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	: : :	HP 14-001 APPLICANT'S NOTICE OF FILING OF EXHIBITS

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You are hereby notified that TransCanada Keystone Pipeline, LP has transmitted its proposed hearing exhibits in electronic format to the South Dakota Public Utilities Commission for positing on the South Dakota PUC's website.

Dated this 22nd day of July, 2015.

WOODS, FULLER, SHULTZ & SMITH P.C.

By /s/ James E. Moore
James E. Moore
PO Box 5027
300 South Phillips Avenue, Suite 300
Sioux Falls, SD 57117-5027
Phone (605) 336-3890
Fax (605) 339-3357
Email James.Moore@woodsfuller.com

- and -

William Taylor
2921 E. 57th Street, #10
Sioux Falls, SD 57108
Phone 605-212-1750
Bill.Taylor@williamgtaylor.com

Attorneys for Applicant TransCanada

CERTIFICATE OF SERVICE

I hereby certify that on the 22nd day of July, 2015, I sent by United States first-class mail, postage prepaid, or e-mail transmission, a true and correct copy of Applicant's Notice of Filing of Exhibits, to the following:

Patricia Van Gerpen
Executive Director
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
patty.vangerpen@state.sd.us

Kristen Edwards
Staff Attorney
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
kristen.edwards@state.sd.us

Brian Rounds
Staff Analyst
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
brian.rounds@state.sd.us

Darren Kearney
Staff Analyst South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
darren.kearney@state.sd.us

Tony Rogers, Director
Rosebud Sioux Tribe - Tribal Utility Commission
153 South Main Street
Mission, SD 57555
tuc@rosebudsiouxtribe-nsn.gov

Cindy Myers, R.N.
PO Box 104
Stuart, NE 68780
csmyers77@hotmail.com

Jane Kleeb
1010 North Denver Avenue
Hastings, NE 68901
jane@boldnebraska.org

Byron T. Steskal
Diana L. Steskal
707 E. 2nd Street
Stuart, NE 68780
prairierose@nntc.net

Terry Frisch
Cheryl Frisch
47591 875th Road
Atkinson, NE 68713
tcfrisch@q.com

Arthur R. Tanderup
52343 857th Road
Neligh, NE 68756
atanderu@gmail.com

Lewis GrassRope
PO Box 61
Lower Brule, SD 57548
wisestar8@msn.com

Carolyn P. Smith
305 N. 3rd Street
Plainview, NE 68769
peachie_1234@yahoo.com

Robert G. Allpress
46165 Badger Road
Naper, NE 68755
bobandnan2008@hotmail.com

Amy Schaffer
PO Box 114
Louisville, NE 68037
amyannschaffer@gmail.com

Louis T. (Tom) Genung
902 E. 7th Street
Hastings, NE 68901
tg64152@windstream.net

Benjamin D. Gotschall
6505 W. Davey Road
Raymond, NE 68428
ben@boldnebraska.org

Nancy Hilding
6300 West Elm
Black Hawk, SD 57718
nhilshat@rapidnet.com

Elizabeth Lone Eagle
PO Box 160
Howes, SD 57748
bethcbest@gmail.com

Paul F. Seamans
27893 249th Street
Draper, SD 57531
jacknife@goldenwest.net

John H. Harter
28125 307th Avenue
Winner, SD 57580
johnharter11@yahoo.com

Viola Waln
PO Box 937
Rosebud, SD 57570
walnranch@goldenwest.net

Peter Capossela
Peter Capossela, P.C.
Representing Standing Rock Sioux Tribe
PO Box 10643
Eugene, OR 97440
pcapossela@nu-world.com

Wrexie Lainson Bardaglio
9748 Arden Road
Trumansburg, NY 14886
wrexie.bardaglio@gmail.com

Travis Clark
Fredericks Peebles & Morgan LLP
Suite 104, 910 5th St.
Rapid City, SD 57701
tclark@ndnlaw.com

Harold C. Frazier
Chairman, Cheyenne River Sioux Tribe
PO Box 590
Eagle Butte, SD 57625
haroldcfrazier@yahoo.com
mailto:kevinckeckler@yahoo.com

Jerry P. Jones
22584 US Hwy 14
Midland, SD 57552

Cody Jones
21648 US Hwy 14/63
Midland, SD 57552

Debbie J. Trapp
24952 US Hwy 14
Midland, SD 57552
mtdt@goldenwest.net

Gena M. Parkhurst
2825 Minnewsta Place
Rapid City, SD 57702
GMP66@hotmail.com

Jennifer S. Baker
Representing Yankton Sioux Tribe
Fredericks Peebles & Morgan LLP
1900 Plaza Dr.
Louisville, CO 80027
jbaker@ndnlaw.com

Joye Braun
PO Box 484
Eagle Butte, SD 57625
jmbraun57625@gmail.com

Duncan Meisel
350.org
20 Jay St., #1010
Brooklyn, NY 11201
duncan@350.org

The Yankton Sioux Tribe
Robert Flying Hawk, Chairman
PO Box 1153
Wagner, SD 57380
robertflyinghawk@gmail.com
Thomasina Real Bird
Attorney for Yankton Sioux Tribe
trealbird@ndnlaw.com

Bruce Ellison
Attorney for Dakota Rural Action
518 6th Street #6
Rapid City, SD 57701
belli4law@aol.com

Chastity Jewett
1321 Woodridge Drive
Rapid City, SD 57701
chasjewett@gmail.com

RoxAnn Boettcher
Boettcher Organics
86061 Edgewater Avenue
Bassett, NE 68714
boettcherann@abbnebraska.com

Bruce Boettcher
Boettcher Organics
86061 Edgewater Avenue
Bassett, NE 68714
boettcherann@abbnebraska.com

Bonny Kilmurry
47798 888 Road
Atkinson, NE 68713
bjkilmurry@gmail.com

Ronald Fees
17401 Fox Ridge Road
Opal, SD 57758

Robert P. Gough, Secretary
Intertribal Council on Utility Policy
PO Box 25
Rosebud, SD 57570
bobgough@intertribalCOUP.org

Tom BK Goldtooth
Indigenous Environmental Network (IEN)
PO Box 485
Bemidji, MN 56619
ien@igc.org

Dallas Goldtooth
38731 Res Hwy 1
Morton, MN 56270
goldtoothdallas@gmail.com

Gary F. Dorr
27853 292nd
Winner, SD 57580
gfdorr@gmail.com

William Kindle, President
Rosebud Sioux Tribe
PO Box 430
Rosebud, SD 575
William.Kindle@rst-nsn.gov
ejantoine@hotmail.com

Paula Antoine
Sicangu Oyate Land Office Coordinator
Rosebud Sioux Tribe
PO Box 658
Rosebud, SD 57570
wopila@gwtc.net
paula.antoine@rosebudsiouxtribe-nsn.gov

Thomasina Real Bird
Representing Yankton Sioux Tribe
Fredericks Peebles & Morgan LLP
1900 Plaza Dr.
Louisville, CO 80027
trealbird@ndnlaw.com

Sabrina King
Dakota Rural Action
518 Sixth Street, #6
Rapid City, SD 57701
sabinra@dakotarural.org

Frank James
Dakota Rural Action
PO Box 549
Brookings, SD 57006
fejames@dakotarural.org

Robin S. Martinez
Dakota Rural Action
Martinez Madrigal & Machicao, LLC
616 West 26th Street
Kansas City, MO 64108
robin.martinez@martinezlaw.net

Tracey A. Zephier
Attorney for Cheyenne River Sioux Tribe
Fredericks Peebles & Morgan LLP
910 5th Street, Suite 104
Rapid City, SD 57701
tzephier@ndnlaw.com

Paul C. Blackburn
4145 20th Avenue South
Minneapolis, MN 55407
paul@paulblackburn.net

Matthew Rappold
Rappold Law Office
on behalf of Rosebud Sioux Tribe
PO Box 873
Rapid City, SD 57709
matt.rappold01@gmail.com

April D. McCart
Representing Dakota Rural Action
Certified Paralegal
Martinez Madrigal & Machicao, LLC
616 W. 26th Street
Kansas City, MO 64108
april.mccart@martinezlaw.net

Kimberly E. Craven
3560 Catalpa Way
Boulder, CO 80304
kimecraven@gmail.com

Joy Lashley
Administrative Assistant
SD Public Utilities Commission
joy.lashley@state.sd.us

Mary Turgeon Wynne
Rosebud Sioux Tribe - Tribal Utility Commission
153 S. Main Street
Mission, SD 57555
tuc@rosebudsiouxtribe-nsn.gov

Eric Antoine
Rosebud Sioux Tribe
PO Box 430
Rosebud, SD 57570
ejantoine@hotmail.com

/s/ James E. Moore
One of the attorneys for TransCanada

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

0-0-0-0-0-0-0-0-0-0-0-0-0-0-0-0-0-0-0-0-0-0-0-0-0

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	: : : : :	DOCKET NUMBER HP _____ CERTIFICATION

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City of Calgary)
) ss
Alberta, Canada)

TransCanada Keystone Pipeline, LP ("Keystone") hereby certifies that the conditions upon which the South Dakota Public Utilities Commission granted the facility permit in Docket HP09-001 for the Keystone XL hydrocarbon pipeline (the "Project") under the Energy Conversion and Transmission Facilities Act continue to be satisfied. The basis for this certification is set forth in the accompanying Petition for Order Accepting Certification under SDCL 49-41B-27. Keystone is in compliance with the conditions attached to the June 29, 2010 Amended Final Decision and Order in this docket, to the extent that those conditions have applicability in the current pre-construction phase of the Project. Keystone certifies that it will meet and comply with all of the applicable permit conditions during construction, operation, and maintenance of the Project.

EXHIBIT
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Case Number: HP ____

STATUTORY DECLARATION

I, COREY GOULET, of CALGARY, in the Province of Alberta, Canada, do solemnly declare as follows:

THAT THE CERTIFICATION CONTAINED HEREIN IS TRUE.

And I make this solemn declaration conscientiously believing it to be true and knowing that it is of the same force and effect as is made under oath.

DECLARED before me at the CITY)
of CALGARY in the)
Province of Alberta, this 17th day)
of SEPTEMBER, A.D. 20 14.)

COREY GOULET

A Commissioner for Oaths/Notary Public

(PRINT OF STAMP NAME HERE)

(Must be legibly printed or stamped in legible printing if appointed under section 1 of the act)

MY APPOINTMENT EXPIRES

SHANNON R. ONOOK
A Notary Public in and for the
Province of Alberta. My Commission
expires at the pleasure of the
Lieutenant Governor-in-Council

020336

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	: : : : :	DOCKET NUMBER HP ____ PETITION FOR ORDER ACCEPTING CERTIFICATION UNDER SDCL § 49-41B-27

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Petitioner TransCanada Keystone Pipeline, LP (Keystone) sought and obtained a permit from the South Dakota Public Utilities Commission (Commission) in 2010 to construct and operate the Keystone XL hydrocarbon pipeline project (Project) through western South Dakota. The Commission granted a final permit in Docket No. HP09-001 on June 29, 2010. More than four years have passed since that time. State law provides that permits are perpetual but if construction has not commenced within four years of issuance, the applicant must certify to the Commission, prior to commencing construction, that the Project continues to meet the conditions upon which the permit was issued (SDCL 49-41B-27). By this filing, Keystone makes the required certification and requests that the Commission issue an order accepting Keystone's certification and finding that the Project continues to meet the conditions upon which the permit was issued.

I.
BACKGROUND

On March 12, 2009, Keystone filed an application in Docket HP 09-001 seeking a permit to construct and operate the Project in South Dakota. A hearing was held before the Commission from November 2-4, 2009. Keystone, Commission staff, and Dakota Rural Action were parties to the proceeding and participated in the hearing. The Commission issued a Final Decision and Order dated March 12, 2010. The Commission issued an Amended Final Decision and Order dated June 29, 2010, to which 50 conditions are attached.

As stated in the Amended Final Decision and Order, the Project originally was proposed to be developed in three segments: the Steele City Segment from Hardisty, Alberta, to Steele City, Nebraska; the Gulf Coast Segment from Cushing, Oklahoma, to Liberty County, Texas; and the Houston Lateral Segment from Liberty County, Texas to refinery markets near Houston, Texas. The Project was conceived to transport incremental crude oil production from the Western Canadian Sedimentary Basin to refineries and markets in the United States. Construction of the Project was proposed to begin in May 2011 and to be completed in 2012.

The Project, as proposed, has been delayed. A Presidential Permit required by Executive Order 11423 of August 16, 1968, and Executive Order 13337 of April 30, 2004, allowing the pipeline to cross the border between Canada and the United States, is still under review before the United States Department of State (DOS). Keystone submitted a Presidential Permit application to the DOS on September 19, 2008. After that application was denied without prejudice due to the Administration's inability to complete its review by a Congressionally imposed deadline, Keystone submitted a revised application on May 4, 2012. Drawing upon an extensive public record and multiple draft and final Environmental Impact Statements, DOS issued a Final Supplemental Environmental Impact Statement (Final SEIS) on January 31, 2014.[1] In the Final SEIS, the DOS concluded, among other things, that:

- Keystone has long-term commitments to ship both Canadian and Bakken oil to Gulf Coast refineries, production of Canadian and Bakken oil is projected to increase, and there is existing demand by Gulf Coast area refiners for stable sources of crude oil. (Final SEIS §§ 1.3.1, 1.4.)

- The analyses of potential impacts associated with construction and normal operation of the pipeline "suggest that significant impacts to most resources are not expected along the proposed Project route" assuming that the Project complies with applicable laws, regulations, and permit conditions. (Final SEIS § 4.16.)

- Due to market developments, the transportation of Canadian crude by rail is already occurring in substantial volumes (an estimated 180,000 bpd), with a greater risk of leaks and spills, as well as injuries and fatalities, than if the oil were transported by pipeline. (Final EIS, §§ E.S. 3.1, E.S.5.4.3.)

On April 18, 2014, the Administration announced an indefinite delay in the current Presidential Permit review process, referencing on-going litigation related to the approval of a revised pipeline route in Nebraska.[2]

During the pendency of the current Presidential Permit application, Keystone proceeded with the Gulf Coast Segment as a stand-alone project based on its independent utility. Construction is complete and that pipeline from Cushing, OK to Liberty County, Texas was placed in service on January 22, 2014. Construction of the Houston Lateral segment is currently

[1] http://keystonepipeline-xl.state.gov/finalseis/index.htm.

[2] In 2012, the Nebraska Legislature approved legislation giving the Governor authority to approve a revised route for the pipeline in that State. After an extensive public review process led by the Department of Environmental Quality, the Governor approved Keystone's proposed re-route in Nebraska. In February 2014, a Nebraska lower court declared the legislation unconstitutional. That case is currently on appeal to the Nebraska Supreme Court and the effect of the lower court's decision is stayed pending the outcome of that appeal.

under way. The currently pending Presidential Permit application involves consideration of the former Steele City segment only (see Appendix A; map of the current proposed Project).

Since the Amended Final Decision and Order, the Bakken Marketlink Project has been made part of the Project. Bakken Marketlink includes a five-mile pipeline, pumps, meters, and storage tanks near Baker, Montana, to deliver light sweet crude oil from the Bakken formation in Montana and North Dakota for transportation through the Project. Bakken Marketlink became commercial after the Amended Final Decision and Order in this case, as the result of a successful open season that closed on November 19, 2010. Bakken Marketlink will deliver up to 100,000 bpd of domestically-produced crude oil into the Keystone XL Pipeline. Approximately 700,000 bpd of Bakken formation production is currently being shipped by rail. Bakken Marketlink may relieve the need for some of that rail transportation while providing improved ratability and lower transportation costs for American producers.

The material aspects of the proposed construction and operation of the Project in South Dakota remain essentially unchanged since the Commission granted its approval in 2010. The Project will extend 315 miles, use 36-inch nominal diameter pipe made of high-strength steel, and be protected by an external fusion bonded epoxy coating and cathodic protection by impressed current. The route corridor through South Dakota is largely unchanged from the route analyzed by the Commission as part of the permitting process.[3] The pipeline will have batching capabilities and will be able to transport products ranging from light crude oil to heavy crude oil.

[3] Keystone has implemented minor route variations designed to accommodate landowner concerns and improve constructability. As required by Condition No. 6 of the Amended Final Decision and Order, any material route changes will be provided to the Commission for review prior to construction.

Since the Amended Final Decision and Order, Keystone has filed seventeen quarterly reports with the Commission as required by Condition No. 8 of the Amended Final Decision and Order. Each report is submitted by Keystone's public liaison officer and addresses the status of land acquisition, construction, permitting, and other items. The most recent quarterly report was submitted on July 29, 2014, and a copy of this report is attached hereto as Appendix B.

II.
THE PROJECT CONTINUES TO MEET THE CONDITIONS UPON WHICH THE PERMIT WAS ISSUED

Accompanying this petition is a Certification, signed by the President of the Keystone Pipeline business unit, attesting that: (i) the conditions upon which the Commission issued the facility permit in this docket continue to be satisfied; (ii) Keystone is in compliance with the conditions attached to the June 29, 2010 order, to the extent that those conditions have applicability in the current pre-construction phase of the Project; and (iii) Keystone will meet and comply with all of the applicable permit conditions during construction, operation, and maintenance of the Project. Compliance with those conditions is further reflected in Keystone's July 29, 2014 Quarterly Report (Appendix B). Thus, Keystone has satisfied the statutory requirement to certify that the Project continues to meet the conditions upon which the Commission's approval was issued.

In addition, Keystone submits that the circumstances and factual underpinnings of the Project that led the Commission to issue the facility permit remain valid. The factual findings underlying the Commission's decision are set forth in the June 29, 2010 Amended Final Decision and Order. In support of this petition, Appendix C hereto presents those findings of fact from the

Commission's Amended Final Decision and Order that have changed since 2010 and describes the nature of those changes. As Appendix C makes clear, to the extent that there have been changes in the underlying facts, those changes are either neutral or positive to the Commission's concerns. In sum, the need, impacts, efficacy, and safety of the Project have not changed since the Amended Final Decision and Order.

III.
CONCLUSION

The attached Certification, together with this petition and the supporting appendices, provides the necessary basis for the Commission to find that the Project continues to meet the conditions upon which the June 2010 permit was issued. Accordingly, Keystone respectfully requests that the Commission accept its certification under SDCL § 49-41B-27.

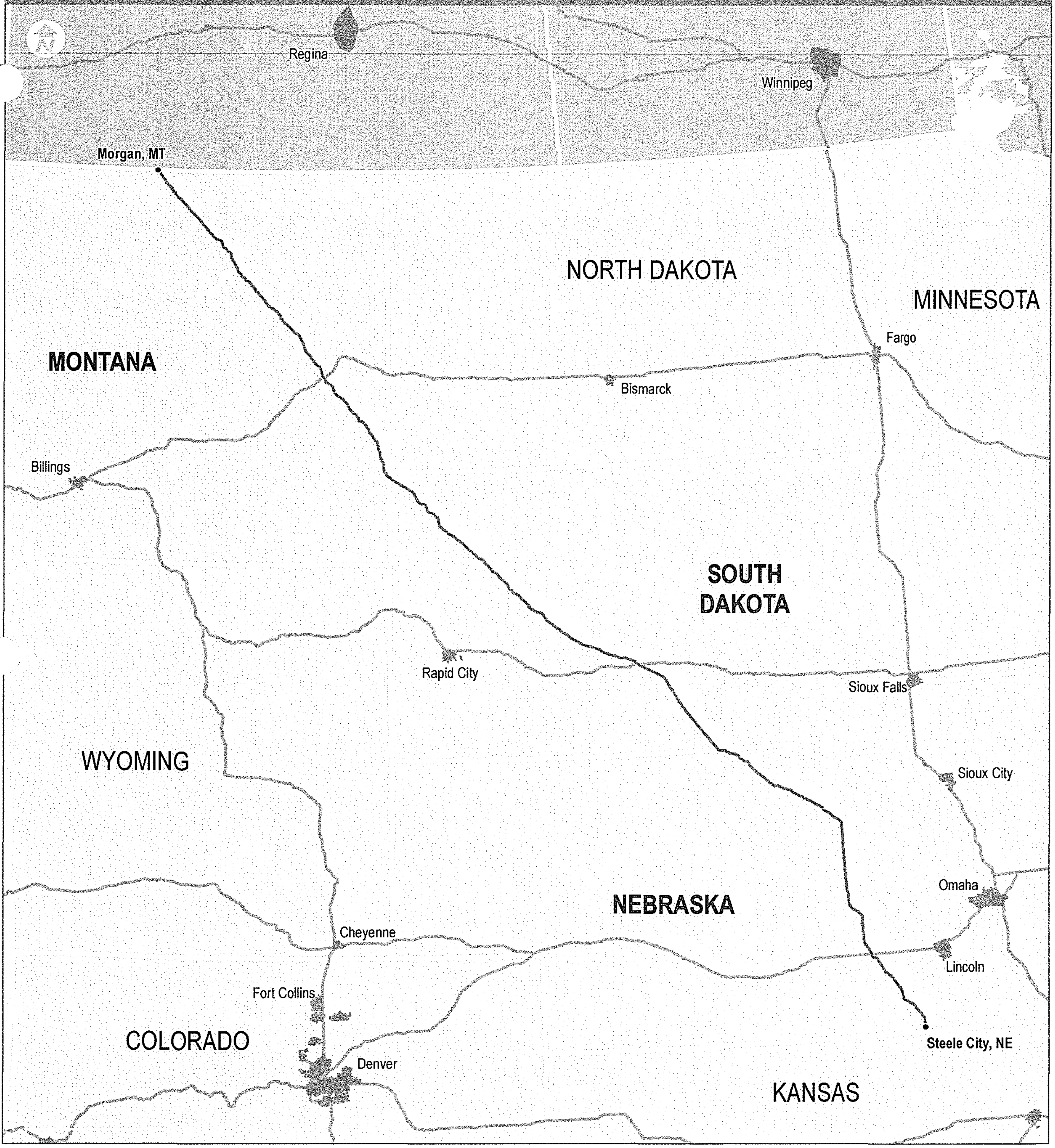
Dated this 15th day of September, 2014.

WOODS, FULLER, SHULTZ & SMITH P.C.

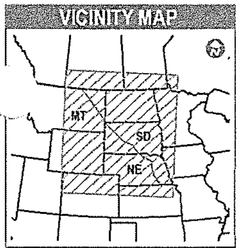
By James E. Moore

William G. Taylor
James E. Moore
PO Box 5027
300 South Phillips Avenue, Suite 300
Sioux Falls, SD 57117-5027
Phone (605) 336-3890
Fax (605) 339-3357
Email james.moore@woodsfuller.com
bill.taylor@woodsfuller.com
Attorneys for Applicant
TransCanada Keystone Pipeline, LP.

KXL PIPELINE PROJECT - OVERVIEW MAP



VICINITY MAP



LEGEND

- KXL CENTERLINE ROUTE
- FREEWAY SYSTEM
- URBAN AREA
- USA Major Lakes
- PROVINCE BOUNDARY
- STATE BOUNDARY

DRAWING INFORMATION

DRAWN BY:	DH	COUNTY:	-
CHECKED BY:	PD	STATE	MT, SD & NE
DATE:	2014-09-09	SHEET:	1 OF 1
DWG #:	XL-P-9339-A	SCALE:	1:6,000,000

REVISIONS

DATE	REVISION	REV.
2014-09-09	ISSUED FOR REVIEW	A

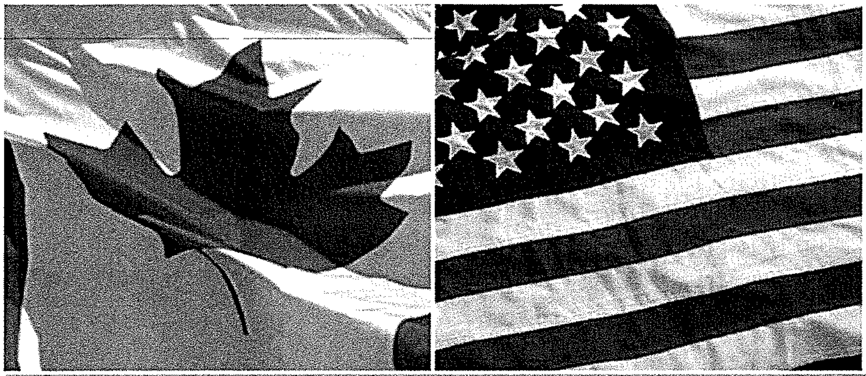
PREPARED BY

exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA

exp.

KXL PIPELINE PROJECT

TransCanada
In business to deliver



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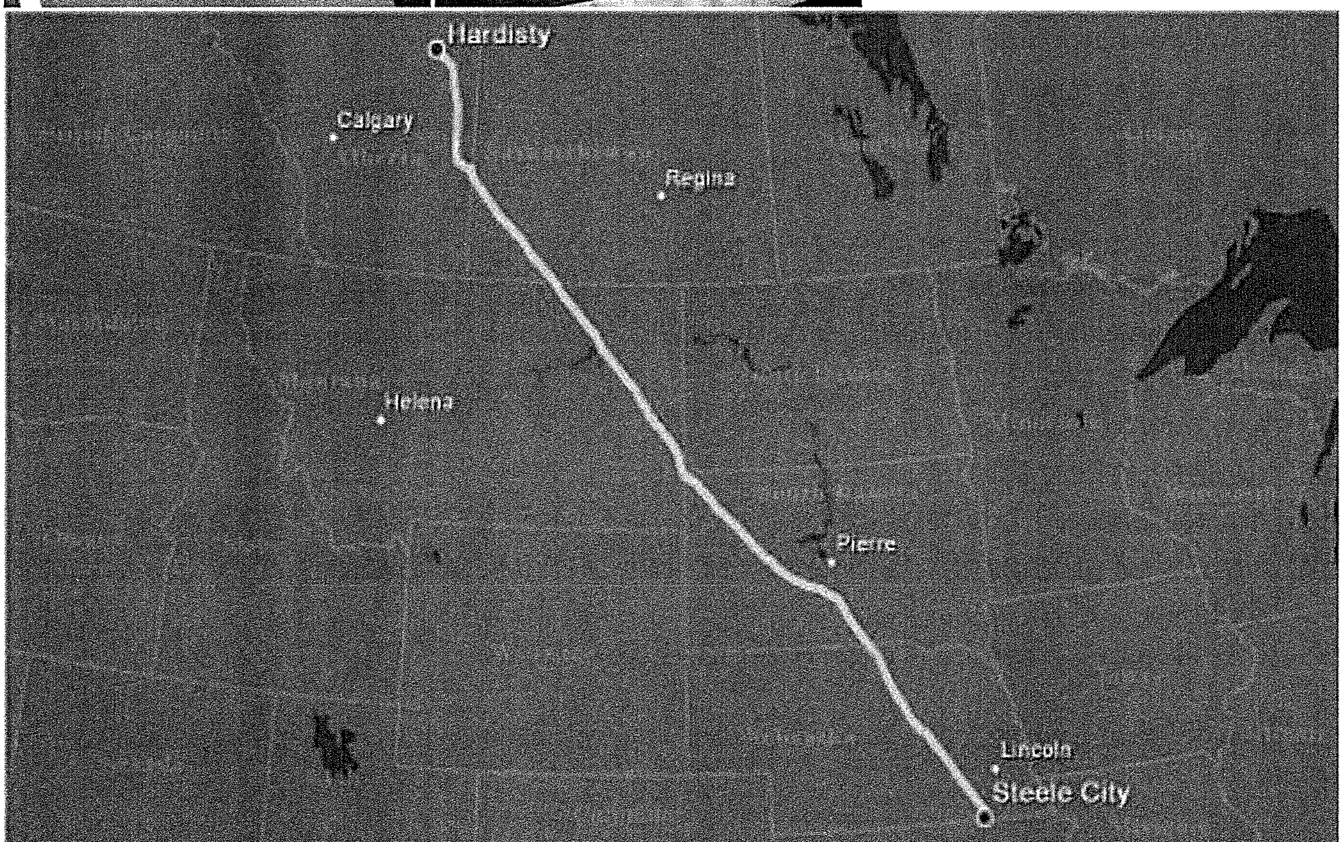

KEYSTONE XL
PIPELINE PROJECT

SOUTH DAKOTA PUBLIC UTILITIES COMMISSION QUARTERLY REPORT

For the Quarter Ending: **June 30, 2014**

TABLE OF CONTENTS

1.0 EXECUTIVE SUMMARY

TransCanada filed a new a Presidential Permit application with the Department of State on May 4, 2012 and on January 31, 2014 the Department of State issued a Final Supplemental Environmental Impact Statement (FSEIS). The project is currently in the National Interest Determination period of the Presidential Permit process. Construction activities have not taken place, or will take place, in South Dakota until the required permits and regulatory approvals are obtained for any proposed construction site. Project personnel are continuing to review the proposed pipeline route to identify any potential construction issues before construction. The construction plan for the portion of the Keystone XL Pipeline Project through South Dakota is dependent on the timing of final regulatory approvals and may include three or four spreads.

Keystone will implement the conditions of federal and state permits at the times specified by those permits. (See Appendix A for a table of the Summary of Consultations with the South Dakota Department of Environmental and Natural Resources.)

2.0 PROJECT DESCRIPTION

The project will include approximately 1,204 miles of 36 inch diameter pipeline from Hardisty, Alberta to Steel City, Nebraska, including approximately 313 miles in South Dakota.

3.0 LAND ACQUISITION STATUS (South Dakota)

3.1 Pipeline Right-of-Way Acquisition

The pipeline centerline crosses property owned by 301 landowners. Keystone has acquired easements from over 99% of the landowners. Easements have been acquired from the vast majority of all private landowners. Acquisition of tracts owned by the State of South Dakota is in process.

3.2 Pump Stations

The pump stations will be located in Harding, Meade, Haakon, Jones, and Tripp County, South Dakota. Keystone has purchased all seven pump station sites. The size of each pump station site is approximately 10 acres.

3.3 Pipe and Contractor Yards

Keystone has leased 11 pipe yards and six contractor yards in South Dakota. The leases were originally for 36 months, commencing on October 10, 2010. The leases have been extended an additional 24 months, expiring on October 1, 2015. The yards are in Harding, Butte, Meade, Haakon, Jones, Lyman and Tripp Counties. Each yard is approximately 30 acres in size.

3.4 Contractor Housing Camps

As outlined in the Keystone XL FSEIS, in Section 2.1.5.4 - Construction Camps, some remote areas in South Dakota do not have sufficient temporary housing near the proposed route to house all construction personnel working on spreads in those areas. In those remote areas, temporary work camps would be constructed to meet the housing needs of the construction workforce. Details of the construction camp configuration will depend on the final construction spread configuration and construction schedule, which is dependent on receipt of the final federal approval.

4.0 Non-Environmental Permitting Status (South Dakota)

4.1 County Roads

102 crossing permit applications have been filed for the pipeline to cross under all county road rights-of-way. Of the 102 applications filed, 101 have been acquired as of September 30, 2013.

4.2 State Roads

Thirteen (13) crossing permits and twenty-four (24) 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.

4.3 Railroads

Two crossing easement permits are being negotiated for the pipeline to cross under existing railroad rights-of-way. The South Dakota State Railroad application was received November 23, 2012. Canadian Pacific Railway was sold to the Genesee & Wyoming Railway; All permitting was transferred and is pending a signed license agreement.

4.4 Pump Stations

The special use permits required for the two Harding County pump stations were approved on September 28, 2010. Of the remaining five pump stations, four do not require a special use permit, leaving only one special use permit needed for the pump station in Jones County.

4.5 Contractor Camps

All construction camps will be permitted, constructed and operated consistent with applicable county, state, and federal regulations. (See Table 2.1-11 of the FSEIS for relevant regulations and permits required for the construction.)

5.0 ENVIRONMENTAL PERMITTING STATUS (South Dakota)

Keystone is awaiting or will be preparing and submitting all remaining applications for required federal and state environmental permits for work in South Dakota and will obtain the required permits in advance of pipeline construction activities.

6.0 FEDERAL PERMITS

TransCanada filed a Presidential Permit application with the U.S. Department of State on May 4, 2012 to authorize the international border crossing for the Keystone XL Project. On January 31, 2014 the US Department of State issued a Final Supplemental Environmental Impact Statement addressing Keystone's May 2012 Presidential Permit application. The project is currently in the National Interest Determination phase. The route through South Dakota is largely unchanged from the route analyzed for the SDPUC permit.

The former "Gulf Coast Segment" of the Keystone XL Project (a pipeline from Cushing Oklahoma to the Gulf Coast in Texas) was determined to have independent utility and was constructed as the stand-alone Gulf Coast pipeline separate from the Keystone XL Project.

Keystone XL pipeline will also file permit applications with the US Army Corps of Engineers for the necessary authorizations under Section 404 of the Clean Water Act and Section 10 of the Rivers and Harbors Act.

6.1 Permit Compliance

Keystone will implement the conditions of federal and state permits at the times specified by those permits. (See Appendix A for a table of the Summary of Consultations with the South Dakota Department of Environmental and Natural Resources.)

7.0 CONSTRUCTION STATUS

No construction activities have taken place, or will take place, in South Dakota until the required permits and regulatory approvals are obtained for any proposed construction site. Project personnel are continuing to review the proposed pipeline route to identify any potential construction issues before construction.

8.0 ENVIRONMENTAL CONTROL ACTIVITIES

Environmental control activities, as required by applicable permit conditions, will be implemented when construction activities start in South Dakota.

9.0 STATUS OF EMERGENCY RESPONSE AND INTEGRITY MANAGEMENT PLANS

9.1 Emergency Response Plan

Development of the Keystone Pipeline Project operational Emergency Response Plan for the U.S. is ongoing and will be submitted to Pipeline and Hazardous Materials Safety Administration (PHMSA) six months before pipeline in-service. New TransCanada-owned emergency response equipment trailers are planned for storage in South Dakota.

Through its public awareness program, TransCanada continues to provide various types of information related to Keystone emergency response and pipeline safety awareness.

9.2 Integrity Management Plan for High Consequence Areas

Development of the Integrity Management Plan for the high consequence areas is ongoing. Progress in identifying high consequence areas and creating their subsequent tactical plans is about 70% complete. These tactical plans will be included in the Emergency Response Plan. After further discussions and coordination with PHMSA, the Integrity Management Plan will be formally submitted to PHMSA.

10.0 OTHER COMPLIANCE MEASURES

See Appendix B for the status of implementation of South Dakota Public Utilities Commission (PUC) conditions.

APPENDIX A

Table 1: Recent Consultations with South Dakota Department of Environment and Natural Resources

Date of Contact	Agency / Individual	Purpose of Consultation	Results of Consultation	Follow-up Required
8-3-10	SD DENR Kelli Buscher, John Miller, Albert Spangler, Brian Walsh, Mike DeFea SDGFP Leslie Murphy, John Lott SD DAG Raymond Sowers, Bill Smith	Discuss both state and federal permitting for the Keystone XL Pipeline project in South Dakota as well as to review the current project status and schedule in South Dakota.	Laid out a blue print for State permitting.	Determine if a construction stormwater discharge permit is required for the camps as it is not required for pipeline related construction
10-23-12	SDGFP Silka Kempana, Travis Runia	Coordination with FWS, DOS, SD GFP regarding Keystone Sage Grouse Protection Plan and mitigation plans	Keystone will modify Sage Grouse Protection Plan to account for SD GFP additional input, conduct ambient noise studies and additional modeling, and revise mitigation plans for SD GFP review.	Updating Sage Grouse Protection Plan, mitigation plans and noise modeling
10-25-12	SD DENR Al Spangler	Verification of permit application process	Discussed water withdrawal and discharge permit application and format required	Keystone will prepare permit applications
12-3-12	SD DENR Ashley Brakke	Followed up with SD DENR with the submitted air permit applications for the contractor camps [for emergency generators].	DENR needs a notarized statement from the applicant saying these were the generators that would be used for emergency electric power. Ms. Brakke was about ½ way through with the applications and none yet required the permit.	Prepare statement for SD Camp Contractor(s) to sign, notarize and send to the DENR Air Quality representative when they are on board.
12-5-12	SD DENR Ashley Brakke	Followed up with SD DENR with the submitted air permit applications for the contractor camps [for emergency generators].	DENR stated that they were OK with the notarized letter not being submitted until the camp contractor had been identified and on board.	Prepare statement for SD Camp Contractor(s) to sign, notarize and send to the DENR Air Quality representative when they are on board.

Date of Contact	Agency / Individual	Purpose of Consultation	Results of Consultation	Follow-up Required
4-10-13	SD DENR Al Spangler	Confirm/discuss whether there would be any issues associated with hydrotest water obtained in SD being used to test pipe in Nebraska as long as the water was pushed back and released in SD near the location where the water was withdrawn.	Al Spangler confirmed that he did not see any issue with this approach. He would double-check with the water people and confirm.	Keystone will follow up with SD DENR on the feasibility of using SD test water in NE.
4-15-13	SD GFP Paul Coughlin	Discuss the potential for water withdrawal from Lake Gardner, which is a SD Game Protection Area.	SD GFP was receptive to the potential water withdrawal from Lake Gardner. SD GFP requested a formal written request.	Keystone will prepare a formal written request for the withdrawal of water from Lake Gardner
5-7-13	SD DENR Genny McMat, Marc Rush SDGFP Leslie Murphy, Gene Galinat, John Lott	Discuss the feasibility of the Keystone utilizing Lake Gardner as a source for hydrostatic test water and dust control water	SDGFP conditionally approved of the water withdrawal from Lake Gardner as long as there was adequate water present. SD GFP also stated that they would have to determine of there would be any other conditions that would need to be met to allow for the water withdrawal.	Follow-up with SDGFP on their progress developing a list of conditions that would permit the use of water from Lake Gardner for the proposed use [no further conditions were proposed] Work with SD GFP to fund restoration or conservation project in exchange for water use.
5-9-13	SDGFP Leslie Murphy	Emailed a pdf map of the proposed water withdrawal location for Lake Gardner	Provided the map following May 7, 2013 meeting	None
11-14-13	SD DENR William Marcouiller	Discuss the renewal process for the temporary discharge permit that had been issued to Keystone in April 2013.	SD DENR confirmed that the permit was good through December 31, 2015.	Keystone would need to renew the permit if discharge activities would occur after December 2015.
04-03-14	SD Natural Heritage Program Casey Heimerl	Request for most recent observation records for northern long –eared bat	Being processed	No
04-16-14	SD Natural Heritage Program Casey Heimerl	Request for most recent observation records for northern long –eared bat	Received via email: tabular and GIS (shapefiles) of the observation records of the northern long-eared bat for the counties that the Project crosses.	No

Date of Contact	Agency / Individual	Purpose of Consultation	Results of Consultation	Follow-up Required
05-28-14	SD Natural Heritage Program Casey Heimerl SD Game, Fish and Parks Tom Kirschenmann	Voluntary Informal Conference with US Fish and Wildlife Service to discuss the potential impacts to northern long-eared bat and red knot resulting from the Project. Both species are proposed for listing under the Endangered Species Act.	Keystone to revise habitat assessment report for the northern long-eared bat and red knot based on the comments and guidance provided during the meeting.	Keystone will submit a revised report to USFWS

APPENDIX B

Table 2: Status of Implementation of South Dakota PUC Conditions

NO.	CONDITION	STATUS OF OTHER MEASURES REQUIRED BY CONDITIONS
1	Keystone shall 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; temporary permits for use of public water for construction, testing or drilling purposes, SDCL 46-5-40.1 and ARSD 74:02:01 :32 through 74:02:01 :34.02 and temporary discharges to waters of the state, SDCL 34A-2-36 and ARSD Chapters 74:52:01 through 74:52:11, specifically, ARSD § 74:52:02:46 and the General Permit issued thereunder covering temporary discharges of water from construction dewatering and hydrostatic testing.	Construction of the project has not been initiated. Keystone will comply with all applicable laws and regulations during construction and operation of the Project.
2	Keystone shall obtain and shall thereafter comply with all applicable federal, state and local permits, including but not limited to: Presidential Permit from the United States Department of State, Executive Order 11423 of August 16, 1968 (33 Fed. Reg. 11741) and Executive 'Order 13337 of April 30, 2004 (69 Fed. Reg. 25229), for the construction, connection, operation, or maintenance, at the border of the United States, of facilities for the exportation or importation of petroleum, petroleum products, coal, or other fuels to or from a foreign country; Clean Water Act § 404 and Rivers and Harbors Act Section 10 Permits; Special Permit if issued by the Pipeline and Hazardous Materials Safety Administration; Temporary Water Use Permit, General Permit for Temporary Discharges and federal, state and local highway and road encroachment permits. Any of such permits not previously filed with the Commission shall be filed with the Commission upon their issuance. To the extent that any condition, requirement or standard of the Presidential Permit, including the Final EIS Recommendations, or any other law, regulation or permit applicable to the portion of the pipeline in this state differs from the requirements of these Conditions, the more stringent shall apply.	Construction of the project has not been initiated. Keystone is in the process of obtaining all applicable permits from Federal, State and Local entities. Upon commencement of construction Keystone will follow all applicable laws and conditions related to these permits.

NO.	CONDITION	STATUS OF OTHER MEASURES REQUIRED BY CONDITIONS
3	Keystone shall comply with and implement the Recommendations set forth in the Final Environmental Impact Statement when issued by the United States Department of State pursuant to its Amended Department of State Notice of Intent To Prepare an Environmental Impact Statement and To Conduct Scoping Meetings and Notice of Floodplain and Wetland Involvement and To Initiate Consultation Under Section 106 of the National Historic Preservation Act for the Proposed TransCanada Keystone XL Pipeline; Notice of Intent--Rescheduled Public Scoping Meetings in South Dakota and extension of comment period (FR vol. 74, no. 54, Mar. 23, 2009). The Amended Notice and other Department of State and Project Documents are available on-line at: http://www.keystonepipeline-xl.state.gov/clientsite/keystonexl.nsf?Open.	The Department of State re-initiated its NEPA review upon receipt of Keystone's May 4, 2012 application for a Presidential Permit. The Department is in the process of preparing a Supplement to the August 2011 Final Environmental Impact Statement for the project. Construction of the project has not been initiated. Keystone will comply with and implement the Recommendations set forth in the Final Environmental Impact Statement, and the Supplemental Environmental Impact Statement, as reflected in the Record of Decision, when issued by the Department of State.
4	The permit granted by this Order shall not be transferable without the approval of the Commission pursuant to SDCL 49-418-29.	N/A at this time.
5	Keystone shall undertake and complete all of the actions that it and its affiliated entities committed to undertake and complete in its Application as amended, in its testimony and exhibits received in evidence at the hearing, and in its responses to data requests received in evidence at the hearing.	Construction of the project has not been initiated. When construction is initiated, Keystone will undertake the actions committed to during the SDPUC hearings.
6.a	The most recent and accurate depiction of the Project route and facility locations is found on the maps in Exhibit TC-14. The Application indicates in Section 4.2.3 that Keystone will continue to develop route adjustments throughout the pre-construction design phase. These route adjustments will accommodate environmental features identified during surveys, property-specific issues, and civil survey information. The Application states that Keystone will file new aerial route maps that incorporate any such route adjustments prior to construction. Ex TC-1.4.2.3, p. 27.	Keystone will file new aerial route maps reflecting route adjustments prior to construction.
6.b	Keystone shall notify the Commission and all affected landowners, utilities and local governmental units as soon as practicable if material deviations are proposed to the route.	Keystone will continue to work with all landowners, utilities, local government and other affected parties as the final route is being developed and will notify the Commission and all affected parties of any material deviations to the proposed route.
6.c	Keystone shall notify affected landowners of any change in the route on their land.	This is a continuing occurrence during engineering review. Keystone will continue to notify landowners of route changes on their land as well as inform them of associated activities, such as civil and environmental surveys.
6.d	At such time as Keystone has finalized the pre-construction route, Keystone shall file maps with the Commission depicting the final preconstruction route	Construction of the project has not been initiated. Keystone will finalize the route and submit to the Commission new maps depicting the final preconstruction route prior to construction.

NO.	CONDITION	STATUS OF OTHER MEASURES REQUIRED BY CONDITIONS
6.e	If material deviations are proposed from the route depicted on Exhibit TC-14 and accordingly approved by this Order, Keystone shall advise the Commission and all affected landowners, utilities and local governmental units prior to implementing such changes and afford the Commission the opportunity to review and approve such modifications.	Keystone has advised the Commission of all material route changes to date and has afforded the commission the opportunity to review and approve such modifications.
6.f	At the conclusion of construction, Keystone shall file detail maps with the Commission depicting the final as-built location of the Project facilities.	Keystone will submit final route maps to the Commission at the conclusion of construction.
7	Keystone shall provide a public liaison officer, approved by the Commission, to facilitate the exchange of information between Keystone, including its contractors, and landowners, local communities and residents and to promptly resolve complaints and problems that may develop for landowners, local communities and residents as a result of the Project. Keystone shall file with the Commission its proposed public liaison officer's credentials for approval by the Commission prior to the commencement of construction. After the public liaison officer has been approved by the Commission, the public liaison officer may not be removed by Keystone without the approval of the Commission. The public liaison officer shall be afforded immediate access to Keystone's on-site project manager, its executive project manager and to contractors' on-site managers and shall be available at all times to the Staff via mobile phone to respond to complaints and concerns communicated to the Staff by concerned landowners and others. Keystone shall also implement and keep an up-dated web site covering the planning and implementation of construction and commencement of operations in this state as an informational medium for the public. As soon as the Keystone's public liaison officer has been appointed and approved, Keystone shall provide contact information for him/her to all landowners crossed by the Project and to law enforcement agencies and local governments in the vicinity of the Project. The public liaison officer's contact information shall be provided to landowners in each subsequent written communication with them. If the Commission determines that the public liaison officer has not been adequately performing the duties set forth for the position in this Order, the Commission may, upon notice to Keystone and the public liaison officer, take action to remove the public liaison officer.	The Commission has approved Sarah Metcalf as the public liaison officer for the Keystone XL project. The liaison can be reached at: Mailing Address: South Dakota Pipeline Liaison Officer PO Box 491 Aberdeen, South Dakota 57402 Phone: (888) 375-1370 Email: smetcalf12@gmail.com Contact information for the South Dakota liaison was sent out in December 2010 to landowners. Notification to law enforcement agencies and local governments in the vicinity of the Project was completed in 1st quarter 2011 in conjunction with notice required by other conditions for these groups. The liaison continues to contact affected counties, townships and other groups as the permit process takes place. The TransCanada Keystone Pipeline website at: http://www.transcanada.com/keystone.html provides general information about planning for construction of the project. When construction commences, more detailed construction information will be posted.

NO.	CONDITION	STATUS OF OTHER MEASURES REQUIRED BY CONDITIONS
8	Until construction of the Project, including reclamation, is completed, Keystone shall submit quarterly progress reports to the Commission that 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. Each report shall include a summary of consultations with the South Dakota Department of Environment and Natural Resources and other agencies concerning the issuance of permits. The reports shall list dates, names, and the results of each contact and the company's progress in implementing prescribed construction, land restoration, environmental protection, emergency response and integrity management regulations, plans and standards. The first report shall be due for the period ending June 30, 2010. The reports shall be filed within 31 days after the end of each quarterly period and shall continue until the project is fully operational.	Keystone will continue to submit quarterly reports until the construction and reclamation of the Keystone XL pipeline is complete and the pipeline is operational.
9	Until one year following completion of construction of the Project, including reclamation, Keystone's public liaison officer shall report quarterly to the Commission on the status of the Project from his/her independent vantage point. The report shall detail problems encountered and complaints received. For the period of three years following completion of construction, Keystone's public liaison officer shall report to the Commission annually regarding post-construction landowner and other complaints, the status of road repair and reconstruction and land and crop restoration and any problems or issues occurring during the course of the year	The public liaison officer will comply with this condition and is currently available to affected landowners and parties in the State. Quarterly reporting will begin with active construction activities.
10	Not later than six months prior to commencement of construction, Keystone shall commence 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 in order to educate such agencies concerning the planned construction schedule and the measures that such agencies should begin taking to prepare for construction impacts and the commencement of project operations.	Keystone has commenced and will continue a program of contacts to inform and coordinate with county and municipal emergency response, law enforcement and highway, road and other infrastructure management agencies regarding planned construction and eventual operation of the Keystone XL Pipeline.
11	Keystone shall conduct a preconstruction conference prior to the commencement of construction to ensure that Keystone fully understands the conditions set forth in this order. At a minimum, the conference shall include a Keystone representative, Keystone's construction supervisor and Staff.	Prior to the start of construction a Keystone representative, the Keystone construction supervisor, and staff will arrange a preconstruction conference with the Commission to ensure a full understanding of the conditions set forth in this order.
12	Once known, Keystone shall 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 as provided in Condition 8.	Keystone will inform the Commission accordingly during the preconstruction conference.
13	Except as otherwise provided in the conditions of this Order and Permit, Keystone shall comply with all mitigation measures set forth in the Construction Mitigation and Reclamation Plan (CMR Plan)	Construction of the project has not been initiated. Keystone will comply with the requirements set forth in the CMR Plan during construction.

