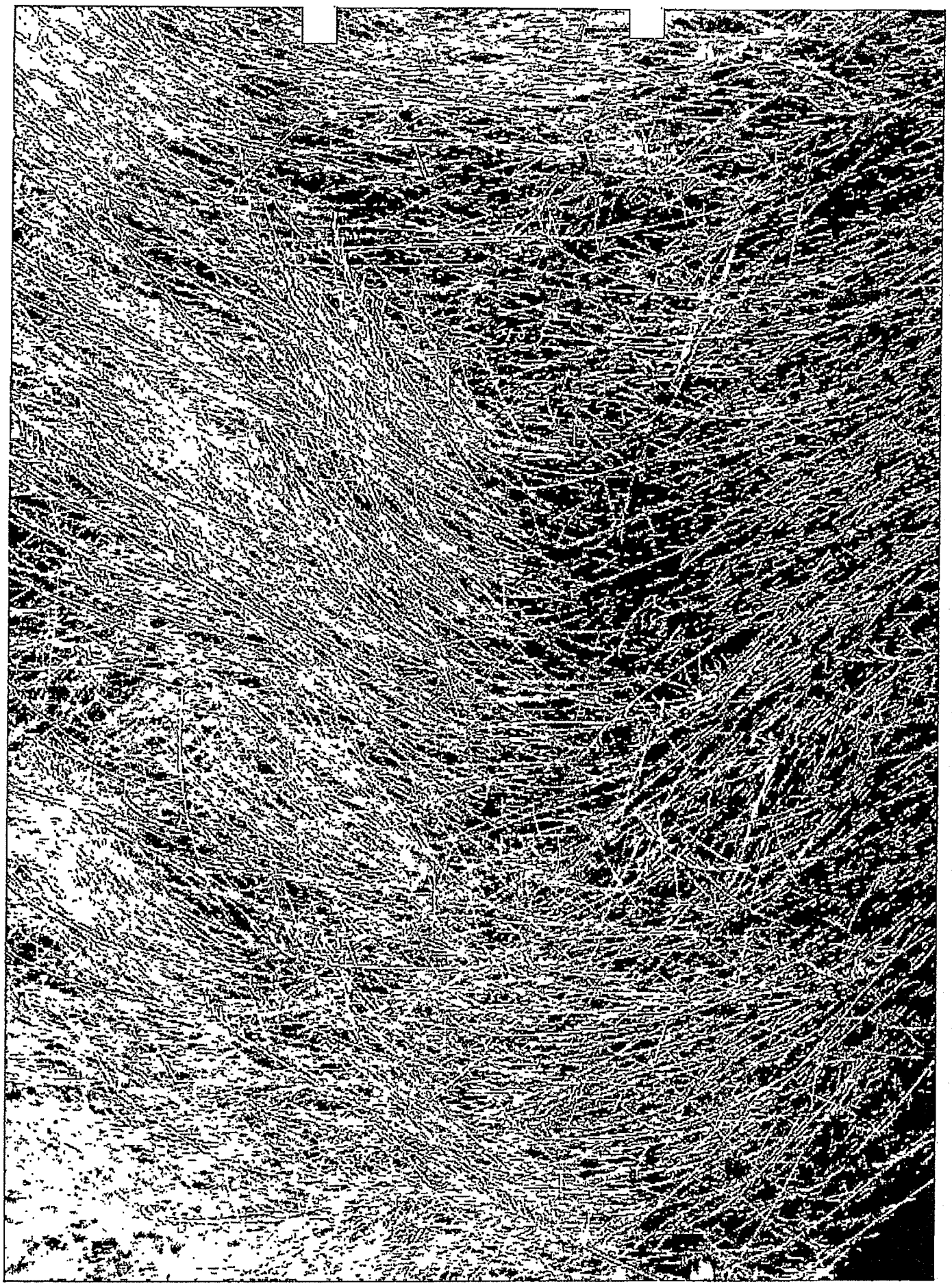
Hi Dusty Johnson:

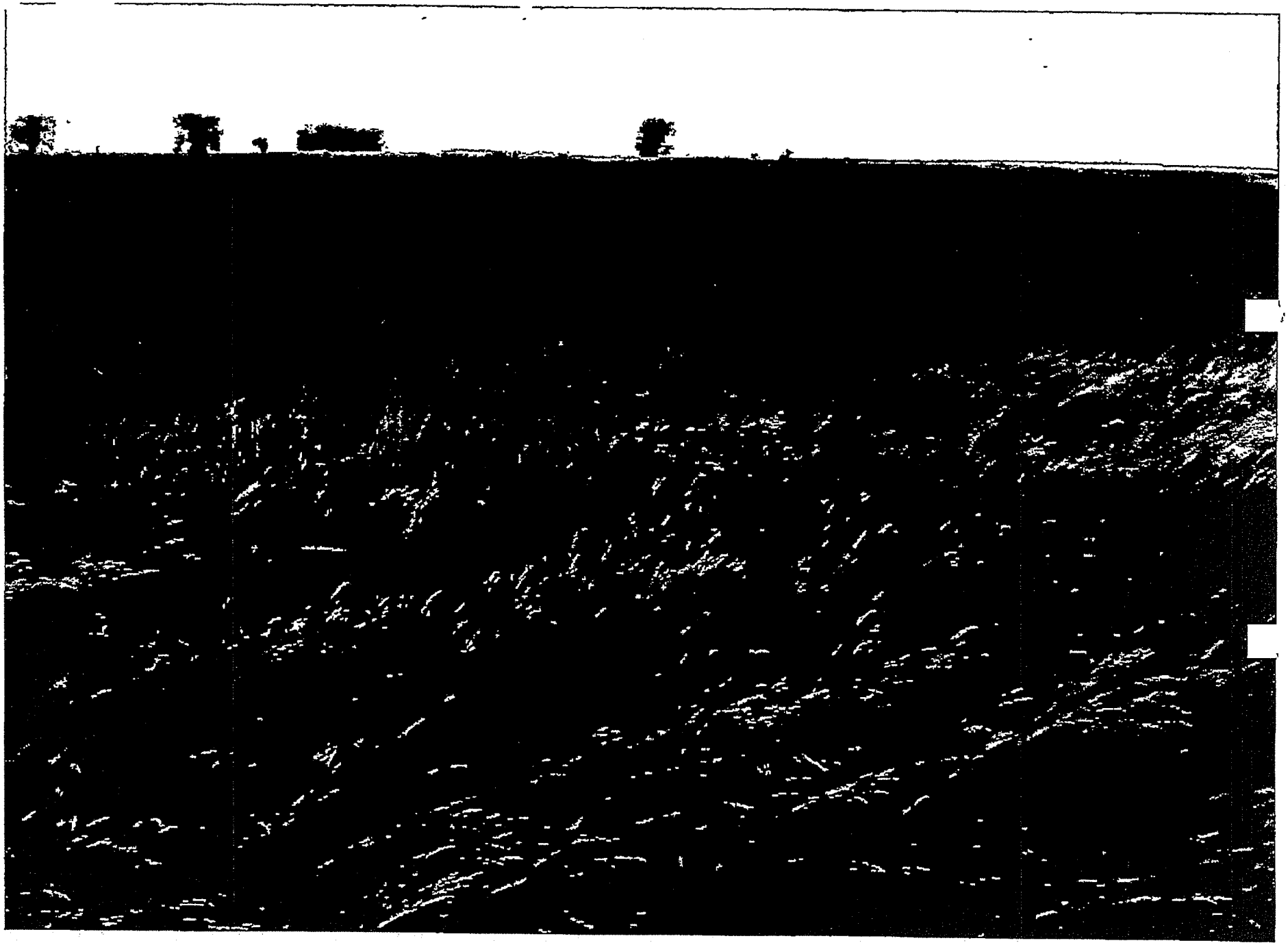
We would like to invite you to our farm and give you a tour of the pipeline easement area. TransCanada has been in the media saying they will leave the land in better shape than they found it. We would like you see our land. Please let us know if you are willing to take a tour.

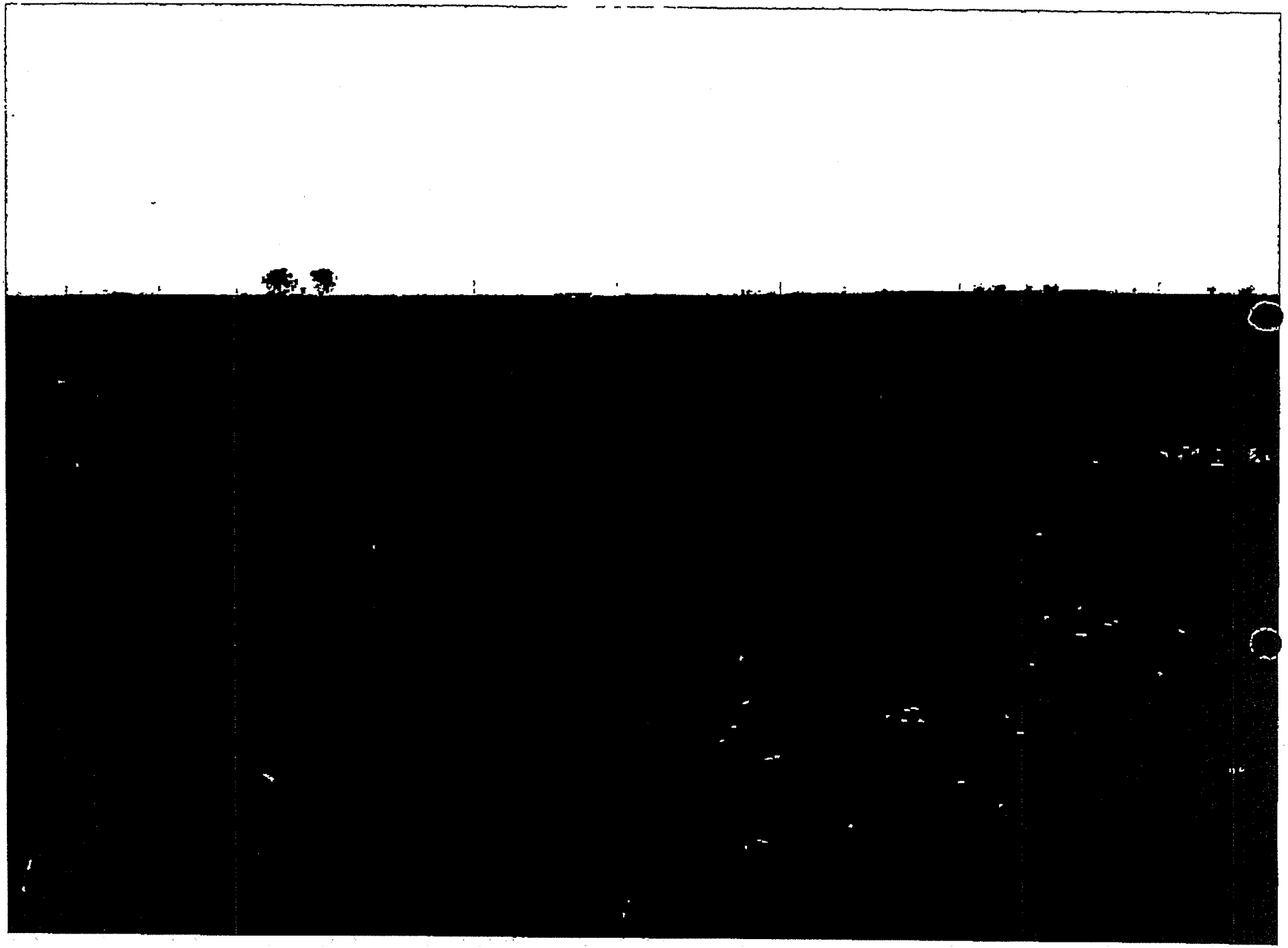
Huron, SD 57350
1-888-375-1370
(605) 228-4736 cell
SDLiaison@keystone.trow.com

--

Sarah Metcalf
South Dakota Liaison Officer
Keystone Pipeline
110 3rd Street SW, Ste. #104
Huron, SD 57350
1-888-375-1370
(605) 228-4736 cell
SDLiaison@keystone.trow.com







Keystone Pipeline Project

Contact Summary Report

Tract No.ML-SD-MN-0795.0000 **Directly Affected __X___ Adjacent _____**

Legal Description ¼ SW - SEC. 28 - TWP. 106N - RGE. 57W

Additional Legal Information: MINER COUNTY S.D.

Landowner(s): MICHAEL B. and SUSAN K. SIBSON

Address: 23782 426TH AVE. City/Town: HOWARD

County: MINER Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business :(605) 770-2800

Tenant(s): NA

Address: _____ City/Town: _____

County: _____ Township: _____ State: S.D. Zip Code: _____

Telephone: Home :(605) _____ Business :(605) _____

Contact Summary: On 10-6-09 I received a call from Sue Sibson asking the status of the rocks that she thinks are buried on their property and that were suppose to be hauled off. I explained to Sue that I sent an e-mail out to the RCS explaining what she had requested and was waiting a response. Sue said that she was not going to let anyone back onto her property to retrieve the rocks. I told Sue that I thought it was still an active construction area and she said Paul you are not going to pull this on us again. I explained that it has been really wet and only specialized crews have worked since Saturday. Sue said, Paul I signed an agreement and you did too requesting the rocks be hauled off. She said the rocks were not hauled off and that is a breach of contract. Sue said "Paul you signed that agreement and I will haul you in". I asked Sue, " You are going to haul me to Jail for what?" Sue then raised her voice and I asked her to calm down and told her there was no reason to raise her voice. She laughed and said I have not raised my voice. I then asked her if she had talked to Mike Brouilette from Michels and she said no she thought she was suppose to talk to me or Sarah first. I said that was correct, but I wanted to make sure that I was not answering something that someone had already answered. Sue said I will just call Mike or Sarah Metcalf and I am done talking with you. I said thank you and hung up.

Paul Kuntz

Land Representative

10-6-09

Date

Keystone Pipeline Project

Contact Summary Report

ML-SD-MN-0796.0000

Tract No. ML-SD-MN-0795.0000 Directly Affected __X___ Adjacent _____

Legal Description S2SW4 - SEC. 28 & all sec 33 - TWP. T-106-N - RGE. R-57-W

Additional Legal Information: Miner County, SD

Landowner(s): Michael B & Susan K Sibson

Address: 23782 426th Ave City/Town: Howard

County: _____ Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business : 605-770-2800

9-16-2013 Sue sent an e-mail stating Frank Maddox won't give her his report and wants to know what the plan is.

9-17-2013 Sue texted me asking what the plan is. I texted her back saying Frank and TCPL management are working on a plan and I will get it to her when I receive it. She texted back ok thanks.

Eric Munz
Land Representative

9-17-2013
Date

Keystone Pipeline Project

Contact Summary Report

ML-SD-MN-0796.0000

Tract No. ML-SD-MN-0795.0000 Directly Affected __X__ Adjacent _____

Legal Description S2SW4 - SEC. 28 & all sec 33 - TWP. T-106-N - RGE. R-57-W

Additional Legal Information: Miner County, SD

Landowner(s): Michael B & Susan K Sibson

Address: 23782 426th Ave City/Town: Howard

County: _____ Township: _____ State: SD Zip Code: 57349

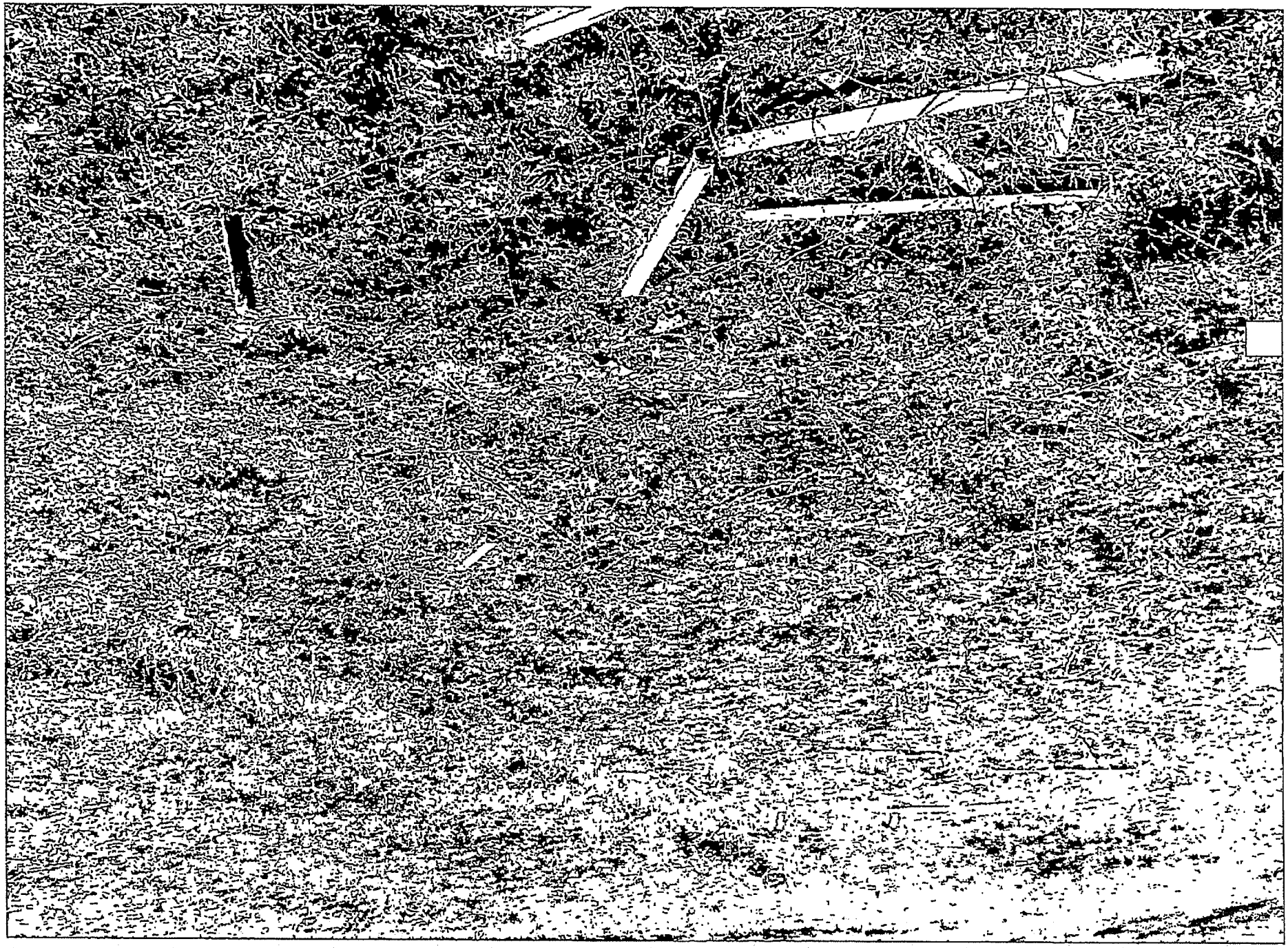
Telephone: Home :(605) 772-5184 Business : 605-770-2800

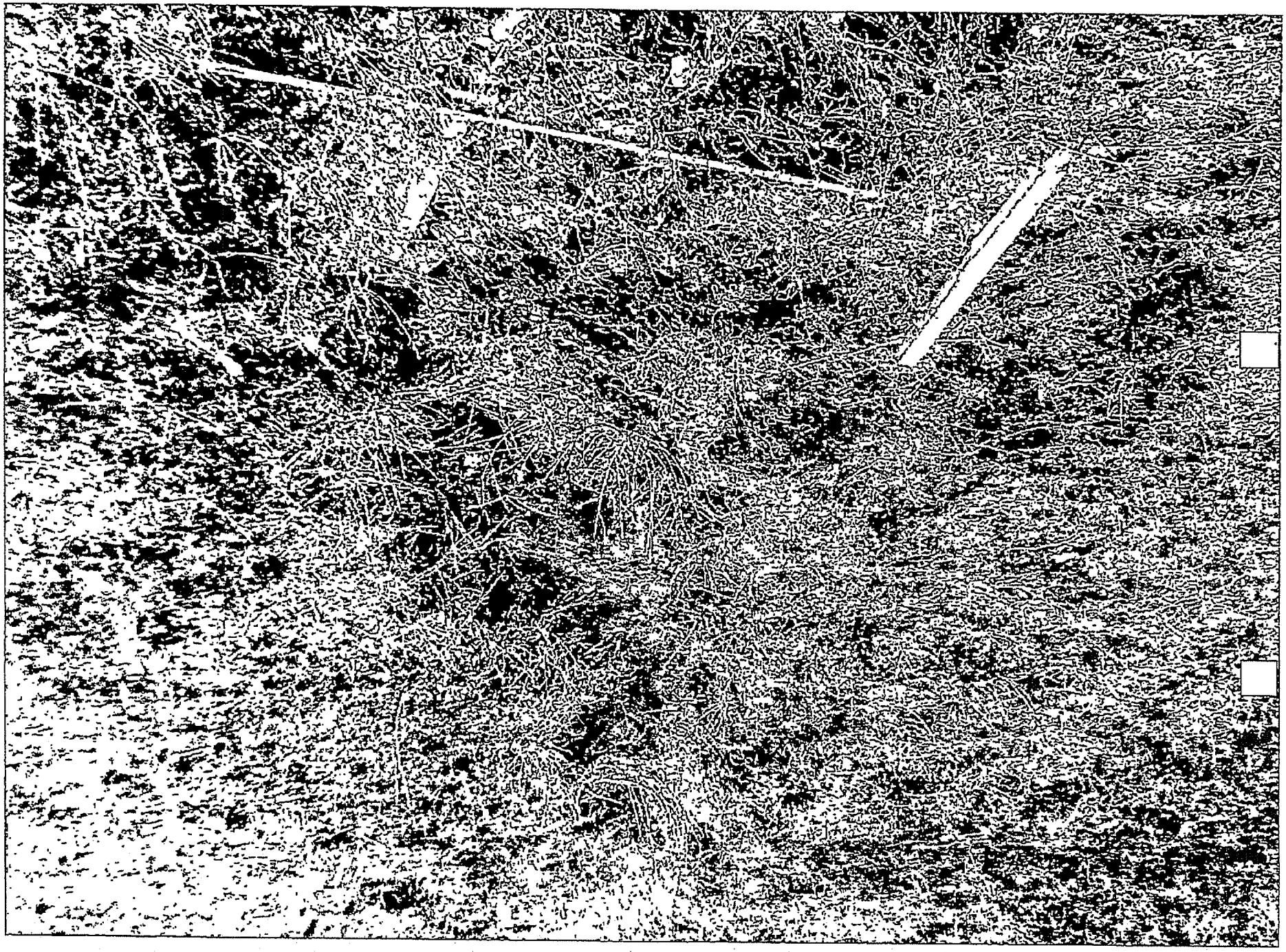
9-18-2013 I called Sue and asked her to take a picture of the wheat grass that they don't want on their property. She texted me 2 pics.

9-20-2013 Sue sent a text asking if I figured out what that grass is. I sent a reply stating the environmental and project management people are working on it and I will let her know when I hear more from them.

Eric Munz
Land Representative

9-18-2013
Date





Regards,

Joshua Thompson

Land Representative, U.S. Land Management

TransCanada

402-214-2082

From: Michael Sibson [mailto:suesibson@alliancewildblue.com]
Sent: Sunday, December 04, 2011 4:59 PM
To: smetcalf12@gmail.com; Joshua Thompson
Subject: pipeline aerial patrol

Hi,

The pipeline aerial patrol flew once again close to our farm/cattle feedlot today. We would really appreciate that the plane could fly over the pipeline easement area where the pipe is located rather than over our farm.

We buy just weaned calves every week thru February and do not need any plane spooking them.

Thanks.

Mike and Sue Sibson

Howard SD

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Joshua Thompson

Subject: FW: pipeline aerial patrol

From: Michael Sibson [mailto:suesibson@alliancewildblue.com]
Sent: Tuesday, December 06, 2011 2:00 PM
To: Joshua Thompson
Subject: RE: pipeline aerial patrol

The policy needs to be updated before we can agree to it. The aerial patrol should fly on the east side of the **pipeline easement area** (needs to be added) above 1000 feet. Please make the changes and email us a copy of the updated policy letter.

Thanks.

Mike and Sue Sibson

--- joshua_thompson@transcanada.com wrote:

From: Joshua Thompson <joshua_thompson@transcanada.com>
To: Michael Sibson <suesibson@alliancewildblue.com>
CC: <smetcalf12@gmail.com>
Subject: RE: pipeline aerial patrol
Date: Tue, 6 Dec 2011 10:39:06 -0600

Mr. & Mrs. Sibson,

I checked with our aerial patrol about this again. They are aware of your situation and have implemented a policy letter of flying on the East side above 1,000 feet from the ground. We hope you will find this satisfactory.

Regards,

Joshua Thompson

Land Representative, U.S. Land Management

TransCanada

402-214-2082

From: Joshua Thompson
Sent: Monday, December 05, 2011 5:08 PM
To: Michael Sibson
Cc: smetcalf12@gmail.com
Subject: RE: pipeline aerial patrol

Mr. and Mrs. Sibson,

I apologize. I will get on this immediately and let our aerial patrol know that it is unacceptable to fly over your feedlot and spook your cattle.

December 19, 2012

TransCanada
In business to deliver

TransCanada Keystone Pipeline Limited Partnership
Address: 13710 FNB Parkway, Suite 300
Omaha, NE 68154
Telephone: 402-492-7459
Facsimile: 402-492-7491
Email: Joshua_Thompson@transcanada.com
Web: www.transcanada.com/keystone

Pamela and Delwin Hofer
40916 192nd Street
Carpenter, SD 57322

RE: Reclamation on the TransCanada Keystone Pipeline Right-of-Way
Tract ML-SD-BD-0695.0000

Dear Mrs. and Mr. Hofer:

TransCanada Keystone has made a good faith effort to complete reclamation on your property. It was reported to us that on November 29, 2012, Mr. Hofer referred to bringing out a shotgun to coerce our contractor to follow his wishes. We consider this reference to be a threat against our reclamation contractor and TransCanada must treat all threats to our employees and contractors with the utmost seriousness. Due to the remarks that you made, we will be unable to allow our reclamation contractors to return to your property to do any additional work.

The assessment of the remaining work on your property has been done by our reclamation crew. They have determined that the majority of the reclamation work has been completed, but there are a few minor items remaining. In their assessment, they have determined that the amount of remaining work could be completed for no more than $35,000.

Included with this letter is check 0008798 for $35,000 which TransCanada feels is generous, and more than enough to restore any unremediated items that could have been caused by the construction of the Keystone pipeline.

This is a final offer on the behalf of TransCanada to compensate you in full for all damages whether now owned or hereafter acquired, known or unknown, accrued or unaccrued that arise out of, relate to, were caused by, or are in any way connected with the claims and causes of action made or which could have been made against TransCanada pertaining to the installation and construction of the pipeline on your property, including, but not limited to damage to the surface, crops, trees, livestock, animals, improvements, fences, groundwater or surface water on the property. Your acceptance of the check will be viewed as your agreement to our offer.

TransCanada Keystone is committed to upholding a high level of land and environmental stewardship, and we look forward to working with you in resolving this issue. If you have any questions or require further discussion, feel free to contact me at (402) 492-7459.

Sincerely,

TRANSCANADA KEYSTONE PIPELINE

Joshua Thompson
Land Representative, TransCanada US Land Management

KEYSTONE PIPELINE PROJECT

110 3rd Street SW, suite 104
Huron, SD 57350
(605) 352-1375 (Office)
(605) 461-9005 (Cell)

May 12, 2010

ML-SD-BD-0695.9999

Pam and Delwin Hofer
40916 192nd Street
Carpenter, SD 57322

RE: Payment for grazing loss that you claimed for your property at: NW4, SEC 9 T-113N R-59W

Pam and Delwin:

Please find the enclosed check for the Settlement Agreement that you signed.
If you should have further questions please feel free to call me at the numbers listed above or contact Sarah Metcalf at 1-88-375-1370.

Thank you,

Sincerely,

Paul Kleist
Right of Way Supervisor
Keystone Pipeline

Felicia Webb

From: Barbara Koch [bkoch@donellis-associates.com]
Sent: Wednesday, January 09, 2013 12:03 PM
To: 'Felicia Webb'
Subject: FW: Hofer Check
Attachments: Check.pdf

Felicia,
This was processed by TCPL not E&A, please put copy of attachment and this email in the file for tract M-SD-BD-0695.0000.

From: eric munz [mailto:northernmn2001@yahoo.com]
Sent: Tuesday, January 08, 2013 4:22 PM
To: Barbara Koch; Kim Austin; Kim Austin
Subject: Fw: Hofer Check

This tract can now be considered complete and taken off the punchlist.

Eric

----- Forwarded Message -----
From: Joshua Thompson <joshua_thompson@transcanada.com>
To: 'Kim Austin' <kdaustin@donellis-associates.com>; Eric Munz <northernmn2001@yahoo.com>; "smetcalf12@gmail.com" <smetcalf12@gmail.com>
Sent: Tuesday, January 8, 2013 4:47 PM
Subject: FW: Hofer Check

Here is the UPS proof of delivery for Hofer.

Joshua Thompson
Land Representative , U.S. Land Management
TransCanada
402-214-2082

From: Rocio Lozano
Sent: Tuesday, January 08, 2013 3:26 PM
To: Joshua Thompson
Subject: FW: UPS Ship Notification, Tracking Number 1Z4R33A70195813170

Proof of Delivery

Close Window

Dear Customer,

This notice serves as proof of delivery for the shipment listed below.

Tracking Number:	1Z4R33A70195813170
Service:	UPS Next Day Air®
Shipped/Billed On:	12/19/2012
Delivered On:	12/20/2012 5:22 P.M.
Delivered To:	CARPENTER, SD, US
Left At:	Side Door

Thank you for giving us this opportunity to serve you.

Sincerely,

UPS

Tracking results provided by UPS: 01/08/2013 4:15 P.M. ET

Print This Page Close Window

Josh, here is the delivery information.

Thanks,

Rocio Lozano

From: Rocio Lozano
Sent: Wednesday, December 19, 2012 11:45 AM
To: Joshua Thompson
Cc: Alex Osborne
Subject: FW: UPS Ship Notification, Tracking Number 1Z4R33A70195813170

Josh,

Attached please find a copy of letter and check sent to Mr. Hofer.

Below is the tracking information.

Thanks,

Rocio Lozano

From: UPS Quantum View [mailto:auto-notify@ups.com]
Sent: Wednesday, December 19, 2012 11:42 AM
To: Rocio Lozano
Subject: UPS Ship Notification, Tracking Number 1Z4R33A70195813170

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PIPELINE CO (HOUSTON) to notify you that the electronic shipment information below has been transmitted to UPS. The physical package(s) may or may not have actually been tendered to UPS for shipment. To verify the actual transit status of your shipment, click on the tracking link below or contact ANR PIPELINE CO (HOUSTON) directly.

Important Delivery Information

Scheduled Delivery: 20-December-2012

Shipment Detail

Ship To:
Delwin O. and Pamela Hofer
40916 192nd Street
CARPENTER
SD
573228207
US

Number of Packages: 1
UPS Service: NEXT DAY AIR
Shipment Type: Letter

Tracking Number: 1Z4R33A70195813170
Click here to track if UPS has received your shipment or visit http://www.ups.com/WebTracking/track?loc=en_US on the Internet.

____2@@2@@2hoGcZwi____

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Contact UPS

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authorization. If you have received this message in error, please notify the sender immediately and delete the original message. Thank you.

December 19, 2012

TransCanada
In business to deliver

TransCanada Keystone Pipeline Limited Partnership
Address: 13710 FNB Parkway, Suite 300
Omaha, NE 68154
Telephone: 402-492-7459
Facsimile: 402-492-7491
Email: Joshua_Thompson@transcanada.com
web: www.transcanada.com/keystone

Pamela and Delwin Hofer
40916 192nd Street
Carpenter, SD 57322

RE: Reclamation on the TransCanada Keystone Pipeline Right-of-Way
Tract ML-SD-BD-0695.0000

Dear Mrs. and Mr. Hofer:

TransCanada Keystone has made a good faith effort to complete reclamation on your property. It was reported to us that on November 29, 2012, Mr. Hofer referred to bringing out a shotgun to coerce our contractor to follow his wishes. We consider this reference to be a threat against our reclamation contractor and TransCanada must treat all threats to our employees and contractors with the utmost seriousness. Due to the remarks that you made, we will be unable to allow our reclamation contractors to return to your property to do any additional work.

The assessment of the remaining work on your property has been done by our reclamation crew. They have determined that the majority of the reclamation work has been completed, but there are a few minor items remaining. In their assessment, they have determined that the amount of remaining work could be completed for no more than $35,000.

Included with this letter is check 0008798 for $35,000 which TransCanada feels is generous, and more than enough to restore any unremediated items that could have been caused by the construction of the Keystone pipeline.

This is a final offer on the behalf of TransCanada to compensate you in full for all damages whether now owned or hereafter acquired, known or unknown, accrued or unaccrued that arise out of, relate to, were caused by, or are in any way connected with the claims and causes of action made or which could have been made against TransCanada pertaining to the installation and construction of the pipeline on your property, including, but not limited to damage to the surface, crops, trees, livestock, animals, improvements, fences, groundwater or surface water on the property. Your acceptance of the check will be viewed as your agreement to our offer.

TransCanada Keystone is committed to upholding a high level of land and environmental stewardship, and we look forward to working with you in resolving this issue. If you have any questions or require further discussion, feel free to contact me at (402) 492-7459.

Sincerely,

TRANSCANADA KEYSTONE PIPELINE

Joshua Thompson
Land Representative, TransCanada US Land Management

TransCanada Keystone Pipeline, LP
717 Texas Street, Suite 2400
Houston TX 77002-2761

0008798

DATE: December 18, 2012 VENDOR NO. B100983

INVOICE NO.	INVOICE DATE	OTHER REF.	DOCUMENT NO.	DESCRIPTION	GROSS AMOUNT	DISCOUNT	NET AMOUNT
1251155	12/10/2012		1251155	DAMAGES	35,000.00	0.00	35,000.00

CONTACT INFORMATION (403) 920-7318 AP HelpLine

TOTAL 35,000.00

TransCanada Keystone Pipeline, LP
717 Texas Street, Suite 2400
Houston TX 77002-2761

Citibank N.A.
399 Park Avenue
New York, New York 10043

210

0008798

DATE 12 18 2012
M M D D Y Y Y Y

PAY Thirty Five Thousand Dollars & 0 Cents

$*****35,000.00**

TO THE ORDER OF

DELWIN O HOFER & PAMELA HOFER
40916 192ND ST
CARPENTER, SD
57322 UNITED STATES

U.S. FUNDS
TransCanada Keystone Pipeline, LP

PER _____

PER _____

⑈0008798⑈ ⑆021000089⑆ 3073190 4⑈

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-BD-0695.0000 **Directly Affected** X **Adjacent** _____

Legal Description NE4 - **SEC.** 9 - **TWP.** T-113-N - **RGE.** R-59-W

Additional Legal Information: Beadle County, SD

Landowner(s): Pamela R Hofer (Delwin)

Address: 40916 192nd Street City/Town: Carpenter

County: _____ Township: _____ State: SD Zip Code: 57322

Telephone: Home :(605) 352-7171 Business : _____

Tenant(s): NA

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

11-25-2012 I called Delwin. He said the fence needs H braces and to be tightened on the South end. He said he needs the laser transit set up to determine the lay of the land. He said he might meet with us tomorrow if he is not too busy. I informed him it would be extremely helpful if he did so he could let us know exactly what needs to be done.

Eric Munz
Land Representative

11-25-2012
Date

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-BD-0695.0000 **Directly Affected** X **Adjacent** _____

Legal Description NE4 - SEC. 9 - TWP. T-113-N - RGE. R-59-W

Additional Legal Information: Beadle County, SD

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Address: 40916 192nd Street City/Town: Carpenter

County: _____ Township: _____ State: SD Zip Code: 57322

Telephone: Home :(605) 352-7171 Business : _____

Tenant(s): NA

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

11-02-2012 Pam called and said she doesn't know how they will be able to see the lay of the land with conrnstalks on it. I told her they planned to bale them. She said there will still be too much stubble. She said she wants the fence fixed for now and to call in a couple weeks to discuss the rest.

Eric Munz
Land Representative

11-02-2012
Date

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-BD-0695.0000 **Directly Affected** X **Adjacent** _____

Legal Description NE4 - **SEC.** 9 - **TWP.** T-113-N - **RGE.** R-59-W

Additional Legal Information: Beadle County, SD

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Address: 40916 192nd Street City/Town: Carpenter

County: _____ Township: _____ State: SD Zip Code: 57322

Telephone: Home :(605) 352-7171 Business : _____

Tenant(s): NA

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

10-31-2012 I called and informed Hofers that Frank Maddox and crew want to meet with them Saturday afternoon and to call me back to confirm.

Eric Munz
Land Representative

10-31-2012
Date

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-BD-0695.0000 **Directly Affected** __X__ **Adjacent** _____

Legal Description NE4 - **SEC.** 9 - **TWP.** T-113-N - **RGE.** R-59-W

Additional Legal Information: Beadle County, SD

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Address: 40916 192nd Street City/Town: Carpenter

County: _____ Township: _____ State: SD Zip Code: 57322

Telephone: Home :(605) 352-7171 Business : _____

Tenant(s): NA

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

I called Delwin. He is still upset about drainage on the land, the fence being loose and road damges. I explained the road damages were paid to the County and the Townships. He also asked about crop loss. I explained he can either show us his yield moniter in his combine or have an adjuster come out to estimate the crop loss and Keystone will pay for yield loss. I asked if he wanted work done soon. He said he does not want anyone out until after he harvests his corn. I told him I would let the crew know to go to his land after harvest. He said they better use a transit this time.

Eric Munz
Land Representative

9-05-2012
Date

013198

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-BD-0695.0000 **Directly Affected** X **Adjacent** _____

Legal Description NE4 - **SEC.** 9 - **TWP.** T-113-N - **RGE.** R-59-W

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County: _____ Township: _____ State: SD Zip Code: 57322

Telephone: Home :(605) 352-7171 Business : _____

Tenant(s): NA

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

10-10-2011 I called and talked to Pam. She said the beans are harvested but wants me to talk to Delwin to get an ok to look at the property or do any work.

Eric Munz
Land Representative

10-10-2011
Date

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-BD-0695.0000 **Directly Affected** X **Adjacent** _____

Legal Description NE4 - **SEC.** 9 - **TWP.** T-113-N - **RGE.** R-59-W

Additional Legal Information: Beadle County, SD

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County: _____ Township: _____ State: SD Zip Code: 57322

Telephone: Home :(605) 352-7171 Business : _____

Tenant(s): NA

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

8-04-2011 I called and informed Pam of survey going in next week.

8-04-2011 Delwin called back and said he does not want anyone in there, not even walking, until the beans are harvested.

Eric Munz
Land Representative

8-04-2011
Date

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-BD-0695.0000 **Directly Affected** X **Adjacent** _____

Legal Description NE4 - **SEC.** 9 - **TWP.** T-113-N - **RGE.** R-59-W

Additional Legal Information: Beadle County, SD

Landowner(s): Pamela R Hofer (Delwin)

Address: 40916 192nd Street City/Town: Carpenter

County: _____ Township: _____ State: SD Zip Code: 57322

Telephone: Home :(605) 352-7171 Business : _____

Tenant(s): NA

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

3-31-2011 Delwin called. He said the fence needs to be fixed. He needs a wooden post put in. Also, the woven wire is loose and not attached correctly. He needs the drainage on the North and the South fixed. He said not to send someone out without a transit or laser and the correct equipment to do the job right. There are places where there is no topsoil because they pushed it in to fill ruts from tracks and holes. He also said he had crop loss due to the line on his property. He said the dirt is sinking over the line and you can see that. He also complained about crushed culverts and the condition of the roads. I explained the townships and county were compensated to repair the roads.

Eric Munz
Land Representative

3-31-2011
Date

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-BD-0695.0000 **Directly Affected** X **Adjacent** _____

Legal Description NE4 - **SEC.** 9 - **TWP.** T-113-N - **RGE.** R-59-W

Additional Legal Information: Beadle County, SD

Landowner(s): Pamela R Hofer (Delwin)

Address: 40916 192nd Street City/Town: Carpenter

County: _____ Township: _____ State: SD Zip Code: 57322

Telephone: Home :(605) 352-7171 Business : _____

Tenant(s): NA

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

3-29-2011 I received a message that Delwin had called TransCanada. I called and left a message for him to call me back.

Eric Munz
Land Representative

3-29-2011
Date

Steve Kolbeck, Chair
Gary Hanson, Vice Chair
Dustin Johnson, Commissioner

SOUTH DAKOTA
PUBLIC UTILITIES COMMISSION

500 East Capitol Avenue
Pierre, South Dakota 57501-5070
www.puc.sd.gov

Capitol Office
(605) 773-3201
1-866-757-6031 fax

Warehouse
(605) 773-5280
(605) 773-3225 fax

Consumer Hotline
1-800-332-1782

ML-SD-BD-0695.0000

December 6, 2010

Mr. and Mrs. Delwin Hofer
40916 192nd Street
Carpenter, SD 57322

Re: Damaged Fence

Mr. and Mrs. Hofer;

Thank you for speaking with our office last week. We are sorry to hear you remain frustrated with TransCanada, but appreciate this opportunity to again explain our complaint resolution process. As you know, we have a Consumer Affairs department that receives all complaints. That department works closely with Sarah Metcalf regarding TransCanada issues. Complaints all start informally and if necessary escalate to a formal complaint. We rarely have formal complaints and are proud of our resolution record. I understand from Sarah Metcalf and Deb Gregg, however, you rejected all TransCanada's informal resolution efforts and your fencing issue remains.

The record shows TransCanada has made multiple site visits in an effort to fix your fence. Most recently the company suggested you choose a professional fencing company, at TransCanada's cost, to remedy the problems. You again rejected the company's offer. It does not appear you have given TransCanada an opportunity to solve the problem. I assume, therefore, you believe you have a legal cause of action against the company. If so, you may complete the enclosed Formal Complaint to utilize the contested case process available at the PUC.

The form includes a description of the contested case process and your resulting obligations and rights. If you choose to file a formal complaint your submission will be "docketed" and become public record. Additionally, the rules of civil procedure and evidence apply. You must specifically state the company's legal obligation, and further specifically describe how it violated the same. Upon receipt of your written complaint and the company's answer we will schedule a hearing at which time you and any others can further explain the problem.

An informal resolution is always most efficient for all parties to a dispute. It does not appear, however, you are willing to negotiate a settlement. As Deb Gregg shared in her call with you, the Commission is available to assist with final resolution of this matter. Please do not hesitate to call if you have any questions.

Sincerely,

Kara Semmler

Kara Semmler
Staff Attorney

ML-SD-BD-0695.0000

Steve Kolbeck, Chair
Gary Hanson, Vice Chair
Dustin Johnson, Commissioner

SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

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Pierre, South Dakota 57501-5070
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December 6, 2010

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40916 192nd Street
Carpenter, SD 57322

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Sincerely,

Kara Semmler
Staff Attorney

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-BD-0695.0000 **Directly Affected** X **Adjacent** _____

Legal Description NE4 - **SEC.** 9 - **TWP.** T-113-N - **RGE.** R-59-W

Additional Legal Information: Beadle County, SD

Landowner(s): Pamela R Hofer

Address: 40916 192nd Street City/Town: Carpenter

County: _____ Township: _____ State: SD Zip Code: 57322

Telephone: Home :(605) 352-7171 Business : _____

Tenant(s): NA

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

11-16-2010 Delwin called and said the fence wasn't fixed right and needs a post not steel post. He also said they didin't do anything on the ROW except drive around in a bobcat and smooth out his tracks.

Eric Munz
Land Representative

11-16-2010
Date

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-BD-0695.0000 **Directly Affected** X **Adjacent** _____

Legal Description NE4 - **SEC.** 9 - **TWP.** T-113-N - **RGE.** R-59-W

Additional Legal Information: Beadle County, SD

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Address: 40916 192nd Street City/Town: Carpenter

County: _____ Township: _____ State: SD Zip Code: 57322

Telephone: Home :(605) 352-7171 Business : _____

Tenant(s): NA

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

11-15-2010 I called and talked to Pam. She said they were still working last time they were out there and she wasn't sure if the fence was fixed correctly. She will talk to Delwin and call the Huron office when they find out if everything was taken care of.

Eric Munz
Land Representative

11-15-2010
Date

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-BD-0695.0000 **Directly Affected** X **Adjacent** _____

Legal Description NE4 - **SEC.** 9 - **TWP.** T-113-N - **RGE.** R-59-W

Additional Legal Information: Beadle County, SD

Landowner(s): Pamela R Hofer

Address: 40916 192nd Street City/Town: Carpenter

County: _____ Township: _____ State: SD Zip Code: 57322

Telephone: Home :(605) 352-7171 Business : _____

Tenant(s): NA

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

3-31-2009 I informed landowner of the upcoming surveys and staking beginning April 6th and construction beginning May 1st.

Eric Munz
Land Representative

3-31-2009
Date

Keystone Pipeline Project

Contact Summary Report

Tract No. ML SD BD 0695.0000 Directly Affected X Adjacent _____

Legal Description NE4 - SEC. 9 - TWP. 113N - RGE. 59W

Additional Legal Information: Beadle County, South Dakota

Landowner(s): Delwin O. & Pamela R. Hofer

Address: 40916 192nd Street city/Town: Carpenter

County: ____ Township: _____ State: SD Zip Code: 57322

Telephone: Home :(605) 352-7171 Business :( )

Tenant(s): N/A

Address: _____ City/Town: __

County: ____ Township: __ State: _____ Zip Code: ____

Telephone: Home :( ) Business :( )

Contact Summary:

3-31-09 I called and talked to Delwin. He said he would prefer full width topsoil stripping on his property. He asked what we did when we encountered rocks. I said they would be hauled off. He said that was stealing. He said he wants his rocks buried back where they were found. He said he will want some breaks in the top soil windrow so he can access both sides of the ROW. He said he may need another approach installed on the north side of the property. I said that he can use the temporary approach that the contractor puts in. I asked if I could stop at his farm and discuss this further. He said I was welcome to stop.

C

Jerry Roitsch

Jerry Roitsch Land Representative

3/31-09

Date

Keystone Pipeline Project

Contact Summary Report

Tract No. ML SD BD 0695.0000 Directly Affected X Adjacent _____

Legal Description NE4 - SEC. 9 - TWP. 113N - RGE. 59W

Additional Legal Information: Beadle County, South Dakota

Landowner(s): Delwin O. & Pamela R. Hofer

Address: 40916 192nd Street city/Town: Carpenter

County: ____ Township: _____ State: SD Zip Code: 57322

Telephone: Home :(605) 352-7171 Business :( )

Tenant(s): N/A

Address: _____ City/Town: ___

County: ___ Township: ___ State: ____ Zip Code: ___

Telephone: Home :( ) Business :( )

Contact Summary:

2-27-09 I was instructed to get a construction agreement from the Hofers. I called and got Delwin. He was very rude and un co-operative. He said he would not fill out a construction agreement. I asked what his thoughts were of top soil stripping. I informed him that the PUC requirements were for the 50' easement area stripped. The only way to get a full width ROW top soiled, would be only if the landowner or tenant requested it. I told him he would not be happy with just the 50' width top soiled. He said he would have to think about it and talk it over with his neighbors. I told him I would call him back in a week or so.

Jerry Raitsch

Jerry Roitsch Land Representative

3/02-09

Date

United States
Department of
Agriculture

Farm and Foreign
Agricultural
Services

Farm Service
Agency

South Dakota State
FSA Office
200 4th Street SW
Huron, SD 57350

(605) 352-1160

FAX
(605) 352-1195

TO: Keystone Pipeline Project
Attn: Suellen Otis
7509 NW Tiffany Springs Parkway
Kansas City, MO 64153

FROM: Thomas J. Kostel
Acting State Executive Director

DATE: February 23, 2009

SUBJECT: Request for Subordination
Pamela Hofer Beadle County, SD

We are returning your request for subordination unsigned at this time. FSA will need to receive an application for subordination from our borrower, Pamela Hofer, prior to any action being taken to approve/deny the subordination. In addition, FSA will need to complete required environmental compliance actions and any proceeds received by the borrower in consideration for the easement must also be accounted for to FSA before issuing the subordination.

FSA will need copies of consultation completed with the South Dakota State Historic Preservation Office including a copy of the cultural resources survey, copies of consultation with the United States Department of Interior Fish and Wildlife Service, and copies of any permits issued by the South Dakota Department of Environment and Natural Resources and Public Utilities Commission.

A copy of your calculations for the determination of value of the easement is needed to determine if an appraisal will be required.

FSA will also need a copy of the proposed easement for review by our legal counsel.

Any questions should be directed to Arnie Claeys State Farm Loan Chief at 605-352-1126.

cc: FLP- Beadle County

USDA is an Equal Opportunity Employer and Lender

KEYSTONE PIPELINE PROJECT

7509 NW Tiffany Parkway
Kansas City, MO 64153

February 21, 2009

FHA/USDA Room 208 Huron Federal Building
200 4th St. SW
Huron, SD 57350

Re: Request for Subordination
Tract No. ML-SD-BD-0695.0000

Dear Sir or Madam:

Transcanada Keystone Pipeline, L.P. is acquiring easements for a pipeline to be constructed from North Dakota to Illinois. A segment of this system crosses a tract of land owned by **Pamela R. Hofer** and being more particularly described as follows:

NE4, Section 9, T113N, R59W

The Public Records of Beadle County, South Dakota, also indicates that **FHA/USDA Room 208 Huron Federal Building** holds a Mortgage/Deed of Trust on this tract. The Mortgage/Deed of Trust is recorded in **Book 401 at Page 57** of the Public Records of **Beadle County, South Dakota.**

So that Transcanada Keystone Pipeline, L.P. can have an unencumbered easement, we ask that FHA/USDA Room 208 Huron Federal Building execute a Subordination to the easement. This will provide Transcanada Keystone Pipeline, L.P. a valid easement in the event of a default. We find that there are no liens against the property or judgments against the property owner and that the Mortgage/Deed of Trust payments are apparently current.

Subject to your review, please execute both copies of the attached Subordination before a notary public and return one copy to me in the enclosed self-addressed and stamped envelope. Should you have any questions, please call me at **816-880-4609.**

Thank you for your cooperation in this matter.

Yours very truly,

BY: Sue Otis

Suellen Otis
Land Administrative Supervisor

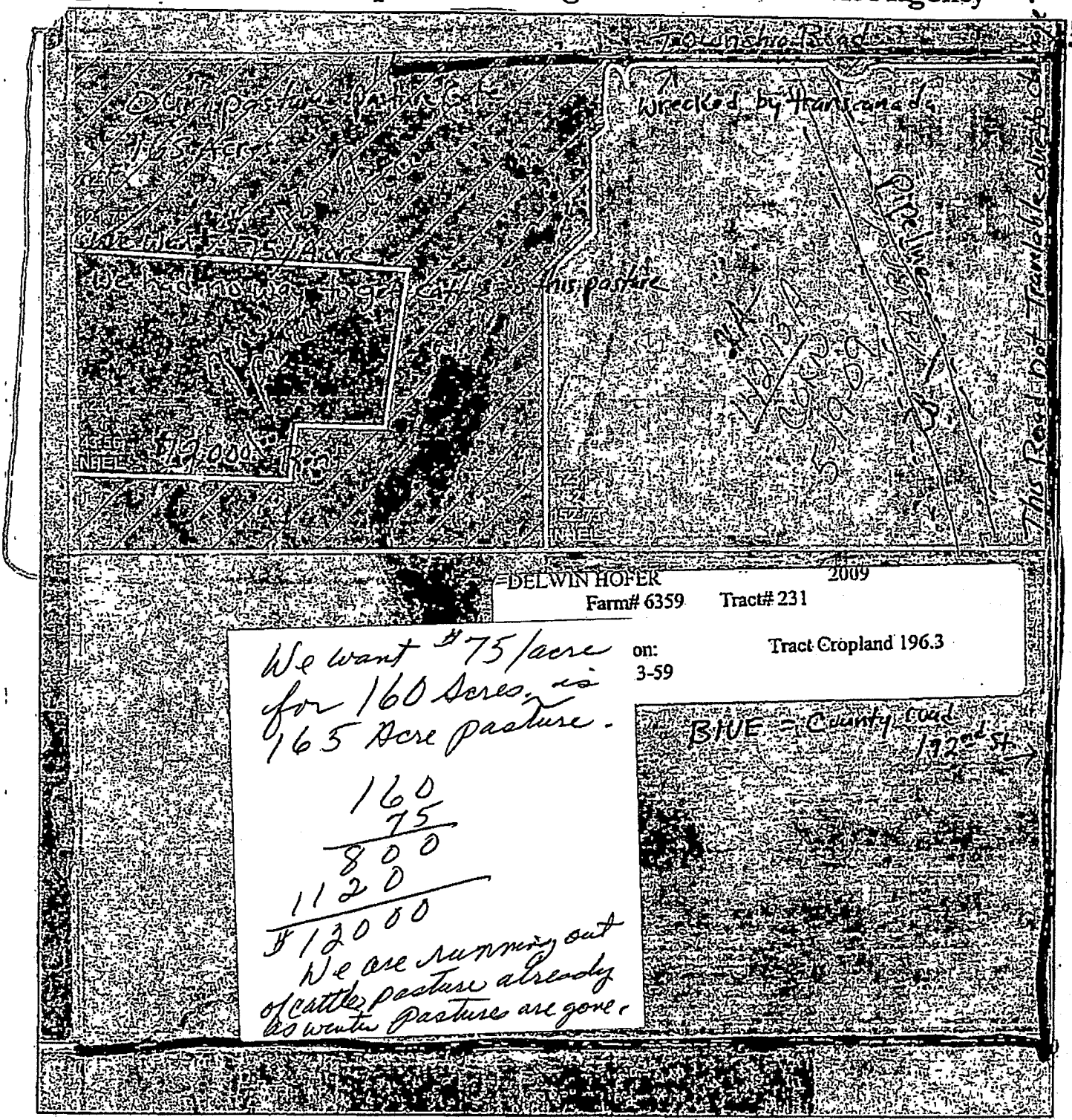
encls.

Sorry dn slow with
this but weir had
a family Emergency
and dn' been busy
with that.

Tom Hofer

013212

United States Department of Agriculture Farm Service Agency



DELWIN HOFER 2009
Farm# 6359 Tract# 231
on: 3-59
Tract Cropland 196.3

We want $75/acre for 160 acres, in 165 acre pasture.

160
75
800
1120
$12000

We are running out of cattle pasture already as winter pastures are gone.

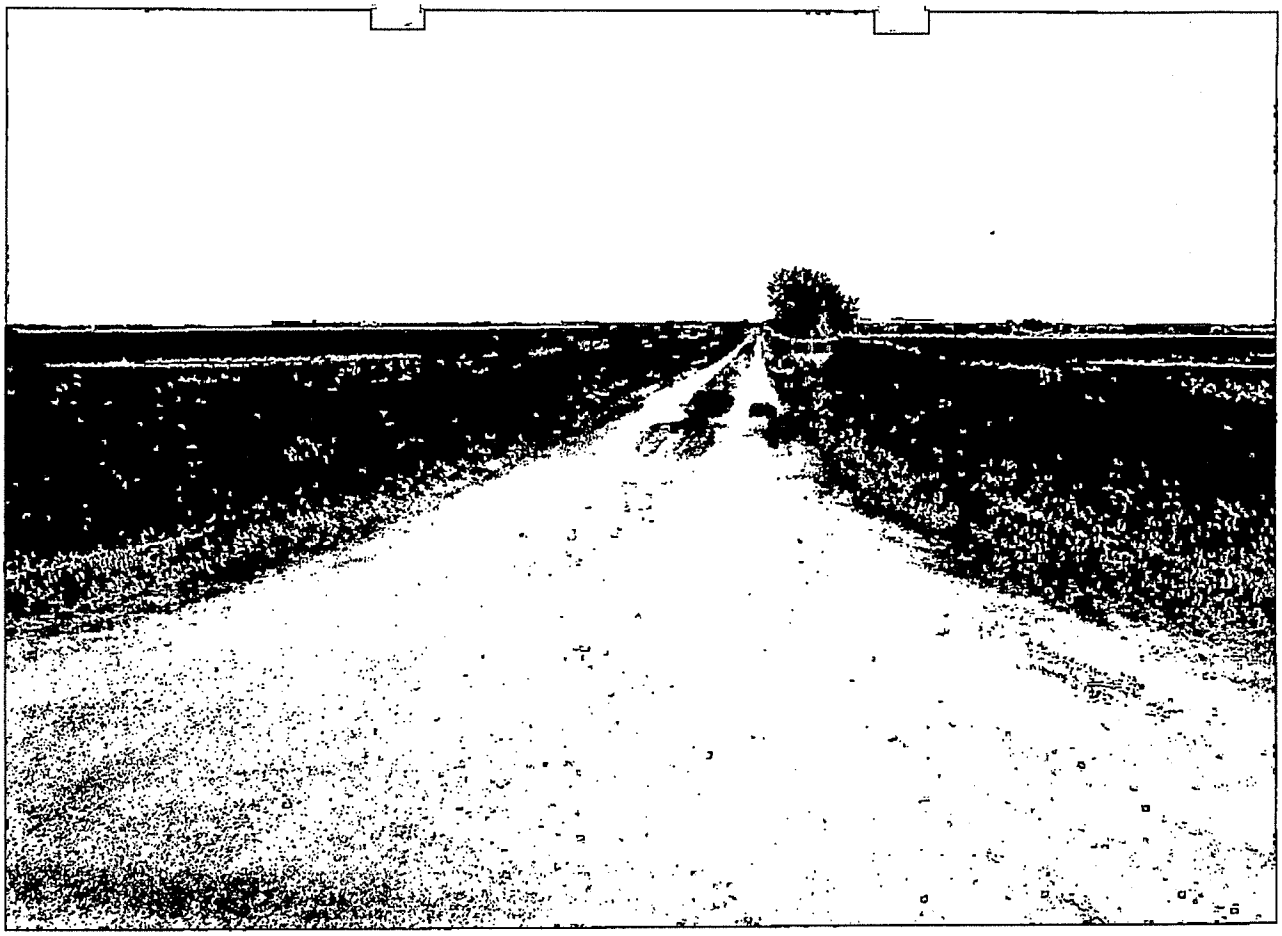
$75/ac for 160 acres

FSA South Dakota
Beadle County

Farm Number 6359
Township-Range-Section 113N59W9

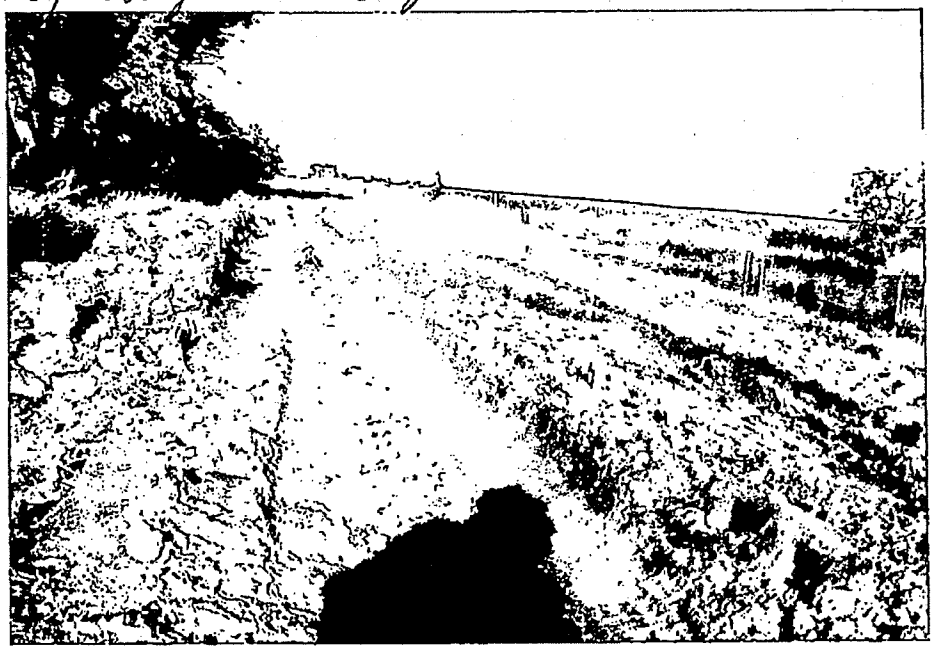
Legend
- Restricted Use
- Limited Restrictions
- Exempt from Conservation Compliance Provisions
- CLU Field Boundary

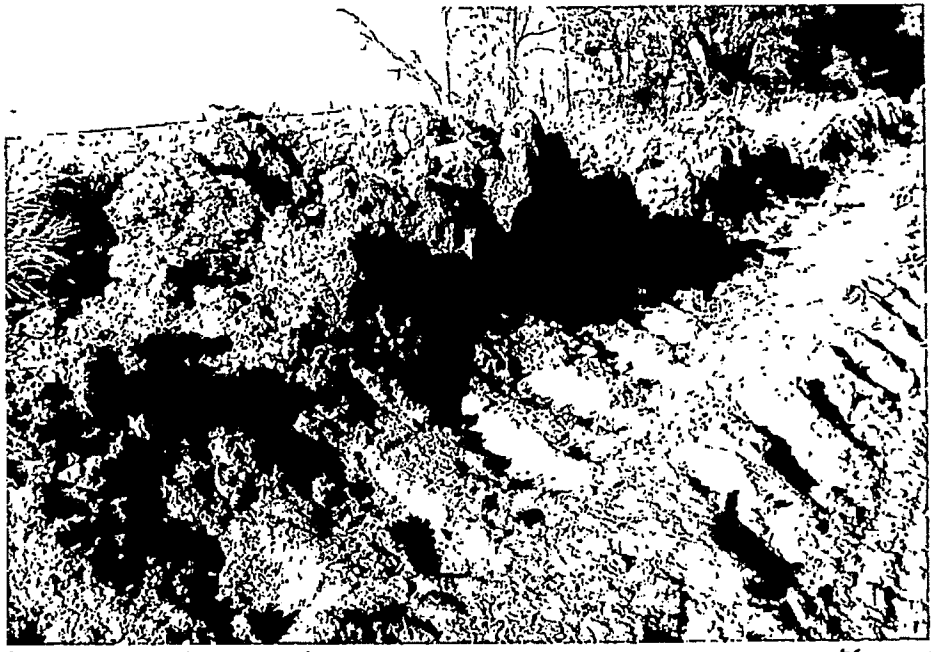
We want $12,000.



This is 191st Street only way to our pasture we could haul cattle on.

191st Street over 4 was bad in June when we wanted to take cattle bad in July & August too Sept bad too.





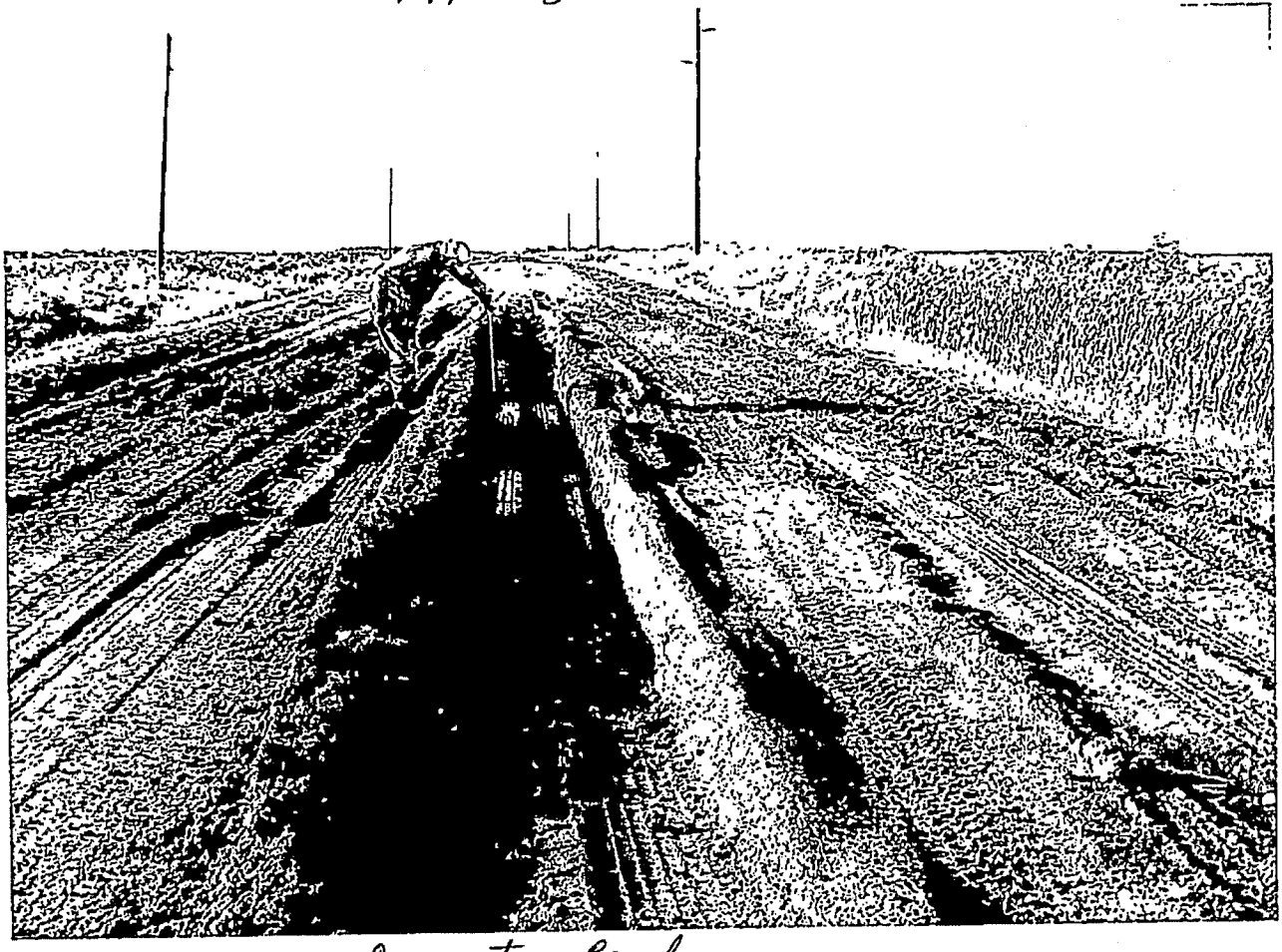
We couldn't go through with 4-wheel drive pickup how can one get roundtrail of cattle through.

013215

Carpenter Road we had to haul on + couldn't [illegible] night at 2 ft deep.

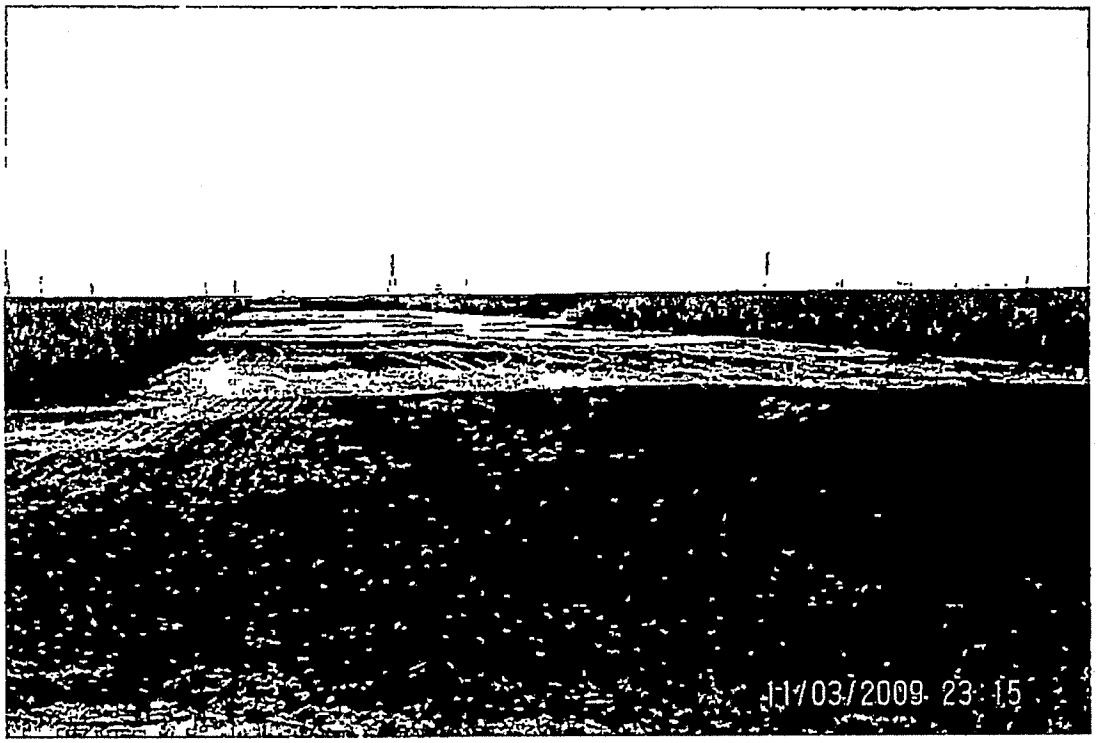
Track stayed this deep a long time. You never even bladed the road at night.

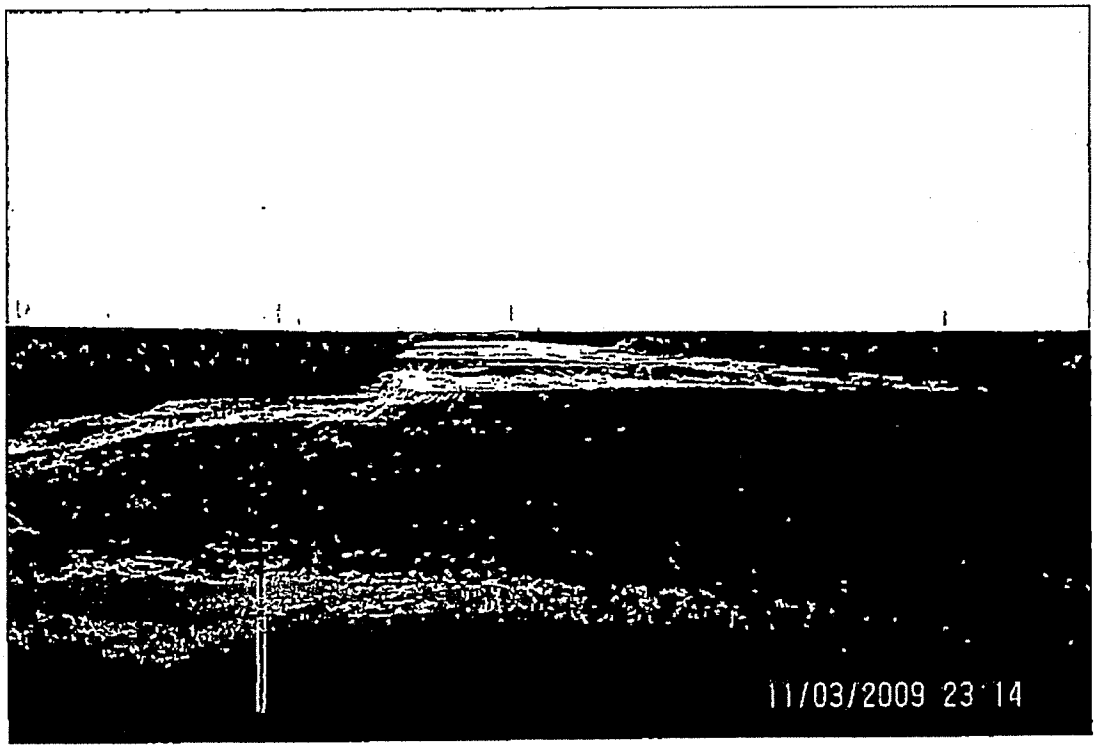
191st Street

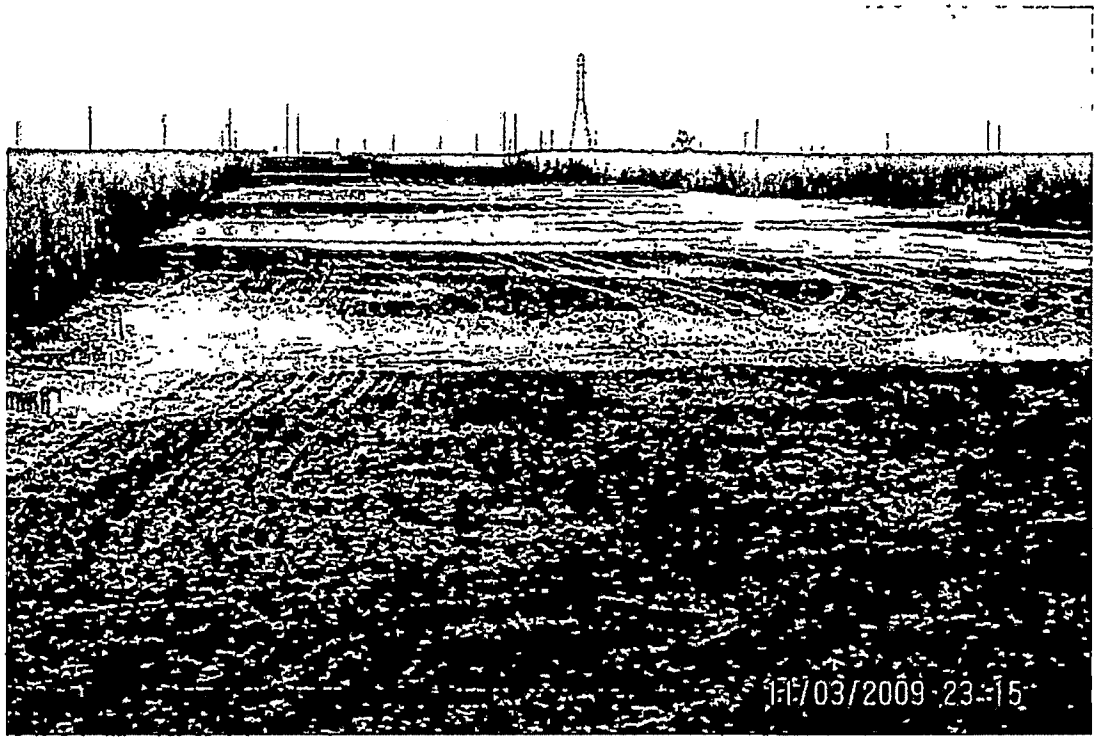


Carpenter Road

This is our land now. All water. You messed up the drain of the land.






11/03/2009 23:15

Keystone Pipeline Project

Contact Summary Report

Tract No. ML SD BD 0695.0000 Directly Affected X Adjacent _____

Legal Description NE4 - SEC. 9 - TWP. 113N - RGE. 59W

Additional Legal Information: Beadle County, South Dakota

Landowner(s): Pamela R. Hofer

Address: 40916 192nd Street city/Town: Carpenter

County: ___ Township: ___ State: SD Zip Code: 57322

Telephone: Home :(605) 352-7171 Business :( )

Tenant(s): N/A

Address: ___ City/Town: ___

County: ___ Township: ___ State: ___ Zip Code: ___

Telephone: Home :( ) Business :( )

Contact Summary: 3/19/08 I called and talked to Delwin. I asked if I could met with him and his wife Pam or met with him, Pam and their attorney. He first referred me to his lawyer, Scott Heidepriem. I told him I had a revised sketch for Pam and he told me to mail it to Scott. I asked if I could leave my name and phone number if they had any questions. He said no. Then he said he had asked at several of TransCanada's meetings if they had liability and for a copy of the policy. He said they always told him they would get back to him but nobody did. I told him TransCanada currently has a $25 million dollar liability policy and I will get him a copy of it. He asked who the contractor would be. I told him Michels of Brownsville, Wisconsin. He said he wants a copy of their liability policy. I told him that I did not have. He said if anyone is going to be on his land he wants a copy of their liability. He said TransCanada was the most dishonest company he has ever dealt with. I told him I would drop by with the copy of the liability policy.
3/20/08 I got an e-mail saying not to contact Delwin and Pam Hofer until further notice.

Jerry Rolfsch Land Representative

3/30/08

RECEIVED
Date
APR 7 2008
Ellis & Associates Inc.

Keystone Pipeline Project

Contact Summary Report

Tract No. ML SD BD 0695.0000 Directly Affected X Adjacent _____

Legal Description NE4 - SEC. 9 - TWP. 113N - RGE. 59W

Additional Legal Information: Beadle County, South Dakota

Landowner(s): Pamela R. Hofer

Address: 40916 192nd Street city/Town: Carpenter

County: ___ Township: ___ State: SD Zip Code: 57322

Telephone: Home :(605) 352-7171 Business :( )

Tenant(s): N/A

Address: ___ City/Town: ___

County: ___ Township: ___ State: ___ Zip Code: ___

Telephone: Home :( ) Business :( )

Contact Summary: 3/19/08 I called and talked to Delwin. I asked if I could met with him and his wife Pam or met with him, Pam and their attorney. He first referred me to his lawyer, Scott Heidepriem. I told him I had a revised sketch for Pam and he told me to mail it to Scott. I asked if I could leave my name and phone number if they had any questions. He said no. Then he said he had asked at several of TransCanada's meetings if they had liability and for a copy of the policy. He said they always told him they would get back to him but nobody did. I told him TransCanada currently has a $25 million dollar liability policy and I will get him a copy of it. He asked who the contractor would be. I told him Michels of Brownsville, Wisconsin. He said he wants a copy of their liability policy. I told him that I did not have. He said if anyone is going to be on his land he wants a copy of their liability. He said TransCanada was the most dishonest company he has ever dealt with. I told him I would drop by with the copy of the liability policy.

Jerry Roitsch

Jerry Roitsch Land Representative

3/18/08
Date

RECEIVED
MAR 2 4 2008
Ellis & Associates Inc.

013221

Keystone Pipeline Project

Contact Summary Report

Tract No.ML-SD-BD-0695.0000 **Directly Affected** __X__ **Adjacent** _____

Legal Description ¼ NE - SEC. 9 - TWP. 113N - RGE. 59W

Additional Legal Information: BEADLE COUNTY S.D.

Landowner(s): DELWIN O. HOFER AND PAMELA R. HOFER

Address: 40916 192ND STREET City/Town: CARPENTER

County: BEADLE Township: _____ State: SD Zip Code: 57322

Telephone: Home :(605) 352-7171 Business :(605) NA

Tenant(s): NA

Address: _____ City/Town: _____

County: _____ Township: _____ State: S.D. Zip Code: _____

Telephone: Home :(605) _____ Business :(605) _____

Contact Summary: On 10-16-07 I called and left a message for the Hofer's stating that I mailed another copy of the easement for them to review. I left my name and number and ask that that call me with any questions.

Paul Kist
Land Representative

10-16-07
Date

RECEIVED
OCT 19 2007
[illegible] Associates Inc.

013222

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-BD-~~0699~~ 0695.0000 **Directly Affected** __X__ **Adjacent** _____

Legal Description ¼ NE - SEC. 9 - TWP. 113N - RGE. 59W

Additional Legal Information: Beadle County, South Dakota

Landowner(s): Delwin O. Hofer and Pamela R. Hofer

Address: 40916 192nd Street City/Town: Carpenter

County: Clark Township: - State: South Dakota Zip Code: 57322

Telephone: Home :(605) 352-7171 Business :( )

Tenant(s): N/A

Address: City/Town:

County: Township: State: Zip Code:

Telephone: Home :( ) Business :( )

Contact Summary: Received by Certified mail- Easement and Right of Way Agreement's-this is due to prior phone conversation with Mrs. Pamela Hofer-was told not to contact again as they had not changed their mind about pipeline

Pama Bruce
Land Representative

7/7/07
Date

RECEIVED
AUG 9 2007
Ellis & Associates Inc.

013223

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-BD-~~0699~~.0000 0695.0000 Directly Affected __X__ Adjacent _____

Legal Description ¼ NE - SEC. 9 - TWP. 113N - RGE. 59W

Additional Legal Information: Beadle County, South Dakota

Landowner(s): Delwin O. Hofer and Pamela R. Hofer

Address: 40916 192nd Street City/Town: Carpenter

County: Clark Township: - State: South Dakota Zip Code: 57322

Telephone: Home :(605) 352-7171 Business :( )

Tenant(s): N/A

Address: City/Town:

County: Township: State: Zip Code:

Telephone: Home :( ) Business :( )

Contact Summary: Mailed by Certified Return Receipt Easement and Right of Way Agreement's-this is due to prior phone conversation with Mrs. Pamela Hofer-was told not to contact again

Pama Bruce
Land Representative

6/21/07
Date

RECEIVED
AUG 9 2007
Ellis & Associates Inc.

Keystone Pipeline Project

Contact Summary Report

ML-SD-MN-0796.0000

Tract No. ML-SD-MN-0795.0000 **Directly Affected** X **Adjacent** _____

Legal Description S2SW4 - **SEC.** 28 & all sec 33 - **TWP.** T-106-N - **RGE.** R-57-W

Additional Legal Information: Miner County, SD

Landowner(s): Michael B & Susan K Sibson

Address: 23782 426th Ave City/Town: Howard

County: _____ Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business : 605-770-2800

9-18-2013 I called Sue and asked her to take a picture of the wheat grass that they don't want on their property. She texted me 2 pics.

9-20-2013 Sue sent a text asking if I figured out what that grass is. I sent a reply stating the environmental and project management people are working on it and I will let her know when I hear more from them.

Eric Munz
Land Representative

9-18-2013
Date

Keystone Pipeline Project

Contact Summary Report

ML-SD-MN-0796.0000

Tract No. ML-SD-MN-0795.0000 Directly Affected __X___ Adjacent _____

Legal Description S2SW4 - SEC. 28 & all sec 33 - TWP. T-106-N - RGE. R-57-W

Additional Legal Information: Miner County, SD

Landowner(s): Michael B & Susan K Sibson

Address: 23782 426th Ave City/Town: Howard

County: _____ Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business : 605-770-2800

9-16-2013 Sue sent an e-mail stating Frank Maddox won't give her his report and wants to know what the plan is.

9-17-2013 Sue texted me asking what the plan is. I texted her back saying Frank and TCPL management are working on a plan and I will get it to her when I receive it. She texted back ok thanks.

Eric Munz
Land Representative

9-17-2013
Date

Keystone Pipeline Project

Contact Summary Report

ML-SD-MN-0796.0000

Tract No. ML-SD-MN-0795.0000 **Directly Affected** X **Adjacent** _____

Legal Description S2SW4 - **SEC.** 28 & all sec 33 - **TWP.** T-106-N - **RGE.** R-57-W

Additional Legal Information: Miner County, SD

Landowner(s): Michael B & Susan K Sibson

Address: 23782 426th Ave City/Town: Howard

County: _____ Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business : 605-770-2800

8-14-2013 Sue texted me and asked when the contractor will be looking at their ROW. I responded that Frank Maddox had indicated it will be sometime after 8-26-2013.

Eric Munz
Land Representative

8-14-2013
Date

Keystone Pipeline Project

Contact Summary Report

ML-SD-MN-0796.0000

Tract No. ML-SD-MN-0795.0000 Directly Affected __X___ Adjacent _____

Legal Description S2SW4 - SEC. 28 & all sec 33 - TWP. T-106-N - RGE. R-57-W

Additional Legal Information: Miner County, SD

Landowner(s): Michael B & Susan K Sibson

Address: 23782 426th Ave City/Town: Howard

County: _____ Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business : 605-770-2800

7-11-2013 Sue called and asked what time the weed sprayer was coming. I called her back and said he said it was too windy and will come tomorrow at 6:30 am.

Eric Munz
Land Representative

7-11-2013
Date

Keystone Pipeline Project

Contact Summary Report

ML-SD-MN-0796.0000

Tract No. ML-SD-MN-0795.0000 **Directly Affected** X **Adjacent** _____

Legal Description S2SW4 - **SEC.** 28 & all sec 33 - **TWP.** T-106-N - **RGE.** R-57-W

Additional Legal Information: Miner County, SD

Landowner(s): Michael B & Susan K Sibson

Address: 23782 426th Ave City/Town: Howard

County: _____ Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business : 605-770-2800

6-25-2013 I called and left a message for Sue. She called back. I asked if they are going to want weed treatments on the ROW. She said she would call me back with an answer.

Eric Munz
Land Representative

6-25-2013
Date

Keystone Pipeline Project

Contact Summary Report

ML-SD-MN-0796.0000

Tract No. ML-SD-MN-0795.0000 **Directly Affected** X **Adjacent** _____

Legal Description S2SW4 - **SEC.** 28 & all sec 33 - **TWP.** T-106-N - **RGE.** R-57-W

Additional Legal Information: Miner County, SD

Landowner(s): Michael B & Susan K Sibson

Address: 23782 426th Ave City/Town: Howard

County: _____ Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business : 605-770-2800

5-10-2013 Sue sent pics of holes in ROW. I called her and she said she would text me a time to meet with her and Mike.
5-12-2013 Sue texted me and said they can meet 8:30 am tomorrow.
5-13-2013 I met with Jeremy from CRA and the Sibsons. We viewed holes in ROW. Jeremey confirmed they are varmint holes and Mike said he will till over them and call if there is anything TCPL needs to do.

Eric Munz
Land Representative

5-13-2013
Date

Felicia Webb

From: eric munz [northernmn2001@yahoo.com]
Sent: Monday, May 13, 2013 1:58 PM
To: Felicia Webb
Subject: Fw: Sibson 0795 & 0796

Felicia, please print out pics and e-mail and put in the file. Thanks,

Eric Munz
Sr. Land Agent - Keystone Pipeline
605-461-8568
northernmn2001@yahoo.com
----- Forwarded Message -----
From: Frank Maddox <frankmaddox@yahoo.com>
To: Frank Maddox <frankmaddox@yahoo.com>
Cc: eric munz <northernmn2001@yahoo.com>; "joshua_thompson@transcanada.com" <joshua_thompson@transcanada.com>; "heath_morton@transcanada.com" <heath_morton@transcanada.com>; "kdaustin@donellis-associates.com" <kdaustin@donellis-associates.com>; brett ohlsen <oble_1999@yahoo.com>
Sent: Monday, May 13, 2013 9:44 AM
Subject: Re: Sibson 0795 & 0796

Eric and Jeromy met with the Simbsons and confirmed our theory of varmint holes . The Sibson's were pleased with the attention and agreed to disc in the holes with normal farming practice. Good job guys ! No money spent and we will follow up when we get in the area

Sent from my iPhone

On May 12, 2013, at 11:53 AM, Frank Maddox <frankmaddox@yahoo.com> wrote:

> Folks this is our old friends TheSibsons. Yesterday Rob Latiner called Eric asking about them and if he knew them , he of course indicated very well. A few minutes later Sue Sibson called Eric and wanted immediate attention at 8:30 AM tomorrow 5-13-2013 , as they are planting. Eric is on his way back to that appointment and I am sending my survey guy Jreomey up there now . He will locate the pipe, check depth , and confirm these are varmant holes. He will communicate those findings to us and I suggest we authorize Eric to pay the Sibsons up to $1,000 to box blade the holes in and go ahead and plant . If they refuse we will have no choice but to mobilize one of Brett's crews up there at a cost of several thousand $.
>
> This I my field decision on this mothers day sunday , thinking this is our best coarse on short notice to avoid any calls to the Comission which they always do
>
> Yours in service Mother Frank
>
> Sent from my iPhone
>
> On May 11, 2013, at 8:31 AM, eric munz <northernmn2001@yahoo.com> wrote:
>
> > Frank, Sue Sibson sent pics of holes in ROW. These are new issues. Jason had

indicated the walk through will end just below the Sibson Property. Their neighbors have called and said they have issues on 0798.0001 & 0799. Do we want to include these areas as well? I will be happy to accompany Jason and crew if these tracts will be included on the walk through. I'm sure the Sibsons will appreciate some attention sooner than later.

Eric Munz
Sr. Land Agent - Keystone Pipeline
605-461-8
northernmn2001@yahoo.com

<Sibson-1.jpg>

<Sibson-2.jpg>

<Sibson-3.jpg>

Felicia Webb

From: eric munz [northernmn2001@yahoo.com]
Sent: Monday, May 13, 2013 1:58 PM
To: Felicia Webb
Subject: Fw: Sibson 0795 & 0796
Attachments: Sibson-1.jpg; Sibson-2.jpg; Sibson-3.jpg

Eric Munz
Sr. Land Agent - Keystone Pipeline
605-461-8568
northernmn2001@yahoo.com
----- Forwarded Message -----
From: eric munz <northernmn2001@yahoo.com>
To: "frankmaddox@yahoo.com" <frankmaddox@yahoo.com>; "joshua_thompson@transcanada.com" <joshua_thompson@transcanada.com>; "heath_morton@transcanada.com" <heath_morton@transcanada.com>; "kdaustin@donellis-associates.com" <kdaustin@donellis-associates.com>
Sent: Saturday, May 11, 2013 8:31 AM
Subject: Sibson 0795 & 0796

Frank, Sue Sibson sent pics of holes in ROW. These are new issues. Jason had indicated the walk through will end just below the Sibson Property. Their neighbors have called and said they have issues on 0798.0001 & 0799. Do we want to include these areas as well? I will be happy to accompany Jason and crew if these tracts will be included on the walk through. I'm sure the Sibsons will appreciate some attention sooner than later.

Eric Munz
Sr. Land Agent - Keystone Pipeline
605-461-8568
northernmn2001@yahoo.com

Keystone Pipeline Project

Contact Summary Report

ML-SD-MN-0796.0000

Tract No. ML-SD-MN-0795.0000 **Directly Affected** X **Adjacent** _____

Legal Description S2SW4 - **SEC.** 28 & all sec 33 - **TWP.** T-106-N - **RGE.** R-57-W

Additional Legal Information: Miner County, SD

Landowner(s): Michael B & Susan K Sibson

Address: 23782 426th Ave City/Town: Howard

County: _____ Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business : 605-770-2800

Sue texted me stating the pipeline patrol plane did a much better job of staying over the easememnt area.

Eric Munz
Land Representative

2-20-2012
Date

Keystone Pipeline Project

Contact Summary Report

ML-SD-MN-0796.0000

Tract No. ML-SD-MN-0795.0000-3 **Directly Affected** __X__ **Adjacent** _____

Legal Description S2SW4 - **SEC.** 28 & all sec 33 - **TWP.** T-106-N - **RGE.** R-57-W

Additional Legal Information: Miner County, SD

Landowner(s): Michael B & Susan K Sibson

Address: 23782 426th Ave City/Town: Howard

County: _____ Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business : 605-770-2800

11-15-012 I met with Sibsons and wrote a check for crop damages. They said they are very happy with the reclamation but don't want to sign off until the native grass is established.

Eric Munz
Land Representative

11-15-2012
Date

Keystone Pipeline Project

Contact Summary Report

ML-SD-MN-0796.0000

Tract No. ML-SD-MN-0795.0000 **Directly Affected** X **Adjacent** _____

Legal Description S2SW4 - SEC. 28 & all sec 33 - TWP. T-106-N - RGE. R-57-W

Additional Legal Information: Miner County, SD

Landowner(s): Michael B & Susan K Sibson

Address: 23782 426th Ave City/Town: Howard

County: _____ Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business : 605-770-2800

10-29-2012 Sue called and said they are ready to settle crop yield loss when I am in the area next.

Eric Munz
Land Representative

10-29-2012
Date

013239

Keystone Pipeline Project

Contact Summary Report

ML-SD-MN-0796.0000

Tract No. ML-SD-MN-0795.0000 Directly Affected __X__ Adjacent _____

Legal Description S2SW4 - SEC. 28 & all sec 33 - TWP. T-106-N - RGE. R-57-W

Additional Legal Information: Miner County, SD

Landowner(s): Michael B & Susan K Sibson

Address: 23782 426th Ave City/Town: Howard

County: _____ Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business : 605-770-2800

9-29-2012 I met with Mike Sibson, Frank Maddox and Brett Ohlson. We toured the ROW and Mike said he is happy with the work they have done and couldn't find anything else he thinks they should do.

Eric Munz
Land Representative

9-29-2012
Date

013240

Keystone Pipeline Project

Contact Summary Report

ML-SD-MN-0796.0000

Tract No. ML-SD-MN-0795.0000 **Directly Affected** X **Adjacent** _____

Legal Description S2SW4 - **SEC.** 28 & all sec 33 - **TWP.** T-106-N - **RGE.** R-57-W

Additional Legal Information: Miner County, SD

Landowner(s): Michael B.& Susan K Sibson

Address: 23782 426th Ave City/Town: Howard

County: _____ Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business : 605-770-2800

Tenant(s): N/A

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

9-14-2012 I called Mike. He said we could meet at 6:00 pm. I met with Mike, Sue, Frank Maddox, Brett Ohlson and crew to view ROW. Crew is devising plan to reclaim.

Eric Munz
Land Representative

7-12-2012
Date

Keystone Pipeline Project

Contact Summary Report

ML-SD-MN-0796.0000

Tract No. ML-SD-MN-0795.0000 **Directly Affected** __X__ **Adjacent** _____

Legal Description S2SW4 - SEC. 28 & all sec 33 - TWP. T-106-N - RGE. R-57-W

Additional Legal Information: Miner County, SD

Landowner(s): Michael B & Susan K Sibson

Address: 23782 426th Ave City/Town: Howard

County: _____ Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business : 605-770-2800

Tenant(s): N/A

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

7-12-2012 I called and informed Mike of the helicopter flyover next week. He said if the cattle are near the easement area they may get spooked if they think the helicopter is coming at them so to try to avoid flying directly over them. He asked that I let him know what day they will be flying over his property so he can keep an eye on the cattle.

Eric Munz
Land Representative

7-12-2012
Date

Keystone Pipeline Project

Contact Summary Report

ML-SD-MN-0796.0000

Tract No. ML-SD-MN-0795.0000 **Directly Affected** X **Adjacent** _____

Legal Description S2SW4 - **SEC.** 28 & all sec 33 - **TWP.** T-106-N - **RGE.** R-57-W

Additional Legal Information: Miner County, SD

Landowner(s): Michael B & Susan K Sibson

Address: 23782 426th Ave City/Town: Howard

County: _____ Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business : 605-770-2800

Tenant(s): N/A

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

11-11-2011 I met with Sarah Metcalf and the Sibsons. I wrote a check for crop loss for this year and pasture loss for 3 years.

Eric Munz
Land Representative

11-11-2011
Date

Keystone Pipeline Project

Contact Summary Report

Tract No.ML-SD-MN-0795.0000 **Directly Affected __X___ Adjacent _____**

Legal Description ¼ SW - SEC. 28 - TWP. 106N - RGE. 57W

Additional Legal Information: MINER COUNTY S.D.

Landowner(s): MICHAEL B. and SUSAN K. SIBSON

Address: 23782 426TH AVE. City/Town: HOWARD

County: MINER Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business :(605) 770-2800

Tenant(s): NA

Address: _____ City/Town: _____

County: _____ Township: _____ State: S.D. Zip Code: _____

Telephone: Home :(605) _____ Business :(605) _____

Contact Summary: On 8-16-11 I met with the Contractor and AC on site and the work was 99% complete. They were hauling out equipment. I then met with Mike and Sue Sibson and they are as satisfied as can be. They told me that the work looks as good as any man could do. They did not want either access road disced or reseeded. Mike and Sue both stated that they were satisfied of the work as of now.

Paul Curt

Land Representative

8-16-11

Date

Keystone Pipeline Project

Contact Summary Report

Tract No.ML-SD-MN-0795.0000 **Directly Affected __X___ Adjacent _____**

Legal Description ¼ SW - SEC. 28 - TWP. 106N - RGE. 57W

Additional Legal Information: MINER COUNTY S.D.

Landowner(s): MICHAEL B. and SUSAN K. SIBSON

Address: 23782 426TH AVE. City/Town: HOWARD

County: MINER Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business :(605) 770-2800

Tenant(s): NA

Address: _____ City/Town: _____

County: _____ Township: _____ State: S.D. Zip Code: _____

Telephone: Home :(605) _____ Business :(605) _____

Contact Summary: On 8-4-11 I met with the Sibson's on site and they said that Sarah had called them about the topsoil being hauled in. The Sibson's stated that they DID NOT WANT TOPSOIL HAULED IN. They said they did not have any topsoil that TCPL could use either. The Sibson's stated that they want the topsoil that is there reworked and that should work.

Paul Kurt
Land Representative

8-4-11
Date

Keystone Pipeline Project

Contact Summary Report

Tract No.ML-SD-MN-0795.0000 **Directly Affected** __X__ **Adjacent** _____

Legal Description ¼ SW - SEC. 28 - TWP. 106N - RGE. 57W

Additional Legal Information: MINER COUNTY S.D.

Landowner(s): MICHAEL B. and SUSAN K. SIBSON

Address: 23782 426TH AVE. City/Town: HOWARD

County: MINER Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business :(605) 770-2800

Tenant(s): NA

Address: _____ City/Town: _____

County: _____ Township: _____ State: S.D. Zip Code: _____

Telephone: Home :(605) _____ Business :(605) _____

Contact Summary: On 8-1-11 Sarah Metcalf and I met with the Sibson's and presented them the work plan for their property. The Sibson's agreed to everything on the plan and were pleased that work was going to begin soon.

Paul Kurt

Land Representative

8-1-11

Date

Keystone Pipeline Project

Contact Summary Report

Tract No.ML-SD-MN-0795.0000 **Directly Affected** __X__ **Adjacent** _____

Legal Description ¼ SW - SEC. 28 - TWP. 106N - RGE. 57W

Additional Legal Information: MINER COUNTY S.D.

Landowner(s): MICHAEL B. and SUSAN K. SIBSON

Address: 23782 426TH AVE. City/Town: HOWARD

County: MINER Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business :(605) 770-2800

Tenant(s): NA

Address: _____ City/Town: _____

County: _____ Township: _____ State: S.D. Zip Code: _____

Telephone: Home :(605) _____ Business :(605) _____

Contact Summary: On 8-2-11 I met Mike Sibson on the road near the ROW. Mike was glad to see the crew moving in and was glad to see I was on site for a while.

Paul Kurt
Land Representative

8-2-11
Date

Keystone Pipeline Project

Contact Summary Report

Tract No.ML-SD-MN-0795.0000 **Directly Affected** __X__ **Adjacent** _____

Legal Description ¼ SW - SEC. 28 - TWP. 106N - RGE. 57W

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Address: 23782 426TH AVE. City/Town: HOWARD

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Telephone: Home :(605) 772-5184 Business :(605) 770-2800

Tenant(s): NA

Address: _____ City/Town: _____

County: _____ Township: _____ State: S.D. Zip Code: _____

Telephone: Home :(605) _____ Business :(605) _____

Contact Summary: On 7-28-11 I met with Mike and Sue Sibson, Sarah Metcalf and the Contractor on the Sibson property. The Sibson's showed the contractor the area and the water and the Fences. The contractor said they would begin actual dirt work on Monday 8-1-11 weather permitting and would possibly sweep the area this weekend.

Paul Kurt

Land Representative

7-28-11

Date

Keystone Pipeline Project

Contact Summary Report

ML-SD-MN-0796.0000

Tract No. ML-SD-MN-0795.0000 **Directly Affected** __X___ **Adjacent** _____

Legal Description S2SW4 - **SEC.** 28 & all sec 33 - **TWP.** T-106-N - **RGE.** R-57-W

Additional Legal Information: Miner County, SD

Landowner(s): Michael B & Susan K Sibson

Address: 23782 426th Ave City/Town: Howard

County: _____ Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business : 605-770-2800

Tenant(s): N/A

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

7-05-2011 I spoke with Mike Sibson today. I called him to notify the weed sprayer was going to be here in the next few days. Mike said that sweet clover has come in and the weeds aren't as bad as they were when I was there last year. He said it's still wet in some areas and rough and may be difficult for the weed sprayer to get to some areas. He would rather they wait to address weeds when the reclamation crew comes in when it dries out.

Eric Munz
Land Representative

7-05-2011
Date

ML-SD-N-0795.0000
& 0796.0000 Sibsons

TINA HALL

From: Sarah Metcalf [smetcalf12@gmail.com]
Sent: Friday, May 20, 2011 11:26 AM
To: Jessica Greven
Cc: Susan Parker; alanjojohnson@msn.com; Tina Hall; Paul Kliest
Subject: Re: FW: Updated plan for Sibson

Thanks Jessica,

I think it is a little early to actually spray but not by much. Last week Sue said a four wheeler could access the ROW but we have had a significant amount of rain again, so I would suspect that we will need to wait for another dry stretch. I would think the weeds should be treated in the next month or so, as plants are up starting to grow now. Sometime in mid June perhaps, and that would also give a window between treatment and seeding, which I doubt we can do until later when it dry's enough to work the soil. Last year we sprayed too late and plants were already beginning to seed when they were sprayed, so the treatment was not as effective as it should have been (likely I will hear from the other SD tracts we treated at some point as well). Keep me posted and I will advise the Sibson's as things progress.

Regards,

Sarah

On Fri, May 20, 2011 at 10:55 AM, Jessica Greven <jessica_greven@transcanada.com> wrote:

Thanks for the update Sarah. I will give a call to Operations – I believe the plan is to use their sub-contractors, rather than the person we used last year. I have a call with Bob Baumgartner in about 10 minutes and will discuss it with him then. Are the weeds in a state to be treated now, or is it too early? Is it too wet for a 4-wheeler to safely traverse their land? We will need to discuss the weed control and subsequent re-seeding planned for the Sibson's property with the applicator to ensure there isn't a contraindication/interaction. I'll let you know what I find out.

Thank you,

Jessica Greven

Keystone Pipeline Project

2700 South Post Oak Blvd.

Suite 400, Galleria Tower 1

Houston, TX 77056

T: 713.693.6495

C: 281.620.8658

jessica_greven@transcanada.com

Please consider the environment before printing this e-mail.

---------- Forwarded message ----------

From: **Sarah Metcalf** <smetcalf12@gmail.com>
Date: Fri, May 20, 2011 at 10:04 AM
Subject: Re: FW: Updated plan for Sibson
To: Jessica Greven <Jessica.Greven@trow.com>
Cc: Susan Parker <susan_parker@transcanada.com>, "alanjojohnson@msn.com" <alanjojohnson@msn.com>, Tina Hall <tinahall@donellis-associates.com>, paul kleist <bunde423@hotmail.com>

Hello,

The Sibson's contacted me regarding reclamation on their property, they said it is far too wet to get any major work done for a while however, they wanted to know about weed control. They said that there are weeds starting to grow in the areas that were sprayed last year, they have complained of weeds in the ROW repeatedly and it was one of the issues they raised with Commissioner Johnson on our tour last summer. I do not see it specifically mentioned in the reclamation plan that I have so I said that I would get back with them.

The contractor who did the weed spraying for us last year called me a couple months ago to say he was available and would like to work for the project again if he was needed. I told him that I would let Keystone know and sent out a email but I told him I was not sure what if any weed control Keystone would do this season.

I told Sue Sibson that I would get back with her, they said that a four wheeler such as was used last year could access the areas that are in need of weed control. Please advise,

Regards,

Sarah

On Thu, Dec 2, 2010 at 10:51 AM, Jessica Greven <Jessica.Greven@trow.com> wrote:

Good morning,

This e-mail will serve as documentation for future reference regarding the final seed mixes agreed upon by Sibsons and TCPL for their tract. I will also note this in the punch list.

The attached seed mix and instructions address the Sibsons concerns expressed in the e-mail chain below.

We've agreed that we will re-check with the Sibsons prior to doing the work in 2011 to make sure the seed mixes are still acceptable.

Please give me a call if there are questions or comments regarding the seed mixes or the protocol outlined in the attached document.

Thank you,

Jessica

From: S Medcalf (SD Liaison)
Sent: Friday, November 19, 2010 10:05 AM
To: Jessica Greven
Cc: Susan Parker; alanjojohnson@msn.com; Tina Hall Redirect; paul kleist; inspectormike71@yahoo.com; Cody Yerger

Subject: Re: FW: Updated plan for Sibson

Jessica,

Sibson's have decided that if we disc the grasslands and start over we are ok with leaving the wheatgrass sp. in the mix and I believe we can apply it all to all their grassland areas. If we just disturb the areas of the ROW with contour issues they would like the existing grass stands mowed and over seeded with a mix containing with no wheatgrass as the grasses already seeded are coming in well.

From my observations I would recommend only disturbing the grassland areas with contour issues, as it would be less invasive, then reseed with the proposed mix. I would then over seed the undisturbed areas with a mix containing a some native species but no wheatgrass. That would of course require two seed mixes to be applied, but it would be less overall disturbance. Of course I am not sure of all the logistics but it would be my suggestion. I also agree with your recommendation to increase the seed rates of all species but the wheatgrass, if the contractor discs and re-seeds the entire area, the existing grass stands on the ROW will likely have a seed bank in the soil. The wheatgrasses seeded last season are coming in well and I don't think anyone would have issues with this grassland area if there wasn't such a stark difference in species composition between the existing grassland and the ROW grasses, the percent cover for year one is looks pretty good.

Let me know if I can be of further assistance on this matter.

Regards,

Sarah

On Fri, Nov 19, 2010 at 9:21 AM, Jessica Greven <Jessica.Greven@trow.com> wrote:

Good morning all,

I've spoken with the reclamation specialist and we can increase the seed rate for all seeds in the mix by 20 percent without harm, with the exception of the wheatgrass. I strongly recommend we increase the seed ratios in order to satisfy any lingering doubts/concerns the Sibsons may have. I will move forward with this unless there are objections.

Sarah, we proposed one seed mix to be applied to all non-crop areas on Sibsons. I'm not sure if Sibsons want both wheatgrass species (slender and western) removed from the mix **or** if the Sibsons want a seed mix with the two species of wheatgrass applied on the grassland portions and a mix without the wheatgrasses applied to the native areas. Please get back with Cody and me re: this issue so we can make sure the seed mix or mixes is/are right before we order.

Thank you,

Jessica

From: S Medcalf (SD Liaison)
Sent: Thursday, November 18, 2010 10:06 AM
To: Susan Parker
Cc: alanjojohnson@msn.com; Tina Hall Redirect; paul kleist; inspectormike71@yahoo.com; Jessica Greven
Subject: Re: FW: Updated plan for Sibson

Hello,

I just spoke with Sue Sibson, they are ok with reclamation taking place this season, **AS LONG AS** we are certain to get the work finished before the ground freezes solid or the snow gets deep. They are concerned with the soil moisture level and the change in the plan to wait, but if it is possible to finish this year they will allow access. They also do not want us to come in and rush through the work they want it to be done correctly. Mrs. Sibson is available today to work with us on a change order to get an access route established to the ROW. She said to have the crew call her cell phone 605-770-2647 and she would meet with them before they enter the property. They are also ok with the seed mixture if the grassland areas are disced first and re-planted, they thought the seed rates were a little low in general compared to the recommendations they had from the grassland study. If we over seed the native areas they would like to have the wheat grass species removed from the mixture. Please let me know if you need anything further and keep me advise as to the schedule on their property.

Regards,

Sarah

On Thu, Nov 18, 2010 at 8:16 AM, Sarah Metcalf <smetcalf12@gmail.com> wrote:

I forwarded the attached revised plan from Alan to the Sibson's last night. They are currently reviewing and said they would get back to me about allowing access this morning. During our conversation last night they did ask why the recommendation to work now changed from the meeting. I asked them to review the plan and explained that if there were areas that were still to wet to work we could address them on site with the contractor, but over all a lot of work that could take place this fall and would get them ahead in the next season. For example spring snow melt will not be held in low spots if they are addressed now. I will update as soon as I hear back from them. Please let me know if I can be of further assistance in this matter.

Regards,

Sarah

On Wed, Nov 17, 2010 at 3:02 PM, Susan Parker <susan_parker@transcanada.com> wrote:

Sarah,

fyi

Susan Parker, P.Eng

Keystone Pipeline Project

(403) 920-6957 phone

(403) 463-3892 bb

susan_parker@transcanada.com

From: Susan Parker
Sent: Wednesday, November 17, 2010 1:46 PM
To: 'alanjojohnson@msn.com'
Subject: FW: Updated plan for Sibson

Hi Allan,

Just a couple of questions

Item 1 & Item 3 filled in -- (presumably topsoil) -- from where and who pays?

Item 6 - submit a minor change order – to whom?

Susan Parker, P.Eng

Keystone Pipeline Project

(403) 920-6957 phone

(403) 463-3892 bb

susan_parker@transcanada.com

From: Alan Johnson [mailto:alanjojohnson@msn.com]
Sent: Wednesday, November 17, 2010 9:28 AM
To: Mike Stewart
Cc: Bob Smith; Susan Parker; Jessica Greven
Subject: Fw: Updated plan for Sibson

Mike; I made some changes, does this sound reasonable?

Susan, Jessica, any comments?

Allan "TC" Johnson
Construction Manager
Keystone Phase 1
Troy Office 636-528-4912
Blackberry 218-398-0010
Cell Phone 218-244-0802
E-mail: alanjojohnson@msn.com

From: Mike Stewart

Sent: Wednesday, November 17, 2010 7:49 AM

To: alan

Cc: Bob

Subject: Updated plan for Sibson

Alan, here is an updated plan as we discussed. If there is anything else I need to change or add just let me know. Thanks

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--
Sarah Metcalf
South Dakota Liaison Officer
Keystone Pipeline
110 3rd Street SW, Ste. #104
Huron, SD 57350
1-888-375-1370
(605) 228-4736 cell
SDLiaison@keystone.trow.com

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for Keystone Pipeline (Phases 1 and 4)
PO Box 912
Aberdeen SD 57402

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PO Box 912
Aberdeen SD 57402
1-888-375-1370

Felicia Webb

ML-SD-MN-0795.0000
ML-SD-MN-0796.0000

From: TINA HALL [tinahall@donellis-associates.com]
Sent: Thursday, December 02, 2010 11:36 AM
To: 'Felicia Webb'
Subject: FW: FW: Updated plan for Sibson

Please put a copy of this message and the attachment in the tract files.

From: Jessica Greven [mailto:Jessica.Greven@trow.com]
Sent: Thursday, December 02, 2010 10:51 AM
To: Susan Parker
Cc: alanjojohnson@msn.com; Tina Hall Redirect; S Medcalf (SD Liaison)
Subject: RE: FW: Updated plan for Sibson

Good morning,

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The attached seed mix and instructions address the Sibsons concerns expressed in the e-mail chain below.

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To: Jessica Greven
Cc: Susan Parker; alanjojohnson@msn.com; Tina Hall Redirect; paul kleist; Inspectormike71@yahoo.com; Cody Yerger
Subject: Re: FW: Updated plan for Sibson

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Subject: Re: FW: Updated plan for Sibson

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Sarah,
fyi
Susan Parker, P.Eng
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(403) 920-6957 phone
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Item 6 - submit a minor change order – to whom?

Susan Parker, P.Eng
Keystone Pipeline Project
(403) 920-6957 phone
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susan_parker@transcanada.com

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Cc: Bob Smith; Susan Parker; Jessica Greven
Subject: Fw: Updated plan for Sibson

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Susan, Jessica, any comments?

Allan "TC" Johnson
Construction Manager
Keystone Phase 1

Troy Office 636-528-4912
Blackberry 218-398-0010
Cell Phone 218-244-0802
E-mail: alanjojohnson@msn.com

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To: alan
Cc: Bob
Subject: Updated plan for Sibson

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--
Sarah Metcalf
South Dakota Liaison Officer
Keystone Pipeline

NOTE

Apply the grassland mix to grassland areas that are disced under for contour repairs.
For undisturbed grassland areas, apply the native grass mix.
Overseed the native grass areas with the native grass mix.

GRASSLAND MIX

SCIENTIFIC NAME	COMMON NAME	VARIETY	SEEDING RATE Pounds PLS/Acre		PLS/ sq.ft.	TOTAL ACRES	TOTAL PLS POUNDS
	Northern Mixed Grass Prairie (NMG)						
Agropyron smithii	Western wheatgrass	Rodan, Walsh, Rosana	1.00	/	3		
Agropyron trachycaulum	Slender wheatgrass	Adanac, Pryor, Revenue	1.00	/	4		
Bouteloua curtipendula	Sideoats grama	Killdeer, Pierre, Butte	2.50	/	11		
Bouteloua gracilis	Blue grama	Bad River	0.75	/	14		
Andropogon gerardii	Big bluestem	Sunnyview, Bison, Bonilla	2.00	/	6		
Schizachyrium scoparium	Little bluestem	Badlands, Itasca, Taylor	1.25	/	7		
Stipa comata	Needle-and-thread	Common	1.25	/	3		
Stipa viridula	Green needlegrass	Lodorm, AC Mallard	3.50	/	15		
			13.25		**63**		

NATIVE GRASS MIX

SCIENTIFIC NAME	COMMON NAME	VARIETY	SEEDING RATE Pounds PLS/Acre		PLS/ sq.ft.	TOTAL ACRES	TOTAL PLS POUNDS
	Northern Mixed Grass Prairie (NMG)						
Bouteloua curtipendula	Sideoats grama	Killdeer, Pierre, Butte	2.50	/	11		
Bouteloua gracilis	Blue grama	Bad River	0.75	/	14		
Andropogon gerardii	Big bluestem	Sunnyview, Bison, Bonilla	2.00	/	6		
Schizachyrium scoparium	Little bluestem	Badlands, Itasca, Taylor	1.25	/	7		
Stipa comata	Needle-and-thread	Common	1.25	/	3		
Stipa viridula	Green needlegrass	Lodorm, AC Mallard	3.50	/	15		
			11.25		**56**		

Keystone Pipeline Project

Contact Summary Report

ML-SD-MN-0796.0000

Tract No. ML-SD-MN-0795.0000 **Directly Affected** X **Adjacent** _____

Legal Description S2SW4 - **SEC.** 28 & all sec 33 - **TWP.** T-106-N - **RGE.** R-57-W

Additional Legal Information: Miner County, SD

Landowner(s): Michael B & Susan K Sibson

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Telephone: Home :(605) 772-5184 Business : 605-770-2800

Tenant(s): N/A

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

11-04-2010 I met with Mike and Sue Sibson, Michael Steware, Jack Kemp, and Sarah Metcalf at the Sibson Farm. We looked at issues on ROW and Michael was to draw up a plan with Jack and submit to Sarah who will submit to the Sibsons

Eric Munz
Land Representative

11-04-2010
Date

Keystone Pipeline Project

Contact Summary Report

Tract No.ML-SD-MN-0795.0000 **Directly Affected __X___ Adjacent _____**

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Telephone: Home :(605) 772-5184 Business :(605) 770-2800

Tenant(s): NA

Address: City/Town:

County: Township: State: S.D. Zip Code:

Telephone: Home :(605) Business :(605)

Contact Summary: On 7-19-10 I met with Mike and Sue Sibson. I delivered the Settlement agreement to the Sibsons and they signed it and I wrote them a check. The Sibson's had a few questions and I answered them or referred them to Sarah Metcalf. This issue is settled per John Hunt's agreement with the Sibson's.

Land Representative

7-19-10
Date

Keystone Pipeline Project

Contact Summary Report

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Tenant(s): NA

Address: _____ City/Town: _____

County: _____ Township: _____ State: S.D. Zip Code: _____

Telephone: Home :(605) _____ Business :(605) _____

Contact Summary: On 7-15-10 I was asked by John Hunt to contact Sue Sibson to set up a time for them to sign the Settlement Agreement and Release. I called Sue and got no answer.
Sue then sent me an e-mail asking if I could meet her today at 4pm. I replied back stating I would be traveling to North Dakota and asked if we could meet Monday July 19th at 12 noon. Sue responded back stating that would work just fine.

Paul Hunt

Land Representative

7-15-10

Date

ML-SD-MN-0795.0000
ML-SD-MN-0796.0000

Sue Otis

From: TINA HALL [tinahall@donellis-associates.com]
Sent: Friday, July 23, 2010 8:05 AM
To: 'Sue Otis'; 'Tammy Smoot'
Subject: FW: Fwd: Fw: Invitation

This e-mail and the photos need to go in the Sibson file. They are a SD tract.

From: Sarah Metcalf [mailto:smetcalf12@gmail.com]
Sent: Thursday, July 22, 2010 4:01 PM
To: Nicole Aitken
Cc: Michael Schmaltz; Jessica.Greven@trow.com; Susan Parker; jrauh@neilpalmerllc.com; Richard Prior; Brett@magt.com; John Hunt; Tina Hall; Don Ellis
Subject: Re: Fwd: Fw: Invitation

FYI

Here are photos from the Sibson ROW tour, sorry for the delay I had some computer difficulties. Please let me know if anyone has any further questions on this tract.

The major concerns I got from the commissioner had to do with native grassland, specifically seed species matching and the time it takes native grasses to recover. He also brought up Keystones ability to maintain quality control between it's contractors, when it comes to clean up and reclamation. He noted to attention to detail the company showed with the quality control related to material and construction work. He also noted the discrepancy in the number of complaints recieve at the PUC between the spreads in the state. Most of which related some how to clean up/reclamation issues and wondered if there was a way to make sure "lessons learned" are carried forward to the next phase of the project.

I will send a follow up email to the Commissioner and inquire as to if he has any specific questions related to the tour that he would like further information from us on. Again let me know if you have any questions or comments.

Regards,

Sarah

On Thu, Jul 15, 2010 at 8:15 AM, Sarah Metcalf <smetcalf12@gmail.com> wrote:
Hello,
I toured the Sibson ROW yesterday with Commissioner Johnson, overall I thought that it went well, but may have some fall out concerning the Phase 4 project. The Sibson's brought up a number of issues they had with the project and eminent domain the Commissioner was very diplomatic in his responses at the same time remaining overall supportive of the project in general.

They detailed some of the hardships they felt they have suffered during the process from the trespass early in the project, trash left on the ROW this winter, as well as the reclamation issues they have now. On the ROW the weed were sprayed on Friday but were just starting to dye off yesterday. The grasses

have started to grow better and there was pretty good cover, I saw two species or wheat grass and a few smooth brome grass trying to come in. Unfortunately, the Commissioner was very concerned that the grass species seeded on the Sibson property are not similar at all to the grasses that were originally growing on the pasture land. I explained that the unless a specific seed mix was identified by the Landowner a standard mix was used as recommended by the env experts on the project. Sibson's said the had asked for the "county mix" used on CRP native grasses, I do not have a copy of their construction agreement to verify what they requested. The copy of the seed tag they have from the contractor shows the wheat grasses, brome and alfalfa were seeded, in their native pasture and over their alfalfa pasture which again the Commissioner asked why pure alfalfa wasn't seeded in this area. I couldn't answer but Sibson's said they would follow up with me as to what they want done on that section of land.

We saw two crop land tracts corn and soy beans, the Commissioner seemed very impressed to see that the crop land showed no sign of change as you went from ROW to adjacent land. There were some areas over center line that have some settling and long cracks, that are according to Sue 10-21 inches deep. The Commissioner asked if that was usually just a first year post construction issue and I said that it was, and that some subsidence and settling occurs just as it would with any excavation and back fill. I explained the tracking list that is maintained for the contractors so that these reclamation issues get addressed as they are identified by landowners, EI's or the areal monitoring.

He did have some concerns with the edges of the ROW, which on Sibson's land (and several other tracts I have been to) drop off at the edge and were not feather back into the adjacent land as well as it could have been. He kept commenting that it really was a big difference in how much more the grassland is impacted by construction than cropland. And how it was obvious that the farmer could work his crop land back to the original contours where as with the grassland he was stuck with the rough areas. He wanted to know that if it wouldn't be better to say that grassland would take 5 yrs to recover to better manage expectations of landowners. He also asked about what kind of quality control there was between the way each contractor operated.

We also looked at a wetland area and he wanted to know if it wouldn't be better to use just the trench line stripping on the grassland tracts as is done in wetlands. I explained that it can be a very site specific decision and in some places trench stripping is the best management practice and in others full ROW is best. Not stripping topsoil will allow native grasses to come back faster from the root zone, but the stripped topsoil will still contain a seed bank and by not stripping you get issues with compaction and the risk of mixing soils during the construction process.

Overall, I thought the tour was pretty good. I do think that the state of Sibson's grassland areas have the Commissioner concerned about Phase 4 due to the fact that the majority of that land on that project is native grassland. He also said that he hoped that "Lessons Learned" on Phase 1 would be carried over to Phase 4 and improve the process for those landowners. Please let me know if anyone would like further detail on this meeting. I will send some photos of the Sibson's ROW when I have them downloaded, as there were some reclamation issues that still need to be addressed.

Regards,

Sarah

On Mon, Jul 12, 2010 at 8:08 AM, Sarah Metcalf <smetcalf12@gmail.com> wrote:

FYI- I am scheduled to meet with Sibson's and Commissioner Johnson at 1:30pm Wed July 14th. The Sibson property has been sprayed for weeds and the need for grass seed will be assessed later in the season when the window for seeding is open again. I will report on the out come of the meeting.

Regards,

Sarah

On Fri, Jun 25, 2010 at 12:42 PM, Nicole Aitken <nicole_aitken@transcanada.com> wrote:
I would suggest we take a look at landowners immediately adjacent to the Sibsons also as Dusty will likely be looking to see if this is a "one of" or if all landowners are experiencing the same type of condition...

N.

From: Michael Schmaltz
Sent: Friday, June 25, 2010 9:04 AM
To: 'Jessica.Greven@trow.com'; Susan Parker
Cc: 'jrauh@neilpalmerllc.com'; Nicole Aitken; Richard Prior; 'Brett@magt.com'; 'smetcalf12@gmail.com'; John Hunt
Subject: Re: Fwd: Fw: Invitation

Suggest employing the same resolution I sent this morning as suggested on the Glanzer property.
Perhaps Land could call today and see if the landowner is interested in addressing (mow or spray) immediately. If not we will need to get Operations weed spraying contractor notified immediately.

From: Sarah Metcalf <smetcalf12@gmail.com>
To: John Hunt
Cc: Jeff Rauh <jrauh@neilpalmerllc.com>; Michael Schmaltz; Susan Parker; Nicole Aitken; Richard Prior; Brett Koenecke <Brett@magt.com>
Sent: Fri Jun 25 08:43:07 2010
Subject: Fwd: Fw: Invitation

Pease forward to whom ever may need to know but I suggest we make a plan to take address the weed problem on the property. Their ROW is full of weeds, no noxious that I saw but when compared to the adjacent land the ROW looks terrible. I would be happy to attend the meeting but I won't have many good explanations as too why the Sibson's grassland is so poorly restored. I beleive that the weeds need to be controlled with spray or mowing, and there are some areas should be over seeded. Please advise.

Sarah

---------- Forwarded message ----------
From: <Dustin.Johnson@state.sd.us>
Date: Fri, Jun 25, 2010 at 9:27 AM
Subject: Fw: Invitation
To: smetcalf12@gmail.com, Kara.Semmler@state.sd.us, Deb.Gregg@state.sd.us

Sarah,

Want to come?

Dusty

From: Sue Sibson <suesibson@alliancewildblue.com>
To: Johnson, Dustin (PUC)
Sent: Fri Jun 25 08:33:18 2010
Subject: RE: Invitation

Dear Dusty Johnson:
If you want, Sarah along that is fine. Sarah was already here on June 1 at our request to look at the easement area.
Thanks
Sue and Mike

From: Dustin.Johnson@state.sd.us [mailto:Dustin.Johnson@state.sd.us]
Sent: Thursday, June 24, 2010 3:07 PM
To: suesibson@alliancewildblue.com
Subject: Re: Invitation

Can I have Sarah Metcalf along? If things aren't as they should be, I'd like to be able to ask her right then and there why that is.

Dusty

From: Sue Sibson <suesibson@alliancewildblue.com>
To: Johnson, Dustin (PUC)
Sent: Wed Jun 23 09:39:46 2010
Subject: RE: Invitation

Good Morning Dusty:

July 14 will work for us. You can let us know what time when the day gets closer.
Thanks
Sue and Mike

From: Dustin.Johnson@state.sd.us [mailto:Dustin.Johnson@state.sd.us]
Sent: Tuesday, June 22, 2010 4:52 PM
To: suesibson@alliancewildblue.com
Subject: Re: Invitation

Wednesday, July 14?

From: Sue Sibson <suesibson@alliancewildblue.com>
To: Johnson, Dustin (PUC)
Sent: Tue Jun 22 09:24:52 2010
Subject: Invitation

Hi Dusty Johnson:

We would like to invite you to our farm and give you a tour of the pipeline easement area. TransCanada has been in the media saying they will leave the land in better shape than they found it. We would like you see our land. Please let us know if you are willing to take a tour.

Sincerely,
Mike and Sue Sibson

No virus found in this incoming message.
Checked by AVG - www.avg.com
Version: 9.0.829 / Virus Database: 271.1.1/2955 - Release Date: 06/22/10 01:36:00

No virus found in this incoming message.
Checked by AVG - www.avg.com
Version: 9.0.829 / Virus Database: 271.1.1/2960 - Release Date: 06/24/10 01:35:00

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Sarah Metcalf
South Dakota Liaison Officer
Keystone Pipeline
110 3rd Street SW, Ste. #104
Huron, SD 57350
1-888-375-1370
(605) 228-4736 cell
SDLiaison@keystone.trow.com

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--
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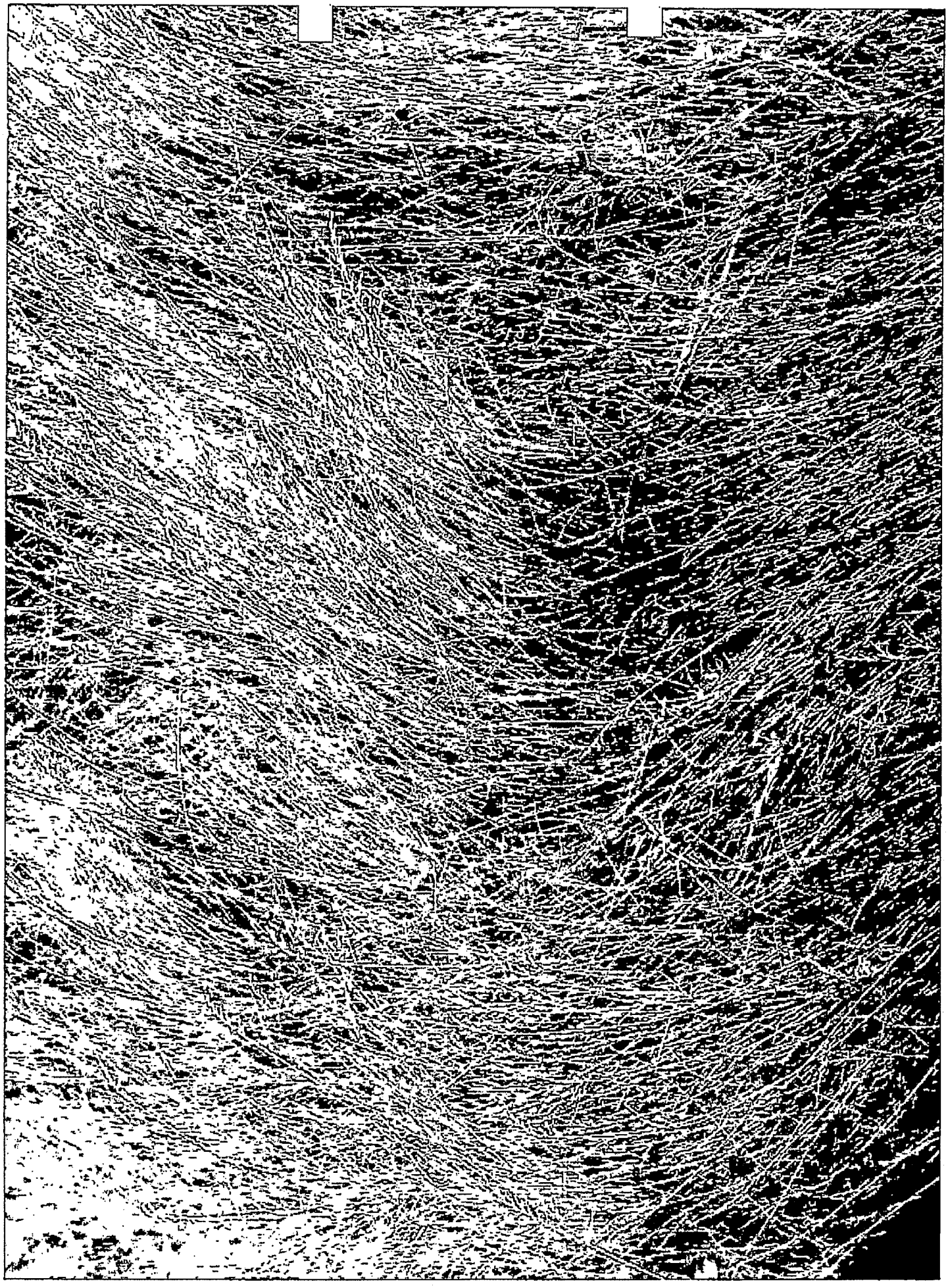

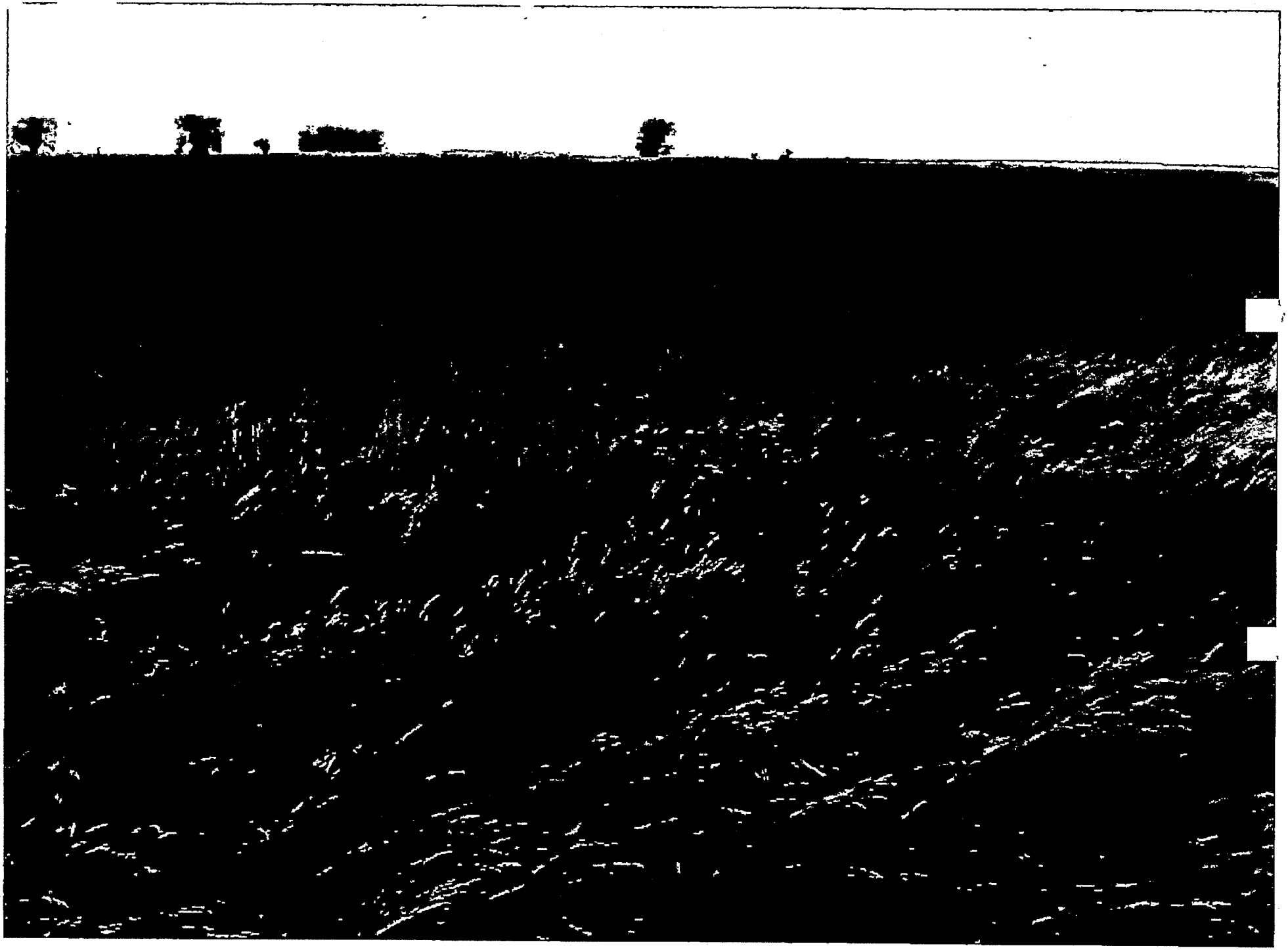

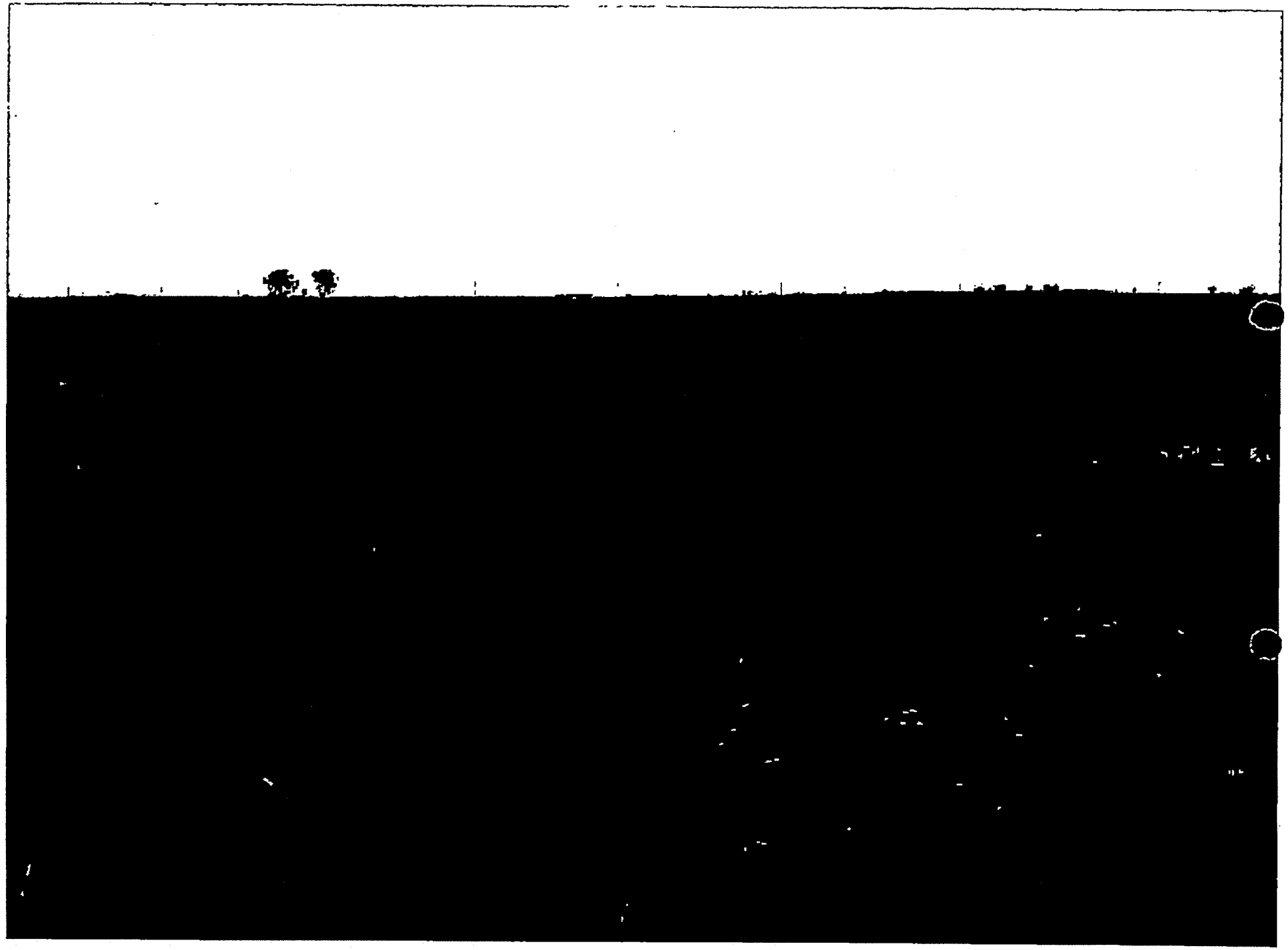

Keystone Pipeline Project

Contact Summary Report

Tract No.ML-SD-MN-0795.0000 **Directly Affected** __X__ **Adjacent** _____

Legal Description ¼ SW - SEC. 28 - TWP. 106N - RGE. 57W

Additional Legal Information: MINER COUNTY S.D.

Landowner(s): MICHAEL B. and SUSAN K. SIBSON

Address: 23782 426TH AVE. City/Town: HOWARD

County: MINER Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business :(605) 770-2800

Tenant(s): NA

Address: _____ City/Town: _____

County: _____ Township: _____ State: S.D. Zip Code: _____

Telephone: Home :(605) _____ Business :(605) _____

Contact Summary: On 10-6-09 I received a call from Sue Sibson asking the status of the rocks that she thinks are buried on their property and that were suppose to be hauled off. I explained to Sue that I sent an e-mail out to the RCS explaining what she had requested and was waiting a response. Sue said that she was not going to let anyone back onto her property to retrieve the rocks. I told Sue that I thought it was still an active construction area and she said Paul you are not going to pull this on us again. I explained that it has been really wet and only specialized crews have worked since Saturday. Sue said, Paul I signed an agreement and you did too requesting the rocks be hauled off. She said the rocks were not hauled off and that is a breach of contract. Sue said "Paul you signed that agreement and I will haul you in". I asked Sue, " You are going to haul me to Jail for what?" Sue then raised her voice and I asked her to calm down and told her there was no reason to raise her voice. She laughed and said I have not raised my voice. I then asked her if she had talked to Mike Brouilette from Michels and she said no she thought she was suppose to talk to me or Sarah first. I said that was correct, but I wanted to make sure that I was not answering something that someone had already answered. Sue said I will just call Mike or Sarah Metcalf and I am done talking with you. I said thank you and hung up.

Paul Kurt

Land Representative

10-6-09

Date

Keystone Pipeline Project

Contact Summary Report

Tract No.ML-SD-MN-0795.0000 **Directly Affected** __X__ **Adjacent** _____

Legal Description ¼ SW - SEC. 28 - TWP. 106N - RGE. 57W

Additional Legal Information: MINER COUNTY S.D.

Landowner(s): MICHAEL B. and SUSAN K. SIBSON

Address: 23782 426TH AVE. City/Town: HOWARD

County: MINER Township: State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business :(605) 770-2800

Tenant(s): NA

Address: City/Town:

County: Township: State: S.D. Zip Code:

Telephone: Home :(605) Business :(605)

Contact Summary: On 10-1-09 I called Sue and Mike and told them that I had e-mailed them the dewatering direction from Steve Craycroft the Environmental Compliance Manager. Sue then went on to say that yesterday she watched Michels bury the rocks on the ROW. She said that they requested the rocks be hauled off. She wanted to know what to do next? I told her I would bring it up at and let the contractor know. She said the ROW was cleaned up and reseeded and the y removed all of the mats. Sue said that for $10,000 the rocks can stay buried.

Paul Kurt

Land Representative

10-1-09

Date

From: Craycroft, Stephen <Stephen.Craycroft@aecom.com>
To: <pkliest@donellis-associates.com>
Subject: FW: Wetland on Sibson Property
Date: Mon, 21 Sep 2009 09:06:29 -0700

ML-SD-MN-0795.0000
ML-SD-MN-0796.0000
COPY

Paul:

Below is a description of the work that will take place to install the pipeline on the Sibson property (tract 0796) at wetland NWI_426261.

The contractor will segregate topsoil over a 15 foot area across the trench line and use the topsoil to construct a soil dike between the timber mats and the open trench line. The trench spoil will be stacked on the spoil side to create a dike along the east side ROW edge. Water collected within the trench line between the topsoil and spoil piles will be pumped across 238th Street onto the landowner immediately south of the roadway. Trench water will be pumped into straw bale and geo-textile straw on the south side of the 238th Street. The contractor will need to temporarily disconnect the buried phone line at station 19005+20 in order to complete the tie-in weld. Once the contractor installs the pipe section concrete weights will be installed and backfill/cleanup will begin. Foam trenchbreakers will be installed at the entry and exit points of the wetland. Cleanup will be completed in two days.

This description of work complies with the Project's permit requirements, including dewatering trench water while installing the pipeline.

Please let me know if you have any additional questions.

Best Regards,

Steve Craycroft

Keystone Project

Environmental Compliance Manager

816-880-4881 ext. 144

970-219-0184 (cell)

Keystone Pipeline Project

Contact Summary Report

ML-SD-MN-0796.0000

Tract No. ML-SD-MN-0795.0000 **Directly Affected** X **Adjacent** _____

Legal Description S2SW4 - SEC. 28 & all sec 33 - TWP. T-106-N - RGE. R-57-W

Additional Legal Information: Miner County, SD

Landowner(s): Michael B & Susan K Sibson

Address: 23782 426th Ave City/Town: Howard

County: _____ Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business : 605-770-2800

Tenant(s): N/A

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

1-23-2009 I met with the Sibsons. They said they want their attorney to review the atws agreement before they sign it. We partially filled out a construction agreement but they want their attorney to review it before they sign it and they will not sign it until they get a few questions answered. They want a permanent fence put up along the West edge of the ROW when construction is done. They will turn that everything East into pasture as they don't want to farm over the pipe. There are a few acres of farm ground that will be cut off by the ROW and want to know if they are going to be compensated for crop loss on it. They want a temporary fence put along the East side of the ROW in 3 areas for their cattle during construction. They will need access across the ROW for their cattle in 2 areas. They want speed limit signs put on the roads surrounding their house. They said they will be watching and they better not see any trash, cigarette butts, or sunflower seeds on their property especially outside the ROW.

I wrote a check for the claim of Michael Sibson and Garry Nutter for extra mileage and labor from the 2008 harvest.

Eric Munz _____ 1-23-2009

Land Representative **Date**

Keystone Pipeline Project

Contact Summary Report

Tract No.ML-SD-MN-0795.0000 **Directly Affected** __X__ **Adjacent** _____

Legal Description ¼ SW - SEC. 28 - TWP. 106N - RGE. 57W

Additional Legal Information: MINER COUNTY S.D.

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County: MINER Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business :(605) 770-2800

Tenant(s): NA

Address: _____ City/Town: _____

County: _____ Township: _____ State: S.D. Zip Code: _____

Telephone: Home :(605) _____ Business :(605) _____

Contact Summary: On 9-10-09 I received a call from Brian Collabella, an EI with AECOM, and he said he received a call from the contractor about pumping water on the Abandoned 237 street that the Sibson's now own. I told him that the Sibson's had said no in the past but wanted to know how much water and where they were going to put it. I asked Brian these questions and he said he would go to the site and find out. Brian called back and said he went to the site and Mike Sibson was there and he told them where they could pump water and gave them permission to pump this bell hole out into a certain location.
I then called Mike Sibson and he confirmed to me that he did giver permission for the contractor to pump this certain bell hole out and to pump into this certain location.

Paul Kurtz
Land Representative

9-10-09
Date

013282

Keystone Pipeline Project

Contact Summary Report

Tract No.ML-SD-MN-0795.0000 **Directly Affected** __X__ **Adjacent** _____

Legal Description ¼ SW - SEC. 28 - TWP. 106N - RGE. 57W

Additional Legal Information: MINER COUNTY S.D.

Landowner(s): MICHAEL B. and SUSAN K. SIBSON

Address: 23782 426TH AVE. City/Town: HOWARD

County: MINER Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business :(605) 770-2800

Tenant(s): NA

Address: _____ City/Town: _____

County: _____ Township: _____ State: S.D. Zip Code: _____

Telephone: Home :(605) _____ Business :(605) _____

Contact Summary: On 9-2-09 I called and talked to Sue and Mike and asked how the Construction was progressing on their property. I received an e-mail from Sue last week stating that they would need to move cattle across the ROW over the weekend and wanted the Contractor informed. I notified Michel's Construction and they stated no activity would be taking place. Sue said everything went very well and were appreciative of the work that has taken place to get the cattle access.
She thanked me for calling and said she would contact me first if any issues came up.

Paul Carl

Land Representative

9-2-09

Date

013283

Keystone Pipeline Project

Contact Summary Report

ML-SD-MN-0796.0000

Tract No. ML-SD-MN-0795.0000 **Directly Affected** X **Adjacent** _____

Legal Description S2SW4 - **SEC.** 28 & all sec 33 - **TWP.** T-106-N - **RGE.** R-57-W

Additional Legal Information: Miner County, SD

Landowner(s): Michael B & Susan K Sibson

Address: 23782 426th Ave City/Town: Howard

County: _____ Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business : 605-770-2800

Tenant(s): N/A

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

6-23-2009 Sue called and said some workers were driving off ROW on her property. She said they drove down the section line and entered a gate where they don't have permission. She said they section line road was closed by the County and she owns it. She said they were putting up the goal posts by the power lines. She also asked for 48 hr notice before anyone enters her property. I told her we gave her notice in April that construction would be starting and they can expect activity anytime after that.

Eric Munz
Land Representative

6-23-2009
Date

Keystone Pipeline Project

Contact Summary Report

ML-SD-MN-0796.0000

Tract No. ML-SD-MN-0795.0000 **Directly Affected** X **Adjacent** _____

Legal Description S2SW4 - **SEC.** 28 & all sec 33 - **TWP.** T-106-N - **RGE.** R-57-W

Additional Legal Information: Miner County, SD

Landowner(s): Michael B & Susan K Sibson

Address: 23782 426th Ave City/Town: Howard

County: _____ Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business : 605-770-2800

Tenant(s): N/A

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

6-03-2009 I called Sue and told her the survey crew was planning on finishing up on their property today. I asked her about the fence estimate. She said her fence people were waiting until the property was staked before they do an estimate. She will mail it to the Huron office when she gets it.

Eric Munz
Land Representative

6-03-2009
Date

6-5

ML-SD-MN-0795.0000
ML-SD-MN-0796.0000
W1/2 Sec. 33 and the SW1/2 Sec. 28, T-106N, R-57W

Mike and Sue Sibson,

Sue about 2 months ago you called my office saying you saw an ad in the paper relating to water lines that could be replaced within 500' of residences. You stated you were unsure if your line fell into the condition of the PUC order but wanted to be on the list. TransCanada has followed up on your request and found that the water line that runs to your house is at least 1000' from the Keystone Pipeline.

I have attached a photo from KingBrook Rural Water that shows the water system near your home. Please note that Keystone Pipeline is further away than 500'.
Please contact me at the information below if you have any further questions.

Sincerely,
Paul Kleist

PAUL KLEIST
Right of Way Supervisor
South Dakota
Keystone Pipeline Project
605-352-1375 Office
605-461-9005 Cell
110 3rd Street SW Suite 104
Huron , SD 57350
"think safe, act safe, be safe, safety is my goal"

From: Charles Stewart <Charles.Stewart@universalensco.com>
To: Jeff Rauh <jrauh@neilpalmerllc.com>, Kerwin Kostad <kkostad@donellis-associates.com>
Cc: Paul Kleist <pkliest@donellis-associates.com>, Denny Needham <dneedham@donellis-associates.com>, Tina Hall <tinahall@donellis-associates.com>, Nate Krommendyk <nate_chelle@dutchmail.com>, Paul Fuhrer <paul_fuhrer@transcanada.com>
Subject: RE: Sue Sibson –Kingbrook Rural Water
Date: Thu, 4 Jun 2009 11:18:21 -0500

ML-SD-MN-0795.0000
ML-SD-MN-0796.0000

Kerwin/Jeff,

Kingbrook sent me their water line service map for the Sibson property on which I plotted the Keystone pipeline from the land plat (See attachment). While the dimensions are not such that you can determine the exact spacing, it is clear that the closest distance between the Sibson water service line and Keystone pipeline is more than 1000 feet, probably between 1200 and 1300 feet. The only way to get the exact spacing would be to pay Kingbrook to dig up the service line and have our surveyors measure the spacing.

Charles E. Stewart

Project Manager

Keystone Pipeline Project

816-880-4881 Office

832-465-5982 Cell

charles.stewart@universalensco.com

From: Jeff Rauh [mailto:jrauh@neilpalmerllc.com]
Sent: Thursday, June 04, 2009 8:09 AM
To: 'Kerwin Kostad'; Charles Stewart
Cc: 'Paul Kleist'; 'Denny Needham'; 'Tina Hall'; 'Nate Krommendyk'; Paul Fuhrer
Subject: RE: Sue Sibson --Kingbrook Rural Water

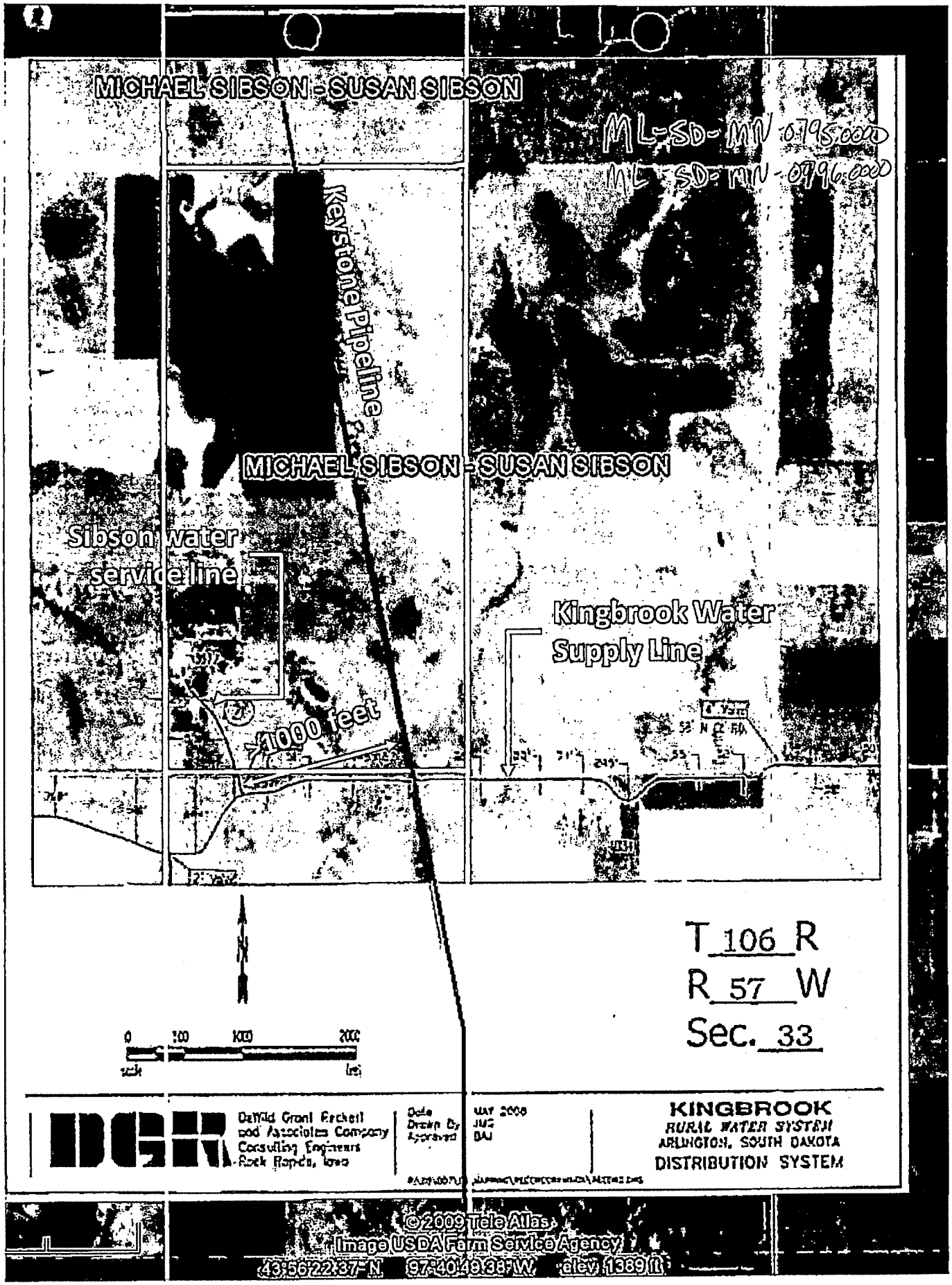
Kerwin –

I believe Charles Stewart has (or had) the action on this item as it relates to Kingbrook. While the PUC Condition does not address required communication with landowners who seek replacement as Sue has done, I presume after our check with Kingbrook is complete, the issue will come back to Land so we can close the loop with Sue to let her know we have addressed her request. (And, given her history with the project, we should make sure our work in response to her request is well documented.)

APPENDIX B

Table 3: Status of implementation of South Dakota PUC conditions

49	At the request of any landowner or public water supply system that offers to provide the necessary access to Keystone over his/her property or easement(s) to perform the necessary work, Keystone shall replace at no cost to such landowner or public water supply system, any polyethylene water piping located within 500 feet of the Project. Keystone shall not be required to replace that portion of any piping that passes through or under a basement wall or other wall of a home or other structure. At least forty-five (45) days prior to commencing construction, Keystone shall publish a notice in at least one newspaper of general circulation in each county through which the Project will be constructed advising landowners and public water supply systems of this condition.


MICHAEL SIBSON - SUSAN SIBSON
ML-SD-MN-0795.000
ML-SD-MN-0796.000
Keystone Pipeline
MICHAEL SIBSON - SUSAN SIBSON
Sibson water service line
1000 feet
Kingbrook Water Supply Line
T 106 R
R 57 W
Sec. 33
0
100
200
DGR
Dewild Grant Reckert and Associates Company
Consulting Engineers
Rock Rapids, Iowa
Date
Drawn By
Approved
MAY 2009
JMG
BAJ
KINGBROOK
RURAL WATER SYSTEM
ARLINGTON, SOUTH DAKOTA
DISTRIBUTION SYSTEM
©2009 Tele Atlas
Image USDA Farm Service Agency
43°56'22.37" N 97°40'49.38" W elev 1389 ft

Keystone Pipeline Project

Contact Summary Report

Tract No.ML-SD-MN-0795.0000 **Directly Affected** __X__ **Adjacent** _____

Legal Description ¼ S2SW4 - SEC. 28 - TWP. 106N - RGE. 57W

Additional Legal Information: MINER COUNTY S.D.

Landowner(s): MICHAEL B. and SUSAN K. SIBSON

Address: 23782 426TH AVE. City/Town: HOWARD

County: MINER Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business :(605) 770-2800

Tenant(s): NA

Address: _____ City/Town: _____

County: _____ Township: _____ State: S.D. Zip Code: _____

Telephone: Home :(605) _____ Business :(605) _____

Contact Summary: On 6-25-09 I received permission from John Hunt to pay the Sibson's for the fence that they have requested. I called the Sibson's and set up an appointment to meet with them at 4pm at their house. I drew up the paperwork and drove to the Sibson's home and met with Michael and Susan. They reviewed the documents and signed them. I wrote the check to Michael B. and Susan K. Sibson in the amount of $21.818.06 for the cost to install and tear down after time the fence.

Pat Hunt
Land Representative

6-25-09
Date

Add Addresses to Contacts | Mark as Junk Mail

View Encoding ...

From: Tina Hall <tinahall@donellis-associates.com>
To: 'Paul Kliest' <pkliest@donellis-associates.com>
Cc: <smetcalf12@gmail.com>
Subject: RE: Re: Sibson Fences ML-SD-MN-0795.0000 and ML-SD-MN-0796.0000
Date: Wed, 24 Jun 2009 11:56:47 -0500

Show Full Message Headers

That's the way I read it = go ahead and get it done

-----Original Message-----
From: Paul Kliest [mailto:pkliest@donellis-associates.com]
Sent: Wednesday, June 24, 2009 10:12 AM
To: tinahall@donellis-associates.com
Cc: smetcalf12@gmail.com
Subject: Fwd: Re: Sibson Fences ML-SD-MN-0795.0000 and ML-SD-MN-0796.0000
Subject: Fwd: Re: Sibson Fences ML-SD-MN-0795.0000 and ML-SD-MN-0796.0000

Tina,
Is this an approval to pay the Fence?
Paul Kleist
ROW Supervisor
Keystone Pipeline Project
South Dakota
605-352-1375 office
605-461-9005 cell
Think safe, act safe, be safe! Safety is my goal

Add Addresses to Contacts | Mark as Junk Mail

From: John Hunt <john_hunt@transcanada.com>
To: <smetcalf12@gmail.com>, <pkliest@donellis-associates.com>
Subject: Re: Sibson Fences ML-SD-MN-0795.0000 and ML-SD-MN-0796.0000
Date: Wed, 24 Jun 2009 08:59:13 -0600

▷ Show Full Message Headers

Let's move forward with them on this basis.

—— Original Message ——
From: Sarah Metcalf <smetcalf12@gmail.com>
To: John Hunt
Sent: Wed Jun 24 06:49:41 2009
Subject: Re: Sibson Fences ML-SD-MN-0795.0000 and ML-SD-MN-0796.0000

It totals, $21,818.06, the bid is for a very good steel and wood post fencing with 12 16-20' steel gates.

On Wed, Jun 24, 2009 at 7:35 AM, John Hunt <john_hunt@transcanada.com> wrote:

> What is the amount Paul? I can't read it on my blackberry.
> Thanks,
> John

Mike and Sue Sibson
23782 426th Ave
Howard SD 57349

Paul Kleist/Right of Way Supervisor South Dakota
Keystone Pipeline
110.3rd St SW
Suite# 104
Huron SD 57350

June 22, 2009

RE: fence estimate for Sibson land

Dear Paul,
Enclosed is a copy of the fence estimate from Heartland Custom Fencing, L.L.C. Please note their payment plan. We would like a decision about our fence request within 7 days or less of this letter.

Thank you.
Sincerely,
Mike and Sue Sibson
Mike and Sue Sibson

Keystone Pipeline Project

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Telephone: Home : _____ Business : _____

5-13-2009 Sue called and left a message for me to call her back on her home phone. I called her and she said she was doing a courtesy call and trying to get along with us by telling us they put cattle in the pasture and to call her before the survey crew stakes so they can make sure the gates are shut and the cows don't bother the survey guys.

Eric Munz
Land Representative

5-13-2009
Date

Keystone Pipeline Project

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4-10-2009 I, Paul Kleist and Sarah Metcalf met with Mike and Sue. They gave us 2 options. Fence where they want or pay them $30,000.00 for loss of income and they will keep their cattle out of the area where the pipeline will go. They believe their yearlings are curious and will get in the way of construction and PETA will go after them for not being responsible farmers and putting their cattle in harms way. Sue said If we don't give them the fence they will bill us for extra security and having to watch their cattle.

Eric Munz
Land Representative

4-10-2009
Date

Keystone Pipeline Project

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Telephone: Home : _____ Business : _____

4-06-2009 Sue called to confirm the meeting with myself, Sarah Metcalf, and Paul Kleist on Fri 4-10-2009 at 1:00 at their place.

Eric Munz
Land Representative

4-06-2009
Date

Keystone Pipeline Project

Contact Summary Report

ML-SD-MN-0796.0000

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1-23-2009 I met with the Sibsons. They said they want their attorney to review the atws agreement before they sign it. We partially filled out a construction agreement but they want their attorney to review it before they sign it and they will not sign it until they get a few questions answered. They want a permanent fence put up along the West edge of the ROW when construction is done. They will turn that everything East into pasture as they don't want to farm over the pipe. There are a few acres of farm ground that will be cut off by the ROW and want to know if they are going to be compensated for crop loss on it. They want a temporary fence put along the East side of the ROW in 3 areas for their cattle during construction. They will need access across the ROW for their cattle in 2 areas. They want speed limit signs put on the roads surrounding their house. They said they will be watching and they better not see any trash, cigarette butts, or sunflower seeds on their property especially outside the ROW.

I wrote a check for the claim of Michael Sibson and Garry Nutter for extra mileage and labor from the 2008 harvest.

Eric Munz _____ 1-23-2009

Land Representative **Date**

Sue called Sara
First time on
10-17-08

October 27, 2008

Gary Nutter
42381 236th St
Howard SD 57349

Mike Sibson
23782 426th Ave
Howard SD 57349

Sarah Metcalf
Keystone Pipeline
110 3rd Street SW
Suite #104
Huron SD 57350

Dear Sarah Metcalf:

Due to the construction of a substation located in Section 1 Perry Township Davison County Mitchell SD, the road (412th Ave) was too rough for loaded farm vehicles and equipment to travel. We had to travel extra miles to get our harvested crops to storage bins. The road was closed for travel during our harvest.
We would like reimbursement for the labor costs (inconvenience) and extra miles traveled for 2008 soybean and corn harvest.

Harvest expense Davison County:

Trucks 36 miles @ $3.00 a load = $108.00

Combine and tractor with gravity wagons 16 miles @ $2.00 a load =$32.00

Pickup 32 miles @.585 = $18.72

Labor 4 hours @ $15.00=$60.00

Total $218.72

Sincerely,
Gary Nutter mike sibson
Gary Nutter and Mike Sibson

Mark Hoffman
605-256-8270
East River Electric

WAPA has 412th Ave
Westinary Power shut down
and it is
still shut down

Keystone Pipeline Project

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Telephone: Home : _____ Business : _____

10-27-2008 I mailed a letter with an explanation of our survey activity on their property and where to find the CMR plan online.

Eric Munz
Land Representative

10-27-2008
Date

Keystone Pipeline 110 3rd Street SW - Suite 104 Huron, SD 57350

October 27, 2008

Michael and Susan Sibson
23782 426th Avenue
Howard SD 57349

Tract #: ML-SD-MN-0795.0000 & ML-SD-MN-0796.0000

T106N-R57W	&	T106N-R57W
28 : S2SW4		33 : W2

Dear Mr. and Mrs. Sibson:

Per your request, the following are findings of survey activity of your property:

Meghan, as I explained on the phone, drove by the property and did not need to survey.

The other information I received was a partial wetland survey about .34 miles on section 33. One wetland was identified. There was no cultural survey on either tract. No cultural resources were identified. No Threatened &Endangered species surveys have been conducted on either tract.

You may find our Construction Mitigation and Reclamation plan online: puc.sd.gov / commission dockets/ hydrocarbonpipeline/ 2007/ HP07-0001 under Exhibit B.

Regards,

Eric Munz
Sr. Land Agent
Keystone Pipeline
605-461-8568
Northernmn2001@yahoo.com

Keystone Pipeline Project

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Tenant(s): N/A

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County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

10-24-2008 Susan called and asked if I had a report yet of surveys on her property. I told her I would get it sent to her soon. She also asked for Sarah Metcalf's phone number. I gave it to her.

Eric Munz
Land Representative

10-24-2008
Date

Keystone Pipeline Project

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9-18-2013 I called Sue and asked her to take a picture of the wheat grass that they don't want on their property. She texted me 2 pics.

9-20-2013 Sue sent a text asking if I figured out what that grass is. I sent a reply stating the environmental and project management people are working on it and I will let her know when I hear more from them.

Eric Munz
Land Representative

9-18-2013
Date

Keystone Pipeline Project

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9-16-2013 Sue sent an e-mail stating Frank Maddox won't give her his report and wants to know what the plan is.

9-17-2013 Sue texted me asking what the plan is. I texted her back saying Frank and TCPL management are working on a plan and I will get it to her when I receive it. She texted back ok thanks.

Eric Munz
Land Representative

9-17-2013
Date

Keystone Pipeline Project

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8-14-2013 Sue texted me and asked when the contractor will be looking at their ROW. I responded that Frank Maddox had indicated it will be sometime after 8-26-2013.

Eric Munz
Land Representative

8-14-2013
Date

Keystone Pipeline Project

Contact Summary Report

ML-SD-MN-0796.0000

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7-11-2013 Sue called and asked what time the weed sprayer was coming. I called her back and said he said it was too windy and will come tomorrow at 6:30 am.

Eric Munz
Land Representative

7-11-2013
Date

Keystone Pipeline Project

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6-25-2013 I called and left a message for Sue. She called back. I asked if they are going to want weed treatments on the ROW. She said she would call me back with an answer.

Eric Munz
Land Representative

6-25-2013
Date

Keystone Pipeline Project

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5-10-2013 Sue sent pics of holes in ROW. I called her and she said she would text me a time to meet with her and Mike.
5-12-2013 Sue texted me and said they can meet 8:30 am tomorrow.
5-13-2013 I met with Jeremy from CRA and the Sibsons. We viewed holes in ROW. Jeremey confirmed they are varmint holes and Mike said he will till over them and call if there is anything TCPL needs to do.

Eric Munz
Land Representative

5-13-2013
Date

Felicia Webb

From: eric munz [northernmn2001@yahoo.com]
Sent: Monday, May 13, 2013 1:58 PM
To: Felicia Webb
Subject: Fw: Sibson 0795 & 0796

Felicia, please print out pics and e-mail and put in the file. Thanks,

Eric Munz
Sr. Land Agent - Keystone Pipeline
605-461-8568
northernmn2001@yahoo.com
----- Forwarded Message -----
From: Frank Maddox <frankmaddox@yahoo.com>
To: Frank Maddox <frankmaddox@yahoo.com>
Cc: eric munz <northernmn2001@yahoo.com>; "joshua_thompson@transcanada.com" <joshua_thompson@transcanada.com>; "heath_morton@transcanada.com" <heath_morton@transcanada.com>; "kdaustin@donellis-associates.com" <kdaustin@donellis-associates.com>; brett ohlsen <oble_1999@yahoo.com>
Sent: Monday, May 13, 2013 9:44 AM
Subject: Re: Sibson 0795 & 0796

Eric and Jeromy met with the Simbsons and confirmed our theory of varmint holes . The Sibson's were pleased with the attention and agreed to disc in the holes with normal farming practice. Good job guys ! No money spent and we will follow up when we get in the area

Sent from my iPhone

On May 12, 2013, at 11:53 AM, Frank Maddox <frankmaddox@yahoo.com> wrote:

> Folks this is our old friends TheSibsons. Yesterday Rob Latiner called Eric asking about them and if he knew them , he of course indicated very well. A few minutes later Sue Sibson called Eric and wanted immediate attention at 8:30 AM tomorrow 5-13-2013 , as they are planting. Eric is on his way back to that appointment and I am sending my survey guy Jreomey up there now . He will locate the pipe, check depth , and confirm these are varmant holes. He will communicate those findings to us and I suggest we authorize Eric to pay the Sibsons up to $1,000 to box blade the holes in and go ahead and plant . If they refuse we will have no choice but to mobilize one of Brett's crews up there at a cost of several thousand $.
>
> This I my field decision on this mothers day sunday , thinking this is our best coarse on short notice to avoid any calls to the Comission which they always do
>
> Yours in service Mother Frank
>
> Sent from my iPhone
>
> On May 11, 2013, at 8:31 AM, eric munz <northernmn2001@yahoo.com> wrote:
>
> > Frank, Sue Sibson sent pics of holes in ROW. These are new issues. Jason had

indicated the walk through will end just below the Sibson Property. Their neighbors have called and said they have issues on 0798.0001 & 0799. Do we want to include these areas as well? I will be happy to accompany Jason and crew if these tracts will be included on the walk through. I'm sure the Sibsons will appreciate some attention sooner than later.