NO.	CONDITION	STATUS OF OTHER MEASURES REQUIRED BY CONDITIONS
13.a	If modifications to the CMR Plan are made by Keystone as it refines its construction plans or are required by the Department of State in its Final EIS Record of Decision or the Presidential Permit, the CMR Plan as so modified shall be filed with the Commission and shall be complied with by Keystone.	Keystone will submit any modifications to the CMR Plan to the Commission and comply with any modifications to the CMR Plan.
14	Keystone shall incorporate environmental inspectors into its CMR Plan and obtain follow-up information reports from such inspections upon the completion of each construction spread to help ensure compliance with this Order and Permit and all other applicable permits, laws, and rules	Construction of the project has not been initiated. Keystone will utilize environmental inspectors and comply with this condition during the construction of the project.
15	Prior to construction, Keystone shall, in consultation with area NRCS staff, develop specific construction/reclamation units (Con/Rec Units) that are applicable to particular soil and subsoil classifications, land uses and environmental settings. The Con/Rec Units shall contain information of the sort described in response to Staff Data Request 3-25 found in Exhibit TC-16.	Keystone has completed the consultation with NRCS and has received the concurrence of the NRCS for Con/Rec Units to be utilized in South Dakota. Keystone will consult further with the NRCS should alterations to the Con/Rec Units be required.
15.a	In the development of the Con/Rec Units in areas where NRCS recommends, Keystone shall conduct analytical soil probing and/or soil boring and analysis in areas of particularly sensitive soils where reclamation potential is low. Records regarding this process shall be available to the Commission and to the specific land owner affected by such soils upon request	Keystone has completed analytical soil probing and/or soil boring and analysis in areas of particularly sensitive soils where reclamation potential is low. Records regarding the process are available to the Commission and to the specific land owner affected by such soil upon request.
15.b	Through development of the Con/Rec Units and consultation with NRCS, Keystone shall identify soils for which alternative handling methods are recommended.	Keystone has completed the analytical soil probing and/or boring in areas of sensitive soils following the NRCS recommendations.
15.b.1	Keystone shall thoroughly inform the landowner regarding the options applicable to their property, including their respective benefits and negatives, and implement whatever reasonable option for soil handling is selected by the landowner. Records regarding this process shall be available to the Commission upon request.	This is discussed with the landowners and itemized in the "Binding Agreement". These agreements are available to the Commission upon request.
15.c	Keystone shall, in consultation with NCRS, ensure that its construction planning and execution process, including Con/Rec Units, CMR Plan and its other construction documents and planning shall adequately identify and plan for areas susceptible to erosion, areas where sand dunes are present, areas with high concentrations of sodium bentonite, areas with sodic, saline and sodic-saline soils and any other areas with low reclamation potential	Keystone's construction planning and execution process consisted of consultation with the NRCS for identified areas susceptible to erosion, areas where sand dunes are present, areas with high concentration of sodium bentonite, areas with sodic, saline and sodic-saline soils and any other areas with low reclamation potential. The identified areas were addressed in the CON/REC Units, CMR Plan, and will be listed on construction alignment sheets.
15.d	The Con/Rec Units shall be available upon request to the Commission and affected landowners. Con/Rec Units may be evaluated by the Commission upon complaint or otherwise, regarding whether proper soil handling, damage mitigation or reclamation procedures are being followed.	Con/Rec Units will be available upon request to the Commission and affected landowners.

NO.	CONDITION	STATUS OF OTHER MEASURES REQUIRED BY CONDITIONS
15.e	Areas of specific concern or of low reclamation potential shall be recorded in a separate database. Action taken at such locations and the results thereof shall also be recorded and made available to the Commission and the affected property owner upon request.	Areas of specific concern or of low reclamation potential will be recorded in a separate database. Action taken at such locations and the results thereof will be recorded and made available to the Commission and the affected property owner upon request.
16	Keystone shall provide each landowner with an explanation regarding trenching and topsoil and subsoil/rock removal, segregation and restoration method options for his/her property consistent with the applicable Con/Rec Unit and shall follow the landowner's selected preference as documented on its written construction agreement with the landowner, as modified by any subsequent amendments, or by other written agreement(s).	This is discussed with the landowners and itemized in the "Binding Agreement".
16.a	Keystone shall separate and segregate topsoil from subsoil in agricultural areas, including grasslands and shelter belts, as provided in the CMR Plan and the applicable Con/Rec Unit.	Keystone will separate and segregate topsoil from subsoil in agricultural areas, including grasslands and shelter belts, as provided in the CMR Plan and the applicable Con/Rec Unit.
16.b	Keystone shall repair any damage to property that results from construction activities	Keystone will address this during or following construction activities.
16.c	Keystone shall restore all areas disturbed by construction to their preconstruction condition, including their original preconstruction topsoil, vegetation, elevation, and contour, or as close thereto as is feasible, except as is otherwise agreed to by the landowner.	Keystone will address this during or following construction activities and will restore disturbed areas as close as feasible to their preconstruction conditions or as otherwise agreed to by the landowner.
16.d	Except where practicably infeasible, final grading and topsoil replacement and installation of permanent erosion control structures shall be completed in non-residential areas within 20 days after backfilling the trench.	Keystone will address this during construction.
16.d.1	In the event that seasonal or other weather conditions, extenuating circumstances, or unforeseen developments beyond Keystone's control prevent compliance with this time frame, temporary erosion controls shall be maintained until conditions allow completion of cleanup and reclamation.	Keystone will address this during construction.
16.d.2	In the event Keystone cannot comply with the 20-day time frame as provided in this Condition, it shall give notice of such fact to all affected landowners, and such notice shall include an estimate of when such restoration is expected to be completed.	Keystone will address this during construction.
16.e	Keystone shall draft specific crop monitoring protocols for agricultural lands.	Keystone is in the process of developing specific crop monitoring protocols for agricultural lands. These protocols will be finalized prior to the start of construction and implemented following construction.

NO.	CONDITION	STATUS OF OTHER MEASURES REQUIRED BY CONDITIONS
16.e.1	If requested by the landowner, Keystone shall provide an independent crop monitor to conduct yield testing and/or such other measurements of productivity as he shall deem appropriate. The independent monitor shall be a qualified agronomist, rangeland specialist or otherwise qualified with respect to the species to be restored. The protocols shall be available to the Commission upon request and may be evaluated for adequacy in response to a complaint or otherwise.	If requested by the landowner, Keystone will provide an independent crop monitor and develop appropriate protocols, which will be available to the Commission upon request
16.f	Keystone shall work closely with landowners or land management agencies to determine a plan to control noxious weeds. Landowner permission shall be obtained before the application of herbicides.	Keystone has prepared a noxious weed control plan and provided a draft to the County Weed Boards for review and approval.
16.g	Keystone's adverse weather plan shall apply to improved hay land and pasture lands in addition to crop lands.	Keystone is in the process of developing an adverse weather plan and will include both improved hay lands and pasture lands in addition to crop lands.
16.h	The size, density and distribution of rock within the construction right-of-way following reclamation shall be similar to adjacent undisturbed areas.	Keystone will require the Contractor to remove excess rocks so that the size density and distribution of rock within the construction right-of-way is similar to the adjacent undisturbed areas.
16.h.1	Keystone shall treat rock that cannot be backfilled within or below the level of the natural rock profile as construction debris and remove it for disposal offsite except when the landowner agrees to the placement of the rock on his property. In such case, the rock shall be placed in accordance with the landowner's directions.	Keystone will require the Contractor to treat rock that cannot be backfilled within or below the level of the natural rock profile as construction debris and remove it for disposal offsite except when the landowner agrees to the placement of the rock on his property. In such case, the rock shall be placed in accordance with the landowner's directions and all Federal and State permits.
16.i	Keystone shall utilize the proposed trench line for its pipe stringing trucks where conditions allow and shall employ adequate measures to de-compact subsoil as provided in its CMR Plan. Topsoil shall be de-compacted if requested by the landowner.	Keystone will utilize the trench line for its pipe stringing trucks when site conditions allow and will employ adequate measures to de-compact subsoil as provided in its CMR Plan and in the specified CON/REC unit.
16.i.1	Topsoil shall be de-compacted if requested by the landowner.	Keystone will employ adequate measures to de-compact subsoil as provided in its CMR Plan and in the specified CON/REC unit, and will de-compact topsoil if requested by the landowner.
16.j	Keystone shall monitor and take appropriate mitigative actions as necessary to address salinity issues when dewatering the trench, and field conductivity and/or other appropriate constituent analyses shall be performed prior to disposal of trench water in areas where salinity may be expected.	Keystone will monitor and take appropriate actions as necessary to address salinity issues when dewatering the trench. Field conductivity and/or other appropriate constituent analyses will be performed prior to disposal of trench water in areas where salinity is expected.

NO.	CONDITION	STATUS OF OTHER MEASURES REQUIRED BY CONDITIONS
16.j.1	Keystone shall notify landowners prior to any discharge of saline water on their lands or of any spills of hazardous materials on their lands of one pint or more or of any lesser volume which is required by any federal, state, or local law or regulation or product license or label to be reported to a state or federal agency, manufacturer, or manufacturer's representative.	Keystone will notify landowners prior to any discharge of saline water on private lands or of any spills of hazardous materials on private lands of one pint or more or of any lesser volume which is required by any federal, state, or local law or regulation or product license or label to be reported.
16.k	Keystone shall install trench and slope breakers where necessary in accordance with the CMR Plan as augmented by Staff's recommendations in Post Hearing Commission Staff Brief, pp. 26-27	Keystone will install trench and slope breakers where necessary in accordance with the CMR Plan and SDPUC recommendations.
16.l	Keystone shall apply mulch when reasonably requested by landowners and also wherever necessary following seeding to stabilize the soil surface and to reduce wind and water erosion. Keystone shall follow the other recommendations regarding mulch application in Post Hearing Commission Staff Brief, p. 27.	Keystone will apply mulch in accordance with the CMR Plan and the specific CON/REC units to stabilize the soil surface and to reduce wind and water erosion. Keystone will apply mulch at the landowners request when the request is reasonable and in accordance with site reclamation requirements. Keystone will follow the other recommendations regarding mulch application in Post Hearing Commission Staff Brief, p. 27.
16.m	Keystone shall reseed all lands with comparable crops to be approved by landowner in landowner's reasonable discretion, or in pasture, hay or native species areas with comparable grass or forage crop seed or native species mix to be approved by landowner in landowner's reasonable discretion.	Keystone has developed seed mixtures in consultation with the NRCS.
16.m.1	Keystone shall actively monitor revegetation of all disturbed areas for at least two years.	Keystone will monitor revegetation on all disturbed areas for at least two years.
16.n	Keystone shall coordinate with landowners regarding his/her desires to properly protect cattle, shall implement such protective measures as are reasonably requested by the landowner and shall adequately compensate the landowner for any loss.	Keystone will coordinate with landowners and implement reasonably requested protective measures during construction and adequately compensate landowners for any loss.
16.o	Prior to commencing construction, Keystone shall file with the Commission a confidential list of property owners crossed by the pipeline and update this list if route changes during construction result in property owner changes	Prior to commencing construction, Keystone will submit to the Commission a confidential list of property owners crossed by the pipeline and will update this list if route changes result in property owner changes during construction.
16.p	Except in areas where fire suppression resources as provided in CMR Plan 2.16 are in close proximity, to minimize fire risk, Keystone shall, and shall cause its contractor to, equip each of its vehicles used in pre-construction or construction activities, including off-road vehicles, with a hand held fire extinguisher, portable compact shovel and communication device such as a cell phone, in areas with coverage, or a radio capable of achieving prompt communication with Keystone's fire suppression resources and emergency services.	Keystone will address compliance with this condition with Contractor prior to the commencement of construction on the right-of-way. Each vehicle that is subject to this condition will be equipped with fire extinguisher, portable compact shovel, and proper communications devices.

NO.	CONDITION	STATUS OF OTHER MEASURES REQUIRED BY CONDITIONS
17	Keystone shall cover open-bodied dump trucks carrying sand or soil while on paved roads and cover open-bodied dump trucks carrying gravel or other materials having the potential to be expelled onto other vehicles or persons while on all public roads.	Keystone will address this with the Contractor. Contractor vehicles carrying sand, soil, or gravel while traveling on paved public roads shall be covered to avoid the potential of expelling the material onto other vehicles or persons.
18	Keystone shall use its best efforts to not locate fuel storage facilities within 200 feet of private wells and 400 feet of municipal wells and shall minimize and exercise vigilance in refueling activities in areas within 200 feet of private wells and 400 feet of municipal wells.	Keystone will address this in the pre-construction planning. Fuel storage tanks and refueling activities shall follow the requirements set forth in the CMRP and Spill Prevention and Containment Plan.
19	If trees are to be removed that have commercial or other value to affected landowners, Keystone shall compensate the landowner for the fair market value of the trees to be cleared and/or allow the landowner the right to retain ownership of the felled trees.	Keystone will comply with this condition during the easement acquisition process.
19.a	Except as the landowner shall otherwise agree in writing, the width of the clear cuts through any windbreaks and shelterbelts shall be limited to 50 feet or less, and the width of clear cuts through extended lengths of wooded areas shall be limited to 85 feet or less. The environmental inspection in Condition 14 shall include forested lands.	Keystone will comply with this condition prior to or during construction.
20.	Keystone shall implement the following sediment control practices: a) Keystone shall use floating sediment curtains to maintain sediments within the construction right of way in open water bodies with no or low flow when the depth of non-flowing water exceeds the height of straw bales or silt fence installation. In such situations the floating sediment curtains shall be installed as a substitute for straw bales or silt fence along the edge or edges of each side of the construction right-of-way that is underwater at a depth greater than the top of a straw bale or silt fence as portrayed in Keystone's construction Detail #11 included in the CMR Plan. b) Keystone shall install sediment barriers in the vicinity of delineated wetlands and water bodies as outlined in the CMR Plan regardless of the presence of flowing or standing water at the time of construction. c) The Applicant should consult with South Dakota Game, Fish and Parks (SDGFP) to avoid construction near water bodies during fish spawning periods in which in-stream construction activities should be avoided to limit impacts on specific fisheries, if any, with commercial or recreational importance.	Keystone will comply with parts (a) and (b) of this condition during construction. Keystone will consult with SDGFP regarding spawning periods. The current construction schedule will avoid impacts to streams during the spawning season.
21	Keystone shall develop frac-out plans specific to areas in South Dakota where horizontal directional drilling will occur. The plan shall be followed in the event of a frac-out.	Keystone has developed a draft frac-out plan and HDD plan in South Dakota. The plan will be finalized with the input from the Contractor. The plan will be followed in the event of a frac-out.

NO.	CONDITION	STATUS OF OTHER MEASURES REQUIRED BY CONDITIONS
21.a	If a frac-out event occurs, Keystone shall promptly file a report of the incident with the Commission. Keystone shall also, after execution of the plan, provide a follow-up report to the Commission regarding the results of the occurrence and any lingering concerns.	Keystone will comply with this section in the event of a frac-out.
22.	Keystone shall comply with the following conditions regarding construction across or near wetlands, water bodies and riparian areas: a) Unless a wetland is actively cultivated or rotated cropland or unless site specific conditions require utilization of Keystone's proposed 85 foot width and the landowner has agreed to such greater width, the width of the construction right-of-way shall be limited to 75 feet in non-cultivated wetlands unless a different width is approved or required by the United States Army Corps of Engineers. b) Unless a wetland is actively cultivated or rotated cropland, extra work areas shall be located at least 50 feet away from wetland boundaries except where site-specific conditions render a 50-foot setback infeasible. Extra work areas near water bodies shall be located at least 50 feet from the water's edge, except where the adjacent upland consists of actively cultivated or rotated cropland or other disturbed land or where site-specific conditions render a 50-foot setback infeasible. Clearing of vegetation between extra work space areas and the water's edge shall be limited to the construction right-of-way. c) Water body crossing spoil, including upland spoil from crossings of streams up to 30 feet in width, shall be stored in the construction right of way at least 10 feet from the water's edge or in additional extra work areas and only on a temporary basis. d) Temporary in-stream spoil storage in streams greater than 30 feet in width shall only be conducted in conformity with any required federal permit(s) and any applicable federal or state statutes, rules and standards. e) Wetland and water body boundaries and buffers shall be marked and maintained until ground disturbing activities are complete. Keystone shall maintain 15-foot buffers where practicable, which for stream crossings shall be maintained except during the period of trenching, pipe laying and backfilling the crossing point. Buffers shall not be required in the case of non-flowing streams. f) Best management practices shall be implemented to prevent heavily silt-laden trench water from reaching any wetland or water body directly or indirectly. g) Erosion control fabric shall be used on water body banks immediately following final stream bank restoration unless riprap or other bank stabilization methods are utilized in accordance with federal or state permits. h) The use of timber and slash to support equipment crossings of wetlands shall be avoided.	Keystone will comply with all ROW widths, setbacks, and BMPS as detailed by the Commission. Keystone is identifying the appropriate locations for these conditions at or near wetlands, water bodies and riparian areas during the pre-construction process and will identify the ROW widths and setbacks on the construction drawings. BMPs will be installed as detailed in the CMRP.

NO.	CONDITION	STATUS OF OTHER MEASURES REQUIRED BY CONDITIONS
	i) Subject to Conditions 37 and 38, vegetation restoration and maintenance adjacent to water bodies shall be conducted in such manner to allow a riparian strip at least 25 feet wide as measured from the water body's mean high water mark to permanently re-vegetate with native plant species across the entire construction right-of way.	
23.	Keystone shall comply with the following conditions regarding road protection and bonding: a. Keystone shall coordinate road closures with state and local governments and emergency responders and shall acquire all necessary permits authorizing crossing and construction use of county and township roads. b) Keystone shall implement a regular program of road maintenance and repair through the active construction period to keep paved and gravel roads in an acceptable condition for residents and the general public. c) Prior to their use for construction, Keystone shall videotape those portions of all roads which will be utilized by construction equipment or transport vehicles in order to document the pre-construction condition of such roads. d) After construction, Keystone shall repair and restore, or compensate governmental entities for the repair and restoration of, any deterioration caused by construction traffic, such that the roads are returned to at least their preconstruction condition. e) Keystone shall use appropriate preventative measures as needed to prevent damage to paved roads and to remove excess soil or mud from such roadways. f) Pursuant to SDCL 49-418-38, Keystone shall obtain and file for approval by the Commission prior to construction in such year a bond in the amount of $15.6 million for the year in which construction is to commence and a second bond in the amount of $15.6 million for the ensuing year, including any additional period until construction and repair has been completed, to ensure that any damage beyond normal wear to public roads, highways, bridges or other related facilities will be adequately restored or compensated. Such bonds shall be issued in favor of, and for the benefit of, all such townships, counties, and other governmental entities whose property is crossed by the Project. Each bond shall remain in effect until released by the Commission, which release shall not be unreasonably denied following completion of the construction and repair period. Either at the contact meetings required by Condition 10 or by mail, Keystone shall give notice of the existence and amount of these bonds to all counties, townships and other governmental entities whose property is crossed by the Project.	During the pre-construction planning period Keystone will develop and implement videotaping of road conditions prior to construction activities. Keystone, Contractor, and County Representatives will be present for evaluation and determination of road conditions. Keystone will notify state and local governments and emergency responders to coordinate and implement road closures. All necessary permits authorizing crossing and construction use of county and township roads will be obtained. Keystone will file the necessary bond prior to construction.

NO.	CONDITION	STATUS OF OTHER MEASURES REQUIRED BY CONDITIONS
24	Although no residential property is expected to be encountered in connection with the Project, in the event that such properties are affected and due to the nature of residential property, Keystone shall implement the following protections in addition to those set forth in its CMR Plan in areas where the Project passes within 500 feet of a residence: a) To the extent feasible, Keystone shall coordinate construction work schedules with affected residential landowners prior to the start of construction in the area of the residences. b) Keystone shall maintain access to all residences at all times, except for periods when it is infeasible to do so or except as otherwise agreed between Keystone and the occupant. Such periods shall be restricted to the minimum duration possible and shall be coordinated with affected residential landowners and occupants, to the extent possible. c) Keystone shall install temporary safety fencing, when reasonably requested by the landowner or occupant, to control access and minimize hazards associated with an open trench and heavy equipment in a residential area. d) Keystone shall notify affected residents in advance of any scheduled disruption of utilities and limit the duration of such disruption. e) Keystone shall repair any damage to property that results from construction activities. f) Keystone shall separate topsoil from subsoil and restore all areas disturbed by construction to at least their preconstruction condition. g) Except where practicably infeasible, final grading and topsoil replacement, installation of permanent erosion control structures and repair of fencing and other structures shall be completed in residential areas within 10 days after backfilling the trench. In the event that seasonal or other weather conditions, extenuating circumstances, or unforeseen developments beyond Keystone's control prevent compliance with this time frame, temporary erosion controls and appropriate mitigative measures shall be maintained until conditions allow completion of cleanup and reclamation.	In the event that Keystone constructs within 500 feet of a residence, it will implement these protective measures and those set forth in the CMR Plan.
25	Construction must be suspended when weather conditions are such that construction activities will cause irreparable damage, unless adequate protection measures approved by the Commission are taken. At least two months prior to the start of construction in South Dakota, Keystone shall file with the Commission an adverse weather land protection plan containing appropriate adverse weather land protection measures, the conditions in which such measures may be appropriately used, and conditions in which no construction is appropriate, for approval of or modification by the Commission prior to the start of construction. The Commission shall make such plan available to impacted landowners who may provide comment on such plan to the Commission	Keystone is preparing this adverse weather land protection plan and will submit it to the Commission after the plan has been completed but at least 2 months prior to start of construction in South Dakota.

NO.	CONDITION	STATUS OF OTHER MEASURES REQUIRED BY CONDITIONS
26	Reclamation and clean-up along the right-of-way must be continuous and coordinated with ongoing construction.	Keystone will implement this requirement during construction of the project.
27	All pre-existing roads and lanes used during construction must be restored to at least their pre-construction condition that will accommodate their previous use, and areas used as temporary roads during construction must be restored to their original condition, except as otherwise requested or agreed to by the landowner or any governmental authority having jurisdiction over such roadway	Keystone is coordinating with county and state road authorities during the pre-construction planning phase. Pre-construction conditions will be documented and pre-existing roads will be restored to pre-construction condition following construction. Keystone will comply with the condition with respect to temporary roads after construction.
28	Keystone shall, prior to any construction, file with the Commission a list identifying private and new access roads that will be used or required during construction and file a description of methods used by Keystone to reclaim those access roads.	The list of private and new access roads that are being planned for use on the Project is being developed. This list of roads, including the reclamation methods that will be implemented will be provided to the Commission prior to construction.
29	Prior to construction, Keystone shall have in place a winterization plan and shall implement the plan if winter conditions prevent reclamation completion until spring. The plan shall be provided to affected landowners and, upon request, to the Commission.	Keystone will develop and submit to the Commission a winterization plan which addresses these factors.
30	Numerous Conditions of this Order, including but not limited to 16, 19, 24, 25, 26, 27 and 51 relate to construction and its effects upon affected landowners and their property. The Applicant may encounter physical conditions along the route during construction which makes compliance with certain of these Conditions infeasible. If, after providing a copy of this order, including the Conditions, to the landowner, the Applicant and landowner agree in writing to modifications of one or more requirements specified in these conditions, such as maximum clearances or right-of-way widths, Keystone may follow the alternative procedures and specifications agreed to between it and the landowner.	Keystone will comply with this condition and through negotiations with the landowner and any such modifications shall be agreed upon in writing. Note: Through the SDPUC liaison, Keystone has validated a typo in this condition with John Smith, the SDPUC General Counsel. The typo occurs in the first sentence and is a reference Condition 51, which does not exist. This should actually reference Condition 45.
31	Keystone shall construct and operate the pipeline in the manner described in the application and at the hearing, including in Keystone's exhibits, and in accordance with the conditions of this permit, the PHMSA Special Permit, if issued, and the conditions of this Order and the construction permit granted herein	Keystone will comply with this condition during construction and operation of the pipeline. Keystone XL has withdrawn its application to PHMSA for a Special Permit, subject to its right to apply for a Special Permit at a later time.
32	Keystone shall require compliance by its shippers with its crude oil specifications in order to minimize the potential for internal corrosion.	Keystone will require compliance by its shippers with its crude oil tariff specifications.

NO.	CONDITION	STATUS OF OTHER MEASURES REQUIRED BY CONDITIONS
33	Keystone's obligation for reclamation and maintenance of the right-of-way shall continue throughout the life of the pipeline.	Keystone will monitor the right-of-way conditions throughout the life of the pipeline.
33.a	In its surveillance and maintenance activities, Keystone shall, and shall cause its contractor to, equip each of its vehicles, including off-road vehicles, with a hand held fire extinguisher, portable compact shovel and communication device such as a cell phone, in areas with coverage, or a radio capable of achieving prompt communication with emergency services.	Keystone will require all Operators to maintain the required equipment in all vehicles on the right-of-way during surveillance and maintenance activities.
34	In accordance with 49 C.F.R. 195, Keystone shall continue to evaluate and perform assessment activities regarding high consequence areas.	Keystone will identify and assess high consequence areas in accordance with 49 C.F.R. 195.
34.a	Prior to Keystone commencing operation, all unusually sensitive areas as defined by 49 CFR 195.6 that may exist, whether currently marked on DOT's HCA maps or not, should be identified and added to the Emergency Response Plan and Integrity Management Plan	Keystone will identify HCA's as defined at 49 CFR 195.6 and add them to the Emergency Response Plan and Integrity Management Plan.
34.b	In its continuing assessment and evaluation of environmentally sensitive and high consequence areas, Keystone shall seek out and consider local knowledge, including the knowledge of the South Dakota Geological Survey, the Department of Game Fish and Parks and local landowners and governmental officials.	Keystone has conducted numerous consultations with South Dakota state agencies, local agencies and landowners and essentially concluded the assessment and evaluation of environmentally sensitive and high consequence areas and has concurrence from stakeholders related to construction and restoration plans within these areas. If new or different information on environmentally sensitive and high consequence areas becomes available, Keystone will assess that information.
35	The evidence in the record demonstrates that in some reaches of the Project in southern Tripp County, the High Plains Aquifer is present at or very near ground surface and is overlain by highly permeable sands permitting the uninhibited infiltration of contaminants. This aquifer serves as the water source for several domestic farm wells near the pipeline as well as public water supply system wells located at some distance and upgradient from the pipeline route. Keystone shall identify the High Plains Aquifer area in southern Tripp County as a hydrologically sensitive area in its Integrity Management and Emergency Response Plans. Keystone shall similarly treat any other similarly vulnerable and beneficially useful surficial aquifers of which it becomes aware during construction and continuing route evaluation	Keystone will identify the High Plains Aquifer area in southern Tripp County and any other similarly vulnerable and beneficially useful surficial aquifers as a hydrologically sensitive area in its Integrity Management and Emergency Response Plans.

NO.	CONDITION	STATUS OF OTHER MEASURES REQUIRED BY CONDITIONS
36	Prior to putting the Keystone Pipeline into operation, Keystone shall prepare, file with PHMSA and implement an emergency response plan as required under 49 CFR 194 and a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies as required under 49 CFR 195.402. Keystone shall also prepare and implement a written integrity management program in the manner and at such time as required under 49 CFR 195.452. At such time as Keystone files its Emergency Response Plan and Integrity Management Plan with PHMSA or any other state or federal agency, it shall also file such documents with the Commission. The Commission's confidential filing rules found at ARSD 20:10:01:41 may be invoked by Keystone with respect to such filings to the same extent as with all other filings at the Commission. If information is filed as "confidential," any person desiring access to such materials or the Staff or the Commission may invoke the procedures of ARSD 20:10:01 :41 through 20: 10:01 :43 to determine whether such information is entitled to confidential treatment and what protective provisions are appropriate for limited release of information found to be entitled to confidential treatment.	Keystone will file its Emergency Response Plan and Integrity Management Plan with the Commission upon filing with PHMSA and will invoke the Commission's confidential filing rules.
37	To facilitate periodic pipeline leak surveys during operation of the facilities in wetland areas, a corridor centered on the pipeline and up to 15 feet wide shall be maintained in an herbaceous state. Trees within 15 feet of the pipeline greater than 15 feet in height may be selectively cut and removed from the permanent right-of-way.	Keystone will maintain a corridor centered on the pipeline and up to 15 feet wide in an herbaceous state to facilitate periodic pipeline leak surveys during operation of the facilities in wetland areas.
38	To facilitate periodic pipeline leak surveys in riparian areas, a corridor centered on the pipeline and up to 10 feet wide shall be maintained in an herbaceous state.	Keystone will maintain a corridor centered on the pipeline and up to 10 feet wide in an herbaceous state to facilitate periodic pipeline leak surveys during operation of the facilities in riparian areas.
39	Except to the extent waived by the owner or lessee in writing or to the extent the noise levels already exceed such standard, the noise levels associated with Keystone's pump stations and other noise-producing facilities will not exceed the L 1 0=55dbA standard at the nearest occupied, existing residence, office, hotel/motel or non-industrial business not owned by Keystone. The point of measurement will be within 100 feet of the residence or business in the direction of the pump station or facility. Post-construction operational noise assessments will be completed by an independent third-party noise consultant, approved by the Commission, to show compliance with the noise level at each pump station or other noise-producing facility. The noise assessments will be performed in accordance with applicable American National Standards Institute standards. The results of the assessments will be filed with the Commission. In the event that the noise level exceeds the limit set forth in this condition at any pump station or other noise producing facility, Keystone shall promptly implement noise mitigation measures to bring the facility into compliance with the limits set forth in this condition and shall report to the Commission concerning the measures taken and the results of post-mitigation assessments demonstrating that the noise limits have been met.	Keystone will design pump stations and other noise-producing facilities so that noise will not exceed the L 1 0 = 55dbA standard at the nearest occupied receptor (existing residence, office, hotel/motel or non-industrial business not owned by Keystone). Keystone will utilize a third-party noise consultant, approved by the Commission, to show post-construction compliance with the noise level at each pump station or other noise-producing facility and will file the assessments with the Commission.

NO.	CONDITION	STATUS OF OTHER MEASURES REQUIRED BY CONDITIONS
40	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 with piping that is resistant to permeation by BTEX.	Keystone will replace polyethylene water piping located within 500 feet of the Project with piping that is resistant to permeation by BTEX when requested and provided access by the landowner or a public water supply system.
40.a	Keystone shall publish a notice in each newspaper of general circulation in each county through which the Project will be constructed advising landowners and public water supply systems of this condition.	Keystone will publish a notice in each newspaper of general circulation in each county through which the Project will be constructed advising landowners and public water supply systems of condition 40.
41	Keystone shall follow all protection and mitigation efforts as identified by the U.S. Fish and Wildlife Service ("USFWS") and SDGFP	Keystone is currently involved in consultation with the USFWS and SDGFP and will follow protection and mitigation efforts agreed to during consultation with the agencies.
41.a	Keystone shall identify all greater prairie chicken and greater sage and sharp-tailed grouse leks within the buffer distances from the construction right of way set forth for the species in the FE IS and Biological Assessment (BA) prepared by DOS and USFWS	Keystone is involved in consultations with SDGFP to identify greater prairie chicken and greater sage and sharp-tailed grouse leks and to develop construction mitigation plans for each species.
41.b	In accordance with commitments in the FEIS and BA, Keystone shall avoid or restrict construction activities as specified by USFWS within such buffer zones between March 1 and June 15 and for other species as specified by USFW Sand SDGFP.	Keystone will address this requirement during pre-construction planning efforts.
42	Keystone shall keep a record of drain tile system information throughout planning and construction, including pre-construction location of drain tiles. Location information shall be collected using a sub-meter accuracy global positioning system where available or, where not available by accurately documenting the pipeline station numbers of each exposed drain tile.	Records will be kept of drain tile system information.
42.a	Keystone shall maintain the drain tile location information and tile specifications and incorporate it into its Emergency Response and Integrity Management Plans where drains might be expected to serve as contaminant conduits in the event of a release.	Keystone will maintain the drain tile location information and tile specifications and incorporate it into its Emergency Response and Integrity Management Plans where drains might be expected to serve as contaminant conduits in the event of a release.
42.b	If drain tile relocation is necessary, the applicant shall work directly with landowner to determine proper location.	Keystone will work directly with landowner to determine proper location should drain tile relocation be necessary.

NO.	CONDITION	STATUS OF OTHER MEASURES REQUIRED BY CONDITIONS
42.c	The location of permanent drain tiles shall be noted on as-built maps. Qualified drain tile contractors shall be employed to repair drain tiles.	Keystone will identify the location of permanent drain tiles on as-built maps. Keystone will employ qualified drain tile contractors to repair drain tiles impacted by the project.
43	Keystone shall follow the "Unanticipated Discoveries Plan," as reviewed by the State Historical Preservation Office ("SHPO") and approved by the DOS and provide it to the Commission upon request. Ex TC-1.6.4, pp. 94-96; Ex S-3.	Keystone will comply with the "Unanticipated Discoveries Plan," as reviewed by the State Historical Preservation Office ("SHPO") and approved by the DOS and will provide the plan to the Commission upon request.
43.a	If during construction, Keystone or its agents discover what may be an archaeological resource, cultural resource, historical resource or gravesite, Keystone or its contractors or agents shall immediately cease work at that portion of the site and notify the DOS, the affected landowner(s) and the SHPO.	Keystone will comply with this condition during construction.
43.b	If the DOS and SHPO determine that a significant resource is present, Keystone shall develop a plan that is approved by the DOS and commenting/signatory parties to the Programmatic Agreement to salvage avoid or protect the archaeological resource.	Keystone will develop a treatment plan that is approved by the DOS and commenting/signatory parties to the Programmatic Agreement to salvage, avoid, or protect an archaeological resource that DOS and SHPO determine as significant.
43.c	If such a plan will require a materially different route than that approved by the Commission, Keystone shall obtain Commission and landowner approval for the new route before proceeding with any further construction.	Keystone will obtain approval from the Commission and affected landowner(s) for any materially different route that may be required as a result of unanticipated discoveries prior to further construction.
43.d	Keystone shall be responsible for any costs that the landowner is legally obligated to incur as a consequence of the disturbance of a protected cultural resource as a result of Keystone's construction or maintenance activities.	Keystone will be responsible for costs that the landowner is legally obligated to incur as a consequence of the disturbance of a protected cultural resource as a result of Keystone's construction or maintenance activities.
44.a	Prior to commencing construction, Keystone shall conduct a literature review and records search, and consult with the BLM and Museum of Geology at the S.D. School of Mines and Technology ("SDSMT") to identify known fossil sites along the pipeline route and identify locations of surface exposures of paleontologically sensitive rock formations using the BLM's Potential Fossil Yield Classification system.	Keystone is currently completing consultations with the BLM and Museum of Geology at the S.D. School of Mines and Technology ("SDSMT") to identify known fossil sites along the pipeline route and identify locations of surface exposures of paleontologically sensitive rock formations using the BLM's Potential Fossil Yield Classification system.
44.a.1	Any area where trenching will occur into the Hell Creek Formation shall be considered a high probability area.	Keystone has identified locations along the pipeline route where trenching will occur into the Hell Creek Formation and has identified these locations as areas of high probability to yield fossils.

NO.	CONDITION	STATUS OF OTHER MEASURES REQUIRED BY CONDITIONS
44.b	Keystone shall at its expense conduct a pre-construction field survey of each area identified by such review and consultation as a known site or high probability area within the construction ROW. Following BLM guidelines as modified by the provisions of Condition 44, including the use of BLM permitted paleontologists, areas with exposures of high sensitivity (PFYC Class 4) and very high sensitivity (PFYC Class 5) rock formations shall be subject to a 100% pedestrial field survey, while areas with exposures of moderately sensitive rock formations (PFYC Class 3) shall be spot-checked for occurrences of scientifically or economically significant surface fossils and evidence of subsurface fossils. Scientifically or economically significant surface fossils shall be avoided by the Project or mitigated by collecting them if avoidance is not feasible. Following BLM guidelines for the assessment and mitigation of paleontological resources, scientifically significant paleontological resources are defined as rare vertebrate fossils that are identifiable to taxon and element, and common vertebrate fossils that are identifiable to taxon and element and that have scientific research value; and scientifically noteworthy occurrences of invertebrate, plant and trace fossils. Fossil localities are defined as the geographic and stratigraphic locations at which fossils are found	Keystone has conducting pre-construction field surveys of each area identified as high probability to yield fossils within the construction ROW. Keystone is conducting pedestrial field surveys of 100% of areas with exposures of high sensitivity (PFYC Class 4) and very high sensitivity (PFYC Class 5) rock formations utilizing the BLM guidelines as modified by the provisions of Condition 44, including the use of BLM permitted paleontologists. Additionally, Keystone is spot-checking areas of moderately sensitive rock formations (PFYC Class 3). Keystone will avoid scientifically or economically significant surface fossils or will mitigate by collecting them if avoidance is not feasible.
44.c	Following the completion of field surveys, Keystone shall prepare and file with the Commission a paleontological resource mitigation plan. The mitigation plan shall specify monitoring locations, and include BLM permitted monitors and proper employee and contractor training to identify any paleontological resources discovered during construction and the procedures to be followed following such discovery. Paleontological monitoring will take place in areas within the construction ROW that are underlain by rock formations with high sensitivity (PFYC Class 4) and very high sensitivity (PFYC Class 5), and in areas underlain by rock formations with moderate sensitivity (PFYC Class 3) where significant fossils were identified during field surveys.	Keystone will prepare and file with the Commission a paleontological resource mitigation plan upon completion of survey.

NO.	CONDITION	STATUS OF OTHER MEASURES REQUIRED BY CONDITIONS
44.d	If during construction, Keystone or its agents discover what may be a paleontological resource of economic significance, or of scientific significance, as defined in subparagraph (b) above, Keystone or its contractors or agents shall immediately cease work at that portion of the site and, if on private land, notify the affected landowner(s). Upon such a discovery, Keystone's paleontological monitor will evaluate whether the discovery is of economic significance, or of scientific significance as defined in subparagraph (b) above. If an economically or scientifically significant paleontological resource is discovered on state land, Keystone will notify SDSMT and if on federal land, Keystone will notify the BLM or other federal agency. In no case shall Keystone return any excavated fossils to the trench. If a qualified and BLM-permitted paleontologist, in consultation with the landowner, BLM, or SDSMT determines that an economically or scientifically significant paleontological resource is present, Keystone shall develop a plan that is reasonably acceptable to the landowner(s), BLM, or SDSMT, as applicable, to accommodate the salvage or avoidance of the paleontological resource to protect or mitigate damage to the resource. The responsibility for conducting such measures and paying the costs associated with such measures, whether on private, state or federal land, shall be borne by Keystone to the same extent that such responsibility and costs would be required to borne by Keystone on BLM managed lands pursuant to BLM regulations and guidelines, including the BLM Guidelines for Assessment and Mitigation of Potential Impacts to Paleontological Resources, except to the extent factually inappropriate to the situation in the case of private land (e.g. museum curation costs would not be paid by Keystone in situations where possession of the recovered fossil(s) was turned over to the landowner as opposed to curation for the public). If such a plan will require a materially different route than that approved by the Commission, Keystone shall obtain Commission approval for the new route before proceeding with any further construction. Keystone shall, upon discovery and salvage of paleontological resources either during pre-construction surveys or construction and monitoring on private land, return any fossils in its possession to the landowner of record of the land on which the fossil is found. If on state land, the fossils and all associated data and documentation will be transferred to the SDSM; if on federal land, to the BLM.	Keystone will comply with this condition during construction.
44.e	To the extent that Keystone or its contractors or agents have control over access to such information, Keystone shall, and shall require its contractors and agents to, treat the locations of sensitive and valuable resources as confidential and limit public access to this information.	To the extent that Keystone or its contractors or agents have control over access to such information, Keystone will, and will require its contractors and agents to treat the locations of sensitive and valuable resources as confidential and limit public access to this information.

NO.	CONDITION	STATUS OF OTHER MEASURES REQUIRED BY CONDITIONS
45	Keystone shall repair or replace all property removed or damaged during all phases of construction and operation of the proposed transmission facility, including but not limited to, all fences, gates and utility, water supply, irrigation or drainage systems.	Keystone will repair or replace all property removed or damaged during all phases of construction and operation of the proposed transmission facility.
45.a	Keystone shall compensate the owners for damages or losses that cannot be fully remedied by repair or replacement, such as lost productivity and crop and livestock losses or loss of value to a paleontological resource damaged by construction or other activities.	Keystone will compensate the owners for damages or losses that result from construction and operation of the proposed transmission facility and cannot be fully remedied by repair or replacement.
46	In the event that a person's well is contaminated as a result of construction or pipeline operation, Keystone shall pay all costs associated with finding and providing a permanent water supply that is at least of similar quality and quantity; and any other related damages, including but not limited to any consequences, medical or otherwise, related to water contamination.	Keystone will pay all costs associated with finding and providing a permanent water supply that is at least of similar quality and quantity and any other related damages related to water contamination in the event that a well is contaminated as a result of construction or pipeline operation.
47	Any damage that occurs as a result of soil disturbance on a persons' property shall be paid for by Keystone	Keystone will compensate for damage that occurs as a result of soil disturbance on a persons' property caused by construction and operation of the Project.
48	No person will be held responsible for a pipeline leak that occurs as a result of his/her normal farming practices over the top of or near the pipeline	Keystone will not hold any person responsible for a pipeline leak that occurs as a result of normal farming practices.
49	Keystone shall pay commercially reasonable costs and indemnify and hold the landowner harmless for any loss, damage, claim or action resulting from Keystone's use of the easement, including any resulting from any release of regulated substances or from abandonment of the facility, except to the extent such loss, damage claim or action results from the gross negligence or willful misconduct of the landowner or its agents.	Keystone will pay commercially reasonable costs and indemnify and hold the landowner harmless for any loss, damage, claim or action resulting from Keystone's use of the easement, including any resulting from any release of regulated substances or from abandonment of the facility, except to the extent such loss, damage claim or action results from the gross negligence or willful misconduct of the landowner or its agents.
50	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 this permit or otherwise having standing to obtain enforcement of the conditions of this Order and Permit.	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 this permit or otherwise having standing to obtain enforcement of the conditions of this Order and Permit.

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KEYSTONE XL PROJECT

CONSTRUCTION, MITIGATION, AND RECLAMATION PLAN

April 2012
~~November 2008~~
Rev. 4~~1~~

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CONSTRUCTION MITIGATION AND RECLAMATION PLAN

9.0 DRAWINGS AND FIGURES

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1.0 INTRODUCTION

The construction, mitigation, and reclamation requirements described in this Plan apply to work on all of TransCanada Keystone Pipeline, L.P.'s (Keystone's) Keystone XL Project (Project) lands, including the following;

- uplands, including agricultural (cultivated or capable of being cultivated) lands, pasture lands; range lands; grass lands; forested lands; lands in residential, commercial, or industrial areas; lands in public rights of way; and lands in private rights-of-way;
- wetlands; and
- waterbodies and riparian areas.

Keystone, during the construction, operation, and maintenance of the Project, shall implement the construction, mitigation, and reclamation actions contained in this Plan to the extent that they do not conflict with the requirements of any applicable federal, state, or local rules and regulations, or other permits or approvals that are applicable to the Project. Additionally, Keystone may deviate from specific requirements of this Plan on specific private lands as agreed to by landowners or as required to suit actual site conditions as determined and directed by Keystone. All work must be in compliance with federal, state, and local permits.

The Project will be designed, constructed, operated and maintained in a manner that meets or exceeds applicable industry standards and regulatory requirements. Keystone's Integrity Management Plan and Emergency Response Plan outlines the preventative maintenance, inspection, line patrol, leak detection systems, SCADA, and other pipeline integrity management procedures to be implemented during operation of the Project.

2.0 GENERAL CONDITIONS

2.1 Training

Experienced, well-trained personnel are essential for the successful implementation of this Plan. Keystone and its Contractors shall undergo prevention and response, as well as safety training. The program shall be designed to improve awareness of safety requirements, pollution control laws and procedures, and proper operation and maintenance of equipment.

The construction contractor (Contractor), and all of his subcontractors shall ensure that persons engaged in Project construction are informed of the construction issues and concerns and that they attend and receive training regarding these requirements as well as all laws, rules and regulations applicable to the work. Prior to construction, all Project personnel will be trained on environmental permit requirements and environmental specifications, including fuel handling and storage, cultural resource protection methods, stream and wetland crossing requirements, and sensitive species protection measures.

Different levels of training shall be required for different groups of Contractor personnel. Contractor supervisors, managers, field foremen, and other Contractor personnel designated by Keystone shall attend a comprehensive environmental training session. All other Contractor personnel shall attend a training session before the beginning of construction and during construction as environmental issues and incidents warrant. Additional training sessions shall be held for newly assigned personnel prior to commencing work on the Project.

All Contractor personnel shall attend the training session prior to entering the construction right-of-way. All Contractor personnel shall sign an acknowledgement of having attended the appropriate level of training and shall display a hard hat sticker that signifies attendance at environmental training. In order to ensure successful compliance, Contractor personnel shall attend repeat or supplemental training if compliance is not satisfactory or as new, significant new issues arise.

All visitors and any other personnel without specific work assignments shall be required to attend a safety and environmental awareness orientation.

2.2 Environmental Inspection

Keystone will use Environmental Inspectors on each construction spread. The Environmental Inspectors will review the Project activities daily for compliance with state, federal and local regulatory requirements. The Environmental Inspectors will have the authority to stop specific tasks as approved by the Chief Inspector. They can also order corrective action in the event that construction activities violate the provisions of this Plan, landowner requirements, or any applicable permit requirements.

2.3 Advance Notice of Access to Property Prior to Construction

Prior to initially accessing landowners' property, Keystone shall provide the landowner or tenant with a minimum of 24 hours prior notice unless otherwise negotiated with the landowner and as described in the Project line list). Additionally, the landowner or tenant shall be provided with Keystone contact information. Landowners may utilize contact information to inform Keystone of any concerns related to construction.

Prior notice shall consist of a personal contact, a telephone contact, or delivery of written notice to the landowner to inform the landowner of whereby the landowner or tenant is informed of Keystone's intent to initially access the land. The landowner or tenant need not acknowledge receipt of written notice before Keystone can enter the landowner's property.

Keystone will coordinate with managers of public lands to reduce conflicts between construction activities and recreational uses. Keystone will consult with land managers on state and federal lands regarding any necessary construction and maintenance restrictions consistent with management and use of such lands. Damages from disruption of recreational uses of private lands will be the subject of compensation negotiations with individual landowners.

If pipeline activities occur during the winter season Keystone will consult with the appropriate regulatory agencies to establish the appropriate protective measures to avoid or mitigate wildlife seasonal, timing or migration concerns.

2.4 Other Notifications

The Contractor shall notify, in writing, both Keystone and the authority having jurisdiction over any road, railroad, canal, drainage ditch, river, foreign pipeline, or other utility to be crossed by the pipeline at least 48 hours (excluding Saturdays, Sundays, and statutory holidays), or as specified on the applicable permit(s), prior to commencement of pipeline construction, in order that the said authority may appoint an inspector to ensure that the crossing is constructed in a satisfactory manner.

The Contractor shall notify Keystone immediately of any spill of a potentially hazardous substance that creates a sheen on a wetland or waterbody, as well as any existing soil contamination discovered during construction.

The Contractor shall immediately notify Keystone of the discovery of previously unreported historic property, other significant cultural materials, or suspected human remains uncovered during pipeline construction.

The Contractor shall immediately notify Keystone of a Project-related injury to or mortality of a threatened or endangered animal.

2.5 Damages to Private Property

Pipeline construction activities shall be confined to the construction right-of-way, temporary work space, additional temporary work space, and approved access routes.

Keystone shall reasonably compensate landowners for any construction-related damages caused by Keystone which occur on or off of the established pipeline construction right-of-way.

Keystone shall reasonably compensate landowners for damages to private property caused by Keystone beyond the initial construction and reclamation of the pipeline, to include those damages caused by Keystone during future construction, operation, maintenance, and repairs relating to the pipeline.

2.6 Appearance of Worksite

The construction right-of-way shall be maintained in a clean, neat condition at all times. At no time shall litter be allowed to accumulate at any location on the construction right-of-way. The Contractor shall provide a daily garbage detail with each major construction crew to keep the construction right-of-way clear of trash, pipe banding and spacers, waste from coating products, welding rods, timber skids, defective materials and all construction and other debris immediately behind construction operations unless otherwise approved by Keystone. Paper from wrapping or coating products or lightweight items shall not be permitted to be scattered by the wind.

The traveled surfaces of roads, streets, highways, etc. (and railroads when applicable) shall be cleaned free of mud, dirt, or any debris deposited by equipment traversing these roads or exiting from the construction right-of-way.

2.7 Access

Prior to the pipeline's installation, Keystone and the landowner shall reach a mutually acceptable agreement on the route that shall be utilized by the Contractor for entering and exiting the pipeline construction right-of-way should access to the construction right-of-way not be practicable or feasible from adjacent segments of the pipeline construction right-of-way, public road, or railroad right-of-way.

All construction vehicles and equipment traffic shall be confined to the public roads, private roads acquired for use by Keystone, and the construction right-of-way. If temporary private access roads are constructed, they shall be designed to maintain proper drainage and shall be built to minimize soil erosion.

Sufficiently sized gaps shall be left in all spoil and topsoil wind rows and a hard or soft plug shall be left in the trench at all temporary private access roads and obvious livestock or wildlife trails unless the landowner agrees prior to construction that these access points can be blocked during construction.

All construction-related private roads and access points to the right-of-way shall be marked with signs. Any private roads not to be utilized during construction shall also be marked.

~~Keystone will develop a site-specific crossing plan for the Corps Fee Title Lands to address the primary concerns of limited access and conflicts with hunters during construction.~~

2.8 Aboveground Facilities

Locations for aboveground facilities shall be selected in a manner so as to be as unobtrusive as reasonably possible to ongoing agricultural or other landowner activities occurring on the lands adjacent to the facilities. If it is not feasible, to avoid interference, such activities shall be located so as to incur the least hindrance to the adjacent agricultural operations (i.e., located in field corners or areas where at least one side is not used for cropping purposes) provided the location is consistent with the design constraints of the pipeline. Aboveground facilities shall avoid floodplains and wetlands to the maximum extent possible. Additionally, they shall be located to avoid existing drain tile systems to the extent possible. To further reduce visual impacts from aboveground pipeline facilities and structures, Keystone will comply with standard industry painting practices with respect to aboveground facilities. Keystone will address any visual aesthetics issues with landowners in individual consultations.

2.9 Minimum Depth of Cover

The pipeline shall be installed so that the top of the pipe and coating is a minimum depth of 5 feet below the bottom of waterbodies including rivers, creeks, streams, ditches, and drains. This depth shall normally be maintained over a distance of 15 feet on each side of the waterbody measured from the top of the defined stream channel. If concrete weights or concrete coated pipe is utilized for negative buoyancy of the pipeline, the minimum depth of cover shall be measured from the top of the concrete to the original ground contour. The following table indicates standard depths that would apply to pipeline construction.