Eric Munz
Sr. Land Agent - Keystone Pipeline
605-461-8
northernmn2001@yahoo.com

<Sibson-1.jpg>

<Sibson-2.jpg>

<Sibson-3.jpg>

Felicia Webb

From: eric munz [northernmn2001@yahoo.com]
Sent: Monday, May 13, 2013 1:58 PM
To: Felicia Webb
Subject: Fw: Sibson 0795 & 0796
Attachments: Sibson-1.jpg; Sibson-2.jpg; Sibson-3.jpg

Eric Munz
Sr. Land Agent - Keystone Pipeline
605-461-8568
northernmn2001@yahoo.com
----- Forwarded Message -----
From: eric munz <northernmn2001@yahoo.com>
To: "frankmaddox@yahoo.com" <frankmaddox@yahoo.com>; "joshua_thompson@transcanada.com" <joshua_thompson@transcanada.com>; "heath_morton@transcanada.com" <heath_morton@transcanada.com>; "kdaustin@donellis-associates.com" <kdaustin@donellis-associates.com>
Sent: Saturday, May 11, 2013 8:31 AM
Subject: Sibson 0795 & 0796

Frank, Sue Sibson sent pics of holes in ROW. These are new issues. Jason had indicated the walk through will end just below the Sibson Property. Their neighbors have called and said they have issues on 0798.0001 & 0799. Do we want to include these areas as well? I will be happy to accompany Jason and crew if these tracts will be included on the walk through. I'm sure the Sibsons will appreciate some attention sooner than later.

Eric Munz
Sr. Land Agent - Keystone Pipeline
605-461-8568
northernmn2001@yahoo.com

Keystone Pipeline Project

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Sue texted me stating the pipeline patrol plane did a much better job of staying over the easememnt area.

Eric Munz
Land Representative

2-20-2012
Date

Keystone Pipeline Project

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11-15-012 I met with Sibsons and wrote a check for crop damages. They said they are very happy with the reclamation but don't want to sign off until the native grass is established.

Eric Munz
Land Representative

11-15-2012
Date

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10-29-2012 Sue called and said they are ready to settle crop yield loss when I am in the area next.

Eric Munz
Land Representative

10-29-2012
Date

013316

Keystone Pipeline Project

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9-29-2012 I met with Mike Sibson, Frank Maddox and Brett Ohlson. We toured the ROW and Mike said he is happy with the work they have done and couldn't find anything else he thinks they should do.

Eric Munz
Land Representative

9-29-2012
Date

Keystone Pipeline Project

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Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

9-14-2012 I called Mike. He said we could meet at 6:00 pm. I met with Mike, Sue, Frank Maddox, Brett Ohlson and crew to view ROW. Crew is devising plan to reclaim.

Eric Munz
Land Representative

7-12-2012
Date

Keystone Pipeline Project

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Tenant(s): N/A

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

7-12-2012 I called and informed Mike of the helicopter flyover next week. He said if the cattle are near the easement area they may get spooked if they think the helicopter is coming at them so to try to avoid flying directly over them. He asked that I let him know what day they will be flying over his property so he can keep an eye on the cattle.

Eric Munz
Land Representative

7-12-2012
Date

Keystone Pipeline Project

Contact Summary Report

ML-SD-MN-0796.0000

Tract No. ML-SD-MN-0795.0000 **Directly Affected** X **Adjacent** _____

Legal Description S2SW4 - **SEC.** 28 & all sec 33 - **TWP.** T-106-N - **RGE.** R-57-W

Additional Legal Information: Miner County, SD

Landowner(s): Michael B & Susan K Sibson

Address: 23782 426th Ave City/Town: Howard

County: _____ Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business : 605-770-2800

Tenant(s): N/A

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

11-11-2011 I met with Sarah Metcalf and the Sibsons. I wrote a check for crop loss for this year and pasture loss for 3 years.

Eric Munz
Land Representative

11-11-2011
Date

Keystone Pipeline Project

Contact Summary Report

Tract No.ML-SD-MN-0796.0000 **Directly Affected** __X__ **Adjacent** _____

Legal Description ¼ W1/2 - SEC. 33 - TWP. 106N - RGE. 57W

Additional Legal Information: MINER COUNTY S.D.

Landowner(s): MICHAEL B. and SUSAN K. SIBSON

Address: 23782 426TH AVE. City/Town: HOWARD

County: MINER Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business :(605) 770-2800

Tenant(s): NA

Address: _____ City/Town: _____

County: _____ Township: _____ State: S.D. Zip Code: _____

Telephone: Home :(605) _____ Business :(605) _____

Contact Summary: On 8-16-11 I met with the Contractor and AC on site and the work was 99% complete. They were hauling out equipment. I then met with Mike and Sue Sibson and they are as satisfied as can be. They told me that the work looks as good as any man could do. They did not want either access road disced or resceded. Mike and Sue both stated that they were satisfied of the work as of now.

Land Representative

8-16-11
Date

[redacted]

[redacted]

Keystone Pipeline Project

Contact Summary Report

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Tenant(s): NA

Address: _____ City/Town: _____

County: _____ Township: _____ State: S.D. Zip Code: _____

Telephone: Home :(605) _____ Business :(605) _____

Contact Summary: On 8-4-11 I met with the Sibson's on site and they said that Sarah had called them about the topsoil being hauled in. The Sibson's stated that they DID NOT WANT TOPSOIL HAULED IN. They said they did not have any topsoil that TCPL could use either. The Sibson's stated that they want the topsoil that is there reworked and that should work.

Paul Kuntz

Land Representative

8-4-11

Date

Keystone Pipeline Project

Contact Summary Report

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County: MINER Township: _____ State: SD Zip Code: 57349

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Tenant(s): NA

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County: _____ Township: _____ State: S.D. Zip Code: _____

Telephone: Home :(605) _____ Business :(605) _____

Contact Summary: On 8-1-11 Sarah Metcalf and I met with the Sibson's and presented them the work plan for their property. The Sibson's agreed to everything on the plan and were pleased that work was going to begin soon.

Paul Kurt

Land Representative

8-1-11

Date

Keystone Pipeline Project

Contact Summary Report

Tract No.ML-SD-MN-0796.0000 **Directly Affected** __X__ **Adjacent** _____

Legal Description ¼ W1/2 - SEC. 33 - TWP. 106N - RGE. 57W

Additional Legal Information: MINER COUNTY S.D.

Landowner(s): MICHAEL B. and SUSAN K. SIBSON

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County: MINER Township: _____ State: SD Zip Code: 57349

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Tenant(s): NA

Address: _____ City/Town: _____

County: _____ Township: _____ State: S.D. Zip Code: _____

Telephone: Home :(605) _____ Business :(605) _____

Contact Summary: On 8-2-11 I met Mike Sibson on the road near the ROW. Mike was glad to see the crew moving in and was glad to see I was on site for a while.

Paul Kurtz
Land Representative

8-2-11
Date

Keystone Pipeline Project

Contact Summary Report

Tract No.ML-SD-MN-0796.0000 **Directly Affected** __X__ **Adjacent** _____

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Telephone: Home :(605) 772-5184 Business :(605) 770-2800

Tenant(s): NA

Address: City/Town:

County: Township: State: S.D. Zip Code:

Telephone: Home :(605) Business :(605)

Contact Summary: On 7-28-11 I met with Mike and Sue Sibson, Sarah Metcalf and the Contractor on the Sibson property. The Sibson's showed the contractor the area and the water and the Fences. The contractor said they would begin actual dirt work on Monday 8-1-11 weather permitting and would possibly sweep the area this weekend.

Paul Kurt

Land Representative

7-28-11

Date

Keystone Pipeline Proje

Contact Summary Report

ML-SD-MN-0796.0000

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Legal Description S2SW4 - SEC. 28 & all sec 33 - TWP. T-106-N - RGE. R-57-W

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Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

7-05-2011 I spoke with Mike Sibson today. I called him to notify the weed sprayer was going to be here in the next few days. Mike said that sweet clover has come in and the weeds aren't as bad as they were when I was there last year. He said it's still wet in some areas and rough and may be difficult for the weed sprayer to get to some areas. He would rather they wait to address weeds when the reclamation crew comes in when it dries out.

Eric Munz
Land Representative

7-05-2011
Date

ML-SP-MN-0795.0000
& 0796.0000

TINA HALL Sibsons

From: Sarah Metcalf [smetcalf12@gmail.com]
Sent: Friday, May 20, 2011 11:26 AM
To: Jessica Greven
Cc: Susan Parker; alanjojohnson@msn.com; Tina Hall; Paul Kliest
Subject: Re: FW: Updated plan for Sibson

Thanks Jessica,

I think it is a little early to actually spray but not by much. Last week Sue said a four wheeler could access the ROW but we have had a significant amount of rain again, so I would suspect that we will need to wait for another dry stretch. I would think the weeds should be treated in the next month or so, as plants are up starting to grow now. Sometime in mid June perhaps, and that would also give a window between treatment and seeding, which I doubt we can do until later when it dry's enough to work the soil. Last year we sprayed too late and plants were already beginning to seed when they were sprayed, so the treatment was not as effective as it should have been (likely I will hear from the other SD tracts we treated at some point as well). Keep me posted and I will advise the Sibson's as things progress.

Regards,

Sarah

On Fri, May 20, 2011 at 10:55 AM, Jessica Greven <jessica_greven@transcanada.com> wrote:

Thanks for the update Sarah. I will give a call to Operations – I believe the plan is to use their sub-contractors, rather than the person we used last year. I have a call with Bob Baumgartner in about 10 minutes and will discuss it with him then. Are the weeds in a state to be treated now, or is it too early? Is it too wet for a 4-wheeler to safely traverse their land? We will need to discuss the weed control and subsequent re-seeding planned for the Sibson's property with the applicator to ensure there isn't a contraindication/interaction. I'll let you know what I find out.

Thank you,

Jessica Greven

Keystone Pipeline Project

2700 South Post Oak Blvd.

Suite 400, Galleria Tower 1

Houston, TX 77056

T: 713.693.6495

C: 281.620.8658

jessica_greven@transcanada.com

Please consider the environment before printing this e-mail.

---------- Forwarded message ----------

From: **Sarah Metcalf** <smetcalf12@gmail.com>
Date: Fri, May 20, 2011 at 10:04 AM
Subject: Re: FW: Updated plan for Sibson
To: Jessica Greven <Jessica.Greven@trow.com>
Cc: Susan Parker <susan_parker@transcanada.com>, "alanjojohnson@msn.com" <alanjojohnson@msn.com>, Tina Hall <tinahall@donellis-associates.com>, paul kleist <bunde423@hotmail.com>

Hello,

The Sibson's contacted me regarding reclamation on their property, they said it is far too wet to get any major work done for a while however, they wanted to know about weed control. They said that there are weeds starting to grow in the areas that were sprayed last year, they have complained of weeds in the ROW repeatedly and it was one of the issues they raised with Commissioner Johnson on our tour last summer. I do not see it specifically mentioned in the reclamation plan that I have so I said that I would get back with them.

The contractor who did the weed spraying for us last year called me a couple months ago to say he was available and would like to work for the project again if he was needed. I told him that I would let Keystone know and sent out a email but I told him I was not sure what if any weed control Keystone would do this season.

I told Sue Sibson that I would get back with her, they said that a four wheeler such as was used last year could access the areas that are in need of weed control. Please advise,

Regards,

Sarah

On Thu, Dec 2, 2010 at 10:51 AM, Jessica Greven <Jessica.Greven@trow.com> wrote:

Good morning,

This e-mail will serve as documentation for future reference regarding the final seed mixes agreed upon by Sibsons and TCPL for their tract. I will also note this in the punch list.

The attached seed mix and instructions address the Sibsons concerns expressed in the e-mail chain below.

We've agreed that we will re-check with the Sibsons prior to doing the work in 2011 to make sure the seed mixes are still acceptable.

Please give me a call if there are questions or comments regarding the seed mixes or the protocol outlined in the attached document.

Thank you,

Jessica

From: S Medcalf (SD Liaison)
Sent: Friday, November 19, 2010 10:05 AM
To: Jessica Greven
Cc: Susan Parker; alanjojohnson@msn.com; Tina Hall Redirect; paul kleist; inspectormike71@yahoo.com; Cody Yerger

Subject: Re: FW: Updated plan for Sibson

Jessica,

Sibson's have decided that if we disc the grasslands and start over we are ok with leaving the wheatgrass sp. in the mix and I believe we can apply it all to all their grassland areas. If we just disturb the areas of the ROW with contour issues they would like the existing grass stands mowed and over seeded with a mix containing with no wheatgrass as the grasses already seeded are coming in well.

From my observations I would recommend only disturbing the grassland areas with contour issues, as it would be less invasive, then reseed with the proposed mix. I would then over seed the undisturbed areas with a mix containing a some native species but no wheatgrass. That would of course require two seed mixes to be applied, but it would be less overall disturbance. Of course I am not sure of all the logistics but it would be my suggestion. I also agree with your recommendation to increase the seed rates of all species but the wheatgrass, if the contractor discs and re-seeds the entire area, the existing grass stands on the ROW will likely have a seed bank in the soil. The wheatgrasses seeded last season are coming in well and I don't think anyone would have issues with this grassland area if there wasn't such a stark difference in species composition between the existing grassland and the ROW grasses, the percent cover for year one is looks pretty good.

Let me know if I can be of further assistance on this matter.

Regards,

Sarah

On Fri, Nov 19, 2010 at 9:21 AM, Je[illegible]a Greven <Jessica.Greven@trow.com> wrote:

Good morning all,

I've spoken with the reclamation specialist and we can increase the seed rate for all seeds in the mix by 20 percent without harm, with the exception of the wheatgrass. I strongly recommend we increase the seed ratios in order to satisfy any lingering doubts/concerns the Sibsons may have. I will move forward with this unless there are objections.

Sarah, we proposed one seed mix to be applied to all non-crop areas on Sibsons. I'm not sure if Sibsons want both wheatgrass species (slender and western) removed from the mix **or** if the Sibsons want a seed mix with the two species of wheatgrass applied on the grassland portions and a mix without the wheatgrasses applied to the native areas. Please get back with Cody and me re: this issue so we can make sure the seed mix or mixes is/are right before we order.

Thank you,

Jessica

From: S Medcalf (SD Liaison)
Sent: Thursday, November 18, 2010 10:06 AM
To: Susan Parker
Cc: alanjojohnson@msn.com; Tina Hall Redirect; paul kleist; inspectormike71@yahoo.com; Jessica Greven
Subject: Re: FW: Updated plan for Sibson

Hello,

I just spoke with Sue Sibson, they are ok with reclamation taking place this season, **AS LONG AS** we are certain to get the work finished before the ground freezes solid or the snow gets deep. They are concerned with the soil moisture level and the change in the plan to wait, but if it is possible to finish this year they will allow access. They also do not want us to come in and rush through the work they want it to be done correctly. Mrs. Sibson is available today to work with us on a change order to get an access route established to the ROW. She said to have the crew call her cell phone 605-770-2647 and she would meet with them before they enter the property. They are also ok with the seed mixture if the grassland areas are disced first and re-planted, they thought the seed rates were a little low in general compared to the recommendations they had from the grassland study. If we over seed the native areas they would like to have the wheat grass species removed from the mixture. Please let me know if you need anything further and keep me advise as to the schedule on their property.

Regards,

Sarah

On Thu, Nov 18, 2010 at 8:16 AM, Sarah Metcalf <smetcalf12@gmail.com> wrote:

I forwarded the attached revised plan from Alan to the Sibson's last night. They are currently reviewing and said they would get back to me about allowing access this morning. During our conversation last night they did ask why the recommendation to work now changed from the meeting. I asked them to review the plan and explained that if there were areas that were still to wet to work we could address them on site with the contractor, but over all a lot of work that could take place this fall and would get them ahead in the next season. For example spring snow melt will not be held in low spots if they are addressed now. I will update as soon as I hear back from them. Please let me know if I can be of further assistance in this matter.

Regards,

Sarah

On Wed, Nov 17, 2010 at 3:02 PM, Susan Parker <susan_parker@transcanada.com> wrote:

Sarah,

fyi

Susan Parker, P.Eng

Keystone Pipeline Project

(403) 920-6957 phone

(403) 463-3892 bb

susan_parker@transcanada.com

From: Susan Parker
Sent: Wednesday, November 17, 2010 1:46 PM
To: 'alanjojohnson@msn.com'
Subject: FW: Updated plan for Sibson

Hi Allan,

Just a couple of questions

Item 1 & Item 3 filled in -- (presumably topsoil) -- from where and who pays?

Item 6 - submit a minor change order – to whom?

Susan Parker, P.Eng

Keystone Pipeline Project

(403) 920-6957 phone

(403) 463-3892 bb

susan_parker@transcanada.com

From: Alan Johnson [mailto:alanjojohnson@msn.com]
Sent: Wednesday, November 17, 2010 9:28 AM
To: Mike Stewart
Cc: Bob Smith; Susan Parker; Jessica Greven
Subject: Fw: Updated plan for Sibson

Mike; I made some changes, does this sound reasonable?

Susan, Jessica, any comments?

Allan "TC" Johnson
Construction Manager
Keystone Phase 1
Troy Office 636-528-4912
Blackberry 218-398-0010
Cell Phone 218-244-0802
E-mail: alanjojohnson@msn.com

From: Mike Stewart

Sent: Wednesday, November 17, 2010 7:49 AM

To: alan

Cc: Bob

Subject: Updated plan for Sibson

Alan, here is an updated plan as we discussed. If there is anything else I need to change or add just let me know. Thanks

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--
Sarah Metcalf
South Dakota Liaison Officer
Keystone Pipeline
110 3rd Street SW, Ste. #104
Huron, SD 57350
1-888-375-1370
(605) 228-4736 cell
SDLiaison@keystone.trow.com

--
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for Keystone Pipeline (Phases 1 and 4)
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Felicia Webb

ML-SD-MN-0795.0000
ML-SD-MN-0796.0000

From: TINA HALL [tinahall@donellis-associates.com]
Sent: Thursday, December 02, 2010 11:36 AM
To: 'Felicia Webb'
Subject: FW: FW: Updated plan for Sibson

Please put a copy of this message and the attachment in the tract files.

From: Jessica Greven [mailto:Jessica.Greven@trow.com]
Sent: Thursday, December 02, 2010 10:51 AM
To: Susan Parker
Cc: alanjojohnson@msn.com; Tina Hall Redirect; S Medcalf (SD Liaison)
Subject: RE: FW: Updated plan for Sibson

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fyi
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(403) 920-6957 phone
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Allan "TC" Johnson
Construction Manager
Keystone Phase 1

Troy Office 636-528-4912
Blackberry 218-398-0010
Cell Phone 218-244-0802
E-mail: alanjojohnson@msn.com

From: Mike Stewart
Sent: Wednesday, November 17, 2010 7:49 AM
To: alan
Cc: Bob
Subject: Updated plan for Sibson

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SDLiaison@keystone.trow.com

NOTE
Apply the grassland mix to grassland areas that are disced under for contour repairs.
For undisturbed grassland areas, apply the native grass mix.
Overseed the native grass areas with the native grass mix.

GRASSLAND MIX

SCIENTIFIC NAME	COMMON NAME	VARIETY	SEEDING RATE Pounds PLS/Acre		PLS/ sq.ft.	TOTAL ACRES	TOTAL PLS POUNDS
	Northern Mixed Grass Prairie (NMG)						
Agropyron smithii	Western wheatgrass	Rodan, Walsh, Rosana	1.00	/	3		
Agropyron trachycaulum	Slender wheatgrass	Adanac, Pryor, Revenue	1.00	/	4		
Bouteloua curtipendula	Sideoats grama	Killdeer, Pierre, Butte	2.50	/	11		
Bouteloua gracilis	Blue grama	Bad River	0.75	/	14		
Andropogon gerardii	Big bluestem	Sunnyview, Bison, Bonilla	2.00	/	6		
Schizachyrium scoparium	Little bluestem	Badlands, Itasca, Taylor	1.25	/	7		
Stipa comata	Needle-and-thread	Common	1.25	/	3		
Stipa viridula	Green needlegrass	Lodorm, AC Mallard	3.50	/	15		
			13.25		**63**		

NATIVE GRASS MIX

SCIENTIFIC NAME	COMMON NAME	VARIETY	SEEDING RATE Pounds PLS/Acre		PLS/ sq.ft.	TOTAL ACRES	TOTAL PLS POUNDS
	Northern Mixed Grass Prairie (NMG)						
Bouteloua curtipendula	Sideoats grama	Killdeer, Pierre, Butte	2.50	/	11		
Bouteloua gracilis	Blue grama	Bad River	0.75	/	14		
Andropogon gerardii	Big bluestem	Sunnyview, Bison, Bonilla	2.00	/	6		
Schizachyrium scoparium	Little bluestem	Badlands, Itasca, Taylor	1.25	/	7		
Stipa comata	Needle-and-thread	Common	1.25	/	3		
Stipa viridula	Green needlegrass	Lodorm, AC Mallard	3.50	/	15		
			11.25		**56**		

Keystone Pipeline Project

Contact Summary Report

Tract No.ML-SD-MN-0796.0000 **Directly Affected __X___ Adjacent _____**

Legal Description ¼ W1/2 - SEC. 33 - TWP. 106N - RGE. 57W

Additional Legal Information: MINER COUNTY S.D.

Landowner(s): MICHAEL B. and SUSAN K. SIBSON

Address: 23782 426TH AVE. City/Town: HOWARD

County: MINER Township: State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business :(605) 770-2800

Tenant(s): NA

Address: City/Town:

County: Township: State: S.D. Zip Code:

Telephone: Home :(605) Business :(605)

Contact Summary: On 7-19-10 I met with Mike and Sue Sibson. I delivered the Settlement agreement to the Sibsons and they signed it and I wrote them a check. The Sibson's had a few questions and I answered them or referred them to Sarah Metcalf. This issue is settled per John Hunt's agreement with the Sibson's.

Paul Kurtz

Land Representative

7-19-10

Date

Keystone Pipeline Project

Contact Summary Report

Tract No.ML-SD-MN-0796.0000 **Directly Affected** __X__ **Adjacent** _____

Legal Description ¼ W1/2 - SEC. 33 - TWP. 106N - RGE. 57W

Additional Legal Information: MINER COUNTY S.D.

Landowner(s): MICHAEL B. and SUSAN K. SIBSON

Address: 23782 426TH AVE. City/Town: HOWARD

County: MINER Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business :(605) 770-2800

Tenant(s): NA

Address: _____ City/Town: _____

County: _____ Township: _____ State: S.D. Zip Code: _____

Telephone: Home :(605) _____ Business :(605) _____

Contact Summary: On 7-15-10 I was asked by John Hunt to contact Sue Sibson to set up a time for them to sign the Settlement Agreement and Release. I called Sue and got no answer.
Sue then sent me an e-mail asking if I could meet her today at 4pm. I replied back stating I would be traveling to North Dakota and asked if we could meet Monday July 19th at 12 noon. Sue responded back stating that would work just fine.

Ron Hunt

Land Representative

7-15-10

Date

ML-SD-MN-0795.0000
ML-SD-MN-0796.0000

Sue Otis

From: TINA HALL [tinahall@donellis-associates.com]
Sent: Friday, July 23, 2010 8:05 AM
To: 'Sue Otis'; 'Tammy Smoot'
Subject: FW: Fwd: Fw: Invitation

This e-mail and the photos need to go in the Sibson file. They are a SD tract.

From: Sarah Metcalf [mailto:smetcalf12@gmail.com]
Sent: Thursday, July 22, 2010 4:01 PM
To: Nicole Aitken
Cc: Michael Schmaltz; Jessica.Greven@trow.com; Susan Parker; jrauh@neilpalmerllc.com; Richard Prior; Brett@magt.com; John Hunt; Tina Hall; Don Ellis
Subject: Re: Fwd: Fw: Invitation

FYI

Here are photos from the Sibson ROW tour, sorry for the delay I had some computer difficulties. Please let me know if anyone has any further questions on this tract.

The major concerns I got from the commissioner had to do with native grassland, specifically seed species matching and the time it takes native grasses to recover. He also brought up Keystones ability to maintain quality control between it's contractors, when it comes to clean up and reclamation. He noted to attention to detail the company showed with the quality control related to material and construction work. He also noted the discrepancy in the number of complaints recieve at the PUC between the spreads in the state. Most of which related some how to clean up/reclamation issues and wondered if there was a way to make sure "lessons learned" are carried forward to the next phase of the project.

I will send a follow up email to the Commissioner and inquire as to if he has any specific questions related to the tour that he would like further information from us on. Again let me know if you have any questions or comments.

Regards,

Sarah

On Thu, Jul 15, 2010 at 8:15 AM, Sarah Metcalf <smetcalf12@gmail.com> wrote:
Hello,
I toured the Sibson ROW yesterday with Commissioner Johnson, overall I thought that it went well, but may have some fall out concerning the Phase 4 project. The Sibson's brought up a number of issues they had with the project and eminent domain the Commissioner was very diplomatic in his responses at the same time remaining overall supportive of the project in general.

They detailed some of the hardships they felt they have suffered during the process from the trespass early in the project, trash left on the ROW this winter, as well as the reclamation issues they have now. On the ROW the weed were sprayed on Friday but were just starting to dye off yesterday. The grasses

have started to grow better and there was pretty good cover, I saw two species or wheat grass and a few smooth brome grass trying to come in. Unfortunately, the Commissioner was very concerned that the grass species seeded on the Sibson property are not similar at all to the grasses that were originally growing on the pasture land. I explained that the unless a specific seed mix was identified by the Landowner a standard mix was used as recommended by the env experts on the project. Sibson's said the had asked for the "county mix" used on CRP native grasses, I do not have a copy of their construction agreement to verify what they requested. The copy of the seed tag they have from the contractor shows the wheat grasses, brome and alfalfa were seeded, in their native pasture and over their alfalfa pasture which again the Commissioner asked why pure alfalfa wasn't seeded in this area. I couldn't answer but Sibson's said they would follow up with me as to what they want done on that section of land.

We saw two crop land tracts corn and soy beans, the Commissioner seemed very impressed to see that the crop land showed no sign of change as you went from ROW to adjacent land. There were some areas over center line that have some settling and long cracks, that are according to Sue 10-21 inches deep. The Commissioner asked if that was usually just a first year post construction issue and I said that it was, and that some subsidence and settling occurs just as it would with any excavation and back fill. I explained the tracking list that is maintained for the contractors so that these reclamation issues get addressed as they are identified by landowners, EI's or the areal monitoring.

He did have some concerns with the edges of the ROW, which on Sibson's land (and several other tracts I have been to) drop off at the edge and were not feather back into the adjacent land as well as it could have been. He kept commenting that it really was a big difference in how much more the grassland is impacted by construction than cropland. And how it was obvious that the farmer could work his crop land back to the original contours where as with the grassland he was stuck with the rough areas. He wanted to know that if it wouldn't be better to say that grassland would take 5 yrs to recover to better manage expectations of landowners. He also asked about what kind of quality control there was between the way each contractor operated.

We also looked at a wetland area and he wanted to know if it wouldn't be better to use just the trench line stripping on the grassland tracts as is done in wetlands. I explained that it can be a very site specific decision and in some places trench stripping is the best management practice and in others full ROW is best. Not stripping topsoil will allow native grasses to come back faster from the root zone, but the stripped topsoil will still contain a seed bank and by not stripping you get issues with compaction and the risk of mixing soils during the construction process.

Overall, I thought the tour was pretty good. I do think that the state of Sibson's grassland areas have the Commissioner concerned about Phase 4 due to the fact that the majority of that land on that project is native grassland. He also said that he hoped that "Lessons Learned" on Phase 1 would be carried over to Phase 4 and improve the process for those landowners. Please let me know if anyone would like further detail on this meeting. I will send some photos of the Sibson's ROW when I have them downloaded, as there were some reclamation issues that still need to be addressed.

Regards,

Sarah

On Mon, Jul 12, 2010 at 8:08 AM, Sarah Metcalf <smetcalf12@gmail.com> wrote:

FYI- I am scheduled to meet with Sibson's and Commissioner Johnson at 1:30pm Wed July 14th. The Sibson property has been sprayed for weeds and the need for grass seed will be assessed later in the season when the window for seeding is open again. I will report on the out come of the meeting.

Regards,

Sarah

On Fri, Jun 25, 2010 at 12:42 PM, Nicole Aitken <nicole_aitken@transcanada.com> wrote:
I would suggest we take a look at landowners immediately adjacent to the Sibsons also as Dusty will likely be looking to see if this is a "one of" or if all landowners are experiencing the same type of condition...

N.

From: Michael Schmaltz
Sent: Friday, June 25, 2010 9:04 AM
To: 'Jessica.Greven@trow.com'; Susan Parker
Cc: 'jrauh@neilpalmerllc.com'; Nicole Aitken; Richard Prior; 'Brett@magt.com'; 'smetcalf12@gmail.com'; John Hunt
Subject: Re: Fwd: Fw: Invitation

Suggest employing the same resolution I sent this morning as suggested on the Glanzer property.
Perhaps Land could call today and see if the landowner is interested in addressing (mow or spray) immediately. If not we will need to get Operations weed spraying contractor notified immediately.

From: Sarah Metcalf <smetcalf12@gmail.com>
To: John Hunt
Cc: Jeff Rauh <jrauh@neilpalmerllc.com>; Michael Schmaltz; Susan Parker; Nicole Aitken; Richard Prior; Brett Koenecke <Brett@magt.com>
Sent: Fri Jun 25 08:43:07 2010
Subject: Fwd: Fw: Invitation

Pease forward to whom ever may need to know but I suggest we make a plan to take address the weed problem on the property. Their ROW is full of weeds, no noxious that I saw but when compared to the adjacent land the ROW looks terrible. I would be happy to attend the meeting but I won't have many good explanations as too why the Sibson's grassland is so poorly restored. I beleive that the weeds need to be controlled with spray or mowing, and there are some areas should be over seeded. Please advise.

Sarah

---------- Forwarded message ----------
From: <Dustin.Johnson@state.sd.us>
Date: Fri, Jun 25, 2010 at 9:27 AM
Subject: Fw: Invitation
To: smetcalf12@gmail.com, Kara.Semmler@state.sd.us, Deb.Gregg@state.sd.us

Sarah,

Want to come?

Dusty

From: Sue Sibson <suesibson@alliancewildblue.com>
To: Johnson, Dustin (PUC)
Sent: Fri Jun 25 08:33:18 2010
Subject: RE: Invitation

Dear Dusty Johnson:
If you want, Sarah along that is fine. Sarah was already here on June 1 at our request to look at the easement area.
Thanks
Sue and Mike

From: Dustin.Johnson@state.sd.us [mailto:Dustin.Johnson@state.sd.us]
Sent: Thursday, June 24, 2010 3:07 PM
To: suesibson@alliancewildblue.com
Subject: Re: Invitation

Can I have Sarah Metcalf along? If things aren't as they should be, I'd like to be able to ask her right then and there why that is.

Dusty

From: Sue Sibson <suesibson@alliancewildblue.com>
To: Johnson, Dustin (PUC)
Sent: Wed Jun 23 09:39:46 2010
Subject: RE: Invitation

Good Morning Dusty:

July 14 will work for us. You can let us know what time when the day gets closer.
Thanks
Sue and Mike

From: Dustin.Johnson@state.sd.us [mailto:Dustin.Johnson@state.sd.us]
Sent: Tuesday, June 22, 2010 4:52 PM
To: suesibson@alliancewildblue.com
Subject: Re: Invitation

Wednesday, July 14?

From: Sue Sibson <suesibson@alliancewildblue.com>
To: Johnson, Dustin (PUC)
Sent: Tue Jun 22 09:24:52 2010
Subject: Invitation

Hi Dusty Johnson:

We would like to invite you to our farm and give you a tour of the pipeline easement area. TransCanada has been in the media saying they will leave the land in better shape than they found it. We would like you see our land. Please let us know if you are willing to take a tour.

Sincerely,
Mike and Sue Sibson

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Checked by AVG - www.avg.com
Version: 9.0.829 / Virus Database: 271.1.1/2955 - Release Date: 06/22/10 01:36:00

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Checked by AVG - www.avg.com
Version: 9.0.829 / Virus Database: 271.1.1/2960 - Release Date: 06/24/10 01:35:00

--
Sarah Metcalf
South Dakota Liaison Officer
Keystone Pipeline
110 3rd Street SW, Ste. #104
Huron, SD 57350
1-888-375-1370
(605) 228-4736 cell
SDLiaison@keystone.trow.com

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--
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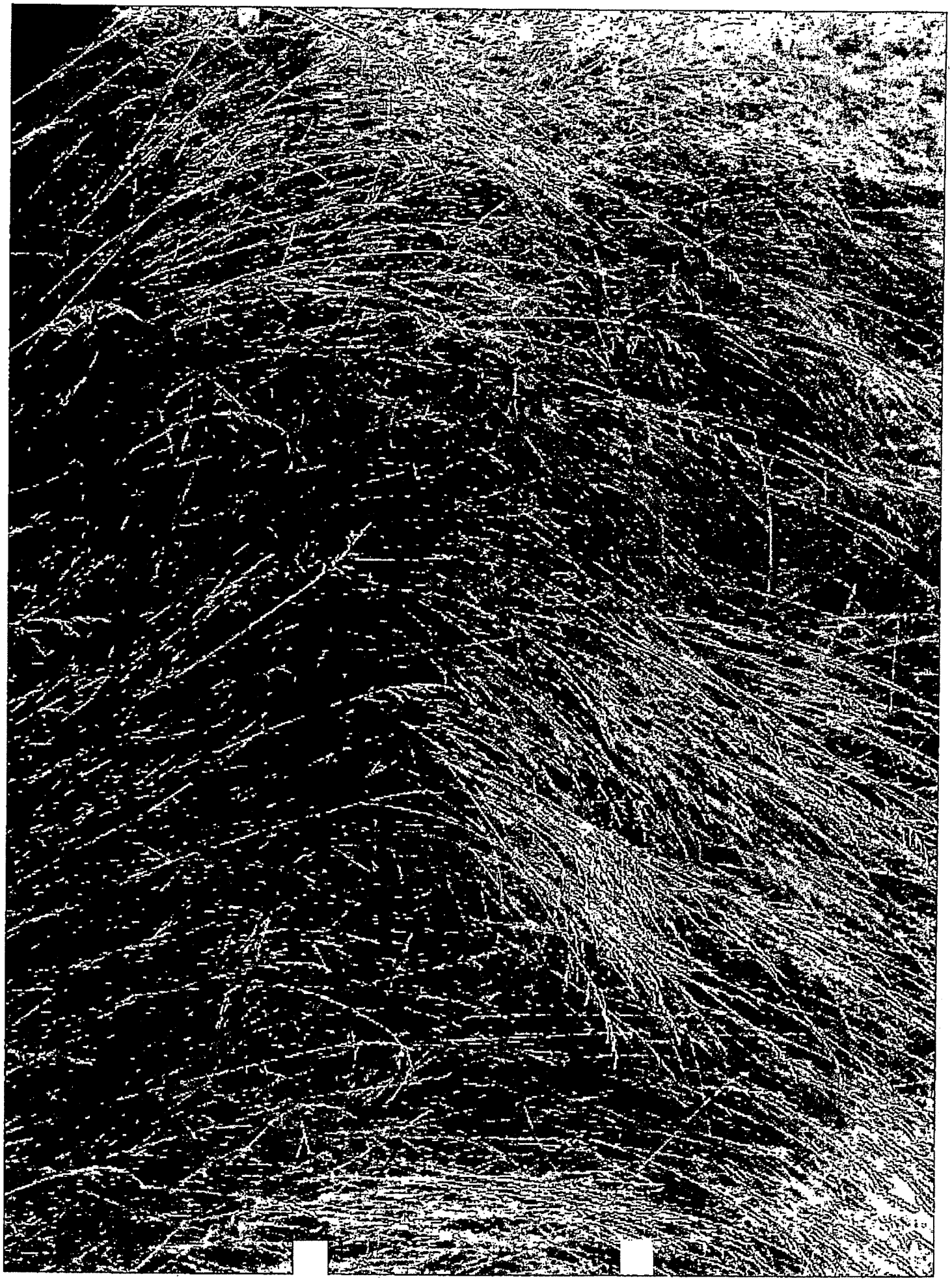

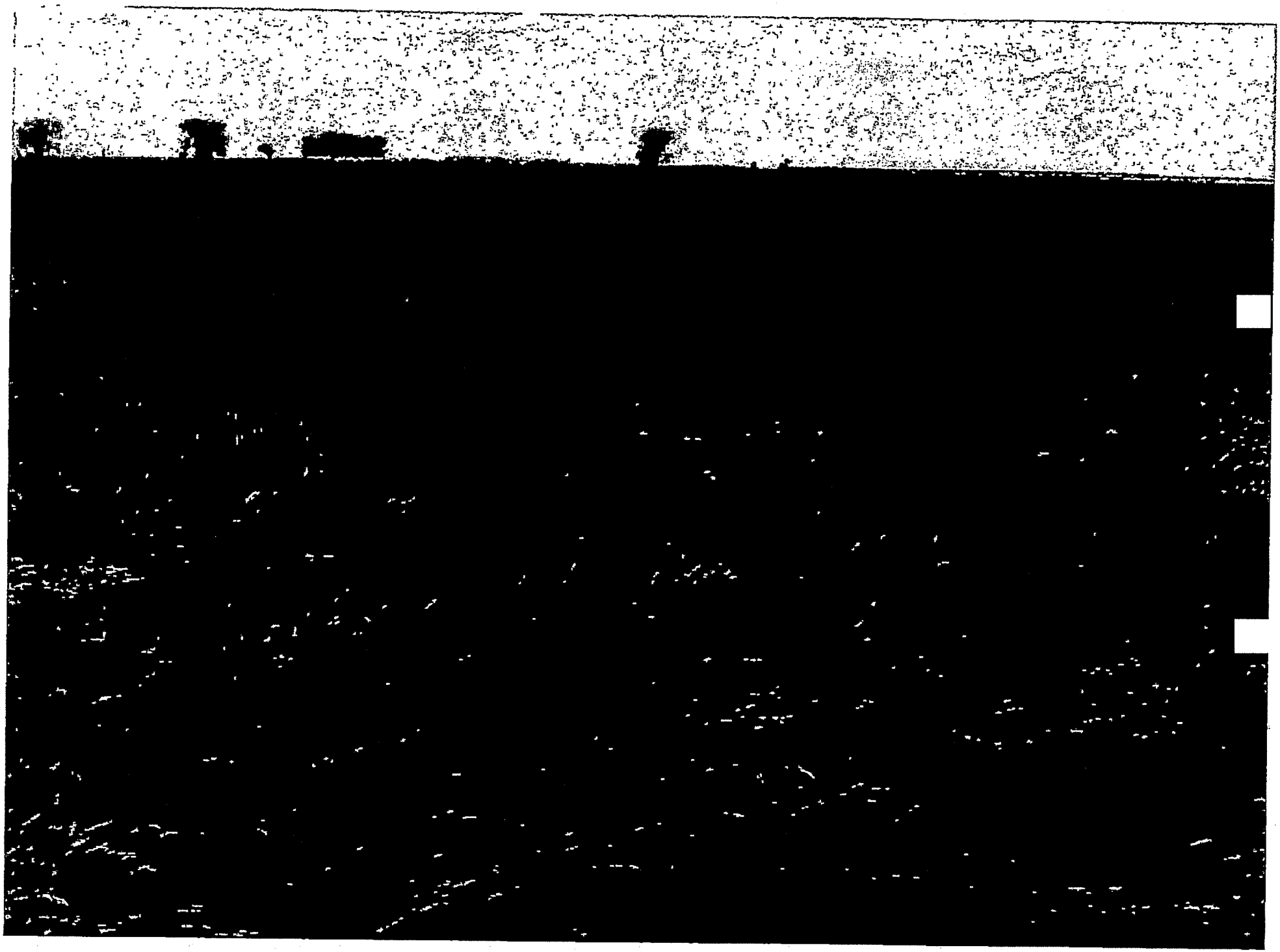

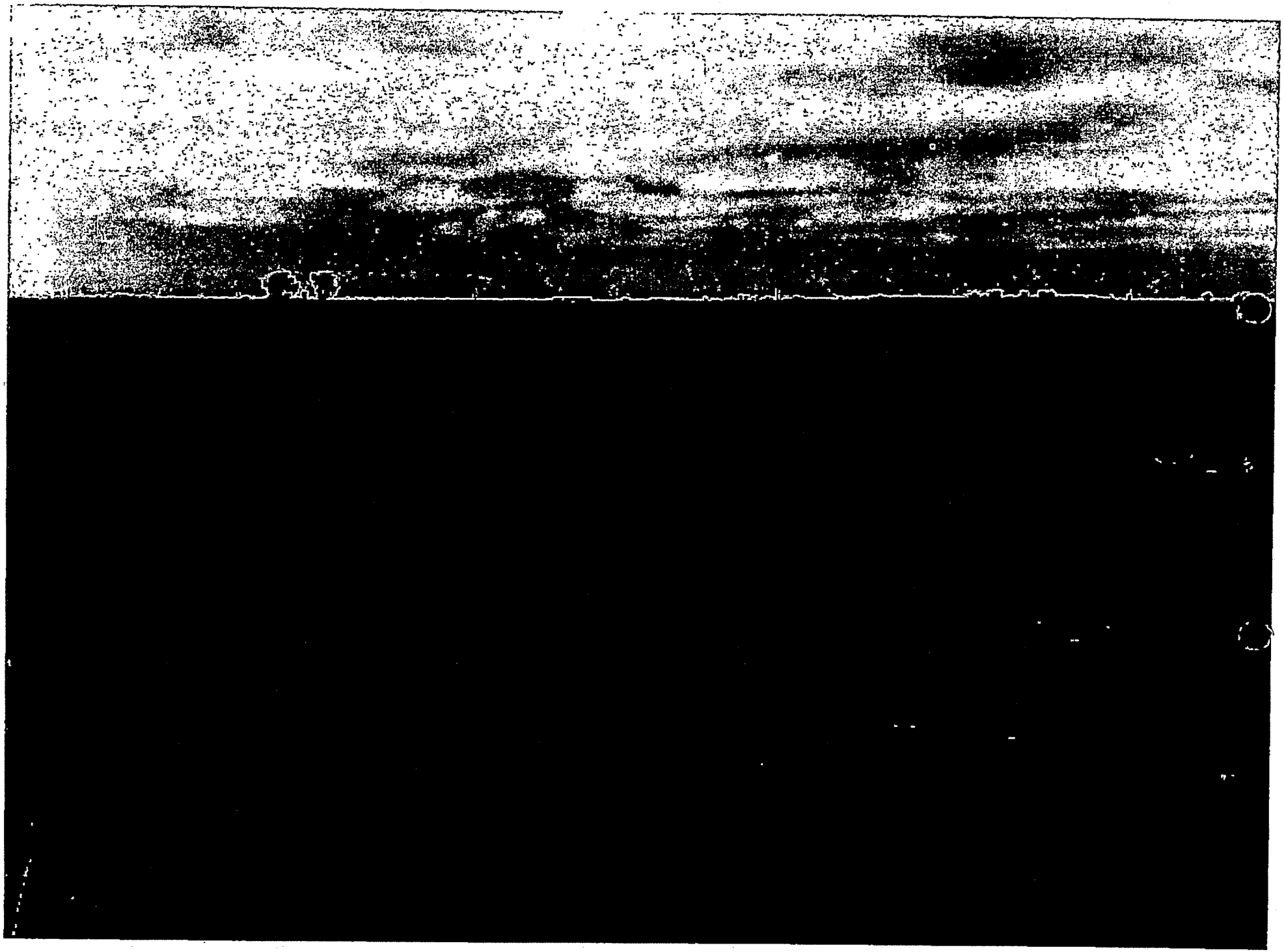

Keystone Pipeline Project

Contact Summary Report

Tract No.ML-SD-MN-0796.0000 **Directly Affected __X___ Adjacent _____**

Legal Description ¼ W1/2 - SEC. 33 - TWP. 106N - RGE. 57W

Additional Legal Information: MINER COUNTY S.D.

Landowner(s): MICHAEL B. and SUSAN K. SIBSON

Address: 23782 426TH AVE. City/Town: HOWARD

County: MINER Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business :(605) 770-2800

Tenant(s): NA

Address: _____ City/Town: _____

County: _____ Township: _____ State: S.D. Zip Code: _____

Telephone: Home :(605) _____ Business :(605) _____

Contact Summary: On 10-6-09 I received a call from Sue Sibson asking the status of the rocks that she thinks are buried on their property and that were suppose to be hauled off. I explained to Sue that I sent an e-mail out to the RCS explaining what she had requested and was waiting a response. Sue said that she was not going to let anyone back onto her property to retrieve the rocks. I told Sue that I thought it was still an active construction area and she said Paul you are not going to pull this on us again. I explained that it has been really wet and only specialized crews have worked since Saturday. Sue said, Paul I signed an agreement and you did too requesting the rocks be hauled off. She said the rocks were not hauled off and that is a breach of contract. Sue said "Paul you signed that agreement and I will haul you in". I asked Sue, " You are going to haul me to Jail for what?" Sue then raised her voice and I asked her to calm down and told her there was no reason to raise her voice. She laughed and said I have not raised my voice. I then asked her if she had talked to Mike Brouilette from Michels and she said no she thought she was suppose to talk to me or Sarah first. I said that was correct, but I wanted to make sure that I was not answering something that someone had already answered. Sue said I will just call Mike or Sarah Metcalf and I am done talking with you. I said thank you and hung up.

Paul Cart

Land Representative

10-6-09

Date

Keystone Pipeline Project

Contact Summary Report

Tract No.ML-SD-MN-0796.0000 **Directly Affected** __X__ **Adjacent** _____

Legal Description ¼ W1/2 - SEC. 33 - TWP. 106N - RGE. 57W

Additional Legal Information: MINER COUNTY S.D.

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Address: 23782 426TH AVE. City/Town: HOWARD

County: MINER Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business :(605) 770-2800

Tenant(s): NA

Address: _____ City/Town: _____

County: _____ Township: _____ State: S.D. Zip Code: _____

Telephone: Home :(605) _____ Business :(605) _____

Contact Summary: On 10-1-09 I called Sue and Mike and told them that I had e-mailed them the dewatering direction from Steve Craycroft the Environmental Compliance Manager. Sue then went on to say that yesterday she watched Michels bury the rocks on the ROW. She said that they requested the rocks be hauled off. She wanted to know what to do next? I told her I would bring it up at and let the contractor know. She said the ROW was cleaned up and reseeded and the y removed all of the mats. Sue said that for $10,000 the rocks can stay buried.

Paul Kurtz

Land Representative

10-1-09

Date

013357

From: Craycroft, Stephen <Stephen.Craycroft@aecom.com>
To: <pkliest@donellis-associates.com>
Subject: FW: Wetland on Sibson Property
Date: Mon, 21 Sep 2009 09:06:29 -0700

ML-SD-MN-0795.000
ML-SD-MN-0796.000

COPY

Paul:

Below is a description of the work that will take place to install the pipeline on the Sibson property (tract 0796) at wetland NWI_426261.

The contractor will segregate topsoil over a 15 foot area across the trench line and use the topsoil to construct a soil dike between the timber mats and the open trench line. The trench spoil will be stacked on the spoil side to create a dike along the east side ROW edge. Water collected within the trench line between the topsoil and spoil piles will be pumped across 238th Street onto the landowner immediately south of the roadway. Trench water will be pumped into straw bale and geo-textile straw on the south side of the 238th Street. The contractor will need to temporarily disconnect the buried phone line at station 19005+20 in order to complete the tie-in weld. Once the contractor installs the pipe section concrete weights will be installed and backfill/cleanup will begin. Foam trenchbreakers will be installed at the entry and exit points of the wetland. Cleanup will be completed in two days.

This description of work complies with the Project's permit requirements, including dewatering trench water while installing the pipeline.

Please let me know if you have any additional questions.

Best Regards,

Steve Craycroft

Keystone Project

Environmental Compliance Manager

816-880-4881 ext. 144

970-219-0184 (cell)

Keystone Pipeline Project

Contact Summary Report

ML-SD-MN-0796.0000

Tract No. ML-SD-MN-0795.0000 **Directly Affected** __X__ **Adjacent** _____

Legal Description S2SW4 - **SEC.** 28 & all sec 33 - **TWP.** T-106-N - **RGE.** R-57-W

Additional Legal Information: Miner County, SD

Landowner(s): Michael B & Susan K Sibson

Address: 23782 426th Ave City/Town: Howard

County: _____ Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business : 605-770-2800

Tenant(s): N/A

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

1-23-2009 I met with the Sibsons. They said they want their attorney to review the atws agreement before they sign it. We partially filled out a construction agreement but they want their attorney to review it before they sign it and they will not sign it until they get a few questions answered. They want a permanent fence put up along the West edge of the ROW when construction is done. They will turn that everything East into pasture as they don't want to farm over the pipe. There are a few acres of farm ground that will be cut off by the ROW and want to know if they are going to be compensated for crop loss on it. They want a temporary fence put along the East side of the ROW in 3 areas for their cattle during construction. They will need access across the ROW for their cattle in 2 areas. They want speed limit signs put on the roads surrounding their house. They said they will be watching and they better not see any trash, cigarette butts, or sunflower seeds on their property especially outside the ROW.

I wrote a check for the claim of Michael Sibson and Garry Nutter for extra mileage and labor from the 2008 harvest.

Eric Munz _____ 1-23-2009

Land Representative **Date**

Keystone Pipeline Project

Contact Summary Report

Tract No.ML-SD-MN-0796.0000 **Directly Affected** __X__ **Adjacent** _____

Legal Description ¼ W1/2 - SEC. 33 - TWP. 106N - RGE. 57W

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Telephone: Home :(605) 772-5184 Business :(605) 770-2800

Tenant(s): NA

Address: _____ City/Town: _____

County: _____ Township: _____ State: S.D. Zip Code: _____

Telephone: Home :(605) _____ Business :(605) _____

Contact Summary: On 9-10-09 I received a call from Brian Collabella, an EI with AECOM, and he said he received a call from the contractor about pumping water on the Abandoned 237 street that the Sibson's now own. I told him that the Sibson's had said no in the past but wanted to know how much water and where they were going to put it. I asked Brian these questions and he said he would go to the site and find out. Brian called back and said he went to the site and Mike Sibson was there and he told them where they could pump water and gave them permission to pump this bell hole out into a certain location.
I then called Mike Sibson and he confirmed to me that he did giver permission for the contractor to pump this certain bell hole out and to pump into this certain location.

Paul Kut
Land Representative

9-10-09
Date

013360

Keystone Pipeline Project

Contact Summary Report

Tract No.ML-SD-MN-0796.0000 **Directly Affected** __X__ **Adjacent** _____

Legal Description ¼ W1/2 - SEC. 33 - TWP. 106N - RGE. 57W

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Telephone: Home :(605) 772-5184 Business :(605) 770-2800

Tenant(s): NA

Address: _____ City/Town: _____

County: _____ Township: _____ State: S.D. Zip Code: _____

Telephone: Home :(605) _____ Business :(605) _____

Contact Summary: On 9-2-09 I called and talked to Sue and Mike and asked how the Construction was progressing on their property. I received an e-mail from Sue last week stating that they would need to move cattle across the ROW over the weekend and wanted the Contractor informed. I notified Michel's Construction and they stated no activity would be taking place. Sue said everything went very well and were appreciative of the work that has taken place to get the cattle access.
She thanked me for calling and said she would contact me first if any issues came up.

Paul Kurtz
Land Representative

9-2-09
Date

Keystone Pipeline Project

Contact Summary Report

ML-SD-MN-0796.0000

Tract No. ML-SD-MN-0795.0000 Directly Affected __X___ Adjacent _____

Legal Description S2SW4 - SEC. 28 & all sec 33 - TWP. T-106-N - RGE. R-57-W

Additional Legal Information: Miner County, SD

Landowner(s): Michael B & Susan K Sibson

Address: 23782 426th Ave City/Town: Howard

County: _____ Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business : 605-770-2800

Tenant(s): N/A

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

6-23-2009 Sue called and said some workers were driving off ROW on her property. She said they drove down the section line and entered a gate where they don't have permission. She said they section line road was closed by the County and she owns it. She said they were putting up the goal posts by the power lines. She also asked for 48 hr notice before anyone enters her property. I told her we gave her notice in April that construction would be starting and they can expect activity anytime after that.

Eric Munz
Land Representative

6-23-2009
Date

Keystone Pipeline Project

Contact Summary Report

ML-SD-MN-0796.0000

Tract No. ML-SD-MN-0795.0000 **Directly Affected** X **Adjacent** _____

Legal Description S2SW4 - **SEC.** 28 & all sec 33 - **TWP.** T-106-N - **RGE.** R-57-W

Additional Legal Information: Miner County, SD

Landowner(s): Michael B & Susan K Sibson

Address: 23782 426th Ave City/Town: Howard

County: _____ Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business : 605-770-2800

Tenant(s): N/A

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

6-03-2009 I called Sue and told her the survey crew was planning on finishing up on their property today. I asked her about the fence estimate. She said her fence people were waiting until the property was staked before they do an estimate. She will mail it to the Huron office when she gets it.

Eric Munz
Land Representative

6-03-2009
Date

6-9-

ML-SD-MN-0795.0000
ML-SD-MN-0796.0000
W1/2 Sec. 33 and the SW1/2 Sec. 28, T-106N, R-57W

Mike and Sue Sibson,

Sue about 2 months ago you called my office saying you saw an ad in the paper relating to water lines that could be replaced within 500' of residences. You stated you were unsure if your line fell into the condition of the PUC order but wanted to be on the list. TransCanada has followed up on your request and found that the water line that runs to your house is at least 1000' from the Keystone Pipeline.

I have attached a photo from KingBrook Rural Water that shows the water system near your home. Please note that Keystone Pipeline is further away than 500'.
Please contact me at the information below if you have any further questions.

Sincerely,
Paul Kleist

PAUL KLEIST
Right of Way Supervisor
South Dakota
Keystone Pipeline Project
605-352-1375 Office
605-461-9005 Cell
110 3rd Street SW Suite 104
Huron , SD 57350
"think safe, act safe, be safe, safety is my goal"

From: Charles Stewart <Charles.Stewart@universalensco.com>
To: Jeff Rauh <jrauh@neilpalmerllc.com>, Kerwin Kostad <kkostad@donellis-associates.com>
Cc: Paul Kleist <pkliest@donellis-associates.com>, Denny Needham <dneedham@donellis-associates.com>, Tina Hall <tinahall@donellis-associates.com>, Nate Krommendyk <nate_chelle@dutchmail.com>, Paul Fuhrer <paul_fuhrer@transcanada.com>
Subject: RE: Sue Sibson --Kingbrook Rural Water
Date: Thu, 4 Jun 2009 11:18:21 -0500

ML-SD-MN-0795.0000
ML-SD-MN-0796.0000

Kerwin/Jeff,

Kingbrook sent me their water line service map for the Sibson property on which I plotted the Keystone pipeline from the land plat (See attachment). While the dimensions are not such that you can determine the exact spacing, it is clear that the closest distance between the Sibson water service line and Keystone pipeline is more than 1000 feet, probably between 1200 and 1300 feet. The only way to get the exact spacing would be to pay Kingbrook to dig up the service line and have our surveyors measure the spacing.

Charles E. Stewart

Project Manager

Keystone Pipeline Project

816-880-4881 Office

832-465-5982 Cell

charles.stewart@universalensco.com

From: Jeff Rauh [mailto:jrauh@neilpalmerllc.com]
Sent: Thursday, June 04, 2009 8:09 AM
To: 'Kerwin Kostad'; Charles Stewart
Cc: 'Paul Kleist'; 'Denny Needham'; 'Tina Hall'; 'Nate Krommendyk'; Paul Fuhrer
Subject: RE: Sue Sibson --Kingbrook Rural Water

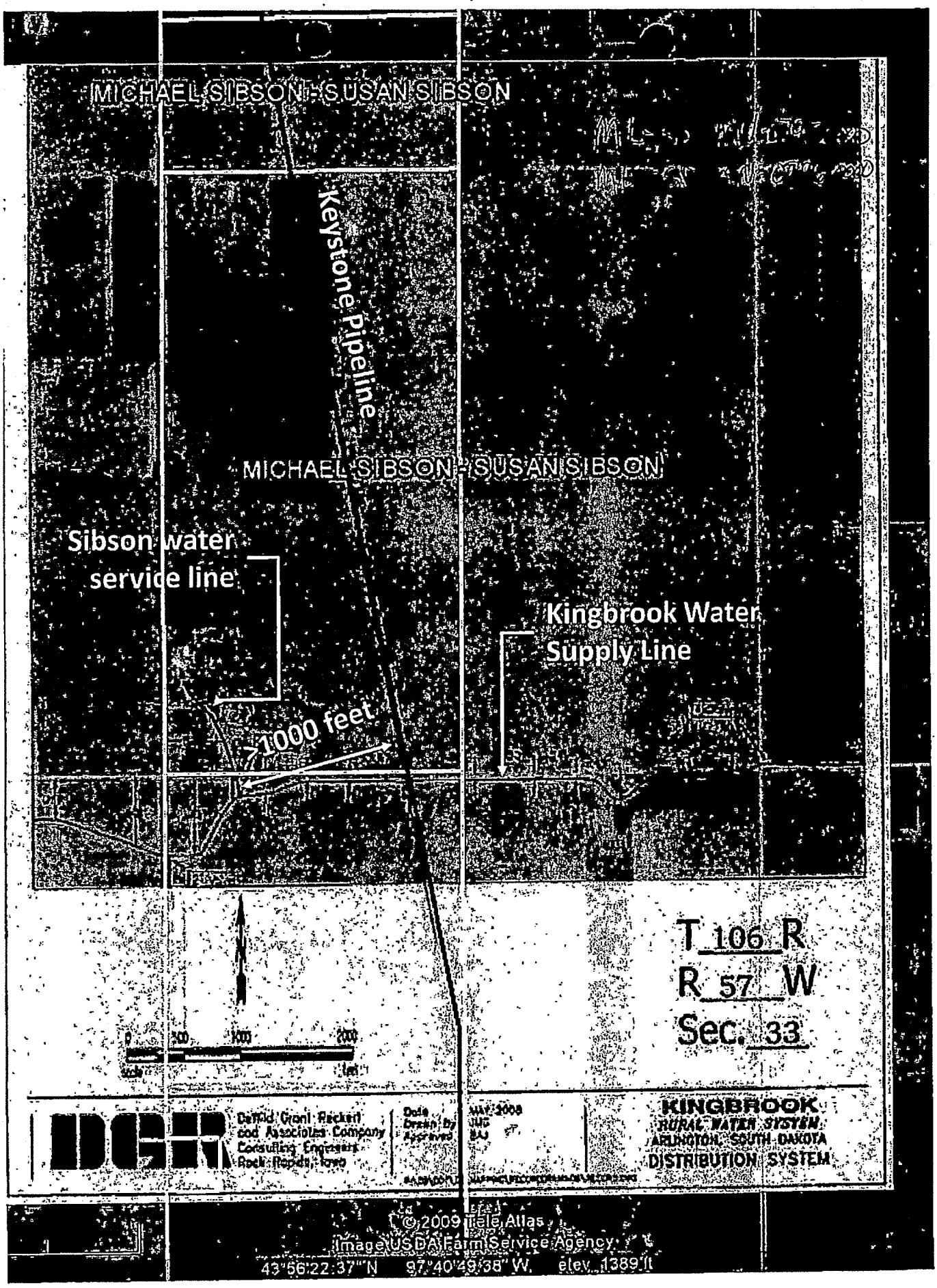
Kerwin –

I believe Charles Stewart has (or had) the action on this item as it relates to Kingbrook. While the PUC Condition does not address required communication with landowners who seek replacement as Sue has done, I presume after our check with Kingbrook is complete, the issue will come back to Land so we can close the loop with Sue to let her know we have addressed her request. (And, given her history with the project, we should make sure our work in response to her request is well documented.)

APPENDIX B

Table 3: Status of implementation of South Dakota PUC conditions

49	At the request of any landowner or public water supply system that offers to provide the necessary access to Keystone over his/her property or easement(s) to perform the necessary work, Keystone shall replace at no cost to such landowner or public water supply system, any polyethylene water piping located within 500 feet of the Project. Keystone shall not be required to replace that portion of any piping that passes through or under a basement wall or other wall of a home or other structure. At least forty-five (45) days prior to commencing construction, Keystone shall publish a notice in at least one newspaper of general circulation in each county through which the Project will be constructed advising landowners and public water supply systems of this condition.


MICHAEL SIBSON - SUSAN SIBSON
Keystone Pipeline
MICHAEL SIBSON - SUSAN SIBSON
Sibson water service line
Kingbrook Water Supply Line
1000 feet
T 106 R
R 57 W
Sec. 33
0
500
1000
2000
feet
DGR
Dahlid Gronl Reckert and Associates Company
Consulting Engineers
Rock Rapids, Iowa
Date
Drawn By
Approved
MAY 2008
JMG
BAJ
KINGBROOK
RURAL WATER SYSTEM
ARLINGTON, SOUTH DAKOTA
DISTRIBUTION SYSTEM
© 2009 Tele Atlas
Image USDA Farm Service Agency
43°56'22.37" N 97°40'49.38" W elev 1389 ft

Keystone Pipeline Project

Contact Summary Report

Tract No.ML-SD-MN-0796.0000 **Directly Affected __X___ Adjacent _____**

Legal Description ¼ ___W1/2___ - SEC. 33 ____ - TWP. 106N _____ - RGE. 57W _____

Additional Legal Information: ___MINER COUNTY S.D. _____

Landowner(s): ____ MICHAEL B. and SUSAN K. SIBSON _____

Address: ___23782 426TH AVE. _____ City/Town: _____ HOWARD _____

County: ___MINER _____ Township: _____ State: ___SD _____ Zip Code: _____57349___

Telephone: Home :(605) 772-5184 _____ Business :(605) 770-2800 _____

Tenant(s): _____ NA _____

Address: _____ City/Town: _____

County: _____ Township: _____ State: ___S.D. _____ Zip Code: _____

Telephone: Home :(605) _____ Business :(605) _____

Contact Summary: Contact Summary: On 6-25-09 I received permission from John Hunt to pay the Sibson's for the fence that they have requested. I called the Sibson's and set up an appointment to meet with them at 4pm at their house. I drew up the paperwork and drove to the Sibson's home and met with Michael and Susan. They reviewed the documents and signed them. I wrote the check to Michael B. and Susan K. Sibson in the amount of $21.818.06 for the cost to install and tear down after time the fence.

Paul Hunt

Land Representative

6-25-09

Date

Add Addresses to Contacts | Mark as Junk Mail

From: John Hunt <john_hunt@transcanada.com>
To: <smetcalf12@gmail.com>, <pkliest@donellis-associates.com>
Subject: Re: Sibson Fences ML-SD-MN-0795.0000 and ML-SD-MN-0796.0000
Date: Wed, 24 Jun 2009 08:59:13 -0600

▷ Show Full Message Headers

Let's move forward with them on this basis.

—— Original Message ——
From: Sarah Metcalf <smetcalf12@gmail.com>
To: John Hunt
Sent: Wed Jun 24 06:49:41 2009
Subject: Re: Sibson Fences ML-SD-MN-0795.0000 and ML-SD-MN-0796.0000

It totals, $21,000.00, the bid is for a very good steel and wood post fencing with 12 16-20' steel gates.

On Wed, Jun 24, 2009 at 7:35 AM, John Hunt <john_hunt@transcanada.com> wrote:

> What is the amount Paul? I can't read it on my blackberry.
> Thanks,
> John.

Add Addresses to Contacts | Mark as Junk Mail

View Encoding ...

From: Tina Hall <tinahall@donellis-associates.com>
To: 'Paul Kliest' <pkliest@donellis-associates.com>
Cc: <smetcalf12@gmail.com>
Subject: RE: Re: Sibson Fences ML-SD-MN-0795.0000 and ML-SD-MN-0796.0000
Date: Wed, 24 Jun 2009 11:56:47 -0500

Show Full Message Headers

That's the way I read it - go ahead and get it done

-----Original Message-----
From: Paul Kliest [mailto:pkliest@donellis-associates.com]
Sent: Wednesday, June 24, 2009 10:12 AM
To: tinahall@donellis-associates.com
Cc: smetcalf12@gmail.com
Subject: Fwd: Re: Sibson Fences ML-SD-MN-0795.0000 and ML-SD-MN-0796.0000
Subject: Fwd: Re: Sibson Fences ML-SD-MN-0795.0000 and ML-SD-MN-0796.0000

Tina,
Is this an approval to pay the Fence?
Paul Kleist
ROW Supervisor
Keystone Pipeline Project
South Dakota
605-352-1375 office
605-461-9005 cell
Think safe, act safe, be safe! Safety is my goal

Mike and Sue Sibson
23782 426th Ave
Howard SD 57349

Paul Kleist/Right of Way Supervisor South Dakota
Keystone Pipeline
110 3rd St SW
Suite# 104
Huron SD 57350

June 22, 2009

RE: fence estimate for Sibson land

Dear Paul,
Enclosed is a copy of the fence estimate from Heartland Custom Fencing, L.L.C. Please note their payment plan. We would like a decision about our fence request within 7 days or less of this letter.

Thank you.
Sincerely,
Mike and Sue Sibson
Mike and Sue Sibson

Keystone Pipeline Project

Contact Summary Report

Tract No.ML-SD-MN-0796.0000 **Directly Affected __X___ Adjacent _____**

Legal Description ¼ W1/2 - SEC. 33 - TWP. 106N - RGE. 57W

Additional Legal Information: MINER COUNTY S.D.

Landowner(s): MICHAEL B. and SUSAN K. SIBSON

Address: 23782 426TH AVE. City/Town: HOWARD

County: MINER Township: State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business :(605) 770-2800

Tenant(s): NA

Address: City/Town:

County: Township: State: S.D. Zip Code:

Telephone: Home :(605) Business :(605)

Contact Summary: On 6-6-09 I called and left the Sibson's a message stating that the water line that goes to there house is located about 1000 feet from the Keystone Pipeline. This is in regards to Sue's inquiry about the ad that was published in the papers for a PUC Condition. Sue called me about 2 months ago and said she was not sure if the water line was the type that fell into the condition or not and asked me to check it out. The line is greater than 1000 feet from the residence.

Paul Kint

Land Representative

6-8-09

Date

Keystone Pipeline Project

Contact Summary Report

ML-SD-MN-0796.0000

Tract No. ML-SD-MN-0795.0000 **Directly Affected** X **Adjacent** _____

Legal Description S2SW4 - **SEC.** 28 & all sec 33 - **TWP.** T-106-N - **RGE.** R-57-W

Additional Legal Information: Miner County, SD

Landowner(s): Michael B & Susan K Sibson

Address: 23782 426th Ave City/Town: Howard

County: _____ Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business : 605-770-2800

Tenant(s): N/A

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

5-13-2009 Sue called and left a message for me to call her back on her home phone. I called her and she said she was doing a courtesy call and trying to get along with us by telling us they put cattle in the pasture and to call her before the survey crew stakes so they can make sure the gates are shut and the cows don't bother the survey guys.

Eric Munz
Land Representative

5-13-2009
Date

Keystone Pipeline Project

Contact Summary Report

ML-SD-MN-0796.0000

Tract No. ML-SD-MN-0795.0000 **Directly Affected** __X__ **Adjacent** _____

Legal Description S2SW4 - **SEC.** 28 & all sec 33 - **TWP.** T-106-N - **RGE.** R-57-W

Additional Legal Information: Miner County, SD

Landowner(s): Michael B & Susan K Sibson

Address: 23782 426th Ave City/Town: Howard

County: _____ Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business : 605-770-2800

Tenant(s): N/A

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

4-10-2009 I, Paul Kleist and Sarah Metcalf met with Mike and Sue. They gave us 2 options. Fence where they want or pay them $30,000.00 for loss of income and they will keep their cattle out of the area where the pipeline will go. They believe their yearlings are curious and will get in the way of construction and PETA will go after them for not being responsible farmers and putting their cattle in harms way. Sue said If we don't give them the fence they will bill us for extra security and having to watch their cattle.

Eric Munz
Land Representative

4-10-2009
Date

Keystone Pipeline Project

Contact Summary Report

ML-SD-MN-0796.0000

Tract No. ML-SD-MN-0795.0000 **Directly Affected** X **Adjacent** _____

Legal Description S2SW4 - **SEC.** 28 & all sec 33 - **TWP.** T-106-N - **RGE.** R-57-W

Additional Legal Information: Miner County, SD

Landowner(s): Michael B & Susan K Sibson

Address: 23782 426th Ave City/Town: Howard

County: _____ Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business : 605-770-2800

Tenant(s): N/A

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

4-06-2009 Sue called to confirm the meeting with myself, Sarah Metcalf, and Paul Kleist on Fri 4-10-2009 at 1:00 at their place.

Eric Munz
Land Representative

4-06-2009
Date

Keystone Pipeline Project

Contact Summary Report

ML-SD-MN-0796.0000

Tract No. ML-SD-MN-0795.0000 Directly Affected __X___ Adjacent _____

Legal Description S2SW4 - SEC. ~~28 & all sec 33~~ W2 - TWP. T-106-N - RGE. R-57-W

Additional Legal Information: Miner County, SD

Landowner(s): Michael B & Susan K Sibson

Address: 23782 426th Ave City/Town: Howard

County: _____ Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business : 605-770-2800

Tenant(s): N/A

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

1-23-2009 I met with the Sibsons. They said they want their attorney to review the atws agreement before they sign it. We partially filled out a construction agreement but they want their attorney to review it before they sign it and they will not sign it until they get a few questions answered. They want a permanent fence put up along the West edge of the ROW when construction is done. They will turn that everything East into pasture as they don't want to farm over the pipe. There are a few acres of farm ground that will be cut off by the ROW and want to know if they are going to be compensated for crop loss on it. They want a temporary fence put along the East side of the ROW in 3 areas for their cattle during construction. They will need access across the ROW for their cattle in 2 areas. They want speed limit signs put on the roads surrounding their house. They said they will be watching and they better not see any trash, cigarette butts, or sunflower seeds on their property especially outside the ROW.

I wrote a check for the claim of Michael Sibson and Garry Nutter for extra mileage and labor from the 2008 harvest.

Eric Munz _____ 1-23-2009

Land Representative **Date**

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-MN-0796.0000 **Directly Affected** X **Adjacent** _____

Legal Description W2 - **SEC.** 33 - **TWP.** T-106-N - **RGE.** R-57-W

Additional Legal Information: Miner County, SD

Landowner(s): Michael B & Susan K Sibson

Address: 23782 426th Ave City/Town: Howard

County: _____ Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business : 605-770-2800

Tenant(s): N/A

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

1-15-2009 I called and talked to Sue. I told her I would be contacting her in the next week or two to meet with them about atws. She said Mondays are bad and I should call around noon to get ahold of them. She said she will also want to talk about getting their property staked to identify the ROW.

Eric Munz
Land Representative

1-15-2009
Date

Sue called Sara
First time on
10-17-08

October 27, 2008

Gary Nutter
42381 236th St
Howard SD 57349

Mike Sibson
23782 426th Ave
Howard SD 57349

Sarah Metcalf
Keystone Pipeline
110 3rd Street SW
Suite #104
Huron SD 57350

Dear Sarah Metcalf:

Due to the construction of a substation located in Section 1 Perry Township Davison County Mitchell SD, the road (412th Ave) was too rough for loaded farm vehicles and equipment to travel. We had to travel extra miles to get our harvested crops to storage bins. The road was closed for travel during our harvest.
We would like reimbursement for the labor costs (inconvenience) and extra miles traveled for 2008 soybean and corn harvest.

Harvest expense Davison County:

Trucks 36 miles @ $3.00 a load = $108.00

Combine and tractor with gravity wagons 16 miles @ $2.00 a load =$32.00

Pickup 32 miles @.585 = $18.72

Labor 4 hours @ $15.00=$60.00

Total $218.72

Sincerely,
Gary Nutter Mike Sibson
Gary Nutter and Mike Sibson

Mark Hoffman
605-256-8270
East River Electric

WAPA has 412th Ave
Westinary Power shut down
and it is
still shut down.

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-MN-0796.0000 **Directly Affected** X **Adjacent** _____

Legal Description W2 - **SEC.** 33 - **TWP.** T-106-N - **RGE.** R-57-W

Additional Legal Information: Miner County, SD

Landowner(s): Michael B & Susan K Sibson

Address: 23782 426th Ave City/Town: Howard

County: _____ Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business : 605-770-2800

Tenant(s): N/A

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

10-27-2008 I mailed a letter with an explanation of our survey activity on their property and where to find the CMR plan online.

Eric Munz
Land Representative

10-27-2008
Date

Keystone Pipeline 110 3rd Street SW - Suite 104 Huron, SD 57350

October 27, 2008

Michael and Susan Sibson
23782 426th Avenue
Howard SD 57349

Tract #: ML-SD-MN-0795.0000 & ML-SD-MN-0796.0000

T106N-R57W	&	T106N-R57W
28 : S2SW4		33 : W2

Dear Mr. and Mrs. Sibson:

Per your request, the following are findings of survey activity of your property:

Meghan, as I explained on the phone, drove by the property and did not need to survey.

The other information I received was a partial wetland survey about .34 miles on section 33. One wetland was identified. There was no cultural survey on either tract. No cultural resources were identified. No Threatened &Endangered species surveys have been conducted on either tract.

You may find our Construction Mitigation and Reclamation plan online: puc.sd.gov / commission dockets/ hydrocarbonpipeline/ 2007/ HP07-0001 under Exhibit B.

Regards,

Eric Munz
Sr. Land Agent
Keystone Pipeline
605-461-8568
Northernmn2001@yahoo.com

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-MN-0796.0000 **Directly Affected** X **Adjacent** _____

Legal Description W2 - **SEC.** 33 - **TWP.** T-106-N - **RGE.** R-57-W

Additional Legal Information: Miner County, SD

Landowner(s): Michael B & Susan K Sibson

Address: 23782 426th Ave City/Town: Howard

County: _____ Township: _____ State: SD Zip Code: 57349

Telephone: Home :(605) 772-5184 Business : 605-770-2800

Tenant(s): N/A

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

10-24-2008 Susan called and asked if I had a report yet of surveys on her property. I told her I would get it sent to her soon. She also asked for Sarah Metcalf's phone number. I gave it to her.

Eric Munz
Land Representative

10-24-2008
Date

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-MR-0519.0000 **Directly Affected** __X__ **Adjacent** _____

Legal Description NE4 - SEC. 14 - TWP. 125-N - RGE. 59-W

Additional Legal Information: Marshall County, SD

Landowner(s): Lillian and Raymond Anderson

Address: 12189 415th Ave City/Town: Langford

County: _____ Township: _____ State: SD Zip Code: 57454

Telephone: Home :(605) 493-6438 Business : 605-448-8059

Tenant(s): N/A

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

Met with Mr. and Mrs. Anderson and we talked over the repairs with Frank and Brett. I also talked to them about the crop damages that was agreed upon with Heath and Eric. I told them that I would need to order the check and my best estimate for delivery would be approximately 10 days..

Patrick Fuller
Land Representative

10/2/14
Date

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-MR-0519.0000 **Directly Affected** __X__ **Adjacent** _____

Legal Description NE4 - SEC. 14 - TWP. 125-N - RGE. 59-W

Additional Legal Information: Marshall County, SD

Landowner(s): Lillian and Raymond Anderson

Address: 12189 415th Ave City/Town: Langford

County: _____ Township: _____ State: SD Zip Code: 57454

Telephone: Home :(605) 493-6438 Business : 605-448-8059

Tenant(s): N/A

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

9-23-2013 I met with Ray and Lillian. I explained our project manager and environmental people agreed they don't have a solution for the erosion over the ROW. Their plan is to fix the drainage on the South, re-grade and bring to level the ROW and plant it to grass. I offered 160 bu corn x 6.8 acres x $7 per bushel x 5 years for crop loss due to ROW being planted to grass. They said they would think about it and get back to me. Lillian said she didn't want the transition line touched. Total amount due $38,080.00

10-11-2013 I called Lillian to inform of upcoming wetland survey. She asked what they were doing and why and for what agency. I called back and informed her.

10-14-2013 Lillian called and said Ray thought it was ok to do the wetland survey. She also said they would agree to the offer made to work on the ROW and plant it to grass. I explained it would be next year when they can do the work.

Eric Munz — 9-23-2013 10-2-14

Land Representative **Date**

Oct 2, 2014 Reviewed -

Frank J Maddox Raymond Anderson

Tract No. ML-SD-MR-0519.0000 Legal Description NE4 - SEC. 14 - TWP. 125-N - RGE. 59-W

Landowner(s): Lillian and Raymond Anderson

Address: 12189 415th Ave City/Town: Langford

County: Marshall Township: State: SD Zip Code: 57454

Telephone: Home :(605) 493-6438 Business : 605-448-8059

From here do the best we can to stop the erosion by levelling and planting grass. Use laser transit. Bring grade up. Need to build up on south side

Mr. Thys. ~~Never~~ washed out until pipeline was cut. Water really started cutting west of ROW after const. ~~first~~ 3 or 4 to 10 years any seed will be washed away. She would to know how much has been spent to do repairs ~~since~~ since construction.

Mr. or Mrs. Anderson are not financially responsible for ~~any~~ any damage repairs ~~on~~ on the ROW or ~~or~~ damages outside of ROW that was caused by the pipeline installation.

Mrs Anderson request this ~~quarter~~ quarter section to be bought by TransCanada. He stated $5000.00 per acre.

R.A. / lw

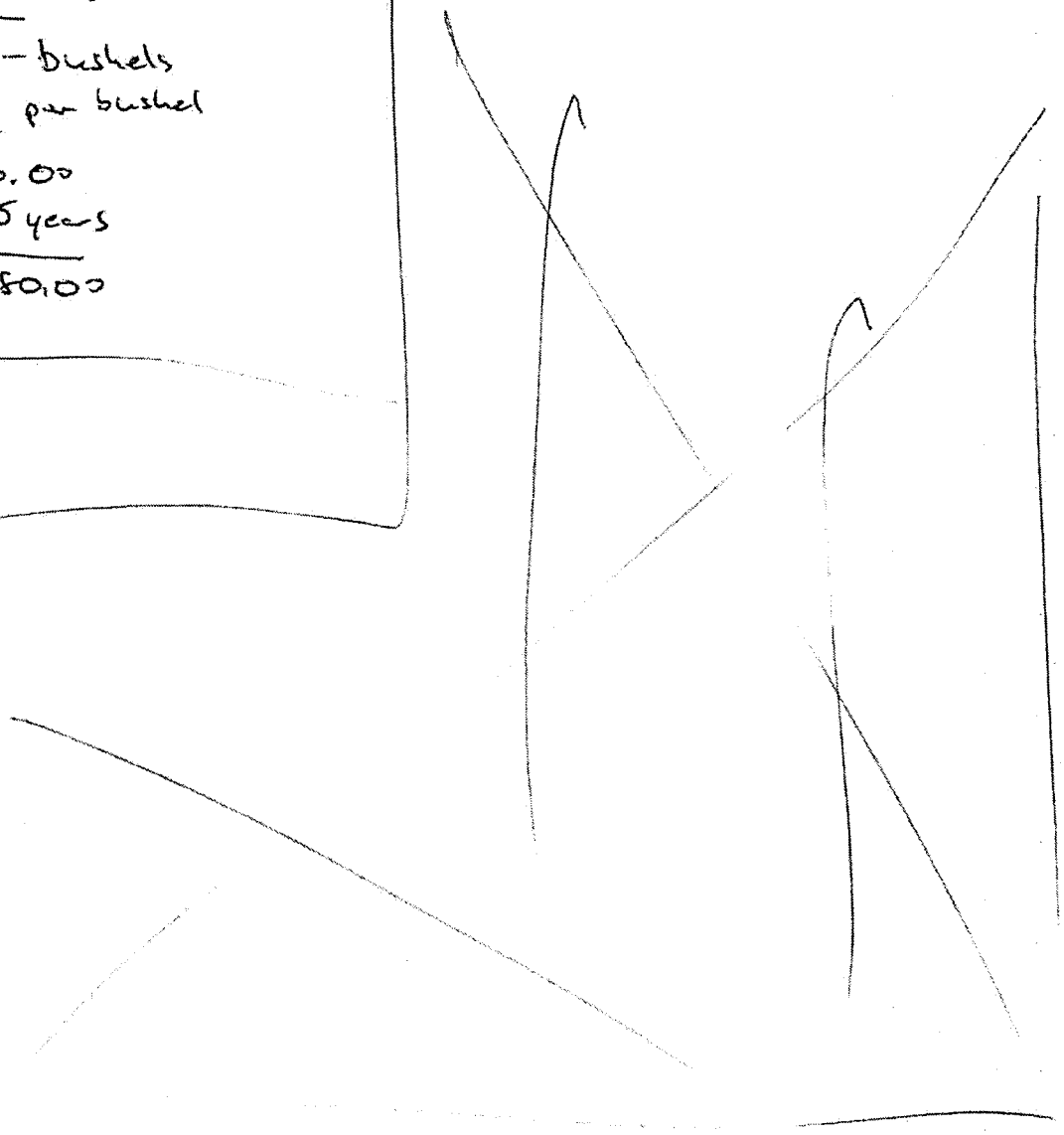
Per Telecon
Frank D. Maddalozzo RI

1

013384

0519

160 ~~Acres~~ bushels corn
X 6.8 acres
1088 – bushels
X $7.00 per bushel
$7616.00
X 5 years
$38,080.00



Raymond Anderson
Raymond Anderson — Date

Lillian Anderson
Lillian Anderson — Date:

Patrick Fuller
Patrick Fuller — 10-2-14 Date

Frank Maddox
Frank Maddox — Oct 2, 2014 Date

[redacted]

Tract No. ML-SD-MR-0519.0000 Legal Description NE4 - SEC. 14 - TWP. 125N - RGE. 59W

Landowner(s): Lillian and Raymond Anderson

Address: 12189 415th Ave City/Town: Langford

County: _____ Township: _____ State: SD Zip Code: 57454

Telephone: Home :(605) 493-6438 Business : 605-448-8059

Frank-
We are here to the best we can to stop the erosion by levelling and planting grass. Use laser transits. Bring grad up. Need to build up on south side.

Mr. & Mrs. Anderson-
Never washed out until pipeline was cut. Water really started cutting west of ROW after construction 8 out of 10 years any seed will be washed away. She would like to know how much has been spent to do repairs since construction.

Mrs. Anderson asked that the following be written.
Mr. and Mrs Anderson are not financially responsible for any damage repairs on the ROW or damages outside the ROW that was caused by the pipeline installation.

Mr. Anderson requests this quarter section to be bought by TransCanada. He stated $5000.00 per acre.

160 bushels corn
X 6.8 acres
1088 bushels
X $7.00 per bushels
$7616.00
5 Years
$38,080.00

The original document was signed and / or initialed by the following on October 2, 2014:

Raymond Anderson—Land owner
Lillian Anderson--Landowner
Frank Maddox—Restoration Inspector
Patrick Fuller—Land agent

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-DY-0542.0000 Directly Affected __X__ **Adjacent** _____

Legal Description SE4 - **SEC.** 20 - **TWP.** 124-N - **RGE.** 59-W

Additional Legal Information: DAY COUNTY, SD

Landowner(s): Doris Jane Townsend

Address: 41419 128th St City/Town: Andover

County: Township: State: SD Zip Code: 57422

Telephone: Home :(605) 325-3459 Business : 605-380-5469

Tenant(s): Dean Townsend Farm, Inc.

Address: 13041 415th Ave City/Town: Andover

County: Township: State: SD Zip Code:57422

Telephone: Home : 605-325-3207 Business : 605-380-1214

20-20-2014 Called Dean and explained he was paid to reclaim 0542 & 0543. He stated he did but there are more issues. He also said there are issues on 0535 which he now owns and on0539.0002 which causes problems on his property.

Eric Munz
Land Representative

10-20-2014
Date

013387

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-DY-0543.0000 **Directly Affected** __X__ **Adjacent** _____

Legal Description NE4 - SEC. 29 - TWP. 124-N - RGE. 59-W

Additional Legal Information: DAY COUNTY, SD

Landowner(s): Doris Jane Townsend & Norman H Townsend

Address: 41419 128th St City/Town: Andover

County: Township: State: SD Zip Code: 57422

Telephone: Home :(605) 325-3459 Business : 605-380-5469

Tenant(s): Dean Townsend Farm, Inc.

Address: 13041 415th Ave City/Town: Andover

County: Township: State: SD Zip Code:57422

Telephone: Home : 605-325-3207 Business : 605-380-1214

10-20-2014 Called Dean and explained he was paid to reclaim 0542 & 0543. He stated he did but there are more issues. He also said there are issues on 0535 which he now owns and on0539.0002 which causes problems on his property.

Eric Munz
Land Representative

10-20-2014
Date

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD- CK 0683.0000 **Directly Affected** X **Adjacent** _____

Legal Description ¼ NW1/4 - SEC. 4 - TWP. 113N - RGE. 59W

Additional Legal Information: CLARK COUNTY SD

Landowner(s): KIM MADSEN REVOCABLE LIVING TRUST

Address: 18852 415TH AVE. City/Town: CARPENTER

County: CLARK Township: _____ State: S.D. Zip Code: 57322

Telephone: Home :(605)352-7399 Business :(605) NA

Tenant(s): NA

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home :(_____) _____ Business :(_____) _____

Called Kim and left him a message that I will contact him again on my trip back to SD to meet with him about the issues around the pump station. Josh stated in the email that Mr. Madsen has some crop loss due to run off from the pump station. Add to punch list.

Patrick Fuller
Land Representative

8/9/14
Date

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-BD-0693.0000 **Directly Affected** __X___ **Adjacent** _____

Legal Description NE4 - **SEC.** 4 - **TWP.** T-113-N - **RGE.** R-59-W

Additional Legal Information: Beadle County, SD

Landowner(s): KimT, Kirk and Velerie D Madsen Revocable Living Trust

Address: 18852 415th Ave City/Town: Carpenter

County: _____ Township: _____ State: SD Zip Code: 57322

Telephone: Home :(605) 352-7339 Business : 605-350-3314

Tenant(s): N/A

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

Met with Kim the landowner and paid him for the grass loss that occurred when the road to the pump station was built. This is a one time payment. $2500.00

Patrick Fuller
Land Representative

9/4/14
Date

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-BD-0693.0000 **Directly Affected** X **Adjacent** _____

Legal Description NE4 - SEC. 4 - TWP. T-113-N - RGE. R-59-W

Additional Legal Information: Beadle County, SD

Landowner(s): KimT, Kirk and Velerie D Madsen Revocable Living Trust

Address: 18852 415th Ave City/Town: Carpenter

County: _____ Township: _____ State: SD Zip Code: 57322

Telephone: Home :(605) 352-7339 Business : 605-350-3314

Tenant(s): N/A

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

Called Kim Madsen and made a time to meet with him about the grass loss.

Patrick Fuller 9/3/14

Land Representative **ate**

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-BD-0693.0000 **Directly Affected** X **Adjacent** _____

Legal Description NE4 - SEC. 4 - TWP. T-113-N - RGE. R-59-W

Additional Legal Information: Beadle County, SD

Landowner(s): KimT, Kirk and Velerie D Madsen Revocable Living Trust

Address: 18852 415th Ave City/Town: Carpenter

County: _____ Township: _____ State: SD Zip Code: 57322

Telephone: Home :(605) 352-7339 Business : 605-350-3314

Tenant(s): N/A

Address: _____ City/Town: _____

County: _____ Township: _____ State: _____ Zip Code: _____

Telephone: Home : _____ Business : _____

Met with Kim Madsen the LO. He showed us the runoff area on this tract. He said he was previously offered $2500 for him to repair.

Patrick Fuller
Land Representative

8/21/14
ate

Keystone Pipeline Project

Contact Summary Report

693

Tract No. ML-SD- CK 0683.0000 **Directly Affected** X **Adjacent** ____

Legal Description ¼NW1/4 - SEC. 4 - TWP. 113N - RGE. 59W

Additional Legal Information: CLARK COUNTY SD

Landowner(s): KIM MADSEN REVOCABLE LIVING TRUST

Address: 18852 415TH AVE. City/Town: CARPENTER

County: CLARK Township: State: S.D. Zip Code: 57322

Telephone: Home :(605)352-7399 Business :(605) NA

Tenant(s): NA

Address: City/Town:

County: Township: State: Zip Code:

Telephone: Home :( ) Business :( )

Called Kim and left him a message that I will contact him again on my trip back to SD to meet with him about the issues around the pump station. Josh stated in the email that Mr. Madsen has some crop loss due to run off from the pump station. Add to punch list.

Patrick Fuller
Land Representative

8/9/14
Date

Keystone Pipeline Project

Contact Summary Report

Tract No. PS-SD-BD-0694.0000 **Directly Affected** X **Adjacent** _____

Legal Description SE4 - **SEC.** 4 - **TWP.** T-113-N - **RGE.** R-59-W

Additional Legal Information: Beadle County, SD

Landowner(s): Larry and Jo Ann Whirledge

Address: 102 4th Avenue City/Town: Iroquois

County: _____ Township: _____ State: SD Zip Code: 57353

Telephone: Home :(605) 546-2191 Business : cell: 605-350-3924

Tenant(s): Kim Madsen

Address: 18852 415th Ave City/Town: Carpenter

County: _____ Township: _____ State: SD Zip Code: 57322

Telephone: Home : 605-352-7339 Business : _____

Met with Kim the tenant and paid him for the corn loss that occurred when water runoff occurs off the pump station. I paid him $3600.00

Patrick Fuller
Land Representative

9/4/14
Date

Keystone Pipeline Project

Contact Summary Report

Tract No. PS-SD-BD-0694.0000 **Directly Affected** X **Adjacent** _____

Legal Description SE4 - **SEC.** 4 - **TWP.** T-113-N - **RGE.** R-59-W

Additional Legal Information: Beadle County, SD

Landowner(s): Larry and Jo Ann Whirledge

Address: 102 4th Avenue City/Town: Iroquois

County: _____ Township: _____ State: SD Zip Code: 57353

Telephone: Home :(605) 546-2191 Business : cell: 605-350-3924

Tenant(s): Kim Madsen

Address: 18852 415th Ave City/Town: Carpenter

County: _____ Township: _____ State: SD Zip Code: 57322

Telephone: Home : 605-352-7339 Business : _____

Called the tenant Kim Madsen and made a time to meet with him about the corn damages.

Patrick Fuller
Land Representative

9/3/14
Date

Keystone Pipeline Project

Contact Summary Report

Tract No. PS-SD-BD-0694.0000 **Directly Affected** X **Adjacent** ____

Legal Description SE4 - SEC. 4 - TWP. T-113-N - RGE. R-59-W

Additional Legal Information: Beadle County, SD

Landowner(s): Larry and Jo Ann Whirledge

Address: 102 4th Avenue City/Town: Iroquois

County: _____ Township: _____ State: SD Zip Code: 57353

Telephone: Home :(605) 546-2191 Business : cell: 605-350-3924

Tenant(s): Kim Madsen

Address: 18852 415th Ave City/Town: Carpenter

County: _____ Township: _____ State: SD Zip Code: 57322

Telephone: Home : 605-352-7339 Business : _____

Met with Kim Madsen the tenant. He showed us the runoff area on this tract. He said he losses approximately 3 acres of crop because of the runoff from the PS.

Patrick Fuller
Land Representative

8/21/14
Date

Keystone Pipeline Project

Contact Summary Report

Tract No. PS-SD-BD-0694.0000 **Directly Affected** X **Adjacent** _____

Legal Description SE4 - **SEC.** 4 - **TWP.** T-113-N - **RGE.** R-59-W

Additional Legal Information: Beadle County, SD

Landowner(s): Larry and Jo Ann Whirledge

Address: 102 4th Avenue City/Town: Iroquois

County: _____ Township: _____ State: SD Zip Code: 57353

Telephone: Home :(605) 546-2191 Business : cell: 605-350-3924

Tenant(s): Kim Madsen

Address: 18852 415th Ave City/Town: Carpenter

County: _____ Township: _____ State: SD Zip Code: 57322

Telephone: Home : 605-352-7339 Business : _____

Met with Kim and we talked while it was raining. He stated there is some area around the pump station that he cannot get to grow crop because of the run off from the station. He stated he wouldn't mind if a french drain was installed and drain tile was installed to the drainage creek. He also stated there is an area that the weeds have overtook and will not allow grazing.

Patrick Fuller
Land Representative

8/14/14
Date

Keystone Pipeline Project

Contact Summary Report

Tract No. PS-SD-BD-0694.0000 **Directly Affected** X **Adjacent** _____

Legal Description SE4 - **SEC.** 4 - **TWP.** T-113-N - **RGE.** R-59-W

Additional Legal Information: Beadle County, SD

Landowner(s): Larry and Jo Ann Whirledge

Address: 102 4th Avenue City/Town: Iroquois

County: _____ Township: _____ State: SD Zip Code: 57353

Telephone: Home :(605) 546-2191 Business : cell: 605-350-3924

Tenant(s): Kim Madsen

Address: 18852 415th Ave City/Town: Carpenter

County: _____ Township: _____ State: SD Zip Code: 57322

Telephone: Home : 605-352-7339 Business : _____

Met with Kim Madsen the tenant. He showed us the runoff area on this tract. He said he losses approximately 3 acres of crop because of the runoff from the PS.

Patrick Fuller
Land Representative

8/21/14
Date

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-MN-0795.0000 & 0796.0000

Legal Description: S2SW4 Sec. 28 T106N R57W

Additional Legal Information: _____

Landowner(s): Michael B. Sibson and Susan K. Sibson

Address: 23782 426th Ave. City/Town: Howard,

County: Township: _____ State: SD Zip Code: 57349

Telephone: Home: 605-772-5184 Cell: 605-770-2800 Business:

Tenant(s):

Address: City/Town:

County: Township: _____ State: NE Zip Code:

Telephone: Home: Cell: Business:

Contact Summary:

Talked with Mike and Sue and waited around while the weed control was being done on their property. Sue asked if they was getting compensated for the water use the repair crew is using to spray other tracts not owned by them. I told them that the repair crew will pay that.

Patrick Fuller
Land Representative

7-18-14
Date

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-MN-0795.0000

Legal Description: S2SW4 Sec. 28 T106N R57W

Additional Legal Information:_____

Landowner(s): Michael B. Sibson and Susan K. Sibson

Address: 23782 426th Ave. City/Town: Howard,

County: Township: _____ State: SD Zip Code: 57349

Telephone: Home: 605-772-5184 Cell: 605-770-2800 Business:

Tenant(s):

Address: City/Town:

County: Township:_____ State: NE Zip Code:

Telephone: Home: Cell: Business:

Contact Summary:

Eric and I went to meet with Mr. & Mrs. Sibson. They called last week complaining about the air plane spooking the calves they have. They stated the plane flew over on the west side of the ROW near there home and cattle pens. They wanted the name and number for the company that does the flights. We was informed by Josh that he is correct person to contact and we informed the Sibson's. They stated that the fly over had been very good about this until the other day. They also stated if they don't do as was promised about flying on the east side they will take this matter up with there attorney. We told them we would inform the proper personnel about this.

Patrick Fuller
Land Representative

1-13-14
Date

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-MN-0795.0000

Legal Description: S2SW4 Sec. 28 T106N R57W

Additional Legal Information: _____

Landowner(s): Michael B. Sibson and Susan K. Sibson

Address: 23782 426th Ave. City/Town: Howard,

County: Township: _____ State: SD Zip Code: 57349

Telephone: Home: 605-772-5184 Cell: 605-770-2800 Business:

Tenant(s):

Address: City/Town:

County: Township: _____ State: NE Zip Code:

Telephone: Home: Cell: Business:

Contact Summary:

Mr. Sibson called this morning and we had a very good conversation. I told him that Eric and myself will be seeing him and his wife next week and we would let him know what day. He said any day would be good except for Thursday. He explained the layout of his property and it made it clearer to me what the issue is. I told him I called yesterday only to assure them that we are on top of the issue. He said he would like to get the number of the company doing the flyovers. I told him we are trying but we could not guarantee that we would get the information.

Patrick Fuller
Land Representative

1-9-14
Date

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-MN-0795.0000

Legal Description: S2SW4 Sec. 28 T106N R57W

Additional Legal Information: _____

Landowner(s): Michael B. Sibson and Susan K. Sibson

Address: 23782 426th Ave. City/Town: Howard,

County: Township: _____ State: SD Zip Code: 57349

Telephone: Home: 605-772-5184 Cell: 605-770-2800 Business:

Tenant(s):

Address: City/Town:

County: Township: _____ State: NE Zip Code:

Telephone: Home: Cell: Business:

Contact Summary:

Received a copy of a email Eric sent to Josh Thompson. It stated the Sibsons called Eric and had a complaint about the flyover. I left the Sibsons a message with my name and phone numbers and informing them we are looking into the issue. I also introduced myself and left them both my phone numbers and told them I look forward to meeting with them. I also asked for them to call me if they would like to.

Patrick Fuller
Land Representative

1-8-14
Date

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-MN-0795.0000 & 0796.0000

Legal Description: S2SW4 Sec. 28 T106N R57W

Additional Legal Information: _____

Landowner(s): Michael B. Sibson and Susan K. Sibson

Address: 23782 426th Ave. City/Town: Howard,

County: Township: _____ State: SD Zip Code: 57349

Telephone: Home: 605-772-5184 Cell: 605-770-2800 Business:

Tenant(s):

Address: City/Town:

County: Township: _____ State: NE Zip Code:

Telephone: Home: Cell: Business:

Contact Summary:

Talked with Mike and Sue and waited around while the weed control was being done on their property. Sue asked if they was getting compensated for the water use the repair crew is using to spray other tracts not owned by them. I told them that the repair crew will pay that.

Patrick Fuller
Land Representative

7-18-14
Date

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-MN-0796.0000

Legal Description: S2SW4 Sec. 28 T106N R57W

Additional Legal Information:_____

Landowner(s): Michael B. Sibson and Susan K. Sibson

Address: 23782 426th Ave. City/Town: Howard,

County: Township: _____ State: SD Zip Code: 57349

Telephone: Home: 605-772-5184 Cell: 605-770-2800 Business:

Tenant(s):

Address: City/Town:

County: Township:_____ State: NE Zip Code:

Telephone: Home: Cell: Business:

Contact Summary:

Eric and I went to meet with Mr. & Mrs. Sibson. They called last week complaining about the air plane spooking the calves they have. They stated the plane flew over on the west side of the ROW near there home and cattle pens. They wanted the name and number for the company that does the flights. We was informed by Josh that he is correct person to contact and we informed the Sibson's. They stated that the fly over had been very good about this until the other day. They also stated if they don't do as was promised about flying on the east side they will take this matter up with there attorney. We told them we would inform the proper personnel about this.

Patrick Fuller
Land Representative

1-13-14
Date

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-MN-0796.0000

Legal Description: S2SW4 Sec. 28 T106N R57W

Additional Legal Information:_____

Landowner(s): Michael B. Sibson and Susan K. Sibson

Address: 23782 426th Ave. City/Town: Howard,

County: Township: _____ State: SD Zip Code: 57349

Telephone: Home: 605-772-5184 Cell: 605-770-2800 Business:

Tenant(s):

Address: City/Town:

County: Township:_____ State: NE Zip Code:

Telephone: Home: Cell: Business:

Contact Summary:

Mr. Sibson called this morning and we had a very good conversation. I told him that Eric and myself will be seeing him and his wife next week and we would let him know what day. He said any day would be good except for Thursday. He explained the layout of his property and it made it clearer to me what the issue is. I told him I called yesterday only to assure them that we are on top of the issue. He said he would like to get the number of the company doing the flyovers. I told him we are trying but we could not guarantee that we would get the information.

Patrick Fuller
Land Representative

1-9-14
Date

Keystone Pipeline Project

Contact Summary Report

Tract No. ML-SD-MN-0796.0000

Legal Description: S2SW4 Sec. 28 T106N R57W

Additional Legal Information: _____

Landowner(s): Michael B. Sibson and Susan K. Sibson

Address: 23782 426th Ave. City/Town: Howard,

County: Township: _____ State: SD Zip Code: 57349

Telephone: Home: 605-772-5184 Cell: 605-770-2800 Business:

Tenant(s):

Address: City/Town:

County: Township: _____ State: NE Zip Code:

Telephone: Home: Cell: Business:

Contact Summary:

Received a copy of a email Eric sent to Josh Thompson. It stated the Sibsons called Eric and had a complaint about the flyover. I left the Sibsons a message with my name and phone numbers and informing them we are looking into the issue. I also introduced myself and left them both my phone numbers and told them I look forward to meeting with them. I also asked for them to call me if they would like to.

Patrick Fuller
Land Representative

1-8-14
Date

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE PETITION OF TRANSCANADA KEYSTONE PIPELINE, LP FOR ORDER ACCEPTING CERTIFICATION OF PERMIT ISSUED IN DOCKET HP09-001 TO CONSTRUCT THE KEYSTONE XL PIPELINE	* * * * * * * * *	**STAFF'S RESPONSE TO DAKOTA RURAL ACTION'S FIRST SET OF INTERROGATORIES AND DATA REQUESTS** **HP14-001**

COMES NOW, Commission Staff by and through its attorney of record, Kristen N. Edwards, and hereby provides the following Response to Dakota Rural Action's First Set of Interrogatories and Data Requests ("Response"). For the purpose of this response any reference to "dockets" refers to HP09-001 and HP14-001, unless otherwise stated.

Dated this 6th day of February, 2015.

Kristen N. Edwards, Staff Attorney
PUC Staff
500 East Capitol Avenue
Pierre, SD 57501

INTERROGATORIES

INTERROGATORY NO. 1. Please identify the person or persons providing each answer to an Interrogatory or portion thereof, giving the full name, address of present residence, date of birth, business address and occupation. *[Applicable Finding or Condition No.: all]*

RESPONSE: OBJECTION. Staff objects as to the relevance of the address of present residence and date of birth for each person providing each answer. Subject to and without waiving its objection, Staff will provide the name, occupation, and business address of the persons providing each answer to the Interrogatories.

Kristen Edwards
Staff Attorney
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501

Darren Kearney
Staff Analyst
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501

Brian Rounds
Staff Analyst
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501

Mary Zanter
Pipeline Safety Program Manager
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501

INTERROGATORY NO. 2. Prior to answering these interrogatories, have you made due and diligent search of all books, records, and papers of the Applicant with the view of eliciting all information available in this action? *[Applicable Finding or Condition No.: all]*

RESPONSE: Staff has exercised due diligence, however, we will continue to review the evidence throughout the certification processes and as new information becomes available.

INTERROGATORY NO. 3. Describe the current status of the following permits and plans required prior to the start of construction of the KXL Pipeline:

A. Permits from US Army Corps of Engineers, S.D. Regulatory Office, including under:

1) §§404/401 of Clean Water Act, for authorization of discharge of fill material into waters of the United States including wetlands or other action;
2) §10 Rivers and Harbors Act, for authorization of pipeline crossings of navigable waters of the United States or other action;
3) Section 106 of the Natural Historic Preservation Act (NHPA), including consultation with potentially impacted Tribes and/or other action;

B. Permits from U.S. Fish and Wildlife Service, S.D. Ecological Services Field Office, including under the Endangered Species Act, Section 7 Consultation, to consider lead agency findings of impacts on federal-listed species, to provide a Biological Opinion if the Project is likely to adversely affect federally-listed or proposed species or their habitats, or other action;

C. Permits from Farm Service Agency of the Natural Resources Conservation Service, including the Crop Reserve Program, for authorization of crossing areas enrolled in the Crop Reserve Program, or other action;

D. Permits from the Pipeline and Hazardous Materials Safety Administration (PHMSA), including under 49 CFR Parts 194 and 195, for development of an Integrity Management Plan (IMP) and Emergency Response Plan (ERP), or other action;

E. Permit(s) from or Plan(s) Required to the South Dakota Department of Environment and Natural Resources (DENR), including under:

1) National Pollutant Discharge Elimination System General Permit for Discharges of Hydrostatic Test Water, regarding proposed discharge into waters of the United States and construction dewatering of waters of the State, or other action;
2) Surface Water Withdrawal Permit, for temporary surface water withdrawal, or other action;
3) SDCL Chapter §34A-18, required submission of an Oil Spill Response Plan or Updated Plan to DENR, or other action;

F. Consultation with SD Game Fish and Parks Department, under State Listed Threatened and Endangered Species;

G. Any Updated Review and Comment from South Dakota State Historical Society, State Preservation Office, under §106 of the NHPA, on activities regarding jurisdictional cultural resources;

H. Crossing Permits from South Dakota Department of Transportation for crossing State highways;

I. Crossing Permits from County Road Departments for crossing of county roads;

J. Flood plain, Conditional Use, and building permits where required from County and Local Authorities.

[Applicable Finding or Condition No.: Conditions 1, 2; Findings 12(1)-(3), 60, 88, 90, 97-99]

RESPONSE: OBJECTION. This question improperly attempts to shift the burden to produce permits from the Company to Staff. Subject to and without waiving the objection, Staff provides the following answer.

Staff does not have this information, nor is it readily obtainable. The PUC is neither the issuer nor the issuee of the permits listed in Interrogatory No. 3. The only information Staff has regarding the status of permits is the information provided by Keystone in its Quarterly Report. This most recent information can be found in Section 5.0 of the December 31, 2014 Quarterly Report, filed in docket HP09-001.

As for consultation with SD Game Fish and Parks Department (GF&P), as described in subpart F of the interrogatory, Staff does not have this information, but does intend to call a witness from GF&P and will continue to work with that witness to gather information. Therefore, no additional information, beyond what is available in Docket No. HP09-001 is available at present. Staff will supplement this response if necessary in the future.

In response to subparts H and I, this information is included in Keystone's Quarterly Report, which the PUC has made available online. For current information, see the most recent quarterly report filed in HP09-001

INTERROGATORY NO. 4. Do you agree that diluted bitumen spills require different spill response techniques and different equipment types and amounts as compared to (a) a spill of conventional crude oil and (b) a spill of Williston Basin light crude oil? Please explain your answer and list any scientific study(ies) providing the basis for your answer. *[Applicable Finding or Condition No.: Amended Condition 31-42]*

RESPONSE: OBJECTION. The question calls for a legal conclusion. Subject to and without waiving the objection, Staff provides the following answer.

Staff does not have an opinion at this time but will continue to work with its experts to investigate this issue.

INTERROGATORY NO. 5. Do you agree that diluted bitumen is heavier than conventional crude and results in greater expenses to remediate leaks or spills? Please explain your answer and identify any known scientific study(ies) providing the basis for your answer. *[Applicable Finding or Condition No.: Amended Condition 31-42/]*

RESPONSE: OBJECTION. This question improperly attempts to shift the burden concerning whether the project continues to meet the conditions upon which the permit was granted from the Company to Staff. Subject to and without waiving the objection, Staff provides the following answer.

Staff does not have an opinion at this time but will continue to work with its experts to investigate this issue.

INTERROGATORY NO. 6. Do you agree that soil and rocks that are contaminated by oil spills cannot be cleaned but instead must be removed and disposed of in hazardous waste facilities? Please explain your answer and list any scientific study(ies) providing the basis for your answer.

A. If so, do you agree that reclamation efforts for oil spills of the magnitude of the worst case discharge amount for the Keystone XL Pipeline fail to recover 100% of the oil contaminating the ground?

B. Identify the Documents created by or on your behalf which would show the basis for your answer to this Interrogatory.

[Applicable Finding or Condition No.: Amended Condition 32-38]

RESPONSE: OBJECTION. This question improperly attempts to shift the burden concerning whether the project continues to meet the conditions upon which the permit was granted from the Company to Staff. Subject to and without waiving the objection, Staff provides the following answer.

Staff does not have an opinion at this time but will continue to work with its experts to review this issue.

INTERROGATORY NO. 7. Describe how the PUC Staff plans to monitor compliance of TransCanada with all conditions imposed by the PUC, together with all applicable laws, and regulations:

A. During construction;
B. During proposed operation;

[Applicable Finding or Condition No.: Amended Condition 1; Finding 73]

RESPONSE: As per the Amended Final Decision and Order in HP09-001, Keystone must provide quarterly reports to the Commission. In addition, the Commission has a formal complaint process available to any person who has a grievance against the company. Staff will also be reviewing compliance filings and following up with any issues we find.

INTERROGATORY NO. 8. Does the PUC Staff have inspectors who will monitor on-site construction of the KXL pipeline?

A. State the number of inspectors;
B. Describe the expertise of each of these inspectors in relevant fields regarding crude oil pipeline construction and operation;
C. Describe how often and what type of inspectors will be on-site:
   i. During construction of the KXL Pipeline;
   ii. During operation of the KXL Pipeline.

[Applicable Finding or Condition No.: Amended Condition 1; Finding 73]

RESPONSE: No. Keystone XL would operate as an interstate pipeline and would, therefore, be under federal jurisdiction for purposes of inspection. The authority to grant siting permits is the sole authority of the PUC with respect to interstate pipelines. Please refer to page 4 of the prefiled testimony of William Walsh in HP09-001.

INTERROGATORY NO. 9. State whether or not the PUC Staff monitors or tracks spill/leak incidents involving operations of TransCanada and its Affiliates:

A. Within South Dakota?

B. Outside South Dakota?
   i. Within the United States;
   ii. Within Canada;

C. To the extend PUC Staff monitors or tracks any of the foregoing, describe the monitoring and tracking procedures engaged in and identify any documents regarding monitoring or tracking procedures, processes or instructions.

[Applicable Finding or Condition No.: Amended Condition 1; Finding 73]

RESPONSE: The PUC does not monitor or track spill/leak incidents involving operations of TransCanada and its Affiliates within or outside of South Dakota. This task is within the jurisdiction of the federal government. Staff suggests contacting either the company itself or the South Dakota Department of Environment and Natural Resources.

INTERROGATORY NO. 10. For each incident since January 1, 2010 in which any pipeline transporting crude oil constructed by TransCanada and its Affiliates in South Dakota leaked or spilled pipeline contents, the:

A. Date;

B. Location:

C. Amount of materials leaked or spilled;

D. Actions taken by the PUC to prevent re-occurrence which did not involve design or construction procedure changes in pipeline material composition or dimensions, or construction procedures for use in the pipeline which suffered the incident.

E. Actions taken to prevent re-occurrence which involved design or construction procedure changes in pipeline material composition or dimensions, or construction procedures for use in construction of the proposed KXL Pipeline;

F. Identify and produce the documents which support your answers, above, including any incident reports.

[Applicable Finding or Condition No.: Findings 12(2)-(3), 41-45, 47, 103; Amended Condition 32-38]

RESPONSE: OBJECTION. This question attempts to shift the regulatory burden from the federal government and the South Dakota Department of Environment Natural Resources (DENR) to the PUC. Subject to and without waiving the objection, Staff provides the following answer.

Because TransCanada reports to the federal government, specifically to agencies such as the Pipeline and Hazardous Materials Safety Administration, Staff does not have this information. Staff suggests contacting either the company itself or DENR. This information may also be accessible through DENR's website (http://arcgis.sd.gov/server/denr/spillsviewer/). However, PUC Staff cannot vouch for the accuracy of the information on DENR's website.

INTERROGATORY NO. 11: Identify all other crude oil pipeline operations of TransCanada and its Affiliates in South Dakota which, since 2009, have or are operating at a maximum operating pressure (MOP) of equal to or greater than 1,440 psig generally and/or 1,600 psig MOP for specific low elevation segments of pipeline with the same design factor and pipe wall thickness as described in Finding 19, close to the discharge of pump stations:

A. For each such pipeline which subsequently developed a leak or spill, regardless of the psig MOP the pipeline was operating at the time, giving date, location, amount spilled/leaked, psig MOP at which pipeline was operating at the time, and describe the amount and nature of damage caused by such a leak or spill;

B. Identify any documents upon which your answers to these Interrogatories were based;

[Applicable Finding or Condition No.: Findings 19, 28]

RESPONSE: The Keystone Pipeline in eastern South Dakota is the only crude oil pipeline operated by TransCanada and its Affiliates in South Dakota of which Staff has knowledge. The PUC sited this pipeline in Docket HP07-001. For information on leaks and spills on this pipeline, see Staff's answer to Interrogatory No. 10.

INTERROGATORY NO. 12: For each spill/leak incident which has occurred from a pipeline transporting Western Canadian Sedimentary Basin (WCSB) crude oil operated by TransCanada and its Affiliates since 2009 in South Dakota, state the dates on which transportation of the crude oil through that pipeline was disrupted by planned maintenance, unplanned maintenance, power outages, spills, leaks, or any other causes. Identify any documents upon which your answers to this Interrogatory was based. *[Applicable Finding or Condition No.: Finding 28]*

RESPONSE: OBJECTION. This question attempts to shift the regulatory burden from the federal government to the state. Subject to and without waiving the objection, Staff provides the following answer.

Because this information is not reported to the PUC, Staff does not have this information.

INTERROGATORY NO. 13: Explain why TransCanada has reduced the maximum operating pressure of the KXL pipeline at most locations to 1,307 psig;

A. State whether the PUC Staff has received information or a commitment from TransCanada about any future plans to subsequently increase this general operating pressure;

B. If your answer to subpart A of this interrogatory is yes, what is the subsequent maximum operating pressure being contemplated for general use during pipeline operations?

C. Explain the PUC Staff's understanding of why TransCanada wants to construct the KXL pipeline pump stations with pumps of sufficient capacity to meet the maximum design flow rate of 830,000 bpd.

[Applicable Finding or Condition No.: Conditions 31-38; Findings 19, 20]

RESPONSE: OBJECTION. This question improperly attempts to shift the burden concerning whether the project continues to meet the conditions upon which the permit was granted from the Company to Staff. Subject to and without waiving the objection, Staff provides the following answer.

This is information that Staff has requested of TransCanada in the discovery process. If necessary, Staff will supplement its response to this interrogatory as more information becomes available.

INTERROGATORY NO. 14: With regard to the plan for mainline valves to be remotely controlled, what guarantee has been received from TransCanada that it is capable of preventing any cyber-security attack on the control system?

A. Describe the worst case scenario which could occur in the event of a computer systems security breach on the control system for the KXL Pipeline.

B. Describe the data security systems TransCanada has indicated to the PUC Staff that it has or plans to be put in place to prevent any such system breach, identify any third-party vendor(s) providing system security software, hardware or monitoring, and identify the particular components or scopes of services such vendors will provide.

C. Identify any documents used to support your answer to this Interrogatory.

[Applicable Finding or Condition No.: Conditions 31-38; Finding 20]

RESPONSE: At this time, Staff does not have the information to answer this question but will continue to investigate this issue throughout the discovery process.

INTERROGATORY NO. 15: Provide the dates on which pipe segments to be used in South Dakota were delivered to storage location in South Dakota or adjacent states and state whether the PUC Staff has or plans to independently inspect the integrity of the stockpiled pipe lengths. If PUC Staff is planning to conduct inspections, describe how those inspections would occur and what factors or information would be reviewed during the course of such inspections.

A. Identify any documents which would support your answers.

[Applicable Finding or Condition No.: Finding 18]

RESPONSE: OBJECTION. The question is argumentative, as it requires the adoption of the assumption that pipe segments have, in fact, been delivered to South Dakota. Subject to and without waiving its objection, Staff provides the following answer.

Staff has no knowledge of pipeline segments being delivered to South Dakota for use on the Keystone XL Pipeline. However, federal regulations do provide for how pipe must be stored, and TransCanada must comply with those regulations.

INTERROGATORY NO. 16: State whether any power lines have been permitted and constructed to provide power to pump stations by local power providers;

A. Identify each such power line;

B. If any State or Tribal permit or other authorization is required for any planned construction of power lines to pump stations:

i. Identify the permits which have been obtained, together with date permit granted;
ii. Identify permits which have not yet been obtained;
iii. Identify which permits have been applied for and are pending.

C. Identify any documents which would support your answers to this interrogatory.

[Applicable Finding or Condition No.: Finding 20; Amended Condition 1]

RESPONSE: No permits have been sought from the PUC for power lines in connection with the Keystone XL pipeline at this time. It is Staff's understanding that Basin Electric Power Cooperative will need to file for a permit to construct a proposed 230-kV transmission line from Big Bend substation to Witten substation. This project is discussed in the Department of State's Final Supplemental Environmental Impact Statement and the Environmental Assessment prepared specifically for the transmission line project.

INTERROGATORY NO. 17: List the changes in the KXL Project route since 2010 and identify any documents which would support your answers. *[Applicable Finding or Condition No.: Finding 33]*

RESPONSE: Staff has sought this information from TransCanada in a discovery request. We do not have this information at this time.

INTERROGATORY NO. 18: Identify paleontological studies within the Upper Cretaceous or Tertiary strata of which you have knowledge were conducted after 2009 in the proximate location of the currently proposed KXL pipeline route and identify any documents which would support your answers. *[Applicable Finding or Condition No.: Findings 34, 36; Conditions 43, 44]*

RESPONSE: OBJECTION. The interrogatory attempts to illicit an answer that would incorrectly have the burden of proof concerning environmental issues to Staff. It is the Company's burden to provide this information.

At this time Staff only has knowledge of certain paleontological studies conducted after 2009 that were completed in order to prepare the Department of State's Final Supplemental Environmental Impact Statement (FSEIS). Descriptions of the studies performed are included in section 3.1.2.3 of the FSEIS.

INTERROGATORY NO. 19: Identify Section 106 type "cultural resource" studies of which you have knowledge that were conducted after 2009 in the proximate location of the currently proposed KXL pipeline route and identify any documents which would support your answers. *[Applicable Finding or Condition No.: Conditions 43, 44]*

RESPONSE: At this time, Staff has knowledge of certain cultural resource studies conducted after 2009 that were completed in order to prepare the Department of State's Final Supplemental Environmental Impact Statement (FSEIS). Descriptions of the studies performed are included in section 3.11.3.3 of FSEIS.

INTERROGATORY NO. 20: TransCanada is to identify the exact locations of active, shut-in, and abandoned wells and any associated underground pipelines in the construction ROW. What is the status of such identification procedures?

A. How long does TransCanada expect such an identification process will take before the Company would be willing to assure the PUC that all such wells and pipelines have been identified;

B. Has TransCanada communicated to the PUC Staff how long it expects such an identification process will take before TransCanada would be willing to assure the PUC that all such wells and pipelines have been identified;

C. How does the PUC Staff intend to ensure compliance by TransCanada with regulations, laws and PUC conditions, in order to protect water resources from contamination?

D. Identify any documents which would support your answers.

[Applicable Finding or Condition No.: Conditions 15, 16, 21, 22, 42]

RESPONSE: OBJECTION. The interrogatory attempts to illicit an answer that would incorrectly have the burden of proof concerning environmental issues to Staff. It is the Company's burden to provide this information.

INTERROGATORY NO. 21. Describe the worst case scenario for landowners of a spill from the proposed pipeline onto only land, as well as other risks deemed "low" by the PUC. Identify any documents which would support your respective answer. *[Applicable Finding or Condition No.: Findings 57; Conditions 16, 31-38]*

RESPONSE: OBJECTION. This question improperly attempts to shift the burden concerning whether the project continues to meet the conditions upon which the permit was granted from the Company to Staff. Subject to and without waiving the objection, Staff provides the following answer.

Staff has requested that TransCanada update that information.

INTERROGATORY NO. 22. Provide a list of claims or complaints (of any kind) made to the Commission by landowners along the existing Keystone I pipeline corridor since 2008. Identify any documents which would support your respective answer. *[Applicable Finding or Condition No.: Finding 57; Conditions 49-50]*

RESPONSE: There have been no formal complaints to the PUC, however, landowner concerns were included in the Liaison Annual Report filed in Docket No. HP09-001. See Section 5 of the most recent Liaison Annual Report.

INTERROGATORY NO. 23. What is the understanding of PUC Staff as to why TransCanada has sought a special permit from the PHMSA for authorization "to design, construct, and operate the Project up to 80% of the steel pipe specified minimum yield strength at most locations."

A. Identify and describe all spills/leaks from TransCanada (or its Affiliates) pipeline operations since 2009 in South Dakota which have involved a "0.8 design factor" and therefore involving use of steel pipe up to 80% of the specified minimum yield strength.

B. Identify documents upon which your answers are based.

[Applicable Finding or Condition No.: Findings 60-61]

RESPONSE: TransCanada is no longer seeking a special permit. TransCanada now seeks to operate at 70% of SMYS.

INTERROGATORY NO. 24. Explain the PUC's understanding of how application of the "0.8 design factor and API 5L PSL2 X70 high-strength steel pipe" with thinner walls would "provide a level of safety equal to or greater than that which would be provided if the pipeline were operated under the otherwise applicable regulations." *[Applicable Finding or Condition No.: Finding 63]*

RESPONSE: This is no longer relevant, as TransCanada is no longer seeking a special permit.

INTERROGATORY NO. 25. Describe how the PUC Staff plans to ensure that TransCanada will thoroughly implement procedures in the CMR to minimize impacts on cultivated lands, grasslands, wetlands, streams, and waterways? Identify documents upon which your answers are based. *[Applicable Finding or Condition No.: Finding 73]*

RESPONSE: There are three methods identified in the *Amended Final Decision and Order; Notice of Entry* that will ensure TransCanada fully and thoroughly implements the CMR. These methods include self-monitoring by TransCanada, self-reporting by TransCanada, and the Commission's formal complaint process.

First, TransCanada will self-monitor the implementation of the CMR through the use of Environmental Inspectors on each construction spread. (Condition 14 and Section 2.2 of the CMR). The Environmental Inspector has the authority, subject to approval from the Chief Environmental Inspector, to stop work and order corrective action if activities violate the CMR. (Section 2.2 of CMR).

Second, TransCanada is required to submit quarterly reports to the Commission until reclamation is complete. According to Condition 8 of the *Amended Final Decision and Order; Notice of Entry*, the quarterly reports must summarize "the status of land acquisition and route finalization, the status of construction, ***the status of environmental control activities***, including permitting status and Emergency Response Plan and Integrity Management Plan development, ***the implementation of the other measures required by these conditions***, and the overall percent of physical completion of the project and design changes of a substantive nature." [***emphasis added***]. PUC Staff expects TransCanada to self-report its implementation of the CMR, or any deviations in the implementation of the CMR, in the quarterly reports in accordance with Condition 8. Should TransCanada self-report any deviations from the CMR, PUC Staff can follow-up with the company in order to ensure proper corrective actions were taken. If issues with CMR implementation remain unresolved, PUC Staff can file a formal complaint against TransCanada as discussed in the following paragraph.

Third, Condition 50 of the *Amended Final Decision and Order; Notice of Entry* identifies that "the Commission's complaint process as set forth in ARSD 20:10:01 shall be available to landowners, other persons sustaining or threatened with damage or the consequences of Keystone's failure to abide by the conditions of the permit or otherwise having standing to obtain enforcement of the conditions of the Order and Permit." Should a landowner or other affected person report to the PUC Staff that TransCanada failed to properly implement the CMR, PUC Staff can either bring a formal complaint against TransCanada or instruct the affected person on how to file a formal complaint. If a complaint is brought before the Commission, the Commission will make its decision on how to resolve the matter based on the specific facts presented during the complaint proceeding.

INTERROGATORY NO. 26. Since 49 CFR Part 195 would require TransCanada Keystone to conduct an "internal inspection" of any pipe section(s) potentially moved by abnormal ground movement, describe the PUC's understanding of the timeframe within which an inspection would take place considering the time required to transport personnel and equipment from their staging area to the most distant segment of the KXL Pipeline in South Dakota, and the time required to notify and mobilize inspectors to their staging area. Identify documents upon which your answers are based.

[Applicable Finding or Condition No.: Finding 101; Conditions 31-38]

RESPONSE: OBJECTION. This question attempts to shift the regulatory burden from the federal government to the state. Subject to and without waiving the objection, Staff provides the following answer.

South Dakota does not have jurisdiction of hazardous liquid lines. Enforcement of 49 CFR is under federal jurisdiction of PHMSA.

INTERROGATORY NO. 27. Identify and produce the most recent IMP submitted to the Commission by TransCanada, including but not limited to section in it related to HCAs. *[Applicable Finding or Condition No.: Finding 102; Conditions 1-2]*

RESPONSE: OBJECTION. This question attempts to shift the regulatory burden from the federal government to the state. Subject to and without waiving the objection, Staff provides the following answer.

South Dakota does not have jurisdiction of hazardous liquid lines. Enforcement of the IMP and related HCAs is under federal jurisdiction of PHMSA.

INTERROGATORY NO. 28. Itemize the property tax payments paid by TransCanada and its Affiliates to respective South Dakota towns, cities, and counties each year since 2010 for the existing Keystone I pipeline and identify the documents upon which you relied to answer these questions;

[Applicable Finding or Condition No.: Finding 23, 102, 108; Conditions]

RESPONSE: The PUC does not have access to this information. It is Staff's belief that this information is held by the Dept. of Revenue.

INTERROGATORY NO. 29. With respect to the jobs TransCanada has alleged it will bring to South Dakota by its proposed pipeline project, describe the most current information provided by TransCanada:

A. As to the number, job title, and expected duration of the temporary construction related jobs provided, and:

i. The percentage of South Dakota citizens are expected to be hired for each job title. ii. Is there any preference for South Dakota citizens to obtain any or all of these
temporary jobs?
iii. State the number and percentage of the total construction jobs expected to be already be filled by out-of-state workers.

B. Describe the most recent information provided by TransCanada as to the number, type, and expected duration of the permanent jobs expected, and;

i. State the number of permanent jobs it expects to be held by current South Dakota citizens, as opposed to someone who moves from out of state to South Dakota to take the job, and;
ii. Will there any preference for South Dakota citizens to obtain any or all of the permanent jobs in South Dakota?

C. Identify the documents upon which you relied to answer these questions;

[Applicable Finding or Condition No.: Finding 23, 102, 108; Conditions 1-2]

RESPONSE: All information the PUC has relevant to this question is posted in Docket No. HP09-001 and is available to the public.

INTERROGATORY NO. 30. Should there be a worst case discharge or even a substantial release of crude oil into farmland and/or water resources and/or an explosion of the pipeline near homes or towns with people, would the PUC Staff still have confidence the proposed KXL Pipeline Project would have only a "minimal" effect on the health, safety, or welfare of its inhabitants. Identify the documents upon which you relied to answer these questions.

[Applicable Finding or Condition No.: Finding 23, 102, 108; Conditions 1,2, 31-36]

RESPONSE: OBJECTION. Staff objects to this interrogatory as it calls for a legal conclusion. Subject to and without waiving its objection, Staff provides the following answer.

SDCL 49-41B-22 does not require the Commission to conclude that the project would have a "minimal" effect on the health, safety, or welfare of the inhabitants. The statute identifies that the company must prove the facility will not "substantially" impair the health, safety, or welfare of the inhabitants.

REQUESTS FOR PRODUCTION

1. All documents identified or referred to in your Answers to DRA's First Interrogatories to you. ***[Applicable Finding or Condition No.: all]***

a. The December 31, 2014 Quarterly Report can be accessed at http://www.puc.sd.gov/commission/dockets/hydrocarbonpipeline/2009/hp09-001/quarterlyreport123114.pdf. All Quarterly Reports submitted by Keystone are available in Docket HP09-001.

b. The Department of State's Final Supplemental Environmental Impact Statement, which can be accessed at: http://keystonepipeline-xl.state.gov/finalseis/

c. The Liaison Annual report, referenced in Staff's answer to Interrogatory No. 22 is also available in Docket HP09-001, and can be accessed at http://www.puc.sd.gov/commission/dockets/HydrocarbonPipeline/2009/HP09-001/liasonreport2014.pdf.

d. U.S. Department of Agriculture Rural Utilities Service's Big Bend to Witten 230-kv Transmission Project Environmental Assessment, which can be accessed at: http://www.wapa.gov/ugp/Environment/documents/BigBendtoWitten_EA_Nov_2014_Final.pdf

2. All documents and correspondence presented to any expert in connection with the above-captioned proceedings, or received from any expert, including but not limited to emails, letters, engagement documents, resumes, curriculum vitaes, reports, analysis, spreadsheets, schedules, and any drafts thereof. ***[Applicable Finding or Condition No.: all]***

a. OBJECTION. Staff objects to the request for all correspondence presented to

any expert or received from any expert. All correspondence was conducted by Staff's attorney of record and is, therefore, attorney work product.

b. OBJECTION. Staff objects to the request for production of engagement documents as not relevant to the proceedings. Subject to and without waiving its objection, staff provides the following subpoenas:

   i. Attachment 9, Subpoena of Brian Walsh

   ii. Attachment 10, Subpoena of Derric Iles

   iii. Attachment 11, Subpoena of Kimberly McIntosh

   iv. Attachment 12, Subpoena of Paige Olson

   v. Attachment 13, Subpoena of Tom Kirschenmann

c. Staff provides the following resumes and curriculum vitae, and will provide the same for its other witnesses as they are received:

   i. Attachment 1, Resume of Darren Kearney

   ii. Attachment 2, Resume of Kimberly McIntosh (not attached, as not been received by Staff)

   iii. Attachment 3, Resume of Brian Walsh

   iv. Attachment 4, Resume of Paige Olson

   v. Attachment 5, Resume of Tom Kirschenmann

   vi. Attachment 3, Resume of Daniel Flo

   vii. Attachment 7, Resume of Jenny Hudson (not attached, has not been received by Staff)

   viii. Attachment 8, Resume of Derric Iles

d. At this time, Staff has not received any reports, analysis, spreadsheets, schedules,

or drafts at this time.

3. The most recent resume or curriculum vitae of each expert whom you expect to call as an expert witness at the hearing before the Commission. ***[Applicable Finding or Condition No.: all]***

See previous answer.

4. The written reports of experts who are expected to testify on behalf of the PUC. ***[Applicable Finding or Condition No.: all]***

Staff has not received any reports at this time.

5. All correspondence between TransCanada or its Affiliates and the Commission or Commission Staff concerning the Project. ***[Applicable Finding or Condition No.: all]***

OBJECTION. Staff objects to this request on the grounds of attorney work product. All communications between Staff and TransCanada have been conducted by attorneys and are, therefore, the subject of attorney work product. Furthermore, Staff operates as a party, separate from the Commission and does not have access to or knowledge of Commission communications.

6. All documents concerning a change in routing of the Project between 2010 and the present date, including but not limited to, any parcel maps showing the precise location of the proposed Project through South Dakota. ***[Applicable Finding or Condition No.: Finding 16]***

OBJECTION. The request attempts to shift the burden for production from the Company to Staff. Subject to and without waiving its objection, Staff asserts that it does not have this information and this time, but has requested updated maps and information from the Company.

7. All documents setting forth TransCanada's proposed construction schedule for the Project, and all contracts for construction of the proposed Project. ***[Applicable Finding or Condition No.: Finding 17]***

OBJECTION. The request attempts to shift the burden for production from the Company to Staff.

8. All documents showing location of power lines for pumping stations proposed for the Project, the location of proposed pumping stations and mainline valves for the Project in South Dakota, and including, but not limited to all communications between TransCanada's or its Affiliates' staff, consultants, advisors, or other parties and the PUC concerning location and operation of pumping stations, mainline valves, and the proposed conversion of valves to remote control operations. ***[Applicable Finding or Condition No.: Finding 20]***

OBJECTION. The request attempts to shift the burden for production from the Company to Staff. Subject to and without waiving its objection, Staff submits that it does not have any relevant information.

9. All documents describing soil types and conditions along the currently-proposed Project route through South Dakota. ***[Applicable Finding or Condition No.: Finding 33]***

OBJECTION. The request attempts to shift the burden for production from the Company to Staff. Subject to and without waiving its objection, Staff informs that it does not have any information supplementary to what has been made publicly available in the dockets.

10. All documents describing, discussing, or setting forth plans for the Project to cross perennial streams and rivers, intermittent streams, and ephemeral streams in

South Dakota, including but not limited to all documents concerning the methodology used by TransCanada (and its Affiliates) or its agents in determining construction plans for the Project across such waterways. ***[Applicable Finding or Condition No.: Finding 41]***

OBJECTION. The request attempts to shift the burden for production from the Company to Staff. Subject to and without waiving its objection, Staff informs that it does not have any information supplementary to what has been made publicly available in the dockets.

11. All documents concerning the reduction in the length of the proposed Project potentially affecting High Consequence Areas. ***[Applicable Finding or Condition No.: Finding 50]***

OBJECTION. The request attempts to shift the burden for production from the Company to Staff. Subject to and without waiving its objection, Staff informs that it does not have any information supplementary to what has been made publicly available in the dockets.

12. All documents concerning TransCanada's (or its Affiliates') decision to withdraw its request to the PHMSA for a special permit referenced in Finding 60. ***[Applicable Finding or Condition No.: Finding 60]***

OBJECTION. The request attempts to shift the burden for production from the Company to Staff. Subject to and without waiving its objection, Staff informs that it does not have any information supplementary to what has been made publicly available in the dockets.

13. All documents containing information concerning construction/reclamation unit mapping referenced in Finding 80, including but not limited to the construction/reclamation unit mapping. ***[Applicable Finding or Condition No.: Finding 80]***

OBJECTION. The request attempts to shift the burden for production from the Company to Staff. Subject to and without waiving its objection, Staff informs that it does not

have any information supplementary to what has been made publicly available in the dockets.

14. All documents, including but not limited to forecasts and projections of tax revenue accruing to the State of South Dakota should construction and operation of the Project commence, together with all documents reflecting payments to towns, cities, counties in South Dakota since 2008 along the operating portions of the original Keystone I pipeline. ***[Applicable Finding or Condition No.: Finding 107]***

OBJECTION. The request attempts to shift the burden for production from the Company to Staff. Subject to and without waiving its objection, Staff informs that it does not have any information supplementary to what has been made publicly available in the dockets.

15. All documents submitted to the PUC by TransCanada evidencing TransCanada's or its Affiliates' compliance efforts with applicable laws and regulations related to construction and operation of the Project. ***[Applicable Finding or Condition No.: Condition 1]***

See Quarterly Reports available in HP09-001. Staff has no additional documentation. Every document submitted by TransCanada is made publicly available in the appropriate docket.

16. All documents submitted to the PUC by TransCanada concerning TransCanada's or its Affiliates' efforts to obtain and comply with applicable permitting referenced in Condition 2, including but not limited to copies of any permits obtained. ***[Applicable Finding or Condition No.: Condition 2]***

See Quarterly Reports available in HP09-001. Staff has no additional documentation. Every document submitted by TransCanada is made publicly available in the appropriate docket.

17. All documents submitted by TransCanada to the PUC concerning TransCanada's or its Affiliates' compliance with the recommendations set forth the DOS's Final Environmental Impact Statement, including but not limited to documents discussing or concerning compliance with Section 106 of the National Historic Preservation Act. ***[Applicable Finding or Condition No.: Condition 3]***

See Quarterly Reports available in HP09-001. Staff has no additional documentation. Every document submitted by TransCanada is made publicly available in the appropriate docket.

18. All documents submitted by TransCanada to the PUC concerning or discussing proposed adjustments or deviations in the route of the Project, including but not limited to copies of notices to affected land owners. ***[Applicable Finding or Condition No.: Condition 6]***

See Quarterly Reports available in HP09-001. Staff has no additional documentation. Every document submitted by TransCanada is made publicly available in the appropriate docket.

19. All documents submitted by TransCanada to the PUC concerning the appointment of a public liaison officer by TransCanada for the Project, and all documents containing information regarding communications between the public liaison officer and landowners affected by the Project. ***[Applicable Finding or Condition No.: Condition 7]***

See Motion for Approval of Public Liaison Officer in docket HP09-001, http://www.puc.sd.gov/commission/dockets/hydrocarbonpipeline/2009/hp09-001/042710.pdf; Letter from Jerry Roitsch regarding the Liaison's Role,

http://www.puc.sd.gov/commission/dockets/hydrocarbonpipeline/2009/hp09-001/050410.pdf; and all Liaison Annual Reports submitted in docket HP09-001.

20. All documents containing information with respect to contacts or communications with state, county and municipal emergency response, law enforcement and highway, road and other infrastructure management agencies regarding the Project. ***[Applicable Finding or Condition No.: Condition 10]***

OBJECTION. The request attempts to shift the burden for production from the Company to Staff. Subject to and without waiving its objection, Staff informs that it does not have any information supplementary to what has been made publicly available in the dockets, see Quarterly Reports available in Docket HP09-001.

21. All documents containing information concerning TransCanada's or its Affiliates' efforts to comply with mitigation measures set forth in the Construction Mitigation and Reclamation Plan submitted to the Commission, regarding the KXL Pipeline and the existing Keystone I pipeline. ***[Applicable Finding or Condition No.: Condition 13]***

OBJECTION. The request attempts to shift the burden for production from the Company to Staff. Subject to and without waiving its objection, Staff informs that it does not have any information supplementary to what has been made publicly available in the dockets.

22. All documents containing information regarding consultations, including but not limited to communications, with Natural Resources Conservation Services ("NRCS") regarding development of construction/reclamation units ("Con/Rec Units"). ***[Applicable Finding or Condition No.: Condition 15]***

OBJECTION. The request attempts to shift the burden for production from the

Company to Staff. Subject to and without waiving its objection, Staff informs that it does not have any information supplementary to what has been made publicly available in the dockets, see Quarterly Reports available in Docket HP09-001.

23. All documents containing information regarding consultations between TransCanada (or its Affiliates) and South Dakota Game, Fish and Parks. ***[Applicable Finding or Condition No.: Condition 20(c)]***

OBJECTION. The request attempts to shift the burden for production from the Company to Staff. Subject to and without waiving its objection, Staff informs that it does not have any information supplementary to what has been made publicly available in the dockets.

24. All documents submitted by TransCanada to the PUC describing the development of frac-out plans in areas where horizontal directional drilling will occur in connection with the Project, including but not limited to any frac-out plans developed. ***[Applicable Finding or Condition No.: Condition 21]***

OBJECTION. The request attempts to shift the burden for production from the Company to Staff. Subject to and without waiving its objection, Staff informs that it does not have any information supplementary to what has been made publicly available in the dockets.

25. All documents describing or containing information regarding TransCanada's or its Affiliates' efforts to comply with conditions regarding construction of the Project near wetlands, water bodies, and riparian areas, such documents including but not limited to compliance plans, construction plans, mitigation plans, and communications with any regulatory agency in such regard. ***[Applicable Finding or Condition No.: Condition 22]***

OBJECTION. The request attempts to shift the burden for production from the

Company to Staff. Subject to and without waiving its objection, Staff informs that it does not have any information supplementary to what has been made publicly available in the dockets, see Quarterly Reports available in Docket HP09-001.

26. All documents containing or referencing adverse weather land protection plans developed in connection with the Project. ***[Applicable Finding or Condition No.: Condition 25]***

OBJECTION. The request attempts to shift the burden for production from the Company to Staff. Subject to and without waiving its objection, Staff informs that it does not have any information supplementary to what has been made publicly available in the dockets.

27. All documents that reference or identify private and new access roads to be used or required during construction of the Project. ***[Applicable Finding or Condition No.: Condition 28]***

OBJECTION. The request attempts to shift the burden for production from the Company to Staff. Subject to and without waiving its objection, Staff informs that it does not have any information supplementary to what has been made publicly available in the dockets.

28. All documents referencing agreements reached with landowners, including but not limited to any agreements reached with landowners modifying any requirements or conditions established by the Commission in connection with the Project. ***[Applicable Finding or Condition No.: Condition 30]***

OBJECTION. The request attempts to shift the burden for production from the Company to Staff. Subject to and without waiving its objection, Staff informs that it does not have any information supplementary to what has been made publicly available in the dockets.

29. All documents containing information regarding assessments performed in

connection with TransCanada's activities in "high consequence areas", including but not limited to documents referencing efforts by you to comply with 49 C.F.R. Part 195, and any communications or consultations with the South Dakota Geological Survey, the Department of Game Fish and Parks ("SDGFP"), affected landowners and government officials. ***[Applicable Finding or Condition No.: Condition 34]***

OBJECTION. The request attempts to shift the burden for production from the Company to Staff. Subject to and without waiving its objection, Staff informs that it does not have any information supplementary to what has been made publicly available in the dockets, see Quarterly Reports available in Docket HP09-001.

30. All documents where TransCanada has identified hydrologically sensitive areas as required by Condition Number 35. ***[Applicable Finding or Condition No.: Condition 35]***

OBJECTION. The request attempts to shift the burden for production from the Company to Staff. Subject to and without waiving its objection, Staff informs that it does not have any information supplementary to what has been made publicly available in the dockets, see Quarterly Reports available in Docket HP09-001.

31. All documents containing information regarding noise-producing facilities in connection with the Project, including but not limited to any studies conducted regarding noise levels, and any noise mitigation measures. ***[Applicable Finding or Condition No.: Condition 39]***

OBJECTION. The request attempts to shift the burden for production from the Company to Staff. Subject to and without waiving its objection, Staff informs that it does not have any information supplementary to what has been made publicly available in the dockets,

see Quarterly Reports available in Docket HP09-001.

32. All documents containing information regarding TransCanada's or its Affiliates' efforts to comply with protection and mitigation requirements of the US Fish and Wildlife Service ("USFWS") and SDGFP with respect to any endangered species. ***[Applicable Finding or Condition No.: Condition 41]***

OBJECTION. The request attempts to shift the burden for production from the Company to Staff. Subject to and without waiving its objection, Staff informs that it does not have any information supplementary to what has been made publicly available in the dockets, see Quarterly Reports available in Docket HP09-001.

33. All documents containing information or details regarding location of drain tiles, including but not limited to all documents containing information regarding the potential for drain tiles to operate as conduits for contaminants in connection with construction or operation of the Project. ***[Applicable Finding or Condition No.: Condition 42]***

OBJECTION. The request attempts to shift the burden for production from the Company to Staff. Subject to and without waiving its objection, Staff informs that it does not have any information supplementary to what has been made publicly available in the dockets.

34. All documents referencing or containing information concerning cultural or paleontological resources along the Project route, including but not limited to all documents identifying cultural and paleontological resources, consultations and communications with the Bureau of Land Management and Museum of Geology at the South Dakota School of Mines and Technology. ***[Applicable Finding or Condition No.: Condition 44]***

OBJECTION. The request attempts to shift the burden for production from the Company to Staff. Subject to and without waiving its objection, Staff informs that it does not have any information supplementary to what has been made publicly available in the dockets, see Quarterly Reports available in Docket HP09-001.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE PETITION OF TRANSCANADA KEYSTONE PIPELINE, LP FOR ORDER ACCEPTING CERTIFICATION OF PERMIT ISSUED IN DOCKET HP09-001 TO CONSTRUCT THE KEYSTONE XL PIPELINE	**STAFF'S RESPONSE TO INTERROGATORIES AND REQUESTS FOR PRODUCTION OF DOCUMENTS FROM PAUL SEAMANS** **HP14-001**

COMES NOW, Commission Staff by and through its attorney of record, Kristen N. Edwards, and hereby provides the following response to Paul Seamans' Interrogatories and Requests for Production of Documents.

Dated this 10th day of March, 2015.

Kristen N. Edwards
Staff Attorney
South Dakota Public Utilities Commission
500 East Capitol Avenue
Pierre, SD 57501

2-1) What I would like to know is whether the Emergency Response Plan (ERP) and the Integrity Management Plan (IMP) for the Keystone XL and Keystone 1 are considered confidential as TransCanada claims they are. As part of discovery I have asked TransCanada to disclose where the High Consequence Areas (HCA's) are located as well as asking to see the ERP and IMP. TransCanada claims that "the PUC's jurisdiction over the emergency response plan is preempted by federal law. See 49 C.F.R. Part 194; 49 U.S.C. 60104(c)".

Response: While not specifically mandated to be kept confidential by the referenced sections of code, the Emergency Response Plan and the Integrity Management Plan contain information and data that may be considered confidential and/or proprietary by TransCanada.

2-2) One incident that started me to thinking about this confidentiality issue is that at the Dakota Access pipeline meeting in Iroquois I asked Joey Malmoud if their ERP would be available to the public. Joey said that yes, it would be available to the public. Here is Dakota Access saying that their ERP will be available for public viewing and on the other hand TransCanada claims the PHMSA requires that their ERP be kept confidential and is proprietary. Is the ERP required by PHMSA to be confidential or is it, or portions of it, available for the public to view?

Response: The Emergency Response Plan required by 195.402 (d) Abnormal Operation and the Response Plans for Onshore Oil Pipelines required by CFR Part 194 contain information and data that may be considered confidential and/or proprietary by TransCanada.

2-3) If the PUC determines that the ERP is accessible to the public then I would like to see the ERP for Keystone 1 as I realize that the ERP for the Keystone XL does not need to be filed until the pipeline is close to operational. I am willing to go through the necessary steps to obtain access to confidential information as required in ARSD 20:10:01:43.

Response: All information submitted to the PUC regarding Keystone I's ERP is available in 7.0 of the company's Quarterly Report. For the last Quarterly Report filed by TransCanada for Keystone I, view the report at http://www.puc.sd.gov/commission/dockets/HydrocarbonPipeline/2007/HP07-001/4thquarterly2010.pdf.
Furthermore, the final version of the Keystone Pipeline Emergency Response Plan will be amended to include Keystone XL. A redacted version of the ERP is available in Appendix I of the Final Supplemental Environmental Impact Study, which is publicly available.

STATE OF SOUTH DAKOTA)
)SS.
COUNTY OF HUGHES)

I, Kristen N. Edwards, attorney for Staff of the Public Utilities Commission, being of legal age, being first duly sworn upon oath, hereby swear or affirm that the forgoing answers and information provided are true and correct to the best of my knowledge.

Kristen Edwards

Subscribed and sworn to before me this 10th day of March, 2015.

Tina Douglas

Notary Public

TINA DOUGLAS
My Commission Expires
April 14, 2017

My Commission expires: _____

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE PETITION OF TRANSCANADA KEYSTONE PIPELINE, LP FOR ORDER ACCEPTING CERTIFICATION OF PERMIT ISSUED IN DOCKET HP09-001 TO CONSTRUCT THE KEYSTONE XL PIPELINE	))))))	**CERTIFICATE OF SERVICE** **HP14-001**

I hereby certify that true and correct copies of Staff's Response to Interrogatories and Requests for Production of Documents from Paul Seamans, Affirmation of Oath and Certificate of Service were served electronically to the Party listed below, on the 10th day of March, 2015, addressed to:

Mr. Paul F. Seamans
27893 249th St.
Draper, SD 57531
jacknife@goldenwest.net

Kristen N. Edwards
Staff Attorney
South Dakota Public Utilities Commission
500 East Capitol
Pierre, SD 57501

2015 Annual and Special Meeting

TransCanada
In business to deliver

Forward Looking Information and Non-GAAP Measures

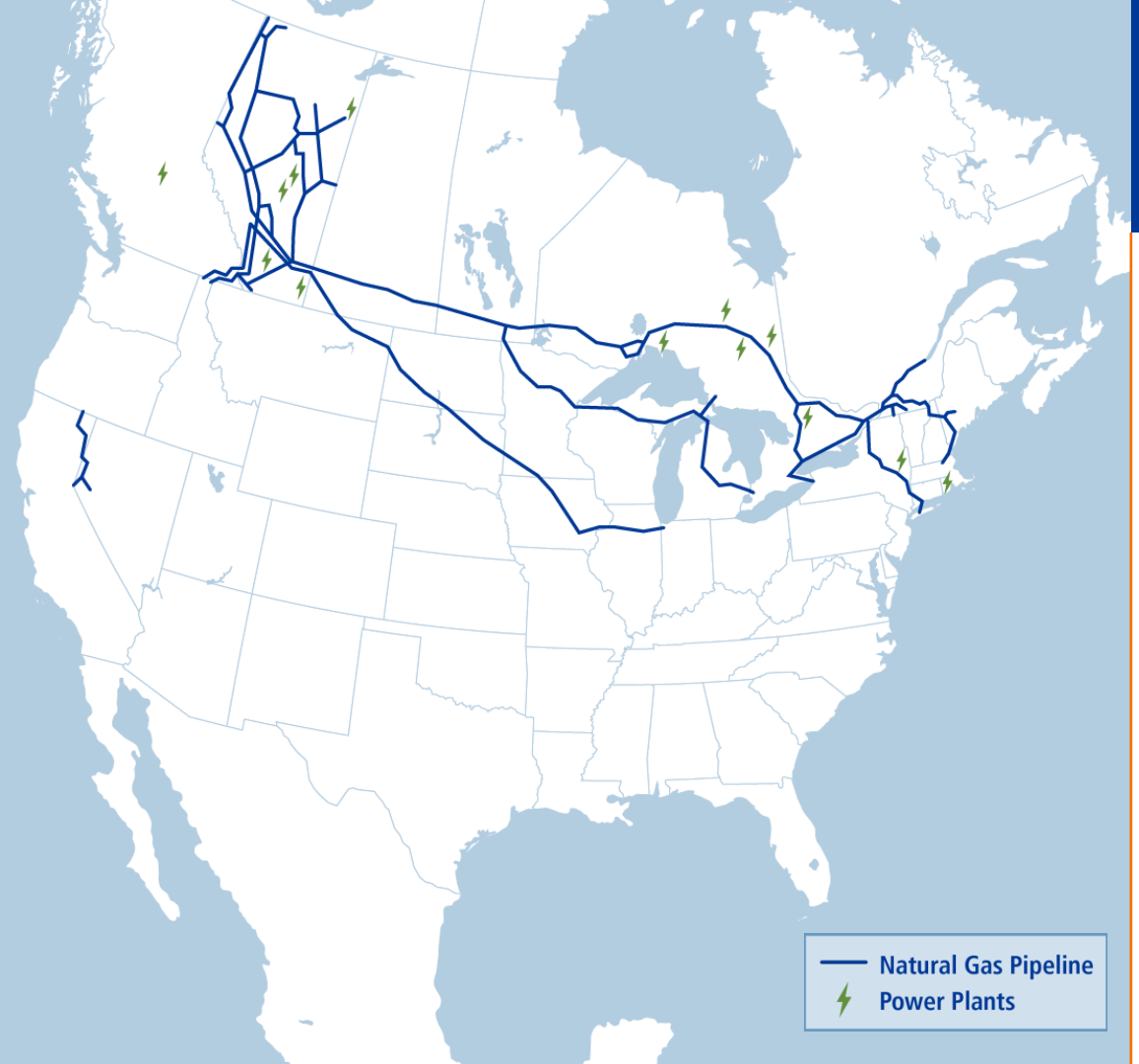
This presentation includes certain forward looking information to help current and potential investors understand management's assessment of our future plans and financial outlook, dividend prospects and our future prospects overall. Statements that are forward-looking are based on certain assumptions and on what we know and expect today and generally include words like anticipate, expect, believe, may, will, should, estimate or other similar words. Forward-looking statements do not guarantee future performance. Actual events and results could be significantly different because of assumptions, risks or uncertainties related to our business or events that happen after the date of this presentation. Our forward-looking information is based on the following key assumptions: inflation rates, commodity prices and capacity prices, timing of financings and hedging, regulatory decisions and outcomes, foreign exchange rates, interest rates, tax rates, planned and unplanned outages and the use of our pipeline and energy assets, integrity and reliability of our assets, access to capital markets, anticipated construction costs, schedules and completion dates, acquisitions and divestitures.

Our forward looking information is subject to risks and uncertainties, including but not limited to: our ability to successfully implement our strategic initiatives and whether they will yield the expected benefits, the operating performance of our pipeline and energy assets, economic and competitive conditions in North America and globally, the availability and price of energy commodities and changes in market commodity prices, the amount of capacity sold and rates achieved in our pipeline businesses, the amount of capacity payments and revenues we receive from our energy business, regulatory decisions and outcomes, outcomes of legal proceedings, including arbitration and insurance claims, performance of our counterparties, changes in the political environment, changes in environmental and other laws and regulations, construction and completion of capital projects, labour, equipment and material costs, access to capital markets, interest and foreign exchange rates, weather, cyber security and technological developments. You can read more about these risks and others in our most recent Quarterly Report to Shareholders and 2014 Annual Report filed with Canadian securities regulators and the U.S. Securities and Exchange Commission (SEC) and available at www.transcanada.com.

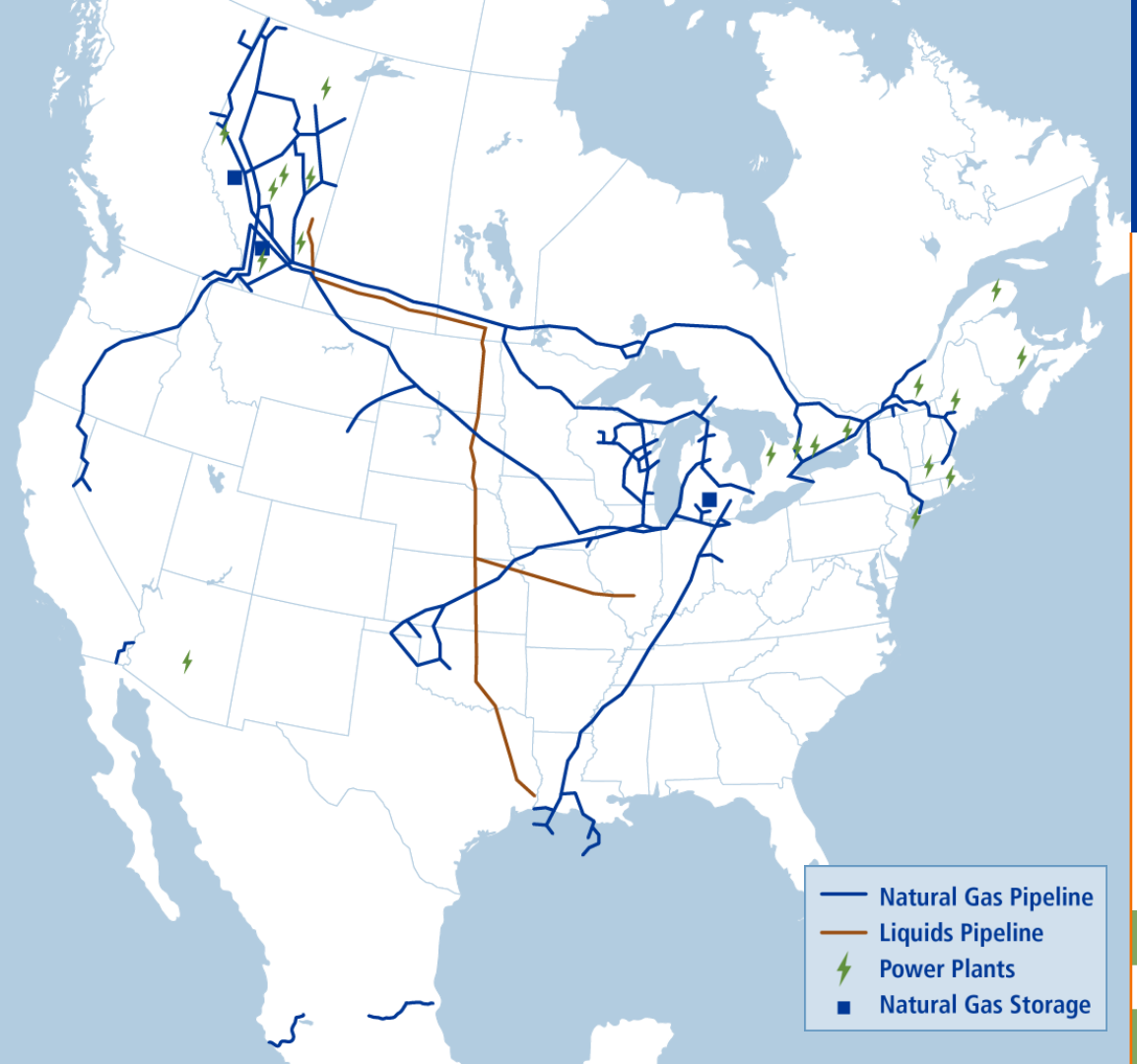
As actual results could vary significantly from the forward-looking information, you should not put undue reliance on forward-looking information and should not use future-oriented information or financial outlooks for anything other than their intended purpose. We do not update our forward-looking statements due to new information or future events, unless we are required to by law.

This presentation contains reference to certain financial measures (non-GAAP measures) that do not have any standardized meaning as prescribed by U.S. generally accepted accounting principles (GAAP) and therefore may not be comparable to similar measures presented by other entities. These non-GAAP measures may include Comparable Earnings, Comparable Earnings per Share, Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA), Comparable EBITDA, and Funds Generated from Operations. Reconciliations to the most closely related GAAP measures are included in our most recent Quarterly Report to Shareholders filed with Canadian securities regulators and the SEC and available at www.transcanada.com.