Location	Normal Excavation (inches)	For Rock Excavation (inches
Most areas	48	36
All waterbodies	60	36
Dry creeks, ditches, drains, washes, gullies, etc.	60	36
Drainage ditches at public roads and railroads	60	48

Depth of cover requirements may be modified by Keystone based on site-specific conditions. However, all depths shall be in compliance with all established codes.

2.10 Non-Hazardous Waste Disposal

Non-hazardous pipeline construction wastes include human waste, trash, pipe banding and spacers, waste from coating products, welding rods, timber skids, cleared vegetation, stumps, and rock.

All waste which contains (or at any time contained) oil, grease, solvents, or other petroleum products falls within the scope of the oil and hazardous substances control, cleanup, and disposal procedures. This material shall be segregated for handling and disposal as hazardous wastes.

The Contractor shall be responsible for ensuring that human wastes are handled and disposed of exclusively by means of portable, self-contained toilets during all construction operations. Wastes from these units shall be collected by a licensed contractor for disposal only at licensed and approved facilities.

The Contractor shall remove all trash from the construction right-of-way on a daily basis unless otherwise approved or directed by Keystone.

The Contractor shall dispose of HDD drill cuttings and drilling mud at a Keystone-approved location. Disposal options may include spreading over the construction right-of-way in an upland location approved by Keystone, or hauling to an approved licensed landfill or other site approved by Keystone.

The Contractor shall remove all extraneous vegetative, rock, and other natural debris from the construction right-of-way by the completion of cleanup

The Contractor shall remove all trash and wastes from Contractor yards, and Pipe Stockpipe Sites, and staging areas when work is completed at each location.

The Contractor shall dispose of all waste materials at licensed waste disposal facilities. Wastes shall not be disposed of in any other fashion such as un-permitted burying or burning.

2.11 Hazardous Wastes

The Contractor shall ensure that all hazardous and potentially hazardous materials are transported, stored, and handled in accordance with all applicable legislation. Workers exposed to or required to handle dangerous materials shall be trained in accordance with the applicable regulator and the manufacturer's recommendations.

The Contractor shall dispose of all hazardous materials at licensed waste disposal facilities. Hazardous wastes shall not be disposed of in any other fashion such as un-permitted burying or burning.

All transporters of oil, hazardous substances, and hazardous wastes shall be licensed and certified according to the applicable state vehicle code. Incidents on public highways shall be reported to the appropriate agencies.

All hazardous wastes being transported off-site shall be manifested. The manifest shall conform to requirements of the appropriate state agency. The transporter shall be licensed and certified to handle hazardous wastes on the public highways. The vehicles as well as the drivers must conform to all applicable vehicle codes for transporting hazardous wastes. The manifest shall conform to 49 CFR Parts 172.101, 172.202, and 172.203.

If toxic or hazardous waste materials or containers are encountered during construction, the Contractor shall stop work immediately to prevent disturbing or further disturbing the waste material and shall immediately notify Keystone. The Contractor shall not restart work until clearance is granted by Keystone.

2.12 Noise Control

The Contractor shall minimize noise during non-daylight hours and within 1 mile of residences or other noise-sensitive areas such as hospitals, motels or campgrounds. Keystone shall abide by all applicable noise regulations regarding noise near residential and commercial/industrial areas. The Contractor shall provide notice to Keystone if noise levels are expected to exceed bylaws for a short duration. Keystone will give advanced notice to landowners within 500 feet of right-of-way prior to construction, limit the hours during which construction activities with high-decibel noise levels are conducted, coordinate work schedules, and ensure that construction proceeds quickly through such areas. The Contractor shall minimize noise in the immediate vicinity of herds of livestock or poultry operations, which are particularly sensitive to noise.

Keystone will set up a toll-free telephone line for landowners to report any construction noise-related issues.

2.13 Weed Control

Keystone will prepare a weed management plan for each state crossed by the project, as required. In general, these plans will consider the following measures listed below.

Prior to mobilization for the Project, the Contractor shall thoroughly clean all construction equipment, including timber mats, prior to moving the equipment to the job site to limit the potential for the spread of noxious weeds, insects and soil-borne pests. The Contractor shall clean the equipment with high-pressure washing equipment.

Prior to construction, Keystone will mark all areas of the right-of-way which contain infestations of noxious, invasive species or soil-borne pests. Such marking will clearly indicate the limits of the infestation along the right-of-way. During construction, the Contractor shall clean the tracks, tires, and blades of equipment by hand (track shovel) or compressed air to remove excess soil prior to movement of equipment out of weed or soil-borne pest infested areas or utilize cleaning stations to remove vegetative materials using water under high pressure (see detail Drawings 30 and 31).

In areas of isolated weed populations, the Contractor shall strip topsoil from the full width of the construction right-of-way and store the topsoil separately from other topsoil and subsoil. The Environmental Inspectors will identify these locations in the field prior to grading activities.

The Contractor shall use mulch and straw or hay bales that are free of noxious weeds for temporary erosion and sediment control.

The Contractor shall implement pre-construction treatments such as mowing prior to seed development or herbicide application to areas of noxious weed infestation prior to other clearing, grading, trenching, or other soil disturbing work at locations identified in the construction drawings.

Keystone will implement Best Management Practices (BMPs) for conducting vegetation control where necessary before and after construction. Typical agricultural herbicides, developed in consultation with county or state regulatory agencies, will be used. Herbicide types will be determined based on the weed species requiring control. The Contractor shall apply herbicides, where required, within one week, or as deemed necessary for optimum mortality success, prior to disturbing the area by clearing, grading, trenching, or other soil disturbing work. Herbicides shall be applied by applicators appropriately licensed or certified by the state in which the work is conducted. All herbicides applied prior to construction shall be non-residual or shall have a significant residual effect no longer than 30 days. Herbicides applied during construction shall be non-residual. Keystone will implement BMPs in the use of pesticides and herbicides along the pipeline corridor to reduce potential impacts to avian and wildlife species.

The Contractor shall not use herbicides in or within 100 feet of a wetland or waterbody.

After pipeline construction, on any construction right-of-way over which Keystone will retain control over the surface use of the land after construction (i.e., valve sites, metering stations, pump stations, etc.), Keystone shall provide for weed control to limit the potential for the spread of weeds onto adjacent lands used for agricultural purposes. Any weed control spraying performed by Keystone shall be done by a state-licensed pesticide applicator.

Keystone shall be responsible for reimbursing all reasonable costs incurred by owners of land adjacent to aboveground facilities when the landowners must control weeds on their land which can be reasonably determined to have spread from land occupied by Keystone's aboveground facilities.

2.14 Dust Control

The Contractor shall at all time control airborne dust levels during construction activities to levels acceptable to Keystone. The Contractor shall employ water trucks, sprinklers or calcium chloride as necessary to reduce dust to acceptable levels. Utilization of calcium chloride is limited to roads.

Dust shall be strictly controlled where the work approaches dwellings, farm buildings, and other areas occupied by people and when the pipeline parallels an existing road or highway. This shall also apply to access roads where dust raised by construction vehicles may irritate or inconvenience local residents. The speed of all Contractor vehicles shall be controlled in these areas. Emissions from construction equipment combustion, open burning, and temporary fuel transfer systems and associated tanks will be controlled to the extent required by state and local agencies through the permit process.

The Contractor shall take appropriate precautions to prevent fugitive emissions caused by sand blasting from reaching any residence or public building. The Contractor shall place curtains of suitable material, as necessary, to prevent wind-blown particles from sand blasting operations from reaching any residence or public building.

Additional measures may be required by state regulations or local ordinances. The Contractor will comply with all applicable state regulations and local ordinances with respect to truck transportation and fugitive dust emissions.

2.15 Off Road Vehicle Control

Keystone shall offer to landowners or managers of forested lands to install and maintain measures to control unauthorized vehicle access to the construction right-of-way where appropriate. These measures may include the following unless otherwise approved or directed by Keystone based on site specific conditions or circumstances:

- signs;
- fences with locking gates;
- slash and timber barriers, pipe barriers, or boulders lined across the construction right-of-way; and
- conifers or other appropriate trees or shrubs across the construction right-of-way.

2.16 Fire Prevention and Control

The Contractor shall comply with all federal, state, county and local fire regulations pertaining to burning permits and the prevention of uncontrolled fires. The following mitigative measures shall be implemented to prevent fire hazards and control of fires:

- A list of relevant fire authorities and their designated representative to contact shall be maintained on site by construction personnel.
- Adequate fire fighting equipment shall be available on site in accordance with the applicable regulatory requirements shall be available on site.
- The level of forest fire hazard shall be posted at the construction office (where visible for workers) and workers shall be made aware of the hazard level and related implications.
- The Contractor shall provide equipment to handle any possible fire emergency. This shall include, although not be limited to, water trucks; portable water pumps; chemical fire extinguishers; hand tools such as shovels, axes, and chain saws; and heavy equipment adequate for the construction of fire breaks when needed.
- Specifically, the Contractor shall supply and maintain in working order an adequate supply of fire extinguishers for each crew engaged in potentially combustible work such as welding, cutting, grinding, and burning of brush or vegetative debris.

- In the event of a fire, the Contractor shall immediately use resources necessary to contain the fire. The Contractor shall then notify local emergency response personnel.
- All tree clearing activities are to be carried out in accordance with local rules and regulations for the prevention of forest fires.
- Burning shall be done in compliance with state, county, or local applicable regulations.
- Any burning will be done within the right-of-way. Only small piles shall be burned to avoid overheating or damage to trees or other structures along the right-of-way.
- Flammable wastes shall be removed from the construction site on a regular basis.
- Flammable materials kept on the construction site must be stored in approved containers away from ignition sources.
- Smoking shall be prohibited around flammable materials.
- Smoking shall be prohibited on the entire construction site when the fire hazard is high.

2.17 Road and Railroad Crossings

Construction across paved roads, highways, and railroads will be in accordance with the requirements of the road and railroad crossing permits and approvals obtained by Keystone. In general, all major paved roads, all primary gravel roads, highways, and railroads will be crossed by boring beneath the road or railroad. Detail drawing 21 illustrates a typical bored road or railroad crossing. Boring requires the excavation of a pit on each side of the feature, the placement of boring equipment in the pit, and boring a hole under the road at least equal to the diameter of the pipe. ~~Once the hole is bored, a prefabricated pipe section will be pulled through the borehole.~~ For long crossings, sections can be welded onto the pipe string just before being pulled through the borehole. Boring will result in minimal or no disruption to traffic at road or railroad crossings. Each boring will be expected to take 1 to 2 days for most roads and railroads and up to 10 days for long crossings such as interstate or four-lane highways.

Most smaller, unpaved roads and driveways will be crossed using the open-cut method where permitted by local authorities or private owners. The open-cut method will require temporary closure of the road to traffic and establishment of detours. If no reasonable detour is feasible, at least one lane of traffic will be kept open, except during brief periods when it is essential to close the road to install the pipeline. Most open-cut road crossings can be finished and the road resurfaced in 1 or 2 days. Keystone will take measures, such as posting signs at open-cut road crossings, to ensure safety and minimize traffic disruptions.

2.18 Adverse Weather

The Contractor shall restrict certain construction activities and work in cultivated agricultural areas in excessively wet soil conditions to minimize rutting and soil compaction. In determining when or where construction activities should be restricted or suspended during wet conditions, the Contractor shall consider the following factors:

- the extent that rutting may cause mixing of topsoil with subsoil layers or damage to tile drains;
- excessive buildup of mud on tires and cleats;
- excessive ponding of water at the soil surface; and
- the potential for excessive soil compaction.

The Contractor shall implement mitigative measures as directed by Keystone in order to minimize rutting and soil compaction in excessively wet soil conditions which may include:

- restricting work to areas on the spread where conditions allow;
- using low ground weight, wide-track equipment, or other low impact construction techniques;
- limiting work to areas that have adequately drained soils or have a cover of vegetation ,such as sod, crops or crop residues, sufficient to prevent mixing of topsoil with subsoil layers or damage to drain tiles; and
- installing geotextile material or construction mats in problem areas.

"Stop work" authority will be designated to the chief inspector but will be implemented when recommended by the Environmental Inspector.

2.19 Cultural Resources

Keystone intends to avoid cultural resources to the extent practicable by rerouting the pipeline corridor and related appurtenances, avoiding construction activities on properties listed in or eligible for listing in the National Register of Historic Places (NRHP), as well as boring or using HDD through culturally sterile soils.

The Contractor shall implement the measures outlined in any unanticipated discovery plan or any Programmatic Agreement that is adopted to minimize disturbance to cultural sites and shall take immediate action as outlined in the Programmatic Agreement if any unanticipated cultural discovery is encountered during construction.

The preferred treatment of any historical property or culturally significant site is avoidance. Where required~~necessary~~, Keystone will monitor the construction spread using a cultural resource monitor working under the direction of a professional who meets the standards of the *Secretary of the Interior's Historic*

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Preservation Professional Qualification Standards (48 FR 44716, September 29, 1983).

Prior to commencing construction, Keystone also will provide an appropriate level of training to all construction personnel so that the requirements of any unanticipated discovery plan or Programmatic Agreement are understood and unanticipated discoveries quickly identified.

In the event an unanticipated cultural discovery is made, the Contractor will immediately halt all construction activities within a 100-foot radius, including traffic; notify the Keystone Environmental Inspector; and implement interim measures to protect the discovery from looting or vandalism. The appropriate federal, state, local, or tribal authorities will be notified of discovery within 48 hours of the initial find. Construction will not proceed within the 100-foot radius of discovery site until all mitigation measures defined in the Programmatic Agreement are concluded and Keystone receives approval from the appropriate agencies that construction may resume. No work or activity within the 100-foot buffer area may take place until approvals are communicated at the spread level by the lead Environmental Inspector.

3.0 SPILL PREVENTION AND CONTAINMENT

Spill prevention and containment applies to the use and management of hazardous materials on the construction right-of-way and all ancillary areas during construction. This includes the refueling or servicing of all equipment with diesel fuel, gasoline, lubricating oils, grease, and hydraulic and other fluids during normal upland applications and special applications within 100 feet of perennial streams or wetlands.

Keystone will prepare a project-specific Spill Prevention Containment and Countermeasure (SPCC) Plan. The Contractor shall provide additional information to complete the SPCC Plan for each construction spread, and shall provide site-specific data that meets the requirements of 40 CFR Part 112 for every location used for staging fuel or oil storage tanks and for every location used for bulk fuel or oil transfer. Each SPCC Plan will be prepared prior to introducing the subject fuel, oil, or hazardous material to the subject location.

3.1 Spill Prevention

3.1.1 Staging Areas

Staging areas (including Contractor yards and pipe stockpile sites) shall be set up for each construction spread. Bulk fuel and storage tanks will be placed only at Contractor yards. No bulk fuel and storage tanks will be placed in the construction ROW. Hazardous materials at staging areas shall be stored in compliance with federal and state laws. The following spill prevention measures shall be implemented by the Contractor:

- Contractor fuel trucks shall be loaded at existing bulk fuel dealerships or from bulk tanks set up for that purpose at the staging area. In the former case, the bulk dealer is responsible for preventing and controlling spills.

- The Environmental Inspector shall inspect the tank site for compliance with the 100-foot setback requirement and approve the tank site prior to installing bulk fuel or storage tanks on the construction yard.
- Fuels and lubricants shall be stored only at designated staging areas. Storage of fuel and lubricants in the staging area shall be at least 100 feet away from the water's edge. Refueling and lubrication of equipment shall be restricted to upland areas at least 100 feet away from ~~perennial~~ streams and wetlands.
- Contractors shall be required to perform all routine equipment maintenance at the staging area and recover and dispose of wastes in an appropriate manner.
- Fixed fuel dispensing locations will be provided with secondary containment to capture fuel from leaks, drips, and overfills.
- Temporary liners, berms, or dikes (secondary containment) shall be constructed around the aboveground bulk tanks, providing 110 percent containment volume of the largest storage tank or trailer within the containment structure, so that potential spill materials shall be contained and collected in specified areas. Tanks shall not be placed in areas subject to periodic flooding or washout.
- Drivers of tank trucks are responsible for safety and spill prevention during tank truck unloading. Procedures for loading and unloading tank trucks shall meet the minimum requirements established by the Department of Transportation.
- Drivers of tank trucks are responsible for setting brakes and chocking wheels prior to off loading. Warning signs requiring drivers to set brakes and chock wheels shall be displayed at all tanks. Proper grounding of equipment shall be undertaken during fuel transfer operations. Drivers shall observe and control the fueling operations at all times to prevent overfilling the temporary tank.
- Prior to departure of any tank truck, all vehicle outlets shall be examined closely by the driver for leakage, tightened, adjusted or replaced to prevent leakage while in transit.
- A supply of sorbent and barrier materials sufficient to allow the rapid containment and recovery of spills shall be maintained at each construction staging area. Sorbent and barrier materials shall also be utilized to contain runoff from contaminated areas.
- Shovels and drums shall be kept at each of the individual staging areas. In the event that small quantities of soil become contaminated, shovels shall be utilized to collect the soil and the material shall be stored in 55-gallon drums. Large quantities of contaminated soil may be bio-remediated on site or disposed in an approved landfill, subject to government approval, or collected utilizing heavy equipment, and

stored in drums or other suitable containers prior to disposal. Should contamination occur adjacent to staging areas as a result of runoff, shovels or heavy equipment shall be utilized to collect the contaminated material. Contaminated soil shall be disposed of in accordance with state and federal regulations.

- Temporary aboveground tanks shall be subject to visual inspection on a monthly basis and when the tank is refilled. Inspection records shall be maintained. Operators shall routinely keep tanks under close surveillance and potential leaks or spills shall be quickly detected.
- Visible fuel leaks shall be reported to the Contractors' designated representative and corrected as soon as conditions warrant. Keystone's designated representative shall be informed.
- Drain valves on temporary tanks shall be locked to prevent accidental or unauthorized discharges from the tank.
- Oil and other hazardous materials stored in 350-gallon totes, 55-gallon drums, 5-gallon pails, smaller retail-size containers or other portable containers will be staged or stored in areas with a secondary temporary containment structure. Secondary containment structures may consist of temporary earthen berms with a chemical resistant liner, or a portable containment system constructed of steel, PVC, or other suitable material. The secondary containment structure will be capable of containing 110 percent of the volume of material stored in these areas.

Keystone may allow modification of the above specifications as necessary to accommodate specific situations or procedures. Any modifications must comply with all applicable regulations and permits.

3.1.2 Construction Right-of-Way

The Contractor will ensure that all equipment is free of leaks prior to use on the Project and prior to entering or working in or near waterbodies or wetlands. Throughout construction, the Contractor will conduct regular maintenance and inspections of the equipment to reduce the potential for spills or leaks.

Rubber-tired vehicles (pickup trucks, buses) normally shall refuel at the construction staging areas or commercial gas stations. Tracked machinery (backhoes, bulldozers) shall be refueled and lubricated on the construction right-of-way. Equipment maintenance shall be conducted in staging areas when practical. When impractical, repairs to equipment can be made on the construction right-of-way when approved by Keystone's representative.

Each fuel truck that transports and dispenses fuel to construction equipment or Project vehicles along the construction ROW or within equipment staging and material areas shall carry an oil spill response kit and spill response equipment onboard at all times. In the event that response materials are depleted through use or their condition is deteriorated through age, the materials will be replenished prior to placing the fueling vehicle back into service.

The following preventive measures apply to refueling and lubricating activities on the construction right-of-way:

- Construction activities shall be conducted to allow for prompt and effective cleanup of spills of fuel and other hazardous materials. Each construction crew, including cleanup crews shall have on hand sufficient tools and material to stop leaks and supplies of absorbent and barrier materials to allow rapid containment and recovery of spilled materials. Crew members must know and follow the procedure for reporting spills.
- Refueling and lubricating of construction equipment shall be restricted to upland areas at least 100 feet away from ~~perennial~~ streams and wetlands. Where this is not possible (e.g., trench dewatering pumps), the equipment shall be fueled by designated personnel with special training in refueling, spill containment, and cleanup. The Environmental Inspector shall ensure that signs are installed identifying restricted areas.
- No fuel, oil or hazardous material storage, staging, or transfer other than refueling will occur within 100 feet of any storm drain, drop inlet, or high consequence area (HCA).
- Spent oils, lubricants, filters, etc. shall be collected and disposed of at an approved location in accordance with state and federal regulations.
- Equipment shall not be washed in streams.
- Stationary equipment will be placed within a secondary containment if it will be operated or require refueling within 100 feet of a wetland or waterbody boundary.

Keystone may allow modification of the above specifications as necessary to accommodate specific situations or procedures. Any modifications must comply with all applicable regulations and permits.

3.2 Contingency Plans

The Contractor shall develop emergency response procedures for all incidents (e.g., spills, leaks, fires) involving hazardous materials which could pose a threat to human health or the environment. The procedures shall address activities in all work areas, as well as during transport to and from the construction right-of-way and to any disposal or recycling facility.

3.3 Equipment

The Contractor shall retain emergency response equipment in all areas where hazardous materials are handled or stored. This equipment shall be readily available to respond to a hazardous material emergency. Such equipment shall include, but not be limited to, the following:

- first aid supplies;
- phone or communications radio;
- protective clothing (Tyvek suit, gloves, goggles, boots);
- hand-held fire equipment;
- absorbent material and storage containers;
- non-sparking bung wrench and shovel; and
- brooms and dust pan.

Hazardous material emergency equipment shall be carried in all mechanic and supervisor vehicles. This equipment shall include, at a minimum:

- first aid supplies;
- phone or communications radio;
- 2 sets of protective clothing (Tyvek suit, gloves, goggles, boots);
- 1 non-sparking shovel;
- 6 plastic garbage bags (20 gallon);
- 10 absorbent socks and spill pads;
- Hand-held fire extinguisher;
- barrier tape; and
- 2 orange reflector cones.

Fuel and service trucks shall carry a minimum of 20 pounds of suitable commercial sorbent material.

The Contractor shall inspect emergency equipment weekly, and service and maintain equipment regularly. Records shall be kept of all inspections and services.

3.4 Emergency Notification

Emergency notification procedures between the Contractor and Keystone shall be established in the planning stages of construction. A Keystone representative shall be identified to serve as contact in the event of a spill during construction activities. In the event of a spill meeting government reporting criteria, the Contractor immediately shall notify the Keystone representative who, in turn, shall notify the appropriate regulatory agencies.

Any material released into water that creates a sheen must be reported immediately to Keystone. The Contractor is required to notify Keystone immediately if there is any spill of oil, oil products, or hazardous materials that reaches a wetland or waterbody. Incidents on public highways shall be reported to Keystone and the appropriate agencies by Keystone.

If a spill occurs on navigable waters of the United States, Keystone shall notify the National Response Center (NRC) at 1-800-424-8802. For spills that occur on public lands, into surface waters, or into sensitive areas, the appropriate governmental agency's district office also shall be notified.

3.5 Spill Containment and Countermeasures

In the event of a spill of hazardous material, Contractor personnel shall:

- notify the appointed Keystone representative;
- identify the product hazards related to the spilled material and implement appropriate safety procedures, based on the nature of the hazard;
- control danger to the public and personnel at the site;
- implement spill contingency plans and mobilize appropriate resources and manpower;
- isolate or shutdown the source of the spill;
- block manholes or culverts to limit spill travel;
- initiate containment procedures to limit the spill to as small an area as possible to prevent damage to property or areas of environment concern (e.g., watercourses); and
- commence recovery of the spill and cleanup operations.

When notified of a spill, the Keystone representative shall immediately ensure that:

- Action is taken to control danger to the public and personnel at the site.
- Spill contingency plans are implemented and necessary equipment and manpower are mobilized.
- Measures are taken to isolate or shutdown the source of the spill.
- All resources necessary to contain, recover and clean up the spill are available.
- Any resources requested by the Contractor from Keystone are provided.
- The appropriate agencies are notified. For spills which occur on public lands, into surface waters or into sensitive areas, the appropriate federal or state managing office shall also be notified and involved in the incident.

For a land spill, berms shall be constructed with available equipment to physically contain the spill. Personnel entry and travel on contaminated soils shall be minimized. Sorbent materials shall be applied or, if necessary, heavily contaminated soils shall be removed to an approved facility. Contaminated sorbent materials and vegetation shall also be disposed of at an approved facility.

For a spill threatening a waterbody, berms or trenches shall be constructed to contain the spill prior to entry into the waterbody. Deployment of booms, skimmers, and sorbent materials shall be necessary if the spill reaches the water. The spilled product shall be recovered and the contaminated area shall be cleaned up in consultation with spill response specialists and appropriate government agencies.

4.0 UPLANDS (AGRICULTURAL, FOREST, PASTURE, RANGE AND GRASS LANDS)

4.1 Interference with Irrigation Systems

If existing irrigation systems (flood irrigation, ditch irrigation, pivot, wheel, or other type of spray irrigation systems), irrigation ditches, or sheet flow irrigation shall be impacted by the construction of the pipeline, the following mitigative measures shall be implemented unless otherwise approved or directed by Keystone:

- If it is feasible and mutually acceptable to Keystone and the landowner or landowner's designate, temporary measures shall be implemented to allow an irrigation system to continue to operate across land on which the pipeline is being constructed.
- If the pipeline or temporary work areas intersect an operational (or soon to be operational) pivot or other spray irrigation system, Keystone shall establish with the landowner or landowner's designate an acceptable amount of time the irrigation system may be out of service. If an irrigation system interruption results in crop damages, either on the pipeline construction right-of-way or off the construction right-of-way, the landowner shall be compensated reasonably for all such crop damages.
- If the pipeline or temporary work areas intersect an operational sheet flow irrigation system, Keystone shall establish with the landowner or landowner's designate an acceptable amount of time the irrigation system may be out of service. If an irrigation system interruption results in crop damages, either on the pipeline construction right-of-way or off the construction right-of-way, the landowner shall be compensated reasonably for all such crop damages.
- Irrigation ditches that are active at the time of construction shall not be stopped or obstructed except for the length of time to install the pipeline beneath the ditch (typically, one day or less) unless otherwise approved or directed by Keystone.

4.2 Clearing

The objective of clearing is to provide a clear and unobstructed right-of-way for safe and efficient construction of the pipeline. The following mitigable measures shall be implemented:

- Construction traffic shall be restricted to the construction right-of-way, existing public roads, and approved private roads.
- Construction right-of-way boundaries including pre-approved temporary workspace shall be clearly staked to prevent disturbance to unauthorized areas.
- If crops are present, they shall be mowed or disced to ground level unless an agreement is made for the landowner to remove.
- Burning is prohibited on cultivated land.
- Construction right-of-way at timber shelterbelts in agricultural areas shall be reduced to the minimum necessary to construct the pipeline.

4.3 Topsoil Removal and Storage

The objective of topsoil handling is to maintain topsoil capability by conserving topsoil for future replacement and reclamation and to minimize the degradation of topsoil from compaction, rutting, loss of organic matter, or soil mixing so that successful reclamation of the right-of-way can occur. The following mitigative measures shall be implemented during topsoil removal and storage unless otherwise approved or directed by Keystone based on site-specific conditions or circumstances. All work shall be conducted in accordance with applicable permits.

- In areas designated for topsoil segregation~~cultivated and agricultural lands~~, the actual depth of the topsoil, to a maximum depth of 12 inches, will be stripped from:
  - The area excavated above the pipeline; or
  - The area above the pipeline plus the spoil storage; or
  - The area above the pipeline plus the working side; or
  - Entire ROW

as required by applicable permit agreements with the landowner or as dictated by site-specific conditions.

- Stripped topsoil is to be stockpiled in a windrow along the edge of the right-of-way. The Contractor shall perform work in a manner to minimize the potential for subsoil and topsoil to be mixed.
- Under no circumstances shall the Contractor use topsoil to fill a low area.
- If required due to excessively windy conditions, topsoil piles shall be tackified using either water or a suitable tackifier (liquid mulch binder).
- Gaps in the rows of topsoil will be left in order to allow drainage and prevent ponding of water adjacent to or on the right-of-way.

- Topsoil shall not be utilized to construct ramps at road or waterbody crossings.

- In areas with defined saline or sodic soil concerns, a triple-ditch method will be used to segregate problem soils as indicated in Detail 67 and 67A.

- If frozen topsoil conditions are encountered during winter construction, specialized construction equipment (i.e. ripping, frozen topsoil cutter, road reclaimer, etc) may be required to adequately segregate and conserve topsoil resources.

4.4 Grading

The objective of grading is to develop a right-of-way that allows the safe passage of equipment and meets the bending limitations of the pipe. The following mitigative measures shall be implemented during grading unless otherwise approved or directed by Keystone based on site-specific conditions or circumstances. However, all work shall be conducted in accordance with applicable permits.

- All grading shall be undertaken with the understanding that original contours and drainage patterns shall be re-established to the extent practicable..
- Agricultural areas that have terraces shall be surveyed to establish pre-construction contours to be utilized for restoration of the terraces after construction.
- On steep slopes, or wherever erosion potential is high, temporary erosion control measures shall be implemented.
- Bar ditches adjacent to existing roadways to be crossed during construction shall be adequately ramped with grade or ditch spoil to prevent damage to the road shoulder and ditch.
- Where the construction surface remains inadequate to support equipment travel, timber mats, timber riprap, or other method shall be used to stabilize surface conditions.

The Contractor shall limit the interruption of the surface drain network in the vicinity of the right-of-way using the appropriate methods:

- providing gaps in the rows of subsoil and topsoil in order to prevent any accumulation of water on the land;
- preventing obstructions in furrows, furrow drains, and ditches;
- installing flumes and ramps in furrows, furrow drains, and ditches to facilitate water flow across the construction right-of-way and allow for construction equipment traffic; and

- installing flumes over the trench for any watercourse where flow is continuous during construction.

4.5 Temporary Erosion and Sediment Control

4.5.1 General

Temporary erosion and sediment control measures shall be installed immediately after initial disturbance of the soil, maintained throughout construction (on a daily basis), and reinstalled as necessary until replaced by permanent erosion control structures or restoration of the construction right-of-way is complete.

Specifications and configurations for erosion and sediment control measures may be modified by Keystone as necessary to suit actual site conditions. However, all work shall be conducted in accordance with applicable permits.

The Contractor shall inspect all temporary erosion control measures at least daily in areas of active construction or equipment operation, weekly in areas with no construction or equipment operation, and within 24 hours of each significant rainfall event of 0.5 inches or greater. The Contractor shall repair all ineffective temporary erosion control measures as expediently as practicable.

4.5.2 Sediment Barriers

Sediment barriers shall be constructed of silt fence, staked hay or straw bales, compacted earth (e.g., drivable berms across travel lanes), sand bags, or other appropriate materials.

The Contractor shall install sediment barriers in accordance with Details 1 and 2 or as otherwise approved or directed by Keystone. The Contractor is responsible for properly installing, maintaining, and replacing temporary and permanent erosion controls throughout construction and cleanup. In wetland or riparian zones, the Contractor will install sediment control structures along the construction right-of-way edges prior to vegetation removal where practicable. The aforementioned sediment barriers may be used interchangeably or together depending on site-specific conditions. In most cases, silt fence shall be utilized where longer sediment barriers are required.

Sediment barriers shall be installed below disturbed areas where there is hazard of offsite sedimentation. These areas include:

- the base of slopes adjacent to road crossings;
- the edge of the construction right-of-way adjacent to and upgradient of a roadway, flowing stream, spring, wetland, or impoundment;

- trench or test water discharge locations where required;
- where waterbodies or wetlands are adjacent to the construction right-of-way; (the Contractor shall install sediment barriers along the edge of the construction right-of-way as necessary to contain spoil and sediment within the construction right-of-way)
- across the entire construction right-of-way at flowing waterbody crossings;
- right-of-way immediately upslope of the wetland boundary at all standard (saturated or standing water) wetland crossings as necessary to prevent sediment flow into the wetland; (Sediment control barriers are not required at "dry" wetlands.)
- along the edge of the construction right-of-way within standard (saturated or standing water) wetland boundaries as necessary to contain spoil and sediment within the construction right-of-way. Sediment control barriers are not required at "dry" wetlands (Detail 8).

Sediment barriers placed at the toe of a slope shall be set a sufficient distance from the toe of the slope, if possible, in order to increase ponding volume.

Sediment control barriers shall be placed so as not to hinder construction operations. If silt fence or straw bale sediment barriers (in lieu of driveable berms) are placed across the entire construction right-of-way at waterbodies, wetlands, or upslope of roads, a provision shall be made for temporary traffic flow through a gap for vehicles and equipment to pass within the structure. Immediately following each day's shutdown of construction activities, a row of straw bales or a section of silt fence shall be placed across the upgradient side of the gap with sufficient overlap at each end of the barrier gap to eliminate sediment bypass flow, followed by bales tightly fitted to fill the gap. Following completion of the equipment crossing, the gap shall be closed using silt fence or straw bale sediment barrier.

The Contractor shall maintain straw bale and silt fence sediment barriers by removing collected sediment and replacing damaged bales. Sediment shall be removed and placed where it shall not reenter the barrier when sediment loading is greater than 40 percent or if directed by Keystone. If straw bale filters cannot be cleaned out due to access problems, the Contractor shall place a new row of sediment barriers upslope.

The Contractor shall use mulch and straw bales that are free of noxious weeds. Mulch or straw bales that contain evidence of noxious weeds or other undesirable species shall be rejected by the Contractor.

The Contractor shall remove sediment barriers, except those needed for permanent erosion and sediment control, during clean up of the construction right-of-way.

4.5.3 Trench Plugs

The Contractor shall use trench plugs at ~~the edge of flowing~~ waterbody and wetland crossings ~~and~~ at the direction of the Environmental Inspector~~edge of wetlands with standing water~~ to prevent diversion of water into upland portions of the pipeline trench and to keep any accumulated trench water out of the waterbody. Trench plugs shall be of sufficient size to withstand upslope water pressure.

4.5.4 Temporary Slope Breakers (Water Bars)

The Contractor shall install temporary slope breakers on slopes greater than 5% on all disturbed lands at the following recommended spacing:

Slope (%)	Spacing (feet)
5 - 15	300
>15 - 30	200
>30	100

The gradient of each slope breaker shall be 2 to 4 percent.

If so directed by the landowner, the Contractor may not install temporary slope breakers (water bars) in cultivated land.

Temporary slope breakers shall be constructed of soil, silt fence, staked straw bales, sand bags, or similar materials authorized by Keystone.

The Contractor shall direct the outfall of each temporary slope breaker to a stable, well-vegetated area or construct an energy-dissipating device at the end of the slope breaker and off the construction right-of-way as permitted in the landowner agreement as shown in Detail 3. The outfall of each temporary slope breaker shall be installed to prevent sediment discharge into wetlands, waterbodies, or other sensitive resources.

Specifications and configurations for temporary slope breakers may be modified by Keystone as necessary to suit actual site conditions. However, all work shall be conducted in accordance with applicable permits.

4.5.5 Drainage Channels or Ditches

Drainage channels or ditches shall be used on a limited basis to provide drainage along the construction right-of-way and toe of cut slopes as well as to direct surface runoff across the construction right-of-way or away from disturbances and onto natural undisturbed ground. Channels or ditches shall be constructed by the Contractor during grading operations. Where there is inadequate vegetation at the channel or ditch outlet, sediment barriers, check berms, or other appropriate measures shall be used to control erosion.

4.5.6 Temporary Mulching and Cover Crops

Unless otherwise directed by Keystone, the Contractor shall apply temporary seed and/or mulch on disturbed construction work areas that have been inactive for one month or are expected to be inactive for a month or more. The Contractor shall not apply temporary mulch in cultivated areas unless specifically requested by the landowner or in areas particularly prone to erosion. The Contractor shall not apply mulch within wetland boundaries.

Temporary mulch of straw or equivalent applied on slopes shall be spread uniformly to cover at least 75 percent of the ground surface at an approximate rate of 2 tons per acre of straw or its equivalent. Mulch application on slopes within 100 feet of waterbodies and wetlands shall be increased to an approximate rate of 3 tons per acre.

All seed that is used as a temporary cover crop will be approved and/or provided by Keystone.

4.5.7 Tackifier

When wetting topsoil piles with water does not prevent wind erosion, the Contractor shall temporarily suspend topsoil handling operations and apply a tackifier to topsoil stockpiles at the rate recommended by the manufacturer. The type of Tackifier will be approved by Keystone.

Should construction traffic, cattle grazing, heavy rains, or other related construction activity disturb the tackified topsoil piles and create a potential for wind erosion, additional tackifier shall be applied by the Contractor.

4.6 Stringing

The objective of stringing is to place the line pipe along the construction right-of-way for bending and welding in an expedient and efficient manner.

The Contractor shall utilize one or more of the following mitigative measures as applicable and when necessary to reduce compaction on the working side of the right-of-way or as directed by Keystone. However, all work shall be conducted in accordance with applicable permits.

- prohibiting access by certain vehicles;
- using only machinery possessing low ground pressure (tracks or extra-wide tires);
- limiting access and thus minimizing the frequency of all vehicle traffic;

- digging ditches to improve surface drainage;
- using timber riprap, matting, or geotextile fabric overlain with soil; and
- stopping construction for a period of time.

4.7 Trenching

The objective of trenching is to provide a ditch of sufficient depth and width with a bottom to continuously support the pipeline. During trenching operations, the following mitigative measures shall be implemented unless otherwise approved or directed by Keystone based on site-specific conditions or circumstances. All work shall be conducted in accordance with applicable permits.

- Where required, subsoil~~Subsoil~~ shall be segregated from topsoil in separate, distinct rows with a separation that shall limit any admixing of topsoil and subsoil during handling.
- Triple ditch soil handling will be completed at sites identified by Keystone according to Detail 67 and 67A to prevent soil degradation.
- Gaps must be left in the spoil piles that coincide with breaks in the strung pipe to facilitate natural drainage patterns and to allow the passage of livestock or wildlife.
- Trenching operations shall be followed as closely as practicable by lower in and backfill operations to minimize the length of time the ditch is open.
- Construction debris (e.g., welding debris) and other garbage shall not be deposited in the ditch.
- If trenching, pipe installation and backfill operations take place during frozen soil conditions, final clean-`up (including additional trench compaction, subsoil feathering, final contouring and topsoil replacement) will be delayed until the subsoil and topsoil thaw completely the following spring/summer. A pronounced subsoil berm will be left over the trenchline until final clean-up takes place to account for settlement of thawing backfill. Gaps will be left in the berm to maintain cross-ROW drainage

The Contractor shall prepare a blasting plan that is applicable to any locations where blasting will be necessary adjacent to existing high pressure pipelines, overhead or underground utilities, farm operations, or public crossings. The Contractor and its blasting supervisor shall be thoroughly familiar with and comply with the rules and regulations of Occupational Safety and Health Administration (OSHA) and all federal, state, county and local regulations governing blasting operations. Keystone will file the blasting plan with applicable state or local jurisdictions, where required. Excavation and blasting along the ROW may uncover paleontological resources of scientific value. Keystone will consult with the appropriate regulatory agencies in each state on the applicability and requirements for Paleontological Resource Protection Plans. Keystone will prepare and file plans addressing vertebrate fossils with any respective states, as required.

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Should blasting be necessary for removal of rock, the following mitigative measures may be implemented:

- The Contractor shall use non-electric initiation systems for all blasting operations. If required by the blasting plan, blasting will be monitored for vibration levels and peak particle velocity. This work shall be performed by a third-party vibration monitoring consultant hired by and reporting to the Constructor Representative. The Contractor shall arrange for detonations to be carried out in cooperation with this consultant.
- Prior to using explosives, the Contractor shall advise residents of the immediate area, in order to prevent any risk of accidents or undue disturbances.
- No blasting shall be done without approval of the Constructor Representative. Prior to any detonation of explosives in the vicinity of a loaded line, dwelling, structure, overhead or underground utility, farm operation, or public crossings, a minimum of 48 hours notice shall be given to the Constructor Representative, in order that the appropriate people can be notified and the upstream and downstream mainline valves can be staffed.
- The Contractor shall obtain all necessary permits and shall comply with all legal requirements in connection with the use, storage, and transportation of explosives.
- Blasting mats or subsoil may be piled over the trench line to prevent rock from being blown outside the construction right-of-way.
- Each blasting location shall be cleared and cleaned up before and after all blasting operations.
- Blasting shall be carried out during regular, daylight working hours.
- The Contractor shall at all times protect his workers and the public from any injury or harm that might arise from drilling dust and the use of explosives.
- Only workers thoroughly experienced in handling explosives shall be permitted to supervise, handle, haul, load or shoot explosives. In those jurisdictions where the licensing of blasters is mandatory, the Contractor shall provide the Constructor Representative with proof of the required certification for every person so required.
- The drilling pattern shall be set in a manner to achieve smaller rock fragmentation (maximum 1 foot in diameter) in order to use as much as possible of the blasted rock as backfill material after the pipe has been padded in accordance with the specifications.
- Blasting testing of surface-water resources and water wells within 150 feet of the centerline will be performed in compliance with all applicable permits.

4.7.1 Trench Dewatering/Well Points

The Contractor shall make all reasonable efforts to discharge trench water in a manner that avoids damage to adjacent agricultural land, crops, and pasture. Damage includes, but is not limited to, the inundation of crops for more than 24 hours, deposition of sediment in ditches, and the deposition of gravel in fields or pastures.

If trench dewatering is necessary in an area where salt damage to adjacent crops is evident, the Environmental Inspector shall conduct a field conductivity test on the trench water before it is discharged. If the conductivity of the trench water is determined to potentially affect soil quality, it shall not be discharged to areas where salt damage to crops is evident, but shall be directed as feasible so that water flows over a well vegetated, non-cropland area or through an energy dissipater and sediment barrier.~~, then directed to nearby ditches or brackish wetlands or waterbodies.~~

When pumping water from the trench for any reason, the Contractor shall ensure that adequate pumping capacity and sufficient hose is available to permit dewatering as follows:

- No heavily silt-laden trench water shall be allowed to enter a waterbody or wetland directly but shall instead be diverted through a well vegetated area, a geotextile filter bag, or a permeable berm (straw bale or Keystone approved equivalent).
- Trench water shall not be disposed of in a manner which could damage crops or interfere with the functioning of underground drainage systems.

The Contractor shall screen the intake hose and keep the hose either one foot off the bottom of the trench or in a container to minimize entrainment of sediment.

4.8 Welding, Field Joint Coating, and Lowering In

The objectives of welding, field joint coating, and lowering in are to provide continuous segments of pipeline, to provide corrosion protection to the weld areas of the pipeline, and to place the pipeline in the center of the trench, without stress, at the required depth of cover. The following mitigative measures shall be followed during pipe welding, field joint coating, and lowering in, unless otherwise specified by Keystone in response to site-specific conditions or circumstances. All work shall be conducted in accordance with applicable permits.

- Shavings produced during beveling of the line pipe are to be removed immediately following this operation to ensure that livestock and wildlife do not ingest this material. When welding operations create a continuous line of pipe that may be left in the right-of-way for an extended period of time due to construction or weather constraints, a gap in the welded pipe shall be

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provided to allow for access at farm road crossings and for passage of livestock and wildlife.

- Prior to the application of epoxy powder, urethane epoxy, or other approved pipe coatings, a tarp shall be placed underneath the pipe in wetlands to collect any overspray of epoxy powder and liquid drippings. Excess powder, liquid, or other hazardous materials (e.g. brushes, rollers, gloves) shall be continuously collected and removed from the construction right-of-way and disposed of in a manner appropriate for these materials.

4.9 Padding and Backfilling

The objective of padding and backfilling is to cover the pipe with material that is not detrimental to the pipeline and pipeline coating. The following mitigative measures shall be utilized during backfilling, unless otherwise approved or directed by Keystone based on site-specific conditions or circumstances. All work shall be conducted in accordance with applicable permits.

- Excessive water accumulated in the trench shall be eliminated prior to backfilling.
- In the event it becomes necessary to pump water from open trenches, the Contractor shall pump the water and discharge it in accordance with the requirements of the Stormwater Pollution Prevention Plan (SWPPP) in order to avoid damaging adjacent areas.~~agricultural land, crops, and pasture.~~ Detail 5 and Detail 6 provide typical examples of dewatering structures.
- If it is impossible to avoid water-related damages (including inundation of crops for more than 24 hours, deposition of sediment in ditches and other water courses, and the deposition of gravel in fields, pastures, and any water courses), Keystone shall reasonably compensate the landowners for the damage and/or shall correct the damage so as to restore the land, crops, pasture, water courses, etc. to their pre-construction condition.
- All pumping of water shall comply with existing drainage laws and local ordinances relating to such activities and provisions of the Clean Water Act.
- Prior to backfilling, all drain tile shall be permanently repaired, inspected, and the repair documented as described in Section 5.5.
- Prior to backfilling, trench breakers shall be installed on slopes where necessary to minimize the potential for water movement down the ditch and potential subsequent erosion.
- During backfill, the stockpiled subsoil shall be placed back into the trench before replacing the topsoil.
- Topsoil shall not be utilized for padding the pipe.
- Backfill shall be compacted to a minimum of 90% of pre-existing conditions where the trench line crosses tracks of wheel irrigation systems (pivots).

- To reduce the potential for ditch line subsidence, spoil shall be replaced and compacted by backhoe bucket or by the wheels or tracks of equipment traversing down the trench.
- The lesser of 4 feet or the actual depth of topsoil cover, shall not be backfilled with soil containing rocks of any greater concentration or size than existed prior to pipeline construction in the pipeline trench, bore pits, or other excavations.

4.10 Cleanup

The objective of cleanup activities shall be to prepare the right-of-way and other disturbed areas to approximate pre-activity ground contours where appropriate and to replace spoil and stockpiled material in a manner which preserves soil capability and quality to a degree reasonably equivalent to the original or that of representative undisturbed land. The following mitigative measures shall be utilized during cleanup, unless otherwise approved or directed by Keystone based on specific conditions or circumstances. All work shall be conducted in accordance with applicable permits.

- Cleanup shall occur immediately following backfilling operations when weather or seasonal conditions allow.
- All garbage and construction debris (e.g., lathing, ribbon, welding rods, pipe bevel shavings, pipe spacer ropes, end caps, pipe skids) shall be collected and disposed of at approved disposal sites.
- The right-of-way shall be re-contoured with spoil material to approximate pre-construction contours and as necessary to limit erosion and subsidence. Loading of slopes with unconsolidated spoil material shall be avoided during slope re-contouring. Topsoil shall be replaced after re-contouring of the grade with subsoil. The topsoil shall be replaced on the subsoil storage area and over the trench so that after settling occurs, the topsoil's approximate original depth and contour (with an allowance for settling) shall be achieved.
- Where topsoil has been segregated, subsoil~~Subsoil~~ shall not be permanently placed on top of topsoil.
- Surface drainage shall be restored and re-contoured to conform to the adjacent land drainage system.
- Erosion control structures such as permanent slope breakers and cross ditches shall be installed on steep slopes where necessary to control erosion by diverting surface run-off from the right-of-way to stable and vegetated off right-of-way areas.
- During cleanup, temporary sediment barriers such as silt fence and hay bale diversions will be removed; accumulated sediment will re-contoured with the rest of the ROW; and permanent erosion controls will be installed as necessary.

- After construction, all temporary access shall be returned to prior construction conditions unless specifically agreed with the landowner or otherwise specified by Keystone.
- Warning signs, aerial markers, and cathodic protection test leads shall be installed in locations in compliance with U.S. Federal code and in locations that shall not impair farming operations where practicable.~~and are acceptable to the landowner.~~
- All bridges, fences and culverts existing prior to construction shall be restored to meet or exceed approximate pre-construction conditions. Caution shall be utilized when re-establishing culverts to ensure that drainage is not improved to a point that would be detrimental to existing waterbodies and wetlands.
- All temporary gates installed during construction shall be replaced with permanent fence unless otherwise requested by the landowner.

4.11 Reclamation and Revegetation

The objectives of reclamation and revegetation are to return the disturbed areas to approximately pre-construction use and capability. This involves the treatment of soil as necessary to preserve approximate pre-construction capability and the stabilization of the work surface in a manner consistent with the initial land use.

The following mitigative measures will be utilized unless otherwise approved or directed by Keystone based on site specific conditions or circumstances. However, all work shall be conducted in accordance with applicable permits.

4.11.1 Relieving Compaction

Compaction will typically be relieved in subsoils that have received substantial construction traffic, as determined by Keystone, prior to replacing and respreading topsoil. Compaction will typically not be relieved in topsoils that have been left in place and that have not been driven on. Any rock that is brought to the surface during decompaction activities will be removed until the quantity, size, and distribution of rock is equivalent to that found on adjacent land as determined by the Environmental Inspector. Compaction will typically be relieved as follows:

- Compacted cropland compacted shall be ripped a minimum of 3 passes at least 18 inches deep and all pasture shall be ripped or chiseled a minimum of three passes at least 12 inches deep before replacing topsoil.
- Areas of the construction right-of-way that were stripped for topsoil salvage shall be ripped a minimum of 3 passes (in cross patterns, as practical) prior to topsoil replacement. The approximate depth of ripping shall be 18 inches (or a lesser depth if damage may occur to existing drain tile systems). After ripping, the subsoil surface shall be

graded smooth and any subsoil clumps broken up (disc and harrow) in an effort to avoid topsoil mixing.

- The de-compacted construction right-of-way shall be tested by the Contractor at regular intervals for compaction in agricultural and residential areas. Tests shall be conducted on the same soil type under similar moisture conditions in undisturbed areas immediately adjacent to the right-of-way to approximate pre-construction conditions. Penetrometers or other appropriate devices shall be used to conduct tests
- Topsoil shall be replaced to pre-existing depths once ripping and discing of subsoil is complete up to a maximum of 12 inches. Topsoil compaction on cultivated fields shall be alleviated with~~by~~ cultivation methods by the contractor.~~.~~
- If there is any dispute between the landowner and Keystone as to what areas need to be ripped or chiseled, the depth at which compacted areas should be ripped or chiseled, or the necessity or rates of lime and fertilizer application, the appropriate NRCS shall be consulted by Keystone and the landowner.

Plowing under of organic matter including wood chips and manure, or planting of a green crop such as alfalfa to decrease soil bulk density and improve soil structure or any other measures in consultation with the Natural Resource Conservation Service (NCRS) shall be considered if mechanical relief of compaction is deemed not satisfactory.

In the first year after construction, Keystone will inspect the ROW to identify areas of erosion or settling. Subsequently, Keystone will monitor erosion and settling through aerial patrols, which are part of Keystone's Integrity Management Plan, and through landowner reporting. Landowner reporting will be facilitated through use of Keystone's toll-free telephone number, which will be made available to all landowners on the ROW. Landowner reporting also may be facilitated through contact with Keystone's field offices.

Keystone plans to minimize impacts on soil productivity that may result from construction activities, but recognizes that some short- to long-term decreases in agricultural productivity are possible. Keystone recognizes its responsibility to restore agricultural productivity on the pipeline ROW and to compensate landowners for demonstrated decreases in productivity that may result from any degradation of agricultural soils along the ROW.

4.11.2 Rock Removal

- Rocks~~On agricultural land, rocks~~ that are exposed on the surface due to construction activity shall be removed from the right-of-way prior to and after topsoil replacement This effort will result in an equivalent quantity, size and distribution of rocks to that found on adjacent lands, as determined by the Environmental Inspectors.~~.~~

- Clearing of rocks may be carried out with a mechanical rock picker or by manual means, provided that preservation of topsoil is assured. Rock removed from the right-of-way shall be hauled off the landowner's premises or disposed of on the landowner's premises at a location that is mutually acceptable to the landowner and to Keystone.

4.11.3 Soil Additives

If site-specific conditions warrant and if agreed to by the landowner, the Contractor shall apply amendments (fertilizer and soil pH modifier materials and formulations) commonly used for agricultural soils in the area and in accordance with written recommendations from the local soil conservation authority, land management agencies, or landowner. Amendments shall be incorporated into the normal plow layer as soon as possible after application.

4.11.4 Seeding

- The final seed mix shall be based on input from the local Natural Resource Conservation Service and the availability of seed at the time of reclamation. The landowner may request specific seeding requirements during easement negotiations.
- Certificates of seed analysis are required for all seed mixes to limit the introduction of noxious weeds.
- Seed not utilized within 12 months of seed testing shall be approved by Keystone prior to use. Seeding shall follow cleanup and topsoil replacement as closely as possible. Seed shall be applied to all disturbed surfaces (except cultivated fields unless requested by the landowner) as indicated on the construction drawings
- If mulch was applied prior to seeding for temporary erosion control, the Contractor shall remove and dispose of the excess mulch prior to seedbed preparation to ensure that seedbed preparation equipment and seed drills do not become plugged with excess mulch; and to support an adequate seedbed; and to ensure that seed incorporation or soil packing equipment can operate without becoming plugged with mulch.
- ~~The Contractor may evenly re-apply and anchor (straw crimp) the removed temporary mulch on the construction right-of-way following seeding.~~
- Identified seeding areas shall be seeded as specified by Keystone.~~at a rate appropriate for the region and stability of the reclaimed surface.~~ Seeding rates shall be based on pure live seed.
- Weather conditions, construction right-of-way constraints, site access, topography and soil type shall influence the seeding method to be

used (i.e., drill seeding versus broadcast seeding). ~~All areas seeded by the Contractor, except for temporary cover crops, shall be drill seeded unless the right-of-way is too steep to facilitate drill seeding. Temporary cover crop seed shall be broadcast.~~

- The Contractor shall delay seeding as directed by Keystone~~necessary~~ until the soil is in the appropriate condition for ~~drill~~ seeding.
- The Contractor shall use a Truax brand or Keystone approved equivalent-type drill seeder equipped with a cultipacker designed and equipped to apply grass and grass-legume seed mixtures with mechanisms such as seed box agitators to allow even distribution of all species in each seed mix, with an adjustable metering mechanism to accurately deliver the specified seeding rate and with a mechanism such as depth bands to accurately place the seed at the specified depth.
- The Contractor shall operate drill seeders at an appropriate speed so the specified seeding rate and depth is maintained, as directed by Keystone.~~.~~
- The Contractor shall calibrate drill seeders so that the specified seeding rate is planted. The row spacing on drill seeders shall not exceed 8 inches.
- The Contractor shall plant seed at depths consistent with the local or regional agricultural practices.
- Broadcast or hydro seeding, used in lieu of drilling, shall utilize NRCS-~~double the~~ recommended seeding rates. Where seed is broadcast, the Contractor shall use a harrow, cultipacker, or other equipment immediately following broadcasting to incorporate the seed to the specified depth and to firm the seedbed.
- The Contractor shall delay broadcast seeding during high wind conditions if even distribution of seed is impeded.
- The Contractor shall hand rake all areas that are too steep or otherwise cannot be safely harrowed or cultipacked in order to incorporate the broadcast seed to the specified depth.
- Hydro seeding may be used, on a limited basis, where the slope is too steep or soil conditions do not warrant conventional seeding methods. Fertilizer, where specified, may be included in the seed, virgin wood fiber, tackifier, and water mixture. When hydro-seeding, virgin wood fiber shall be applied at the rate of approximately 3,000 pounds per acre on an air-dry weight basis as necessary to provide at least 75% ground cover. Tackifier shall consist of biodegradable, vegetable-based material and shall be applied at the rate recommended by the manufacturer. The seed, mulch, and tackifier slurry shall be applied so that it forms a uniform, mat-like covering of the ground.
- Keystone shall work with landowners to discourage intense livestock grazing of the construction right-of-way during the first growing

season by utilization of temporary fencing or deferred grazing, or increased grazing rotation frequency.

4.11.5 Permanent Erosion and Sediment Control

The Contractor shall restore all existing landowner soil conservation improvements and structures disturbed by pipeline construction to the approximate pre-construction line and grade. Soil conservation improvements and structures include, but are not limited to, grassed waterways, toe walls, drop inlets, grade control works, terraces, levees, and farm ponds.

4.11.5.1 Trench Breakers

The Contractor shall install trench breakers in steep terrain where necessary to limit the potential for trench line erosion and at the base of slopes adjacent to waterbodies and wetlands.

Trench breakers shall be constructed of materials such as sand bags, sand/cement bags, bentonite bags, or other suitable materials by the Contractor (Detail 7). The Contractor shall not use topsoil in trench breakers.

4.11.5.2 Permanent Slope Breakers (Water Bars)

Permanent slope breakers (water bars) shall be constructed of soil or, in some instances, sand bags.

The Contractor shall construct permanent slope breakers on the construction right-of-way where necessary to limit erosion, except in cultivated and residential areas. Slope breakers shall divert surface runoff to adjacent stable vegetated areas or to energy-dissipating devices as shown on Detail 3. In general, permanent slope breakers should be installed immediately downslope of all trench breakers. Permanent slope breakers shall be installed as specified on the construction drawings or generally with a minimum spacing as shown on the following table:

Slope (%)	Spacing (feet)
5 - 15	300
>15 – 30	200
>30	100

The gradient (fall) for each slope breaker shall be two percent to four percent unless otherwise approved by Keystone based on site-specific conditions.

The Contractor shall construct slope breakers to divert surface flow to a stable, well-vegetated area. In the absence of a stable area, the Contractor shall construct appropriate energy-dissipating devices at the end of the slope breaker and beyond the area disturbed by construction.

4.11.5.3 Mulching

The Contractor shall apply mulch on all areas with high erosion potential and on slopes greater than 8 percent unless otherwise approved by Keystone based on site-specific conditions or circumstances. The Contractor shall spread mulch uniformly over the area to cover at least 75 percent of the ground surface at an approximate rate of 2 tons per acre of straw or its equivalent. The Environmental Inspector may reduce the application rate or forego mulching an area altogether if there is an adequate cover of rock or organic debris to protect the slope from erosion, or if annual companion crops have stabilized the soil.~~.~~

Mulch application includes straw mulch, ~~or~~ hydro mulch and tackifier or other materials as approved. ~~The Contractor shall not apply mulch in cultivated areas unless deemed necessary~~ by Keystone.

The Contractor shall use mulch that is free of noxious weeds.

The Contractor shall apply mulch immediately following seeding. The Contractor shall not apply mulch in wetlands.

If a mulch blower is used, the majority of strands of the mulching material shall not be shredded to less than 8 inches in length to allow anchoring. The Contractor shall anchor mulch immediately after application to minimize loss by wind and water.

When anchoring (straw crimping) by mechanical means, the Contractor shall use a tool specifically designed for mulch anchoring with flat, notched disks to properly crimp the mulch to a depth of 2 to 3 inches. A regular farm disk shall not be used to crimp mulch. The crimping of mulch shall be performed across the slope of the ground, not parallel to it. In addition, in areas of steep terrain, tracked vehicles may be used as a means of crimping mulch (equipment running up and down the hill to leave crimps perpendicular to the slope), provided they leave adequate coverage of mulch.

In soils possessing high erosion potential, the Contractor may be required to make two passes with the mulch-crimping tool; passes must be as perpendicular to the others as possible.

When anchoring with liquid mulch binders (tackifiers), the Contractor shall use a biodegradable tackifier derived from a vegetable-based, organic source. The Contractor shall apply mulch binders at rates recommended by the manufacturer.

The Contractor shall limit the use of tackifiers for anchoring straw and the use of hydromulch and tackifier to areas that are too steep or rocky to safely or effectively operate mechanical mulch-anchoring tools. No asphalt-based tackifiers shall be used on the Project.

4.11.5.4 Erosion Control Matting

Erosion control matting shall be applied where shown on the construction drawings as shown on Detail 4. The Contractor shall anchor the erosion control matting with staples or other approved devices.

The Contractor shall use erosion control matting made of biodegradable, natural fiber such as straw or coir (coconut fiber).

The Contractor shall prepare the soil surface and install the erosion control matting to ensure it is stable and the matting makes uniform contact with the soil of the slope face or stream bank with no bridging of rills, gullies, or other low areas.

4.11.5.5 Riprap and Stream Bank Stabilization

Disturbed banks of streambeds and waterbodies shall be restored to their approximate original contours unless otherwise directed. Erosion protection shall be applied as specified in the construction drawings.

Most restored banks will be protected through the use of flexible channel liners installed as specified in Detail 19.

If the original stream bank is excessively steep and unstable and/or flow conditions are severe, a more stable final contour may be specified and alternate stabilization measures may be installed.

Alternate stabilization measures may consist of rock riprap, bio-stabilization, or engineered structures such as brush layering, logwalls, cribwalls, or vegetated geo-grids. See Details 20, 23, and 24.

Stream bank riprap structures shall consist of a layer of stone underlain with approved filter fabric or a gravel filter blanket. Riprap shall extend from the stabilized streambed to the top of the stream bank. Native rock shall be utilized wherever practicable.

4.11.6 Fences

Upon completion of all backfilling, cleanup, and restoration, including mulching and seeding of the construction right-of-way, permanent repairs shall be made to all fences by using either the original material or good quality new material similar to existing fences.

Historic fences shall be carefully reassembled by hand from the original material. Where the original material has deteriorated to a state that makes it unsalvageable, replacement material similar to the original shall be used if possible.

4.11.7 Farm Terraces

Keystone will work with landowners and farm service agencies to ensure restoration of farm terraces to their pre-construction function. Keystone may elect to negotiate a fair settlement with the landowner to employ a local land leveling contractor to restore the terrace.

Before any groundwork is performed in areas with farm terraces, Keystone will conduct a civil survey ~~and photograph each terrace from two to three perspectives~~ to document the location and contours of each terrace. Both the channel contour and the terrace berm will be surveyed within the construction right-of-way and up to 100 feet on either side of the ROW boundaries. The pre-construction survey ~~and photographs~~ will provide a baseline to ensure the proper restoration of the terrace following construction.

The Contractor will maintain the pre-disturbance drainage of water along the terrace channel and will install temporary flume pipe for this purpose. As necessary, temporary erosion control measures such as water bars and sediment barriers will be installed and maintained throughout construction to reduce the potential for soil erosion along or off the construction ROW.

Following installation of the pipe, the trench will be backfilled, and the Contractor will restore the terrace contours as agreed to with the landowner.

Should the landowner agree to have a local contractor restore the terraces, the Contractor will backfill the trench and restore the terrace using typical compaction methods for pipeline construction with the understanding that the landowner's contractor will re-excavate the location and re-install the terrace utilizing land levelling equipment and special compaction methods.

Should the landowner desire the Contractor to restore the terraces, the pipeline contractor will compact the trench before the terrace berm is replaced. Following restoration of the terraces, final contours and grades will be re-surveyed and documented with survey notes. ~~Photographs will be taken from a minimum of two or three perspectives to document that the cross-section profile matches the adjacent undisturbed grades.~~ Keystone will perform post-construction monitoring and inspection with the landowner's concurrence. Should the terraces require further work, Keystone will either compensate the landowner to perform the work or arrange for a local contractor to perform the work.

4.11.8 Right-of-Way and Pipeline Markers

Upon completion of all backfilling, cleanup and restoration, including mulching and seeding of the construction right-of-way, and during the time when the Contractor is making permanent repairs to fences, the Contractor shall install pipeline markers on each side of all roads, railroads, fence lines, stream crossings, and other areas where the pipeline markers do not conflict with intended land use.

4.12 Pasture and Range Lands

The following mitigative measures shall be implemented in addition to the requirements previously stated in Sections 4.1 thru 4.11 unless otherwise approved by Keystone based on site-specific conditions or circumstances. All work shall be conducted in accordance with applicable permits.

- Access across the right-of-way during construction shall be provided at locations requested by landowners, if practicable.
- Shavings produced during pipe bevel operations are to be removed immediately to ensure that livestock and wildlife do not ingest this material.
- Litter and garbage shall be collected and removed from the construction site at the end of the day's activities.
- Temporary gates shall be installed at fence lines for access to the construction right-of-way. These gates shall remain closed at all times. Upon completion of construction, the temporary gates shall be removed and the permanent fence replaced.
- Feeding or harassment of livestock or wildlife is prohibited.
- Construction personnel shall not be permitted to have firearms or pets on the construction right-of-way.
- All food and wastes shall be stored and secured in vehicles or appropriate facilities.
- Areas of disturbance in native range shall be seeded with a native seed mix after topsoil replacement.

- Improved pasture shall be seeded with a seed mix approved by individual landowners.

4.13 Forested Lands

Mitigation measures are required to ensure that pipeline construction activities have a minimal impact on forested lands.

Clearing, grubbing, and grading of trees, brush, and stumps shall be performed in accordance with the following mitigative measures in addition to the requirements previously stated in Sections 4.1 thru 4.11 unless otherwise approved or directed by Keystone based on site-specific conditions or circumstances. Keystone will address mitigation, reclamation and remediation measures with individual landowners and comply with any applicable state requirements. These measures include non-vegetative remediation to reverse impacts on windbreaks, shelterbelts, and living snow fences. Where the pipeline follows an existing ROW in forested areas, Keystone attempted to route the pipeline as close as practical to the existing ROW. All work shall be conducted in accordance with applicable permits.

- Prior to the start of clearing activity, right-of-way boundaries, including pre-approved temporary workspaces, shall be clearly staked to prevent disturbance of unauthorized areas.
- If trees are to be removed from the construction right-of-way, Keystone shall consult with the landowner or landowner's designate to see if there are trees of commercial or other value to the landowner. Timber shall be salvaged as per landowner request.
- If there are trees of commercial or other value to the landowner, Keystone shall allow the landowner the right to retain ownership of the trees with the disposition of the trees to be negotiated prior to the commencement of land clearing and included in the easement agreement.
- If not performed by the landowner, the construction right-of-way Contractor may salvage all marketable timber from designated areas.
- Tree stumps shall be grubbed to a maximum of 5 feet on either side of the trench line and where necessary for grading a level surface for pipeline construction equipment to operate safely.
- Keystone shall follow the landowner's or landowner designee's desires as stated in the easement agreement regarding the disposal of trees, brush, and stumps of no value to the landowner by burning, burial, etc., or complete removal from any affected property.
- Timber salvage operations shall use cut-off-type saw equipment. Felling shall be undertaken in a manner that minimizes butt shatter, breakage, and off ROW disturbance. Skidders or alternate equipment shall be used to transport salvaged logs to stacking sites.

- Trees shall be felled to fall toward the center line of the right-of-way to avoid breaking trees and branches off ROW. Leaners (felled trees that inadvertently fall into adjacent undisturbed vegetation) shall be salvaged.
- Trees and slash falling outside the right-of-way shall be recovered and disposed..
- Salvaged logs shall be limbed and topped before removal from the construction right-of-way. Log decks (if required) shall be oriented to best facilitate loading by picker trucks and be located adjacent to the working side of the right-of-way, where possible.
- The Contractor shall not be allowed to dispose of woody debris in wooded areas along the pipeline right-of-way.
- Pruning of branches hanging over the right-of-way shall be done only when necessary for construction. Any branch that is broken or seriously damaged should be cut off near its fork and the collar of the branch preserved.
- All tree wastes, stumps, tree crowns, brushes, branches, and other forest debris shall be either burned, chipped (using a mobile chipper), or removed from the right-of-way according to Keystone instructions contained in the specific mitigation measures. Burial of this waste material on the site by the Contractor shall require the landowner's authorization. Chips must not be spread over cultivated land. However, they may be spread and incorporated with mineral soil over the forest floor at a density that shall not prevent revegetation of grass.
- Stump removal and brush clearing shall be done with bulldozers equipped with brush rakes to preserve organic matter.
- Decking sites shall be established: (1) approximately 2000 feet apart in timbered areas; (2) on sites located on approved temporary workspace in existing cleared areas; (3) in non-merchantable stands of timber; or (4) if no other options are available, in merchantable timber stands. Deck sites shall be appropriately sized to accommodate the loading equipment.
- If the landowner does not want the timber, the Contractor shall remove decked timber from the construction right-of-way and transport it to a designated all-weather access point or mill

4.14 Residential and Commercial/Industrial Areas

4.14.1 Residential and Commercial Areas

The principal measures that shall be used to mitigate impacts on existing residential and commercial areas include the following unless otherwise directed or approved by Keystone based on site-specific conditions or circumstances. All work shall be conducted in accordance with applicable permits.

- notifying landowners prior to construction;
- posting warning signs as appropriate;

- reducing the width of construction right-of-way, if practicable, by eliminating the construction equipment passing lane, reducing the size of work crews, or utilizing the "stove pipe" or "drag section" construction techniques;
- removing fences, sheds, and other improvements as necessary for protection from construction activities;
- to the extent possible, preserving mature trees and landscaping while ensuring the safe operation of construction equipment;
- fencing the edge of the construction work area that is within 25 feet~~adjacent~~ to a residence for a distance of 100 feet on either side of the residence to ensure that construction equipment and materials, including the spoil pile, remain within the construction work area;
- limiting the hours during which operations with high-decibel noise levels
  (i.e., drilling and boring) can be conducted;
- limiting dust impact through prearranged work hours and by utilizing dust minimization techniques;
- ensuring that construction proceeds quickly through such areas, thus minimizing exposure to nuisance effects such as noise and dust;
- maintaining access and traffic flow during construction activities, particularly for emergency vehicles;
- cleaning up construction trash and debris daily;
- fencing or plating open ditches during non-construction activities;
- if the pipeline centerline is within 25 feet of a residence, ensuring that the trench is not excavated until the pipe is ready for installation and that the trench shall be backfilled immediately after pipe installation; and
- immediately after backfilling the trench, restoring all lawn areas, shrubs, specialized landscaping, fences, and other structures within the construction work area to its pre-construction appearance or the requirements of the landowner. Restoration work shall be done by personnel familiar with local horticultural and turf establishment practices.
- to the extent possible, preserving mature trees and landscaping while ensuring the safe operation of construction equipment;

4.14.2 Site-Specific Plans

For any residence or commercial/industrial building closer than 25 feet to the construction work area, Keystone shall prepare a site-specific construction plan. The plan shall include:

- a description of construction techniques to be used;

- a dimensioned site plan that shows, at a minimum:
  - the location of the residence or commercial/industrial area in relation to the new pipeline;
  - the edge of the construction work area;
  - the edge of the new permanent construction right-of-way; and
  - other nearby topographical obstacles including landscaping, trees, structures, roads, parking areas, ditches, and streams; and
- a description of how Keystone would ensure that the trench is not excavated until the pipe is ready for installation and that the trench is backfilled immediately after pipe installation.

4.14.3 Landowner Complaint Resolution Procedure

Keystone shall implement a landowner complaint procedure as follows:

- Landowners should first contact the construction spread office to express their concern over restoration or mitigation of environmental damages on their property. The Construction Manager or his designated representative shall respond to the landowner within 24 hours of receipt of the phone call.
- If the landowner has not received a response or is not satisfied with the response, he can contact Keystone's representative at 1-877-880-4881. The landowner should expect a response within 48 hours.

4.15 ~~Sand Hills~~Fragile Soil Clean-up and Reclamation/Revegetation ~~(Steele City Segment)~~

4.15.1 General

Fragile soil types are a result of the high percentage of sand content that exists within the surficial soil. Theses soil types exist within regions found in southern South Dakota and central Nebraska and are fragile due to their inherent high wind and water erosion potential, low water holding capacity and arid nature of the region, rolling to steep terrain and usually ~~The Sand Hills are an extensive and biologically significant eco-region encompassing many square miles in South Dakota and northern Nebraska. This arid eco-region is an important ecosystem that~~ consists of predominantly native prairie landscapes and supports a variety of uses such as livestock grazing, wildlife habitat and recreational opportunities. ~~The Sand Hills consist of a collection of diverse habitats that vary from highly erosive windswept ridges and blowouts, to wet meadows and alkali lakes in valley bottoms.~~

4.15.2 Right-of-way Construction

- KXL will educate construction personnel regarding these areas~~the fragility of Sand Hill's soils~~, and the necessity to strictly adhere to Project Best Management Practices (BMPs) designed to minimize impacts.
- Minor route re-alignments will be incorporated through these areas~~the Sand Hills region~~ to avoid particularly erosion-prone locations, such as ridgetops and existing blowouts as much as practicable.
- KXL will avoid highly saturated areas, such as wetland, to the maximum extent possible.
- Construction soil handling procedures will strive to reduce the width of disturbance to the native prairie landscape by adopting "Trench-line or Blade-width stripping procedures where practicable.
- Topsoil conservation will be conducted on all areas where excavation occurs.
- Topsoil~~topsoil~~ piles will be protected from erosion through matting, mulching, watering or tackifying as deemed practible.
- Traffic management limitations will be employed on specific areas possessing high erosion potential or sensitive habitat.

4.15.3 Right-of-Way Reclamation

- Native seed mixes will be developed with input from the local NRCS offices and through collaboration with regional experts. All seed will be certified noxious weed-free and will be calculated on a pure live seed (PLS) basis.
- Straw or native prairie hay may be used as mulch, applied to the right-of-way and crimped into the soil to prevent wind erosion. All mulch will be documented as noxious weed-free.
- Land imprinting may be employed to create impressions in the soil, thereby reducing erosion, improving moisture retention and creating micro-sites for seed germination.
- Sediment logs or straw wattles will be used in place of slope breakers (short terraces) that are constructed of soil. Using sediment logs will result in less soil disturbance to the right-of-way.
- Photodegradable matting will be applied on steep slopes or areas prone to extreme wind exposure such as north- or west-facing slopes and ridge tops. Biodegradable pins will be used in place of metal staples to hold the matting in place.
- Keystone will work with landowners to evaluate fencing the right-of-way from livestock, or alternatively, provide compensation to

rest a pasture until vegetation can become established. Management concerns such as livestock access to water or movement within a pasture would be incorporated as necessary.

4.15.4 Post-Construction

Keystone is committed to post-construction monitoring and repair and will monitor reclamation on the right-of-way for several years and repair erosion and reseed poorly revegetated areas as necessary. During monitoring, landowners are informed of our efforts and intentions.

A noxious weed management plan ~~specific to the Sand Hills region~~ will be established on these lands pending consultation with state and county experts

4.16 Operations and Maintenance

Operations and maintenance programs, such as vegetation management, pipeline maintenance, integrity surveys, and hydrostatic testing, may have an impact on the final reclamation of the right-of-way. To ensure the integrity of the facility and land surface reclamation of the right-of-way is maintained after completion of construction and that regulatory requirements are adhered to during operations, the following measures shall be implemented unless otherwise directed by Keystone in response to site-specific conditions or circumstances. All work shall be conducted in accordance with applicable permits.

- Keystone shall monitor the pipeline right-of-way and all stream crossings for erosion or other potential problems that could affect the integrity of the pipeline. Any erosion identified shall be reclaimed as expediently as practicable by Keystone or by compensating to the landowner to reclaim the area.
- Trench depressions on ditch line that may interfere with natural drainage, vegetation establishment, or land use shall be repaired as expediently as practicable by Keystone or by compensating the landowner to repair the area.
- Post-construction monitoring inspections shall be conducted after the first growing season to determine the success of revegetation, unless otherwise required by permit.~~.~~ Areas which have not been successfully re-established shall be revegetated by Keystone or by compensation of the landowner to reseed the area. If, after the first growing season, revegetation is successful, no additional monitoring shall be conducted unless otherwise required by permit.~~.~~
- In non-agricultural areas, revegetation shall be considered successful if, upon visual survey, the density and cover of non-nuisance vegetation are similar in density and cover to adjacent undisturbed lands, unless otherwise required by permit.~~.~~

- In agricultural areas, revegetation shall be considered successful if crop yields are similar to adjacent undisturbed portions of the same field.
- Restoration shall be considered successful if the surface condition is similar to adjacent undisturbed lands, construction debris is removed (unless requested otherwise by the landowner or land managing agency), revegetation is successful, and drainage has been restored.
- Weed control measures shall be implemented as required by any applicable plan and in conjunction with the landowner.
- Keystone shall be responsible for correcting tile line or irrigation system repairs that fail, provided those repairs were made by Keystone. Keystone shall not be responsible for tile line or irrigation system repairs which Keystone compensated the landowner to perform.
- When requested by owners in cultivated land, Keystone shall monitor the yield of land impacted by construction with the help of agricultural specialists. If yield deficiencies are indicated compared to yields on unaffected land, Keystone will compensate the landowner for reduced yields and shall implement procedures to return the land to equivalent capability.
- In residential areas, landowners may use the right-of-way provided they do not interfere with the rights granted to Keystone. Trees, bushes, structures, including houses, tool sheds, garages, poles, guy wires, catch basins, swimming pools, trailers, leaching fields, septic tanks, and any other objects not easily removable, shall not be permitted on the permanent construction right-of-way without the written permission of Keystone, because they could impair access for maintenance of the pipeline.
- Keystone shall maintain communication with the landowner and tenant throughout the operating life of the pipeline to allow expedient communication of issues and problems as they occur. Keystone shall provide the landowner with corporate contact information for these purposes. Keystone shall work with landowners to prevent excessive erosion on lands disturbed by construction. Reasonable methods shall be implemented to control erosion. These may not be implemented if the property across which the pipeline is constructed is bare cropland which the landowner intends to leave bare until the next crop is planted.
- If the landowner and Keystone cannot agree upon a reasonable method to control erosion on the landowner's property, the recommendations of the appropriate NRCS office shall be considered by Keystone and the landowner.

5.0 DRAIN TILE SYSTEMS

5.1 General

If underground drainage tile is damaged by the pipeline installation, it shall be repaired in a manner that ensures the tile line's proper operating condition at the point of repair. Keystone may elect to negotiate a fair settlement with the affected county or landowner for repair of the damaged drain tile. In the event the landowner chooses to have the damaged tile repaired by Keystone, the Contractor shall follow these guidelines and procedures to identify the location of drain tiles, to mitigate damages to drain tiles prior to and during construction, to repair drain tiles damaged during installation of the pipeline, to inspect the proper repair of drain tiles, and to provide post-construction monitoring to determine any impacts caused by repair of drain tiles. Since all public and private drain tile systems are unique, i.e., varying age, depth of cover, type of material, geometry on the land, etc., it is not possible to develop a standard procedure for resolving each county's or landowner's drain tile issues. These guidelines provide a basis on which to develop site specific methodology to mitigate damage and to repair drain tiles affected by construction of the Project. A typical right-of-way layout and typical orientation for crossing drain tiles is provided in Detail 25. Typical header and main crossovers are provided in Details 26 and 27. Actual measures will be developed based on site-specific information unique to specific installations. However, all work will be conducted in accordance with applicable permits.

5.2 Identification and Classification of Drain Tile Systems

Personnel shall attempt to identify and classify existing drain tile systems by meeting with local public officials and county engineers, and individual private landowners and tenants.

5.2.1 Publicly Owned Drain Tiles

Personnel shall identify and meet with the responsible county or local authority responsible for publicly owned drain tiles. Publicly owned drain tiles shall be identified and documented on the Project's 1" = 2000' USGS quad strip maps and additional data collected for input into an electronic spreadsheet by county, township, range, and section; responsible agency; and size, type, and depth of cover (if known). This data shall be cross-referenced to the centerline survey to be completed by Keystone. Additionally, any public records including maps or easement instruments on the drain tiles shall be acquired as well as any requirements of the local authority for installation of the pipeline.

5.2.2 Privately Owned Drain Tiles

Right-of-way agents shall meet with landowners and tenants of privately owned land along the route. As a minimum, the right-of-way agents shall ascertain the data concerning drain tiles outlined in a landowner questionnaire. The questionnaire requests data concerning: type of drain tile system; size, type of material, and depth of cover; preference for repair of drain tiles; and identification of local drain tile contractors. These data shall be collected into an electronic spreadsheet for utilization by right-of-way personnel in negotiating payments for easements and damages and by engineering or construction personnel for inclusion in specifications for the construction Contractor.

5.3 Mitigation of Damage to Drain Tile Systems

Keystone shall undertake mitigation measures to reduce damage to publicly and privately owned drain tile systems prior to and during installation of the pipeline.

5.3.1 Non-interference with Drain Tile

The Project shall be installed at a depth of cover and elevation so as not to interfere with the elevation and grade of existing drain tiles where practicable. Where not practicable, Keystone shall pursue alternative mitigation measures mutually acceptable to the landowner and jurisdictional agencies. Typically, the pipeline shall be installed below the elevation of drain tiles with a minimum clearance of 12 inches. Detail 25, Typical Right-of-Way Layout/Soil Handling, represents a typical drain tile crossing by the pipeline with additional temporary work space to facilitate handling of topsoil and trench spoil created by the additional depth of cover for the pipeline.

5.3.2 Non-disturbance of Drain Tile Mains

Publicly owned and privately owned drain tile mains shall be identified through the processes identified in Section 5.2. Drain tile mains are essential to the overall drainage system of a land area and if disturbed, may require excessive pumping/dewatering of the pipe trench unless temporarily repaired and maintained until permanently repaired.

Keystone shall review drain tile mains and consider their size, flow rate, type of material, depth of cover, and geographic location. If determined to be practicable and reasonable for construction, the drain tile main shall not be cut and repaired during mainline installation (a pipe section shall be left out and installed by a tie-in crew without damaging the drain tile main).

5.3.3 Relocation or Replacement of Existing Drain Tiles Prior to Construction

In many instances, drain tile systems that have been installed after the installation of adjacent existing pipelines were installed with "headers" parallel to the existing pipeline with periodic jumpovers as depicted on Detail 26, Header/Main Crossovers of Keystone XL Pipeline. The distance of these headers from the existing pipeline may vary.

Some of these drain tile headers may be most effectively relocated and/or replaced to the east of the Project. The existing header will be capped and made into a single drain tile as depicted on Detail 27, Relocate/Replace Drainage Header/Main. This could reduce the number of drain tile crossings on a particular landowner's property by a significant quantity, thereby reducing the risk that repairs will fail.

5.3.4 Future Drain Tiles/Systems

Keystone shall attempt to determine where public agencies and private landowners or tenants are proposing to install drain tile systems in the future. These locations shall be input into an electronic spreadsheet by county, township, range, and section; landowner or responsible public agency; and proposed size and depth of cover. Keystone shall endeavor to construct the pipeline at a depth and elevation to accommodate the future installation of the proposed drain tile systems.

5.3.5 Other Mitigation Measures

Other mitigation measures that may be implemented during installation of the pipeline are as follows:

- not removing topsoil from the working side of the construction right-of-way to prevent crushing of drain tile by heavy equipment;
- spreading ditch and spoil side topsoil (not subsoil) over the working side to provide additional soil depth to protect existing drain tiles;
- restricting the work of the pipe lower in crew if ground conditions are too wet to adequately support the heavy equipment;
- limiting travel of heavy equipment the working lane of the construction right-of-way where possible;
- limiting travel of heavy equipment to one pass over the drain tile per work crew where possible; and
- removing and replacing topsoil during drain tile replacement should tile be crushed on the working side of the right-of-way.

5.4 Responsibility for Repair of Drain Tile Systems

Temporary and permanent drain tile repairs shall be the responsibility of the Contractor. The physical repairs shall be made by qualified and experienced drain tile repair personnel.

5.4.1 Local Drain Tile Contractor Repair

Keystone shall identify and qualify local drain tile contractors in the geographical area of the pipeline route from interviews with local public officials, landowners, tenants, and drain tile contractors. The preferred responsibility for permanent repair of drain tiles shall be for the pipeline Contractor to subcontract the supervision and repair to local reputable drain tile contractors acceptable to the landowners and tenants.

5.4.2 Pipeline Contractor Repair

In the event local drain tile contractors are not available to subcontract the supervision and repair, permanent repair shall be made with the Contractor's supervision, equipment, and labor.

5.4.3 Landowner/Tenant Repair

The landowner or tenant may agree to take responsibility for the permanent repair of his drain tiles if not precluded by regulatory agency. The landowner or tenant shall be requested to ensure his ability to coordinate and complete the drain tile repair in a timely manner to allow the pipeline Contractor to completely backfill the damaged drain tile for repair by landowner/tenant in the immediate future. Keystone shall require that its representative be present to ensure the permanent drain tile repairs are made in accordance with the minimum requirements of this manual.

5.5 Drain Tile Repairs

The Contractor shall endeavour to locate all tile lines within the construction right-of-way prior to and during installation so repairs can be made if necessary.

5.5.1 Temporary Repairs During Construction

Drain tiles damaged or cut during the excavation of the trench shall be marked with a lath and ribbon in the spoil bank. Care shall be taken to locate markers where the chance of disturbance shall be minimized and a written record maintained of each drain tile crossing. A work crew following the pipeline trench crew shall complete a temporary repair to allow continuing flow. Detail 28, Temporary Drain Tile Repair, depicts the materials and installation procedure to complete the temporary repair. If a drain tile line shall not be temporarily repaired, the open ends of the drain tile shall be screened to prevent entry of foreign materials and small animals.

5.5.2 Permanent Repairs

Permanent repairs shall be made for all drain tiles damaged by installation of the pipeline.

5.5.2.1 <u>Ditch Line Only Repairs</u>

If water is flowing through a damaged tile line, the tile line shall be immediately and temporarily repaired until such time that permanent repairs can be made. If tile lines are dry and water is not flowing, temporary repairs are not required if the permanent repair is made within 7 days of the time damage occurred. The temporary repair shall be removed just prior to lowering in the pipeline.

Drain tiles must be permanently repaired before the pipeline trench is backfilled and within 14 days of construction completion, weather and soil conditions permitting. All tile lines shall be repaired with materials of the same or better quality as that which was damaged. The drain tile marker shall not be removed until the tile repairs have been inspected, approved, and accepted by Keystone's inspectors, the county inspectors, where applicable, and the landowner or tenant. Detail 29, Permanent Repair Method of Drain Tiles, depicts the minimum materials and installation procedure to complete a permanent repair.

5.5.2.2 Ditch Line and Temporary Work Space Repairs

Prior to making the permanent drain tile repair, the Contractor shall probe a segmented sewer rod with a plug that is not more than 15% smaller than the internal diameter of the drain tile to determine if additional damage has occurred to the drain tile. If the probe does not freely insert into the drain tile across the temporary workspace of pipeline construction, the Contractor shall excavate, expose, and repair the damaged drain tile to its original or better condition.

5.6 Inspection/Acceptance of Drain Tile Repairs

Drain tile repairs shall be inspected by Keystone construction inspectors, county inspectors, as applicable, and the landowner or tenant or his representative.

Keystone shall designate inspector(s) for the sole purpose and responsibility for inspection of all repairs of drain tiles. These inspectors shall be, if possible, employed from local drain tile installation contractors, local farmers with extensive drain tile experience, or previously employed or retired employees of local jurisdictions familiar with drain tile installation and repair. In the event that a sufficient quantity of inspectors from these sources is not available, Keystone shall conduct in-the-field training seminars on drain tile repair for additional inspection personnel.

Inspection personnel shall observe the permanent repair of all drain tiles to ensure the replacement drain tile is: (1) the proper size and type; (2) installed at the proper grade; (3) properly supported and backfill beneath the drain tile is properly placed and compacted; and (4) properly tied into the existing drain tile. The inspection shall be documented on the Drain Tile Inspection Report Form.

A drain tile repair shall not be accepted until Keystone's construction inspector and the landowner or tenant or designated representative approves the inspection form.

6.0 WETLAND CROSSINGS

6.1 General

~~Aboveground facilities shall not be located in a wetland, except where the location of such facilities outside of wetlands would preclude compliance with US Department of Transportation pipeline safety regulations.~~

Wetland boundaries shall be clearly marked in the field with signs and/or highly visible flagging during construction.

In the event a waterbody crossing is located within or adjacent to a wetland crossing, the measures of both Section 6 - Wetland Crossings and Section 7 - Waterbodies and Riparian Lands shall be implemented to the extent practicable. ~~Waterbodies and Riparian Lands shall be implemented to the extent practicable.~~

A dry wetland is defined~~typically has groundwater level some depth below the surface. Trench excavations typically are stable and normal~~ in Section 6.5.1. In these wetlands, equipment~~width. Equipment~~ can traverse the wetland without the support of mats or timber riprap.

A standard wetland environment typically has soils that are saturated and non-cohesive~~noncohesive~~. Difficult trenching conditions are likely resulting in excessively wide trenches. In these wetland environment types, supplemental support in the form of timber riprap or prefabricated equipment mats may be required for construction equipment to safely and efficiently operate.

A flooded wetland involves the presence of standing water over much of the wetland area. Equipment typically cannot traverse the wetland and must generally move around that portion of the area. Access is typically limited to marsh backhoes or equipment working from flexifloats or equivalents.

Keystone may allow modification of the following specifications as necessary to accommodate site-specific conditions or procedures. Any modifications must still comply with all applicable regulations and permits.

6.2 Easement and Workspace

The Contractor shall maintain wetland boundary markers during construction in all areas and until permanent seeding is complete in non-cultivated areas.

The width of the construction right-of-way shall be reduced to 85 feet or less in standard wetlands unless non-cohesive soil conditions require utilization of a greater width and unless the USACE or other regulatory authority authorizes a greater width.~~.~~

The Contractor shall locate extra work areas (such as staging areas and additional spoil storage areas) shall be at least 10 feet away from wetland boundaries, where topographic conditions permit.

The Contractor shall limit clearing of vegetation between extra work areas and the edge of the wetland to the construction right-of-way and limit the size of extra work areas to the minimum needed to construct the wetland crossing.

6.3 Vehicle Access and Equipment Crossing

The only access roads, other than the construction right-of-way, that the Contractor shall use in wetlands are those existing public roads and private roads acquired by Keystone from the landowner shown on the construction drawings.

To the extent practicable, the Contractor's construction equipment operating in saturated wetlands or wetlands with standing water shall be limited to that needed to clear the construction right-of-way, dig the trench, fabricate and install the pipeline, backfill the trench, and restore the construction right-of-way.

If equipment must operate within a wetland containing standing water or saturated soils, the Contractor shall use the following methods for equipment access unless otherwise approved by Keystone based on site-specific conditions:

- wide-track or balloon-tire construction equipment; and
- conventional equipment operated from timber and slash (riprap) cleared from the right-of-way, timber mats, or prefabricated equipment mats.

6.4 Temporary Erosion and Sediment Control

The Contractor shall install sediment barriers across the entire construction right-of-way immediately upslope of the wetland boundary at all standard wetland crossings, as necessary, to prevent sediment flow into the wetland. Sediment barriers must be properly maintained by the Contractor throughout construction and reinstalled as necessary. In the travel lane, these may incorporate removable sediment barriers or driveable berms. Removable sediment barriers can be removed during the construction day, but shall be re-installed after construction has stopped for the day or when heavy precipitation is imminent. The Contractor shall maintain sediment barriers until replaced by permanent erosion controls or restoration of adjacent upland areas is complete. The Contractor shall not install sediment barriers at wetlands designated as "dry" unless otherwise specified by Keystone.

Where standard wetlands are adjacent to the construction right-of-way, the Contractor shall install sediment barriers along the edge of the construction right-of-way as necessary to prevent a sediment flow into the wetland.

6.5 Wetland Crossing Procedures

The following general mitigative procedures shall be followed by the Contractor in all wetlands unless otherwise approved or directed by Keystone based on site-specific conditions. All work shall be conducted in accordance with applicable permits.

- limit the duration of construction-related disturbance within wetlands to the extent practicable;
- use no more than two layers of timber riprap to stabilize the construction right-of-way;
- cut vegetation off at ground level leaving existing root systems in place and remove it from the wetland for disposal;
- limit pulling of tree stumps and grading activities to directly over the trench line unless safety concerns require the removal of stumps from the working-side of the construction ROW;
- segregate a maximum of 12 inches of topsoil from the area disturbed by trenching in dry wetlands, where practicable;
- restore topsoil to its approximate original stratum, after backfilling is complete;
- dewater the trench in a manner to prevent erosion and heavily silt-laden flowing directly into any wetland or waterbody;
- remove all timber riprap and prefabricated equipment mats upon completion of construction;
- locate hydrostatic test manifolds outside wetlands and riparian areas to the maximum extent practicable;
- prohibit storing hazardous materials, chemicals, fuels, lubricating oils, or perform concrete coating activities in a wetland, or within 100 feet of any wetland boundary;
- perform all equipment maintenance and repairs upland locations at least 100 feet from waterbodies and wetlands;
- avoid parking equipment overnight within 100 feet of a watercourse or wetland;
- prohibit washing equipment in streams or wetlands;
- install trench breakers and/or seal the trench to maintain the original wetland hydrology, where the pipeline trench may drain a wetland;
- attempt to refuel all construction equipment in an upland area at least 100 feet from a wetland boundary (otherwise follow the procedures outlined in Section 3); and
- avoid sand blasting in wetlands to the extent practicable. If sandblasting is performed within a wetland, the Contractor shall place a tarp or suitable material in such a way as to collect as much waste shot as possible and dispose of the collected waste. The Contractor shall clean up all visible deposits of wastes and dispose of the waste at an approved disposal facility.

Specific procedures for each type of wetland crossing method are listed below and shall be designated on the construction drawings but may be modified depending on site conditions at the time of construction. All work shall be conducted in accordance with applicable permits.

6.5.1 Dry Wetland Crossing Method

Topsoil shall be segregated. Pipe stringing and fabrication may occur within the wetland adjacent to the trench line or adjacent to the wetland in a designated extra workspace.

The dry wetland crossing procedure depicted in Detail 8 shall be used where this type of wetland is identified on the construction drawings. The following are exceptions to standard wetland crossing methods:

- The width of the construction right-of-way for upland construction is maintained through the wetland.
- Where extra work areas (such as staging areas and additional spoil storage areas) are designated on the construction drawings, they may be placed no closer than 10 feet from the wetland's edge.
- ~~If the wetland is cultivated, the topsoil shall be stripped using the trench and spoil side method at the same depth as the adjacent upland areas.~~
- Seeding requirements for agricultural lands shall be applied to farmed wetlands.

6.5.2 Standard Wetland Crossing Method

Topsoil stripping is impracticable due to the saturated nature of the soil. Pipe stringing and fabrication may occur within the wetland adjacent to the trench line or adjacent to the wetland in a designated extra workspace. Based upon the length of a standard wetland crossing and presence of sufficient water to float the pipe, the Contractor may elect to install a standard wetland crossing utilizing the "push/pull" method.

The standard wetland crossing procedure depicted in Detail 9 shall be used where this type of wetland is identified on the construction drawings.

Procedures unique to standard wetlands include:

- limiting construction right-of-way width to a maximum of 85 feet unless site conditions warrant a wider width;
- utilizing low-ground-pressure construction equipment or support equipment on timber riprap or timber mats; and
- installing sediment barriers across the entire right-of-way where the right-of-way enters and exits the wetland.

6.5.3 Flooded Push/Pull Wetland Crossing Method

Where standing surface water or high groundwater levels make trenching difficult, trench widths up to 35 feet are common. Topsoil stripping is impossible due to the flooded conditions. Pipe stringing and fabrication is required adjacent to the wetland in a designated extra workspace. Using floatation devices, the pipe string is pushed and pulled from the extra workspace to the trench.

The Push/Pull wetland crossing procedure as depicted in Detail 10 shall be used where water is sufficient to float the pipeline in the trench and other site conditions allow.

Clean metal barrels or Styrofoam floats may be used to assist in the flotation of the pipe. Metal banding shall be used to secure the barrels or floats to the pipe. All barrels, floats, and banding shall be recovered and removed upon completion of lower in. Backfill shall not be allowed before recovery of barrels, floats, and banding.

6.6 Restoration and Reclamation

All timber riprap, timber mats, and prefabricated equipment mats and other construction debris shall be removed upon completion of construction. As much as is feasible, the Contractor shall replace topsoil and restore original contours with no crown over the trench. Any excess spoil shall be removed from the wetland. The Contractor shall stabilize wetland edges and adjacent upland areas by establishing permanent erosion control measures and revegetation, as applicable, during final clean up.

For each standard wetland crossed, the Contractor shall install a permanent slope breaker and trench breaker at the base of slopes near the boundary between the wetland and adjacent upland areas. The Contractor shall locate the trench breaker immediately upslope of the slope breaker.

~~In the absence of detailed revegetation plans or until the appropriate seeding season for permanent wetland vegetation in standard wetlands, the Contractor shall apply a temporary cover crop of annual ryegrass or oats on the construction right-of-way at a rate adequate for germination and ground cover unless standing water is present. The Contractor shall apply the temporary cover crop during final cleanup. For farmed wetlands, the Contractor shall apply seeding requirements for agricultural lands or as required by the landowner.~~

The Contractor shall not use fertilizer, lime, or mulch in wetlands unless required in writing by the appropriate land management agency.

All wetland areas within conservation lands or easements will be restored to a level consistent with any additional criteria established by the relevant managing agency.

~~For FWS easement wetlands, topographic surveys will be conducted prior to construction through the wetland. Sediment barriers will be installed at FWS easement wetlands and to protect wetlands adjacent to the right-of-way where determined appropriate by the environmental inspector based on field conditions. During restoration of the FWS wetlands, final grades must be restored to within 0.1 foot of original elevations.~~

7.0 WATERBODIES AND RIPARIAN AREAS

7.1 General

The Contractor shall comply with requirements of all permits issued for the waterbody crossings by federal, state or local agencies.

Waterbody includes any areas delineated as jurisdictional natural or artificial stream, river, or drainage~~ with perceptible flow at the time of crossing~~, and other permanent waterbodies such as ponds and lakes:

- Minor Waterbody includes all waterbodies less than or equal to 10 -feet wide at the water's edge at the time of construction.
- Intermediate Waterbody includes all waterbodies greater than 10 -feet wide but less than or equal to 100 feet wide at the water's edge at the time of construction.
- Major Waterbody includes all waterbodies greater than 100 feet wide at the water's edge at the time of construction.

In the event a waterbody crossing is located within or adjacent to a wetland crossing, the Contractor, to the extent practicable, shall implement the provisions of both Section 6 - Wetland Crossings and Section 7 - Waterbodies and Riparian Areas.

The Contractor shall supply and install advisory signs in a readily visible location along the construction right-of-way at a distance of approximately 100 feet on each side of the crossing and on all roads which provide direct construction access to waterbody crossing sites. Signs shall be supplied, installed, maintained, and then removed upon completion of the Project. Additionally, signs shall be supplied and installed by the Contractor on all intermediate and major waterbodies accessible to recreational boaters warning boaters of pipeline construction operations.

The Contractor shall not store hazardous materials, chemicals, fuels, lubricating oils, or perform concrete coating within 100 feet of any waterbody. The Contractor shall not refuel construction equipment within 100 feet of any waterbody. If the Contractor must refuel construction equipment within 100 feet of a waterbody, it must be done in accordance with the requirements outlined in Section 3. All equipment maintenance and repairs will be performed in upland locations at least 100 feet from waterbodies and wetlands. All equipment parked overnight shall be at least 100 feet from a watercourse or wetland, if possible. Equipment shall not be washed in streams or wetlands.

Throughout construction, the Contractor shall maintain adequate flow rates to protect aquatic life and to prevent the interruption of existing downstream uses.

Keystone may allow modification of the following specifications as necessary to accommodate specific situations or procedures. Any modifications must comply with all applicable regulations and permits. Keystone will complete site-specific crossing plans for certain waterbody crossings if required by the applicable regulatory agencies during federal or state permitting processes.

7.2 Easement and Work Space

The permanent easement, temporary work space, additional temporary work space, and any special restrictions shall be depicted on the construction drawings. The work shall be contained within these areas and be limited in size to the minimum required to construct the waterbody crossing.

The Contractor shall locate all extra work areas (such as staging areas and additional spoil storage areas) at least 10 feet from the water's edge if practicable.

At all waterbody crossings, the Contractor shall install flagging across the construction right-of-way at least 10 feet from the water's edge prior to clearing and ensure that riparian cover is maintained where practicable during construction.

7.3 Vehicle Access and Equipment Crossings

The Contractor shall inspect equipment for fluid leaks prior to entering or crossing over waterbodies.

Equipment bridges shall be installed at all flowing waterbodies and as directed by the Keystone EI.~~.~~ Equipment crossings shall be constructed as described in Details 16, 17 and/or 18.

Equipment crossings shall be perpendicular to drainage bottoms wherever possible.

Erosion and sediment control barriers will be installed and maintained around vehicle access points as necessary to prevent sediment from reaching the waterway.

The Contractor shall be responsible for the installation, maintenance, and removal of all temporary access crossings including portable bridges, bridges made from timber or mats, flumes, culverts, sand bags, subsoil, coarse granular material, and riprap.