TransCanada in 2000



- Asset Base: $26 billion
- Comparable EBITDA: $2.5 billion



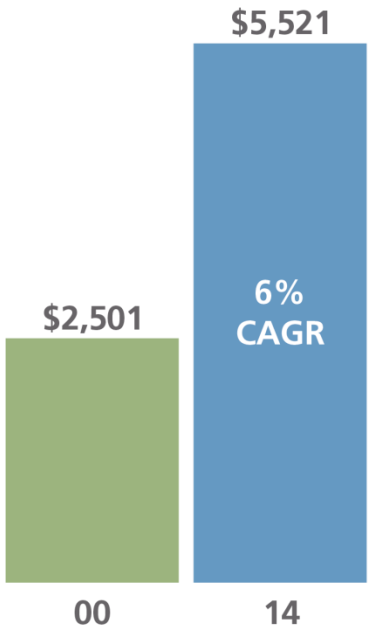
TransCanada Today

- One of North America's Largest Natural Gas Pipeline Networks
  - 68,000 km (42,000 mi) of pipeline
  - 368 Bcf of storage capacity
  - 14 Bcf/d or 20% of continental demand
- Premier Liquids Pipeline System
  - 4,250 km (2,600 mi) of pipeline
  - 530,000 bbl/d or 18% of Western Canadian production
- Largest Private Sector Power Generator in Canada
  - 19 power plants, 10,900 MW
- Enterprise Value ~ $73 billion

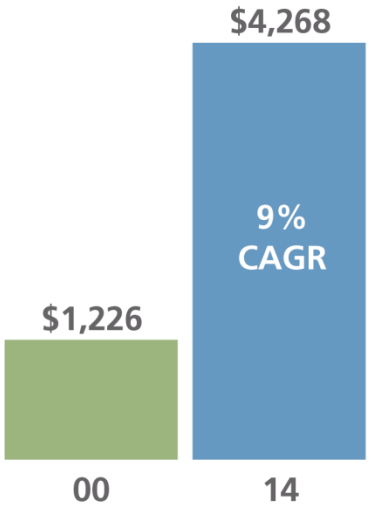
Unparalleled Portfolio of Complementary Energy Infrastructure Assets

Realizing Our Vision

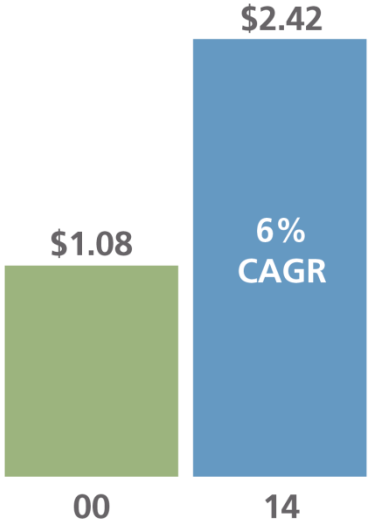
Comparable EBITDA
($Millions)



Funds Generated from Operations ($Millions)



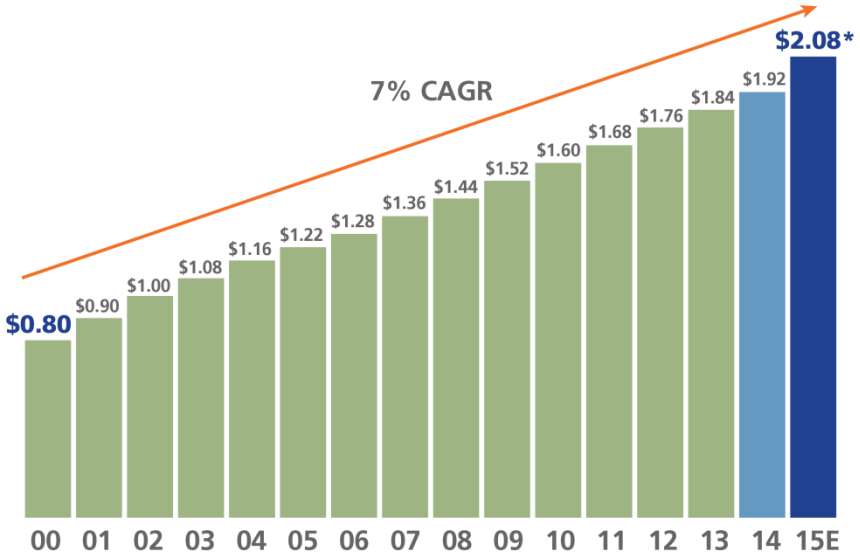
Earnings per Share
(Comparable)



Compound Annual Growth Rate (CAGR)

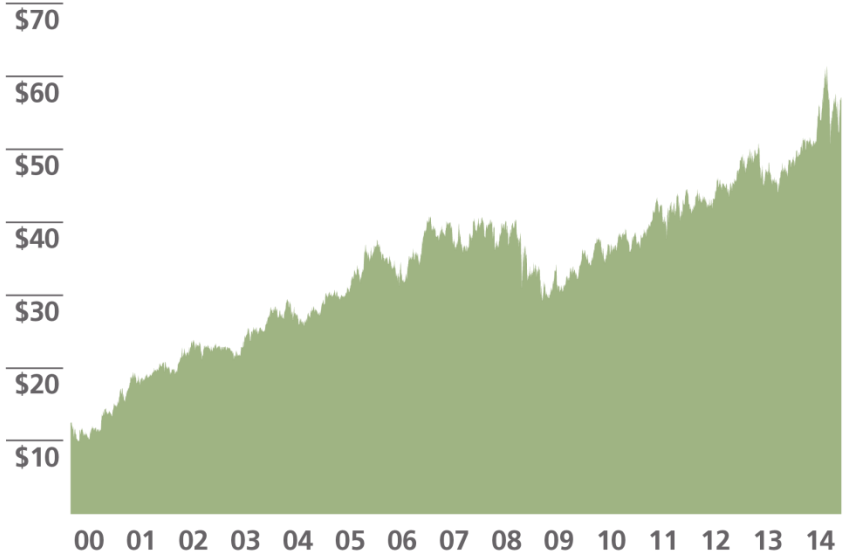
Track Record of Delivering Long-Term Shareholder Value

Common Share Dividend



** Annualized based on second quarter declaration*

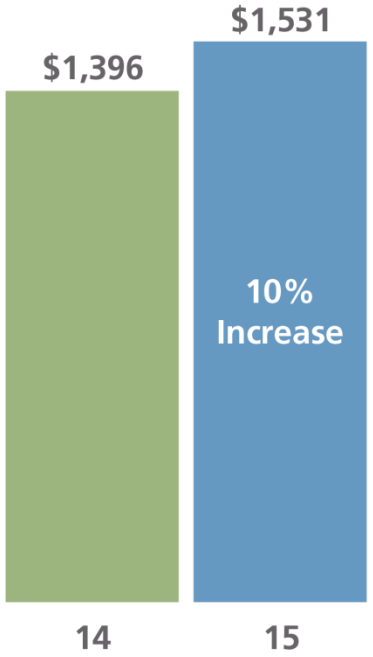
Common Share Price



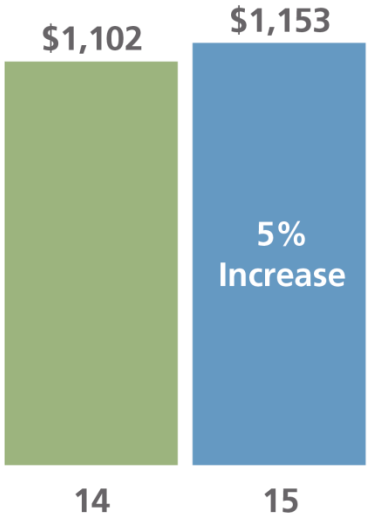
15% Average Annual Total Shareholder Return Since 2000

First Quarter 2015 Financial Highlights

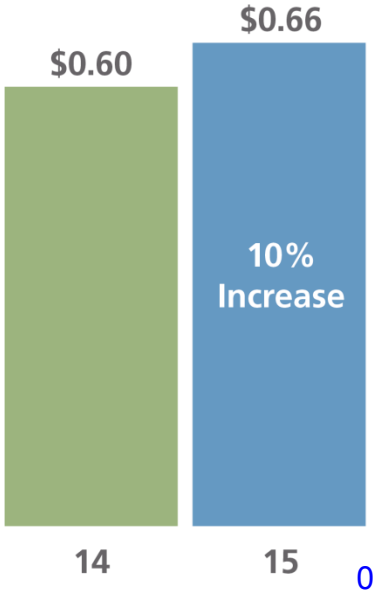
Comparable EBITDA
($Millions)



Funds Generated from Operations ($Millions)



Earnings per Share
(Comparable)



Our Priorities

- Maximize value of our $64 billion asset base
- Complete $46 billion capital program
- Cultivate a portfolio of low-risk growth opportunities
- Maintain financial strength and flexibility

Deliver Superior Long-Term Returns to Shareholders

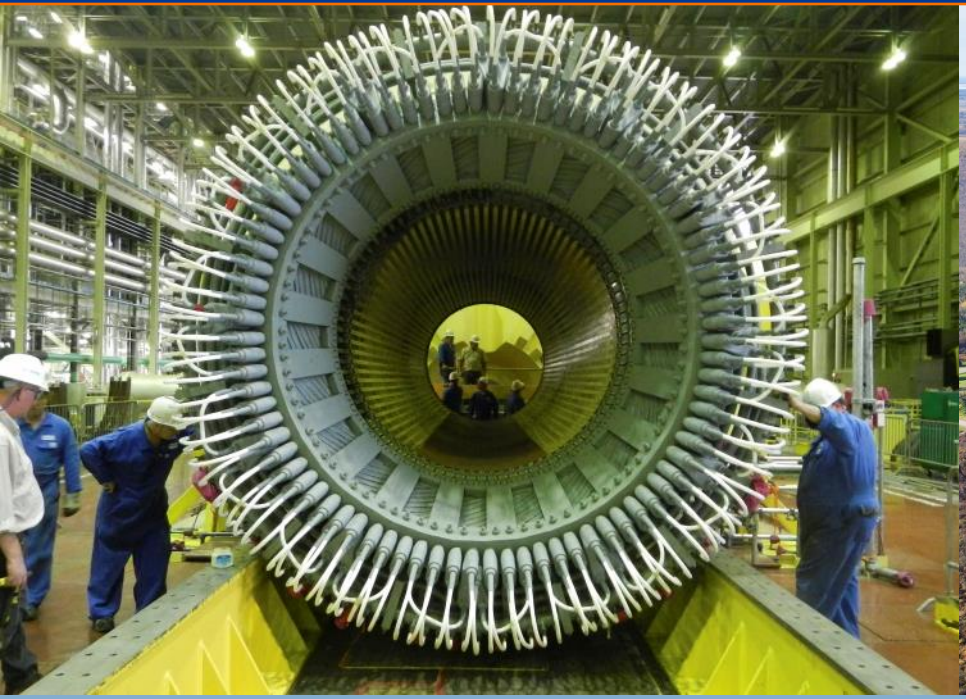
Maximizing the Value of our Base Business

Long-term stability for Canadian Mainline and ANR Pipeline

Maximizing the Value of our Base Business

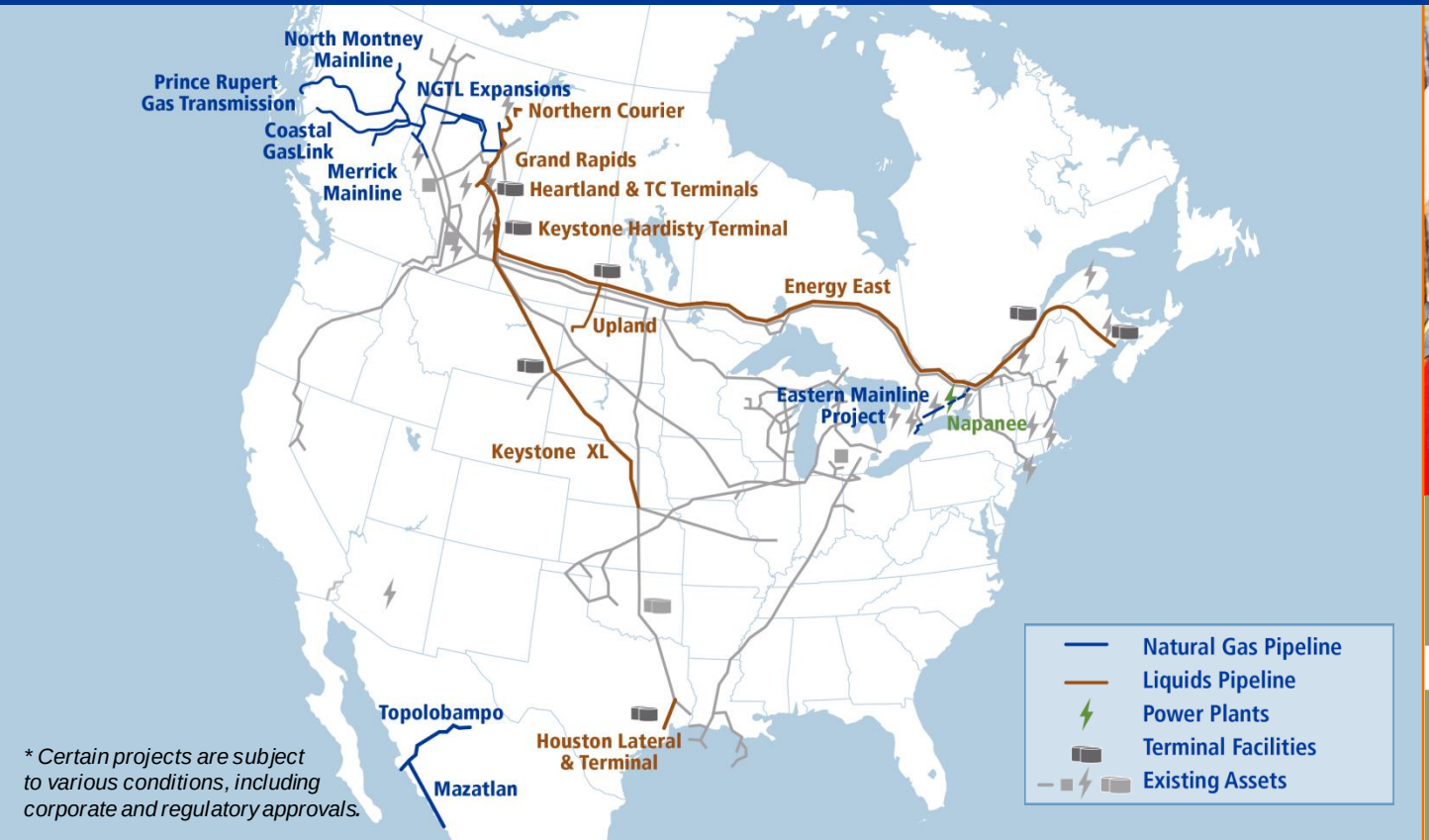
Keystone Pipeline EBITDA surpassed $1 billion

Maximizing the Value of our Base Business



Bruce Power and Ontario Solar online

$46 Billion Portfolio of Commercially Secured Projects*

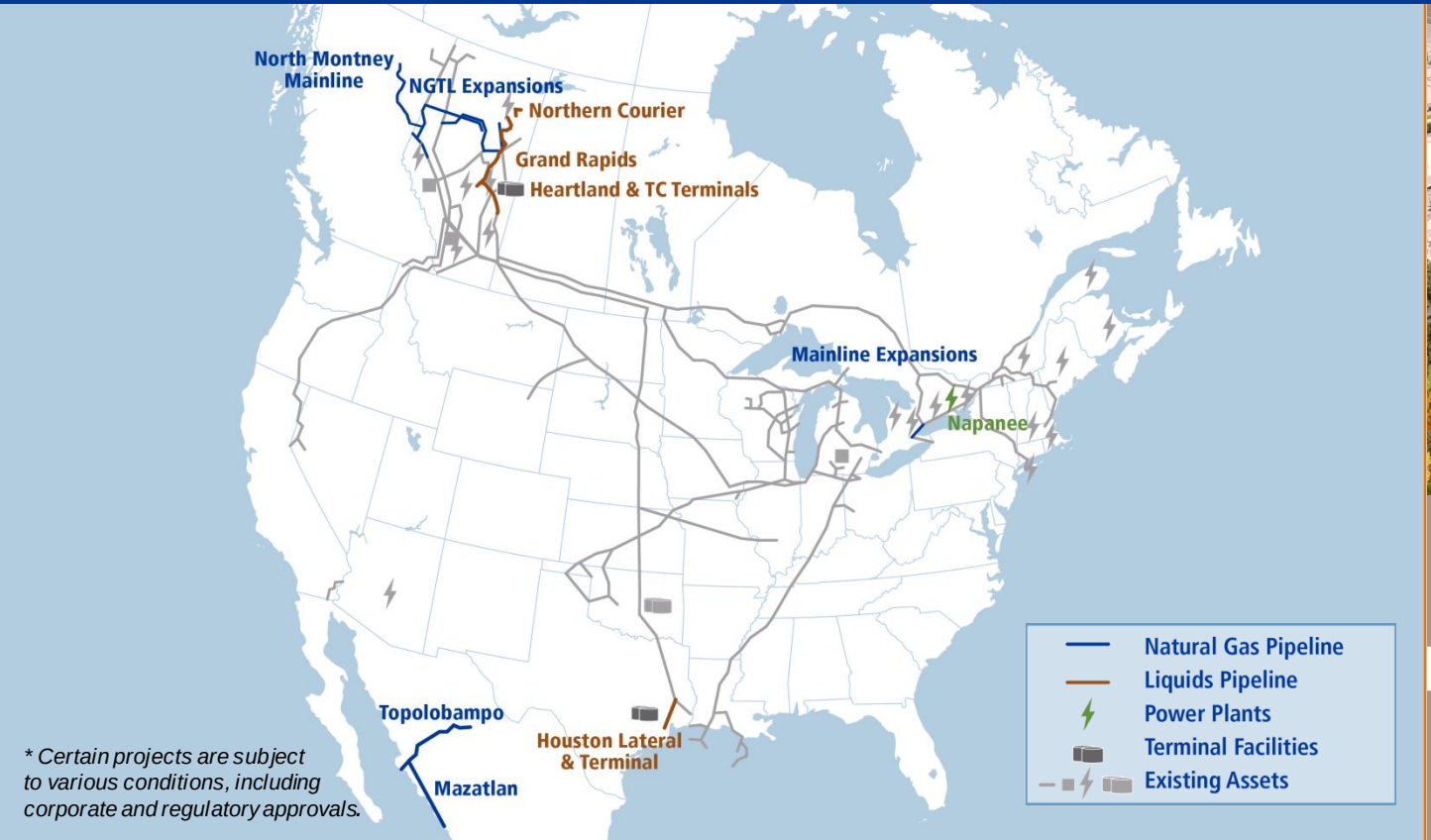


Predictable & stable earnings and cash flow for decades

013469

** Certain projects are subject to various conditions, including corporate and regulatory approvals.*

$12 Billion of Small to Medium-Sized Projects Drive Growth*



Projects expect to be completed by the end of 2017

** Certain projects are subject to various conditions, including corporate and regulatory approvals.*

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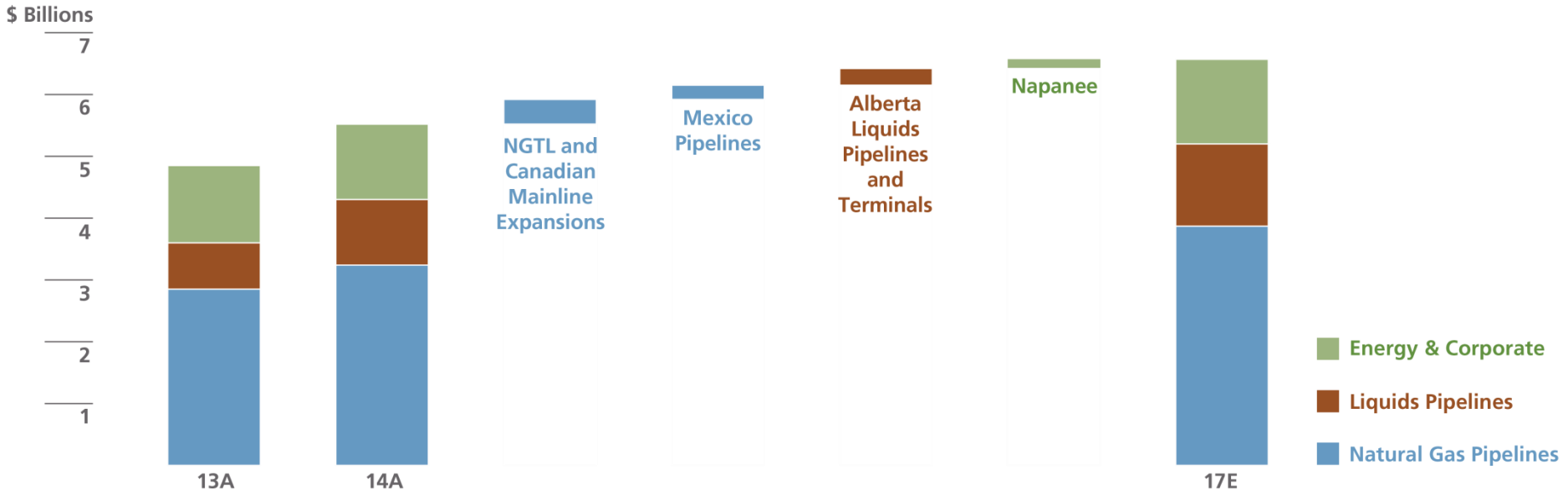
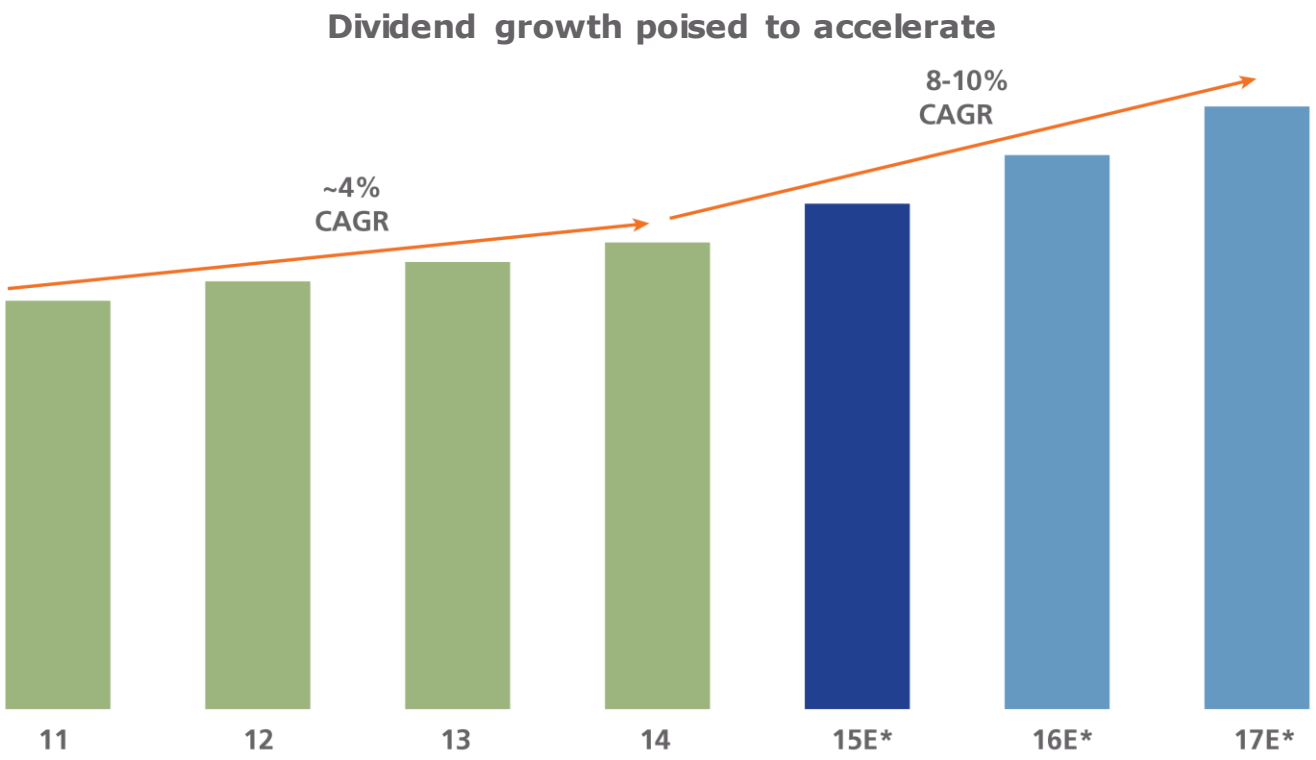
EBITDA Growth 2013A – 2017E*



* TransCanada share in billions of dollars. Certain projects are subject to various conditions including corporate and regulatory approvals. Includes existing assets, non-controlling interests in U.S. Natural Gas Pipelines and full year EBITDA contribution from $12 billion of commercially secured projects expected to be in service by the end of 2017.

~8% CAGR in EBITDA through 2017

Dividend Outlook



* *Dividends are declared at the discretion of the Board of Directors*

Equates to ~35% of cash flow

013472

Strong Platform for Future Growth

- North America requires new and improved energy infrastructure
- Secured $34 billion in large-scale projects
- Numerous additional opportunities in our core markets
- Advancing growth plans will deliver exceptional value for shareholders

Natural Gas Pipelines Growth Opportunities

- Advance $13 billion of large-scale commercially secured projects*
- Leverage NGTL's strong competitive position
- Connect growing Marcellus/Utica gas to market
- Capitalize on build-out of Mexico infrastructure

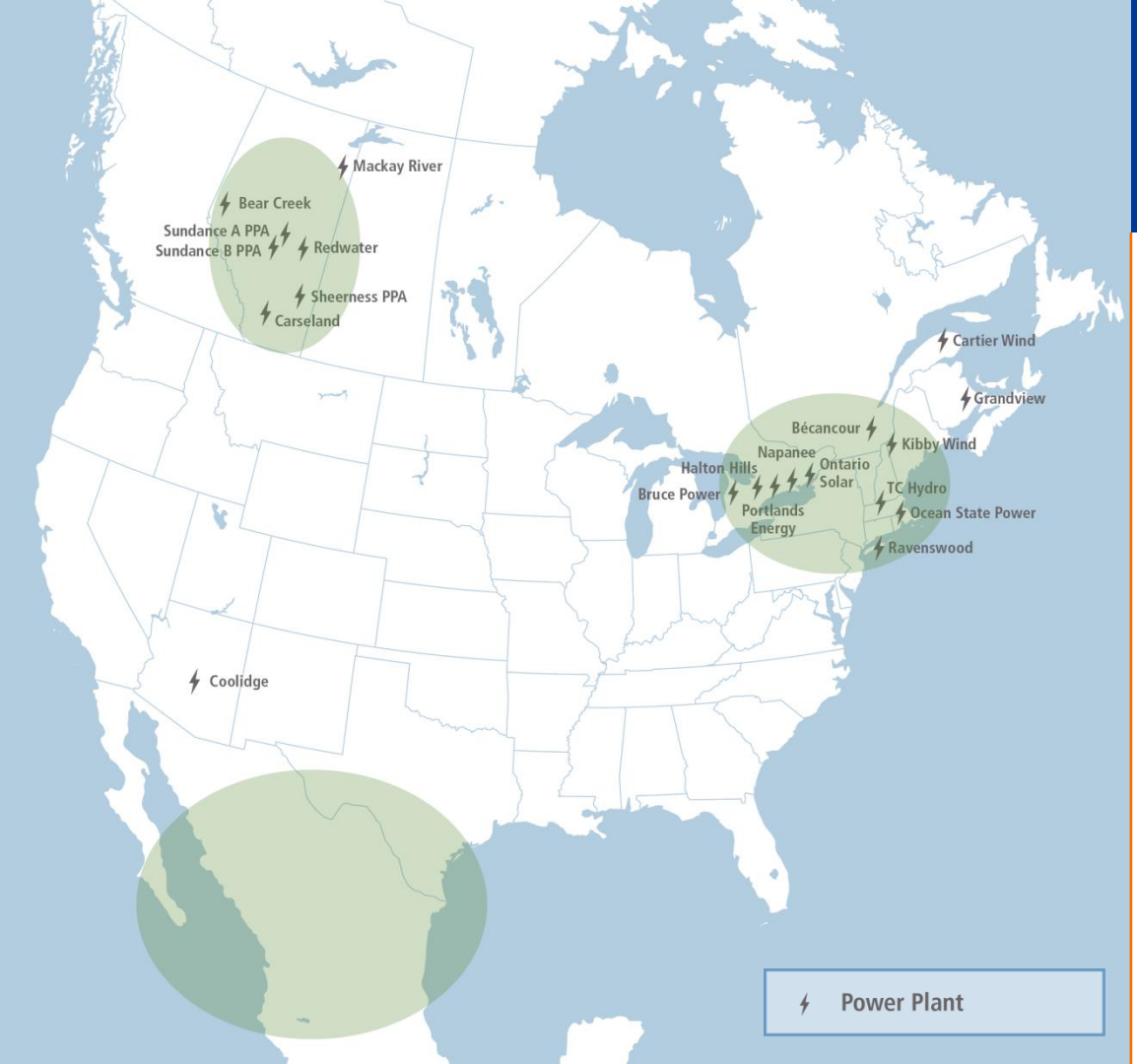
** Certain projects are subject to various conditions, including corporate and regulatory approvals.*

Liquids Pipelines Growth Opportunities

- Advance $21 billion of large-scale commercially secured projects*
- Connect growing Western Canadian and U.S. oil supply to key refining markets
- Capture Alberta regional liquids infrastructure opportunities
- Extend market connectivity

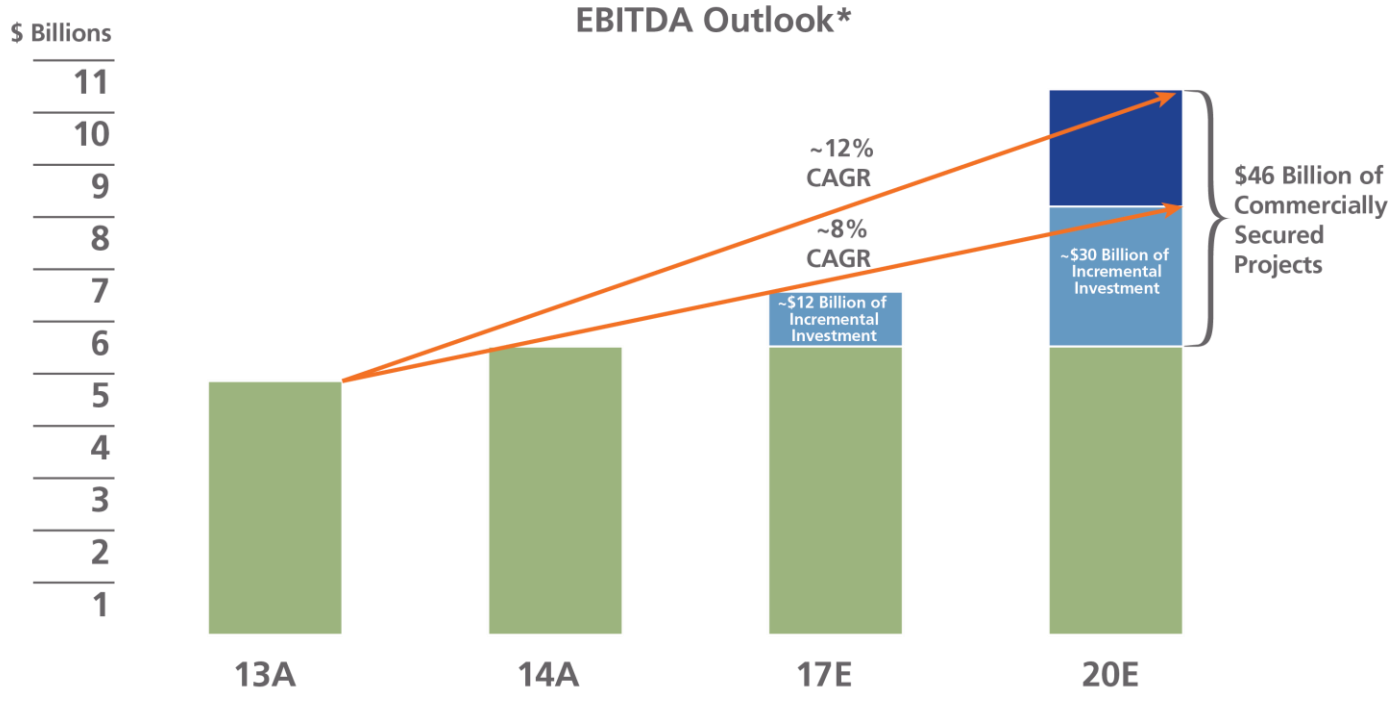
** Certain projects are subject to various conditions, including corporate and regulatory approvals.*

Energy Growth Opportunities



- Bruce Power refurbishments
- Renewables: wind, solar and hydro
- Natural gas-fired generation
- Mexico power
- Repowering opportunities

Deliver Significant Growth

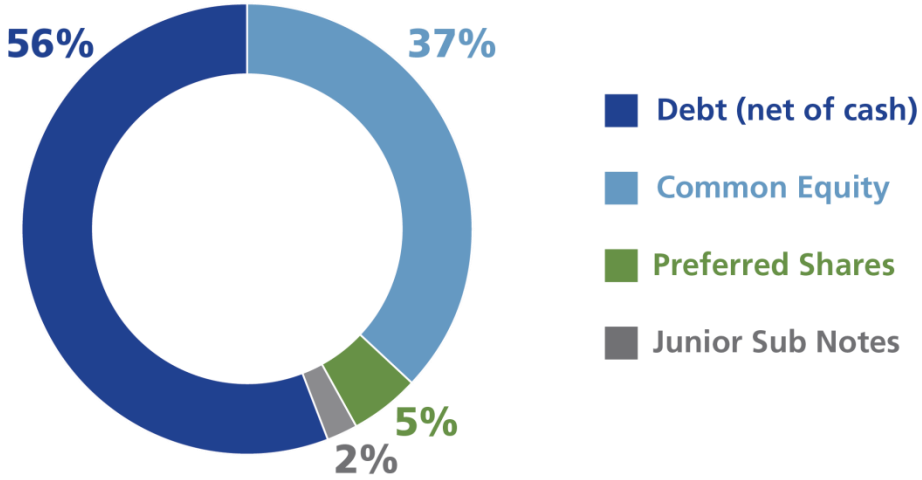


Predictable and sustainable EBITDA growth

* *Includes existing assets, non-controlling interests in U.S. natural gas pipelines and $46 billion of commercially secured projects expected to be in service by 2020, subject to certain conditions including corporate and regulatory approvals.*

Financial Flexibility Enhances Long-Term Shareholder Value

Strong Financial Position*
Supports Access to Significant Capital at Attractive Rates



Funding Options Available:

- Internally generated cash flow
- Senior debt
- Preferred shares and hybrid securities
- Portfolio management including asset sales to TC PipeLines, LP
- Partners/Project Finance
- Dividend reinvestment plan
- Discrete common equity issue

* *At March 31, 2015. Common equity includes non-controlling interests in TC PipeLines, LP and Portland.*

Focus on Safety

Commitment to Responsible Development

Corporate Social Responsibility Report

Summary
2014

013480

TransCanada
In business to deliver

It's what matters.

Conclusion

2015 Annual and Special Meeting

TransCanada
In business to deliver

PREFACE

This document is a revised edition of the Engineering and Geoscience Professions Act, Regulations (including the Code of Ethics) and By-Laws, incorporating all amendments up to March 2012. The Act and Regulations are printed with the permission of the Government of the Province of Alberta.

The Act, (Revised Statutes of Alberta. Chapter E-11.1), is a government consolidation of the 1981 Act, the 1984 Amendment Act and other subsequent amendments. The amendments proclaimed in 2012 created APEGA in the place of APEGGA. The General Regulation is a consolidation of the 1981 Regulation and amendments to the Regulation approved in December 1985, July 1990, April 1996, July 1999 (AR 150/99), February 2003 (AR 37/2003), April 2007 (AR 72/2007), October 2009 (AR 281/2009) and March 2012 (AR 55/2012). A regulation providing for registration of professional technologists (AR 283/2009) was amended by AR 57/2012, and a regulation respecting the operation of ASET (AR 282/2009) was amended by AR 56/2012. All persons making use of this consolidation are reminded that it has no legislative sanction, that the amendments have been embodied for convenience of reference only, and that the original Act, Regulations and amending Acts and Regulations be consulted for all purposes of interpreting and applying the law.

The By-Laws incorporate the amendments which were approved at the APEGGA Annual General Meetings of June 1983, June 1987, April 1991, April 1993, April 1996, April 1997, April 1998, April 1999, April 2000, April 2001, April 2002, April 2004, April 2005, April 2009, and April 2010 and at a special meeting of members in October, 2009. Consequential amendments to Bylaws taking effect in March 2012 with the latest amendments to Act and Regulations are included. These are the latest amendments.

An index is provided for convenient reference to any or all of the three documents.

THE ENGINEERING AND GEOSCIENCE PROFESSIONS ACT

Being Chapter E-11.1
Revised Statutes of Alberta, 2000

Printed April 2012

013484

ENGINEERING AND GEOSCIENCE PROFESSIONS ACT

Chapter E-11

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HER MAJESTY, by and with the advice and consent of the Legislative Assembly of Alberta, enacts as follows:

Definitions

1 In this Act,

(a) "Appeal Board" means the Appeal Board established under section 18;

(a.1) "ASET Council" means the Council continued under section 87;

(b) "Association" means the Association of Professional Engineers and Geoscientists of Alberta;

(c) "Board of Examiners" means the Board of Examiners established under section 30;

(d) "certificate holder" means

(i) a joint firm, and

(ii) a restricted practitioner;

(e) "Council" means the Council of the Association;

(f) "Court" means the Court of Queen's Bench;

(g) "Discipline Committee" means the Discipline Committee established under section 45;

(h) "Investigative Committee" means the Investigative Committee established by the Council pursuant to section 46;

(i) "Joint Board" means the Joint Board of Practice under section 1 of Schedule 8 to the Government Organization Act;

(i.1) "Joint Councils Committee" means the committee established by section 1.1;

(j) "joint firm" means a firm to which a certificate of authorization has been issued under section 35;

(k) "licensee" means an individual who holds a licence under this Act but does not include a professional licensee;

(l) "member of the Association" means a person who is registered as a professional member or a member of a class or category of membership established under this Act;

(m) "member of the public" means, in sections 14, 15 and 30, a person who is

(i) a Canadian citizen or who is lawfully admitted to Canada for permanent residence,

(ii) a resident of Alberta, and

(iii)not a professional member of the Association;

(n) "member-in-training" means engineer-in-training or geoscientist-in-training, as the case may be;

(o) "Minister" means the Minister determined under section 16 of the *Government Organization Act* as the Minister responsible for this Act;

(p) "permit holder" means a partnership or other association of persons or a corporation that holds a permit under this Act but does not include an ASET permit holder as defined in section 86.4;

(q) "practice of engineering" means

(i) reporting on, advising on, evaluating, designing, preparing plans and specifications for or directing the construction, technical inspection, maintenance or operation of any structure, work or process

(A) that is aimed at the discovery, development or utilization of matter, materials or energy or in any other way designed for the use and convenience of humans, and0

(B) that requires in that reporting, advising, evaluating, designing, preparation or direction the professional application of the principles of mathematics, chemistry, physics or any related applied subject, or

(ii) teaching engineering at a university;

(r)"practice of geoscience" means

(i) reporting, advising, evaluating, interpreting, processing, geoscientific surveying, exploring, classifying reserves or examining related to any activity

(A) that relates to the earth sciences or the environment,

(B) that is aimed at the discovery or development of oil, natural gas, coal, metallic or non-metallic minerals, precious stones, other natural resources or water or that is aimed at the investigation of surface or subsurface conditions of the earth, and

(C) that requires, in that reporting, advising, evaluating, interpreting, processing, geoscientific surveying, exploring, classifying reserves or examining, the professional application of the principles of mathematics, chemistry, physics or biology through the application of the principles of geoscience,

or

(ii) teaching geoscience at a university;

(s) repealed 2011 c3 s3;

(t) "Practice Review Board" means the Practice Review Board established under section 15;

(u) "profession" means the profession of engineering or geoscience, as the case may be;

(v) "professional engineer" means an individual who holds a certificate of registration to engage in the practice of engineering under this Act but does not include

(i) a professional licensee (engineering), or

(ii) a professional technologist as defined in section 86.4(m);

(w) "professional geoscientist" means an individual who holds a certificate of registration to engage in the practice of geoscience under this Act but does not include

(i) a professional licensee (geoscience), or

(ii) a professional technologist as defined in section 86.4(m);

(x) repealed 2011 c3 s3;

(x.1) "professional licensee" means a professional licensee (engineering) or a professional licensee (geoscience);

(x.2) "professional licensee (engineering)" means an individual who holds a certificate of registration and an annual licence to engage in the practice of engineering within the scope of practice specified by the Board of Examiners;

(x.3) "professional licensee (geoscience)" means an individual who holds a certificate of registration and an annual licence to engage in the practice of geoscience within the scope of practice specified by the Board of Examiners;

(x.4) repealed 2011 c3 s3;

(y) "professional member" means a professional engineer or professional geoscientist;

(z) "Registrar" means the Registrar appointed under section 13;

(aa) "restricted practitioner" means a registered architect under the *Architects Act* who holds a certificate of authorization under this Act.

RSA 2000 cE-11 s1;2007 c13 s2;2011 c3 s3

Joint Councils Committee

1.1(1) There is established a Joint Councils Committee composed of an equal number of members from the Executive Committees of the Council and ASET Council appointed respectively by the Council and ASET Council.

(2) The purposes of the Joint Councils Committee are to

(a) discuss proposed amendments to this Act and new or proposed amendments to any regulations made under this Act;

(b) provide a forum for discussion, collaboration and co-ordination with respect to matters of mutual interest to the Association and ASET;

(c) perform any other function prescribed by this Act or any regulation made under this Act, or by agreement of the Council and ASET Council.

(3) The Joint Councils Committee shall meet and its procedure shall be governed by rules established by agreement of the Council and ASET Council.

(4) The Council and ASET Council may, by agreement, alter the composition of the Joint Councils Committee described in subsection (1).

2007 13 s3;2011 c3 s4

Part 1
Scope of Practice

Exclusive scope of the practice of engineering

2(1) Except as otherwise provided in this Act, no individual, corporation, partnership or other entity, except a professional engineer, a licensee so authorized in the licensee's licence, a permit holder so authorized in its permit or a certificate holder so authorized in the certificate holder's certificate, shall engage in the practice of engineering.

(2) No individual, corporation, partnership or other entity, shall engage in both the practice of engineering and the practice of architecture as defined in the *Architects Act*, or hold out that it is entitled to engage in both the practice of engineering and the practice of architecture unless it holds a certificate of authorization under this Act or the *Architects Act* permitting it to do so.

(3) A professional engineer, licensee, permit holder or joint firm may engage in the practice of surveying other than land surveying as defined in the *Land Surveyors Act*.

(4) Subsection (1) does not apply to the following:

(a) a person engaged in the execution or supervision of the construction, maintenance, operation or inspection of any process, system, work, structure or building in the capacity of contractor, superintendent, foreman or inspector or in any similar capacity, when the process, system, work, structure or building has been designed by and the execution or supervision is being carried out under the supervision and control of a professional engineer or licensee;

(b) a person engaged in the practice of engineering as an engineer-in-training or engineering technologist in the course of being employed or engaged and supervised and controlled by a professional engineer, licensee, permit holder or certificate holder;

(c) repealed 2007 c13 s4;

(d) a person who in accordance with an Act or regulation in respect of mines, minerals, pipelines, boilers and pressure vessels, building codes or safety codes for buildings is engaged in any undertaking or activity required under or pursuant to that Act or the regulations under that Act;

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(e) a person who, on the person's own property and for the person's sole use or the use of the person's domestic establishment, carries out any work that does not involve the safety of the public;

(f) a member of the Canadian Forces while actually employed on duty with the Forces;

(g) a person engaged or employed by a university whose practice of the profession consists exclusively of teaching engineering at the university.

(5) A restricted practitioner is not authorized by the operation of subsection (1) to engage in the practice of engineering beyond the scope of the practice that is specified in the register.

(6) Subsection (1) does not apply to a person if the person engages in

(a) planning, designing or giving advice on the design of or on the erection, construction or alteration of or addition to,

(b) preparing plans, drawings, detail drawings, specifications or graphic representations for the design of or for the erection, construction or alteration of or addition to, or

(c) inspecting work or assessing the performance of work under a contract for the erection, construction or alteration of or addition to

a building set out in subsection (7).

(7) The buildings referred to in subsection (6) are the following:

(a) a building, 3 storeys or less in height, for assembly occupancy or institutional occupancy that,

(i) in the case of a single storey building, has a gross area of 300 square metres or less,

(ii) in the case of a 2 storey building, has a gross area of 150 square metres or less on each floor, or

(iii) in the case of a 3 storey building, has a gross area of 100 square metres or less on each floor;

(b) a building for residential occupancy that

(i) is a single family dwelling, or

(ii) is a multiple family dwelling, containing 4 dwelling units or less;

(c) a building, 3 storeys or less in height, for residential occupancy as a hotel, motel or similar use that,

(i) in the case of a single storey building, has a gross area of 400 square metres or less,

(ii) in the case of a 2 storey building, has a gross area of 200 square metres or less on each floor, or

(iii) in the case of a 3 storey building, has a gross area of 130 square metres or less on each floor;

(d) a building, 3 storeys or less in height, for warehouse, business and personal services occupancy, for mercantile occupancy or for industrial occupancy that,

(i) in the case of a single storey building, has a gross area of 500 square metres or less,

(ii) in the case of a 2 storey building, has a gross area of 250 square metres or less on each floor, or

(iii) in the case of a 3 storey building, has a gross area of 165 square metres or less on each floor;

(e) a building that is a farm building not for public use;

(f) a relocatable industrial camp building.

RSA 2000 cE-11 s2;2007 c13 s4

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Exclusive use of name engineer

3(1) No individual, corporation, partnership or other entity, except a professional engineer, licensee or permit holder entitled to engage in the practice of engineering, shall

(a) use

(i) the title "professional engineer", the abbreviation "P. Eng." or any other abbreviation of that title,

(i.1)repealed 2011 c3 s5,

(ii) the word "engineer" in combination with any other name, title, description, letter, symbol or abbreviation that represents expressly or by implication that the individual, corporation, partnership or other entity is a professional engineer, licensee or permit holder,

or

(b) represent or hold out, expressly or by implication, that the individual, corporation, partnership or other entity

(i) is entitled to engage in the practice of engineering, or

(ii) is a professional engineer, licensee or permit holder.

(2) No individual, corporation, partnership or other entity, except a professional engineer, licensee or permit holder entitled to engage in the practice of engineering, shall affix the stamp or seal of a professional engineer or licensee or the permit number of a permit holder or allow that stamp, seal or permit number to be affixed to a plan, drawing, detail drawing, specification or other document or a reproduction of any of them unless

(a) that plan, drawing, detail drawing, specification, other document or reproduction was prepared by or under the supervision and control of, and

(b) the stamp, seal or permit number is affixed with the knowledge and consent or in accordance with the direction of

the professional engineer or licensee to whom or the permit holder to which the stamp, seal or permit number was issued.

(3) Notwithstanding subsection (2), a professional engineer, licensee or permit holder may affix a stamp, seal or permit number, as the case may be, to a plan, drawing, detail drawing, specification, other document or reproduction prepared by other persons if the professional engineer, licensee or permit holder completes a thorough review of and accepts professional responsibility for that plan, drawing, detail drawing, specification, other document or reproduction.

RSA 2000 cE-11 s3;2007 c13 s5;2011 c3 s5

Holding out by joint firm

4 A joint firm

(a) may hold itself out as "engineers and architects" or "architects and engineers" only if it has both professional engineers and registered architects as partners or shareholders in an arrangement that is satisfactory to the Council and the council of The Alberta Association of Architects;

(b) shall not hold itself out as "engineers and architects" or "architects and engineers" if the registered architects or professional engineers are employees only and not partners or shareholders, or if the partnership or shareholding arrangement is not satisfactory to the Council or the council of The Alberta Association of Architects.

1981 cE-11.1 s4

Exclusive scope of the practice of geoscience

5(1) Subject to subsection (2), no individual, corporation, partnership or other entity, except a professional geoscientist, a licensee so authorized in the licensee's licence or a permit holder so authorized in the permit, shall engage in the practice of geoscience.

(2) Subsection (1) does not apply to the following:

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(a) a person engaged in the execution or supervision of the construction, maintenance, operation or inspection of any geoscientific investigation, process, system, study, work or instrumentation in the capacity of contractor, superintendent, foreman or inspector, or in any similar capacity, when the investigation, process, system, study, work or instrumentation has been designed by, and the execution or supervision is being carried out under the supervision and control of, a professional geoscientist or licensee;

(b) a person engaged in the practice of geoscience as a geoscientist-in-training or geoscience technologist in the course of being employed or engaged and supervised and controlled by a professional geoscientist, licensee or permit holder;

(c) a person who, as a prospector, is engaged in any activities that are normally associated with the business of prospecting;

(d) a member of the Canadian Forces while actually employed on duty with the Forces;

(e) a person engaged in conducting a routine geoscientific survey or preparing a routine geoscientific report where the specifications and standards for the survey or report have been prepared or approved by a professional geoscientist or licensee;

(f) a person engaged in the routine reduction or plotting of geoscientific data under the supervision and control of a professional geoscientist or licensee;

(g) a person engaged in the routine operation, maintenance or repair of geoscience equipment or facilities;

(h) a person engaged or employed by a university whose practice of the profession consists exclusively of teaching geoscience at the university.

RSA 2000 cE-11 s5;2007 c13 s6;2011 c3 s6

Exclusive use of name geoscientist

6(1) No individual, corporation, partnership or other entity, except a professional geoscientist or a licensee or permit holder entitled to engage in the practice of geoscience, shall

(a) use

(i) the title "professional geoscientist", the abbreviation "P. Geo." or any other abbreviation of that title,

(ii) the word "geoscientist" in combination with any other name, title, description, letter, symbol or abbreviation that represents expressly or by implication that the individual, corporation, partnership or other entity is a professional geoscientist, licensee or permit holder,

or

(b) represent or hold out, expressly or by implication, that the individual, corporation, partnership or other entity

(i) is entitled to engage in the practice of geoscience, or

(ii) is a professional geoscientist, licensee or permit holder.

(2) No individual, corporation, partnership or other entity, except a professional geoscientist or a licensee or permit holder entitled to engage in the practice of geoscience, shall affix the stamp or seal of a professional geoscientist or licensee or the permit number of a permit holder or allow that stamp, seal or permit number to be affixed to a map, geoscientific cross-section, specification, report or other document or a reproduction of any of them unless

(a) that map, geoscientific cross-section, specification, report, other document or reproduction was prepared by or under the supervision and control of, and

(b) the stamp, seal or permit number is affixed with the knowledge and consent or in accordance with the direction of

the professional geoscientist or licensee to whom or the permit holder to which the stamp, seal or permit number was issued.

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(3) Notwithstanding subsection (2), a professional geoscientist, licensee or permit holder may affix a stamp, seal or permit number, as the case may be, to a map, geoscientific cross-section, specification, report, other document or reproduction prepared by other persons if the professional geoscientist, licensee or permit holder completes a thorough review of and accepts professional responsibility for that map, geoscientific cross-section, specification, report, other document or reproduction.

RSA 2000 cE-11 s6;2007 c13 s7;2011 c3 s6

7 and **8** Repealed 2011 c3 s6.

Injunction

9 The Court, on application by the Council, may grant an injunction enjoining any person from doing any act or thing that contravenes this Part, notwithstanding any penalty that may be provided by this Act or the regulations in respect of that act or thing.

RSA 2000 cE-11 s9;2009 c53 s59

Part 2
Association

Association of Professional Engineers and Geoscientists

10(1) The Association of Professional Engineers, Geologists and Geophysicists of Alberta is continued as a corporation with the name "Association of Professional Engineers and Geoscientists of Alberta".

(2) The abbreviated form of the name of the Association is A.P.E.G.A. or APEGA.

(3) No person other than the Association shall use the abbreviated form of the name of the Association or any other abbreviation alone or in combination with any other word or name in a way that represents expressly or by implication that the person is a member of or connected in any way with the Association.

RSA 2000 cE-11 s10;2011 c3 s7

Capacity and powers

11 The Association has the capacity and, subject to this Act, the rights, powers and privileges of a natural person.

RSA 2000 cE-11 s11;2007 c13 s10

Council

12(1) There is hereby established a governing body of the Association called the Council.

(2) The Council shall manage and conduct the business and affairs of the Association and exercise the powers of the Association in the name of and on behalf of the Association.

(3) The Council shall submit annually to the Minister in a form satisfactory to the Minister a report on those matters of the business and affairs of the Association that the Minister requires.

(4) The Minister shall, on receipt of the annual report of the Association, lay it before the Legislative Assembly if it is then sitting, and if it is not then sitting, within 15 days after the commencement of the next sitting.

1981 cE-11.1 s12

Registrar

13 The Council shall appoint a Registrar for the purposes of this Act.

1981 cE-11.1 s13

Council members

14(1) Subject to subsection (2), the Council shall include the president, 2 vice-presidents, the immediate past-president and at least 12 other professional members, the number of which shall be prescribed by the bylaws, each of whom shall be elected by the professional members at the time, in the manner and for the period provided for in the bylaws.

(2) The Council shall consist of

(a) at least 16 professional members among whom there shall be not less than

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(i) 2 professional engineers, and

(ii) 2 professional geoscientists,

and

(b) when the total number of elected professional members does not exceed 20, 3 members of the public, who shall be appointed by the Minister, after consultation with the Association, for a 3-year term of office.

(3) For each 10 elected professional members by which the membership of the Council exceeds 20, an additional member of the public shall be appointed by the Minister, after consultation with the Association, for a 3-year term of office.

(4) A member of the Council appointed under subsection (2)(b) continues to hold office after the expiry of the member's term of office until the member is reappointed or the member's successor is appointed.

(5) The Minister may, after consultation with the Council, revoke the appointment of a member of the Council made under subsection (2)(b).

(6) The Minister may pay to a member of the Council appointed under subsection (2)(b) travelling and living expenses incurred by that member for the member's attendance at any meeting of the Council while away from the member's usual place of residence and fees in an amount prescribed by the Minister.

(7) The powers, duties and operations of the Council under this Act, the regulations and the bylaws are not affected by

(a) the fact that no member of the public is appointed as a member of the Council pursuant to subsection (2)(b),

(b) the revocation under subsection (5) of the appointment of a member of the public, or

(c) the resignation from the Council of a member of the public.

(8) The failure of a member of the public appointed under subsection (2)(b) to attend a meeting of the Council shall not be construed to affect or restrict the Council from exercising at that meeting any powers or performing any duties under this Act, the regulations or the bylaws.

RSA 2000 cE-11 s14;2011 c3 s8

Practice Review Board

15(1) There is hereby established a board called the Practice Review Board consisting of not less than 5 members as follows:

(a) the Council shall appoint not less than 4 professional members who have a combination of knowledge and experience suitable for determining the academic qualifications and experience necessary for a person to continue to engage in the practice of the profession of engineering or geoscience;

(b) the Minister shall appoint one member of the public nominated by the Council.

(2) If the Council fails, within a reasonable period of time after being requested to do so by the Minister, to make a nomination for the purposes of subsection (1)(b), the Minister may appoint a member of the public to the Practice Review Board without the Council's nomination.

(3) The Minister may pay to the member of the Board appointed under subsection (1)(b) travelling and living expenses incurred by that member for the member's attendance at a hearing of the Board while away from the member's usual place of residence and fees in an amount prescribed by the Minister.

(4) The Minister may, after consultation with the Council, revoke the appointment under subsection (1)(b) of a member of the public.

(5) The powers, duties and operations of the Board under this Act, the regulations and the bylaws are not affected by

(a) the fact that no member of the public is appointed as a member of the Board pursuant to subsection (1)(b),

(b) the revocation under subsection (4) of the appointment of a member of the public, or

(c) the resignation as a member of the Board of a member of the public.

(6) The failure of a member of the public appointed under subsection (1)(b) to attend a meeting of the Board shall not be construed to affect or restrict the Board from exercising at that meeting any powers or performing any duties under this Act, the regulations or the bylaws.

RSA 2000 cE-11 s15;2001 c10 s3;2011 c3 s32

Powers of the Practice Review Board

16(1) The Practice Review Board

(a) shall, on its own initiative or at the request of the Council, inquire into

(i) the assessment of existing and the development of new educational standards and experience requirements that are conditions precedent to obtaining and continuing registration under this Act,

(ii) the evaluation of desirable standards of competence of professional members, licensees, permit holders and certificate holders generally,

(iii) the practice of the profession by professional members, licensees, permit holders or certificate holders generally, and

(iv) any other matter that the Council from time to time considers necessary or appropriate in connection with the exercise of its powers and the performance of its duties in relation to competence in the practice of the profession under this Act and the regulations, and

(b) may conduct a review of the practice of a professional member, licensee, permit holder or certificate holder in accordance with this Act and the regulations.

(2) The Board shall report to and advise the Council with respect to any matter dealt with by it pursuant to subsection (1).

(3) A person requested to appear at an inquiry under this section by the Board is entitled to be represented by counsel.

(4) The Board may, after a review under this section with respect to an individual practitioner, make any order that the Discipline Committee may make under section 63 or 64.

(5) The provisions of Part 5 with respect to an investigation by the Investigative Committee apply to a review of an individual practitioner by the Practice Review Board.

(6) The Board may at any time during an inquiry or review under this section recommend to the Investigative Committee that the inquiry or review be conducted by the Investigative Committee pursuant to Part 5.

(7) On receiving a recommendation under subsection (6), the Investigative Committee may proceed with an investigation under Part 5 as if the recommendation were a written complaint.

(8) After each inquiry under this section, the Board shall make a written report to the Council on the inquiry and may make any recommendations to the Council that the Board considers appropriate in connection with the matter inquired into, with reasons for the recommendations.

(9) The Council may, if it considers it to be in the public interest to do so, direct that the whole or any portion of an inquiry by the Board under this section shall be held in camera.

1981 cE-11.1 s16;1995 c14 s6;1998 c14 s5

Appeal to Appeal Board

17 A professional member, licensee, permit holder or certificate holder who is the subject of a hearing or a review by the Practice Review Board may appeal any decision or order of the Board to the Appeal Board as if it were a decision or order of the Discipline Committee under Part 5.

1981 cE-11.1 s17;1995 c14 s7

Appeal Board

18(1) There is hereby established an Appeal Board consisting of

(a) the professional members appointed by the Council in accordance with the regulations, and

(b) one member of the public appointed by the Minister, after consultation with the Association, for a 3-year term of office.

(2) A member of the Appeal Board appointed under subsection (1)(b) continues to hold office after the expiry of the member's term of office until the member is reappointed or the member's successor is appointed.

(3) The Minister may, after consultation with the Appeal Board, revoke the appointment of a member of the Appeal Board made under subsection (1)(b).

(4) The Minister may pay to a member of the Appeal Board appointed under subsection (1)(b) travelling and living expenses incurred by that member for the member's attendance at any meeting of the Appeal Board while away from the member's usual place of residence and fees in an amount prescribed by the Minister.

(5) The powers, duties and operations of the Appeal Board under this Act, the regulations and the bylaws are not affected by

(a) the fact that no member of the public is appointed as a member of the Appeal Board pursuant to subsection (1)(b),

(b) the revocation of the appointment of a member of the public, or

(c) the resignation from the Appeal Board of a member of the public.

(6) The failure of a member of the public appointed pursuant to subsection (1)(b) to attend a meeting of the Appeal Board shall not be construed to affect or restrict the Appeal Board from exercising any powers or performing any duties under this Act, the regulations or the bylaws at that meeting.

1995 c14 s8

Part 3
Regulations and Bylaws

Regulations

19(1) The Council may make regulations

(a) respecting the establishment of categories of and conditions respecting the enrolment of engineers-in-training, geoscientists-in-training, examination candidates and students;

(b) respecting the academic qualifications of and experience requirements for applicants for registration as professional engineers or geoscientists;

(c) governing the evaluation by the Council, the Board of Examiners, the Practice Review Board, the Appeal Board or a committee established by any of them of the academic qualifications of and experience requirements for applicants for registration to engage in the practice of engineering or geoscience and the examination of those applicants with respect to those qualifications or requirements;

(d) respecting the eligibility of applicants generally for registration to engage in the practice of engineering or geoscience;

(e) respecting the powers, duties and functions of the Practice Review Board, including but not limited to the referral of matters by that Board to the Council or the Investigative Committee and appeals from decisions of that Board;

(f) respecting the appointment of members of the Appeal Board, other than the public member;

(g) prescribing the number of members that constitutes a quorum of the Council, the Investigative Committee, the Appeal Board, the Practice Review Board, the Board of Examiners or the Discipline Committee;

(h) governing the establishment of boards or committees of professional members and respecting the delegation of powers of the Council to those boards or committees or the Practice Review Board;

(i) prescribing technical standards for the practice of the profession;

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(j) establishing and providing for the publication of a code of ethics respecting the practice of the profession, the maintenance of the dignity and honour of the profession and the protection of the public interest;

(k) governing the names under which professional members, licensees, permit holders and certificate holders may engage in the practice of the profession;

(l) governing, subject to this Act, the operation and proceedings of the Appeal Board, the Board of Examiners and the Practice Review Board, the designation of chair and vice-chair, the appointment of acting members and the procedures for filling vacancies in the offices of chair and vice-chair and in the membership of any of those Boards, and the appointment to any of those Boards of members by virtue of their office and prescribing their powers, duties and functions;

(m) respecting the procedures of the Discipline Committee, of the Practice Review Board, of the Investigative Committee and of the Appeal Board in matters relating to the conduct or practice of professional members, licensees, permit holders or certificate holders, whether or not a complaint has been made;

(n) respecting the establishment by the Council of a compulsory continuing education program for professional members and licensees;

(o) governing the publication of a notice of the suspension or cancellation of the registration of a professional member, licensee, permit holder or certificate holder in a form and manner prescribed by the Council;

(p) respecting committees of inquiry for reinstatement under Part 5;

(q) - (w) repealed 2007 c13 s11;

(x) establishing classes or categories of professional engineers or geoscientists and licensees or permit holders and prescribing the restrictions of practice and the privileges and obligations of the classes or categories so established;

(y) respecting the academic and other qualifications and the experience required of the classes or categories established under clause (x);

(z) respecting the use of stamps, seals and permit numbers;

(aa) governing the eligibility for registration of persons, firms, partnerships and other entities as permit holders or certificate holders;

(bb) governing the operation of permit holders or certificate holders;

(cc) governing the publication of information with respect to the profession, including but not limited to the publication of surveys of fees;

(dd) respecting registration, licensing, the issuing of permits and certificates, disciplinary matters and the practice of engineering and geoscience generally;

(ee) respecting the service on any person of a document or notice required to be served under this Act.

(2) Repealed 2007 c13 s11.

(3) A regulation under subsection (1) may be made only by the Council.

(4) A regulation must be approved in principle by a majority of the professional members

(a) present and voting at a special meeting called for that purpose,

(b) voting by a mail vote or a vote authorized by bylaw that is conducted by electronic, telecommunication or other appropriate means, or

(c) at the annual general meeting following the Council's adoption of the regulation.

(5) The Council may change the text of a regulation that was approved in principle under subsection (4) if the change

(a) is consistent with the approval in principle, and

(b) is made before the regulation is submitted to the Lieutenant Governor in Council for approval.

(6) A regulation made under this section does not come into force unless it has been approved by the Lieutenant Governor in Council.

RSA 2000 cE-11 s19;2007 c13 s11;2011 c3 s9

Bylaws

20(1) The Council may make bylaws

(a) for the government of the Association and the management and conduct of its affairs;

(b) determining the location of the head office of the Association;

(c) respecting the calling of and conduct of meetings of the Association and the Council;

(d) respecting the nomination, election, number and term of office of Council members and officers of the Association and the appointment of individuals as members of the Council by virtue of their office, the Discipline Committee, the Practice Review Board, the Appeal Board, the Board of Examiners and any other committee established by the Council and prescribing their powers, duties and functions;

(e) prescribing those areas of the professions of engineering and geoscience from which members of the Board of Examiners shall be appointed by the Council;

(f) respecting the appointment, functions, duties and powers of a Chief Executive Officer of the Association;

(g) respecting the establishment of districts and branches of the Association and their operation;

(h) providing for the division of Alberta into electoral districts and prescribing the number of Council members to be elected from each district;

(i) providing for the appointment of a Deputy Registrar who has all of the powers and can perform all of the duties of the Registrar under this Act, the regulations and the bylaws when the Registrar is absent, or unable to act or when there is a vacancy in the office of Registrar;

(j) establishing classes or categories of membership in the Association in addition to professional engineers and professional geoscientists and prescribing the rights, privileges and obligations of the classes or categories of membership so established;

(k) providing for the appointment of acting members of the Council and procedures for the election or appointment of professional members to fill vacancies on the Council;

(l) prescribing the number of professional members that constitutes a quorum at meetings of the Association;

(m) governing the establishment, operation and proceedings of committees, the appointment of members of committees, the appointment of acting members and procedures for filling vacancies on committees and the delegation of any powers or duties of the Council under this Act, the regulations or the bylaws to a committee established by the Council or under this Act;

(n) prescribing fees and expenses payable to members of the Association for attending to the business of the Association;

(o) respecting the establishment and payment of sums of money for scholarships, fellowships and any other educational incentive or benefit program that the Council considers appropriate;

(p) governing the information to be engraved on stamps and seals issued to professional members, licensees and restricted practitioners;

(q) respecting permit numbers issued to permit holders;

(r) respecting the fixing of fees, dues and levies payable to the Association;

(s) respecting the costs payable by any person on the conclusion of a hearing or review by the Practice Review Board or under Part 5;

(t) respecting the establishment, content and maintenance of registers of professional members, licensees, permit holders and certificate holders and of records of other classes or categories of membership to be kept by the Registrar;

(u) respecting the removal from the registers and records of any memorandum or entry made in them under this Act or the bylaws;

(v) requiring professional members, licensees, permit holders and certificate holders to inform the Registrar in writing of their current mailing addresses and of any change of address forthwith after the change occurs;

(w) prescribing the form of a certificate of registration, a licence, a permit, a certificate of authorization and an annual certificate;

(x) respecting the expiry of annual certificates, annual licences, permits and other authorizations.

(2) The Council may make bylaws respecting the holding of mail votes or votes conducted by electronic, telecommunication or other appropriate means on any matter relating to the Association, but a bylaw under this subsection does not come into force unless it is approved by a majority of professional members of the Association present and voting at a general meeting.

(3) A bylaw under subsection (1) does not come into force unless it is approved by a majority of the professional members

(a) present and voting at a general meeting, or

(b) voting by a mail vote or vote conducted by electronic, telecommunication or other appropriate means conducted in accordance with the bylaws.

(4) The *Regulations Act* does not apply to bylaws of the Association made under this section.

RSA 2000 cE-11 s20;2007 c13 s12;2011 c3 s10

Consultation with Ministers required

20.1 Before the Council, by regulation, establishes or amends the academic qualifications for applicants for registration as professional engineers, geologists or geophysicists, the Council must consult with the Minister and the Minister responsible for Parts 1 to 3 of the *Post-secondary Learning Act* and must consider the comments received from those Ministers.

2010 c7 s3

Part 4
Registration

Registers and membership records

21(1) The Registrar shall maintain, in accordance with the bylaws and subject to the direction of the Council, a register for each of the following:

(a) professional engineers;

(b) professional geoscientists;

(c) repealed 2011 c3 s11;

(d) licensees to engage in the practice of

(i) professional engineering, or

(ii) professional geoscience;

(iii)repealed 2011 c3 s11;

(e) permit holders to engage in the practice of

(i) professional engineering, or

(ii) professional geoscience;

(iii)repealed 2011 c3 s11;

(f) joint firms;

(g) restricted practitioners.

(2) The Registrar shall enter in the appropriate register the name of a person who has paid the fee prescribed under the bylaws, and

(a) whose registration to engage in the practice of

(i) engineering, as a professional engineer or licensee, or

(ii) geoscience, as a professional geoscientist or licensee,

(iii)repealed 2011 c3 s11,

has been approved by the Board of Examiners,

(b) whose registration to engage in the practice of the profession as a permit holder has been approved by the Council, or

(c) whose registration to engage in the practice of engineering has been approved

(i) in the case of a joint firm, by the Council, or

(ii) in the case of a restricted practitioner, in accordance with section 37.

(3) The Registrar shall maintain, in accordance with the bylaws and subject to the direction of the Council, a membership record of the members in each class or category of membership established under the regulations and the bylaws.

RSA 2000 cE-11 s21;2011 c3 s11

Registration as professional member

22 The Board of Examiners shall approve for registration as a professional engineer or professional geoscientist an individual who has applied to the Board and is eligible in accordance with this Act and the regulations to become a professional engineer or professional geoscientist, as the case may be.

RSA 2000 cE-11 s22;2011 c3 s12

Registration as licensee

23 The Board of Examiners shall approve the registration as a licensee of an individual who has applied to the Board of Examiners and is eligible in accordance with this Act and the regulations to become registered to engage in the practice of engineering or geoscience as a licensee.

RSA 2000 cE-11 s23;2011 c3 s32

Registration of permit holders

24(1) The Council shall approve the registration as a permit holder of a partnership or other association of persons, or of a corporation incorporated or registered under the *Companies Act* or continued, incorporated or registered under the *Business Corporations Act*, that has applied to the Council and is eligible under this section and the regulations to become registered to engage in the practice of engineering or geoscience as a permit holder.

(2) A partnership or other association of persons or a corporation that applies to the Council is eligible to become registered as a permit holder entitled to engage in the practice of engineering or geoscience if it satisfies the Council that it complies with the Act and the regulations.

RSA 2000 cE-11 s24;2011 c3 s32

Evidence of registration

25(1) On entering the name of a professional engineer or geoscientist in the register, the Registrar shall issue to the professional engineer or geoscientist

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(a) a certificate of registration, and

(b) a stamp or seal engraved as prescribed in the bylaws.

(2) On entering the name of a licensee in the register, the Registrar shall issue to the licensee

(a) a licence to engage in the practice of engineering or geoscience as a licensee as authorized in the licence, and

(b) a stamp or seal engraved as prescribed in the bylaws.

(3) On entering the name of a permit holder in the register, the Registrar shall issue to the permit holder

(a) a permit to engage in the practice of engineering or geoscience as a permit holder as authorized in the permit, and

(b) a permit number as prescribed in the bylaws.

(4) On entering the name of a joint firm in the register, the Registrar shall issue to the joint firm

(a) a certificate of authorization to engage in the practice of engineering and architecture, and

(b) a permit number as prescribed in the bylaws.

(5) On entering the name of a restricted practitioner in the register, the Registrar shall issue to that individual a certificate of authorization to engage in the restricted scope of the practice of engineering that is specified in the certificate.

(6) A certificate of registration, a licence, a permit or a certificate of authorization issued under this section entitles the holder to engage in the practice of engineering or geoscience, as the case may be, subject to this Act, the regulations and the bylaws.

RSA 2000 cE-11 s25;2011 c3 s13

Annual certificate

26(1) A professional member, licensee, permit holder or certificate holder engaged in the practice of engineering or geoscience shall pay to the Association the annual fee prescribed under the bylaws.

(2) The Registrar shall issue an annual certificate in accordance with the bylaws to a professional member, licensee, permit holder or certificate holder

(a) whose registration is not under suspension, and

(b) who has paid the annual fee.

(3) Subject to this Act, an annual certificate entitles the professional member, licensee, permit holder or certificate holder to engage in the practice of engineering or geoscience, as the case may be, during the year for which the annual certificate is issued.

(4) Repealed 2007 c13 s13.

RSA 2000 cE-11 s26;2007 c13 s13;2011 c3 s32

Entries in registers

27(1) The registration of a professional member, licensee, permit holder or certificate holder is suspended when the decision to suspend the registration is made in accordance with this Act.

(2) The Registrar shall enter a memorandum of suspension of a registration in the appropriate register indicating

(a) the duration of the suspension, and

(b) the reason for the suspension.

(3) The registration of a professional member, licensee, permit holder or certificate holder is cancelled when the decision to cancel the registration is made in accordance with this Act.

(4) The Registrar shall enter a memorandum of cancellation of a registration in the appropriate register.

(5) The Registrar shall not remove from the registers any memorandum made by the Registrar under this section, except in accordance with the bylaws.

1981 cE-11.1 s26

List of registrants open to the public

28 The Registrar shall maintain and, during regular office hours, permit any person to inspect a list of all the professional members, licensees, permit holders and certificate holders in good standing.

1981 cE-11.1 s27

Cancellation on request

29(1) The Registrar shall not cancel the registration of a professional member, licensee, permit holder or certificate holder at that person's request unless the request for the cancellation has been approved by the Council.

(2) When a request for cancellation of a registration is approved by the Council

(a) the Registrar shall cancel that registration, and

(b) the professional member, licensee, permit holder or restricted practitioner requesting the cancellation shall, on being notified of the approval,

(i) immediately surrender to the Registrar

(A) the certificate of registration, licence and the stamp or seal, in the case of a professional member, licensee or restricted practitioner, or

(B) the permit and annual certificate, in the case of a permit holder,

and

(ii) cease using the permit number, in the case of a permit holder.

(3) The Council may direct the Registrar to reinstate in the applicable register a registration that was cancelled under this section, subject to any conditions that the Council may prescribe, and to reissue the certificate of registration, licence or permit and the stamp, seal or permit number.

(4) Notwithstanding subsection (3), if a person whose registration is cancelled applies to be reinstated more than 7 years after the date of the cancellation, the application for reinstatement must be referred to the Board of Examiners.

1981 cE-11.1 s28;1995 c14 s12;1998 c14 s9

Board of Examiners

30(1) The Council shall establish a Board of Examiners in accordance with the regulations.

(2) The Minister shall appoint as members of the Board of Examiners 3 persons from a list of members of the public nominated by the Council.

(3) If the Council fails, within a reasonable period of time after being requested to do so by the Minister, to make nominations for the purposes of subsection (2), the Minister may appoint 3 members of the public to the Board of Examiners without the Council's nomination.

(4) The Minister may pay to a member of the Board appointed under subsection (2) travelling and living expenses incurred by that member for the member's attendance at a hearing of the Board while away from the member's usual place of residence and fees in an amount prescribed by the Minister.

(5) The Minister may, after consultation with the Council, revoke the appointment under subsection (2) of a member of the public.

(6) The powers, duties and operations of the Board under this Act, the regulations and the bylaws are not affected by

(a) the fact that no member of the public is appointed as a member of the Board pursuant to subsection (2),

(b) the revocation under subsection (5) of the appointment of a member of the public, or

(c) the resignation as a member of the Board of a member of the public.

(7) The failure of a member of the public appointed under subsection (2) to attend a meeting of the Board is not to be construed to affect or restrict the Board from exercising at that meeting any powers or performing any duties under this Act, the regulations or the bylaws.

(8) The Board of Examiners shall consider applications for the registration of applicants as professional members or licensees in accordance with this Part, the regulations and the bylaws and may

(a) approve the registration,

(b) refuse the registration, or

(c) defer the approval of registration until it is satisfied that the applicant has complied with a requirement made under this section.

(9) The Board of Examiners may, in its discretion, require an applicant for registration

(a) to pass one or more examinations set by the Board,

(b) to obtain more experience of a kind satisfactory to the Board for a period set by the Board, or

(c) to pass one or more examinations and obtain more experience

before it approves the registration.

1981 cE-11.1 s29;1984 c17 s11;1995 c14 s13

Approval by the Board of Examiners

31(1) The Board of Examiners shall approve the registration as a professional member of a person who proves to the satisfaction of the Board that

(a) the person is of good character and reputation,

(b) the person is a Canadian citizen or lawfully admitted to Canada for permanent residence, and

(c) the person meets the requirements of the regulations.

(2) If an applicant for registration as a licensee is not a Canadian citizen or lawfully admitted to Canada for permanent residence but otherwise complies, to the satisfaction of the Board of Examiners, with subsection (1), the Board shall approve the registration.

1981 cE-11.1 s30;1984 c17 s12;1995 c14 s14

Review by the Appeal Board

32(1) The Board of Examiners shall send a written notice of any decision made by it under this Part to the applicant.

(2) If the decision made by the Board is to refuse or defer registration of the applicant, reasons for the decision shall be sent in writing to the applicant.

(3) If the decision made by the Board is to approve the registration, the Registrar shall publish a notice of approval in accordance with the bylaws.

(4) An applicant whose application for registration has been refused by the Board of Examiners may, within 30 days after receiving a notice of refusal and the reasons for refusal, appeal the decision to the Appeal Board by serving a notice of appeal on the Registrar.

(5) On receiving a notice of appeal, the Registrar shall set a date, time and place for the hearing of the appeal and notify the appellant, in writing, of the date, time and place.

(6) The appellant may appear with counsel and make representations to the Appeal Board.

(7) On concluding the hearing, the Appeal Board may make any decision the Board of Examiners was authorized to make.

1981 cE-11.1 s31;1995 c14 s15

Joint firms

33(1) In this section and sections 34 and 35,

(a) "Architects Association" means The Alberta Association of Architects under the *Architects Act*;

(b) "architects firm" means a partnership or corporation

(i) that

(A) confines its practice to providing architectural consulting services, or

(B) if it does not confine its practice to providing architectural consulting services, engages in a practice satisfactory to the Joint Board,

and

(ii) in which registered architects

(A) hold a majority interest, and

(B) control the partnership or corporation,

and that is otherwise entitled to engage in the practice of architecture under the *Architects Act*;

(c) "engineers firm" means a partnership or corporation

(i) that

(A) confines its practice to providing engineering consulting services, or

(B) if it does not confine its practice to providing engineering consulting services, engages in a practice satisfactory to the Joint Board,

and

(ii) in which professional engineers

(A) hold a majority interest, and

(B) control the partnership or corporation,

and that is otherwise entitled to engage in the practice of engineering under this Act;

(d)"proposed engineers and architects firm" means a partnership or corporation

(i) that

(A) proposes to confine its practice to providing engineering consulting services and architectural consulting services, or

(B) if it does not propose to confine its practice to providing engineering consulting services and architectural consulting services, proposes to engage in a practice satisfactory to the Joint Board,

and

(ii) in which professional engineers and registered architects

(A) hold a majority interest, and

(B) control the partnership or corporation,

and that is otherwise entitled to engage in the practice of engineering under this Act or the practice of architecture under the *Architects Act*.

(2) An application for a certificate of authorization may be made by the following:

(a) a professional engineer;

(b) a registered architect;

(c) an engineers firm;

(d) an architects firm;

(e) a proposed engineers and architects firm;

(f) a partnership or corporation that is not referred to in clause (c), (d) or (e) that the Joint Board considers a suitable applicant for a certificate of authorization.

(3) An applicant under subsection (2) shall

(a) if its prime activity is the provision of engineering consulting services, apply to the Council, and

(b) if its prime activity is the provision of architectural consulting services, apply to the council of the Architects Association.

1981 cE-11.1 s32

Approval by Joint Board

34(1) Every application under section 33 shall be referred to the Joint Board by the council to which it was made, with or without comment from that council.

(2) The Joint Board shall consider with respect to each application referred to it whether

(a) the applicant is eligible to apply under section 33(2);

(b) the applicant has at least one full-time employee who is a professional engineer who shall take responsibility for the engineering work of the applicant and at least one full-time employee who is a registered architect who shall take responsibility for the architectural work of the applicant;

(c) the presence of any ownership interests in the applicant will give rise to conflicts with the professional responsibilities of the firm;

(d) the granting of a certificate of authorization to the applicant will give rise to unauthorized practice or otherwise lead to circumvention of this Act or the *Architects Act*;

(e) any detriment to the public would result from the applicant becoming entitled to engage in the practice of both engineering and architecture.

(3) After considering an application for a certificate of authorization referred to it, the Joint Board shall recommend

(a) in the case of an application by a registered architect or an architects firm, to the Council,

(b) in the case of an application by a professional engineer or an engineers firm, to the council of the Architects Association, or

(c) in the case of an application by a proposed engineers and architects firm or other applicant, to the Council and to the council of the Architects Association,

whether or not to grant a certificate of authorization, based on the criteria considered by it under subsection (2).

1981 cE-11.1 s33

Registration of joint firm

35(1) On receipt of a recommendation of the Joint Board under section 34, the Council may approve the registration of a proposed engineers and architects firm if that firm is eligible to become registered under the regulations.

(2) When recommendations are made by the Joint Board to both the Council and the council of the Architects Association with respect to an application for a certificate of authorization, both councils must agree that the certificate should be issued and both shall sign the certificate before it is issued.

(3) Subject to subsection (2), an applicant is entitled to be registered as a joint firm when the Council approves its registration.

1981 cE-11.1 s34

Duties of joint firm

36(1) A joint firm may engage in the practice of both engineering and architecture in

(a) the names of the individuals who are its partners,

(b) its corporate name, or

(c) any other name that is approved by the Council pursuant to the bylaws.

(2) A joint firm shall advise the Registrar in writing of

(a) the names of the individual shareholders, directors and officers of the firm,

(b) the names of the employees who are professional engineers and registered architects, and

(c) of any change in those shareholders, directors, officers or employees forthwith after the change occurs.

(3) When a joint firm causes plans, drawings, detail drawings and specifications prepared in its practice of engineering, or prepared by other persons and reviewed by the professional members in its practice of engineering, to be signed by its proper officers and affixed with the permit number issued to the firm, it shall also cause them to be signed by and imprinted with the stamp or seal of the professional engineer who

(a) had supervision and control over their preparation, or

(b) reviewed and assumed professional responsibility for them.

1981 cE-11.1 s35;1998 c14 s10

Restricted practitioner

37(1) The Joint Board may recommend to the Council that a certificate of authorization be issued to an individual who is a registered architect who

(a) has historically competently provided a service in the practice of professional engineering in Alberta, and

(b) applied for the certificate before October 1, 1982.

(2) On receipt of a recommendation under subsection (1), the Council may approve the registration of an individual who has applied to the Council and is eligible under the bylaws to become registered as a restricted practitioner.

(3) If the Council approves the registration of an individual as a restricted practitioner, it shall specify in the certificate and in the register the restricted scope of the practice of engineering in which the individual is permitted to engage.

1981 cE-11.1 s36;1983 cD-25.5 s23

Exemption from stamp or seal requirement

38 On the recommendation of the Joint Board, the Council may authorize an individual who is a registered architect under the *Architects Act* to apply for a permit authorized by the regulations under the *Safety Codes Act* without the final design drawings and specifications of the building having the stamp or seal of a professional engineer.

1981 cE-11.1 s37;1991 cS-0.5 s70;1995 c14 s16

Cancellation

39(1) The Council may direct the Registrar to cancel the registration of

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(a) a professional member, licensee or permit holder who is in default of payment of annual fees or any other fees, dues or levies payable under this Act, or

(b) a permit holder if it no longer has employees in compliance with this Act,

after the expiration of 30 days following the service on the professional member, licensee or permit holder of a written notice by the Council pursuant to subsection (2), unless the professional member, licensee or permit holder on whom the notice is served complies with the notice.

(2) The notice under subsection (1) shall state that the Registrar may cancel the registration unless

(a) the fees, dues or levies are paid as indicated in that notice, or

(b) evidence satisfactory to the Council has been received by it within the time prescribed in the notice indicating that the permit holder has employees in compliance with this Act.

(3) The Council may direct the Registrar to cancel the registration of a professional member, licensee or permit holder that was entered in error in the register.

(4) If the registration of a professional member or licensee has been cancelled under this section, the professional member or licensee shall forthwith surrender to the Registrar any certificate of registration, licence, stamp or seal issued to the professional member or licensee.

(5) If the registration of a permit holder has been cancelled under this section, the permit holder shall immediately surrender the permit to the Registrar and cease to use the permit number issued to that permit holder.

(6) If a registration has been cancelled pursuant to subsection (1), the Council may direct the Registrar, subject to any conditions that the Council may prescribe, to reinstate that registration in the applicable register and to reissue the certificate of registration, licence or permit and the stamp, seal or permit number.

(7) Notwithstanding subsection (6), if a person whose registration is cancelled applies to be reinstated more than 7 years after the date of the cancellation, the application for reinstatement must be referred to the Board of Examiners.

1981 cE-11.1 s38;1995 c14 s17;1998 c14 s11

Cancellation of a joint firm

40(1) The Council may direct the Registrar to cancel the registration of a joint firm that

(a) is in default of payment of annual fees or any other fees, dues or levies payable under this Act, or

(b) ceases to have at least one professional engineer and at least one registered architect to take the responsibility referred to in section 34(2)(b),

after the expiration of one month following the service on the joint firm of a written notice that the Council intends to cancel the registration, unless the joint firm on which the notice is served complies with the notice.

(2) The notice under subsection (1) shall state that the Registrar may cancel the registration unless

(a) the fees, dues or levies are paid as indicated in the notice, or

(b) the joint firm has at least one professional engineer and at least one registered architect to take the responsibility referred to in section 34(2)(b).

(3) If the registration of a joint firm has been cancelled under this section, the joint firm shall forthwith surrender to the Registrar the certificate of authorization and the stamp issued to it.

(4) The Council may direct the Registrar, subject to any conditions that the Council may prescribe, to reinstate the joint firm in the applicable register and to reissue the certificate of authorization and the stamp.

1981 cE-11.1 s39

Cancellation of restricted practitioners

41(1) The Council may direct the Registrar to cancel the registration of a restricted practitioner who

(a) is in default of payment of annual fees or any other fees, dues or levies payable under this Act, or

(b) who is not a registered architect in good standing under the *Architects Act*,

after the expiration of one month following the service on the restricted practitioner of a written notice that the Council intends to cancel the registration, unless the restricted practitioner on whom the notice is served complies with the notice.

(2) The notice under subsection (1) shall state that the Registrar may cancel the registration unless

(a) the fees, dues or levies are paid as indicated in the notice, or

(b) the restricted practitioner is a registered architect in good standing under the *Architects Act*.

(3) If the registration of a restricted practitioner has been cancelled under this section, the restricted practitioner shall forthwith surrender to the Registrar the certificate of authorization and the stamp issued to it.

(4) The Council may direct the Registrar, subject to any conditions that the Council may prescribe, to reinstate the restricted practitioner in the applicable register and to reissue the certificate of authorization and the stamp.

1981 cE-11.1 s40

Part 5
Discipline

Definitions

42 In this Part,

(a) "conduct" includes an act or omission;

(b) "investigated person" means a professional member, licensee, permit holder, certificate holder or member-in-training with respect to whose conduct an investigation is held under this Part;

(c) "practice of the profession" means practice of engineering or practice of geoscience, as the case may be.

RSA 2000 cE-11 s42;2011 c3 s14

Complaints

43(1) A person may complain to the Registrar, or to a person who is authorized in writing by the Registrar to receive complaints, about the conduct of a professional member, licensee, permit holder, certificate holder or member-in-training, and the complaint shall be dealt with in accordance with this Part and the regulations.

(2) A complaint must be in writing.

(3) A complaint respecting the conduct of a professional member, licensee, permit holder or certificate holder whose registration was cancelled pursuant to this Act may, notwithstanding the cancellation, be dealt with within 2 years following the date of cancellation of the registration as if the cancellation had not occurred.

(4) Notwithstanding section 47, a person designated by the Registrar as a mediator may assist in settling a complaint if the complainant and the person about whose conduct the complaint was made agree, but if within 30 days from the date of receipt of the complaint, or a longer period agreed to by those persons, a settlement of the complaint between those persons does not occur, or in the mediator's opinion is not likely to occur, the complaint shall be referred forthwith by the Registrar to the Investigative Committee.

(5) If a complaint is settled with the assistance of a mediator, any agreement that is reached by the complainant and the person about whose conduct the complaint was made must be reviewed by the Investigative Committee, and that Committee may

(a) approve the agreement, or

(b) proceed with a preliminary investigation in accordance with section 47.

1981 cE-11.1 s42;1984 c17 s13;1995 c14 s18

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Determination of unprofessional conduct and unskilled practice

44(1) Any conduct of a professional member, licensee, permit holder, certificate holder or member-in-training that in the opinion of the Discipline Committee or the Appeal Board

(a) is detrimental to the best interests of the public,

(b) contravenes a code of ethics of the profession as established under the regulations,

(c) harms or tends to harm the standing of the profession generally,

(d) displays a lack of knowledge of or lack of skill or judgment in the practice of the profession, or

(e) displays a lack of knowledge of or lack of skill or judgment in the carrying out of any duty or obligation undertaken in the practice of the profession,

whether or not that conduct is disgraceful or dishonourable, constitutes either unskilled practice of the profession or unprofessional conduct, whichever the Discipline Committee or the Appeal Board finds.

(2) If an investigated person fails to comply with or contravenes this Act, the regulations or the bylaws, and the failure or contravention is, in the opinion of the Discipline Committee, of a serious nature, the failure or contravention may be found by the Discipline Committee to be unprofessional conduct whether or not it would be so found under subsection (1).

1981 cE-11.1 s43;1995 c14 s19

Discipline Committee

45(1) The Council shall establish a Discipline Committee, the members of which shall be appointed in accordance with the regulations.

(2) The Council shall make regulations governing, subject to this Part, the operation and proceedings of the Discipline Committee, the designation of a chair, the appointment of acting members and the procedures for filling vacancies in the offices of the chair and the membership and the appointment of members by virtue of their office, and prescribing their powers, duties and functions.

(3) The Council may make regulations respecting the hearing of a matter under this Part by a panel of the Discipline Committee.

(4) A regulation made under subsection (2) or (3) does not come into force unless it has been approved by the Lieutenant Governor in Council.

1981 cE-11.1 s44;1984 c17 s14

Investigative Committee

46(1) The Council shall establish an Investigative Committee, the members of which shall be appointed in accordance with the regulations.

(2) The Council shall make regulations governing, subject to this Part, the operation and proceedings of the Investigative Committee, the designation of a chair, the appointment of members, acting members and members by virtue of their office and the procedures for filling vacancies in the offices of the chair and the membership, and prescribing their powers, duties and functions.

(3) A regulation made under subsection (2) does not come into force unless it has been approved by the Lieutenant Governor in Council.

1995 c14 s20

Investigation panel

47 When a complaint is referred to the Investigative Committee under section 43, the Investigative Committee shall appoint an investigation panel from among its members to conduct a preliminary investigation.

1981 cE-11.1 s45;1995 c14 s21

Notice of preliminary investigation

48 The Registrar shall forthwith send notice in writing to the investigated person that a preliminary investigation is being conducted.

1981 cE-11.1 s46

Evidence for preliminary investigation

49(1) An investigation panel may

(a) require the investigated person or any other member of the Association to produce any plans, drawings, detailed drawings, specifications, reports, books, papers or other documents or records in that person's possession or control, and

(b) copy and keep copies for the purposes of this Part of any thing that is produced under clause (a).

(2) An investigation panel may investigate any other matter regarding the conduct of the investigated person that arises in the course of the investigation.

1981 cE-11.1 s47;1995 c14 s22

Report to Investigative Committee

50 On concluding a preliminary investigation, the investigation panel shall report its findings to the Investigative Committee.

1981 cE-11.1 s48;1995 c14 s23

Termination of investigation

51(1) The Investigative Committee may terminate an investigation at any time if it is of the opinion that

(a) the complaint is frivolous or vexatious, or

(b) there is insufficient evidence of unskilled practice of the profession or unprofessional conduct.

(2) On terminating an investigation, the Investigative Committee shall direct the Registrar to serve on the investigated person and on the complainant, if any, a notice in accordance with the bylaws that the investigation has been terminated.

(3) A complainant who is served with a notice under subsection (2) informing the complainant that the investigation has been terminated may, by notice in writing to the Registrar within 30 days after receipt of the notice under subsection (2), appeal that decision to the Appeal Board.

(4) On an appeal under subsection (3), the Appeal Board shall

(a) uphold the decision of the Investigative Committee to terminate the investigation if, in the opinion of the Appeal Board,

(i) the complaint is frivolous or vexatious, or

(ii) there is insufficient evidence of unskilled practice of the profession or unprofessional conduct,

or

(b) refer the matter to the Discipline Committee for a formal hearing.

(5) The Appeal Board shall notify the complainant, the investigated person and the Investigative Committee in writing of its decision under subsection (4).

1981 cE-11.1 s49;1984 c17 s15;1995 c14 s24;1998 c14 s12

Power of Investigative Committee to recommend an order

52(1) If an investigation is not terminated under section 51, the Investigative Committee may

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(a) if the investigated person has admitted to conduct that constitutes unskilled practice of the profession or to unprofessional conduct, recommend, in accordance with subsection (2), any order that the Investigative Committee considers appropriate, or

(b) refer the matter to the Discipline Committee for a formal hearing.

(2) An order recommended by the Investigative Committee must be provided to a member of the Discipline Committee who has been designated by that Committee to act as a case manager.

(3) If the case manager agrees with the order recommended by the Investigative Committee, the case manager must discuss the order with the investigated person and, if the investigated person agrees with the order, the order has the same force and effect as an order made by the Discipline Committee following a formal hearing.

(4) If the case manager or the investigated person rejects the order recommended by the Investigative Committee, the matter must be referred to the Discipline Committee for a formal hearing.

1995 c14 s25

Duty of Discipline Committee

53(1) On the referral of a matter to the Discipline Committee for a formal hearing, the Discipline Committee shall hold the hearing forthwith.

(2) Notwithstanding subsection (1), if proceedings in respect of the same circumstances or events are commenced in Provincial Court or the Court of Queen's Bench, the Discipline Committee may adjourn the hearing.

(3) The Registrar shall serve on the investigated person and on the complainant, if any, a notice of hearing stating the date, time and place at which the Discipline Committee will hold the hearing and giving reasonable particulars of the conduct or complaint in respect of which the hearing will be held.

1981 cE-11.1 s50;1984 c17 s16;1995 c14 s26

Further investigation

54(1) The Discipline Committee may also investigate and hear any other matter concerning the conduct of the investigated person that arises in the course of the hearing, but in that event the Committee shall declare its intention to investigate and hear the further matter and shall permit the person sufficient opportunity to prepare the person's answer to the further matter.

(2) Sections 56 to 62 apply to an investigation and hearing of a further matter under subsection (1).

1981 cE-11.1 s51

Suspension pending investigation and hearing

55(1) Notwithstanding anything in this Act, the Investigative Committee may suspend the registration of a professional member, licensee, permit holder, certificate holder or member-in-training pending a preliminary investigation or a decision of the Discipline Committee.

(2) A person whose registration is suspended under subsection (1) may apply to the Court for an order staying the suspension.

(3) A copy of an application under subsection (2) must be served on the Registrar.

RSA 2000 cE-11 s55;2009 c53 s59

Right to counsel and to appearance

56 The Investigative Committee and the investigated person may appear and be represented by counsel at a hearing before the Discipline Committee.

1981 cE-11.1 s53;1984 c17 s18;1995 c14 s28

Public hearings

57 All hearings before the Discipline Committee and the Appeal Board under this Part are open to the public unless that Committee or Board orders otherwise.

1981 cE-11.1 s54;1995 c14 s29

Evidence

58(1) Evidence may be given before the Discipline Committee in any manner that the Committee considers appropriate, and the Committee is not bound by the rules of law respecting evidence applicable to judicial proceedings.

(2) For the purposes of an investigation, hearing or review under this Act, any member of the Appeal Board, the Discipline Committee or the Practice Review Board is conferred with the power of a commissioner for oaths under the *Commissioners for Oaths Act*.

1981 cE-11.1 s55;1995 c14 s30

Witnesses and documents

59(1) The investigated person and any other person who in the opinion of the Discipline Committee has knowledge of the complaint or any conduct being investigated are compellable witnesses in any proceeding under this Part.

(2) A witness may be examined on oath on all matters relevant to the investigation or hearing and is not to be excused from answering any question on the ground that the answer might

(a) tend to incriminate the witness,

(b) subject the witness to punishment under this Part, or

(c) tend to establish the witness's liability

(i) to a civil proceeding at the instance of the Crown or of any other person, or

(ii) to prosecution under any Act or regulations under any Act,

but if the answer so given tends to incriminate the witness, subjects the witness to punishment or tends to establish the witness's liability, it shall not be used or received against the witness in any civil proceedings, in a prosecution under Part 7 or in any proceeding under any other Act, except in a prosecution for or proceedings in respect of perjury or the giving of contradictory evidence.

(3) For the purpose of obtaining the testimony of a witness who is out of Alberta, a judge of the Court on an application ex parte by the Association may direct the obtaining of the evidence of the witness in the manner provided under the *Alberta Rules of Court* for the taking of the evidence of a person outside Alberta.

RSA 2000 cE-11 s59;2009 c53 s59

Enforcement of attendance and production of documents

60(1) The attendance of witnesses before the Discipline Committee and the production of plans, drawings, detail drawings, specifications, reports, books, papers and other documents or records may be enforced by a notice issued by the Registrar requiring the witness to attend and stating the date, time and place at which the witness is to attend and the plans, drawings, detail drawings, specifications, reports, books, papers and other documents or records, if any, the witness is required to produce.

(2) On the written request of the investigated person or of the investigated person's counsel or agent, the Registrar shall without charge issue and deliver to that person or that person's counsel or agent any notices that that person or that person's counsel or agent may require for the attendance of witnesses or the production of documents or records.

(3) A witness other than the investigated person who has been served with a notice to attend or a notice for the production of documents or records under subsection (1) or (2) is entitled to be paid the same fees, expenses and allowances as are payable to witnesses in an action in the Court.

RSA 2000 cE-11 s60;2009 c53 s59

Failure to give evidence

61(1) Proceedings for civil contempt of court may be brought against a witness

(a) who fails

(i) to attend before the Discipline Committee in compliance with a notice to attend,

(ii) to produce any books, papers or other documents or records in compliance with a notice to produce them, or

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(iii)in any way to comply with either notice,

or

(b) who refuses to be sworn or to answer any question directed to be answered by the Discipline Committee.

(2) If the witness referred to in subsection (1) is the investigated person, the witness's failure or refusal may be held to be unprofessional conduct.

(3) The Discipline Committee, on proof of service of the notice of investigation on the investigated person and the complainant, if any, may

(a) proceed with the investigation in the absence of either or both of those persons, and

(b) act on the matter being investigated in the same way as though either or both of those persons were in attendance.

1981 cE-11.1 s58

Finding by the Discipline Committee

62(1) The Discipline Committee may find that the conduct of an investigated person constitutes neither unskilled practice of the profession nor unprofessional conduct.

(2) The Discipline Committee may find that the conduct of an investigated person constitutes unskilled practice of the profession or unprofessional conduct, or both, and shall deal with the investigated person in accordance with this Part.

1981 cE-11.1 s59

Powers of the Discipline Committee

63 If the Discipline Committee finds that the conduct of the investigated person is unprofessional conduct or unskilled practice of the profession, or both, the Discipline Committee may make any one or more of the following orders:

(a) reprimand the investigated person;

(b) suspend the registration of the investigated person for a specified period;

(c) suspend the registration of the investigated person either generally or from any field of practice until

(i) the investigated person has completed a specified course of studies or obtained supervised practical experience, or

(ii) the Discipline Committee is satisfied as to the competence of the investigated person generally or in a specified field of practice;

(d) accept in place of a suspension the investigated person's undertaking to limit the investigated person's practice;

(e) impose conditions on the investigated person's entitlement to engage in the practice of the profession generally or in any field of the practice, including the conditions that the investigated person

(i) practise under supervision,

(ii) not engage in sole practice,

(iii)permit periodic inspections by a person authorized by the Discipline Committee, or

(iv)report to the Discipline Committee on specific matters;

(f) direct the investigated person to pass a particular course of study or satisfy the Discipline Committee as to the investigated person's practical competence generally or in a field of practice;

(g) direct the investigated person to satisfy the Discipline Committee that a disability or addiction can be or has been overcome, and suspend the person until the Discipline Committee is so satisfied;

(h) require the investigated person to take counselling or to obtain any assistance that in the opinion of the Discipline Committee is appropriate;

(i) direct the investigated person to waive, reduce or repay a fee for services rendered by the investigated person that, in the opinion of the Discipline Committee, were not rendered or were improperly rendered;

(j) cancel the registration of the investigated person;

(k) any other order that it considers appropriate in the circumstances.

1981 cE-11.1 s60

Order to pay costs or a fine

64(1) The Discipline Committee may, in addition to or instead of dealing with the investigated person in accordance with section 63, order that the investigated person pay

(a) all or part of the costs of the hearing in accordance with the bylaws,

(b) a fine not exceeding $10 000 to the Association, or

(c) both the costs under clause (a) and a fine under clause (b),

within the time fixed by the order.

(2) If the investigated person ordered to pay a fine, costs, or both, under subsection (1) fails to pay the fine, costs, or both, within the time ordered, the Discipline Committee may suspend the registration of that person until the person has paid the fine, costs or both.

(3) A fine or costs ordered to be paid to the Association under this section is a debt due to the Association and may be recovered by the Association by civil action for debt.

1981 cE-11.1 s61;1984 c17 s19

Service of written decision

65(1) The Discipline Committee shall, within a reasonable time after the conclusion of a hearing, make a written decision on the matter, in which it shall

(a) describe each finding made in accordance with this Part,

(b) state the reasons for each finding made, and

(c) state any order made under this Part.

(2) The Discipline Committee shall immediately forward to the Registrar

(a) the decision, and

(b) the record of the hearing, consisting of all evidence presented before it, including

(i) all exhibits,

(ii) all documents and records, and

(iii) a transcript of all testimony given before it, whether recorded electronically, mechanically or in handwritten form.

(3) The Registrar shall, immediately on receiving the decision and the record of the hearing referred to in subsection (2), serve

(a) a copy of the decision on the investigated person and the Investigative Committee, and

(b) a notice of the nature of the decision on the complainant, if any.

(4) The investigated person or the investigated person's counsel or agent may examine the record or any part of the record of the proceedings and hear any recording or examine any mechanical or handwritten form of record of any testimony.

1981 cE-11.1 s62;1995 c14 s31

Suspension or cancellation pending appeal

66(1) Notwithstanding an appeal under this Part, the Discipline Committee may order that its decision remain in effect until the Appeal Board or the Court of Appeal, as the case may be, makes its decision on the appeal.

(2) An investigated person may apply to the Court for an order staying the decision of the Discipline Committee pending the determination of the appeal.

(2.1) A copy of an application under subsection (2) must be served on the Registrar.

(3) The Court may hear an application made under this section not less than 10 days after the application has been served on the Registrar.

(4) On hearing an application made under this section the Court may, subject to any conditions that it considers proper, stay the decision of the Discipline Committee pending the determination of the appeal.

RSA 2000 cE-11 s66;2009 c53 s59

Appeal to Appeal Board

67(1) The Investigative Committee or the investigated person may appeal to the Appeal Board any finding or order of the Discipline Committee.

(2) An appeal under subsection (1) shall be commenced by a written notice of appeal that shall

(a) describe the finding or order appealed from,

(b) state the reasons for the appeal, and

(c) be served on the Registrar not more than 30 days after the date that the decision of the Discipline Committee was served on the investigated person.

(3) On receiving a notice of appeal from the Investigative Committee, the Registrar shall forthwith provide a copy to the investigated person and make the record of the hearing available to the investigated person.

(4) On receiving a notice of appeal, the Registrar shall provide a copy to the Appeal Board and make the record of the hearing available to each member of the Appeal Board.

1981 cE-11.1 s64;1984 c17 s21;1995 c14 s33

Time of appeal

68(1) The Appeal Board, on receiving a notice of appeal under section 67, shall serve on the investigated person and the Investigative Committee a notice of hearing of an appeal stating the date, time and place that the Appeal Board will hear the matters appealed.

(2) The Appeal Board shall hear an appeal forthwith.

1981 cE-11.1 s65;1995 c14 s34

Powers of the Appeal Board on appeal

69(1) The Appeal Board on an appeal may do any or all of the following:

(a) grant adjournments of the proceedings or reserve the determination of the matters before it for a future meeting of the Appeal Board;

(b) receive further evidence on granting special leave for that purpose;

(c) draw inferences of fact and make a determination or finding that in its opinion ought to have been made by the Discipline Committee;

(d) order that the matter be referred back to the Discipline Committee.

(2) Sections 56 to 62, 65 and 66 apply to the hearing of an appeal by the Appeal Board.

(3) The Appeal Board shall forthwith after the date of the conclusion of all proceedings before it,

(a) make any finding as to the conduct of the investigated person that in its opinion ought to have been made by the Discipline Committee,

(b) quash, confirm or vary the finding or order of the Discipline Committee or substitute or make a finding or order of its own, or

(c) refer the matter back to the Discipline Committee for further consideration in accordance with any direction that the Appeal Board may make.

(4) The Appeal Board may order the investigated person to pay all or part of the costs of the appeal determined in accordance with the bylaws.

1981 cE-11.1 s66;1984 c17 s22;1995 c14 s35

Appeal to the Court of Appeal

70(1) An investigated person may appeal to the Court of Appeal any finding or order made by the Appeal Board under section 69.

(2) The Appeal Board shall be the respondent in an appeal under subsection (1) and may make representations to the Court of Appeal.

(3) An appeal under this section shall be commenced

(a) by filing a notice of appeal with the Registrar of the Court of Appeal in Edmonton or Calgary, and

(b) by serving a copy of the notice of appeal on the Registrar,

both within 30 days from the date on which the decision of the Appeal Board is served on the investigated person.

1981 cE-11.1 s68;1984 c17 s24;1995 c14 s36

Order for stay pending appeal

71 The appellant may, after commencing an appeal and on notice to the Registrar, apply to the Court of Appeal for an order staying all or any part of the order or decision of the Appeal Board appealed.

1981 cE-11.1 s69;1984 c17 s25;1995 c14 s37

Material in support of appeal

72(1) An appeal under section 70 shall be supported by copies, certified by the Registrar, of the decision of the Appeal Board and the record of the appeal before the Appeal Board.

(2) The Registrar, on being paid any disbursements and expenses in connection with a request made by the appellant or the appellant's solicitor or agent, shall furnish to the appellant or the appellant's solicitor or agent the number of copies so requested of the documents mentioned in subsection (1).

1981 cE-11.1 s70;1984 c17 s26;1995 c14 s37

Power of the court on appeal

73(1) The Court of Appeal on hearing the appeal may do any or all of the following:

(a) make any finding that in its opinion ought to have been made;

(b) quash, confirm or vary the order or decision of the Appeal Board or any part of it;

(c) refer the matter back to the Appeal Board for further consideration in accordance with any direction of the Court of Appeal;

(d) direct that a new trial of any mixed questions of law and fact relating to a finding or order, or to both a finding and an order of the Appeal Board made under section 69, be held before the Court.

(2) The Court of Appeal may make any award as to the costs of an appeal to it that it considers appropriate.

1981 cE-11.1 s71;1984 c17 s27;1995 c14 s37

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Fraudulent registration

74(1) If the Council is satisfied, after a hearing on the matter, that a person whose registration is entered in the register obtained registration by means of any false or fraudulent representation or declaration, either oral or written, the Council shall order that the person's registration be cancelled.

(2) The provisions of this Part respecting the procedures of the Discipline Committee apply to a hearing held by the Council under subsection (1).

1981 cE-11.1 s72

Surrender of certificates

75(1) If the registration of a professional member, licensee or restricted practitioner has been cancelled or suspended under this Part, the professional member, licensee or restricted practitioner shall immediately surrender any certificate, stamp or seal to the Registrar.

(2) If the registration of a permit holder or joint firm has been cancelled or suspended under this Part, the permit holder or joint firm shall immediately

(a) surrender the permit or certificate of authorization to the Registrar, and

(b) cease using the permit number issued by the Registrar.

(3) If the registration of a professional member, licensee, permit holder or certificate holder has been cancelled under this Part, the registration shall not be reinstated in the register except by order of the Council, the Court or the Court of Appeal.

(4) No order shall be made under subsection (3) within one year after

(a) the date on which the registration was cancelled, or

(b) if an order was granted staying the imposition of a punishment imposed by the Council and the punishment is later confirmed by the Court or the Court of Appeal, the date on which the Court or the Court of Appeal made its order confirming the punishment.

(5) A member of the Council who is a member of a committee of inquiry appointed pursuant to the regulations to consider an application under this Part for reinstatement of registration may participate in or vote at any proceedings of the Council under this section, and the Registrar and the Association's solicitor may participate in those proceedings.

1981 cE-11.1 s73;1998 c14 s13

Misrepresentation of status

76 The conduct of a person who is or was registered as a professional member, licensee, permit holder or certificate holder who represents or holds out that the person is registered and in good standing while the person's registration is suspended or cancelled may be dealt with as being unprofessional conduct in accordance with this Part.

1981 cE-11.1 s74

Publication

77 After a finding or order is made by the Discipline Committee, the Council, the Appeal Board, the Court or the Court of Appeal under this Part, the name of the investigated person may be published in accordance with the regulations.

1981 cE-11.1 s75;1995 c14 s38

Part 6
General

Use of stamps, seal, permit number

78(1) A professional member, licensee or restricted practitioner shall, in accordance with the regulations,

(a) sign documents or records, and

(b) stamp or seal documents or records.

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(2) A permit holder shall affix its permit number on documents or records in accordance with the regulations.

1981 cE-11.1 s76;1984 c17 s28;1998 c14 s14

Exemption from municipal licence

79 No municipality has the power to require

(a) any professional member, licensee, permit holder or certificate holder to obtain a licence from the municipality to engage in the practice of engineering or the practice of geoscience, or

(b) any member-in-training to obtain a licence from the municipality for or in connection with the performance of any acts or services authorized by this Act to be performed by a member-in-training.

RSA 2000 cE-11 s79;2011 c3 s15

Liability to others

80(1) The relationship between a permit holder or certificate holder engaged in the practice of engineering or geoscience and a person receiving the professional services of the permit holder or certificate holder is subject to this Act, the regulations and any other law applicable to the relationship between a professional member and the professional member's client.

(2) The relationship of a professional member or licensee to a permit holder, whether as member, shareholder or employee of the permit holder, does not affect, modify or diminish the application of this Act, the regulations and the bylaws

(a) to the professional member or licensee personally as a professional member or licensee, or

(b) to the relationship between the professional member or licensee and the professional member's or licensee's client.

RSA 2000 cE-11 s80;2011 c3 s32

Registrar's certificate

81(1) A certificate purporting to be signed by the Registrar and stating that a named person was or was not, on a specified day or during a specified period,

(a) a professional member, licensee or certificate holder, or

(b) an officer of the Association or a member of the Council

shall be admitted in evidence as proof, in the absence of evidence to the contrary, of the facts stated in it without proof of the Registrar's appointment or signature.

(2) A certificate purporting to be signed by the Registrar and stating that a named corporation, partnership or other association of persons was or was not, on a specified day or during a specified period, a permit holder or certificate holder shall be admitted in evidence as proof, in the absence of evidence to the contrary, of the facts stated in it without proof of the Registrar's appointment or signature.

1981 cE-11.1 s78

Protection from liability

82(1) No action lies against

(a) any person conducting a preliminary investigation, a member of the Discipline Committee, the Practice Review Board, the Investigative Committee, the Appeal Board, the Council or the Board of Examiners, the Registrar, the Association or any person acting on the instructions of any of them, or

(b) any member, officer or employee of the Association

for anything done by that person or body in good faith and in purporting to act under this Act, the regulations or the bylaws.

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(2) No action for defamation may be founded on a communication that consists of or pertains to a complaint regarding the conduct of a professional member, licensee, permit holder, certificate holder or member-in-training, if the communication is published to or by

(a) the Association,

(b) a member of the Council, the Discipline Committee, the Practice Review Board, the Investigative Committee, the Appeal Board or the Board of Examiners,

(c) a person conducting a preliminary investigation,

(d) an officer or employee of the Association, or

(e) a person acting on the instructions of any of them

in good faith in the course of investigating the complaint or in the course of any proceedings under Part 5 relating to the complaint.

1981 cE-11.1 s79;1995 c14 s39

Part 7
Professional Licensees

Scope of practice

83 No professional licensee shall engage in the practice of engineering or geoscience except within the scope of practice specified by the Board of Examiners.

2007 c13 s14;2011 c3 s32

Exclusive use of name

83.01(1) No individual, corporation, partnership or other entity, except a professional licensee (engineering) or a permit holder entitled to engage in the practice of engineering, shall use the title "professional licensee (engineering)".

(2) No individual, corporation, partnership or other entity, except a professional licensee (geoscience) or a permit holder entitled to engage in the practice of geoscience, shall use the title "professional licensee (geoscience)".

2011 c3 s16

Prohibition on holding out

83.1 No individual, corporation, partnership or other entity, except a professional licensee, shall represent or hold out, expressly or by implication, that the person is a professional licensee.

2007 c13 s14

Stamp or seal of professional licensee (engineering)

83.2(1) No individual, corporation, partnership or other entity, except a professional licensee (engineering), shall affix the stamp or seal of a professional licensee (engineering) or allow that stamp or seal to be affixed to a plan, drawing, detail drawing, specification or other document or a reproduction of any of them unless

(a) that plan, drawing, detail drawing, specification, other document or reproduction was prepared by or under the supervision and control of, and

(b) the stamp or seal is affixed with the knowledge and consent or in accordance with the direction of

the professional licensee (engineering) to whom the stamp or seal was issued.

(2) Notwithstanding subsection (1), a professional licensee (engineering) may affix a stamp or seal to a plan, drawing, detail drawing, specification, other document or reproduction prepared by other persons if the professional licensee (engineering) completes a thorough review of and accepts professional responsibility for that plan, drawing, detail drawing, specification, other document or reproduction.

2007 c13 s14

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Stamp or seal of professional licensee (geoscience)

83.3(1) No individual, corporation, partnership or other entity, except a professional licensee (geoscience), shall affix the stamp or seal of a professional licensee (geoscience), or allow that stamp or seal to be affixed, to a map, geoscientific cross-section, specification, report or other document or a reproduction of any of them unless

(a) that map, geoscientific cross-section, specification, report, other document or reproduction was prepared by or under the supervision and control of, and

(b) the stamp or seal is affixed with the knowledge and consent or in accordance with the direction of

the professional licensee (geoscience), to whom the stamp or seal was issued.

(2) Notwithstanding subsection (1), a professional licensee (geoscience) may affix a stamp or seal to a map, geoscientific cross-section, specification, report or other document or reproduction prepared by other persons if the professional licensee (geoscience), completes a thorough review of and accepts professional responsibility for that map, geoscientific cross-section, specification, report, other document or reproduction.

2007 c13 s14;2011 c3 s17

Non-application of provisions to professional licensees

83.4(1) Sections 2(1) and 3(1)(b)(i) do not apply to a professional licensee (engineering) engaged in the practice of engineering within the scope of practice specified by the Board of Examiners.

(2) Sections 5(1) and 6(1)(b)(i) do not apply to a professional licensee (geoscience) engaged in the practice of geoscience within the scope of practice specified by the Board of Examiners.

(3) Repealed 2011 c3 s18.

2007 c13 s14;2011 c3 s18

Register for professional licensees

83.5(1) The Registrar shall maintain, in accordance with the bylaws and subject to the direction of the Council, a register for each category of professional licensee.

(2) The Registrar shall enter in the appropriate register the name of a person who has paid the fee prescribed under the bylaws and whose registration to engage in the practice of engineering or geoscience as a professional licensee has been approved by the Board of Examiners.

2007 c13 s14;2011 c3 s32

Eligibility for registration

83.6 A person who meets the requirements of this Act and the regulations and applies to the Registrar for registration is entitled to become registered as a professional licensee.

2007 c13 s14

Application for registration

83.7(1) The Board of Examiners shall consider applications for the registration of applicants as professional licensees in accordance with this Act, the regulations and the bylaws, and may

(a) approve the registration,

(b) refuse the registration, or

(c) defer the approval of registration until it is satisfied that the applicant has complied with a requirement made under this section.

(2) The Board of Examiners may, at its discretion, require an applicant for registration

(a) to pass one or more examinations set by the Board,

(b) to obtain more experience of a kind satisfactory to the Board for a period set by the Board, or

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(c) to pass one or more examinations and obtain more experience

before it approves the registration.

(3) If the Board of Examiners approves the registration of an individual as a professional licensee, it shall specify in the certificate and in the register the scope of practice of engineering or geoscience in which the individual is permitted to engage.

2007 c13 s14;2011 c3 s32

Registration as professional licensee

83.8 The Board of Examiners shall approve for registration as a professional licensee an individual who has applied to the Board and is eligible in accordance with this Act and the regulations to engage in the practice of engineering or geoscience within the scope of practice specified by the Board of Examiners.

2007 c13 s14;2011 c3 s32

Evidence of registration

84 On entering the name of a professional licensee in the register, the Registrar shall issue to that individual

(a) a certificate of registration to engage in the practice of engineering or geoscience, as the case may be, within the scope of practice specified by the Board of Examiners, and

(b) a stamp or seal engraved as prescribed in the bylaws.

2007 c13 s14;2011 c3 s32

Regulation-making authority

85 The Council may make regulations or bylaws applicable to professional licensees in respect of any of the matters under sections 19 and 20.

2007 c13 s14

Fees

86 Fees prescribed under the bylaws in respect of professional licensees must not be greater than the corresponding fees fixed in respect of professional members.

2007 c13 s14

Annual licence

86.1(1) A professional licensee engaged in the practice of engineering or geoscience shall pay to the Association the annual fee prescribed in the bylaws.

(2) The Registrar shall issue an annual licence in accordance with the bylaws to a professional licensee

(a) whose registration is not under suspension, and

(b) who has paid the annual fee.

(3) Subject to this Act, an annual licence entitles the professional licensee to engage in the practice of engineering or geoscience within the scope of practice specified by the Board of Examiners during the year for which the annual licence is issued.

2007 c13 s14;2011 c3 s32

Application of Act

86.2(1) Sections 14, 15, 16, 17, 19(4), 20(3), 24, 27, 28, 29, 31, 39, 78, 79, 80(2), 81 and 82(2) apply to a professional licensee as if the professional licensee were a professional member.

(2) Section 2(4)(a) applies to a professional licensee (engineering) practising within the scope of practice specified by the Board of Examiners as if that professional licensee (engineering) were a professional engineer or licensee.

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(3) Section 5(2)(a) applies to a professional licensee (geoscience) practising within the scope of practice specified by the Board of Examiners as if that professional licensee (geoscience) were a professional geoscientist or licensee.

(4) Repealed 2011 c3 s19.

(5) Section 32 applies to a professional licensee as if the professional licensee were an applicant.

(6) Part 5 applies to a professional licensee as if the professional licensee were a professional member.

2007 c13 s14;2011 c3 s19

Practice prohibitions

86.3(1) A person whose registration as a professional licensee is cancelled or suspended under this Act shall not, without the consent of the Council, engage in the practice of engineering or geoscience or directly or indirectly associate with any professional member, professional licensee, licensee, permit holder or certificate holder in the practice of engineering, geology or geophysics.

(2) No professional licensee shall, in the practice of engineering or geoscience, except with the permission of the Council, directly or indirectly associate with or employ in connection with the professional licensee's practice a person whose registration has been cancelled or suspended under this Act.

2007 c13 s14;2011 c3 s32

Injunction

86.31 The Court, on application by the Council, may grant an injunction enjoining any person from doing any act or thing that contravenes section 83.01 or 83.1, notwithstanding any penalty that may be provided by this Act or the regulations in respect of that act or thing.

2011 c3 s20

Part 8
ASET, Joint Boards and Committees, Professional Technologists and Other ASET Members

Definitions

86.4 In this Part,

(a) "ASET" means the Association of Science and Engineering Technology Professionals of Alberta continued under section 86.5;

(b) "ASET bylaws" means bylaws enacted under section 87.4;

(c) "ASET member" has the meaning given to it in ASET bylaws;

(d) "ASET permit holder" means a partnership, other association of persons or corporation registered under section 90.4 and to which a permit is issued in accordance with ASET bylaws;

(e) "ASET Registrar" means the individual appointed as ASET Registrar under section 87.1;

(f) "ASET regulations" means regulations enacted under section 87.3;

(g) "Joint Appeal Board" means the Joint Appeal Board established by section 87.5;

(h) "Joint Board of Examiners" means the Joint Board of Examiners established by section 87.5;

(i) "Joint Discipline Committee" means the Joint Discipline Committee established by section 87.5;

(j) "Joint Investigative Committee" means the Joint Investigative Committee established by section 87.5;

(k) "Joint Practice Review Board" means the Joint Practice Review Board established by section 87.5;

(l) "JPT Regulations Committee" means the Joint Professional Technologists Regulations Committee established by section 87.5;

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(m) "professional technologist" means an individual who is issued a certificate of registration by the ASET Registrar in accordance with this Act to engage in the practice of engineering or geoscience within the scope of practice specified by the Joint Board of Examiners;

(n) "professional technologist regulations" means regulations enacted under section 88.5 or 88.6;

(o) "regulated member" has the meaning given to it in ASET regulations.

2007 c13 s14;2011 c3 s32

Division 1
ASET

Corporation continued

86.5(1) The Association of Science and Engineering Technology Professionals of Alberta, previously established as a society under the *Societies Act*, is continued as a corporation with that name under this Act.

(2) The abbreviated form of the name of the Association of Science and Engineering Technology Professionals of Alberta is ASET or A.S.E.T.

(3) No person other than the Association of Science and Engineering Technology Professionals of Alberta shall use the abbreviated form of the name of ASET or any other abbreviation alone or in combination with any other word or name in a way that represents expressly or by implication that the person is a member of or connected in any way with ASET.

2007 c13 s14

Capacity and powers

86.6 ASET has the capacity and, subject to this Act, the rights, powers and privileges of a natural person.

2007 c13 s14

ASET Council

87(1) The governing body of ASET continues to be its Council.

(2) ASET Council shall manage and conduct the business and affairs of ASET and exercise the powers of ASET in the name of and on behalf of ASET.

(3) ASET Council shall submit annually to the Minister, in a form satisfactory to the Minister, a report on those matters of the business and affairs of ASET that the Minister requires.

(4) The Minister shall, on receipt of the annual report of ASET, lay it before the Legislative Assembly if it is then sitting, and if it is not then sitting, within 15 days after the commencement of the next sitting.

2007 c13 s14

ASET Registrar

87.1 ASET Council shall appoint a Registrar for the purposes of this Part, ASET regulations and ASET bylaws.

2007 c13 s14

ASET Council members

87.2(1) Subject to subsection (2), ASET Council shall include

(a) a president,

(b) 2 vice-presidents and the past president, and

(c) other members, the number of which shall be prescribed by ASET bylaws,

each of whom shall be elected by ASET members at the time, in the manner and for the period provided for in the bylaws.

(2) ASET Council

(a) shall include, when the total number of elected members does not exceed 20, 3 members of the public appointed by the Minister, after consultation with ASET Council, for a 3-year term of office, and

(b) may also include non-voting members of ASET Council determined by ASET bylaws.

(3) For each 10 elected members by which the membership of ASET Council exceeds 20, an additional member of the public shall be appointed by the Minister, after consultation with ASET Council, for a 3-year term of office.

(4) A member of ASET Council appointed under subsection (2)(a) continues to hold office after the expiry of the member's term of office until the member is reappointed or the member's successor is appointed.

(5) The Minister may, after consultation with ASET Council, revoke the appointment of a member of ASET Council made under subsection (2)(a).

(6) The Minister may pay to a member of ASET Council appointed under subsection (2)(a) travelling and living expenses incurred by that member for the member's attendance at any meeting of ASET Council while away from the member's usual place of residence and fees in an amount prescribed by the Minister.

(7) The powers, duties and operations of ASET Council under this Act, ASET regulations and ASET bylaws are not affected by

(a) the fact that no member of the public is appointed as a member of ASET Council pursuant to subsection (2)(a),

(b) the revocation under subsection (5) of the appointment of a member of the public, or

(c) the resignation from ASET Council of a member of the public.

(8) The failure of a member of the public appointed under subsection (2)(a) to attend a meeting of ASET Council shall not be construed to affect or restrict ASET Council from exercising any powers or performing any duties under this Act, ASET regulations or ASET bylaws at that meeting.

2007 c13 s14

ASET regulations

87.3(1) ASET Council may make regulations

(a) respecting the establishment of categories of, and conditions respecting the enrolment of, regulated members, regulated members in training, examination candidates and students;

(b) respecting the academic qualifications of and experience requirements for applicants for registration as regulated members;

(c) governing the evaluation by ASET Council, the ASET Board of Examiners, the ASET Practice Review Board or the ASET Appeal Board, or a committee established by any of them, of the academic qualifications of and experience requirements for applicants for registration to engage in practice as regulated members and the examination of those applicants with respect to those qualifications or requirements;

(d) respecting generally the eligibility of applicants for registration to engage in practice as regulated members;

(e) respecting the powers, duties and functions of the ASET Practice Review Board, including but not limited to the referral of matters by that Board to ASET Council or the ASET Investigative Committee and appeals from decisions of that Board;

(f) respecting the appointment of members of the ASET Appeal Board;

(g) prescribing the number of members that constitutes a quorum of ASET Council, the ASET Investigative Committee, the ASET Appeal Board, the ASET Practice Review Board, the ASET Board of Examiners or the ASET Discipline Committee;

(h) governing the establishment of boards or committees and respecting the delegation of powers of ASET Council to those boards or committees or to the ASET Practice Review Board;

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(i) prescribing technical standards of practice for regulated members;

(j) establishing and providing for the publication of a code of ethics respecting the practice of regulated members and the protection of the public interest;

(k) governing the names under which regulated members may engage in practice;

(l) governing, subject to this Act, the operation and proceedings of the ASET Appeal Board, the ASET Board of Examiners and the ASET Practice Review Board, the designation of chair and vice-chair, the appointment of acting members and the procedures for filling vacancies in the offices of chair and vice-chair and in the membership of any of those boards, and the appointment to any of those boards of members by virtue of their office, and prescribing their powers, duties and functions;

(m) respecting the procedures of the ASET Discipline Committee, of the ASET Practice Review Board, of the ASET Investigative Committee and of the ASET Appeal Board in matters relating to the conduct or practice of regulated members, whether or not a complaint has been made;

(n) respecting the establishment by ASET Council of a compulsory continuing education program for regulated members;

(o) governing the publication of a notice of the suspension or cancellation of the registration of a regulated member in a form and manner prescribed by ASET Council;

(p) respecting committees of inquiry for reinstatement;

(q) respecting the titles that may be used by regulated members and the circumstances and conditions under which the titles may be used;

(r) establishing classes or categories of regulated members and prescribing the restrictions of practice and the privileges and obligations of the classes or categories so established;

(s) respecting the academic and other qualifications and the experience required of the classes or categories established in addition to regulated members;

(t) governing the eligibility of persons, firms, partnerships and other entities for registration as ASET permit holders or certificate holders under this Part;

(u) governing the operation of ASET permit holders or certificate holders under this Part;

(v) governing the publication of information with respect to ASET and ASET members;

(w) respecting registration, licensing, the issuing of permits and certificates, disciplinary matters and the practice of regulated members generally;

(x) respecting the service on any person of a document or notice required to be served under this Act;

(y) defining "regulated member" for the purposes of all or any provision of this Act, ASET regulations and ASET bylaws.

(2) A regulation under subsection (1) may be made only by ASET Council.

(3) A regulation must be approved in principle by a majority of the ASET members

(a) present and voting at a special meeting called for that purpose,

(b) voting by a mail vote or a vote authorized by bylaw that is conducted by electronic, telecommunication or other appropriate means, or

(c) at the annual general meeting following ASET Council's adoption of the regulation.

(4) ASET Council may change the text of a regulation that has been approved in principle under subsection (3) if the change

(a) is consistent with the approval in principle, and

(b) is made before the regulation is submitted to the Lieutenant Governor in Council for approval.

(5) A regulation under this section does not come into force unless it has been approved by the Lieutenant Governor in Council.

2007 c13 s14

ASET bylaws

87.4(1) ASET Council may make bylaws

(a) for the government of ASET and the management and conduct of its affairs;

(b) determining the location of the head office of ASET;

(c) respecting the calling of and conduct of meetings of ASET members and ASET Council;

(d) respecting the nomination, election, number and term of office of ASET Council members and officers of ASET and the appointment of individuals as members of ASET Council by virtue of their office, the ASET Discipline Committee, the ASET Practice Review Board, the ASET Appeal Board, the ASET Board of Examiners and any other committee established by ASET Council and prescribing their powers, duties and functions;

(e) prescribing those areas of practice from which members of the ASET Board of Examiners shall be appointed by ASET Council;

(f) respecting the appointment, functions, duties and powers of an Executive Director of ASET;

(g) respecting the establishment of districts and branches of ASET and their operation;

(h) providing for the division of Alberta into electoral districts and prescribing the number of ASET Council members to be elected from each district;

(i) providing for the appointment of a Deputy Registrar of ASET who has all of the powers and may perform all of the duties of the ASET Registrar under this Act, ASET regulations and ASET bylaws when the ASET Registrar is absent or unable to act or when there is a vacancy in the office of the ASET Registrar;

(j) establishing classes or categories of membership in ASET in addition to regulated members and professional technologists and prescribing the rights, privileges and obligations of the classes or categories of membership so established;

(k) providing for the appointment of acting members of ASET Council and procedures for an election or appointment to fill vacancies on ASET Council;

(l) prescribing the quorum at meetings of ASET members;

(m) governing the establishment, operation and proceedings of committees, the appointment of members of committees, the appointment of acting members and procedures for filling vacancies on committees and the delegation of any powers or duties of ASET Council under this Act, ASET regulations or ASET bylaws to a committee established by ASET Council or under this Act;

(n) prescribing fees and expenses payable to members of ASET for attending to the business of ASET;

(o) respecting the establishment and payment of sums of money for scholarships, fellowships and any other educational incentive or benefit program that ASET Council considers appropriate;

(p) respecting the issuing of permit numbers to ASET permit holders;

(q) respecting the fixing of fees, dues and levies payable to ASET;

(r) respecting the costs payable by any person on the conclusion of a hearing or review;

(s) respecting the establishment, contents and maintenance of registers of members and of records of other classes or categories of membership to be kept by the ASET Registrar;

(t) respecting the removal from the registers and records of any memorandum or entry made in them;

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(u) requiring members to inform the ASET Registrar in writing of their current mailing addresses and of any change of address forthwith after the change occurs;

(v) prescribing the form of a certificate of registration, a permit, a certificate of authorization and an annual certificate;

(w) defining "ASET members" for the purposes of this Act and ASET regulations and ASET bylaws;

(x) respecting the expiry of annual certificates, annual licences, permits and other authorizations.

(2) ASET Council may make bylaws respecting the holding of mail votes and votes conducted by electronic, telecommunication or other appropriate means on any matter relating to ASET, but a bylaw under this subsection does not come into force unless it is approved by a majority of ASET members present and voting at a general meeting.

(3) A bylaw under subsection (1) does not come into force unless it is approved by a majority of ASET members

(a) present and voting at a general meeting, or

(b) voting by a mail vote or vote conducted by electronic, telecommunication or other appropriate means conducted in accordance with ASET bylaws.

(4) The *Regulations Act* does not apply to ASET bylaws made under this section.

2007 c13 s14

Consultation with Ministers required

87.41 Before the ASET Council, by regulation, establishes or amends the academic qualifications for applicants for registration as regulated members, the Council must consult with the Minister and the Minister responsible for Parts 1 to 3 of the *Post-secondary Learning Act* and must consider the comments received from those Ministers.

2010 c7 s3

Division 2
Joint Boards and Committees

Establishment of joint boards and committees

87.5(1) The following joint boards and committees are established:

(a) Joint Practice Review Board;

(b) Joint Appeal Board;

(c) Joint Professional Technologists Regulations Committee;

(d) Joint Discipline Committee;

(e) Joint Board of Examiners;

(f) Joint Investigative Committee.

(2) Each joint board and committee is, subject to this Act, to be composed of

(a) an equal number of appointees of the Council and ASET Council, and

(b) one member of the public appointed by the Minister, from one or more nominees of the Joint Councils Committee, for a term determined by the Minister.

(3) Every member of a joint board or committee must act solely in the interest of the public and for the safety of the public.

2007 c13 s14

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Public appointees to joint boards and committees

87.6(1) The Minister may pay to a member of the public appointed to a joint board or committee by the Minister travelling and living expenses incurred by that member for the member's attendance at a meeting or hearing of the joint board or committee while away from the member's usual place of residence and fees in an amount prescribed by the Minister.

(2) The Minister may, after consultation with the Joint Councils Committee, revoke the appointment of a member of the public appointed to a joint board or committee.

(3) The powers, duties and operations of a joint board or committee under this Act, the regulations and the bylaws are not affected by

(a) the fact that no member of the public is appointed as a member of the joint board or committee,

(b) the revocation of the appointment of a member of the public, or

(c) the resignation as a member of the joint board or committee of a member of the public.

(4) The failure of a member of the public appointed under this section to attend a meeting of a joint board or committee shall not be construed to affect or restrict the joint board or committee from exercising any powers or performing any duties under this Act or the professional technologist regulations at that meeting.

2007 c13 s14

Governance of joint boards and committees

88(1) After consultation with the Council and ASET Council, the Minister shall, by order, prescribe, subject to any provision to the contrary in this Act, with respect to each joint board and committee established under section 87.5,

(a) the number of members, and

(b) the governance and operation of the committee or board, including

(i) the method of appointment and term of the chair,

(ii) the quorum, and

(iii) procedural matters or delegating to the board or committee the authority to make decisions about procedural matters.

(2) Section 20(7) and (8) of the *Interpretation Act* apply to the joint boards and committees.

(3) The *Regulations Act* does not apply to an order made under this section, but the order must be published in Part I of The Alberta Gazette.

2007 c13 s14

Powers of the Joint Practice Review Board

88.1(1) The Joint Practice Review Board

(a) shall, on its own initiative or at the request of either the Council or ASET Council, inquire into

(i) the assessment of existing and the development of new educational standards and experience requirements that are to be conditions precedent to obtaining and continuing registration under this Act as a professional technologist,

(ii) the evaluation of desirable standards of competence of professional technologists generally,

(iii) the practice of professional technologists generally, and

(iv) any other matter that the Council or ASET Council from time to time considers necessary or appropriate in connection with the exercise of its powers and the performance of its duties in relation to competence in the practice of professional technologists under this Act and the professional technologist regulations,

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and

(b) may conduct a review of the practice of a professional technologist in accordance with this Act and the professional technologist regulations.

(2) The Joint Practice Review Board shall report to and advise the Council and ASET Council with respect to any matter dealt with by it pursuant to subsection (1).

(3) A person requested to appear at an inquiry under this section by the Joint Practice Review Board is entitled to be represented by counsel.

(4) The Joint Practice Review Board may, after a review under this section with respect to a professional technologist, make any order that the Joint Discipline Committee may make under section 63 or 64.

(5) The provisions of Part 5 with respect to an investigation by the Joint Investigative Committee apply to a review of an individual professional technologist by the Joint Practice Review Board.

(6) The Joint Practice Review Board may at any time during an inquiry or review under this section recommend to the Joint Investigative Committee that the inquiry or review be conducted by the Joint Investigative Committee pursuant to Part 5.

(7) On receiving a recommendation under subsection (6), the Joint Investigative Committee may proceed with an investigation under Part 5 as if the recommendation were a written complaint.

(8) After each inquiry under this section, the Joint Practice Review Board shall make a written report to the Council and ASET Council on the inquiry and may make any recommendations to the Council or ASET Council, or both, that the Joint Board considers appropriate in connection with the matter inquired into, with reasons for the recommendations.

(9) The Joint Practice Review Board, if it considers it to be in the public interest to do so, may direct that the whole or any portion of an inquiry by the Joint Practice Review Board under this section shall be held in camera.

2007 c13 s14

Joint Practice Review Board appointees

88.2 The individuals appointed to the Joint Practice Review Board by the Council and ASET Council must each have a combination of knowledge and experience suitable for determining the academic qualifications and experience necessary for a person to continue to engage in practice as a professional technologist.

2007 c13 s14

Appeal to Joint Appeal Board

88.3 A professional technologist who is the subject of a hearing or a review by the Joint Practice Review Board may appeal any decision or order of the Joint Practice Review Board to the Joint Appeal Board as if it were a decision or order of the Joint Discipline Committee under Part 5.

2007 c13 s14

Joint Appeal Board

88.4 The Joint Appeal Board has all the powers, duties and functions with respect to a professional technologist that the Appeal Board has with respect to professional members.

2007 c13 s14

JPT Regulations Committee authority

88.5(1) The JPT Regulations Committee may make regulations

(a) respecting the eligibility of applicants for registration as professional technologists;

(b) respecting the academic and other qualifications and the experience required of an applicant for registration as a professional technologist, and the evaluation of applicants, and their qualifications and experience, by the Joint Board of Examiners;

(c) respecting the examination of applicants for registration as professional technologists;

(d) respecting the establishment and administration of a register of professional technologists and the functions, duties and responsibilities of the ASET Registrar, including the removal of entries from the register;

(e) respecting the stamps or seals issued to professional technologists, the use of stamps and seals, and the circumstances under which a stamp or seal is to be surrendered to the ASET Registrar;

(f) governing the names under which professional technologists may engage in practice;

(g) establishing a continuing education program for professional technologists;

(h) establishing and providing for the publication of a code of ethics for professional technologists respecting the practice of the profession, the maintenance of the dignity and honour of the profession and the protection of the public interest;

(i) respecting notices of suspension or cancellation, and reinstatement committees;

(j) respecting technical standards of practice for professional technologists;

(k) respecting eligibility of professional technologists for registration as ASET permit holders;

(l) respecting registration, and the issue and use of permits, permit numbers and certificates for professional technologists and respecting the discipline, practice review and the practice of professional technologists generally;

(m) respecting service of documents;

(n) requiring professional technologists to notify the ASET Registrar of name and address changes, and requiring them to keep contact information up to date;

(o) prescribing forms for use under this Act and regulations made under this section, or delegating that function;

(p) respecting the expiry of annual certificates, permits and other authorizations issued to professional technologists.

(2) A regulation under subsection (1) does not come into force unless

(a) the regulation is approved by the Council and by ASET Council, and

(b) the regulation is approved by the Lieutenant Governor in Council.

2007 c13 s14

Consultation with Ministers required

88.51 Before the JPT Regulations Committee, by regulation, establishes or amends the academic qualifications for applicants for registration as professional technologists, the Council must consult with the Minister and the Minister responsible for Parts 1 to 3 of the *Post-secondary Learning Act* and must consider the comments received from those Ministers.

2010 c7 s3

Resolving disputes

88.6(1) If after 2 meetings at which a matter has been discussed the JPT Regulations Committee has not resolved the matter, the Committee may refer the matter to the Joint Councils Committee in accordance with rules established by agreement of the Council and ASET Council.

(2) On receipt of a reference, the Joint Councils Committee may do either or both of the following:

(a) refer the matter, or any aspect of it, back to the JPT Regulations Committee with suggestions or directions about how to resolve it;

(b) resolve the matter, or any aspect of it.

(3) If the Joint Councils Committee fully resolves the matter, the JPT Regulations Committee shall, if required, implement the resolution of the Joint Councils Committee.

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(4) If the Joint Councils Committee does not fully resolve the matter and does not refer the matter back to the JPT Regulations Committee under subsection (2), the Joint Councils Committee may, or if 120 days has passed from the date of receipt of the reference from the JPT Regulations Committee, the Joint Councils Committee shall, refer the matter, or any aspect of it that remains unresolved, to arbitration under the *Arbitration Act*.

(5) The Joint Councils Committee may extend the 120-day period if it considers an extension warranted.

(6) The *Arbitration Act* applies to an arbitration under this section with the following change, that the arbitration shall be heard and decided by an arbitration tribunal composed of 3 persons, appointed as follows:

(a) one person shall be appointed by the Council;

(b) one person shall be appointed by ASET Council;

(c) one person shall be appointed as chair of the arbitration tribunal by the Minister.

(7) In addition to the authority of the arbitration tribunal under the *Arbitration Act*, the arbitration tribunal may, as the circumstances require, do either or both of the following:

(a) make a decision binding on the Council, ASET Council and the JPT Regulations Committee;

(b) make a new regulation or amend a regulation respecting professional technologists, and for that purpose the arbitration tribunal has the same authority to make or amend regulations as the JPT Regulations Committee has under section 88.5.

(8) A regulation or amendment made by the arbitration tribunal under subsection (7) does not come into force unless it is approved by the Lieutenant Governor in Council.

2007 c13 s14

Joint Board of Examiners

89 The Joint Board of Examiners has all the powers, duties and functions with respect to professional technologists that the Board of Examiners has with respect to professional members.

2007 c13 s14

Joint Discipline Committee

89.1 The Joint Discipline Committee has all the powers, duties and functions with respect to professional technologists that the Discipline Committee has with respect to professional members.

2007 c13 s14

Joint Investigative Committee

89.2 The Joint Investigative Committee has all the powers, duties and functions with respect to professional technologists that the Investigative Committee has with respect to professional members.

2007 c13 s14

Division 3
Professional Technologists

Scope of practice

89.3 No professional technologist shall engage in the practice of engineering or geoscience except within the scope of practice specified by the Joint Board of Examiners.

2007 c13 s14;2011 c3 s32

Use of title

89.4(1) No individual, corporation, partnership or other entity, except a professional technologist, shall use

(a) the title “professional technologist”, the abbreviation “P. Tech” or any other abbreviation of that title,

(b) the title “professional technologist (engineering)”, the abbreviation “P. Tech (eng)” or any other abbreviation of that title, or

(c) the title "professional technologist (geoscience)", the abbreviation "P. Tech (geo)" or any other abbreviation of that title.

(d) repealed 2011 c3 s21.

(2) No individual, corporation, partnership or other entity, except a professional technologist, shall represent or hold out, expressly or by implication, that the person is a professional technologist.

2007 c13 s14;2011 c3 s22

Stamp or seal

89.5(1) No individual, corporation, partnership or other entity, except a professional technologist (engineering), shall affix the stamp or seal of a professional technologist (engineering) or allow that stamp or seal to be affixed to a plan, drawing, detail drawing, specification or other document or a reproduction of any of them unless

(a) that plan, drawing, detail drawing, specification, other document or reproduction was prepared by or under the supervision and control of, and

(b) the stamp or seal is affixed with the knowledge and consent or in accordance with the direction of

the professional technologist (engineering) to whom the stamp or seal was issued.

(2) Notwithstanding subsection (1), a professional technologist (engineering) may affix a stamp or seal to a plan, drawing, detail drawing, specification, other document or reproduction prepared by other persons if the professional technologist (engineering) completes a thorough review of and accepts professional responsibility for that plan, drawing, detail drawing, specification, other document or reproduction.

(3) No individual, corporation, partnership or other entity, except a professional technologist (geoscience) entitled to engage in the practice of geoscience, shall affix the stamp or seal of a professional technologist (geoscience) or allow that stamp or seal to be affixed to a map, geoscientific cross-section, specification, report or other document or a reproduction of any of them unless

(a) that map, geoscientific cross-section, specification, report, other document or reproduction was prepared by or under the supervision and control of, and

(b) the stamp or seal is affixed with the knowledge and consent or in accordance with the direction of

the professional technologist (geoscience) to whom the stamp or seal was issued.

(4) Notwithstanding subsection (3), a professional technologist (geoscience) may affix a stamp or seal to a map, geoscientific cross-section, specification, report, other document or reproduction prepared by other persons if the professional technologist (geoscience) completes a thorough review of and accepts professional responsibility for that map, geoscientific cross-section, specification, report, other document or reproduction.

2007 c13 s14;2011 c3 s22

Non-application of provisions to professional technologists

89.6 Sections 2(1), 3(1)(b)(i), 5(1) and 6(1)(b)(i) do not apply to a professional technologist engaged in the practice of engineering or geoscience within the scope of practice specified by the Joint Board of Examiners.

2007 c13 s14;2011 c3 s23

Register for professional technologists

90(1) The ASET Registrar shall maintain, in accordance with the professional technologist regulations, a register for professional technologists.

(2) The ASET Registrar shall enter in the register the name of a person who has paid the fee prescribed by ASET bylaws and whose registration to engage in the practice of engineering or geoscience as a professional technologist has been approved by the Joint Board of Examiners.

2007 c13 s14;2011 c3 s32

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Registration as professional technologist and scope of practice

90.1(1) The Joint Board of Examiners shall approve for registration as a professional technologist an individual who is eligible in accordance with this Act and the professional technologist regulations to engage in the practice of engineering or geoscience within the scope of practice specified by the Joint Board of Examiners.

(2) When the Joint Board of Examiners specifies the scope of practice for a professional technologist, it must specify a scope of practice that is the routine application of industry recognized codes, standards, procedures and practices using established engineering or applied science principles and methods of problem solving.

(3) For the purposes of subsection (2), the Joint Board of Examiners may

(a) define or describe "routine application";

(b) define or describe "industry recognized";

(c) specify or describe the codes, standards, procedures and practices applicable;

(d) define or describe all or any of the following terms: "engineering or applied science principles" and "methods of problem solving".

2007 c13 s14;2011 c3 s32

Evidence of registration

90.2 On entering the name of a professional technologist in the register, the ASET Registrar shall issue to that individual

(a) a certificate of registration to engage in the practice of engineering or geoscience, as the case requires, within the scope of practice specified by the Joint Board of Examiners, and

(b) a stamp or seal engraved as prescribed in the professional technologist regulations.

2007 c13 s14;2011 c3 s32

Joint Board of Examiners to consider applications

90.3(1) The Joint Board of Examiners shall consider applications for the registration of applicants as professional technologists in accordance with this Act and the professional technologist regulations and may

(a) approve the registration,

(b) refuse the registration, or

(c) defer the approval of registration until it is satisfied that the applicant has complied with a requirement made under this section.

(2) The Joint Board of Examiners may, in its discretion, require an applicant for registration

(a) to pass one or more examinations set by the Joint Board of Examiners,

(b) to obtain more experience of a kind satisfactory to the Joint Board of Examiners for a period set by the Joint Board of Examiners, or

(c) to pass one or more examinations and obtain more experience

before it approves the registration.

2007 c13 s14

Registration of ASET permit holders

90.4(1) ASET Council shall approve the registration as an ASET permit holder of a partnership or other association of persons, or of a corporation incorporated or registered under the *Companies Act* or continued, incorporated or registered under the *Business Corporations Act*, that has applied to ASET Council and is eligible under this section and the professional technologist regulations to become registered to engage in the practice of engineering or geoscience as an ASET permit holder within the scope of practice of those professional technologists who are responsible for the practice of the ASET permit holder.

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(2) A partnership or other association of persons or a corporation that applies to ASET Council is eligible to become registered as an ASET permit holder under subsection (1) if it satisfies ASET Council that it complies with this Act and the professional technologist regulations.

2007 c13 s14;2011 c3 s32

Annual certificate

90.5(1) A professional technologist or ASET permit holder engaged in the practice of engineering or geoscience shall pay to ASET the annual fee prescribed under ASET bylaws.

(2) The ASET Registrar shall issue an annual certificate in accordance with ASET bylaws to a professional technologist

(a) whose registration is not under suspension, and

(b) who has paid the annual fee.

(3) Subject to this Act, an annual certificate entitles the professional technologist or ASET permit holder to engage in the practice of engineering or geoscience, as the case may be, during the year for which the annual certificate is issued within the scope of practice of the professional technologist or ASET permit holder.

2007 c13 s14;2011 c3 s32

Entries in registers

90.6(1) The registration of a professional technologist or ASET permit holder is suspended when the decision to suspend the registration is made in accordance with this Act.

(2) The ASET Registrar shall enter a memorandum of suspension of a registration in the appropriate register indicating

(a) the duration of the suspension, and

(b) the reason for the suspension.

(3) The registration of a professional technologist or ASET permit holder is cancelled when the decision to cancel the registration is made in accordance with this Act.

(4) The ASET Registrar shall enter a memorandum of cancellation of a registration in the appropriate register.

(5) The ASET Registrar shall not remove from the register any memorandum made by the ASET Registrar under this section except in accordance with the professional technologist regulations.

(6) The ASET Registrar shall provide the Registrar with access to the registers established for professional technologists.

2007 c13 s14

List of registrants open to the public

91 The ASET Registrar shall maintain and, during regular office hours, permit any person to inspect a list of all the professional technologists and ASET permit holders in good standing.

2007 c13 s14

Cancellation on request

91.1(1) The ASET Registrar shall not cancel the registration of a professional technologist or ASET permit holder at that person's request unless the request for cancellation has been approved by ASET Council.

(2) When a request for cancellation of a registration is approved by ASET Council,

(a) the ASET Registrar shall cancel that registration, and

(b) the professional technologist or ASET permit holder requesting the cancellation shall, on being notified of the approval,

(i) immediately surrender to the ASET Registrar

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(A) the certificate of registration, annual certificate and stamp or seal, in the case of a professional technologist, or

(B) the permit and annual certificate, in the case of an ASET permit holder,

and

(ii) cease using the permit number, in the case of an ASET permit holder.

(3) ASET Council may direct the ASET Registrar to reinstate in the applicable register a registration that was cancelled under this section, subject to any conditions that ASET Council may prescribe, and to reissue the certificate of registration, annual certificate or permit and the stamp, seal or permit number.

(4) Notwithstanding subsection (3), if a person whose registration is cancelled applies to be reinstated more than 7 years after the date of the cancellation, the application for reinstatement must be referred to the Joint Board of Examiners.

2007 c13 s14

Review by the Joint Appeal Board

91.2(1) The Joint Board of Examiners shall send a written notice of any decision made by it under this Part to the applicant.

(2) If the decision made by the Joint Board of Examiners is to refuse or defer registration of the applicant, reasons for the decision shall be sent in writing to the applicant.

(3) If the decision made by the Joint Board of Examiners is to approve the registration, the ASET Registrar shall publish a notice of approval in accordance with ASET bylaws.

(4) An applicant whose application for registration has been refused by the Joint Board of Examiners may, within 30 days after receiving a notice of refusal and the reasons for refusal, appeal the decision to the Joint Appeal Board by serving a notice of appeal on the ASET Registrar.

(5) On receiving a notice of appeal, the ASET Registrar shall set a date, time and place for the hearing of the appeal and notify the appellant, in writing, of the date, time and place.

(6) The appellant may appear with counsel and make representations to the Joint Appeal Board.

(7) On concluding the hearing, the Joint Appeal Board may make any decision the Joint Board of Examiners was authorized to make.

2007 c13 s14

Cancellation

91.3(1) ASET Council may direct the ASET Registrar to cancel the registration of

(a) a professional technologist or ASET permit holder who is in default of payment of annual fees or any other fees, dues or levies payable under this Act, or

(b) an ASET permit holder if it no longer has employees in compliance with the professional technologist regulations,

after the expiration of 30 days following the service on the professional technologist or ASET permit holder of a written notice by ASET Council pursuant to subsection (2), unless the professional technologist or ASET permit holder on whom the notice is served complies with the notice.

(2) The notice under subsection (1) shall state that the ASET Registrar may cancel the registration unless

(a) the fees, dues or levies are paid as indicated in that notice, or

(b) evidence satisfactory to ASET Council has been received by it within the time prescribed in the notice indicating that the ASET permit holder has employees in compliance with the professional technologist regulations.

(3) ASET Council may direct the ASET Registrar to cancel the registration of a professional technologist or ASET permit holder that was entered in error in the register.

(4) If the registration of a professional technologist has been cancelled under this section, the professional technologist shall forthwith surrender to the ASET Registrar any certificate of registration, annual certificate and stamp or seal issued to the professional technologist.

(5) If the registration of an ASET permit holder has been cancelled under this section, the ASET permit holder shall immediately surrender the permit to the ASET Registrar and cease to use the permit number issued to that ASET permit holder.

(6) If a registration has been cancelled pursuant to subsection (1), ASET Council may direct the ASET Registrar, subject to any conditions that ASET Council may prescribe, to reinstate that registration in the applicable register and to reissue the certificate of registration, annual certificate or permit and the stamp, seal or permit number.

(7) Notwithstanding subsection (6), if a person whose registration is cancelled applies to be reinstated more than 7 years after the date of the cancellation, the application for reinstatement must be referred to the Joint Board of Examiners.

2007 c13 s14

Application of disciplinary provisions

91.4(1) Part 5, except sections 45 and 46, applies to professional technologists, subject to the following changes:

(a) "professional member" means a professional technologist;

(b) "practice of the profession" means the practice of a professional technologist;

(c) "Registrar" means the ASET Registrar;

(d) "the regulations" means the professional technologist regulations and ASET regulations;

(e) "Investigative Committee" means the Joint Investigative Committee;

(f) "Discipline Committee" means the Joint Discipline Committee;

(g) "Appeal Board" means the Joint Appeal Board;

(h) "bylaws" means the professional technologist regulations and ASET bylaws;

(i) "Council" means the JPT Regulations Committee;

(j) "investigation panel" means an investigation panel established by the Joint Investigative Committee under section 47;

(k) "Association" means ASET;

(l) "Practice Review Board" means the Joint Practice Review Board.

(2) If the registration of a professional technologist has been cancelled under Part 5, the registration shall not be reinstated unless the Joint Board of Examiners approves.

2007 c13 s14

Use of stamps, seals and permit numbers

91.5(1) A professional technologist shall, in accordance with the professional technologist regulations,

(a) sign documents or records, and

(b) stamp or seal documents or records.

(2) An ASET permit holder shall affix its permit number on documents or records in accordance with the professional technologist regulations.

2007 c13 s14

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Exemption from municipal licence

91.6 No municipality has the power to require any professional technologist or ASET permit holder to obtain a licence from the municipality to engage in the practice of engineering or the practice of geoscience.

2007 c13 s14;2011 c3 s24

Liability to others

92(1) The relationship between an ASET permit holder engaged in the practice of engineering or geoscience and a person receiving the professional services of the ASET permit holder is subject to this Act, the professional technologist regulations and any other law applicable to the relationship between a professional technologist and a client.

(2) The relationship of a professional technologist to an ASET permit holder, whether as member, shareholder or employee of the ASET permit holder, does not affect, modify or diminish the application of this Act or the professional technologist regulations

(a) to the professional technologist personally as a professional technologist, or

(b) to the relationship between the professional technologist and the professional technologist's client.

2007 c13 s14;2011 c3 s32

Division 4
Other ASET Members

Registers

92.1(1) In addition to the ASET Registrar's other responsibilities, the ASET Registrar shall maintain in accordance with ASET bylaws and subject to the direction of ASET Council, a register for

(a) certified engineering technologists;

(b) any other class or category of membership in ASET.

(2) The ASET Registrar shall maintain a register for registered engineering technologists in accordance with Part 9 of the *General Regulation* (AR 150/99).

(3) The ASET Registrar shall enter in the appropriate register the name of a person who has paid the fee prescribed in ASET bylaws and who

(a) in the case of a certified engineering technologist, has been approved by the ASET Board of Examiners, or

(b) in the case of any other class or category of regulated member, has been approved by ASET Council.

(4) The ASET Registrar shall maintain, in the case of regulated members, a membership record in accordance with ASET bylaws.

2007 c13 s14

Registration of regulated members

92.2(1) The ASET Board of Examiners shall approve for registration as a regulated member an individual who has applied to the ASET Board of Examiners and is eligible under this Act and ASET regulations to become a regulated member.

(2) Sections 2(1), 3(1)(b)(i), 5(1) and 6(1)(b)(i) do not apply to a regulated member engaged in the practice of engineering or geoscience under the supervision of a professional member, a professional licensee or a professional technologist.

2007 c13 s14;2011 c3 s25

Evidence of registration

92.3 On entering the name of a regulated member in the register, the ASET Registrar shall issue to the regulated member a certificate of registration.

2007 c13 s14

Annual certificate

92.4(1) A regulated member shall pay to ASET the annual fee prescribed under ASET bylaws.

(2) The ASET Registrar shall issue an annual certificate in accordance with ASET bylaws to a regulated member

(a) whose registration is not under suspension, and

(b) who has paid the annual fee.

(3) Subject to this Act, an annual certificate entitles the regulated member to use the title granted to the regulated member during the year for which the annual certificate is issued.

2007 c13 s14

Entries in registers

92.5(1) The registration of a regulated member is suspended when the decision to suspend the registration is made in accordance with this Act.

(2) The ASET Registrar shall enter a memorandum of suspension of a registration in the appropriate register indicating

(a) the duration of the suspension, and

(b) the reason for the suspension.

(3) The registration of a regulated member is cancelled when the decision to cancel the registration is made in accordance with this Act.

(4) The ASET Registrar shall enter a memorandum of cancellation of a registration in the appropriate register.

(5) The ASET Registrar shall not remove from the registers any memorandum made under this section, except in accordance with ASET bylaws.

2007 c13 s14

List of registrants open to the public

92.6 The ASET Registrar shall maintain and, during regular office hours, permit any person to inspect a list of all the regulated members in good standing.

2007 c13 s14

Cancellation on request

93(1) The ASET Registrar shall not cancel the registration of a regulated member at that person's request unless the request for cancellation has been approved by ASET Council.

(2) When a request for cancellation of a registration is approved by ASET Council,

(a) the ASET Registrar shall cancel that registration, and

(b) the regulated member requesting the cancellation shall, on being notified of the approval, immediately surrender to the ASET Registrar

(i) the certificate of registration, and

(ii) the annual certificate.

(3) ASET Council may direct the ASET Registrar to reinstate in the applicable register a registration that was cancelled under this section, subject to any conditions that ASET Council may prescribe, and to reissue the certificate of registration and annual certificate.

(4) Notwithstanding subsection (3), if a person whose registration is cancelled applies to be reinstated more than 7 years after the date of the cancellation, the application for reinstatement must be referred to the ASET Board of Examiners.

2007 c13 s14

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ASET Board of Examiners

93.1(1) ASET Council shall establish a board of examiners in accordance with ASET regulations to be known as the ASET Board of Examiners.

(2) The ASET Board of Examiners shall consider applications for the registration of applicants as regulated members in accordance with this Part, ASET regulations and ASET bylaws and may

(a) approve the registration,

(b) refuse the registration, or

(c) defer the approval of registration until it is satisfied that the applicant has complied with a requirement made under this section.

(3) The ASET Board of Examiners may, in its discretion, require an applicant for registration

(a) to pass one or more examinations set by the ASET Board of Examiners,

(b) to obtain more experience of a kind satisfactory to the ASET Board of Examiners for a period set by the ASET Board of Examiners, or

(c) to pass one or more examinations and obtain more experience

before it approves the registration.

2007 c13 s14

Approval by the ASET Board of Examiners

93.2 The ASET Board of Examiners shall approve the registration as a regulated member of a person who proves to the satisfaction of the ASET Board of Examiners that

(a) the person is of good character and reputation, and

(b) the person meets the requirements of ASET regulations.

2007 c13 s14

Review by the ASET Appeal Board

93.3(1) The ASET Board of Examiners shall send a written notice of any decision made by it under this Division to the applicant.

(2) If the decision made by the ASET Board of Examiners is to refuse or defer registration of the applicant, reasons for the decision shall be sent in writing to the applicant.

(3) If the decision made by the ASET Board of Examiners is to approve the registration, the ASET Registrar shall publish a notice of approval in accordance with ASET bylaws.

(4) An applicant whose application for registration has been refused by the ASET Board of Examiners may, within 30 days after receiving a notice of refusal and the reasons for refusal, appeal the decision to the ASET Appeal Board by serving a notice of appeal on the ASET Registrar.

(5) On receiving a notice of appeal, the ASET Registrar shall set a date, time and place for the hearing of the appeal and notify the appellant, in writing, of the date, time and place.

(6) The appellant may appear with counsel and make representations to the ASET Appeal Board.

(7) On concluding the hearing, the ASET Appeal Board may make any decision the ASET Board of Examiners was authorized to make.

2007 c13 s14

ASET Practice Review Board

93.4 There is hereby established a board called the ASET Practice Review Board consisting of not fewer than 4 members who have a combination of knowledge and experience suitable for determining the academic qualifications and experience necessary for a person to continue to engage in practice as a regulated member.

2007 c13 s14

Powers of the ASET Practice Review Board

93.5(1) The ASET Practice Review Board

(a) shall, on its own initiative or at the request of ASET Council, inquire into

(i) the assessment of existing and the development of new educational standards and experience requirements that are to be conditions precedent to obtaining and continuing registration as a regulated member under this Act,

(ii) the evaluation of desirable standards of competence of regulated members generally,

(iii) the practice of regulated members generally, and

(iv) any other matter that ASET Council from time to time considers necessary or appropriate in connection with the exercise of its powers and the performance of its duties in relation to competence in practice of regulated members under this Act and ASET regulations,

and

(b) may conduct a review of the practice of a regulated member in accordance with this Act and ASET regulations.

(2) The ASET Practice Review Board shall report to and advise ASET Council with respect to any matter dealt with by it pursuant to subsection (1).

(3) A person requested to appear at an inquiry under this section by the ASET Practice Review Board is entitled to be represented by counsel.

(4) The ASET Practice Review Board may, after a review under this section with respect to a regulated member, make any order that the ASET Discipline Committee may make under section 63 or 64.

(5) The provisions of Part 5 with respect to an investigation by the ASET Investigative Committee apply to a review of a regulated member by the ASET Practice Review Board.

(6) The ASET Practice Review Board may at any time during an inquiry or review under this section recommend to the ASET Investigative Committee that the inquiry or review be conducted by the ASET Investigative Committee pursuant to Part 5.

(7) On receiving a recommendation under subsection (6), the ASET Investigative Committee may proceed with an investigation under Part 5 as if the recommendation were a written complaint.

(8) After each inquiry under this section, the ASET Practice Review Board shall make a written report to ASET Council on the inquiry and may make any recommendations to ASET Council that the ASET Practice Review Board considers appropriate in connection with the matter inquired into, with reasons for the recommendations.

(9) ASET Council may, if it considers it to be in the public interest to do so, direct that the whole or any portion of an inquiry by the ASET Practice Review Board under this section shall be held in camera.

2007 c13 s14

Appeal to ASET Appeal Board

94 A regulated member who is the subject of a hearing or a review by the ASET Practice Review Board may appeal any decision or order of the ASET Practice Review Board to the ASET Appeal Board as if it were a decision or order of the ASET Discipline Committee under Part 5.

2007 c13 s14

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ASET Appeal Board

94.1(1) There is hereby established an ASET Appeal Board consisting of the regulated members appointed by ASET Council in accordance with ASET regulations.

(2) A member of the ASET Appeal Board appointed under subsection (1) continues to hold office after the expiry of the member's term of office until the member is reappointed or the member's successor is appointed.

2007 c13 s14

Division 5
Discipline of Regulated Members

ASET Discipline Committee

94.2(1) ASET Council shall establish a discipline committee, to be known as the ASET Discipline Committee, the members of which shall be appointed in accordance with ASET regulations.

(2) ASET Council shall make regulations governing, subject to this Part and Part 5, the operation and proceedings of the ASET Discipline Committee, the designation of a chair, the appointment of members, acting members and members by virtue of their office and the procedures for filling vacancies in the offices of the chair and the membership, and prescribing the powers, duties and functions of the chair and the members.

(3) ASET Council may make regulations respecting the hearing of a matter under Part 5 by a panel of the ASET Discipline Committee.

(4) A regulation made under subsection (2) or (3) does not come into force unless it has been approved by the Lieutenant Governor in Council.

2007 c13 s14

ASET Investigative Committee

94.3(1) ASET Council shall establish an investigative committee to be known as the ASET Investigative Committee, the members of which shall be appointed in accordance with ASET regulations.

(2) ASET Council shall make regulations governing, subject to this Part and Part 5, the operation and proceedings of the ASET Investigative Committee, the designation of a chair, the appointment of members, acting members and members by virtue of their office and the procedures for filling vacancies in the offices of the chair and the membership, and prescribing the powers, duties and functions of the chair and the members.

(3) A regulation made under subsection (2) does not come into force unless it has been approved by the Lieutenant Governor in Council.

2007 c13 s14

Application of Part 5 to regulated members of ASET

94.4 Part 5, except sections 45 and 46, applies to regulated members, subject to the following changes to Part 5:

(a) "professional member" means a regulated member;

(b) "practice of the profession" means the practice of a regulated member;

(c) "Registrar" means the ASET Registrar;

(d) "the regulations" means ASET regulations;

(e) "Investigative Committee" means the ASET Investigative Committee;

(f) "Discipline Committee" means the ASET Discipline Committee;

(g) "Appeal Board" means the ASET Appeal Board;

(h) "bylaws" means ASET bylaws;

(i) "Council" means ASET Council;

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(j) "investigation panel" means an investigation panel established by the ASET Investigative Committee under section 47;

(k) "Association" means ASET;

(l) "Practice Review Board" means the ASET Practice Review Board;

(m) "register" means the ASET register of regulated members.

2007 c13 s14

Division 6
General

ASET Registrar's certificate

94.5(1) A certificate purporting to be signed by the ASET Registrar and stating that a named person was or was not, on a specified day or during a specified period,

(a) a regulated member,

(b) a professional technologist,

(c) an officer of ASET or a member of ASET Council, or

(d) a member of a joint board or committee that is established by this Act,

shall be admitted in evidence as proof, in the absence of evidence to the contrary, of the facts stated in it without proof of the ASET Registrar's appointment or signature.

(2) A certificate purporting to be signed by the ASET Registrar and stating that a named corporation, partnership or other association of persons was or was not, on a specified day or during a specified period, an ASET permit holder shall be admitted in evidence as proof, in the absence of evidence to the contrary, of the facts stated in it without proof of the ASET Registrar's appointment or signature.

2007 c13 s14

Protection from liability

95(1) No action lies against

(a) any person conducting a preliminary investigation, the ASET Registrar, a member of the ASET Discipline Committee, the ASET Practice Review Board, the ASET Investigative Committee, the ASET Appeal Board, ASET Council, the ASET Board of Examiners or ASET or any person acting on the instructions of any of them,

(b) any member, officer or employee of ASET, or

(c) any person conducting a preliminary investigation, a member of the Joint Discipline Committee, the Joint Practice Review Board, the Joint Investigative Committee, the Joint Appeal Board, the JPT Regulations Committee or the Joint Board of Examiners or any person acting on the instructions of any of them

for anything done by that person or entity in good faith and in purporting to act under this Act, ASET regulations, ASET bylaws or the professional technologist regulations.

(2) No action for defamation may be founded on a communication that consists of or pertains to a complaint regarding the conduct of a regulated member or a professional technologist if the communication is published to or by

(a) ASET,

(b) a member of ASET Council, the ASET Discipline Committee, the ASET Practice Review Board, the ASET Investigative Committee, the ASET Appeal Board or the ASET Board of Examiners,

(c) a person conducting a preliminary investigation,

(d) an officer or employee of ASET,

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(e) a member of the JPT Regulations Committee, the Joint Discipline Committee, the Joint Practice Review Board, the Joint Investigative Committee, the Joint Appeal Board or the Joint Board of Examiners, or

(f) a person acting on the instructions of any of the persons or entities referred to in clauses (a) to (e),

in good faith in the course of investigating the complaint or in the course of any proceedings under Part 5 relating to the complaint.

2007 c13 s14

Division 7
Prohibitions and Penalties

Practice prohibitions

95.1(1) A person whose registration as a professional technologist is cancelled or suspended under this Act shall not, without the consent of the Joint Board of Examiners, engage in the practice of engineering or geoscience or directly or indirectly associate in the practice of engineering or geoscience with any professional member, licensee, permit holder, certificate holder or professional technologist.

(2) No person, except a regulated member entitled to do so, shall

(a) use the title "certified engineering technologist" or the abbreviation "C.E.T." or other abbreviations of that title;

(b) represent or hold out, expressly or by implication, that the person is entitled to use the title or abbreviation referred to in clause (a) as a certified engineering technologist;

(c) use the title "registered engineering technologist" or the abbreviation "R.E.T." or other abbreviations of that title.

(3) ASET may hold or continue to hold, and regulate the use of, the following trademarks:

(a) certified engineering technologist and "C.E.T.";

(b) certified technician and "C. Tech";

(c) certified computer information technologist and "C.C.I.T.";

(d) applied science technologist and "A. Sc.T.".

(4) ASET has no legal capacity to apply for, be granted, or to hold, a trademark for any name, title, designation, initials or abbreviation other than those specified in subsection (3) without the consent of the Lieutenant Governor in Council.

(5) No person shall use the title "registered professional technologist", "registered professional technologist (engineering)", "registered professional technologist (geological)", "registered professional technologist (geophysical)" or "registered professional technologist (geoscience)" or the abbreviation "R.P.T.", "R.P.T. (eng)", "R.P.T. (geo)", "R.P.T. (geol)" or "R.P.T. (geoph)".

2007 c13 s14;2011 c3 s26

Injunction

96 The Court, on application by ASET Council, may grant an injunction enjoining any person from

(a) doing any act or thing that contravenes section 95.1(1), (2) or (5), or

(b) using a title or abbreviation referred to in section 95.1(3) contrary to a use permitted by a trademark referred to in section 95.1(3),

notwithstanding any penalty that may be provided by this Act or under this Act in respect of that act, thing or use.

2007 c13 s14;2011 c14 s7

Onus of proof

96.1 In a prosecution under this Act, the burden of proving that a person is a professional technologist or a regulated member is on the accused.

2007 c13 s14

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Part 9
Prohibitions and Penalties

Practice prohibitions

97(1) A person whose registration as a professional engineer, professional geoscientist, licensee, permit holder or certificate holder is cancelled or suspended under this Act shall not, without the consent of the Council, engage in the practice of engineering or geoscience, as the case may be, or directly or indirectly associate the person or itself in the practice of engineering or geoscience with any other professional member, licensee, permit holder or certificate holder.

(2) No professional engineer, professional geoscientist, licensee, permit holder or certificate holder shall, except with the consent of the Council, associate in the practice of engineering or geoscience, as the case may be, directly or indirectly with or employ in connection with that practice a person whose registration has been cancelled or suspended under this Act.

(3) The Council may permit a professional member, licensee, permit holder or certificate holder to employ in connection with the person's practice a person whose registration has been cancelled or suspended under this Act, but the employment shall be in the capacity and subject to the terms and conditions that are prescribed by the Council.

RSA 2000 cE-11 s97;2011 c3 s27

Use of names and abbreviations relating to geology and geophysics

97.1(1) No individual, corporation, partnership or other entity, except

(a) an individual who is registered as a professional geoscientist and was registered as a professional geologist immediately before the coming into force of this subsection,

(b) an individual who is registered to engage in the practice of geoscience as a licensee and was registered to engage in the practice of geology as a licensee immediately before the coming into force of this subsection, or

(c) a corporation, partnership or other association of persons that is registered to engage in the practice of geoscience as a permit holder and was registered to engage in the practice of geology as a permit holder immediately before the coming into force of this subsection,

shall

(d) use the title "professional geologist", the abbreviation "P. Geol." or any other abbreviation of that title,

(e) use the word "geologist" in combination with any other name, title, description, letter, symbol or abbreviation that represents expressly or by implication that the individual, corporation, partnership or other entity is a professional geologist, licensee or permit holder, or

(f) represent or hold out, expressly or by implication, that the individual, corporation, partnership or other entity is a professional geologist.

(2) No individual, corporation, partnership or other entity, except

(a) an individual who is registered as a professional geoscientist and was registered as a professional geophysicist immediately before the coming into force of this subsection,

(b) an individual who is registered to engage in the practice of geoscience as a licensee and was registered to engage in the practice of geophysics as a licensee immediately before the coming into force of this subsection, or

(c) a corporation, partnership or other association of persons that is registered to engage in the practice of geoscience as a permit holder and was registered to engage in the practice of geophysics as a permit holder immediately before the coming into force of this subsection,

shall

(d) use the title "professional geophysicist", the abbreviation "P. Geoph." or any other abbreviation of that title,

(e) use the word "geophysicist" in combination with any other name, title, description, letter, symbol or abbreviation that represents expressly or by implication that the individual, corporation, partnership or other entity is a professional geophysicist, licensee or permit holder, or

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(f) represent or hold out, expressly or by implication, that the individual, corporation, partnership or other entity is a professional geophysicist.

(3) No individual, corporation, partnership or other entity, except

(a) an individual who is registered as a professional licensee (geoscience) and was registered as a professional licensee (geological) immediately before the coming into force of this subsection, or

(b) a corporation, partnership or other association of persons that is registered to engage in the practice of geoscience as a permit holder and was registered to engage in the practice of geology as a permit holder immediately before the coming into force of this subsection,

shall

(c) use the title "professional licensee (geological)" or any abbreviation of that title, or

(d) represent or hold out, expressly or by implication, that the individual, partnership or other entity is a professional licensee (geological).

(4) No individual, corporation, partnership or other entity, except

(a) an individual who is registered as a professional licensee (geoscience) and was registered as a professional licensee (geophysical) immediately before the coming into force of this subsection, or

(b) a corporation, partnership or other association of persons that is registered to engage in the practice of geoscience as a permit holder and was registered to engage in the practice of geophysics as a permit holder immediately before the coming into force of this section,

shall

(c) use the title "professional licensee (geophysical)" or any abbreviation of that title, or

(d) represent or hold out, expressly or by implication, that the individual, partnership or other entity is a professional licensee (geophysical).

(5) No individual, corporation, partnership or other entity, except an individual who is registered as a professional technologist (geoscience) and was registered as a professional technologist (geological) immediately before the coming into force of this subsection, shall

(a) use the title "professional technologist (geological)", the abbreviation "P. Tech (geol)" or any other abbreviation of that title, or

(b) represent or hold out, expressly or by implication, that the individual, partnership or other entity is a professional technologist (geological).

(6) No individual, corporation, partnership or other entity, except an individual who is registered as a professional technologist (geoscience) and was registered as a professional technologist (geophysical) immediately before the coming into force of this subsection, shall

(a) use the title "professional technologist (geophysical)", the abbreviation "P. Tech (geoph)" or any other abbreviation of that title, or

(b) represent or hold out, expressly or by implication, that the individual, partnership or other entity is a professional technologist (geophysical).

2011 c3 s28

Injunction

97.2 The Court, on application by the Council, may grant an injunction enjoining any person from doing any act or thing that contravenes section 97.1(1), (2), (3) or (4), notwithstanding any penalty that may be provided by this Act or the regulations in respect of that act or thing.

2011 c3 s28

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Penalties

98(1) Every person and every member, officer, employee or agent of a firm, partnership or other association of persons and of a corporation who contravenes Part 1, section 29(2)(b), section 39(4), section 83, 83.01, 83.1, 83.2, 83.3 or 86.3, this Part or section 89.3, 89.4, 89.5 or 95.1 is guilty of an offence and liable

(a) for the first offence, to a fine of not more than $2000,

(b) for the 2nd offence, to a fine of not more than $4000, and

(c) for the 3rd and each subsequent offence, to a fine of not more than $6000 or to imprisonment for a term of not more than 6 months or to both a fine and imprisonment.

(2) Repealed 2007 c13 s15.

(3) A prosecution under this section may be commenced within 2 years after the commission of the alleged offence, but not afterwards.