The Contractor shall ensure that culverts and flumes are sized and installed of sufficient diameter to accommodate the existing flow of water and those that may potentially be created by sudden runoffs. Flumes shall be installed with the inlet and outlet at natural grade if possible.

Where bridges, culverts or flumes are installed across the work area, the Contractor shall be responsible for maintaining them (e.g. preventing collapse, clogging or tilting). All flumes and culverts shall be removed as soon as possible upon completion of construction.

The width of the temporary access road across culverts and flumes and the design of the approaches and ramps shall be adequate for the size of vehicle and equipment access required. The ramps shall be of sufficient depth and constructed to prevent collapse of the flumes, and the approaches on both sides of the flume shall be feathered.

Where culverts are installed for access, the culvert shall be of sufficient length to convey the stream flow through the construction zone.

The Contractor shall maintain equipment bridges to prevent soil from entering the waterbody.

7.4 Waterbody Crossing Methods

Construction methods pertinent to waterbody crossings are presented below. Selection of the most appropriate method at each crossing shall be depicted on the construction drawings but may be amended or changed based on site-specific conditions (i.e., environmental sensitivity of the waterbody, depth, and rate of flow, subsurface soil conditions, and the expected time and duration of construction) at the time of crossing. Construction will involve dry-ditch techniques at crossings where the timing of construction does not adequately protect environmentally sensitive waterbodies, as determined by the appropriate regulatory authority. Where required, horizontal directional drilling (HDD) will be used at designated major and sensitive waterbodies crossings. Each waterbody crossing shall be accomplished using one of the following construction methods:

- Non-flowing Open Cut Crossing Method - (Detail 11)
- Flowing Open Cut Crossing Method – Minor, Intermediate or Major Waterbody - (Detail 12)
- Flowing Stream Crossing – Dry Flume Method - (Detail 13)
- Flowing Stream Crossing – Dry Dam-and-Pump Method - (Detail 14)
- Horizontal Directional Drill Crossing - (Detail 15)
- Horizontal Bore Crossing - (Detail 21)

In conjunction with the appropriate jurisdictional agency, Keystone will develop specific crossing plans for major water bodies that contain recreationally or commercially important fisheries, or are classified as special use. Keystone will consult with state fisheries agencies with respect to applicable construction windows for each crossing and develop specific construction and crossing methods for open cuts in conjunction with USACE permitting and USFWS consultation.

7.4.1 Non-flowing Open Cut Crossing Method

The Contractor shall utilize the Non-flowing Open Cut Crossing Method (Detail 11) for all waterbody crossings (ditches, gullies, drains, swales, etc.) with no perceptible flow at the time of construction. Should site conditions change and the waterbody is flowing at the time of construction, the Contractor shall install the crossing utilizing the Flowing Open Cut Crossing Method (Detail 12) unless otherwise approved by Keystone.

7.4.2 Flowing Open Cut Crossing Method of Minor, Intermediate, and Major Waterbodies

For minor waterbody crossings, except where the flume method is used, the Contractor shall complete construction in the waterbody (not including blasting, if required) as shown on Detail 12 within 24 hours if practicable.

For intermediate waterbodies, the Contractor shall attempt to complete trenching and backfill work within the waterbody (not including blasting if required) within 48 hours if practicable as shown on Detail 12.

The Contractor shall construct each major waterbody crossing in accordance with a site-specific plan as shown in the construction drawings. The Contractor shall complete in-stream construction activities as expediently as practicable.

7.4.3 Flowing Stream Crossing – Dry Flume Method

Where required, the Contractor shall utilize the Flowing Open Cut Crossing – Dry Flume Method as shown on Detail 13 with the following "dry ditch" techniques:

- Flume pipe shall be installed after blasting (if necessary), but before any trenching.
- Sand bag, sand bag and plastic sheeting diversion structure, or equivalent shall be used to develop an effective seal and to divert stream flow through the flume pipe (some modifications to the stream bottom may be required in order to achieve an effective seal).
- Flume pipe(s) shall be aligned to prevent bank erosion and streambed scour.

- Flume pipe shall not be removed during trenching, pipe laying, or backfilling activities, or initial streambed restoration efforts.
- All flume pipes and dams that are not also part of the equipment bridge shall be removed as soon as final clean up of the stream bed and bank is complete.

7.4.4 Flowing Stream Crossing – Dry Dam-and-Pump Method

Where specified in the construction drawings, the Contractor shall utilize the Flowing Open Cut Crossing – Dry Dam-and-Pump Method as shown on Detail 14. The dam-and-pump crossing method shall meet the following performance criteria:

- sufficient pumps to maintain 1.5 times the flow present in the stream at the time of construction;
- at least one back up pump available on site;
- dams constructed with materials that prevent sediment and other pollutants from entering the waterbody (e.g., sandbags or clean gravel with plastic liner);
- screen pump intakes installed;
- streambed scour prevented at pump discharge; and
- dam and pumps shall be monitored to ensure proper operation throughout the waterbody crossing.

7.4.5 Horizontal Directional Drill Crossings

Where required, the horizontal directional drill method as shown on Detail 15 shall be utilized for designated major and sensitive waterbodies. The Contractor shall construct each directional drill waterbody crossing in accordance with a site specific plan as shown in the construction drawings.

Drilling fluids and additives utilized during implementation of a directional drill shall be non-toxic to the aquatic environment.

The Contractor shall develop a contingency plan to address a frac-out during a directional drill. The plan shall include instructions for monitoring during the directional drill and mitigation in the event that there is a release of drilling fluids. Additionally, the waterbody shall be monitored downstream by the Contractor for any signs of drilling fluid.

The Contractor shall dispose of all drill cuttings and drilling mud as permitted by the appropriate regulatory authority at a Keystone-approved location. Disposal options may include spreading over the construction right-of-way in an upland location approved by Keystone or hauling to an approved licensed landfill or other site approved by Keystone.

7.4.6 Horizontal Bore Crossings

Where required, the horizontal bore method as shown on Detail 21 shall be utilized for crossing waterbodies. The Contractor shall construct each horizontal bore waterbody crossing in accordance with a site specific plan as shown in the construction drawings.

7.5 Clearing

Except where rock is encountered and at non-flowing open cut crossings, all necessary equipment and materials for pipe installation must be on site and assembled prior to commencing trenching in a waterbody. All staging areas for materials and equipment shall be located at least 10 feet from the waterbody edge. The Contractor shall preserve as much vegetation as possible along the waterbody banks while allowing for safe equipment operation.

Clearing and grubbing for temporary vehicle access and equipment crossings shall be carefully controlled to minimize sediment entering the waterbody from the construction right-of-way.

Clearing and grading shall be performed on both sides of the waterbody prior to initiating any trenching work. All trees shall be felled away from watercourses.

Plant debris or soil inadvertently deposited within the high water mark of waterbodies shall be promptly removed in a manner that minimizes disturbance of the waterbody bed and bank. Excess floatable debris shall be removed above the high water mark from areas immediately above crossings.

Vegetation adjacent to waterbody crossings by horizontal directional drill or boring methods shall not be disturbed except by hand clearing as necessary for drilling operations.

7.6 Grading

The construction right-of-way adjacent to the waterbody shall be graded so that soil is pushed away from the waterbody rather than towards it whenever possible.

In order to minimize disturbance to woody riparian vegetation within extra workspaces adjacent to the construction right-of-way at waterbody crossings, the Contractor shall minimize grading and grubbing of waterbody banks. To the extent practicable, grubbing shall be limited to the ditch line plus an appropriate width to accommodate safe vehicle access and the crossing.

7.7 Temporary Erosion and Sediment Control

The Contractor shall install and maintain sediment barriers across the entire construction right-of-way at all flowing waterbody crossings.

The Contractor shall install sediment barriers immediately after initial disturbance of the waterbody or adjacent upland. Sediment barriers must be properly maintained throughout construction and reinstalled as necessary (such as after backfilling of the trench) until replaced by permanent erosion controls or restoration of adjacent upland areas is complete.

Where waterbodies are adjacent to the construction right-of-way, the Contractor shall install and maintain sediment barriers along the edge of the construction right-of-way as necessary to contain spoil and sediment within the construction right-of-way.

7.8 Trenching

The following requirements apply to all waterbody crossings except those being installed by the non-flowing open cut crossing method.

All equipment and materials shall be on site before trenching in the active channel of all minor waterbodies containing state-designated fisheries, and in intermediate and major waterbodies. All activities shall proceed in an orderly manner without delays until the trench is backfilled and the stream banks stabilized. The Contractor shall not begin in-stream activity until the in-stream pipe section is complete and ready to be installed in the waterbody.

The Contractor shall use trench plugs at the end of the excavated trench to prevent the diversion of water into upland portions of the pipeline trench and to keep any accumulated upland trench water out of the waterbody. Trench plugs must be of sufficient size to withstand upslope water pressure.

The Contractor shall conduct as many in-stream activities as possible from the banks of the waterbodies. The Contractor shall limit the use of equipment operating in waterbodies to that needed to construct each crossing.

The Contractor shall place all spoil from minor and intermediate waterbody crossings and upland spoil from major waterbody crossings in the construction right-of-way at least 10 feet from the water's edge or in additional extra work areas. No trench spoil, including spoil from the portion of the trench across the stream channel, shall be stored within a waterbody unless the crossing cannot be reasonably completed without doing so.

The Contractor shall install and maintain sediment barriers around spoil piles to prevent the flow of spoil into the waterbody.

Spoil removed during ditching shall be used to backfill the trench usually with a backhoe, clamshell, or a dragline working from the waterbody bank. Sand, gravel, rockshield, or fill padding shall be placed around the pipe where rock is present in the channel bottom.

7.9 Pipe Installation

The following requirements apply to all waterbody crossings except those being installed by the non-flowing open cut crossing method.

A "free stress" pipe profile shall be used at all minor, intermediate, and major waterbodies with gradually sloping stream banks. The "box bend" pipe profile may~~shall~~ be used for intermittent and major waterbodies with steep stream banks.

The trench shall be closely inspected to confirm that the specified cover and adequate bottom support can be achieved, and shall require Keystone approval prior to the pipe being installed. Such inspections shall be performed by visual inspection and/or measurement by a Keystone representative. In rock trench, the ditch shall be adequately padded with clean granular material to provide continuous support for the pipe.

The pipe shall be pulled into position or lowered into the trench and shall, where necessary, be held down by suitable negative buoyancy control, as-built recorded and backfilled immediately to prevent the pipe from floating.

The Contractor shall provide sufficient approved lifting equipment to perform the pipe installation in a safe and efficient manner. As the coated pipe is lowered in, it shall be prevented from swinging or rubbing against the sides of the trench. Only properly manufactured slings, belts, and cradles suitable for handling coated pipe shall be used. All pipes shall be inspected for coating flaws and/or damage as it is being lowered into the trench. Any damage to the pipe or coating shall be repaired.

7.10 Backfilling

The following requirements apply to all waterbody crossings except those being installed by the non-flowing open cut crossing method.

Trench spoil excavated from waterbodies shall be used to backfill the trench across waterbodies.

After lowering in is complete, but before backfilling, the line shall be re-inspected to ensure that no skids, brush, stumps, trees, boulders, or other debris is in the trench. If discovered, such materials or debris shall be removed from the trench prior to backfilling.

For each major waterbody crossed, the Contractor shall install a trench breaker at the base of slopes near the waterbody unless otherwise directed by Keystone based on site specific conditions. The base of slopes at intermittent waterbodies shall be assessed on site and trench breakers installed only where necessary.

Slurred muck or debris shall not be used for backfill. At locations where the excavated native material is not acceptable for backfill or must be supplemented, the Contractor shall provide granular material approved by Keystone.

If specified in the construction drawings, the top of the backfill in the stream shall be armored with rock riprap or bio-stabilization materials as appropriate.

7.11 Stabilization and Restoration of Stream Banks and Slopes

The Contractor will restore the contours of the bed and banks of waterways immediately after pipe installation and backfill, except over the travel lane. Travel lanes and bridges may stay in place until hydrostatic testing and cleanup are complete. All materials used to support construction activities will be removed from waterbodies and wetlands, including, but not limited to, flumes, mats, plastic sheeting, and sandbags.

The stream bank contour shall be re-established. All debris shall be removed from the streambed and banks. Stream banks shall be stabilized and temporary sediment barriers shall be installed within 24 hours of completing the crossing if practicable.

Approach slopes shall be graded to an acceptable slope for the particular soil type and surface run off controlled by installation of permanent slope breakers. Where considered necessary, the integrity of the slope breakers shall be ensured by lining with erosion control blankets.

Immediately following reconstruction of the stream banks, the Contractor shall install seed and flexible channel liners on waterbody banks as shown in Detail 19.

If the original stream bank is excessively steep and unstable or flow conditions are severe, or if specified on the construction drawings, the banks shall be stabilized with rock riprap, gabions, stabilizing cribs, or bio-stabilization measures to protect backfill prior to reestablishing vegetation.

Stream bank riprap structures shall consist of a layer of stone, underlain with approved filter fabric or a gravel filter blanket in accordance with Detail 20. Riprap shall extend from the stabilized streambed to the top of the stream bank. Where practicable, native rock shall be utilized.

Bio-stabilization techniques which may be considered for specific crossings are shown in Details 23 and 24.

The Contractor shall remove equipment bridges as soon as possible after final clean up.

8.0 HYDROSTATIC TESTING

8.1 Testing Equipment Location

The Contractor shall provide for the safety of all pipeline construction personnel and the general public during hydrostatic test operations by placing warning signs in populated areas.

The Contractor shall locate hydrostatic test manifolds 100 feet outside wetlands and riparian areas to the maximum extent practicable.

8.2 Test Water Source and Discharge Locations

Keystone is responsible for acquiring all permits required by federal, state and local agencies for procurement of water and for the discharge of water used in the hydrostatic testing operation. Keystone shall provide the Contractor with a copy of the appropriate withdrawal/discharge permits for hydrostatic test water. The Contractor shall keep water withdrawal/discharge permits on site at all times during testing operations.

Any water obtained or discharged shall be in compliance with permit notice requirements and with sufficient notice for Keystone's Testing Inspector to make water sample arrangements prior to obtaining or discharging water. Keystone will obtain water samples for analysis from each source before filling the pipeline. In addition, water samples will be taken prior to discharge of the water, as required by state and federal permits.

In some instances sufficient quantities of water may not be available from the permitted water sources at the time of testing. Withdrawal rates may be limited as stated by the permit. Under no circumstances shall an alternate water source be used without prior authorization from Keystone.

The Contractor shall be responsible for obtaining any required water analyses from each source to be used in sufficient time to have a lab analysis performed prior to any filling operations. The sample bottle shall be sterilized prior to filling with the water sample. The analysis shall determine the pH value and total suspended solids. Each bottle shall be marked with:

- source of water with pipeline station number;
- date taken;
- laboratory order number; and
- name of person taking sample.

Staging/work areas for filling the pipeline with water will be located a minimum of 100 feet from the waterbody or wetland boundary if topographic conditions permit. The Contractor will install temporary sediment filter devices adjacent to all streams to prevent sediments from leaving the construction site.

The Contractor shall screen the intake hose to prevent the entrainment of fish or debris. The hose shall be kept at least 1 foot off the bottom of the waterbody. Refueling of construction equipment shall be conducted a minimum distance of 100 feet from the stream or a wetland. Pumps used for hydrostatic testing within 100 feet of any waterbody or wetland shall be operated and refueled in accordance with Section 3.

During hydrostatic test water withdrawals, the Contractor will maintain adequate flow rates in the waterbody to protect aquatic life and provide for downstream uses, in compliance with regulatory and permit requirements.

The Contractor shall not use chemicals in the test water. The Contractor shall not discharge any water containing oil or other substances that are in sufficient amounts as to create a visible color film or sheen on the surface of the receiving water.

~~Potential hydrostatic water sources for the Steele City, Gulf Coast segments, and Houston Lateral are as follows:~~

~~Table 1 – Steele City Segment Drainage Basins and Water Sources~~

~~Drainage Basins & Water Sources~~	~~Location Where Pipeline Crosses Water Source (Mile Post)~~
~~Frenchman Creek~~	~~25~~
~~Willow Creek~~	~~40~~
~~Milk River~~	~~82~~
~~Missouri River~~	~~88~~
~~Redwater River~~	~~146~~
~~Yellowstone River~~	~~195~~
~~Drainage Basins & Water Sources~~	~~Location Where Pipeline Crosses Water Source (Mile Post)~~
~~Cabin Creek~~	~~201~~
~~Sandstone Creek~~	~~244~~
~~Little Beaver Creek~~	~~262~~
~~Boxelder Creek~~	~~281~~
~~Little Missouri River~~	~~291~~
~~South Fork Grand River~~	~~317~~
~~Clarks Fork Creek~~	~~323~~
~~North Fork Moreau River~~	~~356~~
~~South Fork Moreau River~~	~~364~~

~~Cheyenne River~~	~~425~~
~~Bad River~~	~~480~~
~~Dry Creek~~	~~493~~
~~White River~~	~~535~~
~~Cottonwood Creek~~	~~541~~
~~Buffalo Creek~~	~~594~~
~~Keya Paha River~~	~~598~~
~~Spring Creek~~	~~602~~
~~Niobrara River~~	~~613~~
~~North Branch Elkhorn River~~	~~627~~
~~Elkhorn River~~	~~628~~
~~South Fork Elkhorn River~~	~~658~~
~~Cedar River~~	~~695~~
~~Loup River~~	~~738~~
~~Prairie Creek~~	~~745~~
~~Platte River~~	~~754~~
~~Big Blue River~~	~~763~~
~~Beaver Creek~~	~~778~~
~~West Fork Big Blue River~~	~~787~~
~~Turkey Creek~~	~~807~~
~~South Fork Swan Creek~~	~~824~~

~~Table 2 – Gulf Coast Segment Drainage Basins and Water Sources~~

~~Drainage Basins & Water Sources~~	~~Location Where Pipeline Crosses Water Source (Mile Post)~~
~~North Canadian River~~	~~39~~
~~Canadian River~~	~~75~~
~~Red River~~	~~155~~
~~Bois D'Arc Creek~~	~~161~~
~~North Sulphur River~~	~~190~~
~~South Sulphur River~~	~~200~~
~~Sabine River~~	~~262~~
~~East Fork Angelina~~	~~312~~
~~Angelina~~	~~332~~

~~Neches River~~	~~366~~
~~Menard Creek~~	~~393~~
~~Hillebrandt Bayou~~	~~469~~

~~**Table 3 – Houston Lateral Segment Drainage Basins and Water Sources**~~

~~Drainage Basins & Water Sources~~	~~Location Where Pipeline Crosses Water Source (Mile Post)~~
~~Trinity River~~	~~22~~
~~San Jacinto River~~	~~44~~

Selected road, railroad, and river crossing pipe sections may be specified to be pre-tested for a minimum of 4 hours. The water for pre-testing of any road and railroad crossings shall be hauled by a tanker truck from an approved water source. Water for pre-testing of a river crossing may be hauled or taken from the respective river if it is an approved water source. Since the volume of water utilized in these pre-tests shall be relatively small, the water shall be discharged overland along the construction right-of-way and allowed to soak into the ground utilizing erosion and sediment control mitigative measures.

Selection of final test water sources will be determined based on site conditions at the time of construction and applicable permits.

8.3 Filling the Pipeline

After final positioning of the pipe, the Contractor shall fill the pipe with water. Pipe ends shall not be restrained during the fill. The fill pump shall be set on a metal catch pan of sufficient dimensions to contain all leaking lubricants or fuel and prevent them from entering the water source. The suction inlet must be placed in a screened enclosure located at a depth that shall not allow air to be drawn in with the water. The screened enclosure shall be such that the fill water is free of organic or particulate matter.

The Contractor shall provide a filter of the backflushing or cartridge type with a means of cleaning without disconnecting the piping. The filter shall have the specifications of 100 mesh screen. If the cartridge type is used, a sufficient quantity of cartridges shall be on hand at the filter location. The Contractor shall install the filter between the fill pump and the test header. The Contractor shall be responsible for keeping the backflush valve on the filter closed during the filling operation. The Contractor shall be responsible for the proper disposal of materials backflushed from the filter or filter cartridges. The Contractor shall not be allowed to backflush the filter into the stream or other water source.

During water-filling of the pipeline, the Contractor shall employ fill pumps capable of injecting water into the pipeline at a maximum rate of approximately 0.7 to 1.0

mile per hour, except as limited by permits or the maintenance of adequate flow rates in the waterbody, as follows:

Nominal OD	Max GPM
36"	3000

The Contractor shall maintain flow rates as necessary to protect aquatic life, provide for all waterbody uses, and provide for downstream withdrawals of water by existing users.

~~In waterbodies where sensitive species are located, Keystone will generally avoid withdrawal of hydrostatic test water until after August 1, unless specific approval is obtained in advance from the appropriate regulatory or resource agencies.~~ In areas where zebra mussels are known to occur, all equipment used during the hydrostatic test withdrawal and discharge will be thoroughly cleaned before being used at subsequent hydrostatic test locations to prevent the transfer of zebra mussels or their larvae (veligers) to new locations.

8.4 Dewatering the Pipeline

The Contractor shall comply with state-issued NPDES permits for discharging test water.

The Contractor shall not discharge any water containing oil or other substances that are in sufficient amounts as to create a visible color film on the surface of the receiving water.

The Contractor shall not discharge into state-designated exceptional value waters, waterbodies which provide habitat for federally listed threatened or endangered species, or waterbodies designated as public water supplies, unless appropriate federal, state, and local permitting agencies grant written permission. To avoid impacts from introduced species, no inter-basin transfers (discharge) of hydrostatic test water will occur.

The discharge operation will be monitored and water samples will be taken prior to the beginning of the discharge to ensure that it complies with the Project and permit requirements. If required by state permits, additional water quality testing will be conducted during discharge, in accordance with permit conditions.

The Contractor shall calculate, record, and provide to Keystone the day, date, time, location, total volume, maximum rate, and methods of all water discharged to the ground or to surface water in association with hydrostatic testing.

The Contractor shall regulate the pig velocity discharge rate (3000 gpm maximum), use energy dissipation devices, and install sediment barriers, as necessary, to prevent erosion, streambed scour, suspension of sediments, or excessive stream flow. Water must be disposed of using good engineering judgment so that all federal, state, and local environmental standards are met.

Dewatering lines shall be of sufficient strength and be securely supported and tied down at the discharge end to prevent whipping during this operation.

To reduce the velocity of the discharge, The Contractor shall utilize an energy-dissipating device described as follows:

8.4.1 Splash Pup

A splash pup consists of a piece of large diameter pipe (usually over 20" outside diameter) of variable length with both ends partially blocked that is welded perpendicularly to the discharge pipe. As the discharge hits against the inside wall of the pup, the velocity is rapidly reduced and the water is allowed to flow out either end. A variation of the splash pup concept, commonly called a diffuser, incorporates the same design, but with capped ends and numerous holes punched in the pup to diffuse the energy.

8.4.2 Splash Plate

The splash plate is a quarter section of 36-inch pipe welded to a flat plate and attached to the end of a 6-inch discharge pipe. The velocity is reduced by directing the discharge stream into the air as it exits the pipe. This device is also effective for most overland discharge.

8.4.3 Plastic Liner

In areas where highly erodible soils exist or in any low flow drainage channel, it is a common practice to use layers of visqueen (or any of the new construction fabrics currently available) to line the receiving channel for a short distance. One anchoring method may consist of a small load of rocks to keep the fabric in place during the discharge. Additional best management practices, such as the use of plastic sheeting or other material to prevent scour, will be used as necessary to prevent excessive sedimentation during dewatering.

8.4.4 Straw Bale Dewatering Structure

Straw bale dewatering structures are designed to dissipate and remove sediment from the water being discharged. Straw bale structures are used for on land discharge of wash water and hydrostatic test water and in combination with other energy dissipating devices for high volume discharges. A straw bale dewatering structure is shown In Detail 6. A dewatering filter bags may be sued as an alternative to show bale dewatering structures. A dewatering filter bag is shown in Detail 5.

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Typical Drawing Index

Details 12A, 16A, 18A, 22, 67 & 67A are new additions

NOTE: The following typical drawings are included for ease of reference.

- Details 1 through 31 can be found in the Construction Mitigation and Reclamation Plan

REVISIONS		
01	2008-11-05	REVISED TITLES, ADDED/DEL. DETAILS
02	2010-10-08	REVISED TITLES
03	2010-10-11	REVISED TITLE BLOCK

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CHECKED BY:	WSF
DESIGN CHECKER:	RW
	KEYSTONE XL PROJECT
FIA #	4359
CHAINAGE:	
DISCIPLINE #	03
TITLE	DETAIL INDEX
SCALE	N.T.S.
DWG No	4359-03-ML-00-700
REV	03

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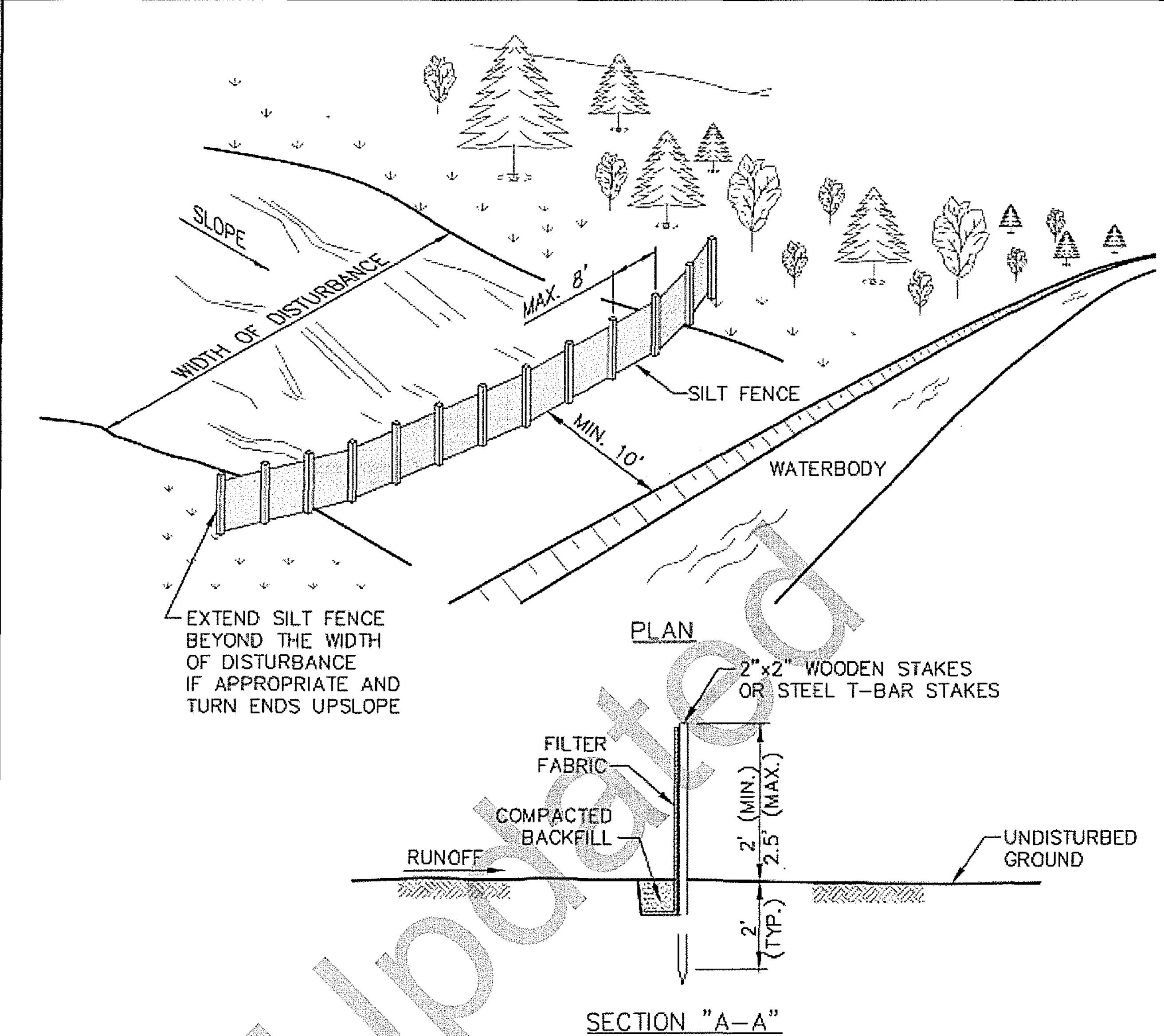

NOTES:

1. MATERIAL SHOULD BE WOVEN GEOTEXTILE FABRIC SUCH AS EXXON GTF 180 OR MIRAFI 600X, OR AN APPROVED EQUIVALENT. SECONDARY REINFORCEMENT, SUCH AS A CONSTRUCTION BARRIER FENCE OR WIRE MESH CAN ALSO BE USED BEHIND THE FILTER FABRIC.
2. SILT FENCE TO BE REINFORCED WITH 2"x2" WOODEN STAKES OR STEEL T-BAR STAKES PLACED EVERY 8' OR CLOSER AS CONDITIONS REQUIRE.
3. ATTACH FILTER FABRIC AT EACH POST AT A MINIMUM OF 3 LOCATIONS.
4. THE FILTER FABRIC MINIMUM LENGTH OF 1' IS TO BE ANCHORED IN A TRENCH WITH WELL COMPACTED BACKFILL OVER THE FABRIC TO PREVENT UNDERMINING.
5. TO ELIMINATE POSSIBLE END FLOW, BOTH ENDS OF THE SILT FENCE SHALL BE TURNED AND EXTENDED UPSLOPE.
6. SILT FENCES ARE TO BE CHECKED AND MAINTAINED ON A REGULAR BASIS. REMOVE ANY BUILD-UP OF SEDIMENT. REPLACE DAMAGED OR INEFFECTIVE SILT FENCE AS SOON AS POSSIBLE.
7. WHERE ANCHORING CONDITIONS FOR THE SILT FENCE ARE POOR, PLACE STRAW BALES ON DOWNSTREAM SIDE OF THE SILT FENCE.
8. INSTALLATION TO BE MODIFIED BY THE PROJECT AS NECESSARY TO SUIT ACTUAL SITE CONDITIONS.

REVISIONS		
01	2008-11-04	UPDATED DRAWING NOTES
02	2010-10-08	UPDATED DRAWING NOTES
03	2010-10-11	REVISED TITLE BLOCK

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DESIGN CHECKER: RW	TITLE: DETAIL 1 TYPICAL SILT FENCE BARRIER	
	SCALE N.T.S.	DWG No 4359-03-ML-05-701 / REV 03

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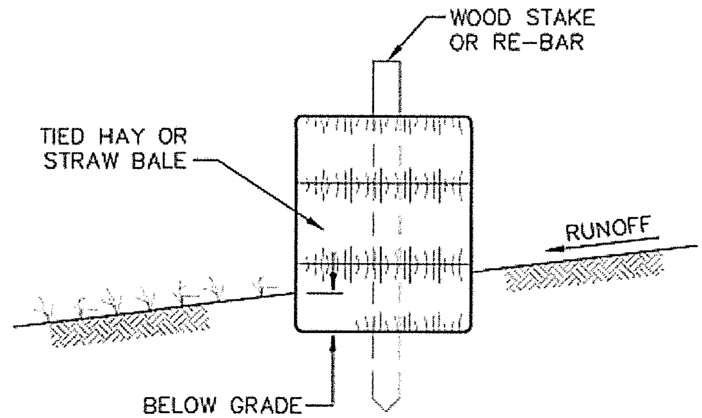
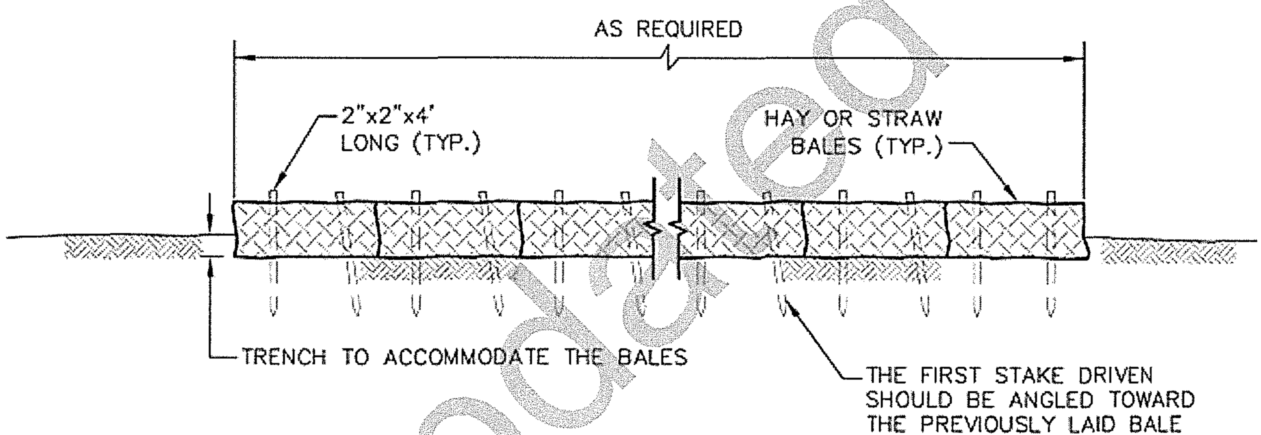


SECTION



SECTION

NOTES:

1. TO ELIMINATE POSSIBLE END FLOW, BOTH ENDS OF THE STRAW BALE BARRIER SHOULD BE TURNED AND EXTENDED UPSLOPE.
2. EACH BALE SHOULD BE SECURED BY AT LEAST 2 STAKES. THE FIRST STAKE IN EACH BALE SHALL BE DRIVEN TOWARD THE PREVIOUSLY LAID BALE TO FORCE THE BALES TOGETHER. ANY GAPS CAN BE FILLED IN BY WEDGING LOOSE STRAW BETWEEN THE BALES. STAKES SHOULD BE DRIVEN. REBAR OR STANDARD "T" OR "U" STEEL POSTS CAN BE USED AS STAKES, BUT IT SHOULD BE NOTED THAT THEY MAY POSE A HAZARD TO EQUIPMENT IF THE BALES DISINTEGRATE.
3. COMPACT THE EXCAVATED SOIL AGAINST THE UPHILL SIDE OF THE BARRIER TO PREVENT PIPING.
4. STRAW OR HAY BALE BARRIERS REQUIRE CONTINUAL MAINTENANCE TO REMOVE COLLECTED SEDIMENT AND REPLACE DAMAGED BALES AS SOON AS POSSIBLE. PAY CLOSE ATTENTION TO THE REPAIR OF DAMAGED BALES, END RUNS AND UNDERCUTTING BENEATH BALES.
5. INSTALLATION TO BE MODIFIED BY THE PROJECT AS NECESSARY TO SUIT ACTUAL SITE CONDITIONS.

REVISIONS		
01	2008-11-04	UPDATED DRAWING NOTES
02	2010-10-08	UPDATED DRAWING NOTES
03	2010-10-11	UPDATED DRAWING NOTES

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	FIA # 4359	CHAINAGE:	DISCIPLINE # 03
	TITLE: DETAIL 2 TYPICAL STRAW OR HAY BALE BARRIER		
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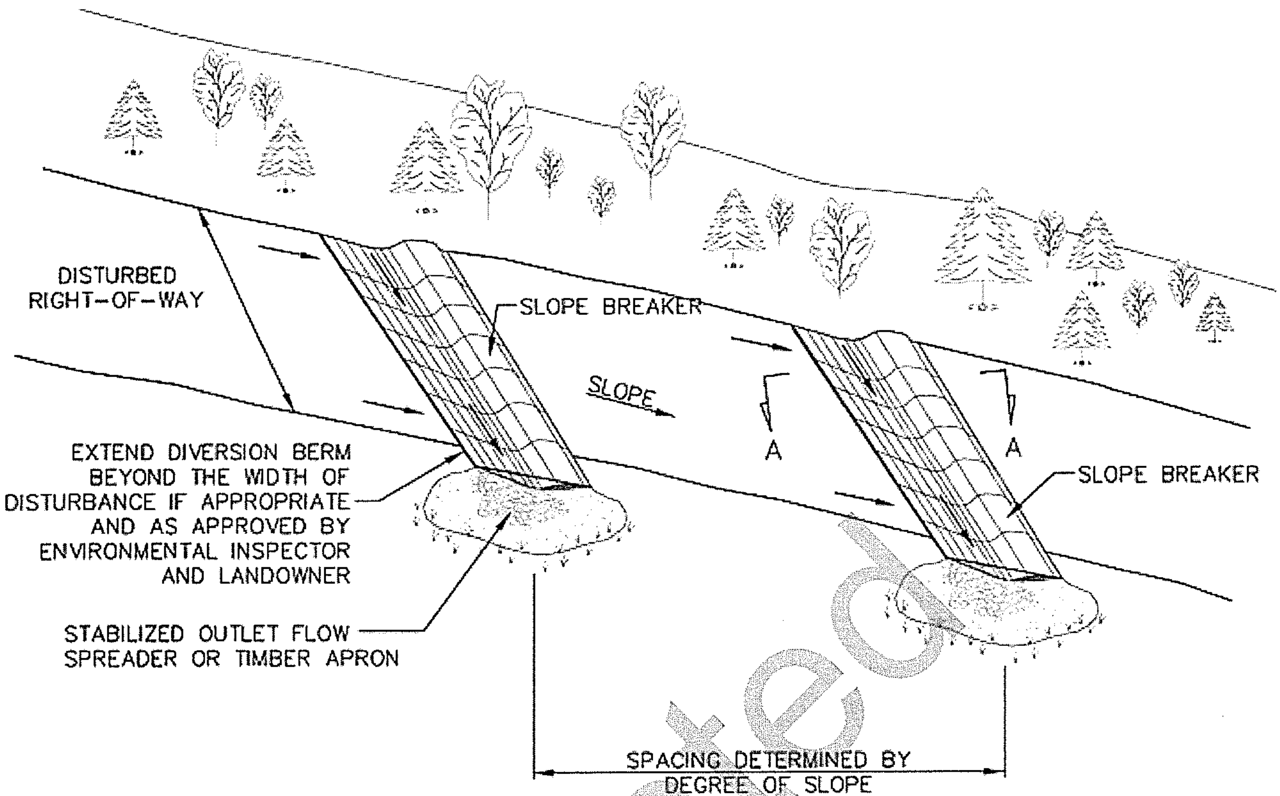

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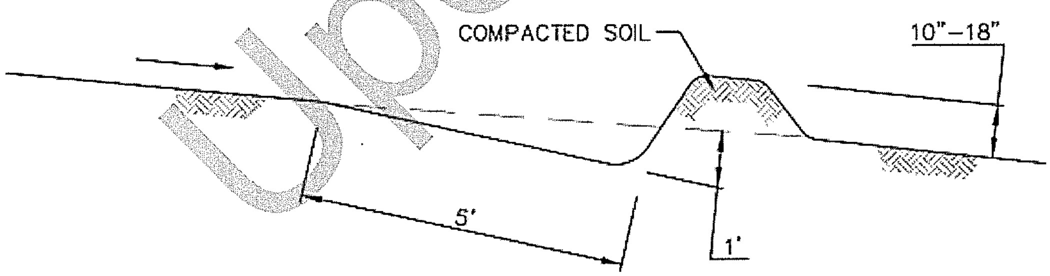

NOTES:

1. PERMANENT SLOPE BREAKERS TO PROVIDE POSITIVE DRAINAGE TO A STABILIZED OUTLET.
2. INSTALLATION SPECIFICATIONS TO BE MODIFIED BY THE PROJECT AS NECESSARY TO SUIT ACTUAL SITE CONDITIONS.
3. THE CONTRACTOR SHALL INSTALL TEMPORARY AND PERMANENT SLOPE BREAKERS ON SLOPES GREATER THAN APPROXIMATELY 5% ON ALL DISTURBED LANDS AT THE FOLLOWING RECOMMENDED SPACING:

SLOPE (%)	SPACING (FEET)
5–15	300
>15–30	200
>30	100

REVISIONS	
01	2008-11-04 MODIFIED DRAWING NOTES
02	2010-10-08 UPDATED DRAWING NOTES
03	2010-10-11 REVISED TITLE BLOCK

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		TITLE: DETAIL 3 TEMPORARY/PERMANENT SLOPE BREAKER DETAIL (WATER BARS)	
		SCALE N.T.S.	DWG No 4359-03-ML-05-703	REV 03

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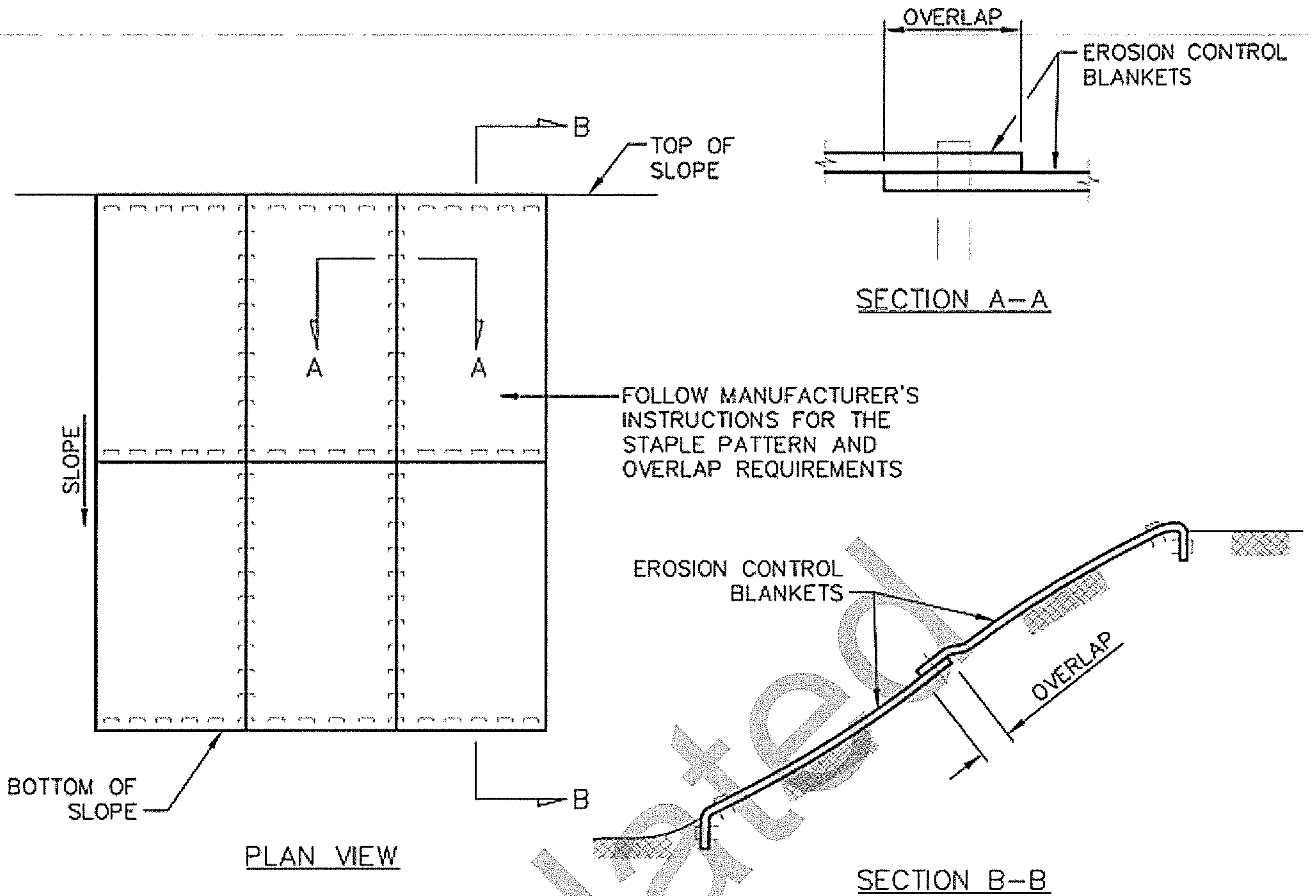

NOTES:

1. INSTALL MATTING IN ACCORDANCE WITH MANUFACTURER'S INSTRUCTIONS.
2. PREPARE SOIL BEFORE INSTALLING MATTING, INCLUDING GRADING, REMOVAL OF LARGE ROCKS AND DEBRIS, AND THE APPLICATION OF SEED AND FERTILIZER IF NOT USING PRE–SEEDED MATTING.
3. EROSION CONTROL MATTING SHALL EXTEND COMPLETELY ACROSS DISTURBED AREAS TO PROTECT ERODIBLE SURFACES.
4. BEGIN AT THE TOP OF THE SLOPE BY ANCHORING THE MATTING IN A TRENCH. BACKFILL AND COMPACT THE TRENCH AFTER STAPLING.
5. ROLL THE MATTING DOWN THE SLOPE IN THE DIRECTION OF THE WATER FLOW.
6. AS AN ALTERNATIVE TO STAPLES, WOODEN STAKES OR BIO–DEGRADEABLE PINS CAN BE USED WHERE SPECIFIED BY THE COMPANY.
7. ENSURE COMPLETE CONTACT BETWEEN THE MATTING AND THE SLOPE FACE. ADDITIONAL STAPLES CAN BE USE TO ELIMINATE GAPS.
8. INSTALLATION SPECIFICATIONS TO BE MODIFIED BY THE PROJECT AS NECESSARY TO SUIT ACTUAL SITE CONDITIONS.

REVISIONS
01 2008–11–04 MODIFIED DRAWING NOTES
02 2010–10–08 UPDATED DRAWING NOTES
03 2010–10–11 REVISED TITLE BLOCK

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	FIA # 4359	CHAINAGE:	DISCIPLINE # 03
CHECKED BY: WSF	DESIGN CHECKER: RW P7100	TITLE: DETAIL 4 EROSION CONTROL MATTING INSTALLATION
SCALE N.T.S.	DWG No 4359–03–ML–05–704	REV 03

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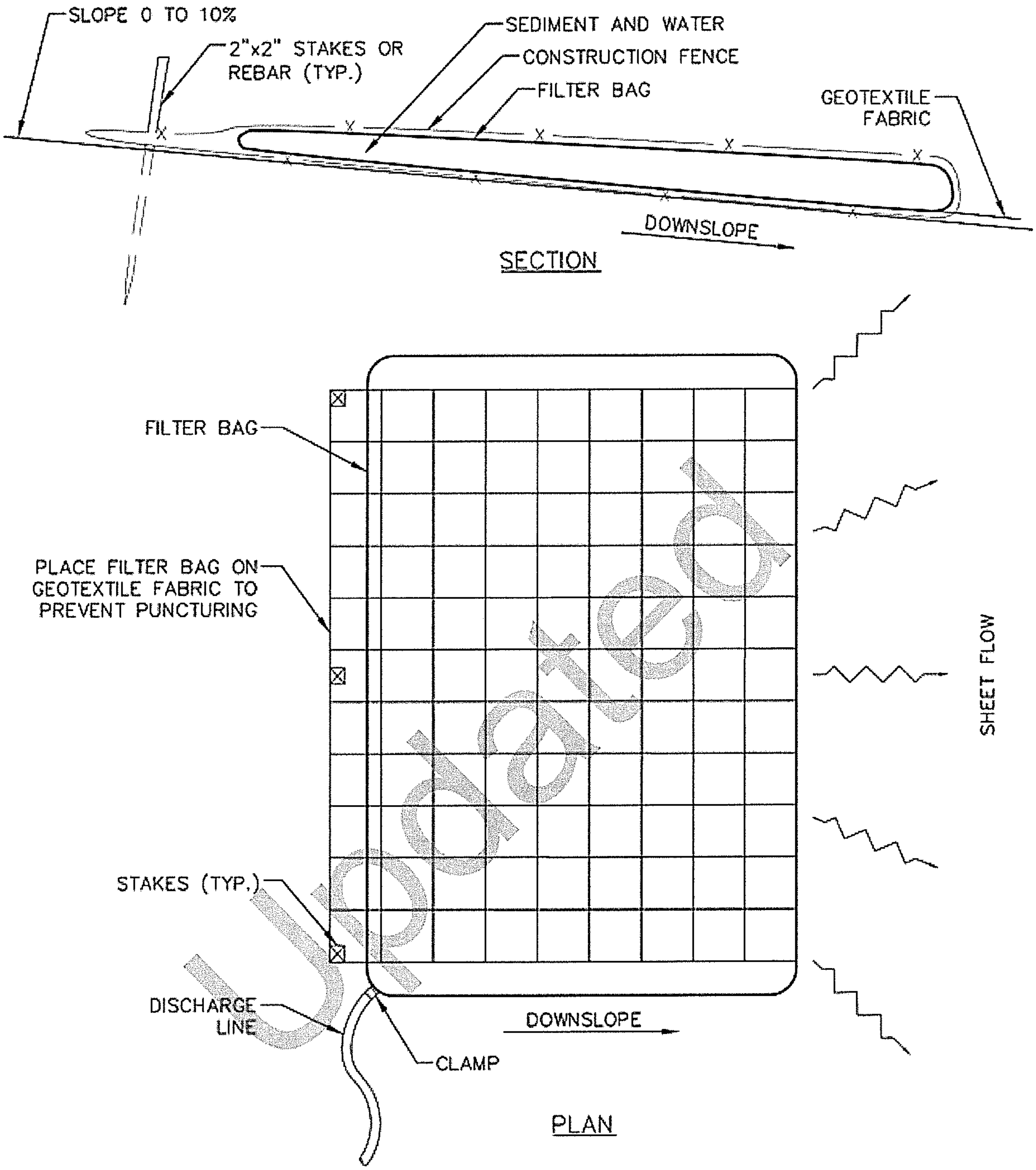

NOTES:

1. MANUFACTURED NONWOVEN (FELT) FILTER BAGS ARE A SUITABLE ALTERNATIVE TO STRAW BALE STRUCTURES FOR TRENCH DEWATERING. FILTER BAGS SHALL BE INSTALLED AS SPECIFIED BY THE MANUFACTURER.
2. INSTALLATION SPECIFICATIONS TO BE MODIFIED AS NECESSARY TO SUIT ACTUAL SITE CONDITIONS.

REVISIONS	
01	2008-11-04 MODIFIED DRAWING NOTES
02	2010-10-11 REVISED TITLE BLOCK

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CHECKED BY: WSF	DESIGN CHECKER: RW P7100	TITLE: DETAIL 5 TYPICAL DEWATERING FILTER BAG	
		SCALE N.T.S.	DWG No 4359-03-ML-05-705	REV 02

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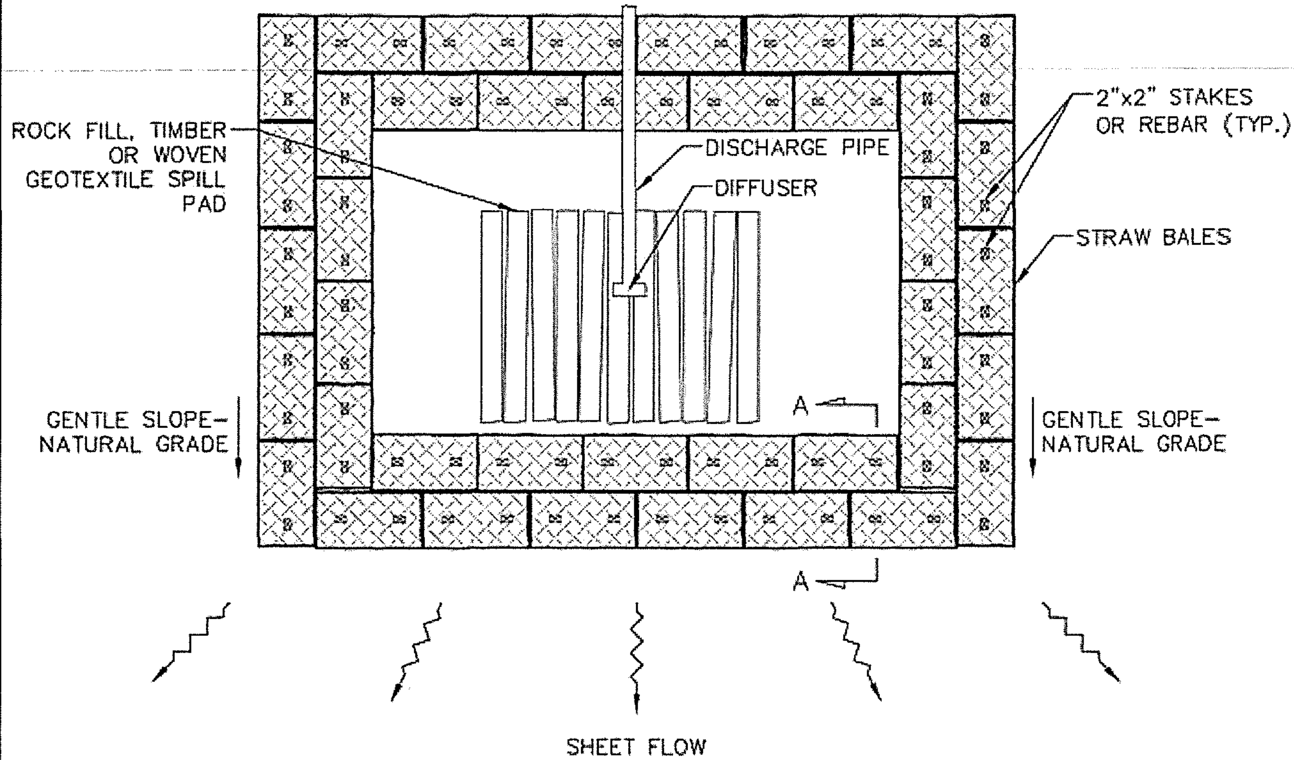

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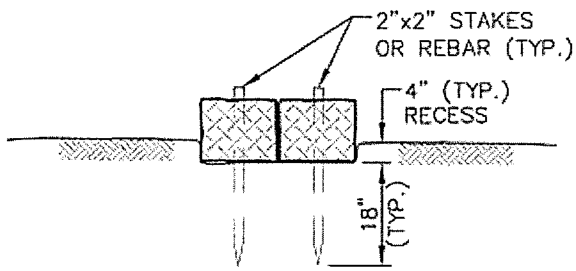

SECTION A–A

NOTES:

1. INSTALL A STRAW BALE DEWATERING STRUCTURE WHEREVER IT IS NECESSARY AND AS DIRECTED BY THE ENVIRONMENTAL INSPECTOR TO PREVENT THE FLOW OF HEAVILY SILT LADEN WATER INTO WATERBODIES OR WETLANDS.
2. DISCHARGE SITE SHOULD BE WELL VEGETATED AND LOCATED AT LEAST 50 FEET FROM ANY WATERBODY. THE TOPOGRAPHY OF THE SITE SHOULD BE SUCH THAT WATER WILL FLOW INTO THE DEWATERING STRUCTURE AND AWAY FROM ANY WORK AREAS. THE AREA DOWNSLOPE FROM THE DEWATERING SITE MUST BE REASONABLY FLAT OR STABILIZED BY VEGETATION OR OTHER MEANS TO ALLOW THE FILTERED WATER TO CONTINUE AS SHEET FLOW.
3. DIRECT THE PUMPED WATER ONTO A STABLE SPILL PAD CONSTRUCTED OF ROCKFILL, WEIGHTED TIMBERS, OR A WOVEN GEOTEXTILE STAKED TO THE GROUND SURFACE, SUCH AS MIRAFI 600X, TERRAFIX 400W, OR A COMPANY APPROVED EQUIVALENT. BEYOND THE SPILL PAD FORCE THE DISCHARGE WATER INTO SHEET FLOW USING STRAW BALES AND THE NATURAL TOPOGRAPHY.
4. DISCHARGE RATES SHOULD BE SUCH THAT THE CAPACITY OF THE STRUCTURE WILL NOT BE EXCEEDED.
5. DISCHARGE WATER SHALL BE FORCED INTO SHEET FLOW IMMEDIATELY BEYOND THE SPILL PAD USING A COMBINATION OF STRAW BALES AND THE NATURAL TOPOGRAPHY. RECESS STRAW BALES. DRIVE TWO (2) STAKES OR REBAR INTO EACH BALE TO ANCHOR THEM IN PLACE.
6. INSTALLATION SPECIFICATIONS TO BE MODIFIED AS NECESSARY TO SUIT ACTUAL SITE CONDITIONS.

REVISIONS

01	2008-11-04	MODIFIED DRAWING NOTES
02	2010-10-08	UPDATED DRAWING NOTES
03	2010-10-11	UPDATED DRAWING NOTES

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		FIA # 4359	CHAINAGE:
		DISCIPLINE # 03	
CHECKED BY: WSF	DESIGN CHECKER: RW	TITLE: DETAIL 6 TYPICAL STRAW BALE DEWATERING STRUCTURE	
		SCALE N.T.S.	DWG No 4359-03-ML-05-706 REV 03

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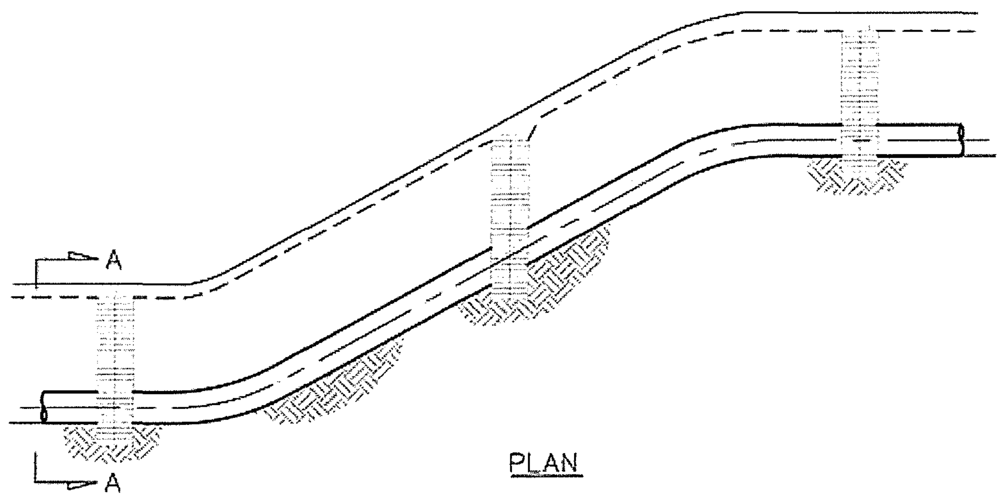
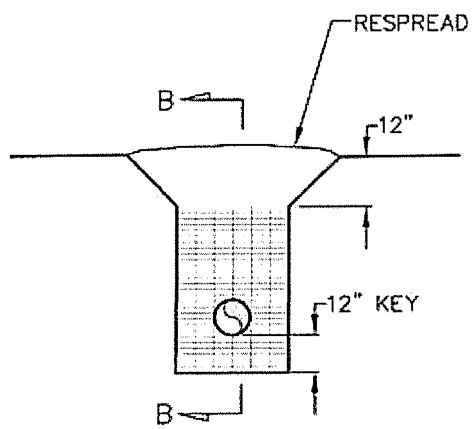
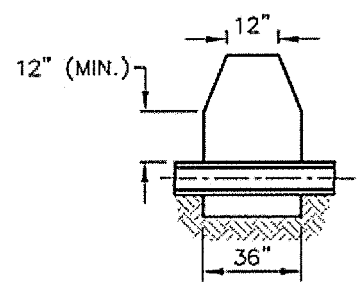


PLAN



SECTION A–A



SECTION B–B

NOTES:

1. TRENCH BREAKERS TO BE INSTALLED AS SHOWN ON THE CONSTRUCTION DRAWINGS, WHERE DESCRIBED IN THE PLAN, AND AS DIRECTED.
2. OPEN WEAVE HEMP OR JUTE SACKS SHALL BE FILLED WITH AN AVERAGE 55 LBS. MIXTURE OF:
   1) ONE (1) PART CEMENT AND SIX (6) PARTS SAND OR SUBSOIL, OR
   2) ONE (1) PART CEMENT, THREE (3) PARTS FLYASH, AND FIVE (5) PARTS SAND OR SUBSOIL
   3) SAND WITH JUST SUFFICIENT WATER TO PERMIT MIXTURE TO EXUDE AND BOND SACKS TOGETHER. TOPSOIL IS NOT TO BE USED IN SACKS.
3. KEY EACH TRENCH BREAKER A MINIMUM OF ONE (1) FT. INTO BOTTOMS AND SIDES OF TRENCH.
4. FOAM TRENCH BREAKERS MAY BE USED IN LIEU OF SAND SACK TRENCH BREAKERS.
5. INSTALLATION SPECIFICATIONS TO BE MODIFIED AS NECESSARY TO SUIT ACTUAL SITE CONDITIONS.
6. TRENCH BREAKERS SHALL BE INSTALLED SUCH THAT THE TOP OF EACH DOWNSLOPE BREAKER IS ABOVE THE BOTTOM OF THE NEXT UPSLOPE BREAKER.

REVISIONS
01 2008-11-04 UPDATED DRAWING NOTES
02 2010-10-11 UPDATED PLAN DETAIL

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DESIGNER: JMP (NAME) 2010-10-21 (DATE)
CHECKED BY: WSF
DESIGN CHECKER: RW P7100

KEYSTONE XL PROJECT
FTA # 4359
CHAINAGE:
DISCIPLINE # 03
TITLE
DETAIL 7
TYPICAL PERMANENT TRENCH BREAKER
SCALE N.T.S.
DWG No 4359-03-ML-05-707
REV 02

TC_A4_BR.DWG 8.5X11

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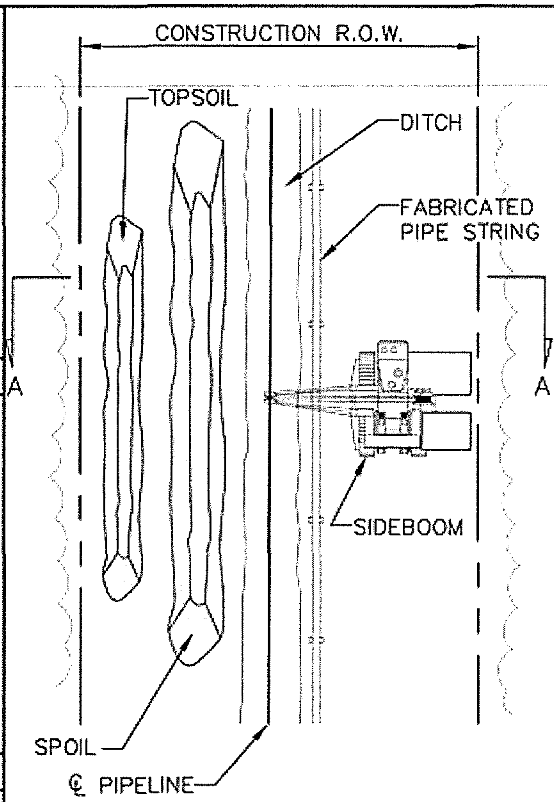
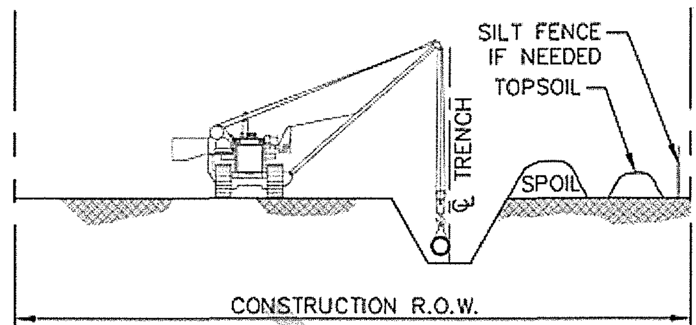


PLAN VIEW



SECTION "A–A"

CONSTRUCTION PROCEDURES:

1. IF THE WETLAND IS BEING CULTIVATED AND FARMED, NO WETLAND CONSTRUCTION PROCEDURES ARE REQUIRED.
2. FLAG WETLAND BOUNDARIES PRIOR TO CLEARING.
3. NO REFUELING OF MOBILE EQUIPMENT IS ALLOWED WITHIN 100 FEET OF WETLAND. PLACE "NO FUELING" SIGN POSTS APPROXIMATELY 100 FEET BACK FROM WETLAND BOUNDARY. REFUEL STATIONARY EQUIPMENT AS PER THE PROJECT'S SPILL PREVENTION PROCEDURES.
4. INSTALL TEMPORARY SLOPE BREAKER UPSLOPE WITHIN 100 FEET OF WETLAND BOUNDARY IF DIRECTED BY THE PROJECT.
5. DO NOT TRENCH WETLAND UNTIL PIPE IS READY TO INSTALL.
6. CONSTRUCT WHEN DRY, IF POSSIBLE. IF SITE BECOMES WET AT TIME OF TRENCHING, AVOID SOIL COMPACTION BY UTILIZING TIMBER RIP–RAP OR PREFABRICATED EQUIPMENT MATS.
7. AVOID ADJACENT WETLANDS. INSTALL SEDIMENT BARRIERS (STRAW BALES AND/OR SILT FENCE) AT DOWN SLOPE EDGE OF RIGHT–OF–WAY ALONG WETLAND EDGE IF NEEDED TO CONTAIN SPOIL WITHIN RIGHT–OF–WAY.
8. RESTRICT ROOT GRUBBING TO ONLY THAT AREA OVER THE DITCHLINE AND REMOVE STUMPS FROM WETLAND FOR DISPOSAL.
9. CONDUCT TRENCH LINE TOPSOIL STRIPPING (IF TOPSOIL IS NOT SATURATED). SALVAGE TOPSOIL TO ACTUAL DEPTH OR A MAXIMUM DEPTH OF 12 INCHES.
10. TRENCH THROUGH WETLANDS.
11. PIPE SECTION TO BE FABRICATED WITHIN THE WETLAND AND ADJACENT TO ALIGNMENT, OR IN STAGING AREA OUTSIDE THE WETLAND AND WALKED IN.
12. LOWER–IN PIPE. PRIOR TO BACKFILLING TRENCH, IF REQUIRED, TRENCH PLUGS SHALL BE INSTALLED AS REQUIRED. BACKFILL TRENCH.
13. RESTORE GRADE TO NEAR PRE–CONSTRUCTION TOPOGRAPHY, REPLACE TOPSOIL AND INSTALL PERMANENT EROSION CONTROL.
14. IF UTILIZED, REMOVE TIMBER MATS OR PRE–FABRICATED MATS FROM WETLANDS UPON COMPLETION.
15. IN THE ABSENCE OF A DETAILED REVEGETATION PLANS, APPLY A TEMPORARY COVER CROP AS DIRECTED BY KEYSTONE.

REVISIONS	
01	REVISED NOTES 3 & 4
02	2010-10-08 UPDATED DRAWING NOTES
03	2010-10-11 UPDATED DRAWING NOTES

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KEYSTONE XL PROJECT

FIA #	CHAINAGE:	DISCIPLINE #
4359		03

TITLE: DETAIL 8
"DRY" WETLAND CROSSING METHOD

SCALE	DWG No	REV
N.T.S.	4359–03–ML–03–701	03

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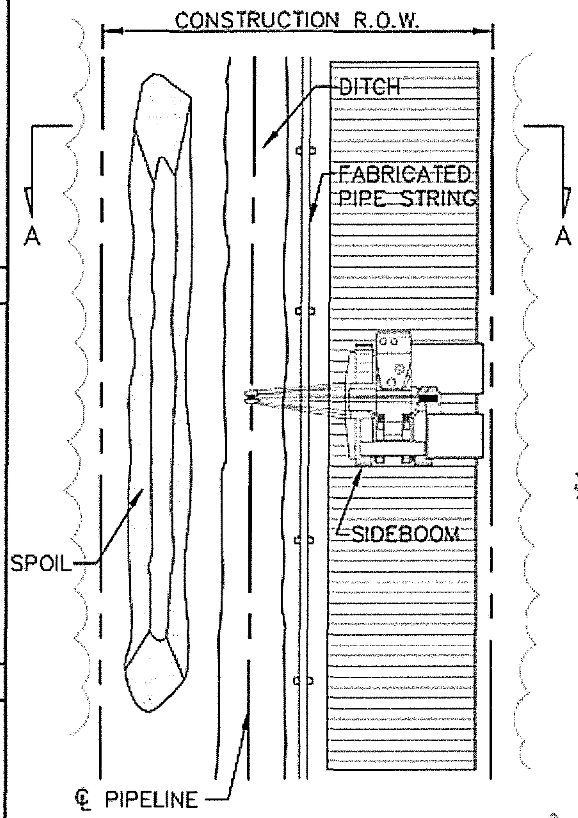
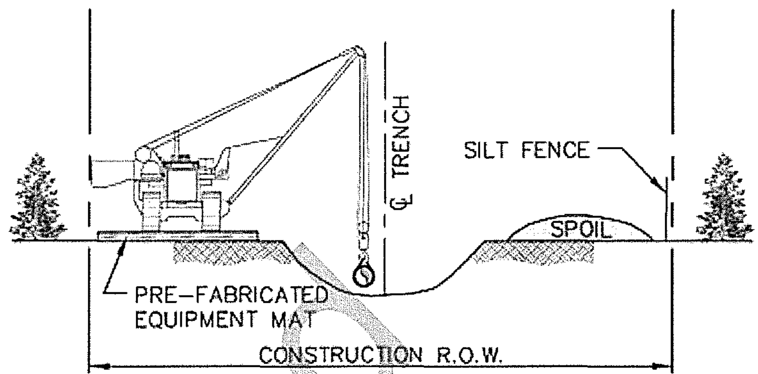


PLAN VIEW



SECTION A-A

CONSTRUCTION PROCEDURES:

1. FLAG WETLAND BOUNDARIES PRIOR TO CLEARING.
2. NO REFUELING OF MOBILE EQUIPMENT IS ALLOWED WITHIN 100 FEET OF WETLAND. PLACE "NO FUELING" SIGN POSTS 100 FEET BACK FROM WETLAND BOUNDARY. REFUEL STATIONARY EQUIPMENT AS PER THE PROJECT'S SPILL PREVENTION PROCEDURES.
3. INSTALL TEMPORARY SLOPE BREAKER UPSLOPE WITHIN 100 FEET OF WETLAND BOUNDARY IF DIRECTED BY THE PROJECT.
4. INSTALL TIMBER MATS/RIPRAP THROUGH ENTIRE WETLAND AREA. EQUIPMENT NECESSARY FOR RIGHT-OF-WAY CLEARING MAY MAKE ONE (1) PASS THROUGH THE WETLAND BEFORE MATS ARE INSTALLED.
5. AVOID ADJACENT WETLANDS. INSTALL SEDIMENT BARRIERS (STRAW BALES AND/OR SILT FENCE) AT DOWNSLOPE EDGE OF RIGHT-OF-WAY AND ALONG WETLAND EDGE AS REQUIRED.
6. RESTRICT ROOT GRUBBING TO ONLY THAT AREA OVER THE DITCHLINE AND DITCH SPOIL AREAS AND REMOVED FROM WETLAND FOR DISPOSAL.
7. DO NOT TRENCH WETLAND UNTIL PIPE IS READY TO INSTALL.
8. TOPSOIL STRIPPING SHALL NOT BE REQUIRED IN SATURATED SOIL CONDITIONS.
9. LEAVE HARD PLUGS AT EDGE OF WETLAND UNTIL JUST PRIOR TO TRENCHING.
10. PIPE SECTION MAY BE FABRICATED WITHIN THE WETLAND AND ADJACENT TO ALIGNMENT, OR IN STAGING AREA OUTSIDE THE WETLAND AND WALKED IN.
11. TRENCH THROUGH WETLANDS.
12. LOWER-IN PIPE, INSTALL TRENCH PLUGS AT WETLAND EDGES AS REQUIRED AND BACKFILL IMMEDIATELY.
13. REMOVE TIMBER MATS OR PRE-FABRICATED MATS FROM WETLAND UPON COMPLETION.
14. RESTORE GRADE TO NEAR PRE-CONSTRUCTION TOPOGRAPHY, REPLACE TOPSOIL IF SALVAGED AND INSTALL PERMANENT EROSION CONTROL.

REVISIONS	
01	REVISED NOTES 2 & 3
02	2010-10-11 UPDATED DRAWING NOTES

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	FIA # 4359	CHAINAGE:	DISCIPLINE # 03
CHECKED BY: WSF / DESIGN CHECKER: RW	TITLE: DETAIL 9 STANDARD WETLAND CROSSING METHOD		
	SCALE N.T.S.	DWG No 4359-03-ML-03-702	REV 02

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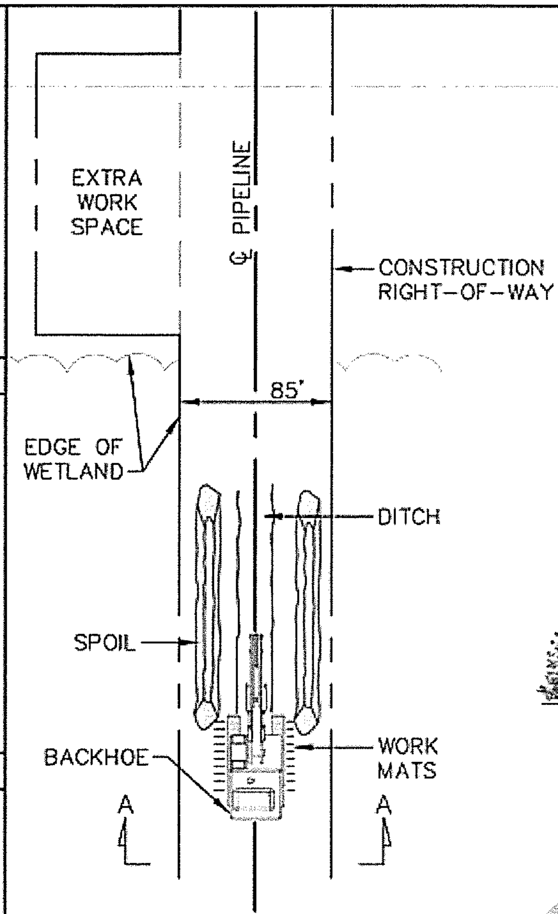
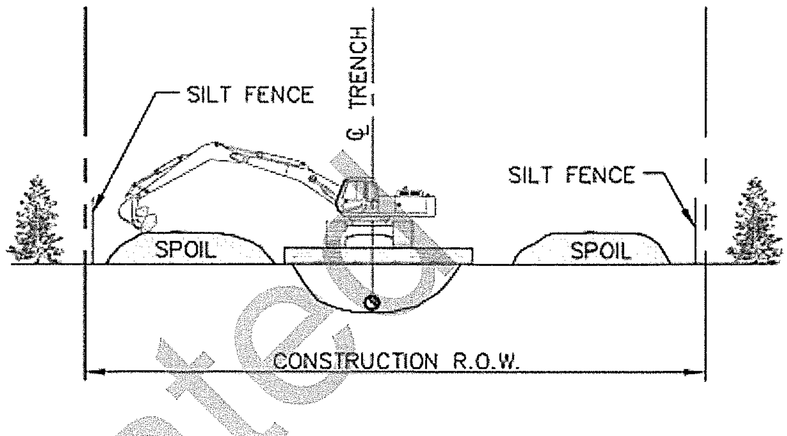


PLAN VIEW



SECTION A-A

CONSTRUCTION PROCEDURES:

1. FLAG WETLAND BOUNDARIES PRIOR TO CLEARING.
2. NO REFUELING OF MOBILE EQUIPMENT IS ALLOWED WITHIN 100 FEET OF WETLAND. PLACE "NO FUELING" SIGN POSTS 100 FEET BACK FROM WETLAND BOUNDARY. REFUEL STATIONARY EQUIPMENT AS PER THE PROJECT'S SPILL PREVENTION PROCEDURES.
3. INSTALL TEMPORARY SLOPE BREAKER UPSLOPE WITHIN 100 FEET OF WETLAND BOUNDARY AS DIRECTED BY THE PROJECT.
4. RESTRICT ROOT GRUBBING TO ONLY THE AREA OVER THE DITCHLINE.
5. DO NOT TRENCH WETLAND UNTIL PIPE IS READY TO INSTALL.
6. TOPSOIL STRIPPING SHALL NOT BE REQUIRED IN SATURATED SOIL CONDITIONS.
7. UTILIZE AMPHIBIOUS EXCAVATORS (PONTOON MOUNTED BACKHOES) OR TRACKED BACKHOES SUPPORTED BY FABRICATED TIMBER MATS OR FLOATS TO EXCAVATE TRENCH. IF FABRICATED TIMBER MATS ARE USED FOR STABILIZATION, THE BACKHOE SHALL GRADUALLY MOVE ACROSS THE WETLAND BY MOVING THE MAT FROM IMMEDIATELY BEHIND TO IMMEDIATELY IN FRONT OF THE BACKHOE'S PATH.
8. AVOID ADJACENT WETLANDS. INSTALL SEDIMENT BARRIERS (STRAW BALES AND/OR SILT FENCE) AT EDGE OF RIGHT-OF-WAY AND ALONG WETLAND EDGE IF PRACTICAL.
9. FABRICATE PIPE IN STAGING AREA OUTSIDE THE WETLAND IN THE EXTRA WORK SPACE AS INDICATED ON THE CONSTRUCTION DRAWINGS.
10. LEAVE HARD PLUGS AT THE EDGE OF THE WETLAND UNTIL JUST PRIOR TO PIPE PLACEMENT.
11. FLOAT PIPE IN PLACE, LOWER-IN, INSTALL TRENCH PLUGS AT WETLAND EDGES WHERE REQUIRED AND BACKFILL IMMEDIATELY.
12. REMOVE TIMBER MATS OR PRE-FABRICATED MATS OF NON-NATIVE MATERIAL FROM WETLANDS UPON COMPLETION.
13. RESTORE GRADE TO NEAR PRE-CONSTRUCTION TOPOGRAPHY AND INSTALL PERMANENT EROSION CONTROL.
14. THE CONSTRUCTION RIGHT-OF-WAY FOR THIS TYPE OF CONSTRUCTION SHALL BE 85 FEET.

REVISIONS	
01	REVISED NOTES 2, 3 & 13
02	2010-10-11 UPDATED DRAWING NOTES

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		TITLE DETAIL 10 PUSH/PULL WETLAND CROSSING METHOD		
CHECKED BY: WSF	DESIGN CHECKER: RW	SCALE N.T.S.	DWG No 4359-03-ML-03-703	REV 02

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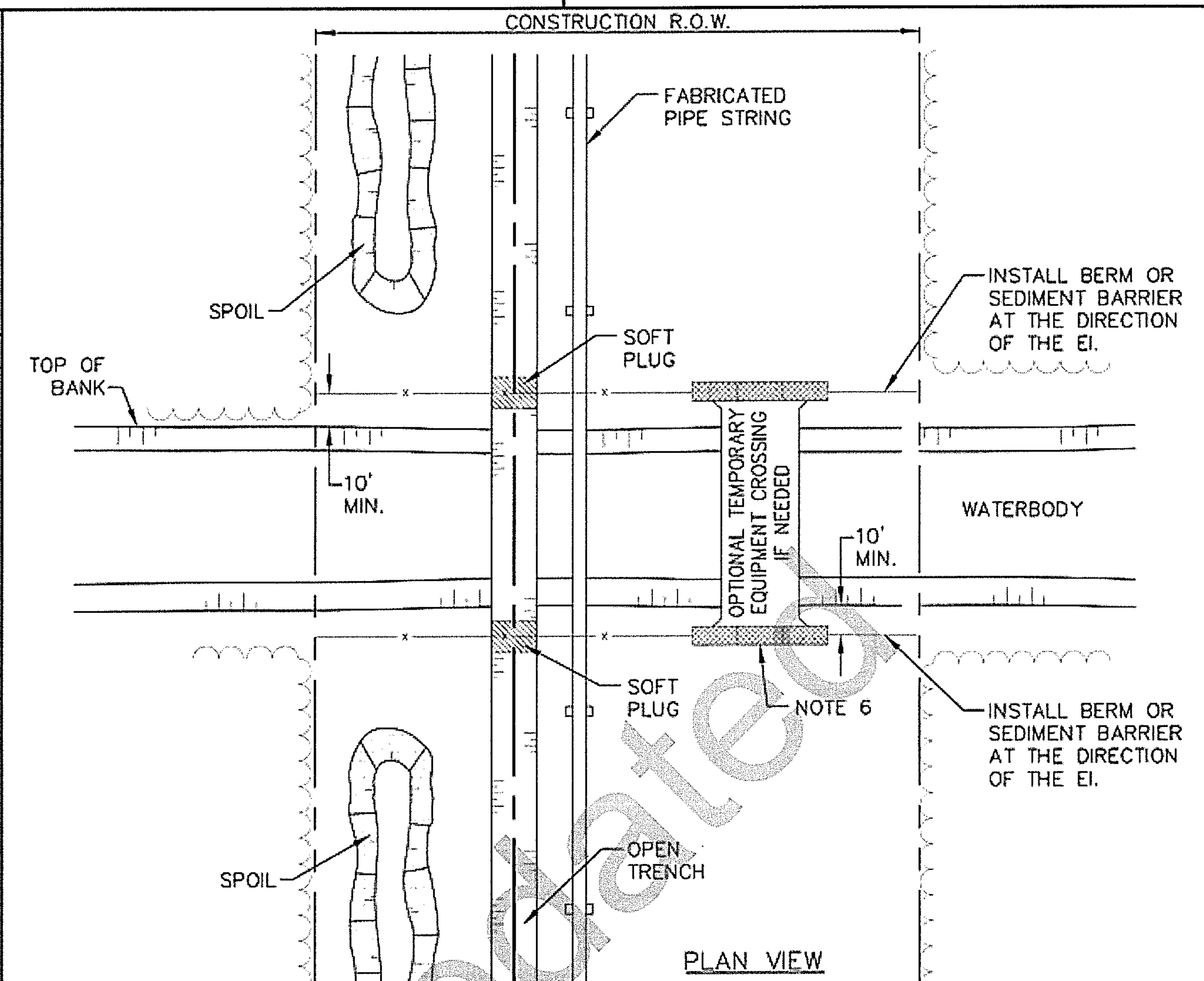

NOTES:

1. THIS METHOD APPLIES TO DRY WASHES, SWALES, INCISED DRAINAGES AND DITCHES WITH NO PERCEPTIBLE FLOW AT TIME OF CROSSING. IF FLOWS ARE PRESENT DURING CONSTRUCTION REFER TO DETAIL 12. CLEARING AND GRADING, TOPSOIL SALVAGE AND TOPSOIL STRIPPING DEPTHS SHALL BE THE SAME AS INDICATED FOR ADJACENT UPLAND UNLESS OTHERWISE DIRECTED BY KEYSTONE.
2. EI TO FLAG THE ORDINARY HIGH WATER MARK (OHWM) PRIOR TO CLEARING.
3. INSTALL SILT FENCE OR A BERM AT DIRECTION OF KEYSTONE EI TO PREVENT RUNOFF FROM ROW TO ADJACENT, UNDISTURBED DRAINAGE.
4. STOCKPILE TOPSOIL AND SPOIL SEPARATELY. TOPSOIL SHALL NOT BE STOCKPILED ACROSS THE DRAINAGE CHANNEL AND SHALL BE PLACED A MINIMUM OF 15 FEET FROM THE OHWM OR TO SUIT CONDITIONS AND PROTECT THE DRAINAGE AS DETERMINED BY KEYSTONE.
5. INSTALL TEMPORARY SLOPE BREAKERS WHERE IDENTIFIED BY THE EI.
6. TRENCH, STRING PIPE, AND BACKFILL USING STANDARD UPLAND CONSTRUCTION PROCEDURES UNLESS OTHERWISE DIRECTED BY KEYSTONE.
7. RESTORE WATERCOURSE CHANNEL AND BANKS (EXCEPT TRAVEL LANE IF USED) TO APPROXIMATE PRE-CONSTRUCTION PROFILE IMMEDIATELY AFTER PIPE IS LOWERED IN AND BACKFILLED. INSTALL PERMANENT EROSION CONTROLS WHERE DIRECTED BY KEYSTONE.
8. REMOVE ANY TEMPORARY CROSSING STRUCTURES AND/OR GRAVEL.

REVISIONS	
01	UPDATED DRAWING NOTES
02	2010-10-08 UPDATED DRAWING NOTES
03	2010-10-11 UPDATED DRAWING NOTES

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DESIGN CHECKER:	RW
KEYSTONE XL PROJECT	
FIA #	4359
CHAINAGE:	
DISCIPLINE #	03
TITLE	DETAIL 11 TYPICAL OPEN CUT WET CROSSING METHOD NON-FLOWING WATERBODY
SCALE	N.T.S.
DWG No	4359-03-ML-03-704
REV	03

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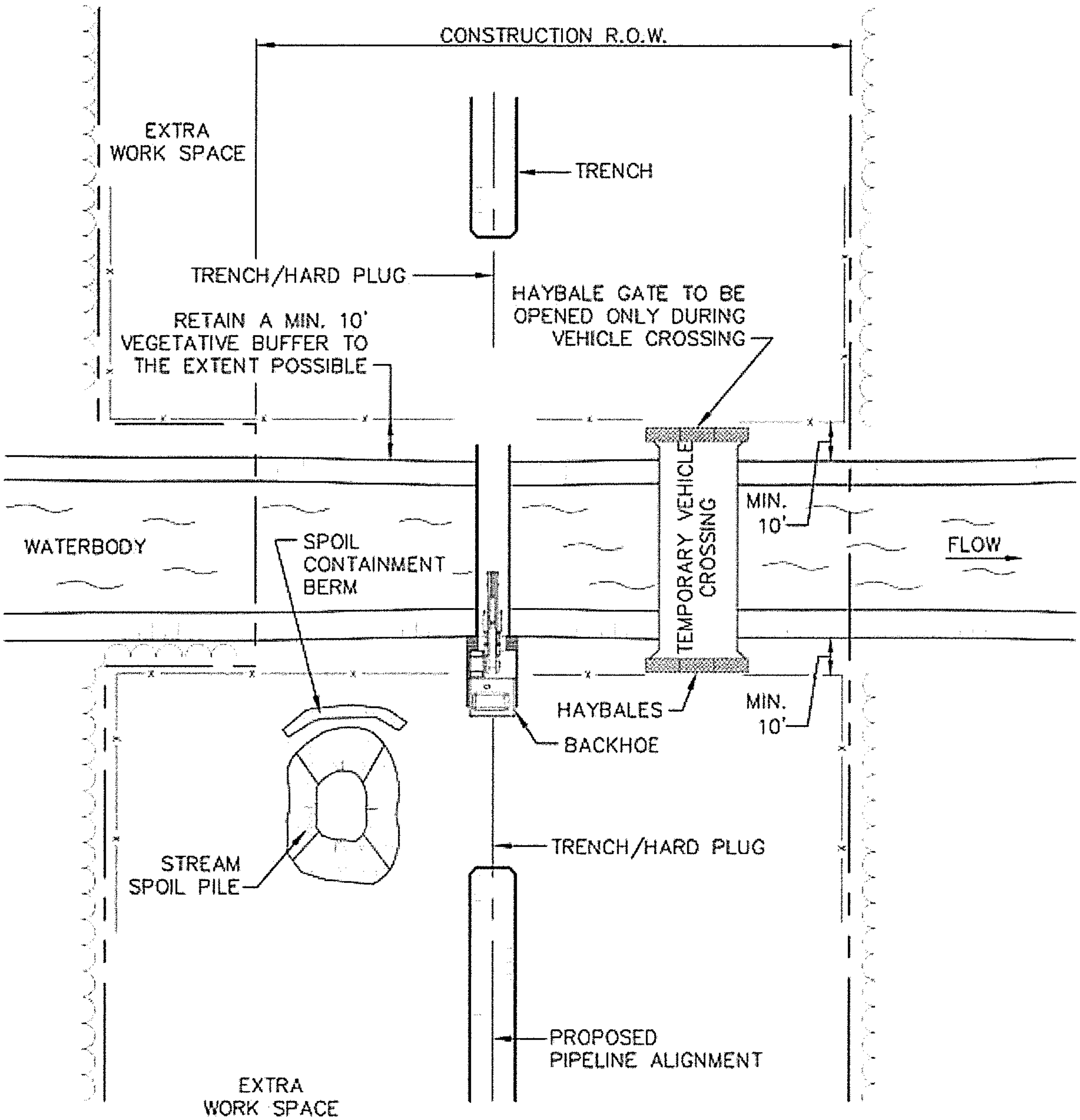

PLAN VIEW

REVISIONS		
01	UPDATED DRAWING NOTES	
02	2010-10-11 REVISED TITLE BLOCK	

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DESIGN CHECKER: RW

KEYSTONE XL PROJECT

FIA # 4359 | CHAINAGE: | DISCIPLINE # 03

TITLE
DETAIL 12
TYPICAL OPEN CUT WET CROSSING METHOD
FLOWING WATERBODY

SCALE N.T.S. | DWG No 4359-03-ML-03-705 | REV 02

TC_A4_BR.DWG 8.5X11

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CONSTRUCTION PROCEDURES:

1. RIGHT-OF-WAY BOUNDARIES AND WORK SPACE LIMITS SHALL BE CLEARLY DELINEATED. STAGING FOR MAKEUP SHALL BE LOCATED A MINIMUM OF 10 FEET FROM WATERBODY.

2. CLEARING LIMITS WILL BE CLEARLY DELINEATED AND 10 FOOT VEGETATIVE BUFFER STRIP BETWEEN DISTURBED AREA AND THE WATERBODY SHALL BE MAINTAINED TO THE EXTENT POSSIBLE. ALL CLEARING SHALL BE MINIMIZED TO THE EXTENT POSSIBLE AND TO ONLY THAT NECESSARY FOR CONSTRUCTION. WOODY VEGETATION SHALL BE CUT AT GROUND LEVEL AND THE STUMPS/ROOTS LEFT IN PLACE TO THE EXTENT POSSIBLE.

3. TOPSOIL SHALL BE STRIPPED FROM THE DITCH LINE IN ALL WETLANDS RIPARIAN.

4. CONTRACTOR SHALL INSTALL SIGNS APPROXIMATELY 100 FEET MINIMUM FROM EACH WATERBODY AND WETLAND TO IDENTIFY THE HAZARDOUS MATERIALS EXCLUSION AREA.

5. EROSION AND SEDIMENT CONTROL
   a. CONTRACTOR SHALL SUPPLY, INSTALL AND MAINTAIN SEDIMENT CONTROL STRUCTURES, AS DEPICTED OR ALONG DOWN GRADIENT SIDES OF WORK AREAS AND STAGING AREAS SUCH THAT NO HEAVILY SILT LADEN WATER ENTERS WATERBODY OR WETLAND.

   b. NO HEAVILY SILT LADEN WATER SHALL BE DISCHARGED DIRECTLY OR INDIRECTLY INTO THE WATERBODY. ALL EROSION AND SEDIMENT CONTROL STRUCTURE LOCATIONS AS DEPICTED ARE APPROXIMATE AND MAY BE ADJUSTED AS DIRECTED BY THE COMPANY INSPECTOR TO SUIT ACTUAL SITE CONDITIONS. SILT FENCE OR STRAW BALE INSTALLATIONS SHALL INCLUDE REMOVABLE SECTIONS TO FACILITATE ACCESS DURING CONSTRUCTION.

   c. SEDIMENT LADEN WATER FROM TRENCH DEWATERING SHALL BE DISCHARGED TO A WELL VEGETATED UPLAND AREA INTO A STRAW BALE DEWATERING STRUCTURE OR GEOTEXTILE FILTER BAG. SEDIMENT CONTROL STRUCTURES MUST BE IN PLACE AT ALL TIMES ACROSS THE DISTURBED CONSTRUCTION RIGHT-OF-WAY EXCEPT DURING EXCAVATION/INSTALLATION OF THE CROSSING PIPE.

   d. SOFT DITCH PLUGS MUST REMAIN IN PLACE AT CONVENIENT LOCATIONS TO SEPARATE MAINLINE DITCH FROM THE WATERBODY CROSSING UNTIL THE WATER CROSSING IS INSTALLED AND BACKFILLED.

   e. TRENCH BREAKERS ARE TO BE INSTALLED AT THE SAME SPACING AND IMMEDIATELY UPSLOPE OF PERMANENT SLOPE BREAKERS, OR AS DIRECTED BY THE COMPANY.

6. CONTRACTOR SHALL MAINTAIN HARD PLUGS IN THE DITCH AT THE WATERBODY UNTIL JUST PRIOR TO PIPE INSTALLATION. CONTRACTOR SHALL EXCAVATE TRENCH AND INSTALL PIPE AS EXPEDIENTLY AS PRACTICAL TO REDUCE THE DURATION OF WORK ACTIVITIES IN THE WATERBODY BED.

7. CONTRACTOR SHALL PLACE TRENCH SPOIL ONLY IN CERTIFICATED WORK SPACE AND A MINIMUM OF 10 FEET FROM THE WATERBODY BANKS TO PREVENT ENTRY OF SPOIL INTO THE WATERBODY. SPOIL SHALL BE CONTAINED AS NECESSARY USING EITHER A STRAW BALE BARRIER OR AN EARTH/ROCK BERM.

8. CONTRACTOR SHALL RESTORE THE WATERBODY AND BANKS TO APPROXIMATE PRE-CONSTRUCTION CONTOURS, UNLESS OTHERWISE APPROVED BY THE COMPANY. CONTRACTOR SHALL INSTALL PERMANENT EROSION AND SEDIMENT CONTROL STRUCTURES AS INDICATED. ANY MATERIALS PLACED IN THE WATERBODY TO FACILITATE CONSTRUCTION SHALL BE REMOVED DURING RESTORATION. BANKS SHALL BE STABILIZED AND TEMPORARY SEDIMENT BARRIERS INSTALLED AS SOON AS POSSIBLE AFTER CROSSING, BUT WITHIN 24 HOURS OF COMPLETING THE CROSSING. MAINTAIN A SILT FENCE OR STRAW BALE BARRIER ALONG THE WATERBODY AND WETLAND BOUNDARIES UNTIL VEGETATION IS ESTABLISHED IN ADJACENT DISTURBED AREAS.

9. VEHICLE CROSSING CAN BE CONSTRUCTED USING EITHER A FLUME CROSSING OR A TEMPORARY BRIDGE. VEHICLE CROSSING ONLY REQUIRED IF STREAM SUPPORTS A STATE DESIGNATED FISHERY.

REVISIONS | 01 | 2010-10-11 | REVISED TITLE BLOCK

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	FIA # 4359	CHAINAGE:	DISCIPLINE # 03
CHECKED BY: WSF	DESIGN CHECKER: RW	TITLE: DETAIL 12A TYPICAL OPEN CUT WET CROSSING METHOD FLOWING WATERBODY – CONSTRUCTION PROCEDURES
SCALE N.T.S.	DWG No 4359-03-ML-03-706	REV 01

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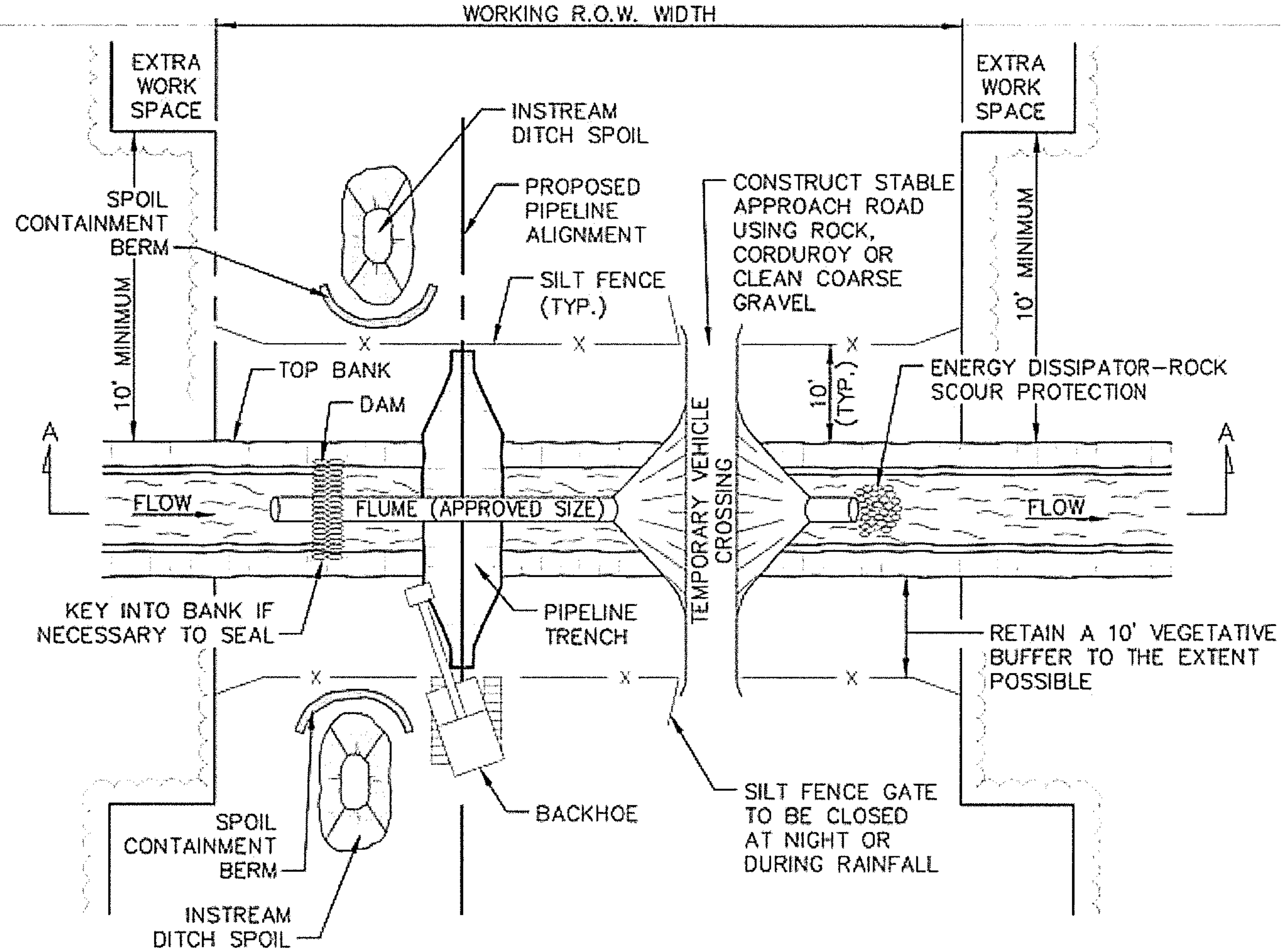
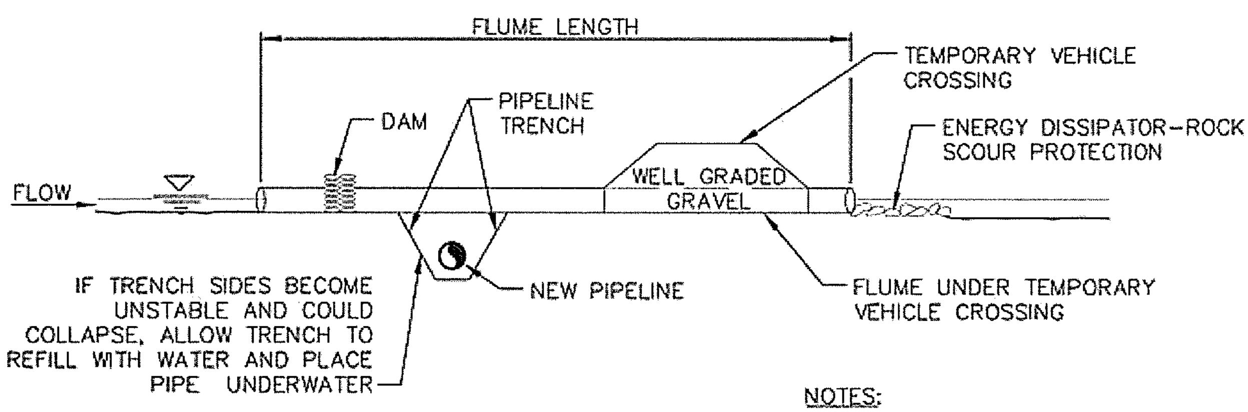


PLAN VIEW



SECTION A-A

NOTES:

1. PIPELINE PLACEMENT WITHIN RIGHT-OF-WAY CONCEPTUAL ONLY.
2. SEE DETAIL 13A FOR CONSTRUCTION PROCEDURES.

REVISIONS | 01 | 2010-10-11 REVISED TITLE BLOCK

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		FIA # 4359 | CHAINAGE:	DISCIPLINE # 03
		TITLE: DETAIL 13 TYPICAL DRY FLUME CROSSING METHOD	
	CHECKED BY: WSF | DESIGN CHECKER: RW	SCALE N.T.S. | DWG No 4359-03-ML-03-707	REV 01

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CONSTRUCTION PROCEDURES:

1. MARK OUT AND MAINTAIN LIMITS OF AUTHORIZED WORK AREAS WITH FENCING OR FLAGGING TAPE TO AVOID UNNECESSARY DISTURBANCE OF VEGETATION. ENSURE EQUIPMENT OPERATORS WORKING ON THE CROSSING HAVE BEEN BRIEFED ABOUT THIS PLAN AND THE MEASURE NEEDED TO PROTECT WATER QUALITY.
2. ALL NECESSARY EQUIPMENT AND MATERIALS TO BUILD THE FLUME MUST BE ON-SITE OR READILY AVAILABLE PRIOR TO COMMENCING IN-WATER WORK.
3. TO THE EXTENT POSSIBLE, MAINTAIN A MINIMUM 10 FT. VEGETATIVE BUFFER STRIP BETWEEN DISTURBED AREAS AND THE WATERCOURSE. INSTALL AND MAINTAIN A SILT FENCE OR STRAW BALE BARRIER UPSLOPE OF THE BUFFER STRIP ON EACH SIDE OF THE WATERCOURSE.
4. CONTRACTOR SHALL SUPPLY, INSTALL AND MAINTAIN SEDIMENT CONTROL STRUCTURES, AS DEPICTED OR ALONG DOWN GRADIENT SIDES OF WORK AREAS AND STAGING AREAS SUCH THAT NO HEAVILY SILT LADEN WATER ENTERS STREAM.
   a. NO HEAVILY SILT LADEN WATER SHALL BE DISCHARGED DIRECTLY INTO THE STREAM.
   b. EROSION AND SEDIMENT CONTROL STRUCTURE LOCATIONS AS DEPICTED ARE APPROXIMATE AND MAY BE ADJUSTED AS DIRECTED BY THE COMPANY INSPECTOR TO ACTUAL SITE CONDITIONS.
   c. SILT FENCE OR STRAW BALE INSTALLATIONS SHALL INCLUDE REMOVABLE SECTIONS TO FACILITATE ACCESS DURING CONSTRUCTION. UTILIZE STRAW BALE BARRIERS ONLY IN LIEU OF A SILT FENCE WHERE FREQUENT ACCESS IS REQUIRED.
   d. SEDIMENT LADEN WATER FROM TRENCH DEWATERING SHALL BE DISCHARGED TO A WELL VEGETATED UPLAND AREA INTO A STRAW BALE DEWATERING STRUCTURE OR GEOTEXTILE FILTER BAG.
   e. SEDIMENT CONTROL STRUCTURES MUST BE IN PLACE AT ALL TIMES ACROSS THE DISTURBED PORTIONS OF THE RIGHT-OF-WAY EXCEPT DURING EXCAVATION/INSTALLATION OF THE CROSSING PIPE.
   f. SOFT DITCH PLUGS MUST REMAIN IN PLACE AT CONVENIENT LOCATIONS TO SEPARATE MAINLINE DITCH FROM THE RIVER CROSSING UNTIL THE RIVER CROSSING IS INSTALLED AND BACKFILLED.
5. PIPE SHALL BE STRUNG AND WELDED FOR READY INSTALLATION PRIOR TO WATERCOURSE TRENCHING.
6. FLUME CAPACITY DURING DRY CROSSING SHALL BE SUFFICIENT TO ACCOMMODATE 1.5 TIMES THE FLOW MEASURED AT THE TIME OF CONSTRUCTION PROVIDED THAT THE FLUMES WILL BE IN PLACE NOT MORE THAN 96 HOURS AND NO PRECIPITATION IS FORECAST. FLUME CAPACITY FOR VEHICLE ACCESS SHALL BE SUFFICIENT TO PASS THE 2 YEAR DESIGN FLOW OR THE FLOW REASONABLY EXPECTED TO OCCUR DURING THE INSTALLATION. EXCESS FLUMES REQUIRED FOR LONGER TERM ACCESS SHALL BE CAPPED DURING DRY CROSSING PROCEDURES.
7. ENSURE THAT THE DAMS AND VEHICLE CROSSING ARE LOCATED FAR ENOUGH APART TO ALLOW FOR A WIDE EXCAVATION.
8. FLUMES ARE TO BE SET WITH 10 PERCENT OF THEIR DIAMETER BELOW STREAMBED LEVEL WHERE SOIL CONDITIONS PERMIT (OTHERWISE INSTALLED AT STREAM GRADE AND SLOPE.)
9. PLACE IMPERVIOUS DAMS AT EACH END OF THE FLUME, UPSTREAM FIRST, THEN DOWNSTREAM. ACCEPTABLE ALTERNATIVES INCLUDE GRAVEL WITH RIP-RAP PROTECTION, SAND BAGS, STEEL PLATE AND ROCKFILL. DURING INSTALLATION, INSTALL AN IMPERVIOUS MEMBRANE, IF NECESSARY, TO LIMIT LEAKAGE. DAMS MAY NEED KEYING INTO THE BANK AND STREAMBED.