RSA 2000 cE-11 s98;2007 c13 s15;2011 c3 s29

Onus of proof

99 In a prosecution under this Act, the burden of proving that a person is a professional engineer, professional geoscientist, professional licensee (engineering), professional licensee (geoscience), registered professional technologist (engineering), licensee, permit holder or certificate holder, or that a person is not prohibited by section 97.1(1), (2), (3), (4), (5) or (6) from using a title, abbreviation or word or doing an act or thing, is on the accused.

RSA 2000 cE-11 s99;2011 c3 s30

Name change

100 If the name of the Alberta Society of Engineering Technologists is changed after April 29, 1999, the reference to the Alberta Society of Engineering Technologists is to be construed as a reference to the Alberta Society of Engineering Technologists by its new name.

1999 c8 s6

Part 10
Transitional Provisions

Existing registrations

101(1) Where, immediately before the coming into force of this subsection, an individual is registered as a professional geologist or professional geophysicist, on the coming into force of this subsection

(a) the individual is deemed to be registered as a professional geoscientist, and

(b) the certificate of registration as a professional geologist or professional geophysicist held by the individual is deemed to be a certificate of registration as a professional geoscientist.

(2) Where, immediately before the coming into force of this subsection, an individual is registered to engage in the practice of geology or geophysics as a licensee, on the coming into force of this subsection

(a) the individual is deemed to be registered to engage in the practice of geoscience as a licensee,

(b) the licence to engage in the practice of geology or geophysics as a licensee as authorized in the licence held by the individual is deemed to be a licence to engage in the practice of geoscience as authorized in the licence, and

(c) the authorization to engage in the practice of geology or geophysics contained in the licence held by the individual is to be construed as an authorization to engage in the practice of geoscience to an equivalent extent, and references in the authorization to the scope of practice of geology or geophysics are to be construed as references to the scope of practice of geoscience.

(3) Where, immediately before the coming into force of this subsection, a corporation, partnership or other association of persons is registered to engage in the practice of geology or geophysics as a permit holder, on the coming into force of this subsection

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(a) the corporation, partnership or other association of persons is deemed to be registered to engage in the practice of geoscience as a permit holder,

(b) the permit to engage in the practice of geology or geophysics as a permit holder as authorized in the permit held by the corporation, partnership or other association of persons is deemed to be a permit to engage in the practice of geoscience as authorized in the permit, and

(c) the authorization to engage in the practice of geology or geophysics contained in the permit held by the corporation, partnership or other association of persons is to be construed as an authorization to engage in the practice of geoscience to an equivalent extent and references in the authorization to the scope of practice of geology or geophysics are to be construed as references to the scope of practice of geoscience.

(4) Where, immediately before the coming into force of this subsection, an individual is registered as a professional licensee to engage in the practice of geology or geophysics within the scope of practice specified in the register, on the coming into force of this subsection

(a) the individual is deemed to be registered as a professional licensee to engage in the practice of geoscience within the scope of practice specified in the register,

(b) the certificate of registration to engage in the practice of geology or geophysics within the scope of practice specified in the certificate held by the individual is deemed to be a certificate of registration to engage in the practice of geoscience within the scope of practice specified in the certificate, and

(c) the scope of practice of geology or geophysics that is specified in the register and the certificate of registration as the scope of practice within which the individual is permitted to engage is to be construed as the scope of practice of geoscience within which the individual is permitted to engage.

(5) Where, immediately before the coming into force of this subsection, an individual is registered as a professional technologist to engage in the practice of geology or geophysics within the scope of practice specified by the Joint Board of Examiners, on the coming into force of this subsection

(a) the individual is deemed to be registered as a professional technologist to engage in the practice of geoscience within the scope of practice specified by the Joint Board of Examiners,

(b) the certificate of registration to engage in the practice of geology or geophysics within the scope of practice specified in the certificate held by the individual is deemed to be a certificate of registration to engage in the practice of geoscience within the scope of practice specified by the Joint Board of Examiners, and

(c) the scope of practice of geology or geophysics that is specified by the Joint Board of Examiners as the scope of practice for the professional technologist is to be construed as the scope of practice of geoscience for the professional technologist.

(6) Where, immediately before the coming into force of this subsection, a corporation, partnership or other association of persons is registered as an ASET permit holder to engage in the practice of geology or geophysics as an ASET permit holder within the scope of practice of those professional technologists who are responsible for the practice of the ASET permit holder, on the coming into force of this subsection the corporation, partnership or other association of persons is deemed to be registered as an ASET permit holder to engage in the practice of geoscience as an ASET permit holder within the scope of practice of those professional technologists who are responsible for the practice of the ASET permit holder.

(7) The Registrar or the ASET Registrar, as the case may be, shall make any necessary changes and take all necessary action to revise or create registers and records and issue certificates, licences, permits and other documentation to implement subsections (1) to (6).

2011 c3 s31

Use of titles and stamps relating to geology and geophysics

102(1) Subject to the regulations, where section 97.1(1), (2), (3), (4), (5) or (6) excepts an individual, licensee or permit holder from a prohibition against using a title, an abbreviation or a word or doing an act or thing, the individual, licensee or permit holder may use the title, the abbreviation or the word and may do the act or thing.

(2) Subject to the regulations and bylaws, an individual referred to in subsection (1) may use a stamp or seal bearing a title or abbreviation that the person is authorized by subsection (1) to use.

2011 c3 s31

Transitional regulations

103(1) The Lieutenant Governor in Council may make regulations

(a) respecting the transition of anything under this Act, including this Act as it read immediately before the coming into force of this section, relating to the transition from the profession of geology or the profession of geophysics to the profession of geoscience, including the interpretation of any transitional provision in this Act;

(b) to remedy any confusion, difficulty, inconsistency or impossibility resulting from the transition from the profession of geology or the profession of geophysics to the profession of geoscience.

(2) A regulation made under subsection (1) may be made retroactive to the extent set out in the regulation.

(3) A regulation made under subsection (1) is repealed on the earliest of

(a) the coming into force of an amendment that adds the subject-matter of the regulation to this Act;

(b) the coming into force of a regulation that repeals the regulation made under subsection (1);

(c) 3 years after the regulation comes into force.

(4) The repeal of a regulation under subsection (3)(b) or (c) does not affect anything done, incurred or acquired under the authority of the regulation before the repeal of the regulation.

2011 c3 s31

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THE ENGINEERING AND GEOSCIENCE PROFESSIONS ACT

REGULATIONS

GENERAL REGULATION

Consisting of Alberta Regulation
150/99 dated July 14, 1999,
37/2003 dated February 26, 2003,
72/2007 dated April 4, 2007,
281/2009 dated October 15, 2009,
346/2009 dated December 16, 2009
and 55/2012 dated March 15, 2012

(Consolidated up to 55/2012)

ALBERTA REGULATION 150/99
ENGINEERING AND GEOSCIENCE PROFESSIONS ACT
ENGINEERING AND GEOSCIENCE PROFESSIONS

GENERAL REGULATION

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Definitions

1 In this Regulation,

(a) "Act" means the Engineering and Geoscience Professions Act;

(b) "confirmatory examination" means an examination required by the Board of Examiners for the purpose of assessing an engineering or geoscience or related degree held by the applicant and not for a purpose related to the correction of perceived academic deficiencies;

(b.1) "domestic trade agreement" means a domestic trade agreement as defined in section 2 of Schedule 6 to the *Government Organization Act*;

(c) "licensee" includes a provisional licensee except where this Regulation specifically provides to the contrary.

AR 150/99 s1;72/2007;55/2012

Part 1
Membership in the Association

Division 1
General

Application

2(1) An application for registration must be submitted to the Registrar and must

(a) be in a form acceptable to the Board of Examiners, and

(b) be fully completed and accompanied by

(i) all required supporting documentation, and

(ii) any fees that are prescribed by the Council.

(2) The Registrar shall refer an application to the Board of Examiners if the application meets the requirements of subsection (1) and the Registrar is satisfied that the applicant meets the eligibility requirements for one of the categories of membership in the Association.

Annual fees

3 A person who is entered in a record or register under this Part shall pay any annual fees that are prescribed by the Council.

Non-payment

4 The Council may direct the Registrar to strike the name of a person from a record or register if the person fails to pay a prescribed fee.

Registers and records

5 The Registrar shall keep the following records and registers for the purposes of this Part:

(a) a record of students;

(b) a record of examination candidates;

(c) a record of members-in-training.

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Division 2
Students

Eligibility

6 A person who meets the following requirements and applies to the Registrar for registration is entitled to be enrolled as a student:

(a) the applicant is of good character and reputation;

(b) the applicant

(i) is enrolled in a full-time program at a university in Alberta that is recognized by the Board of Examiners as leading to a degree in engineering or geoscience, or

(ii) has at least 2 years of post-secondary education acceptable to the Board of Examiners in areas that relate to the science or technology of engineering or geoscience, together with

(A) one year of experience in work of an engineering or geoscientific nature acceptable to the Board of Examiners where the post-secondary education consists of an engineering or geoscientific technology program recognized by the Board of Examiners, or

(B) 3 years of such work experience, where the post-secondary education consists of education other than such a program.

AR 150/99 s6;55/2012

Striking from record

7 The Council may direct the Registrar to strike the name of a student from the record of students

(a) if the Council considers that the student has engaged in behaviour that constitutes unprofessional conduct,

(b) if the student ceases to be enrolled in a program referred to in section 6(b)(i), or

(c) if, in the opinion of the Board of Examiners, the student fails to make satisfactory progress toward registration as a professional member.

Division 3
Examination Candidates

Eligibility

8 A person who meets the following requirements and applies to the Registrar for registration is entitled to be admitted as an examination candidate:

(a) the applicant is of good character and reputation;

(b) the applicant is a graduate of

(i) a university program in engineering or geoscience, or

(ii) a related academic program that is acceptable to the Board of Examiners,

but the Board of Examiners has required the applicant to complete one or more confirmatory examinations or examinations for the purpose of correcting a perceived academic deficiency.

AR 150/99 s8;55/2012

Striking from record

9(1) The Council may direct the Registrar to strike the name of an examination candidate from the record of examination candidates

(a) if the Council considers that the examination candidate has engaged in behaviour that constitutes unprofessional conduct, or

(b) if, in the opinion of the Board of Examiners, the examination candidate fails to make satisfactory progress toward registration as a professional member.

(2) A person whose name is struck from the record is no longer eligible to proceed with the writing of examinations.

Division 4
Members-in-training

Eligibility

10(1) A person who meets the following requirements and applies to the Registrar for registration is entitled to be enrolled as an engineer-in-training or geoscientist-in-training:

(a) the applicant is of good character and reputation;

(b) the applicant

(i) is a graduate of a university program in engineering or geoscience or a related university program that is acceptable to the Board of Examiners, but does not have the work experience required for registration as a professional member, or

(ii) is registered as an examination candidate under section 8(b) and has completed the examinations referred to in that provision, but does not have the work experience required for registration as a professional member.

(2) Notwithstanding subsection (1), an applicant is entitled to be enrolled as an engineer-in-training or geoscientist-in-training if

(a) the applicant is of good character and reputation, and

(b) the applicant is registered and in good standing with a professional regulatory organization under an Act of another province or territory of Canada to perform an occupation that, in the opinion of the Board of Examiners, is substantially equivalent, in terms of scope of practice and competencies, to that of a member-in-training.

AR 150/99 s10;346/2009;55/2012

Domestic trade agreements

10.1 Where section 10(2) applies in respect of an applicant and the professional regulatory organization is in a province or territory that is a signatory to one or more domestic trade agreements that is in force in Alberta, the applicant's application must be dealt with in a manner consistent with the applicable domestic trade agreements.

AR 55/2012 s6

Time limits

11(1) Subject to subsection (2), no person may remain in the record of members-in-training for more than 6 years.

(2) The Council may in particular cases extend the period referred to in subsection (1) to not more than 8 years.

Professionally qualified persons inadmissible

12 No person may be enrolled as an engineer-in-training or geoscientist-in-training if at the time of application the person is qualified to be registered as a professional member or licensee.

AR 150/99 s12;55/2012

Division 5
Professional Members

Eligibility

13(1) A person who meets the following requirements and applies to the Registrar for registration is entitled to be registered as a professional member:

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(a) the applicant is a Canadian citizen or is lawfully admitted to Canada for permanent residence;

(b) the applicant is of good character and reputation;

(c) the applicant has a knowledge of the Act and the regulations under the Act, and general knowledge related to the practice of engineering or geoscience, which has been demonstrated by passing an examination that is prescribed by the Board of Examiners;

(d) the applicant demonstrates to the Board of Examiners that the applicant has a proficiency in the English language that is sufficient to enable the applicant to responsibly practise the profession of engineering or geoscience;

(e) the applicant meets one of the following requirements:

(i) the applicant is enrolled as a member-in-training and has obtained at least 4 years of experience in work of an engineering or geoscientific nature that is acceptable to the Board of Examiners;

(ii) the applicant is enrolled as a student under section 6(b)(ii) and

(A) has completed all examinations prescribed by the Board of Examiners, and

(B) has obtained at least 8 years of experience in work of an engineering or geoscientific nature that is acceptable to the Board of Examiners, at least one year of which is obtained after completion of the examinations referred to in paragraph (A);

(iii) the applicant is admitted as an examination candidate and

(A) has completed the examinations referred to in section 8(b), and

(B) has obtained at least 4 years of experience in work of an engineering or geoscientific nature that is acceptable to the Board of Examiners;

(iv) the applicant is not in a register or record referred to in subclause (i), (ii) or (iii), but has the combined academic qualifications and experience acceptable to the Board of Examiners that would be required for registration as a professional member had the applicant progressed through one of those registers or records.

(2) Notwithstanding subsection (1), an applicant is entitled to be registered as a professional member if

(a) the applicant is of good character and reputation, and

(b) the applicant is registered and in good standing with a professional regulatory organization under an Act of another province or territory of Canada to perform an occupation that, in the opinion of the Board of Examiners, is substantially equivalent, in terms of scope of practice and competencies, to that of a professional member.

AR 150/99 s13;37/2003;346/2009;55/2012

Domestic trade agreements

13.1 Where section 13(2) applies in respect of an applicant and the professional regulatory organization is in a province or territory that is a signatory to one or more domestic trade agreements that is in force in Alberta, the applicant's application must be dealt with in a manner consistent with the applicable domestic trade agreements.

AR 55/2012 s9

Division 6
Licensees

Registration as licensee

14(1) A person who meets all of the requirements of section 13 for registration as a professional member, except the requirement set out in section 13(1)(a), is entitled to be registered as a licensee.

(2) Notwithstanding subsection (1), an applicant is entitled to be registered as a licensee if

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(a) the applicant is of good character and reputation, and

(b) the applicant is registered and in good standing with a professional regulatory organization under an Act of another province or territory of Canada to perform an occupation that, in the opinion of the Board of Examiners, is substantially equivalent, in terms of scope of practice and competencies, to that of a licensee.

AR 150/99 s14;72/2007;346/2009

Domestic trade agreements

14.01 Where section 14(2) applies in respect of an applicant and the professional regulatory organization is in a province or territory that is a signatory to one or more domestic trade agreements that is in force in Alberta, the applicant's application must be dealt with in a manner consistent with the applicable domestic trade agreements.

AR 55/2012 s10

Registration as a provisional licensee

14.1(1) The Board of Examiners may approve the registration of a person as a provisional licensee if

(a) the person is legally entitled to work in Canada, whether or not the person meets the requirements of section 13(1)(a),

(b) the person meets all of the other requirements of section 13 for registration as a professional member, except the requirement set out in section 13(1)(e),

(c) the person has academic qualifications and experience in work of an engineering or geoscientific nature that is acceptable to the Board of Examiners, and

(d) the Board of Examiners considers that it is appropriate to register the person as a provisional licensee.

(1.1) Notwithstanding subsection (1), an applicant is entitled to be registered as a provisional licensee if

(a) the applicant is of good character and reputation, and

(b) the applicant is registered and in good standing with a professional regulatory organization under an Act of another province or territory of Canada to perform an occupation that, in the opinion of the Board of Examiners, is substantially equivalent, in terms of scope of practice and competencies, to that of a provisional licensee.

(2) A provisional licensee may practise engineering or geoscience only under the supervision and control of

(a) a professional member,

(b) a licensee, other than a provisional licensee, or

(c) a registered professional technologist

who has appropriate training and experience in the same area of practice.

(3) A provisional licensee may not vote in any matter affecting the Association or hold office in the Association.

(4) Subjection to subsection (5), no person may remain in the register of provisional licensees for more that 2 years.

(5) The Council may, in a particular case, extend the time period in subsection (4) to not more than 4 years where the Council considers it appropriate to do so.

AR 72/2007 s3;346/2009;55/2012

Domestic trade agreements

14.2 Where section 14.1(1.1) applies in respect of an applicant and the professional regulatory organization is in a province or territory that is a signatory to one or more domestic trade agreements that is in force in Alberta, the applicant's application must be dealt with in a manner consistent with the applicable domestic trade agreements.

AR 55/2012 s12

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Division 7
Board of Examiners

Board of Examiners - constitution

15(1) The Board of Examiners consists of

(a) an executive committee constituted under subsection (5),

(b) other members, who must be professional members, and who are appointed by the Council, and

(c) any other persons appointed by the Minister under the Act.

(2) The Board of Examiners shall meet at least twice each year to consider matters of policy, significant changes in procedure, examination results and other matters referred to it by its executive committee or the Council.

(3) The executive committee shall meet as is necessary to rule on applications for registration.

(4) The Council shall designate a person as chair of the Board of Examiners and that person shall also serve as chair of the executive committee.

(5) The executive committee of the Board consists of

(a) the deans of engineering at universities in Alberta, or persons designated by the deans,

(b) a senior professor, who must be a professional engineer, from each of the major engineering disciplines at universities in Alberta,

(c) a senior professor, who must be a professional geoscientist, from each of the departments of geoscience at universities in Alberta,

(d) repealed AR 55/2012 s13,

(e) other professional members of the Association equal to the number of members specified in clauses (a) to (c), who are not directly associated with any of the universities and are representative of the disciplines of engineering and geoscience,

(f) the Registrar of the Association or the Registrar's designate,

(g) one member of the public appointed by the Minister in accordance with section 30(2) of the Act, and

(h) 2 registered professional technologists (engineering) or engineering technologists appointed by the Minister under section 91 of the Act.

(6) Where the executive committee sits for the purposes of ruling on applications for registration, members appointed under subsection (5)(h) may sit only in respect of applications for registration as a registered professional technologist (engineering).

(7) The Council shall appoint the persons referred to in subsection (5)(b) to (e).

(8) The term of appointment for the chair and members of the Board of Examiners who are appointed by the Council is 3 years, and they may be reappointed.

(9) Where a vacancy occurs in a category of membership referred to in subsection (5)(a) to (f), the Council shall appoint a professional member to the position for the unexpired portion of the term.

(10) A quorum for a meeting of the Board of Examiners is 1/4 of the members of the Board.

(11) A quorum for a meeting of the executive committee of the Board of Examiners is 1/4 of the members of the executive committee.

AR 150/99 s15;8/2005;55/2012

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Part 2
Continuing Professional Development Program

Interpretation

15.1 In this Part, "licensee" does not include provisional licensee.

AR 72/2007 s4

Education program established

16(1) The Council establishes the Continuing Professional Development Program of the Association as the compulsory continuing education program for professional members and licensees.

(2) The Practice Review Board shall administer the Continuing Professional Development Program.

Mandatory compliance

17 A professional member or licensee shall comply with the requirements of the Continuing Professional Development Program as it applies to that person's practice of engineering or geoscience, as the case may be.

AR 150/99 s17;55/2012

Exemption

18(1) Notwithstanding section 17, a professional member or licensee who files with the Association a declaration in writing stating that that person is not actively engaged in the practice of a profession is exempt from the requirements of this Part.

(2) An exemption under this section is only effective for one year from the date the declaration is received by the Association but may be renewed for additional yearly periods.

(3) A professional member or licensee shall not engage in the practice of a profession while an exemption under this section is in effect.

(4) A professional member or licensee who has filed a declaration under subsection (1) must immediately notify the Association in writing if that person intends to resume the practice of the profession.

(5) The Practice Review Board may require a professional member or licensee who has notified the Association under subsection (4) to comply with any conditions that the Board may set prior to allowing that person to resume the practice of the profession.

Written records

19 A professional member or licensee must

(a) maintain a written record of activities undertaken in accordance with the Continuing Professional Development Program, and

(b) produce the record under clause (a) on the request of the Practice Review Board.

Striking from register

19.1 The Council may direct the Registrar to strike from the register of professional members or licensees the name of a person who fails to comply with a notice that is served on the professional member or licensee and direct the professional member or licensee to comply with section 19 within 30 days after the date of service of the notice.

AR 37/2003 s3

Proof of compliance

20(1) On the request of the Practice Review Board, a professional member or licensee must satisfy the Board that that person is complying with the requirements of the Continuing Professional Development Program.

(2) Where a professional member or licensee fails to satisfy the Practice Review Board under subsection (1), the Board may

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(a) conduct a review of the practice of that person in accordance with the Act and this Regulation, and

(b) at any time during a review recommend to the Investigative Committee that the review be conducted by the Investigative Committee under Part 5 of the Act as if the recommendation were a written complaint.

Part 3
Practice Review Board

Interpretation

20.1 In this Part, "licensee" does not include provisional licensee.

AR 72/2007 s5

Constitution

21(1) The Council shall appoint not fewer than 2 professional engineers and one professional geoscientist as members of the Practice Review Board.

(2) The Council shall designate one of the professional members as chair.

(3) The Registrar or the Registrar's designate shall serve as Secretary to the Practice Review Board.

(4) The chair and professional members must be appointed for a 3-year term, and may be reappointed.

(5) A quorum of the Practice Review Board is 4 of its members.

(6) Where a vacancy occurs in the Practice Review Board, other than with respect to the member of the public appointed under section 15(1)(b) of the Act, the Council shall appoint a professional member to the position for the unexpired portion of the term.

(7) In appointing professional members to the Practice Review Board under this section, the Council

(a) shall not appoint a professional member unless the professional member has at least 10 years of experience in the practice of the profession, and

(b) shall appoint professional members so that the membership will represent a combination of academic qualifications and experience such that the Practice Review Board can effectively review and assess registration requirements and procedures and disciplinary procedures in order to ensure the continuing competency of members of the Association, and advise the Council on those matters.

AR 150/99 s21;55/2012

Items considered

22(1) The Practice Review Board shall meet at least twice each year, and more frequently if the chair considers it necessary, to consider

(a) items referred to the Board by the Council, the Board of Examiners or the Discipline Committee,

(b) reports from the Registrar submitted under subsection (2),

(c) items that have come to the attention of the Board from other sources and that reflect a need to review the procedures of the Association with respect to registration, discipline or maintenance of professional competency, and

(d) any other items that may be considered by the Board pursuant to the Act.

(2) The Registrar shall submit at each regular meeting of the Practice Review Board a report setting out

(a) the number and nature of appeals and complaints relating to rulings of the Board of Examiners, and

(b) the number and nature of complaints dealt with under Part 5 of the Act and the disposition of the complaints, with special emphasis on cases reflecting on the competency of members of the Association.

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Investigation by Practice Review Board

23(1) If the Practice Review Board undertakes a review of the practice of a professional member, licensee, permit holder or certificate holder, it shall proceed with the review in accordance with this section.

(2) The Board shall appoint a person to conduct an initial review and report to the Board with respect to the substance of the conclusions on which the Board based its decision to commence an investigation.

(3) If, on receipt of the report, the Board decides that further investigation is not warranted, the Board shall discontinue the review and report its decision to the Council, along with any recommendations the Board considers appropriate.

(4) If, on receipt of the report, the Board decides that investigation of a specific practice is necessary, it shall

(a) issue notice of investigation to the professional member, licensee, permit holder or certificate holder if it is of the opinion that the matter to be investigated relates to matters other than to unskilled practice of the profession or unprofessional conduct, and proceed with its investigation in the same manner as provided for in a discipline investigation, or

(b) lodge an appropriate complaint with the Investigative Committee if it is of the opinion that further investigation may lead to a finding of unskilled practice of the profession or unprofessional conduct.

Report to Council

24 Following each meeting, the Practice Review Board shall report through its chair to the Council and may make any recommendations as to changes in procedures regarding registration, discipline or maintenance of competency that the Board considers appropriate.

Part 4
Council

President and Vice-presidents - election and powers

25(1) The President of the Association must be elected annually by the professional members of the Association, and holds office until a successor is elected.

(2) The President shall act as the presiding officer at meetings of the Council and at meetings of the Association.

(3) The President may vote at meetings of the Council or the Association only in the event of a tied vote.

(4) The 2 Vice-presidents must be elected annually by the professional members of the Association and must be designated as First Vice-president and Second Vice-president on the basis of the number of votes cast for each of them.

(4.1) The First Vice-president is deemed to be the President Elect and must be the sole nominee for the office of President in the succeeding year.

(5) The First Vice-president or, failing the First Vice-president, the Second Vice-president, has all the powers of the President during the absence of the President for any cause.

AR 150/99 s25;37/2003

Election of Council

26(1) The professional members of the Council, other than those mentioned in section 25, must be elected annually by the professional members of the Association.

(2) The term of the members referred to in subsection (1) is 3 years and the elections must be conducted so that as close as possible to 1/3 of the positions come up for election each year.

Vacancy

27(1) Where there is a vacancy in the Council, the remaining members of the Council shall appoint a professional member to fill the vacancy until the next regular election.

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(2) Where a vacancy is filled at a regular election, the person elected holds office for the unexpired portion of the term of office of the person being replaced.

Quorum

28 A quorum for meetings of the Council is

(a) at least one of the President, the 2 Vice-presidents or the immediate Past President, and

(b) 6 other professional members of the Council.

Executive Committee

29(1) There is hereby established an Executive Committee of the Council consisting of the President, who is the chair, the immediate Past President, the 2 Vice-presidents and the Executive Director of the Association.

(2) The Executive Committee has the delegated authority and power of the Council with respect to any decisions or actions necessary between Council meetings.

Other boards, committees and task forces

30(1) In addition to the Discipline Committee, Investigative Committee, Board of Examiners, Practice Review Board, Appeal Board and Executive Committee, the Council may appoint any other standing or special committees, task forces or boards that it considers necessary to serve the interests of the Association, and shall at the time of the appointment, delegate any authority it considers necessary for the committees, task forces or boards to perform their function.

(2) Except for the Discipline Committee, Investigative Committee, Board of Examiners, Practice Review Board, Appeal Board and Executive Committee, the Council shall determine the terms of reference for all committees, task forces or boards.

Part 5
Code of Ethics

Application and availability

31(1) Professional members, licensees, permit holders, members-in-training, examination candidates and students shall comply with the Code of Ethics in the Schedule to this Regulation.

(2) The Association shall publish interpretations of the rules comprising the Code of Ethics and distribute them to professional members, licensees, permit holders, members-in-training, examination candidates and students.

(3) The Association shall make the Code of Ethics available on request to members of the public.

Part 6
Discipline

Investigative Committee

32(1) There is hereby established an Investigative Committee consisting of professional members and registered professional technologists (engineering) or engineering technologists appointed by the Council and the member of the public appointed under section 33(1).

(2) The Council shall designate one professional member as the chair of the Investigative Committee.

(3) The chair or in the absence of the chair a majority of the members of the Investigative Committee may appoint an acting chair who has all the powers of the chair in the absence of the chair.

Public member

33(1) The Minister shall appoint one member of the public, from a list of persons nominated by the Council, to the Investigative Committee.

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(2) The Minister may, after consultation with the Council, revoke the appointment of the member of the public.

(3) The powers, duties and operations of the Investigative Committee are not affected by

(a) the failure of the Minister to appoint a member of the public,

(b) the revocation of the appointment of the member of the public,

(c) the resignation from the Investigative Committee of the member of the public, or

(d) the absence of the member of the public from a meeting of the Investigative Committee.

(4) The Minister may pay to the member of the public appointed to the Investigative Committee travelling and living expenses incurred by that member for attendance at meetings of the Investigative Committee away from the member's usual place of residence and fees in an amount prescribed by the Minister.

Term of office

34(1) The term of office of each member of the Investigative Committee is 3 years, and members may be reappointed.

(2) Where there is a vacancy in the membership of the Investigative Committee appointed by the Council, the Council may appoint a person to fill the vacancy for the unexpired portion of the term.

(3) Where there is a vacancy in the public membership on the Investigative Committee, the Minister may appoint a person to fill the vacancy for the unexpired portion of the term.

Quorum

35 A quorum of the Investigative Committee consists of the chair or the acting chair and the number of professional members and registered professional technologists (engineering) or engineering technologists determined by the Council.

Discipline Committee

36(1) There is hereby established a Discipline Committee consisting of professional members appointed by the Council and the member of the public appointed under section 37(1).

(2) The Council shall designate one professional member as the chair of the Discipline Committee.

(3) The chair or in the absence of the chair a majority of the members of the Discipline Committee may appoint an acting chair who has all the powers of the chair in the absence of the chair.

Public member

37(1) The Minister shall appoint one member of the public, from a list of persons nominated by the Council, to the Discipline Committee.

(2) The Minister may, after consultation with the Council, revoke the appointment of the member of the public.

(3) The powers, duties and operations of the Discipline Committee are not affected by

(a) the failure of the Minister to appoint a member of the public,

(b) the revocation of the appointment of the member of the public,

(c) the resignation from the Discipline Committee of the member of the public, or

(d) the absence of the member of the public from a meeting of the Discipline Committee.

(4) The Minister may pay to the member of the public appointed to the Discipline Committee travelling and living expenses incurred by that member for attendance at meetings of the Discipline Committee away from the member's usual place of residence and fees in an amount prescribed by the Minister.

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Term of office

38(1) The term of office of each member of the Discipline Committee is 3 years, and members may be reappointed.

(2) Where there is a vacancy in the professional members on the Discipline Committee, the Council may appoint a person to fill the vacancy for the unexpired portion of the term.

(3) Where there is a vacancy in the public membership on the Discipline Committee, the Minister may appoint a person to fill the vacancy for the unexpired portion of the term.

Quorum

39 A quorum of the Discipline Committee consists of the chair or the acting chair and the number of professional members determined by the Council.

Appeal Board

40(1) The Council shall appoint professional members, including one Past President of the Association, as members of the Appeal Board.

(2) The Council shall designate one professional member as the chair of the Appeal Board.

(3) The chair or in the absence of the chair a majority of the members of the Appeal Board may appoint an acting chair who has all the powers of the chair in the absence of the chair.

Term of office

41(1) The term of office of each member of the Appeal Board appointed under section 40 is 3 years, and members may be reappointed.

(2) Where there is a vacancy in the membership of the Appeal Board appointed under section 40, the Council may appoint a professional member to fill the vacancy for the unexpired portion of the term.

Quorum

42 A quorum of the Appeal Board consists of the chair or the acting chair and the number of professional members determined by the Council.

Adjournment of investigation if court proceedings commenced

43 A preliminary investigation under Part 5 of the Act may be adjourned if the complaint that gave rise to the investigation is the subject of proceedings in the Provincial Court of Alberta or the Court of Queen's Bench of Alberta.

Assistance in conducting preliminary investigation

44 An investigation panel appointed under section 47 of the Act may employ any technical consultants and legal counsel it considers necessary to conduct a preliminary investigation.

AR 150/99 s44;8/2005

Panel of the Discipline Committee

45(1) A panel of the Discipline Committee must consist of at least 3 members of the Discipline Committee who are professional members.

(2) A member of the Discipline Committee who has been designated to act as a case manager under section 52(2) of the Act in respect of a matter must not sit as part of the panel of the Discipline Committee that is hearing the matter under section 53 of the Act.

(3) A panel of the Discipline Committee has all the powers and authority of the Discipline Committee.

AR 150/99 s45;8/2005

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Publication

46 The Discipline Committee or the Appeal Board may direct that reports of disciplinary investigations be published.

Reinstatement of disciplined individuals

47(1) A professional member or licensee whose registration has been cancelled or a permit holder whose permit has been revoked under Part 5 of the Act as a result of the disciplinary proceedings may apply to the Council to be reinstated.

(2) An application under subsection (1) may not be made until at least one year after the date on which the registration was cancelled or the permit was revoked, or from the date on which the Court made its order confirming or varying the decision of the Council.

(3) The Council may establish a Committee of Inquiry to consider the application for reinstatement and make recommendations to the Council.

(4) The Council may require the former professional member, licensee or permit holder to demonstrate by means prescribed by the Council that that person is competent to re-engage in the practice of engineering or geoscience.

(5) Where an application for reinstatement is not approved by the Council, no further application may be made by the former professional member, licensee or permit holder until at least one year after the date the Council ruled on the previous application.

AR 150/99 s47;55/2012

Part 7
Registration of Permit Holders

Interpretation

47.1 In this Part, "licensee" does not include a provisional licensee.

AR 72/2007 s6

Requirements for issue of permit

48(1) The Council may issue to a partnership, corporation or other entity a permit to practice engineering or geoscience in its own name if

(a) an application is made to the Registrar in the form and containing the information required by the Council,

(b) the application is accompanied with the fees prescribed by the Council,

(c) the Council is satisfied that the practice will be carried on under the direct personal supervision and responsibility of a full-time permanent employee or member of the partnership, corporation or other entity who is also a professional member or licensee and who is qualified by education and experience in the field of engineering or geoscience in which the partnership, corporation or other entity intends to engage, and

(d) the professional member or licensee certifies to the satisfaction of the Council that the partnership, corporation or other entity has in place and will follow a professional management plan that is appropriate to its professional practice.

(2) A permit expires one year after the date on which it is issued.

(3) When the Council issues a permit, it shall provide the permit holder with a permit number.

(4) No person shall use a permit number where the permit to which the number is assigned has been cancelled or suspended.

AR 150/99 s48;37/2003;55/2012

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Seminars

48.1 A professional member or licensee who accepts responsibility under section 48(1)(c) shall every 5 years attend a permit to practice seminar acceptable to the Council.

AR 37/2003 s6

Signing and sealing of documents

49 When the practice of engineering or geoscience is carried on by a partnership, corporation or other entity pursuant to a permit under section 48, all final plans, specifications, reports or documents of a professional nature must

(a) be signed by and be stamped or sealed with the stamp or seal of

(i) the professional member or licensee who prepared them or under whose supervision and control they were prepared, or

(ii) in the case of plans, specifications, reports or documents that were prepared by other persons, the professional member or licensee who thoroughly reviewed and accepted professional responsibility for them,

and

(b) show the permit number issued to the partnership, corporation or other entity under section 48.

AR 150/99 s49;55/2012

Notification to Association

50(1) A partnership, corporation or other entity practising pursuant to a permit under section 48 shall keep the Association advised of the name of the professional member or licensee referred to in that section.

(2) The professional member or licensee referred to in section 48 shall forthwith advise the Registrar if the professional member or licensee

(a) ceases to be the person accepting responsibility under that section, or

(b) is no longer able to provide the certification referred to in section 48(1)(d).

AR 150/99 s50;37/2003

Revocation of permit

51 The Council may revoke a permit issued under section 50 if the permit holder contravenes the Act, this Regulation or a term or condition of the permit.

AR 150/99 s51;8/2005

Name of firm

52 No partnership, corporation or other entity may be incorporated or registered in the Province of Alberta under a name including the words “Engineering”, “Geology”, “Geophysics” or “Geoscience”, or variations of those words, unless it holds and continues to hold a valid permit issued under section 48.

AR 150/99 s52;55/2012

Control and use of stamps and seals

53 The permit number issued to a permit holder may only be used by the professional members or licensees referred to in section 48(1)(c).

Waiver of compliance

53.1 The Council may, subject to any terms and conditions it considers appropriate, waive compliance with the requirements of sections 48(1)(d) and 48.1.

AR 37/2003 s8

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Part 8
General

Use of stamps and seals issued to members

54(1) A stamp or seal issued to a professional member or licensee must at all times remain under that person's direct control and must be applied by the professional member or licensee or by a person acting under the professional member's or licensee's immediate and direct control to all final plans, specifications, reports or documents of a professional nature

(a) that were prepared by the professional member or licensee or under the professional member's or licensee's supervision and control, or

(b) that were prepared by another person in circumstances where the professional member or licensee has thoroughly reviewed them and accepted professional responsibility for them.

(2) No person shall permit a stamp or seal to be physically located in a manner that would allow its use by a person other than the professional member or licensee to whom it was issued.

(3) When a stamp or seal is applied, the professional member or licensee to whom it was issued shall ensure that the stamp or seal is accompanied with that person's signature and the date on which the stamp or seal is applied.

(4) A stamp or seal may be applied to the cover page or final page of reports or documents in a manner that clearly indicates acceptance of professional responsibility for the reports or documents, without being applied to each page.

(5) A professional member or licensee shall not acquire a stamp or seal from any source other than the Registrar.

(6) A professional member or licensee shall only use a stamp or seal while that person is registered pursuant to this Regulation.

(7) Stamps and seals are the property of the Association and a person in possession of a stamp or seal shall surrender it to the Association on demand.

(8) A professional member or licensee may, with the approval of the Registrar, apply a computer generated facsimile of the stamp or seal if that person otherwise meets the requirements of the Act and this Regulation.

(9) In this section, "licensee" does not include a provisional licensee.

AR 150/99 s54;72/2007

Association publications

55 The Association shall issue on a regular basis as directed by the Council the publications known as *The Annual Report* and *The PEGG* for the general information of members on the affairs of the Association and the professions generally.

Publications on professional services

56 The Association may publish, on an annual basis or as directed by the Council, for the information of members and the public, conditions of engagement and surveys of professional fees for particular types of professional engineering and geoscientific services.

AR 150/99 s56;55/2012

Publications on professional services

57 The Association may publish a guide to the selection of professional engineers and geoscientists for consulting services to assist clients in the selection of professionally and legally qualified consultants and consulting firms.

AR 150/99 s57;55/2012

Publications on professional services

58 The Association may publish guides that define for clients the scope of professional services to be expected from a consulting engineer or geoscientist.

AR 150/99 s58;55/2012

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Publications on professional services

59 The Association may issue, on an annual basis or as directed by the Council, publications for the purpose of promoting high standards of professional services and adequate remuneration for those services, and the maintenance and improvement of the competency of members.

Membership register

60 The Association may publish from time to time as directed by the Council, a register, in a format directed by the Council, of professional members, licensees, permit holders, joint firms and restricted practitioners.

Service of notices

61(1) If notice is required to be given to a person under the Act, this Regulation or the bylaws, the notice is sufficiently given if

(a) it is served personally on the person,

(b) it is sent by prepaid mail to the person at the latest address provided to the Registrar by the person, or

(c) where the person has provided to the Registrar an electronic address for the purpose of receiving notices that meets the requirements of the Council, it is sent to the person by electronic transmission to that address.

(1.1) If a notice is served by electronic transmission in accordance with subsection (1), unless the contrary is proved, the service is presumed to be effected on the date on which the notice was transmitted.

(2) If notice is served by mail in accordance with subsection (1), unless the contrary is proved, the service is presumed to be effected

(a) 7 days from the date of mailing if the document is mailed to an address in Alberta, or

(b) 14 days from the date of mailing if the document is mailed to an address outside Alberta.

AR 150/99 s61;37/2003;72/2007

Enforcement Review Committee

62(1) There is hereby established an Enforcement Review Committee consisting of not fewer than 9 professional members appointed by the Council.

(2) The Council shall designate one member of the Committee as the chair.

(3) A member of the Committee may be appointed for a term of not more than 3 years and may be reappointed.

(4) A quorum of the Committee is the chair and 3 of its members.

(5) The chair may designate a member of the Committee as vice-chair, and the vice-chair may exercise all the powers of the chair in the absence of the chair.

(6) The Council may delegate to the Committee matters respecting the enforcement of compliance with Part 1 of the Act and this Regulation, subject to the directions of the Council.

AR 150/99 s62;37/2003

Part 9
Registered Engineering Technologists

Definition

63 In this Part, "registered engineering technologist" means a person who was registered as a registered engineering technologist under this Part immediately before the coming into force of the *Engineering, Geological and Geophysical Amendment Act, 2007*.

AR 150/99 s63;281/2009

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Transitional

63.1 Subject to the Act and the *ASET Regulation*, a person who was registered as a registered engineering technologist under this Part immediately before the coming into force of the *Engineering, Geological and Geophysical Amendment Act, 2007* continues to be so registered under section 63.2.

AR 281/2009 s3

Register to be maintained

63.2 For the purposes of section 92.1(2) of the Act, the ASET Registrar shall maintain a register for registered engineering technologists.

AR 281/2009 s3

64 to 72 Repealed AR 281/2009 s4.

Part 10
Professional Licensees

73 Repealed AR 281/2009 s6.

Application

74(1) An application for registration as a professional licensee must be submitted to the Registrar and must

(a) be in a form acceptable to the Board of Examiners, and

(b) be fully completed and accompanied by

(i) all required supporting documentation, and

(ii) any fees that are prescribed by the Council.

(2) The Registrar shall refer an application for registration as a professional licensee to the Board of Examiners if the application meets the requirements of subsection (1) and the Registrar is satisfied that the applicant meets the eligibility requirements for registration set out in section 77.

AR 150/99 s74;37/2003;281/2009

Annual fees

75 A person who is entered in a register of professional licensees shall pay any annual fees that are prescribed by the Council.

AR 150/99 s75;37/2003; 281/2009

Non-payment

76 The Council may direct the Registrar to strike the name of a person from a register of professional licensees if the person fails to pay a prescribed fee.

AR 150/99 s76;37/2003;281/2009

Eligibility

77(1) A person who meets the following requirements and applies to the Registrar for registration is entitled to be registered as a professional licensee:

(a) the applicant is of good character and reputation;

(b) the applicant has at least 2 years of post-secondary education acceptable to the Board of Examiners in areas that relate to the practice of engineering or geoscience;

(c) the applicant has a knowledge of the Act and regulations under the Act, and general knowledge related to the practice of engineering or geoscience, which has been demonstrated by passing an examination for those purposes that is prescribed by the Board of Examiners;

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(d) the applicant demonstrates to the Board of Examiners that the applicant has a proficiency in the English language that is sufficient to enable the applicant to responsibly practise the profession of engineering or geoscience;

(e) the applicant has obtained at least 6 years of experience in work of an engineering or geoscientific nature that is acceptable to the Board of Examiners, at least 2 of which are in the applicant's specific area of professional practice and were completed under the supervision and control of a professional member.

(2) Notwithstanding subsection (1), an applicant is entitled to be registered as a professional licensee if

(a) the applicant is of good character and reputation, and

(b) the applicant is registered as a professional licensee or in an equivalent capacity in good standing with a regulated entity in another province that, in the opinion of the Board of Examiners, is equivalent to the Association.

AR 150/99 s77;281/2009;55/2012

Domestic trade agreements

77.1 Where section 77(2) applies in respect of an applicant and the regulated entity is in a province that is a signatory to one or more domestic trade agreements that is in force in Alberta, the applicant's application must be dealt with in a manner consistent with the applicable domestic trade agreements.

AR 55/2012 s20

Application of regulations

78 Sections 16, 17, 18, 19, 20, 22, 23, 25, 26, 27, 28, 29, 30, 31, 32, 47, 48, 48.1, 49, 50, 51, 53, 54, 59, 60 and the Schedule apply in respect of professional licensees as if they were professional members.

AR 150/99 s78;37/2003;72/2007;281/2009

Part 11
Repeal and Expiry

Repeal

79 The *General Regulation* (AR 244/81) is repealed.

Expiry

79.1 For the purpose of ensuring that this Regulation is reviewed for ongoing relevancy and necessity, with the option that it may be repassed in its present or an amended form following a review, this Regulation expires on September 30, 2021.

AR 281/2009 s10;55/2012

80 Repealed AR 37/2003 s15.

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Schedule

CODE OF ETHICS

(established pursuant to section 20(1)(k) of the Engineering and Geoscience Professions Act)

Preamble

Professional engineers and geoscientists shall recognize that professional ethics is founded upon integrity, competence, dignity and devotion to service. This concept shall guide their conduct at all times.

Rules of Conduct

1 Professional engineers and geoscientists shall, in their areas of practice, hold paramount the health, safety and welfare of the public and have regard for the environment.

2 Professional engineers and geoscientists shall undertake only work that they are competent to perform by virtue of their training and experience.

3 Professional engineers and geoscientists shall conduct themselves with integrity, honesty, fairness and objectivity in their professional activities.

4 Professional engineers and geoscientists shall comply with applicable statutes, regulations and bylaws in their professional practices.

5 Professional engineers and geoscientists shall uphold and enhance the honour, dignity and reputation of their professions and thus the ability of the professions to serve the public interest.

AR 150/99 Sched.;37/2003;8/2005;55/2012

THE ENGINEERING AND GEOSCIENCE PROFESSIONS ACT

BY-LAWS

As approved by the Association and incorporating amendments
approved at the Annual General Meetings of
June 1983, June 1987, April 1991,
April 1993, April 1996,
April 1997, April 1998, April 1999, April 2000,
April 2001, April 2002, April 2005, April 2009
October 2009 (Special Meeting), April 2012
and consequential changes approved March 2012.

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Adopted by Authority of Section 19 of the Engineering and Geoscience Professions Act.

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Part 1
Head Office, Branches and Districts

Location

1(1) The Head Office of the Association shall be located in the City of Edmonton in the Province of Alberta.

(2) Council may establish such branches and districts as it deems necessary for the benefit of members of the professions concentrated in specific regions of the province. Constitution, structure and operation of the branches and districts shall be subject to the approval of the Council.

Part 2
Election of Council

Nominating Committee

2 A nominating committee shall be appointed at the annual meeting to serve for the ensuing year. The Committee shall consist of a minimum of 11 professional members of the Association, 1 of who shall be the retiring president, who shall be the chairman. Council shall fill any vacancies which may occur in this nominating committee.

Nominees

3(1) Not less than 150 days prior to the annual meeting the nominating committee shall submit to the Chief Executive Officer a list of nominees for Council, which shall include the president-elect as the sole nominee for president, 3 nominees for vice-president, and at least 3 more nominees for Councillors than there are vacancies to be filled on Council.

(2) Nominees for president or vice-president shall have served at least 1 year on the Council.

Nominees selection

4(1) The nominating committee, in selecting nominees, shall give due consideration to the composition of the Council as required by the Act, regulations and by-laws and to the geographical distribution and field of practice of the nominees.

(2) The written consent of the nominees to act if elected shall be secured and shall accompany the list of nominees submitted to the Chief Executive Officer.

(3) Not less than 120 days prior to the annual meeting the Chief Executive Officer shall distribute to each professional member, either directly by mail or via the Association publication known as the PEG, a list of the nominations made by the nominating committee.

Additional nominations

5 Additional nominations for any office or any offices, except the president may be made in writing by any 10 professional members. Such nominations shall reach the Chief Executive Officer properly endorsed not later than 90 days prior to the annual meeting and shall be accompanied by the written consent of the nominee or nominees to act if elected.

Conduct of elections

6(1) Elections shall be conducted by letter ballot.

(2) The names of all persons nominated for office shall be placed on the ballot form in groups relating to each office. The number**,** professional classification and term of Councillors to be elected shall be made clear on the ballot form. Ballot forms shall be mailed to the professional members by the Chief Executive Officer not later than 50 days prior to the annual meeting.

(3) Each professional member is entitled to one vote for one candidate for vice-president, and to vote for as many candidates as there are vacancies to be filled for Council, or for a lesser number.

(4) The poll shall close at noon on the 20th day prior to the annual meeting and no ballots received after that time shall be considered.

Electronic Voting

6.1 Notwithstanding Section 6, a member may vote electronically as prescribed by such terms and conditions established by Council from time to time and such vote shall be received and treated by the Association as having the same force and effect as if sent by letter ballot pursuant to Bylaw 6.

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Ballot counting committee

7(1) At least 20 days before the annual meeting the president shall appoint 6 professional members including a chairman to act as a ballot counting committee.

(2) This committee shall meet at a time and place designated by the president, but at least 15 days prior to the annual meeting, and shall receive then the package containing the ballots from the Chief Executive Officer.

(3) The envelope containing the ballots shall be opened by a member or members of the ballot counting committee who shall scrutinize and count the votes cast and keep a record thereof.

Counting of ballots

8(1) Of the candidates for the offices of vice-presidents, the one receiving the highest number of votes shall be elected first vice-president and the one receiving the second highest number of votes shall be elected second vice-president.

(2) The candidate elected as first vice-president shall be deemed to be the president-elect and shall be the sole nominee for the president in the succeeding year.

(3) The requisite number of persons who receive the highest number of votes for the office of Councillor shall be elected as Councillors for a term of 3 years. If there are any vacancies in Council to be filled the person or persons receiving the next highest number of votes for the office of Councillor shall be elected as Councillors for the balance of the unexpired term or terms to be filled, and as among them, the person or persons receiving the highest number of votes shall fill any vacancy or vacancies which have the longer unexpired term or terms.

(4) On completion of the counting of the ballots, the chairman of the ballot counting committee shall deliver to the president or the Chief Executive Officer the results of the poll, together with the ballots and tally sheets in a separate sealed package.

Results of election

9(1) Prior to the annual meeting, the president or the Chief Executive Officer shall inform the candidates in the election of the results of the balloting including the number of votes cast for each candidate.

(2) The results of the election shall be announced at the annual meeting by the chairman of the meeting.

(3) In case of equality of votes for any officer or Councillor, the president or, in the absence of the president, the chairman of the nominating committee shall cast the deciding vote.

Objection and recount

10(1) Any objection to the poll as announced will be valid only if made immediately after the announcement and a proper motion for a recount will then be in order. If such a motion is made and carried the chairman shall appoint a ballot counting committee of not less than 12 professional members who shall forthwith recount all ballots. Candidates may be present or represented at such recount.

(2) On completion of the recount the results shall be communicated in writing to the chairman who shall announce it to the annual meeting immediately. Such recount shall be final and binding.

(3) Following the announcement of the poll or of the recount, as the case may be, the ballots and any tally sheets shall be destroyed.

Failure to comply with procedures

11 In the event of any failure to comply with procedures relating to the election of members of Council, Council shall have the power to take any action it deems necessary to validate the nomination, the counting of the ballots or the election.

Part 3
Meetings of the Council

Council meetings

12(1) Council shall meet at the call of the president or on request in writing to the Chief Executive Officer signed by not less than 4 Councillors.

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(2) The time and place of Council meetings shall be fixed by the president or by the councillors, whichever called the meeting.

(3) Professional members of the Association shall be informed as to the time and place of Council meetings and may attend meetings of the Council as observers if advance notification of their attendance is given to the Chief Executive Officer.

(4) If any member of Council is unable to attend a meeting of Council he shall so inform the Chief Executive Officer or the executive secretary prior to the meeting.

(5) If any member of Council absents himself from 3 consecutive meetings of Council without the approval of Council, Council may declare his seat to be vacant.

Expenses

13 Members of Council and, at the discretion of Council, appointed representatives of the Association, members of committees of the Association, members invited for special purposes and the representatives of other organizations shall be paid the reasonable out of-pocket expense of attending meetings of the Council or of the Association or when travelling on business of the Association.

Honorarium President

13.1 An honorarium shall be paid to the President, or the President's nominee in an amount and under such conditions as may be determined by the Council from time to time.

Part 4
Representatives to and from other Organizations and Groups

Representatives on other organizations

14(1) Council may appoint professional members to represent the Association on the Engineering Faculty Councils and Science Faculty Councils of Universities in Alberta and shall appoint a director of the Canadian Council of Professional Engineers.

(2) Council may appoint a professional member to represent the Association on the Council, governing body, or committees of any other organization or association.

(3) Representatives appointed under the provisions of subsections (1) and (2) hereof, if not members of Council, may be invited by Council to attend meetings of Council and to take part in the proceedings of Council but shall not be entitled to vote on any question.

Representatives from other organizations

15(1) Council may invite any organization or association to appoint a member of its executive as a representative to sit with Council at such meetings of Council as Council may determine.

(2) Any representative appointed pursuant to subsection (1) hereof, if not a member of Council, may be invited by Council to attend meetings of Council and to take part in the proceedings of Council but shall not be entitled to vote on any question.

Part 5
Meetings of the Association

Annual meetings

16(1) An annual meeting of the Association shall be held in every calendar year with the period between such meetings not to exceed 18 months. At each annual meeting the Council shall submit a recommendation as to the date and place of the next annual meeting.

(2) Notice of the annual meeting shall be distributed, either directly by mail or via the Association publication known as the PEG, to all members at least 90 days in advance of the meeting.

(3) At the annual meeting of the Association a quorum shall consist of 60 professional members.

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Agenda

17(1) The following items of business shall be dealt with at the annual meeting:

(a) minutes of the last annual meeting and of any special meetings held since the last annual meeting;

(b) business arising from the minutes;

(c) address of the president,

(d) reports of representatives of the Association;

(e) reports of committees;

(f) auditor's report;

(g) appointment of auditor;

(h) new business;

(i) fixing of the date and place of the next annual meeting;

(j) announcement of the results of the annual election;

(k) objection, if any, to the election results as announced;

(1) appointment of the nominating committee.

(2) Any resolution carried at an annual meeting shall be considered at the next regular meeting of the Council.

Special meetings

18(1) Special meetings of the Association may be held when considered necessary by the Council or upon written request to the Chief Executive Officer signed by not less than 30 professional members of the Association. A special meeting summoned pursuant to the written request of the 30 or more professional members shall be held not more than 45 days after the request is received by the Chief Executive Officer.

(2) Written notice calling a special meeting of the Association shall be distributed to all members, directly either by mail or via the Association publication known as the PEG, at least 14 days in advance of the meeting and shall clearly state the object of the meeting, and no other business shall be transacted at the meeting.

(3) At any special meetings of the Association a quorum shall consist of 60 professional members.

(4) Any resolution carried at a special meeting shall be considered at the next regular meeting of the Council.

District meetings

19(1) District meetings of the Association may be held as approved by Council or as directed by the executive of a properly constituted Branch of the Association.

(2) Notice of a district meeting shall be distributed to all members resident in the district, either directly by mail or via the Association publication known as the PEG, at least 14 days in advance of the meeting.

(3) Council shall approve the holding of a district meeting of the Association on a request to the Chief Executive Officer signed by not less than 30 professional members of the Association.

(4) A quorum at a district meeting shall be 10 professional members.

(5) Any resolution carried at a district meeting shall be considered by Council at its next regular meeting.

Procedures at meetings

20(1) The proceedings at any meeting of the Association and of Council shall be governed by the rules laid down in the latest edition of Robert's Rules of Order, except as these by-laws may otherwise provide.

(2) Only professional members are entitled to vote at annual, district or special meetings of the Association.

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Part 6
Chief Executive Officer, Deputy Registrar

Responsibilities

21 (1) The Chief Executive Officer shall be a professional member of the Association and shall post a security bond at the expense of the Association in a sum to be fixed by Council.

(2) The Chief Executive Officer shall be in responsible charge, under Council, of all property of the Association and shall be responsible for the work of all employees of the Association.

(3) The Chief Executive Officer shall be responsible for

(a) the presentation of business and recording of proceedings at all meetings of the Association and of Council,

(b) conducting the correspondence of the Association and keeping full records thereof,

(c) the books and accounts of the Association and ensuring that all monies due the Association are collected and deposited with the funds of the Association,

(d) the drawing of cheques against the funds of the Association to be signed by the Chief Executive Officer and president or alternates approved by the Council,

(e) providing from time to time such information and reports as may be requested by Council, or which he deems necessary in the interest of the Association, and

(f) such other functions as are necessary or expedient for the proper administration of the Act, regulations and by-laws, and the affairs of the Association generally.

Deputy Registrar

22 The Council may appoint a Deputy Registrar who has all the powers and can perform all the duties of the Registrar under the Act, the regulations and the by-laws when the Registrar is absent or unable to act, or when there is a vacancy in the office of the Registrar.

Part 7
Finances of the Association

Auditing

23(1) The finances of the Association shall be audited annually as of the 31st day of December.

(2) The auditors shall be a firm of chartered accountants who shall be appointed annually at the annual meeting.

(3) The auditors shall submit a written report for the annual meeting, a copy of which shall be sent to members prior to the meeting either directly by mail or via one of the Association publications.

Fees

24(1) The annual fee for a professional member shall be as specified from time to time by Council and shall be payable in advance, on the anniversary date of the member's initial or current registration, subject to such discount, if any, as Council may from time to time direct.

(2) The registration fee shall consist of an administrative charge as established by Council from time to time plus any other fees payable with the application for registration.

(3) In the case of new applicants, the annual fee for the following 12 months shall be payable at the time of registration.

(4) The annual fee for a licensee shall be fixed by Council from time to time, and shall not be less than the annual fee for a professional member.

(5)(a) The annual fee for a permit holder shall be fixed by Council from time to time and shall be not less than the annual fee for the professional member or licensee assuming direct personal supervision of and responsibility for the practice of the permit holder.

(b) Council may, in its discretion, on application of a permit holder waive or reduce the annual fee.

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Part 8
Life and Honorary Members

Life Member

25(1) Council, may confer life membership in the Association upon any professional member who

(a) has been a professional member for 25 or more years; or has held equivalent registration in a jurisdiction recognized by the Association, and professional membership totalling a minimum of 25 years, of which at least the last 10 years have been with the Association, and

(b) has retired from the practice of the profession

(2) Notwithstanding Section 25(1), Council, in its sole discretion, may confer life membership in the Association upon any professional member it deems worthy.

(3) Subject to Section 25(1), life members retain all of the obligations, duties and privileges of professional membership and pay annual fees as may be specified by Council.

Honorary Life Member

26(1) Council, in its discretion by unanimous vote, may confer Honorary Life Membership in the Association upon any professional member who has rendered significant service to the Association.

(2) Honorary Life Members retain all of the obligations, duties and privileges of professional membership but are exempted from payment of annual fees.

Honorary Member

27(1) Council, in its discretion by unanimous vote, may confer honorary membership in the Association upon persons who have given eminent service to the profession. There shall at no time be more than 30 honorary members in the Association.

(2) Honorary membership may be revoked by unanimous vote of the Council for conduct considered detrimental to the profession.

(3) Honorary members do not have the right to vote on Association affairs, to call themselves professional members or create the impression that they are professional members, or to engage in the practice of engineering, geology or geophysics.

(4) Honorary members are not required to pay any annual fees.

Part 9
Committees

Procedures and appointments

28(1) Standing Committees, Task Forces, or Boards, appointed by the Council pursuant to the Act and Regulations, shall proceed in accordance with terms of reference and procedures designated by the Council at the time of appointment.

(2) The Chair and members of Standing Committees, Task Forces, and Boards shall be appointed by the Council or if the Council so directs, by the Chief Executive Officer.

(3) Members of Standing Committees, Task Forces, and Boards, shall be appointed by the Council or by Chairmen in consultation with the Chief Executive Officer with ratification by the Council.

Expenses

29 The Chairs and members of Standing Committees, Task Forces and Boards shall receive reimbursement of expenses incurred in performing their designated functions.

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Part 10
Scholarships and Benefit Programs

Program

30(1) The Council in its discretion may establish such scholarship or other educational incentive programs that it considers will serve the interests of the professions of engineering, geology or geophysics and shall decide from time to time the amount of financial support to be provided for such programs.

(2) The Council in its discretion may establish such other types of benefit programs that it considers will advance the welfare of the professions of engineering, geology or geophysics and shall decide from time to time the amount of financial support to be provided for such programs.

Part 11
Register of Members

Content

31(1) The Registrar shall be responsible for maintaining an up-to-date register providing a record of

(a) professional members,

(b) licensees,

(c) permit holders,

(d) Life Members, Honorary Life Members, and Honorary Members,

(e) members-in-training,

(f) examination candidates,

(g) students,

(h) joint firms, and

(i) restricted practitioners, and

(j) provisional licensees, and

(k) professional licensees.

(2) The Registrar shall be responsible for entering any memoranda in the register related to cancellations and suspensions and any subsequent modifications to such memoranda and shall advise the next regular meeting of the Council of any memoranda entered or modified.

Mailing addresses

32 Professional members, licensees, permit holders, professional licensees, provisional licensees, Life Members, Honorary Life Members, Honorary Members, members-in-training, examination candidates, students, joint firms and certificate holders shall provide the Registrar with their current mailing addresses and advise the Registrar forthwith in writing of any change in address.

Onus to respond

32.1 Professional members, licensees, permit holders, life members, professional licensees, provisional licensees, members in training, joint firms, or certificate holders, shall respond promptly and appropriately to any duly served communication of a regulatory nature received from the Association that contemplates a reply.

Part 12
Seals, Stamps and Certificates

Seals and stamps

33(1) Seals and stamps issued to professional members shall be in a form prescribed by the Council and shall show the professional category of the professional member as Professional Engineer or Professional Geoscientist.

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(2) Seals and stamps issued to licensees shall be in a form prescribed by the Council and shall show the professional category of the licensee as Professional Engineer or Professional Geoscientist and in addition shall carry the word "licensee",

(3) Stamps issued to permit holders shall be in a form prescribed by the Council and shall show the designation "Permit Holder".

(4) Stamps issued to joint firms shall be in a form prescribed by the Council and shall show the designation "Engineers and Architects" or "Architects and Engineers".

(5) Seals and stamps issued to professional licensees shall be in a form prescribed by the Council and shall show the designation “Professional Licensee (Engineering), or (Geoscience)” as the case may be.

Certificates

34(1) The Registrar shall issue to each professional member a certificate in a form prescribed by the Council signed by the president and Registrar showing the date of registration and the professional category in which the member is registered; and upon renewal an annual certificate.

(2) The Registrar shall issue to each licensee a license certificate in a form prescribed by the Council signed by the president and Registrar showing the date of registration and the professional category of the licensee; and upon renewal of the license an annual certificate in the form of a license renewal card.

(3) The Registrar shall issue to each permit holder a certificate in a form prescribed by the Council signed by the president and Registrar showing the permit number assigned to the permit holder and professional category in which the permit holder is entitled to practice; and upon renewal of the permit an annual certificate in the form of a permit renewal card.

(4) The Registrar shall issue to each restricted practitioner a certificate in a form prescribed by the Council signed by the president and Registrar and showing the date of registration and the restricted area of practice in which the certificate holder may engage; and upon renewal of registration as a restricted practitioner, an annual certificate in the form of a restricted practice renewal card.

(5) The Registrar shall issue to each professional licensee a certificate in a form prescribed by the Council, signed by the President and Registrar, and showing the date of registration and the area of practice in which the professional licensee may engage; and upon renewal of registration as a professional licensee an annual certificate in the form of a renewal card.

Surrender of seals, stamps and certificates

35 Professional members, licensees, permit holders, certificate holders, and professional licensees shall surrender to the Registrar, forthwith upon development of any of the following eventualities, any seals, stamps and certificates that have been issued to them:

(a) temporary withdrawal of the professional member, licensee, permit holder, certificate holder, or professional licensee from practice of the profession for a period estimated to exceed 1 year;

(b) resignation of the professional member, licensee, permit holder, certificate holder, or professional licensee from the Association;

(c) the suspension or cancellation of the professional membership, license, permit or certificate.

Part 13
Assessment of Costs for Hearings and Appeals

Content

36 Where the Discipline Committee, Practice Review Board or the Appeal Board orders an investigated person to pay the costs of the hearing, or the costs of the appeal, or both the costs of the hearing and the costs of the appeal, those costs may include all or any of the following costs and expenses:

(a) any honorarium, payment, or professional fees paid to a person retained to participate in the hearing or appeal;

(b) costs of any transcripts of evidence taken in the proceedings;

(c) costs of reproduction of all or any documents including drawings and plans relating to the proceedings;

(d) witness fees;

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(e) cost of renting rooms, renting recording equipment, or hiring a reporter to take transcript of the evidence;

(f) fees payable to the solicitor acting on behalf of the Association in the proceedings;

(g) any other expenses incurred that are attributable to the hearing or an appeal resulting from it.

Part 14
General

Voting by mail

37(1) The Council may direct that a mail vote be conducted on any matter related to the Association.

(2) Announcement of a mail vote giving full details of the matter to be voted upon must be made to all professional members at least 21 days in advance of the vote being taken and if objections to a mail vote are received by the Registrar in writing at least 3 days before the announced date of the vote from at least 30 professional members of the Association the matter shall be held over to a meeting of the Association.

(3) A vote by mail shall be declared valid if at least 10 percent of the professional members respond and the matter shall be declared carried or defeated on the basis of a simple majority of the votes returned.

(4) The results of a mail vote shall be considered by the Council at its next regular meeting.

Electronic Voting

37.1 For purposes of Bylaw 37, a mail vote shall be deemed to include electronic communications within such terms and conditions as may be prescribed from time to time by the Council of the Association and such vote shall be received and treated by the Association as having the same force and effect as if sent by mail under Bylaw 37.

Amendments to By–laws

38(1) Proposed amendments to by-laws shall be submitted to a properly convened meeting of the Association and shall not be effective unless approved by a majority of the professional members present and voting at the meeting, or shall be submitted to the professional members for a mail vote in accordance with section 37.

(2) If the proposed amendments are to be voted on at a meeting of the Association, full details of the proposed amendments shall be disclosed to all professional members at least 14 days in advance of the meeting.

Validation

39 When any act or thing under the provisions of these by-laws directed to be done within a limited time is not so done, or is not properly or effectually done, then anything actually done prior to such omission or improper or ineffectual act shall not be thereby vitiated, but shall remain in full effect and the Council, either prior or subsequent to such act not properly or effectually done or omitted, may extend the time for completing or perfecting such act or thing, which when completed or perfected, shall have the same effect as if done strictly in accordance with the provisions of these by-laws.

Professional Licensees

40 Sections 2, 5, 6, 7, 12(3), 16(3), 18, 19, 20, 37 and 38 of these Bylaws apply to professional licensees (engineering), and professional licensees (geoscience) as if they were professional members.

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THE ENGINEERING AND GEOSCIENCE PROFESSIONS ACT

REGULATIONS

ASET REGULATION

Consisting of Alberta Regulation
282/2009 DATED October 15, 2009
and 56/2012 DATED March 2012

(Consolidated up to 56/2012)

ALBERTA REGULATION 282/2009
ENGINEERING AND GEOSCIENCE PROFESSIONS ACT

ASET REGULATION

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Schedule

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Definitions

1 In this Regulation,

(a) "Act" means the Engineering and Geoscience Professions Act;

(b) "certified technician" means an individual who holds a certificate of registration as a certified technician granted by the ASET Board of Examiners under the Act;

(c) "certified technologist" means an individual who holds a certificate of registration as a certified engineering technologist, applied science technologist or certified computer information technologist granted by the ASET Board of Examiners under the Act;

(c.1) "domestic trade agreement" means a domestic trade agreement as defined in section 2 of Schedule 6 to the *Government Organization Act*;

(d) "registered engineering technologist" means an individual who holds a certificate of membership as a registered engineering technologist under Part 9 of the *Engineering and Geoscience Professions General Regulation* (AR 150/99) immediately before the coming into force of this Regulation;

(e) "regulated member" means

(i) a certified technician,

(ii) a certified technologist, or

(iii) except in sections 13, 14 and 15(5) and (8), a registered engineering technologist.

AR 282/2009 s1;56/2012

Part 1
Membership in ASET

Division 1
General

Application

2(1) An application for registration must be submitted to the ASET Registrar and must

(a) be in a form acceptable to the ASET Board of Examiners, and

(b) be fully completed and accompanied by

(i) all required supporting documentation, and

(ii) any fees that are prescribed by ASET Council.

(2) The ASET Registrar shall refer an application to the ASET Board of Examiners if the application meets the requirements of subsection (1) and the ASET Registrar is satisfied that the applicant meets the eligibility requirements for one of the categories of membership in ASET.

Annual fees

3 A person who is entered in a record or register under this Part or Part 9 of the Engineering and Geoscience Professions General Regulation (AR 150/99) shall pay any annual fees that are prescribed by ASET Council pursuant to the ASET bylaws.

AR 282/2009 s3;56/2012

Non-payment

4 ASET Council may direct the ASET Registrar to strike the name of a person from a record or register if the person fails to pay a prescribed fee.

Registers and records

5 The ASET Registrar shall keep and maintain records and registers for regulated members and other ASET members.

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Division 2
Students

Eligibility

:

(a) the applicant is of good character and reputation;

(b) the applicant

(i) is enrolled as a full-time student in an applied science, information or engineering technology program that is recognized by the ASET Board of Examiners, or

(ii) is a regulated member who returns to full-time education in an applied science, information or engineering technology program that is recognized by the ASET Board of Examiners.

(2) The ASET Board of Examiners may establish what part, if any, of a program referred to in subsection (1) an applicant must have successfully completed in order to be enrolled as a student.

Striking from record

7 ASET Council may direct the ASET Registrar to strike the name of a student from the record of students

(a) if ASET Council considers that the student has engaged in behaviour that constitutes unprofessional conduct,

(b) if the student ceases to be enrolled in a program referred to in section 6(1)(b), or

(c) if the registration was entered in error in the register.

Division 3
Examination Candidates

Eligibility

8 A person who meets the following requirements and applies to the ASET Registrar for registration is entitled to be admitted as an examination candidate:

(a) the applicant is of good character and reputation;

(b) the applicant is a graduate of

(i) an applied science, information or engineering technology program that is recognized by the ASET Board of Examiners, or

(ii) a related academic program that is recognized by the ASET Board of Examiners,

but the ASET Board of Examiners has required the applicant to either complete educational upgrading, examinations or other assessment activities for the purpose of correcting a perceived academic deficiency or acquire additional experience in work of an applied science, information or engineering technology nature.

Striking from record

9(1) ASET Council may direct the ASET Registrar to strike the name of an examination candidate from the record

(a) if ASET Council considers that the examination candidate has engaged in behaviour that constitutes unprofessional conduct,

(b) if, in the opinion of the ASET Board of Examiners, the examination candidate fails to make satisfactory progress toward registration as a regulated member, or

(c) if the registration was entered in error in the register.

(2) Subject to subsection (3), no person may remain on the record of examination candidates for more than 5 years.

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(3) The ASET Registrar may extend the period referred to in subsection (2) to not more than a total of 7 years.

(4) A person whose name is struck from the record is no longer eligible to proceed with the educational upgrading, examinations or other assessment activities.

Division 4
Members-in-Training

Definition

10 In this Division, "member-in-training" means a technician-in-training or a technologist-in-training.

Eligibility

11(1) A person who meets the following requirements and applies to the ASET Registrar for registration is entitled to be admitted as a member-in-training:

(a) the applicant is of good character and reputation;

(b) the applicant is

(i) a graduate of an applied science, information or engineering technology program that is recognized by the ASET Board of Examiners, but does not have the work experience required for registration as a regulated member, or

(ii) is a member-in-training or the equivalent of a member-in-training in good standing with a regulated entity in another province that is in the opinion of the ASET Board of Examiners equivalent to ASET.

(2) Notwithstanding subsection (1), a person may not be admitted as a member-in-training if at the time of application the person is qualified to be registered as a regulated member.

Domestic trade agreements

11.1 Where section 11(1)(b)(ii) applies in respect of an applicant and the regulated entity is in a province that is a signatory to one or more domestic trade agreements that is in force in Alberta, the applicant's application must be dealt with in a manner consistent with the applicable domestic trade agreements.

AR 56/2012 s4

Striking from record

12(1) **ASET** Council may direct the ASET Registrar to strike the name of a member-in-training from the record of members-in-training

(a) if ASET Council considers that the member-in-training has engaged in behaviour that constitutes unprofessional conduct,

(b) if, in the opinion of the ASET Board of Examiners, the member-in-training fails to make satisfactory progress toward registration as a regulated member, or

(c) if the registration was entered in error in the register.

(2) Subject to subsection (3), no person may remain on the record of members-in-training for more than 4 years after graduation.

(3) The ASET Registrar may extend the period referred to in subsection (2).

Division 5
Regulated Members

Eligibility

13(1) A person who meets the following requirements and applies to the ASET Registrar for registration is entitled to be registered as a regulated member:

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(a) the applicant is a Canadian citizen or is lawfully entitled to work in Canada;

(b) the applicant is of good character and reputation;

(c) the applicant has a knowledge of the Act and the regulations under the Act, and general knowledge related to the practice of applied science, information or engineering technology, which has been demonstrated by passing an examination that is prescribed by the ASET Board of Examiners;

(d) the applicant demonstrates to the ASET Board of Examiners that the applicant has a proficiency in the English language that is sufficient to enable the applicant to responsibly practise the profession of applied science, information or engineering technology;

(e) the applicant meets one of the following requirements:

(i) the applicant has obtained at least 2 years of experience in work of an applied science, information or engineering technology nature that is acceptable to the ASET Board of Examiners;

(ii) the applicant is admitted as an examination candidate and

(A) has completed the educational upgrading, examinations or other assessment activities referred to in section 8(b), and

(B) has obtained at least 2 years of experience in work of an applied science, information or engineering technology nature that is acceptable to the ASET Board of Examiners;

(iii) the applicant has, in the opinion of the ASET Board of Examiners, through a combination of academic qualification and experience demonstrated the competence required for registration as a regulated member.

(2) Notwithstanding subsection (1), an applicant is entitled to be registered as a regulated member if

(a) the applicant is of good character and reputation, and

(b) the applicant is a regulated member or the equivalent of a regulated member in good standing with a regulated entity in another province that is in the opinion of the ASET Board of Examiners equivalent to ASET.

Domestic trade agreements

13.1 Where section 13(2) applies in respect of an applicant and the regulated entity is in a province that is a signatory to one or more domestic trade agreements that is in force in Alberta, the applicant's application must be dealt with in a manner consistent with the applicable domestic trade agreements.

AR 56/2012 s5

Designations

14(1) A person who meets the requirements for registration under section 13 and is entitled to be registered as a regulated member shall be granted one of the following designations as determined by the ASET Board of Examiners:

(a) certified technician;

(b) certified engineering technologist;

(c) applied science technologist;

(d) certified computer information technologist.

(2) Only those regulated members who are granted one of the designations as set out in subsection (1), and whose registration has not been cancelled or suspended, may use such designation or the following abbreviations:

(a) C. Tech;

(b) C.E.T.;

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(c) A.Sc.T.;

(d) C.C.I.T.

Division 6
ASET Board of Examiners

ASET Board of Examiners constitution

15(1) ASET Council shall appoint no more than 20 regulated members to the ASET Board of Examiners.

(2) The term of appointment for members of the Board of Examiners is 3 years, and they may be reappointed.

(3) ASET Council shall appoint a Chair and a Vice-Chair of the Board of Examiners.

(4) The term of office **for** the Chair and Vice-Chair is 3 years and they may be reappointed.

(5) The ASET Board of Examiners shall meet as is necessary to rule on applications for registration as a regulated member in accordance with section 93.1 of the Act.

(6) A quorum of the ASET Board of Examiners is one quarter of its members.

(7) The ASET Board of Examiners may appoint individuals from academic institutions and industry to a Panel of Examiners to advise the Board of Examiners on the academic qualifications of applicants.

(8) In addition to considering applications for registration as a regulated member, the ASET Board of Examiners shall meet as necessary to consider matters of policy, significant changes in procedure and other matters referred to it by ASET Council.

(9) The ASET Board of Examiners and the Panel of Examiners have the power to consult with any persons or organizations in order to properly assess the work experience and academic qualifications of applicants.

Part 2
Continuing Education Program and Practice Reviews

Division 1
Continuing Professional Development Program

Education program established

16(1) ASET Council establishes the Continuing Professional Development Program of ASET as the compulsory continuing education program for regulated members.

(2) The ASET Practice Review Board shall administer the Continuing Professional Development Program.

(3) The Continuing Professional Development Program comprises

(a) self-assessment by regulated members of their individual professional development needs,

(b) the preparation by regulated members of a continuing professional development plan,

(c) self-directed professional development activities,

(d) the ability of the ASET Practice Review Board to require that regulated members demonstrate compliance with the Continuing Professional Development Program, and

(e) practice visits in accordance with section 21(2)(a).

(4) ASET Council shall make rules governing the operation of the Continuing Professional Development Program, including, without limitation, the following:

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(a) the format of the Continuing Professional Development Plan;

(b) the approval of programs, courses and other learning activities that may be completed as part of the self-directed continuing professional development;

(c) declarations by regulated members that they have developed a Continuing Professional Development Plan and declarations with respect to the professional development activities that have been undertaken in accordance with the plan;

(d) audits of regulated members to ensure that Continuing Professional Development Plans have been prepared and that the professional development activities are being undertaken in accordance with the Continuing Professional Development Plan;

(e) the written records that must be maintained by regulated members with respect to their Continuing Professional Development Plan and activities undertaken in accordance with that plan.

(5) ASET Council may determine when the Continuing Professional Development Program comes into effect for regulated members.

Mandatory compliance

17 A regulated member shall comply with the requirements of the Continuing Professional Development Program as it applies to that person's profession of applied science, information technology or engineering technology.

Exemption

18(1) Notwithstanding section 17, a regulated member who files with ASET a declaration in writing stating that the person is not actively engaged in the practice of the profession set out in section 17 is exempt from the requirements of this Part.

(2) An exemption under this section is effective only for one year from the date the declaration is received by ASET, but may be renewed for additional yearly periods.

(3) A regulated member shall not engage in the practice of a profession while an exemption under this section is in effect.

(4) A regulated member who has filed a declaration under subsection (1) shall immediately notify ASET in writing if that person intends to resume the practice of the profession.

(5) The ASET Practice Review Board may require a regulated member who has notified ASET under subsection (4) to comply with any conditions that the Board may set prior to allowing that person to resume the practice of the profession.

Written records

19(1) In accordance with the rules established by ASET Council, regulated members shall develop and maintain written records of their Continuing Professional Development Plan and professional development activities.

(2) Regulated members shall produce the records under subsection (1) on the request of the ASET Practice Review Board.

Striking from register

20 ASET Council may direct the ASET Registrar to strike from the register of regulated members the name of a person who fails to comply with a request that is served on the regulated member under section 19(2).

Proof of compliance

21(1) On the request of the ASET Practice Review Board, a regulated member shall satisfy the Board that that person is complying with the requirements of the Continuing Professional Development Program.

(2) Where a regulated member fails to satisfy the ASET Practice Review Board under subsection (1), the Board may

(a) conduct a review of the practice of that person in accordance with the Act and this Regulation, including practice visits, and

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(b) at any time during a review recommend to the ASET Investigative Committee that the review be conducted by the ASET Investigative Committee under Part 8, Division 5 of the Act as if the recommendation were a written complaint.

Division 2
ASET Practice Review Board

ASET Practice Review Board constitution

22(1) ASET Council shall appoint not fewer than 4 regulated members as members of the ASET Practice Review Board.

(2) ASET Council shall designate one of the regulated members as chair.

(3) The ASET Registrar or the ASET Registrar's designate shall serve as Secretary to the ASET Practice Review Board.

(4) The chair and regulated members must be appointed for a 3-year term, and may be reappointed.

(5) A quorum of the Practice Review Board is a majority of its members.

(6) Where a vacancy occurs in the ASET Practice Review Board, ASET Council shall appoint a regulated member to the position for the unexpired portion of the term.

(7) In appointing regulated members to the ASET Practice Review Board under this section, ASET Council

(a) shall not appoint a regulated member unless the regulated member has at least 5 years of experience in the practice of the professions of applied science, information technology or engineering technology, and

(b) shall appoint regulated members so that the membership will represent a combination of academic qualifications and experience such that the ASET Practice Review Board can effectively review and assess registration requirements and procedures and disciplinary procedures in order to ensure the continuing competency of members of ASET, and advise ASET Council on those matters.

Items considered

23(1) The ASET Practice Review Board shall meet at least twice each year, and more frequently if the chair considers it necessary, to consider

(a) items referred to the ASET Practice Review Board by ASET Council, the ASET Board of Examiners or the ASET Discipline Committee,

(b) reports from the ASET Registrar submitted under subsection (2),

(c) items that have come to the attention of the ASET Practice Review Board from other sources and that reflect a need to review the procedures of ASET with respect to registration, discipline or maintenance of professional competency, and

(d) any other items that may be considered by the ASET Practice Review Board pursuant to the Act.

(2) The ASET Registrar shall submit at each regular meeting of the ASET Practice Review Board a report setting out

(a) the number and nature of appeals and complaints relating to rulings of the ASET Board of Examiners, and

(b) the number and nature of complaints dealt with under Part 8, Division 5 of the Act and the disposition of the complaints, with special emphasis on cases reflecting on the competency of members of ASET.

Investigation by ASET Practice Review Board

24(1) If the ASET Practice Review Board undertakes a review of the practice of a regulated member or permit holder, it shall proceed with the review in accordance with this section.

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(2) The ASET Practice Review Board shall appoint a person to conduct an initial review and report to the ASET Practice Review Board with respect to the substance of the conclusions on which the ASET Practice Review Board based its decision to commence an investigation.

(3) If, on receipt of the report, the ASET Practice Review Board decides that further investigation is not warranted, it shall discontinue the review and report its decision to ASET Council, along with any recommendations the ASET Practice Review Board considers appropriate.

(4) If, on receipt of the report, the ASET Practice Review Board decides that investigation of a specific practice is necessary, it shall

(a) issue notice of investigation to the regulated member or permit holder if it is of the opinion that the matter to be investigated relates to matters other than to unskilled practice of the profession or unprofessional conduct, and proceed with its investigation in the same manner as provided for in a discipline investigation, or

(b) lodge an appropriate complaint with the ASET Investigative Committee if it is of the opinion that further investigation may lead to a finding of unskilled practice of the profession or unprofessional conduct.

(5) For the purposes of conducting an investigation under this section, any or all of the members of the ASET Practice Review Board may, in order to ensure that continuing competence requirements are met, do one or more of the following:

(a) subject to subsection (6), at any reasonable time and on having given notice, conduct a practice visit by entering and inspecting any place where the regulated member works in the profession of applied science, information technology or engineering technology;

(b) interview a regulated member about the member's work in the profession of applied science, information technology or engineering technology;

(c) observe the regulated member working in the profession of applied science, information technology or engineering technology;

(d) interview or survey clients, co-workers, the regulated member's employer or the regulated member about the regulated member's work in the profession of applied science, information technology or engineering technology;

(e) review documents and examine substances and things that

(i) are owned by or under the control of the regulated member, and

(ii) are related to the work in the profession of applied science, information technology or engineering technology by the regulated member;

(f) assess the safety and condition of equipment and technology used by the regulated member.

(6) No member of the ASET Practice Review Board may enter a private dwelling place or any part of a place that is designed to be used and is being used as a permanent or temporary private dwelling place except with the consent of the occupant of the dwelling place.

Report to ASET Council

25 Following each meeting, the ASET Practice Review Board shall report through its chair to ASET Council and may make any recommendations as to changes in procedures regarding registration, discipline or maintenance of competency that the Board considers appropriate.

Part 3
ASET Council

President and Vice-presidents — election and powers

26(1) The President of ASET must be elected annually by the members of ASET in accordance with the bylaws and holds office until a successor is elected.

(2) The President shall act as the presiding officer at meetings of ASET Council and at meetings of ASET.

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(3) The President may vote at meetings of ASET Council or ASET only in the event of a tied vote.

(4) The 2 Vice-presidents must be elected annually by the members of ASET in accordance with the bylaws and hold office until a successor is elected.

(5) The First Vice-president or, failing the First Vice-president, the Second Vice-president, has all the powers of the President during the absence of the President for any cause.

Quorum

27(1) A quorum for meetings of ASET Council is a majority of its members.

Other boards, committees and task forces

28(1) In addition to the ASET Discipline Committee, ASET Investigative Committee, ASET Board of Examiners, ASET Practice Review Board, ASET Appeal Board and Executive Committee, ASET Council may appoint any other standing or special committees, task forces or boards that it considers necessary to serve the interests of ASET, and shall at the time of the appointment, delegate any authority it considers necessary for the committees, task forces or boards to perform their function.

(2) Except for the ASET Discipline Committee, ASET Investigative Committee, ASET Board of Examiners, ASET Practice Review Board, ASET Appeal Board and Executive Committee, ASET Council shall determine the terms of reference for all committees, task forces or boards.

Part 4
Code of Ethics

Application and availability

29(1) Regulated members shall comply with the Code of Ethics in the Schedule to this Regulation.

(2) ASET may publish interpretations of the rules comprising the Code of Ethics and distribute them to regulated members.

(3) ASET shall make the Code of Ethics available on request to members of the public.

Part 5
Discipline

Aware of unprofessional conduct

30 Despite not receiving a complaint under section 43 of the Act, but subject to section 43(3) of the Act, if the ASET Registrar has reasonable grounds to believe that the conduct of a regulated member or former member constitutes unprofessional conduct or unskilled practice, the ASET Registrar may treat the information as a complaint and act on it under section 43 of the Act.

Division 1
ASET Investigative Committee

ASET Investigative Committee

31(1) ASET Council shall appoint at least 3 regulated members to the ASET Investigative Committee.

(2) ASET Council shall designate one regulated member as the chair of the ASET Investigative Committee.

(3) The chair or, in the absence of the chair, a majority of the members of the ASET Investigative Committee may appoint an acting chair who has all the powers of the chair in the absence of the chair.

Public member

32(1) The Minister shall appoint one member of the public, from a list of persons nominated by the Council, to the ASET Investigative Committee.

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(2) The Minister may, after consultation with the Council, revoke the appointment of the member of the public.

(3) The powers, duties and operations of the ASET Investigative Committee are not affected by

(a) the failure of the Minister to appoint a member of the public,

(b) the revocation of the appointment of the member of the public,

(c) the resignation from the ASET Investigative Committee of the member of the public, or

(d) the absence of the member of the public from a meeting of the ASET Investigative Committee.

(4) The Minister may pay to the member of the public appointed to the ASET Investigative Committee travelling and living expenses incurred by that member for attendance at meetings of the ASET Investigative Committee away from the member's usual place of residence and fees in an amount prescribed by the Minister.

Term of office

33(1) The term of office of each member of the ASET Investigative Committee is 3 years, and members may be reappointed.

(2) Where there is a vacancy in the membership of the ASET Investigative Committee appointed by ASET Council, ASET Council may appoint a person to fill the vacancy for the unexpired portion of the term.

(3) Where there is a vacancy in the public membership on the ASET Investigative Committee, the Minister may appoint a person to fill the vacancy for the unexpired portion of the term.

Quorum

34 A quorum of the ASET Investigative Committee consists of a majority of its members.

Adjournment of investigation if court proceedings commenced

35 A preliminary investigation under Part 5 of the Act may be adjourned if the complaint that gave rise to the investigation is the subject of judicial proceedings.

Assistance in conducting preliminary investigation

36 An investigation panel appointed under section 47 of the Act may employ any technical consultants and legal counsel it considers necessary to conduct a preliminary investigation.

Division 2
ASET Discipline Committee

ASET Discipline Committee

37(1) ASET Council shall appoint at least 3 regulated members to the ASET Discipline Committee.

(2) ASET Council shall designate a regulated member as the chair of the ASET Discipline Committee.

(3) The chair or, in the absence of the chair, a majority of the members of the ASET Discipline Committee may appoint an acting chair who has all the powers of the chair in the absence of the chair.

Public member

38(1) The Minister shall appoint one member of the public, from a list of persons nominated by ASET Council, to the ASET Discipline Committee.

(2) The Minister may, after consultation with ASET Council, revoke the appointment of the member of the public.

(3) The powers, duties and operations of the ASET Discipline Committee are not affected by

(a) the failure of the Minister to appoint a member of the public,

(b) the revocation of the appointment of the member of the public,

(c) the resignation from the ASET Discipline Committee of the member of the public, or

(d) the absence of the member of the public from a meeting of the ASET Discipline Committee.

(4) The Minister may pay to the member of the public appointed to the ASET Discipline Committee travelling and living expenses incurred by that member for attendance at meetings of the ASET Discipline Committee away from the member's usual place of residence and fees in an amount prescribed by the Minister.

Term of office

39(1) The term of office of each member of the ASET Discipline Committee is 3 years, and members may be reappointed.

(2) Where there is a vacancy in the regulated members on the ASET Discipline Committee, ASET Council may appoint a person to fill the vacancy for the unexpired portion of the term.

(3) Where there is a vacancy in the public membership on the ASET Discipline Committee, the **Minister** may appoint a person to fill the vacancy for the unexpired portion of the term.

Quorum

40 A quorum of the ASET Discipline Committee consists of a majority of its members.

Panel of the ASET Discipline Committee

41(1) A panel of the ASET Discipline Committee must consist of at least 3 members of the ASET Discipline Committee.

(2) A member of the ASET Discipline Committee who has been designated to act as a case manager under sections 52(1) and 94.4 of the Act in respect of a matter must not sit as part of the panel of the ASET Discipline Committee that is hearing the matter under section 53 of the Act.

(3) A panel of the ASET Discipline Committee has all the powers and authority of the ASET **Discipline** Committee.

Right to counsel

42(1) The ASET Discipline Committee may be advised by counsel at a hearing before the ASET Discipline Committee.

(2) If the ASET Discipline Committee is advised by counsel acting on behalf of the ASET Discipline Committee at a hearing, that counsel may not lead or present evidence or argument at the hearing on behalf of ASET nor be the counsel of the ASET Registrar.

Division 3
ASET Appeal Board

ASET Appeal Board

43(1) ASET Council shall appoint at least 3 regulated members as members of the ASET Appeal Board.

(2) ASET Council shall designate one regulated member as the chair of the ASET Appeal Board.

(3) The chair or, in the absence of the chair, a majority of the members of the ASET Appeal Board may appoint an acting chair who has all the powers of the chair in the absence of the chair.

Term of office

44(1) The term of office of each member of the ASET Appeal Board appointed is 3 years, and members may be reappointed.

(2) Where there is a vacancy in the membership of the ASET Appeal Board appointed by ASET Council, ASET Council may appoint a regulated member to fill the vacancy for the unexpired portion of the term.

Quorum

45 A quorum of the ASET Appeal Board consists of a majority of its members.

Right to counsel

46(1) The ASET Appeal Board may be advised by counsel at an appeal hearing before the ASET Appeal Board.

(2) If the ASET Appeal Board is advised by counsel acting on behalf of the ASET Appeal Board at an appeal hearing, that counsel may not lead or present evidence or argument at the appeal hearing on behalf of the Investigative Committee nor be the counsel of the ASET Registrar or the Investigative Committee.

Division 4
General Matters

Publication

47 The ASET Discipline Committee or the ASET Appeal Board may direct that reports or summaries of disciplinary decisions, including the regulated member's personal information, be published in any manner it deems appropriate.

Reinstatement of disciplined individuals

48(1) A regulated member whose registration has been cancelled or a permit holder whose permit has been revoked under Part 5 of the Act as a result of the disciplinary proceedings may apply to ASET Council to be reinstated.

(2) An application under subsection (1) may not be made until at least one year after the date on which the registration was cancelled or the permit was revoked, or from the date on which the Court made its order confirming or varying the decision of ASET Council.

(3) ASET Council may establish an ASET Committee of Inquiry to consider the application for reinstatement and make recommendations to ASET Council.

(4) ASET Council may require the former regulated member or permit holder to demonstrate by means prescribed by ASET Council that that person is competent to re-engage in the practice of applied science, information or engineering technology.

(5) Where an application for reinstatement is not approved by ASET Council, no further application may be made by the former regulated member or permit holder until at least one year after the date ASET Council ruled on the previous application.

Part 6
General

Use of stamps and seals issued to members

49(1) A stamp or seal issued to a regulated member must at all times remain under that person's direct control and must be applied by the regulated member or by a person acting under the regulated member's immediate and direct control to all final plans, specifications, reports or documents of a professional nature

(a) that were prepared by the regulated member or under the regulated member's supervision and control, or

(b) that were prepared by another person in circumstances where the regulated member has thoroughly reviewed them and accepted professional responsibility for them.

(2) No person shall permit a stamp or seal to be physically located in a manner that would allow its use by a person other than the regulated member to whom it was issued.

(3) When a stamp or seal is applied, the regulated member to whom it was issued shall ensure that the stamp or seal is accompanied with that person's signature and the date on which the stamp or seal is applied.

(4) A stamp or seal may be applied to the cover page or final page of reports or documents in a manner that clearly indicates acceptance of professional responsibility for the reports or documents, without being applied to each page.

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(5) A regulated member shall not acquire a stamp or seal from any source other than the ASET Registrar.

(6) A regulated member shall only use a stamp or seal while that person is registered pursuant to this Regulation.

(7) Stamps and seals are the property of ASET and a person in possession of a stamp or seal shall surrender it to ASET on demand.

(8) A regulated member may, with the approval of the ASET Registrar, apply a computer-generated facsimile of the stamp or seal if that person otherwise meets the requirements of the Act and this Regulation.

Publications on professional services

50(1) ASET may publish, on an annual basis or as directed by ASET Council, for the information of members and the public,

(a) conditions of engagement and surveys of professional fees for particular types of applied science, information or engineering technology services,

(b) a guide to the selection of applied science, information or engineering technology members for consulting services to assist clients in the selection of professionally and legally qualified consultants and consulting firms,

(c) guides that define for clients the scope of professional services to be expected from regulated members, and

(d) publications for the purpose of promoting high standards of professional services and adequate remuneration for those services, and the maintenance and improvement of the competency of members.

Membership register

51 ASET may publish, from time to time as directed by ASET Council, a register, in a format directed by ASET Council, of regulated members and permit holders.

Service of notices

52(1) If notice is required to be given to a person under the Act, this Regulation or the ASET bylaws, the notice is sufficiently given if

(a) it is served personally on the person,

(b) it is sent by prepaid mail to the person at the latest address provided to the ASET Registrar by the person, or

(c) where the person has provided to the ASET Registrar an electronic address for the purpose of receiving notices that meets the requirements of ASET Council, it is sent to the person by electronic transmission to that address.

(2) If notice is served personally in accordance with subsection (1), unless the contrary is proved, the service is presumed to be effected

(a) if it is served personally on that person, or

(b) sent to that person by registered mail or courier at the address last shown for that person on the records of ASET.

(3) If personal service or service by prepaid mail under subsection (1) is not reasonably possible, the service is presumed to be effected by publishing the document or notice at least twice, not more than a week apart, in a local newspaper circulated at or near the latest address provided to the ASET Registrar by the person.

(4) If notice is served by mail in accordance with subsection (1), unless the contrary is proved, the service is presumed to be effected

(a) 7 days from the date of mailing if the document is mailed to an address in Alberta, or

(b) 14 days from the date of mailing if the document is mailed to an address outside Alberta.

(5) If a notice is served by electronic transmission in accordance with subsection (1), unless the contrary is proved, the service is presumed to be effected on the date on which the notice was transmitted.

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Expiry

53 For the purpose of ensuring that this Regulation is reviewed for ongoing relevancy and necessity, with the option that it may be repassed in its present or an amended form following a review, this Regulation expires on September 30, 2021.

AR 282/2009 s53;56/2012

Coming into force

54 This Regulation comes into force on the coming into force of the *Engineering, Geological and Geophysical Professions Amendment Act, 2007*.

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Schedule

Code of Ethics
(established pursuant to section 87.3(1)(j of the Engineering and Geoscienc Professions Act)

1 Regulated members shall

(a) hold paramount the safety, health and welfare of the public, the protection of the environment and the promotion of health and safety within the workplace,

(b) undertake and accept responsibility for professional assignments only when qualified by training and experience,

(c) provide an opinion on a professional subject only when it is founded upon adequate knowledge and honest conviction,

(d) act with integrity towards clients or employers, maintain confidentiality and avoid a conflict of interest, but where such conflict arises fully disclose the circumstances without delay to the employer or client,

(e) uphold the principle of appropriate and adequate compensation for the performance of their work,

(f) keep informed to maintain proficiency and competence, to advance the body of knowledge within their discipline and further opportunities for the professional development of their associates,

(g) conduct themselves with fairness, honesty, courtesy and good faith towards clients, colleagues and others, give credit where it is due and accept, as well as give, honest and fair professional comment,

(h) present clearly to employers and clients the possible consequences if professional decisions or judgments are overruled or disregarded,

(i) report to the appropriate agencies any hazardous, illegal or unethical professional decisions or practices by other members or others, and

(j) promote public knowledge and appreciation of applied science, information and engineering technology and protect ASET from misrepresentation and misunderstanding.

AR 282/2009 Sched.;56/2012

013605

THE ENGINEERING AND GEOSCIENCE PROFESSIONS ACT

REGULATIONS

PROFESSIONAL TECHNOLOGISTS REGULATION

Consisting of Alberta Regulation
283/2009 DATED October 15, 2009
and 57/2012 DATED March 2012

(Consolidated up to 57/2012)

ALBERTA REGULATION 283/2009
ENGINEERING AND GEOSCIENCE PROFESSIONS ACT

PROFESSIONAL TECHNOLOGISTS REGULATION

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Schedule

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Definition

1 In this Regulation, "Act" means the Engineering and Geoscience Professions Act.

AR 283/2009 s1;57/2012

Part 1
Membership as a Professional Technologist

Division 1
General

Application

2(1) An application for registration as a professional technologist must be submitted to the ASET Registrar and must

(a) be in a form acceptable to the Joint Board of Examiners, and

(b) be fully completed and accompanied by

(i) all required supporting documentation, and

(ii) any fees that are prescribed by ASET Council pursuant to the ASET bylaws.

(2) The ASET Registrar shall refer an application to the Joint Board of Examiners if the application meets the requirements of subsection (1) and the ASET Registrar is satisfied that the applicant meets the eligibility requirements for registration as a professional technologist.

Annual fees

3 A person who is entered in a record or register under this Part shall pay any annual fees that are prescribed by ASET Council pursuant to the ASET bylaws.

Registers and records

4 The ASET Registrar shall keep and maintain records and a register of professional technologists, which shall be made available to the Registrar of the Association on request.

Division 2
Professional Technologists

Eligibility

5(1) A person who meets the following requirements and applies to the ASET Registrar for registration is entitled to be registered as a professional technologist:

(a) the applicant is of good character and reputation;

(b) the applicant holds a certificate of registration as a certified engineering technologist with ASET;

(c) the applicant has a knowledge of the Act and the regulations under the Act, and general knowledge related to the proposed scope of practice of engineering or geoscience, which has been demonstrated by passing an examination for those purposes that is prescribed by the Joint Board of Examiners;

(d) the applicant demonstrates to the Joint Board of Examiners that the applicant has a proficiency in the English language that is sufficient to enable the applicant to responsibly practice the profession of engineering or geoscience within the prescribed scope of practice;

(e) the applicant has at least 2 years of post-secondary education acceptable to the Joint Board of Examiners in areas that relate to engineering or geoscience;

(f) the applicant has obtained at least 6 years of experience in areas that relate to engineering or geoscience that is acceptable to the Joint Board of Examiners, at least 2 years of which are in the applicant's proposed area and scope of practice and were completed under the supervision and control of a professional member;

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(g) the applicant meets any other requirements established by the Joint Board of Examiners.

(2) Notwithstanding subsection (1), an applicant is entitled to be registered as a professional technologist if the applicant

(a) is of good character and reputation, and

(b) is a professional technologist who, in respect of another province,

(i) is eligible to engage in the practice of engineering or geoscience within the scope of practice specified by the Joint Board of Examiners, and

(ii) is a member in good standing with a regulated entity in that other province that, in the opinion of the Joint Board of Examiners, is equivalent to ASET.

AR 283/2009 s5;57/2012

Domestic trade agreements

5.1(1) In this section, "domestic trade agreement" means a domestic trade agreement as defined in section 2 of Schedule 6 to the *Government Organization Act.*

(2) Where section 5(2) applies in respect of an applicant and the regulated entity is in a province that is a signatory to one or more domestic trade agreements that is in force in Alberta, the applicant's application must be dealt with in a manner consistent with the applicable domestic trade agreements.

AR 57/2012 s3

Designations

6(1) A person who meets the requirements for registration in section 5 and is entitled to be registered as a professional technologist shall be granted one or more of the following designations as determined by the Joint Board of Examiners:

(a) professional technologist;

(b) professional technologist (engineering);

(c) professional technologist (geoscience).

(d) repealed AR 57/2012 s4.

(2) Only those persons who are granted one or more of the designations as set out in subsection (1), and whose registration has not been cancelled or suspended under Part 5 of the Act, may use such designation or the following abbreviations:

(a) P.Tech;

(b) P.Tech (eng.);

(c) P.Tech (geo).

(d) repealed AR 57/2012 s4.

AR 283/2009 s6;57/2012

Division 3
Joint Board of Examiners

Items considered

7(1) The Joint Board of Examiners shall meet as is necessary to rule on applications for registration in accordance with section 90.3 of the Act.

(2) In addition to considering applications for registration as a professional technologist, the Joint Board of Examiners shall meet as necessary to consider matters of policy, significant changes in procedure, examination results and any matters referred to it by any member of the Joint Board of Examiners or the Joint Councils Committee.

Joint Board of Examiners authority

8 The Joint Board of Examiners has the power to consult with any persons or organizations in order to properly assess the academic qualifications of applicants.

Part 2
Continuing Education Program and Practice Reviews

Division 1
Continuing Professional Development Program

Education program established

9(1) The Continuing Professional Development Program of ASET is established as a compulsory continuing education program for professional technologists.

(2) The Joint Practice Review Board shall administer the Continuing Professional Development Program.

(3) The Continuing Professional Development Program comprises

(a) self-assessment by professional technologists of their individual professional development needs,

(b) the preparation by professional technologists of a continuing professional development plan,

(c) self-directed professional development activities,

(d) the ability of the Joint Practice Review Board to require that professional technologists demonstrate compliance with the Continuing Professional Development Program, and

(e) practice visits in accordance with section 14(2)(a).

(4) ASET Council shall make rules governing the operation of the Continuing Professional Development Program, including, without limitation, the following:

(a) the format of the Continuing Professional Development Plan;

(b) the approval of programs, courses and other learning activities that may be completed as part of the self-directed continuing professional development;

(c) declarations by professional technologists that they have developed a Continuing Professional Development Plan and declarations with respect to the professional development activities that have been undertaken in accordance with the plan;

(d) audits of professional technologists to ensure that Continuing Professional Development Plans have been prepared and that the professional development activities are being undertaken in accordance with the Continuing Professional Development Plan;

(e) the written records that must be maintained by professional technologists with respect to their Continuing Professional Development Plan and activities undertaken in accordance with that plan.

(5) ASET Council may determine when the Continuing Professional Development Program comes into effect for professional technologists.

Mandatory compliance

10 A professional technologist shall comply with the requirements of the Continuing Professional Development Program as it applies to that person's practice.

Exemption

11(1) Notwithstanding section 10, a professional technologist who files with ASET a declaration in writing stating that the person is not actively engaged in the practice of the profession set out in section 10 is exempt from the requirements of this Part.

(2) An exemption under this section is effective only for one year from the date the declaration is received by ASET, but may be renewed for additional yearly periods.

(3) A professional technologist shall not engage in the practice of a profession while an exemption under this section is in effect.

(4) A professional technologist who has filed a declaration under subsection (1) shall immediately notify ASET in writing if that person intends to resume the practice of the profession.

(5) The Joint Practice Review Board may require a professional technologist who has notified ASET under subsection (4) to comply with any conditions that the Board may set prior to allowing that person to resume the practice of the profession.

Written records

12(1) In accordance with the rules established by ASET Council, professional technologists shall develop and maintain written records of their Continuing Professional Development Plan and professional development activities.

(2) Professional technologists shall produce the records under subsection (1) on the request of the Joint Practice Review Board.

Striking from register

13 ASET Council may direct the ASET Registrar to strike from the register of professional technologists the name of a person who fails to comply with a request that is served on the professional technologist under section 12(2).

Proof of compliance

14(1) On the request of the Joint Practice Review Board, a professional technologist shall satisfy the Board that that person is complying with the requirements of the Continuing Professional Development Program.

(2) Where a professional technologist fails to satisfy the Joint Practice Review Board under subsection (1), the Board may

(a) conduct a review of the practice of that person in accordance with the Act and this Regulation, including practice visits, and

(b) at any time during a review recommend to the Joint Investigative Committee that the review be conducted by the Joint Investigative Committee under Part 8 Division 5 of the Act as if the recommendation were a written complaint.

Division 2
Joint Practice Review Board

Items considered

15(1) The Joint Practice Review Board shall meet at least twice each year, and more frequently if the chair considers it necessary, to consider

(a) items referred to the Joint Practice Review Board by the Joint Councils Committee or the Joint Discipline Committee,

(b) reports from the ASET Registrar submitted under subsection (2),

(c)items that have come to the attention of the Joint Practice Review Board from other sources relating to the registration, discipline or maintenance of professional competency of professional technologists, and

(d) any other items that may be considered by the Joint Practice Review Board pursuant to the Act.

(2) The ASET Registrar shall submit at each regular meeting of the Joint Practice Review Board a report setting out

(a) the number and nature of appeals and complaints relating to rulings of the Joint Board of Examiners, and

(b) the number and nature of complaints dealt with by the Joint Discipline Committee and the disposition of the complaints, with special emphasis on cases reflecting on the competency of professional technologists.

Investigation by Joint Practice Review Board

16(1) If the Joint Practice Review Board undertakes a review of the practice of a professional technologist or permit holder, it shall proceed with the review in accordance with this section.

(2) The Joint Practice Review Board shall appoint a person to conduct an initial review and report to the Joint Practice Review Board with respect to the substance of the conclusions on which the Joint Practice Review Board based its decision to commence an investigation.

(3) If, on receipt of the report, the Joint Practice Review Board decides that further investigation is not warranted, it shall discontinue the review and report its decision to the Joint Councils Committee, along with any recommendations the Joint Practice Review Board considers appropriate.

(4) If, on receipt of the report, the Joint Practice Review Board decides that investigation of a specific practice is necessary, it shall

(a) issue notice of investigation to the professional technologist or permit holder if it is of the opinion that the matter to be investigated relates to matters other than to unskilled practice of the profession or unprofessional conduct, and proceed with its investigation in the same manner as provided for in a discipline investigation, or

(b) lodge a complaint with the Joint Investigative Committee if it is of the opinion that further investigation may lead to a finding of unskilled practice of the profession or unprofessional conduct.

(5) For the purposes of conducting an investigation under this section, any or all of the members of the Joint Practice Review Board may, in order to ensure that continuing competence requirements are met, do one or more of the following:

(a) subject to subsection (6), at any reasonable time and on having given notice, conduct a practice visit by entering and inspecting any place where the professional technologist works in the practice of engineering or geoscience;

(b) interview a professional technologist about the member's work in the profession of engineering or geoscience;

(c) observe the professional technologist working in the profession of engineering or geoscience;

(d) interview or survey clients, co-workers, the professional technologist's employer or the professional technologist about the professional technologist's work in the profession of engineering or geoscience;

(e) review documents and examine substances and things that

(i) are owned by or under the control of the professional technologist, and

(ii) are related to the work in the profession of engineering or geoscience by the professional technologist;

(f) assess the safety and condition of equipment and technology used by the professional technologist.

(6) No member of the Joint Practice Review Board may enter a private dwelling place or any part of a place that is designed to be used and is being used as a permanent or temporary private dwelling place except with the consent of the occupant of the dwelling place.

AR 283/2009 s16;57/2012

Report to Joint Councils Committee

17 Following each meeting, the Joint Practice Review Board shall report through its chair to the Joint Councils Committee and may make any recommendations as to changes in procedures regarding registration, discipline or maintenance of competency that the Board considers appropriate.

Part 3
Code of Ethics

Application and availability

18(1) Professional technologists shall comply with the Code of Ethics in the Schedule to this Regulation.

(2) ASET may publish interpretations of the rules comprising the Code of Ethics and distribute them to professional technologists and permit holders.

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(3) ASET shall make the Code of Ethics available on request to members of the public.

Part 4
Discipline

Aware of unprofessional conduct

19 Despite not receiving a complaint under section 43 of the Act, but subject to section 43(3) of the Act, if the ASET Registrar has reasonable grounds to believe that the conduct of a professional technologist or former member constitutes unprofessional conduct or unskilled practice, the ASET Registrar may treat the information as a complaint and act on it under section 43 of the Act.

Adjournment of investigation if court proceedings commenced

20 A preliminary investigation under Part 5 of the Act may be adjourned if the complaint that gave rise to the investigation is the subject of judicial proceedings.

Assistance in conducting preliminary investigation

21 An investigation panel appointed under section 47 of the Act may employ any technical consultants and legal counsel it considers necessary to conduct a preliminary investigation.

Non-participation of case manager in hearing

22 A member of the Joint Discipline Committee who has been designated to act as a case manager under section 52(2) of the Act in respect of a matter must not participate as part of the quorum of the Joint Discipline Committee that is hearing the matter under section 53 of the Act.

Right to counsel

23(1) The Joint Discipline Committee may be advised by counsel at a hearing before the Joint Discipline Committee.

(2) If the Joint Discipline Committee is advised by counsel acting on behalf of the Joint Discipline Committee at a hearing, that counsel may not lead or present evidence or argument at the hearing on behalf of ASET nor be the counsel of the ASET Registrar.

Right to counsel

24(1) The Joint Appeal Board may be advised by counsel at an appeal hearing before the Joint Appeal Board.

(2) If the Joint Appeal Board is advised by counsel acting on behalf of the Joint Appeal Board at an appeal hearing, that counsel may not lead or present evidence or argument at the appeal hearing on behalf of the Joint Investigative Committee nor be the counsel of the Registrar, the ASET Registrar or the Joint Investigative Committee.

Publication

25 The Joint Discipline Committee or the Joint Appeal Board may direct that reports or summaries of disciplinary decisions, including the professional technologist's personal information, be published in any manner it deems appropriate.

Reinstatement of disciplined individuals

26(1) A professional technologist whose registration has been cancelled or a permit holder whose permit has been revoked under Part 5 of the Act as a result of the disciplinary proceedings may apply to the Joint Councils Committee to be reinstated.

(2) An application under subsection (1) may not be made until at least one year after the date on which the registration was cancelled or the permit was revoked, or from the date on which the Court made its order confirming or varying the decision of the Joint Councils Committee.

(3) The Joint Councils Committee may establish a Committee of Inquiry to consider the application for reinstatement and make recommendations to the Joint Councils Committee.

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(4) The Joint Councils Committee may require the former professional technologist or permit holder to demonstrate by means prescribed by the Joint Councils Committee that that person is competent to re-engage in the practice of engineering or geoscience.

(5) Where an application for reinstatement is not approved by the Joint Councils Committee, no further application may be made by the former professional technologist or permit holder until at least one year after the date the Joint Councils Committee ruled on the previous application.

AR 283/2009 s26;57/2012

Part 5
Registration of Permit Holders

Requirements for issue of permit

27(1) ASET Council may issue to a partnership, corporation or other entity a permit to practice engineering or geoscience in its own name within the scope of practice of those professional technologists who are responsible for the practice of the ASET permit holder if

(a) an application is made to the ASET Registrar in the form and containing the information required by ASET Council,

(b) the application is accompanied with the fees prescribed by ASET Council pursuant to the ASET bylaws,

(c) ASET Council is satisfied that the practice will be carried on under the direct personal supervision and responsibility of a full-time permanent employee or member of the partnership, corporation or other entity who is also a professional technologist and who is qualified by education and experience in the field of engineering or geoscience in which the partnership, corporation or other entity intends to engage, and

(d) the professional technologist certifies to the satisfaction of ASET Council that the partnership, corporation or other entity has in place and will follow a professional management plan that is appropriate to the professional technologist's professional practice.

(2) A permit expires one year after the date on which it is issued.

(3) When ASET Council issues a permit, it shall provide the permit holder with a permit number.

(4) The permit shall include a statement that the permit holder is entitled to engage in the practice of engineering or geoscience within the scope of practice of those professional technologists who are responsible for the ASET permit holder.

(5) No person shall use a permit number where the permit to which the number is assigned has been cancelled or suspended.

(6) A professional technologist who accepts responsibility under subsection (1)(c) shall every five years attend a permit to practice seminar acceptable to ASET Council.

AR 283/2009 s27;57/2012

Signing and sealing of documents

28 When the practice of engineering or geoscience is carried on by a partnership, corporation or other entity pursuant to a permit under section 27, all final plans, specifications, reports or documents of a professional nature must

(a) be signed by and stamped or sealed with the stamp or seal of

(i) the professional technologist who prepared them or under whose supervision and control they were prepared, or

(ii) in the case of plans, specifications, reports or documents that were prepared by other persons, the professional technologist who thoroughly reviewed and accepted professional responsibility for them,

and

(b) show the permit number issued to the partnership, corporation or other entity under section 27.

AR 283/2009 s28;57/2012

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Notification to ASET

29(1) A partnership, corporation or other entity practising pursuant to a permit under section 27 shall keep ASET advised of the name of the professional technologist referred to in that section.

(2) The professional technologist referred to in section 27 shall forthwith advise the ASET Registrar if the professional technologist

(a) ceases to be the person accepting responsibility under that section, or

(b)is no longer able to provide the certification referred to in section 27(1)(d).

Revocation of permit

30 The Joint Councils Committee may revoke a permit issued under section 27 if the permit holder contravenes the Act, this Regulation or a term or condition of the permit.

Name of firm

31 No partnership, corporation or other entity may be incorporated or registered in the province of Alberta under a name including the words "Engineering", "Geology", "Geophysics" or "Geoscience", or variations of those words, unless it holds and continues to hold a valid permit issued under section 27.

AR 283/2009 s31;57/2012

Use of permit holder

32(1) The permit number issued to a permit holder may only be used by the professional technologist referred to in section 27(1)(c).

(2) ASET Council may, subject to any terms and conditions it considers appropriate, waive compliance with the requirements of section 27(1)(d) and (5).

Part 6
General

Seals and stamps

33(1) Seals and stamps issued to professional technologists must be in a form prescribed by ASET Council and shall show the professional category of the professional technologist as Engineering, Geology, Geophysics or Geoscience.

(2) Stamps issued to permit holders must be in a form prescribed by ASET Council and shall show the designation "Permit Holder".

AR 283/2009 s33;57/2012

Use of stamps and seals issued to members

34(1) A stamp or seal issued to a professional technologist must at all times remain under that person's direct control and must be applied by the professional technologist or by a person acting under the professional technologist's immediate and direct control to all final plans, specifications, reports or documents of a professional nature

(a) that were prepared by the professional technologist or under the professional technologist's supervision and control, or

(b)that were prepared by another person in circumstances where the professional technologist has thoroughly reviewed them and accepted professional responsibility for them.

(2) No person shall permit a stamp or seal to be physically located in a manner that would allow its use by a person other than the professional technologist to whom it was issued.

(3) When a stamp or seal is applied, the professional technologist to whom it was issued shall ensure that the stamp or seal is accompanied with that person's signature and the date on which the stamp or seal is applied.

(4) A stamp or seal may be applied to the cover page or final page of reports or documents in a manner that clearly indicates acceptance of professional responsibility for the reports or documents, without being applied to each page.

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(5) A professional technologist shall not acquire a stamp or seal from any source other than the ASET Registrar.

(6) A professional technologist shall only use a stamp or seal while that person is registered pursuant to this Regulation.

(7) Stamps and seals are the property of ASET and a person in possession of a stamp or seal shall surrender it to ASET on demand.

(8) A professional technologist may, with the approval of the ASET Registrar, apply a computer-generated facsimile of the stamp or seal if that person otherwise meets the requirements of the Act and this Regulation.

Service of notices

35(1) If notice is required to be given to a person under the Act, this Regulation or the ASET bylaws, the notice is sufficiently given if

(a) it is served personally on the person,

(b) it is sent by prepaid mail to the person at the latest address provided to the ASET Registrar by the person, or

(c) where the person has provided to the ASET Registrar an electronic address for the purpose of receiving notices that meets the requirements of ASET Council, it is sent to the person by electronic transmission to that address.

(2) If notice is served personally in accordance with subsection (1), unless the contrary is proved, the service is presumed to be effected

(a) if it is served personally on that person, or

(b) sent to that person by registered mail or courier at the address last shown for that person on the records of ASET.

(3) If personal service or service by prepaid mail under subsection (1) is not reasonably possible, the service is presumed to be effected by publishing the document or notice at least twice, not more than a week apart, in a local newspaper circulated at or near the latest address provided to the ASET Registrar by the person.

(4) If notice is served by mail in accordance with subsection (1), unless the contrary is proved, the service is presumed to be effected

(a) 7 days from the date of mailing if the document is mailed to an address in Alberta, or

(b) 14 days from the date of mailing if the document is mailed to an address outside Alberta.

(5) If a notice is served by electronic transmission in accordance with subsection (1), unless the contrary is proved, the service is presumed to be effected on the date on which the notice was transmitted.

Providing information

36 Professional technologists must notify the ASET Registrar immediately if there is a change to the name of the professional technologist, or of a change of address or other contact information that is required to be submitted when applying for registration or renewal of an annual certificate.

Expiry

37 For the purpose of ensuring that this Regulation is reviewed for ongoing relevancy and necessity, with the option that it may be repassed in its present or an amended form following a review, this Regulation expires on September 30, 2021.

AR 283/2009 s37;57/2012

Coming into force

38 This Regulation comes into force on the coming into force of the *Engineering, Geological and Geophysical Professions Amendment Act, 2007*.

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Schedule

Code of Ethics

(established pursuant to section 88.5(1)(h) of the Engineering and Geoscience Professions Act)

1 Professional technologists shall

(a) hold paramount the safety, health and welfare of the public, the protection of the environment and the promotion of health and safety within the workplace,

(b)undertake and accept responsibility for professional assignments only when qualified by training and experience,

(c) provide an opinion on a professional subject only when it is founded upon adequate knowledge and honest conviction,

(d)act with integrity towards clients or employers, maintain confidentiality and avoid a conflict of interest, but where such conflict arises fully disclose the circumstances without delay to the employer or client,

(e) uphold the principle of appropriate and adequate compensation for the performance of their work,

(f) keep informed to maintain proficiency and competence, to advance the body of knowledge within their discipline and further opportunities for the professional development of their associates,

(g) conduct themselves with fairness, honesty, courtesy and good faith towards clients, colleagues and others, give credit where it is due and accept, as well as give, honest and fair professional comment,

(h) present clearly to employers and clients the possible consequences if professional decisions or judgments are overruled or disregarded,

(i) report to the appropriate agencies any hazardous, illegal or unethical professional decisions or practices by other members or others, and

(j) promote public knowledge and appreciation of applied science, information and engineering technology and protect ASET from misrepresentation and misunderstanding.

AR 283/2009 Sched.;57/2012

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National Energy Board *Onshore Pipeline Regulations, 1999* (OPR-99) Final Audit Report for Integrity Management Programs

File Number: OF-Surv-OpAud-T211-2012-2013 01

TransCanada PipeLines Limited
and National Energy Board-Regulated Subsidiaries (TransCanada)
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Canada

013631

Executive Summary

The safety of Canadians and protection of the environment is paramount for the National Energy Board (Board or NEB) when considering the performance of its regulated companies. The NEB requires regulated companies to anticipate, prevent, mitigate and manage any hazards and risks associated with their operations. The Board holds these companies accountable for safety and environmental outcomes in the public interest.

The NEB uses a risk-informed approach to identifying which regulated companies, facilities and activities require regulatory oversight, and which compliance tool is appropriate. Management Systems audits are an effective tool to proactively detect and correct a company's non-compliances before these non-compliances have any opportunity to grow and potentially impact public safety or environmental protection.

This report documents the Board's focused audit of TransCanada's Integrity Management Programs (IMPs) as they apply to its NEB-regulated pipeline facilities. The Board had previously scheduled an audit of TransCanada's Integrity Management Programs to start in the second quarter of 2013. As a result of allegations of regulatory non-compliance brought to the Board by a then employee of TransCanada (complainant), the Board advanced the timing of its audit and integrated an assessment of the allegations within the scope and technical protocols developed for the audit. The Integrity Management Program audit was conducted between November 2012 and August 2013.

Over the course of this audit, the Board conducted a detailed assessment of NEB management system requirements as they relate to TransCanada's integrity management programs. TransCanada was required to demonstrate the adequacy and effectiveness of its IMPs as well as its compliance with NEB requirements through interviews with company personnel, and the provision of adequate supporting documentation and records.

The Board's audit was conducted following its Audit Protocol, which identifies Management System elements. These elements are further broken down into sub-elements. Each sub-element reflects a number of regulatory requirements. The NEB requires companies to be fully compliant with one hundred percent of the regulatory requirements of a sub-element being assessed. If a company's program is found to be deficient with respect to any regulatory requirement, the entire sub-element will be found Non-Compliant.

The Board is of the view that the processes presently used by TransCanada have identified the majority, and most significant, of its hazards and risks.

The Board finds TransCanada to be compliant in five sub-elements of the audit, those being Organizational Structure, Roles and Responsibilities; Training, Competence and Evaluation; Operational Control-Normal Operations; Corrective and Preventive Actions; and Internal Audit.

The Board finds TransCanada to be non-compliant in four sub-elements of the audit, those being Hazard Identification, Risk Assessment and Control; Operational Control-Upset or Abnormal Operating Conditions; Inspection, Measurement and Monitoring; and Management Review.

With regards to concerns presented to the Board by the complainant, the audit has confirmed that in response to these allegations, TransCanada has developed and implemented a program of actions with the goal of correcting and preventing similar occurrences. The Board notes that a number of the allegations of regulatory non-compliance were identified and addressed by TransCanada only after the complainant's allegations were made and were not proactively identified by the company's management system. Details of the Board's assessment for each complainant allegation are contained in Element 4.4, Internal Audit, in Appendix II of this Final Audit Report.

The Board will make the Final Audit Report public and will post it to the Board's external website. TransCanada will be required to submit a Corrective Action Plan (CAP) to address the Non-Compliant findings identified through this audit, for approval, within 30 days of the Final Audit Report being issued by the Board. TransCanada's CAP will also be made public.

The Board will continue to monitor and assess all of TransCanada's corrective actions until they are fully implemented. The Board will also continue to monitor the overall implementation and effectiveness of TransCanada's IMPs and management system through targeted compliance verification activities as a part of its on-going regulatory mandate.

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1.0 Audit Terminology and Definitions

Audit: A systematic, independent and documented process for obtaining evidence and evaluating it objectively to determine the extent to which audit criteria are fulfilled.

Corrective Action Plan (CAP): Addresses the non-compliances identified in the Audit Report and explains the methods and actions which will be used to "correct" them.

Compliant: A program element meets legal requirements. The company has demonstrated that it has developed and implemented programs, processes and procedures that meet legal requirements.

Finding: The evaluation or determination of the adequacy of programs or elements in meeting the requirements of the NEB Act and its associated regulations.

Non-Compliant: A program element does not meet legal requirements. The company has not demonstrated that it has developed and implemented programs, processes and procedures that meet the legal requirements. A corrective action must be developed and implemented.

Procedure: A documented series of steps followed in a regular and defined order allowing individual activities to be completed in an effective and safe manner. The procedure will also outline roles, responsibilities and authorities required for completing each step.

Process: A systematic series of actions or changes taking place in a definite order and directed towards a result.

Program: A documented set of processes and procedures to regularly accomplish a result. The program outlines how plans and procedures are linked, and how each one contributes towards the result.

2.0 Introduction: NEB Purpose and Framework

The NEB's purpose is to promote safety and security, environmental protection, and efficient energy infrastructure and markets in the Canadian public interest within the mandate set by Parliament in the regulation of pipelines, energy development and trade**.**

The NEB takes a proactive approach to management of hazards and risks. The NEB's compliance verification activities allow it to identify potential issues with regulated companies and, if necessary, address them with appropriate enforcement measures. Actions include conducting compliance verification activities such as inspections, compliance meetings, emergency exercises, investigations, and audits such as this one.

The NEB requires that each company be able to demonstrate the adequacy and implementation of the methods they have selected and employed in ordered to proactively identify and manage hazards and risks to achieve compliance. To evaluate compliance, the NEB undertakes audits of its regulated companies. Following the audits, companies are required to submit and implement a Corrective Action Plan (CAP) to address and mitigate non-compliances identified. The results of the audits are considered as a part of the NEB's risk-informed life cycle approach to compliance assurance.

A risk-informed approach enables the NEB to further assess and understand risks to public or worker safety and the environment as a result of pipeline operations. It also allows for public resources to be utilized in the most productive and responsible way possible.

The Board's audit was conducted following its Audit Protocol, which identifies Management System elements. These elements are further broken down into sub-elements. Each sub-element reflects a number of regulatory requirements. The NEB requires companies to be fully compliant with one hundred percent of the regulatory requirements of a sub-element being assessed. If a company's program is found to be deficient with respect to any regulatory requirement, the entire sub-element will be found Non-Compliant.

3.0 Background

Since November of 2012, NEB auditors and inspectors have visited field facilities and TransCanada's head office auditing the adequacy and effectiveness of TransCanada`s integrity management programs in order to assess its compliance with the *National Energy Board Act* (NEB Act)[1], other regulations and industry standards such as the Canadian Standards Association (CSA). The targeted audit was thorough and included all of TransCanada's NEB-regulated subsidiaries.

This audit constituted a focused assessment of TransCanada's IMPs as they apply to its NEB-regulated pipeline facilities. The audit scope addressed the following management system sub-elements as they relate to TransCanada's IMPs:

- Hazard Identification, Risk Assessment and Control;
- Organizational Structure, Roles and Responsibilities;
- Training, Competence and Evaluation;
- Operational Control-Normal Operations;
- Operational Control-Upset or Abnormal Operating Conditions;
- Inspection, Measurement and Monitoring;
- Corrective and Preventive Actions;
- Internal Audit; and
- Management Review.

The TransCanada subsidiaries included in the scope of this audit included specifically:

- TransCanada PipeLines Limited;
- TransCanada Keystone Pipeline GP Ltd.;
- Trans Québec & Maritimes Pipeline Inc.;
- Foothills Pipe Lines Ltd.; and
- NOVA Gas Transmission Ltd.

These subsidiaries hold the certificates for TransCanada's NEB-regulated facilities, which include the Canadian Mainline (operating under TransCanada Pipelines Limited), Keystone Pipeline (operating under TransCanada Keystone Pipeline GP Ltd.), TQM Pipeline System (operating under Trans Québec & Maritimes Pipeline Inc.), Foothills System (operating under Foothills Pipe Lines Ltd.), and the Alberta (NGTL) System (operating under NOVA Gas Transmission Ltd).

[1] On 17 July 2013, the NEB issued an updated Management System and Protection Program Audit Protocol. As this audit was ongoing at that time, it was continued under the former Audit Protocol, which is reproduced in Appendix II.

On 1 May 2012, the Board received a submission from a complainant outlining allegations of regulatory non-compliance against TransCanada. The Board initiated actions to investigate and confirm there were no immediate threats to public safety or the environment stemming from these allegations. In light of the concerns being brought forward, the Board advanced the timing of a TransCanada audit previously scheduled to begin in the 2nd quarter of 2013 and integrated an assessment of the allegations within the scope and technical protocol developed for that audit.

4.0 Audit Objectives and Scope

The scope of the audit included an assessment of whether TransCanada was fulfilling the requirements set out in:

- the NEB Act;
- the OPR-99[2];
- *CSA Z662-11, Oil and Gas Pipeline Systems*; and
- TransCanada's policies, practices and procedures.

More specifically, the audit examined nine sub-elements of the NEB management system requirements as they relate to TransCanada's integrity management programs. These sub-elements were selected using the Board's risk-informed approach to focus the scope of the audit on areas that have previously been shown to have the highest rates of non-compliance among NEB-regulated companies and to expedite and focus the assessment of the IMP technical programs in light of the allegations.

In order to assess compliance with the sub-elements, TransCanada was required to demonstrate the adequacy and effectiveness of its IMPs as well as its compliance with the requirements listed above through interviews with company personnel and the provision of adequate supporting documentation and records.

As noted, the audit protocol was modified to specifically evaluate the allegations of regulatory non-compliance brought to the Board by the complainant. This included, but was not limited to:

- confirmation that TransCanada's practices around welding inspections and non-destructive examination meet NEB requirements to be performed by a certified, third party reporting directly to TransCanada, independent of the contractors performing the work;

[2] On 10 April 2013, the OPR-99 was amended and renamed the *National Energy Board Onshore Pipeline Regulations* (OPR). As this audit was ongoing at that time, it was continued under the OPR-99 and all references in this audit report are to the OPR-99 unless otherwise noted. Development of IMPs is also required under the OPR and any Non-Compliant finding in this audit under OPR-99 would also be a Non-Compliant finding under the OPR. TransCanada was also audited to the requirements of CSA Z662-11, *Oil and Gas Pipeline Systems*. These requirements remained unchanged during the audit.

- examination of the revisions TransCanada has made to its internal practice of engineering guidance and determination as to whether or not it meets NEB requirements;
- evaluation of the specific remediation measures that have been implemented based on the findings in TransCanada's internal audit;
- determination of whether or not TransCanada's revised inspection processes meet the requirements set out in the OPR-99;
- evaluation of the new training program for inspectors on new non-destructive examination procedures to determine its adequacy; and
- review of the job description for the new Quality Assurance/Quality Control Manager and confirmation of his/her responsibilities.

5.0 Audit Process

On 8 November 2012, an opening meeting was conducted in Calgary, Alberta with representatives from TransCanada to discuss the Board's audit objectives, scope and the process, and to develop a schedule for conducting the staff interviews and site verifications. The interviews at TransCanada's head office and field verifications were carried out between November 2012 and July 2013. At the end of each day, daily summaries with action items were provided to TransCanada. On 27 August 2013, an Audit close-out meeting was conducted at the NEB office, where the results of the audit, including an outline of the draft audit non-compliances, were reviewed with TransCanada.

Since that time, the Board has been reviewing and assessing the information collected during the audit including written submissions, transcripts of interviews with company personnel, and the provision of adequate supporting documentation.

For a list of TransCanada representatives interviewed and meeting attendees, refer to Appendix III. For a list of documents and records reviewed, refer to Appendix IV.

6.0 Audit Results – Summary

The following summary represents a high-level overview of the Board's audit findings. The detailed findings of the NEB's assessments for each of the nine sub-elements of TransCanada's IMPs evaluated in this audit are provided in Appendix II. The Board's assessment of the complainant's allegations of regulatory non-compliance can be found in Appendix II, Sub-element 4.4 – Internal Audit.

Hazard Identification, Risk Assessment and Control

The Management System Audit Sub-Element 2.1, Hazard Identification, Risk Assessment and Control, refers to the regulations that require a company to have procedures to identify all possible hazards, to assess the degree of risk associated with the hazards and to implement control measures to minimize or eliminate risk.

TransCanada has implemented a system to identify and manage its operating and maintenance risk. Risks are calculated by incorporating the probability of events and the potential magnitude of the consequences. Records indicate that for pipelines and facilities, work is planned and risk-assessments are conducted with consideration given to safety, health, and the environment. TransCanada's process for threat identification was reviewed for all threats and was assessed to be compliant with the requirements.

The audit identified only one area of non-compliance in the sub-element of hazard identification, risk assessment and control. TransCanada developed a new management program for high pressure piping in gas facilities. This new program has been assessed and is adequate in terms of its content, but has not yet been fully implemented throughout all of TransCanada's facilities.

Management System Audit Sub-Element Finding: Based on the incomplete implementation of the required high pressure station piping program, TransCanada is assessed to be non-compliant with the requirements of the OPR-99 and CSA Z662-11, and is therefore non-compliant with this audit sub-element.

Organizational Structure, Roles and Responsibilities

The Management System Audit Sub-Element 3.1, Organizational Structure, Roles and Responsibilities, refers to the regulations that require a company to have an organizational structure that allows its management and protection programs to effectively function. It also requires companies to have clear roles and responsibilities, which may include responsibilities for the implementation of these programs.

TransCanada has approximately 310 employees performing work related to its integrity management programs across its Canadian pipeline system. This is complemented by approximately 80 field technicians who execute integrity-related activities.

The audit determined that for gas and liquid pipeline IMPs, roles and responsibilities are well-defined and have adequate, dedicated resources. The audit also assessed TransCanada's revised plant IMP, now known as the Facility, Integrity and Reliability Management Program (FIRM), and found that it addresses the roles and responsibilities that were lacking in the previous version.

Management System Audit Sub-Element Finding: Based on documents reviewed and interviews with personnel, TransCanada was able to demonstrate that it was in compliance with the requirements of the OPR-99 and CSA Z662-11, and is therefore compliant with the requirements of this audit sub-element.

Training, Competence and Evaluation

The Management System Audit Sub-Element 3.3, Training, Competence and Evaluation, refers to the regulations that require a company to have a documented training program for employees and contractors related to the company's management and protection programs. Training programs are expected to include program-specific policies, emergency preparedness, environmental response and information on the potential consequences of not responding appropriately. Training must also evaluate the competency to ensure knowledge requirements have been met.

Based on documents and records reviewed, the audit determined that TransCanada has developed effective methods to manage the training and qualification of its employees and contractors.

Management System Audit Sub-Element Finding: Based on documents reviewed and interviews with personnel, TransCanada was able to demonstrate that it was in compliance with the requirements of the OPR-99 and CSA Z662-11, and is therefore compliant with the requirements of this audit sub-element.

Operational Control – Normal Operations

The Management System Audit Sub-Element 3.6, Operational Control – Normal Operations, refers to the regulations that require a company to establish and maintain a process to develop, implement and communicate measures meant to mitigate, prevent and protect against the hazards identified in sub-sections 2.0 and 3.0. This includes measures to proactively reduce or eliminate risks and hazards at their source.

The audit determined that TransCanada's threat management programs provide a listing of appropriate integrity measures for managing identified risks and threats. Some of these threats include but are not limited to: pipeline corrosion; construction and manufacturing; weather and outside forces; and mechanical damage.

Management System Audit Sub-Element Finding: Based on documents reviewed and interviews with personnel, TransCanada was able to demonstrate that it was in compliance with the requirements of the OPR-99 and CSA Z662-11, and is therefore compliant with the requirements of this audit sub-element.

Operational Control – Upset or Abnormal Operating Conditions

The Management System Audit Sub-Element 3.7, Operational Control – Upset or Abnormal Operating Conditions, refers to the regulations that require a company to establish and maintain procedures to identify potential upset or abnormal operating conditions, accidental releases, incidents and emergency situations.

TransCanada has implemented a number of processes and procedures to identify potential upset or abnormal operating conditions. TransCanada's pipeline infrastructure is monitored remotely 24 hours a day, 365 days a year using a Supervisory Control and Data Acquisition (SCADA) system and is backed up by an onsite standby system. In the event that both of these systems fail due to a catastrophic event, a secondary control centre at a different location contains full duplicate primary and secondary back-up systems.

This audit also determined that TransCanada's pressure-limiting and relieving systems, leak detection, gas quality, alarm call-out, shutdown devices and valve operation systems were all adequate and compliant with the OPR-99 and CSA-Z662-11 requirements.

While over-pressure protection for TransCanada's oil pipeline systems was found to be adequate, the Board has determined the NOVA Gas Transmission Ltd (NGTL) system is not conducting sufficient inspections or audits of its customer installations to ensure that the system is operated in compliance with the OPR-99 and CSA-Z662-11 requirements. Based on that system's history of over-pressure incidents and the fact that TransCanada has not fully implemented its plan of action to verify compliance with requirements, the company is not in compliance with the OPR-99 and CSA-Z662-11 requirements and is therefore not in compliance with this audit sub-element.

Management System Audit Sub-Element Finding: Based on the documents assessed and interviews with personnel for programs related to over-pressure protection systems on the Alberta (NGTL) System, TransCanada is assessed to be non-compliant with the requirements of the OPR-99 and CSA Z662-11, and is therefore non-compliant with this audit sub-element.

Inspection, Measurement and Monitoring

The Management System Audit Sub-Element 4.1, Inspection, Measurement and Monitoring, refers to the regulations that require a company to develop and implement surveillance and monitoring programs including contract work being performed on behalf of the company. These programs are expected to include measures for evaluating a company's management and protection programs.

Based on documents and records reviewed, the audit determined that TransCanada has developed and implemented a number of effective inspection, measurement and monitoring programs.

Other sections of this sub-element were identified as non-complaint with regulatory requirements due to inadequate or incomplete program implementation. This included:

- TransCanada's position that ongoing monitoring of all shipped commodities for sour crude on the Keystone pipeline is not required since recent testing confirmed the current non-sour nature of these products;
- TransCanada's inability to produce sufficient evidence proving the adequacy of its ongoing integrity management programs for corrosion on unpiggable sections of the NGTL system; and
- background descriptions for the facility pipe inspection program that were too generic and did not provide the level of specificity required for adequate, effective and consistent implementation.

Management System Audit Element Finding: Based on the documents assessed and interviews with personnel as it relates to: monitoring of Hydrogen Sulfide (H_2S) in crude oil in the Keystone Pipeline; monitoring of external corrosion on the Alberta (NGTL) System's unpiggable pipelines; and the integrity monitoring of below-ground station piping on all of TransCanada's facilities, TransCanada is assessed to be non-compliant with the requirements of the OPR-99 and CSA Z662-11, and is therefore non-compliant with this audit sub-element.

Corrective and Preventive Actions

The Management System Audit Sub-Element 4.2, Corrective and Preventive Actions, refers to the regulations that require a company to have a process to investigate incidents or any non-compliance that may occur, including a process to mitigate any potential or actual impacts arising from the non-compliances. The company is also required to develop procedures to analyze incident data in order to identify deficiencies and opportunities for proactive improvement.

During the course of this audit, TransCanada provided evidence of its analysis of possible incident types. The company also demonstrated it had compiled and analyzed key performance indicator data in order to assess trends and establish root causes of incidents.

When issues or incidents are identified, the Board noted that TransCanada's internal non-compliance and incident reporting processes were adequate but could be more detailed in the areas of preventative action and information sharing across the company. TransCanada has committed to improving the level of detail in these items.

Management System Audit Sub-Element Finding: Based on documents reviewed and interviews with personnel, TransCanada was able to demonstrate that it was in compliance with the requirements of the OPR-99 and CSA Z662-11, and is therefore compliant with the requirements of this audit sub-element.

Internal Audit

The Management System Audit Sub-Element 4.4, Internal Audit, refers to the regulations that require a company to develop and implement a documented process for auditing its management and protection programs and procedures. The audit process is expected to include and manage training and competency requirements for staff carrying out the audits and be conducted on a regular basis.

Internal audits of TransCanada's IMPs are conducted by personnel that are independent of the areas to be audited or by a contracted third party. Quarterly field-based compliance audits are conducted at multiple locations across Canada. All audit findings are tracked and are required to be resolved. Findings are also categorized as either site-specific or systemic and responsibility for these is assigned accordingly. The progress of resolving audit findings is monitored and escalated where necessary.

Management System Audit Sub-Element Finding: Based on documents reviewed and interviews with personnel, TransCanada was able to demonstrate that it was in compliance with the requirements of the OPR-99 and CSA Z662-11, and is therefore compliant with the requirements of this audit sub-element.

Management Review

The Management System Audit Sub-Element 5.1, Management Review, refers to the regulations that require a company to formally review its management and protection programs for continuing suitability, adequacy and effectiveness. Reviews are expected to be based on appropriate documentation and records, be formal and documented, and occur on a regular basis.

The audit concluded TransCanada has undertaken several initiatives aimed at reviewing its IMPs. These include:

- Designating an executive to be accountable for management review;
- Having appropriate levels of responsibility and accountability at each level of the organization; and
- Participation in industry associations in order to share learnings and best practices.

Some of the non-compliances identified during the audit, such as insufficient overpressure protection and management of hazards associated with external corrosion, illustrate the results of a management review process that was not entirely effective. This element of the audit also included a review of the allegations presented by the complainant along with the corroborating internal review by TransCanada resulting from that complaint (see section below, Allegations of Non-Compliance).

Management System Audit Element Finding: Based on the documents assessed and interviews with personnel as related to Management Review, TransCanada is assessed to be non-compliant with the requirements of the OPR-99 and CSA Z662-11, and is therefore non-compliant with this audit sub-element.

Allegations of Non-Compliance

On 1 May 2012, the Board received a submission from a complainant outlining allegations of regulatory non-compliance against TransCanada's integrity management practices. These concerns were brought to the Board's attention after the complainant had voiced similar concerns through TransCanada's internal mechanisms.

The Board had previously scheduled an audit of TransCanada's Integrity Management Programs to start in the second quarter of 2013. As a result of allegations of regulatory non-compliance brought to the Board by a then employee of TransCanada (complainant), the Board advanced the timing of its audit and integrated an assessment of the allegations within the scope and technical protocols developed for the audit.

The Board's IMP audit conducted a detailed assessment of TransCanada's procedures as well as records of any corrective and preventative actions taken by TransCanada to address the allegations. Details of the Board's verification for each complainant allegation are contained in the audit sub-element 4.4, Internal Audit, in Appendix II of this Audit Report. The Board's audit has confirmed that the company has developed and implemented actions to correct and prevent similar occurrences for those issues confirmed to be valid. The Board's audit also identified that some of the complainant's allegations did not reflect issues of non-compliance with the regulatory requirements.

The Board assessed relevant company procedures along with records of any corrective and preventative actions taken to address the allegations. The Board also assessed TransCanada's internal investigation relating to its compliance with technical standards and procedures and notes that many of the allegations of regulatory non-compliance identified by the complainant were confirmed by TransCanada's internal audit.

The Board's audit has confirmed that as of the close of this audit, TransCanada has developed and implemented actions to correct and prevent similar occurrences for confirmed non-compliances identified by the complainant.

The Board finds that TransCanada's practices and procedures to deal with reporting of employee concerns at the time of the audit were not effectively implemented, supporting the Board's Non-Compliant finding with the audit sub-element 5.1 Management Review.

A detailed listing of the Board's assessment of each allegation has been documented in Appendix II, 4.4 Internal Audit.

Management System Audit Sub-Element Finding: See Finding for audit sub-element 4.4 – Internal Audit above.

7.0 Conclusions

NEB-regulated companies must demonstrate a proactive commitment to continual improvement in safety, security, and environmental protection. Pipeline companies under the Board's regulation are required to incorporate integrity management programs into their day-to-day operations. These programs include the tools, technologies and actions needed to ensure that pipelines are safe and remain that way over time. Integrity management programs enable pipeline companies to predict and prevent failures.

The Board has determined that TransCanada is compliant in five sub-elements of this audit including:

3.1 Organizational Structure, Roles and Responsibilities;
3.3 Training, Competence and Evaluation;
3.6 Operational Control-Normal Operations;
4.0 Corrective and Preventive Actions; and
4.4 Internal Audit.

The Board has determined that TransCanada is non-compliant in four sub-elements of the audit including:

2.1 Hazard Identification, Risk Assessment and Control;
3.7 Operational Control-Upset or Abnormal Operating Conditions;
4.1 Inspection, Measurement and Monitoring; and
5.1 Management Review.

The Board is of the view that the processes presently used by TransCanada have identified the majority, and most significant, of its hazards and risks. Notwithstanding this, the audit identified that the non-compliant findings are related to the following contributing factors:

- recognition of all potential hazards and integrating them into the program sub-elements that have been found to be non-compliant, and

- issues related to TransCanada's internal management practices. Examples of these include: over-reliance on lagging indicators; inadequate consideration of NEB safety advisories notifying where hazardous conditions existed and regulatory requirements were not being met; and ineffective implementation of internal practices to address the complainant's issues prior to Board notification.

With respect to the Board's investigation of the complainant's allegations of regulatory non-compliance against TransCanada integrity management practices, the Board's assessment has confirmed that TransCanada has now developed and implemented actions to correct and prevent similar occurrences for the confirmed issues. The NEB recognizes that even with a solid regulatory framework, it cannot be everywhere at every moment. That is why the Board encourages concerned individuals to voice their safety concerns with companies internally and, when necessary, to bring them to the attention of the Board.

The Board is also investigating certain steel pipe and fittings installed on the Keystone Pipeline with the potential to exhibit lower than specified yield strength. This investigation remains ongoing. Resolution of the investigation and any required remedial actions will be determined outside the audit.

An effective and well-implemented Integrity Management Program is only part of the overall requirement for NEB-regulated companies. As of the time this audit report is released, separate and concurrent audits of TransCanada's Safety, Environmental Protection, Emergency Management, Crossings and Public Awareness programs remain ongoing. The Board will make this Final Audit Report public and it will be posted on the Board's website.

TransCanada will be required to submit a CAP for Board approval within 30 days of the Final Audit Report being issued, detailing how the company will address findings of non-compliance identified in this audit. The Board will conduct further compliance verification activities to confirm that the improvements outlined in the CAP are being proactively implemented in an expedient manner and on a system-wide basis.

APPENDIX I

TRANSCANADA PIPELINES LIMITED AND NEB-REGULATED SUBSIDIARIES (TRANSCANADA)

MAPS AND SYSTEM DESCRIPTIONS

The following maps and descriptions are of TransCanada subsidiaries that were included in the scope of this audit, specifically:

- TransCanada PipeLines Limited;
- TransCanada Keystone Pipeline GP Ltd.;
- Trans Québec & Maritimes Pipeline Inc.;
- Foothills Pipe Lines Ltd.; and
- NOVA Gas Transmission Ltd.

These subsidiaries hold the certificates for TransCanada's NEB-regulated facilities, which include the Canadian Mainline, Keystone Pipeline, TQM Pipeline System, Foothills System, and the Alberta (NGTL) System.

The Canadian Mainline, shown in Figure 1, is a 14,100 km natural gas pipeline that extends from the Alberta/Saskatchewan border east to the Quebec/Vermont border and connects with other natural gas pipelines in Canada and the United States.

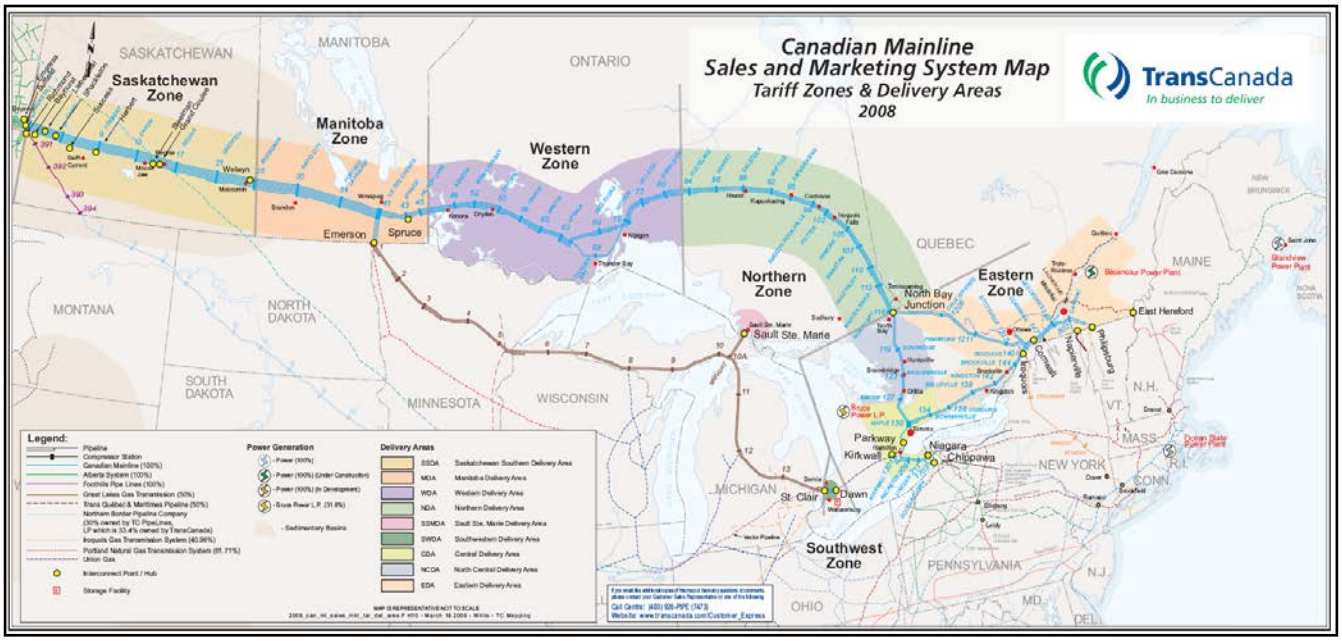

Figure 1: Canadian Mainline

The Keystone Pipeline, shown in Figure 2, is a 1,251 km pipeline that transports crude oil from Hardisty, Alberta to the Manitoba/North Dakota border. The Keystone Pipeline continues into the United States.

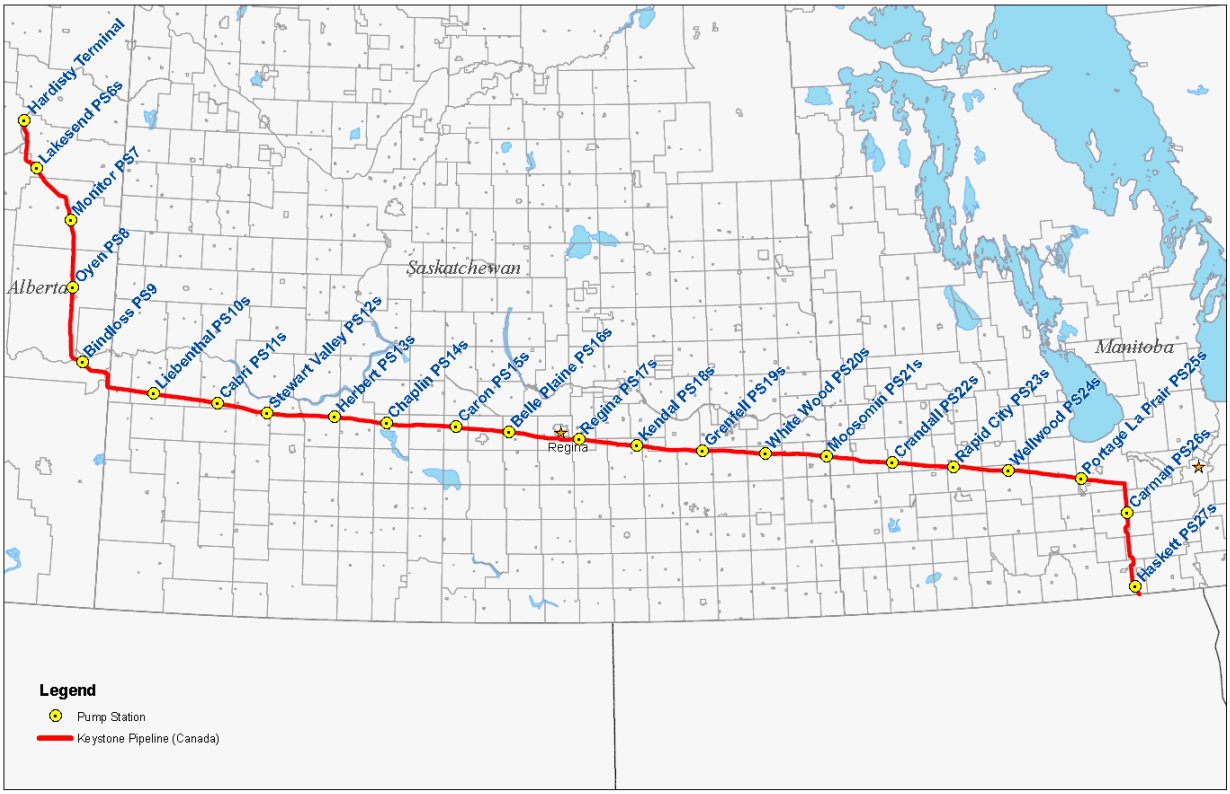

Figure 2: Keystone Pipeline

The TQM Pipeline System, shown in Figure 3, is a 573 km natural gas pipeline network in the Province of Quebec between Saint-Lazare, located west of Montreal, and Saint-Nicolas, located on the South Shore of Quebec City, and between Lachenaie, located East of Montreal, and East Hereford on the New Hampshire border.

Figure 3: TQM Pipeline System

The Foothills System, shown in Figure 4, is a 1,046 km natural gas pipeline system which carries natural gas from central Alberta to the United States.

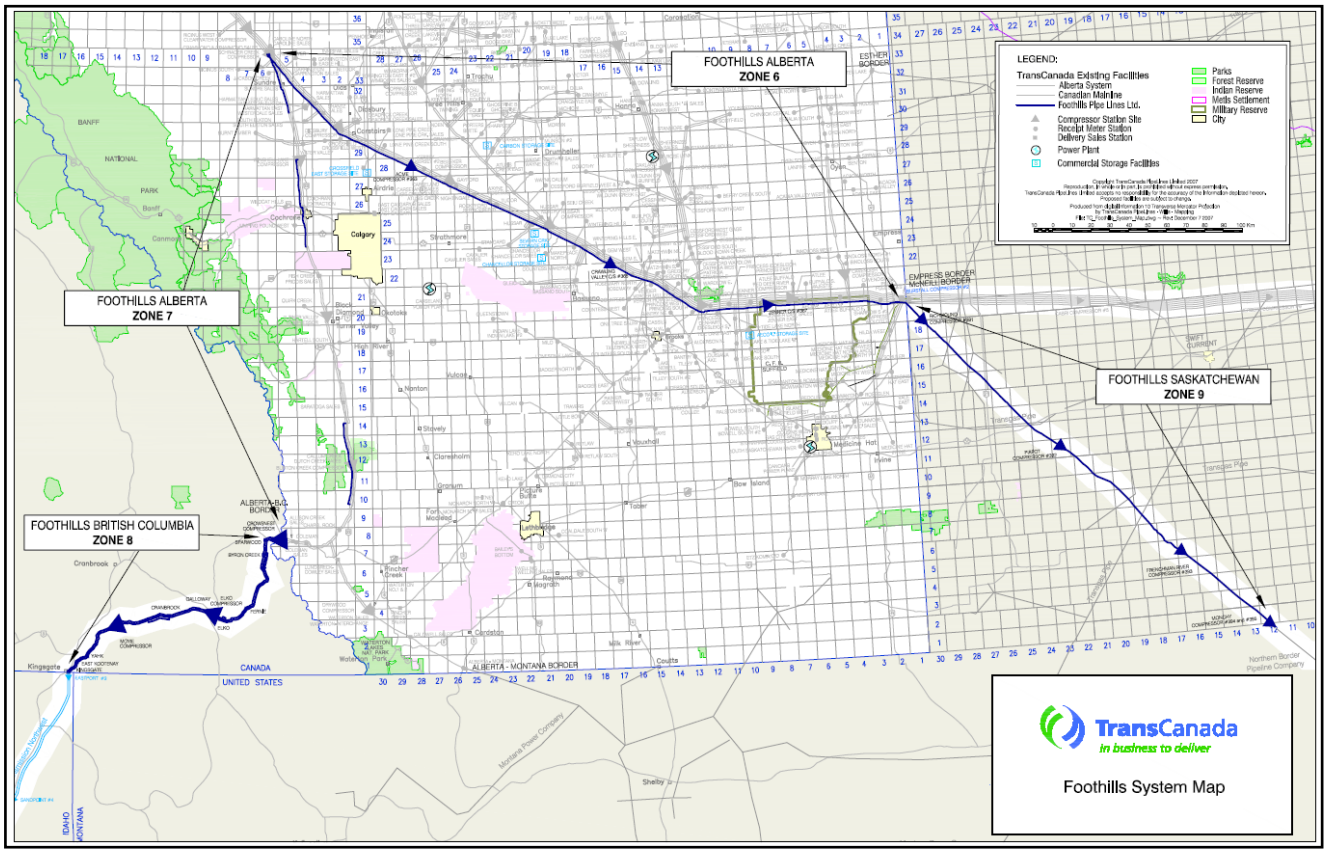

Figure 4: Foothills System

The Alberta (NGTL) System, shown in Figure 5, is a 24,828 km pipeline which gathers natural gas for use within the Province of Alberta, and which delivers natural gas to connection points with the Canadian Mainline, Foothills System, and the natural gas pipelines of other companies.

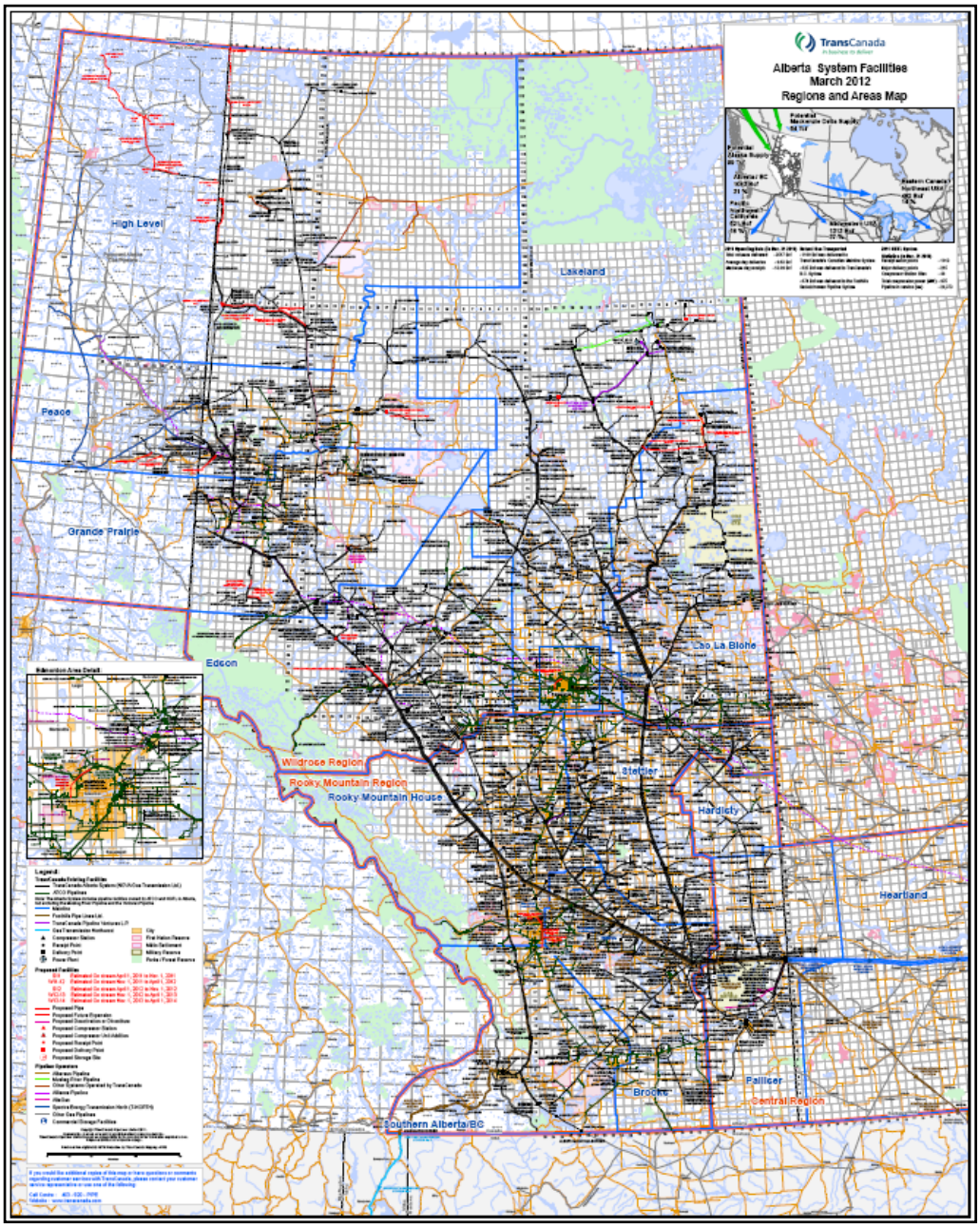

Figure 5: Alberta (NGTL) System

APPENDIX II
TRANSCANADA PIPELINES LIMITED AND NEB-REGULATED SUBSIDIARIES (TRANSCANADA)
INTEGRITY MANAGEMENT PROGRAM AUDIT ASSESSMENT

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APPENDIX II

TRANSCANADA PIPELINES LIMITED AND NEB-REGULATED SUBSIDIARIES (TRANSCANADA)
INTEGRITY MANAGEMENT PROGRAM AUDIT ASSESSMENT

INTRODUCTION:

TransCanada has three Integrity Management Programs (IMPs), which are:

- Canadian Gas Pipeline Integrity Management Program (CND-GAS-IMP);
- Canadian Liquid Integrity Management Program (CDN-LIQ-IMP); and
- Plant Integrity Management Program (Plant IMP).

These IMPs are referred to throughout this Audit Evaluation Table as the Gas Pipeline IMP, Liquid Pipeline IMP, and Plant IMP, respectively.

The TransCanada subsidiaries included in this audit included specifically:

- TransCanada PipeLines Limited;
- TransCanada Keystone Pipeline GP Ltd.;
- Trans Québec & Maritimes Pipeline Inc.;
- Foothills Pipe Lines Ltd.; and
- NOVA Gas Transmission Ltd.

AUDIT OBJECTIVES AND SCOPE:

The scope of the audit included an assessment of whether TransCanada was fulfilling the requirements of:

- the NEB Act;
- the OPR-99;
- *CSA Z662-11, Oil and Gas Pipeline Systems*; and
- TransCanada's policies, practices and procedures.

More specifically, the audit examined nine sub-elements of the NEB management system requirements as they relate to TransCanada's integrity management programs. These sub-elements were selected using the Board's risk-informed approach to focus the scope of the audit on areas that have previously been shown to have the highest rates of non-compliance among

NEB-regulated companies and to expedite and focus the assessment of the IMP technical programs in light of the allegations.

1.0 POLICY AND COMMITMENT

1.1 Policy and Commitment Statements

Expectations: The Company shall have a policy approved and endorsed by senior management (the Policy). It should include goals and objectives and commit to improving the performance of the Company.

References:

OPR-99 section 4
CSA Z662-11, Clauses 3.1.2 and 3.2

Audit Assessment:

This Management System sub-element was not formally assessed during the Integrity Management Program audit.

Compliance Status: Not Assessed

2.0 PLANNING

2.1 Hazard Identification, Risk Assessment and Control[1]

Expectations: The company shall be able to demonstrate a procedure to identify all possible hazards. The company shall assess the degree of risk associated with these hazards. The company should be able to support the rationale for including or excluding possible risks in regard to its environment, safety, integrity, crossings and awareness and emergency management and protection programs (management and protection programs). The company shall be able to implement control measures to minimize or eliminate the risk.

References:

OPR-99 sections 4 (2), 39, 40 and 41
CSA Z662-11, Clauses 3.1.2(f), 3.2(a), 3.2(b), 10.5.1.1(d) and 16.2

Audit Assessment:

General

During interviews and in documents submitted, TransCanada stated that it has developed procedures to identify threats (hazards), assess the degree of risk associated with those threats, and implement control measures to mitigate or eliminate the risk of the threats. TransCanada explained that its Engineering and Asset Reliability (E&AR) department is accountable for managing the operational performance, cost and risks of TransCanada's pipeline and facility assets. This includes developing and implementing asset strategies and integrity management systems to manage operating and maintenance risk. Within the E&AR department, subject matter experts in the Pipe Integrity and Facilities Integrity departments are responsible for developing Integrity Management Programs (IMPs). Pipe Integrity is grouped into threat-specific teams, and Facilities Integrity is grouped into equipment-specific teams. These teams are accountable for assessing risks and developing annual maintenance and assessment work plans.

Hazard Identification Process

[1] Hazard: Source or situation with a potential for harm in terms of injury of ill health, damage to property, damage to workplace environment, or a combination of these. Risk: Combination of the likelihood and consequence(s) of a specified hazardous event occurring.

Processes for threat[2] identification and risk assessment and control are documented in TransCanada's three IMPs, which are:

- Canadian Gas Pipeline Integrity Management Program (CND-GAS-IMP);
- Canadian Liquid Integrity Management Program (CDN-LIQ-IMP); and
- Plant Integrity Management Program (Plant IMP).

Threat Identification Process

TransCanada's threat identification process is meant to verify conditions that may exist that would make a line segment susceptible to a threat. The determination of these conditions varies with each threat category. TransCanada considers threats according to the following:

- Time Dependent
  - External corrosion
  - Internal corrosion
  - Environmental cracking (e.g. stress corrosion cracking)
- Time Independent
  - Mechanical damage
  - Incorrect operations
  - Weather-related and outside forces
- Static or Resident
  - Manufacturing related defects
  - Welding or fabrication related defects
  - Equipment failures

TransCanada's process for threat identification was reviewed for all threats and, except where noted for the threat to high pressure station piping in gas facilities, was assessed to be compliant with the requirements. An example of one of the threat assessments for mechanical damage (dents) is provided to illustrate TransCanada's process.

Individual Threat Assessments: Mechanical Damage (Dents)

TransCanada's dent program is managed according to TEP-ILI-DEF-CDN Analysis of Deformation In-Line Inspection (ILI) Data for CDN Pipelines (EDMS No. 006980190) and TEP-ITM-Mechanical Damage Threat Management Program (TEP-ITM-MECH, EDMS No. 006786487). TransCanada uses data from the ILI program to characterize dents in its pipeline system and TransCanada continues to develop this technology with the tool vendors. The

[2] TransCanada uses the term "threat" for "hazard" in its documents.

detection and characterization of geometric anomalies undergoes further processing to develop prioritized remediation activities in specific areas, based on previous excavation reports from other programs and in areas where dents have been previously mitigated. When dents are excavated, TransCanada applies the methodologies of CSA Z662-11, ASME B31.8 and its own modified B31.8 formula to determine which remediation or mitigation techniques may be applied. TransCanada considers the threat of mechanical damage from external sources as low, due to its Public Awareness Program and the Right of Way (ROW) patrols that it conducts. Additional measures are applied to areas determined to have a threat of mechanical damage that is higher than low (e.g., population density, history of damage, increased construction activity).

Pipelines

For pipelines, TransCanada has detailed nine potential threat categories that are considered during its threat identification process (Gas Pipeline IMP, Section 9.7, and Liquid Pipeline IMP, Section 3.1.2). The threat categories also include sub-threats derived from consideration of CSA Z662-11, Annex H, Clause H.2.6 and ASME B31.8S.

TransCanada's Threat Management Programs for the nine threat categories referred to above are as follows:

- Mechanical Damage Threat Management Program (TEP-ITM-MECH, EDMS No. 006786487);
- External Corrosion Threat Management Program (CDN) (TEP-ITM-ECOR, EDMS No. 006570955);
- Internal Corrosion Threat Management Program (TEP-ITM-IC, EDMS No. 006786402);
- Stress Corrosion Cracking Threat Management Program (TEP-ITM-SCC-CDN, EDMS No. 005767613);
- Equipment Failure Threat Management Program (TEP-ITM-EQUIP, EDMS No. 006786449);
- Incorrect Operations Threat Management Program (TEP-ITM-IOPS, EDMS No. 006810297);
- Construction and Manufacturing Threat Management Program (TEP-ITM-MANUF, EDMS No. 006786458);
- Weather and Outside Forces Threat Management Program (TEP-ITM-WOF, EDMS No. 005767611); and
- Facility Pipe Threat Management Program (CDN) (TEP-ITM-FPIPE-CDN, EDMS No. 007379193).

Section 9 of the Gas Pipeline IMP specifies how each threat management program has a consistent approach whereby threat identification is one step in an overall threat management process. Pipe segments susceptible to a threat are identified and the rationale for including or excluding threats is documented within each threat management program. Risk analyses are completed and the results of the analyses are used to prioritize and plan activities to reduce or eliminate the probability of failure, the consequences of failure, or both. Selected activities for the upcoming budget cycle are captured annually in TransCanada's Pipeline Maintenance Plan. Results obtained from the execution of the Pipeline Maintenance Plan are assessed and used as additional inputs into the next planning cycle.

Facilities

The TransCanada Facility Group is divided into several areas of expertise, which include Mechanical, Field SCADA, Civil Engineering, Design Engineering Support, Measurement Engineering, Controls, and Electrical. As per Section 2.5.5 of the Plant IMP, new construction is completed in compliance with the applicable codes, which address the associated hazards and corresponding risks. In addition, many of the potential operating hazards are identified and mitigated during the early design stage through Hazard Identification Studies (HAZID) and Hazard and Operability Studies (HAZOP) analyses. With the Project Turnover Memorandum, residual risks are identified and documented for the facility integrity group. To address ongoing reliability, applicable existing plans are used, or new integrity plans are created, to maintain the equipment functionality so that the identified hazards, associated designs and codes are managed throughout the lifecycle of the equipment.

High Pressure Station Piping in Gas Facilities

TransCanada developed a new management program in December 2012 for high pressure piping in gas facilities (e.g., meter and compressor stations, valves sites). This is documented in the Facility Pipe Threat Management Program (TEP-ITM-FPIPE-CDN, EDMS No. 007379193). Before this new program was developed, the station piping was managed under TransCanada's *Integrity Management Process for Pipelines - Revision 2* process. The new program includes a documented process for identifying the hazard and assessing the risk of high pressure station piping. The new program was assessed as adequate in terms of its content, but it has not yet been fully implemented throughout TransCanada's facilities. TransCanada indicated in its response to an Audit Information Request that "*the risk assessment and selection of mitigation plans is planned for completion in November of 2013*". Given that the new program has not yet been fully implemented, TransCanada is non-compliant with the requirements of this audit sub-element and with CSA Z662-11, Clauses 3.1.2(f) and 3.2.

Risk Assessment

TransCanada has implemented its Asset Management System (AMS) to manage its operating and maintenance risk. The risk management element of the AMS outlines a requirement for Operations and Engineering to develop and maintain a risk register to capture risk events for all assets that TransCanada operates. The Asset Management System & Governance (AMS&G) team oversees the development of the register, but inputs are collected from engineering, field operations, commercial operations, corporate health and safety, and compliance departments. Risks are calculated by aligning the probability of events and the potential magnitude of consequences. The risk register is currently entered and maintained within a Microsoft Access database and is controlled by the AMS&G team during its developmental stages to maintain integrity of the data. An assessment of the establishment and implementation of the risk assessment processes follows, based on facility categorizations.

Pipelines

Risk Assessment and Management methodologies are documented in Section 10 of the Gas Pipeline IMP and Section 4 of the Liquid Pipeline IMP. As noted previously under Threat Identification, the processes used to assess risk are threat-specific, and process details are provided in the Risk Assessment and Prioritization of TransCanada's Integrity Threat Management Programs.

TransCanada's risk assessment and risk management are achieved using either of the following two approaches:

1. For pipelines where assessment or direct examination anomalies have been detected, or similar conditions are inferred, the specific anomalies are assessed, and control or mitigation activities are planned.

2. For pipelines where assessment data has not been collected, risk assessment is performed by integrating information from various sources, including: subject matter expertise; applied learnings from other similar segments of pipe across the TransCanada system, including historical performance; the TransCanada risk algorithm Risk Assessment Using PRIME (TEP-INT-PRIME, EDMS No. 003972569), for External Corrosion and SCC threat; and, the tracking of leading indicators, such as an elevation in communication to stakeholders in response to a spike in the frequency of unauthorized encroachments on the ROW or relevant information from industry associations.

Where assessment data is available, a pre-screening is performed to look for urgent repair conditions. This is followed by a reliability based assessment to evaluate the probability of

failure and account for measurement uncertainties. The technical details of the model are included in the document Risk Models for Corrosion Using ILI Data (TER-COR-RSK, EDMS No. 005767603). With the assessment data, near-term and future remediation is planned, and priority is assigned according to population density. Additionally, ongoing safety is addressed through a temporary pressure restriction. The criteria for determining when a pressure restriction is required are outlined in Analysis of MFL In-Line Inspection for CDN Pipelines (CDN) (TEP-INT-ILI-CDN EDMS No. 006570876). The procedure for implementing the pressure restriction is outlined in the TOP Pipeline Restriction Procedure. Pressure control is addressed per the System Design & Commercial Operations Pipeline MAOP De-rate Procedure (EDMS No. 006837355).

When assessment data has not been collected, a risk assessment is performed by executing the TransCanada risk algorithm Risk Assessment Using PRIME (TEP-INT-PRIME, EDMS No. 003972569). Subject matter experts integrate the PRIME data results with other relevant information to prioritize the pipeline inspection schedules.

An example of risk assessment and management is provided for the Weather and Outside Forces (WOF) threat. This threat is managed according to the Weather and Outside Forces Threat Management Program (TEP-ITM-WOF, EDMS No. 005767611). The approach is to conduct a Phase 1 geotechnical study along all of the company pipeline assets. Areas of elevated concern are identified and then reviewed further with Phase 2 and Phase 3 studies. The collected information is used to determine the actual risk to the pipeline asset, and then mitigation, control or monitoring programs are planned, based on the results. TransCanada's risk assessment and risk management process for the threat of WOF was assessed to be adequate.

Facilities

Integrity management of facilities at TransCanada comprises four risk-assessed components:

1. Integrity Planning, including System Assessment, Facilities Assessment, and Integrity Programs;
2. Project Integrity, including Project Risk Analysis, Business Value Analysis, and Project Ranking;
3. Design Integrity, including Inter Disciplinary Design Check Meetings, and Reliability and Maintainability; and
4. Maintenance Integrity, including Facility Criticality.

In managing the integrity of non-pipe facilities, TransCanada identified a number of potential integrity threats, including equipment failure, inability to operate as expected, obsolescence, and

environmental and safety concerns. Consequences of facility threats and potential failures include public safety impact, loss of life, customer/business impact, regulatory impact, and environmental impact. Risk assessments are performed on the potential threats and consequences to identify potential impacts as well as corrective and preventive actions. When activities are required to manage the risk, the details on conducting these activities are then documented in TransCanada's equipment-specific integrity plans. Each equipment-specific integrity plan is developed with input from the regions, equipment manufacturers, Issue and Incident Tracking (IIT), other operators, Pipeline System Operations, and the previous year's integrity plans. The equipment-specific integrity plans reference the relevant TransCanada Operating Procedures (TOPs) that were developed to manage threats and mitigate risks to the reliable operation of facility equipment.

Specific equipment integrity plans that address the risk requirements have been written for many equipment types. Examples are provided in the following documents:

- The Mainline Field SCADA Engineering Integrity Plan (EDMS No. 004782175) contains a section on Risk Assessment (Section 4), and identifies issues of concern, the resulting impact, and an action plan to address the issue. Additionally, Section 3 of the document contains the operating and maintenance strategy that includes planned, predictive and reactive maintenance.
- The Pressure Vessels Integrity Plan (EDMS No. 003763099) contains a section on Risk Assessment (Section 4). Pressure vessel inspection is addressed and reference is made to the TOP Pressure Vessel External and Internal Inspection (EDMS No. 003694710).

Recent Threat Identification or Risk Assessments

Threat identification and risk assessment activities are aggregated annually as part of the pipeline and facilities maintenance program budget approval process. The Pipeline and Facilities Maintenance Programs (PMP) for 2013, which are the output of the aggregated threat identification risk assessment, were finalized in September 2012.

Records indicated that for pipelines and facilities, work is planned and risk assessments are conducted with consideration given to the consequences of safety, health, the environment and individual risk. Consequences are considered during prioritization of remediation, prevention, control and mitigation activities, and also in repair criteria.

For gas pipelines, mitigation and repair activities requiring excavation of pipeline assets are conducted under the TOP Excavation Procedure (EDMS No. 003672343). The procedure references consultation with a TransCanada Environmental Specialist, and requires all work to

be performed in compliance with the Environmental Field Procedures Guide (EDMS No. 003671954).

For liquid pipelines, risk assessments take into consideration the consequences of a potential release. For example, potential consequences that are considered are oil releases into what TransCanada refers to as “highly sensitive receptors”. These are defined by TransCanada as specific areas where a release from a pipeline could have significant consequences on public health, the environment or the economy.

For the risk associated with third party damage, TransCanada has pipeline class location and urban development programs to evaluate the issue relating to protecting the public and the pipeline as population growth encroaches on pipelines (Pipeline Crossing and Encroachment Procedure Canada TOP, (EDMS No. 003674617), Pipeline Right-Of-Way Procedures Canada TOP (EDMS No. 003672613), and TEP-INT-CLA Class Analysis and Remediation (CDN) (EDMS No. 005766974). TransCanada stated that its Public Awareness Program (TOP Pipeline Public Awareness Program Plan, EDMS No. 003860909) educates and increases awareness of pipeline safety.

Upon completion of a threat identification and risk assessment, the individual threat teams develop a threat-specific Pipeline Maintenance Plan (PMP). Asset-based program planners assemble the threat specific sections of the PMP into a single, asset specific, PMP. During audit interviews and through documents reviewed, the Board confirmed that threat identification for the liquid pipeline has been performed primarily by the liquid integrity team, with adequate support from the threat-specific subject matter experts as required.

Risk control measures are identified through several avenues, including the following:

- The remediation and mitigation measures required to address specific defects are identified in the Threat Management Programs.
- The Corrosion Prevention team is accountable for corrosion control through inspection, maintenance and remediation of the cathodic protection system.
- TransCanada Operating Procedures (TOPs) are built, where applicable, to manage a particular threat or risk (e.g., the TOP Keystone Pressure Control Valve Vibration Evaluation Procedure (EDMS No. 006811833)).
- TOPs are also developed to ensure that routine, consistent inspection and maintenance is performed (e.g., the TOP Relief Valve Inspection and Overhaul Program (EDMS No. 003694631) and the TOP Valve and Valve Operator Inspection and Servicing (EDMS No. 003849601)).

Low Strength Steel Pipe and Fittings

In 2008, the NEB became aware that certain steel pipe and fittings procured and installed on the Keystone Pipeline had the potential to exhibit lower that specified yield strengths. The NEB subsequently initiated an investigation. This investigation preceded the audit and is ongoing. The low yield issue was confirmed during the audit, and documents were reviewed and interviews conducted with TransCanada personnel related to the issue. However, as the issue continues to be under investigation by the NEB, resolution of the investigation and any required remedial actions will be determined outside of the audit.

Summary: Hazard Identification, Risk Assessment and Control

The Management System Audit Element 2.1, Hazard Identification, Risk Assessment and Control, requires a company to have a procedure to identify all possible hazards, to assess the degree of risk associated with these hazards, and to implement control measures to minimize or eliminate the risk.

TransCanada has implemented a system to identify and manage its operating and maintenance risk. Risks are calculated by incorporating the probability of events and the potential magnitude of the consequences. Records indicate that for pipelines and facilities, work is planned and risk-assessments are conducted with consideration given to safety, health, and the environment. TransCanada's process for threat identification was reviewed for all threats and was assessed to be compliant with the requirements.

The audit identified only one area of non-compliance in the sub-element of hazard identification, risk assessment and gas control. TransCanada developed a new management program for high pressure piping in facilities. This new program has been assessed and is adequate in terms of its content, but has not yet been fully implemented throughout all of TransCanada's facilities.

Management System Audit Sub-Element Finding: Based on the incomplete implementation of the required high pressure station piping program for its gas facilities, TransCanada is assessed to be non-compliant with the requirements of the OPR-99 and CSA Z662-11, and is therefore non-compliant with this audit sub-element.

Compliance Status: Non-Compliant

2.2 Legal Requirements

Expectations: The Company shall have a verifiable process for the identification and integration of legal requirements into its management and protection programs. The Company should have a documented procedure to identify and resolve non-compliances as they relate to legal requirements which includes updating the management and protection programs as required.

References:

OPR-99 sections 4, 6, 40 and 41(1)
CSA Z662-11, Clause 3.2

Audit Assessment

This Management System sub-element was not formally assessed during the Integrity Management Program audit.

Compliance Status: Not Assessed

2.3 Goals, Objectives and Targets

Expectations: The Company shall have goals, objectives and quantifiable targets relevant to the risks and hazards associated with the Company's facilities and activities (i.e. construction, operations and maintenance). The objectives and targets should be measurable and consistent with the Policy and legal requirements and ideally include continual improvement and prevention initiatives, where appropriate.

References:

OPR-99 section 40
CSA Z662-11, Clauses 3.1.2 (h) (ii) and 3.2

Audit Assessment

This Management System sub-element was not formally assessed during the Integrity Management Program audit.

Compliance Status: Not Assessed

3.0 IMPLEMENTATION

3.1 Organizational Structure, Roles and Responsibilities

Expectations: The company shall have an organizational structure that allows its management and protection programs to effectively function. The company shall have clear roles and responsibilities, which may include responsibilities for the implementation of the management and protection programs.

References:

OPR-99 sections 40, 47 and 48
CSA Z662-11, Clauses 3.1.1, 3.1.2(b) and 3.2

Audit Assessment

General
During interviews and in documents submitted, TransCanada stated that it has an organizational structure that allows it's Integrity Management Programs (IMPs) to function effectively and efficiently across its gas and liquids pipelines and facilities assets.

TransCanada stated that the employees (primarily engineers and technologists) managing its Canadian IMPs are primarily based in Calgary. Approximately 160 staff performs work related to the Gas and Liquid Pipeline IMPs and approximately 150 staff performs work related to the Plant IMP. In addition, approximately 80 integrity specialists are located in regional offices across the Canadian pipeline system. These individuals are complemented by Field Technicians who execute integrity related activities.

The hierarchy of authority for the IMPs within TransCanada extends from an Executive Vice President, to Vice President, to Director, to Manager, to Program Lead/Manager levels. Under the Vice President of Engineering and Asset Reliability, one Director is responsible for pipe integrity and another Director is responsible for facilities (plant) integrity. The authorities and associated responsibilities are detailed in the respective IMP documents, specifically:

- Gas Pipeline IMP, Section 3 and Appendix A;
- Liquid Pipeline IMP, Section 2 and Appendix A; and
- Plant IMP, Section 2 and Appendix C.

The audit determined that, for the Gas and Liquid Pipeline IMPs, roles and responsibilities are defined and documented for the key positions. These two IMPs also describe the accountabilities and responsibilities of the relevant TransCanada organizational units, arranged by Threats. The roles and responsibilities for each organizational unit are further detailed in the TransCanada Engineering Procedures (TEPs) for each Threat, as follows:

- IMP Management Review: TEP-INT-MREV Pipe Integrity Management Review Process;
- External Corrosion: TEP-ITM-ECOR-CDN External Corrosion Threat Management Program;
- Internal Corrosion: TEP-ITM-IC Internal Corrosion Threat Management Program;
- Equipment Failure: TEP-ITM-EQUIP Equipment Failure Threat Management Program;
- Incorrect Operations: TEP-ITM-IOPS Incorrect Operations Threat Management Program;
- Manufacturing: TEP-ITM-MANUF-CDN Manufacturing, Fabrication and Construction Threat Management Program;
- Mechanical Damage: TEP-ITM-MECH Mechanical Damage Threat Management Program;
- Stress Corrosion Cracking: TEP-ITM-SCC-CDN Stress Corrosion Cracking Threat Management Program; and
- Geotechnical: TEP-ITM-WOF Weather and Outside Forces (Geotechnical) Threat Management Process.

Based on documentation reviewed and interviews with personnel, TransCanada's organizational structure, roles and responsibilities for the Gas and Liquid Pipeline IMPs are compliant with the requirements for this sub-element. The organizational structures relevant to these two IMPs are well defined, with adequate dedicated resources.

The audit determined that the roles and responsibilities for the Plant IMP are not as well defined. In Section 2.2 of the Plant IMP (Lines of Responsibility and Development of IMP/Risk Mitigation Process), only high level positions (e.g., Executive Vice President, Vice President, Director) are identified with respect to the Plant IMP. The functional key positions for the Plant IMP are not specified. The organizational chart in Appendix C of the Plant IMP is considerably less detailed than the organizational charts provided in Appendix A of both the Gas Pipeline IMP and the Liquid Pipeline IMP.

During the audit, TransCanada was in the process of revising its Plant IMP. The Facility Integrity and Reliability Management Program (FIRM) (EDMS No. 007803540) were approved by TransCanada management in July 2013. Section 2.2 (Roles and Responsibilities) of the FIRM

more explicitly details the functions and processes of the FIRM Program, departmental interactions and the organizational structure. The roles and responsibilities for pressure vessels, over-pressure protection, relief valves and tanks were referenced in the appropriate TEPs, TransCanada Engineering Specifications (TESs), TransCanada Operating Procedures (TOPs) and TransCanada Engineering Directives (TEDs). The FIRM references Section 6 of TransCanada's Quality Assurance Manual (QMS) (EDMS No. 003722000) that identifies the roles and responsibilities for pressure vessels, heating boilers and ASME pressure relief vessels across the organization. TransCanada's revised FIRM addresses the requirements of roles and responsibilities that were lacking in the Plant IMP.

In addition to the organizational structure related to TransCanada's IMPs, the audit assessed the roles and responsibilities of integrity personnel as they relate to construction projects. This information was required because the IMPs are under the main organizational structure of Operations and Engineering (O&E), while construction activities are under the main organizational structure of Major Projects. In light of this separate organizational structure, the audit assessed whether sharing of information on integrity related issues, incidents and learnings identified is occurring. Sharing of information related to issues identified during the operational life of pipelines and facilities (by the IMP personnel) is important because it could require changes to the design and/or construction of future pipelines and facilities (by the Major Projects personnel). Conversely, sharing of information related to issues identified during construction is important because it could have an impact on the subsequent IMPs for both pipelines and facilities.

During audit interviews, TransCanada explained how its Capital Projects Management System requires that functional engagement and support between O&E and Major Projects occur, and that the O&E Functional Engagement and Support document describes the engagement accountabilities for the Project Manager, Project Engineering Manager and the Integration Manager. The documents and records examined confirmed adequate communication between the O&E integrity personnel and Major Projects personnel.

Summary: Organizational Structure, Roles and Responsibilities

The Management System Audit Element 3.1, Organizational Structure, Roles and Responsibilities, requires a company to have an organizational structure that allows its management and protection programs to effectively function. It also requires companies to have clear roles and responsibilities, which may include responsibilities for the implementation of these programs.

TransCanada has approximately 310 employees performing work related to its integrity management programs across its Canadian pipeline system. This is complemented by approximately 80 field technicians who execute integrity-related activities.

The audit determined that for gas and liquid pipeline IMPs, roles and responsibilities are well-defined and have adequate, dedicated resources. The audit also assessed TransCanada's revised plant IMP, now known as the Facility, Integrity and Reliability Management Program (FIRM), and found that it addresses the roles and responsibilities that were lacking in the previous version.

Management System Audit Sub-Element Finding: Based on documents reviewed and interviews with personnel, TransCanada was able to demonstrate that it was in compliance with the requirements of the OPR-99 and CSA Z662-11, and is therefore compliant with the requirements of this audit sub-element.

Compliance Status: Compliant

3.2 Management of Change

Expectations: The Company shall have a management of change program. The program should include:

- identification of changes that could affect the management and protection programs;
- documentation of the changes; and
- analysis of implications and effects of the changes, including introduction of new risks or hazards or legal requirements.

References:

OPR-99 section 6
CSA Z662-11, Clause 3.1.2 (g)

Audit Assessment

This Management System sub-element was not formally assessed during the Integrity Management Program audit.

Compliance Status: Not Assessed

3.3 Training, Competence and Evaluation

Expectations: The company shall have a documented training program for employees and contractors related to the company's management and protection programs. The company shall inform visitors to company maintenance sites of the practices and procedures to be followed. Training requirements should include information about program-specific policies. Training should include emergency preparedness and environmental response requirements as well as the potential consequences of not following the requirements. The company shall determine the required levels of competency for employees and contractors. Training shall evaluate competency to ensure desired knowledge requirements have been met. Training programs should include record management procedures. The training program should include methods to ensure staff remains current in their required training. The program should include requirements and standards for addressing any identified non-compliances to the training requirement.

References:

OPR-99 sections 4, 18, 29 and 46
CSA Z662-11, Clauses 3.1.2(c), 3.2 and 10.2.1

Audit Assessment:

General

During interviews and in documents submitted, TransCanada stated that it has a documented training program for employees and internal contractors related to its Integrity Management Programs (IMPs). TransCanada indicated that training requirements for external contractors are specified within its service contracts that are verified through inspections and supervision by TransCanada personnel.

TransCanada uses the following methods to manage the training and qualification of employees, and in some instances internal contractors:

- Learning Management System (LMS);
- Active Management;
- Practice of Engineering (POE); and
- Performance Management Process.

Learning Management System

The LMS is a web-based tool used to manage the training and competency evaluation for TransCanada employees and internal contractors. LMS is also used to document the results of technical tasks evaluated through three competency evaluation methods (Manager Review, Discuss and Describe, and Jobsite Observation), which are discussed below. Any worker who has not been deemed competent or qualified for a particular task is prohibited from independently performing that task.

Field Role Technical Competency

In 2011, TransCanada introduced its Field Role Task Evaluation Project to improve the quality of the learning, development and competency evaluation programs related to field-based work. The competency evaluation method and training requirements for field technical tasks utilizes a model developed by the Canadian Gas Association and has been adapted for TransCanada's use. For field role evaluations, interviews or jobsite task observations or simulations are required to demonstrate competency. TransCanada uses three methods of competency evaluation:

- Manager Review – Applies to low risk level task evaluations. Under this method of evaluation, the manager, in consultation with a Qualified Technician, will approve task competency of the employee.
- Discuss and Describe – Applies to medium risk level task evaluations. Under this method of evaluation, the manager will approve task competency of an employee based on a successful interview evaluation conducted by a qualified evaluator.
- Jobsite Observation – Applies to high risk level task evaluations. Under this method of evaluation, the manager will approve task competency of the employee based on successful jobsite task simulation or performance in the presence of a qualified evaluator.

Active Management

TransCanada's leadership is responsible for ensuring that its employees and internal contractors are properly trained and competent to perform their assigned tasks. Managers complete this by actively assigning and monitoring work, providing feedback and reviewing staff competency on an ongoing basis.

Practice of Engineering (POE)

TransCanada's POE specification, TES-ENG-POE (EDMS No. 003672108), defines the required professional member jurisdictional registration for engineering staff and defines scope of practice. APEGA (Association of Professional Engineers and Geoscientists of Alberta)

registration is a hiring requirement for engineering positions located in Alberta. The POE specifies qualifications for Engineer-in-Charge, Responsible Engineers and design discipline checkers. The Engineer-in-Charge is accountable for ensuring that personnel carrying out engineering work are qualified and competent to do so for the jurisdiction in which the engineering and construction are occurring.

Performance Management Process

During the audit interviews and document review, TransCanada stated that it monitors and manages employee development and training through its Performance Management Process (PMP), which is used to establish annual performance expectations and document the development and training plan of each employee. The PMP identifies employee development requirements, including training. Adjustments are made to an employee's development plan to meet evolving job requirements, as required. Performance management, specifically related to pipe integrity, is documented in TEP-INT-COMP Pipe Integrity Hiring, Training and Competency Evaluation Procedure (EDMS No. 007379172), that outlines the methodology used to identify and communicate training requirements and evaluation of competency. Records of training and competency, which were reviewed during the audit, are provided in Element 4.1 Inspection, Measurement and Monitoring, as they applied to TransCanada's programs.

Summary: Training, Competence and Evaluation

The Management System Audit Element 3.3, Training, Competence and Evaluation, requires a company to have a documented training program for employees and contractors related to the company's management and protection programs. Training program should include program-specific policies, emergency preparedness, environmental response and information on the potential consequences of not responding appropriately. Training must also evaluate the competency to ensure knowledge requirements have been met.

Based on documents and records reviewed, the audit determined that TransCanada has developed effective methods to manage the training and qualification of its employees and contractors as follows:

- Learning Management System (LMS), a web-based tool to document competency evaluation methods and track whether employees and contractors have been deemed qualified for a particular task;

- Active Management, a leadership tool to actively assign and monitor work, provide feedback, and provide ongoing review of staff competency;

- Practice of Engineering (POE), which defines the required professional registration for engineering staff, defines scope of practice and specifies qualifications for the Engineer-in-Charge; and

- Performance Management Process, used to establish annual performance expectations and document the development and training plan of each employee.

Management System Audit Sub-Element Finding: Based on documents reviewed and interviews with personnel, TransCanada was able to demonstrate that it was in compliance with the requirements of the OPR-99 and CSA Z662-11, and is therefore compliant with the requirements of this audit sub-element.

Compliance Status: Compliant

3.4 Communication

Expectations: The Company shall have an adequate, effective and documented communication process(es):

- to inform all persons associated with the Company's facilities and activities (interested persons) of its management and protection programs policies, goals, objectives and commitments;
- to inform and consult with interested persons about issues associated with its operations;
- to address communication from external stakeholders;
- for communicating the legal and other related requirements pertaining to the management and protection programs to interested persons;
- to communicate the program's roles and responsibilities to interested persons.

References:

OPR-99 sections 4, 18, 28, 29, 40, 47 and 48
CSA Z662-11 Clauses 3.1.2 (d) and 3.2

Audit Assessment

This Management System sub-element was not formally assessed during the Integrity Management Program audit.

Compliance Status: Not Assessed

3.5 Documentation and Document Control

Expectations: The Company shall have documentation to describe the elements of its management and protection programs- where warranted. The documentation should be reviewed and revised at regular and planned intervals. Documents should be revised immediately where changes are required as a result of legal requirements or where failure to make immediate changes may result in negative consequences. The Company should have procedures within its management and protection programs to control documentation and data as it relates to the risks identified in element 2.0.

References:

OPR-99 sections 4, 27, 47 and 48
CSA Z662-11, Clauses 3.1.2 (e)(f), 3.2 and 10.5.1.1 (d)

Audit Assessment

This Management System sub-element was not formally assessed during the Integrity Management Program audit.

Compliance Status: Not Assessed

3.6 Operational Control-Normal Operations

Expectations: The company shall establish and maintain a process to develop, implement and communicate mitigative, preventive and protective measures to address the risks and hazards identified in elements 2.0 and 3.0. The process shall include measures to reduce or eliminate risks and hazards at their source.

References:

OPR-99 sections 4, 27, 36, 37, 39 and 40
CSA Z662-11, Clause 3.1.2(f), 3.2 and 10

Audit Assessment:

General

During interviews and in documents submitted, TransCanada stated that it establishes and maintains processes to develop, implement and communicate surveillance and condition monitoring, and preventive, protective, mitigative, and remedial measures to address identified risks and threats.

Once TransCanada has completed its risk analysis and threat identification, integrity actions are selected to control and manage identified and potential threats. The selected actions are documented in TransCanada's annual Pipe and Facility Maintenance Plans (Maintenance Plans). Following implementation of the Maintenance Plans, the results are analyzed as part of TransCanada's improvement cycle. The audit confirmed that the processes for the development of the Maintenance Plans are documented in TransCanada's Integrity Management Programs (IMPs). The relevant sections of the IMPs are:

- Gas Pipeline IMP, Sections 11 and 12;
- Liquid Pipeline IMP, Sections 6 and 9; and
- Plant IMP, Sections 4 and 5.

TransCanada's Pipe Integrity Threat Management Programs (Threat Management Programs) provide a listing of appropriate integrity measures employed for managing specific types of threats. The Threat Management Programs are as follows:

- Mechanical Damage Threat Management Program (TEP-ITM-MECH, EDMS No. 006786487);

- External Corrosion Threat Management Program (CDN) (TEP-ITM-ECOR, EDMS No. 006570955);
- Internal Corrosion Threat Management Program (TEP-ITM-IC, EDMS No. 006786402);
- Stress Corrosion Cracking Threat Management Program (TEP-ITM-SCC-CDN, EDMS No. 005767613);
- Equipment Failure Threat Management Program (TEP-ITM-EQUIP, EDMS No. 006786449);
- Incorrect Operations Threat Management Program (TEP-ITM-IOPS, EDMS No. 006810297);
- Construction and Manufacturing Threat Management Program (TEP-ITM-MANUF, EDMS No. 006786458);
- Weather and Outside Forces Management Program (TEP-ITM-WOF, EDMS No. 005767611); and
- Facility Pipe Threat Management Program (CDN) (TEP-ITM-FPIPE-CDN, EDMS No. 007379193).

The reviewed threat control and risk reduction activities employed by TransCanada can be divided into the following five categories (discussed in more detail below): surveillance and condition monitoring; proactive measures; preventive measures; mitigative measures; and remedial measures. These threat control and risk reduction activities are addressed within the Gas Pipeline IMP, Liquid Pipeline IMP, and the Plant IMP, as well as within the individual Threat Management Programs.

Surveillance and Condition Monitoring

Surveillance and condition monitoring is used to detect the presence of threats and monitor threat progression. TransCanada's activities associated with surveillance and condition monitoring include:

- Pipeline patrols (TOP Pipeline Right of Way Procedures Canada (EDMS No. 003672613), TOP Aerial Pipeline Patrol (EDMS No. 003672387) and Pipeline Ground Based Patrols (EDMS No. 003875137));
- Leak detection surveys (Natural Gas Leak Detection Procedure Canada (EDMS No. 003676669));
- Cathodic protection surveys (TEP-CP-PRGM Corrosion Prevention Program (EDMS No. 006786483) and TES-CP-SS Cathodic Protection Survey Specification (EDMS No. 003670956));

- Geotechnical and water crossing surveys (Phase I Geologic Hazards Assessment Canadian Portion of the Keystone Oil Pipeline Alberta, Saskatchewan, Manitoba, Canada (103-93179), TEP-ITM-WOF Weather and Outside Forces Management Program (EDMS No. 007773954) and TOP Pipeline Underwater Inspections (EDMS No. 003671756)); and
- Various types of facilities and equipment inspections, with some examples of these being the TransCanada Engineering Procedures (TEP) or TransCanada Operating Procedures (TOP) as follows: TEP-ITM-FPIPE-CDN Facilities Piping Integrity Management Program (EDMS No. 007379193), TEP-ITM-EQUIP Equipment Failure Threat Management Program (EDMS No. 006786449), TOP Critical Gas Pressure Regulator Inspection and Maintenance (DEMS No. 007585439), TOP Valve and Valve Operator Inspection and Servicing (EDMS NO. 003849601), TOP Control Valve Inspection Canada and Mexico (EDMS No. 003832589) and TOP Pipeline Pressure Relief Valve Blow Off Valve Inspection (EDMS No. 003866831).

Preventive Measures

Preventive measures are intended to eliminate or prevent the presence of a threat and may include improved manufacturing and construction practices, improved material selection, increased security, public awareness activities and signage. The Board reviewed several TransCanada Operating Procedures (TOPs) that describe and direct TransCanada's Public Awareness Program (PAP). TransCanada's PAP is intended to eliminate or reduce potential third-party damage through communications with the public, excavators and contractors, emergency officials and local public officials. The Public Awareness Program is documented in the TOP Pipeline Public Awareness Program Plan (EDMS No. 003860909). The TOP One Call and Locating and Marking Procedures Canada (EDMS No. 003671859) details the necessary steps to complete prior to undertaking activities such as any ground disturbance, heavy equipment travel, excavating, blasting, or construction within 30 meters of facilities. The TOP TransCanada Signage Procedure (EDMS No. 003676680) provides information on sign types, sizes, content and posting areas, depending on the intent of the sign. While documents were received with respect to TransCanada's PAP, it was not assessed in detail in this IMP audit.

Protective Measures

Physical protective measures are intended to guard the pipeline and facilities equipment against damage and failure. Coatings are an example of protective measures, as they are intended to separate the pipe from sources of corrosion. The consensus in industry is that corrosion prevention is most effective when a high integrity coating is used in conjunction with cathodic protection. The Board reviewed TransCanada's Corrosion Prevention Program (TEP-CP-PRGM,

EDMS No. 006786483, TES-CP-CR Cathodic Protection Criteria Specification EDMS No. 00378793, and TES-CP-SS Cathodic Protection Survey Specification EDMS No. 003670956) detailing the characteristics of its program to mitigate corrosion on protected structures using cathodic protection and assessed it to be adequate.

Mitigative Measures

Mitigation methods are intended to reduce failure probability or failure consequences, and include methods such as pressure reduction, pipe material upgrades, slabbing over pipelines, increased backfill, equipment upgrades, pipeline rerouting, corrosion inhibitor injection, secondary containment and pig cleaning runs. The methods considered for risk reduction and threat control depend on the threat type. During the audit, the Board noted that TransCanada's IMPs, as well as the Threat Management Programs, included adequate mitigative options to address potential threats and risks. For example, preventive and mitigative measures are detailed in Section 9 of the Liquid Pipeline IMP.

Remedial Measures

Remediation is completed to correct known issues, such as pipeline defects and excessive stresses due to geotechnical concerns (e.g. ground movement). Data inputs, such as defect assessments, hydrostatic testing, monitoring measurements, and indirect examination results are analyzed to identify areas requiring further investigation and/or repairs. During the audit, the Board noted that TransCanada's Threat Management Programs and IMPs reference specific procedures for gathering additional data, analyzing monitoring and assessment results, and assessed them as being adequate.

The audit examined examples of TransCanada's procedures for analyzing in-line inspection results, where imperfections are evaluated to determine threats to the integrity of the pipeline. Special consideration is given to features such as dents, girth welds or seam welds that might be associated with other conditions. The following TransCanada procedures detail the approaches to analyze in-line inspection results:

- Analysis of Deformation In-Line Inspection Data for Canadian Pipelines (TEP-ILI-DEF-CDN, EDMS No. 006980190);
- Analysis of EMAT Crack Detection In-Line Inspection Data for Gas Pipelines (TEP-ILI-EMAT, EDMS No. 006980178);
- Analysis of Hard Spots in In-Line Inspection Data (TEP-ILI-HS, EDMS No. 006980212); and
- Analysis of In-Line Inspection Data (TEP-INT-ILI-CDN, EDMS No. 006570876).

Activities such as direct evaluation and hydrostatic testing may be required to further characterize suspected and identified features. Methods of defect repair include recoating, pipe cut-outs and strain reliefs, as well as installation of sleeves, composite reinforcement wraps and clamps. Assessments and anticipated remedial measures are then included in TransCanada's Maintenance Plans.

Defect Assessment and Repair Procedures

For investigation of known or suspected features, non-destructive testing methods may be used, and might require pipeline exposure. A temporary reduction in operating pressure or other safety measures may be implemented to ensure that safety is maintained. Analysis of the data gathered in consideration of the design, material, construction, operating and maintenance history and expected operating conditions of the pipeline determines appropriate remediation and repair methods necessary to return the pipeline to full service. During the audit, the Board reviewed TransCanada's procedures that are relevant to these activities:

- TOP Pipeline Restriction Procedure (EDMS No. 003820831);
- TOP Pipeline Defect Assessment and Repair Procedures (EDMS No. 003674615);
- TOP Maximum Pressure for Pipelines With Known or Suspected Integrity Concerns (EDMS No. 003671945); and
- Assessment of Features in Pipelines (TEP-INT-FASS, EDMS No. 004214235).

The Board also reviewed records of TransCanada's voluntary pressure restrictions that were in place during pipe exposure, defect assessment and repair and noted that TransCanada had followed its required procedures.

Hydrotest Procedures for Defect Testing

Pressure testing is a method that produces a pass/fail result for defects contained in the pipeline test segment. Defects detected through pressure test failures are remediated by removal/replacement of the affected pipe segment. Hydrostatic Test Specification for Integrity Testing of Existing Pipelines (TES-HYDRO-HT4, EDMS No. 003697288) describes the procedure for pressure testing an existing pipeline to validate its suitability for continued operation at a previously qualified maximum operating pressure. During the audit, the Board reviewed TransCanada's hydrotest procedure and assessed it as being adequate.

Approving, Documenting and Communicating the Maintenance Plans

Maintenance Plans for the remedial activities described previously are presented to TransCanada management for review and approval. For Pipe Integrity, information on the Maintenance Plan is communicated as per Pipe Integrity Communication Procedure (TEP-INT-COMM, EDMS No. 006980248). The Vice President of Engineering and Asset Reliability approves the Maintenance Plans for Pipe Integrity and Facilities Integrity. Preventive maintenance work is communicated, documented and tracked in Avantis, which is a maintenance management system that is used by TransCanada.

Maintenance Plan Implementation

Maintenance Plans are implemented by integrity personnel, central planning personnel, regional staff, and project managers of Pipeline Maintenance Projects, as appropriate. A program schedule is developed based on the urgency of risk reduction, operational efficiencies, resource and material availability and access. Repair or mitigation of known conditions may be scheduled independently of other activities if an urgent action is required. If a planned activity cannot be completed within the established timeframe, justification for the deferral and an explanation of why the change will not jeopardize integrity are documented through either a variance (System Improvement Decision Summary Variance Approval, EDMS No. 003909431) or a management of change (TEP-INT-MOC Pipe Integrity Management of Change Procedure, EDMS No. 006425143), as appropriate. A temporary reduction in operating pressure or other appropriate actions may be required. Section 12 of the Gas Pipeline IMP, Section 7 of the Liquid Pipeline IMP, and Sections 4 and 5 of the Plant IMP address implementation of the Maintenance Plans.

Conducting Maintenance Plans

TransCanada stated that all surveillance and condition monitoring, as well as preventive, protective, mitigative and remedial activities, are conducted, managed and monitored in a manner that is intended to minimize environmental and safety risks. The Health, Safety and Environment (HS&E) Management System (EDMS No. 003721961) contains more specific information on how these risks are managed. HS&E was not in the scope of the audit and was therefore not assessed during this IMP audit.

Maintenance Plan Evaluation and Communication

Evaluations of the effectiveness of Maintenance Plans are completed periodically by TransCanada's Integrity Program Managers, Threat Program Managers, and Integrity Plan owners in consideration of the following:

- past and current assessment results;

- data integration and risk assessments;
- remediation results;
- performance of new technology or applications;
- non-conformances/non-compliances;
- performance measures; and
- incident investigations.

The maintenance plan evaluation results may be used to modify the programs, if required. For Pipe Integrity, the evaluations are documented in threat-specific Pipeline Maintenance Annual Reports and in the Assessment Plan for hazardous liquids. The Pipeline Maintenance Plan Annual Reports are communicated to management as per the Pipe Integrity Communication Procedure (TEP-INT-COMM, EDMS No. 006980248). For Facilities Integrity, Maintenance Plan results are communicated to management through performance measure reports, activity reports and integrity plans.

Summary: Operational Control-Normal Operations

The Management System Audit Element 3.6, Operational Control – Normal Operations, requires a company to establish and maintain a process to develop, implement and communicate measures meant to mitigate, prevent and protect against the hazards identified in sub-sections 2.0 and 3.0. This includes measures to proactively reduce or eliminate risks and hazards at their source.

The audit determined that TransCanada's threat management programs provide a listing of appropriate integrity measures for managing identified risks and threats. Some of these threats include but are not limited to: pipeline corrosion; construction and manufacturing; weather and outside forces; and mechanical damage.

TransCanada was found to manage these risk and threats through in the following ways:

- Surveillance and condition monitoring used to detect the presence of threats and monitor threat progression;

- Preventative measures intended to eliminate or prevent the presence of threats such as improved material selection, public awareness activities and signage;

- Physical protective measures intended to protect infrastructure from damage and failure such as pipeline coating to prevent corrosion;

- Mitigation measures to reduce the probability of failure and related consequences such as pipeline rerouting, pressure reductions and equipment upgrades;

- Remediation to correct known issues (including maintenance plan development, implementation evaluation and communication);

- Non-destructive testing methods to investigate known or suspected anomalies; and

- Hydrotesting that produces a pass/fail result for defect identification.

Management System Audit Sub-Element Finding: Based on documents reviewed and interviews with personnel, TransCanada was able to demonstrate that it was in compliance with the requirements of the OPR-99 and CSA Z662-11, and is therefore compliant with the requirements of this audit sub-element.

Compliance Status: Compliant

3.7 Operational Control-Upset or Abnormal Operating Conditions

Expectations: The company shall establish and maintain plans and procedures to identify the potential for upset or abnormal operating conditions, accidental releases, incidents and emergency situations. The company shall also define proposed responses to these events and prevent and mitigate the likely consequence and/or impacts of these events. The procedures must be periodically tested and reviewed and revised where appropriate (for example, after emergency events).

References:

OPR-99 sections 4, 32, 37, 40 and 52
CSA Z662-11, Clauses 3.1, 3.2, 4.18, 10.9.5

Audit Assessment:

General

During interviews and in documents submitted, TransCanada stated that it has the operational controls and procedures that are to be followed to identify the potential for operational upset or abnormal operating conditions, and it has developed the plans and procedures to prevent and mitigate the impacts of these upset or abnormal operating events. TransCanada also submitted procedures that would be implemented in response to pipeline and facilities upset or abnormal operating conditions, including accidental releases, incidents or emergency situations. TransCanada's emergency response plan (ERP) was not within the scope of this audit and was therefore not assessed during this IMP audit.

Pipelines – SCADA

Oil Control Operations

The Keystone Pipeline is remotely monitored and controlled from TransCanada's Calgary based Oil Control Centre (OCC). Pipeline controllers at the OCC are responsible for the overall operation of the pipeline 24 hours a day, 365 days a year. Pipeline controllers monitor critical data points along the pipeline and are able to issue supervisory commands such as pump start/stop and valve open/close commands using a computerized Supervisory Control and Data Acquisition (SCADA) system. To address service reliability, the OCC has fully redundant SCADA and leak detection systems. In the event of a SCADA or leak detection system failure, a hot standby system will immediately take over. If both the OCC primary and standby systems become unavailable due to a catastrophic event, a secondary Back-Up Control Centre contains

full duplicate primary and secondary SCADA and leak detection systems. CSA Z662-11, Annex M (Informative), Guidance for System Control, Monitoring and Protection of Liquid Pipelines, provides non-mandatory guidance for the use of SCADA. TransCanada's use of a SCADA system for the Keystone Pipeline conforms to this non-mandatory guidance.

The Keystone Pipeline is operated in accordance with its written operating procedures for normal, abnormal and emergency operations. TransCanada stated that the procedures comply with CSA Z662-11, Clause 10.5.2, Pipeline Emergencies. OCC procedures are documented and available to the OCC controllers via an internal OCC website. The OCC procedures include normal operations, abnormal/emergency operations, leak detection operations and incident management. The OCC emergency procedures were outside the scope of this IMP audit and were not formally assessed.

Examples of TransCanada's Operating Procedures (TOPs) provided to support operational control are: TOP Emergency Shutdown System Inspection (EDMS NO. 003830466), TransCanada Commissioning Procedures, Station Control System and Commissioning Check Sheet - Station Control System (both documents have an effective date of 2012/05/01 but have no document ID numbers), and SCADA Mainline Unit speed Control Commissioning Guide (Document ID N/A, but the internal TransCanada Website address is given as http://wscada).

Gas Control Operations

TransCanada's gas pipeline operations are remotely monitored and controlled from the Calgary Gas Control (GC) Centre. Pipeline controllers are responsible for the overall operation of the pipeline 24 hours a day, 365 days a year. The pipeline controllers monitor critical data points along the pipeline and are able to issue supervisory commands such as compressor start/stop and valve open/close commands using a computerized SCADA system. To address service reliability, the Gas Control SCADA systems are fully redundant. If the primary SCADA system fails, a hot standby system will immediately take over. If both the Gas Control primary and standby systems become unavailable due to a catastrophic event, a secondary Back-Up Control Centre contains a full duplicate primary and secondary Gas Control SCADA system. CSA Z662-11, Annex M (Informative), Guidance for System Control, Monitoring and Protection of Liquid Pipelines, provides non-mandatory guidance for the use of SCADA for liquids pipelines only. TransCanada's use of a SCADA system for its gas pipeline operations is voluntary and conforms to the intent this non-mandatory guidance.

TransCanada's gas pipeline system is operated in accordance with written operating procedures for normal, abnormal and emergency operations. TransCanada stated that the procedures comply

with CSA Z662-11, Clause 10.5.2, Pipeline Emergencies. Gas Control consists of two processes, the Monitor and Control Process (EDMS No. 003835728) and the Emergency Preparedness and Response Process (EDMS No. 003835729). The Monitor and Control Process describes the methodology used to ensure that the 24-hour operation of the pipeline system is carried out under controlled conditions. The Emergency Preparedness and Response (ERP) Process describes the methodology used to ensure programs, processes and plans are in place to ensure controlled responses to emergency situations. While TransCanada provided information on its emergency preparedness and response program, its ERP program was not formally assessed in this IMP audit.

Facility Automation

Oil Operations

During the audit interviews, TransCanada stated that the Keystone Pipeline pump stations and all other oil pipeline facilities, including terminals and pipeline isolation valve sites, are equipped with fully automated control systems. These control systems monitor critical parameters, such as pressures and flows, 24 hours a day, 365 days a year, and will automatically regulate these parameters as required. If any parameter exceeds normal operating limits, the local control system will automatically shut down the oil facility. Key elements of the facility control systems, as related to abnormal or emergency operations, are: facility emergency shutdown (ESD) and isolation; pressure control and overpressure protection; and fire detection.

Gas Operations

During the audit interviews, TransCanada stated its compressor stations are equipped with fully automated control systems. These control systems monitor critical parameters, such as pressures and temperatures, 24 hours a day, 365 days a year, and will automatically regulate these parameters as required. If any parameter exceeds normal operating limits, the local control system will automatically shut down the facility. Key elements of the gas facility control systems, as related to abnormal or emergency operations, are: facility ESD and isolation; pressure control and overpressure protection; and fire and gas detection.

CSA Z662-11, Clause 10.9.1.1, Compressor and Pump Units, states that *"Gas compressor and pump units shall be started, operated, and shut down in accordance with procedures established by the operating company"*. TransCanada's facility automation for both its oil and gas operations is in compliance with the requirements of CSA Z662-11.

Station ESD and Isolation

Oil Operations

During the audit interviews, TransCanada stated that its pump stations are equipped with an ESD system that is designed to automatically isolate the station from the pipeline upon the occurrence of abnormal conditions. An ESD event will result in the immediate shutdown of all pumps, both the mainline pumps as well as sump re-injection pumps. Once the pumps have shut down, the station mainline bypass valve opens and station suction and discharge side valves close. The station valves are interlocked so that the station suction and discharge side valves do not close until the station mainline bypass valve is fully open. Once a pump station is in emergency shutdown, it is locked out to the OCC until the incident is investigated and cleared by a facility technician. An "Isolate" command is also available to the OCC and is intended for non-emergency isolation at the pump station. This will result in the station bypass valve opening and the side valves closing, but will not lock out the facility to the OCC. Similar ESD systems are in place at oil receipt facilities.

CSA Z662-11, Clause 4.14.3.3(a) states that "*Pump stations shall have emergency shutdown systems that meet the following requirements: (a) Such systems shall provide a means to block liquids out of the station.*" TransCanada is assessed to be compliant with this requirement. The OPR-99, section 12(a) states that "*A compressor station or pump station shall be equipped with an alternate source of power capable of (a) operating the station's emergency shut-down system*". On 6-9 June, 2011, NEB staff conducted an inspection of Keystone's Portage La Prairie, Rapid City, Moosomin and Richardson pump stations located in Manitoba and Saskatchewan. The inspection revealed that the pump stations on the Keystone system are not equipped with an alternate source of power capable of operating each station's ESD system and NEB staff identified this as a non-compliance with subsection 12(a) of the OPR-99.

On 17 August 2012, the Board issued Order SO-T241-002-2012 directing TransCanada to provide a corrective action plan to address a non-compliance to the OPR-99 sub-section 12 (a). TransCanada had been found non-complaint with the OPR-99 sub-section 12 (a) because it did not have an alternate source of power capable of operating its pump station's ESD systems. The Board accepted TransCanada's corrective action plan with Amending Order AO-001-SO-T241-002-2012 on 15 October 2012. The corrective action plan is being implemented and all corrective actions are to be completed by 31 March 2014.

Gas Operations

If the facility programmable logic controller (PLC) detects a fire or high gas concentration, or an over-pressure condition, it automatically initiates a plant ESD. The ESD will isolate the affected plant by closing all adjacent yard valves and opening blow-off valves to vent yard piping. A fire condition will also cause plant fire suppression systems to activate, where installed.

Pressure Control and Over-Pressure Protection

Oil Operations

TransCanada stated that its oil pressure control and over-pressure protection systems are designed in accordance with CSA Z662-11, Clause 4.18.2: General Design Requirements for Systems for Pressure Control and Over-pressure Protection, to ensure that the failure of either system will not cause the other to become inoperative.

Pump station suction and discharge pressures are controlled via a combination of pump speed control and pressure control valve modulation. The majority of pump stations are fitted with variable frequency drives to control pump speed, and all pump stations are fitted with a pressure control valve on the discharge side of the pump station. Upon loss of the control system, all pumps at that station will trip and SCADA will drive the upstream pump station to safe discharge pressure settings.

Pump station suction and discharge pressures are monitored by the local facility control system and the SCADA system for over-pressure conditions. If suction pressures exceed safe limits, all pumps at all stations upstream of the station with the high suction pressure will be immediately shut down. If discharge pressures exceed safe limits, all pumps at that station will be immediately shut down. If the SCADA system detects a blocked flow path (such as a valve closure) anywhere on the pipeline, then all pumps at all stations upstream of the facility with the blocked flow will be immediately shut down.

Gas Operations

TransCanada's Gas Control Over-Pressure Procedure (EDMS No. 003723302) references six levels of protection to prevent pipeline over-pressure. Four levels of protection take place at compressor station locations and protect against over-pressure conditions that are initiated by the compressor station only. The fifth and sixth levels of protection, which augment the compressor station controls, protect against other sources of pipeline over-pressure. If an over-pressure condition occurs, a station's programmable logic controllers (PLCs) has the ability to slow down the operating parameters of the unit, shut down the unit completely, or relieve the pressure via

unit or station relief valves. TransCanada stated that typically, over-pressure protection is also provided at upstream producer facilities. Requirements for these protection systems are directed under the Gas Tariff.

Over-Pressure Hazard

The Board identified a non-compliance with this audit element related to the management of the over-pressure hazard on the NOVA Gas Transmission Ltd. (NGTL) system receipt meter stations. The Board determined that NGTL is not conducting sufficient inspections or audits of its customer's installations to ensure that the NGTL system is operated in compliance with CSA Z662-11, Clauses 4.18.1.1, 4.18.1.2 and 4.18.2, and as required by the OPR-99 sections 4 and 53(1).[3]

CSA Z662-11, Clause 4.18.1.2 states that "*where failure of the pressure-control system, or other causes, can result in the maximum operating pressure of the piping being exceeded, overpressure protection shall be installed to ensure that the maximum operating pressure is not exceeded by more than 10% or by 35 kPa, whichever is greater.*"

The CSA Z662-11 design requirements for over-pressure protection (OPP) are specified in sub-clause 4.18.2 as:

"Systems for pressure control and over-pressure protection shall:

(a) be designed such that a failure in either system cannot cause the other system to become inoperative;

(b) be designed with sufficient capacity and sensitivity for the intended service;

(c) be designed for the intended service environment;

(d) be designed and installed so that they can be readily tested, inspected, and calibrated;

(e) be designed and installed to prevent unauthorized operation of valves or equipment that would make these systems inoperative;

(f) be designed to minimize the risk of being physically damaged; and

(g) where practicable, be designed such that a failure will not result in an over-pressure condition of the piping".

The NEB has reviewed TransCanada's past incident history and identified over-pressure incidents on the NGTL system. Through an Audit Information Request and audit interviews with TransCanada, TransCanada was asked to demonstrate how the NGTL approach of relying on its customers and NGTL's General Terms and Agreement (GTA) meets the requirements of CSA

[3] See the amended and re-named *National Energy Board Onshore Pipeline Regulations*, sections 4 and 53(1), for the corresponding provisions.

Z662-11, Clause 4.18 and the OPR-99 sections 4 and 53(1). In addition, NGTL was asked whether it had implemented the preventative actions highlighted in the NEB's Safety Advisory (NEB SA99-1), which referenced the requirements of CSA Z662-11, Clause 4.18.1.2, on OPP at Receipt Points, issued in September 1999.

TransCanada stated that, as a result of its over-pressure incidents, it had initiated a review of how its customers meet the GTA. TransCanada stated that in December 2010 it implemented a procedure for new meter stations that verifies that the customer's OPP meets CSA Z662-11 requirements. TransCanada stated that it has reviewed its customers' philosophies concerning how they meet the GTA for 30 receipt meter stations and that it is currently developing a plan to verify compliance to OPP requirements on approximately 1100 additional receipt meter stations.

Further, TransCanada indicated that in February 2012, it had communicated the following OPP Plan of Action to its customers:

- TransCanada will re-initiate verification of its OPP requirements with NGTL customers in April 2013.
- NGTL stakeholders (including customers) will be informed at that time that in order to be compliant with CSA Z662-11, the OPR-99 and NEB Safety Advisories, NGTL will require information from all Interconnecting Operators at receipt meter stations regarding the status of their OPP Systems.
- Failure to provide adequate information regarding the status of the Interconnecting Operator's OPP System may ultimately result in either the shut-in of the receipt stations, or installation at the customer's cost of OPP systems at the NGTL receipt stations.
- A risk-based methodology is used to determine the meter station information required to allow both TransCanada and its customers to prioritize the meter stations under initial review in 2013. The balance of the meter station information will be required and reviewed by the end of 2014.
- Currently, meter stations with one or more of the following characteristics are prioritized to provide OPP information:
    - The meter station has an automated block valve;
    - The meter station has had a prior over-pressure event; and
    - The meter station has one or more producer tie-ins where there are a number of unclear areas on how to ensure OPP. In such cases OPP information will be required from all of the applicable upstream operators.

Based on the history of over-pressure incidents on the NGTL system, the fact that TransCanada only recently initiated a Plan of Action to verify compliance with the OPP requirements of CSA

Z662-11, Clause 4.18, and the fact that the Plan of Action has not been fully implemented, TransCanada is not in compliance with this audit sub-element.

Pressure-Limiting and Pressure-Relieving Systems

Oil Operations

Relief valves on the Keystone Pipeline are tested annually, as directed under TransCanada's Relief Valve Inspection and Overhaul Maintenance for Oil Pipelines Procedure (EDMS No. 007603025), and in accordance with CSA Z662-11, Clause 10.9.5.3. TransCanada is currently assembling the supporting evidentiary data as required by CSA Z662-11, Clause 10.9.5.3(b) to assess and justify an appropriate alternate pressure-relief system inspection and maintenance interval for these facilities.

Gas Operations

The audit identified that settings for mechanical relief valves, as well as pressure relief set-points coded into the control system, are managed according to TransCanada's document Compressor Station Limits Canada (EDMS No. 003671820).

During the audit, TransCanada stated that it overhauls conventional and pilot-operated pressure relief valves at three or five-year intervals, in accordance with CSA Z662-11, Clause 10.9.5 Pressure-control, pressure-limiting and pressure-relieving systems and/or API 576, Inspection of Pressure Relieving Devices. CSA Z662-11, Clause 10.9.5.3(b) states that *"pressure-relieving systems (or devices), except for rupture disks, shall be inspected, assessed, and tested, at least once per calendar year with a maximum interval of 18 months (Clause 10.9.5.3(a)) or at intervals appropriate to their application and operation, as determined by the operating company, as specified in API 576, and in accordance with supporting evidentiary data and documentation (Clause 10.9.5.3(b))."*

The audit determined that TransCanada is moving to a five-year inspection and maintenance interval for its pressure-relief inspection and maintenance program, as it assesses the requirements for each site under its internal audit process according to the TOP Pressure Relief Valve Audit Procedure (EDMS No. 003954090). TransCanada's Pressure Equipment Quality Management System (QMS) and CSA Z662-11, Clause 10.9.5.3(b) both require TransCanada to review the equipment to justify extension of inspection intervals. TransCanada stated that, to date, no incidents have listed the longer pressure-relief inspection and maintenance interval as a contributing factor, and no increase in relief valve incidents have occurred since the move to the longer interval was initiated. Based on the evidentiary data and documentation as required by

CSA Z662-11, Clause 10.9.5.3(b), TransCanada's rationale for the increased inspection interval is in compliance with requirements for pressure-relief valve inspection and maintenance.

Leak Detection

Oil Operations

The audit identified that TransCanada's leak detection methodology on oil systems is performed via a computerized Leak Detection system that alerts the Oil Control Centre (OCC) controller of any suspected leak event, so that the controller can take appropriate action to shut down and isolate the pipeline system. In addition, aerial patrols are performed 26 times a year (TOP Aerial Pipeline Patrol, EDMS No. 003672387). If a leak is identified during an aerial patrol, the OCC is notified to immediately shut down and isolate the system. CSA Z662-11, Clause 11.18, Leak Detection, requires that "*Where appropriate, pipelines shall have leak detection systems. Leak detection devices and procedures, where used, shall be capable of providing early detection of leaks. Where appropriate, line balance methods may be used.*" TransCanada's leak detection system for its oil operations is in compliance with the CSA Z662-11 requirements.

Gas Operations

During the audit, TransCanada stated that if a leak is detected or suspected on a gas pipeline, the guidance provided under the Pressure Control of Leaking Pipelines (EDMS No. 003841207) is followed to manage the confirmed or suspected leak. Leak detection on gas pipeline systems is also performed via regularly scheduled aerial and ground based patrols in accordance with the Natural Gas Leak Detection Procedure (EDMS No. 003676669) and the Pipeline Integrity Leak Detection and Evaluation Procedure (TEP-INT-LEAK, EDMS No. 007379105). These procedures describe the requirements to perform natural gas leak detection activities. CSA Z662-11, Clause 11.18, Leak Detection, requires that "*Where appropriate, pipelines shall have leak detection systems. Leak detection devices and procedures, where used, shall be capable of providing early detection of leaks. Where appropriate, line balance methods may be used.*" TransCanada's leak detection system for its gas operations is in compliance with the CSA Z662-11 requirements.

Gas Quality

As mentioned in the audit sub-element 4.1 Inspection, Measurement and Monitoring, TransCanada has identified key personnel, such as field technicians and gas controllers, who are trained to identify and manage gas quality off-specification Tariff conditions. The governance and systematic approach to managing gas quality are outlined in the Gas Quality Procedure (EDMS No. 003671916) and the H_2S Risk Mitigation Procedure (EDMS No. 003999947). At

locations where sour potential or other contaminants are of concern, additional instrumentation and automated equipment is employed with shut-in capability. In the event that a sour gas slug is introduced to the pipeline system, the Alberta and Foothills System H_2S Contamination Procedure (EDMS No. 003723279) provides procedures and guidelines for Gas Control to manage the H_2S contamination event. Records of TransCanada's gas quality monitoring program were examined in conjunction with the assessment of the Internal Corrosion Threat Management Program (Ref_2_2012 IC Susceptible Lines.xlsx). The programs that TransCanada has developed and implemented to manage gas quality are in compliance with the requirements of the OPR-99, section 6.5(1) (e) and (f).

Fire and High Gas Concentration Detection

During the audit, TransCanada stated that all stations are equipped with sensors to continuously monitor for both fire (gas and oil facilities) and high gas concentrations (gas facilities only), as per CSA Z662-11. Clause 4.14.2.7 states that "*compressor buildings shall have suitable systems for the detection of fire and hazardous atmospheres*" and Clause 4.14.3.5 states that "*pump buildings shall have suitable systems for the detection of fire and hazardous atmosphere*". TransCanada stated that, as directed by its Fire Detection Equipment Inspection Procedure (EDMS No. 005018693), the fire and gas detection equipment are tested and calibrated on prescribed maintenance schedules, typically annually or bi-annually, depending on the type of detection equipment. Fire and gas detection equipment are on an annual inspection and maintenance interval. Catalytic gas detectors have a known susceptibility to gas "poisoning" over time, which may reduce their ability to detect gas. Although catalytic gas detectors are not typically exposed to gas during normal operations, bi-annual inspections are prescribed by TransCanada as a preventive measure.

In terms of the applicable regulatory requirements for an inspection schedule, CSA Z662-11 remains silent on the inspection and maintenance interval requirements as does the American Petroleum Institute (API) and the National Research Council Canada (National Fire Code of Canada, 2010). In general terms, the OPR-99 section 36(b), states that "A company shall periodically test instruments and equipment at the pipeline stations to verify their proper and safe operation."[4] TransCanada's inspection and maintenance program frequencies for its fire and gas monitoring equipment are therefore assessed to be compliant with these requirements.

[4] See the amended and re-named *National Energy Board Onshore Pipeline Regulations*, section 36(b), for the corresponding provision.

Alarm Call-Out System

During the audit, TransCanada identified its gas control and oil control personnel who monitor the pipeline system and acknowledge all alarms that come in through the SCADA system. The alarms are grouped in "bundles" that allow the operator to identify from which sub-system the alarm originates. The operator then notifies the appropriate field personnel to respond to and investigate the alarm. Gas Control direction is provided under the Alarm and Event Management Procedure (EDMS No. 003821127). Oil Control direction is provided via various procedures available on the OCC web page. TransCanada's alarm call-out system relates to its emergency preparedness and response program, which was not included in the scope of this audit and therefore not formally assessed.

Shutdown Devices and Systems

During the audit, TransCanada stated that each compressor and pump station contains instrumentation and controls which include pressure transmitters, pressure switches, mainline valve pressure switches, blow-off valve high-pressure switches, level switches and mainline pressure and temperature transmitters. To ensure the equipment is configured and functions correctly, guidance is provided under the Control and Monitoring Inspection Procedure (EDMS No. 003834760). CSA Z662-11, Clause 10.9, Operation and Maintenance of Facilities and Equipment, and more specifically, sub-clause 10.9.1, Compressor and Pump Stations, states that "*gas compressor and pump units shall be started, operated, and shut down in accordance with procedures established by the operating company*". TransCanada's shutdown devices and systems are in compliance with the requirements of CSA Z662-11.

Valve Operation

TransCanada stated that remotely located mainline valves on gas pipelines are equipped with low-pressure shut-off devices which, when a low-pressure condition is observed, will automatically close the valve isolating the pipeline section. Remote mainline valves on the Keystone Pipeline are electrically actuated and can be closed and opened, as required, via remote command from the OCC.

The following procedures provide guidance to ensure that pipeline valves (oil and gas) operate as required during normal, abnormal and emergency conditions:

- Control Valve Inspection (EDMS No. 003832589);
- Gate Valve Position Inspection (EDMS No. 006493970);
- Oil Pipeline Valve and Valve Operator Inspection (EDMS No. 005505594);
- Control Valve Inspection Canada and Mexico (EDMS No. 0038332589);

- Valve and Valve Operator Leak and Cycle Test (EDMS No. 003864109); and
- Valve and Valve Operator Inspection and Servicing (EDMS No. 003849601).

CSA Z662-11, Clause 10.9, Operation and Maintenance of Facilities and Equipment, and more specifically, sub-clause 10.9.6.2, Valves, states that "*Pipeline valves that can be necessary during an emergency shall be inspected and partially operated at least once per calendar year, with a maximum interval of 18 months between such inspections and operations*." TransCanada's procedure, Valve and Valve Operator Inspection and Servicing (EDMS No. 003849601), Section 3.0 Frequency, specifies that "*inspection shall be conducted once per calendar year with a minimum interval between inspections of 18 months*." TransCanada's task package Control Valve Inspection Canada and Mexico (EDMS No. 0038332589), Section 3.0 Frequency, specifies "*the standard frequency for performing the inspection is M12 (12 months).*" Valve inspection records were reviewed during the audit (Control Valve Inspection Track WO No. 741331 and Slam Shut Inspection Track WO No. 725105) to confirm implementation of the inspection and maintenance procedures. TransCanada's procedures for its valve maintenance and inspection are assessed to be in compliance with the requirements of CSA Z662-11.

Emergency Preparedness and Response Procedure

TransCanada's emergency preparedness and response program (EMP) was not included in the scope of this IMP audit and was therefore not formally assessed.

Summary: Operational Control-Upset or Abnormal Operating Conditions

The Management System Audit Element 3.7, Operational Control – Upset or Abnormal Operating Conditions, requires a company to establish and maintain procedures to identify potential upset or abnormal operating conditions, accidental releases, incidents and emergency situations.

TransCanada has implemented a number of processes and procedures to identify potential upset or abnormal operating conditions. TransCanada's pipeline infrastructure is monitored remotely 24 hours a day, 365 days a year using a Supervisory Control and Data Acquisition (SCADA) system and is backed up by an onsite standby system. In the event that both of these systems fail due to a catastrophic event, a secondary control centre at a different location contains full duplicate primary and secondary back-up systems.

This audit also found that TransCanada's pressure-limiting and relieving systems, leak detection, gas quality, alarm call-out, shutdown devices and valve operation systems were all adequate and compliant with the OPR-99 and CSA Z662-11 requirements.

While over-pressure protection for TransCanada's oil pipeline systems was found to be adequate, the Board has determined the NOVA Gas Transmission Ltd (NGTL) system is not conducting sufficient inspections or audits of its customer installations to ensure that the system is operated in compliance with the OPR-99 and CSA-Z662-11 requirements. Based on that system's history of over-pressure incidents and the fact that TransCanada has not fully implemented its plan of action to verify compliance with requirements, the company is not in compliance with the OPR-99 and CSA-Z662-11 requirements and is therefore not in compliance with this audit sub-element.

Management System Audit Sub-Element Finding: Based on the documents assessed and interviews with personnel for programs related to over-pressure protection systems on the Alberta (NGTL) System, TransCanada is assessed to be non-compliant with the requirements of the OPR-99 and CSA Z662-11, and is therefore non-compliant with this audit sub-element.

Compliance Status: Non-Compliant

4.0 CHECKING AND CORRECTIVE ACTION

4.1 Inspection, Measurement and Monitoring

Expectations: The company shall develop and implement surveillance and monitoring programs. These programs should address contract work being performed on behalf of the company. These programs should include qualitative and quantitative measures for evaluating the management and protection programs and should, at a minimum, address legal requirements as well as the risks identified as significant in elements 2.0 and 3.0. The company should integrate the surveillance and monitoring results with other data in risk assessments and performance measures, including proactive trend analyses. The company shall have documentation and records of its surveillance and monitoring programs.

References:

OPR-99 sections 4, 27, 28, 36, 37, 39, 47, 48, 53 (1) and 54 (1)
CSA Z662-11, Clauses 3.1.2(h)(i), 3.2, 9 and 10

Audit Assessment:

General

During interviews and in documents submitted, TransCanada indicated that it has developed and implemented surveillance and monitoring programs to address the hazards and risks to its pipeline systems. TransCanada's Engineering and Asset Reliability (E&AR) department is accountable for identifying the relevant programs and for ensuring adherence of these programs to applicable regulations. Subsequent trending and evaluation of the programs provide input to ensure continued effectiveness of the Integrity Management Programs (IMPs).

It was noted that TransCanada's processes for monitoring and analyzing hazards are identified within the Quality Management, Quality Assurance and Management Review sections of TransCanada's IMPs.

Surveillance and Condition Monitoring Programs

Gas Quality Monitoring

During the audit, TransCanada identified personnel, such as field technicians and gas controllers, who are trained to identify and manage gas quality off-specification conditions. The governance and systematic approach to managing gas quality are outlined in the Gas Quality Procedure

(EDMS No. 003671916). At locations where sour potential is of concern, additional instrumentation, sour bottles and automated equipment are employed to ensure that off-specification gas (>16 ppm H_2S) does not enter the mainline or reach a sales location.

Testing methods used to manage the gas quality can include:

- manual water and hydrocarbon dew points;
- gas samples (carbon dioxide, oxygen, and heating value);
- hydrogen sulphide and total sulphur screening via gas samples and on-line instrumentation;
- objectionable material detection via dew point monitoring;
- orifice plate inspection;
- H_2S gas sniffer analysis; and
- scrubber and meter run inspections.

There are currently 292 receipt meter stations with H_2S protection on the NOVA Gas Transmission Ltd. (NGTL) system. The TransCanada philosophy for sour meter station design is to monitor, control, contain, and reject a customer's gas if off-specification gas is detected. In addition, all receipt and delivery meter stations are screened monthly via gas samples for H_2S and total sulphur levels, and sweet stations are tested monthly through H_2S gas sniffer tubes. Several mainline H_2S analyzers are also installed throughout the NGTL system to detect potential H_2S slugs that may have entered the system.

The audit identified that all TransCanada meter stations and compressor stations contain gas scrubber equipment. Any recovered liquids are measured on a regular basis. Excessive liquid recovery prompts the applicable customer to rectify the problem.

Non-sour off-specification conditions are managed directly with the customers and may include shutting in the customer until the off-specification condition is rectified. As outlined in the TransCanada Operating Procedure (TOP) Meter Station General Maintenance Gas Transmission (EDMS No. 003834481), the typical visitation schedule at TransCanada meter stations is monthly unless otherwise specified. TransCanada stated that the program is considered to be effective as there are no known internal corrosion defects caused by off-specification gas conditions. The absence of significant defects caused by internal corrosion was confirmed during the audit of the Internal Corrosion Threat Management Program.

With respect to specific requirements for gas quality specifications and monitoring, CSA Z661-11 remains silent. The requirements for gas quality fall under identification of hazards and subsequent development and implementation of monitoring programs for the identified hazards.

CSA Z662-11, Clause 3.1, Safety and Loss Management System and specifically Clause 3.1.2 states *"The safety and loss management system shall include the following elements: (f) operational controls, including the development of procedures for hazard identification and risk management, design and material selection, construction, operations and maintenance, pipeline system integrity management, and security management."* TransCanada was assessed to be in compliance with the requirements for control and monitoring of gas quality for its gas pipeline operations.

Table 4.1 summarizes the gas quality indices in the general terms and conditions section of each tariff.

Gas Quality Specifications	NGTL	Canadian Mainline	Foothills (SK) Zone 9	Foothills (BC) Zone 8	TQM
Hydrogen sulphide	23 mg/m3	23 mg/m3	23 mg/m3	23 mg/m3	23 mg/m3
Total sulphur	115 mg/m3	115 mg/m3	230 mg/m3	230 mg/m3	115 mg/m3
Carbon dioxide	Max 2%	Max 2%	Max 2%	Max 2%	Max 2%
Oxygen	Max 0.4%	Max 0.4%	Max 0.4%	Max 0.4%	Max 0.4%
Temperature	49ºC	50ºC	49ºC	43.3ºC	50ºC
Heating value	Min 36 MJ/m3	Min 36 MJ/m3, Max 41.34 MJ/m3	Min 36 MJ/m3	Min 36 MJ/m3	Min 36 MJ/m3
Water	Max 65 mg/m3 or min -10C @ >8,275 kPa	Max 65 mg/m3	Max 65 mg/m3 or min -10 C @ >,8275 kPa	Max 65 mg/m3 or min -10 C @ >8,275 kPa	Max 65 mg/m3
Hydrocarbon Dew Point	Min -10 C @ operating pressure	Min -10 C @ 5,500 kPa absolute	Min -10 C @ operating pressure	Min -10 C @ operating pressure	Not specified

Sediment and Water Monitoring

Sediment and water (S&W) is a measure of the residual unwanted impurities (water and particulate matter) that are contained in crude oil, which is applicable to the Keystone Pipeline. TransCanada stated that every oil batch is tested for compliance with an S&W maximum of 0.5% of volume as per Article 4.2(ii) of the Keystone Petroleum Tariff agreements. In addition to the manual testing used for custody transfer, the Hardisty terminal is equipped with an online water cut analyzer to continuously measure the receipt water cut, to ensure that off-spec product does not enter the pipeline undetected. Beyond efforts to minimize S&W within the product stream, samples of crude and sediment (sludge) were collected from early cleaning runs across the Keystone Pipeline system in order to assess its corrosivity. TransCanada identified that the exposure tests using these samples validated that, in the absence of sludge, and exposed to pipeline crude only, the corrosion rate was negligible.

Information reviewed identified that the Keystone Pipeline system was designed to minimize the potential for sediment accumulation by having a nominal flow rate that generates a turbulent flow regime (maintains water and sediment suspended and entrained in the crude). Typically, sediment deposition is unavoidable during situations such as line fill and initial start-up. Accordingly, cleaning tools were run the entire length of the system twice after initial start-up. As well, a cleaning tool is also run prior to each in-line inspection (ILI) run. By early 2013 all ILI metal loss runs on the Keystone Pipeline system in Canada will be completed. Re-inspection is currently scheduled on a five-year interval. The ILI data is specifically reviewed for indicators of the initiation and presence of internal corrosion. TransCanada stated that none of the ILI data to date has exhibited evidence of internal, under-sediment corrosion. This was confirmed during the audit of the Internal Corrosion Threat Management Program.

Another consideration in the design of the Keystone Pipeline was the minimization of dead legs, with normal flow through the barrels as one manifestation of this approach. Corrosion monitoring will be performed to confirm ongoing applicability of initial exposure tests during scheduled facility inspections, as per Keystone Facility Piping Non Destructive Inspection (EDMS No. 006790574).

CSA Z662-11, Clause 4.14.3.8 (b) states *"The designer shall avoid dead-ended piping unless corrosion is mitigated in such piping sections. Consideration shall be given to sizing piping to maintain a flow velocity sufficient to minimize the accumulation of water and sediment."* TransCanada's was assessed to be in compliance with the requirements to design to control and to monitor sediment and water in its oil pipeline operations.

H_2S Content in Crude Oil Monitoring

CSA Z662-11, Clause 16.2.1 (b) defines sour service for pipeline systems not containing a gas phase (gas-free liquid pipeline systems), such as the Keystone Pipeline, as "*service in which the effective hydrogen sulphide partial pressure exceeds 0.3 kPa at the bubble point absolute pressure*".

In its February 2013 response to an Audit Information Request, TransCanada indicated that the crude oil it carries in the Keystone Pipeline does not constitute sour service. During the audit, TransCanada could not demonstrate that the crude oil it carries in the Keystone Pipeline did not constitute sour service (as defined by CSA Z662-11), since it had not conducted any testing to verify the partial pressure of the H_2S at the bubble point absolute pressure.

Subsequently, in April 2013, TransCanada committed to implement a sampling program to verify the H_2S content of all the products it carries on the Keystone Pipeline. In June 2013, TransCanada indicated that it had tested all of its regularly shipped commodities using the standard method Universal Oil Products (UOP) 163-10, which is a potentiometric titration method, to verify the H_2S content of the crude oil. All of the commodity tests produced a modeled partial H_2S pressure less than 0.3 kPa and therefore confirmed the non-sour nature of these products. TransCanada's report stated that given the conservative nature of the test, additional testing of these products is not intended at this time.

Based on the fact that TransCanada has not monitored the H_2S content of the different batches of products it carries on the Keystone Pipeline, and based on the fact that TransCanada's planned practice is not to monitor the H_2S content of the different batches of products it carries, or will carry in the future, on the Keystone Pipeline, TransCanada is not in compliance with the requirements of this audit sub-element and CSA Z662-11, Clause 3.2.

Monitoring of Corrosion on Un-Piggable Pipelines

TransCanada's documentation indicated that the risk assessment and risk management of the external corrosion threat are achieved using either of the following two approaches:

1. For pipelines where an in-line inspection (ILI) has been completed, the specific anomalies are assessed, and control or mitigation activities are planned based on a defect management approach.
2. For pipelines where ILI has not been completed, risk mitigation activities are determined based on TransCanada's risk assessment results (PRIME), subject matter expertise, and applied learnings from other similar segments of pipe across the TransCanada system, including historical performance.

In terms of the NOVA Gas Transmission Ltd. (NGTL) system, it is mostly un-piggable (approximately 25% of the NGTL system has been in-line inspected). TransCanada's 2013 results from PRIME for the NGTL System indicated that 234 pipeline segments exceeded TransCanada's stated risk tolerance. The PRIME technical documentation, Section 4, Consequence Models, contains TransCanada's Societal Risk Acceptance Curve (FN). The Unacceptable Region of the FN curve is where the Societal Risk does not meet TransCanada's Individual or Societal Risk criteria and these segments are prioritized for risk-reduction activities in the current year's program.

For NGTL's un-piggable segments, mitigation programs should normally be applied to reduce the risk to an acceptable level. Documentation submitted by TransCanada indicated that not all of the pipeline segments in the NGTL system exceeding TransCanada's risk tolerance had mitigation plans for 2013. According to documents reviewed, 160 of the 234 pipeline segments of the NGTL system exceeding TransCanada's risk tolerances and had no mitigation plans for 2013.

During the audit, TransCanada was asked to justify the absence of mitigation plans for these 160 pipeline segments. In response, TransCanada provided modified risk assessment results indicating that these segments were now acceptable to TransCanada's risk criteria. TransCanada explained that its modified risk assessment process includes information gathered after inspecting (ILI or direct examination) nearby pipelines in similar condition. The nearby pipeline conditions are now factored in the probability component of the risk assessment, with the result being that all but one of the 160 pipeline segments had acceptable risk results. TransCanada indicated that there are no further mitigation plans for any of the 160 segments, except for the one segment that still exceeded TransCanada's risk tolerance with the new risk assessment process and for which TransCanada had added a mitigation plan for 2013.

TransCanada did not provide evidence proving the validity of its new risk assessment methodology of using nearby or parallel pipeline information as an adequate way to monitor the integrity of its pipeline segments. The Board notes that this methodology is not an industry recognized method for determining the integrity of a pipeline, as opposed to recognized methods such as ILI, hydrotesting or the NACE External Corrosion Direct Assessment (ECDA) Process. Whether corrosion occurs or not, or is severe or not corrosive, is specific to the local conditions of the pipeline and the pipeline's interaction with its surrounding environment. Several factors such as manufacturing process, construction practices, cathodic protection (CP) levels, soil type and composition, moisture levels, mechanical damage (1^{st}, 2^{nd}, 3^{rd} parties or pipe/soil movements) could affect the condition of the pipe coating, all of which could affect the susceptibility of the segments to external corrosion. Nearby pipeline conditions can give an indication of the potential corrosivity of an area and conditions of a pipeline, but it is not

information that can be relied on to effectively demonstrate the integrity of a pipeline. As such, the Board is of the opinion that nearby or parallel pipeline information cannot be used directly in the risk assessment process.

TransCanada's monitoring programs for external corrosion on these un-piggable pipeline segments is limited to the *Corrosion Control Surveys* section covered later in this section. While these programs are common industry practices, monitoring CP systems alone is not a recognized practice for thoroughly assessing the effectiveness of the CP system, which is typically done with pipe-to-soil close interval surveys. Also, for pipelines coated with shielding coatings such as PE Tape, which is the coating on many of TransCanada's un-piggable segments, CP can be ineffective at preventing corrosion under a disbonded coating condition.

Relying on nearby or parallel pipeline information and CP monitoring as described in the *Corrosion Control Surveys* section below is not an adequate monitoring method of the external corrosion threat of the un-piggable or non-hydrotested pipelines on the NGTL system. Therefore, TransCanada is assessed to be in non-compliance with this audit element and CSA Z662-11, Clause 3.2.

Overall, the NGTL un-piggable pipeline systems have been characterized by TransCanada as follows:

- For small diameter pipelines (<20"):
    - Low societal and environmental consequence;
    - Probable failure mechanism is leak versus rupture;
    - Low probability of ignition; and
    - Approximately 56% FBE or extruded polyethylene.

- For large diameter pipelines (>20"):
    - Low societal and environmental consequence;
    - Probable failure mechanism is leak versus rupture;
    - Low probability of ignition;
    - Approximately 89% FBE or extruded polyethylene; and
    - Low performance coated (Ptape) pipes have been 75%-88% hydrotested.

In terms of its current activities and forward plans to address un-piggable pipelines, the Board notes that TransCanada has provided the following information:

- Installation of 5 sets of launchers and receivers on the Canadian mainline in 2013;
- Completion of CP close interval surveys on un-piggable segments in TQM in 2012 and subsequent ILI and investigative dig inspections in 2013;

- Scheduling of 2 ILI runs and 15 investigative digs on the Foothills System in 2013;
- Scheduling 21 sets of launchers and receivers and 7 tethered ILI runs for the Alberta System in 2013;
- Inclusion in the 2014 – 2017 budgets plans to install 8 to 10 sets of new launchers and receivers per year in its un-piggable pipeline systems;
- Scheduling direct assessment, ILI or hydrotests within the next 7 years for 58 segments that have high consequence, but have high performance coatings;
- Scheduling direct assessment, ILI or hydrotests within the next 5 years for 19 segments that are have consequence, but have low performance coatings;
- Scheduling ILI by prioritization of 35 segments that have polyethylene tape (Ptape) coatings and pipe diameters greater than 12"; and
- Scheduling ILI in 2013/2014 of 8 segments that have high societal risk.

Corrosion Control Surveys

During the audit, TransCanada's information indicated that the TransCanada Pipe Integrity group is responsible for managing and administering the corrosion control programs for pipeline, pump station and terminal facilities. CP readings are performed by Regional field personnel either at site or via remote monitoring. The requirement for corrosion control monitoring, as outlined in CSA Z662-11, Clause 9, is detailed in TransCanada Operating Procedures (TOPs) Cathodic Protection Rectifier Inspection (EDMS No. 004258831), Cathodic Protection Survey Inspection (EDMS No. 004258833), and Cathodic Protection Rectifier and Bond Reading Inspection (EDMS No. 004258832).

To ensure the proper operation of its CP system, TransCanada inspects all impressed current facilities twelve times in a calendar year, not to exceed an interval of 6 weeks. Annual rectifier inspections are conducted, which involves reading AC inputs, calculating rectifier efficiency, conducting visual inspections and performing maintenance cleaning. Test lead surveys are performed annually to ensure all facilities are receiving adequate cathodic protection levels. In addition to monitoring CP facilities, CP isolation surveys are also undertaken on an annual basis to ensure the applicable facilities are not interfering with the normal operation of the CP system.

When in-line inspection (ILI) data is unavailable, or to further monitor areas of potential concern, close interval surveys (CIS) are used to investigate performance of the cathodic protection system and to assess for external corrosion concerns. CIS surveys augment the annual test lead surveys by investigating CP protection levels between test leads. The requirement for these surveys is based on an engineering evaluation of the area in question. The criteria used to prioritize CIS requirements include previous CP history, Magnetic Flux Leakage (MFL) ILI

results, type of coating, stress corrosion cracking (SCC) and corrosion risk assessment results. TransCanada's corrosion control survey methodology with respect to CP is assessed as compliant with the requirements of this audit sub-element.

Aerial Patrols, Aerial Leak Detection and Ground Based Leak Detection

Regulatory Requirements for Pipeline Patrols

CSA Z662-11, Clause 10.6.1.1 states that "*Operating companies shall periodically patrol their pipelines in order to observe conditions and activities on and adjacent to their rights-of-way that can affect the safety and operation of the pipelines. Particular attention shall be given to the following:*

a) construction activity;
b) dredging operations;
c) erosion; ice effects;
d) scour;
e) seismic activity;
f) soil slides;
g) subsidence;
h) loss of cover; and
i) evidence of leaks."

CSA Z662-11, Clause 10.6.1.2 states "*The frequency of pipeline patrolling shall be determined by considering such factors as*

a) operating pressure activity;
b) pipeline size;
c) population density;
d) service fluid;
e) terrain;
f) weather; and
g) agricultural and other land use".

The OPR-99, section 39 states that "*A company shall develop a surveillance and monitoring program for the protection of the pipeline, the public and the environment."* Section 53(1) of the OPR-99 states that *"A company shall conduct inspections on a regular basis".*

In the Unites States, the US Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) sets out the pipeline patrol requirements in the Code of Federal Regulations (CFR), Part 192 – Transportation of Natural and Other Gas by Pipeline: Minimum

Federal Safety Standards (49 CFR 192) in section 192.705 and Part 195 – Transportation of Hazardous Liquids by Pipeline (49 CFR 195) in section 195.412. The United States regulations are mentioned because TransCanada has developed its pipeline patrol program to meet the most prescriptive requirements, which in terms of ROW patrol frequencies, are those set out in the 49 CFR 192 and 195.

During the audit, TransCanada indicated that it implements its pipeline patrols to meet at in accordance with the requirements of CSA Z662-11, Clause 10.6.1.1 Pipeline Patrolling. Aerial patrols are completed to look for construction activity, vegetation, signage, erosion, geotechnical concerns, encroachments, leaks, and water crossings. Patrol frequencies are outlined in the TOPs Aerial Pipeline Patrol (EDMS No. 003672387) and Pipeline Ground Based Patrols (EDMS No. 003875137). All natural gas pipelines are to be patrolled a minimum of two times per year. Liquid pipelines are to be patrolled 26 times per year. Additional patrols are to be completed at increased frequencies as warranted, based on a review of historic observations, levels of activity along the ROW, known integrity concerns, or as may be directed by the applicable regulator. Aerial patrols are to be executed with the use of helicopter or fixed wing aircraft as per the aircraft operating company assigned to complete the patrol. Aerial leak detection for natural gas pipeline systems is a component of the overall leak detection strategy, as are observations from landowners, contractors and employees working near the pipeline. Aerial leak detection is to be performed at least annually on natural gas pipeline systems, as described in Pipe Integrity Leak Detection and Evaluation (TEP-LEAK-INT, EDMS No. 007379105). Aerial leak detection on gas pipeline systems is to be performed with the use of helicopters. Supplemental ground based leak patrols are to be initiated as per the TOP Pipeline Ground Based Patrols (EDMS No. 003875137) either when aerial patrol frequency does not meet the minimum regulatory requirements, or where anomalies identified during aerial leak detection require ground based confirmation.

Both the TransCanada's TOP Aerial Pipeline Patrol (EDMS No. 003672387), Section 4.2 - Frequency and the TOP Pipeline Ground Based Patrols (EDMS No. 003875137), Section 3.0 – Frequency, address the patrol frequency requirements based on, for example, class location, highway and railroad crossings, levels of activity, integrity concerns and pipeline commodity. While CSA Z662-11, Clause 10.6.1.1 uses the term "periodically" and the OPR-99, section 39 remains silent on the patrol frequency, TransCanada's patrol frequencies are assessed to be in compliance with the intent of the standard and the regulation with respect to pipeline patrol frequency.

TransCanada's Aerial and Ground Patrol TOPs, sections 4.4 - ROW Monitoring and 4.6 - Reporting in the former and section 4.1 -Pipeline Ground Based Patrols in the latter, address the

pipeline patrol requirements for monitoring and reporting conditions and activities as required by CSA Z662-11, Clauses 10.6.1.1 and 10.6.1.2. The Board examined a random aerial patrol record requested for an incident (OB9_Aerial Patrol Reported_DOC_IIT#233782) related to a sink hole at 10-27-34-5W4 (Keystone Pipeline ROW) reported 23 April 2012 and noted that the record met the requirements for monitoring and reporting. TransCanada's pipeline patrol TOPs have been developed to address the most stringent, prescriptive pipeline patrol requirements and have been assessed to be in compliance with the standard and regulation.

Facilities Integrity Inspections

During the audit, TransCanada indicated that its Facilities Integrity Inspections procedure (EDMS No. 003857228) for gas transmission facilities and Keystone Facilities Integrity Inspections procedure (EDMS No. 006787339) for liquid facilities are designed to ensure that critical equipment is functioning as intended. Mechanical, electrical, civil and environmental components are to be inspected at intervals as described in these documents.

At liquid facilities, the Keystone Facility Piping Non Destructive Inspection (EDMS No. 006790574) Task Package is used. The purpose of this Non Destructive inspection package is to determine the condition of pressure piping and associated fittings, including the coating and insulation, and is designed to ensure fitness for service and proactively identify applicable maintenance requirements. TransCanada was assessed to be in compliance for its inspection program of its liquid facilities.

As described in the following evaluation of TransCanada's inspection program for high pressure station piping for its gas facilities, TransCanada's previous facility pipe integrity program was managed under the Integrity Management Process for Pipelines (EDMS No. 003892900). Chapter 7 of this document, Facility Pipe Integrity, contained sections which described, in general terms, the background descriptions for;

- corrosion control (section 7.1.1);
- overpressure protection (section 7.1.2);
- mechanical damage (section 7.1.3);
- operating/maintenance procedures (section 7.1.4);
- employee/contractor training (section 7.1.5);
- localized attack mechanisms (section 7.2);
- soil-to-air interface (section 7.2.1);
- contact corrosion (section 7.2.2);
- corrosion under insulation (section 7.2.3); and
- erosion and corrosion/erosion (section 7.2.4).

The Board is of the view that these generic background descriptions do not provide the level of specificity required for the implementation of an adequate and effective gas facility pipe inspection program. Therefore, as the following evaluation has concluded, TransCanada's gas facility inspection program is not in compliance with the requirements of this audit element and with CSA Z662-11, Clause 3.2.

High Pressure Station Piping (Gas Facilities)

The audit identified that TransCanada utilizes different methods to monitor its facility piping integrity. The methods include regular site visits, annual CP surveys, visual inspection, and preventative maintenance activities such as valve and valve operator inspections. Visual inspection is performed at facilities during planned facility inspections, facility pipeline projects, and regular site visits. Hazardous or abnormal conditions, such as leaks or frost heaved piping, are to be checked for during site visits. Issues identified are to be communicated through the company Incident and Issue Tracking (IIT) system for follow-up. In regions where atmospheric corrosion is more of a concern due to a more humid environment, such as the Eastern region, a riser assessment program was recently implemented to assess external corrosion on the risers at the air-to-soil interfaces and other locations where atmospheric corrosion also could be present, such as between supports the piping. As part of the audit verification process, NEB staff conducted an inspection on 6 June 2013 of the riser assessment program in Quebec that demonstrated the implementation of this program and no non-compliances were identified during the inspection.

TransCanada indicated that only a limited number of excavations with the primary purpose of performing a direct examination of the integrity of the station piping have been done so far, but that some opportunistic excavations (due to maintenance or modifications for example) have been used to assess the condition of the buried station piping at some locations. TransCanada provided records of these opportunistic facility piping inspections, which included:

- Field Lake Compressor Station (NGTL) for external corrosion, 7 May 2011;
- Mainline Rideau Riser Assessment and Recoat Project for atmospheric corrosion, September 2012;
- Mainline Quebec Riser Assessment and Recoat Project for atmospheric corrosion, September 2012;
- TQM Riser Assessment and Recoat Project for atmospheric corrosion, September 2012;
- Mainline Maple and Niagara Riser Assessment and Recoat Project, September 2012; and
- Torrington Compressor Station / Storage Facility for external corrosion, September 2012.

TransCanada stated that it has assessed the risk of external corrosion as being low for its station piping, taking into consideration the fact that the station piping is operating at a lower stress level than the main line pipe, that there are no unresolved CP issues at its stations, and because it has never had a rupture and was not aware of any leak on the pipe body at any of its stations.

As previously described, TransCanada's station piping was managed under the *Integrity Management Process for Pipelines - Revision 2* process. Review of Sections 7.3 and 7.4 of this process indicates that the integrity monitoring program was focused on the above ground piping and limited to CP monitoring, leak surveys and opportunistic excavations for standard monitoring of the below ground piping. Review of these sections also indicated that only if issues with CP or external corrosion were identified would inspection techniques such as ILI, direct assessment or leak testing be used. Therefore, a proactive or adequate monitoring program was not in place for the integrity of the station piping prior to the new Facility Pipe Threat Management Program, which was approved by TransCanada management for use in December 2012, has not yet been fully implemented throughout TransCanada's gas facilities.

The audit identified that, at the time of the audit activities, TransCanada has not conducted adequate direct assessments, hydrotests or ILI programs to assess the potential for external corrosion of its below-ground station piping. With the exception of the riser assessment program in the Eastern region, where the station risers are exposed for approximately 50 cm, there has not been a formal system-wide assessment for potential external corrosion of its below-ground or air-to-soil interface station piping. Where there is no riser program in place, the integrity monitoring for the below-ground or air-to-soil interface station piping is limited to CP pipe-to-soil potential and rectifier monitoring and a limited number of opportunistic excavations.

Although TransCanada stated that, to its knowledge, it has not yet identified any external corrosion issues on its below-ground station piping, the methods used by TransCanada are not adequate to demonstrate the appropriate integrity management of the station piping and TransCanada is therefore determined to be non-compliant with the requirements of this audit element and with CSA Z662-11, Clause 3.2.

Tank Inspections

TransCanada operates oil storage tanks as part of its Keystone Pipeline system at Hardisty, Alberta. Storage tanks are to be inspected as per CSA Z662-11, Clause 10.9, Operation and Maintenance of Facilities and Equipment. Specifically, CSA Z662-11, Clause 10.9.2, Aboveground Tanks and Pressure Vessels and sub-clause 10.9.2.1 states that "*the inspection,*

repair, alteration, and reconstruction of aboveground atmospheric steel tanks shall be as specified in API 653".

API 653, Tank Inspection, Repair, Alteration and Reconstruction, Section 4 – Inspection, details the requirements for internal and external inspections as well as for the requirement that the inspections be carried out by an Authorized Inspector. Intervals are specified in Sections 4.2.2 for external inspection and 4.4.2 for internal inspection. Section 4.4.3 provides for an alternative to the procedures in 4.4.2 where an owner-operator may establish the internal inspection interval using a risk-based inspection (RBI) procedure.

TransCanada has developed the TOP API 653 Aboveground Storage Tank Inspections (EDMS No. 007167240) for inspection of its aboveground storage tanks. Section 3.0 Frequency, of this procedure specifies the standard inspection intervals (expressed as months, for example M12 is every 12 months) as follows:

- Routine In-service Inspections: M01;
- Internal/External Floating Roof Tanks Secondary Seal Inspection: M12;
- External Visual Inspection: M60 (Adjust inspection interval based on the condition of the Tank);
- External Ultrasonic Thickness Inspection: M60;
- Internal/External Floating Roof Tank Primary Seal Inspection: M60; and
- Internal Inspection M120.

Section 4.0 Procedures, details the requirements for the following:

- routine in-service inspections;
- internal floating roof tanks secondary seal inspection;
- external floating roof tanks secondary seal inspection;
- external visual inspection;
- external ultrasonic thickness inspection;
- internal/external floating roof tank primary seal inspection;
- internal inspection;
- inspection locations; and
- documentation / reporting requirements.

TransCanada requires that its inspectors are certified to API 653 (i.e. Authorized Inspectors) and that the inspection reports are reviewed by TransCanada engineers who are competent in aboveground storage tank design, operation and maintenance. TransCanada provided records of aboveground storage tank inspections at the Hardisty terminal indicating that the frequency and extent of inspections met the requirements of API 653. TransCanada also provided records of its

aboveground storage tank inspector qualifications which included API 653 certified storage tank inspector.

The Board has determined that TransCanada's procedures for inspection of its aboveground storage tanks are in compliance with the requirements of CSA Z662-11 and API 653.

TransCanada's facilities also have underground tanks, commonly referred to as "drip tanks". CSA Z662-11, Clause 10.9.3 Underground Storage and specifically Clause 10.9.3.1 states "*underground tanks shall be inspected periodically and maintained as necessary. The inspection program shall include the periodic monitoring of any leak detection systems*".

TransCanada has developed two TOPs for underground drip tank inspections: Underground Drip Tank Inspection (EDMS No. 003719673) and Underground Drip Tank Inspection Task Package (EDMS No. 003719218) to comply with CSA Z662-11, Clause 10.9.3. The Underground Drip Tank Inspection procedure, Section 3.0 – Frequency, prescribes a frequency of M36 (36 month inspection interval) for its drip tank inspections. TransCanada provided a list of stations containing underground drip tanks that are to be included in its M36 inspection procedure and samples of records of past underground drip tank inspections.

The Board has determined that TransCanada's procedure for inspection of its underground drip tanks is in compliance with the requirements of CSA Z662-11, Clause 10.9.3.1.

Boiler and Pressure Vessel Inspections

During the audit, TransCanada indicated that its boiler and pressure vessel inspections are carried out in accordance with the Quality Assurance Manual (QAM) for the Integrity Management of Pressure Equipment Including Repairs and Alterations (EDMS No. 003722000). This procedure is based on the API 510 Pressure Vessel Inspection Code, Alberta inspection standards and industry practice. The inspection of pressure vessels follows the TOP Pressure Vessel External and Internal Inspection (EDMS No. 003694710), under the direction of TransCanada's Chief Inspector for pressure equipment. Pressure vessel inspections are documented and the vessels are certified for continued service by the Chief Inspector. The Pressure Vessel Integrity Plan (EDMS No. 003763099) is reviewed periodically by Facilities Engineering to review risks and to direct future inspection programs. Heating boiler inspections are carried out in accordance with Part 5 of the Canada Occupational Health and Safety Regulations by the provincial jurisdictional authority or by an insurance company authorized by the provincial jurisdictional authority. Occasionally in Alberta (only), heating boiler inspections are carried out by the Chief Inspector, as authorized by the provincial jurisdictional authority.

TransCanada provided a sample of the qualification records for its Chief Inspectors, who are employees of TransCanada, which included:

- ABSA In-Service Boiler and Pressure Vessel Inspector;
- National Board Commissioned Inspector;
- API 510 Pressure Vessel Inspector;
- API 570 Pressure Piping Inspector;
- API 653 Storage Tank Inspector;
- API 580 Risk-Based Inspection;
- ABSA Welding Examiner;
- CSA W47.1/CWB Welding Supervisor;
- IIW International Welding Engineer; and
- CSA W178.2/CWB Welding Inspector Level 3.

Additionally, the Chief Inspector qualifications included membership in the following:

- Professional Engineer of APEGA
- Technical Committee Member of CSA B51 Boiler, Pressure Vessel and Piping Code
- Member of Upstream Chief Inspector Association
- Member of American Society of Non-destructive Testing

TransCanada's QAM applies to approximately 2500 vessels and boilers registered in the province of Alberta in a quality management system registered with ABSA, the Pressure Equipment Safety Authority in Alberta. Section 11 of the QAM specifies the inspection intervals for pressure equipment, including pressure vessels, boilers, pressure relief valves based on the requirements of API 510 and API 572 (pressure vessels), API 570 (pressure piping), API 574 (piping system components) and API 576 (pressure relieving devices) as well as the inspection requirements of the National Board Inspection Code (NB23) and ABSA's Inspection and Servicing Requirements for In-Service Pressure Equipment (ABSA AB-506).

At the Board's request, TransCanada provided samples of inspection records for its pressure equipment; a 2012 internal audit of its QAM; a 2011 audit by ABSA of TransCanada's Pressure Equipment Integrity Management System; a 2011 internal audit report at CrossAlta Gas Storage Facility for the Owner-User Pressure Equipment Integrity Management System; and a 2010 internal audit for the QAM Owner-User Program for the Integrity Management of Pressure Equipment Including Repairs and Alterations.

The Board has determined that TransCanada's procedures for inspection of its pressure equipment are in compliance with the requirements of the applicable codes and standards.

Geotechnical Monitoring

Regulatory Requirements for Geotechnical Monitoring

CSA Z662 clause 10.6.1.1(f), (g) and (h) address the requirements for pipeline monitoring for geotechnical issues. This clause states that "*Operating companies shall periodically patrol their pipelines in order to observe conditions and activities on and adjacent to their rights-of-way that can affect the safety and operation of the pipelines. Particular attention shall be given to the following:*

f) seismic activity;
g) soil slides; and
h) subsidence".

In terms of the required frequency of the pipeline monitoring activities, CSA Z662-11, Clause 10.6.1.2 states "*The frequency of pipeline patrolling shall be determined by considering such factors as*

a) operating pressure activity;
b) pipeline size;
c) population density;
d) service fluid;
e) terrain;
f) weather; and
g) *agricultural and other land use"*.

The OPR-99, section 39 states that "*A company shall develop a surveillance and monitoring program for the protection of the pipeline, the public and the environment.*" Section 53(1) of the OPR-99 states that "*A company shall conduct inspections on a regular basis*".

Based on audit interviews and documents reviewed, the Board noted that geotechnical hazards, such as susceptible landslide locations, are identified in a Phase 1 Geo-Hazards Assessment, as described in the Weather and Outside Forces (WOF) Threat Management Program (TEP-ITM-WOF, EDMS No. 005767611). As per Section 5, Roles, Responsibilities and Qualifications of the WOF procedure, higher risk sites are further assessed by TransCanada senior geotechnical engineers (E4-5 classification and evidenced by records requested during the audit and provided by TransCanada). Appropriate actions (e.g., regular inspection and monitoring, slope remediation) are taken based on the results of the assessment. Geotechnical and river crossing monitoring activities are supplemented by TransCanada's Aerial Pipeline Patrol program and by field personnel observations. TransCanada's IIT system is used to track issues related to geotechnical remediation and monitoring programs for follow-up and resolution.

TransCanada's Weather and Outside Forces Threat Management Program (WOF) (TEP-ITM-WOF, EDMS No. 005767611), contains Section 6 Background, which describes the threat types that are to be evaluated during the execution of the geotechnical monitoring program. These include:

- 6.1.1 Landslides;
- 6.1.2 Seismic events;
- 6.1.3 Fault planes;
- 6.1.4 Subsidence and heave;
- 6.1.5 Water flow; and
- 6.1.6 Meteorological events.

Appendix A of TransCanada's WOF provides a Geological Hazards Classification Summary for the above threats, with quantitative descriptions of the threat classifications of low, medium and high. The threat classifications guide the risk assessment process and subsequent remediation, mitigation and monitoring programs as per the WOF Management Procedure illustrated in Figure 7-1 of the WOF TEP and the procedural steps detailed in Section 8 of the WOF.

During the audit interviews, TransCanada stated that it has performed a Phase 1 survey for all of its pipeline systems. At the Board's request, TransCanada provided samples of the following documents and records of its Phase I Geo-Hazards Assessments:

- Phase I Implementation of Rainfall Ground Movement Models (September 1999);
- Visual Inspection of Slopes: Summary of Observations for 11 Slopes in Northern Alberta (11 October 2001);
- Unnamed Creek Cranberry Lake Lateral Geotechnical Instrumentation Installation Report (20 January 2003);
- Pembina River Slope Stability (20 October 2001); and
- Keystone Canada Phase I Geohazard Assessment (2010).

The Board also requested that TransCanada provide examples of its Phase II and Phase III surveys. TransCanada provided an example of the TQM Phase I, followed by a Phase II survey for TQM and well as examples of Phase III surveys with the following descriptions:

> "Cranberry Lake Lateral, Unnamed Creek SW-22-85-20-W5 site was identified in the 1999 Phase 1 report as having a medium potential for ground movement. A subsequent Phase II study was completed in 2001, and findings documented in a 2001 report titled "Summary of Observations for 11 Slopes in Northern Alberta". In order to mitigate the risk to the pipeline, a Phase III investigation, which resulted in the installation of slope monitoring equipment, was completed in 2003".

> "Edson Mainline, Pembina River SW-28-48-15-5 site was identified in the 1999 Phase I report as having a high potential for ground movement. A subsequent Phase II study was completed in May 2000 to assess the site conditions. The findings were documented in a technical memorandum titled "Assessment of Slope Movement Potential, Site Visit Report". The Phase III assessment, which included a ground survey, was completed in 2001".

During the audit, it was observed that TransCanada's WOF program did identify areas of geological sensitivity, but this information did not appear to influence the scope and/or frequency of the geological hazard patrol program. TransCanada responded to this audit observation by stating that "TransCanada determines the scope and typical frequency of ROW patrol based on class locations, history of the lines, and other factors. Additional patrols are initiated in response to unforeseen geotechnical and meteorological events. TEP-ITM-WOF Section 8.4 Step 35 specifies that an aerial or ground survey shall be performed when investigating significant meteorological events; Section 8.4 Step 27 specifies that an aerial or ground survey shall be performed to investigate areas where earthquake magnitudes exceed 0.2 g peak ground acceleration. Identifying geotechnical threats is a part of the ROW patrol, but usually not a main factor that dictates the frequency of the patrol, because geotechnical threats, once identified, are dealt with separately in its own systematic way. Once an area of geological sensitivity is identified and verified through ground investigation, we install monitoring equipment and perform regular ground inspections. There are sites of active ground movement (Simonette River crossing for instance) where we have inspection and monitoring up to three times a year, in addition to regular aerial ROW patrol. Our experience so far has demonstrated that the regular scheduled aerial patrols supplemented by additional ground inspections/monitoring at sensitive areas have been effective in identifying WOF related hazards before they become threats to the integrity of our pipelines."

The Board has determined that TransCanada's program for geotechnical monitoring is in compliance with the requirements of CSA Z662 clause 10.6.1.1(f), (g) and (h), clause 10.6.1.2 and the OPR-99 sections 39 and 53(1).

Water Crossing Surveys

Regulatory Requirements for Water Crossing Surveys

CSA Z662-11, Clauses 10.6.4.1 and 10.6.4.2 detail the requirements for pipeline crossings of water bodies.

Clause 10.6.4.1: "*Special consideration shall be given to the inspection and maintenance of pipeline crossings of (a) major utilities; (b) other pipelines; (c) railways; (d) roads; and (e) water"*.

Clause 10.6.4.2: "*Underwater crossings shall be inspected periodically for adequacy of cover, accumulation of debris, and other conditions that can affect the safety or integrity of the crossing*".

TransCanada's pipeline systems have numerous water crossings that require inspection and monitoring programs. During the audit interviews, TransCanada indicated that periodic inspections are conducted at stream crossing locations of concern for adequacy of cover, accumulation of debris, and other conditions that may affect the safety or integrity of the crossing. Underwater depth of cover surveys are performed at selected stream crossing locations based on size of stream bed, visibility during aerial patrols, results of previous surveys, potential for mechanical damage, and severity of identified consequences. Minimum stream crossing cover specifications and stream crossing survey procedures are found in the TOP Pipeline Underwater Inspections (EDMS No. 003671756).

During the audit interviews, the Board noted that TransCanada's geological hazards classification summary refers to geotechnical threats and erosion threats, but the WOF program does not cover soil erosion and/or flooding threats. The Board requested that TransCanada address this concern. TransCanada's response was as follows:

"The Geological Hazards Classification Summary in the TQM Phase I Geo-hazard Assessment reports refers to slope stability and erosion as two main geotechnical threats that could impact pipelines on the TQM system. They are addressed in the *TEP-ITM-WOF Weather and Outside Forces Management Program* somewhat differently due to nature of the threats with respect to integrity. Slope stability impacts pipe integrity in a direct way, so actions dealing with slope movement are clearly defined in the TEP. Soil erosion itself is not an integrity threat, until it leads to pipe exposure. As such, TransCanada does not address soil erosion in the TEP-ITM-WOF. Rather the procedures in dealing with pipe exposure are outlined and documented in Steps 40 to 49 (page 20 to 22) of the TEP-ITM-WOF.

The document, TEP-ITM-WOF Weather and Outside Forces Management Program contains the following references to flooding:

1) The definition of a "weather and outside force integrity event", (page 9), defines floods as among the events that may impact the integrity of the pipeline.
2) Section 6.1.5 describes water flow events, including floods that could lead to pipe exposures and therefore increase the potential for mechanical damage.

3) Section 8.2, step 8 instructs the reader to identify areas of exposed pipe or having the potential to become exposed. Flooding is directly mentioned in that step.
4) Section 8.4, steps 28 to 33 are applied "when investigating significant flooding.
5) Section 8.4 Step 35 instructs the reader to perform and aerial or ground survey when investigating significant meteorological events.

The potential threat of stream erosion, which could lead to pipe exposure, is managed through regular underwater survey in major stream crossings. The TEP-ITM-WOF Section 8.2, step 8 states "Identify exposed pipe locations and areas of potential exposure from underwater surveys. The underwater surveys are performed as described in TOP Pipeline Underwater Inspections, (EDMS 003671756). During the audit, the Board reviewed TransCanada's water crossing monitoring procedures and assessed them to be in compliance with the requirements.

Summary: Inspection, Measurement and Monitoring

The Management System Audit Element 4.1, Inspection, Measurement and Monitoring, requires a company to develop and implement surveillance and monitoring programs including contract work being performed on behalf of the company. These programs are expected to include measures for evaluating the management and protection programs.

Based on documents and records reviewed, the audit determined that TransCanada has developed and implemented a number of effective inspection, measurement and monitoring programs. This includes but is not limited to:

- Sediment and water monitoring and mitigation programs to prevent and reduce internal corrosion on the Keystone pipeline system;
- Conducting both aerial and ground-based pipeline patrols in accordance with CSA Z662-11 requirements with additional patrols as warranted or as directed by the regulator;
- Development of monitoring programs to evaluate specific geotechnical hazards in each operating region; and
- Regular inspection and monitoring of sensitive areas including river crossings and susceptible landslide locations.

Other sections of this sub-element were identified as non-complaint with regulatory requirements due to inadequate or incomplete program implementation. This included:

- TransCanada's position that ongoing monitoring of all shipped commodities for sour crude on the Keystone pipeline is not required since recent testing confirmed the current non-sour nature of these products;

- TransCanada's inability to produce sufficient evidence proving the adequacy of its ongoing integrity management programs for corrosion on unpiggable sections of the NGTL system; and
- background descriptions for the facility pipe inspection program that were too generic and did not provide the level of specificity required for adequate, effective and consistent implementation.

Management System Audit Element Finding: Based on the documents assessed and interviews with personnel as it relates to: monitoring of Hydrogen Sulfide (H_2S) in crude oil in the Keystone Pipeline; monitoring of external corrosion on the Alberta (NGTL) System's unpiggable pipelines; and the integrity monitoring of below-ground station piping on all of TransCanada's facilities, TransCanada is assessed to be non-compliant with the requirements of the OPR-99 and CSA Z662-11, and is therefore non-compliant with this audit sub-element.

Compliance Status: Non-Compliant

4.2 Corrective and Preventive Actions

Expectations: The company shall have a process to investigate incidents or any non-compliance that may occur. The company shall have a process to mitigate any potential or actual issues arising from such incidents or non-compliances. Such mitigation may include appropriate timing and actions for addressing the issues that arise. The company shall demonstrate that it has established a documented procedure to:

- set criteria for non-compliance;
- identify the occurrence of any non-compliances;
- investigate the cause(s) of any non-compliances;
- develop corrective and/or preventative actions; and
- effectively implement the required corrective and/or preventative actions.

The company shall develop procedures to analyze incident data in order to identify deficiencies and opportunities for improvement in its management and protection programs and procedures.

References:

OPR-99 sections 4, 6 and 52
CSA Z662-11, Clauses 3.1.2(g) and 3.1.2(h)(i), 3.2, 10.3.6, 10.4.4 and 10.5

Audit Assessment:

Incident Management System

During interviews and in documents submitted, TransCanada indicated that it has an Incident Management System (InMS), which is a set of management tools and processes used to investigate incidents or any non-compliance. Within the InMS, TransCanada has the Incident and Issue Management Program (InMP), which utilizes the following tools:

- An Incident and Issue Tracking (IIT) system, which is an electronic database tool used to report and track the investigation of an incident, a near-hit or an identified non-compliance. The criteria for incidents, near-hits and non-compliances are listed on the company's IIT incident summary sheet.
- A Classification Guide, which is a document defining the incident and issue event types reportable in the IIT system. These are a detailed breakdown of the event types into four levels of severity (Minor, Serious, Major and Critical).
- An InMP website, which is the TransCanada internal website that provides reference material, investigation templates, documentation, and manual forms.

TransCanada's Incident Management System, with its criteria for incident classification and investigation were assessed to be in compliance with the requirements of CSA Z662-11, Clause 10.3.6, Pipeline system incident investigations.

Issue Management Program

TransCanada provided information on the six main steps in its InMP, as follows:

1. Response: All TransCanada employees and its contractors are expected to participate in the InMP. They are responsible for recognizing that an incident or issue has occurred and for alerting the appropriate personnel in the event of an incident occurrence.
2. Notification: Once the response has taken place, an employee is to enter the incident into the IIT system, which is responsible for the notification of applicable personnel and regulatory agencies.
3. Investigation: All incidents and issues are to be reviewed. The level of rigor of investigation of each incident is dependent on the severity of the incident. Once investigation findings have been determined, appropriate corrective and preventive actions are to be identified and implemented to minimize or avoid future incidents.
4. Documentation and Implementation: Documented recommendations are updated into IIT and/or incorporated into TransCanada's Integrity Management Programs (IMPs), as appropriate.
5. Follow-up: Once the recommendations have been implemented, follow-up is to take place to ensure the recommendations were successful in addressing the incident or issue.
6. Sharing of Learnings: The final step of the InMP is to share the learnings with TransCanada's employees, contractors and external parties, with the goal of preventing a future undesirable consequence from occurring.

CSA Z662-11, Clause 3.1, Safety and Loss Management System, and specifically Clause 3.1.2 (h)(i) states *"The safety and loss management system shall include the following elements: (h) a continual improvement process, including performance monitoring for the ongoing assessment of conformance with the requirements of the safety and loss management system, and the mechanisms for taking corrective and preventive measures in the event of nonconformance"*. In addition, CSA Z662-11, Clause 10.3.6, Pipeline system incident investigations, states *"Operating companies shall investigate damage incidents related to external interference and failure incidents to determine their causes. Measures to prevent the occurrence of incidents due to similar causes shall be identified and implemented"*. TransCanada's procedures for incident management were assessed to be in compliance with the requirements, but as discussed under the topic of Incident Reporting, TransCanada's incident reports lack detail with respect to preventive

actions, follow-up and sharing of learnings. TransCanada has committed to working with the Board to improve the level of detail in its DIRs.

Incident and Issue Tracking (IIT)

During the course of this audit and in response to an Audit Information Request, TransCanada provided evidence of its analysis of six incident types:

- overpressure of pipelines and/or facilities piping;
- pump station leaks;
- other station releases;
- pipe body leaks and pipe body ruptures; and
- uninterruptable power supply (UPS) battery incidents.

The purpose of the interviews and document reviews relating to these incident types was to assess whether TransCanada had effectively implemented its IMS processes and procedures to identify the incident root cause(s), implement adequate and effective corrective and preventive action(s), and adequately and effectively followed its InMP processes and procedures for follow-up and sharing of learnings from the incidents, particularly for incidents related to TransCanada's IMPs. As discussed under the topic of Incident Reporting, TransCanada's incident reports lack detail with respect to preventive actions, follow-up and sharing of learnings. TransCanada has committed to working with the Board to improve the level of detail in its DIRs.

Integrity Threat Management Scorecards

TransCanada also submitted documents (Integrity Threat Management Scorecards) to demonstrate that it had compiled and analyzed key performance indicator (KPI) and incident data. The Scorecards submitted and reviewed were:

- Internal Corrosion;
- External Corrosion;
- Mechanical Damage;
- Construction Defects;
- Weather and Outside Forces;
- Manufacturing Defects;
- Equipment;
- Stress Corrosion Cracking (SCC);
- Leaks and Ruptures;

- Engineering and Asset Reliability IIT; and
- Customer Perfect Days.

In addition, TransCanada submitted the document "Gas Release-Leak (Canada) 2007-2012 Chart Q4r1.xls" that compiled the gas releases reportable to the Board from 2007 to 2012. TransCanada presented these figures as evidence of its process to analyze and trend incidents and their root causes. The document submitted contained histogram representations of the trends and/or causal factors relating to the gas releases as follows:

- Figure 1: Gas Leak and Release Trends;
- Figure 2: Gas Leak Breakdown, (Causal Factors);
- Figure 3: Electrical / Instrument / PLC Failures;
- Figure 4: Gaskets / Packing / O-ring / Etc.; and
- Figure 5: Piping / Tubing / Fittings.

TransCanada's Scorecards contained information on the individual threat management programs, including: goals and objectives; failure statistics (incident rates x 10^3 per km·yr) due to each threat; in-service leaks and ruptures; and histograms and pie charts of threat related data. The Scorecards were assessed to be in compliance with CSA Z662-11, Clause 10.3.6, Pipeline system incident investigations.

Non-Compliance Process

TransCanada stated that it has a systematic approach to addressing non-compliances. Non-compliances at the IMP level, and non-compliances with regulations and codes, are addressed and tracked through its IIT system. Corrective actions, including completion dates and follow-up, are assigned to specific individuals in the IIT system. The status of IIT incidents and issues, and action items, are reviewed by management monthly. In addition to day-to-day monitoring, non-conformances are identified through the following: audit findings (external and internal); process reviews, including TransCanada's Operating Procedures (TOPs); and incident investigations (failures, near-hits).

Pipelines (Oil and Gas)

For its pipeline systems (gas and liquids), TransCanada stated that corrective and preventive actions identified through internal audit findings are consolidated in an action log. The audit log lists identified actions to address the deficiencies, responsible individuals, completion dates and status. The status of corrective or preventative actions is included in the CDN-LIQ-IMP *Annual Review and Improvement Report*. Process Reviews of procedures are conducted annually, as described in the *Pipe Integrity Process Review Procedure*.

Facilities

For its facilities, TransCanada stated that corrective actions are also identified, investigated, evaluated and prioritized, based on the engineering discipline and equipment type, using other systems such as the TransCanada Operating Procedures (TOPs), Avantis (TransCanada's work management system) and health monitoring motor trending. Other tools, such as a Decision Support System (DSS), health monitoring, and pressure vessel and tank investigations, are used to complete trending analyses to determine if further actions are required for systemic issues and if these actions need to be tracked in a corrective log with monthly review by all stakeholders. Actions are then implemented in the General Plan Maintenance Capital (GPMC) program or the Preventive Maintenance (PM) program, which determines whether the risk is tolerated, terminated or transferred.

TransCanada stated that it ensures that corrective actions are implemented and followed up as part of the management review process. Management review includes monitoring the status of corrective and preventive actions in IIT monthly, and reviewing program performance measures to determine the effectiveness of the overall program.

Assessment of TransCanada's InMS and InMP determined that within its internal processes and procedures, TransCanada has demonstrated compliance with the requirements of this audit element for its facilities. As discussed in the following text, TransCanada's incident reporting, in the form of Detailed Incident Reports (DIRs) submitted to the Board, lacks detail with respect to preventive actions, follow-up and sharing of learnings.

Incident Reporting

In a meeting held 7 March 2013 to discuss TransCanada's DIRs, it was communicated to TransCanada that: the DIR corrective actions were assessed to be generally adequate; preventive actions tended to address local issues only; and incident follow-up and sharing of learnings were generally inadequate. TransCanada stated that the timeframe of submitting its DIRs to the Board and its internal incident investigation processes accounted for the discrepancies in the level of detail. That is, its DIRs are written and submitted more immediately following an incident, whereas its internal incident processes are generally conducted in detail some months later. To address the issue, TransCanada committed to working with the Board to improve the level of detail in its DIRs, and both the Board and TransCanada have committed to improving their communications with respect to TransCanada meeting the Board's expectations for incidents investigation and reporting.

Reporting of Non-Compliances

TransCanada was asked to provide its policies and procedures for the internal reporting of non-compliances. TransCanada stated that there are many available outlets for employees to bring concerns forward to TransCanada's management. These included the Incident and Issue Tracking (IIT) system; Ethics Help line; informal and formal reports to technical managers, non-conformance reports (NCRs); and the TransCanada Code of Business Ethics policy and procedures. TransCanada stated that employees are trained on these procedures during the onboarding process and through the annual employee Code of Business Ethics policy training and certification. TransCanada's internal Human Resources website provides employees with a list of the Compliance Coordinators for different areas of the company and a link to this document was, and continues to be, accessible to employees in the "Raise the Concern" section of the website. TransCanada stated that its management encourages open and honest discussion of all areas of concern and promotes an environment where safety is the paramount goal. TransCanada provided the following documentation to support its internal reporting of non-compliances:

- TransCanada Code of Business Ethics (TRP901-a77en);
- Code of Business Ethics Policy (EMDS No. 003721479);
- Ethics and Compliance (website printout);
- Ethics and Compliance organization (website printout);
- Ethics Help Line (website printout);
- List of Compliance Coordinators by Department (3 page document containing 12 coordinators for pipelines);
- Raising a Concern (website print out); and
- Frequently Asked Questions (website printout).

Summary: Corrective and Preventive Actions

The Management System Audit Element 4.2, Corrective and Preventive Actions, requires a company to have a process to investigate incidents or any non-compliance that may occur, including a process to mitigate any potential or actual impacts arising from the non-compliances. The company is also required to develop procedures to analyze incident data in order to identify deficiencies and opportunities for proactive improvement.

During the course of this audit, TransCanada provided evidence of its analysis of possible incident types. The company also demonstrated it had compiled and analyzed key performance indicator data in order to assess trends and establish root causes of incidents.

The Board noted that TransCanada's internal non-compliance and incident reporting processes were adequate but could be more detailed in the areas of preventative action and information sharing across the company. TransCanada has committed to improving the level of detail in these items.

Management System Audit Sub-Element Finding: Based on documents reviewed and interviews with personnel, TransCanada was able to demonstrate that it was in compliance with the requirements of the OPR-99 and CSA Z662-11, and is therefore compliant with the requirements of this audit sub-element.

Compliance Status: Compliant

4.3 Records Management

Expectations: The Company shall establish and implement procedures to ensure that the records supporting the management and protection programs are retained, accessible and maintained. The Company shall, as a minimum, retain all records for the minimum lengths of time as required by the applicable legislation, regulation and standards incorporated by reference into the regulation.

References:

OPR-99 sections 4, 41 and 56
CSA Z662-11 Clauses 3.1, 3.2, 9.11, 10.4 and 10.5

Audit Assessment

This Management System sub-element was not formally assessed during the Integrity Management Program audit.

Compliance Status: Not Assessed

4.4 Internal Audit

Expectations: The company shall develop and implement a documented process to undertake audits of its management and protection programs and procedures. The audit process should identify and manage the training and competency requirements for staff carrying out the audits. These audits shall be conducted on a regular basis.

References:

OPR-99 sections 4, 53 and 55
CSA Z662-11, Clauses 3.1.2(c) and 3.1.2(h)(iii)

Audit Assessment:

General

During interviews and in documents submitted, TransCanada stated that the mandate of TransCanada's internal audit department (Internal Audit) is to act as an independent assessor, reporting on the company's system of internal controls, governance and risk management processes. Internal Audit reports functionally to the Audit Committee of the Board of Directors and administratively to the Chief Compliance Officer. Internal Audit is authorized to perform internal audits, including those involving Integrity Management Programs (IMPs). For TransCanada's IMPs, Internal Audit follows a maximum interval between audits of three years.

The following IMP documents state the requirements of TransCanada's internal audit program:

- Gas Pipeline IMP, Section 4.10;
- Liquid Pipeline IMP, Section 11.3.5; and
- Plant IMP, Section 2.5.2.

On a one to three-year basis, all procedural documents are reviewed for effectiveness by document owners and other shareholders. With respect to the IMPs, the engineering procedures are reviewed annually following the Pipe Integrity Process Review Procedure (TEP-INT-PR, EDMS No. 006522487). The effectiveness of the process and management system elements within each document is reviewed to identify non-compliances/non-conformances and/or areas requiring improvement.

Internal audits are conducted by TransCanada personnel that are independent of the areas to be audited, consistent with Annex N "Guidelines for pipeline system integrity management programs" of CSA Z662-11, specifically Clause N.15.4(d). In this respect, IMP audits are

completed by the Quality Management and Engineering Standards group or a third-party auditor. The Quality Manager is responsible for ensuring that employees are competent to complete internal office audits through documented skills, certifications, training or education. As a minimum, the Lead Auditor is qualified to the ISO Internal Auditor training, CSA Internal Auditor training or equivalent. The competency of third-party auditors is managed through the vendor qualification process, which includes requirements for documentation addressing the third-party auditor training and certification.

On a quarterly basis, TransCanada conducts field-based Targeted Compliance Audits that are performed at multiple locations within the Canadian Pipeline Operations Regions. The results are consolidated in a single report, which identifies systemic issues related to the topic assessed during the audit. Field-based audits are conducted by Canadian Pipeline Operations Compliance (CPO Compliance) team members comprised of a Senior Compliance Specialist and three Field Compliance Specialists. All team members attend internal training courses and receive certification from a training course conducted by an external third party. It is the responsibility of the CPO Compliance Manager to ensure employees are competent to complete field-based audits through documented skills, certifications, training or education. The process for completing audits is documented in TransCanada Operating Procedure (TOP) Compliance Assurance Program (EDMS No. 005364423) and the associated TOP Targeted Audit (EDMS No. 006281982).

The Quality Management and Engineering Standards internal audit processes and procedures requires the person accountable for the program that has been audited to resolve all findings. Audit findings are tracked in action logs or the Incident and Issue Tracking (IITs) database. Issues related to each audit are identified, and corrective and preventive actions, accountabilities, and timelines are recommended by the CPO Compliance audit team. Site-specific findings that are not considered to be systemic in nature are provided to the specific area manager to address. The finalized audit report is provided to the Vice President, Canadian Pipeline Operations, the regional leadership teams (Directors and Managers) and leaders of other departments who have been assigned specific actions to address identified deficiencies, and on whom the audit may have an impact. The Senior Compliance Specialist is responsible for monitoring the progress of audit resolutions and for escalating issues when deemed necessary. The status of completion of the actions is also tracked in the monthly CPO Compliance Scorecard, which is issued to and reviewed by the Vice President, Canadian Pipeline Operations, and the Directors.

NEB's Investigation of TransCanada's Response to a complainant's Allegations

TransCanada's Internal Audit Department conducted an audit of a complainant's allegations. The focus of the audit was as follows:

1. Independent Third Party Non-Destructive Examination
2. Independent Visual Surveillance of Welders
3. Non-Destructive Examination of Pressure Vessels
4. Qualification of Welders on the Keystone Pipeline
5. Practice of Engineering within TransCanada
6. Joining Pipe of Different Wall Thicknesses
7. Use of Automatic Ultrasonic Testing
8. Submission to the NEB of TransCanada's Joining Program
9. TransCanada's Formal Audit Program

The findings of TransCanada's internal audit and the resulting remediation measures taken by TransCanada were submitted to the Board on 18 July 2012. In addition, NEB audit interviews were held with TransCanada with respect to the resolution of a complainant's allegations on 18 March 2013. TransCanada was directed to provide additional information and supporting documents to substantiate the responses given during the interviews.

Each of the issues investigated in TransCanada's internal audit, as well as the NEB's assessment of the ongoing and completed remediation measures identified by TransCanada in response to the audit findings, are described below.

1. Independent Third Party Non-Destructive Examination

TransCanada's internal audit concluded that there had been instances where TransCanada did not ensure that qualified, third party non-destructive examination (NDE) vendors were hired under the direct supervision of TransCanada (and not by the pipeline, facility or fabrication contractor), resulting in a lack of independence. This was a non-compliance with the OPR-99, section 54(1), which states: *"When a company constructs a pipeline, the company or an agent independent of any construction contractor retained by the company shall inspect the construction to ensure that it meets the requirements of these Regulations and complies with the terms and conditions of any certificate or order issued by the Board."*

TransCanada's internal audit noted that a process was being implemented to ensure independent NDE inspections. During the NEB audit interviews, TransCanada confirmed that new processes were in place to ensure that NDE vendors were hired by TransCanada directly. NEB auditors requested that TransCanada demonstrate that it had a plan in place to examine past NDE results

in order to validate whether these non-independent inspections would constitute a future integrity hazard. TransCanada responded as follows:

"For fabrication of piping assemblies between May 2004 and August 2011, TransCanada used fabrication shops with certified Quality Management Systems. The fabrication facilities were responsible for hiring qualified third party NDE contractors to complete the inspections. TransCanada hired a third party inspector to oversee the work produced by the fabrication shop and the NDE contractor. The TransCanada inspector was responsible for ensuring the fabrication shops met the specification and procedure requirements for materials, welding, non-destructive examination, pressure testing and coating. The inspector was responsible for checking the radiographic film to ensure the level of quality was met and that all welds were inspected. The fabrication of piping assemblies was completed in accordance with the requirements of CSA Z662 and the piping assemblies were completed using TransCanada's welding specification (TEP-NDT-ADT, EDMS No. 003797402), which requires 100% NDE of welds. The TransCanada specifications for NDE required that all radiographic film interpretation be completed by a Canadian Government Standards Board (CGSB) Level II technician. TransCanada stated that the fabricated assemblies in question were all subjected to a high pressure hydrostatic test before going into service and are not considered an integrity hazard."

TransCanada completed a review of the projects on which fabrication of piping assemblies was completed for the time frame of 2004 to 2011 and determined that there are approximately 50 meter stations and 7 pipeline projects where fabricated pipeline assemblies were installed under NEB jurisdiction without independent third party NDE. To address the issue, TransCanada proposed an audit of the projects using its NDE procedure TEP-NDT-ADT, Clauses 7.2.2 to 7.2.4 (inclusive), which specifies a 15% progressive audit of the radiographs involved. The Board reviewed TransCanada's proposed audit criteria to determine whether it would provide adequate examination of the welds that had occurred in the past projects. The Board determined that TransCanada's proposed audit procedure (15% of the welds) did not meet the requirements of the OPR-99, section 17.[5] TransCanada subsequently revised its audit criteria to include 100% of the subject welds and is therefore now in compliance with the OPR-99, section 17 requirements.

To ensure that TransCanada will provide qualified, third party non-destructive examination (NDE) contractors that are hired under the direct supervision of TransCanada, and not by the pipeline, facility or fabrication contractor, TransCanada stated that it has developed new Master

[5] See the amended and re-named *National Energy Board Onshore Pipeline Regulations*, section 17, for the corresponding provision.

Service Agreement (MSA) contracts with its approved NDE contractors, under which TransCanada is solely responsible for hiring the NDE personnel. TransCanada stated that it had also developed revised Work Authorization contract documents for work not covered by the MSAs, which specifically state that the NDE contractors will be hired directly by TransCanada. As a result of its internal audit, TransCanada also developed a procedure (TEP-NDE-INSP-SHOP, Fabrication Shop Non-Destructive Examination Inspection Procedure, EDMS No. 006684544) outlining the requirements for conducting NDE in fabrication shops. This procedure had an effective date of October 15, 2011 and the procedure stated under Clause 1 that: "*TransCanada will hire: (1) A Fabricator to construct assemblies; (2) An NDE contractor to conduct non-destructive examinations of the welds; and (3) A Fabrication Inspector to inspect the results prepared by the NDE contractor.*"

Summary: Independent Third Party Non-Destructive Examination

The Board noted that had been instances where TransCanada did not ensure that qualified, third party non-destructive examination (NDE) vendors were hired under its direct supervision. Therefore, TransCanada had been non-compliant with the OPR-99, section 54(1). However, the Board also concluded that the measures taken by TransCanada to ensure independent third-party NDE inspections, as well as TransCanada's commitment to undertake an audit of 100% of the previously affected welds, adequately addresses the issue of independent third-party NDE.

2. Independent Visual Surveillance of Welders

TransCanada's internal audit concluded that, in the past, TransCanada was non-compliant with CSA Z662-11, Clause 7.10.2 (Visual Inspection), and specifically sub-clause 7.10.2.1, which states that: "*The completed welds on the outside surface of the piping shall be visually inspected for 100% of the weld length for any imperfections that are not detectable by non-destructive inspection, in accordance with documented procedures approved by the company. Such procedures shall include requirements for extent and frequency of visual inspection, personnel qualification and visual acuity, maximum viewing distance and angle, lighting conditions, evaluation tools, and reporting.*"

TransCanada's internal audit noted that TransCanada's management agreed to follow up on this issue. TransCanada's Materials Engineering met with Construction Services management, welders and foremen to discuss the issue of inspection/audit procedures for maintenance welding to ensure compliance with the requirements of CSA Z662-11, Clause 7.10.2.1. TransCanada stated that its personnel completed a full review of the welding and NDE specifications and procedures applicable to their responsibilities. A qualified technical specialist provided welder training and witnessed the qualification test welds. In addition, a revised method for tracking welder qualifications was implemented. TransCanada's Construction Services department

created and filled the position of a Construction Services Manager responsible for Equipment, Quality Assurance/Quality Control, Welding and Fabrication. The Materials Engineering Department met with the Construction Services Manager to discuss the actions that had been implemented up to the date of the internal audit, as well as the implementation of further recommendations on training and the overall inspection requirements with respect to welder supervision and inspection.

As a result of the NEB audit interviews, TransCanada provided its engineering procedure, TEP-NDT-VT Visual Examination (EDMS No. 007381161) and examples of welder inspection reports as supporting documentation that TransCanada meets the requirements set out in CSA Z662 Clause 7.10.2.1. The TEP-NDT-VT engineering procedure is based on CSA Z662-11 Oil and Gas Pipeline Systems; ASME Section V, Article 9, Guidelines; and API 1104, Welding of Pipelines and Related Facilities. The engineering procedure applies to visual examination that is to be conducted to determine the condition of the part, component or surface examined including such conditions as weld quality, alignment of mating surfaces, crack, wear, corrosion, erosion, evidence of leakage, or physical damage. The records of visual weld examinations requested by NEB auditors for a specific project (36" Edson Extension Hydro Test Project, ED-120 to ED-130, 2012) included a weld tally with visual inspection and weld parameter confirmation records, all visual inspection reports for the project, welding inspector's daily reports for the project, and the Company Representative and Welder Inspector's Check List.

Summary: Independent Visual Surveillance of Welders

The Board concluded that TransCanada was non-compliant with CSA Z662-11, Clause 7.10.2 (Visual Inspection) and specifically sub-clause 7.10.2.1. The Board also concluded that TransCanada has the processes and procedures in place to meet the requirements of CSA Z662-11, Clause 7.10.2.1 and that those processes and procedures adequately address the issue of independent visual surveillance of welders.

3. Non-Destructive Examination of Pressure Vessels

TransCanada's internal audit concluded that a variance to the American Society of Mechanical Engineers (ASME), Section V – Non-destructive Examination had occurred in that, in one instance, the NDE of a pressure vessel was known to be insufficient due to the NDE inspector being unable to inspect the full weld beneath a plate attached to a nozzle. The NDE inspection report did not meet code as it incorrectly indicated full inspection had occurred. Had the NDE inspection report indicated that the complete weld inspection had not occurred due to restricted access, the report would have met the requirements of the code.

TransCanada's response to the internal audit finding was that the pressure vessel in question was for the NGTL Gold Creek Compressor Station project. This project was taken out of service by

TransCanada's Engineering Department in September 2011. A complete review of the design drawings, fabrication welding procedures and NDE inspection procedures was completed by TransCanada through September, October and November 2011. An internal report was competed on this review and, in particular, the questions raised regarding the NDE for the nozzle weld. The review determined the NDE of the small diameter nozzles was completed, but the NDE technician referenced the incorrect procedure and did not indicate the restricted inspection area in the report. This was addressed with the third party NDE company and resolved. The pressure vessel was released for installation in November 2011 and the pressure vessel was included in the field pressure testing program for the station piping at the Gold Creek Compressor Station. The report also recommended changes to the process for procurement and third party inspection of pressure vessels. TransCanada's Materials Engineering department has revised the third party surveillance checklist used for pressure vessels and has worked directly with the third party inspection company to provide the third party inspectors with training on the specification requirements and expectations on reporting.

Summary: Non-Destructive Examination of Pressure Vessels

The Board concluded that a variance to the American Society of Mechanical Engineers (ASME), Section V – Non-destructive Examination had occurred in TransCanada's NGTL Gold Creek Compressor Station project. The Board also concluded that TransCanada has the processes and procedures in place to ensure that NDE inspections of pressure vessels meet the ASME code requirements and that reporting of NDE results accurately reflects the NDE procedures. The measures taken by TransCanada adequately address the issue of NDE of pressure vessels.

4. Qualification of Welders on the Keystone Pipeline

TransCanada's internal audit confirmed that a number of welds on the Keystone Pipeline did not comply with CSA Z662-11, Clause 7.8, Arc and Gas welding - Qualification of Welders, due to welding being performed by an unqualified welder. TransCanada stated that the lack of welder qualification was discovered by a TransCanada inspection and documents coordinator, who ordered corrective action to be taken, which consisted of removal of the welds in question. TransCanada required that all of the welds in question be redone by a qualified welder. To ensure that no other pipeline welds performed on the Keystone Pipeline were out of compliance due to welder qualifications, a review was conducted of all of the Keystone Pipeline welder qualification records. TransCanada reinforced the requirement that no work should be started on a project without the inspector present at the contractor's fabrication facility and completion of assurance of welder qualifications.

Summary: Qualification of Welders on the Keystone Pipeline

The Board concluded that TransCanada's Keystone Pipeline project contained a number of welds that were not in compliance with CSA Z662-11, Clause 7.8, Arc and Gas welding - Qualification of Welders. The Board also concluded that the measures taken by TransCanada adequately address the issue of qualification of welders on the Keystone Pipeline and that TransCanada has the processes and procedures in place to ensure appropriate welder qualifications on TransCanada's future projects.

5. Practice of Engineering within TransCanada

TransCanada's internal audit concluded that the final review and signing of designs completed by an external engineering company was done under TransCanada's permit to practice and by professional engineers registered in Alberta. To ensure TransCanada engineers and technologists were clear in their roles and responsibilities, TransCanada management implemented a review of the Engineering requirements in the Practice of Engineering specification (TES-ENG-POE, TransCanada Practice of Engineering (POE) EMDS # 003672108, revised in Nov. 2011). The Practice of Engineering specification includes guidance on the requirements for both internal TransCanada and third party engineering (Sections 5.1 and 5.2 respectively).

In 2012, TransCanada management also implemented mandatory training on TransCanada's Practice of Engineering and TransCanada's Professional Engineering Management Plan for engineers and technologists within the company. This training is currently being added into the TransCanada Learning Management System (LMS) as a requirement for Engineers to take every 3 years. TransCanada's Practice of Engineering outlines authentication requirements for engineering documents produced by or for TransCanada. TransCanada's Professional Engineering Management Plan outlines principle information regarding the management of engineering within TransCanada. TransCanada procedures related to projects have design reviews by technical and engineering resources that are designed to occur at the 30%, 60% and 90% design stages. When the work is completed by external engineering companies, the final designs are authenticated or signed by professional engineers based on the requirements of the jurisdiction in which the work and/or construction is taking place. For designs completed by internal TransCanada resources, the company's permit to practice stamp is applied.

Summary: Practice of Engineering within TransCanada

The Board concluded that TransCanada is in compliance with its internal Practice of Engineering specification governing the practice of its professional engineers. The Board also concluded that the measures taken by TransCanada adequately address the issue of practice of engineering within TransCanada and for its external engineering contractors.

6. Joining Pipe of Different Wall Thicknesses

TransCanada's internal audit investigated an allegation that using back-beveled transition welds is prone to higher incidence of failure than using counter-bore and taper welds.

The internal audit concluded that the failure incident reference was made to historical welding practices that were acceptable at that time. TransCanada stated that the use of taper (back beveling) is a common practice within the pipeline industry. Clause 7, Joining, of CSA Z662-11, provides guidance on the recommended designs of unequal wall thickness weld joints. Figure 7.1, *Examples of end preparations and combinations of end preparations*, and specifically Figure 7.1(a) with its guidance note states that for internal diameters unequal "*where the nominal internal offset is 2.4 mm or less, no special treatment is necessary, provided that full penetration and bond is accomplished in welding.*" Figures 7.1(b) through 7.1(g) and the corresponding guidance notes detail the requirements cases of internal offset greater than 2.4 mm, external diameters unequal and internal, and unequal external diameters.

The joining requirements in CSA Z662-11 were compared to TransCanada's specification for transitioning of weld joints with unequal wall thickness pipe (TEP-MECH-TRAN, Selection of Transition Pieces and Joining Methods, EDMS No. 000006256). This internal specification provides guidance on determining when to use the back bevel design or the counter-bored and taper design. TransCanada currently implements this specification when the wall thickness difference of two adjoining pieces of pipeline is greater than 1.0 mm (TEP-MECH-TRAN, Figure 2(a) through Figure 2(d) of Section 4.0). TransCanada's joining specification meets the requirements of Clause 7 of CSA Z662-11. TransCanada also manages the risk of weld joint cracking through control of welding parameters such as preheat, welding heat input and pipe movement during welding and, in addition, Section 2.0.3 of the TransCanada specification states that "*the transition weld shall not be located in the immediate region of high bending moments (such as may be generated by filed overbends, sidebends or sagbends). The transition weld shall be located at a minimum distance of 3D from the end of the bend to the transition. Unless it can be demonstrated that a lesser distance will not adversely affect the structural integrity of the pipeline.*"

Summary: Joining Pipe of Different Wall Thicknesses

The Board concluded that TransCanada's joining specification meets the requirements of CSA Z662-11, Clause 7, Joining. The Board also concluded that TransCanada has the processes and procedures in place to address the issue of joining pipe of different wall thicknesses that could affect the weld joints and the integrity of the pipeline.

7. Use of Automated Ultrasonic Testing

TransCanada's internal audit investigated an allegation that the use of Automatic Ultrasonic Testing (AUT) is more sensitive in picking up defects than radiographic inspection. TransCanada's internal audit stated that CSA Z662-11 and the OPR-99 allow for the use of radiography or ultrasonic methods to examine girth welds. TransCanada uses either AUT or radiography (RT) for the non-destructive examination of butt welds on pipeline construction. Both of these non-destructive techniques have been used in pipeline construction for many years and the requirements for their use are included in CSA Z662-11, Clause 7.10.4 Non-destructive inspection. TransCanada uses radiography for butt welds on Nominal Pipe Size (NPS) 2" to NPS 48" pipe to pipe joints or pipe to component joints. The AUT method is applied to NPS 20" to NPS" 48 pipe to pipe mainline and tie-in welds on pipelines projects where the wall thickness is 6.4 mm and greater. The minimum diameter limit is applied to the projects due to the wall thicknesses being less than 6.4 mm and the inspection system's physical size as it sits on the pipe. TransCanada's specification used for automatic ultrasonic inspection is TES-NDT-UT1, Mechanized Ultrasonic Examination of Pipeline Girth Welds (EDMS No. 00367096) that contains within the scope of the document the wall thickness limits for UT weld inspection.

Summary: Use of Automated Ultrasonic Testing
The Board concluded that TransCanada is in compliance with CSA Z662-11, Clause 7.10.4 Non-Destructive Inspection and the OPR-99 with respect to the use of radiographic and ultrasonic inspection methods. The Board also concluded that TransCanada has the processes and procedures in place to address the issue of weld inspections and that these processes and procedures meet the requirements of CSA Z662-11 and the OPR-99.

8. Submission to the NEB of TransCanada's Joining Program

TransCanada internal audit investigated an allegation that TransCanada submitted a joining program for the Cutbank River Lateral Loop Project to the NEB that had not been fully customized and updated for the Project as required by the OPR-99, section 16, which states that *"A company shall develop a joining program in respect of the joining of pipe and the components to be used in the pipeline and shall submit it to the Board when required to do so"*.
TransCanada's internal audit confirmed that the allegation was valid. An updated version of the joining program was subsequently submitted to the Board. The internal audit further noted that the learnings from the Cutbank River Lateral Loop Project led to a complete review of the standard shielded metal arc welding (SMAW) procedures to confirm that the welding datasheets were accurate and correct, to ensure the supporting documents referenced (Procedure Qualification Record (PQR) and Welding Procedure Specification (WPS)) were part of the submission to the NEB, and to ensure each datasheet was properly supported by PQRs.

TransCanada stated that, going forward, all welding procedures submitted for its projects will be reviewed for compliance prior to their issuance.

Summary: Submission to the NEB of TransCanada's Joining Program

The Board concluded that TransCanada was not in compliance with the OPR-99, section 16 with respect to submitting a customized and updated joining program for the Cutbank River Lateral Loop Project. The Board also concluded that TransCanada has the processes and procedures in place to address the issue of submission of complete, accurate and updated welding procedures to the NEB.

9. TransCanada's Formal Audit Program

TransCanada's internal audit investigated an allegation that the audit and inspection process required by the OPR-99 did not exist within TransCanada. TransCanada's internal audit confirmed that there was an audit and investigation process within TransCanada, but that there were opportunities for continuous improvement. As noted above in the Board's assessment of this audit for sub-element 4.4 Internal Audit, TransCanada has demonstrated that it has a formal audit process for its Integrity Management Programs.

Summary: TransCanada's Formal Audit Program

The Board concluded that TransCanada is in compliance with the requirements of the OPR-99, section 55(1)(b) and CSA Z662-11, Clause 3.1.2(h)(iii). The Board also concluded that TransCanada has the processes and procedures in place to address the requirements of a formal audit and inspection program.

Summary: Internal Audit

The Management System Audit Element 4.4, Internal Audit, requires a company to develop and implement a documented process for auditing its management and protection programs and procedures. The audit process is expected to include and manage training and competency requirements for staff carrying out the audits and be conducted on a regular basis.

Internal audits of TransCanada's IMPs are conducted by personnel that are independent of the areas to be audited or by a contracted third party. Quarterly field-based compliance audits are conducted at multiple locations across Canada. All audit findings are tracked and are required to be resolved. Findings are also categorized as either site-specific or systemic and responsibility for these is assigned accordingly. The progress of resolving audit findings is monitored and escalated where necessary.

With regards to the internal audit of TransCanada's investigation stemming for concerns raised by a complainant, the Board finds the company's internal audit procedures effectively identified and assigned resolution of any regulatory non-compliances.

Management System Audit Sub-Element Finding: Based on documents reviewed and interviews with personnel, TransCanada was able to demonstrate that it was in compliance with the requirements of the OPR-99 and CSA Z662-11, and is therefore compliant with the requirements of this audit sub-element.

Compliance Status: Compliant

5.0 MANAGEMENT REVIEW

5.1 Management Review

Expectations: The company shall formally review the management and protection programs for continuing suitability, adequacy and effectiveness. The review should be based on appropriate documentation and records including the results of the surveillance, monitoring and audit programs. This review should be formal and documented and should occur on a regular basis. The management review should include a review of any decisions, actions and commitments that relate to the improvement of the programs and the company's overall performance.

References:

OPR-99 sections 4, 40 and 55

CSA Z662-11, Clauses 3.1.2 (h)(iii) and 3.2

Audit Assessment:

General

During interviews and in documents submitted, TransCanada described its management review processes and procedures.

At quarterly meetings of the Board of Directors' Health, Safety and Environment (HSE) Committee, TransCanada leadership present and discuss a scorecard on Operational Safety, which includes the Integrity Management Program (IMP) elements.

TransCanada's Senior Vice President of Operations and Engineering leads the Senior Governance Committee (SGC), which includes the Vice Presidents of Engineering and Asset Reliability, Canadian Pipeline Operations and Operations and Pipeline Services. The SGC provides the highest level of management governance, overseeing strategic aspects such as the policy and direction of the Asset Management System (AMS), which governs TransCanada's IMPs. The following sections of the IMPs provide the processes and procedures that are necessary to meet the requirements of the AMS:

- Gas Pipeline IMP, Section 8.0;
- Liquid Pipeline IMP, Section 2.1; and
- Plant IMP, Section 2.2.

TransCanada Threat Management Scorecards

TransCanada submitted documents (Integrity Threat Management Scorecards) to demonstrate that it had compiled and analyzed key performance indicator (KPI) and incident data. The TransCanada Integrity Threat Management Scorecards submitted and reviewed were:

- Internal Corrosion;
- External Corrosion;
- Mechanical Damage;
- Construction Defects;
- Weather and Outside Forces;
- Manufacturing Defects;
- Equipment;
- Stress Corrosion Cracking;
- Leaks and Ruptures;
- Engineering and Asset Reliability Incident and Issue Tracking (IIT); and
- Customer Perfect Days.

TransCanada's Scorecards contained information on the individual threat management programs, including: goals and objectives; failure statistics (incident rates x 10^3 per km·yr) due to each threat; in-service leaks and ruptures; and histograms and pie charts of threat related data. The Scorecards were assessed to be in compliance with CSA Z662-11, Clauses 3.1.2 (h)(iii) and 3.2 (d).

Key Performance Indicators

At the beginning of each year, the SGC sets direction through goals and objectives, along with overall KPIs for the IMPs. These common goals and objectives cascade down through the organization from the SGC to the individual employee. At each successive level of the organization, more specific goals, objectives and KPIs are monitored and reviewed to evaluate TransCanada's various programs, including the IMPs, for continued suitability, adequacy and effectiveness. At the SGC level, monthly management review meetings are held to discuss the KPI areas of asset reliability, safety, compliance, risk and cost. Regular updates through the chain of command are provided though weekly reporting and a monthly review of all outstanding incidents and issues.

Management Review System for the IMPs

Responsibility for review and revision of the IMPs extends from the IMP program manager up through the respective leadership team to the Vice President of Engineering and Asset Reliability. The IMPs and supporting documentation are revised on a regular basis to capture any significant improvement opportunities. Modification to the IMPs and their associated supporting procedures and processes is typically driven by lessons learned, and include the following inputs:

- IIT;
- Review of goals and objectives through KPIs;
- Audit findings and follow-up actions;
- IMP Reviews; and
- Industry learnings.

Incident and Issue Tracking (IIT)

IIT is the primary mechanism by which TransCanada identifies and takes actions on incidents and issues, including those related to the IMP. Automated notifications facilitate management oversight and governance. Resolution of action items is tracked within the IIT system and is to be reviewed monthly by the appropriate leadership within TransCanada.

Review of Goals and Objectives through Key Performance Indicators

To evaluate the IMPs for continued suitability, adequacy and effectiveness, common goals and objectives used to monitor progress cascade down through each level of the organization and are reflected in the specific KPIs. At the Vice President level, more detailed KPIs are part of the Engineering and Asset Reliability Leadership Team management review. At the Director and Manager level, more detailed KPIs are tracked for the IMP and associated procedures as part of the IMPs. During the audit, TransCanada provided documentation (TransCanada KPIs – Performance Measures, December 2012) on its IMP related KPIs. In general, in the 500+ KPIs provided, there were numerous listings of what are considered to be pipeline attributes rather than KPIs. For example, pipeline system length, outer diameter, wall thickness, material grade, design class, coating type and pipe manufacturer. These are simply fixed attributes of the pipeline system and provide no useful information for tracking performance. Additionally, of the extensive list of KPIs provided, only a few have provided direct input into the individual threat management scorecards.

Integrity Management Program Reviews

Specific IMP review activities are conducted, including:

- Management Business Reviews: Semi-annually, a meeting between the Pipe Integrity leadership team and individual subject matter experts is held to review the status of their individual programs. At the end of the year, Facilities Integrity conducts a business review that includes a Strengths, Weakness, Opportunities and Threats (SWOT) Analysis, to align key strategies with the facilities' objectives. The objectives are then linked to success of the integrity programs and plans being implemented in the following year.
- Annual Maintenance Plan Review: Integrity threat groups develop annual maintenance plans, which form the work plan to be completed in the following year. On an annual basis, leadership up to the Senior Vice President of Engineering and Operations is provided an overview of the previous year's maintenance plan and the proposed next year's maintenance plan.
- Process Reviews: The outcome of the reviews of IMP supporting documents (e.g., integrity plans, procedures) is reported to management. The TEP-INT-PR Pipe Integrity Process Review Procedure (EDMS No. 006522487) outlines Pipe Integrity's process review methodology. The TEP-INT-MREV Pipe Integrity Management Review Procedure (EDMS No. 006980169) details the management review process of Pipe Integrity's natural gas integrity management programs. During the audit, TransCanada provided the Integrity Management Program Review (January 26 – February 12, 2010) as an example of its IMP review report. Essentially, the 16 page document, of which 6 pages contained the actual review, was a high level process review rather than a zero-based compliance and effectiveness review of TransCanada's IMPs. Within the document, TransCanada stated that a technical review of the data and reports generated by the various activities, assessments and plans was not included in the scope. Appendix 2 – Integrity Management Program Checklist contained 25 questions meant to cover 12 management sections (with 4 missing sections in the numbering system). Appendix 2 in the report was blank. No information was contained in the report on the answers to the questions or references to documentation examined. This Integrity Management Program Review document was assessed to be inadequate for the purpose stated and inadequate as evidence of TransCanada's management review process.

Industry Learnings

TransCanada stated that it also tracks its performance relative to industry by participating in industry associations, such as the Canadian Energy Pipeline Association (CEPA). For the past ten years, CEPA has tracked approximately 30 KPIs, allowing TransCanada to compare itself to industry using detailed measures such as failure causation, in-line inspections and site investigations. During the audit, TransCanada provided documentation (excerpts from the

Annual Performance Indicator Report 2012 (EDMS No. 008029673) to illustrate a comparison of its KIPs to those of other regulatory agencies and of industry associations.

Summary: Management Review

The Management System Audit Element 5.1, Management Review, requires a company to formally review its management and protection programs for continuing suitability, adequacy and effectiveness. Reviews are expected to be based on appropriate documentation and records, be formal and documented, and occur on a regular basis.

The audit concluded TransCanada has undertaken several initiatives aimed at reviewing its IMPs. These include:

- Designating an executive to be accountable for management review;
- Having appropriate levels of responsibility and accountability at each level of the organization; and
- Participation in industry associations in order to share learnings and best practices.

Some of the non-compliances identified during the audit, such as insufficient overpressure protection and management of hazards associated with external corrosion, illustrate the results of a management review process that was not effective. This element of the audit also included a review of the allegations presented by the complainant along with the corroborating internal review by TransCanada resulting from that complaint.

Management System Audit Element Finding: Based on the documents assessed and interviews with personnel as related to Management Review, TransCanada is assessed to be non-compliant with the requirements of the OPR-99 and CSA Z662-11, and is therefore non-compliant with this audit sub-element.