   EXCAVATE TRENCH THROUGH PLUGS AND UNDER FLUME FROM BOTH SIDES. WORK IS TO BE COMPLETED AS QUICKLY AS POSSIBLE.
   a. LOWER IN PIPE BY PASSING UNDER FLUME AND BACKFILL IMMEDIATELY WITH SPOIL MATERIAL.
   b. IT IS NOT NECESSARY TO DEWATER THE IN-STREAM TRENCH, HOWEVER, DISPLACED WATER SHALL BE PUMPED TO A STABLE UPLAND AREA TO AVOID OVERTOPPING OF DAMS DURING PIPE PLACEMENT.
   c. IF THE SPOIL MATERIAL IS NOT SUITABLE, USE IMPORTED CLEAN GRANULAR MATERIAL.
   d. IF BLASTING IS REQUIRED, USE CONTROLLED BLASTING TECHNIQUES TO PREVENT DAMAGE TO THE FLOW CONVEYANCE SYSTEM. ALTERNATIVELY, BLASTING MAY BE ACCOMPLISHED PRIOR TO THE FLUME INSTALLATION BY DRILLING THROUGH THE OVERBURDEN.
10. EXCAVATED MATERIAL MUST NOT BE STOCKPILED WITHIN 10 FT. OF THE WATERCOURSE. THIS MATERIAL SHALL BE CONTAINED TO PREVENT SATURATED SOIL FROM FLOWING BACK INTO THE WATERCOURSE.
11. DEWATERING OF THE ONLAND TRENCH SHOULD OCCUR IN A STABLE VEGETATED AREA A MINIMUM OF 50 FT. FROM ANY WATERBODY. THE PUMP DISCHARGE SHOULD BE DIRECTED ONTO A STABLE SPILL PAD CONSTRUCTED OF ROCKFILL OR TIMBERS TO PREVENT LOCALIZED EROSION. THE DISCHARGE WATER SHOULD ALSO BE FORCED INTO SHEET FLOW IMMEDIATELY BEYOND THE SPILL PAD BY USING STRAW BALES AND THE NATURAL TOPOGRAPHY.
12. FLUMES SHOULD BE REMOVED AS SOON AS POSSIBLE, WHEN NO LONGER REQUIRED FOR PIPE LAYING OR FOR ROAD ACCESS, IN THE FOLLOWING MANNER:
   a. REMOVE THE VEHICLE CROSSING RAMP. BANKS ARE TO BE RESTORED TO A STABLE ANGLE AND PROTECTED WITH EROSION RESISTANT MATERIAL COMPATIBLE WITH THE FLOW CONDITIONS (E.G., EROSION CONTROL BLANKETS, CRIBBING, ROCK RIP-RAP, ETC.) TO THE MAXIMUM EXTENT POSSIBLE BEFORE REMOVING THE DAMS.
   b. REMOVE DOWNSTREAM DAM.
   c. REMOVE UPSTREAM DAM.
   d. REMOVE FLUME.
   e. COMPLETE BANK TRIMMING AND EROSION PROTECTION. IF SANDBAGS ARE USED FOR THE DAMS, PLACE AND REMOVE BY HAND TO AVOID EQUIPMENT BREAKING BAGS.
13. RESTORE THE STREAMBED AND BANKS TO APPROXIMATE PRE-CONSTRUCTION CONTOURS, BUT NOT TO EXCEED 2 HORIZONTAL TO 1 VERTICAL.
   a. INSTALL PERMANENT EROSION AND SEDIMENT CONTROL STRUCTURES AS INDICATED ON A SITE SPECIFIC BASIS. IN THE ABSENCE OF SITE SPECIFIC INFORMATION, A FLEXIBLE CHANNEL LINER SUCH AS NAG C125 OR C350 WHICH IS CAPABLE OF WITHSTANDING ANTICIPATED FLOW SHALL BE INSTALLED. ALTERNATIVELY, ROCK RIP-RAP SHALL BE INSTALLED.
   b. ANY MATERIALS PLACED IN THE STREAM TO FACILITATE CONSTRUCTION SHALL BE REMOVED DURING RESTORATION. BANKS SHALL BE STABILIZED AND TEMPORARY SEDIMENT BARRIERS INSTALLED AS SOON AS POSSIBLE AFTER CROSSING, BUT WITHIN 24 HOURS OF COMPLETING THE CROSSING.
   c. MAINTAIN A SILT FENCE OR STRAW BALE BARRIER ALONG THE WATER COURSE UNTIL VEGETATION IS ESTABLISHED IN ADJACENT DISTURBED AREAS.

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		SCALE N.T.S.	DWG No 4359-03-ML-03-708	REV 02

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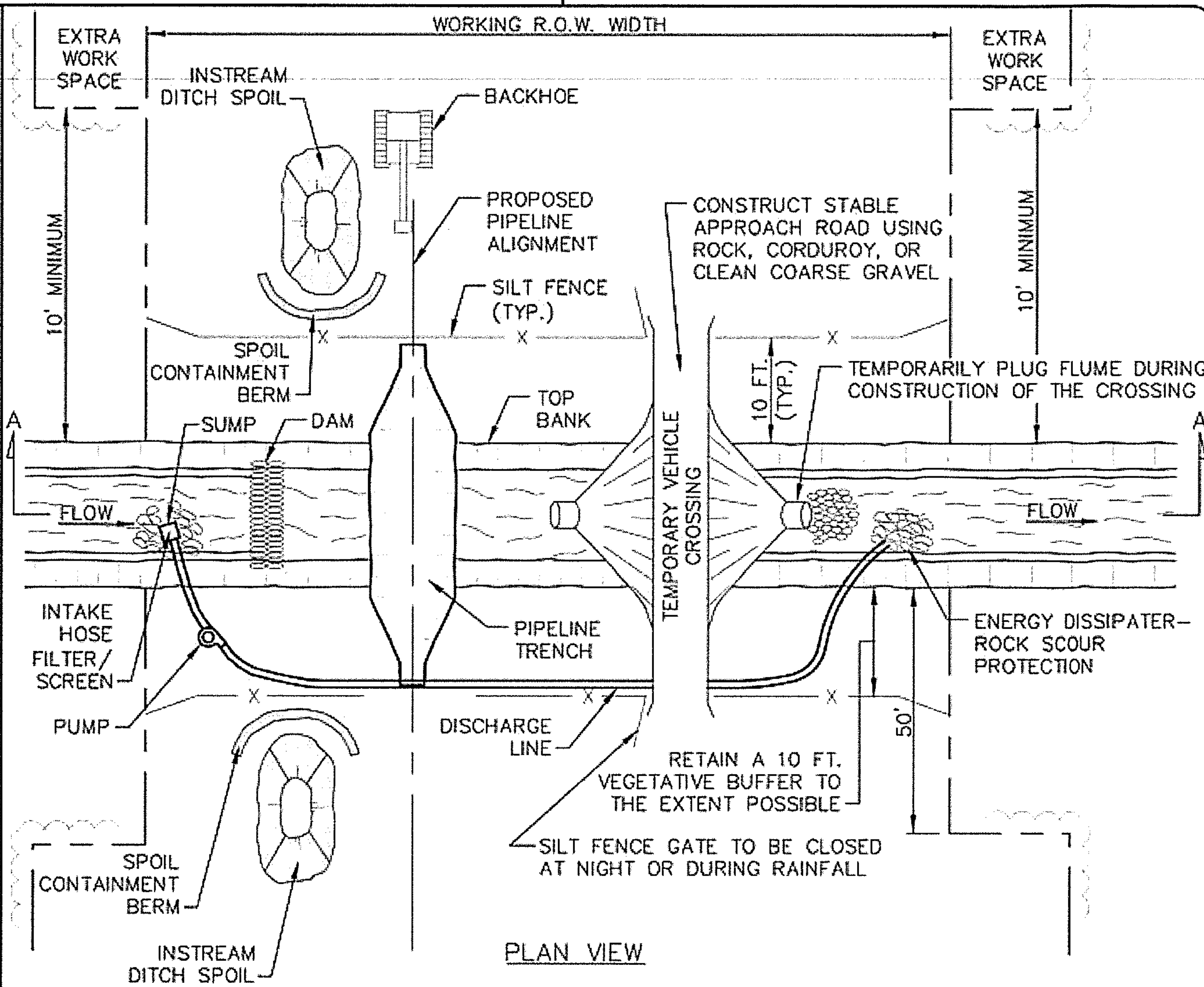
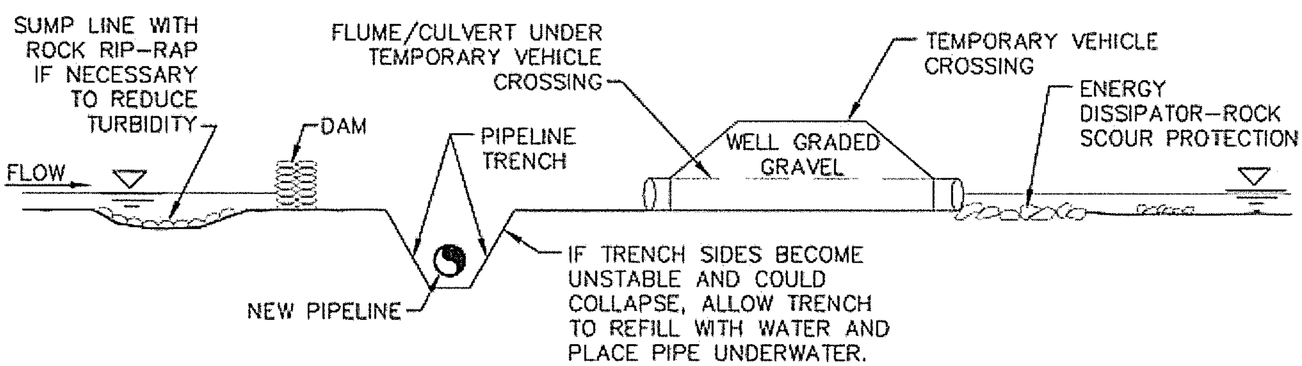


PLAN VIEW



SECTION A–A

NOTES:

1. PIPELINE PLACEMENT WITHIN RIGHT–OF–WAY CONCEPTUAL ONLY.
2. SEE DETAIL 14A FOR CONSTRUCTION PROCEDURES.

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CONSTRUCTION PROCEDURES:

1. WHERE NECESSARY, OBTAIN PRIOR APPROVAL BEFORE USING THE DAM AND PUMP METHOD.
2. IF THERE IS ANY FLOW IN THE WATERCOURSE, INSTALL PUMPS TO MAINTAIN STREAMFLOW AROUND THE BLOCKED OFF SECTIONS OF CHANNEL. THE PUMP IS TO HAVE 1.5 TIMES THE PUMPING CAPACITY OF ANTICIPATED FLOW. A SECOND STANDBY PUMP OF EQUAL CAPACITY IS TO BE READILY AVAILABLE AT ALL TIMES. AN ENERGY DISSIPATER IS TO BE BUILT TO ACCEPT PUMP DISCHARGE WITHOUT STREAMBED OR STREAMBANK EROSION. IF THE CROSSING IS PROLONGED BEYOND ONE DAY THE OPERATION NEEDS TO BE MONITORED OVERNIGHT.
3. SCHEDULE INSTREAM ACTIVITY FOR LOW FLOW PERIODS IF POSSIBLE.
4. MARK OUT AND MAINTAIN LIMITS OF AUTHORIZED WORK AREAS WITH FENCING OR FLAGGING TAPE TO AVOID UNNECESSARY DISTURBANCE OF VEGETATION. ENSURE EQUIPMENT OPERATORS WORKING ON THE CROSSING HAVE BEEN BRIEFED ABOUT THIS PLAN AND THE MEASURES NEEDED TO PROTECT WATER QUALITY. INSTALL PRE-WORK SEDIMENT CONTROL MEASURES AS SPECIFIED IN THE PLAN. ALL NECESSARY EQUIPMENT AND MATERIALS TO BUILD THE DAMS AND TO PUMP WATER MUST BE ON SITE OR READILY AVAILABLE PRIOR TO COMMENCING IN-WATER CONSTRUCTION. PIPE SHOULD BE STRUNG, WELDED AND COATED AND READY FOR INSTALLATION PRIOR TO WATERCOURSE TRENCHING.
5. CONTRACTOR SHALL SUPPLY, INSTALL AND MAINTAIN SEDIMENT CONTROL STRUCTURES, AS DEPICTED AND ALONG DOWN GRADIENT SIDES OF WORK AREAS AND STAGING AREAS SUCH THAT NO HEAVILY SILT LADEN WATER ENTERS STREAM.
   a. NO HEAVILY SILT LADEN WATER SHALL BE DISCHARGED DIRECTLY INTO THE STREAM.
   b. EROSION AND SEDIMENT CONTROL STRUCTURE LOCATIONS AS DEPICTED ARE APPROXIMATE AND MAY BE ADJUSTED AS DIRECTED BY THE COMPANY INSPECTOR TO ACTUAL SITE CONDITIONS.
   c. SILT FENCE OR STRAW BALE INSTALLATIONS SHALL INCLUDE REMOVABLE SECTIONS TO FACILITATE ACCESS DURING CONSTRUCTION. UTILIZE STRAW BALE BARRIERS ONLY IN LIEU OF A SILT FENCE WHERE FREQUENT ACCESS IS REQUIRED.
   d. SEDIMENT LADEN WATER FROM TRENCH DEWATERING SHALL BE DISCHARGED TO A WELL VEGETATED UPLAND AREA INTO A STRAW BALE DEWATERING STRUCTURE OR GEOTEXTILE FILTER BAG.
   e. SEDIMENT CONTROL STRUCTURES MUST BE IN PLACE AT ALL TIMES ACROSS THE DISTURBED PORTIONS OF THE RIGHT-OF-WAY EXCEPT DURING EXCAVATION/INSTALLATION OF THE CROSSING PIPE.
   f. SOFT DITCH PLUGS MUST REMAIN IN PLACE AT CONVENIENT LOCATIONS TO SEPARATE MAINLINE DITCH FROM THE RIVER CROSSING UNTIL THE RIVER CROSSING IS INSTALLED AND BACKFILLED.
6. TO THE EXTENT POSSIBLE, MAINTAIN A MINIMUM 10 FEET VEGETATIVE BUFFER STRIP BETWEEN DISTURBED AREAS AND THE WATERCOURSE. INSTALL AND MAINTAIN A SILT FENCE UPSLOPE OF THE BUFFER STRIP ON EACH SIDE OF THE WATERCOURSE. THE SILT FENCE SHOULD INCORPORATE REMOVABLE "GATES" AS REQUIRED TO ALLOW ACCESS WHILE MAINTAINING EASE OF REPLACEMENT FOR OVERNIGHT OR DURING PERIODS OF RAINFALL.
7. CONSTRUCT A TEMPORARY SUMP UPSTREAM OF THE DAM AND LINE WITH ROCKFILL IF A NATURAL POOL DOES NOT EXIST. INSTALL THE PUMP OR PUMP INTAKE IN THE POOL OR SUMP. DISCHARGE WATER ONTO AN ENERGY DISSIPATER DOWNSTREAM OF THE WORK AREA.
8. EXCAVATED MATERIAL MUST NOT BE STOCKPILED WITHIN 10 FT. OF THE WATERCOURSE. THIS MATERIAL MUST BE CONTAINED WITHIN BERM CONTAINMENT, WITH SECONDARY SILT FENCE PROTECTION TO PREVENT SATURATED SOIL FROM FLOWING BACK INTO THE WATERCOURSE.
9. CHEMICALS, FUELS, LUBRICATING OILS SHALL NOT BE STORED AND EQUIPMENT REFUELED WITHIN 100 FT. OF THE WATERBODY. PUMPS ARE TO BE REFUELED AS PER THE SPCC PLANS.
10. STAGING AREAS ARE TO BE LOCATED AT LEAST 10 FT. FROM THE WATER'S EDGE (WHERE TOPOGRAPHIC CONDITIONS PERMIT) AND SHALL BE THE MINIMUM SIZE NEEDED.
11. DAMS ARE TO BE MADE OF STEEL PLATE, INFLATABLE PLASTIC DAM, SAND BAGS, COBBLES, WELL GRADED COARSE GRAVEL FILL, OR ROCK FILL. DAMS MAY NEED KEYING INTO THE BANKS AND STREAMBED. ENSURE THAT THE DAM AND VEHICLE CROSSING ARE LOCATED FAR ENOUGH APART TO ALLOW FOR A WIDE EXCAVATION. CAP FLUMES USED UNDER VEHICLE CROSSING DURING DRY CROSSING.
12. DEWATER AREA BETWEEN DAMS IF POSSIBLE. DEWATERING SHOULD OCCUR IN A STABLE VEGETATIVE AREA A MINIMUM OF 50 FT. FROM ANY WATERBODY. THE PUMP DISCHARGE SHOULD BE DISCHARGED ONTO A STABLE SPILL PAD CONSTRUCTED OF ROCKFILL, SANDBAGS, OR TIMBERS TO PREVENT LOCALIZED EROSION. THE DISCHARGE WATER SHOULD ALSO BE FORCED INTO SHEET FLOW IMMEDIATELY BEYOND THE SPILL PAD BY USING STRAW BALES AND THE NATURAL TOPOGRAPHY DISCHARGED WATER SHALL NOT BE ALLOWED TO FLOW INTO ANY WATERCOURSE OR WETLAND. IF IT IS NOT POSSIBLE TO DEWATER THE EXCAVATION DUE TO SOILS WITH A HIGH HYDRAULIC CONDUCTIVITY, THE EXCAVATION AND PIPE PLACEMENT IS TO BE CARRIED OUT IN THE STANDING WATER. PUMP ANY DISPLACED WATER AS DESCRIBED ABOVE TO PREVENT OVERTOPPING OF DAMS.
13. EXCAVATE TRENCH THROUGH PLUGS AND STREAMBED FROM BOTH SIDES, RE-POSITIONING DISCHARGE HOSE AS NECESSARY. LOWER THE PIPE IN THE TRENCH AND BACKFILL IMMEDIATELY. DURING THIS OPERATION WORK IS TO BE COMPLETED AS QUICKLY AS POSSIBLE.
14. CONTRACTOR SHALL RESTORE THE STREAM BED AND BANKS TO APPROXIMATE PRE-CONSTRUCTION CONTOURS, BUT NOT TO EXCEED 2 HORIZONTAL TO 1 VERTICAL.
   a. CONTRACTOR SHALL INSTALL PERMANENT EROSION AND SEDIMENT CONTROL STRUCTURES AS INDICATED ON A SITE SPECIFIC BASIS. IN THE ABSENCE OF SITE SPECIFIC INFORMATION, A FLEXIBLE CHANNEL LINER SUCH AS NAG C125 OR C350 WHICH IS CAPABLE OF WITHSTANDING ANTICIPATED FLOW SHALL BE INSTALLED. ALTERNATIVELY, ROCK RIP-RAP SHALL BE INSTALLED.
   b. ANY MATERIALS PLACED IN THE STREAM TO FACILITATE CONSTRUCTION SHALL BE REMOVED DURING RESTORATION. BANKS SHALL BE STABILIZED AND TEMPORARY SEDIMENT BARRIERS INSTALLED AS SOON AS POSSIBLE AFTER CROSSING, BUT WITHIN 24 HOURS OF COMPLETING THE CROSSING.
   c. MAINTAIN A SILT FENCE OR STRAW BALE BARRIER ALONG THE WATER COURSE UNTIL VEGETATION IS ESTABLISHED IN ADJACENT DISTURBED AREAS.
15. WHEN THE STREAMBED HAS BEEN RESTORED, THE CREEK BANKS ARE TO BE CONTOURED TO A STABLE ANGLE AND PROTECTED WITH EROSION RESISTANT MATERIAL COMPATIBLE WITH FLOW VELOCITY BETWEEN DAMS (E.G., EROSION CONTROL BLANKETS, CRIBBING, ROCK RIP-RAP, ETC.). THE DAMS ARE TO BE REMOVED DOWNSTREAM FIRST. KEEP PUMP RUNNING UNTIL NORMAL FLOW IS RESUMED. COMPLETE BANK TRIMMING AND EROSION PROTECTION. IF SANDBAGS ARE USED FOR THE DAMS, PLACE AND REMOVE BY HAND TO AVOID EQUIPMENT BREAKING BAGS.

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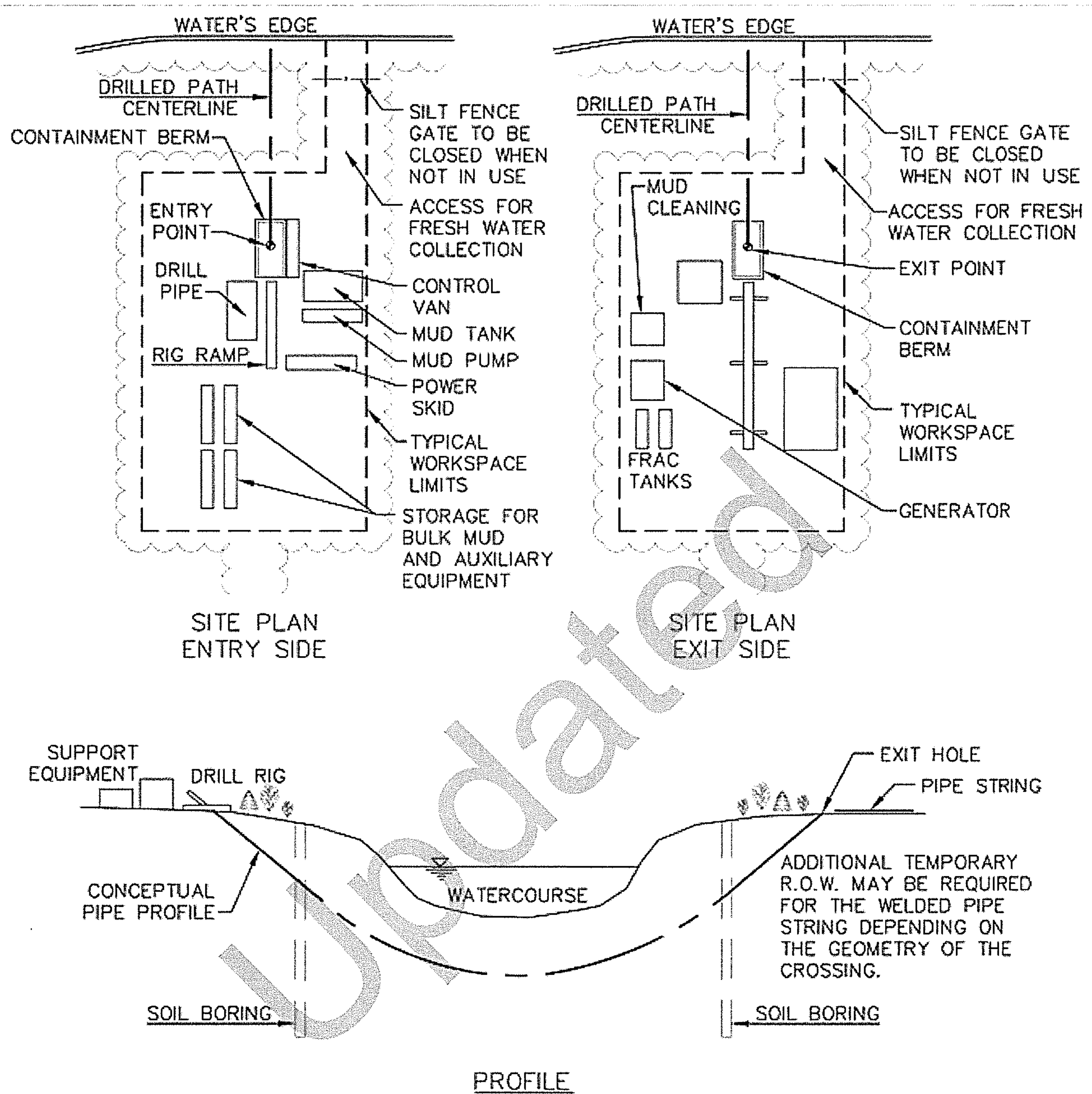

PROFILE

NOTES:

1. SET UP DRILLING EQUIPMENT A MINIMUM OF 100 FEET FROM THE EDGE OF THE WATERCOURSE. LIMIT CLEARING BETWEEN DRILL ENTRY AND EXIT POINT TO HAND CUTTING BRUSH FOR TRACKING WIRES.
2. ENSURE THAT ONLY BENTONITE-BASED DRILLING MUD IS USED.
3. INSTALL SUITABLE DRILLING MUD TANKS OR SUMPS TO PREVENT CONTAMINATION OF WATERCOURSE.
4. INSTALL BERMS DOWNSLOPE FROM THE DRILL ENTRY AND ANTICIPATED EXIT POINTS TO CONTAIN ANY RELEASE OF DRILLING MUD.
5. DISPOSE OF DRILLING MUD IN ACCORDANCE WITH THE APPROPRIATE REGULATORY AUTHORITY REQUIREMENTS.

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TITLE
DETAIL 15
TYPICAL HORIZONTAL DRILL (HDD) SITE PLAN & PROFILE

SCALE	DWG No	REV
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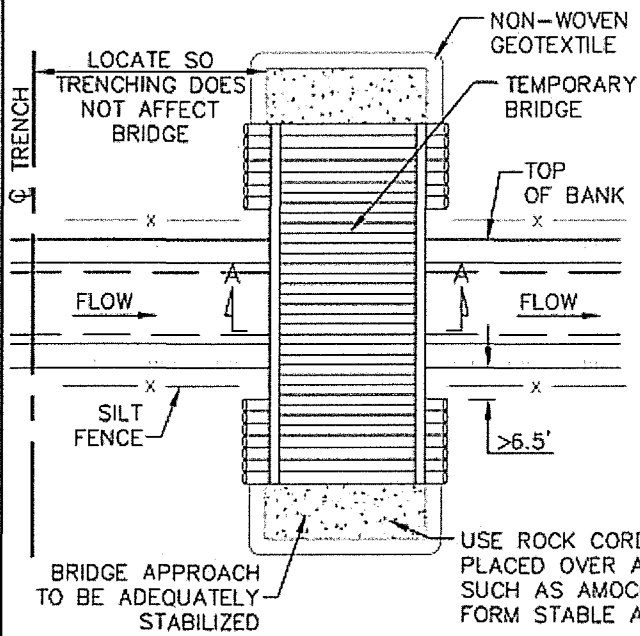
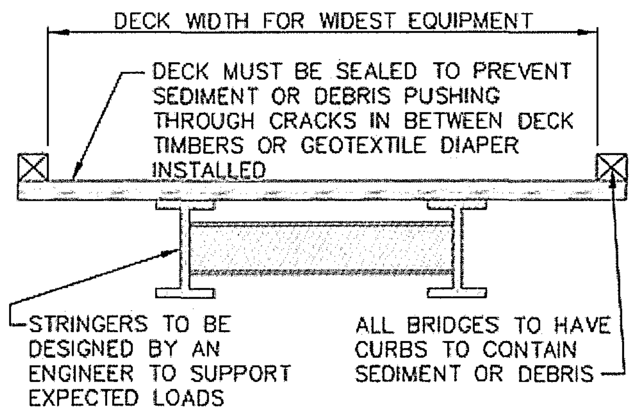
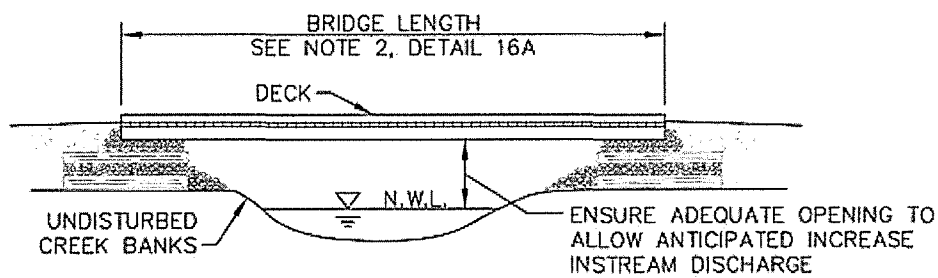


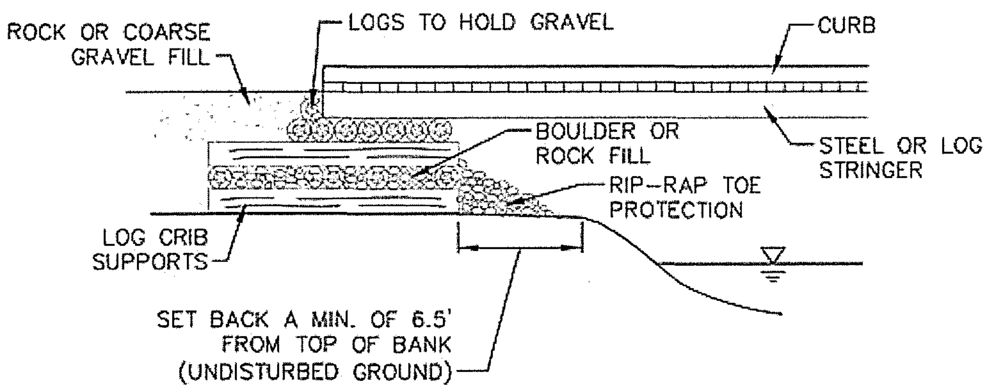
PLAN VIEW



SECTION A–A



BRIDGE PROFILE



TYPICAL TEMPORARY CRIB ABUTMENT

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SCALE N.T.S.	DWG No 4359-03-ML-03-712	REV 01

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CONSTRUCTION PROCEDURES:

IN GENERAL TERMS, THE FOLLOWING IS A SEQUENCE OF CONSTRUCTION PROCEDURES THAT ARE RECOMMENDED TO BE FOLLOWED FOR TEMPORARY BRIDGE CROSSINGS:

1. A PORTABLE BRIDGE, FLEXI-FLOAT OR FLUMED VEHICLE CROSSING MAY BE SUBSTITUTED FOR THE TEMPORARY BRIDGE. IT IS IMPORTANT THAT THE SIZE OF THE TOTAL OPENING BE SELECTED SO THE STRUCTURE CAN SAFELY PASS FLOOD FLOWS THAT CAN REASONABLY BE EXPECTED TO OCCUR DURING THE LIFE OF THE CROSSING.

2. DETERMINE BRIDGE LENGTH REQUIRED AND FOLLOW EITHER METHOD A) OR B) FOR DETERMINING THE OPENING SIZE. IF A) IS FOLLOWED, A MINIMUM 6.5 FT. SETBACK FROM TOP OF BANK MUST BE PRESERVED AS A "NO DISTURBANCE AREA". IF ABUTMENTS OR PIERS IN THE STREAMBED ARE REQUIRED, METHOD B) IS TO BE FOLLOWED.

3. INSTALL THE BRIDGE IN A MANNER THAT WILL MINIMIZE SEDIMENT ENTERING THE WATER. STRINGERS MUST BE DESIGNED TO SUPPORT THE LOADS EXPECTED ON THE BRIDGE. CURBS MUST BE INSTALLED ALONG THE EDGE OF THE DECK TO CONTAIN SEDIMENT AND DEBRIS ON THE BRIDGE. FASTENERS CONNECTING COMPONENTS MUST BE STRONG ENOUGH TO HOLD THEM IN POSITION DURING THE LIFE OF THE BRIDGE. CRIBS ARE TO BE FILLED WITH ROCK OR COBBLE. RIP-RAP EROSION PROTECTION IS TO BE PLACED AROUND THE CRIBS AND ON ANY FILL SLOPES PROJECTING INTO THE WATERBODY.

4. ROAD APPROACHES LEADING TO THE BRIDGE MUST BE RAISED AND STABLE SO EQUIPMENT LOADS ARE SUPPORTED A SUFFICIENT DISTANCE BACK FROM THE WATER TO REDUCE SEDIMENT AND DEBRIS ENTERING THE WATERBODY FROM EQUIPMENT TRACKS. THIS MAY REQUIRE USING MATERIALS SUCH AS GRAVEL, ROCK OR CORDUROY. DO NOT USE SOIL TO CONSTRUCT OR STABILIZE EQUIPMENT BRIDGES. IF CUTS ARE NEEDED TO OBTAIN A SATISFACTORY GRADE, THEY ARE TO BE DUG WITH SIDE DITCHES AND STABLE SLOPES. EROSION AND SEDIMENT CONTROL MEASURES ARE TO BE INSTALLED TO KEEP SEDIMENT ON LAND (E.G., SILT FENCING, FILTER CLOTH, RIP-RAP, SEED AND MULCH, ETC.)

5. MAINTAIN A SILT FENCE ON EACH SIDE OF THE WATERBODY EXTENDING A MINIMUM OF 10 FEET BEYOND THE WIDTH OF DISTURBANCE UNTIL VEGETATION HAS BEEN ESTABLISHED IN UPSLOPE AREAS.

6. PERIODICALLY CHECK BRIDGE INSTALLATION AND REMOVE ANY BUILD-UP OF SEDIMENT OR DEBRIS ON THE BRIDGE. DISPOSE OF THIS MATERIAL IN A LOW LYING AREA AT LEAST 100 FEET FROM THE WATERBODY.

7. REMOVE TEMPORARY CROSSINGS AS SOON AS POSSIBLE AFTER FINAL CLEAN-UP. MATERIALS PLACED ALONG THE WATERBODY SHOULD BE COMPLETELY REMOVED DURING FINAL CLEAN-UP. REMOVAL SHOULD NOT OCCUR OUTSIDE THE CONSTRUCTION WINDOWS. SURPLUS GRAVEL IS TO BE SPREAD ON THE RIGHT-OF-WAY AS GRAVEL SHEETING, IF GRADATION IS SUITABLE, OR MOVED AT LEAST 100 FEET FROM TOP OF BANK FOR DISPOSAL. BRIDGE MATERIALS ARE TO BE REMOVED FROM THE CROSSING AREA. THE WATERBODY BED AND BANKS ARE TO BE RESTORED TO A STABLE ANGLE AND PROTECTED WITH EROSION RESISTANT MATERIAL COMPATIBLE WITH THE EXPECTED FLOW CONDITIONS.

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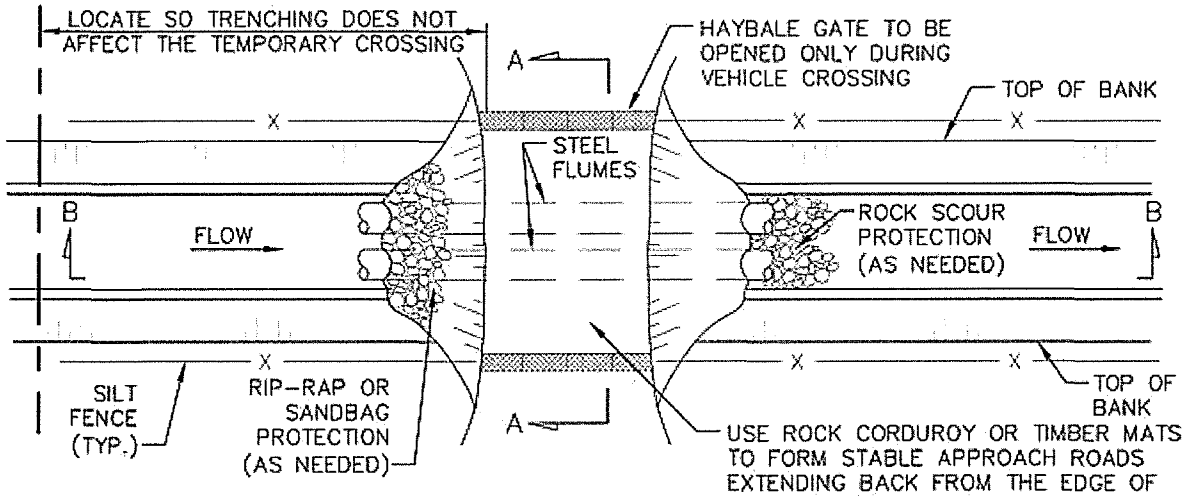

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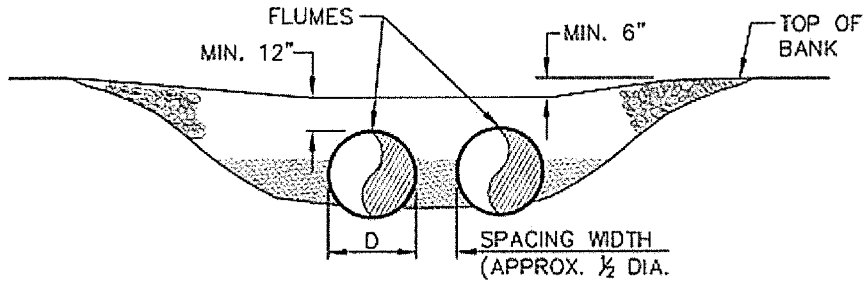
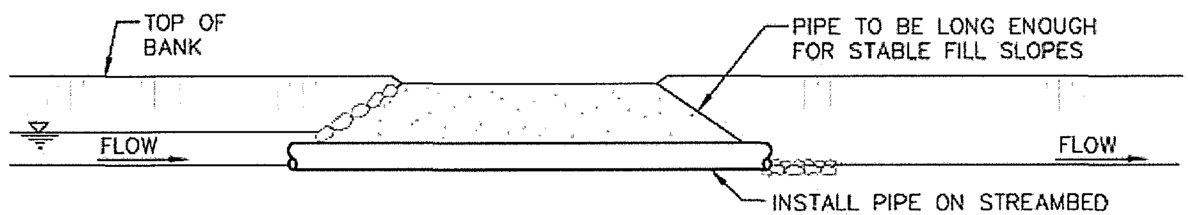


SECTION A–A



SECTION B–B

CONSTRUCTION PROCEDURES:

THE FOLLOWING IS A SEQUENCE OF CONSTRUCTION AND PROCEDURES MEASURES TO BE FOLLOWED AT ALL TEMPORARY FLUME VEHICLE CROSSINGS.

1. A PORTABLE FLEXI-FLOAT, OR TEMPORARY BRIDGE MAY BE SUBSTITUTED FOR THE TEMPORARY FLUME CROSSING.
2. THE LENGTH OF THE FLUME SHALL BE SUFFICIENT TO SPAN THE ENTIRE AREA REQUIRED FOR VEHICULAR ACCESS, EXTENDING 4 FEET BEYOND TOE OF FILL MATERIAL, SO TRENCHING WILL NOT AFFECT THE ROAD CROSSING. A LONGER PIPE IS TO BE USED, IF NEEDED, TO MAINTAIN STABLE SIDE SLOPES. FLUME CAPACITY TO BE BASED ON THE 2-YEAR DESIGN FLOW OR MAXIMUM FLOW ANTICIPATED TO OCCUR DURING INSTALLATION, AS SPECIFIED IN CONSTRUCTION DOCUMENTS.
3. WHERE PRACTICAL, BACKFILL AROUND THE PIPES AT THE ROAD WITH CLEAN, COARSE ROCK FILL MATERIAL. IF SCOUR IS POSSIBLE, RIP-RAP IS TO BE PLACED ON THE WATERBODY BED DOWNSTREAM OF THE PIPE OUTLET EXTENDING A MINIMUM OF TWO PIPE DIAMETERS. ALTERNATIVELY, TIMBER EQUIPMENT MATS, SAND BAGS OR TIMBER CORDUROY MAY BE USED TO FORM THE TRAVEL SURFACE.
4. TO REDUCE DEBRIS ENTERING THE WATERBODY FROM EQUIPMENT TRACKS, THE APPROACH ROAD LEADING TO THE CULVERT CROSSING MUST BE RAISED AND STABLE SO EQUIPMENT LOADS ARE SUPPORTED A SUFFICIENT DISTANCE BACK FROM THE WATER. IF CUTS ARE NEEDED TO OBTAIN A SATISFACTORY GRADE, THEY ARE TO BE DUG WITH SIDE DITCHES AND STABLE SLOPES. EROSION AND SEDIMENT CONTROL MEASURES ARE TO BE INSTALLED TO LIMIT THE POTENTIAL FOR SEDIMENT TO ENTER THE WATERBODY (E.G., CHECK DAMS, SILT FENCE, RIP-RAP, SEED AND MULCH, SEDIMENT TRAPS, ETC.).
5. PERIODICALLY CHECK THE TEMPORARY CROSSING INSTALLATION AND REMOVE ANY BUILD-UP OF SEDIMENT OR DEBRIS ON THE BRIDGE. DISPOSE OF THIS MATERIAL AT LEAST 100 FEET FROM THE WATERBODY AND ABOVE THE HIGH WATER LEVEL.
6. FOLLOWING COMPLETION OF THE CROSSING, REMOVE ROCKFILL IN/OR AROUND FLUME PIPES FROM THE WATERBODY OR WETLAND.
7. RESTORE STREAM BANKS AND WATERBODY BOTTOM.

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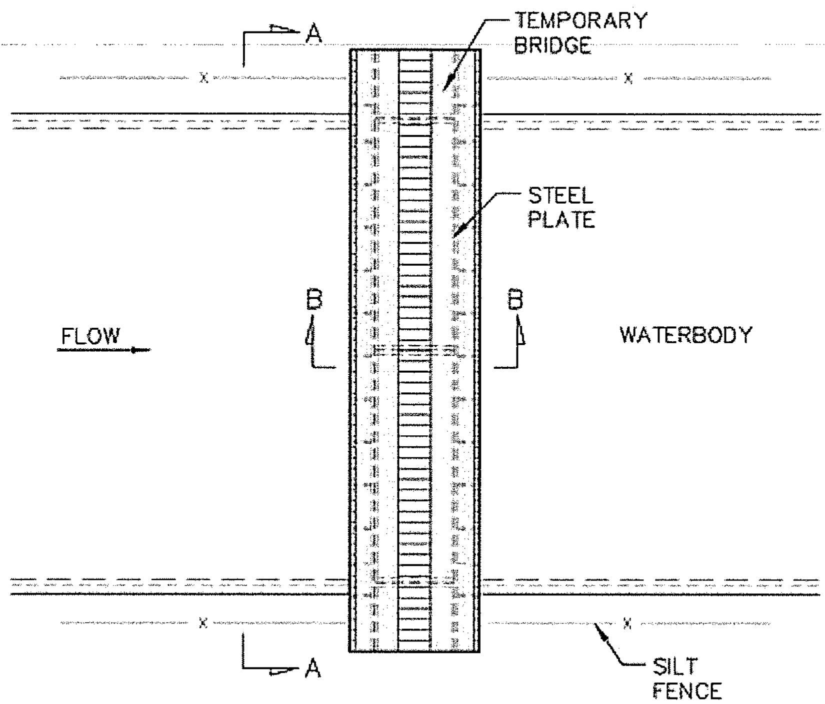
DESIGNER: JMP (NAME) 2010-10-21 (DATE)	KEYSTONE XL PROJECT		
	FIA # 4359	CHAINAGE:	DISCIPLINE # 03
	TITLE: DETAIL 17 TYPICAL FLUME BRIDGE CROSSING		
CHECKED BY: WSF / DESIGN CHECKER: RW	SCALE N.T.S.	DWG No 4359-03-ML-03-714	REV 01

TC_A4_BR.DWG 8.5X11

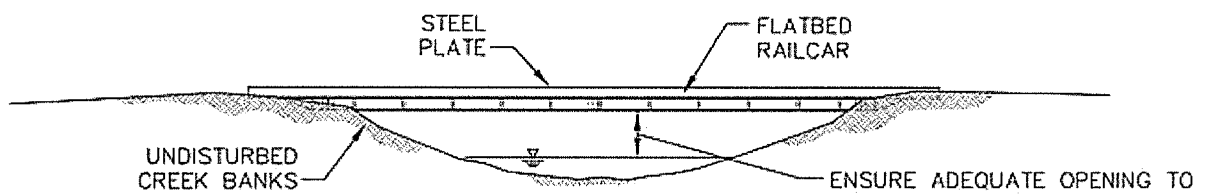
CADD DRAWING: DO NOT MAKE MANUAL REVISIONS

020476

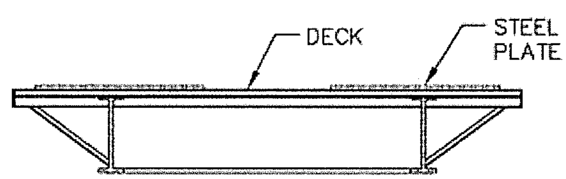
THESE ARE TYPICAL DRAWINGS; ACTUAL SITE CONDITIONS MAY VARY FROM THE SITE GRAPHICALLY REPRESENTED.