Compliance Status: Non-Compliant

Appendix III

TransCanada OPR-99 Integrity Management Program Audit

TransCanada Representatives Interviewed and Meeting Attendees

TransCanada Representative Interviewed	Job Title
[redacted]	Program Manager, Program Planning -Pipe Integrity
[redacted]	Canadian Facility Pipe Integrity Team Lead
[redacted]	Manager, Facility Integrity and Reliability Management Program
[redacted]	Engineer, Program Strategy, Pipe Integrity
[redacted]	Program Manager, Pipe Integrity – Damage Prevention
[redacted]	Legal Counsel
[redacted]	Program Manager, Program Planning –Pipe Integrity
[redacted]	Manager, Facilities Applications, Law and Regulatory Affairs
[redacted]	Manager, Program Strategy, Pipe Integrity
[redacted]	Technologist, Pipeline Integrity – Damage Prevention
[redacted]	Program Strategy, Liquid Pipeline Integrity
[redacted]	Program Manager, Liquid Pipeline Integrity
[redacted]	Cathodic Protection Program Manager, Canada
[redacted]	Legal Counsel
[redacted]	Manager, Project Support – CPMS
[redacted]	Damage Prevention – Public Awareness Program Manager
[redacted]	Corrosion Engineer, Pipe Integrity, Integrity Services and Support
[redacted]	Director, Facilities Integrity
[redacted]	Vice President, Engineering and Asset Reliability
[redacted]	Director, Pipe Integrity
[redacted]	Engineer, Automation Engineering
[redacted]	Manager, Materials Engineering
[redacted]	Regulatory Compliance Specialist, PLSC Regulatory Compliance CDN

TransCanada Representative Interviewed	Job Title
[redacted]	Manager, Regulatory Support Services
[redacted]	Valve specialist, Engineering & Asset Reliability – Pipeline Integrity Program Support
[redacted]	Engineer, Program Planning, Pipeline Integrity
[redacted]	Engineer, EAR Mechanical Engineering CAD
[redacted]	Integrity Engineer, Program Planning, Pipe Integrity
[redacted]	Manager, Pipeline Integrity – Damage Prevention
[redacted]	Integrity Management Consultant
[redacted]	Manager, Program Governance and Compliance, Pipe Integrity
[redacted]	Program Governance and Compliance, Pipe Integrity
[redacted]	Manager, Welding and NDT, Materials Engineering
[redacted]	Corrosion Specialist Pipe Integrity – Program Strategy
[redacted]	Program Manager, Program Planning –Pipe Integrity
[redacted]	Senior Legal Counsel, Law and Regulatory Research
[redacted]	Management Representative, Mechanical and Civil Engineering
[redacted]	Tank Integrity Lead, Mechanical Engineering
[redacted]	Manager, Quality Management – E&AR
[redacted]	Manager, Maintenance Program Planning CDN
[redacted]	Integrity Engineer, Program Planning, Pipe Integrity
[redacted]	Project Manager, Regulatory Services
[redacted]	US Gas PL IMP Program Manager
[redacted]	Entity MOS & Governance, Maintenance Program Planning CDN
[redacted]	Manager, Program Support – Pipe Integrity
[redacted]	Director, Regulatory Services
[redacted]	Engineer, Program Planning, Pipe Integrity
[redacted]	Manager, CA & Eastern US Pipelines - Ops Planning
[redacted]	Program Manager, Pipe integrity, Engineering
[redacted]	ICAM Program Manager, Program Governance & Compliance, Pipe Integrity
[redacted]	Integrity Engineer, Program Support, Pipe Integrity
[redacted]	Integration Manager, Business Development and Project Support

TransCanada Representative Interviewed	Job Title
[redacted]	Manager, PLSC Regulatory Compliance CDN
[redacted]	Principal Engineer, Pipe Integrity
[redacted]	Legal Counsel, Operations and Engineering Law
[redacted]	Associate, Regulatory Support Services
[redacted]	Senior Legal Counsel, USPL Legal Operations
[redacted]	Internal Corrosion Specialist, Program Planning – Pipe Integrity
[redacted]	Manager, Program Planning – Pipe Integrity
[redacted]	Engineering Intern – Pipe Integrity
[redacted]	Valve & Operations Specialist, Pipe Integrity
[redacted]	Program Planning – Pipe Integrity
[redacted]	Canadian Gas PL IMP Program Manager, Program Governance and Compliance, Pipe Integrity

Appendix IV
TransCanada OPR-99 Integrity Management Program Audit
Documents Reviewed

2012-11-15 Letter IMPs and Commitment Statement

- 01 CDN-LIQ-IMP Liquids IMP Rev 02 DRAFT 5742060.pdf
- 02 CDN-GAS-IMP Canadian Gas Pipeline IMP 3892900.PDF
- 03 Plant IMP 3899337.pdf
- 04 Pipe Integrity Commitment Statement 7058269.pdf
- 05 TEP-INT-DOC Pipe Integrity Doc Control 6765885.pdf
- 06 Letter to NEB IMPs 15Nov12.pdf

2012-11-27 - Additional TransCanada Materials

- TransCanada Aerial Pipeline Patrol TOP Nov. 27.pdf
- TransCanada Incident and Issue Mgmt Program.pdf
- TransCanada Incident Mgmt Classification Guide 3976290.pdf
- TransCanada Issues Mgmt Classification Guide 3976292.pdf
- TransCanada Pipeline Public Awareness Program - TOP Nov. 27.pdf
- TransCanada PL Crossing and Encroachment Proc. Canada - TOP Nov. 27.pdf
- TransCanada PL Ground Based Patrols TOP Nov. 27.pdf

2012-11-29 Elements 3.1 and 4.2 - Nov 29 12

- Element 3.1 Org Structure Roles and Responsibilities Re-draft Nov 29 12.pdf
- Element 4.2 Corrective and Preventive Actions Draft Nov 22 2012.pdf
- Letter to NEB Audit General Confidentiality 22Nov12 (2).pdf

2012-12-06 Elements 2.1 and 4.4 - Dec 6 12

- 01 Element 2.1 Hazard ID, Risk Assess, Control Dec 6 12.pdf
- 02 Integrity Management System.pdf
- 03 Asset Management System Framework.pdf
- 04 Element 4.4 Internal Audit Dec 6 12.pdf

2012-12-06 Elements 3.3 and 5.1 - Dec 6 12

- Element 3.3 Training Competence and Evaluation - Re-Draft Dec 6.pdf
- Element 3.3 Training Competence and Evaluation First Draft Nov 29 12.pdf
- Element 5.1 Management Review Draft Nov. 29 12.pdf
- TEP-INT-MREV Pipe Integrity Mgmt Review Proc.pdf

2012-12-12 TransCanada Materials Provided to NEB

- TEP-ITM-ECOR-CDN External Corrosion Threat Management Program (CDN) 6570955.pdf
- TEP-ITM-EQUIP Equipment Failure Threat Management Program 6786449.pdf
- TEP-ITM-IC Internal Corrosion Threat Management Program (Cdn-US) 6786402.pdf
- TEP-ITM-IOPS Incorrect Operations Threat Management Program 6810297.pdf
- TEP-ITM-MANUF-CDN Manufacturing, Fabrication and Construction Threat Management Program (Cdn) 6786458.pdf
- TEP-ITM-MECH Mechanical Damage Threat Management Program (CDN-US-MEX) 6786487.pdf
- TEP-ITM-SCC-CDN Stress Corrosion Cracking Threat Management Program 6786458.pdf
- TEP-ITM-WOF Weather and Outside Forces (Geotechnical and Meteorological) Threat Management Process (Cdn-US-Mex) 5767611.pdf

2012-12-14 Elements 3.6, 3.7 and 4.1 - Dec 14

- 3.6 NEB Audit Evaluation - Operational Control - Normal Operations Dec 14 12.pdf
- 3.7 NEB Audit Evaluation - Ops Control - Upset or Abnormal Ops Dec 14 12.pdf
- 4.1 NEB Audit Evaluation - Inspection Measurement and Monitoring Dec 14 12.pdf

2012-12-14 TransCanada Materials Provided to NEB

- TransCanada Corrective and Preventive Actions DRAFT 3 Dec 14.pdf
- Presentation - NEB Audit 2.1 - Hazards Ident.pdf
- Presentation - NEB Audit 4.4 - Internal Audits.pdf
- TransCanada - Scope of PIMP and FIMS.pdf

2012-12-18 TransCanada Materials Provided to NEB

- Presentation KPIs and Corrective and Preventive Measures Dec 6.pdf
- Presentation 3.6 Introduction and Normal Operations Dec 14.pdf
- Presentation 3.7 Upset or Abnormal Operating Conditions Dec 14.pdf
- Presentation 4.1 Inspection Measurement and Monitoring Dec 14.pdf
- TransCanada - ECOR (CDN) Scorecard.pdf
- TransCanada - Leaks and Ruptures Scorecard.pdf
- TransCanada - SCC Scorecard.pdf

2012-12-19 TransCanada Materials Provided to NEB

- TransCanada - Facilities Control Integ Plan Internal Audit Report 2011.pdf
- TransCanada - Pipeline Integrity Mgmt Program Review 2010.pdf
- TransCanada KPIs - Performance Measures.pdf

2012-12-21 Elements Re-draft 2.1, 3.6, 3.7, 4.1 and related docs Dec 21

- 2.1 NEB Audit Evaluation - Hazard ID, Risk Assess, Control Redraft Dec 21 2012.pdf

- 3.6 NEB Audit Evaluation - Operational Control - Normal Operations Redraft Dec 21 2012.pdf
- 3.7 NEB Audit Evaluation - Ops Control Upset or Abnormal Ops Redraft Dec 21 2012.pdf
- 4.1 NEB Audit Evaluation - Inspect Measure and Monitor Redraft Dec 21 2012.pdf
- TQM Threat Identification and Risk Assess Dec 21 2012.pdf
- TransCanada Presentation - Update to NEB 22-06-2012_Dec 21 2012.pdf

2013-01-31 TransCanada Materials Provided to NEB

- Table 3 3-1.doc

2013-02-08 - ITM Performance Measures - Scorecards

- Construction - Integrity Threat Management Scorecard.pdf
- Equipment - Integrity Threat Management Scorecard.pdf
- Incorrect Operations - Integrity Threat Management Scorecard.pdf
- Internal Corrosion - Integrity Threat Management Scorecard.pdf
- Manufacturing - Integrity Threat Management Scorecard.pdf
- Mechanical Damage - Integrity Threat Management Scorecard.pdf
- Weather Outside Forces - Integrity Threat Management Scorecard.pdf

2013-02-14 NEB Audit Information Request Responses Round 2

NEB AIR 2-1.1 to 2-1.4

- NEB AIR 2-1.1 - Final Response 15Feb13.pdf
- NEB AIR 2-1.2 - Final Response 15Feb13.pdf
- NEB AIR 2-1.3 - Final Response 15Feb13.pdf
- NEB AIR 2-1.4 - Final Response 15Feb13.pdf
- NEB AIR 2-2.1 - Final Response 15Feb13.pdf
- NEB AIR 2-2.2 - Final Response 15Feb13.pdf
- NEB AIR 2-2.3 - Final Response 15Feb13.pdf
- NEB AIR 2-2.4 - Final Response 15Feb13.pdf

Records Supporting NEB AIR 2-1

- Corrective and Preventive Action Procedure 006262052.pdf
- CPMS Control of Records 006416311.pdf
- CPMS Internal Audit Procedure 006271464.pdf
- CPMS Manage Continual Improvement 006556411.pdf
- CPMS Manage Project Design (006740639).pdf
- CPMS Manage Project Turnover 007044410.pdf
- CPMS NEB Summary.pdf
- CPMS One Page.pdf
- CPMS Overview_08Feb13.pdf
- CPMS Scope Diagram.pdf

- Lessons Learned Procedure 003788443.pdf
- Major Project O&E Functional Engineering and Support 007218421.pdf
- NEB AIR 1.4 Example - Project Turnover to Operations Deliverables List (Parkway Loop Project).pdf
- TEP-QUAL-ESM-DOC Document Control Procedure (Cdn-US-Mex) 003764703.pdf
- TransCanada Nonconformance Procedure (006556411).pdf

Records Supporting NEB AIR 2-2

- 2011 Annual Geotechnical Threat Management PMP Activities Report - WOF 007765534.pdf
- 2012 Oct - Pipe Integrity Business Review Meeting Presentation (redacted).pdf
- 2012 Process Review Weather and Outside Forces TEP-ITM-WOF - Meeting Minutes 007773954.pdf
- 2012-02-11 IIT Action Report - PGC.pdf
- 2013 Canadian Corrosion Program.pdf
- 2013 PI Keystone Maintenance Plan.pdf
- Canadian Liquid Integrity Management Program CDN-LIQ-IMP Dec 2012.pdf
- CPO Capital Project Performance Report - Dec 2012 7822977.pdf
- ICAM Scorecard Program Planning Example.pdf
- IIT Overview TEP-INT-COMM.pdf
- IIT Report - Feb. 1, 2013.pdf
- Integrity Plan Revision, Review and Approval Process 4497609.pdf
- Integrity Plans 101 4786600.pdf
- Liquid Pipeline Systems Assessment Plan TER-AP-LIQ-CDN 005933450.pdf
- NEB AIR 2.2.4 OE December 2012 data block.pdf
- NEB AIR 2.2.4 Reference Summary of O_E Scorecard.pdf
- Pipe Integrity Business Review Meeting Q3 2012 Keystone.pdf
- Quality Team Meeting 7 Agenda Nov 28 2012 (2).pdf
- RB211 2012 Integrity Plan 6995890.pdf
- TOPs Report.pdf

2013-03-12 NEB Audit Meeting Documents Provided

- TEP-ILI-DEF-CDN Analysis of Deformation ILI Data for CDN Pipelines 6980190.pdf
- TEP-INT-CLA Class Analysis and Remediation (CDN) 5766974.pdf
- TEP-INT-ILI-CDN Analysis of MFL In Line Inspection (ILI) Data for CDN Pipelines 6570876.pdf
- TEP-INT-PR Pipe Integrity Management - Process Review Procedure 6522487.pdf
- TEP-ITM-FPIPE-CDN Facilities Piping Integrity Management Program (CDN) 7379193.pdf

2013-03-14 NEB Audit Meeting Documents Provided

- TEP-CP-PRGM Corrosion Prevention Program (Cdn-US-Mex) 6786483.pdf

2013-03-18 Pressure Vessel Integrity Material

- 0.1 QMS Pressure Vessels 2011.pdf
- 0.2 PRESSURE VESSEL INTEGRITY PLAN.pdf
- 0.3 PRV INTEGRITY PLAN.pdf
- 06.1 training list.pdf
- 06.2 John ISPVC certificate.pdf
- 06.3 Bill Yang's Qualification Summary.pdf
- 06.4 training schock.pdf
- 06.5 owners inspector training list.pdf
- 08.1 Approved Manufacturers List REDACTED.pdf
- 08.2 SMS Service Listing- Testing.pdf
- 09 sample calibration cert.pdf
- 10.1 screenshot Avantis Hierarchy.pdf
- 10.3 TOP Pressure vessel Integrity External Inspection.pdf
- 10.4 TOP scrubber vessel inspection.pdf
- 10.5 TOP strainer vessel inspection.pdf
- 10.6 TOP Pressure Relief Valve Inspection.pdf
- 10.7 TOP Feedback.pdf
- 11.1 API 510_e9.pdf
- 11.1A API 576_e3.pdf
- 11.2 AB-506 ABSA standard.pdf
- 11.3 CDN Gas Leaks Only Q4-2012.pdf
- 11.3a PSV failure trending.pdf
- 11.3b Gas Leak Analysis feedback.pdf
- 11.4 vessel inspection documents.pdf
- 11.5 vessel and piping UT data.pdf
- 12 Repair of heating Boiler.pdf
- 13.1 TES-MATL-PV1.pdf
- 13.2 design data.pdf
- 13.4 3PI manufacturing inspection.pdf
- 13.6 Completion of Construction.pdf
- 13.7 commissioning docs 1.pdf
- 13.8 commissioning docs 2.pdf
- 13.9 AB-10 change of status.pdf
- 16.01 Internal Audit procedure for QMS.pdf
- 16.02 Internal Audit QMS 2012.pdf
- 16.03 ABSA External Audit QMS-8119 2011.pdf
- 16.03a ABSA External Audit Completion 2011.pdf
- 16.04 QMS 2011 Internal Audit Report.pdf
- 16.05 QMS 2010 Internal Audit Report.pdf
- 16.06 Pressure Relief Valve Audit Procedure R2.pdf
- 16.07 Tunis Station 102 Relief valve Audit pictures.pdf
- 16.08 Tunis Station 102 Relief Valve Audit.pdf
- 16.11 QMS Internal Audit checklist 2012.pdf
- 18.2 IIT 194030 Provincial Inspection Findings.pdf

- 19.02 IIT180040 Stn45 FG heater.pdf
- 19.03 IIT180040 Investigation Stn45 FG heater.pdf
- 19.04 Metallurgical Report IIT180040.pdf
- 19.05 MOC Stn45 FG heater.pdf
- 19.06 TOP HVAC.pdf
- 19.07 IIT1161890 Norwalk FG filter.pdf
- 19.08 IIT 161890 Investigation FG filter.pdf
- 19.09 Norwalk inspection.pdf
- 19.10 Compressed Air Systems Integrity Plan.pdf
- 19.99 CDN Gas Leaks Only Q4-2012.pdf
- 19.99 Gas Leaks and Releases Q4-2012.pdf
- 19.99a PSV failure trending.pdf
- 19.99b Gas Leak Analysis feedback.pdf
- 20.1 LMS owners inspector.pdf
- 20.2 owners inspector training.pdf
- 21.1 MOC.pdf
- 22.1 Station 45 heater failure DIR.pdf

2013-03-19 Facilities - Controls - Automation Engineering Material

- A - Compressor Station Pressure Limits and Settings Canada.pdf
- B - Control and Monitoring Inspection.pdf
- C - Emergency Shutdown System Inspection.pdf
- D - Emergency Shutdown System M12 Inspection Station 116C 2011 M12 ESD Checklist WO 682966-1.pdf
- E - Station 1211 Work Orders.pdf
- F - Station Control System Procedure.pdf
- G - Station Control System Commissioning Checksheet.pdf
- H - SCADA Commissioning Guide Rev 0.pdf
- I - Station 1211 Station Control System Upgrade.pdf
- J - IIT 246462 Station 1211 Control System Design Change.pdf

2013-03-19 Facilities - Mechanical - Compressor Stations Material

- COM 1 Approved Manufacturers List.pdf
- COM 3 PSSR.pdf
- DES 1 Excerpt HPG Guiding principal.pdf
- DES 2 HL Station Relief Valve Re-IFP.pdf
- INT IIT 1 CDN Gas Leaks Only Q4-2012.pdf
- INT IIT 2 PSV failure trending.pdf
- INT IIT 3 Gas Leak Analysis feedback.pdf
- INT 1 PRV INTEGRITY PLAN.pdf
- INT 2 QMS Pressure Equip 2011.pdf
- INT 3 Tunis Station 102 Relief Valve Audit.pdf

- INT 4 PRV Audit Procedure R2.pdf
- INT 5 Tunis Station 102 PRV Audit pictures.pdf
- INT T1 John ISPVC certificate.pdf
- INT T2 Bill Yang's Qualification Summary (3).pdf
- INT T3 owners inspection training list.pdf
- MTC 1 TOP Pressure Relief Valve Inspection.pdf
- MTC 10 API 576_e3.pdf
- MTC 11 AB-506.pdf
- MTC 2 TOP Inspection and Cycle test for Emergency valves.pdf
- MTC 3 TOP Surge Valve Set-point Verification.pdf
- MTC 4 Vendor service reports.pdf
- MTC 5 Avantis data.pdf
- MTC 5a Avantis screenshot.pdf
- MTC 5b Avantis screenshot.pdf
- MTC 6 NCR List vessels.pdf
- MTC 7 194030 Provincial inspection findings.pdf
- MTC 9 TOP Feedback.pdf
- OPS 1 TOP Facilities Integrity Inspections.pdf
- QMS Pressure Equipment 2011.pdf

2013-03-19 Facilities - Mechanical - Pipe, Valve Integrity Material

- 01 Valve Integrity Mail box snapshot.pdf
- 02 TEP_ITM_IOPS Incorrect Operations Threat Management Program.pdf
- 03 TEP-ITM-EQUIP Equipment Failure Threat Management Program.pdf
- 04 2013 PMP approval document example.pdf
- 05 Pipeline Pressure Relief Valve Blow off Valve Inspection.pdf
- 06 Valve and Valve Operator Inspection and Servicing.pdf
- 07 Valve and Valve Operator Leak Inspection and Cycle Test (Canada).pdf
- 08 Control Valve Inspection Canada and Mexico.pdf
- 09 Alberta System (Down Stream of Delivery Stations) Over Pressure Protection Devices.pdf
- 10 Mainline Over Pressure Protection Devices (Canada).pdf
- 11 Critical Gas Pressure Regulator Inspection and Maintenance.pdf
- 12 Non Critical Gas Pressure Regulator Inspection and Maintenance.pdf
- 13. Valve and Valve Operator Leak Inspection and Cycle Test for Emergency valves.pdf
- Example. auto blowoff inspection track.wo 726096.pdf
- Example. Control Valve inspection track.wo741331.pdf
- Example. Slam shut inspection track.wo725105.pdf

2013-03-19 Facilities - Mechanical - Tanks Material

Hardisty Tank Inspection and TOP Feedback Process

- 2007 Pass Creek West Underground Drip tank M36 Inspection.pdf
- 2007 Underground Drip Tank Inspection M36 Inspection.pdf
- Aboveground Tank Containment Area Inspection 2009 Shelbyville 005787568.pdf
- CS - Central - Cavendish - 2010 Test report.pdf
- CS - WR - Beaver Creek - 2002 Test Inspection 005370386.pdf
- CS-WR-Buffalo Creek - 2001 Test Report 005370396.pdf
- IIT 144757 French Man River sample.pdf
- MS - WR - High River East - 2011 006495829.pdf
- Revision 3 Frenchmar River Underground Tank Leak Report and Findings 003823430.pdf
- Tanks Inspections test reports wildrose.pdf
- TransCanada reports and Invoices Leak technologies 2012 (2).pdf
- TransCanada reports and Invoices Leak technologies 2012.pdf
- Underground Drip tank Inspection Athabasca.pdf
- Underground Drip Tank Inspection Prosperity.pdf
- Underground Drip tank Inspection Record Kaybob 2013 006232688.pdf
- Underground drip tank inspection screen shot EDMS search 1.pdf
- Underground drip tank inspection screen shot EDMS search 2.pdf
- Underground drip tank inspection screen shot EDMS search 3.pdf
- Underground drip tank inspection screen shot EDMS search.pdf
- Underground Drip Tank M36 Inspection00.pdf
- Underground Drip Tank M36 Inspection01.pdf
- Underground Drip Tank Test Alta Beaver Creek.pdf
- Underground Drip Tank Test Berland River.pdf
- Underground TOP version history.pdf

Tank Integrity Program TOP History

- 1.1 Presentation screen shots.pdf
- 1.1.2 API 653 TOPs screen shot.pdf
- 1.2 Canada Tanks Bar graph.pdf
- 1.2.1 Screen Shot Existing TOPs.pdf
- 1.2.2 Screen Shot TOP feedback completed.pdf
- 1.2.3 Screen shot feedback answer.pdf
- 1.3 - API 653 Aboveground Storage Tank Inspection.pdf
- 1.3.1- API 653 Aboveground Storage Tank Monthly or Weekly Inspection Form.pdf
- 1.3.2 - API 653 Aboveground Storage Tank Out of Service Inspection Form.pdf
- 1.4 - Storage Tank Inspection and Testing Excludes API 650 or API 12C.pdf
- 1.5 - Underground Drip Tank Inspection.pdf
- 1.5.1 Underground Drip Tank Inspection Record.pdf
- 1.5.2 Underground Drip Tank Testing Summary.pdf
- 1.6 Aboveground Storage Tank Cleaning Form.pdf
- 1.7 Aboveground Storage Tank Repairs Form.pdf
- 3 Screen Shot Avantis Data.pdf

- 3.1 Screen Shot PM Plan Tk 01.pdf
- 3.2 Screen Shot Activity History Tank 01.pdf
- 3.3 Screen Shot PM Task info.pdf
- Aboveground Hardisty tank PM Plan screen shot Work History.pdf
- Aboveground Hardisty tank PM Plan screen shot.pdf
- Aboveground Hardisty tank screen shot Work Task.pdf
- Aboveground Tank Inspection Hardisty Tank 1.pdf

2013-04-19 - Data Room Requests ECOR SWRA (PRIME)

- 2013 Budget CND ECOR Redacted.pdf
- AB 2013 PRIME Risk Assessment - Final Results.pdf
- Finalized SWRA Data.pdf

2013-05-01 PRIME 2013 Results

- 2013 PRIME Foothills Final Results.pdf
- 2013 PRIME Mainline Final Results.pdf
- 2013 PRIME Mainline Final Results.xls
- 2013 PRIME TQM Final Results.pdf

2013-05-06 2013 SWRA Data

- 2013 SWRA Foothills Data.pdf
- 2013 SWRA Mainline Data.pdf
- 2013 SWRA TQM Data.pdf

2013-05-08 IC Follow Up Response

- 2012 IC Susceptible Lines with GQ Issues Review.xls
- AITF Sludge Corrosion Testing and Chemical Analysis v6.pdf
- Craigend East - 10 years Gas Quality Data.pdf
- Craigend East - Non-Compliance Water Content Letter.pdf
- NEB - Internal Corrosion response - final.pdf

2013-06-10 Canadian External Corrosion

- NEB Interview Action Item AIR No3 Observation 1.1 and 1.2 June 2013.pdf
- NEB Interview Action Item AIR No3 Observation 1.3 June 2013.pdf
- NEB Interview Action Item AIR No3 Observation 1.4 June 2013.pdf
- NEB Interview Action Item AIR No3 Observation 1.5 June 2013.pdf
- NEB Interview Action Item AIR No3 Observation 1.6 June 2013.pdf
- NEB Interview Action Item AIR No3 Table 1a and Table 2a.pdf

2013-06-14 Facility Piping AIR

- NEB AIR Non Sour Service - Follow Up.pdf

2013-07-09 FIRM Document

- Facility Integrity and Reliability Management Program (CDN-US-MEX) 7803540.pdf

Day 1 - 4 Risk Items - Consolidated Response

- Appendix C - Tech Memo EMAT Analysis rev1.pdf
- Appendix E 2010 Golders field assessment draft.pdf
- NEB Action Items - Consolidated Risk Response Mar 28.pdf
- Prime Technical Documentation APPENDIX A 8041010.pdf
- Prime Technical Documentation APPENDIX B 8041012.pdf
- Prime Technical Documentation APPENDIX C 8041014.pdf
- Prime Technical Documentation APPENDIX D 8041034.pdf
- Prime Technical Documentation APPENDIX E 8041038.pdf
- Prime Technical Documentation APPENDIX F 8041040.pdf
- Prime Technical Documentation APPENDIX G 8041042.pdf
- Prime Technical Documentation APPENDIX H 8041044.pdf
- PRIME Technical Documentation July 2006 8041008.pdf
- TEP-INT-PRIME Risk Assessment Using PRIME 003972569.pdf
- TER-COR-RSK Risk Models for Corrosion using ILI Data 5767603.pdf
- TER-RISK-CON - 2009 Consequence Models within PRIME (highlighted) 5767605.pdf
- TER-RISK-CON Consequence Models Within System Wide Risk Assessment and Integrity Management 7326298.pdf
- TER-RISK-SWR- 2009 System Wide Risk Assessment (highlighted) 5767607.pdf
- TOP Pipeline Inspection Report 3841211.doc
- TOP Pipeline Right Of Way Procedures Canada 3672613.pdf
- TransCanada Aerial Pipeline Patrol TOP Nov. 27.pdf
- TransCanada Pipeline Public Awareness Program - TOP Nov. 27.pdf
- TransCanada PL Crossing and Encroachment Proc. Canada - TOP Nov. 27.pdf
- 2013 Mar 12 - Performance Indicators Report for 2012 - Pipe Integrity - Risk 8029673

Day 1 March 12 - (EC) External Corrosion and Dent Program

10 Action - PRIME risk assessment

- NEB Action Items - Consolidated Risk Response Mar 28.pdf

11 Action - Facilities Piping TEP

- TEP-ITM-FPIPE-CDN Facilities Piping Integrity Management Program (CDN) 7379193.pdf

2 Obs - Communication of EC Program

- 2 Observation ECOR - NEB Response - TEP-INT-ILI-CDN.pdf
- 2 Observation ECOR - NEB Response - TEP-ITM-ECOR-CDN.pdf
- CDN-GAS-IMP Canadian Gas Pipeline Integrity Management Program 003892900.pdf
- MOC 12-065 Revision of TEP-INT-ILI-CDN 007722164.pdf
- MOC 12-066 Revision of TEP-ITM-ECOR (Cdn) 007722167.pdf
- TEP-INT-ILI-CDN Analysis of MFL ILI Data 006570876.pdf
- TEP-INT-MOC Pipe Integrity - Management of Change Procedure 006425143.pdf
- TEP-ITM-ECOR-CDN External Corrosion Threat Management Program 006570955.pdf
- TES-CORR-PMP Corrosion Pipeline Maintenance Plan Development 005767609.pdf

4 Action - EC Process Review and Annual EC Reports

- Pipe Integrity Process Review – External Corrosion (ECOR) Canada (EDMS 007728805) (in data room)
- Canadian External Corrosion Pipeline Maintenance Plan (PMP) Annual Report for 2012 (EDMS 008055282) (in data room)
- Canadian External Corrosion Pipeline Maintenance Plan (PMP) Annual Report for 2011 (EDMS 008038129) (in data room)

6(a) Action - RA Consequence Inputs and Outputs

- NEB Action Items - Consolidated Risk Response Mar 28.pdf

6(b) Action - Societal Risks and Individual Risks

- NEB Action Items - Consolidated Risk Response Mar 28.pdf

6(d) Action - Unpiggable segment seriatim

- 2013 Budget Presentation - CDN ECOR 008037970.pdf
- 6d Action ECOR - NEB Response - Unpiggable segment.pdf
- TEP-INT-PRIME Risk Assessment Using PRIME 003972569.pdf
- TEP-ITM-ECOR-CDN External Corrosion Threat Management 006570955.pdf
- 2011 Pipeline Maintenance Plan (PMP) Annual Report (EDMS No. 008038129) (Data room)
- 2012 Pipeline Maintenance Plan (PMP) Annual Report (Data room)

6(e) Action - Top 10 Unpiggable

- 6e Action ECOR - NEB Response - Top 10 Unpiggable.pdf
- PRIME Technical Documentation 008041008.pdf
- Prime Technical Documentation APPENDIX A 8041010.pdf
- Prime Technical Documentation APPENDIX B 8041012.pdf

- Prime Technical Documentation APPENDIX C 8041014.pdf
- Prime Technical Documentation APPENDIX D 8041034.pdf
- Prime Technical Documentation APPENDIX E 8041038.pdf
- Prime Technical Documentation APPENDIX F 8041040.pdf
- Prime Technical Documentation APPENDIX G 8041042.pdf
- Prime Technical Documentation APPENDIX H 8041044.pdf
- PRIME Technical Documentation July 2006 8041008.pdf
- TEP-INT-PRIME Risk Assessment Using PRIME 003972569.pdf
- TEP-ITM-ECOR-CDN External Corrosion Threat Management Program 006570955.pdf
- 2013 SWRA Alberta Final Results.xls (Data Room)
- Finalized SWRA Data.xlsx (Data Room)

6(f) Action - Number of Unpiggable

- 2013 Budget Presentation - CDN ECOR 008037970.pdf
- 6f Action ECOR - NEB Response - Number of Unpiggable.pdf
- NC Technical Memo TM 1347 Relative Failure Frequency of Large Diameter vs Small Diameter.pdf
- Nova Chemicals TR 2283 Relative Failure Frequency on Small versus Large Diameter Pipe.pdf
- 2011 Pipeline Maintenance Plan (PMP) Annual Report (EDMS No. 008038129) (Data Room)
- 2012 Pipeline Maintenance Plan (PMP) Annual Report (Data Room)

6(g) Action - Incorporation of CP Data

- NEB Response - See folder 'Day 1 - 4 Risk Items - Consolidated Response'

6(h) Action - CP Data in EC RA

- 6h Action - NEB Response - CP Data in EC RA.pdf
- TEP-ITM-ECOR-CDN External Corrosion Threat Management 006570955.pdf
- AB CP.xls (Data Room)
- 2013 AB Summary.xlsx (Data Room)

6(i) Action - Interaction of Threats

- NEB Action Items - Consolidated Risk Response Mar 28.pdf

7 Action - EC Performance Measures

- 7 Action ECOR - NEB Response - Performance Measures.pdf
- TEP-ITM-ECOR-CDN External Corrosion Threat Management 006570955.pdf
- Canadian External Corrosion Pipeline Maintenance Plan Annual Report for 2012

9(c) Action - Dent Eng Assessments

- 9c Action ECOR - NEB Response - Dent Eng Assessments.pdf

- ANG Kootenay - Kingsgate DENT Strain Analysis Report.pdf
- MLV45-52-1 dent strain report - Caliper.pdf
- PR-218-063511Development of a Model for Predicting the Severity of Pipeline Damage Identified by In-Line Inspection.pdf
- Technical Memo - MLV46-52-1 DNT Assessment.pdf
- Technical Memorandum - ANG Kootenay-Kingsgate Dent Assessmen.pdf
- TEP-ILI-DEF-CDN Analysis of Deformation In-Line Inspection Data 006980190.pdf

9(d) Action - Dent TEP and CP TEP

- TEP-CP-PRGM Corrosion Prevention Program (Cdn-US-Mex) 6786483.pdf
- TEP-ILI-DEF-CDN Analysis of Deformation ILI Data for CDN Pipelines 6980190.pdf

9(e) Action - Dent program consequences

- NEB Action Items - Consolidated Risk Response Mar 28.pdf

9(f) Action - Dent with no high res tool

- 9f Action ECOR - NEB Response - Dents with no high resolution tool.pdf

Day 2 March 13 - (CP) Cathodic Protection

1 Action - CP over potentials

- 1 Action CP - NEB Response - CP Overprotection.pdf
- IPC2002 27267 Permeable Coatings and CP Compatibility.pdf
- IPC2004 000570 Long Term FBE Performance.pdf
- TES-PIPE-EW Specification for Electric Welded Pipe (CDN) 3670788.pdf
- TES-PIPE-SAW Specification for Double Submerged Arc Welded Pipe 3776714.pdf
- WIC Example 7932-313_FINAL.PDF

2 Action - CP on potential surveys only

- 2 Action CP - NEB Response - ON Potential Criteria.pdf
- 900mV ON Memo 2003.pdf
- Nova Criteria Study.pdf
- Prairie ON Criteria Study.pdf
- TES-CP-CR Cathodic Protection Criteria Specification 003678793.pdf

3 Action - CP Annual Report

- Corrosion Prevention Pipeline Maintenance Plan Annual Report for 2012 Alberta and BC (in data room)

- Corrosion Prevention Pipeline Maintenance Plan Annual Report for 2012 – MLV 2-16 (in data room)
- Corrosion Prevention Pipeline Maintenance Plan Annual Report for 2012 – MLV 16-58 (in data room)
- Corrosion Prevention Pipeline Maintenance Plan Annual Report for 2013 in NONT and EONT (in data room)
- Corrosion Prevention Pipeline Maintenance Plan Annual Report for 2012 (Overall Canada Summary, with KPI's) (in data room)

5 Obs - CP low potential survey prioritization

- 5 Observation CP - NEB Response - CP Prioritization.pdf

Day 2 March 13 - (SCC) Stress Corrosion Cracking

1 Action - SCC Annual Report

- 1 Action SCC - NEB Response - SCC Annual Report.pdf
- SCC Pipeline Maintenance Plan Annual Report for 2012.(in data room)

2 Action - Monthly Threat Interaction Meetings

- 2 Action SCC - NEB Response - Monthly Threat Interaction Meetings.pdf
- Shared Group Activities Meeting December 2010.pdf
- Shared Group Activities Meeting Minutes_May_2012.pdf
- Shared Group Activities Meeting Minutes_November_2011.pdf
- Shared Group Activities Meeting Minutes_October_2012.pdf

3 Action - SCC Program deliverables

- 3 Action SCC - NEB Response - SCC Program Deliverables.pdf
- Evidence 002 - SCC Cost Reasoning Spreadsheet.pdf
- Evidence 003 - 2161505_PI2011 Mainline EMAT Inspection MLV 130 - 139 Line 1.pdf
- Evidence 004 - 2168666_PI2011 Post-ILI SCC Excavations from EMAT run between MLV 130-139 Line 1.pdf
- Evidence 005 - 2171464_PI2011 SCC Extra EMAT Data Analysis between MLV 130-139 Line 1.pdf
- Evidence 001: 2012 Process Review SCC TEP-ITM-SCC-CDN Meeting Notes (in data room)

4 Action - SCC risk assessment consequences

- NEB Action Items - Consolidated Risk Response Mar 28.pdf

5 Action - SCC high pH

- 5 Action SCC - NEB Response - High pH SCC Management.pdf
- GE EMAT Specfication.pdf
- Rosen EMAT Specification.pdf
- TES-ILI-EMAT Specification for EMAT In-Line Inspection Technologies (CDN).pdf

6 Action - SCC fatigue growth

- 2012-01-12 - 2012 Eastern Mainline Expansion s58 Application Responses to NEB Information Requests NEB 1-7 Part A.pdf
- 6 Action SCC - NEB Response - Fatigue Crack Growth.pdf
- CEPA study on Characterization of Pipeline Pressure Fluctuations in Terms Relevant to Stress Corrosion Cracking.pdf
- MLV 107-2 Engineering Assessment of Line 2 Report.pdf
- MLV 76-2 Acuren Investigation.pdf

Day 2 March 13 - (WOF) Weather and Outside Forces

1 Action - WOF TEP revisions

- 1 Action WOF - NEB Response - WOF TEP Revisions.pdf

12 Obs - WOF risk assessment consequences

- NEB Action Items - Consolidated Risk Response Mar 28.pdf

13 Obs - WOF influence on ROW patrol program

- 13 Obs WOF - NEB Response - WOF Influence on ROW patrol program.pdf
- TOP Aerial Pipeline Patrol 3672387.pdf

2 Action - WOF process review

- (Data Room) 2012 Process Review TEP-ITM-WOF Weather and Outside Forces Management Program Meeting Minutes 7773954.pdf

2 Obs - Reference to CSA Z662-07

- 2 Observation WOF - NEB Response - Reference to CSA Z662-07.pdf
- (Data Room) 2012 Process Review TEP-ITM-WOF Weather and Outside Forces Management Program Meeting Minutes 7773954.pdf

4 Action - Phase 1 surveys

- 1999 - AB - Phase I Implementation of Rainfall Ground Mvt Models Action Item 4.pdf
- 2001 - AB - Visual Inspection of 11 slopes - Evidence 3.pdf

- 2003 SI Installations Cranberry Creek Lateral - Evidence 4.pdf
- 4 Action WOF - NEB Response - Phased Surveys.pdf
- CND Keystone Phase I Geohazard Analysis 2010_Action Item 4.pdf
- Pembina River Slope Monitoring _Edson Mainline Evidence 6.doc
- Evidence 005 2000 Assessment of Slope Movement Potential, Site Visit Report (in data room)

7 Action - Soil erosion - flooding threat

- 7 Action WOF - NEB Response - Soil erosion flooding threat.pdf
- TOP Pipeline Underwater Inspections 003671756.pdf

99 Action - TOPs and WOF annual report PR process review

- 99 Action WOF - NEB Response - Requested Documents.pdf
- TOP Aerial Pipeline Patrol 3672387.pdf
- TOP Pipeline Underwater Inspections 3671756.pdf
- 2012 Process Review Management Systems TEP-INT-PR – Meeting Minutes 7898342 (in data room)
- Weather and Outside Forces Pipeline Maintenance Plan Annual Report for 2012 8029726 (in data room)

Day 3 March 14 - (IC) Internal Corrosion

6(f) Action - Coincident dig sites

- 6f Action IC - NEB Response - Coincident Dig Sites.pdf

6(h) Action - IC annual report

6h Action IC - NEB Response - IC Annual Report .pdf
1. 2012 PMP Annual Report IC Canada EDMS No. 008029989 (in data room)

6(j) Obs - RA and Prioritizations

- 6j Observation IC - NEB Response - Completion of IC Program.pdf
- Ref 2_2012 IC Susceptible Lines.xlsx
- Ref 3_2013 Approved PMP Budget ICOR Redacted.pdf
- Ref 4_Dec Sum for 2013 IC Corrosion Coupons and Solids-Liquids Sampling - Financials Redacted.pdf

6(k) Action - IC process review

- 6k Action IC - NEB Response - IC Process Review .pdf

Day 3 March 14 - (MFC) Manufacturing Fabrication and Construction

1 Action - PHMSA Advisory on Pipe

- 1 Action MFC - NEB Response - PHMSA Advisory on Pipe.pdf
- Response to NEB Audit in Regards to Pipe Manufacturing Threats for New Pipe Manufacturing 13 03 17.pdf

2 Action - R ratios

- 2 Action MFC - NEB Response - R Ratios - Supplemental.pdf
- 2 Action MFC - NEB Response - R Ratios.pdf
- Reference 1 Pressure Data for Western Mainline (Cabri CS).pdf
- Reference 2 Pressure Data for Line 2 in Northern Ontario (Dryden CS).pdf
- Reference 3 Pressure Data for Canadian Mainline Toronto - Montreal, Youngstown Pipe Line (Cobourg CS).pdf

2 Obs - MFC consequence

- NEB Action Items - Consolidated Risk Response Mar 28.pdf

6 Obs - TC audit plan

- 6 Action MFC - NEB Response - TC Audit Plan.pdf
- TEP-NDT-ADT Procedure for Non-Destructive Examination (NDE) Audits 3797402.pdf

7 Obs - Low Strength fittings

- 7 Observation MFC - NEB Response - Validation of Existing Fittings.pdf

Day 3 March 14 - Liquid IMP - Keystone

1 Action - Purchasing substandard materials

- 1 and 2 Action Liquid IMP - NEB Response - Validation of Pipe and Fittings.pdf
- Various documents in data room

2 Action - Low Strength Fittings

- 1 and 2 Action Liquid IMP - NEB Response - Validation of Pipe and Fittings.pdf
- 2 Action Liquid IMP - NEB Response - Below Spec Fittings.pdf
- Liquid Pipeline Systems Assessment Plan TER-AP-LIQ-CDN 005933450.pdf

3 and 4 Actions - Non Sour Keystone Service

- Non Sour Keystone Service Liquid IMP - Action Items 3 and 4.pdf
- Non Sour Service of Keystone - Addendum - 2013-03-20.pdf

- TransCanada Hydrocarbon Exposure Control Procedures TOP EDMS 005528684.pdf
- TransCanada Hydrogen Sulphide Exposure Control TOP EDMS 003671879.pdf
- TransCanada Portable Gas Detection of the Atmosphere TOP EDMS 003835957.pdf

Day 4 March 15 - (Equip IOPs) Equipment and Incorrect Operations

1 Action - Cdn Gas Leaks

- 1 Action - Equip IOPs NEB Response - Canadian Gas Leaks.pdf
- Gas Release-Leak (Canada) 2007-2012Chart Q4 r1.xls

10 Obs - TEP Additions

- 10 Observation Equip IOPs - NEB Response - Threat References.pdf

11 Obs - Program specific risk assessment

- 11 Observation Equip IOPs - NEB Response - Risk Assessment.pdf

2 Action - Annual report

- 2 Action Equip IOPs - NEB Response - Annual Summary.pdf
- 2013 Valve WIG KPIs.pdf
- Valve Issues and Actions Summary2012.pdf

3 Action - Monthly management review

- 3 Action Equip IOPs - NEB Response - Monthly Management Review.pdf
- Engineering and Asset Reliability October 2012 Business Review filed (in data room)

Day 4 March 15 - (FPIPE) Facility Piping

1 Action - Annual report

- 2012 PMP Annual Report FPIPE (CDN) Final (in data room)

2 Action - 9 Obs - Past station piping program

- 2 Action FPIPE - NEB Response - Previous Process.pdf
- 2003.04.TEP-CP-DT Cathodic Protection Diagn.PDF
- 2004.03.25 TES-CP-CR.pdf
- 2005.07.07 TES-CP-SS Cathodic Protection Survey Spec.pdf
- 2008.12.21 Fugitive Emissions Inspection.doc
- 2009.01.07 Relief Valve Inspection and Overhaul Program.doc
- 2009.06.25 Excavation Procedure (Canada and Mexico).doc
- 2009.06.29 Facilities Integrity Inspections.doc

- 2009.07.24 Meter Station General Maintenance Gas Transmission.doc
- 2009.07.29 Valve and Valve Operator Inspection and Servicing.doc
- 2009.07.30 Valve and Valve Operator Leak Inspection and Cycle Test (Canada).DOC
- 2161986_PI2011 Edson Meter Station Sour Bottle Integrity Assessment and Permanent Drain Scoping.pdf
- A1-1206ST-80-L1-FG56_14.tif
- A1-1206ST-80-L1-FG78_12.tif
- AB Field Lake CS - 2011 Facility Pipe Assessment Report.pdf
- Action 2 FPIPE - NEB Response - Previous Process.pdf
- CP Annual Station Exception Report - Rideau Area.pdf
- CP Annual Station Exception Report - STN 1206 Deux Rivieres CS.pdf
- CP Annual Station Report - STN 1401 Iroquois CS.pdf
- CP Remedial Station 1206_IFC_Set.pdf
- Dec Sum AB Field Lake Compressor Station Piping Recoat 2011_March14.doc
- Facilities Integrity Work Orders Canada 2010.xls
- IIT Issue 172642.pdf
- IIT Issue 209400.pdf
- IIT Issue 228504.pdf
- IIT Issue 228656.pdf
- IIT Issue 228827.pdf
- IIT Issue 229998.pdf
- Measurement Routine M1-M12 2010 Canada.xls
- ML Maple Niagara Riser Program - 2012 Facility Pipe Assessment Report.pdf
- ML Quebec Riser Program - 2012 Facility Pipe Assessment Report.pdf
- ML Rideau Riser Program - 2012 Facility Pipe Assessment Report.pdf
- Motor Vehicle Operation Program.pdf
- Pipeline Inspection Report - Torrington CS - Sep 11 2012.doc
- Snow Removal Procedures.doc
- TES-COAT-EPU External Multi-Component Liquid Coating Systems for Below Ground Facilities (Cdn-US-Mex).pdf
- TES-COAT-P1 Paint Systems for Above Ground Facilities (Non-Coastal) (Cdn-US-Mex).pdf
- TQM Riser Program - 2012 Facility Pipe Assessment Report.pdf

2 Obs - New Program Implementation

- 2 Observation FPIPE - NEB Response - New TEP.pdf
- Integrity Management Process for Pipelines Rev 2.0 3892900.pdf

3 Obs - Station piping body leaks

- 3 Observation FPIPE - NEB Response - Pipe Body Leaks.pdf

6 Obs - Class locations and consequences

- 6 Observation FPIPE - NEB Response - Class Locations and Consequences.pdf
- TEP-INT-PR Pipe Integrity Process Review Procedure 006522487.pdf
- TEP-INT-PRIME Risk Assessment Using PRIME 003972569.pdf
- TEP-ITM-FPIPE-CDN Facility Pipe Integrity Management Program 007379193.pdf

Day 5 March 19 - (MECH) Mechanical Damage and Public Awareness

1 Action - Excavation Checklist

- 1 Action MECH - NEB Response - Excavation Checklist.pdf
- Action1_Completed Excavation Checklist.pdf

2 Action - Excavation to threat managers

- 2 Action MECH - NEB Response - Interaction of Threats for Planned Excavations.pdf
- Calnash Trucking Crossing email.pdf
- PI 2009 SI Project Dec Summary- AB-Simonette River Crossing-Monitoring Equipment Installation and Corrosion 3776714.pdf
- RE D-8994-1, Calnash Trucking - Corrosion response.pdf
- RE D-8994-1, Calnash Trucking - Geotech response.pdf
- RE D-8994-1, Calnash Trucking - SCC Response.pdf
- TEP-ITM-ECOR-CDN External Corrosion Threat Management Program.pdf

3 Action - Excavation life cycles

- 3 Action MECH - NEB Response - Excavation Lifecycle Examples.pdf
- EX1_Email_Correspondence_MLV 19-20-3 Safe Dig Pressures.htm
- EX1_Engineering_Evaluation_Safe Dig Pressure MLV 19-20-3.pdf
- EX1_Excavation Procedure Checklist.pdf
- EX1_Field Integrity Report.pdf
- EX1_PulDown_ Compressor Elog Entry (19-20-3)-2.pdf
- EX1_PullDown_Compressor Elog Entry2 (19-20-3).pdf
- EX1_Stake Out Report.pdf
- EX2_Excavation Check List - SMS Line.pdf
- EX2_FW Longlac Lateral Safe Dig Pressure.htm
- EX2_Integrity Field Report.pdf
- EX2_Locate Request.docx
- EX2_Longlac email Ops to Field and Gas Control.pdf
- EX2_Longlac excavation Gas Control Logs.pdf
- EX2_One Call Ticket.pdf
- EX2_Safe Excavation Pressure Engineering Evaluation.pdf
- EX2_Stake Out Report.pdf
- EX3_3RD_ Party_PipeLine_Inspection_Report.pdf
- EX3_3RD_Party_Crossing_Agreement.pdf
- EX3_3RD_Party_Crossing_AsBuilt.pdf

- EX3_3RD_Party_OneCall.pdf
- EX3_3RD_Party_StakeOut_Report.pdf
- FW SCADANET DATA TRENDING DATABASE.msg
- MLV 19-20 Line 100-3 Isolation Procedure.pdf

4 Action - Mechanical Damage Committee 2011 Annual Review

- 4 Action Mechanical Damage - NEB Response - Excavation Steering Committee.pdf
- Excavation Report - March 2013.pdf
- Excavation Steering Committee Meeting Minutes.pdf
- Excavation with Spoon Attachment - April 2008 4846083.pdf
- Ground Disturbance Excavation Requirements - January 2008 4784248.pdf
- TES-PROJ-OHP Powerline Specification_IFR.pdf
- TOP Excavation Procedure 3672343.pdf
- TOP Overhead Powerline Procedure IFR.pdf

5 Action - Pressure Reduction Request

- 5 Action MECH - NEB Response - Safe Dig Pressure.pdf
- Document 1_Derate Calculation Request_Email.pdf
- Document 2_Engineering_Evaluation_Safe Dig Pressure .pdf
- Document 3_Isolation Procedure.pdf
- Document 4_ Compressor Elog Entry (19-20-3)-2.pdf
- Document 5_Compressor_Elog Entry2 (19-20-3).pdf

6 Action - Regional Public Awareness Programs

- 2012 Eastern Region Approved IPA Regional Overview Plan.pdf
- 2012 RMR IPA Regional Plan FINAL.PDF
- 6 Action MECH - NEB Response - Regional Public Awareness Programs.pdf
- IPA Regional Plan Overview NOR_MAR2_2012_FINAL.PDF
- IPA Regional Plan Overview Wildrose.pdf
- PA Regional Plan Overview (Central Region)2012 Final.pdf

9 Obs - Depth of Cover Surveys

- 2012 12 03 NEB Agricultural Crossing Consultation.pdf
- 9 Observation MECH - NEB Response - Depth of Cover Surveys.pdf
- NEB_Exemption_Order_MO-21-2010.pdf
- OB9_Aerial Patrol Reported_DOC_IIT233782.pdf
- OB9_Integrity Field Report.pdf
- OB9_Landowner Reported_DOC_IIT230784.pdf
- OB9_Pipeline Inspection Report.pdf

10 Obs - Safe Operating Pressure

- 10 Observation MECH - NEB Response - Safe Operating Pressure.pdf
- TOP Maximum Pressure Pipelines with Known or Suspected Integrity Concerns Canada 3671945.pdf
- TOP Pipeline Defect Assessment and Repair Procedures Canada 3674615.pdf

Day 5 March 19 – Complainant Allegations

1 Add Issue - Fittings Components Procurement Specifications

- 1 Add Issue - NEB Response - Fittings Components procurement Specs.pdf

1a Issue - Non-Independent Inspections

- 1a Issue - NEB Response -Non-Independent Inspections.pdf
- TEP-NDT-ADT Procedure for Non-Destructive Examination (NDE) Audits 3797402.pdf

1b Issue - Welding Inspections

- 1b Issue - NEB Response - Welding Inspections.pdf
- Edson Extension Hydro Test-Visual and Weld Parameter Record Overview.pdf
- Edson Ext-Weld Parameter Records.pdf
- Edson VT Reports.pdf
- Edson-Daily Inspection Reports.pdf

2 Add Issue - Reporting of Non-Compliances

- 2 Add Action - NEB Response - Reporting of Nonconformances.pdf
- Code of Business Ethics Policy.pdf
- Ethics and Compliance Organization.pdf
- Ethics and Compliance.pdf
- Ethics Help Line.pdf
- FAQ.pdf
- List of compliance coordinators by department.pdf
- Raising A Concern.pdf
- TransCanada Code of Business Ethics.pdf

3 Add Issue - NonCompliance Reporting

- 3 Add Issue - NEB Response – Non-Compliance Procedure Reporting.pdf
- TEP-NDT-VT Visual Examination 7381161.pdf

4 Issue - Non POE sign off follow up

- 5 Action - NEB Response - Non POE Sign off.pdf
- TES-ENG-POE Practice of Engineering 3672108.pdf

5 Issue - Transitions and Joining

- 6 Issue - NEB Response - Transitions and Joining.pdf
- TEP-MECH-TRAN Selection of Transition Pieces and Joining Methods 6256.pdf

6 Issue - AUT Criteria

- 7 Issue - NEB Response - AUT Criteria.pdf
- TES-NDT-UT1 Mechanized Ultrasonic Examination of Pipeline Girth Welds 3670963.pdf

7 Issue - NDE Audit Procedure

- 9 Issue - NEB Response - NDE Audit Procedure.pdf
- TEP-NDT-ADT Procedure for Non-Destructive Examination (NDE) Audits 3797402.pdf

Day 6 March 20 - OPP

01 Action - Pressure Control and OPP Procedure

- 1 Action OPP - NEB Response - Over Pressure Protection.pdf
- Evidence 1_IIT 240971 Information.pdf
- Evidence 10 IIT 241921 Technical Memo Lifting derate.pdf
- Evidence 11 IIT 241924 - SCADA Pressure Data.xls
- Evidence 12 IIT 241924 Elog Entries.doc
- Evidence 13 IIT 241924 Facility Notepad.pdf
- Evidence 2_IIT 240971 Technical memo_Derate.pdf
- Evidence 3_IIT 240971 Technical memo Lifting derate.pdf
- Evidence 4 IIT 240971 - SCADA Pressure Data.xls
- Evidence 5 IIT 240971 Elog Entries.doc
- Evidence 6 IIT 240971 Facility Notepad.pdf
- Evidence 7 IIT 240971 Isolation Procedure.pdf
- Evidence 8 IIT 241924 Information.pdf
- Evidence 9 IIT 241924 Technical Memo Derate.pdf

02 Action - Meter Station OPP Plan

- 2 Action 8 Observations OPP - NEB Response - Meter Station Over Pressure Protection.pdf
- TEF-OPP-VER-S-OFF-CDN Customer OPP Systems for New Meter Stations – TransCanada Sign-Off Form 7772654.pdf
- TEF-VER-OPP-RFI-CDN Customer OPP Systems for New Receipt Meter Stations - Request for Information Form 6587713.pdf

Day 6 March 20 - Pressure Vessels

01 Action - Qualification req for Examiner

- 1 Action Pressure Vessel - NEB Response - Examiner Qualifications.pdf
- Pressure Vessel Attachment 1: Vendor Qualification.pdf
- Pressure Vessel Attachment 2: Internal training.pdf

02 Action - -29C pressure vessel Comm

- Action 2 Pressure Vessel - NEB Response - -29C Pressure Vessel.pdf

Day 6 March 20 - Tanks

01 Action - low pressure piping integrity program

- 1 Action Tanks - NEB Response - Low Pressure Piping rev 01.pdf

04 Obs - Inventory

- 4 Observation Tanks - NEB Response - Underground tank inventory.pdf

07 Obs - Ground Tank Inspection

- 7 Observation Tanks - NEB Response - Tank Inspection Audit.pdf

Day 6 March 20 - Valves for OPP and Pressure Control

01 Action - Leaking Valve Process and List

- 1 Action Valves for OPP - NEB Response - Leaking Valve Process and List.pdf
- TOP Gate Valve Position Inspection 6493970.pdf
- TOP Gate Valve Position Inspection Form 6598306.pdf
- TOP Pipeline Operations Gas Handling 3672508.pdf

01 Add Action - Sour Service Response

- 1 Add Action Valves for OPP - NEB Response - Sour Service Response.pdf

Day 7 April 2 - (CA-PA) Corrective and Preventive Actions

- 2 Action Day 8 CA-PA - TransCanada Corrective and Preventive Actions DRAFT April 5 2013.pdf
- TEP-ILI-DEF-CDN Analysis of Deformation In-Line Inspection Data 006980190.pdf
- TOP Aerial Pipeline Patrol 3672387.pdf
- TOP Pressure Control of Leaking Pipelines 3841207.pdf
- TransCanada Oil Pipelines Unit Start-Stop Procedure 6813148.pdf

Day 7 April 2 - WOF Water Crossings

- 1-4 Action Day 7 WOF - NEB Response - Water Crossings.pdf
- B-18b_-_Keystone_Responses_to_NEB_IR_3_(A0Y4Q8)_.pdf
- Consolidated Valve and Geotech Water Crossing Listing.xls

Day 8 April 3 - Corrective and Preventive Actions

- 5 Action -Day 8 CA-PA - NEB Response - Significant SCC.pdf
- NEB Notification Significant SCC NPS30 MLV 115-116 and NPS20 MLV 130-139 Line 100-1 March 22 2012.pdf

Day 8 April 3 - Leaking Dents

- 1 Action Day 8 - NEB Response - Leaking Dent.pdf

Day 8 April 3 - Liquid Sour Service and H2S Tests

- 2 and 3 Actions Day 8 - NEB Response - Liquid Sour Service and H2S Tests.pdf
- Gibson MSDS Petroleum Crude Oil 2008 12 31.pdf
- TOP API 653 Aboveground Storage Tank Inspection 7167240.pdf
- TOP Portable Gas Detection of the Atmosphere 3835957.pdf
- 2008 Assay report for Surmont Heavy Blend (SHB).xls (in data room)
- Commodity Approval Form for their Access Western Blend (AWB).pdf (in data room)
- Commodity Approval Form for their Peace Heavy (PH assay).pdf (in data room)

Day 8 April 3 - List of Upcoming Excavations

- 2013 ML TQM Risers Program - Site List NEB Visit.xls
- 4 Action Day 8 Excavation-Inspection Schedule April May 2013.pdf

Day 8 Post Meeting - Potential for SCC

- Post Meeting Day 8 - NEB Response - Potential for SCC.pdf

Additional Documents Requested

- Natural Gas Leak Detection Procedure Canada, EDMS No. 003676669
- TEP-INT-LEAK Pipe Integrity Leak Detection and Evaluation, EDMS No. 007379105
- Pressure Control of Leaking Pipelines, EDMS No. 003841207
- 2013-07-25 Response to NEB Audit Questions June 14 2013.pdf

2013-09-08 Response to NEB Audit Questions

- 2013-08-15 Below Specification Facility Fittings Response.pdf
- CB2013-208-0075781_01-01R0 HTR-18597 Lakesend Pump Station.pdf
- CB2013-208-0075781_01-01R0 HTR-26056-01 Monitor Pump Station.pdf
- CB2013-208-0075781_01-01R0 U13508VOR Lakesend Elbows.pdf
- CB2013-208-0075781_01-01R0 U13509VOR Lakesend Tees.pdf
- CB2013-208-0075781_01-01R0 U-20130727-01HS.PDF
- Emc2 Keystone Fitting Report-for Canada.pdf
- Piping Stress Analysis Report – Cdn Pump Stn Fittings Analysis 8288118.pdf
- 9-8-2013_Response to NEB regarding Keystone Expanded Pipe.pdf
- Blade Energy Report_Keystone Coupon Mech and Metallurgical Testing.pdf

Analysis of Frequency, Magnitude and Consequence of Worst-Case Spills From the Proposed Keystone XL Pipeline

John Stansbury, Ph.D., P.E.

Executive Summary

TransCanada is seeking U.S. regulatory approval to build the Keystone XL pipeline from Alberta, Canada to Texas. The pipeline will transport diluted bitumen (DilBit), a viscous, corrosive form of crude oil across Montana, South Dakota, Nebraska, Kansas, Oklahoma and Texas. As part of the regulatory process, TransCanada is required by the National Environmental Policy Act (NEPA) to evaluate the potential environmental impacts of a pipeline spill. The Clean Water Act (CWA) also requires TransCanada to estimate the potential worst-case discharge from a rupture of the pipeline and to pre-place adequate emergency equipment and personnel to respond to a worst-case discharge and any smaller spills. The Keystone XL environmental assessment documents (e.g., Draft Environmental Impact Assessment) as well as the environmental impacts documents for the previously built Keystone pipeline, can be found on the US State Department web site. It is widely recognized that the environmental assessment documents for the Keystone XL pipeline are inadequate, and that they do not properly evaluate the potential environmental impacts that may be caused by leaks from the pipeline (e.g., USEPA 2011a). The purpose of this paper is to present an independent assessment of the potential for leaks from the pipeline and the potential for environmental damage from those leaks.

The expected frequency of spills from the Keystone XL pipeline reported by TransCanada (DNV, 2006) was evaluated. According to TransCanada, significant spills (i.e., greater than 50 barrels (Bbls)) are expected to be very rare (0.00013 spills per year per mile, which would equate to 11 significant spills for the pipeline over a 50 year design life). However, TransCanada made several assumptions that are highly questionable in the calculation of these frequencies. The primary questionable assumptions are: (1) TransCanada ignored historical data that represents 23 percent of historical pipeline spills, and (2) TransCanada assumed that its pipeline would be constructed so well that it would have only half as many spills as the other pipelines in service (on top of the 23 percent missing data), even though they will operate the pipeline at higher temperatures and pressures and the crude oil that will be transported through the Keystone XL pipeline will be more corrosive than the conventional crude oil transported in existing pipelines. All of these factors tend to increase spill frequency; therefore, a more realistic assessment of expected frequency of significant spills is 0.00109 spills per year per mile (from the historical data (PHMSA, 2009)) resulting in 91 major spills over a 50 year design life of the pipeline.

The CWA requires that TransCanada estimate the "worst-case spill" from the proposed pipeline (ERP, 2009). TransCanada's calculation of the worst-case spill from the proposed Keystone XL pipeline was not available at the time of this assessment, so an assessment of the methods used by TransCanada for the existing Keystone pipeline and a comparison of the results of those methods with the methods recommended in this analysis were made. The worst-case spill volume at the Hardisty Pumping Station on the Keystone (the original pipeline will be referred to as simply the Keystone pipeline while the proposed pipeline is the Keystone Xl pipeline) pipeline predicted using methods recommended in this analysis was 87,964 barrels (Bbl), while the worst-case spill predicted using TransCanada's methods was 41,504 Bbl (ERP, 2009). The difference is a factor of more than 2 times. The primary difference between the two methods was the expected time to shut down the pumps and valves on the pipeline.

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TransCanada used 19 minutes (TransCanada states that it expects the time to be 11.5 minutes for the Keystone XL pipeline). Since a very similar pipeline recently experienced a spill (the Enbridge spill), and the time to finally shutdown the pipeline was approximately 12 hours, and during those 12 hours the pipeline pumps were operated for at least 2 hours, it is clear that the assumption of 19 minutes or 11.5 minutes is not appropriate for the shut-down time for the worst-case spill analysis. Therefore, worst-case spill volumes are likely to be significantly larger than those estimated by TransCanada. The worst-case spill volumes from the Keystone XL pipeline for the Missouri, Yellowstone, and Platte River crossings were estimated by this analysis to be 122,867 Bbl, 165,416 Bbl, and 140,950 Bbl, respectively. In addition, this analysis estimated the worst-case spill for a subsurface release to groundwater in the Sandhills region of Nebraska to be 189,000 Bbl (7.9 million gallons).

Among numerous toxic chemicals that would be released in a spill, the benzene (a human carcinogen) released from the worst-case spill into a major river (e.g., Missouri River) could contaminate enough water to form a plume that could extend more than 450 miles at concentrations exceeding the Safe Drinking Water Act Maximum Contaminant Level (MCL) (i.e., safe concentration for drinking water). Therefore, serious impacts to drinking water intakes along the river would occur. Contaminants from a release at the Missouri or Yellowstone River crossings would enter Lake Sakakawea in North Dakota where they would adversely affect drinking water intakes, aquatic wildlife, and recreation. Contaminants from a spill at the Platte River crossing would travel downstream unabated into the Missouri River for several hundred miles and affect drinking water intakes for hundreds of thousands of people in cities like Lincoln, NE; Omaha, NE; Nebraska City, NE; St. Joseph, MO; and Kansas City, MO, as well as aquatic habitats and recreational activities. In addition, other constituents from the spill would pose serious risks to aquatic species in the river. The Missouri, Yellowstone, and Platte Rivers all provide habitat for threatened and endangered species including the pallid sturgeon, the interior least tern, and the piping plover. A major spill in one of these rivers could pose a significant threat to these species.

The benzene released by the worst-case spill to groundwater in the Sandhills region of Nebraska would be sufficient to contaminate 4.9 billion gallons of water at concentrations exceeding the safe drinking water levels. This water could form a plume 40 ft thick by 500 ft wide by 15 miles long. This plume, and other contaminant plumes from the spill, would pose serious health risks to people using that groundwater for drinking water and irrigation.

Introduction

TransCanada is seeking U.S. regulatory approval to build the Keystone XL pipeline from Alberta, Canada to Texas. The pipeline will transport diluted bitumen (DilBit), a viscous, corrosive form of crude oil across Montana, South Dakota, Nebraska, Kansas, Oklahoma, and Texas. As part of the regulatory process, TransCanada is required by the National Environmental Policy Act (NEPA) to evaluate the potential environmental impacts of a pipeline spill. The Clean Water Act (CWA) also requires TransCanada to estimate the potential worst-case discharge from a rupture of the pipeline and to pre-place adequate emergency equipment and personnel to respond to a worst-case discharge and any smaller spills. The Keystone XL environmental assessment documents (e.g., Draft Environmental Impact Assessment) as well as the environmental impacts documents for the previously built Keystone pipeline, can be found on the US State Department web site. It is widely recognized that the environmental assessment documents for the Keystone XL pipeline are inadequate, and that they do not properly evaluate the potential environmental impacts that may be caused by leaks from the pipeline (e.g., USEPA, 2011a). The purpose of this paper is to present an independent assessment of the potential for leaks from the pipeline and the potential for environmental damage from those leaks.

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In addition to evaluating potential environmental damage from pipeline leaks, TransCanada is required by law to pre-position emergency equipment and personnel to respond to any potential spill. This paper does not address these requirements. However, an independent assessment of TransCanada's emergency response plans for the previously built Keystone pipeline was done by Plains Justice (Blackburn, 2010). This document clearly shows that the emergency response plan for the Keystone pipeline is woefully inadequate. Considering that the proposed Keystone XL pipeline will cross much more remote areas (e.g., central Montana, Sandhills region of Nebraska) than was crossed by the Keystone pipeline, there is little reason to believe that the emergency response plan for Keystone XL will be adequate.

Since spills from these pipelines will occur, and since they will be extremely difficult and expensive to clean up (likely tens to hundreds of millions of dollars), it is imperative that TransCanada be required to be bonded for these clean-up costs before any permits are granted. This proposed requirement is supported by the recent Enbridge spill, where a smaller crude-oil pipeline leak released crude oil into a tributary of the Kalamazoo River, and early clean-up costs, as reported by the U.S. EPA, have exceeded $25 million.

Worst-Case Spill

One of the requirements of the CWA is to calculate the worst-case potential spill from the pipeline. An assessment of the potential worst-case spill from the Keystone pipeline was conducted by TransCanada; however, some of the methods and assumptions in that assessment are in question. The primary focus of this paper is to provide an independent assessment of the worst-case spill from the Keystone XL pipeline and to compare that to the assessment done by TransCanada.

Spill frequency

To support understanding of the potential impacts due to releases from the pipeline, an assessment of the likely frequency of spills from the pipeline is made. TransCanada calculated the likely frequency of a pipeline spill for the Keystone XL pipeline in the Draft Environmental Impact Statement (ENTRIX, 2010) using statistics from the Pipeline and Hazardous Materials Safety Administration (PHMSA). Nation-wide statistics from PHMSA for spills from crude oil pipelines show 0.00109 significant (i.e., greater than 50 Bbl) spills per mile of crude oil pipelines per year. When this rate is applied to the Keystone XL pipeline with a length of 1,673 miles, the expected frequency of spills is 1.82 spills per year (0.00109 spills/mi * 1,673 mi). Adjusting the nation-wide PHMSA data to only include data from the states through which the Keystone XL pipeline will pass results in a frequency of 3.86 spills per year for the pipeline length (ENTRIX, 2010). The state-specific data are more applicable to the Keystone location; however, the smaller state-specific data base might over-estimate spill frequency. Therefore, the frequency of 1.82 per year is adopted as the best available value for this assessment. Assuming a design life of 50 years for the pipeline, 1.82 spills per year results in 91 expected significant spills (i.e., greater than 50 barrels) for the Keystone Pipeline project. According to the TransCanada Frequency-Volume Study of the Keystone Pipeline (DNV, 2006), 14 percent of the spills would likely result from a large hole (i.e., greater than 10 inches in diameter). Using the 14 percent value, the 91 expected spills during a 50-year lifetime for the pipeline would result in 13 major spills (i.e., from holes larger than 10 inches in the pipeline).

However, TransCanada diverged from historical data and modified the estimate of the expected frequency of spills from the pipeline (DNV, 2006). The company's primary rationale for reducing the frequency of spills from the pipeline was that modern pipelines are constructed with improved materials and methods. Therefore, TransCanada assumed that pipelines constructed with these new improved

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materials and methods are likely to experience fewer leaks. The revised expected frequency for spills was reported in the Frequency-Volume Study (DNV, 2006) to be 0.14 spills/year over the 1,070 miles from the Canadian border to Cushing, OK. This value was adjusted to 0.22 spills per year for the total 1,673 miles of pipeline, including the Gulf Coast Segment (ENTRIX, 2010). Using the 0.22 spills/year, TransCanada predicted 11 spills greater than 50 barrels would be expected over a 50-year project life.

This reduced frequency estimated by TransCanada is probably not appropriate for a couple of reasons. First, the study of the revised frequency ignored some of the historical spill data; i.e., the spill cause category of "other causes" in the historical spill data set (DNV, 2006). The "other causes" category was assigned for spills with no identified causes. Since this category represents 23 percent of the total spills, this is a significant and inappropriate reduction from the spill frequency data. In addition, the assumed reduction in spill frequency resulting from modern pipeline materials and methods is probably overstated for this pipeline. TransCanada used a reduction factor of 0.5 in comparison to historical data for this issue. That is, according to TransCanada, modern pipeline construction materials and methods would result in half as many spills as the historical data indicate. However, the PHSMA data used in the TransCanada report were from the most recent 10 years. Therefore, at least some of the pipelines in the analysis were modern pipelines. That is, the initial frequency estimate was calculated in part with data from modern pipelines; therefore, a 50 percent reduction of the frequency estimates is highly questionable based on the data set used. More importantly, DilBit, the type of crude oil to be transported through the Keystone XL pipeline will be significantly more corrosive and abrasive than the conventional crude oil transported in most of the pipelines used in the historical data set. The increased corrosion and abrasion are due to 15 – 20 times the acidity (Crandall, 2002), 5 – 10 times the sulfur content (Crandall, 2002), and much higher levels of abrasive sediments (NPRA, 2008) compared to conventional crude oil. In addition, the high viscosity of DilBit requires that the pipeline be operated at elevated temperatures (up to 158oF for DilBit and ambient temperature for conventional oil) and pressures (up to 1440 psi for DilBit and 600 psi for conventional oil) compared to conventional crude oil pipelines (ENTRIX, 2010). Since corrosion and pressure are the two most common failure mechanisms resulting in crude oil releases from pipelines (DNV, 2006), increased corrosion and pressure will likely negate any reduced spill frequency due to improvement in materials and methods. Although pipeline technology has improved, new pipelines are subject to proportionally higher stress as companies use this improved technology to maximize pumping rates through increases in operational pressures and temperatures, rather than to use this improved technology to enhance safety margins.

Also, TransCanada relies heavily on "soft" technological improvements, such as computer control and monitoring technology, rather than only on "hard" improvements, such as improved pipe fabrication technology. Whereas "hard" technological improvements are built into pipelines, "soft" improvements require an ongoing commitment of monitoring and maintenance resources, which should not be assumed to be constant over the projected service life of the pipeline, and are also subject to an ongoing risk of error in judgment during operations. As demonstrated by the spill from Enbridge's pipeline into the Kalamazoo River, as pipelines age maintenance costs increase, but pipeline company maintenance efforts may be insufficient to prevent major spills, especially if operators take increased risks to maintain return on investment. Moreover, TransCanada assumes that future economic conditions will allow it to commit the same level of maintenance resources from its first year to its last year of operation. Given future economic uncertainty, this is not a reasonable assumption. It is reasonable to assume that decades from now TransCanada or a future owner will likely fail to commit adequate maintenance resources, fail to comply with safety regulations, or take increased operational risks during periods of lower income. Overtime, PHMSA should assume that the risk of spill from the Keystone XL Pipeline will increase due to weakening of "soft" technological enhancements. Over the service life of the pipeline it is not reason-

able to rely on TransCanada's "soft" technological improvements to the same extent as built-in "hard" improvements.

The TransCanada spill frequency estimation consistently stated the frequency of spills in terms of spills per year per mile. This is a misleading way to state the risk or frequency of pipeline spills. Spill frequency estimates averaged per mile can be useful; e.g., for extrapolating frequency data across varying pipeline lengths. However, stating the spill frequency averaged per mile obfuscates the proper value to consider; i.e., the frequency of a spill somewhere along the length of the pipeline. Stating the spill frequency in terms of spills per mile is comparable to acknowledging that although some 33,000 deaths from automobile accidents occur annually in the U.S., the average annual fatality rate across 350 million people is only 0.000094; therefore, fatalities from automobile accidents are so rare as to be unimportant. In other words, it is of little importance to know the risk (frequency) of a release in any particular mile segment (frequency per mile); rather it is important to know the risk of a release from the pipeline. As shown above, the expected number of spills for the pipeline over the pipeline lifetime ranges between 11 and 91 spills, depending on the data and assumptions used.

In summary, there is no compelling evidence to reduce the frequency of spills because of modern materials and methods. The increased corrosiveness and erosiveness of the product being transported will likely cancel any gains due to materials and methods improvements and soft technological safeguards will likely become less effective over time. Moreover, the modified frequency stated by TransCanada should not have been reduced by omitting an important failure category. The frequency of spills should have been stated as frequency of spills across the pipeline length per year and per pipeline lifetime. Therefore, the best estimate for spill frequency is the value from the PHSMA historical data set resulting in 1.82 spills/yr or 91 significant spills over the pipeline lifetime. Table 1 compares the predicted number of spills over the lifetime of the pipeline computed from TransCanada's assumptions and from historical data.

Table 1: Predicted Number of Spills from Keystone XL Pipeline Over a 50-Year Lifetime.

	TransCanada Estimate	Estimates Using Historical Data
Spills per year per mile	0.00013[(a)]	0.00109[(a)]
Pipeline spills per year	0.22[(b)]	1.82[(b)]
Pipeline spills per 50-year lifetime	11[(c)]	91[(c)]
Pipeline spills from > 10 inch hole	1.54[(d)]	12.74[(d)]

(a) ENTRIX, 2010

(b) spills/year-mile *1673 miles

(c) spills/year* 50 years of pipeline lifetime

(d) spills/lifetime * 14 percent spills from > 10 inch hole

Most Likely Spill Locations

Crude oil could be spilled from any part of the pipeline system that develops a weakness and fails. Likely failure points include welds, valve connections, and pumping stations. A vulnerable location of special interest along the pipeline system is near the side of a major stream where the pipeline is underground but at a relatively shallow depth. At these locations, the pipeline is susceptible to high rates of corrosion because it is below ground (DNV, 2006). Since the pipeline is below ground, small initial leaks due to corrosion-weakened pipe would potentially go undetected for extended periods of time (e.g., up to 90 days) (DNV, 2006) providing conditions for a catastrophic failure during a pressure spike.

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In these locations, pressures would be relatively high due to the low elevation near the river crossing. In addition, major leaks at these locations are likely to result in large volumes of crude oil reaching the river.

In addition to river crossings, areas with shallow groundwater overlain by pervious soils (such as the Sandhills region in Nebraska) where slow leaks could go undetected for long periods of time (e.g., up to 90 days) (DNV, 2006), pose risks of special concern.

Worst Case Spill Volume

The volume of a spill is calculated in two parts: the pumping rate volume and the drain-down volume. The pumping rate volume is the volume of crude oil that is pumped from the leaking pipe during the time between the pipe failure and stoppage of the pumps. The time to shut down the pumps after a leak can be divided into two phases: the time to detect the leak, and the time to complete the shut-down process. The pumping rate volume also depends on the size of the hole in the pipe and the pressure in the pipe. The drain-down volume is the volume of crude oil that is released after the pumps are stopped, as the crude oil in the pipe at elevations above the leak drains out. The following sections explain how the pumping rate volume, the drain-down volume, and the total spill volume is calculated.

Pumping Rate Volume

The pumping rate volume is calculated as:

PRV = PR * (DT + SDT)

Where:

PRV = pumping rate volume (Bbl)

PR = pumping rate (Bbl/min)

DT = detection time (time required to detect and confirm a leak and order pipeline shut-down (min))

SDT = shut-down time (time required to shut down pumps and to close valves (min))

TransCanada's Frequency-Volume Study (DNV, 2006) states that detection of a leak in an underground pipeline section can range from 90 days for a leak less than 1.5 percent of the pipeline flow rate to 9 minutes for a leak of 50 percent of the pipeline flow rate. The 90-day time to detection is for a very slow leak that would not be detected by the automatic leak detection system. The 9 minute time to detection is for a leak that is large enough to be readily detected by the leak detection system. However, this time estimate is questionable because, as has been shown by experience, it is difficult for the leak detection system to distinguish between leaks and other transient pressure fluctuations in a pipeline transporting high viscosity materials such as DilBit. For example, in the Enbridge pipeline spill, signals from the leak detection system were misinterpreted, and up to 12 hours elapsed between the time of the leak and final pipeline shut-down (Hersman, 2010). During the 12-hour period between the initial alarm and the final shut-down, the pipeline pumps were operated intermittently for at least two hours. It should be noted that the location of the Enbridge spill was a populated area where field verification of the leak should have been quick and easy. Indeed, local residents called 911 complaining about petroleum odors (likely from the leak) 10 hours before the pipeline was shut down. In the case of the Keystone XL pipeline, leaks could occur in remote areas (e.g., central Montana, or the Sandhills region of Nebraska) where direct observation would only occur by sending an observer to the suspected site; this could take many hours.

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TransCanada states that the time to complete the pipeline shut-down sequence is 2.5 minutes (ERP, 2009). Therefore, using TransCanada's time estimates, for a 1.5 percent leak, the total time between leak initiation and shut-down could be up to 90 days, and for a large (>50 percent) leak, the total time between leak initiation and shut-down would be 11.5 minutes (ERP, 2009).

However, given the difficulty for operators to distinguish between an actual leak and other pressure fluctuations, the shut-down time for the worst case volume calculation should not be considered to be less than 30 minutes for a leak greater than 50 percent of the pumping rate. This would allow for 4 alarms (5 minutes apart) to be evaluated by operators and a 5th alarm to cause the decision to shut down. In addition, the time to shut down the systems (pumps and valves) would require another 5 minutes. The assumption that the decision to shut the pipeline down can be made after a single alarm, as is suggested by TransCanada (ERP, 2009) is unreasonable considering the difficulty in distinguishing between a leak and a pressure anomaly. The ability to make the decision to shut down the pipeline after 5 alarms is likely a reasonable "best-case" assumption. However, this "best-case" does not describe the "worst case" conditions that are being assessed here. Rather, the worst case should consider confusing and confounding circumstances where a shut-down decision is not clear and where the leak site is remote and not verifiable in a short time period. The total time is then considered to be between 30 minutes (a best-case scenario) and 12 hours (the time for the Enbridge final shut-down) from leak initiation to shut-down. Considering that the Keystone XL pipeline will cross extremely remote areas and that verification of a leak could take many hours, a shut-down time of 2 hours (i.e., the time the pumps were operated during the Enbridge shutdown process) is a reasonable time for the worst-case analysis.

Therefore, for the worst-case spill for a large leak, a shut-down time of 2 hours is assumed. With a maximum pumping rate of 900,000 Bbl/d, and a shut-down time of 2 hours, the pumping rate volume is 75,000 Bbl (900,000 Bbl/d * 1 d/24 hr * 2 hr). This pumping rate volume (75,000 Bbl) is used in the calculation of the total worst-case spill volume for all high-rate leaks (i.e., greater than 50 percent flow-rate).

The worst-case spill for a small leak could occur where the pipeline is buried and in a remote location (such as central Montana or the Sandhills region of Nebraska), and where direct observation would be infrequent. According to TransCanada documents (DNV, 2006), a slow leak of less than 1.5 percent of the pumping rate could go undetected for up to 90 days. However, since pipeline inspections are scheduled every few weeks, it is likely that the oil would reach the surface and be detected before the entire 90 days elapsed. Assuming that the pipeline is buried at a depth of 10 feet and that the 1.5 percent leak (75,802 ft^3/d) is on the bottom of the pipe, oil would fill the pore spaces in the soil mostly in a downward direction, but it would also be forced upward toward the surface. Assuming that the oil initially fills a somewhat conical volume that extends twice as far below the pipeline as above it, the oil would emerge at the surface within about one day (volume of a cone 30 feet deep with a base diameter of 30 feet is 7,068 ft^3). Therefore, the leak would likely be detected in 14 days during the next inspection (assuming bi-weekly inspections). A 1.5 percent spill at a pumping rate of 900,000 Bbl/d over 14 days would result in a release of 189,000 Bbl (7.9 million gallons).

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Table 2: Pumping Rate Volume for Various Sized Leaks

Leak as percent of Pumping Rate[a]	Detection and Shut-Down Time	Pumping Rate Volume[d]
<1.5 percent	14 days[b]	189,000 Bbl
100 percent	2 hours	75,000 Bbl
100 percent	11.5 minutes[c]	7,188 Bbl

(a) Design pumping rate for Keystone XL = 900,000 Bbl/d. Calculation of worst-case spill requires 100 percent of pumping rate.

(b) Time between pipeline inspections.(DNV, 2006)

(c) TransCanada's assumed shut-down time (ERP, 2009)

Drain-Down Volume

The drain-down volume is the volume in the pipe between the leak and the nearest valve or the nearest high point. Some oil in locally isolated low spots will tend to remain in the pipe. TransCanada arbitrarily assigned a drain-down factor of 0.6 for the Keystone XL pipeline, meaning that 40 percent of the oil in the draining pipeline at elevations above the leak will be captured in low spots. However, since siphon effects will tend to move much of the oil even in local low spots, the 40 percent retention factor is likely too high for a worst-case analysis. PHMSA regulations require valves to be placed on either side of a major water crossing. If these valves are working, they should limit the amount of crude oil that drains from the pipeline to the amount that is between the valves. However, to calculate a worst case spill, the volume should be calculated assuming that at least some of the valves fail (recall the failures of the safety devices in the recent Gulf oil spill). If the valves fail, the drain-down volume would be limited by the major high elevation points on either side of the leak, with a reasonable adjustment for residual crude oil remaining in the pipeline. For this worst-case analysis, a reasonable estimate for residual crude oil remaining in the pipeline is assumed at 20 percent of the total volume of oil at elevations above the leak. All of these parameters are site-specific; therefore, for this assessment, the worst case drain-down volumes will be calculated for several of the river crossings of the Keystone XL pipeline, including the Missouri, Yellowstone, and Platte Rivers.

The drain-down volume is calculated using:

$$DDV = PLDV * DF$$

Where:

DDV = Drain Down volume (Bbl)

PLDV = Pipeline Drain Volume (Bbl) (volume of pipeline either side of the leak to next valve or high elevation point)

DF = Drainage Factor (80 percent)

Worst-Case Release Calculation for the Missouri River Crossing

The Missouri River crossing is located at mile post (MP) 89 along the Keystone XL pipeline. The upstream valve is located at MP84, and the downstream valve is located at MP 91. The river is at an elevation of 2,035 feet. Figure 1 shows the elevation profile of the crossing at the Missouri River. Since there are no major high elevations between the river and the valve at MP 84, it is likely that nearly all of the oil in the pipeline between the valve and a hypothetical leak at the river will be siphoned or drained via gravity. If the valve at MP 84 fails, all of the oil in the pipeline between that point and the next valve (MP 81.5) could drain since the pipeline rises gradually in elevation between MP 84 and MP 81 (eleva-

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tion of 2,225 feet). If the valve on the downstream side of the crossing (MP 91) fails, oil in the pipeline up to the major high point at MP 93 could drain to the hypothetical leak at the river crossing.

There are several scenarios that could affect the drain-down volume. In the worst-case scenario both valves could fail, and the drain-down volume would then be the cross-sectional area of the pipe, times the length of pipeline draining times 80 percent. For this scenario, the length of pipe is 11.5 miles (MP 81.5 to MP 93). The cross-sectional area of the 36 inch pipe is 7.07 ft^2. Thus the drain-down volume is $3.43x10^5$ ft^3 (61,164 Bbls, 2.57 million gallons). However it is highly unlikely that both valves will fail at the same time.

A second scenario would occur if both valves operated correctly but the siphon effect removed the oil from the high point downstream of the valve at MP 84. Under this scenario, the length of drained pipe is 7 miles, and the resulting drain-down volume is $2.09x10^5$ ft^3 (37,230 Bbls, 1.56 million gallons).

A third scenario would occur if both valves operated correctly,and the siphon effect did not remove the oil between the high point at MP 86.5 and the valve at MP 84. In this scenario, the length of drained pipe is 4.5 miles (valve at MP 91 to the high point at MP 86.5), and the drain-down volume is $1.34x10^5$ ft^3 (23,934Bbls, 1.01 million gallons).

A fourth scenario would occur if one of the valves fails. To be conservative, the valve closest to the river will be the assumed failed valve. In this scenario, the drain-down distance would be 9 miles (between the valve at MP 84 and the high point at MP 93). The resulting drain-down volume would be 2.69×10^5 ft^3 (9 mi * 5,280 ft/mi * 7.07 ft^2 * 0.8) (47,867 Bbl, 2.01 million gallons).

While the first scenario is very unlikely, valve failure is a reasonable consideration in the worst-case spill analysis. So for the purposes of this analysis the fourth scenario, where one of the valves fails, is used to calculate the worst-case spill drain-down volume for the Missouri River crossing site. Therefore, using the fourth drain-down scenario, the drain-down volume is 47,867Bbls. Adding the pumping rate volume of 75,000 Bbl, the worst-case release volume for the Missouri River crossing is 122,867 Bbl (5.16 million gallons).

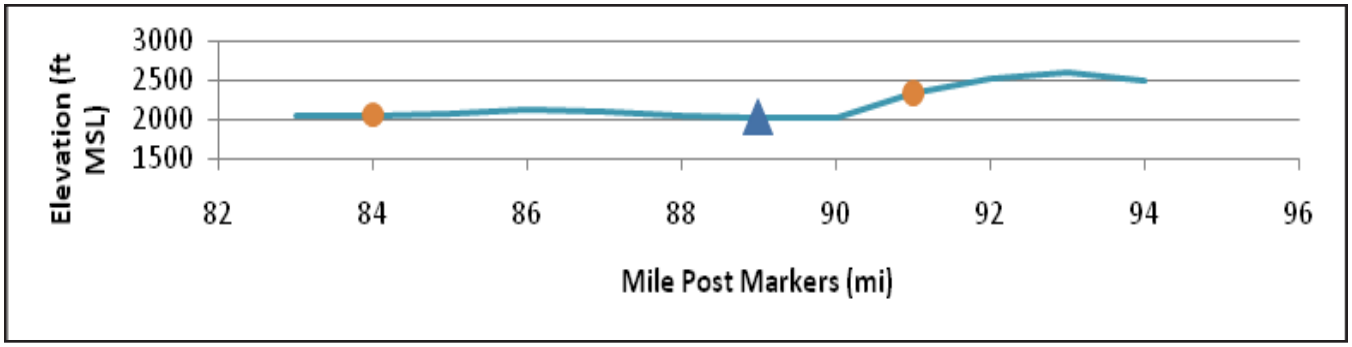

Figure 1: Horizontal profile of surface elevations at the Missouri River crossing. Note that the vertical axis is exaggerated compared to the horizontal axis. Solid circles show locations of pipeline valves. The solid triangle shows the location of the river crossing.

Worst Case Release Volume Calculation for the Yellowstone River

The crossing on the Yellowstone River is at MP 196.5 which is at an elevation of 2,125 feet. The closest upstream valve is at MP 194.5 at an elevation of 2,230 feet. The nearest major high point on the upstream side is at MP 183 at an elevation of 2,910 feet. The closest valve on the downstream side is at MP 200 at an elevation of 2,506 which is also the high point on the downstream side of the crossing. Figure 2 shows the elevation profile for the crossing at the Yellowstone River.

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The first scenario for drain-down volume is if all valves work properly. The drain-down volume is 80 percent of the volume between the valves (the cross-sectional area of the pipe (7.07 ft^2) times the pipe length between the valves (5.5. miles)) which equals $1.64x10^5$ ft^3 (29,252 Bbl, 1.23 million gallons).

Another scenario considers the volume if the valve at MP 194.5 does not work. In this case, the drain-down volume is the volume of the pipe between the two high elevations which are at MP 183 and MP 200 (17 miles). In this scenario the drain-down volume is $5.07x10^5$ ft^3 (90,416 Bbl, 3.80 million gallons). Assuming failure of the valve at mile-post 194.5 is a reasonable assumption for conditions of the worst-case spill volume. The total worst-case volume is then the drain-down volume of 90,416 Bbl plus the pumping rate volume of 75,000 Bbl totaling 165,416 Bbl (6.95 million gallons).

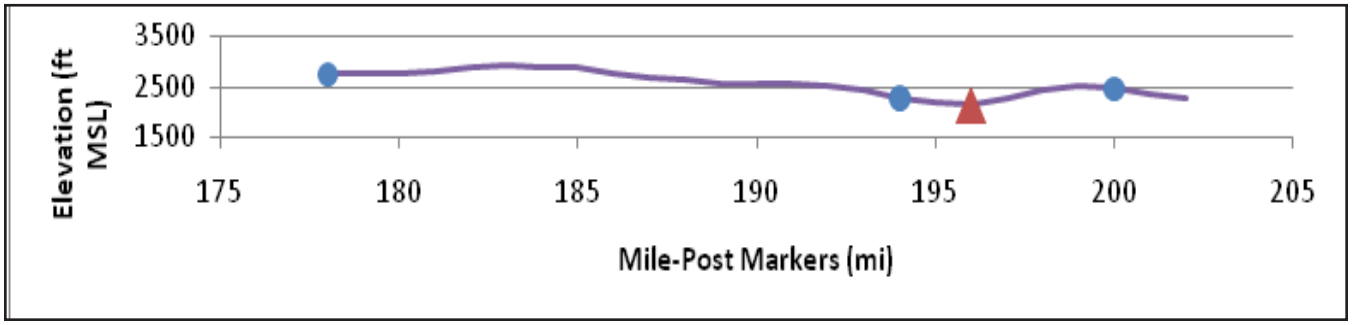

Figure 2: Horizontal profile of surface elevations at the Yellowstone River crossing. Note that the vertical axis is exaggerated compared to the horizontal axis. Solid circles show locations of pipeline valves. The solid triangle shows the location of the river crossing.

Worst-Case Release Volume Calculation for the Platte River, NE

The Keystone XL Pipeline is proposed to cross the Platte River in Nebraska at MP 756.5. There is an upstream valve at MP 747.6 and a downstream valve at MP 765. Figure 3 shows the elevation profile for the crossing at the Platte River. A reasonable worst-case spill scenario is to consider the valve at MP 765 (i.e., closest to the river) to fail. The drain-down volume would then be the pipeline volume between the high point at MP 760 and the valve at MP 747.6. The resulting drain-down volume would be $3.70x10^5$ ft^3 (65,950 Bbl, 2.77 million gallons). Adding the pumping rate volume, the worst-case spill at the Platte River crossing would be 140,950 Bbl (5.92 million gallons).

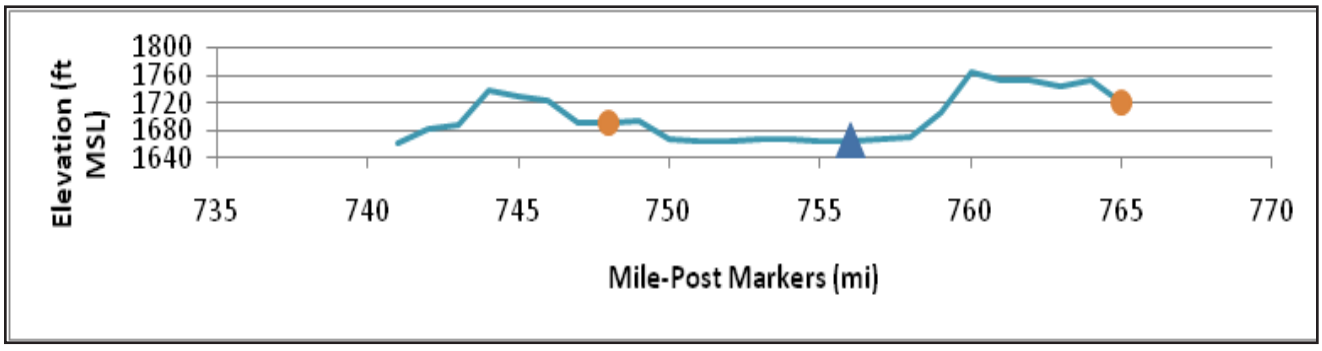

Figure 3: Horizontal profile of surface elevations at the Platte River crossing. Note that the vertical axis is exaggerated compared to the horizontal axis. Solid circles show locations of pipeline valves. The solid triangle shows the location of the river crossing.

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Table 3: Worst-Case Spill Volume Estimates.

Location	Estimate from this analysis		
	Pumping Rate Volume (Bbl)	Drain Down Volume (Bbl)	Total Release (Bbl)
Groundwater	189,000[a]	NA	189,000
Missouri River	75,000[b]	47,867[c]	122,867
Yellowstone River	75,000[b]	90,416[c]	165,416
Platte River	75,000[b]	65,950[c]	140,950

(a) 900,000 Bbl/d (Keystone XL design pumping rate)* 1.5percent leak * shut-down time of 14 days

(b) 900,000 Bbl/d (Keystone XL design pumping rate) * shut-down time of 2 hours

(c) Expected volume to drain from ruptured pipeline after pumps and valves closed

Comparison to TransCanada methods

TransCanada calculated the total Worst-Case Release Volume in a way that appears to be flawed. The worst-case volume was calculated from (ERP, 2009):

$$WCV = ALV + PRV$$

Where:

WCV = worst-case volume (Bbl)

ALV = adjusted line volume (Bbl)

PRV = pumping rate volume (Bbl) i.e., pumping rate (Bbl/min) * time to shut-down (min)

The adjusted line volume was calculated from:

$$ALV = (ILFV – PRV) * 0.60$$

Where:

ILFV = initial line fill volume (Bbl) i.e., the volume of the pipe between the leak and the nearest valve on both sides of the leak.

0.60 = drain-down factor where 60 percent of the oil in the pipe will drain after shut-down.

For the Hardisty Pump Station/Regina Pump Station (Keystone pipeline) calculation, the ILFV was stated as 63,346 Bbl. The pumping rate was 662,400 Bbl/day, and the time to shut down was 19 minutes (10 minutes of evaluation of whether a leak had occurred and 9 minutes to shut down the system). This resulted in a PRV of 8,740 Bbl, and an ALV of 32,763 Bbl. The ALV plus the PRV resulted in a total release of 41,503 Bbl.

TransCanada does not explain how the initial line fill volume is calculated. They simply provide a value (ERP, 2009). For the Hardisty Pump Station/Regina Pump Station calculation, they state the value to be 63,346 Bbl. There is no way to verify this value. Whatever method was used, the value should be the pipeline volume between the leak and the high points of elevation on both sides of the leak. TransCanada then, in what appears to be a flawed process, subtracts the pumping rate volume from the initial line fill volume. It is not clear why this subtraction was done. Apparently, TransCanada considered that since the PRV would be pumped out of the pipeline during the leak discovery and shut-down time, that volume of oil would not be still in the pipeline during draining. However, even though the PRV would be removed from the pipeline during shutdown time, an equal amount would be pumped into the draining section. Therefore, the DDV should be calculated as simply the volume of the drain-

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ing pipeline modified by the fraction of oil trapped in local low points. That is, the PRV should not have been subtracted from the ILFV. The result of subtracting the PRV from the ILFV was then multiplied by 0.60 to account for 40 percent of the oil in the pipe being caught in locally low spots in the pipeline and failing to drain out. Certainly some of the oil in the pipe will fail to drain, especially in locally low spots; however, considering siphon effects, it is very likely that nearly all of the oil will drain even through the locally low spots. Therefore, the 60 percent drain factor is likely to be a significant underestimate of the fraction of oil that will drain. For this worst case spill analysis, a drainage factor of 80 percent is a more reasonable assumption.

Table 4 shows the PRV, DDV, and total worst-case release estimates for the Hardisty Pumping Station on the original Keystone pipeline using methods recommended in this analysis and methods used by TransCanada (ERP, 2009). Note that the PRV values using the method of this paper are much larger than those using TransCanada's method because the assumed shut-down time is much shorter in TransCanada's method (19 minutes compared to 2 hours). The drain-down volumes used for both methods are the reported drain-down volumes from TransCanada's method because sufficient detail was not available in the TransCanada report (ERP, 2009) to allow a comparison of methods.

Table 4: Worst-Case spill volume estimate using the method recommended in this analysis and the method used by TransCanada for the Keystone Pipeline.

	Estimate from this Paper			TransCanada Estimate[a]		
	PRV (Bbl)	DDV (Bbl)	Total Release (Bbl)	PRV (Bbl)	DDV (Bbl)	Total Release (Bbl)
Hardisty Pumping Station	55,200[b]	32,764[c]	87,964	8,740[d]	32,764[c]	41,504

(a) ERP, 2009

(b) Pumping rate volume = 662,400 Bbl/d (Hardisty) * shut-down time of 2 hours

(c) Drain-down volume reported by TransCanada (ERP, 2009)

(d) Pumping rate = 662,400 Bbl/d * shut-down time of 19 min

Impacts from Worst-Case Spill

Impacts to the Air

The primary impacts to the air will be from benzene, hydrogen sulfide, and light molecular weight constituents of the DilBit. The DilBit will be pumped at high temperatures (up to 158°F) and pressures (up to 1440 psi) causing these compounds to volatilize into the air at the site of the spill. The Occupational Health and Safety Agency (OSHA) acceptable concentration of benzene in the air for a workplace is 3.25 mg/m^3 (NIOSH, 1990) for short-term (8-hour) exposures. Since benzene is denser than air, it could accumulate in low-lying areas that are protected from the wind. Under these conditions, the benzene concentration could be above acceptable levels for inhalation. The basements of buildings located above groundwater plumes could also trap benzene gases that exceed safe levels. This could have serious consequences for the occupants of such a building, who may not be aware that a plume of benzene lies beneath the building.

Hydrogen sulfide is another toxic gas that could cause dangerous conditions at the site. The OSHA acceptable concentration for a workplace is 14 mg/m^3 for an 8-hour exposure and 21 mg/m^3 for even a momentary exposure (NIOSH, 1990). The concentrations of hydrogen sulfide in the air are

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expected to be above acceptable levels in areas near a spill site (Enbridge, 2010) and will likely be a serious health threat to emergency workers, remediation workers, and possibly to local residents.

In addition to toxicity effects, benzene, hydrogen sulfide, and the light molecular weight fractions of the oil could create explosive conditions as they volatilize from the spilled oil. Again, this risk will be greatest in areas that are protected from the wind and where concentrations could reach the explosive limits.

Impacts to Terrestrial Resources

The proposed pipeline will cross numerous types of terrestrial habitats (e.g., upland prairies, lowland prairies, woodlands, northern high plains, etc.) as it passes from Canada to Texas. Each of these habitats is unique in terms of its physical conditions (e.g., soils, climates), biological communities, and human communities. Because the physical, biological, and human conditions are so varied in these habitats, the potential impacts from a spill will be different for each type of habitat and location. Therefore, it is not possible to thoroughly assess the potential impacts to terrestrial habitats in this paper.

In general, a primary negative impact caused by a crude oil spill on land will be burial and smothering of plants and ground-dwelling animals. The spilled DilBit will form a very dense and thick layer over the ground that will kill essentially any organisms that are contacted. This effect will be localized to the immediate area of the spill, and most animals will be able to avoid contact with the oil. However, some animals may inadvertently contact the oil (e.g., birds landing in the oil) and be harmed or killed. In addition, the spill will release toxic constituents such as benzene, hydrogen sulfide, light molecular weight oil fractions, and polycyclic aromatic hydrocarbons (PAHs), all of which will have toxic effects on local wildlife. A significant concern arises when the pipeline crosses habitats of the numerous threatened or endangered species that are found along the pipeline route. Finally, the spill could affect human communities via exposures to the toxic constituents.

Impacts to Surface Water Resources

The primary constituents of concern in surface water are: benzene, PAHs, hydrogen sulfide, and bulk crude oil. The amounts of these constituents in the surface water are affected by several factors including: the concentration of the constituent in the crude oil, the solubility of the constituent, and the turbulence and velocity of the water. Constituents of special concern are benzene and certain PAHs because they are carcinogenic.

Benzene makes up 0.1 to 1.0 percent of DilBit crude oil (Shell Canada, 2008), and it is relatively soluble in water. The amount of benzene that will be dissolved in the water can be estimated from the octanol-water partition coefficient (a measure of how much of a contaminant will dissolve into the water) which is 131.8 for benzene (LaGrega et al., 2001). Using the octanol-water relationship, and assuming that the benzene concentration in the DilBit is 1 per cent (~$1x10^4$ mg/L), results in a benzene water concentration immediately at the oil/water interface of 75 mg/L ($1x10^4$ mg/L ÷ 131.8). This benzene concentration is 15,000 times the MCL for benzene of 0.005 mg/L. Since the temperature of the DilBit will be up to 158°F, the actual water concentration at the spill will likely be somewhat higher than this calculation, which is based on an octanol-water partition coefficient for ambient temperatures. The benzene concentration will decrease with distance from the oil/water interface. TransCanada's Risk Assessment calculated that the average (mixed) benzene concentration in surface water for a 10,000 Bbl spill in a 10,000 ft^3/sec stream would be 2.2 mg/L (ENTRIX, 2010); however, this calculated concentration assumes that all of the benzene would be released into the water within one hour (likely over-estimates resulting concentrations) and that the benzene is immediately mixed across the entire stream (under-

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estimates resulting concentrations). Note that 2.2 mg/L is 440 times the MCL for benzene. In most cases, the benzene will form a plume that travels downstream from the spill site. The concentration in the plume will gradually decrease as it moves farther from the spill site.

Besides human health risks from contaminated drinking water supplies, benzene also poses risks to aquatic species. The EPA Region III screening water concentration for benzene designed to be protective of aquatic biota is 0.370 mg/L (EPA, 2011b). The predicted benzene concentration at the oil/water interface is 75 mg/L which is 200 times higher than the screening concentration. Therefore, negative ecological impacts due to toxicity are expected, at least in localized areas where benzene is actively dissolving from the oil.

If a spill of 150,000 Bbl (i.e., in the range of predicted worst-case spill volumes) were to occur in a stream with a flow of 10,000 ft^3/sec and a velocity of 3 ft/sec (e.g., the Missouri River below Fort Peck dam has a flow of 9,225 cfs, and the Yellowstone River at Miles City, MT has a flow of 11,180 cfs (USGS, 2009)), the mass and resulting plume of the benzene in the water could be characterized as follows. Assuming that benzene makes up 1.0 percent of the DilBit, 150,000 Bbl of DilBit would contain approximately $2.3x10^5$ Kg of benzene (150,000 Bbl * 42 gal/Bbl * 3.788 L/gal * 1 Kg/L * 0.01). If 80 percent of the benzene is lost via volatilization and product removal during and immediately after the spill, $4.77x10^4$ Kg of benzene would remain in the stream. This benzene would dissolve through time into the water from the DilBit mixture. To be released into the water, the benzene in the mass of crude would have to diffuse to the oil/water interface. Since the composition of DilBit is variable and since the thickness of the crude mass is case-specific (i.e., depends on turbulence, temperature, etc.), it is not possible to predict precisely the rate at which the benzene will diffuse to the oil/water interface; however, a reasonable assumption would be that 5 percent of the benzene would reach the oil/water interface per day. If this assumption is too high, these calculations will over estimate the water concentrations but underestimate the duration of the negative impacts, and if it is too small, the opposite will be true. Assuming 5 percent of the benzene is released into the water per day, over 2.3 million grams of benzene will be released to the water per day. This will result in a water concentration of 0.09 mg/L ($2.3x10^6$ g/d * sec/10,000 ft^3 * 1d/86,400 sec * 1,000 mg/g * 35.3 ft^3/m^3 * 0.001 m^3/L) once the contaminant plume completely mixes across the entire width of the stream (several miles downstream of the spill). This concentration exceeds the MCL of 0.005 mg/L by 18.8 times. As the benzene plume migrates downstream, the concentration will decrease because of processes such as degradation and volatilization. Reported half-lifes of benzene in surface water range from 1 to 6 days (USEPA, 1986). Assuming a half-life of 3 days, a stream velocity of 3 ft/sec, and a tributary contribution of 20 cfs/mi (the measured value for the Missouri River downstream of the proposed crossing (USGS, 2009)), the plume would reach over 450 miles before its concentration would drop to the MCL and be safe for public water intakes. The plume length was modeled using a series of 10-mile long river reaches with first-order decay ($k=-0.231d^{-1}$) and increased flow of 200 cfs/10 mi reach.

Contaminants from a release at the Missouri or Yellowstone River crossing would enter Lake Sakakawea in North Dakota where they would adversely affect drinking water intakes, aquatic wildlife, and recreation. Contaminants from a spill at the Platte River crossing would travel downstream unabated into the Missouri River for several hundred miles affecting drinking water intakes for hundreds of thousands of people (e.g., Lincoln, NE; Omaha, NE; Nebraska City, NE; St. Joseph, MO; Kansas City, MO) as well as aquatic habitats and recreational activities. In addition, other constituents from the spill would pose serious risks to humans and to aquatic species in the river.

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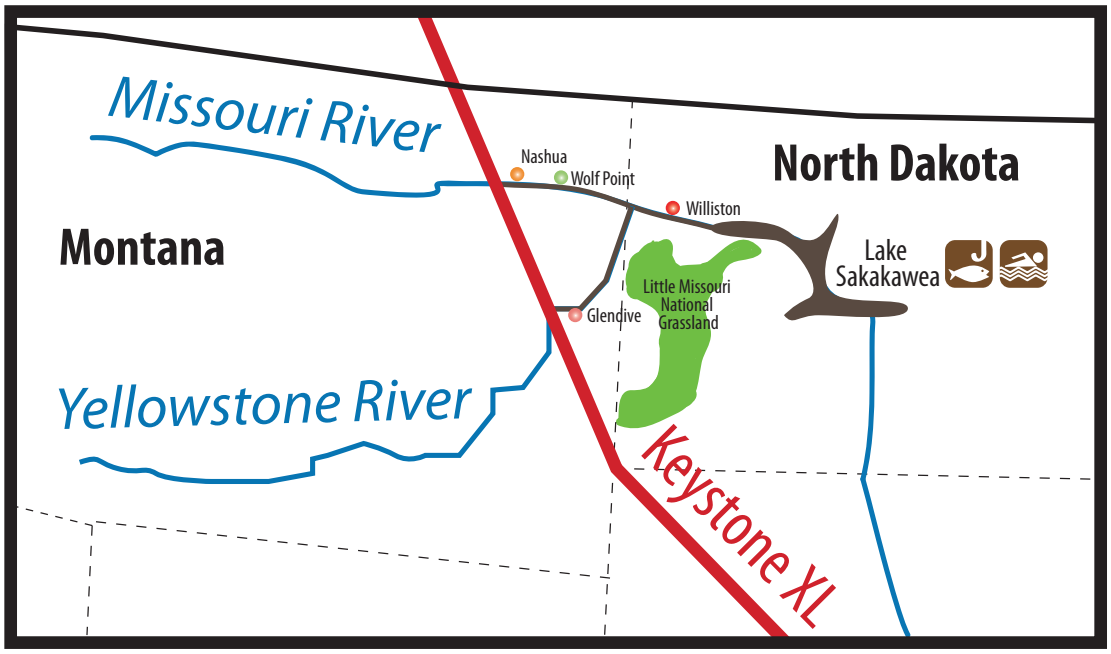
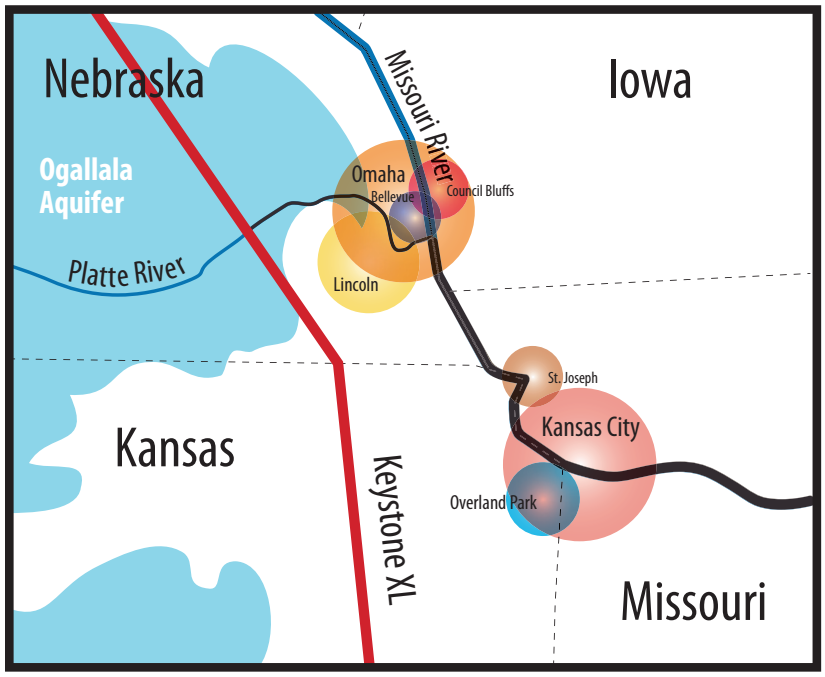
Worst-case spill at the Missouri River or Yellowstone River crossing.



A spill at either crossing could release millions of gallons of crude oil into the rivers and extending downstream as far as Lake Sakakawea, polluting drinking water, and threatening endangered species and recreation areas.

Populations affected by a worst-case spill at the Platte River

- Kansas City - approx. 447K
- Omaha - approx. 420K
- Lincoln - approx. 241K
- Overland Park- approx. 167K
- St. Joseph - approx. 73K
- Council Bluffs - approx. 60K
- Bellevue - approx. 48K



Population estimates based on available data from the U.S. Census Bureau, http://quickfacts.census.gov. Circles representing these cities are for illustrative purposes and are not to scale.

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Of course other assumptions (e.g., shorter half-life) would give somewhat different results. For example, assuming that benzene makes up only 0.3 percent of DilBit and that 10 percent of the benzene is released per day, the calculated plume length would be reduced to around 200 miles. However, since the case-specific details are not known at this point, the precise impacts cannot be calculated; however, it has been clearly shown that if a worst-case spill occurs in a major stream, the impacts would be serious, far-reaching, and long-lasting, and claims to the contrary should be challenged.

The concentrations of PAHs (e.g., benz(a)pyrene) are not specified in the Material Safety Data Sheet (MSDS) for DilBit (Shell Canada, 2008). Also, the risk assessment done for the pipeline (ENSR, 2006) discusses the presence of PAHs, but doesn't detail specific concentrations. Therefore, this analysis will assume that PAHs make up 2 percent of DilBit, and that benz(a)pyrene (BaP) makes up one-tenth of the PAHs or 0.2 percent of the DilBit. This is likely an underestimate. PAHs are not as soluble or as mobile in surface water as is benzene. Much of the released PAH mass will sorb to sediments and remain closer to the location of the spill. However, they will be transported downstream with suspended solids and sediments, and the PAH fraction that does dissolve will form a plume and also be transported downstream. Since they are less soluble and mobile than benzene, PAHs pose less of a threat to municipal water intakes. Using the octanol-water coefficient for benz(a)pyrene (BaP) of 1.1×10^6 (LaGrega et al., 2001), the BaP concentration at the oil/water interface would be 0.0018 mg/L (1.8 μg/L). This concentration exceeds the MCL for BaP of 0.0002 mg/L by a factor of about ten; however, this concentration would be quickly reduced as the plume mixes in the stream. Therefore, based on the assumption that PAHs make up 2 percent of the DilBit, drinking water is probably not significantly threatened from release of PAHs.

However, PAHs are toxic to aquatic organisms. The EPA Region III water quality criteria for benz(a)pyrene to protect aquatic species is 0.015 μg/L (EPA, 2011b). In addition, there are several other PAHs with water quality values to protect aquatic species (e.g., benzo(a)anthracene (0.018 μg/L), fluoranthene (0.04 μg/L), and naphthalene (1.1 µg/L)) that are likely to have concentrations that exceed water quality criteria in a major spill. Therefore, the estimated concentration of PAHs is approximately 100 times the allowable level for protection of aquatic life.

Hydrogen sulfide is very volatile, and much of it will likely volatilize to the air during a major spill. However, some of the hydrogen sulfide will dissolve into the surface water and cause toxic effects to the aquatic biota. The EPA Region III screening water concentration protective of aquatic species is 2.0 μg/L. Since the hydrogen sulfide will quickly volatilize, it is expected that these toxic effects will be limited to areas near the spill.

Bitumen, which makes up most of the DilBit, is more dense than water, so it will sink to the bottom and smother any aquatic plants or sediment-dwelling organisms. These effects will be limited to the immediate area of the spill and are expected to pose a significant risk primarily if the stream is the habitat to threatened or endangered species. Since the Missouri, Yellowstone, and Platte Rivers all provide habitat to threatened and endangered species, including the pallid sturgeon, interior least tern, and piping plover, these impacts should be considered potentially significant.

Table 5: Benzene Plume Development for Spill of 150,000 Bbl into a 10,000 cfs Stream.

	Estimate From This Analysis
Spill Volume	150,000 Bbl
Stream Discharge	10,000 cfs
Fully Mixed Concentration[(a)]	0.09 mg/L

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Ratio of Concentration to MCL [b]	18.8
Length of Plume > MCL [c]	450 miles
Duration of Release to Water [d]	20 days

(a) mg/sec benzene release to stream ÷ L/sec of flow (10,000 cfs = 283,286 L/sec)

(b) fully mixed concentration ÷ 0.005 mg/L

(c) assumes half-life of 3 d; velocity of 3 ft/sec;

(d) assumes 5 percent of benzene is released from DilBit mass per day

Impacts to Groundwater Resources

The primary constituent of concern for a spill into groundwater is benzene. Since DilBit is very viscous, the bulk crude oil will not likely migrate through the soil to groundwater in large quantities. However, if a small, underground leak remains undetected for an extended period of time, a large amount of benzene will be released with the DilBit. The released benzene could then be transported to groundwater via infiltrating rainwater. According to a TransCanada publication "Frequency-Volume Study of Keystone Pipeline" (DNV, 2006), a leak of 1.5 percent of total flow could remain undetected for 90 days. For this analysis, the discovery and shut-down time is assumed to be 14 days which corresponds to the time between pipeline inspections. At the design flow rate of 900,000 Bbl/d, a 1.5 percent leak would release 189,000 Bbl (7.9 million gallons) of DilBit in 14 days. Since DilBit is 0.1 to 1.0 percent benzene, this would result in a release of up to 79,380 gallons of benzene.

A spill of the magnitude of 189,000 Bbl of DilBit would occupy approximately 2.65×10^6 cubic feet of subsurface sands with a porosity of 0.4 (189,000 Bbl * 5.61 ft^3/Bbl ÷ 0.4). Assuming that the DilBit mass occupies a somewhat cylindrical volume and that the aquifer is 20 feet below the pipeline, the DilBit would spread to an area approximately 335 feet in diameter (335 feet diameter X 30 feet high). A reasonable worst-case 100-year, 24-hour storm would deposit 6 inches of rain water on the site. In the Sandhills of Nebraska, nearly all of this water would infiltrate. Six inches of water infiltrating onto a contaminated area of 8.8×10^4 ft^2 (335 feet diameter) results in 4.4×10^4 cubic feet of water (8.8×10^4 ft^2 * 0.5 ft infiltrating water) contacting the DilBit. Using the octanol-water partition coefficient of 131.8 (LaGrega et al., 2001), the benzene concentration in the infiltrating water would be approximately 75 mg/L. The 4.4×10^4 cubic feet of water at a concentration of 75 mg/L equates to 9.35×10^7 milligrams of benzene. Thus, this storm would transport 9.35×10^7milligrams of benzene to the groundwater. Once in the groundwater, the benzene plume would migrate down-gradient, potentially to down-gradient water supplies or basements where it could pose a cancer risk to residents. The 9.35×10^7milligrams of benzene in the groundwater, if evenly distributed (not likely) could pollute 1.9×10^{10} L (4.9×10^9 gallons) of groundwater at the MCL, enough water to form a plume 40 feet thick by 500 feet wide by more than 15 miles long (assuming porosity of 0.4) at the MCL. These plume dimensions are given for illustrative purposes only. The actual dimensions of a groundwater plume cannot be determined with the available information. Of course, the benzene would not be evenly distributed; however, the plume would still be many miles long. In addition, future storms would transport additional benzene to the groundwater increasing the size of the plume.

The worst-case site for such a spill is in the Sandhills region of Nebraska. The Sandhills are ancient sand dunes that have been stabilized by grasses. Because of their very permeable geology, nearly 100 percent of the annual rainfall infiltrates to a very shallow aquifer, often less than 20 feet below the surface. This aquifer is the well-known Ogallala Aquifer that is one of the most productive and important aquifers in the world.

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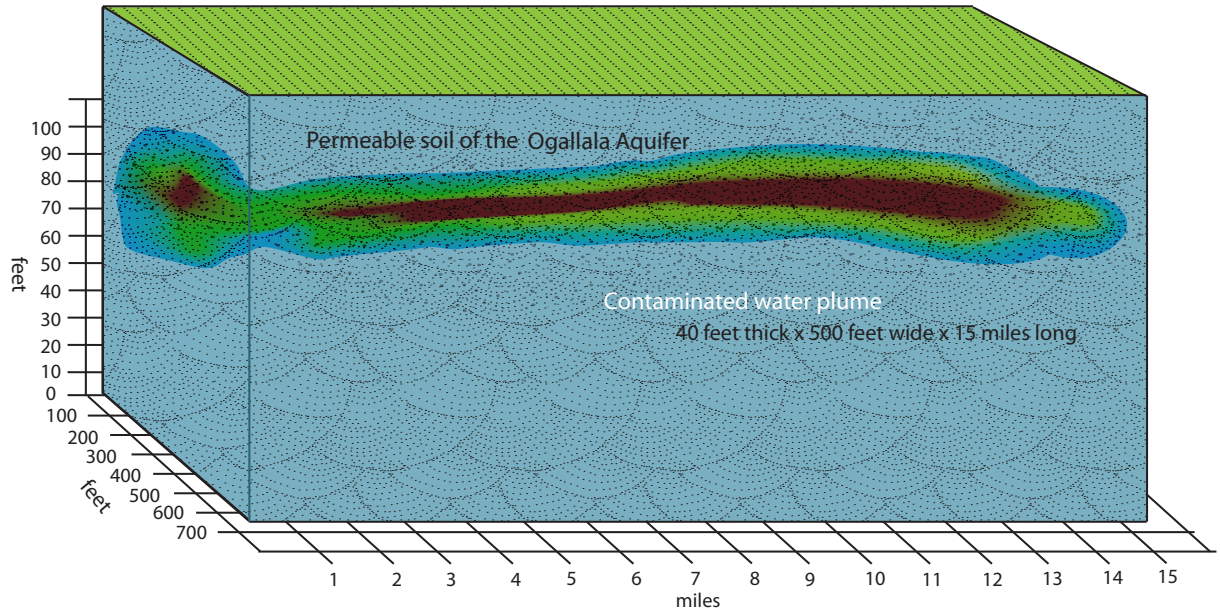
Worst-case spill above the Nebraska Sandhills.



A spill over 14 days, releasing 7.9 million gallons of crude oil could contaminate 4.9 billion gallons of water and form a plume 40 feet thick by 500 feet wide by 15 miles long. By comparison:

The length of the plume is equal to 264 football fields.
Manhattan is 13.4 miles long.
The volume of the plume (1,584,000,000 feet^3) is equal to that of 19,631 Olympic sized pools.

Table 6: Benzene Plume from a189,000 Bbl Spill to Groundwater.

Volume of released DilBit (Bbl)	189,000
Volume of benzene in spill (gal)	79,380
Mass of benzene dissolved in groundwater (mg)	9.35×10^7
Volume of contaminated water > MCL (gal)	4.9×10^9
Equivalent plume dimensions	40 feet X 500 feet X 15 miles

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The attached report, "**Analysis of Frequency, Magnitude and Consequence of Worst-Case Spills from the Proposed Keystone XL Pipeline", was written solely by Dr. John Stansbury who is solely responsible for its contents. Dr. Stansbury is employed by the University of Nebraska, but the report** does not represent the opinion or views of the University or the UNL Water Center.

The purpose of the report is to provide decision-makers (e.g., State Legislators, Congressmen, State Department representatives) an independent and unbiased assessment, based on available data, of the magnitude and impacts of potential worst-case spills from the Keystone XL pipeline. The intended use of this report is neither to lobby for or against the proposed pipeline. Rather it is intended to provide unbiased information to decision-makers to assist them in making informed decisions regarding the pipeline.

Any questions or comments regarding this report should be directed to Dr. Stansbury (jstansbury2@unl.edu).

Exponent®

Third-Party Consultant Environmental Review of the TransCanada Keystone XL Pipeline Risk Assessment

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Third-Party Consultant Environmental Review of the TransCanada Keystone XL Pipeline Risk Assessment

Prepared for

TransCanada Keystone Pipeline, LP
and
U.S. Department of State

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Disclaimer

This final report summarizes the results of work performed by Exponent representing the "Environmental Review" of the Keystone XL Project Risk Assessment (Appendix P of FEIS) and related sections in the Final Environmental Impact Statement (FEIS). This work represents a limited and directed scope of review focused specifically on the Risk Assessment (Appendix P of FEIS) and on specific questions addressed to Exponent as detailed in Section 1 of our report. The findings presented herein are made to a reasonable degree of scientific certainty based on information and data provided by the U.S. Government (i.e., DOS/PHMSA/EPA), through the U.S. Department of State (DOS) and by TransCanada Keystone Pipeline, LP (Keystone). Limited data gathering was involved. Exponent reserves the right to supplement this report and to expand or modify findings and opinions based on our review of additional material as it becomes available through ongoing correspondence with DOS/PHMSA/EPA and Keystone and/or through any additional work or review of additional work performed by Battelle and others. Also, due to the limited and directed scope of this review, this report shall not be considered to have identified or analyzed all scenarios and all sensitive resources that could potentially be impacted by the Keystone XL Project. In our review we point out the limitations of work conducted previously by others. To the extent that we have conducted analyses to address the questions posed to us, these analyses represent very limited and time-constrained analyses, and therefore cannot and should not be construed as filling gaps or inadequacies. In particular we recognize that Keystone will undertake a more detailed analysis to address questions related to the final design of the Keystone XL Project and the potential for environmental impacts. Determining the adequacy of the Biological Assessment performed as part of the FEIS in regard to threatened and endangered species and other special status species is outside Exponent's scope of work as determined by DOS. Rather Exponent used the information in the FEIS on special status species in support of our review. The report addresses comments on Exponent's draft report. Exponent's review was based on the initial route for the pipeline; the modifications of that route have not been specifically evaluated. However, the general recommendations made in this report are broadly applicable.

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Acronyms and Abbreviations

BGEPA	Bald and Golden Eagle Protection Act
BLM	U.S. Bureau of Land Management
BTEX	benzene, toluene, ethylbenzene, and xylenes
CPS	contributory pipeline segment
DOS	U.S. Department of State
EIS	environmental impact statement
EPA	U.S. Environmental Protection Agency
ERP	Emergency Response Plan
ESA	Endangered Species Act
ESA	ecologically sensitive area
FEIS	Final Environmental Impact Statement
FWCA	Fish and Wildlife Coordination Act
HDD	horizontal directional drilling
HSSM	Hydrocarbon Spill Screening Model
LNAPL	light, nonaqueous-phase liquid
MBTA	Migratory Bird Treaty Act
MCL	maximum contaminant level
NAPL	nonaqueous-phase liquid
NEPA	National Environmental Policy Act
PAH	polycyclic aromatic hydrocarbon
PHMSA	Pipeline and Hazardous Materials Safety Administration
Project	Keystone XL Project
Risk Assessment	Keystone XL Project risk assessment
RBWMD	Rainwater Basin Wildlife Management District
SARA	saturates, aromatic, resins, and asphaltenes
SCO	synthetic crude oil
T&E	threatened and endangered
TAN	total acid number
TransCanada	TransCanada Keystone Pipeline, LP
USA	unusually sensitive area
USDOT	U.S. Department of Transportation
USFWS	U.S. Fish and Wildlife Service
WCSP	Western Canadian Sedimentary Basis
WPA	Waterfowl Production Area

Executive Summary

This report provides Exponent's third-party independent environmental review of a specific set of issues identified by the U.S. Department of State (DOS) in consultation with the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA) and the U.S. Environmental Protection Agency (the agencies) that relate to the Keystone XL Project (Project) preliminary risk assessment (Risk Assessment) prepared by AECOM and Dynamic Risk Assessment Systems, Inc., on behalf of TransCanada Keystone Pipeline, LP (Keystone). These issues are described in Section 1 of our environmental review. The Risk Assessment document is presented in Appendix P–*Pipeline Risk Assessment and Environmental Consequence Analysis* dated July 2009 contained within the Final Environmental Impact Statement (FEIS) prepared for DOS by Cardno ENTRIX, contractor for DOS. The agencies thought it advisable to have an additional environmental review of the Risk Assessment because of the highly technical nature of the issues involved, and the desire to ensure that the Project-specific Special Conditions are properly implemented in the event that a Presidential Permit is issued. To address the issues identified by the agencies, we relied on information in the Risk Assessment and FEIS as well as information we obtained that related to the issues identified by the agencies. The report addresses comments on Exponent's draft report. Exponent's review was based on the initial route for the pipeline; the modifications of that route have not been specifically evaluated. However, the general recommendations made in this report are broadly applicable.

The agencies determined that Keystone should commission an engineering analysis that would, at a minimum, assess the advisability of additional valves and/or the deployment of external leak detection systems in areas of particularly sensitive environmental resources. Battelle was chosen by the agencies to provide that ***engineering review***. Exponent was tasked by the agencies to provide the ***environmental review***, part of which was to consider the presence of other sensitive environmental resources along the Project that may warrant additional environmental protection. These potentially sensitive environmental resources were in addition to those that had been the focus of the Risk Assessment. Based on the Scope of Work described in Section 1 of this environmental review, Exponent performed the following tasks:

1. Provided an overview of the overall Keystone Risk Assessment methodology
2. Examined the characteristics of the crude oil being transported
3. Evaluated transport and fate characteristics of spilled crude oil
4. Addressed sensitive issue Area 1: Shallow groundwater
5. Addressed sensitive issue Area 2: Small stream crossings less than 100 ft in width and associated ecological concerns.

This executive summary provides a brief overview of each of these tasks, along with our key findings and recommendations. Exponent's findings will be used, in part, by Battelle to make recommendations related to engineering considerations that could be used to address environmental safety issues related to the Project.

Review of Crude Oil Composition

Exponent reviewed Keystone's consideration of the chemical and physical characteristics of the oil blends to be transported in the pipeline, and compiled crude oil compositional data required in the subsequent sections of our report. Exponent compared the characteristics of diluted bitumen (dilbit) and synthetic crude oil (SCO) to typical crude oil using data from a number of publically available sources.

Key Findings/Conclusions

- The physical and chemical characteristics of dilbit are consistent with a heavy crude oil
- The physical and chemical characteristic of SCO are consistent with a medium gravity crude oil
- The benzene concentrations of both oils are within the range of typical crude oils
- The chemical compositions of the oils are within the range of typical crude oils, although there are some significant gaps in our knowledge about all the constituents
- For the factors considered by Keystone in the Risk Assessment, we agree with their conclusion that dilbit and SCO are sufficiently similar to crude oil and that they should not result in an excess risk in case of a release.

Recommendations

- While not required at this stage in the process, Keystone should consider obtaining additional information on the chemistry of the oils as this information will be needed for developing clean-up and remediation plans
- Knowledge on the chemistry of dilbit continues to increase, and that new information should be incorporated into planning and operations as appropriate (e.g., to improve spill response planning).

Transport and Fate of Spilled Oil

To address questions about potential environmental consequences of oil spills raised by the agencies, Exponent conducted additional transport and fate analyses to better describe the

behavior of potential spills. Our review relied on information provided in the Risk Assessment and FEIS as well as on information and data in the scientific literature such as the viscosity of the oil and distance that oil spills have been known to travel in surface water. We conducted screening-level calculations to quantitatively check statements made in the Risk Assessment about the behavior of oil spills, and to support other aspects of our evaluation.

Our evaluation of possible risks to sensitive areas of groundwater and surface waters depends in part on how the spilled oil will behave when released from a buried pipeline. Therefore, we evaluated how quickly large and small spills might reach aquifers and the behavior of dissolved constituents in these aquifers. Our screening calculations are not an exhaustive transport and fate analysis. The detailed analyses that are required by Special Condition 14 and PHMSA regulations, as part of the Integrity Management Program, will be conducted after the final route is selected as part of the final design of the project. The rate of migration of an oil spill to and in groundwater is an important consideration in the development of the Environmental Response Plan (ERP). It bears directly on response time and the ability to contain and clean up spills that might occur. Similarly, the distance that oil spilled into surface waters of small streams could travel is important for identifying ecologically sensitive areas or other high consequence areas (HCAs) that might be impacted.

Quantitative screening-level estimates of the potential transport of oil to groundwater are provided for two scenarios: a large volume spill or rupture, and a small leak. We also provide a discussion on the potential transport of oil overland. Exponent's analyses are based on the general range of conservative conditions and are intended to provide a sense of scale of potential oil impact. Thus, findings are expected to be a conservative characterization of what could happen along the pipeline. Based on these analyses, Exponent considered the ramifications of the findings in light of the implications they would have on the final Project design and ERP. The following are Exponent's key findings/ conclusions, followed by our recommendations.

Key Findings/Conclusions

- The flow of oil overland is affected by many variables including spill rate, topography, soil type, and vegetation. To provide a sense of scale, a highly simplified case of a sudden spill of 25,000 bbl to a flat surface is presented. If the spill flows in a radial pattern, is 1 ft deep, and there is no spill response, it would spread with a radius of about 200 ft. A pool with a depth of 0.1 ft would spread to a radius of about 700 ft. If a surface spill was influenced by topography and flowed in a channelized manner, the distance traveled could be on the order of thousands of feet, depending on the steepness of the terrain, presence of vegetation, etc. Keystone conservatively assumed in the Risk Assessment that a large spill would be capable of moving overland up to 1 mile. Therefore, considering our analyses, the 1 mile distance criterion used in the Risk Assessment is considered adequate. Where HCAs are located within 1 mile of the pipeline, Keystone is required to perform a site-specific evaluation of overland flow (spreading analysis).

- Exponent applied a numerical screening model, the hydrocarbon spill screening model or HSSM, to estimate the behavior of a large spill of dilbit from the pipeline in an area with a high permeability shallow aquifer. The HSSM modeling simulation showed that groundwater impacts from a large spill would likely occur first from infiltration from the trench near the rupture and not from oil spread across the ground surface. Oil in the potentially filled trench near the rupture could begin forming a non-aqueous phase liquid lens at the water table in less than 1 day if the water table is 1 ft below the trench (8 ft below ground surface), in 7 days if the water table is 3 ft below the trench (10 ft below ground surface), and in 50 days if the water table is 10 ft below the trench (17 ft below ground surface). In contrast, oil infiltrating from the ground surface would reach a water table 8 ft below ground surface after approximately 240 days.

- Results from HSSM simulations of a large spill (25,000 bbl) illustrate that plume lengths for dissolved hydrocarbons (i.e., benzene at or above the under typical groundwater gradients could be between 100 and 900 ft in length. This range is consistent with those reported in the literature; most reported plumes are less than 200–300 ft and a very small number of plumes exceed 1,000 ft. HSSM simulations were also performed to explore an elevated groundwater gradient, representing the potential influence of groundwater extraction (irrigation wells) near the pipeline. When coupled with a simulated low degradation rate (representing an upper bound condition), the higher groundwater gradient could extend the plume length to as much as 2,600 ft.

- Modeling results agree with the conclusions in the Risk Assessment that a small leak going undetected indefinitely is unlikely. More likely, oil from a small "pin hole" leak (28 bbl/day) would reach the ground surface on a time scale of a few months. Based on the screening-level modeling, a benzene plume that may form because of a small leak was estimated to travel downgradient by as much as 600 ft.

- Many private wells located near the pipeline do not meet the criteria to be classified as HCAs in the Risk Assessment. Exponent considered potential factors that could be used to identify non-HCA groundwater areas for shallow groundwater (< 50 ft) where more extensive spill prevention measures and monitoring may be warranted. Based on our analysis of possible plume dimensions, we selected a downgradient distance of 1,000 ft from the proposed centerline of the pipeline as a reasonable boundary of a plume for identifying shallow groundwater and associated wells that could be within the influence of an oil spill. This distance recognizes that large spills would be readily detected and remediated and that small leaks that could take longer to be detected would have smaller plumes. Based on an independent review of the NEDNR well database in Nebraska, Exponent identified approximately 260 wells (not screened by depth) within 1,000 ft of the proposed centerline of the pipeline. Most of these wells are used for irrigation purposes but

domestic wells are also present, several of which draw from shallow groundwater. This list will need to be revised once the final pipeline is determined.

- The relative vulnerability/sensitivity of groundwater resources to a dissolved hydrocarbon plume from an oil spill can be assessed by considering combinations of several factors: 1) proximity to the pipeline (<1,000 ft); 2) depth from point of the oil release to the water table (e.g., release of oil at or below the water table will affect groundwater quality more quickly than releases many feet above the water table); 3) depths of receptor wells (wells that are tens of feet deep are more vulnerable than wells that are hundreds of feet deep); and 4) the pumping of receptor wells (wells with higher pumping rates are more likely to draw plumes further downgradient than wells with lower pumping rates). This combination of factors could be used to identify groundwater resources that do not meet the listing criteria for HCAs but may be more vulnerable to a dissolved benzene plume emanating from an oil spill. An example of this would be a cluster of irrigation wells and domestic wells located within 1,000 ft of a pipeline segment where a release of oil occurred in or within a few feet of the water table.

- The assessment in the FEIS conservatively assumes that in the event of a worst-case spill in which all of the benzene partitions from the oil into water in streams with a range of flow rates. The assessment is useful for comparison of worst-case benzene concentrations to human health and ecological concentration benchmarks and is discussed further in Section 5 of our review. However, the FEIS does not provide an evaluation of possible transport distances of oil via surface water. This appears to be a gap that needs to be addressed.

- The primarily qualitative assessment of the transport and fate of oil in the event of a spill presented in the Risk Assessment is consistent with our analysis and review of the literature. Ultimately, quantitative analysis of transport and fate in surface waters is required by Special Condition 14 and PHMSA regulations as part of the Integrity Management Program during the final design of the project after the final route is selected. These evaluations should take into account the lessons learned from the pipeline rupture in Enbridge, Michigan, in 2010.

Recommendations

- Keystone, as part of the final Project design, should perform further evaluation of overland flow (spreading analysis) of spilled oil, and further evaluation of the transport of spilled oil in small streams (e.g., the downstream distance crude oil could travel from the proposed centerline of the pipeline) for purposes of ERP. These analyses should take into account potential density and viscosity increases associated with the loss of volatiles from heavy crudes and diluted bitumen.

- Keystone should use the screening criteria (e.g., well depth, depth of release compared to water table, lithology between pipeline and aquifer) suggested in our report for identifying vulnerable/sensitive groundwater resources adjacent to the pipeline that do not classify as HCAs but that may be more vulnerable to exposure to a benzene plume in the event of a an oil spill. For example, these could be defined as clusters of both domestic and irrigation wells within 1,000 ft of a pipeline segment where an oil spill could occur in or within a few feet of the water table. Exponent recommends that additional modeling be performed as part of the final design of the Project to further refine the appropriate downgradient distance criteria to be used for identifying sensitive clusters of wells. Exponent recommends that these non-HCA groundwater resources be afforded a degree of protection from the occurrence of an oil spill and from the consequences of a spill similar to what is currently afforded to groundwater resources that are defined HCAs.

- Considering the above-mentioned screening analysis, Exponent recommends that Keystone consider how to improve upon external leak detection through more frequent inspections and education of property owners for wells within these areas of sensitive groundwater resources.

Analysis of Risks Related to Small Stream Crossings

Exponent was asked to evaluate whether there are sensitive environments associated with stream crossings that are less than 100 ft wide that may warrant additional analyses and perhaps mitigation or control measures. Exponent used a set of ecologically-relevant criteria to identify such areas. This part of the environmental review also included an examination of information in the FEIS related to special status species, in particular, the presence of these species and their habitats relative to small stream crossings.

As part of our small stream crossing evaluation Exponent performed the following tasks:

- Reviewed the adequacy of the risk characterization of PHMSA-defined HCAs in the Risk Assessment with a specific focus on ecologically sensitive areas (ESAs)

- Evaluated whether there were other sensitive environmental resources downstream of small stream crossings not already identified by the PHMSA-defined ESAs

- Evaluated the adequacy of relying on benzene as a surrogate chemical to address the magnitude of aquatic toxicity of crude oil spilled into small streams

- Evaluated whether the Risk Assessment process adequately considered the presence of special status species (e.g., threatened and endangered species) when defining sensitive ecological resources.

Exponent considered the implications of our findings with respect to the final Project design and ERP. The following are Exponent's key findings/conclusions, followed by our recommendations.

Key Findings/Conclusions

- The Risk Assessment appropriately followed standard PHMSA guidelines for identifying contributory pipeline segments (CPSs) associated with small stream crossings and the HCAs potentially affected.

- Based on our assessment of transport and fate of oil into surface waters, we used a downstream distance of 10 miles as a basis for identifying locations of sensitive areas around small stream crossings. Using a set of ecologically-relevant criteria, Exponent identified at least ten small stream crossings areas that should be considered for additional protection. An additional four small stream crossings were identified as having special water bodies within 10 miles downstream of the proposed centerline of the pipeline that likely have high wildlife habitat value which should also be given further consideration.

- Exponent agrees with the assessment of the potential magnitude of risk of an oil spill on aquatic life in the water column associated with the toxicity of dissolved oil as represented by benzene. While the toxicity assessment based on benzene is not rigorous, it appears to be sufficiently conservative for assessing short-term effects to aquatic biota residing in the water column. However, depending upon the characteristics of the water body into which a spill occurs, some portion of the spilled oil could come into contact with sediments along shorelines or the bottom of the water body. The oil and associated chemicals that may be present within sediments could exert longer-term chronic effects on aquatic biota that are not captured by considering benzene alone.

- Exponent determined that the list of special status species identified in the FEIS is comprehensive and complete. Exponent also found that the preliminary findings of which species are likely to be adversely affected (one species, the American burying beetle) were arrived at through a sufficiently rigorous review of the distribution, abundance, and biological use of the Project area by special status species.

- Exponent believes that there could be habitat utilized now or in the future by special status species that is not specifically identified as PHMSA-designated ESAs.

- Exponent believes ongoing natural shifts in resources underpinning the distribution and abundance of special status species and the species they rely upon will likely result in a shifting of locations where special status species occur during the lifetime of the Project. These changes will necessitate that

the environmental protection of the areas which these species use as habitat along the pipeline corridor be updated over time.

Recommendations

- A distance of at least 10 miles downstream from the proposed centerline of the pipeline should be used for the identification of sensitive areas and for identifying CPSs during the final design phase of the Project.
- Based on location-specific analyses of fate and effects of spills that Keystone will undertake prior to construction, Keystone should consider the use of additional valves and/or noninvasive boring technologies at the small stream crossings that Exponent identified as associated with additional potentially sensitive ecological areas, and where Keystone's release analysis shows the potential exists for medium to very large spills.
- Keystone should rely upon stream-specific scour analyses for small stream crossings to identify where the pipeline should be buried deeper than 5 ft or where horizontal directional drilling may be warranted. The particular small stream crossings identified by Exponent should be given attention in this regard.
- Exponent recommends that the ERP consider the possibility that spilled oil may be entrained into sediments and that these types of conditions be anticipated as part of spill response and clean-up.
- Exponent recommends that the ERP also take into account the additional ecologically sensitive resources identified in our review. For example, wildlife habitat for special status species, within close proximity of the pipeline could be designated as "special and/or unique areas" for purposes of the ERP.
- Exponent recommends that Keystone develop explicit plans for updating the status and presence of special status species and their habitat every 2 years, and that identified changes be incorporated into the ERP.

1 Introduction

This report provides Exponent's third-party independent environmental review[1] of a specific set of issues identified by the U.S. Department of State (DOS) in consultation with the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA) and the U.S. Environmental Protection Agency (EPA) (the agencies) that relate to the Keystone XL Project (Project) preliminary risk assessment (Risk Assessment) prepared by AECOM and Dynamic Risk Assessment Systems, Inc., on behalf of TransCanada Keystone Pipeline, LP (Keystone). This Risk Assessment document is presented in Appendix P–*Pipeline Risk Assessment and Environmental Consequence Analysis* dated July 2009 contained within the Final Environmental Impact Statement (FEIS) prepared for DOS by Cardno ENTRIX, contractor for DOS. The agencies thought it advisable to have an additional environmental review of the Risk Assessment because of the highly technical nature of the issues involved, and the desire to ensure that the Project-specific Special Conditions are properly implemented in the event that a Presidential Permit is issued. To address the issues identified by the agencies, we relied on information in the Risk Assessment and FEIS as well as information we obtained that related to the issues identified by the agencies. The report addresses comments on Exponent's draft report. Exponent's review was based on the initial route for the pipeline; the modifications of that route have not been specifically evaluated. However, the general recommendations made in this report are broadly applicable.

The agencies determined that Keystone should commission an engineering analysis that would, at a minimum, assess the advisability of additional valves and/or the deployment of external leak detection systems in areas of particularly sensitive environmental resources. Battelle was chosen by the agencies to provide that ***engineering review***. Exponent was tasked by the agencies to provide the ***environmental review***, part of which was to consider the presence of other sensitive environmental resources along the Project that may warrant additional environmental protection via mitigation methods such as the use of valves to control spills. These potentially sensitive environmental resources were in addition to those that had been the focus of the Risk Assessment. The Scope of Work provided to Exponent[2] described our tasks as follows:

> *Potentially Sensitive Environmental Resources*
>
> With respect to the identification of particularly sensitive environmental resources, the risk assessment (Note: we refer to our work as an environmental review) should draw from the information included in the final Environmental Impact Statement regarding the potentially affected environment.

[1] Because many assessment terms are used throughout this document, we refer to the Exponent work as an ***environmental review*** to distinguish our work from the Risk Assessment and from the FEIS.

[2] Keystone Project (US) Supply Agreement – Consulting Services Agreement No. 9646 for Keystone –Phase 3&4 Environmental Review dated September 6, 2001 between TransCanada Keystone Pipeline, LP by its agent TC Oil Pipeline Operations Inc., and Exponent, Inc. Schedule A Scope of Work.

The risk assessment (i.e., environmental review) should take into consideration the fact that the focus of 49 CFR 195.6(2) and (3) is to protect particularly sensitive drinking water resources; especially sensitive drinking water resources that have no adequate alternative water supply and whose intakes lie within highly vulnerable aquifers. The identification of sensitive environmental resources, however, should not be limited by those existing code requirements. Rather it should also be informed by the information, analysis, and federal, state, and public input developed through the EIS process.

In light of the information, analysis, and public input received, the examination of sensitive environmental resources should focus on areas of shallow groundwater (defined as a depth to water of less than 50 feet below ground surface), and river crossings less than 100 feet with the presence of sensitive resources. These areas can be identified based on information in the final EIS.

The analysis of potentially sensitive environmental resources should also take account of the particular characteristics of the crude oil likely to be released into the environment in the event of a spill, particularly into an aquatic environment. This should include any specific characteristics that may affect the fate and transport of potential contaminants in the aquatic environment and/or affecting the difficulty of emergency response operations, containment, oil recovery, and remediation efforts. This information would be used to enhance and inform decisions on the DOT response plan(s) for the pipeline if a Presidential Permit were granted.

Exponent's scope does not involve an environmental review of the overall National Environmental Policy Act (NEPA) process as it was carried out for the Project, nor does it provide an independent review of the selected route for the pipeline. The main aspect considered in our environmental review was the potential for the pipeline to impact sensitive environmental resources that border the Project route described in the FEIS and in the Risk Assessment. To carry out our assessment we undertook several tasks, which are described below along with the rationale for undertaking them to meet the objectives of our scope.

1. **Provide Overview of the Overall Keystone Risk Assessment Methodology.** This task was carried out so Exponent would have the necessary understanding of how risks were evaluated and to provide the foundation for identifying other environments that may be sensitive, in addition to those that were explicitly considered in the Risk Assessment and FEIS, as performed by others. The Risk Assessment method used for the Project has been utilized in other pipeline risk assessments and has evolved over the last decade. However, there is no "standard" risk assessment method prescribed by PHMSA. Therefore, in line with Exponent's specific scope of work, our environmental review specifically evaluates the thoroughness of the methodology used in the Risk Assessment to identify potentially sensitive environmental resources (e.g., drinking water aquifer, sensitive ecological resources such as special status species [federal or state-listed as threatened, endangered, proposed or candidate species, BLM

sensitive species, or species of conservation concern]) that have been designated to be considered for additional protection in the event of a spill.

2. **Examine the Characteristics of the Crude Oil Being Transported.** An understanding of the characteristics of the crude oil is essential for evaluating the transport, fate, and effects of this crude in the event of a spill. Therefore, Exponent reviewed these characteristics, as utilized in the Risk Assessment and FEIS and supplemented those evaluations with information from our independent evaluation of the literature. This information was used to support other tasks.

3. **Evaluate Transport and Fate Characteristics**. We examined transport and fate characteristics of spilled crude to evaluate how these spills might affect sensitive environmental resources (e.g., drinking water aquifers and ecological sensitive resources). We focused on larger spills as well as smaller spills that may be below the capability of the Project system for leak detection[3]. We relied upon information provided in the Risk Assessment as well as empirical data reported in the literature. To check certain presumptions about transport, screening-level modeling was carried out to assess the behavior of the spilled oil with respect to transport to and within groundwater, expression at the ground surface, spreading upon the ground surface, and transport in surface water.

4. **Address Sensitive Issue Area 1: Shallow Groundwater.** This task involved an environmental review of the methodology used in the Risk Assessment to evaluate risk to shallow groundwater resources. The agencies raised questions concerning whether there are non-HCA areas that could be particularly sensitive to groundwater contamination and that might warrant additional protection beyond that being planned.

   This task included an evaluation of the spill and transport and fate components of the Risk Assessment with respect to consequences of spills along the pipeline overlying the aquifers. We understand that the context for this particular task is that the Risk Assessment focused mainly on defined HCAs. However, the agencies also expressed a concern about: a) water withdrawal locations that are not defined HCAs (e.g., water withdrawals for agricultural purposes from areas that are not HCAs); b) the possibility that a spill at distance from an HCA or other sensitive area could spread quickly through the aquifer and contaminate the identified HCA or other sensitive area; and c) the issue of future groundwater resources.

[3] Larger spills were considered as 25,000 bbl spills, which is the maximum estimated spill volume according to the Updated Analysis of Incident Frequencies and Spill Volumes for Environmental Consequence Estimation for the Keystone XL Project, October 2011; p. A-12, Figure A-2. Smaller spills were estimated based on simulations of infiltration of diluted bitumen in permeable sand, which provided estimates for detection times and potential spill volumes (see Section 4).

5. **Address Sensitive Issue Area 2: Stream Crossings Less Than 100 Ft in Width and Associated Ecological Concerns.** While there are regulatory requirements and specified mitigation and control measures specified in the FEIS for river crossings in excess of 100 ft, we were asked to examine the environmental risk and need for any additional mitigation measures for small stream crossings that are less than 100 ft. For these smaller stream crossings, the pipe will be buried to at least 5 ft, but would not necessarily include valves for limiting spillage into the stream. We evaluated the available information to assess whether there were sensitive environments associated with small stream crossings that are less than 100 ft wide that may warrant additional protection. Related to this issues, we also reviewed information on the aquatic toxicity of constituents in the crude as a check on the assessment made in the Risk Assessment of the potential effects of an oil spill to a surface water body. This part of the environmental review also included an examination of information in the FEIS related to special status species, in particular, the presence of these species and their habitats relative to small stream crossings.

   We also commented on how special status species and their habitats might change over the operational history of the pipeline, and how those changes might alter their risk of exposure to potential spills. We provided suggestions for how these changes could be addressed during the lifetime of the pipeline.

To carry out these five tasks, Exponent scientists were organized into teams that addressed each specific topic. The teams shared their evaluation results throughout the process. Our scientists relied mainly on information provided in the Risk Assessment, the FEIS, and on supplemental information provided directly by Keystone. However, we also searched for and accessed relevant publically available information and utilized that information in our evaluation. Numerous questions arose during the course of our evaluation and we relied upon daily calls with Keystone, the agencies, and Battelle to identify additional information and provide the information necessary to help answer these questions. We also held a series of calls with Battelle to coordinate our effort with theirs and to obtain and share information from our respective assessments.

The Exponent environmental review team is described below.

1.1 Exponent Environmental Review Team Roles and Members

The Exponent environmental review team is presented below by role. Brief resumes for the environmental review team members can be found in Appendix A. Specific technical environmental review teams were formed to review the following in more detail:
1) characteristics of crude oil including physical, chemical, and toxicology properties;
2) transport and fate of crude oil as it relates to impacts to groundwater and surface water;

3) small stream crossings in regard to the presence of ecologically sensitive areas (ESAs) associated with them, and 4) special status species considerations related to the Project.

Overall Management

Charles Menzie, Ph.D. (Project Manager)
Michael Kierski, Ph.D.

Technical Review of Document and Quality Control

Paul Boehm, Ph.D.
Walter Shields, Ph.D.

Risk Assessment Methodology

Randall Wentsel, Ph.D. (Team Leader)
Charles Menzie, Ph.D.
Anne Fairbrother, D.V.M., Ph.D.

Crude Oil Characterization Team

Kirk O'Reilly, Ph.D. (Team Leader)
Sungwoo Ahn, Ph.D.
Anne Fairbrother, DVM, Ph.D.
Sheryl Law, M.S.

Transport and Fate Team

Gary Bigham. (Team Leader)
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Farrukh Mohsen, Ph.D., P.E.
Scott Shock, P.E.

Small Stream Crossing Evaluation Team

Anne Fairbrother, DVM, Ph.D. (Team Leader)
Ashley Kaiser, M.S.
Michael Kierski, Ph.D.
Sheryl Law, M.S.
Jane Ma, Ph.D.

Special Status Species Evaluations Team

Richard Podolsky, Ph.D. (Team Leader)
Jane Ma, Ph.D.
Ashley Kaiser, M.S.

2 Risk Assessment Methodology Description

This section presents a description, not a critique, of the Risk Assessment methodology and provides a road map for what portions of the Risk Assessment Exponent and Battelle are reviewing in detail. Areas where Exponent is performing additional evaluations in support of our environmental review are discussed briefly in this section. The detailed evaluations used to support our environmental review are provided in subsequent sections of this report.

In general, the risk assessment approach used by others (AECOM and Dynamic Risk 2009) combines information on the potential for oil spills of particular sizes with information on the proximity of that spill to sensitive areas. From a spill mitigation standpoint those sensitive areas include HCAs. HCAs are collectively identified by PHMSA and include input from multiple federal and state agencies, environmental groups, and the public; they are listed in a national database maintained by PHMSA and are updated periodically. For the pipeline route presented in the FEIS, the locations of HCAs were obtained from PHMSA by Keystone and were mapped in relation to the pipeline.[4] The definition of PHMSA-defined HCAs is discussed later in this report. The distances in miles from the proposed centerline of the pipeline to the HCAs were then calculated and compared to specific distance criteria provided in Table B-1 in Appendix B of the Risk Assessment to assess whether the HCAs could potentially be affected in the event an oil spill were to occur.

For each segment of the pipeline a combination of factors, including potential spill volumes, proximity to HCAs, and numbers of potential HCAs that may be impacted, were used as criteria for ranking the risks of a spill at each pipe segment. As part of the Risk Assessment and FEIS process, Keystone sought input from state agencies and natural resource trustees concerning locations referred to as operator-defined HCAs, which include other sensitive areas such as groundwater protection areas and USFWS-defined critical habitat for threatened and endangered (T&E) species. While no operator-defined HCAs were identified, Keystone conservatively classified all groundwater source water protection areas (SWPA) and wellhead protection areas (WHPAs) as HCAs for the Risk Assessment, regardless of whether they met regulatory criteria as PHMSA-defined HCAs. In Section 5of this report, we describe the methods we used as part of our own evaluation of whether there may be other particularly sensitive resources along the proposed route that are not specifically defined as HCAs, but where additional protection may be warranted.

The Risk Assessment states that a more detailed analysis of the risk to HCAs will be conducted by Keystone prior to commencing Project operations to support the development of an Emergency Response Plan (ERP) in compliance with the U.S. Department of Transportation's (USDOT) Integrity Management Rule (49 CFR Part 195). The final detailed analysis will reflect the final pipeline route selected after completion of the route alternative evaluations in the FEIS. Exponent was informed that the detailed analysis will evaluate worst case discharge volumes released at any location along the pipe, identifying potential spill flow paths, potential

[4] The locations of certain types of HCAs, including ecological and drinking water HCAs, are confidential due to Homeland Security issues.

for downstream transport under maximum stream flow velocities (over 20 miles), transport and fate of the released oil, and intersection with HCAs. We would suggest that a final detailed analysis incorporate lessons learned from the Enbridge spill in Marshall, Michigan, concerning fate, toxicity, and response actions. Keystone should also recognize that additional studies on the characterization of dilbit may be necessary. Keystone provided the preliminary HCA evaluation (Appendix B[5] of the Risk Assessment) to assist DOS in its preparation of the FEIS.

The following five sections summarize the *Structure* of the Risk Assessment (Section 2.1), *Purpose* of the Risk Assessment (Section 2.2), an overview of the *Risk Assessment Process* (Section 2.3), the approach for *Assessing Risks to Human Populations* and HCAs (Section 2.4), and the *Delineation of Pipeline Segments Potentially Affecting HCAs and the Risk Ranking Process* (Section 2.5). This section provides the reader with a summary of the methods used for the Risk Assessment. In addition, a brief description of the additional evaluations performed by Exponent and Battelle are provided to put the evaluations provided in Sections 3 through 6 of this report into context.

2.1 Structure

The Risk Assessment includes a brief Project overview and introduction, a section on incident frequency and spill volumes, a discussion on the consequences of a spill, a section on the pipeline safety program, conclusions, and two confidential appendices (Appendices A and B) addressing incident frequencies and spill volumes for environmental consequence estimation and risk ranking.

The sections on the pipeline safety program and mitigations measures in Appendix A of the Risk Assessment (Appendix P of the FEIS) discuss leak detection measures, quality control, a pipeline maintenance program, third-party issues, and threat mitigation measures (e.g., corrosion prevention and emergency response).

2.2 Purpose

The purpose of the Risk Assessment is to provide decision makers with sufficient information to understand the potential hazards associated with the transportation of crude oil through the Keystone XL Pipeline. Specifically, the Risk Assessment identified the predicted spill frequency, relative magnitude of potential risk along the pipeline (i.e., the pipe) using a relative risk modeling approach, pipeline segments most susceptible to spills, and environmental consequences of a spill from the pipe. Because the preliminary Risk Assessment was developed early in the design and NEPA permitting process, the Risk Assessment was not intended as a predictive modeling effort that evaluated site-specific risk associated with an oil spill from the pipeline nor was the Risk Assessment intended to be an exhaustive transport and fate analysis conducted for operational and emergency response purposes. Those detailed analyses are required by Special Condition 14 and PHMSA regulations (as part of the Integrity Management

[5] Appendices A and B of the Risk Assessment are confidential due to site-specific information related to HCAs. These appendices were available to reviewing agencies, but not to the general public.

Program) and will be conducted after the final route is selected as part of the final design of the Project. As stated in the Risk Assessment, its purpose is threefold:

1. To provide a conservative range of anticipated effects from the operation
2. To provide a preliminary evaluation of potential risk during the pipeline's design phase
3. To provide Keystone with an initial basis for the development of emergency response planning and Keystone's Integrity Management Program.

2.3 Risk Assessment Process

2.3.1 Exposure Pathways Identified

Keystone conducted a threat assessment, which identified five primary threats that could result in a release:

- Corrosion (external, internal, and stress corrosion cracking)
- Materials and construction (e.g., pipe steel flaws, defective welds)
- Accidental damage from third-party excavation
- Incorrect pipeline operations
- Facility damage from natural hazards (e.g., landslides, floods).

The Battelle report, that is a companion to our environmental review, evaluates pipe design characteristics and the potential for leaks.

2.3.2 Estimated Frequency of Spills

The Risk Assessment utilized the PHMSA incident database (2008) and stated that the spill frequency analysis produced a conservative incident frequency of 0.000135 incidents per mile per year, equivalent to no more than 2.2 spills in 10 years for the 1,672 miles of the Project, including the Keystone Cushing Extension. An initial spill frequency of 1.38 spills per year was calculated and Keystone incorporated several factors such as technological advances, strength of material, increased regulatory control, and depth of cover to reduce the spill estimate about six fold to 0.22 spills per year. The number of 2.2 spills in 10 years was used throughout the report to calculate risks and impacts.

These estimates are reviewed and discussed in Battelle's companion report and an evaluation of the adequacy is not discussed further in Exponent's report.

2.3.3 Spill Volume Estimates

PHMSA's incident database (2008) was the source of the spill volume data used for comparison to the spill volumes estimated in the Risk Assessment. The Risk Assessment reported that the PHMSA data set (2002 to present) indicated that the majority of actual pipeline spills are relatively small; with 50 percent of the spills consisting of 3.0 barrels or less. In 85 percent of the cases, the spill volume was 100 barrels or less. In over 95 percent of the incidents, spill volumes were less than 1,000 barrels. Oil spills of 10,000 barrels or larger occurred in only 0.5 percent of cases. In Table 3-2 of the Risk Assessment, the frequencies of oil spills of different volumes that are predicted to occur over a 10-year interval were presented. Maximum spill volumes were discussed in the Executive Summary of the Risk Assessment.

These estimates are reviewed and discussed in Battelle's companion report and an evaluation of the adequacy is not discussed further in Exponent's report.

2.3.4 Transport and Fate of Spilled Oil

Section 4.2.2 of the Risk Assessment discusses transport and fate issues and contains a generic description of physical, chemical, and biological parameters, and the processes of oil degradation in soil and aquatic systems. Much of the discussion concerned crude oil in general and was not developed for the specific crude oil blends planned to be utilized in the pipeline: diluted bitumen and synthetic crude oil. Additional studies on the specific crude oil blends are needed.

Exponent has carried out an independent assessment of transport, fate, and the aquatic toxicity of the transported crude. This assessment is provided later in this report.

2.3.5 Effects/Consequences

Consequences of oil spills were evaluated in the Risk Assessment and FEIS using information on estimated spill probabilities and spill volumes together with proximity to sensitive areas. Impacts of spills were evaluated with respect to soils, vegetation and soil ecosystems, wildlife, water resources (groundwater and surface water), aquatic organisms, and wetlands/reservoirs/ lakes. For soils, plants and soil ecosystems, and wildlife, a general description of impacts was presented. The chemical benzene, one of the more toxic yet volatile and hence ephemeral constituents in crude, was used to judge the implications of exposure, risks, and the required clean-up in the event of a spill. When a more detailed analysis is conducted, a comparative study between the aquatic toxicity observed in the Enbridge spill in Marshall, Michigan, and benzene would be beneficial.

Consequences of a spill to groundwater were considered with respect to the following location characteristics where migration to groundwater would be more probable:

- Relatively shallow water table is present (as opposed to locations where a deeper, confined aquifer system is present)

- Soils with high permeability are present throughout the unsaturated zone
- Proximity to specific groundwater resources designated as HCAs.

The Risk Assessment relied on transport, fate, and potential risks associated with benzene to judge relative risks to groundwater resources. *Exponent evaluates the methodology and considers vulnerable groundwater areas later in this report.*

The Risk Assessment evaluated impacts to downstream surface water sources by comparing projected surface water benzene concentrations with the national maximum contaminant level (MCL) for benzene (5 parts per billion [ppb]) to evaluate drinking water safety and with aquatic toxicity thresholds to evaluate environmental safety. Because the pipeline will cross hundreds of perennial, intermittent, and ephemeral streams, the Risk Assessment evaluated categories of streams, based on the magnitude of stream flow and stream width. For surface waters, the assessment utilized the following three conservative assumptions to estimate potential spill effects for planning purposes:

- The entire volume of a spill was released directly into a waterbody
- Complete, instantaneous mixing occurred
- The entire benzene content was solubilized into the water column.

Exponent performed an independent evaluation of the effects and consequences analysis in the Risk Assessment, and performed additional independent evaluations to put the results in the Risk Assessment into perspective.

2.3.6 Wetlands, Reservoirs, and Lakes

The Risk Assessment included a discussion of potential impacts to wetlands, reservoirs, and lakes, and stated that the predicted effects of a spill reaching standing water (e.g., reservoirs, lakes) would depend largely upon the volume of crude oil entering the waterbody and the volume of water within the waterbody. Estimates were made of the amount of water necessary to dilute spill volumes below aquatic toxicity and drinking water thresholds. The Risk Assessment acknowledged that while this approach does not account for transport and fate mechanisms, mixing zones, environmental factors, and emergency response capabilities, it provides an initial screening benchmark for identifying areas of potential concern.

Exponent performed an independent evaluation using the information in the FEIS on these types of sensitive ecological habitats (wetland, reservoirs, and lakes) to determine if they were located along the pipeline in close proximity (i.e., 10 miles) of small stream crossings.

2.4 Risk to Human Populations and HCAs

Pipeline safety regulations use the concept of HCAs to identify specific locales and areas where a release could have the most significant adverse consequences. HCAs are defined within the Integrity Management Rule (49 CFR Section 195.450) and include:

- Populated areas (e.g., city, town, village, or other designated residential areas)
- Commercially navigable waterways
- Designated zones around public drinking water intakes using PHMSA-defined drinking water unusually sensitive areas (USAs)
- Unusually sensitive ecological resource areas that could be damaged by a hazardous liquid pipeline release, including:
  - An area containing critically imperiled species or ecological community
  - Multi-species assemblage areas
  - A migratory waterbird concentration area
  - Areas containing imperiled special status species or imperiled ecological communities where the species is aquatic, aquatic dependent, or terrestrial with a limited range
  - An area containing special status species where the species or community occurrence is one of the most viable, highest quality, or best condition, as identified by an element occurrence ranking (EORANK) of A or B.

The Risk Assessment identified a total of 141.2 miles of pipeline associated with HCAs, with 84.3 miles associated with drinking water source HCAs, 63.9 miles associated with ecologically sensitive area HCAs, and 17.2 miles associated with populated area HCAs. Keystone consulted with USFWS on special status species and identified appropriate conservation measures as necessary.[6] The probability of a spill occurring in a pipeline segment associated with a particular type of HCA was predicted based on the number of miles of pipeline associated with each type of HCA and the base number of average spills predicted to occur (e.g., 1 spill in 53 years for all HCAs crossed by the pipeline).

The Risk Assessment states that the portions of the pipeline that could potentially affect HCAs will be subject to higher levels of inspection and repair criteria (per 49 CFR Part 195), and identifies additional valve locations beyond the original design and regulatory requirements, as a

[6] Exponent was informed that DOS prepared a biological assessment that evaluated the impacts of construction and operation impacts on T&E and candidate species for the entire pipeline. USFWS issued the biological opinion on September 23, 2011, that concurred with the biological assessment findings.

measure to reduce potential risk to HCAs. As a result of the preliminary HCA evaluation, some proposed valve locations were moved and additional valves were added to protect HCAs. In addition, a yearly survey of HCA locations is planned to update the Integrity Management Program.

Exponent used information on the locations of HCAs provided by Keystone to assess the number of HCAs within 10 miles of the proposed center line of the pipeline along specific segments of the pipeline.

2.5 Pipeline Segments Potentially Affecting HCAs and the Risk Ranking Process

The Risk Assessment discussed specific portions of the Project referred to as contributory pipeline segments (CPSs) where, if a spill were to occur, crude oil has the potential to reach HCAs (i.e., "could affect" segments). The authors then developed a process to rank, in risk levels from 1 to 4, the degree of the potential risk for specific pipeline segments by assessing the spill volume and physical transport pathway factors.

The Integrity Management Rule requires that the pipeline be evaluated to identify pipeline segments in which the released crude oil from a failure occurring anywhere between the two endpoints of the value segments could migrate to and affect a HCA. To identify the segments of the pipeline that could potentially affect HCAs, a three-step process was used:

- In the first step, HCAs were screened to determine which areas were within a reasonable proximity to the Project's proposed centerline of the pipeline and also had a viable physical pathway to transport a spill to the HCA.
- The second step of the process was to review those specific segments of the pipeline where, if a spill were to occur, crude oil could potentially reach areas of a HCA or HCA buffer area that contribute to the purpose of the HCA. CPSs were eliminated if the intersection of HCA buffer with the pipeline did not interfere with the purpose of the HCA (e.g., the drinking water HCA buffer area intersects with pipeline below the drinking water intake).
- The third step ranked the relative risk of each pipeline segment capable of affecting a HCA.

Most of the pipeline was removed from consideration in Step 1 and Step 2 of the process. The risk ranking step utilized five factors to categorize the identified CPSs into one of four levels, with level 1 being of the highest concern and level 4 being of lower concern for potential impacts to impact HCAs. The proximity and number of HCAs and maximum spill volume within the CPS were key factors in the ranking of a CPS. The evaluation conservatively assumed 900,000 bpd throughput to calculate maximum spill volume.

The ranking process identified 196.5 miles of the pipeline where the CPSs were ranked from 1 to 4. For risk category 1 (the highest concern), 63.7 miles of the pipeline consisting of nine CPSs, were identified. The higher risk ranking was associated with major river crossings.

The CPS locations are a particular focus for Exponent's review because they are identified in relation to HCAs and because Exponent was tasked with identifying environmental characteristics that may indicate where other sensitive areas are located along the proposed route that are not specifically defines as HCAs. To the extent that such areas are identified in our review, the pipeline segments near these locations may be considered CPSs for the purpose of considering the advisability of additional oil spill controls (e.g., valves) or countermeasure plans.

3 Review of Crude Oil Composition

3.1 Introduction

The purpose of this section is to assess Keystone's characterization of the chemical and physical properties of the oil blends to be transported in the pipeline, and to compile crude oil compositional data used in the subsequent sections of this report. Exponent compared the characteristics of diluted bitumen (dilbit) and synthetic crude oil (SCO) to typical crude oil using data from a number of sources. The following are Exponent's key findings/conclusions, followed by our recommendations. The remainder of this section provides the documentation to support these findings/conclusions and recommendations.

3.1.1 Key Findings/Conclusions

- The physical and chemical characteristics of dilbit are consistent with a heavy crude oil
- The physical and chemical characteristic of SCO are consistent with a medium gravity crude oil
- The benzene concentrations of both oils are within the range of typical crude oils
- The concentrations of PAHs are within the range of typical crude oils.
- While the total acid number of dilbit is within the range of acidic crude oils, the fraction of the acids consisting of naphthenic acids is unknown
- For the factors considered by Keystone in the Risk Assessment, we agree with their conclusion that dilbit and SCO are sufficiently similar to crude oil so that they should not result in an excess risk in case of a release.

3.1.2 Recommendations

- Although PAH concentrations in petroleum are low compared to some environmental sources, this class of compounds can be a long-term driver for remediation and risk management following an oil spill. While not required at this stage in the process, Keystone should consider obtaining addition information on the PAH chemistry of the oils to be transported.
- Given the perceived link between tar sands processing and aquatic toxicity due to naphthenic acids, Keystone should consider obtaining addition information on the naphthenic acid content of the oils to be transported.

- Knowledge on the chemistry of dilbit continues to increase. This new information should be incorporated into planning and operations as appropriate (e.g., to improve the spill response planning).

3.2 Chemical Characteristics and Physical Properties

The FEIS and Risk Assessment focused on the two oils, dilbit and SCO, that will be primarily shipped from Alberta. As noted in the FEIS, the precise composition of these will vary by production location and as the result of upgrading processes. Data on the nature and chemical composition of these oils are available from the online database crudemonitor.ca. This database contains the results of regularly conducted analyses of western Canadian crudes including six heavy sour Canadian crude oils, eight types of dilbit, and seven SCOs. Using this information, Keystone concluded that the oil to be shipped by the pipeline is consistent with crude oils commonly shipped by pipeline and processed in the United States.

To evaluate this conclusion, we compiled data on Alberta dilbit and SCO from a number of published sources and compared their chemistry to that of typical crude oils. As summarized in Table 1 and on Figure 1, diluted heavy bitumen (dilbit) is generally similar in its physical characteristics to the heavy sour crudes. Distillation curves reveal the mass of the oil present in specific boiling ranges and indicate the relative distribution of lighter and heavier compounds. Lighter crudes are typically more mobile under environmental conditions, but are also more susceptible to weathering (e.g., evaporation) and biodegradation. Crudes with more heavy ends are less mobile, and while also subject to various weathering processes, can be more persistent in the environment. Because of the processing used to generate SCO, its characteristics are generally similar to a light crude. For these bulk characteristics, our findings are consistent with Keystone's conclusions.

In the National Transportation Safety Board's Pipeline Accident Report (NTSB 2012) on the Enbridge release in Marshall, Michigan, material similar to what will be transported in the XL pipeline was described as:

> Cold Lake Blend and Western Canadian Select crude oil condensate mixtures are regulated by the U.S. Department of Transportation (DOT) as class 3 flammable hazardous materials. Heavy crude typically is a mixture of crude oil (from 50 to 70 percent) and hydrocarbon diluent (from 30 to 50 percent). The material contains 20 to 30 percent volatiles by volume. The mixture is used as raw material in the production of fuels and lubricants. It is a brown or black liquid with a hydrocarbon odor; it is lighter than water with a specific gravity of 0.65 to 0.75. It exhibits a flashpoint of -31° F. The vapor is heavier than air, with a lower explosive limit of 0.8 percent and an upper explosive limit of 8 percent vapor concentration in air.

While slightly more detailed, this is consistent with the description used in TransCanada's risk assessment. If more chemical or oil characteristic data become available from the Enbridge incident, it should be incorporated as appropriate in spill response planning documents.

Table 1. Summary of crude characteristics data from crudemonitor.ca.

	Density (kg/m^3)	Gravity (deg. API)	Sulphur (wt%)	TAN (mgKOH/g)	Salt (ptb)	Nickel (mg/L)	Vanadium (mg/L)	Benzene (vol%)	Toluene (vol%)	Ethyl Benzene (vol%)	Xylenes (vol%)
Heavy Sour Conventional Blend											
Average	929.40	20.61	3.05	0.67	59.05	44.44	93.11	0.09	0.15	0.06	0.24
SD	4.64	0.76	0.12	0.12	38.62	5.05	10.78	0.03	0.05	0.01	0.05
Max	937.50	21.80	3.39	1.10	136.50	64.20	127.30	0.15	0.32	0.11	0.52
Heavy Sour Dilbit Blend											
Average	922.30	21.80	3.94	1.70	6.81	72.02	193.52	0.29	0.50	0.06	0.39
SD	5.66	0.94	0.10	0.12	1.38	5.01	12.27	0.03	0.07	0.01	0.08
Max	932.60	23.50	4.15	1.94	10.00	83.00	227.00	0.37	0.74	0.11	0.57
Sweet Syncrude Blend											
Average	862.08	32.49	0.10	--	--	0.44	0.93	0.04	0.14	0.10	0.32
SD	3.65	0.69	0.02	--	--	0.27	0.46	0.02	0.04	0.02	0.05
Max	870.10	35.50	0.19	--	--	0.88	1.50	0.11	0.26	0.19	0.49

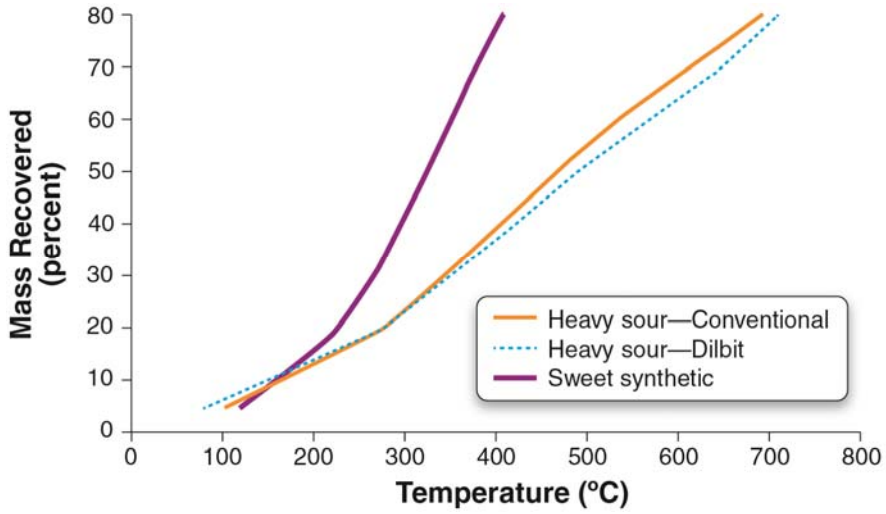

Figure 1. Simulated distillation curves based on 5-year average data from crudemonitor.ca.

Certain physical characteristics are important factors in predicting the transport and fate of petroleum in the environment. These are density, viscosity, and surface tension. Density information is available in the crudemonitor.ca database. Both the dilbit and SCO have densities below one, with the dilbit (929 kg/m^3) being heavier than the SCOs (857 kg/m^3). This means these oils are less dense than water when shipped, but the density can increase following a release due to the loss of the lighter hydrocarbon fractions. As with the transport of other heavy crudes, response plans should consider both floating and sinking oil. The viscosity of both dilbit and SCO can be changed by varying the relative mixture of heavier and lighter cuts. Keystone requires that material shipped in the Keystone XL Pipeline have a viscosity of 350 cST (Kothari 2010). The range of surface tension of crude oils is typically around 30 dynes/cm, and the interfacial oil/water tension varies with API gravity and is near 20 dynes/cm for heavy crudes (Lyons 1996).

Additional information on the chemical characteristics of dilbit may be available from entities involved in the response to the July 2010 Enbridge oil spill in Marshall, Michigan. Chemical fingerprinting of the source oil was conducted by the U.S. Coast Guard's (USCG) Marine Safety Laboratory. While one page summaries are available through the EPA Region 5 website, details were not provided. The full data reports including chromatograms can be requested from the USCG laboratory.

3.3 Potential Risk Drivers

To evaluate potential impacts of a release, it is important to have information on the concentrations of compounds that can drive risk to human health or ecological receptors. Benzene is a typical petroleum compound of concern and a focus of much of the evaluation of potential impacts to surface water and groundwater. The concentration of benzene in some dilbit is twice as high as the mean but well below the maximum benzene concentration of

69 crude oils (Rixey 2001; Table 2). The benzene concentration of SCO is less than the mean concentration for crude oil. These findings suggest that the risk due to benzene for either dilbit or SCO should not be greater than that due to a typical crude.

Table 2. Mean, standard deviation, and maximum benzene concentrations (mg/kg crude) from crudemonitor.ca compared to a screen of 69 crude oils (Rixey 2001)

	Mean	Standard Deviation	Maximum
Benzene (mg/kg)			
Sixty-nine crudes	1,340	-	5,900
Heavy sour conventional blend	857	280	1,501
Heavy sour dilbit blend	2,773	299	3,515
Sweet syncrude blend	374	163	1,122

Although PAH concentrations in petroleum are low compared to some environmental sources, this class of compounds can be a long-term driver for remediation and risk management following an oil spill. While not required at this stage in the process, Keystone should consider obtaining addition information on the PAH chemistry of the oils to be transported. The FEIS contains little discussion about the concentrations or potential environmental impacts of PAHs. While PAHs are considered to be among the most toxic of the nonvolatile compounds in petroleum, their concentrations are typically low (less than 1 percent to about 3 percent by weight) compared to their concentrations in materials such as coal tars. Oil contains both the unalkylated PAHs that are typically measured as part of environmental assessments and a number of alkyl-substituted forms. Recently published data on the PAH chemistry of dilbit and SCO (Yang et al. 2011) indicate the total concentration is in the low range (<0.5 percent) of crude oils. Table 3 compares the concentration of individual PAHs for a typical crude oil (Boehm 2006), dilbit, and SCO. The lower total PAH concentration is due primarily to depletion of the two- and three-ringed compounds such as the naphthalenes and fluorenes. Because of the ubiquitous nature of these compounds and the multiple sources other than oil, they are often present in sediments, unrelated to crude oil or petroleum. An understanding of the PAH profiles of pipeline oils would allow for differentiation between baseline and spill impacts.

Table 3. PAH concentrations (µg/kg) in a typical crude oil (Boehm 2006), dilbit, and SCO (Yang et al. 2011)

PAH	Crude Oil	Dilbit	SCO
Naphthalene	1,268	25	31
C1-Naphthalenes	3,886	112	155
C2-Naphthalenes	4,511	376	333
C3-Naphthalenes	2,988	682	406
C4-Naphthalenes	1,000	741	354
Biphenyl	233	ND	9
Acenaphthylene	--	3	2
Acenaphthene	47	7	5
Fluorene	267	20	14
C1-Fluorenes	521	70	54
C2-Fluorenes	682	171	124
C3-Fluorenes	420	251	188
Anthracene	ND	10	6
Phenanthrene	370	31	55
C1-Phenanthrenes/Anthracenes	718	101	195
C2-Phenanthrenes/Anthracenes	716	166	321
C3-Phenanthrenes/Anthracenes	460	200	374
C4-Phenanthrenes/Anthracenes	154	146	357
Fluoranthene	14	6	19
Pyrene	18	18	206
Benz[a]anthracene	2	4	38
Chrysene	32	8	53
C1-Chrysenes	51	48	359
C2-Chrysenes	67	89	502
C3-Chrysenes	38	83	379
Benzo[b]fluoranthene	9	5	25
Benzo[k]fluoranthene	--	1	6
Benzo[e]pyrene	12	7	75
Benzo[a]pyrene	--	4	50
Perylene	--	9	28
Indeno[1,2,3-cd]pyrene	--	2	21
Dibenz[a,h]anthracene	--	2	22
Benzo[ghi]perylene	4	5	109

Given the perceived link between tar sands processing and aquatic toxicity due to naphthenic acids, Keystone should consider obtaining additional information on the potential range of naphthenic acid content of the oils to be transported in the future. Naphthenic acids are a class of compounds found in Canadian oil sands that can potentially result in aquatic toxicity if released into the environment and have been the subject of significant research (Clemente and Fedorak 2005). While questions about the link between these compounds and corrosion are discussed in the Section 3-13 of the FEIS, the FEIS does not discuss the potential environmental implications of this class of compounds. Exponent was informed that the majority of naphthenic acids are removed from Alberta crude upon extraction but that data are lacking on concentrations. The total acid number (TAN) is used as a surrogate. Although the toxicity associated with raw tar sand and tar sand process waters has been well studied, less is known about the acids found in dilbit. Because of the caustic soda washing process used to separate bitumen from oil sands, the acids remaining in dilbit should be depleted more than in water soluble compounds. TAN is an indicator, but not a direct measurement of, naphthenic acids found in crude. TAN values for heavy WCSB and dilbit are consistent with data from 18 international crudes (Aske et al. 2001; Table 4). With a TAN of > 1.0, dilbit would be considered to be an acidic crude, while the heavy WCSB crude is moderately acidic (APEC 2005). Naphthenic acids are not present in SCO.

Table 4. Total acid number (mg KOH/g) compared to a screen of 18 crude oils (Aske et al. 2001)

Mean of 18 Crudes	Median of 18 Crudes	Heavy Sour–Conventional	Heavy Sour–Dilbit	Sweet Synthetic
1.20	0.60	0.64	1.46	0.00

4 Transport and Fate of Spilled Oil

4.1 Introduction

This section presents Exponent's independent assessment of the potential transport and fate of oil in the event of a spill from the Keystone XL pipeline as discussed in the Risk Assessment (Appendix P of the FEIS). Exponent conducted additional transport and fate analyses and a review of the empirical literature related to crude oil spills to provide additional detail on the behavior of potential spills beyond that provided in the Risk Assessment. This information was needed to address questions that DOS and other agencies have posed to Exponent concerning identification of sensitive environmental resources and potential impacts not addressed in the Risk Assessment.

The FEIS provides extensive discussion of groundwater and surface water resources along the path of the pipeline. An evaluation of the potential magnitude of spills and the consequences of a spill to these resources is presented in the Risk Assessment. The PHMSA spill information and the methods used by Keystone to predict the magnitude of potential crude oil spills from the Keystone XL Project presented in the Risk Assessment are reviewed in detail as part of Battelle's third-party review, and are not discussed in Exponent's evaluation.

The Keystone transport and fate evaluation in the Risk Assessment related to spilled oil is primarily a qualitative description of the physical and chemical processes that act upon oil in the environment and influence the distance that the oil may travel. The extent of transport of a particular spill depends on the leak rate and duration, properties of the oil released (presented in Section 3), as well as specific site conditions. The Risk Assessment provides limited quantitative evaluation to estimate the potential extent of a spill. Our review of transport and fate takes into account the characteristics of the oil as described in Section 3 of the Risk Assessment. Our assessment relies on information provided in the Risk Assessment and FEIS, on empirical and literature data (e.g., viscosity of the oil and distance that oil spills have been known to travel in surface water), and on screening calculations made to quantitatively check statements in the Risk Assessment and to help support other aspects of our evaluation.

Our evaluation of sensitive groundwater and surface waters depends in part on how the spilled oil will behave in these environments. Therefore, we were interested in considering how quickly large and small spills might reach aquifers and the behavior of dissolved constituents in these aquifers. Our screening calculations are not an exhaustive transport and fate analysis. The detailed analyses that are required by Special Condition 14 and PHMSA regulations, as part of the Integrity Management Program, will be conducted after the final route is selected as part of the final design of the project. As noted, our evaluation in this regard is essentially a check on the work that has been conducted for the Risk Assessment, but also supports our examination of locations of shallow groundwater receptors that may be impacted by a spill. The rate of migration of an oil spill to and in groundwater is an important consideration because the relative speed of these processes is an important consideration for ERP development and bears directly on response time planning and the ability to contain and clean up spills that might occur.

Similarly, the distance that a spill to surface waters could travel is important for identification of HCAs and for spill response planning.

The following sections provide quantitative estimates of the potential transport of oil to groundwater for two scenarios: a large volume spill or rupture, and a small leak. A discussion of the potential transport of oil overland is also provided. The analyses are based on a general range of conservative conditions and are intended to provide a sense of scale of potential oil impact. Thus, findings are expected to be a conservative characterization of what could happen along the pipeline. For each of the quantitative evaluations described above, we considered the ramifications of the findings of our evaluation in light of the effects they would have on the final Project design and ERP. The following are Exponent's key findings/conclusions, followed by our recommendations. The remainder of this section provides the documentation to support these findings/conclusions and recommendations.

4.1.1 Key Findings/Conclusions

- The flow of oil overland is affected by many variables including spill rate, topography, soil type, and vegetation. To provide a sense of scale, a highly simplified case of a sudden spill of 25,000 bbl to a flat surface is presented. If the spill flows in a radial pattern, is 1 ft deep, and there is no spill response, it would spread with a radius of about 200 ft. A pool with a depth of 0.1 ft would spread to a radius of about 700 ft. If a surface spill was influenced by topography and flowed in a channelized manner, the distance traveled could be on the order of thousands of feet, depending on the steepness of the terrain, presence of vegetation, etc. Keystone conservatively assumed in the Risk Assessment that a large spill would be capable of moving overland up to 1 mile. Therefore, considering our analyses, the 1 mile distance criterion used in the Risk Assessment is considered adequate. Where HCAs are located within 1 mile of the pipeline, Keystone is required to perform a site-specific evaluation of overland flow (spreading analysis).

- Exponent applied a numerical screening model, the hydrocarbon spill screening model or HSSM, to estimate the behavior of a large spill of dilbit from the pipeline in an area with a high permeability shallow aquifer. The HSSM modeling simulation showed that groundwater impacts from a large spill would likely occur first from infiltration from the trench near the rupture and not from oil spread across the ground surface. Oil in the potentially filled trench near the rupture could begin forming a non-aqueous phase liquid (NAPL) lens at the water table in less than 1 day if the water table is 1 ft below the trench (8 ft below ground surface), in 7 days if the water table is 3 ft below the trench (10 ft below ground surface), and in 50 days if the water table is 10 ft below the trench (17 ft below ground surface). In contrast, oil infiltrating from the ground surface would reach a water table 8 ft below ground surface after approximately 240 days.

- Results from HSSM simulations of a large spill (25,000 bbl) illustrate that plume lengths for dissolved hydrocarbons (i.e., benzene at or above the

MCL) under typical groundwater gradients could be between 100 and 900 ft in length. This range is consistent with those reported in the literature; most reported plumes are less than 200-300 ft and a very small number of plumes exceed 1,000 ft. HSSM simulations were also performed to explore an elevated groundwater gradient, representing the potential influence of groundwater extraction (irrigation wells) near the pipeline. When coupled with a simulated low degradation rate (representing an upper bound condition), the higher groundwater gradient could extend the plume length to as much as 2,600 ft.

- Modeling results agree with the conclusions in the Risk Assessment that a small leak going undetected indefinitely is unlikely. More likely, oil from a small "pin hole" leak (28 bbl/day) would reach the ground surface on a time scale of a few months. Based on the screening level modeling, a benzene plume that may form because of a small leak was estimated to travel downgradient by as much as 600 ft.

- Many private wells located near the pipeline do not meet the criteria to be classified as HCAs in the Risk Assessment. Exponent considered potential factors that could be used to identify non-HCA groundwater areas for shallow groundwater (< 50 ft) where more extensive spill prevention measures and monitoring may be warranted. Based on our analysis of possible plume dimensions, we selected a downgradient distance of 1,000 ft from the proposed centerline of the pipeline as a reasonable boundary of a plume for identifying shallow groundwater and associated wells that could be within the influence of an oil spill. This distance recognizes that large spills would be readily detected and remediated and that small leaks that could take longer to be detected would have smaller plumes. Based on an independent review of the NEDNR well database in Nebraska, Exponent identified approximately 260 wells (not screened by depth) within 1,000 ft of the proposed centerline of the pipeline. Most of these wells are used for irrigation purposes but domestic wells are also present, several of which draw from shallow groundwater. This list will need to be revised once the final pipeline is determined.

- The relative vulnerability/sensitivity of groundwater resources to a dissolved hydrocarbon plume from an oil spill can be assessed by considering combinations of several factors: 1) proximity to the pipeline (<1,000 ft); 2) depth from point of the oil release to the water table (e.g., release of oil at or below the water table will affect groundwater quality more quickly than releases many feet above the water table); 3) depths of receptor wells (wells that are 10s of feet deep are more vulnerable than wells that are 100s of feet deep); and 4) the pumping of receptor wells (wells with higher pumping rates are more likely to draw plumes further downgradient than wells with lower pumping rates). The following combination of factors could be used to identify groundwater resources that do not meet the listing criteria for HCAs but may be more vulnerable to a dissolved benzene plume emanating from an

oil spill. An example of this would be a cluster of irrigation wells and domestic wells located within 1,000 ft of a pipeline segment where a release of oil occurred in or within a few feet of the water table.

- The assessment in the FEIS conservatively assumes that in the event of a worst-case spill in which all of the benzene partitions from the oil into water in streams with a range of flow rates. The assessment is useful for comparison of worst-case benzene concentrations to human health and ecological concentration benchmarks and is discussed further in Section 5 of our review. However, the FEIS does not provide an evaluation of possible transport distances of oil via surface water. This appears to be a gap that needs to be addressed.

- The primarily qualitative assessment of the transport and fate of oil in the event of a spill presented in the Risk Assessment is consistent with our analysis and review of the literature. Ultimately, quantitative analysis of transport and fate in surface waters is required by Special Condition 14 and PHMSA regulations as part of the Integrity Management Program during the final design of the project after the final route is selected. These evaluations should take into account the lessons learned from the pipeline rupture in Enbridge, Michigan in 2010.

4.1.2 Recommendations

- Keystone, as part of the final Project design, should perform further evaluation of overland flow (spreading analysis) of spilled oil, and further evaluation of the transport of spilled oil in small streams (e.g., the downstream distance crude oil could travel from the proposed centerline of the pipeline) for purposes of ERP. These analyses should take into account potential density and viscosity increases associated with the loss of volatiles from heavy crudes and diluted bitumen.

- Keystone should use the screening criteria (e.g., well depth, depth of release compared to water table, lithology between pipeline and aquifer) suggested in our report for identifying vulnerable/sensitive groundwater resources adjacent to the pipeline that do not classify as HCAs but that may be more vulnerable to exposure to a benzene plume in the event of a an oil spill. For example, these could be defined as clusters of both domestic and irrigation wells within 1,000 ft of a pipeline segment where an oil spill could occur in or within a few feet of the water table. Exponent recommends that additional modeling be performed as part of the final design of the Project to further refine the appropriate downgradient distance criteria to be used for identifying sensitive clusters of wells. Exponent recommends that these non-HCA groundwater resources should be afforded a degree of protection from the occurrence of an oil spill and from the consequences of a spill similar to what is currently afforded to groundwater resources that are defined HCAs.

- Considering the above-mentioned screening analysis, Exponent recommends that Keystone consider how to improve upon external leak detection through more frequent inspections and education of property owners for wells within these areas of sensitive groundwater resources.

4.2 Transport and Fate on Land (Overland Flow)

An assessment of overland flow provides insight into the vulnerability of sensitive areas with respect to distance from the pipeline. Overland flow of a large spill will depend on many factors, including topography, ground cover, soil type, product characteristics (e.g., dilbit versus more traditional crudes), meteorological conditions, and other factors that affect infiltration, evaporation, and flow of spilled product, as discussed in FEIS Section 3.13.5.1. However, the FEIS does not appear to include a quantitative evaluation of how far spilled oil might move over land.

Keystone updated the analysis of spill frequencies and volumes (TransCanada 2011) that had been presented in the Risk Assessment. The updated analysis evaluates the worst-case volume of a spill at specific points along the pipeline based on topography, valve location, and other factors. This analysis reflects a major pipe leak or rupture, which results in complete draining of oil from a section of the pipeline. The calculation was performed at varying intervals based on where the most accurate elevation data were available. Fifty percent of all spills modeled by Keystone were less than 6,375 bbl and the maximum was approximately 25,000 bbl (TransCanada 2011, p. A-12, Figure A-2).

For the purposes of conducting a simple screening calculation to evaluate how far oil might travel, upper bound values (i.e., maximum values for travel distance) can be calculated using simplifying assumptions. For example, using a spill size of 25,000 bbl, if uniform radial flow from a spill source is assumed on a flat landscape, the product could spread hundreds of feet, depending on the pool depth assumption. Only accounting for the geometry of the pool, a 25,000 bbl pool of 1 ft depth would spread with a radius of about 200 ft; a pool with a depth of 0.1 ft would spread to a radius of about 700 ft.

If a surface spill occurs in a situation where topography causes the product to flow in a channelized manner, the distance traveled could be on the order of thousands of feet, depending on the steepness of the terrain, presence of vegetation, etc. This projected distance is less than that used for the Risk Assessment, which conservatively assumed a large spill would be capable of moving overland for 1 mile. Using this distance, Keystone evaluated whether a spill that travels 1 mile would intersect with the buffer zone surrounding HCAs. HCAs included sensitive drinking water resources that were identified during the EIS process. Any pipeline segment that could contact an HCA buffer was considered a "could affect" segment. Future detailed analysis of overland flow that accounts for such factors as topography, transport channels, and the presence of water is required by Special Condition 14 and PHMSA regulations as part of the Integrity Management Program during the final design of the Project. So, the initial 1-mile criteria will be expanded as appropriate during the final design phase of the Project.

4.3 Transport and Fate in Groundwater

In support of Exponent's review of the Risk Assessment, and to address specific issues from DOS, the following sections discuss transport and fate processes in groundwater; evaluate large spill and small spill scenarios and their potential impacts on groundwater; and provide an evaluation of sensitive groundwater areas near the pipeline.

4.3.1 Transport and Fate Processes in Groundwater

The FEIS (Section 3.13) points to the Bemidji, Minnesota, crude oil spill site as a basis for predicting the potential impacts to groundwater of an oil release. Exponent agrees with this approach because of the consistency in dissolved hydrocarbon behavior at Bemidji and other petroleum impacted sites (Newell and Conner 1998; U.S. EPA 2002; Essaid et al. 2011). These studies indicate microorganisms that can consume hydrocarbons are ubiquitous in shallow groundwater. Biodegradation of dissolved petroleum constituents result in a reduction of mass and limits plume lengths. This process, called natural attenuation, is recognized as a valid remedial technology by EPA and other regulatory agencies (ITRC 1998; U.S. EPA 2002, 2004).

Exponent agrees with the FEIS finding that even if oil reaches groundwater, dissolved hydrocarbon plume lengths are unlikely to be more than a few hundred feet. The FEIS cites an American Petroleum Institute report (Newell and Conner 1998) that presented the results of four studies (a total of 600 plumes evaluated) that found the median dissolved hydrocarbon plume length ranged from about 100 to 200 ft. Seventy percent of the 600 plumes considered in the studies were less than 200 ft and 90 percent were less than 320 ft. Our review of more recent studies (Ruiz-Aguilar et al 2003; Shih et al. 2004; Kamath et al., 2012) confirms the finding that most benzene plumes are less than 200 ft and very few plumes exceed 1,000 ft. Dissolved BTEX plumes were observed at the Bemidji site approximately 20 years after the spill and extended from 300 ft to 600 ft downgradient (in the direction of groundwater flow) (Essaid et al. 2011), which further supports the length scales for potential dissolved groundwater plumes discussed in the FEIS.

Most of the hydrocarbon plumes studied were in shallow groundwater and at sites not under the influence of large volume groundwater extraction (irrigation) systems. Large volume groundwater production wells have the potential to locally increase hydraulic gradients resulting in more rapid transport of groundwater contaminants. Site-specific modeling is required to determine whether such systems may influence local plume lengths.

In the following sections, we apply screening models to evaluate the potential range of downgradient migration distances for dissolved hydrocarbons. These analyses are intended as a crosscheck against the empirical data found in the literature, based on potential spill and migration scenarios in the pipeline context.

4.3.2 Large Spill

We used a screening model to examine the behavior of a large spill from the pipeline. The purpose of the analysis was to gain insight into the rate of transport and spreading and the

distances and areas that may be impacted. This information is used elsewhere in this report to assist in evaluating the vulnerability of potentially sensitive groundwater areas. A key consideration in this regard is the ability to respond to and control a spill before it spreads to sensitive areas or before it results in a dissolved hydrocarbon plume that may affect such areas. Our assessment has been incorporated into recommendations concerning mitigation that are provided in the Fate and Transport from an Engineering Perspective section of the Battelle report.

4.3.2.1 Infiltration and Potential Groundwater Contamination

The potential scale of infiltration of oil and dissolved constituents and subsequent contamination of groundwater from a large, rapid release, such as the pipeline spill in Bemidji, Minnesota, in 1979 was evaluated using the Hydrocarbon Spill Screening Model (HSSM) developed for EPA (Weaver et al. 1994). HSSM is a screening model that includes a variety of chemical and hydrologic processes and is based on a simple conceptualization of a LNAPL release. The model simulates vertical LNAPL flow and transport from the ground surface to the water table due to gravity and capillary forces. The LNAPL is then simulated to float and spread radially in the capillary fringe forming a LNAPL lens. Additionally, HSSM simulates dissolution of chemical constituents of the LNAPL into the aquifer and migration in the direction of groundwater flow creating contaminant plumes. Simulations with HSSM are an illustrative and simplified screening-level calculation and should not be relied upon for final risk determinations, emergency, and/or environmental planning/response actions.

HSSM was used to estimate the potential for groundwater contamination from oil spilled on highly permeable soil (i.e., sand) and the downgradient groundwater transport of dissolved contaminants (i.e., benzene) from the spill in an area with a highly permeable, shallow aquifer. These conditions represent a potential worst-case scenario that may occur along the pipeline. The objective for these simulations is to evaluate if the Risk Assessment made realistic statements about the potential impacts of a large spill to shallow groundwater.

A simple conceptual model of a large spill is used for HSSM simulations. A large release is defined as 25,000 bbl (1,050,000 gallons) which is consistent with the large spill volume considered for the over-land flow calculations (see Section 4.2). The spilled oil is assumed to be released rapidly and quickly move from the pipe up to the ground surface and spread over an area of 4.5 acres[7] (in circular area with a radius of 250 ft)[8]. Surface spreading of the oil reduces the rate of oil infiltration as the thickness of the oil on the surface (and therefore the pressure driving flow) decreases. High-pressure oil is assumed to move to the ground surface because of the low vertical pressure applied by the overlying trench backfill relative to the anticipated pipeline operating pressure (the FEIS specified the maximum pipeline operating pressure to be

[7] 4.5 acres was the approximate aerial extent of the Bemidji, MN spill and was assumed as the surface area for large spill modeling. This assumption is conservative in that the modeled large release is more than double the volume of the Bemidji, MN spill (25,000 bbl versus 10,700 bbl) (Essaid et al. (2011)) but is being applied over the same area.

[8] This was an assumed area for calculations using HSSM. The spill footprint would likely vary depending on local topographic conditions. Smaller footprints would tend to lead to higher infiltration as oil would pond deeper and have more head to induce flow. Larger areas would have an opposite effect.

1,600 psig). Oil released at high pressure is anticipated to move in the direction of the lowest principle stress (i.e., upward) and away from lateral and underlying soil confinement. Based on an assumed area of 4.5 acres, and a volume of 25,000 bbl, oil is simulated to initially pond at a depth of 0.75 ft (i.e., all oil is assumed to move to the ground surface). The spill is assumed to occur instantaneously over the 4.5-acre area, and exist at a constant depth of 0.75 ft for one hour[9] followed by a gradual decrease to zero surface depth as the ponded oil infiltrates. This model simulates the vertical infiltration of oil spread on a uniform ground surface.

In addition to oil infiltrating from the ground surface, if a large rapid release occurred from the buried pipeline, localized filling of the trench with oil might result. This zone of filled trench will have a greater depth of oil to drive infiltration than oil spread on the ground surface, and will originate from an elevation closer to the water table than the ground surface. Based on this conceptual model of infiltration from a large spill, a second scenario was developed for HSSM simulations in which oil was simulated to infiltrate from the bottom of the filled trench. The trench was assumed to be 7-ft deep[10], and was modeled to be filled with 7 ft of oil[11] atop the trench bottom for one hour (during the release) followed by a gradual decrease to zero ponded depth as the oil infiltrated. Although the maximum operating pressure in the pipeline is specified in the FEIS to be 1,600 psig, oil released at high pressure is assumed to rapidly lose pressure as oil spreads outward into the trench backfill and to the ground surface. Thus, our trench simulation assumes that only gravity and capillary forces drove flow.

For both scenarios, i.e., infiltration from ground surface over a large area and infiltration from the filled trench, the water table was assumed to be at least 0.3 ft below the base of the trench[12] to evaluate behavior where groundwater is shallow but spills do not occur directly in groundwater.

Hydrologic parameters were defined for permeable sand, a worst case soil condition in terms of maximized transport, based on data in U.S. EPA (1985a,b), and Carsel and Parrish (1988). Soil porosity and vertical hydraulic conductivity (to water)[13] were assumed to be 0.35 and 23ft/day, respectively. Horizontal hydraulic conductivity was assumed to be 10 times the vertical hydraulic conductivity or 230 ft/day. Of note, less permeable soil conditions, i.e., less conservative soil conditions, are present for the majority of the proposed pipeline route (FEIS, Section 3.2). These materials are likely to be orders-of-magnitude less permeable and would likely result in longer times for infiltrating oil to reach groundwater and shorter plume lengths than those described in our simplified and conservative simulations.

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[9] One-hour release duration was used to be consistent with Section 4.2.3.4 of the RA.

[10] PHMSA Special Condition 19 requires the pipeline soil cover be at minimum forty-eight inches plus the thirty-six inch pipeline diameter.

[11] The soil in the trench immediately adjacent to the rupture was neglected due to the unknown effects of a large and rapid release on the porosity of this soil.

[12] Since HSSM cannot simulate a spill below the water table, the spill is assumed at least 0.3 ft below the trench; 0.3 ft is the minimum soil thickness that can be accurately simulated by HSSM.

[13] Hydraulic conductivity is a fluid specific parameter. HSSM corrects the water hydraulic conductivity for oil hydraulic conductivity.

The viscosity of the oil was assumed to be 350 cSt (325 cP at a specific gravity of 0.93) consistent with viscosity reported for diluted bitumen (Kothari 2010). The viscosity assumed for diluted bitumen is considered to be a conservative assumption, once volatile components of the oil evaporate, because viscosity has been shown to rapidly increase, which will slow transport (Belore 2010). Increases in the viscosity of diluted bitumen after release from the pipeline will be greater than for synthetic crude (Kothari 2010), but to be conservative, this is not taken into account in this analysis[14].

Modeling attenuation requires inclusion of a first order decay rate (λ). Based on a review of published results, EPA suggests a rate λ between 0.001 and 0.01 per day (U.S. EPA 2002) for benzene and other petroleum hydrocarbons. All other model parameters were within typical value ranges proposed by Weaver et al. (1994) for use in HSSM.

Figure 2 shows the time for LNAPL to reach the water table and begin forming a groundwater plume as a function of the depth from the ground surface to the water table. Figure 2 does not show depths to water table less than seven feet, i.e. the pipeline at or below the water table, because groundwater plume formation would be immediate. LNAPL simulated to infiltrate from the bottom of the initially filled trench reaches groundwater and begins forming a plume far before LNAPL infiltrating from the surface due to both the reduced depth to the water table and the greater pressure of the deeper ponded oil filling the trench (initially 7 ft versus 0.75 ft). For the assumed conditions, these results illustrate that oil from the filled trench could reach a water table 1 ft below the trench (8 ft below ground surface) within 1 day of release, or a water table 3 ft below the trench (10 ft below ground surface) within 7 days of release. However, a water table 10 ft below the trench (17 ft below ground surface) would take approximately 50 days. In contrast, oil infiltrating from the ground surface would reach a water table 8 ft below ground surface only after approximately 240 days. Because a large spill would likely be detected and appropriate responses taken, infiltration from the simulated trench is likely to govern potential plume generation.

The period between the spill event and the development of a groundwater plume is an important consideration for judging the efficacy of spill control. For the situation described here for infiltration from the filled trench, rapid clean-up would be required to minimize groundwater impacts.

[14] Note that the pipeline may carry synthetic crude, which would have a lower viscosity. The significance of this is discussed further below.

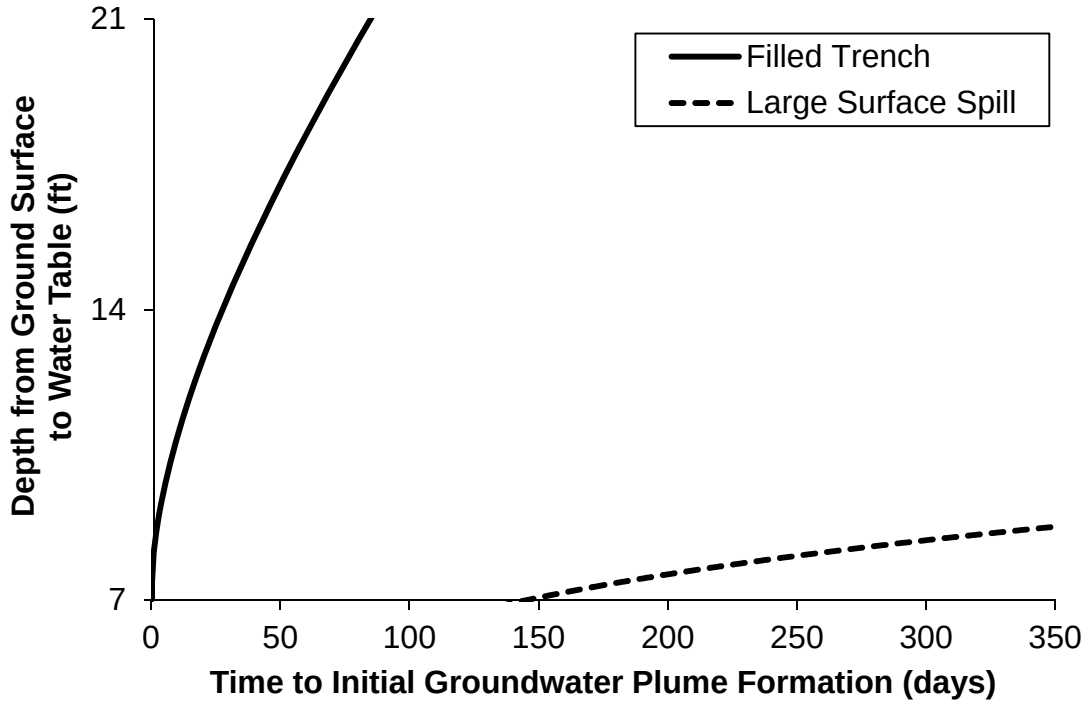

Figure 2. Time for spilled oil to reach the water table and initiate formation of a groundwater plume versus the depth from the ground surface to the water table.

HSSM was used to simulate dissolved benzene transport from the NAPL plume[15] associated with infiltration from the filled trench simulation described previously. Plume simulations were conducted for water table depths of 0.3, 1, and 10 ft below the trench bottom (i.e., 7.3, 8, and 17 ft below the ground surface). These depths were chosen to provide a sense of scale associated with different potential water table depths. For these simulations, the groundwater hydraulic gradient was assumed to range from 0.001 to 0.01. This range represents a reasonably low natural gradient (0.001)[16] to an increased gradient (0.01). Gradients occurring due to groundwater extraction depend on the local aquifer characteristics, the distance from the extraction well, and pumping rates. Since HSSM does not directly simulate pumping wells, a gradient of 0.01 was used to approximate an elevated gradient possibly associated with groundwater extraction. However, hydraulic gradients induced by pumping wells could be higher under certain local conditions. A range of half-lives ($t_{1/2}$) from 639 to 63.9 days[17] was used to account for the degradation of benzene. The hydraulic gradient and benzene concentrations were varied due to the high variability associated with these parameters.

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[15] Partitioning and transport parameters for benzene were determined from Weaver et al. (1994) and McMillen et al. (2001). Partitioning coefficients for benzene for crude oil were assumed.

[16] Based on the FEIS (Section 3.3; p. 3.3-9); a groundwater velocity of 1 ft/day is reported with a hydraulic conductivity of 60 ft/day for the High Plains Aquifer. Considering that natural porosities generally range between 0.3 and 0.4, the corresponding groundwater gradient is between 0.005 and 0.007, which is within the range simulated. Gradients are probably locally variable, thus assumed values provide a reasonable range for evaluation.

[17] Half-lives for benzene were calculated based on first order decay rates of $\lambda = 0.001$/day to $\lambda = 0.01$/day using the equation $t_{1/2} = Ln(2)/\lambda$.

The HSSM simulation conservatively assumes that no action is taken to remove the oil from the trench after the spill, although such actions are anticipated in the FEIS (Section 4). Oil recovery would reduce the impacts of infiltrating oil. A large, rapid spill would likely be more of a concern to surface water and sensitive areas, which could be impacted more quickly by overland flow or direct release to a water body and this is discussed subsequently. The HSSM simulations indicate that dissolved plumes (defined as groundwater benzene concentrations exceeding the MCL of 5 ppb) may develop from a large spill. LNAPL was assumed to vertically infiltrate over a 6-ft diameter circle, equal to half the average width of typical trench described in Section 2.3.2.3 of the FEIS. Table 5 summarizes the simulated plume lengths resulting from each water table depth, hydraulic gradient, and benzene half-life considered.

Table 5. Benzene plume lengths estimated by HSSM for a large (25,000 bbl) rapid release of diluted bitumen for different depths from trench bottom to water table, hydraulic gradients, and half-lives ($t_{1/2}$).

Depth from Trench to Water Table	Hydraulic Gradient	Plume Length	
		$t_{1/2}$ = 69.3 days	$t_{1/2}$ = 693 days
0.3 ft[a]	0.001	100 ft	200 ft
0.3 ft[a]	0.01	300 ft	500 ft
1.0 ft	0.001	200 ft	400 ft
1.0 ft	0.01	700 ft	2,300 ft
10 ft	0.001	300 ft	900 ft
10 ft	0.01	700 ft	2,600 ft

[a] Minimum depth that can be modeled accurately with HSSM.

The HSSM simulation results indicate that plume lengths resulting from a large release may be between 100 and 2,600 ft in length. For the more conservative longer half-life simulations, plume lengths were increasingly sensitive to the applied hydraulic gradient.

For the large-spill scenarios considered, the plume lengths estimated using HSSM are generally consistent with the literature compilations of field studies described previously in this section and in the FEIS[18]. Our review of literature on observed dissolved plumes related to hydrocarbon releases (see Section 4.3.1) indicates that a very small number of plumes exceed 1,000 ft with most plumes less than 200–300 ft. Thus, the plume lengths associated with groundwater gradients typical of the natural conditions (e.g., 0.001) reported in Table 5 are consistent with what has been observed in the field. Plume lengths of up to 2,600 ft in Table 5 are associated with the higher groundwater gradient of 0.01 which is intended to represent the potential influence of groundwater extraction near the pipeline (conditions not necessarily accounted for in the case studies discussed in Section 4.3.1). Although pumping wells increase hydraulic gradients, this increase is typically limited to a finite zone surrounding the well, the extent of which is dependent on pumping rate and aquifer characteristics. Analyses that include these site-specific conditions are required by Special Condition 14 and PHMSA regulations as

[18] Assumes no action is taken for 1–2 years which allows NAPL to reach water table and for a plume to develop.

part of the Integrity Management Program during the final design of the project. These analyses should include the potential for longer plume lengths, i.e., > 1,000 ft, in fractured or karst terrains discussed in Section 3.1 (Geology) of the FEIS.

The HSSM simulations do not account for a release below the water table. This type of release could occur in locations where the pipe may be seasonally or permanently submerged below the water table. In the event of a leak below the water table, because of buoyancy the oil would tend to float to the water table surface and form a NAPL lens. This type of release would also result in immediate contact between the NAPL and groundwater resulting in immediate development of a dissolved NAPL plume. Because other factors controlling the size of the plume (e.g., degradation and groundwater gradient) would be similar, plume sizes would be expected to be similar.

4.3.3 Small Leak

Large leaks, as evaluated above, are easier to detect because they will likely trigger alarms from components of the leak detection system described in the Risk Assessment. However, very small leaks could potentially go undetected for longer periods of time. The Risk Assessment provides a description of four pipeline leak detection methods that are based on measured flow rates, pressures, and other measured and calculated values. Each of the four methods has different minimum leak sizes (flows) that can be detected, down to 1.5–2.0 percent of the pipeline flow rate[19]. One method is capable of identifying low rate releases below the 1.5–2.0 percent; however, how much below 1.5–2 percent is not stated in the Risk Assessment.

Because small leaks may go undetected for longer periods of time, there is a potential for transport of oil spilled from the pipeline (i.e., diluted bitumen or synthetic crude oil) and the development of a dissolved constituent (i.e., benzene) plume that could ultimately result in impacts to groundwater resources downgradient from the pipeline. The potential extent of downgradient impacts in not quantitatively evaluated in the FEIS and discussed here.

Under shallow groundwater conditions, leaking oil will infiltrate downward through the vadose zone (soil not saturated with water between the ground surface and the water table) until the water table is intersected. Once the oil reaches the water table, vertical migration of the oil slows and oil begins to accumulate in the vadose zone above the water table. For a buried pipe in relatively flat terrain, this could result in filling of the pipe trench and ultimately surface expression of the oil. Lateral (sideways) migration of the oil along the length of the pipeline could occur within the trench, which could extend the time until surface expression of the leaking oil occurs. For buried pipe in sloping terrain, lateral migration of oil could be greater, but also may result in surface expression sooner, when a barrier to oil flow (e.g., trench blocker) is encountered.

[19] 1.5–2% of daily flow rate = 13,500–18,000 bbl (assuming a pipeline flow of 900,000 bbl/day).

As part of the screening analysis, HSSM was used to estimate the following:

- Rates of slow oil leaks that may go undetected below the surface for extended periods of time for a flat terrain condition (assuming detection is only possible through direct inspection or survey of the pipeline because the leak rate is below the limit of other leak detection methods)
- Possible volume of a crude oil spill resulting from a slow and undetected leak
- Possible downgradient extent of dissolved contaminant plume in groundwater (defined as groundwater benzene concentrations exceeding the MCL of 5 ppb).

As in the case of the large spill simulations discussed previously, the small leak calculations are intended to provide insights into the potential transport and fate of oil spilled from the pipeline. This information is used to provide insights into which sensitive groundwater resources may be vulnerable if a spill of oil would occur, which in turn will help provide a check of the distances used in the Risk Assessment to evaluate whether a groundwater resource should be considered vulnerable during preliminary project design. For the slow-leak HSSM simulations, the leak rate is assumed to be below the detection limits for any of the pipeline remote leak detection systems. Thus, leak detection is assumed to be limited to visual or aerial inspection which would be conducted at least every 3 weeks (FEIS; Appendix U)[20].

Estimation of Undetected Rate of Leakage. HSSM was used to estimate the maximum steady-state leak rate (i.e., where infiltration is equal to leak rate out of the pipeline) per area of trench floor. A constant head of 7 ft was assumed based on the distance between the bottom of the trench and ground surface as discussed in Section 2.3.2.3 of the FEIS, see conceptual model shown in Figure 3). A head of 7 ft is a conservative assumption in that this head would only be attained as the oil reached ground surface. Leak rates higher than the maximum steady-state infiltration rate would eventually fill the pore-space in the trench backfill at a rate equal to the difference between the infiltration rate and the leak rate. This method results in an estimate of the approximate time for the surfacing of leaking oil for an assumed area of trench floor. Lateral spreading is not included in this simplified evaluation.

The results from HSSM simulations show that the maximum leakage rate of diluted bitumen that can be vertically infiltrated through permeable sand is approximately 0.005 bbl/d/ft^2 (0.2 gallons/day/ft^2) meaning that for every 1 ft^2 of trench floor, 0.005 bbl/day may infiltrate through that single square foot in 1 day. The area of the spill footprint on the bottom of the trench (i.e., infiltration site) affects the total rate of infiltration. For instance, a circular footprint of trench floor with a diameter of 3 ft (shown in the conceptual model shown in Figure 3) has an area of 7 ft^2, which would correspond to a total infiltration rate of 0.035 bbl/day (0.035bbl/day = 0.005 bbl/d/ft^2 × 7 ft^2). Thus, a leakage rate over the 3-ft diameter circle of 0.035 bbl/day could

[20] This is the statutory requirement for inspection intervals per the FEIS Appendix U. However, if the leak is located near residents or stakeholders who have been educated on identifying leakage signs, a more rapid identification of a leak is possible than considered for this analysis. This analysis assumes no such alternative detection.

theoretically infiltrate indefinitely without surfacing because the infiltration rate is equal to the leak rate.

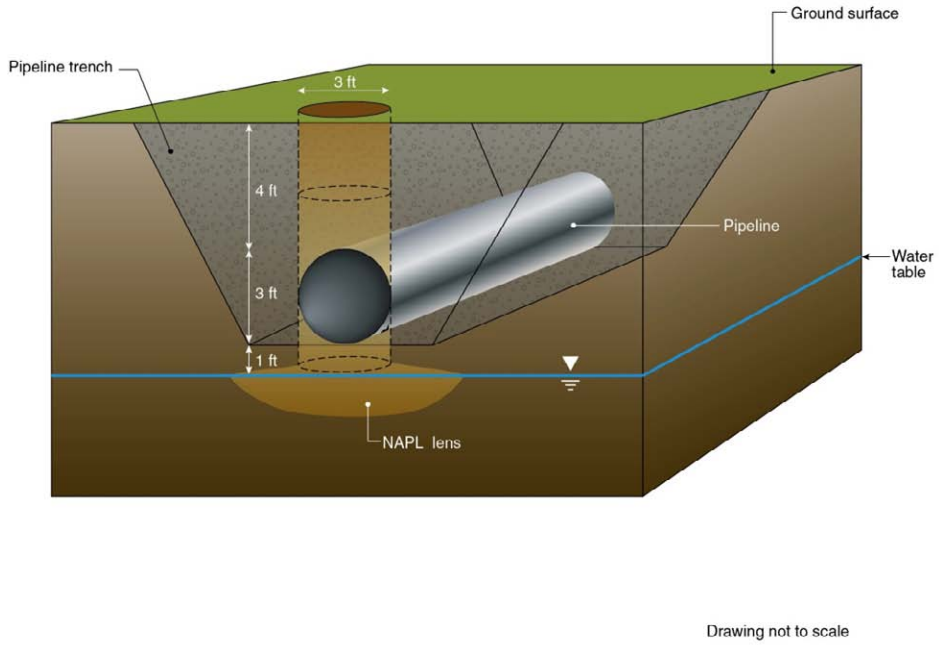

Figure 3. Conceptual model of slow leak. HSSM simulates LNAPL infiltration from trench bottom to water table and subsiquent formation of the NAPL lens.

To provide a sense of scale for a small leak that could go undetected, further analyses were conducted assuming infiltration occurs over a 3-ft diameter circle of trench floor; 3 ft was selected to coincide with the diameter of the pipe. However, the geometry and area of the spill footprint could be highly variable. If lateral movement of the oil through the trench backfill occurred, the area of the infiltration zone would increase, which would increase the volume of oil that could be infiltrated. These factors could result in higher leak volumes that may not express at the surface and therefore not be detected by inspection. Conversely, the vertical case considered for this analysis, rather than the lateral flow scenario, is also conservative in that the infiltration rate would be greater for a given area due to the larger head, which shortens the time to contamination of groundwater.

Figure 4 shows potential leak rates and the associated estimated time to detection. The time to detection was calculated by determining the flow exceeding the 0.035 bbl/day that can be infiltrated through the 3-ft diameter circular area shown in Figure 3. Flow in excess of this rate was assumed to fill pore spaces within a cylindrical volume of the backfill trench directly above the infiltration zone (shown in Figure 3). The total volume spilled was calculated as the product of the leak rate and the time to detection and is shown in Figure 4 as a function of time to detection.

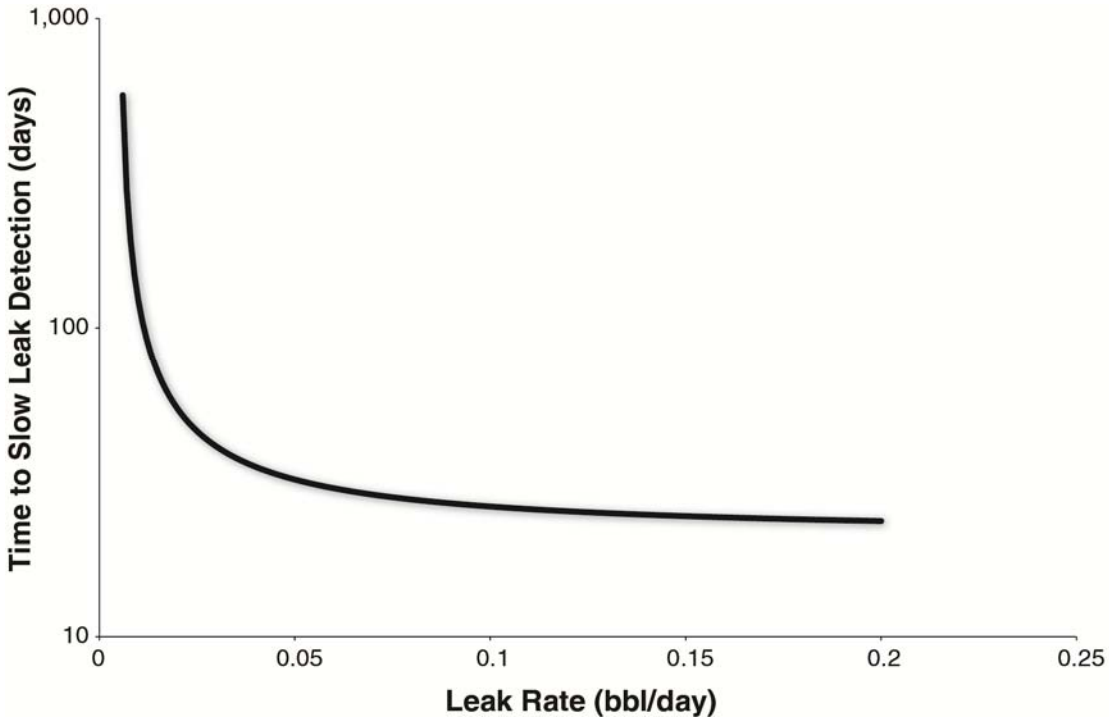

Figure 4. Time to slow leak detection as a function of leak rate for various slow leak rates based on a 3-ft diameter circular infiltration footprint and previously stated assumptions.

As an example, Figure 4 indicates that a leak rate of 0.05 bbl/day of diluted bitumen could be detected (by surfacing oil) within approximately 32 days (providing the underlying assumptions discussed above are met). This corresponds to a release of 1.6 bbl (67 gallons) of oil.

According to the report prepared by Battelle (2011), a leak rate of 28 bbl/day is expected from a "pin-hole" leak defined as a leak through a 1/32-in. diameter hole. The duration or time to surfacing would be dependent on the area over which oil infiltration occurs. If the oil spreads to a larger footprint, surfacing and potential detection will take longer than if the oil spreads to a smaller footprint. The size of the spill footprint will depend on several site-specific factors including but not limited to the permeability of trench backfill, and the permeability of soil surrounding the pipe trench. However, it is likely that a spill of 28 bbl/day would result in oil surfacing and being detected on the time scale of a few months. The "pin-hole" leak rate, 28 bbl/day, is almost three orders-of-magnitude greater than the maximum infiltration rate into permeable sand over the assumed area described previously under the small leak scenario. Therefore, a small leak that goes undetected indefinitely along the pipeline is unlikely.

Evaluation of Dissolved Plume Migration. The potential for development of a dissolved benzene plume was also considered for the constant 7-ft head condition used to estimate the steady-state infiltration rate under the small leak scenario. This results in a constant leak rate of 0.035 bbl/day over a 3-ft diameter circular infiltration area. This represents a hypothetical condition where the oil is near the ground surface but is not detected at the surface for a long period of time. The same transport and degradation conditions were used for these simulations

as used in the large-spill evaluation above. A plume was assumed to reach a downgradient location when simulated benzene concentrations reached 5 ppb. A leak duration of 2,000 days (5.5 years) was assumed, although this duration is likely longer than would be expected prior to detection[21]. The objective was to determine whether natural attenuation (i.e., degradation) mechanisms would limit plume size in the event of a release occurring over an extended time period.

Table 6 summarizes the simulated plume extent for dissolved benzene[22]. The plume sizes range from between 200 ft and 600 ft depending on transport and degradation conditions. These plume lengths are consistent with those in the literature discussed previously in this section and in the FEIS. Our assessment of consequence presumes that a small leak occurs at a location that is upgradient of an extraction well; such that is could be affect by the spill. However, if a small leak does occur, the likelihood that the leak would occur upgradient of a well or group of wells is low.

Table 6. Length of plume developing downgradient from pipeline and the time for this plume length to develop. Downgradient plume extent, time required to reach plume extent

	$t_{1/2}$ = 693 days		$t_{1/2}$ = 69.3 days	
Gradient	0.001	0.01	0.001	0.01
Plume length (ft)	200	600	100	200
Time to plume length (days)	411	324	218	100

In areas where groundwater is deeper, there is less likelihood of oil accumulating above the water table and therefore a small oil leak (less than the infiltration rate of the soil) may never appear at the surface unless the infiltration rate of the soil is exceeded by the leak rate. Although the oil may never surface, when groundwater is deeper, the oil may also not reach the aquifer for extended periods of time, or, more likely, much of it would be degraded before it reaches the aquifer. Leaks of this nature were not simulated directly, but would be assumed to be slow enough as to not exceed the maximum infiltration rate of the soil and therefore would likely only result in large release volumes if not detected for very long time periods (on the order of years). However, based on the small leak rates stated by Battelle (2011), 28 bbl/day, relative to the calculated maximum infiltration rates, 0.005 bbl/d/ft^2, an indefinitely undetected leak, while theoretically possible, is not likely to occur.

Along some stretches of the pipeline, the water table will be at or above the pipeline. In these instances, because the leaking oil would tend to float on the water table, a leak would likely be detected sooner than in the scenario described above because the thickness of the soil layer, and thus the volume available for oil to fill before surfacing, would be smaller. A leak below groundwater would result in earlier development of a dissolved plume and arrival of the plume

[21] Based on information provided in Battelle's report, the actual duration is more likely to be on the scale of months rather than years.

[22] Plume extent was determined by determining the maximum distance to which benzene exceeded 5 ppb in HSSM during the simulation.

at downgradient locations sooner after the leak occurs. The change in time for transport to receptor wells would be dependent on the area over which a leak occurs.

4.3.4 Evaluation of Sensitive Groundwater Areas

There are many wells that are near the pipeline corridor but are not within a defined HCA. For example, the FEIS in Section 3.3.1.1 identifies 29 private wells within approximately 100 ft of the proposed centerline of the pipeline[23]. In addition, Appendix X of the FEIS enumerates all wells, HCA and non-HCA, in Montana, South Dakota, and Nebraska that are within 1 mile of the pipeline. The FEIS also identifies a number of groundwater protection related HCAs in the Appendix P HCA and CPS maps.

Exponent was tasked to consider whether there may be sensitive groundwater resources that do not classify as HCAs but that might warrant additional protection beyond that being planned. Our approach to considering this involved identifying a distance within which wells might be at risk in the event of a spill, by considering characteristics of wells that would make them more or less vulnerable, and by reviewing aspects of planned spill prevention, control, and countermeasures. Based on our screening model analysis and a review of the literature, presented in Section 4.3.2.1, a distance of 1,000 ft is reasonable for identifying wells that might be within the influence of a plume of dissolved hydrocarbons such as benzene. The wells within 1,000 ft of the pipeline are those that, based on our preliminary analysis of dissolved plume migration, could potentially be affected in the event of a release from the pipeline[24]. To provide an example of how this distance criterion could be applied for wells not included within defined HCAs, Exponent conducted an independent review of the NEDNR well database in Nebraska. According to our screening of the database, approximately 260 wells occur within 1,000 ft of the proposed centerline of the pipeline[25]. For the most part, these wells would not be captured by the HCA analysis performed as part of the Risk Assessment. A table enumerating these wells and select data from the NEDNR database is shown as Appendix C. This table provides characteristics that are useful for considering the vulnerability of a well in the event of an oil spill and the potential human health or environmental implications of a plume reaching a well. This screening methodology may be applied to alternative routes as they are developed during the final design of the pipeline.

In earlier sections, we described how an oil spill would behave. Our analysis of the behavior of the oil itself indicated that the oil would remain in the soil or would reside near the surface of the water table and therefore would be unlikely to be entrained into a well. The spill components that could reach a well are those associated with hydrocarbons that dissolve into the groundwater. Our analysis showed that depth to groundwater is an important factor for plume development. Plumes are more likely to develop when the spilled oil is in close proximity or within the groundwater. For these reasons, wells adjacent to locations where the pipeline is

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[23] Exponent's analysis of the NEDNR website indicates that 17 wells are less than or equal to 100 ft. Considering wells up to 160 ft from the pipeline results in 29 wells.

[24] 1,000 ft was selected based on the review of literature presented in Section 4.3.1 and our analysis results in Sections 4.3.2 and 4.4.3. This is meant to be a conservative distance (further than expected plume travel).

[25] Note that wells may only be located, at best, within ¼-¼ section areas.

within a few feet of the groundwater or within the groundwater would be more vulnerable than wells located elsewhere along the pipeline.

Well depth and pumping rate are other factors that can influence vulnerability to impacts from a dissolved hydrocarbon plume. Generally, shallower wells will be more vulnerable than deeper wells because of their proximity to the dissolved plume. Wells with higher pumping rates will also tend to be more vulnerable than wells with lower pumping rates, because they will have a larger impact on groundwater flow and thus a higher potential of drawing the dissolved plume towards them.

Based on the above, the following factors can be used to classify groundwater and associated wells with respect to vulnerability to a spill and to identify areas where additional protective measures may be warranted for sensitive groundwater resources (i.e., shallow aquifers and the wells constructed within these aquifers) that do not meet the listing criteria for HCAs:

- Proximity to the pipeline (<1,000 ft)
- Depth to groundwater (groundwater resources adjacent to pipeline segments that are within a few feet of groundwater or within groundwater are more vulnerable than groundwater resources that are located deeper)
- Depth of well (wells that are 10s of feet deep are more vulnerable than wells that are 100s of feet deep)
- Pumping of wells (wells with higher pumping rates are more likely to draw plumes than wells with lower pumping rates)
- Clusters of wells (clusters of wells would more likely draw plumes than individual wells).

The characteristics of wells in Appendix C provide some insight into the relative vulnerability to a dissolved hydrocarbon plume. Approximately 260 wells are identified. Appendix C does not include the depth to the upper water table and this information could be used to further differentiate groundwater with respect to vulnerability to the formation of a dissolve hydrocarbon plume resulting from an oil spill. The risk factors we have identified can be used to classify areas as being more or less vulnerable to a dissolved hydrocarbon plume in the event of an oil spill. In our view, the most vulnerable areas are locations with the following combinations of factors: areas that have a cluster of wells within 1,000 ft of a segment of pipeline that is in or within few feet of water table.

4.4 Transport and Fate in Surface Waters

Impacts to flowing surface waters are addressed in the FEIS by estimating the impact of benzene from a dilbit spill and a synthetic crude oil (SCO) spill. The assessment in the FEIS conservatively assumes that in a worst-case spill with a duration of 1 hour all of the benzene partitions from the oil into the water in streams with a range of flow rates. The assessment is useful for comparison of worst-case benzene concentrations to human health and ecological

concentration benchmarks and is discussed further in Section 3 of our review. The FEIS does not provide an evaluation of possible transport distances of oil via surface water. This appears to be a gap that needs to be addressed, considering that the Enbridge spill to the Kalamazoo River involved surface water transport of oil to distances greater than 10 miles from the spill location (U.S. EPA 2010). Surface water transport and fate analyses should take into account potential density increases associated with the loss of volatiles from heavy crudes and diluted bitumen, the effects of which were illustrated at Enbridge (NTSBA 2012). Ultimately, an analysis of transport and fate in surface waters is required by Special Condition 14 and PHMSA regulations as part of the Integrity Management Program as part of the final design of the project after the final route is selected. These evaluations should take into account the lessons learned from the pipeline rupture in Enbridge, Michigan in 2010.

5 Analysis of Risks Related to Small Stream Crossings

5.1 Introduction

While there are PHMSA-related regulatory requirements and mitigation and control measures specified in the Risk Assessment and FEIS for river crossings greater than 100 ft in width, Exponent was asked to evaluate whether there were sensitive environments associated with stream crossings that are less than 100 ft wide that may warrant additional analyses and perhaps mitigation measures. As described in this section, Exponent used a set of ecologically-relevant criteria to identify such areas. This part of the environmental review also included an examination of information in the FEIS related to special status species, in particular, the presence of these species and their habitats relative to small stream crossings.

As part of our small stream crossing evaluation Exponent performed the following tasks:

- Reviewed the adequacy of the risk characterization of PHMSA-defined HCAs (i.e., specifically focused on ESAs) in the Risk Assessment
- Evaluated whether there were other sensitive environmental resources downstream of small stream crossings not already identified by the PHMSA-defined ESAs
- Evaluated the adequacy of relying on benzene as a surrogate chemical to address the magnitude of aquatic toxicity of crude oil spilled into small streams
- Evaluated whether the Risk Assessment process adequately considered the presence of special status species (e.g., threatened and endangered species) when defining sensitive ecological resources.

For each of these tasks, we considered the ramifications of our findings in light of what effects the findings would have on the final Project design and emergency response planning (ERP). The following are Exponent's key findings/conclusions, followed by our recommendations. The remainder of this section provides the documentation to support these findings/conclusions and recommendations.

5.1.1 Key Findings/Conclusions

- The Risk Assessment appropriately followed standard PHMSA guidelines for identifying contributory pipeline segments (CPSs) associated with small stream crossings and the high consequence areas (HCAs) potentially affected.

- Based on transport and fate analyses described in Section 4 of our report, we used a downstream distance of 10 miles as a basis for identifying locations of sensitive areas around small stream crossings. Using a set of ecologically-relevant criteria, Exponent identified at least ten small stream crossings areas that should be considered for additional protection. An additional four small stream crossings were identified as having special water bodies within 10 miles downstream of the proposed centerline of the pipeline that likely have high wildlife habitat value which should also be given further consideration.

- Exponent agrees with the assessment of the potential magnitude of risk of an oil spill on aquatic life in the water column associated with the toxicity of dissolved hydrocarbons (represented by benzene). While the toxicity assessment based on benzene is not rigorous, it appears to be sufficiently conservative for assessing short-term effects to aquatic biota residing in the water column. However, depending upon the characteristics of the water body into which a spill occurs, some portion of the spilled oil could come into contact with shorelines or with the bottom of the water body and be entrained into sediments. The oil and associated chemicals that may be present within sediments could exert longer-term chronic effects on aquatic biota that are not captured by considering benzene alone.

- Exponent determined that the list of special status species identified in the FEIS was a comprehensive and a complete list in the Project area. Exponent also found that the preliminary findings of "May Affect, Not Likely to Adversely Affect (NLAA), No Effect (NE) or Not Applicable (NA)" for 29 of the 30 species and "May Affect, Likely to Adversely Affect (MALAA)" for 1 species (American burying beetle) were arrived at through a sufficiently rigorous review of the distribution, abundance, and biological use of the Project area by special status species.

- Exponent believes that there could be habitat utilized now or in the future by special status species that is not specifically identified as PHMSA-designated ESAs based on our review of information in the FEIS.

- Exponent believes ongoing natural shifts in resources underpinning the distribution and abundance of special status species and the species they rely upon will likely result in a shifting of locations where special status species occur during the lifetime of the Project. Keystone is planning annual updates along the entire pipeline route. This will include new consultations with USFWS to identify critical T&E species that may not be captured within the existing PHMSA database, and may result in the environmental protection of additional areas along the pipeline corridor.

5.1.2 Recommendations

- A distance of at least 10 miles downstream from the proposed centerline of the pipeline should be used for the identification of sensitive areas and for identifying CPSs during the final design phase of the Project.
- Based on location-specific analyses of fate and effects of spills that Keystone will undertake prior to construction, consider the use of additional valves and/or noninvasive boring technologies at the small stream crossings that Exponent identified as associated with additional potentially sensitive ecological areas, and where Keystone's release analysis shows the potential exists for medium to very large spills to occur.
- Keystone should rely upon stream-specific specific scour analyses for small stream crossings to identify where the pipeline should be buried deeper than 5 ft or where HDD may be warranted. The particular small stream crossings identified by Exponent should be given attention in this regard.
- While Exponent is not charged with reviewing the ERP, we recommend that the ERP consider the possibility that spilled oil may be entrained into sediments and that these types of conditions be anticipated as part of response and clean-up.
- The ERP should also take into account the sensitive areas identified in our review (e.g., Rainwater Basin, small stream crossings associated with ESAs, and special downstream water bodies). For example, wildlife habitat for special status species, within close proximity of the pipeline could be designated as "special and/or unique areas" for purposes of the ERP.
- Exponent recommends that Keystone develop explicit plans for updating the status and presence of special status species and the habitat they rely upon every 2 years, and that identified changes be incorporated into the ERP.

5.2 Small Streams

The FEIS defines small streams crossed by the pipeline as streams less than 100 ft in width. For major stream crossings greater than 100 ft, the pipeline design uses horizontal directional drilling (HDD), which places the pipe well below the stream bed (i.e., 25 ft or greater). The HDD method will not disrupt the stream bed because the pipe is placed in a borehole that is drilled beneath the streambed and drilling occurs well back from the stream bank. For small stream crossings there is no requirement to use HDD, so in most places the pipeline will cross small streams using open-cut crossings (dry, flowing, dry flume, or dry dam-and-pump). According to discussions with Keystone, during the final design phase of the pipeline, specific small stream crossings will also use HDD or micro-bore methods to cross the stream if scour analyses indicate that the pipe would have to be placed deeper than 5 ft below the stream bed to protect it from stream bed erosion. According to Keystone, the crossing method for each stream will be identified in the 401 crossing permit applications that will be evaluated by the U.S.

Army Corps of Engineers. For purposes of our review, because this final design is not yet completed, we conservatively assumed that the pipeline would be buried only 5 ft below the streambed for all the small stream crossings. As a consequence of the shallower burial depth, small stream crossings may be at higher risk of a pipeline rupture as a result of scouring or other bed disturbance. All streams (both large and small) crossed by the pipeline are listed in Tables E-1 and E-2 in Appendix E of the FEIS.

5.3 High Consequence Areas

The Risk Assessment used PHMSA-defined HCAs within specified distances of the pipeline to determine CPSs. Several types of HCAs were considered, including populated areas, drinking water protection areas, and ESAs. Depending on the receptors and potentially complete pathways, the various types of HCAs had different buffers from the pipeline. CPSs were defined using the HCA proximity rules listed in the Risk Assessment with site-specific hydrology assessments conducted as needed to evaluate viable downstream pathways.

Exponent reviewed the CPS identification process using the maps and information provided in the Risk Assessment. A review of the maps revealed that several CPSs were not identified where the southern end of the Houston Lateral passes directly through a populated area (MP 36.7–41 and 43.6 to 47.2 [Figure 5]). CPSs should have been identified where the pipeline is within 1 mile of a populated area or within 5 miles of a viable downstream connection to a populated area. Exponent communication with Keystone staff indicates that this was a mapping error, but according to Keystone, the areas were included in the HCA analysis and summary. Given the topographical specificity needed to accurately determine a viable downstream pathway, Exponent did not re-analyze the downstream pathway along the entire 1,375-mile pipeline and instead relied on the accuracy of the original analysis.

While the southern end of the Houston Lateral was the only section of the pipeline that clearly violated the CPS identification rules, the rules themselves (specifically the distances) seemed arbitrary. The explanation provided for the distances selected for each type of HCA was either vague or absent. As the analysis described in Section 4 indicates, evaluating viable downstream pathways to a distance of 10 miles, rather than 5 miles, would be more appropriately protective of HCAs. Exponent has been informed by Keystone that they plan to evaluate downstream transport for more than 20 miles.

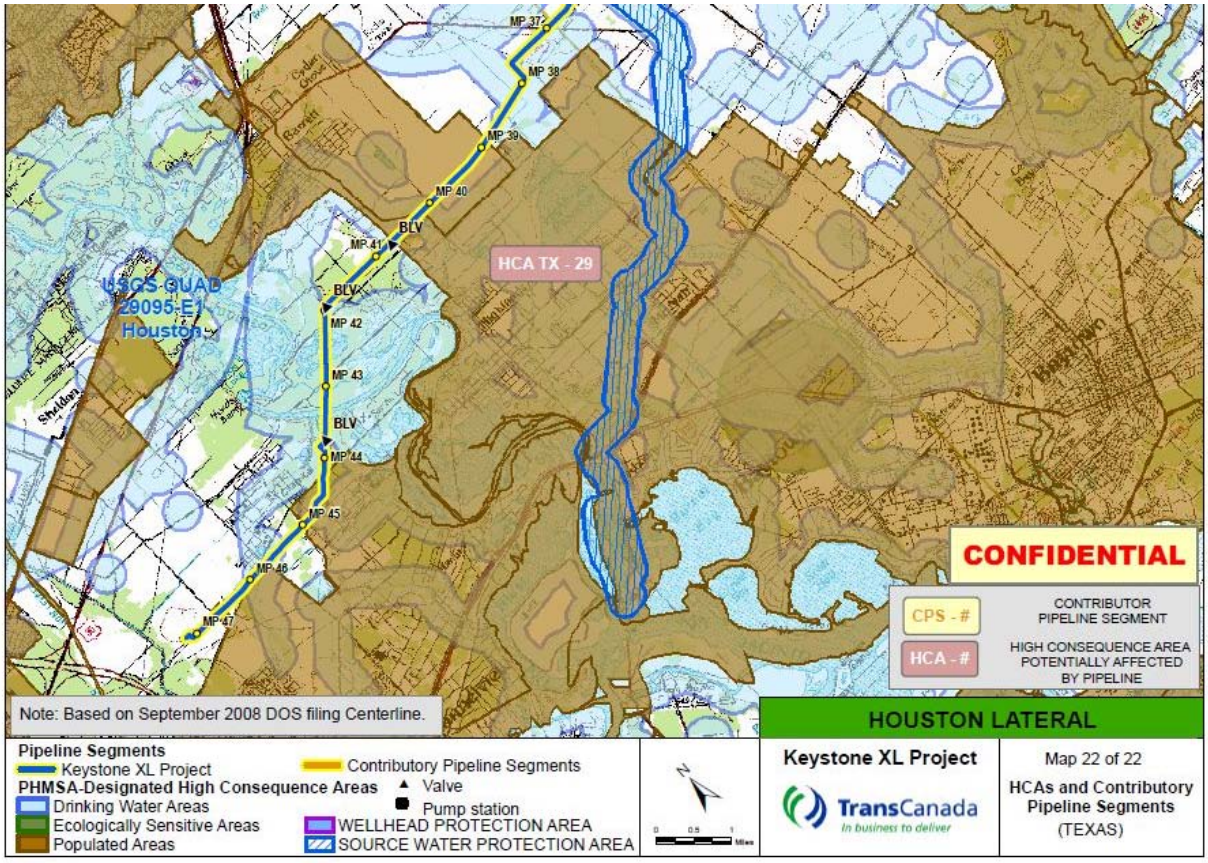

Figure 5. Project passes directly through a populated area and no CPS is identified

While it is very likely that more HCAs will be identified by expanding the downstream search criteria for HCAs from 5 to 10 miles, the purpose of the Risk Assessment was to identify CPS locations, where one or more HCAs could be affected. It is likely that most CPSs are identified using a 5-mile limit for stream and river crossings. However, it is also possible that HCAs may not be encountered within the first 5 miles; thus, extending the search criteria to 10 miles could identify CPSs that may have been missed using the 5 mile criterion. As part of its charge to examine whether sensitive environments are associated with small stream crossings, Exponent carried out several types of analyses, one of which was to examine HCAs located 5–10 miles downstream of stream crossings. Based on discussions with Keystone, it was explained to Exponent that the 5-mile limit was only used for purposes of the FEIS, and that as part of the final design, HCAs located more than 20 miles downstream from the pipeline will be considered if there is a viable flow pathway (e.g., from small stream crossings).

In order to complete our assessment of sensitive environments associated with small stream crossings, Exponent requested information on HCAs within 10 miles of the pipeline in a GIS format that was readily mapped over the pipeline route. Exponent considered what effect such an analysis might have by searching for HCAs located within 10 miles downstream, but more than 5 miles downstream, of the pipeline. This preliminary analysis identified 60 additional HCAs in Nebraska alone (Figure 6). If applied along the entire length of the pipeline, this adjustment in the search criteria distance will likely result in the identification of more HCAs

potentially affected by a spill. We recognize that many of these HCAs will have already been captured by the existing CPS analysis since many HCAs are co-located along major river systems. Although each HCA that is identified by such a process will need further evaluation of type (population, groundwater municipal intake, or ecologically sensitive area) and hydrologic connectivity, it is likely that such an analysis will result in the designation of additional CPSs. This detailed analysis is required by Special Condition 14 and by federal regulations. Such a detailed analysis was beyond the scope of Exponent's review because it requires in-field analysis of the conditions near the pipeline.

5.4 Ecologically Sensitive Areas

As described in the Risk Assessment and according to 49 CFR 195, PHMSA identifies ESAs using the following criteria:

- An area containing critically imperiled species or ecological community
- Multi-species assemblage areas
- A migratory water bird concentration area
- Areas containing imperiled special status species or imperiled ecological communities where the species is aquatic, aquatic dependent, or terrestrial with a limited range
- An area containing special status species where the species or community occurrence is one of the most viable, highest quality, or best condition, as identified by an element occurrence ranking (EORANK) of A or B.

The Risk Assessment used PHMSA-identified ESAs to determine CPSs. However, it is possible that the ESA criteria are unnecessarily narrow and may exclude some areas that are very important to sensitive fish and wildlife populations, as identified in the FEIS. Exponent gave consideration to additional areas of special ecological concern other than those identified by PHMSA by considering wetlands of special concern and important wildlife habitats crossed by the pipeline, as identified in the FEIS. Exponent also evaluated where small streams crossed by the pipeline sustained important fisheries within at least 0.5 miles of the pipeline (as identified in Section 3.7 of the FEIS). In addition, Exponent searched for major waterbodies up to 10 miles downstream of the pipeline (as opposed to the 5 miles considered in the Risk Assessment) that were hydrologically connected to small streams crossed by the pipeline.

As an additional check on the comprehensiveness of PHMSA-designated ESAs, Exponent searched for Nature Conservancy sites within 10 miles of the pipeline. Locations from http://my.nature.org/preserves/ were mapped as an overlay on the pipeline route. No Nature Conservancy sites were identified within 10 miles on either side of the pipeline.

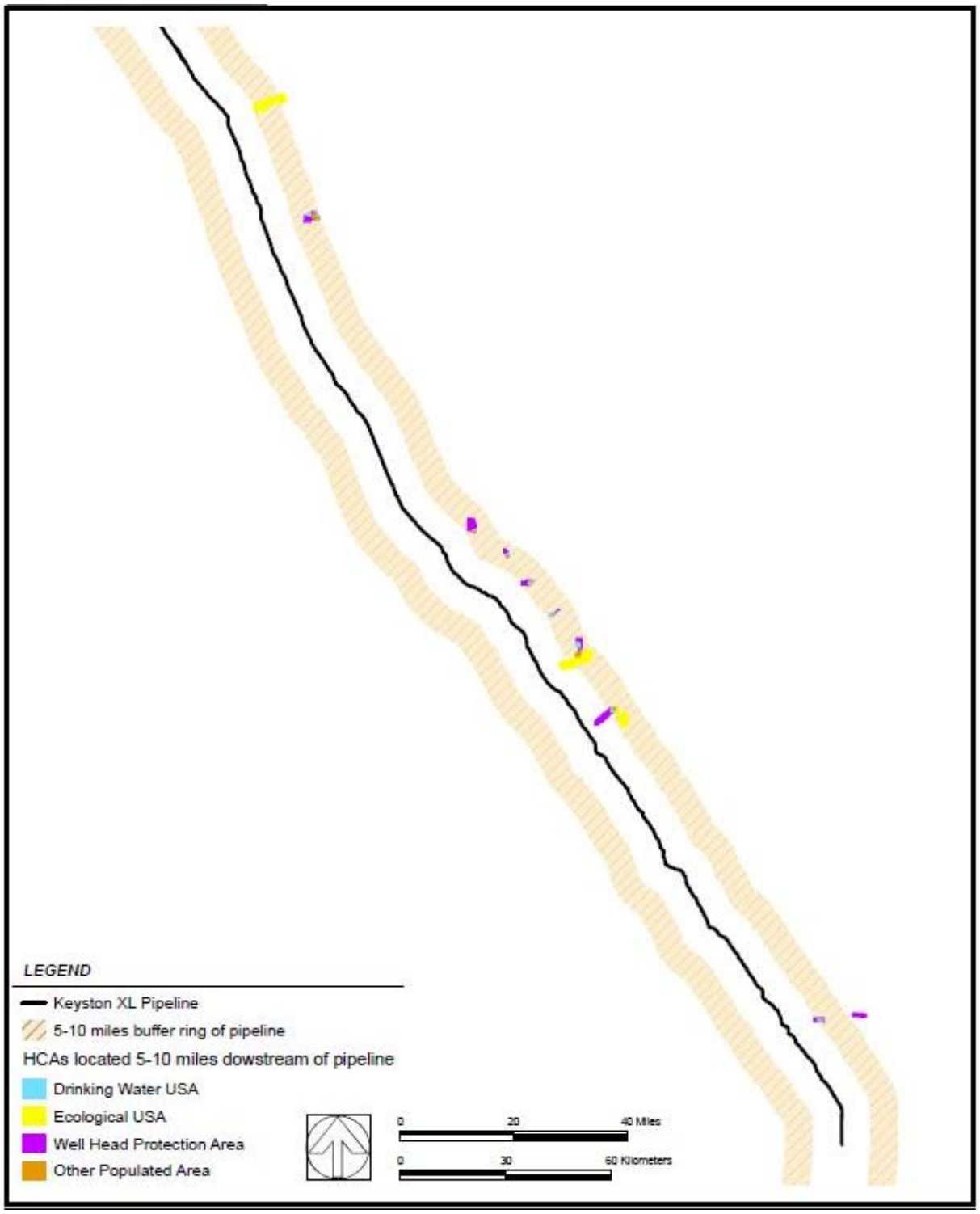

Figure 6. HCAs located between 5 and 10 miles downstream of the Project in Nebraska

5.4.1 Areas of Special Ecological Consideration

Exponent compiled location and pipeline crossing information for additional areas of special ecological concern (as defined above) in Appendix B using information provided in the following documents:

- FEIS Tables
  - Table 2.3.3-1. Waterbodies Crossed Using the Horizontal Directional Drilling Method
  - Table 3.4.2-1. Number and Type of Wetlands Crossed by the Proposed Project within Wetland Areas of Special Concern or Value
  - Table 3.6.2-1. Important Wildlife Habitats within or near the Proposed Project ROW
  - Table 3.7.2-1. Proposed Perennial Stream Crossings at or Upstream of Fisheries Habitat along the Proposed Project Route
- FEIS Appendix P. Pipeline Risk Assessment and Environmental Consequence Analysis
  - Attachment 2 CPS/HCA Risk Ranking Table of Appendix C
- FEIS Appendix E
  - Table E-1. Waterbodies Crossed by the Project – Steele City
  - Table E-2. Waterbodies Crossed by the Project – Gulf Coast
  - Table E-4. Waterbodies within 10 Miles Downstream of Proposed Water Crossings.

After compiling Appendix B, Exponent used the data to identify locations where the pipeline crosses small streams near multiple areas of special ecological consideration (i.e., fisheries, wildlife habitat, wetlands, major waterbodies, or special waterbodies). Pipeline stream crossings in the vicinity of multiple areas of special ecological consideration were identified as posing higher risk to ecological resources if they were not already designated in the FEIS as CPSs or as HDD crossings. Pipelines crossing larger waterways (i.e., stream crossings of greater than 100 ft) using HDD techniques were deemed to have a lower risk of rupture than non-HDD crossings as a result of their substantial depth (≥25 ft) below the stream bed. In addition, crossings identified as posing higher risk to ecological resources had to meet at least one of the following two specific criteria:

1. Stream crossings with at least four of the following five attributes: wetland areas of special concern or value, important wildlife habitats, fisheries within 0.5 miles downstream, waterbodies within 10 miles downstream, and

waterbodies within 10 miles downstream with high quality habitats (defined in Section 5.4.2).

2. Stream crossings with all three of the following FEIS-defined attributes: wetland areas of special concern or value, important wildlife habitats, and fisheries within 0.5 miles downstream.

The following small stream crossings were identified by Exponent as posing higher risk to ecological resources using these two criteria:

- **Keya Paha River, Nebraska (MP 599.9):** As identified in the FEIS, the Project crosses this perennial river at a location with wetlands of special concern (NE Sand Hills Wetlands), with important wildlife habitat (Keya Paha River Valley), and within 0.5 miles of a fishery (Class A WW).
- **Niobrara River, Nebraska (MP 615.38):** As identified in the FEIS, the Project crosses this perennial river at a location with wetlands of special concern (NE Sand Hills Wetlands), with important wildlife habitat (Niobrara River Valley), and within 0.5 miles upstream of a fishery (Class A WW).
- **South Fork Elkhorn River, Nebraska (MP 630.46):** As identified in the FEIS, the Project crosses this perennial river at a location with wetlands of special concern (NE Sand Hills Wetlands), with important wildlife habitat (Sand Hills), and within 0.5 miles of a fishery (Class A WW). The crossing is also within 10 miles upstream of Atkinson Reservoir.
- **Holt Creek, Nebraska (MP 647.31):** As identified in the FEIS, the Project crosses this perennial creek at a location with wetlands of special concern (NE Sand Hills), with important wildlife habitat (Sand Hills), and within 0.5 miles upstream of a fishery (Class A WW).
- **South Fork Elkhorn River, Nebraska (660.22 and 660.23):** As identified in the FEIS, the Project crosses this perennial river at a location with wetlands of special concern (NE Sand Hills Wetlands), with important wildlife habitat (Sand Hills), and within 0.5 miles of a fishery (Class A WW).
- **Big Blue River, Nebraska (MP 765.5):** As identified in the FEIS, the Project crosses this perennial river at a location with wetlands of special concern (Rainwater Basin Wetlands), with important wildlife habitat (Rainwater Basin), and within 0.5 miles upstream of a fishery (Class B WW).
- **Lincoln Creek, Nebraska (MP 774.93):** As identified in the FEIS, the Project crosses this perennial stream at a location with wetlands of special concern (Rainwater Basin Wetlands), with important wildlife habitat (Rainwater Basin), and within 0.5 miles upstream of a fishery (Class B WW).
- **West Fork Big Blue River (MP 789.57):** As identified in the FEIS, the Project crosses this perennial river at a location with wetlands of special

concern (Rainwater Basin Wetlands), with important wildlife habitat (Rainwater Basin), and within 0.5 miles upstream of a fishery (Class A WW).

- **Unnamed tributary to Turkey Creek, Nebraska (MP 807.54):** As identified in the FEIS, the Project crosses this perennial stream at a location with wetlands of special concern (Rainwater Basin Wetlands), with important wildlife habitat (Rainwater Basin), and within 0.5 miles upstream of a fishery (Class B WW).
- **Cotton Creek, Texas (MP 457.92 and 457.96):** As identified in the FEIS, the Project crosses this perennial creek at a location with wetlands of special concern (Water Oak–Willow Oak Community) and within 0.5 miles upstream of a fishery (high value). The crossing is also within 10 miles upstream of Big Thicket National Preserve.

These stream crossings warrant additional consideration and may necessitate additional protective measures or special consideration in the ERP. The Risk Assessment acknowledges that spills may be transported downstream up to 5 miles, and Exponent's analysis (see Section 4) indicates that transport distances of 10 or more miles are reasonably likely. Keystone indicated to Exponent during the review process that the detailed transport and fate analysis that will be conducted after the pipeline is constructed, as required by Special Condition 14 and federal regulations, will identify CPSs associated with HCAs located more than 20 miles downstream. Exponent also notes that the 208 fisheries located within 0.5 miles of the pipeline (FEIS Table 3.7.2-1) may be at risk from a spill due to acute toxicity of the oil (see Section 3); however, we considered small streams to be of special ecological concern only if they had three or more critical attributes as described above (e.g., fisheries, wildlife habitat, etc.).

5.4.2 Major Waterbodies

Exponent gave special consideration to Table E-4 in Appendix E of the FEIS to identify waterbodies within 10 miles of the pipeline that may provide high quality wildlife habitat. The 10-mile distance was used as a criterion based on transport and fate considerations that suggested spills of oil to a stream can reasonably move downstream this distance or greater (refer to Section 4). Therefore, the 5-mile criterion used in the FEIS and Risk Assessment (Appendix P) did not appear to be sufficiently protective. Downstream waterbodies include lakes, reservoirs, and proposed reservoirs, most of which are likely to attract migratory water birds at some times of the year. Exponent identified stream crossings with waterbodies within 10 miles downstream of the proposed centerline for the pipeline that are likely to provide high quality habitat to these birds (Appendix B). High quality habitat was subjectively defined for purposes of our evaluation using descriptions of the waterbodies within the "comment" column in Appendix B. Waterbodies that were described as wildlife management areas, year-round bird watching areas, and preserves were designated high quality habitats for purposes of our assessment. We used the spirit of the ESA definition provided earlier to identify those waterbodies that were considered associated with areas of high quality habitat. These waterbodies, all in Texas, included:

- **Pat Mayse Lake:** This lake is situated on the western edge of Pat Mayse Wildlife Management Area. The wildlife management area is an 8,925-acre area managed for recreational uses such as hunting, wildlife viewing, and camping.

- **Lake Bob Sandlin (and Lake Cypress Springs which is contiguous with Lake Bob Sandlin):** This lake is a 9,400-acre reservoir which provides eagle viewing in the winter and other bird watching opportunities year round.

- **Waterbodies Associated with Big Thicket National Preserve:** This preserve is a UNESCO "Biosphere Reserve" noted for the high biodiversity that results from its mix of virgin pine and cypress forest, hardwood forest, meadow, and blackwater swamp.

- **Waterbodies Associated with Trinity River National Wildlife Refuge**: This 25,000-acre wildlife refuge is valued for its high diversity of waterfowl species. Nearly 50 percent of the neotropical bird species listed by USFWS use this wildlife refuge during migration or nesting.

5.5 Toxicity Assessment

Exponent reviewed the aquatic toxicity information presented in Section 4.2.3.4 of the Risk Assessment (Appendix P of FEIS) in light of the information on crude oil (dilbit) chemical content and composition to evaluate whether the conclusions were based on adequately conservative assumptions for small stream crossings. The Risk Assessment's analysis of toxicity in surface water resulting from a release to small streams focused on the toxicity resulting from benzene alone. While benzene is a toxic constituent of crude oil, it is one of many crude oil constituents and forms only a very small proportion of the total volume and potential toxicity. Oil can also result in physical effects as has been described in the FEIS.

Exponent investigated the possibility that other crude oil constituents may pose a greater toxicological risk to aquatic organisms than benzene by evaluating the potential of the following constituents to cause toxicity to aquatic organisms: ethylbenzene, toluene, xylene, nickel, vanadium, chrysene, fluorene, naphthalene, and phenanthrene. Concentrations of the metals and BTEX constituents are shown in Table 1 and PAH concentrations are listed in Table 3. Based on this information, quantitative estimates of water concentrations of these chemicals resulting from a spill could be determined. Using the known water solubility of the different constituents and the same assumptions about water flow rates and sizes of releases as used in Tables 4-7 and 4-8 of the Risk Assessment, Exponent approximated the concentrations of these constituents in surface waters following a release. Although these water concentrations were meant to model an acute event (1 hour of stream flow), we compared them to EPA ecological benchmarks that are protective of aquatic life chronically exposed to these chemicals (EPA Region 6, 7, or 8 benchmarks were given priority; in the absence of any of those, national level criteria were applied [U.S. EPA 2011]).

This evaluation indicated that, of the crude oil constituents evaluated, only nickel and vanadium were likely to exceed chronic water quality thresholds and that these constituents were only

likely to exceed for large (10,000 barrels) or moderate (1,000 barrels) spills, but not smaller spills (Tables 7–10). Since these findings show less risk than predicted for benzene, the Risk Assessment's evaluation of toxicity resulting from spills to surface water appears to be sufficient for judging the potential for toxic effects on aquatic organisms. If cleanup was delayed or incomplete, as the oil in a spill ages the concentrations of alkylated PAH compounds will increase on a relative basis as more volatile compounds evaporate, and they will tend to persist for a longer time than their parent non-alkylated forms. The prediction of acute toxicity from most spills into small- to medium-sized streams based on the conservative assessment of benzene toxicity is sufficiently conservative to account for this eventuality. As noted here and in the FEIS, spilled oil can also have physical effects that can adversely affect some wildlife species such as birds and habitats if, for example, the oil comes into contact with soils and sediments.

Exponent recognizes that dilbit also contains additional toxic constituents such as naphthenic acids. While data are lacking on concentrations of these chemicals in the crude oil, it should be noted that these acids are more soluble than similarly size hydrocarbons, and are highly acutely toxic to zooplankton (0.15 mg/L), although less so to fish (25 mg/L) (Clemente and Fedorak 2005). While acid concentrations are reduced by the caustic washing of tar sand to produce dilbit, the FEIS has not discussed the possibility that these chemicals could contribute to the toxicity associated with a spill. However, as our analysis has shown, the selection of benzene within the Risk Assessment to judge the potential for toxicity provides a reasonable basis for assessing the potential for risks to aquatic organisms. Still, because crude oils are complex mixtures, Exponent recognizes there are remaining uncertainties that will be addressed during a response following a spill.

5.6 Special Status Species

DOS submitted a Biological Assessment for the Keystone XL Pipeline that evaluated potential impacts of construction and operation (including spills) to special status species and their habitats. The Biological Assessment was reviewed by USFWS and on September 23, 2011, the USFWS issued a Biological Opinion that concurred with the DOS findings.

Because many of the special status species of concern within the Project area rely on wetlands and other water resources, Exponent reviewed Section 3.8, T&E Species, of the FEIS with special attention to both the large and small stream crossings (also referred to here as wetlands and/or riparian areas collectively). Exponent also reviewed the cumulative impact section of the FEIS (Section 3.14.3.8), with special attention to those cumulative impacts that might impact special status species in wetlands and riparian areas located at or downstream of small stream crossings. Finally, Exponent reviewed Appendix C of 49 CFR 195 to ascertain if the proposed future monitoring of the Project was sufficient to protect special status species from future environmental changes.

5.6.1 General Special Status Species Review

Exponent determined that the list of some 30 threatened, endangered, proposed-for-listing, and candidate-for-listing species covered in Section 3.8 (including 4 mammals, 9 birds, 1 amphibian, 6 reptiles, 4 fish, 2 insects, and 4 plants) was a comprehensive and a complete list of the relevant special status species in the Project area.

Similarly, Exponent determined that the correct federal agencies were consulted during the FEIS process. Specifically, that USFWS provided T&E consultation relative to the Endangered Species Act (ESA), the Fish and Wildlife Coordination Act (FWCA), the Migratory Bird Treaty Act (MBTA), Bald and Golden Eagle Protection Act (BGEPA), and National Environmental Protection Act (NEPA).

Exponent found that the preliminary findings of "May Affect, Not Likely to Adversely Affect (NLAA), No Effect (NE) or Not Applicable (NA)" for 29 of the 30 species and "May Affect, Likely to Adversely Affect (MALAA)" for 1 species (American burying beetle) were arrived at through a sufficiently rigorous review of the distribution, abundance, and biological use of the Project area by T&E Species.

5.6.2 ESAs for Special Status Species

As stated earlier in this section, it is possible that the ESA criteria as specified by PHMSA are narrow with regard to T&E and other special status species. Considering this fact, Exponent used the example of the whooping crane, which is the most imperiled of the T&E species identified in the FEIS, to illustrate that there are other non-ESA defined areas associated with stream crossings that should be considered for additional mitigation during the final design of the Project.

5.6.2.1 Whooping Crane

The Project generally follows much of the migratory corridor of the whooping crane, which runs from Canada to Texas (Figure 7). While the Project is either to the east (in the north) or to the west (in the south) of the migration corridor, the Project does intersect the migration corridor substantially, for nearly 500 miles at the South Dakota/Nebraska line (Figure 7). Furthermore, whooping cranes (Lewis 1995), as well as piping plover (Elliott-Smith and Haig 2004) and least terns (Thompson et al. 1997), are known to use small and large stream areas and other wetlands during migratory stopovers (cranes, plovers, and terns) and as annual breeding habitats (terns and plovers). There are a number of ESAs and CPSs identified along the whooping crane migration corridor.

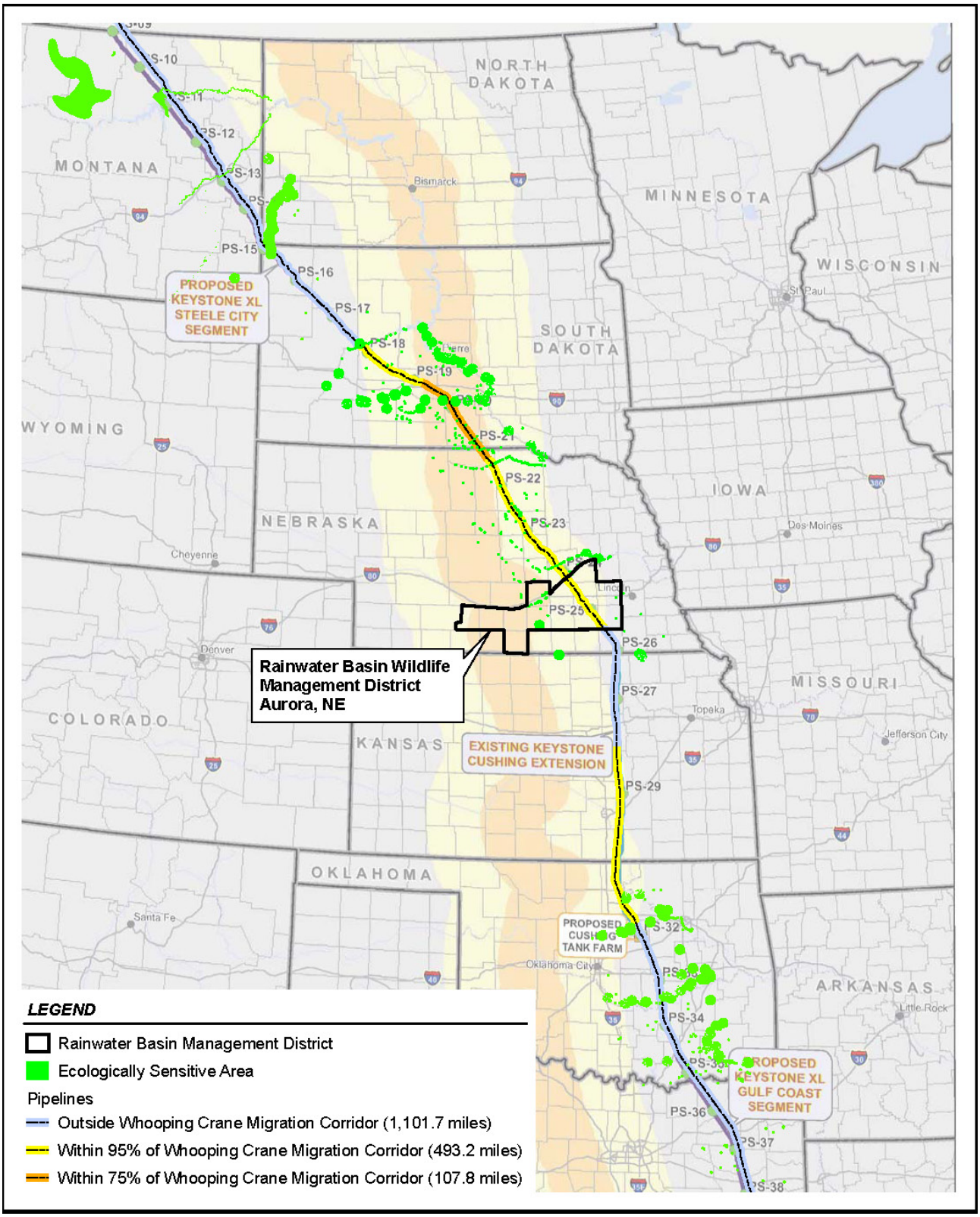

Figure 7. Ecologically sensitive areas (green) are shown within and near the region of the Project that crosses 75% and 95% the whooping crane migration corridor

However, the Project is routed directly through the Rainwater Basin Wildlife Management District (RBWMD) in southeastern Nebraska (Figure 8), and thereby has the potential to impact this important known whooping crane and shorebird migration stopover site (WHSRN 2004). USFWS manages 61 Massie Waterfowl Production Areas (WPAs) in the Rainwater Basin, and the Nebraska Game and Parks Commission manages 35 State Wildlife Management Areas within the Rainwater Basin. The Rainwater Basin Joint Venture, founded in 1992, is a broad coalition of government agencies, non-government organizations, and farmers dedicated to acquisition, restoration, and management of the region's wetlands and surrounding upland habitats. In 2005, the Nebraska Natural Legacy Project (the State's wildlife action plan) identified the Rainwater Basin as a biologically unique landscape. There are also 80 Wetland Reserve Projects within the Rainwater Basin (WHSRN 2004).

There is the possibility that whooping cranes may already be using the RBWMD and/or may relocate into suitable wetlands within the RBWMD during the lifetime of the Project. Some of the potential wetlands within the RBWMD are identified as ESAs. However, many of the wetlands that whooping cranes and other birds could conceivably use or move into near the Project within the RBWMD are not considered ESAs as defined by PHMSA.

Exponent reviewed the information on special status wetlands provided within Table 3.4.2-1 of the FEIS and cross referenced that information to stream crossings within the RBWMD (refer to Appendix B). Removing stream crossings from consideration that are already CPSs or where HDD methods will be used to cross the small stream, there are 59 small stream crossings within the RBWMD that have special status wetlands at the stream crossing that could potentially be used by whooping cranes and other wetland dependent special status species. For this reason, Exponent recommends that these stream crossings should be considered for additional mitigation measures to protect the whooping crane habitat of the RBWMD, because of its importance as a stopover area for feeding and resting by the whooping crane.

Lastly, while most whooping cranes stay within their migration corridor, whooping cranes are seen outside the corridor on a regular basis and may have even begun prospecting new areas (Lewis 1995). Related to this point, many other special status species are capable of utilizing new areas on a yearly basis. A further complication is that according to USGS (2004), many water bird habitats within the RBWMD may be in a state of deterioration, and may already be compelling whooping cranes to utilize unprotected wetlands within the Project. Therefore, Exponent suggests that Keystone should conduct a bi-annual consultation with USFWS to identify areas of high potential for use by special status species and to update the Project ERPs as appropriate.

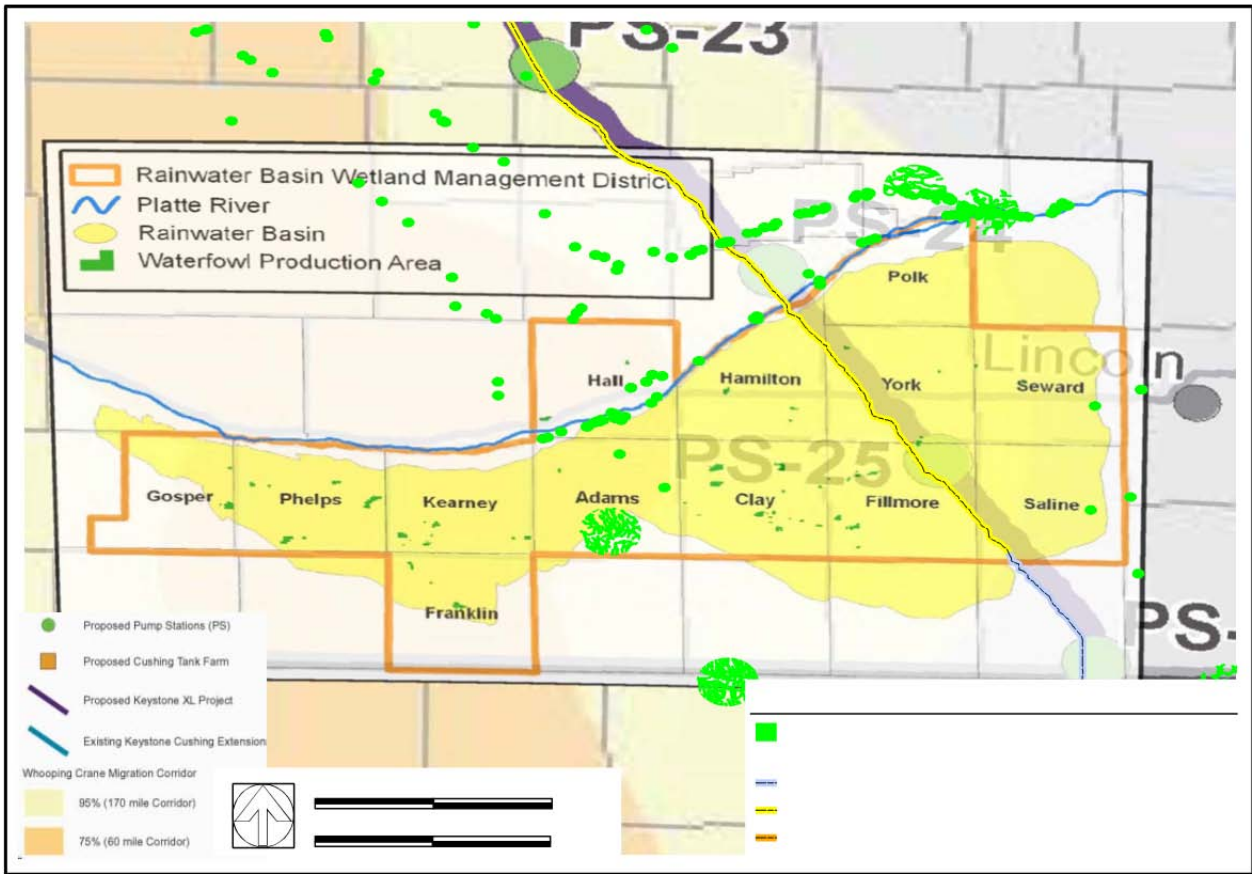

Figure 8. The Project intersects the Rainwater Basin Wetland Management District (shown in yellow), yet few of the wetlands in the RBWMD are identified ESAs.

5.6.3 Recommendations for Special Status Monitoring

Appendix C of CFR 195 (§195.452(d)(3)) states: "An operator is also responsible for periodically evaluating its pipeline segments to look for population or environmental changes that may have occurred around the pipeline and to keep its program current with this information." Yet closer examination of this section of the CFR reveals that it only pertains to physical factors that might impact pipeline integrity and does not explicitly include any biological aspects that might help detect any future impacts to T&E and other special status species. Slightly more relevant to T&E populations is CFR §195.452(d)(3) which states: "An operator must incorporate a new unusually sensitive area into its baseline assessment plan within one year from the date the area is identified. An operator must complete the baseline assessment of any line pipe that could affect the newly-identified high consequence area within five years from the date the area is identified." However, as discussed earlier in this section, these conditions would still not consider additional protection for areas not defined as HCAs (e.g., ESAs), such as the areas identified earlier within this section.

Given the 50-year projected lifespan of the Project and the possibility that one or more special status species may move into the vicinity of the Project during that timeframe, Exponent

concludes that the monitoring outlined in CFR 195 may be insufficient to protect special status species over the lifespan of the Project. Specifically, Exponent recommends that in addition to monitoring physical factors that might impact pipeline integrity, Keystone develop a biological monitoring plan for these special and unique special status habitats to periodically determine whether T&E and other special status species are using these habitats within the Project area and whether they are afforded sufficient protection under the ERP.

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Appendix A

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Professional Profile

Dr. Sungwoo Ahn is a Senior Scientist in Exponent's Environmental Sciences practice who specializes in the transport and fate of hydrophobic organic contaminants including PAHs, PCBs, and polybrominated diphenyl ethers (PBDEs), and their bioavailability. Dr. Ahn also has expertise in the environmental behavior of nanomaterials. He is knowledgeable in the use of a variety of laboratory analytical methods including gas chromatography (GC) and mass spectrometry (GC/MS), transmission electron microscopy (TEM), scanning electron microscopy (SEM), x-ray photoelectron spectroscopy (XPS), and x-ray diffraction (XRD).

Before joining Exponent, Dr. Ahn worked as a postdoctoral scholar at Stanford University, where he conducted research on the degradation of flame retardant PBDEs by various forms of nano-scale zerovalent iron (nZVI). Dr. Ahn studied the reaction kinetics and the degradation pathways of PBDEs with positional preference in the debromination. As a part of the research, he synthesized the nanoparticle, as well as its catalyzed and carbon supported particles, in the laboratory and characterized them using analytical tools such as TEM, SEM, XPS, and XRD.

During his Ph.D. work, Dr. Ahn studied the transport and fate of PAHs in contaminated soil and sediment amended with a carbon sorbents for *in situ* contaminant stabilization. The study included physicochemical characterization of contamination at the micro-scale for source identification, assessment of PAH bioavailability and availability to the surroundings, and model simulation of contaminant mass transfer in sediment-sorbent systems, to predict the fate of PAHs and the long-term effect of carbon amendment. In addition, he also has extensive field and laboratory experience in *in situ* stabilization of PCBs in contaminated sediment using carbon amendment.

Academic Credentials and Professional Honors

Ph.D., Civil and Environmental Engineering, Stanford University, 2006
M.S., Civil and Environmental Engineering, Stanford University, 2001
M.S., Chemical Engineering, Yonsei University, South Korea, 1997
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Gary N. Bigham, L.G.
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Professional Profile

Mr. Gary Bigham is a Principal in Exponent's Environmental Sciences practice who specializes in the evaluation of transport, fate, and effects of contaminants in aquatic habitats, soil, sediment, and groundwater. He has managed and been the principal investigator of field, laboratory, and theoretical assessments of a wide variety of contaminants in lakes, rivers, estuarine waters, ocean waters, and groundwater. Mr. Bigham has also directed RI/FSs, human health and ecological risk assessments, cost allocation studies, and NRDAs for sites involving soils, sediments, and waters contaminated with arsenic, chlorinated benzenes, dioxin, mercury, metals, PAHs, PCBs, petroleum hydrocarbons, and solvents. He has also completed several evaluations of mercury in indoor air. Recent examples of contaminant transport and fate analyses include the development of a numerical model of mercury cycling and bioaccumulation for Onondaga Lake; a detailed evaluation and modification of sediment transport and PCB bioaccumulation models for the Fox River and Green Bay, Wisconsin; and an evaluation of the effects of eutrophication on mercury bioaccumulation in the Florida Everglades. Mr. Bigham is the author of numerous publications on the behavior of mercury in the environment.

Mr. Bigham has been designated an expert witness in class action and individual tort claims on the issue of PCB and PAH transport in streams and rivers, and dioxins/furans in a lake; in litigation involving mercury bioaccumulation in the Florida Everglades; and assessments of exposure to mercury vapor, crude oil, and produced water. Mr. Bigham has also completed environmental forensic investigations of mercury-contaminated sediments and soil, groundwater contaminated with chlorinated solvents and petroleum hydrocarbons, and for allocation of remediation costs of a PAH-contaminated sediment site in Boston Harbor. He has also had a lead role in NRDAs related to mercury contamination in surface waters and involving solvents in groundwater. He has also served as a consulting expert on a major NRD claim involving confined animal feeding operations (CAFOs) in Oklahoma and Arkansas.

Mr. Bigham's international experience includes serving as resident manager for a multi-year air quality and marine environmental monitoring program in Saudi Arabia. He led the technical development of a natural resource damage claim for the Kingdom of Jordan to the United Nations Compensation Commission for damages arising from the first Gulf War. He recently completed an environmental assessment for a major oil export facility in Abu Dhabi and evaluated potential human exposure to spilled oil and produced-water discharges in the Amazon basin of Ecuador. He applied a water quality model to predict conditions in and downstream of a proposed reservoir in Bolivia and assessed water quality and greenhouse gas emissions for a proposed reservoir in Guyana. He has also completed an assessment of potential human exposure to mercury vapor from a spill in the Peruvian highlands.

Academic Credentials and Professional Honors

Post-graduate course work in Environmental Engineering, University of Southern California, 1975–1976

M.S., Geophysical Sciences, Georgia Institute of Technology, 1972
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Professional Profile

Dr. Paul D. Boehm has overall responsibility for Exponent's Environmental business. He has devoted his 34 years of consulting experience to advising industrial, legal, and government clients on scientific aspects of: contaminated sediments and terrestrial sites; oil spills; and the use of environmental forensic methods to investigate background contamination, to chemically fingerprint contaminants to determine sources, to apportion contamination to allocate liabilities, and to reconstruct historical releases and doses. Dr. Boehm has provided scientific support to clients on natural resource damage assessments, environmental and toxic tort claims, maritime pollution cases, and other litigation matters, including providing expert testimony. His work as an analytical, environmental, and geo-chemist has involved petroleum hydrocarbons, fuel additives, natural gas, polycyclic aromatic hydrocarbons (PAHs), polychlorinated biphenyls (PCBs), chlorophenols, chlorinated solvents (TCE, PCE), mercury, lead, and other chemicals and elements. A significant part of Dr. Boehm's work has focused on oil refineries, fuel terminals, and offshore platforms; marine and aquatic oil spills; Superfund sites; manufactured gas plant (MGP); pulp and paper mills, and natural gas storage fields; medical exposures; and transactional disputes. With regards to chemical releases, he specializes in the historical reconstruction of release histories. With regards to petroleum fuels he has focused on petroleum chemistry associated with evolution of refining processes and the use of fuel additives such as alkylated leads, MTBE, TAME, and other compounds.

Dr. Boehm has been engaged in numerous natural resource damage assessments (NRDAs) at oil spill and CERCLA sites where he has provided technical support on sources, divisibility, bioavailability of PAHs, PCBs, petroleum and other chemical sources; exposure and bioavailability; divisibility and apportionment of contamination, and allocation of associated liability. His extensive knowledge of the strategic application and practice of environmental forensics (geo-chemical fingerprinting, transport and fate, source attribution, and allocation) has been applied to numerous cases involving complex environmental liability and litigation matters.

As an oil spill expert, he has studied and published on the fate and effects of most major oil spills in the United States, Europe, and the Middle East. As a natural gas and petroleum chemist and geochemist, he has also investigated geochemical aspects relating to the migration of natural gas from storage fields. His work has also included assessments of the exposure of people to petroleum contaminants in toxic tort cases.

He has been appointed to serve on several national panels on environmental/ marine pollution and has served on several National Research Council panels.

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Ph.D., Oceanography, University of Rhode Island, 1977
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Dr. Ronald Breitmeyer is a Senior Associate in Exponent's Environmental Sciences practice. Dr. Breitmeyer is a geoenvironmental engineer and hydrogeologist specializing in environmental modeling. Dr. Breitmeyer has expertise in the study and modeling of multi-phase flow and transport in a wide variety of geomaterials. He has experience with numerous environmental modeling tools and software, including HYDRUS, UNSATH, MODFLOW, HSSM, AERMOD, and CALPUFF. Dr. Breitmeyer has conducted research on characterization and modeling of liquid flow in bioreactor landfills and in landfill covers. He has expertise in laboratory testing and field-scale experimentation and instrumentation for characterizing the mechanical and hydraulic properties of geomaterials. He has also designed, fabricated, and operated custom laboratory equipment and instrumentation for geomaterial testing.
Dr. Breitmeyer also has experience performing feasibility-level remediation cost estimates for contaminated sites and accrual purposes and has experience using RACER to develop remedial cost estimates.

Academic Credentials and Professional Honors

Ph.D., Geological Engineering, University of Wisconsin, Madison, 2011
M.S., Hydrogeology, University of Nevada, Reno/Desert Research Institute, 2006
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Principal Scientist and Office Director

Professional Profile

Dr. Anne Fairbrother is a Principal Scientist in Exponent's EcoSciences practice, with more than 30 years of experience in Ecotoxicology, wildlife toxicology, contaminated site assessment, and regulatory science for existing and emerging chemicals in the U.S. and Europe. She recently served on a Science Advisory Panel to the state of Utah and as a consultant to the British Columbia (BC) Ministry of Environment to set site-specific water quality standards for selenium that protect fish and wildlife. She has conducted large-area (>100 sq mile) risk assessments at mines in tropical, desert, and mountain ecosystems, determining risk thresholds for plants and wildlife. She provided consultation on future development of mine pit lakes, assessed the risk to livestock from use of wastewater on irrigated pasture during mine closure operations, and conducted an assessment of risk to terrestrial and aquatic organisms from an abandoned mercury mine. Dr. Fairbrother conducted an assessment of the potential ecological risks to aquatic life in San Francisco Bay and coastal southern California posed by use of copper pipes. She also assessed risks to wildlife at sites contaminated with organic chemicals, including DDT, PCBs, dioxins, and petroleum hydrocarbons in Delaware, Texas, Oregon, and California, integrating ecological risks with human health risk assessments.

As a consultant, Dr. Fairbrother has supported various chemical industry groups in compiling and reviewing data from the literature in support of both U.S. and European regulatory processes. Historically, this included preparation of screening information data sets (SIDs) for submission through EPA to the OECD's High Production Volume (HPV) data call-in program. More recently, she also has input the data into the IUCLID database for Europe-wide risk assessments and the REACH chemical registration program.

Dr. Fairbrother has participated in or led the development of guidance documents for ecological risk assessments. For example, she was co-author of the EPA's *Framework for Metals Risk Assessment* and for BC Ministry of Environment guidance for implementing Tier 1 ecological risk assessments of contaminated sites and for setting soil clean-up values, and participated in the development of Ecological Soil Screening Levels (Eco-SSLs) for EPA.

While a scientist at the EPA, Dr. Fairbrother led research into the ecological risks of bioengineered crops, methods for assessing risks of nanomaterials, and some of the early guidance for field assessments of Superfund sites and effects of pesticides on birds. She researched and developed methods for assessment of chemical effects on bird immune and endocrine systems.

Dr. Fairbrother has published more than 80 peer-reviewed articles and book chapters that reflect her expertise in wildlife toxicology, immunotoxicology, endocrine-disrupting chemicals, and ecological risk assessment. She serves on numerous scientific boards, expert panels, and

editorial boards in support of scientific and regulator y issues. A veterinarian and Certified Wildlife Biologist, Dr. Fairbrother served as President of the Society of Environmental Toxicology and Chemistry, American Association of Wildlife Veterinarians, and Wildlife Disease Association (WDA). She is the recipient of the WDA Distinguished Service Award (2002), and a gold medal for Commendable Service from EPA. Dr. Fairbrother holds an adjunct professorship at Oregon State University, Department of Environmental and Molecular Toxicology.

Academic Credentials and Professional Honors

Ph.D., Veterinary Science, University of Wisconsin, Madison, 1985
M.S., Veterinary Science, University of Wisconsin, Madison, 1982
D.V.M., Veterinary Medicine, University of California, Davis, 1980
B.S., Wildlife and Fisheries Biology, University of California, Davis, 1976

Distinguished Service Award, Wildlife Disease Association, 2002
Gold Medal for Commendable Service, EPA, 2005
Bronze Medal for Commendable Service, EPA, 2006, 2008

Licenses and Certifications

Certified Wildlife Biologist, The Wildlife Society, 1995
40-hour Hazwoper Training and Certification

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Ashley Kaiser
Senior Scientist

Professional Profile

Ms. Ashley Kaiser is a Senior Scientist in Exponent's EcoSciences practice. Ms. Kaiser has 10 years of experience as an environmental professional, including more than 7 years in consulting. She works as a risk assessor, assistant project manager, data analyst, researcher, and health and safety coordinator. In these roles, her responsibilities have included human health and ecological risk calculations, project management, statistical analysis, site assessment, research, compliance assurance, sampling method development, and biotic and abiotic fieldwork.

Ms. Kaiser has experience evaluating human health and ecological risks from chemicals in soil, groundwater, surface water, tissue, and air on sites where PCBs, dioxins, PAHs, and/or metals are the primary chemicals of interest. She has provided technical support for multiple projects in Oregon, Washington, and California at a wide range of sites, including retail gasoline stations, bulk petroleum terminals, former gun clubs, abandoned mine sites, electrical substations, lumber mills, and in-water sediment areas. With an interdisciplinary background and a versatile skill set, Ms. Kaiser specializes in projects that do not fit into well-defined categories.

Academic Credentials and Professional Honors

M.S., Environmental Science and Engineering, Oregon Health and Science University, 2003
B.S., Biology, Environmental Science and Policy, Duke University, 2001

Licenses and Certifications

OSHA Hazardous Waste Operations and Emergency Response 40-hour certification

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Michael W. Kierski, Ph.D.
Managing Scientist

Professional Profile

Dr. Michael Kierski is an environmental biologist and toxicologist who provides senior-level expertise in human and ecological risk assessment and evaluation of complex environmental problems. Over the past 24 years, Dr. Kierski has evaluated risks associated with chemicals in air, soil, water, sediment, and biota to both people and the environment. He brings specialized expertise on the fate and effects of metals such as lead, hydrocarbons such as benzene and polycyclic aromatic hydrocarbons (PAHs), synthetic organic chemicals such as PCBs, pesticides, chlorinated solvents, and explosives.

Much of Dr. Kierski's work is directed toward the evaluation, remediation, and redevelopment of contaminated properties. This requires not only technical expertise but also an ability to work with regulatory agencies at the state level (e.g., in Indiana, Wisconsin, Iowa, Illinois, Michigan, New York, North Carolina, New Jersey, etc.) and at the federal level (EPA, U.S. Fish and Wildlife Service, and the Department of Defense). Dr. Kierski's primary clients include electric and gas utilities, chemical companies, the Department of Defense, law firms, and other environmental and engineering companies. Dr. Kierski is often called upon to represent these clients in public and regulatory forums.

Dr. Kierski has extensive training and practical experience in the areas of environmental toxicology, environmental biology, and environmental chemistry, which he has used to develop scientifically defensible approaches for the risk evaluations he has performed. He has utilized this experience within a wide variety of risk assessment projects, tailoring each assessment to the particular needs of his clients. He has emphasized practical applications of risk assessment techniques on projects over his career, using innovative techniques as needed to meet his client's specific needs.

Academic Credentials and Professional Honors

Ph.D., Environmental and Occupational Health, University of Minnesota, 1992
B.A., Environmental Biology, St. Mary's College of Minnesota, 1984

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Sheryl Law
Managing Scientist

Professional Profile

Ms. Sheryl Law is a Managing Scientist in Exponent's EcoSciences practice. She has a strong background in environmental chemistry including extensive work in aquatic systems, contaminant modeling and analytical instrumentation (ion chromatography, neutron activation, spectrophotometry, atomic absorption spectrometry, high performance liquid chromatography, gas chromatography, and mass spectrometry). She has experience coordinating with chemical laboratories to develop analytical methods and sample preparation techniques for identification of chemicals that cannot be identified with conventional analyses. Her research with chiral analysis of optical isomers has applications in fields of natural attenuation and fate and transport modelling. She is broadly trained in environmental science and chemistry and provides strong technical support on ecological risk assessments, natural resource damage assessments, litigation projects and site remedial investigations. In addition, she is an experienced technical writer and has prepared a variety of data reports and literature reviews.

She received her MBA with a focus on enterprise risk and sustainability or corporate social responsibility issues. She has researched the value of public companies with respect to their "triple bottom line" and has created decision analysis models that derive additional cash flow from ecological assets, mitigation banks, and carbon credits.

Academic Credentials and Professional Honors

M.B.A., Seattle University, 2006
M.S., Environmental Chemistry, University of Toronto, 2000
B.Sc., Environmental Science, University of Toronto *(honors with distinction)*, 1998

University of Toronto Fellowship Award (2000); University of Toronto Open Fellowship Award (1998); Golden Key Honor Society Top 15% Scholar; NSERC Undergraduate Research Award in Industry

Licenses and Certifications

OSHA Hazardous Waste Operations and Emergency Response 40-hour certification

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Jane Ma, Ph.D.
Senior Scientist

Professional Profile

Dr. Jane Ma is a Senior Scientist in Exponent's EcoSciences practice. She has a strong interdisciplinary background in geosciences and Computer Science including extensive work in geographic information systems (GIS), remote sensing, landscape/watershed analysis, geostatistics, on-line web mapping, environmental/ecological model implementation, and decision support system (DSS) development. Her scientific expertise is principally in the areas of water resources management, with an emphasis on wetland assessment. Her study involves with aquatic habitat evaluation, wetland vulnerability assessment, headwater wetland mitigation, low-impact Best Management Practices (BMPs) design, and watershed-scale ecological restoration study.

Dr. Ma is highly skilled in geospatial analysis and GIS programming. She is experienced in ArcGIS suite, ERDAS, Plone, PostgreSQL and programming languages in Visual Basic, Python, and C++. She has developed numerous desktop and web-based GIS applications customized to meet the requirement of different projects.

Academic Credentials and Professional Honors

Ph.D., Geosciences and Computer Science, University of Missouri, Kansas City, 2006
M.S., GIS and Remote Sensing, Peking University, China 2001
B.S., Geography, Beijing Normal University, China 1998

Licenses and Certifications

Wetland Delineation Training and Field Practicum, Adaptive Ecosystems, Inc., Kansas City, Missouri, April 19–23, 2004, Certified

Languages

Chinese

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Charles A. Menzie, Ph.D.

Principal Scientist and Practice Director

Professional Profile

Dr. Charles A. Menzie is a Principal Scientist and Director of Exponent's Ecological and Biological Sciences practice. Dr. Menzie's primary area of expertise is the environmental fate and effects of physical, biological, and chemical stressors on terrestrial and aquatic systems. This includes work on chemicals in the environment, oil and gas operations, fossil fuel and nuclear power plants, alternative energy projects, invasive species, and climate change impacts. Dr. Menzie has worked at more than 100 hazardous waste sites, including many high-profile Superfund Sites and NRDA-related cases. He has been called upon to evaluate environmental damage claims related to the use of pesticides, herbicides, and other chemicals. He has provided expertise related to the environmental implications of atmospheric emissions and of point and nonpoint sources of nutrients and toxic chemicals to aquatic and marine environments (through Total Maximum Daily Loads or TMDL programs). Dr. Menzie has worked on a broad range of contaminants, including solvents (TEC, PCE, TCA, and others), persistent chlorinated compounds such as PCBs, dioxins, and pesticides, as well as hydrocarbons including PAHs, cyanides, and metals such as lead, hexavalent chromium, mercury, and cadmium. Employing his deep understanding of risk-based studies and remediation, Dr. Menzie has directed the development of work plans, the implementation of remedial investigations, and the selection of remedial measures, on behalf of individual potentially responsible parties (PRPs), as well as PRP groups. Dr. Menzie has worked in all EPA Regions, including the Midwest and South (Regions 4, 5, and 6), the Northeast and East Coast (Regions 1, 2, and 3), and the West (Regions 8, 9, and 10). He has an active international practice including projects in Ecuador, Uruguay, and Yemen. He has extensive litigation experience and has provided steady and compelling advice and guidance in many controversial and contentious situations. He is the co-inventor of SediMite™, a low-impact method for remediating contaminated sediments.

Dr. Menzie is recognized as one of the leaders in the field of risk assessment and was awarded the Risk Practitioner Award by the Society for Risk Analysis. He has served on the Councils of SRA and SETAC, the two major professional organizations in this field. Dr. Menzie has led numerous peer reviews for industry and for government. He has taken the lead in developing guidance documents for industry and government and has focused on methods that are workable and acceptable to a broad range of parties. He has developed and applied a formal causal-analysis methodology for assessing causation in cases of environmental impairment and contributions of chemical contamination. He was one of the committee members to draft the ASTM Standard for risk-based corrective action (RBCA) for chemical release sites and extended that standard to ecological considerations. He served on the National Research Council's Committee on Bioavailability of Chemicals in Soils and Sediments. In addition to his work on chemical risk-related matters, Dr. Menzie has developed and applied methods for identifying third parties who have contributed to contamination in aquatic and terrestrial environments. These projects have involved meshing historical information with transport-and-

fate analyses, risk considerations (remediation drivers), and forensic analyses. He has provided expert advice on historical use and disposal of asbestos products and historical assessments of asbestos in fill.

Academic Credentials and Professional Honors

Ph.D., Biology, City University of New York, 1978
M.A., Biology, City College of New York, 1974
B.S., Biology, Manhattan College, 1971

Licenses and Certifications

OSHA Certified Eight-Hour HAZWOPER Annual Refresher Training in Hazardous Waste Operations and Emergency Response, updated annually; OSHA Certified 40-Hours of Training in Hazardous Waste Operations and Emergency Response

Patents

U.S. Patent # 7,824,129: A Low-Impact Delivery System for In-Situ Treatment of Contaminated Sediment.

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Farrukh Mohsen, Ph.D., P.E.
Senior Managing Engineer

Professional Profile

Dr. Farrukh Mohsen is a Senior Managing Engineer in Exponent's Environmental Sciences practice. He has 34 years of experience in hydrogeology and groundwater flow and contaminant transport modeling. He has applied his technical strengths in assisting corporate clients nationwide by providing expert opinions in litigation, environmental compliance, and liability allocations. Dr. Mohsen focuses primarily on developing an understanding of the transport and fate of constituents in the subsurface in both groundwater and soil vapor. He has helped his clients by determining the source of groundwater contamination, designing and evaluating remedial options, conducting risk assessments and regulatory negotiations, achieving environmental compliance, delivering public presentations, providing expert opinions, and refuting claims by other experts. He serves as both a testifying and consulting expert.

Prior to joining Exponent, Dr. Mohsen worked as Senior Project Manager at Gannet Fleming and Environ International Corporation. He has been a Visiting Professor at Rutgers University, a Visiting Fellow at Princeton University, an Associate Professor at the University of Petroleum and Minerals, and a lecturer at Bangladesh University of Engineering and Technology.

Academic Credentials and Professional Honors

Ph.D., Environmental Engineering and Water Resources, University of Waterloo, 1975
M.A.Sc., Environmental Engineering and Water Resources, University of Waterloo, 1972
B.Sc., Civil Engineering, Bangladesh University of Engineering and Technology, 1968

Licenses and Certifications

Registered Professional Engineer, New Jersey, #41041
OSHA Hazardous Waste Operations and Emergency Response 40-hour certification

Languages

Bangali

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Kirk O'Reilly, Ph.D., J.D.
Managing Scientist

Professional Profile

Dr. Kirk O'Reilly is a Managing Scientist in Exponent's Environmental Sciences practice and is based in Bellevue, Washington. He has more than 25 years of experience investigating the interaction between environmental and biological chemistry, and spent 15 years as an in-house consultant for a major oil company. He is a recognized expert in environmental chemistry, petroleum source identification, and bioremediation, and has played a significant role in developing the oil industry's technical response to managing MTBE in the environment. Dr. O'Reilly was a founding member of Chevron's Oil Spill Environmental Functional Team and is trained in aspects of spill management, response, monitoring, and remediation. He has responded to spills of both crude oil and refined products, and served as on-site liaison to environmental regulators. Dr. O'Reilly has provided litigation support in toxic tort and property damage suits, and managed projects focused on the remediation of soils, sediments, and groundwater, as well as on improving industrial wastewater treatment. Specific contaminants studied include crude oil, refined products, chlorinated solvents, wood treatment compounds, pesticides, and fertilizers. He developed innovative methods for monitoring the transformation and assessing the risk of petroleum. He has also conducted toxicity identification evaluations on refinery effluents and managed waste and water issues on offshore platforms. Experienced working within the constraints of the RCRA, CERCLA, and NPDES programs, Dr. O'Reilly promotes the use of strategic site assessments to reduce costs while improving quality. He has participated in collaborative research projects with regulators at the federal, state, and local levels, and taught technical courses sponsored by regulatory agencies, universities, and industrial trade groups. Dr. O'Reilly is a member of the Washington State Bar.

Academic Credentials and Professional Honors

J.D., University of Idaho College of Law (*magna cum laude)*, 2007
Ph.D., Biochemistry, University of Idaho, 1989
M.S., Biology, Portland State University, 1985
B.S., Biology, University of California, Irvine, 1980

Licenses and Certifications

Washington State Bar, #39473

Patents

Patent 6,924,404: Inhibition of Biological Degradation of Fischer-Tropsch Products, 2005 (with M. Moir, and D. O'Rear).

Patent 6,849,664: Process for Disposing Biocidecontaining Cooling Water, 2005 (with M. Moir, D. O'Rear, and R. Moore).

Patent 6,800,101: Deactivatable Biocides for hydrocarbonaceous Products, 2004 (with M. Moir and D. O'Rear).

Patent 6,626,122: Deactivatable biocides in Ballast Water, 2003 (with M. Moir, D. O'Rear, M. Buetzow, M. Dorsch, and V. Brian).

Patent 6,569,909: Inhibition of Biological Degradation in Fischer-Tropsch products, 2003 (with M. Moir, and D. O'Rear).

Patent 5,236,594: Process for removing toxicants from aqueous petroleum waste streams, 1993 (with J. Suzuki).

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Richard Podolsky, Ph.D.
Senior Managing Scientist

Professional Profile

Dr. Richard Podolsky is a Senior Managing Scientist in Exponent's EcoSciences practice. Dr. Podolsky's training is in ecology and he assists clients with all aspects of environmental compliance, including environmental conservation, natural resource assessments, ecological/environmental restoration, site assessment/site investigations (SA/SI), habitat evaluations, resource conservation and recovery, the Migratory Bird Treaty Act (MBTA), Marine Mammal Protection Act (MMPA), National Environmental Policy Act (NEPA), and Endangered Species Act (ESA), particularly Section 7 Consultations pertaining to ESA.

Dr. Podolsky has 30 years of experience in assisting land developers and oil, gas, and electric generation companies in reducing potentially adverse environmental effects of a wide range of projects and achieving regulatory compliance. He is experienced in researching and successfully applying cost-effective, state-of-the-art environmental techniques, materials, and software to new development and mitigation projects, proactively addressing the environmental concerns of nonprofit organizations and community groups, and troubleshooting with governmental officials to achieve regulatory compliance. Dr. Podolsky has worked on the impact of the built environment on wildlife, especially wind and solar power, artificial lighting big boxes, skyscrapers, and communication and utility towers.

Dr. Podolsky has in-depth experience with the application of computers and modeling to scientific problems, specifically with GIS integration, pattern recognition, data mining, risk assessment, and remote sensing. He regularly designs and develops software and models for environmental scientists, including the Avian Risk of Collision (ARC) Model, which quantifies risk of birds around wind turbines and communication towers; FullPixelSearch, an image mining software tool; GAIA, the first GIS designed for Macintosh OS; Diversidad, a software model for mapping biodiversity hot spots; and FireTower, a software tool for modeling wildfire spread.

Academic Credentials and Professional Honors

Ph.D., Natural Resources, University of Michigan, 1985
M.S., Ecology, Rutgers University, 1980
B.A., Biology, University of Wisconsin, 1976

Licenses and Certifications

Certified Senior Ecologist, Ecological Society of America

Patents

U.S. Patent #7,315,799: Method of and Article of Manufacture for Determining Probability of Avian Collision. Date of Patent: January 2008.

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Walter J. Shields, Ph.D., C.P.S.S.

Principal Scientist and Practice Director, Environmental and Earth Sciences

Professional Profile

Dr. Walter Shields is the Director of Exponent's Environmental and Earth Sciences practice. A Certified Professional Soil Scientist, he specializes in the study of transport and geochemical fate of toxic pollutants and their environmental effects. He has 34 years of experience conducting and managing environmental studies in more than 30 states and four Canadian provinces. He provides scientific and strategic consultation to industrial clients on the design and implementation of CERCLA and RCRA investigations, cost-effective remediation approaches, and negotiations with state and federal agencies. Dr. Shields manages multidisciplinary investigations, risk assessments, and feasibility studies. He investigates the industrial archeology of sites to understand the history of contaminant sources in a given area. He serves as an expert witness in environmental forensics and has testified on the origin, transport, and fate of chemicals in air, soils, sediments, surface water, groundwater, and biota, and exposure of humans and ecological receptors to those chemicals. He has particular expertise in the environmental chemistry and source identification of dioxins and furans, PCBs, PAHs, and heavy metals and metalloids. Dr. Shields has also testified on the allocation and appropriateness of remediation costs at a variety of sites. He has specialized expertise in the forest products industry and at mining and smelting sites.

Academic Credentials and Professional Honors

Ph.D., Soil Science, University of Wisconsin, 1979
M.S., Forest Management (Soil Science), University of Idaho, 1976
B.S., Forest Science, University of Washington, 1974

Elected to Phi Kappa Phi (honor society for higher education)
Elected to Sigma Xi (honor society for science and engineering)

Hazardous Waste Operations Management and Supervisor training
ISC/AERMOD Air Dispersion Modeling Course

License and Certifications

Certified Professional Soil Scientist, No. 02471, American Registry of Certified Professionals in Agronomy, Crops and Soils

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Scott S. Shock, P.E.
Managing Engineer

Professional Profile

Mr. Shock is a Managing Engineer in Exponent's Environmental Sciences practice. His diverse project experience includes site investigation and characterization, contaminant transport and fate, human health and ecological risk assessment, soil and groundwater remediation, groundwater modeling, cost analysis, and litigation support. Mr. Shock has planned and implemented numerous field investigations involving a wide variety of contaminants in soil, groundwater, and sediment. He is skilled in data interpretation and evaluation, and development of effective conceptual site models.

One of Mr. Shock's specialties is assessing environmental impacts associated with mining, particularly in sensitive habitats. He is a leader in the development of proactive and preventive risk management strategies designed to minimize the environmental impacts of mining. Mr. Shock is also skilled in risk communication, and in facilitating cooperation among diverse stakeholder groups.

Mr. Shock's cost analysis experience includes feasibility studies under CERCLA and RCRA, and cost allocations associated with cost recovery litigation and insurance coverage. He employs tools such as cost/benefit analysis, Monte Carlo uncertainty analysis, sensitivity analysis, uncertainty reduction (e.g., through targeted supplemental data collection), net environmental benefits analysis, and other decision analysis methods to help clients make more informed and robust remediation and liability management decisions.

Mr. Shock's contaminated-site remediation experience includes evaluating and comparing remedial technologies; costing, planning, and implementing field pilot tests of remediation systems; and designing and supervising the installation, startup, monitoring, and closure of full-scale remediation systems. He has evaluated ongoing remedial actions to improve operational performance, and has assessed the appropriateness of past remedial actions in support of litigation and cost allocation negotiations, particularly with respect to volatile organics in soil and groundwater.

Academic Credentials and Professional Honors

M.S., Civil/Environmental Engineering, University of Washington, 1994
B.S., Civil Engineering, University of Washington, 1992

Licenses and Certifications

Professional Engineer in Washington State, License No. 37417
OSHA Hazardous Waste Operations and Emergency Response 40-hour certification

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Randall Wentsel, Ph.D.
Senior Managing Scientist

Professional Profile

Dr. Randall Wentsel is a Senior Managing Scientist in Exponent's EcoSciences practice. Dr. Wentsel has over 30 years of experience in environmental sciences in areas including: sediment, aquatic, and terrestrial toxicology; ecological risk assessment; research strategies; and science policy. Dr. Wentsel has authored over 30 open literature publications, 70 government publications, and various book chapters addressing state-of-the-art techniques and environmental toxicology and risk assessment issues.

One of Dr. Wentsel's strengths is the ability to lead multi-disciplinary groups of scientists to address complex issues and to delineate attainable goals; these efforts have resulted in providing guidance to the scientific community. Primary examples (that he has led or co-led) include the Environmental Protection Agency (EPA) Framework for Metals Risk Assessment, the EPA Office of Solid Waste and Emergency Response (OSWER) Guidance on Ecological Soil Screening Levels, a White House Committee for Environment and Natural Resources (CENR) document on Ecological Risk Assessment in the Federal Government, and a DoD Tri-service guidance on Ecological Risk Assessment.

Dr. Wentsel has served in several Federal government positions. He was the National Program Director (NPD) for Contaminated Sites/Resource Conservation in the EPA's Office of Research and Development (ORD), where he provided scientific direction of the program, strategic planning, and documentation of research impacts and applications. In the EPA Office of Water, Dr. Wentsel was a Branch Chief and supervised a staff addressing nutrient criteria, biosolids issues, and sedimentation criteria. He also worked in the ORD National Center for Environmental Assessment and the Office of Science Policy. Working for DoD, Dr. Wentsel managed research activities in ecological risk assessment, aquatic and terrestrial toxicology and biotechnology at the U.S. Army Edgewood Research, Development, and Engineering Center.

Dr. Wentsel has a unique breadth of experience in science policy through completion of the Senior Executive Fellows program at the JFK School of Government, Harvard University, being chosen as the SETAC Science Fellow on the U.S. Senate Environment and Public Works Committee, serving as the DoD member on the White House National Science and Technology Council, Committee on the Environment and Natural Resources, and working with the White House Office of Science and Technology Policy staff on risk and cost benefit issues.

Dr. Wentsel is active in peer review panels, advisory committees, and technical workshops. In the EPA development of ecological risk assessment (ERA) methods, Dr. Wentsel was a peer reviewer on the ERA Framework report, case studies, and guidelines. Technical workshops

have included: assessing multiple stressors to ecosystems, ecological risk management, population modeling, soil quality standards, and bioavailability.

Academic Credentials and Professional Honors

Ph.D., Bionuclear, Purdue University, 1977
M.S., Biology, Butler University, 1974
B.S., Zoology, De Pauw University, 1973

EPA Science Achievement Award for Biology/Ecology

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Appendix B

Evaluation of Additional Areas of Special Ecological Concern

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Steele City	Montana	No	25.4	X			X		2	Frenchman Creek	Perennial	--	--	25.4	Frenchman Creek	--	--
Steele City	Montana	No	25.75			X			1	Unnamed waterbody	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	27.06			X			1	Unnamed tributary to Panhandle Coulee	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	27.16			X			1	Unnamed tributary to Panhandle Coulee	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	28.8			X			1	Unnamed tributary to Panhandle Coulee	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	30.45			X			1	Unnamed tributary to Jordan Coulee	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	32.4			X			1	East Fork Cache Creek	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	34.7			X			1	Unnamed tributary to Pasture Coulee	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	35.02			X			1	Pasture Coulee	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	35.34			X			1	Unnamed tributary to Pasture Coulee	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	35.51			X			1	Unnamed tributary to Pasture Coulee	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	35.54			X			1	Unnamed tributary to Pasture Coulee	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	35.81			X			1	Unnamed tributary to Pasture Coulee	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	35.84			X			1	Unnamed tributary to Pasture Coulee	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	35.95			X			1	Unnamed tributary to Pasture Coulee	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	36.01			X			1	Unnamed tributary to Pasture Coulee	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	36.12			X			1	Jones Coulee	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	37.97			X			1	Hay Coulee	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	38.59			X			1	Unnamed tributary to Rock Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	39.06			X			1	Unnamed tributary to Rock Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	39.08			X			1	Unnamed tributary to Rock Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	39.09			X			1	Unnamed tributary to Rock Creek	Man-made ditch	--	--	--	--	--	--
Steele City	Montana	No	39.16	X		X			2	Rock Creek	Perennial	--	--	39.2	Rock Creek	--	--
Steele City	Montana	No	40.52	X		X			2	Willow Creek	Perennial	--	--	40.5	Willow Creek	--	--
Steele City	Montana	No	40.92			X			1	Unnamed tributary to Willow Creek	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	41.06			X			1	Unnamed tributary to Willow Creek	Ephmeral	--	--	--	--	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Steele City	Montana	No	41.72			X			1	Unnamed tributary to Willow Creek	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	42.55			X			1	Unnamed tributary to Willow Creek	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	44.24			X			1	Unnamed tributary to Lime Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	44.58			X			1	Unnamed tributary to Lime Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	45.05			X			1	Lime Creek	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	45.13			X			1	Lime Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	47.95			X			1	Black Coulee	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	48.02			X			1	Unnamed tributary to Black Coulee	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	48.03			X			1	Unnamed tributary to Black Coulee	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	48.26			X			1	Unnamed tributary to Black Coulee	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	48.32			X			1	Unnamed tributary to Black Coulee	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	48.54			X			1	Unnamed tributary to Black Coulee	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	49.9			X			1	Unnamed tributary to Bear Creek	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	49.94			X			1	Unnamed tributary to Bear Creek	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	50.53			X			1	Unnamed tributary to Bear Creek	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	51.3			X			1	Brush Fork	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	51.41			X			1	Unnamed tributary to Brush Fork Creek	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	51.44			X			1	Unnamed tributary to Brush Fork Creek	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	51.53			X			1	Unnamed tributary to Brush Fork Creek	Ephmeral	--	--	--	--	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Steele City	Montana	No	51.61			X			1	Unnamed tributary to Brush Fork Creek	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	52.47			X	X		2	Bear Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	52.58			X	X		2	Unnamed tributary to Bear Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	53.49			X			1	Unger Coulee	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	53.64			X			1	Unnamed tributary to Unger Coulee	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	53.79			X			1	Unnamed tributary to Unger Coulee	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	54.14			X			1	Unnamed tributary to Unger Coulee	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	55.03			X			1	Unnamed tributary to Buggy Creek	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	55.22			X			1	Unnamed tributary to Buggy Creek	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	55.46			X			1	Buggy Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	55.67			X			1	Unnamed tributary to Buggy Creek	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	56.03			X			1	Unnamed tributary to Buggy Creek	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	56.04			X			1	Unnamed tributary to Buggy Creek	Ephmeral	--	--	--	--	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Steele City	Montana	No	56.07			X			1	Unnamed tributary to Buggy Creek	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	56.12			X			1	Unnamed tributary to Buggy Creek	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	56.27			X			1	Unnamed tributary to Buggy Creek	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	56.41			X			1	Unnamed tributary to Buggy Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	56.45			X			1	Unnamed tributary to Buggy Creek	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	56.71			X			1	Unnamed tributary to Buggy Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	56.72			X			1	Unnamed tributary to Buggy Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	57.15			X			1	Alkali Coulee	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	57.55			X			1	Unnamed tributary to Alkali Coulee	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	57.55			X			1	Unnamed tributary to Alkali Coulee	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	57.7			X			1	Unnamed tributary to Alkali Coulee	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	57.74			X			1	Unnamed tributary to Alkali Coulee	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	57.91			X			1	Unnamed tributary to Alkali Coulee	Ephmeral	--	--	--	--	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Steele City	Montana	No	58.04			X			1	Unnamed tributary to Alkali Coulee	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	59.5			X			1	Wire Grass Coulee	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	59.55			X			1	Unnamed tributary to Wire Grass Coulee	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	60.02			X			1	Spring Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	61.87			X			1	Mooney Coulee	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	62.93			X			1	Unnamed tributary to Mooney Coulee	Ephmeral	--	--	--	--	--	--
Steele City	Montana	MT-1	65.97			X			1	Unnamed tributary to Cherry Creek	Ephmeral	--	--	--	--	--	--
Steele City	Montana	MT-1	67.2			X			1	Cherry Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	MT-1	67.25			X			1	Cherry Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	MT-1	67.41			X			1	Unnamed tributary to Cherry Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	MT-1	68.5			X			1	Foss Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	MT-1	68.52			X			1	Foss Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	MT-1	68.64			X			1	Foss Creek	Intermittent	--	--	--	--	--	--

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Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Steele City	Montana	MT-1	69.41			X			1	Unnamed tributary to East Fork	Ephmeral	--	--	--	--	--	--
Steele City	Montana	No	70.43			X			1	Spring Coulee	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	82.95	X		X	X		3	Milk River	Perennial	82.9	Yes	82.9	Milk River	--	--
Steele City	Montana	No	89.17	X		X			2	Missouri River	Perennial	89.2	Yes	89.2-89.3	Missouri River	--	--
Steele City	Montana	No	89.26	X		X			2	Missouri River	Perennial	89.2	Yes	89.2-89.3	Missouri River	--	--
Steele City	Montana	No	93.88	X					1	Unnamed tributary to Struple Coulee	Perennial	--	--	93.9	Unnamed tributary to Struple Coulee	--	--
Steele City	Montana	No	94.89	X					1	Unnamed tributary to Jorgensen Coulee	Perennial	--	--	94.9	Unnamed tributary to Jorgensen Coulee	--	--
Steele City	Montana	No	102.27				X		1	Unnamed tributary to Bear Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	102.73				X		1	Unnamed tributary to Bear Creek	Ephemeral	--	--	--	--	--	--
Steele City	Montana	No	102.78				X		1	Unnamed tributary to Bear Creek	Ephemeral	--	--	--	--	--	--
Steele City	Montana	No	103.18				X		1	Unnamed tributary to Bear Creek	Ephemeral	--	--	--	--	--	--
Steele City	Montana	No	105.61				X		1	Bear Creek	Ephemeral	--	--	--	--	--	--
Steele City	Montana	No	105.62				X		1	Bear Creek	Ephemeral	--	--	--	--	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Steele City	Montana	No	107.44				X		1	Unnamed tributary to North Prong Shade Creek	Ephemeral	--	--	--	--	--	--
Steele City	Montana	No	107.63				X		1	Unnamed tributary to North Prong Shade Creek	Ephemeral	--	--	--	--	--	--
Steele City	Montana	No	107.68				X		1	Unnamed tributary to North Prong Shade Creek	Ephemeral	--	--	--	--	--	--
Steele City	Montana	No	107.78				X		1	Unnamed tributary to North Prong Shade Creek	Ephemeral	--	--	--	--	--	--
Steele City	Montana	No	107.79				X		1	Unnamed tributary to North Prong Shade Creek	Ephemeral	--	--	--	--	--	--
Steele City	Montana	No	108.15				X		1	Unnamed tributary to North Prong Shade Creek	Ephemeral	--	--	--	--	--	--
Steele City	Montana	No	108.58				X		1	North Prong Shade Creek	Ephemeral	--	--	--	--	--	--
Steele City	Montana	No	110.72				X		1	Shade Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	110.74				X		1	Shade Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	110.77				X		1	Shade Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	110.8				X		1	Unnamed tributary to Shade Creek	Ephemeral	--	--	--	--	--	--
Steele City	Montana	No	111.71				X		1	Unnamed tributary to Shade Creek	Ephemeral	--	--	--	--	--	--
Steele City	Montana	No	111.73				X		1	Unnamed tributary to Shade Creek	Ephemeral	--	--	--	--	--	--
Steele City	Montana	No	111.92				X		1	Unnamed tributary to Shade Creek	Ephemeral	--	--	--	--	--	--
Steele City	Montana	No	112.14				X		1	Unnamed tributary to Shade Creek	Ephemeral	--	--	--	--	--	--
Steele City	Montana	No	112.41				X		1	Unnamed tributary to Shade Creek	Ephemeral	--	--	--	--	--	--
Steele City	Montana	No	112.44				X		1	Unnamed tributary to Shade Creek	Ephemeral	--	--	--	--	--	--
Steele City	Montana	No	114.55				X		1	South Fork Shade Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	115.81				X		1	Unnamed tributary to South Fork Shade Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	115.9				X		1	Unnamed tributary to South Fork Shade Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	116.25				X		1	Unnamed tributary to South Fork Shade Creek	Ephemeral	--	--	--	--	--	--
Steele City	Montana	No	116.41				X		1	Unnamed tributary to South Fork Shade Creek	Ephemeral	--	--	--	--	--	--
Steele City	Montana	No	117.17				X		1	Unnamed tributary to South Fork Shade Creek	Ephemeral	--	--	--	--	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Steele City	Montana	No	127.99	X					1	East Fork Prairie Elk Creek	Perennial	--	--	128	East Fork Prairie Elk Creek	--	--
Steele City	Montana	No	134.78				X		1	Unnamed tributary to Lost Creek	Ephemeral	--	--	--	--	--	--
Steele City	Montana	No	136.6				X		1	Unnamed tributary to Lost Creek	Ephemeral	--	--	--	--	--	--
Steele City	Montana	No	138.65				X		1	Unnamed tributary to Lost Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	139.19				X		1	Unnamed tributary to Lost Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	139.75				X		1	Unnamed tributary to Lost Creek	Ephemeral	--	--	--	--	--	--
Steele City	Montana	No	146.97	X					1	Redwater River	Perennial	--	--	147	Redwater River	--	--
Steele City	Montana	No	153.69	X					1	Buffalo Spings Creek	Perennial	--	--	153.7	Buffalo Spings Creek	--	--
Steele City	Montana	No	159.63	X					1	Berry Creek	Perennial	--	--	159.6	Berry Creek	--	--
Steele City	Montana	No	166.59				X		1	Upper Seven Mile Creek	Ephemeral	--	--	--	--	--	--
Steele City	Montana	No	175.6	X					1	Clear Creek	Perennial	--	--	175.6	Clear Creek	--	--
Steele City	Montana	MT-4	196.06	X					1	Side channel of Yellowstone River	Perennial	--	--	196.1	Side channel of Yellowstone River	--	--
Steele City	Montana	No	196.36	X		X			2	Yellowstone River	Perennial	196.4	Yes	196.4	Yellowstone River	--	--
Steele City	Montana	No	234.7	X					1	Pennel Creek	Perennial	--	--	234.7	Pennel Creek	--	--
Steele City	Montana	No	236.02	X					1	Unnamed tributary to Pennel Creek	Perennial	--	--	236	Unnamed tributary to Pennel Creek	--	--
Steele City	Montana	No	246.45				X		1	Unnamed tributary to Red Butte Creek	Ephemeral	--	--	--	--	--	--
Steele City	Montana	No	246.51				X		1	Red Butte Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	246.65				X		1	Unnamed tributary to Red Butte Creek	Ephemeral	--	--	--	--	--	--
Steele City	Montana	No	249				X		1	Unnamed tributary to Red Butte Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	250.2				X		1	Red Butte Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	250.22				X		1	Red Butte Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	250.27				X		1	Red Butte Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	250.9				X		1	Red Butte Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	251.11				X		1	Red Butte Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	251.12				X		1	Red Butte Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	251.13				X		1	Red Butte Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	251.2				X		1	Red Butte Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	251.28				X		1	Red Butte Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	251.45				X		1	Unnamed tributary to Red Butte Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	251.91				X		1	Unnamed tributary to Red Butte Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	252.45				X		1	Unnamed tributary to Red Butte Creek	Intermittent	--	--	--	--	--	--
Steele City	Montana	No	262.68	X					1	Little Beaver Creek	Perennial	--	--	262.7	Little Beaver Creek	--	--
Steele City	Montana	MT-7	281.47	X					1	Boxelder Creek	Perennial	--	--	281.5	Boxelder Creek	--	--

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Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Steele City	South Dakota	SD-2	292.08	X					1	Little Missouri River	Perennial	292.1	Yes	292.1	Little Missouri River	--	--
Steele City	South Dakota	No	303.27				X		1	Unnamed tributary to Jones Creek	Intermittent	--	--	--	--	--	--
Steele City	South Dakota	No	303.95				X		1	Unnamed tributary to Jones Creek	Intermittent	--	--	--	--	--	--
Steele City	South Dakota	No	304.22				X		1	Unnamed tributary to Jones Creek	Ephemeral	--	--	--	--	--	--
Steele City	South Dakota	No	304.75				X		1	Unnamed tributary to Jones Creek	Intermittent	--	--	--	--	--	--
Steele City	South Dakota	No	306.09				X		1	Unnamed tributary to Jones Creek	Ephemeral	--	--	--	--	--	--
Steele City	South Dakota	No	306.65				X		1	Unnamed tributary to Jones Creek	Ephemeral	--	--	--	--	--	--
Steele City	South Dakota	No	307.43				X		1	Unnamed tributary to Jones Creek	Ephemeral	--	--	--	--	--	--
Steele City	South Dakota	No	308.21				X		1	Unnamed tributary to Rush Creek	Ephemeral	--	--	--	--	--	--
Steele City	South Dakota	No	308.28				X		1	Unnamed tributary to Rush Creek	Ephemeral	--	--	--	--	--	--
Steele City	South Dakota	No	308.6				X		1	Unnamed tributary to Rush Creek	Ephemeral	--	--	--	--	--	--
Steele City	South Dakota	No	308.7				X		1	Unnamed tributary to Rush Creek	Ephemeral	--	--	--	--	--	--
Steele City	South Dakota	No	309.13				X		1	Unnamed tributary to Rush Creek	Ephemeral	--	--	--	--	--	--
Steele City	South Dakota	No	309.55				X		1	Unnamed tributary to Rush Creek	Ephemeral	--	--	--	--	--	--
Steele City	South Dakota	No	311.67				X		1	Unnamed tributary to Rush Creek	Ephemeral	--	--	--	--	--	--
Steele City	South Dakota	No	318.09	X					1	South Fork Grand River	Perennial	--	--	318.1	South Fork Grand River	--	--
Steele City	South Dakota	No	322.88	X					1	Clark's Fork Creek	Perennial	--	--	322.9	Clark's Fork Creek	--	--
Steele City	South Dakota	No	328.67				X		1	West Squaw Creek	Intermittent	--	--	--	--	--	--
Steele City	South Dakota	No	328.74				X		1	West Squaw Creek	Intermittent	--	--	--	--	--	--
Steele City	South Dakota	No	328.82				X		1	West Squaw Creek	Intermittent	--	--	--	--	--	--
Steele City	South Dakota	No	328.83				X		1	West Squaw Creek	Intermittent	--	--	--	--	--	--
Steele City	South Dakota	No	328.86	X			X		2	West Squaw Creek	Intermittent	--	--	328.9	West Squaw Creek	--	--
Steele City	South Dakota	No	329.07				X		1	Unnamed tributary to West Squaw Creek	Ephemeral	--	--	--	--	--	--
Steele City	South Dakota	No	329.09				X		1	Unnamed tributary to West Squaw Creek	Ephemeral	--	--	--	--	--	--
Steele City	South Dakota	No	329.33				X		1	Unnamed tributary to West Squaw Creek	Ephemeral	--	--	--	--	--	--
Steele City	South Dakota	No	330.34				X		1	Unnamed tributary to West Squaw Creek	Ephemeral	--	--	--	--	--	--
Steele City	South Dakota	No	330.53				X		1	Unnamed tributary to West Squaw Creek	Intermittent	--	--	--	--	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Steele City	South Dakota	No	330.62				X		1	Unnamed tributary to West Squaw Creek	Intermittent	--	--	--	--	--	--
Steele City	South Dakota	No	331.01				X		1	Unnamed tributary to West Squaw Creek	Intermittent	--	--	--	--	--	--
Steele City	South Dakota	No	331.12				X		1	Unnamed tributary to West Squaw Creek	Intermittent	--	--	--	--	--	--
Steele City	South Dakota	No	331.32				X		1	Unnamed tributary to West Squaw Creek	Ephemeral	--	--	--	--	--	--
Steele City	South Dakota	No	331.7				X		1	Unnamed tributary to West Squaw Creek	Intermittent	--	--	--	--	--	--
Steele City	South Dakota	No	331.91				X		1	Unnamed tributary to West Squaw Creek	Intermittent	--	--	--	--	--	--
Steele City	South Dakota	No	331.98				X		1	Unnamed tributary to West Squaw Creek	Intermittent	--	--	--	--	--	--
Steele City	South Dakota	No	353.1	X					1	Unnamed tributary to North Fork Moreau River	Perennial	--	--	353.1	Unnamed tributary to North Fork Moreau River	--	--
Steele City	South Dakota	No	356.94	X					1	North Fork Moreau River	Perennial	--	--	356.9	North Fork Moreau River	--	--
Steele City	South Dakota	No	364.83	X					1	South Fork Moreau River	Perennial	--	--	364.8	South Fork Moreau River	--	--
Steele City	South Dakota	No	383.72	X					1	Pine Creek	Perennial	--	--	383.7	Pine Creek	--	--
Steele City	South Dakota	No	408.94	X					1	Red Owl Creek	Perennial	--	--	408.9	Red Owl Creek	--	--
Steele City	South Dakota	SD-4	425.42	X					1	Narcelle Creek	Perennial	--	--	425.4	Narcelle Creek	--	--
Steele City	South Dakota	SD-4	426.02			X			1	Unnamed tributary to Cheyenne River	Ephemeral	--	--	--	--	--	--
Steele City	South Dakota	SD-4	426.07	X		X			2	Cheyenne River	Perennial	426.1	Yes	426.1	Cheyenne River	--	--
Steele City	South Dakota	SD-4	429.11	X					1	Bridger Creek	Perennial	--	--	429.1	Bridger Creek	--	--
Steele City	South Dakota	No	443.84	X					1	West Plum Creek	Perennial	--	--	443.8	West Plum Creek	--	--
Steele City	South Dakota	No	460.92					X	1	Witcher Holes Creek	Intermittent	--	--	--	--	--	--
Steele City	South Dakota	No	460.94					X	1	Witcher Holes Creek	Intermittent	--	--	--	--	--	--
Steele City	South Dakota	No	461.63					X	1	Unnamed tributary to Witcher Holes Creek	Ephemeral	--	--	--	--	--	--
Steele City	South Dakota	SD-5	479.27	X					1	Mitchell Creek	Perennial	--	--	479.3	Mitchell Creek	--	--
Steele City	South Dakota	No	481.54	X					1	Bad River	Perennial	--	--	481.5	Bad River	--	--
Steele City	South Dakota	SD-6	537.09	X		X			2	White River	Ephemeral	--	--	537.1	White River	--	--
Steele City	South Dakota	No	537.13	X		X			2	White River	Perennial	537.2	Yes	537.1	White River	--	--
Steele City	Nebraska	No	599.9	X	X	X			3	Keya Paha River	Perennial	--	--	599.9	Keya Paha River	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	601.12		X				1	Unnamed tributary to Keya Paha River	Intermittent	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	601.46		X				1	Unnamed tributary to Keya Paha River	Intermittent	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	604.19	X	X				2	Spring Creek	Perennial	--	--	604.2	Spring Creek	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	604.53		X				1	Unnamed tributary to Spring Creek	Ephemeral	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	615.38	X	X	X			3	Niobrara River	Perennial	--	--	615.4-651.6	Niobrara River	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	615.48	X	X	X			3	Niobrara River	Perennial	615.5	Yes	615.4-651.6	Niobrara River	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	615.61	X	X	X			3	Niobrara River	Perennial	615.5	Yes	615.4-651.6	Niobrara River	600-746	NE Sand Hills Wetlands

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Steele City	Nebraska	No	624.65		X	X			2	Ash Creek	Intermittent	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	628.81		X	X	X		3	Unnamed tributary to North Branch Elkhorn River	Ephemeral	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	628.92		X	X	X		3	North Branch Elkhorn River	Intermittent	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	630.16		X	X	X		3	Unnamed tributary to South Branch Elkhorn River	Intermittent	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	630.46	X	X	X	X		4	South Fork Elkhorn River	Perennial	--	--	630.5	South Fork Elkhorn River	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	630.69		X	X	X		3	Unnamed tributary to South Branch Elkhorn River	Intermittent	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	634.18		X	X	X		3	Unnamed tributary to Keegan Creek	Man-made ditch	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	636.33		X	X	X		3	Keegan Creek	Intermittent	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	636.35		X	X	X		3	Keegan Creek	Intermittent	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	636.36		X	X	X		3	Keegan Creek	Intermittent	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	639.88		X	X			2	Unnamed tributary to Dry Creek	Ephemeral	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	640.57		X	X			2	Dry Creek	Intermittent	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	647.1		X	X			2	Unnamed tributary to Holt Creek	Ephemeral	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	647.31	X	X	X			3	Holt Creek	Perennial	--	--	647.3	Holt Creek	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	648		X	X			2	Unnamed tributary to Holt Creek	Ephemeral	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	649.98		X	X			2	Unnamed tributary to Holt Creek	Intermittent	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	654.18		X	X			2	Unnamed tributary to Dry Creek	Intermittent	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	656.17		X	X			2	Unnamed tributary to Dry Creek	Ephemeral	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	657.84		X	X			2	Dry Creek	Intermittent	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	658.79		X	X			2	Dry Creek	Intermittent	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	660.22	X	X	X			3	South Fork Elkhorn River	Perennial	--	--	660.2	South Fork Elkhorn River	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	660.23	X	X	X			3	South Fork Elkhorn River	Perennial	--	--	660.2	South Fork Elkhorn River	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	697.3	X	X	X			3	Cedar River	Perennial	697.3	Yes	697.3	Cedar River	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	708.57		X				1	Unnamed tributary to Freeman Creek	Intermittent	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	712.3		X				1	Unnamed tributary to Troy Creek	Ephemeral	--	--	--	--	600-746	NE Sand Hills Wetlands

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Steele City	Nebraska	No	712.63		X				1	Unnamed tributary to Troy Creek	Ephemeral	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	712.76		X				1	Unnamed tributary to Troy Creek	Ephemeral	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	712.97		X				1	Unnamed tributary to Troy Creek	Ephemeral	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	713.52		X				1	Unnamed tributary to Troy Creek	Ephemeral	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	714.06		X				1	Troy Creek	Ephemeral	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	714.35		X				1	Unnamed tributary to Troy Creek	Ephemeral	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	715.56		X				1	Unnamed tributary to Troy Creek	Ephemeral	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	715.78		X				1	Unnamed tributary to Troy Creek	Man-made waterbody	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	720.58		X				1	Unnamed tributary to Troy Creek	Ephemeral	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	722.21		X				1	Unnamed tributary to Troy Creek	Ephemeral	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	722.28		X				1	Unnamed tributary to South Branch Timber Creek	Ephemeral	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	722.41		X				1	Unnamed tributary to South Branch Timber Creek	Ephemeral	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	722.52		X				1	Unnamed tributary to South Branch Timber Creek	Ephemeral	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	722.55		X				1	Unnamed tributary to South Branch Timber Creek	Ephemeral	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	722.82		X				1	Unnamed tributary to South Branch Timber Creek	Ephemeral	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	722.85		X				1	Unnamed tributary to South Branch Timber Creek	Ephemeral	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	722.9		X				1	Unnamed tributary to South Branch Timber Creek	Ephemeral	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	727.96		X				1	Unnamed tributary to South Branch Timber Creek	Ephemeral	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	728.52	X	X				2	South Branch Timber Creek	Perennial	--	--	728.5	South Branch Timber Creek	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	729.39		X				1	Unnamed tributary to South Branch Timber Creek	Ephemeral	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	729.69	X	X				2	Unnamed tributary to South Branch Timber Creek	Perennial	--	--	729.7	Unnamed tributary to South Branch Timber Creek	600-746	NE Sand Hills Wetlands

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Steele City	Nebraska	No	729.77		X				1	Unnamed tributary to South Branch Timber Creek	Perennial	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	730.44		X				1	Unnamed tributary to South Branch Timber Creek	Ephemeral	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	731.35		X				1	Unnamed tributary to South Branch Timber Creek	Ephemeral	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	732.99		X				1	Unnamed tributary to Timber Creek	Ephemeral	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	735.48		X				1	Unnamed tributary to Horse Creek	Open Water	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	735.5		X				1	Unnamed tributary to Horse Creek	Ephemeral	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	736.57		X				1	Unnamed tributary to Horse Creek	Ephemeral	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	NE-5	738.63	X	X				2	Fullerton Canal	Perennial	--	--	738.6	Fullterton Canal	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	740.72	X	X	X			3	Loup River	Perennial	740.7	Yes	740.7	Loup River	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	741.06		X				1	Unnamed tributary to Loup River	Ephemeral	--	--	--	--	600-746	NE Sand Hills Wetlands
Steele City	Nebraska	No	747.14	X					1	Prairie Creek	Perennial	--	--	747.1	Prairie Creek	--	--
Steele City	Nebraska	No	755.74	X					1	Warm Slough	Perennial	--	--	755.7	Warm Slough	--	--
Steele City	Nebraska	No	756.28	X		X			2	Platte River	Perennial	756.3	Yes	756.3-756.5	Platte River	--	--
Steele City	Nebraska	NE-7	758.13	X	X	X			3	Unnamed tributary to Platte River	Perennial	--	--	758.1-758.2	Unnamed tributary to Platte River	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	NE-7	758.24	X	X	X			3	Unnamed tributary to Platte River	Perennial	--	--	758.1-758.2	Unnamed tributary to Platte River	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	NE-7	759.2		X	X			2	Unnamed tributary to Platte River	Ephemeral	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	759.45		X	X			2	Unnamed tributary to Platte River	Intermittent	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	759.72		X	X			2	Unnamed tributary to Platte River	Intermittent	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	759.73		X	X			2	Unnamed tributary to Platte River	Intermittent	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	759.75		X	X			2	Unnamed tributary to Platte River	Intermittent	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	765.5	X	X	X			3	Big Blue River	Perennial	--	--	765.5	Big Blue River	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	767.12		X	X			2	Unnamed tributary to Big Blue River	Ephemeral	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	774.93	X	X	X			3	Lincoln Creek	Perennial	--	--	774.9	Lincoln Creek	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	775.2		X	X			2	Unnamed tributary to Lincoln Creek	Intermittent	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	778.02		X	X	X		3	Unnamed tributary to Beaver Creek	Intermittent	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	778.03		X	X	X		3	Unnamed tributary to Beaver Creek	Intermittent	--	--	--	--	758-847.4	Rainwater Basin Wetlands

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Steele City	Nebraska	NE-9	780.21	X	X	X	X		4	Beaver Creek	Perennial	--	--	780.21	Beaver Creek	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	NE-9	786.15		X	X			2	Unnamed tributary to West Fork Big Blue River	Intermittent	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	787.31		X	X			2	Unnamed tributary to West Fork Big Blue River	Intermittent	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	788.12		X	X			2	Unnamed tributary to West Fork Big Blue River	Intermittent	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	789.57	X	X	X			3	West Fork Big Blue	Perennial	--	--	789.6	West Fork Big Blue	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	789.84		X	X			2	Unnamed tributary to West Fork Big Blue River	Ephemeral	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	790.48		X	X			2	Unnamed tributary to West Fork Big Blue River	Ephemeral	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	791.29		X	X			2	Unnamed tributary to West Fork Big Blue River	Ephemeral	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	795.05		X	X			2	Indian Creek	Intermittent	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	799.43		X	X			2	Unnamed tributary to Indian Creek	Man-made ditch	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	801.55		X	X			2	Unnamed tributary to Turkey Creek	Man-made ditch	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	806.38		X	X			2	Unnamed tributary to Turkey Creek	Intermittent	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	807.54	X	X	X			3	Unnamed tributary to Turkey Creek	Perennial	--	--	807.54	Unnamed tributary to Turkey Creek	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	NE-12	808.55	X	X	X			3	Turkey Creek	Perennial	--	--	808.6	Turkey Creek	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	808.91		X	X			2	Unnamed tributary to Turkey Creek	Intermittent	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	810.08		X	X			2	Unnamed tributary to Turkey Creek	Intermittent	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	810.1		X	X			2	Unnamed tributary to Turkey Creek	Intermittent	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	813.19		X	X	X		3	Unnamed tributary to North Fork Swan Creek	Intermittent	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	815.14		X	X	X		3	Unnamed tributary to North Fork Swan Creek	Intermittent	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	815.36		X	X	X		3	Unnamed tributary to North Fork Swan Creek	Intermittent	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	816.36		X	X	X		3	Unnamed tributary to North Fork Swan Creek	Intermittent	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	816.41		X	X	X		3	Unnamed tributary to North Fork Swan Creek	Intermittent	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	816.45		X	X	X		3	Unnamed tributary to North Fork Swan Creek	Intermittent	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	817.16		X	X	X		3	Unnamed tributary to North Fork Swan Creek	Ephemeral	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	817.55		X	X	X		3	Unnamed tributary to North Fork Swan Creek	Ephemeral	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	823.48		X	X	X		3	Unnamed tributary to South Fork Swan Creek	Intermittent	--	--	--	--	758-847.4	Rainwater Basin Wetlands

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Steele City	Nebraska	No	823.54		X	X	X		3	Unnamed tributary to South Fork Swan Creek	Intermittent	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	823.61		X	X	X		3	Unnamed tributary to South Fork Swan Creek	Intermittent	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	823.97		X	X	X		3	Unnamed tributary to South Fork Swan Creek	Man-made ditch	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	825.04		X	X	X		3	Unnamed tributary to South Fork Swan Creek	Intermittent	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	825.04		X	X	X		3	Unnamed tributary to South Fork Swan Creek	Intermittent	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	826.27		X	X	X		3	South Fork Swan Creek	Intermittent	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	829.47		X	X	X		3	Unnamed tributary to South Fork Swan Creek	Intermittent	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	829.81		X	X	X		3	Unnamed tributary to South Fork Swan Creek	Ephemeral	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	829.88		X	X	X		3	Unnamed tributary to South Fork Swan Creek	Ephemeral	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	829.99		X	X	X		3	Unnamed tributary to South Fork Swan Creek	Ephemeral	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	830.61		X	X	X		3	Unnamed tributary to South Fork Swan Creek	Ephemeral	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	831.33		X	X	X		3	Unnamed tributary to Cub Creek	Ephemeral	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	832.18		X	X	X		3	Unnamed tributary to Cub Creek	Ephemeral	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	832.71		X	X	X		3	Unnamed tributary to Cub Creek	Ephemeral	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	832.73		X	X	X		3	Unnamed tributary to Cub Creek	Ephemeral	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	832.74		X	X	X		3	Unnamed tributary to Cub Creek	Ephemeral	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	833.9		X	X	X		3	Unnamed tributary to Cub Creek	Ephemeral	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	835.29		X	X	X		3	Cub Creek	Intermittent	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	NE-14	836.32		X	X	X		3	Unnamed tributary to Cub Creek	Ephemeral	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	NE-14	836.94		X	X	X		3	Unnamed tributary to Cub Creek	Intermittent	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	837.46		X	X	X		3	Unnamed tributary to Cub Creek	Ephemeral	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	837.53		X	X	X		3	Unnamed tributary to Cub Creek	Ephemeral	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	838.62		X	X	X		3	Unnamed tributary to Cub Creek	Ephemeral	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	838.76		X	X	X		3	Unnamed tributary to Cub Creek	Ephemeral	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	840.59		X	X	X		3	Unnamed tributary to Cub Creek	Ephemeral	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	843.03		X	X	X		3	Big Indian Creek	Intermittent	--	--	--	--	758-847.4	Rainwater Basin Wetlands

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Steele City	Nebraska	No	847.32		X	X	X		3	Unnamed tributary to Big Indian Creek	Man-made ditch	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	No	847.34		X	X	X		3	Unnamed tributary to Big Indian Creek	Man-made ditch	--	--	--	--	758-847.4	Rainwater Basin Wetlands
Steele City	Nebraska	NE-17	848.66				X		1	Unnamed tributary to Big Indian Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	1.24	X					1	Wildhorse Creek	Perennial	--	--	1.2	Wildhorse Creek	--	--
Gulf Coast	Oklahoma	No	2.45	X					1	Turkey Creek	Perennial	--	--	2.5	Turkey Creek	--	--
Gulf Coast	Oklahoma	No	2.94	X					1	Unnamed tributary to Euchee Creek	Perennial	--	--	2.9	Unnamed tributary to Euchee Creek	--	--
Gulf Coast	Oklahoma	No	3.27	X					1	Unnamed tributary to Euchee Creek	Perennial	--	--	3.3	Unnamed tributary to Euchee Creek	--	--
Gulf Coast	Oklahoma	No	6.98	X			X		2	Unnamed tributary to Camp Creek	Perennial	--	--	7	Unnamed tributary to Camp Creek	--	--
Gulf Coast	Oklahoma	No	7.6				X		1	Unnamed tributary to Camp Creek	Unknown	--	--	--	--	--	--
Gulf Coast	Oklahoma	OK-2	7.83	X			X		2	Unnamed tributary to Camp Creek	Perennial	--	--	7.8	Unnamed tributary to Camp Creek	--	--
Gulf Coast	Oklahoma	OK-2	8.38				X		1	Unnamed tributary to Camp Creek	N/A	--	--	--	--	--	--
Gulf Coast	Oklahoma	OK-2	9.1				X		1	Unnamed tributary to Camp Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	9.37				X		1	Unnamed tributary to Camp Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Oklahoma	OK-3	14.06	X					1	Salt Creek	Perennial	--	--	14.1	Salt Creek	--	--
Gulf Coast	Oklahoma	OK-3	14.84	X					1	Unnamed tributary to Salt Creek	Perennial	--	--	14.8-15.3	Unnamed tributary to Salt Creek	--	--
Gulf Coast	Oklahoma	OK-3	15.23	X					1	Unnamed tributary to Salt Creek	Perennial	--	--	14.8-15.3	Unnamed tributary to Salt Creek	--	--
Gulf Coast	Oklahoma	OK-3	15.25	X					1	Unnamed tributary to Salt Creek	Perennial	--	--	14.8-15.3	Unnamed tributary to Salt Creek	--	--
Gulf Coast	Oklahoma	No	19.52	X					1	Unnamed tributary to Deep Fork River	Perennial	--	--	19.5	Unnamed tributary to Deep Fork River	--	--
Gulf Coast	Oklahoma	No	22.15	X	X	X			3	Deep Fork River	Perennial	22.2	Yes	22.2	Deep Fork River	22.1-23.3	Deep Fork Wildlife Management Area

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Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Gulf Coast	Oklahoma	No	22.99		X	X			2	Unnamed tributary to Deep Fork River	Intermittent	--	--	--	--	22.1-23.3	Deep Fork Wildlife Management Area
Gulf Coast	Oklahoma	No	24.03	X					1	Pettiquah Creek	Perennial	--	--	24	Pettiquah Creek	--	--
Gulf Coast	Oklahoma	No	28.3	X					1	Little Hilliby Creek	Perennial	--	--	28.3	Little Hilliby Creek	--	--
Gulf Coast	Oklahoma	No	30.41	X					1	Hilliby	Perennial	--	--	30.4	Hilliby	--	--
Gulf Coast	Oklahoma	No	32.65	X					1	Unnamed tributary to Hilliby Creek	Perennial	--	--	32.7	Unnamed tibutary to Hilliby Creek	--	--
Gulf Coast	Oklahoma	No	38.3	X					1	Unnamed tributary to North Canadian River	Perennial	--	--	38.3	Unnamed tributary to North Canadian River	--	--
Gulf Coast	Oklahoma	No	38.55	X		X			2	North Canadian River	Perennial	38.6	Yes	38.6	North Canadian River	--	--
Gulf Coast	Oklahoma	No	39.9	X					1	Tributary to North Canadian River	Perennial	--	--	39.9	Tributary to North Canadian River	--	--
Gulf Coast	Oklahoma	No	43.53	X					1	Sand Creek	Perennial	--	--	43.5	Sand Creek	--	--
Gulf Coast	Oklahoma	OK-4	46.82	X					1	Unnamed tributary to Little Wewoka Creek	Perennial	--	--	46.8	Unnamed tributary to Little Wewoka Creek	--	--
Gulf Coast	Oklahoma	No	47.29	X					1	Unnamed tributary to Little Wewoka Creek	Perennial	--	--	47.3	Unnamed tributary to Little Wewoka Creek	--	--
Gulf Coast	Oklahoma	No	47.95	X					1	Little Wewoka Creek	Perennial	--	--	48	Little Wewoka Creek	--	--
Gulf Coast	Oklahoma	No	50.01	X					1	Unnamed tributary to Little Wewoka Creek	Perennial	--	--	50	Unnamed tributary to Little Wewoka Creek	--	--
Gulf Coast	Oklahoma	No	52.44	X					1	Unnamed tributary to Long George Creek	Perennial	--	--	52.4	Unnamed tributary to Long George Creek	--	--
Gulf Coast	Oklahoma	No	58.7	X					1	Wewoka Creek	Perennial	--	--	58.7	Wewoka Creek	--	--
Gulf Coast	Oklahoma	No	59.84	X					1	Jacobs Creek	Perennial	--	--	59.8-60.3	Jacobs Creek	--	--
Gulf Coast	Oklahoma	No	59.98	X					1	Unnamed tributary to Jacobs Creek	Ephemeral	--	--	59.8-60.3	Jacobs Creek	--	--
Gulf Coast	Oklahoma	No	60.28	X					1	Jacobs Creek	Perennial	--	--	59.8-60.3	Jacobs Creek	--	--
Gulf Coast	Oklahoma	No	60.33	X					1	Jacobs Creek	Perennial	--	--	59.8-60.3	Jacobs Creek	--	--
Gulf Coast	Oklahoma	OK-6	67.22	X					1	Bird Creek	Perennial	--	--	67.2	Bird Creek	--	--
Gulf Coast	Oklahoma	OK-6	70.38	X					1	Little River	Perennial	70.4	Yes	70.4	Little River	--	--
Gulf Coast	Oklahoma	No	72.95	X					1	Unnamed tributary to Little River	Perennial	--	--	73	Unnamed tributary to Little River	--	--
Gulf Coast	Oklahoma	OK-6	74.05	X		X			2	Canadian River	Perennial	74.1	Yes	74.1	South Canadian River	--	--
Gulf Coast	Oklahoma	OK-6	74.74	X					1	Unnamed tributary to Canadian River	Perennial	--	--	74.7	Unnamed tributary to Canadian River	--	--
Gulf Coast	Oklahoma	OK-7	79.56	X					1	Unnamed tributary to Big Sandy Creek	Perennial	--	--	79.6	Unnamed tributary to Big Sandy Creek	--	--
Gulf Coast	Oklahoma	No	80.17	X					1	Unnamed tributary to Big Sandy Creek	Perennial	--	--	80.2	Unnamed tributary to Big Sandy Creek	--	--
Gulf Coast	Oklahoma	No	87.34	X					1	Muddy Boggy Creek	Perennial	--	--	87.3	Muddy Boggy Creek	--	--
Gulf Coast	Oklahoma	No	95.02	X					1	Unnamed tributary to Turkey Creek	Perennial	--	--	95	Unnamed tributary to Turkey Creek	--	--
Gulf Coast	Oklahoma	No	96.14	X					1	Unnamed tributary to Turkey Creek	Perennial	--	--	96.1	Unnamed tributary to Turkey Creek	--	--
Gulf Coast	Oklahoma	No	102.25	X					1	Unnamed triburaty to Little Caney Boggy Creek	Perennial	--	--	102.3	Unnamed triburaty to Little Caney Boggy Creek	--	--
Gulf Coast	Oklahoma	No	102.69	X					1	Unnamed triburaty to Little Caney Boggy Creek	Perennial	--	--	102.7	Unnamed triburaty to Little Caney Boggy Creek	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Gulf Coast	Oklahoma	No	111.06	X					1	Unnamed tributary to Coal Creek	Perennial	--	--	111.1	Unnamed tributary to Coal Creek	--	--
Gulf Coast	Oklahoma	No	119.15	X					1	Unnamed tributary to Fronterhouse Creek	Perennial	--	--	119.2	Unnamed tributary to Fronterhouse Creek	--	--
Gulf Coast	Oklahoma	No	122.57	X					1	Fronterhouse Creek	Perennial	122.6	Yes	122.6	Fronterhouse Creek	--	--
Gulf Coast	Oklahoma	No	123.08	X					1	Unnamed tributary to Fronterhouse Creek	Perennial	--	--	123.1	Unnamed tributary to Fronterhouse Creek	--	--
Gulf Coast	Oklahoma	No	124.08	X					1	Unnamed tributary to Fronterhouse Creek	Perennial	--	--	124.1	Unnamed tributary to Fronterhouse Creek	--	--
Gulf Coast	Oklahoma	No	125.62	X					1	Unnamed tributary to Clear Boggy Creek	Perennial	--	--	125.6	Unnamed tributary to Clear Boggy Creek	--	--
Gulf Coast	Oklahoma	No	126.2	X					1	Unnamed tributary to Clear Boggy Creek	Perennial	--	--	126.2	Unnamed tributary to Clear Boggy Creek	--	--
Gulf Coast	Oklahoma	No	126.89	X					1	Clear Boggy Creek	Perennial	--	--	126.9	Clear Boggy Creek	--	--
Gulf Coast	Oklahoma	No	127.09	X					1	Unnamed tributary to Clear Boggy Creek	Perennial	127.1	Yes	127.1-127.3	Unnamed tributary to Clear Boggy Creek	--	--
Gulf Coast	Oklahoma	No	127.26						0	Unnamed tributary to Clear Boggy Creek	Perennial	--	--	127.1-127.3	Unnamed tributary to Clear Boggy Creek	--	--
Gulf Coast	Oklahoma	No	129.45	X					1	Unnamed tributary to Clear Boggy Creek	Perennial	--	--	129.5	Unnamed tributary to Clear Boggy Creek	--	--
Gulf Coast	Oklahoma	No	131.34	X					1	Cowpen Creek	Perennial	--	--	131.3	Cowpen Creek	--	--
Gulf Coast	Oklahoma	No	133.24	X					1	Unnamed tributary to Long Branch Creek	Perennial	--	--	133.2	Unnamed tributary to Long Branch Creek	--	--
Gulf Coast	Oklahoma	No	155.68	X		X			2	Red River	Perennial	155.7	Yes	155.6	Unnamed tributary to Red River	--	--
Gulf Coast	Oklahoma	No	155.73	X		X			2	Red River	Perennial	155.7	Yes	155.7-155.8	Red River	--	--
Gulf Coast	Texas	No	158.53	X					1	Unnamed tributary to Red River	Perennial	--	--	158.5	Unnamed tributary to Red River	--	--
Gulf Coast	Texas	No	162.02	X	X	X			3	Bois D'Arc Creek	Perennial	162	Yes	162	Bois D'Arc Creek	162	WRP Contract Land
Gulf Coast	Texas	No	165.65	X					1	Unnamed tributary to Slough Creek	Perennial	--	--	165.7	Unnamed tributary to Slough Creek	--	--
Gulf Coast	Texas	No	166.16	X					1	Slough Creek	Perennial	--	--	166.2	Slough Creek	--	--
Gulf Coast	Texas	No	168.32				X	X	2	Unnamed tributary to Shooter Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	168.33				X	X	2	Unnamed tributary to Shooter Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	168.33				X	X	2	Unnamed tributary to Shooter Creek	Ephemeral	--	--	--	--	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Gulf Coast	Texas	No	168.84				X	X	2	Unnamed tributary to Shooter Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	169.29	X			X	X	3	Shooter Creek	Perennial	--	--	169.3	Shooter Creek	--	--
Gulf Coast	Texas	No	169.48				X	X	2	Collins Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	170.3				X	X	2	Unnamed tributary to Sanders Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	170.39				X	X	2	Unnamed tributary to Sanders Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	170.9	X			X	X	3	Unnamed tributary to Sanders Creek	Perennial	--	--	170.9	Unnamed tributary to Sanders Creek	--	--
Gulf Coast	Texas	No	171.16	X			X	X	3	Sanders Creek	Perennial	--	--	171.2	Sanders Creek	--	--
Gulf Coast	Texas	No	172.71	X			X	X	3	Cottonwood Creek	Perennial	--	--	172.7	Cottonwood Creek	--	--
Gulf Coast	Texas	No	173.41				X	X	2	Unnamed tributary to Cottonwood Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	174.22	X					1	Unnamed triburaty to Doss Creek	Perennial	--	--	174.2	Unnamed triburaty to Doss Creek	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Gulf Coast	Texas	No	184				X		1	Unnamed tributary to Mallory Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	184.08				X		1	Unnamed tributary to Mallory Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	185.09				X		1	Unnamed tributary to Mallory Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	186.41				X		1	Mallory Creek	Perennial	--	--	--	--	--	--
Gulf Coast	Texas	No	187.51				X		1	Mallory Creek	Perennial	--	--	--	--	--	--
Gulf Coast	Texas	No	188.52				X		1	Unnamed tributary to Mallory Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	189.31				X		1	Justiss Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	190.52			X	X		2	Unnamed tributary of North Sulphur River	Intermittent	--	--	--	--	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Gulf Coast	Texas	No	190.52			X	X		2	Unnamed tributary of North Sulphur River	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	190.52			X	X		2	Unnamed tributary of North Sulphur River	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	190.66			X	X		2	Unnamed tributary of North Sulphur River	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	190.67			X	X		2	Unnamed tributary of North Sulphur River	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	190.75			X	X		2	North Sulphur River	Perennial	190.8	Yes	--	--	--	--
Gulf Coast	Texas	No	190.76	X		X	X		3	North Sulphur River	Perennial	190.8	Yes	190.8	North Sulphur River	--	--
Gulf Coast	Texas	No	190.76	X		X	X		3	North Sulphur River	Perennial	190.8	Yes	190.8	North Sulphur River	--	--
Gulf Coast	Texas	No	190.76	X		X	X		3	North Sulphur River	Perennial	190.8	Yes	190.8	North Sulphur River	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Gulf Coast	Texas	No	190.82				X		1	Unnamed tributary of North Sulphur River	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	191.05				X		1	Unnamed tributary of North Sulphur River	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	192.85				X		1	Unnamed tributary of North Sulphur River	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	193.67				X		1	Unnamed tributary of North Sulphur River	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	194.24				X		1	Unnamed tributary to Lake Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	194.25				X		1	Unnamed tributary to Lake Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	194.26				X		1	Unnamed tributary to Lake Creek	Ephemeral	--	--	--	--	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Gulf Coast	Texas	No	194.96				X		1	Unnamed tributary to Lake Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	195.87				X		1	Unnamed tributary to Lake Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	195.91				X		1	Unnamed waterbody	Perennial	--	--	--	--	--	--
Gulf Coast	Texas	No	196.37				X		1	Unnamed tributary to Lake Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	199.59				X		1	Evans Branch	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	199.84				X		1	Evans Branch	Seasonal	--	--	--	--	--	--
Gulf Coast	Texas	No	201.77	X			X		2	South Sulphur River	Perennial	201.8	Yes	201.7-201.8	South Sulphur River	--	--
Gulf Coast	Texas	No	201.78	X			X		2	South Sulphur River	Perennial	201.8	Yes	201.7-201.8	South Sulphur River	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Gulf Coast	Texas	No	202.95				X		1	Unnamed tributary to South Sulphur River	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	202.95				X		1	Unnamed tributary to South Sulphur River	Perennial	--	--	--	--	--	--
Gulf Coast	Texas	No	203.4				X		1	Unnamed tributary to South Sulphur River	Unknown	--	--	--	--	--	--
Gulf Coast	Texas	No	203.76				X		1	Unnamed tributary to South Sulphur River	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	203.77				X		1	Unnamed tributary to South Sulphur River	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	203.79				X		1	Unnamed tributary to South Sulphur River	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	203.95				X		1	Unnamed tributary to South Sulphur River	Perennial	--	--	--	--	--	--
Gulf Coast	Texas	No	204.09				X		1	Unnamed tributary to South Sulphur River	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	204.14				X		1	Unnamed tributary to South Sulphur River	Ephemeral	--	--	--	--	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Gulf Coast	Texas	No	212.11	X					1	Crosstimber Creek	Perennial	--	--	212.1	Crosstimber Creek	--	--
Gulf Coast	Texas	No	212.82	X					1	White Oak Creek	Perennial	212.8	Yes	212.8	White Oak Creek	--	--
Gulf Coast	Texas	No	217.18	X					1	Unnamed tributary to Stouts Creek	Perennial	--	--	217.2	Unnamed tributary to Stouts Creek	--	--
Gulf Coast	Texas	No	218.23	X					1	Stouts Creek	Perennial	--	--	218.2	Stouts Creek	--	--
Gulf Coast	Texas	No	220.91	X					1	Greenwood Creek	Perennial	--	--	220.9	Greenwood Creek	--	--
Gulf Coast	Texas	TX-1	223.05				X	X	2	Unnamed tributary to Huggings Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	224.15	X			X	X	3	Unnamed tributary to Little Cypress Creek	Perennial	--	--	224.2	Unnamed tributary to Little Cypress Creek	--	--
Gulf Coast	Texas	No	225.03				X	X	2	Unnamed tributary to Little Cypress Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	225.38				X	X	2	Unnamed tributary to Little Cypress Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	225.42				X	X	2	Unnamed tributary to Little Cypress Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	TX-1	226.04				X	X	2	Unnamed tributary to Little Cypress Creek	Unknown	--	--	--	--	--	--
Gulf Coast	Texas	TX-1	226.2				X	X	2	Unnamed tributary to Little Cypress Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	TX-1	226.23				X	X	2	Unnamed tributary to Little Cypress Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	TX-1	226.29				X	X	2	Unnamed tributary to Little Cypress Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	226.68	X			X	X	3	Unnamed tributary to Little Cypress Creek	Perennial	--	--	226.7	Unnamed tributary to Little Cypress Creek	--	--
Gulf Coast	Texas	No	226.76	X			X	X	3	Unnamed tributary to Little Cypress Creek	Perennial	--	--	226.8	Unnamed tributary to Little Cypress Creek	--	--
Gulf Coast	Texas	No	227.52				X	X	2	Unnamed tributary to Big Cypress Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	227.53				X	X	2	Unnamed tributary to Big Cypress Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	227.58				X	X	2	Unnamed tributary to Big Cypress Creek	Perennial	--	--	--	--	--	--
Gulf Coast	Texas	No	227.68				X	X	2	Unnamed tributary to Big Cypress Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	227.91				X	X	2	Unnamed tributary to Big Cypress Creek	Perennial	--	--	--	--	--	--
Gulf Coast	Texas	No	227.95				X	X	2	Unnamed tributary to Big Cypress Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	228.34				X	X	2	Unnamed tributary to Big Cypress Creek	Perennial	228.4	Yes	--	--	--	--
Gulf Coast	Texas	No	228.48	X			X	X	3	Unnamed tributary to Big Cypress Creek	N/A	--	--	228.5	Unnamed tributary to Little Cypress Creek	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Gulf Coast	Texas	No	228.86				X	X	2	Unnamed tributary to Big Cypress Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	228.88				X	X	2	Unnamed tributary to Big Cypress Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	230.07				X	X	2	Unnamed tributary to Brushy Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	230.41				X	X	2	Unnamed tributary to Brushy Creek	Unknown	--	--	--	--	--	--
Gulf Coast	Texas	No	230.42				X	X	2	Unnamed tributary to Brushy Creek	Unknown	--	--	--	--	--	--
Gulf Coast	Texas	No	230.89				X	X	2	Unnamed tributary to Brushy Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	231.22				X	X	2	Unnamed tributary to Brushy Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	231.43				X	X	2	Unnamed tributary to Brushy Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	231.6				X	X	2	Unnamed tributary to Brushy Creek	Unknown	--	--	--	--	--	--
Gulf Coast	Texas	No	231.85				X	X	2	Unnamed tributary to Brushy Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	232.65	X			X	X	3	Brushy Creek	Perennial	--	--	232.7	Brushy Creek	--	--
Gulf Coast	Texas	No	232.75	X			X	X	3	Unnamed tributary to Brushy Creek	Perennial	--	--	232.8	Unnamed tributary to Brushy Creek	--	--
Gulf Coast	Texas	No	233.08	X			X	X	3	Unnamed tributary to Brushy Creek	Perennial	--	--	233.1	Unnamed tributary to Brushy Creek	--	--
Gulf Coast	Texas	No	234.13	X			X	X	3	Unnamed tributary to Briary Creek	Perennial	--	--	234.1	Unnamed tributary to Briary Creek	--	--
Gulf Coast	Texas	No	234.21				X	X	2	Briary Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	234.59	X			X	X	3	Sand Branch	Perennial	--	--	234.6	Sand Branch	--	--
Gulf Coast	Texas	No	234.7				X	X	2	Unnamed tributary to Sand Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	235.05	X			X	X	3	Unnamed tributary to Briary Creek	Perennial	--	--	235.1	Unnamed tributary to Briary Creek	--	--
Gulf Coast	Texas	TX-2	235.54	X			X	X	3	Unnamed tributary to Briary Creek	Perennial	--	--	235.5	Unnamed tributary to Briary Creek	--	--
Gulf Coast	Texas	TX-2	236.81				X	X	2	Unnamed tributary to Stout Creek	Intermittent	--	--	--	--	--	--

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Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Gulf Coast	Texas	TX-2	238.19				X	X	2	Unnamed tributary to Stout Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	TX-2	239.45				X		1	Unnamed tributary to Caney Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	TX-2	239.67				X		1	Unnamed tributary to Caney Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	241.61				X		1	Unnamed tributary to Little Cypress Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	241.83				X		1	Unnamed tributary to Little Cypress Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	241.86				X		1	Unnamed tributary to Little Cypress Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	242.09				X		1	Unnamed tributary to Little Cypress Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	242.24				X		1	Unnamed tributary to Little Cypress Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	242.71	X			X		2	Unnamed tributary to Little Cypress Creek	Perennial	--	--	242.7	Unnamed tributary to Little Cypress Creek	--	--
Gulf Coast	Texas	No	243.9	X			X		2	Unnamed tributary to Little Cypress Creek	Perennial	--	--	243.9	Unnamed tributary to Little Cypress Creek	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Gulf Coast	Texas	No	244.87	X			X		2	Unnamed tributary to Little Cypress Creek	Perennial	--	--	244.9	Unnamed tributary to Little Cypress Creek	--	--
Gulf Coast	Texas	No	245.44	X			X		2	Unnamed tributary to Little Cypress Creek	Perennial	--	--	245.4	Unnamed tributary to Little Cypress Creek	--	--
Gulf Coast	Texas	No	245.53				X		1	Unnamed tributary to Little Cypress Creek	Perennial	--	--	--	--	--	--
Gulf Coast	Texas	No	246.39				X		1	Unnamed tributary to Little Cypress Creek	Unknown	--	--	--	--	--	--
Gulf Coast	Texas	No	246.62	X			X		2	Unnamed tributary to Little Cypress Creek	Perennial	--	--	246.6	Unnamed tributary to Little Cypress Creek	--	--
Gulf Coast	Texas	No	247.51				X		1	Clear Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	248.01	X			X		2	Unnamed tributary to Clear Creek	Perennial	--	--	248	Unnamed tributary to Clear Creek	--	--
Gulf Coast	Texas	TX-4	248.6				X		1	Unnamed tributary to Clear Creek	Perennial	--	--	--	--	--	--
Gulf Coast	Texas	TX-4	249.96				X		1	Honey Creek	Intermittent	--	--	--	--	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Gulf Coast	Texas	TX-4	250.28				X		1	Unnamed tributary to Honey Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	TX-5	252.97	X					1	Blue Branch	Perennial	--	--	253	Blue Branch	--	--
Gulf Coast	Texas	No	254.89	X					1	Unnamed waterbody	Unknown	254.8	Yes	254.9	Private Lake	--	--
Gulf Coast	Texas	No	255.17	X					1	Perin Branch	Perennial	--	--	255.2	Perin Branch	--	--
Gulf Coast	Texas	No	256.92	X					1	Big Sandy Creek	Perennial	256.9	Yes	256.9	Big Sandy Creek	--	--
Gulf Coast	Texas	No	258.35		X				1	Unnamed tributary to Big Sandy Creek	Intermittent	--	--	--	--	258-261	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	258.72		X				1	Unnamed tributary to Big Sandy Creek	Intermittent	--	--	--	--	258-261	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	260.05		X				1	Unnamed tributary to Little Cypress Creek	Ephemeral	--	--	--	--	258-261	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	260.94		X				1	Unnamed tributary to Rogers Creek	Seasonal	--	--	--	--	258-261	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	261.24		X				1	Unnamed tributary to Rogers Creek	Intermittent	--	--	--	--	258-261	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	263.5	X					1	Sabine River	Perennial	263.5	Yes	263.5	Sabine River	--	--
Gulf Coast	Texas	TX-6	267.89	X					1	Unnamed tributary to	Perennial	--	--	267.9	Unnamed tributary to Simpson Creek	--	--
Gulf Coast	Texas	TX-6	268.86	X					1	Simpson Creek	Perennial	--	--	268.9	Simpson Creek	--	--
Gulf Coast	Texas	TX-6	270.67	X					1	Unnamed tributary to Simpson Creek	Perennial	--	--	270.7	Unnamed tributary to Simpson Creek	--	--
Gulf Coast	Texas	TX-6	270.84	X					1	Unnamed tributary to Simpson Creek	Perennial	--	--	270.8	Unnamed tributary to Simpson Creek	--	--
Gulf Coast	Texas	No	272.14	X					1	Unnamed tributary to Sunstroke Creek	Perennial	--	--	272.1	Unnamed tributary to Sunstroke Creek	--	--
Gulf Coast	Texas	TX-7	275.08	X			X		2	Unnamed tributary to Prairie Creek	Perennial	--	--	275.1	Unnamed tributary to Prairie Creek	--	--
Gulf Coast	Texas	TX-7	275.48				X		1	Unnamed roadside ditch	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	TX-7	275.53	X			X		2	Prairie Creek	Perennial	--	--	275.5	Prairie Creek	--	--
Gulf Coast	Texas	TX-7	275.55				X		1	Unnamed tributary to Prairie Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	TX-7	277.06				X		1	Unnamed tributary to Mud Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	277.34	X			X		2	Unnamed tributary to Mud Creek	Perennial	--	--	277.3	Unnamed tributary to Mud Creek	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Gulf Coast	Texas	No	277.66	X			X		2	Unnamed tributary to Mud Creek	Perennial	--	--	277.7	Unnamed tributary to Mud Creek	--	--
Gulf Coast	Texas	TX-8	279.73	X			X		2	Unnamed tributary to Mud Creek	Perennial	--	--	279.7	Unnamed tributary to Mud Creek	--	--
Gulf Coast	Texas	No	280.12				X		1	Unnamed tributary to Caney Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	280.71	X			X		2	Unnamed tributary to Caney Creek	Perennial	--	--	280.7	Unnamed tributary to Caney Creek	--	--
Gulf Coast	Texas	TX-9	281.84				X		1	Unnamed tributary to Caney Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	TX-9	281.97				X		1	Unnamed tributary to Caney Creek	Seasonal	--	--	--	--	--	--
Gulf Coast	Texas	TX-9	282.02				X		1	Unnamed tributary to Caney Creek	Seasonal	--	--	--	--	--	--
Gulf Coast	Texas	TX-10	283.06	X			X		2	Unnamed tributary to Caney Creek	Perennial	--	--	283.1	Unnamed tributary to Caney Creek	--	--
Gulf Coast	Texas	TX-10	283.45	X			X		2	Unnamed tributary to Caney Creek	Perennial	--	--	283.5	Unnamed tributary to Caney Creek	--	--
Gulf Coast	Texas	TX-10	283.49	X			X		2	Unnamed tributary to Caney Creek	Perennial	--	--	283.5	Caney Creek	--	--
Gulf Coast	Texas	TX-10	283.54				X		1	Caney Creek	Perennial	--	--	--	--	--	--
Gulf Coast	Texas	TX-10	284.62	X			X		2	Unnamed tributary to Caney Creek	Perennial	--	--	284.6	Unnamed tributary to Caney Creek	--	--
Gulf Coast	Texas	TX-10	286.77	X			X		2	Unnamed tributary to Kickapoo Creek	Perennial	--	--	286.8	Unnamed tributary to Kickapoo Creek	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Gulf Coast	Texas	No	287.55				X		1	Kickapoo Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	287.84				X		1	Unnamed tributary to Kickapoo Creek	Perennial	--	--	--	--	--	--
Gulf Coast	Texas	No	288.15				X		1	Unnamed tributary to Kickapoo Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	288.24				X		1	Unnamed tributary to Kickapoo Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	297.62	X			X		2	Unnamed tributary to Mills Creek	Perennial	--	--	297.6	Unnamed tributary to Mills Creek	--	--
Gulf Coast	Texas	No	297.67				X		1	Unnamed tributary to Mills Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	297.68				X		1	Mill Creek	Perennial	--	--	--	--	--	--
Gulf Coast	Texas	No	300.74				X		1	Unnamed tributary to Bowles Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	TX-11	301.32	X			X		2	Johnsons Creek	Perennial	--	--	301.3	Johnson Creek	--	--
Gulf Coast	Texas	No	301.74				X		1	Unnamed tributary to Johnsons Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	302.32				X		1	Unnamed tributary to Johnsons Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	302.99				X		1	Unnamed tributary to Boggy Branch	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	303				X		1	Unnamed tributary to Boggy Branch	Ephemeral	--	--	--	--	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Gulf Coast	Texas	No	303.1				X		1	Boggy Branch	Seasonal	--	--	--	--	--	--
Gulf Coast	Texas	No	303.83				X		1	Unnamed tributary to Striker Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	303.88				X		1	Unnamed tributary to Striker Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	304.27				X		1	Unnamed tributary to Striker Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	304.75				X		1	Unnamed tributary to Striker Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	TX-11	308.27	X					1	Wheelus Branch	Perennial	--	--	308.3	Wheelus Branch	--	--
Gulf Coast	Texas	TX-12	313.18		X				1	East Fork Angelina River	Perennial	--	--	--	--	313-315	Water Oak - Willow Oak Community
Gulf Coast	Texas	TX-12	313.23		X				1	East Fork Angelina River	Perennial	--	--	--	--	313-315	Water Oak - Willow Oak Community
Gulf Coast	Texas	TX-12	313.3	X	X				2	East Fork Angelina River	Perennial	313.3	Yes	313.3	East Fork Angelina River	313-315	Water Oak - Willow Oak Community
Gulf Coast	Texas	TX-12	313.55		X				1	East Fork Angelina River	Perennial	--	--	--	--	313-315	Water Oak - Willow Oak Community
Gulf Coast	Texas	TX-12	313.68		X				1	Unnamed tributary to East Fork Angelina River	Perennial	--	--	--	--	313-315	Water Oak - Willow Oak Community
Gulf Coast	Texas	TX-12	314.5		X				1	Unnamed tributary to East Fork Angelina River	Ephemeral	--	--	--	--	313-315	Water Oak - Willow Oak Community
Gulf Coast	Texas	TX-12	314.98		X				1	Unnamed tributary to East Fork Angelina River	Ephemeral	--	--	--	--	313-315	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	315.31		X				1	Unnamed tributary to East Fork Angelina River	Ephemeral	--	--	--	--	313-315	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	316.68	X					1	Indian Creek	Perennial	--	--	316.7	Indian Creek	--	--
Gulf Coast	Texas	TX-13	319.34	X					1	Unnamed tributary to Beech Creek	Perennial	--	--	319.3	Unnamed tributary to Beech Creek	--	--
Gulf Coast	Texas	TX-13	320.25	X					1	Unnamed tributary to Beech Creek	Perennial	--	--	320.3	Unnamed tributary to Beech Creek	--	--
Gulf Coast	Texas	TX-13	320.79	X					1	Beech Creek	Perennial	--	--	320.8	Beech Creek	--	--
Gulf Coast	Texas	No	334.17	X					1	Angelina River	Perennial	334.2	Yes	334.2	Angelina River	--	--
Gulf Coast	Texas	No	337.73		X				1	Unnamed tributary to Stokes Creek	Ephemeral	--	--	--	--	337-340	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	338.31		X				1	Unnamed tributary to Stokes Creek	Intermittent	--	--	--	--	337-340	Water Oak - Willow Oak Community

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Gulf Coast	Texas	No	338.48		X				1	Unnamed tributary to Stokes Creek	Ephemeral	--	--	--	--	337-340	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	338.49		X				1	Unnamed tributary to Stokes Creek	Ephemeral	--	--	--	--	337-340	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	338.52		X				1	Stokes Creek	Intermittent	--	--	--	--	337-340	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	338.53		X				1	Unnamed tributary to Stokes Creek	Ephemeral	--	--	--	--	337-340	Water Oak - Willow Oak Community
Gulf Coast	Texas	TX-14	338.69		X				1	Unnamed tributary to Stokes Creek	Ephemeral	--	--	--	--	337-340	Water Oak - Willow Oak Community
Gulf Coast	Texas	TX-14	338.77		X				1	Unnamed tributary to Stokes Creek	Ephemeral	--	--	--	--	337-340	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	340.17		X				1	Unnamed tributary to Doyle Creek	Intermittent	--	--	--	--	337-340	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	340.18		X				1	Unnamed tributary to Doyle Creek	Intermittent	--	--	--	--	337-340	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	342.53	X					1	Red Bayou	Perennial	--	--	342.5	Red Bayou	--	--
Gulf Coast	Texas	No	344.69				X		1	Unnamed tributary to Watson Branch	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	344.94	X			X		2	Watson Branch	Perennial	--	--	344.9	Watson Branch	--	--
Gulf Coast	Texas	No	345.45				X		1	Unnamed tributary to Watson Branch	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	345.46				X		1	Unnamed tributary to Watson Branch	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	345.52				X		1	Unnamed tributary to Watson Branch	Perennial	--	--	--	--	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Gulf Coast	Texas	No	345.59				X		1	Unnamed tributary to Watson Branch	Perennial	--	--	--	--	--	--
Gulf Coast	Texas	No	345.6	X			X		2	Unnamed tributary to Watson Branch	Perennial	--	--	345.6	Unnamed tributary to Watson Branch	--	--
Gulf Coast	Texas	No	346.52				X		1	Unnamed tributary to Red Bayou	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	346.52				X		1	Unnamed tributary to Red Bayou	Unknown	--	--	--	--	--	--
Gulf Coast	Texas	No	346.59				X		1	Unnamed tributary to Red Bayou	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	346.6				X		1	Unnamed tributary to Red Bayou	Unknown	--	--	--	--	--	--
Gulf Coast	Texas	No	347.76	X			X		2	Red Bayou	Perennial	--	--	347.8	Red Bayou	--	--
Gulf Coast	Texas	No	348.05				X		1	Unnamed tributary to Red Bayou	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	350.01		X		X		2	Unnamed tributary to Neches River	Intermittent	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	350.23		X		X		2	Unnamed tributary to Neches River	N/A	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	351.02	X	X		X		3	Buncombe Creek	Perennial	--	--	351	Buncombe Creek	350-368	Water Oak - Willow Oak Community

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Gulf Coast	Texas	No	351.15	X	X		X		3	Unnamed tributary to Buncombe Creek	Perennial	--	--	351.2	Unnamed tributary to Buncombe Creek	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	351.66		X		X		2	Unnamed tributary to Buncombe Creek	Perennial	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	352.18	X	X		X		3	Unnamed tributary to Neches River	Perennial	--	--	352.2	Unnamed tributary to Neches River	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	352.93		X		X		2	Unnamed tributary to Crawford Creek	Ephemeral	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	352.94		X		X		2	Unnamed tributary to Crawford Creek	Ephemeral	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	352.99		X		X		2	Unnamed tributary to Crawford Creek	Ephemeral	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	TX-15	353.12		X		X		2	Unnamed tributary to Crawford Creek	Ephemeral	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	353.26	X	X		X		3	Crawford Creek	Perennial	--	--	353.3	Crawford Creek	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	353.28		X		X		2	Stock pond	Unknown	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	TX-16	354.18		X		X		2	Unnamed tributary to Neches River	Ephemeral	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	TX-16	354.2		X		X		2	Unnamed tributary to Neches River	Intermittent	--	--	--	--	350-368	Water Oak - Willow Oak Community

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Gulf Coast	Texas	TX-16	355.01		X		X		2	Unnamed tributary to Neches River	Intermittent	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	TX-16	355.11		X		X		2	Unnamed tributary to Neches River	Intermittent	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	TX-16	355.22		X		X		2	Unnamed tributary to Neches River	Ephemeral	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	TX-16	355.27		X		X		2	Unnamed tributary to Neches River	Ephemeral	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	TX-16	355.45	X	X		X		3	Unnamed tributary to Neches River	Perennial	--	--	355.5	Unnamed tributary to Neches River	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	TX-16	355.64		X		X		2	Unnamed tributary to Neches River	Ephemeral	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	356.08		X		X		2	Unnamed tributary to Neches River	Intermittent	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	356.74		X		X		2	Unnamed tributary to Neches River	Intermittent	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	356.91		X		X		2	Unnamed tributary to Neches River	Ephemeral	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	357.41		X		X		2	Unnamed tributary to Neches River	Ephemeral	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	357.5		X		X		2	Unnamed tributary to Neches River	Ephemeral	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	357.92		X		X		2	Unnamed tributary to Neches River	Ephemeral	--	--	--	--	350-368	Water Oak - Willow Oak Community

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				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Gulf Coast	Texas	No	358.17	X	X		X		3	Unnamed tributary to Neches River	Perennial	--	--	358.2	Unnamed tributary to Neches River	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	358.39		X		X		2	Unnamed tributary to Neches River	Intermittent	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	358.83		X				1	Unnamed tributary to Neches River	Intermittent	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	359.08		X				1	Unnamed tributary to Neches River	Intermittent	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	359.25		X				1	Unnamed tributary to Neches River	Intermittent	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	359.66		X				1	Unnamed tributary to Neches River	Intermittent	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	359.71		X				1	Unnamed tributary to Neches River	Ephemeral	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	359.81		X				1	Unnamed tributary to Neches River	Ephemeral	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	360.54		X				1	Unnamed tributary to Jack Creek	Perennial	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	360.69		X				1	Unnamed tributary to Jack Creek	Perennial	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	360.77		X				1	Unnamed tributary to Jack Creek	Perennial	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	360.81		X				1	Unnamed tributary to Jack Creek	Perennial	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	360.89	X	X				2	Jack Creek	Perennial	--	--	360.9	Jack Creek	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	361.09	X	X				2	Cedar Creek	Perennial	--	--	361.1	Cedar Creek	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	361.12	X	X				2	Cedar Creek	Perennial	--	--	361.1	Cedar Creek	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	361.24		X				1	Unnamed tributarty to Hurricane Creek	Intermittent	--	--	--	--	350-368	Water Oak - Willow Oak Community

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Gulf Coast	Texas	No	362.14		X				1	Unnamed tributary to Neches River	Ephemeral	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	TX-17	362.79	X	X				2	Unnamed tributary to Neches River	Ephemeral	--	--	362.8	Unnamed tributary to Neches River	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	TX-17	362.81		X				1	Unnamed tributary to Neches River	Ephemeral	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	TX-17	362.81		X				1	Unnamed tributary to Neches River	Perennial	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	TX-17	363.17		X				1	Unnamed tributary to Neches River	Perennial	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	366.4		X				1	Unnamed tributary to Fiberboard Lake	Ephemeral	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	366.9		X				1	Fiberboard Lake	Perennial	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	366.94		X	X			2	Fiberboard Lake	Perennial	--	--	--	--	350-368	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	368.6	X					1	Neches River	Perennial	368.6	Yes	368.6	Neches River	--	--
Gulf Coast	Texas	TX-19	376.43	X					1	Piney Creek	Perennial	--	--	376.4	Piney Creek	--	--
Gulf Coast	Texas	TX-19	376.74	X					1	Unnamed tributary to Piney Creek	Perennial	--	--	376.7	Unnamed tributary to Piney Creek	--	--
Gulf Coast	Texas	No	377.66	X					1	Unnamed tributary to Bear Creek	Perennial	--	--	377.7	Unnamed tributary to Bear Creek	--	--
Gulf Coast	Texas	No	377.85	X					1	Bear Creek	Perennial	--	--	377.9	Bear Creek	--	--
Gulf Coast	Texas	No	381.51	X					1	Unnamed tributary to Jones Creek	Perennial	--	--	381.5	Unnamed tributary to Jones Creek	--	--
Gulf Coast	Texas	No	381.9	X					1	Jones Creek	Perennial	--	--	381.9	Jones Creek	--	--
Gulf Coast	Texas	No	382.64	X					1	Brushy Creek	Perennial	--	--	382.6	Brushy Creek	--	--
Gulf Coast	Texas	No	385.56	X					1	Bundix Branch	Perennial	--	--	385.6	Bundix Branch	--	--
Gulf Coast	Texas	No	388.49	X					1	Big Sandy Creek	Perennial	--	--	388.5	Big Sandy Creek	--	--
Gulf Coast	Texas	No	389.69	X					1	Big Sandy Creek	Perennial	--	--	389.7	Big Sandy Creek	--	--
Gulf Coast	Texas	No	391.67	X					1	Big Sandy Creek	Perennial	--	--	391.7	Big Sandy Creek	--	--
Gulf Coast	Texas	TX-20	397.18	X					1	East Menard Creek	Perennial	--	--	397.2	East Menard Creek	--	--
Gulf Coast	Texas	No	400.67			X	X		2	Unnamed tributary to Bluff Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	400.84			X	X		2	Unnamed tributary to Bluff Creek	Ephemeral	--	--	--	--	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Gulf Coast	Texas	No	401.35	X			X	X	3	Unnamed tributary to Bluff Creek	Perennial	--	--	401.4	Unnamed tributary to Bluff Creek	--	--
Gulf Coast	Texas	No	404.09	X			X	X	3	Menard Creek	Perennial	--	--	404.1	Menard Creek	--	--
Gulf Coast	Texas	No	404.1				X	X	2	Menard Creek	Perennial	--	--	--	--	--	--
Gulf Coast	Texas	No	404.33				X	X	2	Unnamed tributary to Menard Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	404.57				X	X	2	Unnamed tributary to Menard Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	404.74				X	X	2	Unnamed tributary to Menard Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	404.75				X	X	2	Unnamed tributary to Menard Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	405.4				X	X	2	Unnamed tributary to Menard Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	407.13	X			X	X	3	Unnamed tributary to Dry Branch	Perennial	--	--	407.1	Unnamed tributary to Dry Branch	--	--
Gulf Coast	Texas	No	407.15				X	X	2	Unnamed tributary to Dry Branch	Perennial	--	--	--	--	--	--

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				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Gulf Coast	Texas	No	407.22				X	X	2	Unnamed tributary to Dry Branch	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	407.24				X	X	2	Unnamed tributary to Dry Branch	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	407.24				X	X	2	Unnamed tributary to Dry Branch	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	407.26				X	X	2	Unnamed tributary to Dry Branch	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	TX-22	411.68				X	X	2	Unnamed tributary to Williams Creek	Unknown	--	--	--	--	--	--
Gulf Coast	Texas	TX-22	413.66				X	X	2	Unnamed tributary to Williams Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	414.35				X	X	2	Unnamed tributary to Williams Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	414.36				X	X	2	Unnamed tributary to Williams Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	414.7				X	X	2	Unnamed tributary to Bear Foot Lake	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	415.34	X			X	X	3	Unnamed tributary to Bear Foot Lake	Perennial	--	--	415.3	Unnamed tributary to Bear Foot Lake	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Gulf Coast	Texas	No	415.35				X	X	2	Unnamed tributary to Bear Foot Lake	Perennial	--	--	--	--	--	--
Gulf Coast	Texas	No	415.35				X	X	2	Unnamed tributary to Bear Foot Lake	Perennial	--	--	--	--	--	--
Gulf Coast	Texas	No	416.19				X	X	2	Unnamed tributary to Menard Creek	Unknown	--	--	--	--	--	--
Gulf Coast	Texas	No	416.35	X		X	X	X	4	Menard Creek	Unknown	416.3	Yes	416.4	Menard Creek	--	--
Gulf Coast	Texas	No	422.69				X	X	2	Beef Head Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	431.71				X		1	Unnamed tributary to Batiste Creek	Intermittent	--	--	--	--	--	--
Gulf Coast	Texas	No	432.87				X		1	Unnamed tributary to Batiste Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	433.44				X		1	Unnamed tributary to Batiste Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	433.46				X		1	Unnamed tributary to Batiste Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	434.11				X		1	Unnamed tributary to Batiste Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	434.12				X		1	Unnamed tributary to Batiste Creek	Ephemeral	--	--	--	--	--	--
Gulf Coast	Texas	No	439.5	X					1	Meyhaw Creek	Perennial	--	--	439.5	Meyhaw Creek	--	--
Gulf Coast	Texas	No	449.03	X					1	Pine Island Bayou	Perennial	448.9	Yes	449	Pine Island Bayou	--	--
Gulf Coast	Texas	No	451.56	X					1	Pine Island Bayou	Perennial	--	--	451.6	Pine Island Bayou	--	--

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Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Gulf Coast	Texas	No	457.92	X	X		X	X	4	Cotton Creek	Perennial	--	--	457.9	Cotton Creek	457-462	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	457.96	X	X		X	X	4	Cotton Creek	Perennial	--	--	457.9	Cotton Creek	457-462	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	459.16		X		X	X	3	Unnamed tributary to Pine Island Bayou	Intermittent	--	--	--	--	457-462	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	459.94		X		X	X	3	Unnamed tributary to Pine Island Bayou	Unknown	--	--	--	--	457-462	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	460.46		X		X	X	3	Unnamed tributary to Pine Island Bayou	Unknown	--	--	--	--	457-462	Water Oak - Willow Oak Community
Gulf Coast	Texas	TX-24	461.77	X	X				2	Lower Neches Valley Canal Authority	Perennial	461.8	Yes	461.8	Aggie Rd/Lower Neches River	457-462	Water Oak - Willow Oak Community
Gulf Coast	Texas	No	462.5	X					1	B1 Canal	Perennial	462.5	Yes	462.5	Lower Neches River	457-462	Water Oak - Willow Oak Community
Gulf Coast	Texas	TX-25	469.89	X					1	Jefferson County Canal/Willow Marsh Bayou	Unknown	469.9	Yes	469.9	Willow Marsh Bayou	--	--
Gulf Coast	Texas	TX-25	473.56				X	X	2	Unnamed waterbody	Perennial	--	--	--	--	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Stream Crossing (Tables E-1 and E2)		HDD (Table 2.3.3-1)		Fisheries (Table 3.7.2-1)		Wetlands (Table 3.4.2-1)	
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Crossing Name	Type	Approx. Milepost	Crossing?	Approx. Milepost	Waterbody Name	Approx. Milepost	Name
Gulf Coast	Texas	TX-25	473.79				X	X	2	Unnamed tributary to Hillebrant Bayou	Perennial	473.8	Yes	--	--	--	--
Gulf Coast	Texas	TX-25	473.83	X			X	X	3	Hillebrandt Bayou	Perennial	--	--	473.8	Hillebrandt Bayou	--	--
Gulf Coast	Texas	TX-25	474.93				X	X	2	Unnamed tributary to Hillebrant Bayou	Unknown	--	--	--	--	--	--
Houston Lateral	Texas	TX-29	35.6	X					1	Cedar Bayou	Perennial	35.6	Yes	35.6	Cedar Bayou	--	--
Houston Lateral	Texas	No	43.3	X		X			2	San Jacinto River	--	43.3	Yes	43.3	San Jacinto River	--	--
Houston Lateral	Texas	Parts	18-28	X	X	X			3	Various unspecified waterways	--	--	Some	22.8	Trinity River	18-28	Water Oak - Willow Oak Community

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Steele City	Montana	No	25.4	X			X		2	--	--	25.4	Frenchman Reservoir	Pipeline passes approx. 0.5 mile upstream on Frenchman Cr.	The area is clearly surrounded by more lush vegetation than the surrounding hills.
Steele City	Montana	No	25.75			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	27.06			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	27.16			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	28.8			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	30.45			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	32.4			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	34.7			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	35.02			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	35.34			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	35.51			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	35.54			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	35.81			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	35.84			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	35.95			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	36.01			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	36.12			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	37.97			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	38.59			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	39.06			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	39.08			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	39.09			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	39.16	X		X			2	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	40.52	X		X			2	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	40.92			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	41.06			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--

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Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Steele City	Montana	No	41.72			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	42.55			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	44.24			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	44.58			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	45.05			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	45.13			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	47.95			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	48.02			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	48.03			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	48.26			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	48.32			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	48.54			X			1	25.5-69.7	North Valley Grasslands Important Bird Area (IBA)	--	--	--	--
Steele City	Montana	No	49.9			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	49.94			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	50.53			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	51.3			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	51.41			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	51.44			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	51.53			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--

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Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Steele City	Montana	No	51.61			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	52.47			X	X		2	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	52.47	Reservoir Number Four	Pipeline passes within 0.1 mile of reservoir	--
Steele City	Montana	No	52.58			X	X		2	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	52.58	Reservoir Number Four	Pipeline passes within 0.1 mile of reservoir	--
Steele City	Montana	No	53.49			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	53.64			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	53.79			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	54.14			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	55.03			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	55.22			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	55.46			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	55.67			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	56.03			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	56.04			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--

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Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Steele City	Montana	No	56.07			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	56.12			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	56.27			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	56.41			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	56.45			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	56.71			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	56.72			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	57.15			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	57.55			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	57.55			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	57.7			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	57.74			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	57.91			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--

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Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Steele City	Montana	No	58.04			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	59.5			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	59.55			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	60.02			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	61.87			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	62.93			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	MT-1	65.97			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	MT-1	67.2			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	MT-1	67.25			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	MT-1	67.41			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	MT-1	68.5			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	MT-1	68.52			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	MT-1	68.64			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--

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Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Steele City	Montana	MT-1	69.41			X			1	25.5-69.7 49.4-70.9	North Valley Grasslands Important Bird Area (IBA) Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	70.43			X			1	49.4-70.9	Cornwell Ranch Conservation Easement (proposed)	--	--	--	--
Steele City	Montana	No	82.95	X		X	X		3	82.9	Milk River Valley	82.95	Unnamed reservoir	Pipeline passes within 0.1 mile of oxbow on floodplain	
Steele City	Montana	No	89.17	X		X			2	89.2	Missouri River Valley	--	--	--	--
Steele City	Montana	No	89.26	X		X			2	89.2	Missouri River Valley	--	--	--	--
Steele City	Montana	No	93.88	X					1	--	--	--	--	--	--
Steele City	Montana	No	94.89	X					1	--	--	--	--	--	--
Steele City	Montana	No	102.27				X		1	--	--	102.27	Fort Peck Lake and Charles M. Russell Wildlife Refuge	Highway 24 is located between project and reservoir	1,100,000 acres, the largest refuge in Montana, big game hunting, walleye fishing; Fort Peck lake is a large reservoir up stream of the Missouri River crossing. Otherwise a highway is located between the lake and the pipeline.
Steele City	Montana	No	102.73				X		1	--	--	102.73	Fort Peck Lake and Charles M. Russell Wildlife Refuge	Highway 24 is located between project and reservoir	1,100,000 acres, the largest refuge in Montana, big game hunting, walleye fishing; Fort Peck lake is a large reservoir up stream of the Missouri River crossing. Otherwise a highway is located between the lake and the pipeline.
Steele City	Montana	No	102.78				X		1	--	--	102.78	Fort Peck Lake and Charles M. Russell Wildlife Refuge	Highway 24 is located between project and reservoir	1,100,000 acres, the largest refuge in Montana, big game hunting, walleye fishing; Fort Peck lake is a large reservoir up stream of the Missouri River crossing. Otherwise a highway is located between the lake and the pipeline.
Steele City	Montana	No	103.18				X		1	--	--	103.18	Fort Peck Lake and Charles M. Russell Wildlife Refuge	Highway 24 is located between project and reservoir	1,100,000 acres, the largest refuge in Montana, big game hunting, walleye fishing; Fort Peck lake is a large reservoir up stream of the Missouri River crossing. Otherwise a highway is located between the lake and the pipeline.
Steele City	Montana	No	105.61				X		1	--	--	105.61	Fort Peck Lake and Charles M. Russell Wildlife Refuge	Highway 24 is located between project and reservoir	1,100,000 acres, the largest refuge in Montana, big game hunting, walleye fishing; Fort Peck lake is a large reservoir up stream of the Missouri River crossing. Otherwise a highway is located between the lake and the pipeline.
Steele City	Montana	No	105.62				X		1	--	--	105.62	Fort Peck Lake and Charles M. Russell Wildlife Refuge	Highway 24 is located between project and reservoir	1,100,000 acres, the largest refuge in Montana, big game hunting, walleye fishing; Fort Peck lake is a large reservoir up stream of the Missouri River crossing. Otherwise a highway is located between the lake and the pipeline.

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Steele City	Montana	No	107.44				X		1	--	--	107.44	North Dam	Pipeline passes within 0.1 mile of reservoir	--
Steele City	Montana	No	107.63				X		1	--	--	107.63	North Dam	Pipeline passes within 0.1 mile of reservoir	--
Steele City	Montana	No	107.68				X		1	--	--	107.68	North Dam	Pipeline passes within 0.1 mile of reservoir	--
Steele City	Montana	No	107.78				X		1	--	--	107.78	North Dam	Pipeline passes within 0.1 mile of reservoir	--
Steele City	Montana	No	107.79				X		1	--	--	107.79	North Dam	Pipeline passes within 0.1 mile of reservoir	--
Steele City	Montana	No	108.15				X		1	--	--	108.15	North Dam	Pipeline passes within 0.1 mile of reservoir	--
Steele City	Montana	No	108.58				X		1	--	--	108.58	North Dam	Pipeline passes within 0.1 mile of reservoir	--
Steele City	Montana	No	110.72				X		1	--	--	110.72	--	Pipeline passes within 0.1 mile of reservoir	--
Steele City	Montana	No	110.74				X		1	--	--	110.74	--	Pipeline passes within 0.1 mile of reservoir	--
Steele City	Montana	No	110.77				X		1	--	--	110.77	--	Pipeline passes within 0.1 mile of reservoir	--
Steele City	Montana	No	110.8				X		1	--	--	110.8	--	Pipeline passes within 0.1 mile of reservoir	--
Steele City	Montana	No	111.71				X		1	--	--	111.71	--	Pipeline passes within 0.1 mile of reservoir	--
Steele City	Montana	No	111.73				X		1	--	--	111.73	--	Pipeline passes within 0.1 mile of reservoir	--
Steele City	Montana	No	111.92				X		1	--	--	111.92	--	Pipeline passes within 0.1 mile of reservoir	--
Steele City	Montana	No	112.14				X		1	--	--	112.14	--	Pipeline passes within 0.1 mile of reservoir	--
Steele City	Montana	No	112.41				X		1	--	--	112.41	--	Pipeline passes within 0.1 mile of reservoir	--
Steele City	Montana	No	112.44				X		1	--	--	112.44	--	Pipeline passes within 0.1 mile of reservoir	--
Steele City	Montana	No	114.55				X		1	--	--	114.55	Christianson Reservoir	Pipeline passes within 0.1 mile of reservoir	--
Steele City	Montana	No	115.81				X		1	--	--	115.81	Christianson Reservoir	Pipeline passes within 0.1 mile of reservoir	--
Steele City	Montana	No	115.9				X		1	--	--	115.9	Christianson Reservoir	Pipeline passes within 0.1 mile of reservoir	--
Steele City	Montana	No	116.25				X		1	--	--	116.25	Christianson Reservoir	Pipeline passes within 0.1 mile of reservoir	--
Steele City	Montana	No	116.41				X		1	--	--	116.41	Christianson Reservoir	Pipeline passes within 0.1 mile of reservoir	--
Steele City	Montana	No	117.17				X		1	--	--	117.17	Christianson Reservoir	Pipeline passes within 0.1 mile of reservoir	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Steele City	Montana	No	127.99	X					1	--	--	--	--	--	--
Steele City	Montana	No	134.78				X		1	--	--	134.78	Unnamed reservoir	Downstream from Haynie Reservoir, with additional tribs.	
Steele City	Montana	No	136.6				X		1	--	--	136.6	Unnamed reservoir	Downstream from Haynie Reservoir, with additional tribs.	
Steele City	Montana	No	138.65				X		1	--	--	138.65	Unnamed reservoir	Downstream from Haynie Reservoir, with additional tribs.	
Steele City	Montana	No	139.19				X		1	--	--	139.19	Unnamed reservoir	Downstream from Haynie Reservoir, with additional tribs.	
Steele City	Montana	No	139.75				X		1	--	--	139.75	Unnamed reservoir	Downstream from Haynie Reservoir, with additional tribs.	
Steele City	Montana	No	146.97	X					1	--	--	--	--	--	--
Steele City	Montana	No	153.69	X					1	--	--	--	--	--	--
Steele City	Montana	No	159.63	X					1	--	--	--	--	--	--
Steele City	Montana	No	166.59				X		1	--	--	166.59	Lindsay Reservoir	Approximately 10 river miles downstream	
Steele City	Montana	No	175.6	X					1	--	--	--	--	--	--
Steele City	Montana	MT-4	196.06	X					1	--	--	--	--	--	--
Steele City	Montana	No	196.36	X		X			2	196.4	Yellowstone River Valley	--	--	--	--
Steele City	Montana	No	234.7	X					1	--	--	--	--	--	--
Steele City	Montana	No	236.02	X					1	--	--	--	--	--	--
Steele City	Montana	No	246.45				X		1	--	--	246.45	Red Butte Dam	--	--
Steele City	Montana	No	246.51				X		1	--	--	246.51	Red Butte Dam	--	--
Steele City	Montana	No	246.65				X		1	--	--	246.65	Red Butte Dam	--	--
Steele City	Montana	No	249				X		1	--	--	249	Red Butte Dam	--	--
Steele City	Montana	No	250.2				X		1	--	--	250.2	Red Butte Dam	--	--
Steele City	Montana	No	250.22				X		1	--	--	250.22	Red Butte Dam	--	--
Steele City	Montana	No	250.27				X		1	--	--	250.27	Red Butte Dam	--	--
Steele City	Montana	No	250.9				X		1	--	--	250.9	Red Butte Dam	--	--
Steele City	Montana	No	251.11				X		1	--	--	251.11	Red Butte Dam	--	--
Steele City	Montana	No	251.12				X		1	--	--	251.12	Red Butte Dam	--	--
Steele City	Montana	No	251.13				X		1	--	--	251.13	Red Butte Dam	--	--
Steele City	Montana	No	251.2				X		1	--	--	251.2	Red Butte Dam	--	--
Steele City	Montana	No	251.28				X		1	--	--	251.28	Red Butte Dam	--	--
Steele City	Montana	No	251.45				X		1	--	--	251.45	Red Butte Dam	--	--
Steele City	Montana	No	251.91				X		1	--	--	251.91	Red Butte Dam	--	--
Steele City	Montana	No	252.45				X		1	--	--	252.45	Red Butte Dam	--	--
Steele City	Montana	No	262.68	X					1	--	--	--	--	--	--
Steele City	Montana	MT-7	281.47	X					1	--	--	--	--	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Steele City	South Dakota	SD-2	292.08	X					1	--	--	--	--	--	--
Steele City	South Dakota	No	303.27				X		1	--	--	303.27	Unnamed reservoir	Approx. 10 river miles downstream	
Steele City	South Dakota	No	303.95				X		1	--	--	303.95	Unnamed reservoir	Approx. 10 river miles downstream	
Steele City	South Dakota	No	304.22				X		1	--	--	304.22	Unnamed reservoir	Approx. 10 river miles downstream	
Steele City	South Dakota	No	304.75				X		1	--	--	304.75	Unnamed reservoir	Approx. 10 river miles downstream	
Steele City	South Dakota	No	306.09				X		1	--	--	306.09	Unnamed reservoir	Approx. 10 river miles downstream	
Steele City	South Dakota	No	306.65				X		1	--	--	306.65	Unnamed reservoir	Approx. 10 river miles downstream	
Steele City	South Dakota	No	307.43				X		1	--	--	307.43	Unnamed reservoir	Approx. 10 river miles downstream	
Steele City	South Dakota	No	308.21				X		1	--	--	308.21	Gardner Lake	--	Reservoir
Steele City	South Dakota	No	308.28				X		1	--	--	308.28	Gardner Lake	--	Reservoir
Steele City	South Dakota	No	308.6				X		1	--	--	308.6	Gardner Lake	--	Reservoir
Steele City	South Dakota	No	308.7				X		1	--	--	308.7	Gardner Lake	--	Reservoir
Steele City	South Dakota	No	309.13				X		1	--	--	309.13	Gardner Lake	--	Reservoir
Steele City	South Dakota	No	309.55				X		1	--	--	309.55	Gardner Lake	--	Reservoir
Steele City	South Dakota	No	311.67				X		1	--	--	311.67	Gardner Lake	--	Reservoir
Steele City	South Dakota	No	318.09	X					1	--	--	--	--	--	--
Steele City	South Dakota	No	322.88	X					1	--	--	--	--	--	--
Steele City	South Dakota	No	328.67				X		1	--	--	328.67	Unnamed reservoir	State Experiment Farm and Antelope Reserve	
Steele City	South Dakota	No	328.74				X		1	--	--	328.74	Unnamed reservoir	State Experiment Farm and Antelope Reserve	
Steele City	South Dakota	No	328.82				X		1	--	--	328.82	Unnamed reservoir	State Experiment Farm and Antelope Reserve	
Steele City	South Dakota	No	328.83				X		1	--	--	328.83	Unnamed reservoir	State Experiment Farm and Antelope Reserve	
Steele City	South Dakota	No	328.86	X			X		2	--	--	328.86	Unnamed reservoir	State Experiment Farm and Antelope Reserve	
Steele City	South Dakota	No	329.07				X		1	--	--	329.07	Unnamed reservoir	State Experiment Farm and Antelope Reserve	
Steele City	South Dakota	No	329.09				X		1	--	--	329.09	Unnamed reservoir	State Experiment Farm and Antelope Reserve	
Steele City	South Dakota	No	329.33				X		1	--	--	329.33	Unnamed reservoir	State Experiment Farm and Antelope Reserve	
Steele City	South Dakota	No	330.34				X		1	--	--	330.34	Unnamed reservoir	State Experiment Farm and Antelope Reserve	
Steele City	South Dakota	No	330.53				X		1	--	--	330.53	Unnamed reservoir	State Experiment Farm and Antelope Reserve	

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Steele City	South Dakota	No	330.62				X		1	--	--	330.62	Unnamed reservoir	State Experiment Farm and Antelope Reserve	
Steele City	South Dakota	No	331.01				X		1	--	--	331.01	Unnamed reservoir	State Experiment Farm and Antelope Reserve	
Steele City	South Dakota	No	331.12				X		1	--	--	331.12	Unnamed reservoir	State Experiment Farm and Antelope Reserve	
Steele City	South Dakota	No	331.32				X		1	--	--	331.32	Unnamed reservoir	State Experiment Farm and Antelope Reserve	
Steele City	South Dakota	No	331.7				X		1	--	--	331.7	Unnamed reservoir	State Experiment Farm and Antelope Reserve	
Steele City	South Dakota	No	331.91				X		1	--	--	331.91	Unnamed reservoir	State Experiment Farm and Antelope Reserve	
Steele City	South Dakota	No	331.98				X		1	--	--	331.98	Unnamed reservoir	State Experiment Farm and Antelope Reserve	
Steele City	South Dakota	No	353.1	X					1	--	--	--	--	--	--
Steele City	South Dakota	No	356.94	X					1	--	--	--	--	--	--
Steele City	South Dakota	No	364.83	X					1	--	--	--	--	--	--
Steele City	South Dakota	No	383.72	X					1	--	--	--	--	--	--
Steele City	South Dakota	No	408.94	X					1	--	--	--	--	--	--
Steele City	South Dakota	SD-4	425.42	X					1	--	--	--	--	--	--
Steele City	South Dakota	SD-4	426.02			X			1	426	Cheyenne River Valley	--	--	--	--
Steele City	South Dakota	SD-4	426.07	X		X			2	426	Cheyenne River Valley	--	--	--	--
Steele City	South Dakota	SD-4	429.11	X					1	--	--	--	--	--	--
Steele City	South Dakota	No	443.84	X					1	--	--	--	--	--	--
Steele City	South Dakota	No	460.92				X		1	--	--	460.92	Unnamed reservoir	--	--
Steele City	South Dakota	No	460.94				X		1	--	--	460.94	Unnamed reservoir	--	--
Steele City	South Dakota	No	461.63				X		1	--	--	461.63	Unnamed reservoir	--	--
Steele City	South Dakota	SD-5	479.27	X					1	--	--	--	--	--	--
Steele City	South Dakota	No	481.54	X					1	--	--	--	--	--	--
Steele City	South Dakota	SD-6	537.09	X		X			2	537.1	White River Valley	--	--	--	--
Steele City	South Dakota	No	537.13	X		X			2	537.1	White River Valley	--	--	--	--
Steele City	Nebraska	No	599.9	X	X	X			3	599.9	Keya Paha River Valley	--	--	--	--
Steele City	Nebraska	No	601.12		X				1	--	--	--	--	--	--
Steele City	Nebraska	No	601.46		X				1	--	--	--	--	--	--
Steele City	Nebraska	No	604.19	X	X				2	--	--	--	--	--	--
Steele City	Nebraska	No	604.53		X				1	--	--	--	--	--	--
Steele City	Nebraska	No	615.38	X	X	X			3	615.5	Niobrara River Valley	--	--	--	--
Steele City	Nebraska	No	615.48	X	X	X			3	615.5	Niobrara River Valley	--	--	--	--
Steele City	Nebraska	No	615.61	X	X	X			3	615.5	Niobrara River Valley	--	--	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Steele City	Nebraska	No	624.65		X	X			2	617.1-663.9	Sand Hills	--	--	--	--
Steele City	Nebraska	No	628.81		X	X	X		3	617.1-663.9	Sand Hills	628.81	Atkinson Reservoir	Atkinson Lake Recreation Area	Picnic, camping, parkland
Steele City	Nebraska	No	628.92		X	X	X		3	617.1-663.9	Sand Hills	628.92	Atkinson Reservoir	Atkinson Lake Recreation Area	Picnic, camping, parkland
Steele City	Nebraska	No	630.16		X	X	X		3	617.1-663.9	Sand Hills	630.16	Atkinson Reservoir	Atkinson Lake Recreation Area	Picnic, camping, parkland
Steele City	Nebraska	No	630.46	X	X	X	X		4	617.1-663.9	Sand Hills	630.46	Atkinson Reservoir	Atkinson Lake Recreation Area	Picnic, camping, parkland
Steele City	Nebraska	No	630.69		X	X	X		3	617.1-663.9	Sand Hills	630.69	Atkinson Reservoir	Atkinson Lake Recreation Area	Picnic, camping, parkland
Steele City	Nebraska	No	634.18		X	X	X		3	617.1-663.9	Sand Hills	634.18	Atkinson Reservoir	Atkinson Lake Recreation Area	Picnic, camping, parkland
Steele City	Nebraska	No	636.33		X	X	X		3	617.1-663.9	Sand Hills	636.33	Atkinson Reservoir	Atkinson Lake Recreation Area	Picnic, camping, parkland
Steele City	Nebraska	No	636.35		X	X	X		3	617.1-663.9	Sand Hills	636.35	Atkinson Reservoir	Atkinson Lake Recreation Area	Picnic, camping, parkland
Steele City	Nebraska	No	636.36		X	X	X		3	617.1-663.9	Sand Hills	636.36	Atkinson Reservoir	Atkinson Lake Recreation Area	Picnic, camping, parkland
Steele City	Nebraska	No	639.88		X	X			2	617.1-663.9	Sand Hills	--	--	--	--
Steele City	Nebraska	No	640.57		X	X			2	617.1-663.9	Sand Hills	--	--	--	--
Steele City	Nebraska	No	647.1		X	X			2	617.1-663.9	Sand Hills	--	--	--	--
Steele City	Nebraska	No	647.31	X	X	X			3	617.1-663.9	Sand Hills	--	--	--	--
Steele City	Nebraska	No	648		X	X			2	617.1-663.9	Sand Hills	--	--	--	--
Steele City	Nebraska	No	649.98		X	X			2	617.1-663.9	Sand Hills	--	--	--	--
Steele City	Nebraska	No	654.18		X	X			2	617.1-663.9	Sand Hills	--	--	--	--
Steele City	Nebraska	No	656.17		X	X			2	617.1-663.9	Sand Hills	--	--	--	--
Steele City	Nebraska	No	657.84		X	X			2	617.1-663.9	Sand Hills	--	--	--	--
Steele City	Nebraska	No	658.79		X	X			2	617.1-663.9	Sand Hills	--	--	--	--
Steele City	Nebraska	No	660.22	X	X	X			3	617.1-663.9	Sand Hills	--	--	--	--
Steele City	Nebraska	No	660.23	X	X	X			3	617.1-663.9	Sand Hills	--	--	--	--
Steele City	Nebraska	No	697.3	X	X	X			3	697.3	Cedar River Valley	--	--	--	--
Steele City	Nebraska	No	708.57		X				1	--	--	--	--	--	--
Steele City	Nebraska	No	712.3		X				1	--	--	--	--	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Steele City	Nebraska	No	712.63		X				1	--	--	--	--	--	--
Steele City	Nebraska	No	712.76		X				1	--	--	--	--	--	--
Steele City	Nebraska	No	712.97		X				1	--	--	--	--	--	--
Steele City	Nebraska	No	713.52		X				1	--	--	--	--	--	--
Steele City	Nebraska	No	714.06		X				1	--	--	--	--	--	--
Steele City	Nebraska	No	714.35		X				1	--	--	--	--	--	--
Steele City	Nebraska	No	715.56		X				1	--	--	--	--	--	--
Steele City	Nebraska	No	715.78		X				1	--	--	--	--	--	--
Steele City	Nebraska	No	720.58		X				1	--	--	--	--	--	--
Steele City	Nebraska	No	722.21		X				1	--	--	--	--	--	--
Steele City	Nebraska	No	722.28		X				1	--	--	--	--	--	--
Steele City	Nebraska	No	722.41		X				1	--	--	--	--	--	--
Steele City	Nebraska	No	722.52		X				1	--	--	--	--	--	--
Steele City	Nebraska	No	722.55		X				1	--	--	--	--	--	--
Steele City	Nebraska	No	722.82		X				1	--	--	--	--	--	--
Steele City	Nebraska	No	722.85		X				1	--	--	--	--	--	--
Steele City	Nebraska	No	722.9		X				1	--	--	--	--	--	--
Steele City	Nebraska	No	727.96		X				1	--	--	--	--	--	--
Steele City	Nebraska	No	728.52	X	X				2	--	--	--	--	--	--
Steele City	Nebraska	No	729.39		X				1	--	--	--	--	--	--
Steele City	Nebraska	No	729.69	X	X				2	--	--	--	--	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Steele City	Nebraska	No	729.77		X				1	--	--	--	--	--	--
Steele City	Nebraska	No	730.44		X				1	--	--	--	--	--	--
Steele City	Nebraska	No	731.35		X				1	--	--	--	--	--	--
Steele City	Nebraska	No	732.99		X				1	--	--	--	--	--	--
Steele City	Nebraska	No	735.48		X				1	--	--	--	--	--	--
Steele City	Nebraska	No	735.5		X				1	--	--	--	--	--	--
Steele City	Nebraska	No	736.57		X				1	--	--	--	--	--	--
Steele City	Nebraska	NE-5	738.63	X	X				2	--	--	--	--	--	--
Steele City	Nebraska	No	740.72	X	X	X			3	740.7	Loup River Valley	--	--	--	--
Steele City	Nebraska	No	741.06		X				1	--	--	--	--	--	--
Steele City	Nebraska	No	747.14	X					1	--	--	--	--	--	--
Steele City	Nebraska	No	755.74	X					1	--	--	--	--	--	--
Steele City	Nebraska	No	756.28	X		X			2	756.3	Platte River Valley	--	--	--	--
Steele City	Nebraska	NE-7	758.13	X	X	X			3	758-847.4	Rainwater Basin	--	--	--	--
Steele City	Nebraska	NE-7	758.24	X	X	X			3	758-847.4	Rainwater Basin	--	--	--	--
Steele City	Nebraska	NE-7	759.2		X	X			2	758-847.4	Rainwater Basin	--	--	--	--
Steele City	Nebraska	No	759.45		X	X			2	758-847.4	Rainwater Basin	--	--	--	--
Steele City	Nebraska	No	759.72		X	X			2	758-847.4	Rainwater Basin	--	--	--	--
Steele City	Nebraska	No	759.73		X	X			2	758-847.4	Rainwater Basin	--	--	--	--
Steele City	Nebraska	No	759.75		X	X			2	758-847.4	Rainwater Basin	--	--	--	--
Steele City	Nebraska	No	765.5	X	X	X			3	758-847.4	Rainwater Basin	--	--	--	--
Steele City	Nebraska	No	767.12		X	X			2	758-847.4	Rainwater Basin	--	--	--	--
Steele City	Nebraska	No	774.93	X	X	X			3	758-847.4	Rainwater Basin	--	--	--	--
Steele City	Nebraska	No	775.2		X	X			2	758-847.4	Rainwater Basin	--	--	--	--
Steele City	Nebraska	No	778.02		X	X	X		3	758-847.4	Rainwater Basin	778.02	Unnamed reservoir	--	--
Steele City	Nebraska	No	778.03		X	X	X		3	758-847.4	Rainwater Basin	778.03	Unnamed reservoir	--	--

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Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Steele City	Nebraska	NE-9	780.21	X	X	X	X		4	758-847.4	Rainwater Basin	780.21	Unnamed reservoir	--	--
Steele City	Nebraska	NE-9	786.15		X	X			2	758-847.4	Rainwater Basin	--	--	--	--
Steele City	Nebraska	No	787.31		X	X			2	758-847.4	Rainwater Basin	--	--	--	--
Steele City	Nebraska	No	788.12		X	X			2	758-847.4	Rainwater Basin	--	--	--	--
Steele City	Nebraska	No	789.57	X	X	X			3	758-847.4	Rainwater Basin	--	--	--	--
Steele City	Nebraska	No	789.84		X	X			2	758-847.4	Rainwater Basin	--	--	--	--
Steele City	Nebraska	No	790.48		X	X			2	758-847.4	Rainwater Basin	--	--	--	--
Steele City	Nebraska	No	791.29		X	X			2	758-847.4	Rainwater Basin	--	--	--	--
Steele City	Nebraska	No	795.05		X	X			2	758-847.4	Rainwater Basin	--	--	--	--
Steele City	Nebraska	No	799.43		X	X			2	758-847.4	Rainwater Basin	--	--	--	--
Steele City	Nebraska	No	801.55		X	X			2	758-847.4	Rainwater Basin	--	--	--	--
Steele City	Nebraska	No	806.38		X	X			2	758-847.4	Rainwater Basin	--	--	--	--
Steele City	Nebraska	No	807.54	X	X	X			3	758-847.4	Rainwater Basin	--	--	--	--
Steele City	Nebraska	NE-12	808.55	X	X	X			3	758-847.4	Rainwater Basin	--	--	--	--
Steele City	Nebraska	No	808.91		X	X			2	758-847.4	Rainwater Basin	--	--	--	--
Steele City	Nebraska	No	810.08		X	X			2	758-847.4	Rainwater Basin	--	--	--	--
Steele City	Nebraska	No	810.1		X	X			2	758-847.4	Rainwater Basin	--	--	--	--
Steele City	Nebraska	No	813.19		X	X	X		3	758-847.4	Rainwater Basin	813.19	Unnamed reservoir	--	--
Steele City	Nebraska	No	815.14		X	X	X		3	758-847.4	Rainwater Basin	815.14	Unnamed reservoir	--	--
Steele City	Nebraska	No	815.36		X	X	X		3	758-847.4	Rainwater Basin	815.36	Unnamed reservoir	--	--
Steele City	Nebraska	No	816.36		X	X	X		3	758-847.4	Rainwater Basin	816.36	Unnamed reservoir	--	--
Steele City	Nebraska	No	816.41		X	X	X		3	758-847.4	Rainwater Basin	816.41	Unnamed reservoir	--	--
Steele City	Nebraska	No	816.45		X	X	X		3	758-847.4	Rainwater Basin	816.45	Unnamed tributary to North Fork Swan Creek	--	--
Steele City	Nebraska	No	817.16		X	X	X		3	758-847.4	Rainwater Basin	817.16	Unnamed reservoir	--	--
Steele City	Nebraska	No	817.55		X	X	X		3	758-847.4	Rainwater Basin	817.55	Unnamed reservoir	--	--
Steele City	Nebraska	No	823.48		X	X	X		3	758-847.4	Rainwater Basin	823.48	Unnamed reservoir	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Steele City	Nebraska	No	823.54		X	X	X		3	758-847.4	Rainwater Basin	823.54	Unnamed reservoir	--	--
Steele City	Nebraska	No	823.61		X	X	X		3	758-847.4	Rainwater Basin	823.61	Unnamed reservoir	--	--
Steele City	Nebraska	No	823.97		X	X	X		3	758-847.4	Rainwater Basin	823.97	Unnamed reservoir	--	--
Steele City	Nebraska	No	825.04		X	X	X		3	758-847.4	Rainwater Basin	825.04	Unnamed reservoir	--	--
Steele City	Nebraska	No	825.04		X	X	X		3	758-847.4	Rainwater Basin	825.04	Unnamed reservoir	--	--
Steele City	Nebraska	No	826.27		X	X	X		3	758-847.4	Rainwater Basin	826.27	Unnamed reservoir	--	--
Steele City	Nebraska	No	829.47		X	X	X		3	758-847.4	Rainwater Basin	829.47	Unnamed reservoir	--	--
Steele City	Nebraska	No	829.81		X	X	X		3	758-847.4	Rainwater Basin	829.81	Unnamed reservoir	--	--
Steele City	Nebraska	No	829.88		X	X	X		3	758-847.4	Rainwater Basin	829.88	Unnamed reservoir	--	--
Steele City	Nebraska	No	829.99		X	X	X		3	758-847.4	Rainwater Basin	829.99	Unnamed reservoir	--	--
Steele City	Nebraska	No	830.61		X	X	X		3	758-847.4	Rainwater Basin	830.61	Unnamed reservoir	--	--
Steele City	Nebraska	No	831.33		X	X	X		3	758-847.4	Rainwater Basin	831.33	Cub Creek Reservoir 14-C	--	--
Steele City	Nebraska	No	832.18		X	X	X		3	758-847.4	Rainwater Basin	832.18	Cub Creek Reservoir 14-C	--	--
Steele City	Nebraska	No	832.71		X	X	X		3	758-847.4	Rainwater Basin	832.71	Cub Creek Reservoir 14-C	--	--
Steele City	Nebraska	No	832.73		X	X	X		3	758-847.4	Rainwater Basin	832.73	Cub Creek Reservoir 14-C	--	--
Steele City	Nebraska	No	832.74		X	X	X		3	758-847.4	Rainwater Basin	832.74	Cub Creek Reservoir 14-C	--	--
Steele City	Nebraska	No	833.9		X	X	X		3	758-847.4	Rainwater Basin	833.9	Cub Creek Reservoir 14-C	--	--
Steele City	Nebraska	No	835.29		X	X	X		3	758-847.4	Rainwater Basin	835.29	Cub Creek Reservoir 13-C	Pipeline passes within 0.2 mile of reservoir	--
Steele City	Nebraska	NE-14	836.32		X	X	X		3	758-847.4	Rainwater Basin	836.32	Cub Creek Reservoir 13-C	Pipeline passes within 0.2 mile of reservoir	--
Steele City	Nebraska	NE-14	836.94		X	X	X		3	758-847.4	Rainwater Basin	836.94	Cub Creek Reservoir 13-C	Pipeline passes within 0.2 mile of reservoir	--
Steele City	Nebraska	No	837.46		X	X	X		3	758-847.4	Rainwater Basin	837.46	Cub Creek Reservoir 13-C	Pipeline passes within 0.2 mile of reservoir	--
Steele City	Nebraska	No	837.53		X	X	X		3	758-847.4	Rainwater Basin	837.53	Cub Creek Reservoir 13-C	Pipeline passes within 0.2 mile of reservoir	--
Steele City	Nebraska	No	838.62		X	X	X		3	758-847.4	Rainwater Basin	838.62	Cub Creek Reservoir 13-C	Pipeline passes within 0.2 mile of reservoir	--
Steele City	Nebraska	No	838.76		X	X	X		3	758-847.4	Rainwater Basin	838.76	Cub Creek Reservoir 13-C	Pipeline passes within 0.2 mile of reservoir	--
Steele City	Nebraska	No	840.59		X	X	X		3	758-847.4	Rainwater Basin	840.59	Big Indian Creek Reservoir 10-A	Pipeline passes within 0.3 mile of reservoir	--
Steele City	Nebraska	No	843.03		X	X	X		3	758-847.4	Rainwater Basin	843.03	Big Indian Creek Reservoir 10-A	Pipeline passes within 0.3 mile of reservoir	--

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Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes					Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Steele City	Nebraska	No	847.32		X	X	X		3	758-847.4	Rainwater Basin	847.32	Big Indian Creek Reservoir 8-E	Pipeline passes within 0.3 mile of reservoir	--
Steele City	Nebraska	No	847.34		X	X	X		3	758-847.4	Rainwater Basin	847.34	Big Indian Creek Reservoir 8-E	Pipeline passes within 0.3 mile of reservoir	--
Steele City	Nebraska	NE-17	848.66				X		1	--	--	848.66	Big Indian Creek Reservoir 8-E	Pipeline passes within 0.3 mile of reservoir	--
Gulf Coast	Oklahoma	No	1.24	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	2.45	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	2.94	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	3.27	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	6.98	X			X		2	--	--	6.98	Stroud Lake	Perennial drainage flows southeast from the centerline into Stroud Lake via Camp Creek	Reservoir used for fishing, appears to be an ESA outside of the 5 mile boundary.
Gulf Coast	Oklahoma	No	7.6				X		1	--	--	7.6	Stroud Lake	Intermittent drainage flows southeast from the centerline into Stroud Lake via Camp Creek	Reservoir used for fishing, appears to be an ESA outside of the 5 mile boundary.
Gulf Coast	Oklahoma	OK-2	7.83	X			X		2	--	--	7.83	Stroud Lake	Intermittent drainage flows southeast from the centerline into Stroud Lake via Camp Creek	Reservoir used for fishing, appears to be an ESA outside of the 5 mile boundary.
Gulf Coast	Oklahoma	OK-2	8.38				X		1	--	--	8.38	Stroud Lake	Intermittent drainage flows southeast from the centerline into Stroud Lake via Camp Creek	Reservoir used for fishing, appears to be an ESA outside of the 5 mile boundary.
Gulf Coast	Oklahoma	OK-2	9.1				X		1	--	--	9.1	Stroud Lake	Intermittent drainage flows southeast from the centerline into Stroud Lake via Camp Creek	Reservoir used for fishing, appears to be an ESA outside of the 5 mile boundary.
Gulf Coast	Oklahoma	No	9.37				X		1	--	--	9.37	Stroud Lake	Intermittent drainage flows southeast from the centerline into Stroud Lake via Camp Creek	Reservoir used for fishing, appears to be an ESA outside of the 5 mile boundary.
Gulf Coast	Oklahoma	OK-3	14.06	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	OK-3	14.84	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	OK-3	15.23	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	OK-3	15.25	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	19.52	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	22.15	X	X	X			3	22.1-23.3	Deep Fork Wildlife Management Area	--	--	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Gulf Coast	Oklahoma	No	22.99		X	X			2	22.1-23.3	Deep Fork Wildlife Management Area	--	--	--	--
Gulf Coast	Oklahoma	No	24.03	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	28.3	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	30.41	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	32.65	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	38.3	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	38.55	X		X			2	38.6	North Canadian River Valley	--	--	--	--
Gulf Coast	Oklahoma	No	39.9	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	43.53	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	OK-4	46.82	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	47.29	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	47.95	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	50.01	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	52.44	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	58.7	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	59.84	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	59.98	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	60.28	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	60.33	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	OK-6	67.22	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	OK-6	70.38	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	72.95	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	OK-6	74.05	X		X			2	74.2	South Canadian River Valley	--	--	--	--
Gulf Coast	Oklahoma	OK-6	74.74	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	OK-7	79.56	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	80.17	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	87.34	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	95.02	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	96.14	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	102.25	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	102.69	X					1	--	--	--	--	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Gulf Coast	Oklahoma	No	111.06	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	119.15	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	122.57	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	123.08	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	124.08	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	125.62	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	126.2	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	126.89	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	127.09	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	127.26						0	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	129.45	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	131.34	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	133.24	X					1	--	--	--	--	--	--
Gulf Coast	Oklahoma	No	155.68	X		X			2	155.7	Red River Valley	--	--	--	--
Gulf Coast	Oklahoma	No	155.73	X		X			2	155.7	Red River Valley	--	--	--	--
Gulf Coast	Texas	No	158.53	X					1	--	--	--	--	--	--
Gulf Coast	Texas	No	162.02	X	X	X			3	162	Wetland Reserve Program	--	--	--	--
Gulf Coast	Texas	No	165.65	X					1	--	--	--	--	--	--
Gulf Coast	Texas	No	166.16	X					1	--	--	--	--	--	--
Gulf Coast	Texas	No	168.32				X	X	2	--	--	168.32	Pat Mayse Lake/WMA	Ephemeral drainage flows northeast from centerline into Pat Mayse Lake/WMA via Collins Creek	8,925 acre wildlife management area on the western edge of Pat Mayse Reservoir. Waterfowl viewing and hunting. This is an ESA, but it is outside of the 5 mile buffer from the pipeline.
Gulf Coast	Texas	No	168.33				X	X	2	--	--	168.33	Pat Mayse Lake/WMA	Ephemeral drainage flows northeast from centerline into Pat Mayse Lake/WMA via Collins Creek	8,925 acre wildlife management area on the western edge of Pat Mayse Reservoir. Waterfowl viewing and hunting. This is an ESA, but it is outside of the 5 mile buffer from the pipeline.
Gulf Coast	Texas	No	168.33				X	X	2	--	--	168.33	Pat Mayse Lake/WMA	Ephemeral drainage flows northeast from centerline into Pat Mayse Lake/WMA via Collins Creek	8,925 acre wildlife management area on the western edge of Pat Mayse Reservoir. Waterfowl viewing and hunting. This is an ESA, but it is outside of the 5 mile buffer from the pipeline.

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Gulf Coast	Texas	No	168.84				X	X	2	--	--	168.84	Pat Mayse Lake/WMA	Intermittent drainage flows northeast from centerline into Pat Mayse Lake/WMA via Collins Creek	8,925 acre wildlife management area on the western edge of Pat Mayse Reservoir. Waterfowl viewing and hunting. This is an ESA, but it is outside of the 5 mile buffer from the pipeline.
Gulf Coast	Texas	No	169.29	X			X	X	3	--	--	169.29	Pat Mayse Lake/WMA	--	8,925 acre wildlife management area on the western edge of Pat Mayse Reservoir. Waterfowl viewing and hunting. This is an ESA, but it is outside of the 5 mile buffer from the pipeline.
Gulf Coast	Texas	No	169.48				X	X	2	--	--	169.48	Pat Mayse Lake/WMA	--	8,925 acre wildlife management area on the western edge of Pat Mayse Reservoir. Waterfowl viewing and hunting. This is an ESA, but it is outside of the 5 mile buffer from the pipeline.
Gulf Coast	Texas	No	170.3				X	X	2	--	--	170.3	Pat Mayse Lake/WMA	Ephemeral drainage flows north from centerline into Pat Mayse Lake/WMA via Sanders Creek.	8,925 acre wildlife management area on the western edge of Pat Mayse Reservoir. Waterfowl viewing and hunting. This is an ESA, but it is outside of the 5 mile buffer from the pipeline.
Gulf Coast	Texas	No	170.39				X	X	2	--	--	170.39	Pat Mayse Lake/WMA	Ephemeral drainage flows north from centerline into Pat Mayse Lake/WMA via Sanders Creek	8,925 acre wildlife management area on the western edge of Pat Mayse Reservoir. Waterfowl viewing and hunting. This is an ESA, but it is outside of the 5 mile buffer from the pipeline.
Gulf Coast	Texas	No	170.9	X			X	X	3	--	--	170.9	Pat Mayse Lake/WMA	Ephemeral drainage flows north from centerline into Pat Mayse Lake/WMA via Sanders Creek	8,925 acre wildlife management area on the western edge of Pat Mayse Reservoir. Waterfowl viewing and hunting. This is an ESA, but it is outside of the 5 mile buffer from the pipeline.
Gulf Coast	Texas	No	171.16	X			X	X	3	--	--	171.16	Pat Mayse Lake/WMA	--	8,925 acre wildlife management area on the western edge of Pat Mayse Reservoir. Waterfowl viewing and hunting. This is an ESA, but it is outside of the 5 mile buffer from the pipeline.
Gulf Coast	Texas	No	172.71	X			X	X	3	--	--	172.71	Pat Mayse Lake/WMA	--	8,925 acre wildlife management area on the western edge of Pat Mayse Reservoir. Waterfowl viewing and hunting. This is an ESA, but it is outside of the 5 mile buffer from the pipeline.
Gulf Coast	Texas	No	173.41				X	X	2	--	--	173.41	Pat Mayse Lake/WMA	Ephemeral drainage flows north from centerline into Pat Mayse Lake/WMA via Cottonwood Creek	8,925 acre wildlife management area on the western edge of Pat Mayse Reservoir. Waterfowl viewing and hunting. This is an ESA, but it is outside of the 5 mile buffer from the pipeline.
Gulf Coast	Texas	No	174.22	X					1	--	--	--	--	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Gulf Coast	Texas	No	184				X		1	--	--	184	Proposed George Parkhouse Reservoir	Intermittent drainage flows south from centerline into area considered for proposed George Parkhouse Reservoir via Mallory Creek	--
Gulf Coast	Texas	No	184.08				X		1	--	--	184.08	Proposed George Parkhouse Reservoir	Ephemeral drainage flows south from centerline into area considered for proposed George Parkhouse Reservoir via Mallory Creek	--
Gulf Coast	Texas	No	185.09				X		1	--	--	185.09	Proposed George Parkhouse Reservoir	Ephemeral drainage flows south from centerline into area considered for proposed George Parkhouse Reservoir via Mallory Creek	--
Gulf Coast	Texas	No	186.41				X		1	--	--	186.41	Proposed George Parkhouse Reservoir	Intermittent drainage flows south from centerline into area considered for proposed George Parkhouse Reservoir via Mallory Creek	--
Gulf Coast	Texas	No	187.51				X		1	--	--	187.51	Proposed George Parkhouse Reservoir	--	--
Gulf Coast	Texas	No	188.52				X		1	--	--	188.52	Proposed George Parkhouse Reservoir	Intermittent drainage flows south from centerline into area considered for proposed George Parkhouse Reservoir via Mallory Creek	--
Gulf Coast	Texas	No	189.31				X		1	--	--	189.31	Proposed George Parkhouse Reservoir	--	--
Gulf Coast	Texas	No	190.52		X		X		2	190.2	North Sulphur River Valley	190.52	Proposed George Parkhouse Reservoir	Intermittent drainage flows south from centerline into area considered for proposed George Parkhouse Reservoir via North Sulphur River	--

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Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Gulf Coast	Texas	No	190.52			X	X		2	190.2	North Sulphur River Valley	190.52	Proposed George Parkhouse Reservoir	Intermittent drainage flows south from centerline into area considered for proposed George Parkhouse Reservoir via North Sulphur River	--
Gulf Coast	Texas	No	190.52			X	X		2	190.2	North Sulphur River Valley	190.52	Proposed George Parkhouse Reservoir	Intermittent drainage flows south from centerline into area considered for proposed George Parkhouse Reservoir via North Sulphur River	--
Gulf Coast	Texas	No	190.66			X	X		2	190.2	North Sulphur River Valley	190.66	Proposed George Parkhouse Reservoir	Ephemeral drainage flows north from centerline into area considered for proposed George Parkhouse Reservoir via North Sulphur River	--
Gulf Coast	Texas	No	190.67			X	X		2	190.2	North Sulphur River Valley	190.67	Proposed George Parkhouse Reservoir	Ephemeral drainage flows north from centerline into area considered for proposed George Parkhouse Reservoir via North Sulphur River	--
Gulf Coast	Texas	No	190.75			X	X		2	190.2	North Sulphur River Valley	190.75	Proposed George Parkhouse Reservoir	Perennial drainage flows north from centerline into area considered for proposed George Parkhouse Reservoir via North Sulphur River	--
Gulf Coast	Texas	No	190.76	X		X	X		3	190.2	North Sulphur River Valley	190.76	Proposed George Parkhouse Reservoir	Perennial drainage flows north from centerline into area considered for proposed George Parkhouse Reservoir via North Sulphur River	--
Gulf Coast	Texas	No	190.76	X		X	X		3	190.2	North Sulphur River Valley	190.76	Proposed George Parkhouse Reservoir	--	--
Gulf Coast	Texas	No	190.76	X		X	X		3	190.2	North Sulphur River Valley	190.76	Proposed George Parkhouse Reservoir	--	--

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Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Gulf Coast	Texas	No	190.82				X		1	--	--	190.82	Proposed George Parkhouse Reservoir	Ephemeral drainage flows north from centerline into area considered for proposed George Parkhouse Reservoir via North Sulphur River	--
Gulf Coast	Texas	No	191.05				X		1	--	--	191.05	Proposed George Parkhouse Reservoir	Ephemeral drainage flows north from centerline into area considered for proposed George Parkhouse Reservoir via North Sulphur River	--
Gulf Coast	Texas	No	192.85				X		1	--	--	192.85	Proposed George Parkhouse Reservoir	Intermittent drainage flows southeast from centerline into area considered for proposed George Parkhouse Reservoir via Lake Creek.	--
Gulf Coast	Texas	No	193.67				X		1	--	--	193.67	Proposed George Parkhouse Reservoir	Intermittent drainage flows southeast from centerline into area considered for proposed George Parkhouse Reservoir via Lake Creek.	--
Gulf Coast	Texas	No	194.24				X		1	--	--	194.24	Proposed George Parkhouse Reservoir	Ephemeral drainage flows east from centerline into area considered for proposed George Parkhouse Reservoir via Lake Creek.	--
Gulf Coast	Texas	No	194.25				X		1	--	--	194.25	Proposed George Parkhouse Reservoir	Ephemeral drainage flows east from centerline into area considered for proposed George Parkhouse Reservoir via Lake Creek.	--
Gulf Coast	Texas	No	194.26				X		1	--	--	194.26	Proposed George Parkhouse Reservoir	Ephemeral drainage flows east from centerline into area considered for proposed George Parkhouse Reservoir via Lake Creek.	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Gulf Coast	Texas	No	194.96				X		1	--	--	194.96	Proposed George Parkhouse Reservoir	Intermittent drainage flows east from centerline into area considered for proposed George Parkhouse Reservoir via Lake Creek.	--
Gulf Coast	Texas	No	195.87				X		1	--	--	195.87	Proposed George Parkhouse Reservoir	Ephemeral drainage flows east from centerline into area considered for proposed George Parkhouse Reservoir via Lake Creek.	--
Gulf Coast	Texas	No	195.91				X		1	--	--	195.91	Proposed George Parkhouse Reservoir	Perennial drainage flows east from centerline into area considered for proposed George Parkhouse Reservoir via Lake Creek.	--
Gulf Coast	Texas	No	196.37				X		1	--	--	196.37	Proposed George Parkhouse Reservoir	Ephemeral drainage flows east from centerline into area considered for proposed George Parkhouse Reservoir via Lake Creek.	--
Gulf Coast	Texas	No	199.59				X		1	--	--	199.59	Proposed George Parkhouse Reservoir	Intermittent drainage flows south from centerline into area considered for proposed George Parkhouse Reservoir via Evans Branch.	--
Gulf Coast	Texas	No	199.84				X		1	--	--	199.84	Proposed George Parkhouse Reservoir	Seasonal drainage flows south from centerline into area considered for proposed George Parkhouse Reservoir via Evans Branch.	--
Gulf Coast	Texas	No	201.77	X			X		2	--	--	201.77	Proposed George Parkhouse Reservoir	Perennial drainage flows north from centerline into area considered for proposed George Parkhouse Reservoir via South Sulphur River.	--
Gulf Coast	Texas	No	201.78	X			X		2	--	--	201.78	Proposed George Parkhouse Reservoir	Perennial drainage flows north from centerline into area considered for proposed George Parkhouse Reservoir via South Sulphur River.	--

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Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Gulf Coast	Texas	No	202.95				X		1	--	--	202.95	Proposed George Parkhouse Reservoir	--	--
Gulf Coast	Texas	No	202.95				X		1	--	--	202.95	Proposed George Parkhouse Reservoir	Perennial drainage flows north from centerline into area considered for proposed George Parkhouse Reservoir via South Sulphur River.	--
Gulf Coast	Texas	No	203.4				X		1	--	--	203.4	Proposed George Parkhouse Reservoir	Drainage flows north from centerline into area considered for proposed George Parkhouse Reservoir via South Sulphur River.	--
Gulf Coast	Texas	No	203.76				X		1	--	--	203.76	Proposed George Parkhouse Reservoir	Ephemeral drainage flows north from centerline into area considered for proposed George Parkhouse Reservoir via South Sulphur River.	--
Gulf Coast	Texas	No	203.77				X		1	--	--	203.77	Proposed George Parkhouse Reservoir	Ephemeral drainage flows north from centerline into area considered for proposed George Parkhouse Reservoir via South Sulphur River.	--
Gulf Coast	Texas	No	203.79				X		1	--	--	203.79	Proposed George Parkhouse Reservoir	--	--
Gulf Coast	Texas	No	203.95				X		1	--	--	203.95	Proposed George Parkhouse Reservoir	Perennial drainage flows north from centerline into area considered for proposed George Parkhouse Reservoir via South Sulphur River.	--
Gulf Coast	Texas	No	204.09				X		1	--	--	204.09	Proposed George Parkhouse Reservoir	Ephemeral drainage flows north from centerline into area considered for proposed George Parkhouse Reservoir via South Sulphur River.	--
Gulf Coast	Texas	No	204.14				X		1	--	--	204.14	Proposed George Parkhouse Reservoir	Ephemeral drainage flows north from centerline into area considered for proposed George Parkhouse Reservoir via South Sulphur River.	--

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Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Gulf Coast	Texas	No	212.11	X					1	--	--	--	--	--	--
Gulf Coast	Texas	No	212.82	X					1	--	--	--	--	--	--
Gulf Coast	Texas	No	217.18	X					1	--	--	--	--	--	--
Gulf Coast	Texas	No	218.23	X					1	--	--	--	--	--	--
Gulf Coast	Texas	No	220.91	X					1	--	--	--	--	--	--
Gulf Coast	Texas	TX-1	223.05				X	X	2	--	--	223.05	Lake Cypress Springs	--	Attached to Lake Bob Sandlin
Gulf Coast	Texas	No	224.15	X			X	X	3	--	--	224.15	Lake Cypress Springs	--	Attached to Lake Bob Sandlin
Gulf Coast	Texas	No	225.03				X	X	2	--	--	225.03	Lake Cypress Springs	Intermittent drainage flows south from centerline into Lake Cypress Springs via Little Cypress Creek.	Attached to Lake Bob Sandlin
Gulf Coast	Texas	No	225.38				X	X	2	--	--	225.38	Lake Cypress Springs	Ephemeral drainage flows south from centerline into Lake Cypress Springs via Little Cypress Creek.	Attached to Lake Bob Sandlin
Gulf Coast	Texas	No	225.42				X	X	2	--	--	225.42	Lake Cypress Springs	Ephemeral drainage flows south from centerline into Lake Cypress Springs via Little Cypress Creek.	Attached to Lake Bob Sandlin
Gulf Coast	Texas	TX-1	226.04				X	X	2	--	--	226.04	Lake Cypress Springs	--	Attached to Lake Bob Sandlin
Gulf Coast	Texas	TX-1	226.2				X	X	2	--	--	226.2	Lake Cypress Springs	--	Attached to Lake Bob Sandlin
Gulf Coast	Texas	TX-1	226.23				X	X	2	--	--	226.23	Lake Cypress Springs	--	Attached to Lake Bob Sandlin
Gulf Coast	Texas	TX-1	226.29				X	X	2	--	--	226.29	Lake Cypress Springs	--	Attached to Lake Bob Sandlin
Gulf Coast	Texas	No	226.68	X			X	X	3	--	--	226.68	Lake Cypress Springs	--	Attached to Lake Bob Sandlin
Gulf Coast	Texas	No	226.76	X			X	X	3	--	--	226.76	Lake Cypress Springs	--	Attached to Lake Bob Sandlin
Gulf Coast	Texas	No	227.52				X	X	2	--	--	227.52	Lake Cypress Springs	--	Attached to Lake Bob Sandlin
Gulf Coast	Texas	No	227.53				X	X	2	--	--	227.53	Lake Cypress Springs	--	Attached to Lake Bob Sandlin
Gulf Coast	Texas	No	227.58				X	X	2	--	--	227.58	Lake Cypress Springs	--	Attached to Lake Bob Sandlin
Gulf Coast	Texas	No	227.68				X	X	2	--	--	227.68	Lake Cypress Springs	--	Attached to Lake Bob Sandlin
Gulf Coast	Texas	No	227.91				X	X	2	--	--	227.91	Lake Cypress Springs	--	Attached to Lake Bob Sandlin
Gulf Coast	Texas	No	227.95				X	X	2	--	--	227.95	Lake Cypress Springs	--	Attached to Lake Bob Sandlin
Gulf Coast	Texas	No	228.34				X	X	2	--	--	228.34	Lake Cypress Springs	--	Attached to Lake Bob Sandlin
Gulf Coast	Texas	No	228.48	X			X	X	3	--	--	228.48	Lake Cypress Springs	--	Attached to Lake Bob Sandlin

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Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Gulf Coast	Texas	No	228.86				X	X	2	--	--	228.86	Lake Cypress Springs	--	Attached to Lake Bob Sandlin
Gulf Coast	Texas	No	228.88				X	X	2	--	--	228.88	Lake Cypress Springs	--	Attached to Lake Bob Sandlin
Gulf Coast	Texas	No	230.07				X	X	2	--	--	230.07	Lake Bob Sandlin	--	9,400 acre reservoir, eagles in winter months, bird watching,
Gulf Coast	Texas	No	230.41				X	X	2	--	--	230.41	Lake Bob Sandlin	--	9,400 acre reservoir, eagles in winter months, bird watching,
Gulf Coast	Texas	No	230.42				X	X	2	--	--	230.42	Lake Bob Sandlin	--	9,400 acre reservoir, eagles in winter months, bird watching,
Gulf Coast	Texas	No	230.89				X	X	2	--	--	230.89	Lake Bob Sandlin	Ephemeral drainage flows south of the centerline into Lake Bob Sandlin via Gum Branch.	9,400 acre reservoir, eagles in winter months, bird watching,
Gulf Coast	Texas	No	231.22				X	X	2	--	--	231.22	Lake Bob Sandlin	Ephemeral drainage flows south of the centerline into Lake Bob Sandlin via Gum Branch.	9,400 acre reservoir, eagles in winter months, bird watching,
Gulf Coast	Texas	No	231.43				X	X	2	--	--	231.43	Lake Bob Sandlin	Ephemeral drainage flows south of the centerline into Lake Bob Sandlin via Gum Branch.	9,400 acre reservoir, eagles in winter months, bird watching,
Gulf Coast	Texas	No	231.6				X	X	2	--	--	231.6	Lake Bob Sandlin	--	9,400 acre reservoir, eagles in winter months, bird watching,
Gulf Coast	Texas	No	231.85				X	X	2	--	--	231.85	Lake Bob Sandlin	--	9,400 acre reservoir, eagles in winter months, bird watching,
Gulf Coast	Texas	No	232.65	X			X	X	3	--	--	232.65	Lake Bob Sandlin	--	9,400 acre reservoir, eagles in winter months, bird watching,
Gulf Coast	Texas	No	232.75	X			X	X	3	--	--	232.75	Lake Bob Sandlin	--	9,400 acre reservoir, eagles in winter months, bird watching,
Gulf Coast	Texas	No	233.08	X			X	X	3	--	--	233.08	Lake Bob Sandlin	--	9,400 acre reservoir, eagles in winter months, bird watching,
Gulf Coast	Texas	No	234.13	X			X	X	3	--	--	234.13	Lake Bob Sandlin	--	9,400 acre reservoir, eagles in winter months, bird watching,
Gulf Coast	Texas	No	234.21				X	X	2	--	--	234.21	Lake Bob Sandlin	--	9,400 acre reservoir, eagles in winter months, bird watching,
Gulf Coast	Texas	No	234.59	X			X	X	3	--	--	234.59	Lake Bob Sandlin	--	9,400 acre reservoir, eagles in winter months, bird watching,
Gulf Coast	Texas	No	234.7				X	X	2	--	--	234.7	Lake Bob Sandlin	--	9,400 acre reservoir, eagles in winter months, bird watching,
Gulf Coast	Texas	No	235.05	X			X	X	3	--	--	235.05	Lake Bob Sandlin	--	9,400 acre reservoir, eagles in winter months, bird watching,
Gulf Coast	Texas	TX-2	235.54	X			X	X	3	--	--	235.54	Lake Bob Sandlin	Perennial drainage flows north of the centerline into Lake Bob Sandlin via Sand Branch.	9,400 acre reservoir, eagles in winter months, bird watching,
Gulf Coast	Texas	TX-2	236.81				X	X	2	--	--	236.81	Lake Bob Sandlin	Intermittent drainage flows east of the centerline into Lake Bob Sandlin via South Fork Brushy Creek.	9,400 acre reservoir, eagles in winter months, bird watching,

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Gulf Coast	Texas	TX-2	238.19				X	X	2	--	--	238.19	Lake Bob Sandlin	--	9,400 acre reservoir, eagles in winter months, bird watching,
Gulf Coast	Texas	TX-2	239.45				X		1	--	--	239.45	Proposed Little Cypress Reservoir	Intermittent drainage flows southeast from centerline into area considered for proposed Little Cypress Reservoir via Caney Creek.	--
Gulf Coast	Texas	TX-2	239.67				X		1	--	--	239.67	Proposed Little Cypress Reservoir	Ephemeral drainage flows southeast from centerline into area considered for proposed Little Cypress Reservoir via Caney Creek.	--
Gulf Coast	Texas	No	241.61				X		1	--	--	241.61	Proposed Little Cypress Reservoir	Ephemeral drainage flows southeast from centerline into area considered for proposed Little Cypress Reservoir via Caney Creek.	--
Gulf Coast	Texas	No	241.83				X		1	--	--	241.83	Proposed Little Cypress Reservoir	Drainage flows southeast from centerline into area considered for proposed Little Cypress Reservoir via Caney Creek.	--
Gulf Coast	Texas	No	241.86				X		1	--	--	241.86	Proposed Little Cypress Reservoir	Intermittent drainage flows southeast from centerline into area considered for proposed Little Cypress Reservoir via Little Cypress Creek.	--
Gulf Coast	Texas	No	242.09				X		1	--	--	242.09	Proposed Little Cypress Reservoir	Ephemeral drainage flows southeast from centerline into area considered for proposed Little Cypress Reservoir via Little Cypress Creek.	--
Gulf Coast	Texas	No	242.24				X		1	--	--	242.24	Proposed Little Cypress Reservoir	Intermittent drainage flows southeast from centerline into area considered for proposed Little Cypress Reservoir via Little Cypress Creek.	--
Gulf Coast	Texas	No	242.71	X			X		2	--	--	242.71	Proposed Little Cypress Reservoir	Perennial drainage flows southeast from centerline into area considered for proposed Little Cypress Reservoir via Little Cypress Creek.	--
Gulf Coast	Texas	No	243.9	X			X		2	--	--	243.9	Proposed Little Cypress Reservoir	--	--

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Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Gulf Coast	Texas	No	244.87	X			X		2	--	--	244.87	Proposed Little Cypress Reservoir	Perennial drainage flows southeast from centerline into area considered for proposed Little Cypress Reservoir via Little Cypress Creek.	--
Gulf Coast	Texas	No	245.44	X			X		2	--	--	245.44	Proposed Little Cypress Reservoir	Perennial drainage flows southeast from centerline into area considered for proposed Little Cypress Reservoir via Little Cypress Creek.	--
Gulf Coast	Texas	No	245.53				X		1	--	--	245.53	Proposed Little Cypress Reservoir	Perennial drainage flows southeast from centerline into area considered for proposed Little Cypress Reservoir via Little Cypress Creek.	--
Gulf Coast	Texas	No	246.39				X		1	--	--	246.39	Proposed Little Cypress Reservoir	Drainage flows southeast from centerline into area considered for proposed Little Cypress Reservoir via Little Cypress Creek.	--
Gulf Coast	Texas	No	246.62	X			X		2	--	--	246.62	Proposed Little Cypress Reservoir	Perennial drainage flows southeast from centerline into area considered for proposed Little Cypress Reservoir via Little Cypress Creek.	--
Gulf Coast	Texas	No	247.51				X		1	--	--	247.51	Lake Greenbriar	Intermittent drainage flows southwest from centerline into Lake Greenbriar via Clear Creek.	Residential area, reservoir
Gulf Coast	Texas	No	248.01	X			X		2	--	--	248.01	Lake Greenbriar	Perennial drainage flows southwest from centerline into Lake Greenbriar via Clear Creek.	Residential area, reservoir
Gulf Coast	Texas	TX-4	248.6				X		1	--	--	248.6	Lake Greenbriar	Perennial drainage flows southwest from centerline into Lake Greenbriar via Clear Creek.	Residential area, reservoir
Gulf Coast	Texas	TX-4	249.96				X		1	--	--	249.96	Lake Greenbriar	Intermittent drainage flows southwest from centerline into Lake Greenbriar via Honey Creek.	Residential area, reservoir

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Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Gulf Coast	Texas	TX-4	250.28				X		1	--	--	250.28	Lake Greenbriar	Intermittent drainage flows southwest from centerline into Lake Greenbriar via Honey Creek.	Residential area, reservoir
Gulf Coast	Texas	TX-5	252.97	X					1	--	--	--	--	--	--
Gulf Coast	Texas	No	254.89	X					1	--	--	--	--	--	--
Gulf Coast	Texas	No	255.17	X					1	--	--	--	--	--	--
Gulf Coast	Texas	No	256.92	X					1	--	--	--	--	--	--
Gulf Coast	Texas	No	258.35		X				1	--	--	--	--	--	--
Gulf Coast	Texas	No	258.72		X				1	--	--	--	--	--	--
Gulf Coast	Texas	No	260.05		X				1	--	--	--	--	--	--
Gulf Coast	Texas	No	260.94		X				1	--	--	--	--	--	--
Gulf Coast	Texas	No	261.24		X				1	--	--	--	--	--	--
Gulf Coast	Texas	No	263.5	X					1	--	--	--	--	--	--
Gulf Coast	Texas	TX-6	267.89	X					1	--	--	--	--	--	--
Gulf Coast	Texas	TX-6	268.86	X					1	--	--	--	--	--	--
Gulf Coast	Texas	TX-6	270.67	X					1	--	--	--	--	--	--
Gulf Coast	Texas	TX-6	270.84	X					1	--	--	--	--	--	--
Gulf Coast	Texas	No	272.14	X					1	--	--	--	--	--	--
Gulf Coast	Texas	TX-7	275.08	X			X		2	--	--	275.08	Prairie Creek Reservoir	Perennial drainage flows east from centerline into Prairie Creek Reservoir via Prairie Creek.	For water storage, recently constructed.
Gulf Coast	Texas	TX-7	275.48				X		1	--	--	275.48	Prairie Creek Reservoir	--	For water storage, recently constructed.
Gulf Coast	Texas	TX-7	275.53	X			X		2	--	--	275.53	Prairie Creek Reservoir	--	For water storage, recently constructed.
Gulf Coast	Texas	TX-7	275.55				X		1	--	--	275.55	Prairie Creek Reservoir	--	For water storage, recently constructed.
Gulf Coast	Texas	TX-7	277.06				X		1	--	--	277.06	Lake Tyler	Intermittent drainage flows west of centerline into Lake Tyler via Mud Creek.	Picnic and wildlife/bird watching
Gulf Coast	Texas	No	277.34	X			X		2	--	--	277.34	Lake Tyler	Perennial drainage flows west of centerline into Lake Tyler via Mud Creek.	Picnic and wildlife/bird watching

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Gulf Coast	Texas	No	277.66	X			X		2	--	--	277.66	Lake Tyler	Perennial drainage flows east of centerline into Lake Tyler via Mud Creek.	Picnic and wildlife/bird watching
Gulf Coast	Texas	TX-8	279.73	X			X		2	--	--	279.73	Lake Tyler	--	Picnic and wildlife/bird watching
Gulf Coast	Texas	No	280.12				X		1	--	--	280.12	Lake Tyler	Intermittent drainage flows east of centerline into Lake Tyler via Mud Creek.	Picnic and wildlife/bird watching
Gulf Coast	Texas	No	280.71	X			X		2	--	--	280.71	Lake Tyler	Perennial drainage flows east of centerline into Lake Tyler via Mud Creek.	Picnic and wildlife/bird watching
Gulf Coast	Texas	TX-9	281.84				X		1	--	--	281.84	Lake Tyler	Ephemeral drainage flows southwest of centerline into Lake Tyler via Caney Creek.	Picnic and wildlife/bird watching
Gulf Coast	Texas	TX-9	281.97				X		1	--	--	281.97	Lake Tyler	Seasonal drainage flows south of centerline into Lake Tyler via Caney Creek.	Picnic and wildlife/bird watching
Gulf Coast	Texas	TX-9	282.02				X		1	--	--	282.02	Lake Tyler	Seasonal drainage flows south of centerline into Lake Tyler via Caney Creek.	Picnic and wildlife/bird watching
Gulf Coast	Texas	TX-10	283.06	X			X		2	--	--	283.06	Lake Tyler	Intermittent drainage flows south of centerline into Lake Tyler via Caney Creek.	Picnic and wildlife/bird watching
Gulf Coast	Texas	TX-10	283.45	X			X		2	--	--	283.45	Lake Tyler	Perennial drainage flows south of centerline into Lake Tyler via Caney Creek.	Picnic and wildlife/bird watching
Gulf Coast	Texas	TX-10	283.49	X			X		2	--	--	283.49	Lake Tyler	Perennial drainage flows south of centerline into Lake Tyler via Caney Creek.	Picnic and wildlife/bird watching
Gulf Coast	Texas	TX-10	283.54				X		1	--	--	283.54	Lake Tyler	--	Picnic and wildlife/bird watching
Gulf Coast	Texas	TX-10	284.62	X			X		2	--	--	284.62	Lake Tyler	Perennial drainage flows north of centerline into Lake Tyler via Caney Creek.	Picnic and wildlife/bird watching
Gulf Coast	Texas	TX-10	286.77	X			X		2	--	--	286.77	Proposed Lake Columbia	Perennial drainage flows southwest of centerline into area considered for proposed Columbia Lake via Kickapoo Creek.	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Gulf Coast	Texas	No	287.55				X		1	--	--	287.55	Proposed Lake Columbia	Intermittent drainage flows west of centerline into area considered for proposed Columbia Lake via Kickapoo Creek.	--
Gulf Coast	Texas	No	287.84				X		1	--	--	287.84	Proposed Lake Columbia	Intermittent drainage flows west of centerline into area considered for proposed Columbia Lake via Kickapoo Creek.	--
Gulf Coast	Texas	No	288.15				X		1	--	--	288.15	Proposed Lake Columbia	Intermittent drainage flows west of centerline into area considered for proposed Columbia Lake via Kickapoo Creek.	--
Gulf Coast	Texas	No	288.24				X		1	--	--	288.24	Proposed Lake Columbia	Intermittent drainage flows west of centerline into area considered for proposed Columbia Lake via Kickapoo Creek.	--
Gulf Coast	Texas	No	297.62	X			X		2	--	--	297.62	Lake Striker	Perennial drainage flows south of centerline into Lake Striker via Mill Creek.	2,400 acre reservoir, industrial water, recreational uses (fishing)
Gulf Coast	Texas	No	297.67				X		1	--	--	297.67	Lake Striker	Intermittent drainage flows south of centerline into Lake Striker via Mill Creek	2,400 acre reservoir, industrial water, recreational uses (fishing)
Gulf Coast	Texas	No	297.68				X		1	--	--	297.68	Lake Striker	--	2,400 acre reservoir, industrial water, recreational uses (fishing)
Gulf Coast	Texas	No	300.74				X		1	--	--	300.74	Lake Striker	Ephemeral drainage flows south of centerline into Lake Striker via Mill Creek	2,400 acre reservoir, industrial water, recreational uses (fishing)
Gulf Coast	Texas	TX-11	301.32	X			X		2	--	--	301.32	Lake Striker	--	2,400 acre reservoir, industrial water, recreational uses (fishing)
Gulf Coast	Texas	No	301.74				X		1	--	--	301.74	Lake Striker	Ephemeral drainage flows north of centerline into Lake Striker via Johnson Creek	2,400 acre reservoir, industrial water, recreational uses (fishing)
Gulf Coast	Texas	No	302.32				X		1	--	--	302.32	Lake Striker	Ephemeral drainage flows west of centerline into Lake Striker via Striker Creek	2,400 acre reservoir, industrial water, recreational uses (fishing)
Gulf Coast	Texas	No	302.99				X		1	--	--	302.99	Lake Striker	Ephemeral drainage flows south of centerline into Lake Striker via Boggy Branch	2,400 acre reservoir, industrial water, recreational uses (fishing)
Gulf Coast	Texas	No	303				X		1	--	--	303	Lake Striker	Ephemeral drainage flows south of centerline into Lake Striker via Boggy Branch	2,400 acre reservoir, industrial water, recreational uses (fishing)

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Gulf Coast	Texas	No	303.1				X		1	--	--	303.1	Lake Striker	--	2,400 acre reservoir, industrial water, recreational uses (fishing)
Gulf Coast	Texas	No	303.83				X		1	--	--	303.83	Lake Striker	Intermittent drainage flows west, directly into Lake Striker	2,400 acre reservoir, industrial water, recreational uses (fishing)
Gulf Coast	Texas	No	303.88				X		1	--	--	303.88	Lake Striker	Intermittent drainage flows west, directly into Lake Striker	2,400 acre reservoir, industrial water, recreational uses (fishing)
Gulf Coast	Texas	No	304.27				X		1	--	--	304.27	Lake Striker	Intermittent drainage flows west, directly into Lake Striker	2,400 acre reservoir, industrial water, recreational uses (fishing)
Gulf Coast	Texas	No	304.75				X		1	--	--	304.75	Lake Striker	Intermittent drainage flows west, directly into Lake Striker	2,400 acre reservoir, industrial water, recreational uses (fishing)
Gulf Coast	Texas	TX-11	308.27	X					1	--	--	--	--	--	--
Gulf Coast	Texas	TX-12	313.18		X				1	--	--	--	--	--	--
Gulf Coast	Texas	TX-12	313.23		X				1	--	--	--	--	--	--
Gulf Coast	Texas	TX-12	313.3	X	X				2	--	--	--	--	--	--
Gulf Coast	Texas	TX-12	313.55		X				1	--	--	--	--	--	--
Gulf Coast	Texas	TX-12	313.68		X				1	--	--	--	--	--	--
Gulf Coast	Texas	TX-12	314.5		X				1	--	--	--	--	--	--
Gulf Coast	Texas	TX-12	314.98		X				1	--	--	--	--	--	--
Gulf Coast	Texas	No	315.31		X				1	--	--	--	--	--	--
Gulf Coast	Texas	No	316.68	X					1	--	--	--	--	--	--
Gulf Coast	Texas	TX-13	319.34	X					1	--	--	--	--	--	--
Gulf Coast	Texas	TX-13	320.25	X					1	--	--	--	--	--	--
Gulf Coast	Texas	TX-13	320.79	X					1	--	--	--	--	--	--
Gulf Coast	Texas	No	334.17	X					1	--	--	--	--	--	--
Gulf Coast	Texas	No	337.73		X				1	--	--	--	--	--	--
Gulf Coast	Texas	No	338.31		X				1	--	--	--	--	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Gulf Coast	Texas	No	338.48		X				1	--	--	--	--	--	--
Gulf Coast	Texas	No	338.49		X				1	--	--	--	--	--	--
Gulf Coast	Texas	No	338.52		X				1	--	--	--	--	--	--
Gulf Coast	Texas	No	338.53		X				1	--	--	--	--	--	--
Gulf Coast	Texas	TX-14	338.69		X				1	--	--	--	--	--	--
Gulf Coast	Texas	TX-14	338.77		X				1	--	--	--	--	--	--
Gulf Coast	Texas	No	340.17		X				1	--	--	--	--	--	--
Gulf Coast	Texas	No	340.18		X				1	--	--	--	--	--	--
Gulf Coast	Texas	No	342.53	X					1	--	--	--	--	--	--
Gulf Coast	Texas	No	344.69				X		1	--	--	344.69	Davy Crockett National Forest	Ephemeral drainage located within David Crocket National Forest which drains south into Watson Branch.	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	No	344.94	X			X		2	--	--	344.94	Davy Crockett National Forest	Ephemeral drainage located within David Crocket National Forest which drains south into Watson Branch.	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	No	345.45				X		1	--	--	345.45	Davy Crockett National Forest	Intermittent drainage located within David Crockett National Forest which drains northeast into Watson Branch.	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	No	345.46				X		1	--	--	345.46	Davy Crockett National Forest	Intermittent drainage located within David Crockett National Forest which drains northeast into Watson Branch.	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	No	345.52				X		1	--	--	345.52	Davy Crockett National Forest	Perennial drainage located within David Crockett National Forest which drains northeast into Watson Branch.	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.

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Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Gulf Coast	Texas	No	345.59				X		1	--	--	345.59	Davy Crockett National Forest	Perennial drainage located within David Crockett National Forest which drains northeast into Watson Branch.	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	No	345.6	X			X		2	--	--	345.6	Davy Crockett National Forest	Perennial drainage located within David Crockett National Forest which drains northeast into Watson Branch.	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	No	346.52				X		1	--	--	346.52	Davy Crockett National Forest	--	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	No	346.52				X		1	--	--	346.52	Davy Crockett National Forest	--	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	No	346.59				X		1	--	--	346.59	Davy Crockett National Forest	--	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	No	346.6				X		1	--	--	346.6	Davy Crockett National Forest	--	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	No	347.76	X			X		2	--	--	347.76	Davy Crockett National Forest	Ephemeral drainage located within David Crocket National Forest which drains west into Bodan Creek	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	No	348.05				X		1	--	--	348.05	Davy Crockett National Forest	--	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	No	350.01		X		X		2	--	--	350.01	Davy Crockett National Forest	--	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	No	350.23		X		X		2	--	--	350.23	Davy Crockett National Forest	--	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	No	351.02	X	X		X		3	--	--	351.02	Davy Crockett National Forest	Perennial drainage located within David Crockett National Forest which drains west into Buncombe Creek	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Gulf Coast	Texas	No	351.15	X	X		X		3	--	--	351.15	Davy Crockett National Forest	Perennial drainage located within David Crockett National Forest which drains west into Buncombe Creek	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	No	351.66		X		X		2	--	--	351.66	Davy Crockett National Forest	Perennial drainage located within David Crockett National Forest which drains west into Neches River	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	No	352.18	X	X		X		3	--	--	352.18	Davy Crockett National Forest	Perennial drainage located within David Crockett National Forest which drains west into Neches River	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	No	352.93		X		X		2	--	--	352.93	Davy Crockett National Forest	Ephemeral drainage located within David Crockett National Forest which drains west into Crawford Creek.	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	No	352.94		X		X		2	--	--	352.94	Davy Crockett National Forest	Ephemeral drainage located within David Crockett National Forest which drains west into Crawford Creek.	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	No	352.99		X		X		2	--	--	352.99	Davy Crockett National Forest	Ephemeral drainage located within David Crockett National Forest which drains west into Crawford Creek.	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	TX-15	353.12		X		X		2	--	--	353.12	Davy Crockett National Forest	Ephemeral drainage located within David Crockett National Forest which drains west into Crawford Creek.	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	No	353.26	X	X		X		3	--	--	353.26	Davy Crockett National Forest	Ephemeral drainage located within David Crockett National Forest which drains west into Crawford Creek.	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	No	353.28		X		X		2	--	--	353.28	Davy Crockett National Forest	--	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	TX-16	354.18		X		X		2	--	--	354.18	Davy Crockett National Forest	--	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	TX-16	354.2		X		X		2	--	--	354.2	Davy Crockett National Forest	--	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Gulf Coast	Texas	TX-16	355.01		X		X		2	--	--	355.01	Davy Crockett National Forest	--	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	TX-16	355.11		X		X		2	--	--	355.11	Davy Crockett National Forest	--	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	TX-16	355.22		X		X		2	--	--	355.22	Davy Crockett National Forest	--	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	TX-16	355.27		X		X		2	--	--	355.27	Davy Crockett National Forest	--	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	TX-16	355.45	X	X		X		3	--	--	355.45	Davy Crockett National Forest	Drainage located within David Crockett National Forest which drains west into Neches River.	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	TX-16	355.64		X		X		2	--	--	355.64	Davy Crockett National Forest	--	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	No	356.08		X		X		2	--	--	356.08	Davy Crockett National Forest	--	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	No	356.74		X		X		2	--	--	356.74	Davy Crockett National Forest	--	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	No	356.91		X		X		2	--	--	356.91	Davy Crockett National Forest	--	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	No	357.41		X		X		2	--	--	357.41	Davy Crockett National Forest	--	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	No	357.5		X		X		2	--	--	357.5	Davy Crockett National Forest	--	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	No	357.92		X		X		2	--	--	357.92	Davy Crockett National Forest	--	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Gulf Coast	Texas	No	358.17	X	X		X		3	--	--	358.17	Davy Crockett National Forest	Perennial drainage located within David Crockett National Forest which drains southwest into Neches River.	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	No	358.39		X		X		2	--	--	358.39	Davy Crockett National Forest	--	National forest managed for timber, grazing, oil production, hunting, and recreation. Range of birds seen in the park, including migratory game birds.
Gulf Coast	Texas	No	358.83		X				1	--	--	--	--	--	--
Gulf Coast	Texas	No	359.08		X				1	--	--	--	--	--	--
Gulf Coast	Texas	No	359.25		X				1	--	--	--	--	--	--
Gulf Coast	Texas	No	359.66		X				1	--	--	--	--	--	--
Gulf Coast	Texas	No	359.71		X				1	--	--	--	--	--	--
Gulf Coast	Texas	No	359.81		X				1	--	--	--	--	--	--
Gulf Coast	Texas	No	360.54		X				1	--	--	--	--	--	--
Gulf Coast	Texas	No	360.69		X				1	--	--	--	--	--	--
Gulf Coast	Texas	No	360.77		X				1	--	--	--	--	--	--
Gulf Coast	Texas	No	360.81		X				1	--	--	--	--	--	--
Gulf Coast	Texas	No	360.89	X	X				2	--	--	--	--	--	--
Gulf Coast	Texas	No	361.09	X	X				2	--	--	--	--	--	--
Gulf Coast	Texas	No	361.12	X	X				2	--	--	--	--	--	--
Gulf Coast	Texas	No	361.24		X				1	--	--	--	--	--	--

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Gulf Coast	Texas	No	362.14		X				1	--	--	--	--	--	--
Gulf Coast	Texas	TX-17	362.79	X	X				2	--	--	--	--	--	--
Gulf Coast	Texas	TX-17	362.81		X				1	--	--	--	--	--	--
Gulf Coast	Texas	TX-17	362.81		X				1	--	--	--	--	--	--
Gulf Coast	Texas	TX-17	363.17		X				1	--	--	--	--	--	--
Gulf Coast	Texas	No	366.4		X				1	--	--	--	--	--	--
Gulf Coast	Texas	No	366.9		X				1	--	--	--	--	--	--
Gulf Coast	Texas	No	366.94		X	X			2	367.3	Neches River Valley	--	--	--	--
Gulf Coast	Texas	No	368.6	X					1	--	--	--	--	--	--
Gulf Coast	Texas	TX-19	376.43	X					1	--	--	--	--	--	--
Gulf Coast	Texas	TX-19	376.74	X					1	--	--	--	--	--	--
Gulf Coast	Texas	No	377.66	X					1	--	--	--	--	--	--
Gulf Coast	Texas	No	377.85	X					1	--	--	--	--	--	--
Gulf Coast	Texas	No	381.51	X					1	--	--	--	--	--	--
Gulf Coast	Texas	No	381.9	X					1	--	--	--	--	--	--
Gulf Coast	Texas	No	382.64	X					1	--	--	--	--	--	--
Gulf Coast	Texas	No	385.56	X					1	--	--	--	--	--	--
Gulf Coast	Texas	No	388.49	X					1	--	--	--	--	--	--
Gulf Coast	Texas	No	389.69	X					1	--	--	--	--	--	--
Gulf Coast	Texas	No	391.67	X					1	--	--	--	--	--	--
Gulf Coast	Texas	TX-20	397.18	X					1	--	--	--	--	--	--
Gulf Coast	Texas	No	400.67			X		X	2	--	--	400.67	Drainage in Big Thicket National Preserve	Ephemeral drainage located within Big Thicket National Preserve which drains east into Bluff Creek.	Forested area with high biodiversity due to mix of habitats, bird watching (~186 birds live in or migrate through), fishing, camping, etc. Designated "Biosphere Reserve" by UNESCO in 1981.
Gulf Coast	Texas	No	400.84			X		X	2	--	--	400.84	Drainage in Big Thicket National Preserve	Ephemeral drainage located within Big Thicket National Preserve which drains east into Bluff Creek.	Forested area with high biodiversity due to mix of habitats, bird watching (~186 birds live in or migrate through), fishing, camping, etc. Designated "Biosphere Reserve" by UNESCO in 1981.

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Gulf Coast	Texas	No	401.35	X			X	X	3	--	--	401.35	Drainage in Big Thicket National Preserve	--	Forested area with high biodiversity due to mix of habitats, bird watching (~186 birds live in or migrate through), fishing, camping, etc. Designated "Biosphere Reserve" by UNESCO in 1981.
Gulf Coast	Texas	No	404.09	X			X	X	3	--	--	404.09	Drainage in Big Thicket National Preserve	Drainage located within Big Thicket National Preserve which drains south into Menard Creek.	Forested area with high biodiversity due to mix of habitats, bird watching (~186 birds live in or migrate through), fishing, camping, etc. Designated "Biosphere Reserve" by UNESCO in 1981.
Gulf Coast	Texas	No	404.1				X	X	2	--	--	404.1	Drainage in Big Thicket National Preserve	--	Forested area with high biodiversity due to mix of habitats, bird watching (~186 birds live in or migrate through), fishing, camping, etc. Designated "Biosphere Reserve" by UNESCO in 1981.
Gulf Coast	Texas	No	404.33				X	X	2	--	--	404.33	Drainage in Big Thicket National Preserve	--	Forested area with high biodiversity due to mix of habitats, bird watching (~186 birds live in or migrate through), fishing, camping, etc. Designated "Biosphere Reserve" by UNESCO in 1981.
Gulf Coast	Texas	No	404.57				X	X	2	--	--	404.57	Drainage in Big Thicket National Preserve	--	Forested area with high biodiversity due to mix of habitats, bird watching (~186 birds live in or migrate through), fishing, camping, etc. Designated "Biosphere Reserve" by UNESCO in 1981.
Gulf Coast	Texas	No	404.74				X	X	2	--	--	404.74	Drainage in Big Thicket National Preserve	--	Forested area with high biodiversity due to mix of habitats, bird watching (~186 birds live in or migrate through), fishing, camping, etc. Designated "Biosphere Reserve" by UNESCO in 1981.
Gulf Coast	Texas	No	404.75				X	X	2	--	--	404.75	Drainage in Big Thicket National Preserve	--	Forested area with high biodiversity due to mix of habitats, bird watching (~186 birds live in or migrate through), fishing, camping, etc. Designated "Biosphere Reserve" by UNESCO in 1981.
Gulf Coast	Texas	No	405.4				X	X	2	--	--	405.4	Drainage in Big Thicket National Preserve	--	Forested area with high biodiversity due to mix of habitats, bird watching (~186 birds live in or migrate through), fishing, camping, etc. Designated "Biosphere Reserve" by UNESCO in 1981.
Gulf Coast	Texas	No	407.13	X			X	X	3	--	--	407.13	Drainage in Big Thicket National Preserve	--	Forested area with high biodiversity due to mix of habitats, bird watching (~186 birds live in or migrate through), fishing, camping, etc. Designated "Biosphere Reserve" by UNESCO in 1981.
Gulf Coast	Texas	No	407.15				X	X	2	--	--	407.15	Drainage in Big Thicket National Preserve	--	Forested area with high biodiversity due to mix of habitats, bird watching (~186 birds live in or migrate through), fishing, camping, etc. Designated "Biosphere Reserve" by UNESCO in 1981.

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Gulf Coast	Texas	No	407.22				X	X	2	--	--	407.22	Drainage in Big Thicket National Preserve	--	Forested area with high biodiversity due to mix of habitats, bird watching (~186 birds live in or migrate through), fishing, camping, etc. Designated "Biosphere Reserve" by UNESCO in 1981.
Gulf Coast	Texas	No	407.24				X	X	2	--	--	407.24	Drainage in Big Thicket National Preserve	--	Forested area with high biodiversity due to mix of habitats, bird watching (~186 birds live in or migrate through), fishing, camping, etc. Designated "Biosphere Reserve" by UNESCO in 1981.
Gulf Coast	Texas	No	407.24				X	X	2	--	--	407.24	Drainage in Big Thicket National Preserve	--	Forested area with high biodiversity due to mix of habitats, bird watching (~186 birds live in or migrate through), fishing, camping, etc. Designated "Biosphere Reserve" by UNESCO in 1981.
Gulf Coast	Texas	No	407.26				X	X	2	--	--	407.26	Drainage in Big Thicket National Preserve	--	Forested area with high biodiversity due to mix of habitats, bird watching (~186 birds live in or migrate through), fishing, camping, etc. Designated "Biosphere Reserve" by UNESCO in 1981.
Gulf Coast	Texas	TX-22	411.68				X	X	2	--	--	411.68	Drainage in Big Thicket National Preserve	Intermittent drainage located within Big Thicket National Preserve which drains southwest into Williams Creek.	Forested area with high biodiversity due to mix of habitats, bird watching (~186 birds live in or migrate through), fishing, camping, etc. Designated "Biosphere Reserve" by UNESCO in 1981.
Gulf Coast	Texas	TX-22	413.66				X	X	2	--	--	413.66	Drainage in Big Thicket National Preserve	Ephemeral drainage located within Big Thicket National Preserve which drains southwest into Williams Creek.	Forested area with high biodiversity due to mix of habitats, bird watching (~186 birds live in or migrate through), fishing, camping, etc. Designated "Biosphere Reserve" by UNESCO in 1981.
Gulf Coast	Texas	No	414.35				X	X	2	--	--	414.35	Drainage in Big Thicket National Preserve	Ephemeral drainage located within Big Thicket National Preserve which drains west into Williams Creek.	Forested area with high biodiversity due to mix of habitats, bird watching (~186 birds live in or migrate through), fishing, camping, etc. Designated "Biosphere Reserve" by UNESCO in 1981.
Gulf Coast	Texas	No	414.36				X	X	2	--	--	414.36	Drainage in Big Thicket National Preserve	Ephemeral drainage located within Big Thicket National Preserve which drains west into Williams Creek.	Forested area with high biodiversity due to mix of habitats, bird watching (~186 birds live in or migrate through), fishing, camping, etc. Designated "Biosphere Reserve" by UNESCO in 1981.
Gulf Coast	Texas	No	414.7				X	X	2	--	--	414.7	Drainage in Big Thicket National Preserve	Ephemeral drainage located within Big Thicket National Preserve	Forested area with high biodiversity due to mix of habitats, bird watching (~186 birds live in or migrate through), fishing, camping, etc. Designated "Biosphere Reserve" by UNESCO in 1981.
Gulf Coast	Texas	No	415.34	X			X	X	3	--	--	415.34	Drainage in Big Thicket National Preserve	Perennial drainage located within Big Thicket National Preserve	Forested area with high biodiversity due to mix of habitats, bird watching (~186 birds live in or migrate through), fishing, camping, etc. Designated "Biosphere Reserve" by UNESCO in 1981.

Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Gulf Coast	Texas	No	415.35				X	X	2	--	--	415.35	Drainage in Big Thicket National Preserve	Perennial drainage located within Big Thicket National Preserve	Forested area with high biodiversity due to mix of habitats, bird watching (~186 birds live in or migrate through), fishing, camping, etc. Designated "Biosphere Reserve" by UNESCO in 1981.
Gulf Coast	Texas	No	415.35				X	X	2	--	--	415.35	Drainage in Big Thicket National Preserve	Perennial drainage located within Big Thicket National Preserve	Forested area with high biodiversity due to mix of habitats, bird watching (~186 birds live in or migrate through), fishing, camping, etc. Designated "Biosphere Reserve" by UNESCO in 1981.
Gulf Coast	Texas	No	416.19				X	X	2	--	--	416.19	Drainage in Big Thicket National Preserve	Perennial drainage located within Big Thicket National Preserve which drains south into Menard Creek	Forested area with high biodiversity due to mix of habitats, bird watching (~186 birds live in or migrate through), fishing, camping, etc. Designated "Biosphere Reserve" by UNESCO in 1981.
Gulf Coast	Texas	No	416.35	X		X	X	X	4	417.8-418.3	Big Thicket National Preserve (Menard Creek Unit)	416.35	Drainage in Big Thicket National Preserve	Perennial drainage located within Big Thicket National Preserve which drains south into Menard Creek	Forested area with high biodiversity due to mix of habitats, bird watching (~186 birds live in or migrate through), fishing, camping, etc. Designated "Biosphere Reserve" by UNESCO in 1981.
Gulf Coast	Texas	No	422.69				X	X	2	--	--	422.69	Trinity River National Wildlife Refuge	Ephemeral drainage located in National Wildlife Refuge which drains west into Beef Head Creek	25,000 acre wildlife refuge developed to protect bottomland hardwood forest ecosystem. Is valued for its high diversity of waterfowl species. Used during migration or nesting by nearly 50 percent of the neotropical migratory bird species listed by the U.S. Fish and Wildlife Service.
Gulf Coast	Texas	No	431.71				X		1	--	--	431.71	Daisetta Swamp	Ephemeral drainage flows south into Daisetta Swamp via Batiste Creek	Not much information available. There appears to be a wetland mitigation bank nearby.
Gulf Coast	Texas	No	432.87				X		1	--	--	432.87	Daisetta Swamp	Ephemeral drainage flows south into Daisetta Swamp via Batiste Creek	Not much information available. There appears to be a wetland mitigation bank nearby.
Gulf Coast	Texas	No	433.44				X		1	--	--	433.44	Daisetta Swamp	--	Not much information available. There appears to be a wetland mitigation bank nearby.
Gulf Coast	Texas	No	433.46				X		1	--	--	433.46	Daisetta Swamp	Ephemeral drainage flows west into Daisetta Swamp via Batiste Creek	Not much information available. There appears to be a wetland mitigation bank nearby.
Gulf Coast	Texas	No	434.11				X		1	--	--	434.11	Daisetta Swamp	Ephemeral drainage flows west into Daisetta Swamp via Batiste Creek	Not much information available. There appears to be a wetland mitigation bank nearby.
Gulf Coast	Texas	No	434.12				X		1	--	--	434.12	Daisetta Swamp	--	Not much information available. There appears to be a wetland mitigation bank nearby.
Gulf Coast	Texas	No	439.5	X					1	--	--	--	--	--	--
Gulf Coast	Texas	No	449.03	X					1	--	--	--	--	--	--
Gulf Coast	Texas	No	451.56	X					1	--	--	--	--	--	--

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Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Gulf Coast	Texas	No	457.92	X	X		X	X	4	--	--	457.92	Drainage in Big Thicket National Preserve	Drainage located within Big Thicket National Preserve which drains into Cotton Creek.	Forested area with high biodiversity due to mix of habitats, bird watching (~186 birds live in or migrate through), fishing, camping, etc. Designated "Biosphere Reserve" by UNESCO in 1981.
Gulf Coast	Texas	No	457.96	X	X		X	X	4	--	--	457.96	Drainage in Big Thicket National Preserve	--	Forested area with high biodiversity due to mix of habitats, bird watching (~186 birds live in or migrate through), fishing, camping, etc. Designated "Biosphere Reserve" by UNESCO in 1981.
Gulf Coast	Texas	No	459.16		X		X	X	3	--	--	459.16	Drainage in Big Thicket National Preserve	Intermittent drainage located within Big Thicket National Preserve which drains into Pine Island Bayou.	Forested area with high biodiversity due to mix of habitats, bird watching (~186 birds live in or migrate through), fishing, camping, etc. Designated "Biosphere Reserve" by UNESCO in 1981.
Gulf Coast	Texas	No	459.94		X		X	X	3	--	--	459.94	Drainage in Big Thicket National Preserve	Drainage located within Big Thicket National Preserve which drains into Pine Island Bayou.	Forested area with high biodiversity due to mix of habitats, bird watching (~186 birds live in or migrate through), fishing, camping, etc. Designated "Biosphere Reserve" by UNESCO in 1981.
Gulf Coast	Texas	No	460.46		X		X	X	3	--	--	460.46	Drainage in Big Thicket National Preserve	Drainage located within Big Thicket National Preserve which drains into Pine Island Bayou.	Forested area with high biodiversity due to mix of habitats, bird watching (~186 birds live in or migrate through), fishing, camping, etc. Designated "Biosphere Reserve" by UNESCO in 1981.
Gulf Coast	Texas	TX-24	461.77	X	X				2	--	--	--	--	--	--
Gulf Coast	Texas	No	462.5	X					1	--	--	--	--	--	--
Gulf Coast	Texas	TX-25	469.89	X					1	--	--	--	--	--	--
Gulf Coast	Texas	TX-25	473.56				X	X	2	--	--	473.56	Drainage in J.D. Murphree WMA	Perennial drainage that flows southeast from centerline into J.D. Murphree WMA via Hillebrandt Bayou.	Wildlife Management Area for wildlife viewing and hunting. 24,250 acres of fresh, intermediate, and brackish water within the prairie marsh zone along the upper coast of Texas. Key nesting area for mottled ducks, with increasing nesting by Fulvous and Black-bellied whistling ducks. A large colonial water bird rockery is located west of Lost Lake Camp. The area is the center of the small, but principle stopover and staging area for much of the waterfowl of the Central Flyway and provides high quality winter habitat.

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Appendix B. Evaluation of Additional Areas of Special Ecological Concern

				Special Attributes						Wildlife (Table 3.6.2-1)		Downstream Waterbody within 10 Miles (Table E-4)			
Segment	State	CPS?	Approx. Milepost	Fishery	Wetland	Wildlife	Waterbody	Special Waterbody	Count	Approx. Milepost	Name	Approx. Milepost	Downstream Reservoir/ Fishery/ Wildlife Area	Other Description	Comment
Gulf Coast	Texas	TX-25	473.79				X	X	2	--	--	473.79	Drainage in J.D. Murphree WMA	Perennial drainage that flows east from centerline into J.D. Murphree WMA via Hillebrandt Bayou.	Wildlife Management Area for wildlife viewing and hunting. 24,250 acres of fresh, intermediate, and brackish water within the prairie marsh zone along the upper coast of Texas. Key nesting area for mottled ducks, with increasing nesting by Fulvous and Black-bellied whistling ducks. A large colonial water bird rockery is located west of Lost Lake Camp. The area is the center of the small, but principle stopover and staging area for much of the waterfowl of the Central Flyway and provides high quality winter habitat.
Gulf Coast	Texas	TX-25	473.83	X			X	X	3	--	--	473.83	Drainage in J.D. Murphree WMA	Perennial drainage that flows east from centerline into J.D. Murphree WMA via Hillebrandt Bayou.	Wildlife Management Area for wildlife viewing and hunting. 24,250 acres of fresh, intermediate, and brackish water within the prairie marsh zone along the upper coast of Texas. Key nesting area for mottled ducks, with increasing nesting by Fulvous and Black-bellied whistling ducks. A large colonial water bird rockery is located west of Lost Lake Camp. The area is the center of the small, but principle stopover and staging area for much of the waterfowl of the Central Flyway and provides high quality winter habitat.
Gulf Coast	Texas	TX-25	474.93				X	X	2	--	--	474.93	Drainage in J.D. Murphree WMA	--	Wildlife Management Area for wildlife viewing and hunting. 24,250 acres of fresh, intermediate, and brackish water within the prairie marsh zone along the upper coast of Texas. Key nesting area for mottled ducks, with increasing nesting by Fulvous and Black-bellied whistling ducks. A large colonial water bird rockery is located west of Lost Lake Camp. The area is the center of the small, but principle stopover and staging area for much of the waterfowl of the Central Flyway and provides high quality winter habitat.
Houston Lateral	Texas	TX-29	35.6	X					1	--	--	--	--	--	--
Houston Lateral	Texas	No	43.3	X		X			2	43.3	San Jacinto River Valley	--	--	--	--
Houston Lateral	Texas	Parts	18-28	X	X	X			3	18.9-22.4	Trinity River National Wildlife Refuge (Champion Lake Unit)	--	--	--	--

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Appendix C

Listing of All Private Wells Registered with the State of Nebraska That Are Located within 1,000 ft of the Proposed Centerline of the Pipeline

Appendix C. Listing of All Private Wells Registered with the State of Nebraska That Are Located within 1,000 ft of the Proposed Centerline of the Pipeline

NEDNR ID Number	Status	Use ID	County	Pumping Rate (gpm)	Total Depth (ft bgs)	Static Water Level (ft bgs)	Pumping Water Level (ft bgs)	Latitude (dec. degrees)	Longitude (dec. degrees)	Distance to Pipeline (ft)
30427	A	I	York	660	183	74	83	41.01028	-97.798267	4
28803	A	I	Hamilton	1,200	290	80	101	41.059731	-97.852276	5
61324	A	I	Merrick	350	70	14	60	41.242161	-98.016796	12
75707	A	I	York	150	110	65	105	40.888707	-97.690476	17
42653	A	I	York	750	141	55	75	40.782133	-97.601828	25
47927	A	I	Jefferson	1,250	247	79	103	40.266113	-97.109539	28
9908	A	I	Hamilton	750	130	0	75	41.062904	-97.854304	31
22440	A	I	Merrick	650	33	8	31	41.176807	-97.958705	33
172381	A	I	Merrick	200	40	15	35	41.236514	-98.011453	34
51138	A	I	Merrick	650	43	10	37	41.225131	-98.002211	47
75180	A	I	Merrick	750	38	6	33	41.207272	-97.980464	52
67383	A	I	Hamilton	1,300	338	99	124	41.071923	-97.861468	58
465	A	I	Merrick	1,500	0	0	0	41.169443	-97.953584	66
104461	A	I	Fillmore	800	210	65	140	40.564252	-97.392373	67
32921	A	I	Jefferson	700	188	80	92	40.258929	-97.102671	72
199449	I	S	Keya Paha	0	37	27	35	42.954722	-99.496806	78
57180	A	I	York	1,000	248	80	175	40.841615	-97.662228	98
34246	A	I	Jefferson	1,000	100	22	50	40.349683	-97.196142	102
50627	A	I	York	250	111	80	110	40.894246	-97.697454	115
117611	A	I	Merrick	600	50	6	30	41.203815	-97.9794	116
159532	A	S	Greeley	5	220	120	122	41.673611	-98.525611	117
169826	A	I	Fillmore	800	329	170	200	40.6006	-97.430136	124
43852	A	I	Greeley	900	232	102	120	41.614042	-98.458622	129
153843	A	I	York	800	340	88	108	40.738556	-97.563917	131
66594	A	I	Merrick	800	45	8	20	41.151244	-97.934331	133
56057	A	I	Fillmore	850	286	105	135	40.604308	-97.439867	148
19979	A	I	Fillmore	750	264	85	97	40.679225	-97.515783	151
205091	A	D	Fillmore	15	200	65	67	40.566833	-97.395611	154
130219	A	I	Jefferson	800	202	102	124	40.179005	-97.034202	159
37318	A	I	York	1,000	240	105	137	40.709423	-97.540136	166
33722	A	I	York	350	105	73	96	40.890521	-97.691683	168
11797	A	I	York	1,000	181	64	76	41.012047	-97.800698	168
63338	A	I	Jefferson	800	160	80	90	40.344116	-97.196278	169
127940	A	I	Merrick	200	60	8	50	41.224085	-97.999751	171
76206	A	I	Merrick	500	64	7	55	41.235633	-98.011622	172
29114	A	I	York	1,200	201	88	104	40.953358	-97.752276	177
108255	A	I	Merrick	400	30	3	20	41.194018	-97.973064	179
72304	A	I	Merrick	500	65	8	50	41.235461	-98.0116	185
9906	A	I	York	500	174	90	100	40.999445	-97.783731	189
69187	A	I	Merrick	350	45	15	44	41.219986	-97.996264	193
51161	A	I	York	300	80	35	73	40.853294	-97.665757	193
153611	A	I	York	800	140	71	100	40.849833	-97.664417	204
843	A	I	Merrick	0	0	0	0	41.229053	-98.0069	206
8180	A	I	York	1,200	160	64	86	40.932265	-97.728512	207
60133	A	I	Fillmore	800	312	110	130	40.593276	-97.420806	208
8081	A	I	York	1,200	190	74	100	41.021	-97.812671	211
117841	A	I	Merrick	400	37	7	34	41.188829	-97.968467	222
174509	A	I	Nance	250	56	10	48	41.287333	-98.085167	242
31897	A	I	Jefferson	600	240	102	114	40.274534	-97.119935	244
208543	A	I	Greeley	800	405	97	130	41.53475	-98.344389	246
108513	A	I	York	600	110	73	100	40.882224	-97.687714	248
58778	A	I	Holt	900	117	7	17	42.481921	-99.1517	258
55203	A	I	Jefferson	2,000	218	114	130	40.280618	-97.128448	261
56967	A	I	York	1,000	260	85	140	41.006664	-97.793429	267
42320	A	I	Holt	1,000	136	4	15	42.65552	-99.240837	268
51285	A	I	Fillmore	1,000	261	110	150	40.68753	-97.523711	271
32376	A	I	York	1,300	150	85	95	40.799823	-97.64498	272
117843	A	I	Merrick	300	38	5	26	41.183805	-97.963775	272
144605	I	I	Merrick	300	40	10	32	41.21293	-97.98523	277

Appendix C. (cont.)

NEDNR ID Number	Status	Use ID	County	Pumping Rate (gpm)	Total Depth (ft bgs)	Static Water Level (ft bgs)	Pumping Water Level (ft bgs)	Latitude (dec. degrees)	Longitude (dec. degrees)	Distance to Pipeline (ft)
44157	A	I	York	1,253	186	96	112	40.785368	-97.613106	278
55605	A	I	Fillmore	900	260	105	127	40.694764	-97.52607	290
170095	A	S	Nance	12	235	140	145	41.394683	-98.162717	297
96532	A	I	Merrick	350	30	6	20	41.196972	-97.9731	300
41484	A	I	Merrick	400	53	17	0	41.219599	-97.998111	308
129627	A	I	Fillmore	800	307	96	190	40.651307	-97.497589	313
7557	I	I	York	0	77	38	60	40.745375	-97.568575	322
13206	A	I	Merrick	700	40	10	32	41.202552	-97.979393	322
67521	A	I	Garfield	900	240	72	92	42.040275	-98.829304	327
55702	A	I	Jefferson	800	164	106	135	40.162662	-97.022663	329
8274	I	I	Hamilton	0	135	68	118	41.055131	-97.846089	330
17548	A	I	Merrick	500	26	6	20	41.197285	-97.973157	338
59843	A	I	York	600	120	72	94	40.879742	-97.686928	345
46684	A	I	Hamilton	1,200	390	107	160	41.082942	-97.871089	346
14699	A	I	Merrick	500	86	26	70	41.223278	-97.998126	347
126306	A	S	Wheeler	15	164	90	100	41.836026	-98.67932	348
21920	A	I	Jefferson	0	154	58	94	40.251611	-97.100124	352
15580	A	I	Merrick	500	30	6	0	41.187209	-97.969544	353
40595	A	I	Holt	1,000	151	23	42	42.648384	-99.241	359
10134	A	I	York	730	120	73	93	40.910512	-97.71423	359
66596	A	I	Merrick	900	45	8	20	41.154786	-97.939553	360
34981	A	I	Rock	900	50	10	18	42.684789	-99.260517	363
60670	A	I	Fillmore	1,250	327	108	121	40.574897	-97.401514	364
46232	A	I	York	2,000	187	82	93	40.789058	-97.631594	366
19925	A	S	Nance	400	201	56	201	41.329499	-98.121407	369
60329	A	I	York	800	104	40	90	40.86161	-97.669294	370
185510	I	I	Wheeler	0	0	0	0	41.758438	-98.629327	374
189303	A	I	Jefferson	800	195	95	103	40.338694	-97.194111	376
191288	A	I	Jefferson	410	195	132	182	40.07725	-97.000583	377
78236	A	I	Merrick	450	43	10	40	41.229332	-98.004562	383
65531	A	I	Merrick	150	43	10	35	41.229332	-98.004562	383
170746	A	I	York	800	200	63	180	40.767427	-97.578302	385
9625	I	I	Fillmore	0	270	85	105	40.596847	-97.424461	388
207198	A	S	Keya Paha	5	77	7.8	8.5	42.863964	-99.403142	394
36154	A	I	Jefferson	900	230	93	115	40.268015	-97.114337	395
195968	I	S	Holt	0	76	14	15	42.4919	-99.156483	402
59101	A	I	Greeley	1,000	401	115	250	41.52936	-98.33212	405
4558	A	I	York	0	0	0	0	40.926759	-97.726128	408
114045	A	I	Merrick	800	60	7	35	41.121462	-97.904294	412
209729	A	I	Jefferson	666	155	120	131	40.193781	-97.043622	412
37499	A	I	York	750	140	80	120	40.827421	-97.649384	423
72839	A	I	York	1,000	169	90	125	40.791897	-97.632958	429
88806	A	D	York	12	147	115	135	40.713447	-97.542324	430
168867	A	I	Merrick	650	50	7	40	41.142758	-97.924886	431
66636	A	I	Fillmore	1,250	352	84	100	40.584234	-97.40888	441
208566	A	I	Jefferson	800	180	97	104	40.157194	-97.015556	445
16448	A	I	York	1,200	201	88	103	40.958638	-97.754843	448
179946	A	S	Keya Paha	10	40	10	20	42.921333	-99.4618	450
207098	A	D	York	20	165	80	80	40.73655	-97.5601	466
197028	I	S	Fillmore	0	188	70	0	40.538861	-97.371111	466
197027	A	S	Fillmore	24	186	74	76	40.538806	-97.371028	470
50172	A	I	York	1,200	208	100	130	40.951865	-97.750022	473
117842	A	I	Merrick	600	30	4	20	41.186605	-97.969539	475
20672	A	I	Hamilton	700	158	89	140	41.068321	-97.856647	478
172076	A	D	Saline	3	134	35	125	40.434388	-97.281194	479
67130	A	I	Merrick	1,350	60	10	25	41.166087	-97.948617	486
213134	A	I	Jefferson	800	241	99	106	40.146333	-97.009611	490
80753	A	I	Saline	1,200	136	71	0	40.360766	-97.21227	492
72159	A	I	York	1,050	143	52	68	41.030096	-97.824589	498
27093	A	I	York	1,000	182	107	122	40.817436	-97.649282	499

013989

Appendix C. (cont.)

NEDNR ID Number	Status	Use ID	County	Pumping Rate (gpm)	Total Depth (ft bgs)	Static Water Level (ft bgs)	Pumping Water Level (ft bgs)	Latitude (dec. degrees)	Longitude (dec. degrees)	Distance to Pipeline (ft)
46890	A	I	York	550	78	25	62	40.856014	-97.665626	500
31257	A	I	Fillmore	1,350	280	90	120	40.665381	-97.507089	502
57179	A	I	York	800	128	76	86	40.837971	-97.657439	504
46078	A	I	Wheeler	1,250	210	28	39	41.902624	-98.717518	505
33373	A	I	York	1,300	217	77	86	40.937682	-97.738208	512
172023	I	I	Merrick	0	41	0	0	41.2118	-97.987883	515
173595	A	S	Greeley	5	139	70	70	41.718472	-98.590278	520
26649	A	I	Merrick	400	72	21	50	41.223072	-98.001906	524
179163	A	D	Nance	35	63	15	50	41.279694	-98.0795	524
100946	A	I	York	400	103	60	90	40.886685	-97.687359	529
11188	A	I	York	1,050	108	57	92	40.872361	-97.683119	534
181346	A	I	Fillmore	800	311	99	200	40.611706	-97.44922	539
128865	A	D	Saline	10	105	23	50	40.474502	-97.311259	547
165913	I	D	Jefferson	0	85	31	58	40.131139	-97.003697	551
15735	A	I	York	1,000	202	92	109	40.970382	-97.764578	560
68268	A	I	Holt	400	117	7	14	42.485525	-99.156602	563
181917	A	I	York	1,000	108	73	85	40.912297	-97.716756	563
109111	A	S	Greeley	15	200	85	100	41.52717	-98.328508	565
76938	A	I	York	1,000	185	89	114	40.794511	-97.637974	568
98761	A	D	Merrick	20	53	10	12	41.176942	-97.956508	570
145277	A	I	Merrick	0	72	0	0	41.221082	-98.00011	573
132571	I	I	Merrick	300	33	8	0	41.19385	-97.969883	574
29115	A	I	York	1,200	201	91	105	40.952681	-97.75488	574
37501	A	I	York	1,005	141	80	100	40.829765	-97.652756	575
174508	A	I	Nance	250	63	10	55	41.285417	-98.081528	577
172943	A	I	Jefferson	500	222	141	200	40.077389	-97.004	580
16987	A	I	York	750	83	35	54	40.862631	-97.674058	588
201276	A	D	York	10	154	82	85	40.793642	-97.636444	591
57181	A	I	York	485	130	79	125	40.837992	-97.662211	606
200555	A	S	Holt	10	76	7	8	42.620333	-99.22545	608
133223	A	I	Hamilton	1,400	260	82	116	41.046674	-97.842294	613
183184	A	I	Merrick	500	65	31	42	41.263889	-98.0475	615
32682	A	I	Saline	600	140	99	120	40.379233	-97.220457	616
8281	A	I	Merrick	750	52	5	20	41.147731	-97.933314	617
208652	A	S	Holt	5	155	25	42	42.167694	-98.9595	618
17698	A	I	Merrick	800	39	9	39	41.21265	-97.98294	618
60476	A	I	Hamilton	600	150	25	38	41.100911	-97.90004	619
6959	A	I	Merrick	700	0	0	0	41.176399	-97.960809	630
59912	A	I	York	680	104	42	90	40.859781	-97.666821	632
104551	I	D	York	0	110	70	100	40.888813	-97.687748	632
54013	A	I	Merrick	1,000	50	10	0	41.172909	-97.958711	634
22007	A	I	Hamilton	800	215	90	140	41.091852	-97.885494	638
80261	A	I	Merrick	500	55	12	30	41.225819	-98.006031	639
84203	A	I	Merrick	950	48	0	0	41.172769	-97.958624	640
74891	A	I	Holt	900	199	25	42	42.157126	-98.947709	642
51254	I	I	York	0	214	26	62	40.749261	-97.566547	646
172813	A	I	Jefferson	700	257	114	150	40.287931	-97.137306	647
108512	A	I	York	600	110	73	100	40.882226	-97.689161	648
152485	A	D	Jefferson	12	180	97	105	40.320694	-97.170504	648
51045	A	I	Merrick	400	58	6	47	41.227823	-98.002126	654
146020	A	D	Saline	15	124	34	80	40.394	-97.231333	656
166806	A	I	Merrick	850	50	9	35	41.172778	-97.95875	668
37674	I	I	Fillmore	1,200	304	92	127	40.600512	-97.425293	669
34376	A	I	Merrick	600	40	7	40	41.200685	-97.979564	673
14701	A	I	Merrick	500	55	11	40	41.223944	-97.997241	688
51761	A	I	York	1,000	248	88	132	40.824358	-97.654764	689
183177	A	I	Jefferson	700	220	62	77	40.258889	-97.105028	692
78615	A	I	York	450	130	85	110	40.905576	-97.709669	693
37347	A	I	Jefferson	1,200	220	106	115	40.306886	-97.151301	693
72588	A	I	Fillmore	1,200	143	13	26	40.549914	-97.376283	696

013990

Appendix C. (cont.)

NEDNR ID Number	Status	Use ID	County	Pumping Rate (gpm)	Total Depth (ft bgs)	Static Water Level (ft bgs)	Pumping Water Level (ft bgs)	Latitude (dec. degrees)	Longitude (dec. degrees)	Distance to Pipeline (ft)
81435	A	I	York	1,200	161	75	96	40.796809	-97.639924	699
57345	A	I	Merrick	500	62	12	40	41.234864	-98.008125	704
105347	A	S	Holt	10	40	10	20	42.187117	-98.976777	704
27735	A	I	Fillmore	1,250	292	123	142	40.629613	-97.487853	705
12319	A	I	Merrick	1,000	56	8	45	41.136939	-97.916997	706
5292	A	I	Hamilton	850	0	0	0	41.067989	-97.861465	708
41120	A	I	York	1,000	208	85	120	41.035553	-97.82395	710
170166	A	I	Saline	1,250	135	59	69	40.350066	-97.193235	710
12812	A	I	Merrick	450	40	13	30	41.237621	-98.014481	713
70184	A	I	Merrick	1,000	65	6	36	41.126332	-97.913663	717
15136	A	I	Merrick	350	41	20	35	41.217856	-97.998161	734
8181	A	I	York	1,100	260	78	96	40.9413	-97.745369	736
175316	A	I	Jefferson	1,000	248	119	126	40.295168	-97.146672	738
98857	A	S	Holt	10	117	24	25	42.249583	-99.009571	746
182926	A	D	York	49	175	87	110	40.992002	-97.779245	747
17697	A	I	Merrick	680	40	14	40	41.20574	-97.977155	753
13394	A	I	Hamilton	1,000	198	91	120	41.077731	-97.861669	756
167639	I	D	Jefferson	15	200	90	130	40.305444	-97.157083	758
19318	I	I	Fillmore	0	260	87	105	40.578881	-97.404526	759
37574	A	I	Nance	300	68	12	64	41.279466	-98.081244	766
204794	A	S	Greeley	15	280	160	160	41.624444	-98.459167	767
76357	A	I	York	1,000	221	85	100	40.948508	-97.745357	769
122010	A	I	York	1,200	255	85	130	40.700743	-97.532217	775
127939	A	I	Merrick	100	50	12	45	41.216518	-97.987868	776
176426	I	I	Jefferson	0	192	120	185	40.081972	-96.999056	780
22998	A	I	Fillmore	1,050	280	78	92	40.618624	-97.463546	795
153838	A	I	York	1,200	120	23	80	40.922806	-97.720778	795
9905	A	I	York	1,000	218	91	125	40.99332	-97.779244	799
76336	A	I	Merrick	450	40	7	28	41.23625	-98.00815	807
210817	I	S	Merrick	0	92	45	0	41.260683	-98.050933	807
72164	A	I	Merrick	300	45	9	35	41.218231	-97.99025	809
15579	A	I	Merrick	500	28	6	0	41.185784	-97.963136	820
45628	A	I	York	1,000	207	25	51	40.753378	-97.572083	822
58027	A	I	Saline	1,250	160	102	112	40.368046	-97.221699	824
30499	A	I	York	1,200	210	78	89	40.941354	-97.736464	830
201131	A	D	Jefferson	20	200	89	175	40.336	-97.189639	830
19317	A	I	Fillmore	1,500	100	12	25	40.549861	-97.3819	834
82418	A	I	York	300	120	80	95	40.890141	-97.697003	839
128998	A	I	York	1,200	200	80	118	41.01754	-97.803193	840
147500	A	I	Merrick	800	52	10	40	41.267902	-98.064251	843
52629	A	I	Jefferson	800	163	128	145	40.184996	-97.043768	844
7636	A	O	Fillmore	1,000	297	102	140	40.629756	-97.482016	850
38443	A	I	Hamilton	1,250	412	105	127	41.089979	-97.875887	854
61802	A	I	Holt	600	80	5	8	42.510782	-99.171834	866
12239	A	I	York	1,100	186	82	88	40.948477	-97.753061	869
27273	A	I	York	550	100	0	85	40.895989	-97.702259	870
8046	A	I	York	1,002	192	83	113	40.961298	-97.762129	871
49083	A	I	York	1,200	199	29	60	40.751089	-97.565911	871
61349	A	I	Fillmore	1,250	283	121	142	40.578755	-97.411259	875
14460	A	I	York	360	99	68	88	40.895189	-97.693976	876
9552	A	I	York	575	138	75	130	40.845239	-97.66699	877
194508	A	I	Jefferson	800	250	116	121	40.295194	-97.1375	877
146382	I	S	Rock	0	30	7	10	42.69265	-99.258033	880
106294	I	I	Jefferson	400	240	120	240	40.171711	-97.025042	885
162318	A	D	Nance	20	133	20	55	41.445556	-98.221389	887
75706	A	I	York	150	110	65	105	40.892331	-97.690449	892
59270	A	I	York	700	130	40	60	40.776439	-97.590045	894
174510	I	I	Nance	0	62	10	58	41.284917	-98.079472	900
41912	A	I	Holt	900	117	14	27	42.496036	-99.15695	900
187821	A	D	Fillmore	20	285	116	126	40.6245	-97.464389	905

Appendix C. (cont.)

NEDNR ID Number	Status	Use ID	County	Pumping Rate (gpm)	Total Depth (ft bgs)	Static Water Level (ft bgs)	Pumping Water Level (ft bgs)	Latitude (dec. degrees)	Longitude (dec. degrees)	Distance to Pipeline (ft)
62852	A	I	Fillmore	1,250	290	152	175	40.624152	-97.485462	907
76951	A	I	York	1,000	208	74	87	41.012082	-97.795914	909
79323	A	I	York	1,300	260	26	61	40.745587	-97.563979	910
80857	A	I	Jefferson	1,200	172	95	108	40.149903	-97.015475	912
153063	A	S	Holt	10	75	9	10	42.482445	-99.156559	918
34269	A	I	York	1,300	192	87	94	40.779972	-97.606971	926
161323	A	S	Nance	13	285	170	200	41.39	-98.157222	933
169829	A	I	Fillmore	800	300	92	200	40.658623	-97.497581	936
5293	A	I	Hamilton	1,100	327	87	120	41.066814	-97.861467	938
34815	A	I	Jefferson	900	168	136	150	40.197052	-97.054071	940
168868	A	I	Merrick	700	55	8	45	41.135431	-97.924208	947
52506	A	I	Merrick	420	46	21	42	41.215137	-97.98485	949
22439	A	I	Merrick	550	34	8	32	41.177912	-97.963401	949
6469	A	I	York	800	70	24	40	40.760133	-97.567597	951
172021	A	I	Merrick	150	24	0	0	41.204417	-97.983167	960
168882	A	I	Fillmore	1,200	287	143	167	40.622421	-97.478391	971
189085	A	I	Jefferson	775	204	124	180	40.171722	-97.034056	974
34611	A	I	Merrick	900	42	4	35	41.245785	-98.016715	977
156066	A	I	York	650	312	102	180	40.71379	-97.540391	980
197470	A	O	York	23	120	55	65	40.889956	-97.697486	987
127041	A	I	York	700	97	53	94	40.882932	-97.683233	991
115595	A	S	Holt	8	83	2	3	42.413603	-99.109327	992
101637	A	I	York	500	120	70	96	40.885251	-97.692602	993

Note: Data from Nebraska Department of Natural Resources (NEDNR) searchable database: http://dnrdata.dnr.ne.gov/wellscs/Menu.aspx

bgs - below ground surface

Status Codes:

A - active
- inactive

Use ID Codes:

D - domestic
I - irrigation
O - other
S - livestock