PLAN VIEW



SECTION A-A



SECTION B-B

REVISIONS		
01	2010-10-11	REVISED TITLE BLOCK

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DESIGNER: JMP (NAME) 2010-10-21 (DATE)		KEYSTONE XL PROJECT	
		FIA # 4359	CHAINAGE:	DISCIPLINE # 03
		TITLE: DETAIL 18 TYPICAL RAILCAR BRIDGE CROSSING	
CHECKED BY: WSF	DESIGN CHECKER: RW	SCALE N.T.S.	DWG No 4359-03-ML-03-715	REV 01

TC_A4_BR.DWG 8.5X11

CADD DRAWING: DO NOT MAKE MANUAL REVISIONS

020477

THESE ARE TYPICAL DRAWINGS; ACTUAL SITE CONDITIONS MAY VARY FROM THE SITE GRAPHICALLY REPRESENTED.

CONSTRUCTION PROCEDURES:

1. THIS TYPICAL DRAWING PROVIDES FOR A RAILCAR BRIDGE EQUIPMENT CROSSING.

2. BRIDGE SHOULD BE A MINIMUM OF 12 FEET LONGER THAN BANK TO BANK WIDTH.

3. BEST MANAGEMENT PRACTICES UTILIZING EROSION CONTROL DEVICES, SUCH AS HAY BALES AND SILT FENCE ARE REQUIRED TO PREVENT SEDIMENTATION OF THE STREAM. EROSION PROTECTION SHALL BE PLACED ON THE STREAM BANKS.

4. DURING FINAL CLEAN-UP, REMOVE TEMPORARY EQUIPMENT CROSSINGS AS SOON AS POSSIBLE. INSTALLED MATERIALS, SUCH AS HAY BALES AND SILT FENCE MUST BE REMOVED AND DISPOSED IN ACCORDANCE WITH STATE AND LOCAL REGULATIONS AND REQUIREMENTS. THE STREAMBED, BANKS AND AREAS AFFECTED BY CONSTRUCTION OF THE TEMPORARY EQUIPMENT CROSSING SHOULD BE RESTORED TO A STABLE CONDITION. IF REQUIRED TO PREVENT TRANSPORT OF SEDIMENTATION TO THE STREAM, SILT FENCE SHOULD BE INSTALLED AT THE TOP OF THE BANKS.

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DESIGNER: JMP (NAME) 2010-10-21 (DATE)	KEYSTONE XL PROJECT		
	FIA # 4359	CHAINAGE:	DISCIPLINE # 03
CHECKED BY: WSF / DESIGN CHECKER: RW P7100	TITLE: DETAIL 18A TYPICAL RAILCAR BRIDGE CROSSING – CONSTRUCTION PROCEDURES		
	SCALE N.T.S.	DWG No 4359-03-ML-03-716	REV 01

TC_A4_BR.DWG 8.5X11

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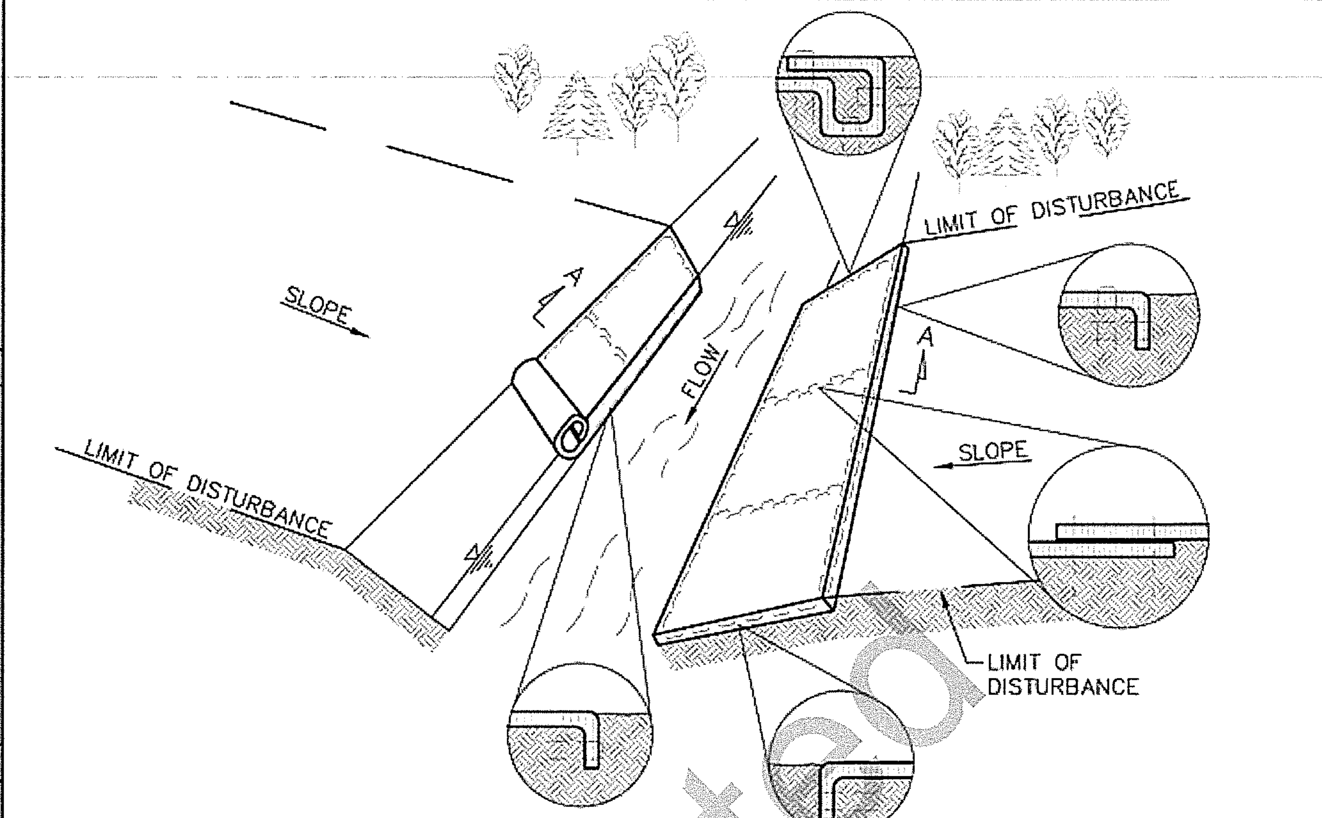
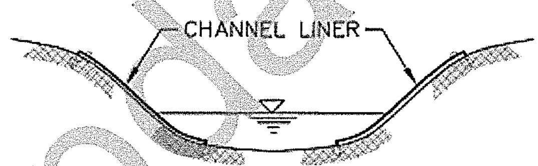


PLAN VIEW



SECTION A–A

NOTES:

1. INSTALL AND ANCHOR LINERS FOLLOWING MANUFACTURER'S INSTRUCTIONS.
2. PREPARE SOIL BEFORE INSTALLING CHANNEL LINER, INCLUDING THE APPLICATION OF
3. SEED. CHANNEL LINERS SHOULD EXTEND COMPLETELY ACROSS DISTURBED BANK AREAS TO PROTECT ERODIBLE SURFACES.
4. BEGIN AT THE END OF THE CHANNEL BY ANCHORING THE LINER IN A TRENCH. BACKFILL AND COMPACT THE TRENCH AFTER STAPLING.
5. ROLL LINER IN DIRECTION OF WATER FLOW.
6. INSTALL LINERS END–OVER–END (SHINGLE STYLE) WITH OVERLAP USING A DOUBLE ROW OF STAGGERED STAPLES 4 INCHES BELOW THE FIRST ROW IN A STAGGERED PATTERN.
7. IN HIGH FLOW CHANNEL APPLICATIONS, A STAPLE CHECK SLOT IS RECOMMENDED AT 30 TO 40 FEET INTERVALS. USE A ROW OF STAPLES 4 INCHES BELOW THE FIRST ROW IN A STAGGERED PATTERN.
8. INSTALL CHANNEL LINER TO THE TOP OF THE DEFINED CHANNEL SECTION. TWO OR MORE ROWS OF BLANKETS MAY BE NECESSARY, THESE LINERS MUST BE OVERLAPPED 4 INCHES AND STAPLED.
9. THE CHANNEL LINER SHOULD EXTEND TO THE BASE OF THE CHANNEL AND STAPLED. FOR CHANNELS WITH VERY LITTLE OR NO FLOW, EXTEND A MINIMUM OF 1 FOOT BELOW THE LOW WATER LEVEL AND STAPLE IN PLACE.
10. INSTALLATION SPECIFICATIONS TO BE MODIFIED AS NECESSARY TO SUIT ACTUAL SITE CONDITIONS.

REVISIONS		
01	2008–11–04	UPDATED DRAWING NOTES
02	2010–10–11	REVISED TITLE BLOCK

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CHECKED BY:	WSF
DESIGN CHECKER:	RW
KEYSTONE XL PROJECT	
FIA #	4359
CHAINAGE:	
DISCIPLINE #	03
TITLE	DETAIL 19 FLEXIBLE CHANNEL LINER INSTALLATION
SCALE	N.T.S.
DWG No	4359–03–ML–05–708
REV	02

TC_A4_BR.DWG 8.5X11

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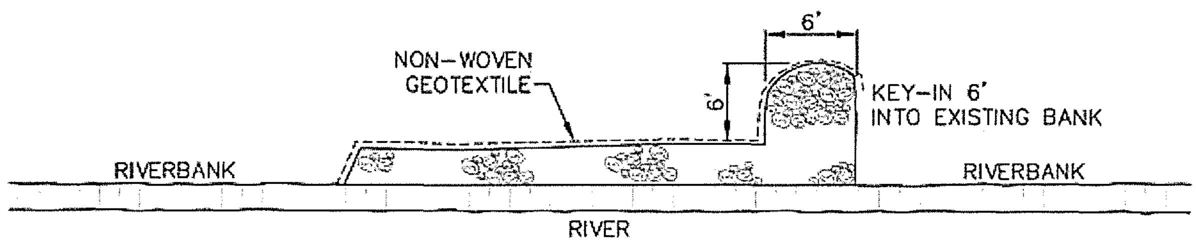
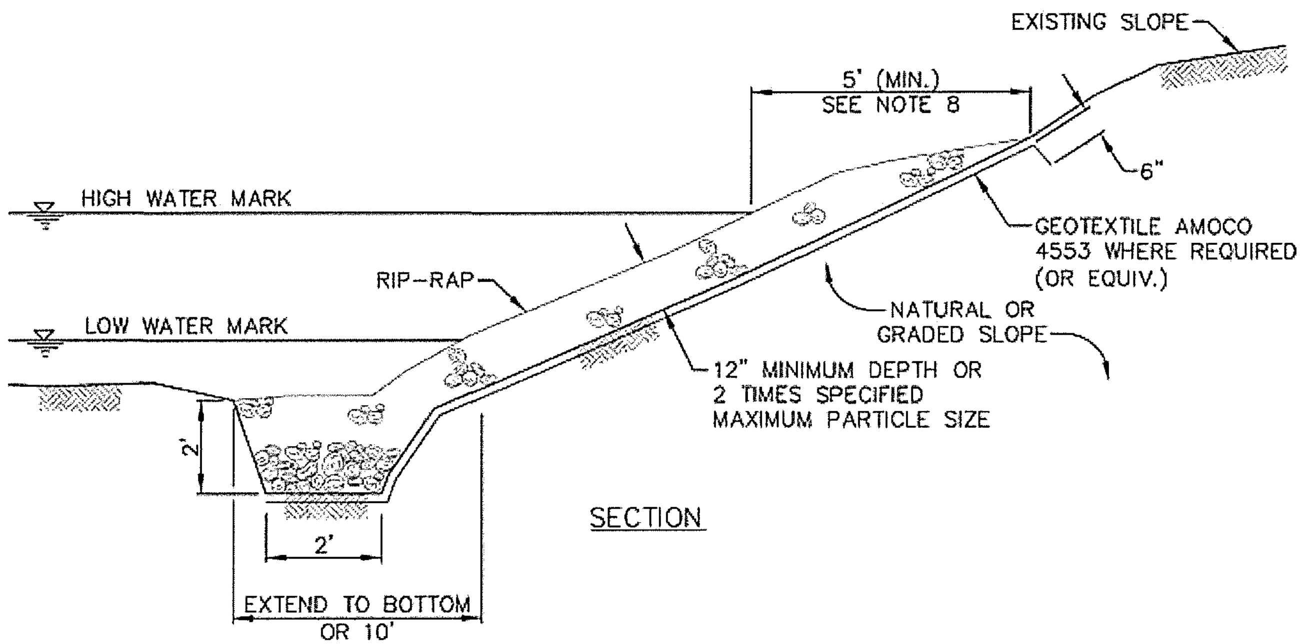


PLAN



SECTION

NOTES:

1. REMOVE ALL STUMPS, ORGANIC MATERIAL AND PREPARE BANKS TO A STABLE CONFIGURATION TO A MAXIMUM SLOPE OF 2 HORIZONTAL TO 1 VERTICAL.
2. CONSTRUCT TOE TRENCH TO KEY IN BOTTOM OF RIP-RAP PROTECTION.
3. INSTALL FILTER CLOTH (GEOTEXTILE), SUCH AS AMOCO 4553 OR EQUIVALENT, UNDER ROCK WHERE SPECIFIED OR AS DIRECTED BY THE COMPANY. ADJOINING EDGES OF CLOTH SHALL OVERLAP A MINIMUM OF 12".
4. ROCK UTILIZED FOR RIP-RAP SHALL CONSIST OF SOUND, DURABLE ROCK, AND RESISTANT TO WEATHERING. INDIVIDUAL PIECES SHOULD BE ANGULAR, BLOCK SHAPED AND HAVE A MINIMUM SPECIFIC GRAVITY OF 2.2.
5. INSTALL RIP-RAP TO A THICKNESS OF APPROXIMATELY 2 TIMES THE MAXIMUM EQUIVALENT DIAMETER OF THE RIP-RAP. EACH LOAD SHOULD BE WELL GRADED. A WELL GRADED MIXTURE IS COMPOSED 60% (MINIMUM) OF LARGER SIZES WITH 40% OF SMALLER SIZES TO FILL THE VOIDS.
6. SIZE OF RIP-RAP IS DEPENDENT UPON THE PREDICTED FLOW CONDITIONS.
7. KEY IN THE EDGES OF THE RIP-RAP AND FILTER CLOTH TO NATURAL GROUND CONTOURS SO THAT UNDERMINING DOES NOT OCCUR.
8. RIP-RAP IS TO BE INSTALLED TO 2 FEET. ABOVE THE NORMAL HIGH WATER MARK OR 5 FEET ALONG THE SLOPE, WHICHEVER IS LESS.
9. INSTALLATION SPECIFICATIONS TO BE MODIFIED TO SUIT ACTUAL SITE CONDITIONS.

REVISIONS		
01	2008-11-04	UPDATED DRAWING NOTES
02	2010-10-11	REVISED TITLE BLOCK

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CHECKED BY:	WSF
DESIGN CHECKER:	RW
PROJECT	KEYSTONE XL PROJECT
FIA #	4359
CHAINAGE:	
DISCIPLINE #	03
TITLE	DETAIL 20 TYPICAL ROCK RIP-RAP
SCALE	N.T.S.
DWG No	4359-03-ML-05-709
REV	02

TC_A4_BR.DWG 8.5X11

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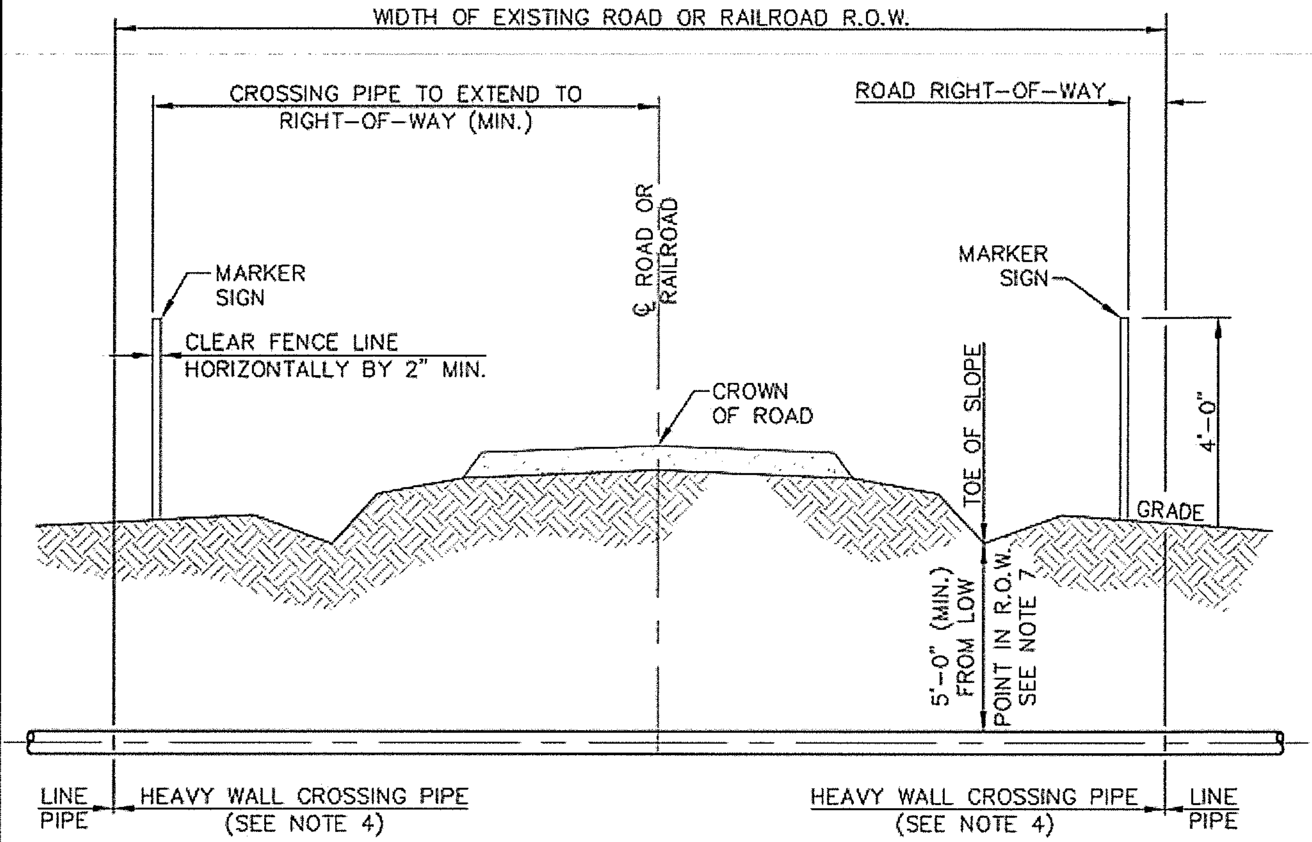

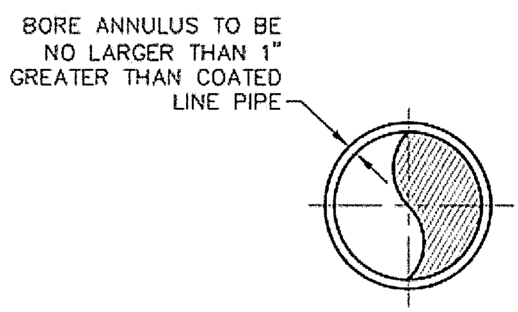

NOTES:

1. CROSSINGS SHALL BE IN ACCORDANCE WITH APPLICABLE PERMIT.
2. ROAD CROSSING PIPE SHALL EXTEND AT MINIMUM TO RIGHT-OF-WAY LINE UNLESS OTHERWISE SPECIFIED.
3. THE TYPE AND MINIMUM REQUIRED LENGTH OF PIPE FOR CROSSINGS OF ROADS SHALL BE AS SPECIFIED ON ALIGNMENT SHEETS.
4. PIPE FOR BORED CROSSINGS TO INCLUDE ABRASION-RESISTANT (ARB) COATING.
5. PIPELINE MARKER AND TEST STATIONS TO BE INSTALLED ON RIGHT-OF-WAY LINE NEXT TO FENCE IF POSSIBLE.
6. THE CROSSING PIPE SHALL BE STRAIGHT WITH NO VERTICAL OR HORIZONTAL BENDS WITHIN ROAD RIGHT-OF-WAY.
7. MINIMUM PIPELINE COVER IN DRAINAGE DITCHES AT PUBLIC ROADS IS 60 INCHES; 36 INCHES IN CONSOLIDATED ROCK.

REVISIONS		
01	REVISED DIMENSION	
02	2010-10-11	REVISED TITLE BLOCK

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DESIGNER: JMP (NAME) 2010-10-21 (DATE)	KEYSTONE XL PROJECT		
	FIA # 4359	CHAINAGE:	DISCIPLINE # 03
	TITLE: DETAIL 21 TYPICAL UNCASED ROAD/RAILROAD CROSSING BORE DETAIL		
CHECKED BY: WSF / DESIGN CHECKER: RW	SCALE N.T.S.	DWG No 4359-03-ML-03-717	REV 02

TC_A4_BR.DWG 8.5X11

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020481

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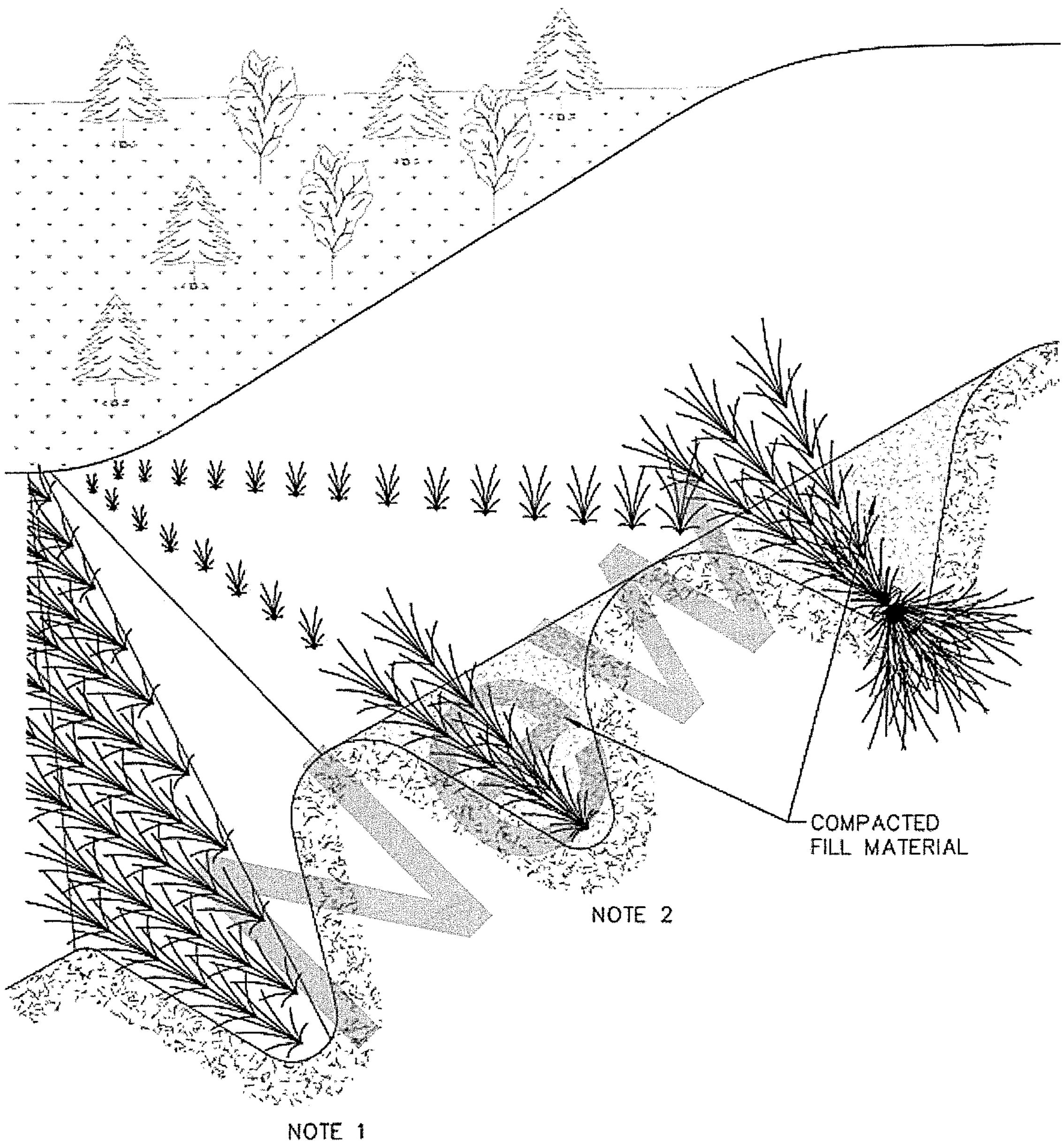

NOTES:

1. CUT TRENCH ACROSS SLOPE. FILL WITH DORMANT WOODY PLANT MATERIAL.
2. FILL IS PLACED ON TOP OF BRANCH LAYER AND COMPACTED.
3. INSTALLATION SPECIFICATIONS TO BE MODIFIED AS NECESSARY TO SUIT SITE CONDITIONS.

REVISIONS		
01	2008-11-04	UPDATED DRAWING NOTES
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KEYSTONE XL PROJECT

FIA # 4359	CHAINAGE:	DISCIPLINE # 03

TITLE
DETAIL 22
STREAMBANK RECLAMATION –
BRUSH LAYER IN CROSS CUT SLOPE

SCALE N.T.S.	DWG No 4359-03-ML-05-710	REV 02

TC_A4_BR.DWG 8.5X11

CADD DRAWING: DO NOT MAKE MANUAL REVISIONS

020482

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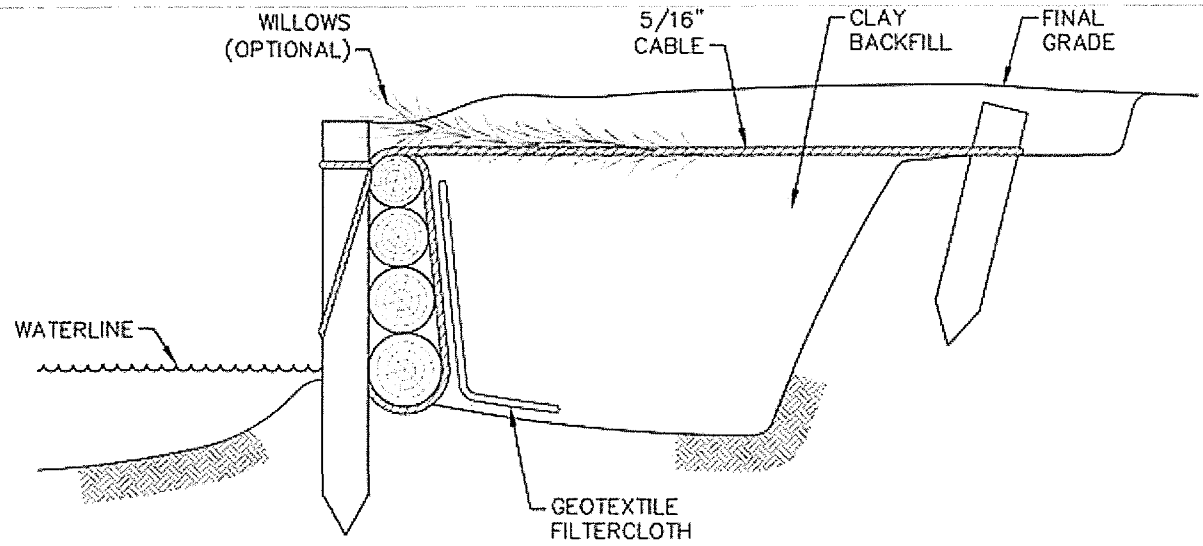

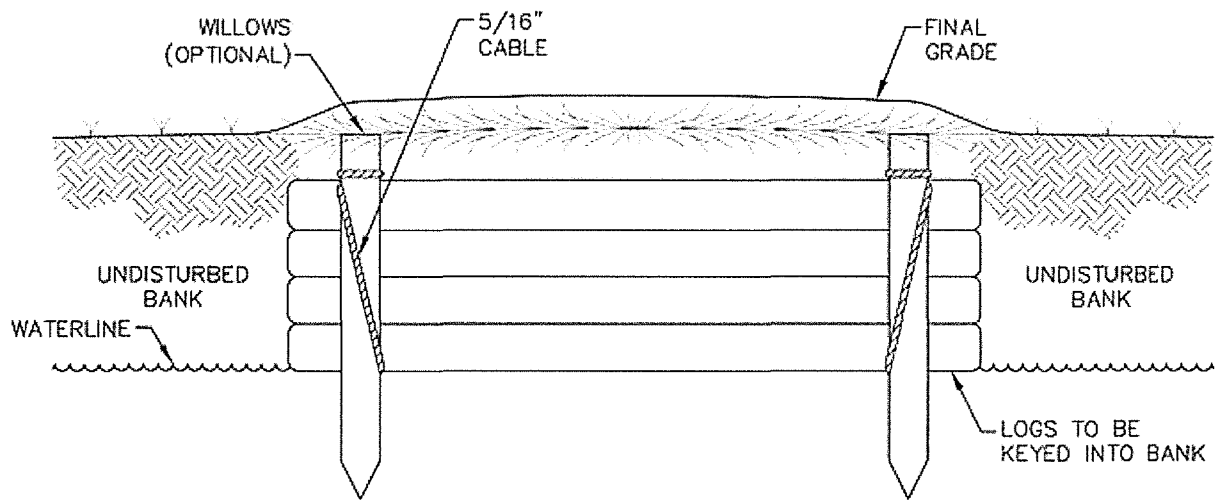

NOTES:

1. LOG WALLS TO BE CONSTRUCTED USING CONIFEROUS MATERIAL.
2. NATURE BACKFILL OR LOOSE GRADE MATERIAL SHOULD BE USED AS FILL MATERIAL.
3. ANCHOR PILINGS OR DEADMAN ANCHORS TO BE USED TO SECURE CABLE IN BANK.
4. NON-WOVEN FILTER CLOTH (NYLEX C34 OR EQUIVALENT) TO BE USED TO LINE LOG WALL.
5. INSTALLATION SPECIFICATIONS TO BE MODIFIED AS NECESSARY TO SUIT ACTUAL SITE CONDITIONS.

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01	2008-11-04	UPDATED DRAWING NOTES
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KEYSTONE XL PROJECT

FIA #	CHAINAGE:	DISCIPLINE #
4359		03

TITLE
DETAIL 23
STREAMBANK RECLAMATION – LOGWALL

SCALE	DWG No	REV
N.T.S.	4359-03-ML-05-711	02

TC_A4_BR.DWG 8.5X11

CADD DRAWING: DO NOT MAKE MANUAL REVISIONS

020483

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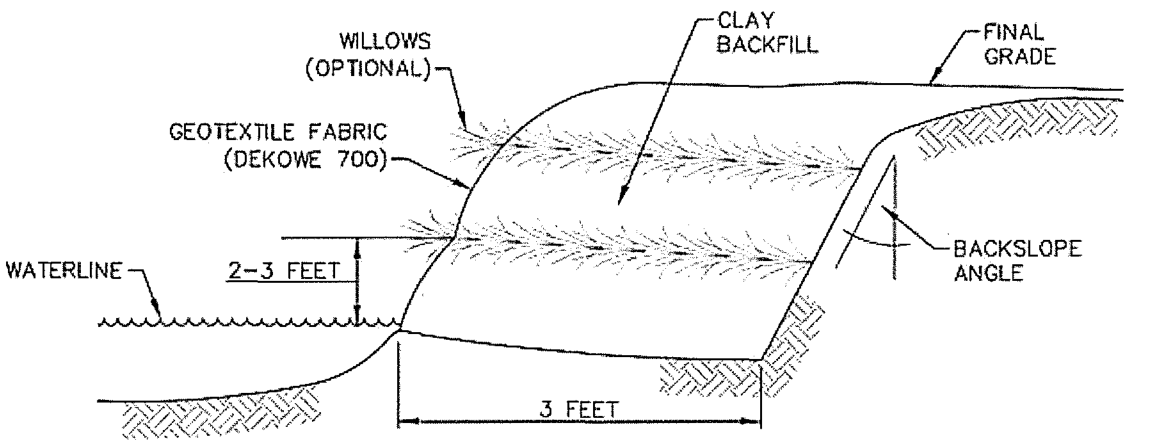

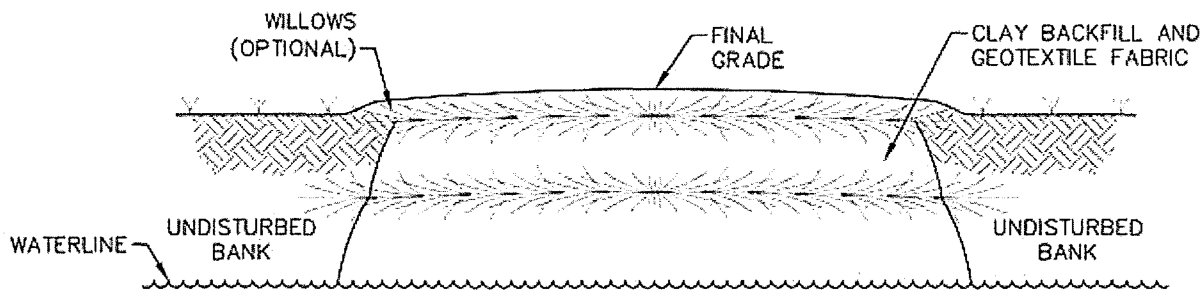

NOTES:

1. NATURE BACKFILL OR LOOSE GRADE MATERIAL SHOULD BE USED TO MINIMIZE AIR SPACES. THIS ALLOWS PROPER SOIL FABRIC CONTACT, WHICH MINIMIZES STEELING AND SCOURING DURING RUNOFF AND ENSURES SURVIVAL OF THE WILLOW CUTTINGS.
2. PLYWOOD FORMS (8'x2') MAY BE REQUIRED TO HELP RECONSTRUCT STEEP OR VERTICAL BANKS.
3. GRID LAYERS SHOULD NOT EXCEED 3 FEET IN HEIGHT WITH A MINIMUM OF 3 FEET SET IN BANK.
4. WILLOWS SHOULD BE HARVESTED AS CLOSE TO INSTALLATION AS POSSIBLE, PREFERABLY THE PREVIOUS DAY BUT NO MORE THAN 2 DAYS EARLY.
5. WILLOWS SHOULD BE 0.5 TO 1 INCH IN DIAMETER AND 2 TO 3 FEET LONG WITH NO MORE THAN 10 INCHES LEFT EXPOSED.
6. PLANTING RATE SHOULD BE APPROXIMATELY 1 STEM PER 6 INCHES.
7. INSTALLATION TO BE MODIFIED AS NECESSARY TO SUIT ACTUAL SITE CONDITIONS.

REVISIONS		
01	2008-11-04	UPDATED DRAWING NOTES
02	2010-10-11	REVISED TITLE BLOCK

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JMP (NAME)	2010-10-21 (DATE)	FIA # 4359	CHAINAGE:	DISCIPLINE # 03
CHECKED BY: WSF	DESIGN CHECKER: RW	TITLE DETAIL 24 STREAMBANK RECLAMATION – VEGETATED GEOTEXTILE INSTALLATION		
	P7100	SCALE N.T.S.	DWG No 4359-03-ML-05-712	REV 02

TC_A4_BR.DWG 8.5X11

CADD DRAWING: DO NOT MAKE MANUAL REVISIONS

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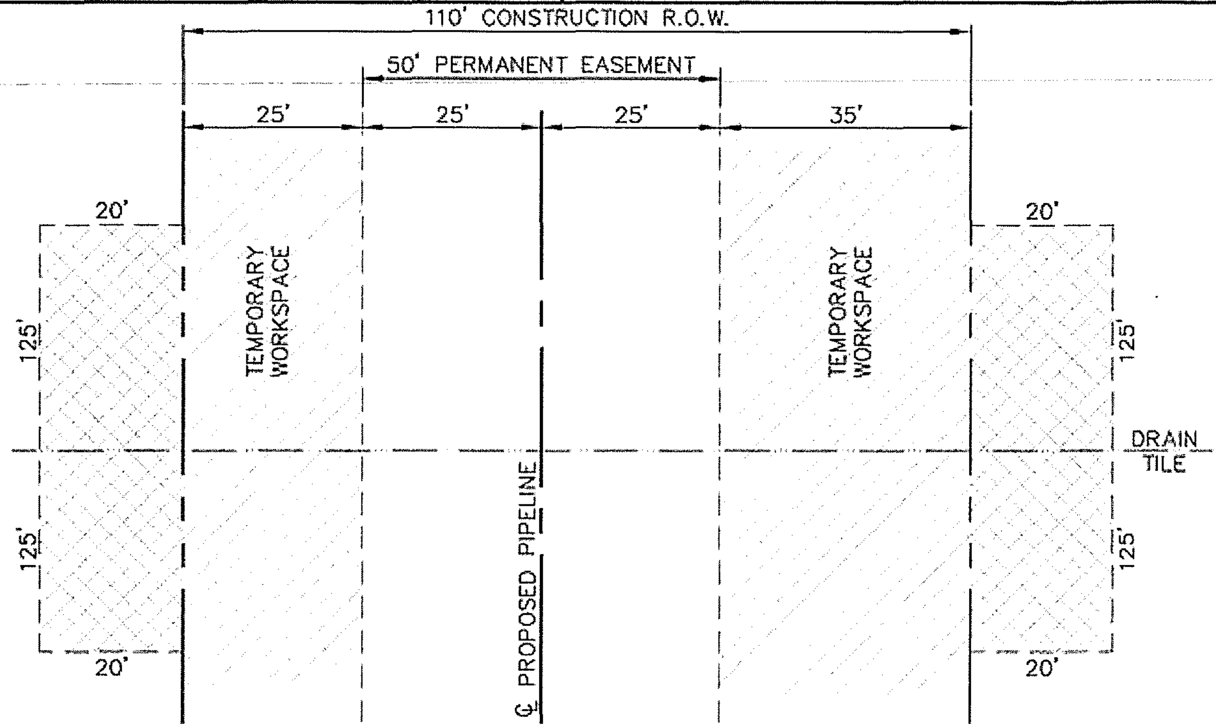
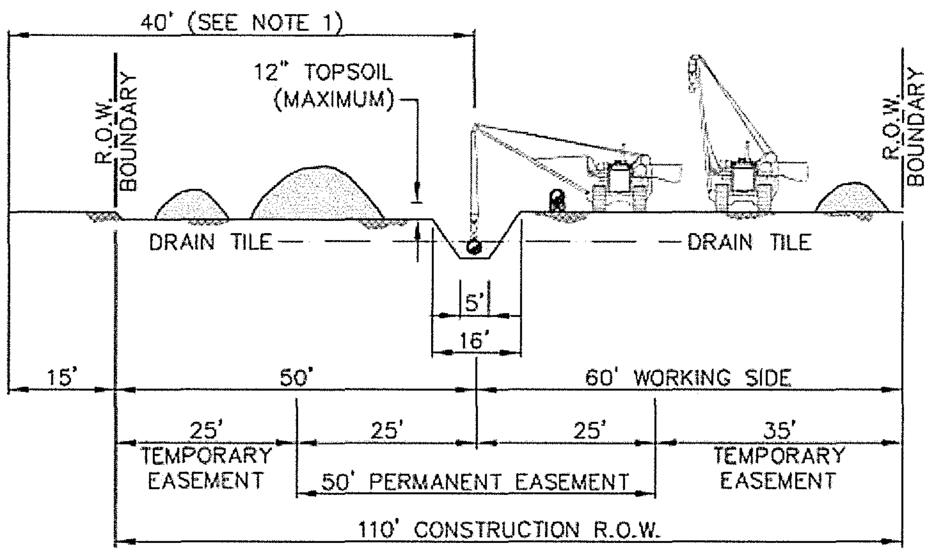


PLAN VIEW



ELEVATION

NOTES:

1. THE OFFSET FROM A FOREIGN PIPELINE, WHERE APPLICABLE, WILL BE 40' FOR MOST LOCATIONS, BUT MAY BE INCREASED OR DECREASED DEPENDING ON THE SITE SPECIFIC CONSTRUCTION REQUIREMENTS.

2. THE MINIMUM CLEARANCE BETWEEN THE TOP OF PIPE AND THE BOTTOM OF DRAIN TILE WILL BE 12 INCHES.

3. INSTALLATION SPECIFICATIONS TO BE MODIFIED AS NECESSARY TO SUIT ACTUAL SITE CONDITIONS.

REVISIONS
01 REVISED NOTE 3; DELETED DIMENSION
02 2010-10-11 REVISED TITLE BLOCK

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DESIGNER: JMP (NAME) 2010-10-21 (DATE)		KEYSTONE XL PROJECT
		FIA # 4359 — CHAINAGE: — DISCIPLINE # 03
		TITLE: DETAIL 25 TYPICAL R.O.W. LAYOUT/SOIL HANDLING 110' CONSTRUCTION R.O.W. 50' EASEMENT DRAIN TILE CROSSING
CHECKED BY: WSF	DESIGN CHECKER: RW P7100	SCALE N.T.S. — DWG No 4359-03-ML-03-718 — REV 02

TC_A4_BR.DWG 8.5X11

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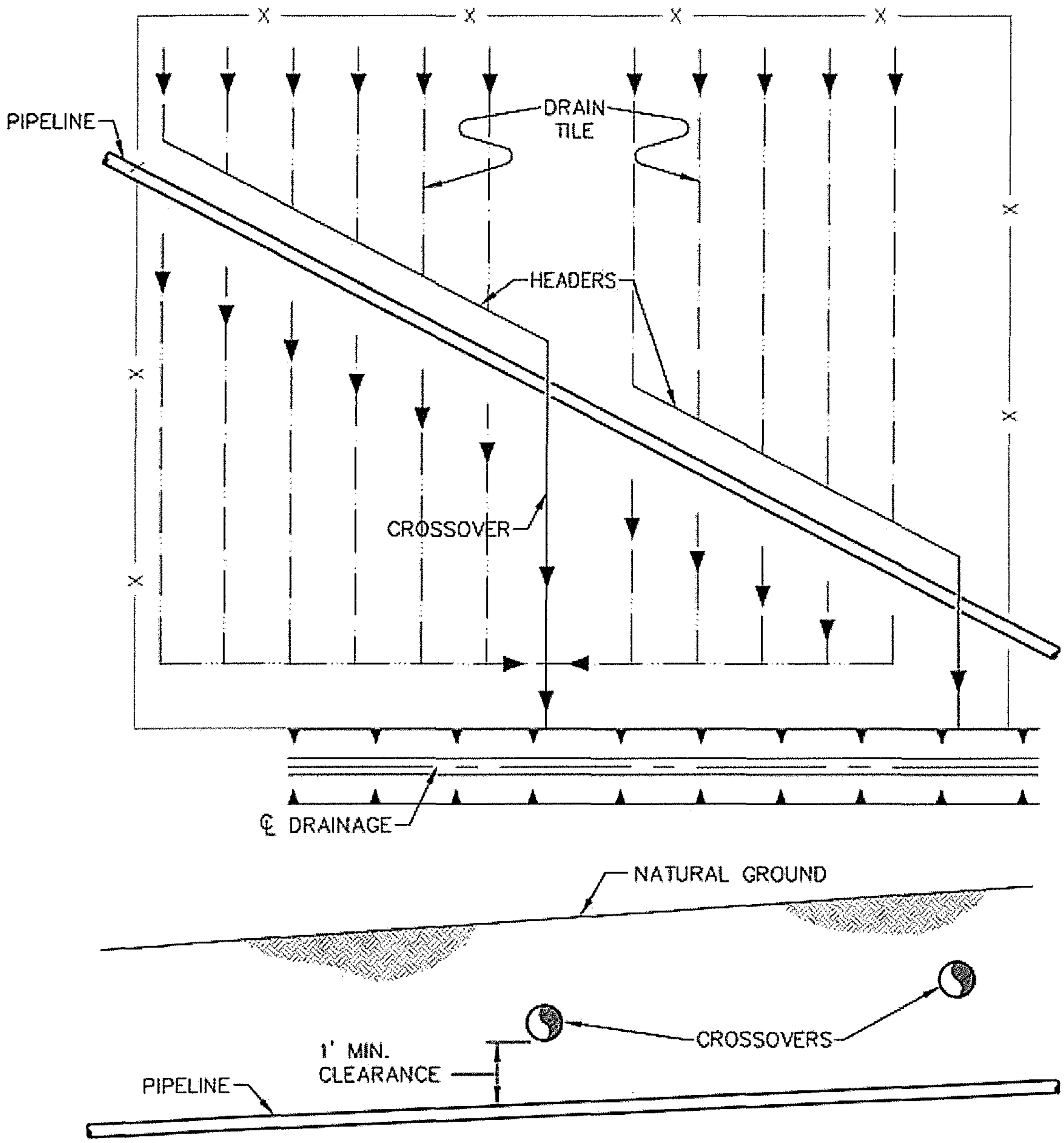

PROFILE

REVISIONS | 01 | ADDED DIMENSION | 02 | 2010-10-11 REVISED TITLE BLOCK

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DESIGNER: JMP (NAME) 2010-10-21 (DATE)	KEYSTONE XL PROJECT		
	FIA # 4359	CHAINAGE:	DISCIPLINE # 03
CHECKED BY: WSF	TITLE DETAIL 26 HEADER/MAIN CROSSOVERS OF PIPELINE		
DESIGN CHECKER: RW	SCALE N.T.S.	DWG No 4359-03-ML-03-719	REV 02

TC_A4_BR.DWG 8.5X11

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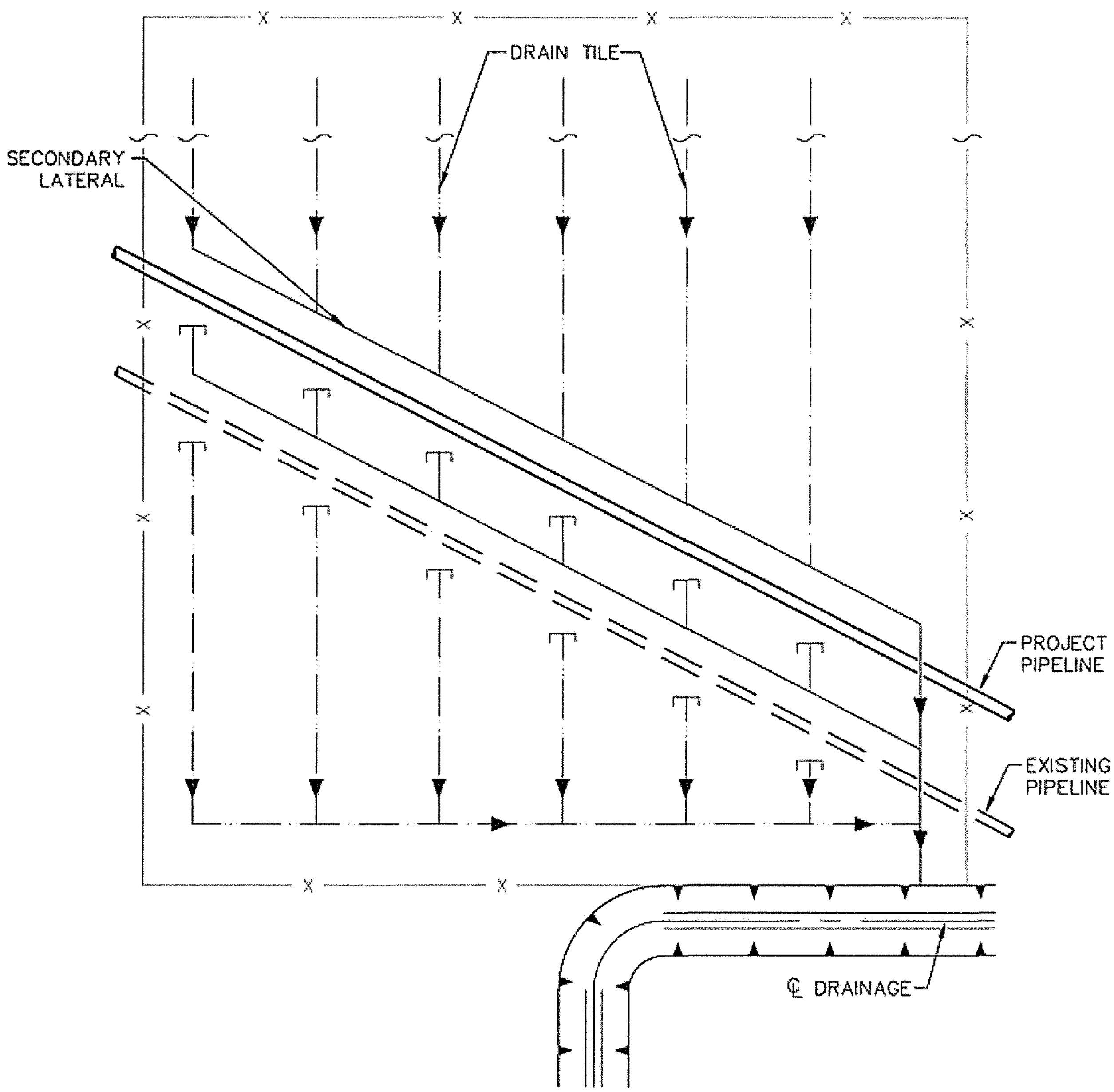
RELOCATE/REPLACE DRAINAGE HEADER/MAIN



REVISIONS
01 REVISED LABELS
02 2010-10-11 REVISED TITLE BLOCK

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DESIGNER: JMP (NAME) 2010-10-21 (DATE)		KEYSTONE XL PROJECT	
		FIA # 4359	CHAINAGE:	DISCIPLINE # 03
CHECKED BY: WSF	DESIGN CHECKER: RW	TITLE: DETAIL 27 HEADER/MAIN CROSSOVERS OF PIPELINE	
		SCALE N.T.S.	DWG No 4359-03-ML-03-720	REV 02

TC_A4_BR.DWG 8.5X11

CADD DRAWING: DO NOT MAKE MANUAL REVISIONS

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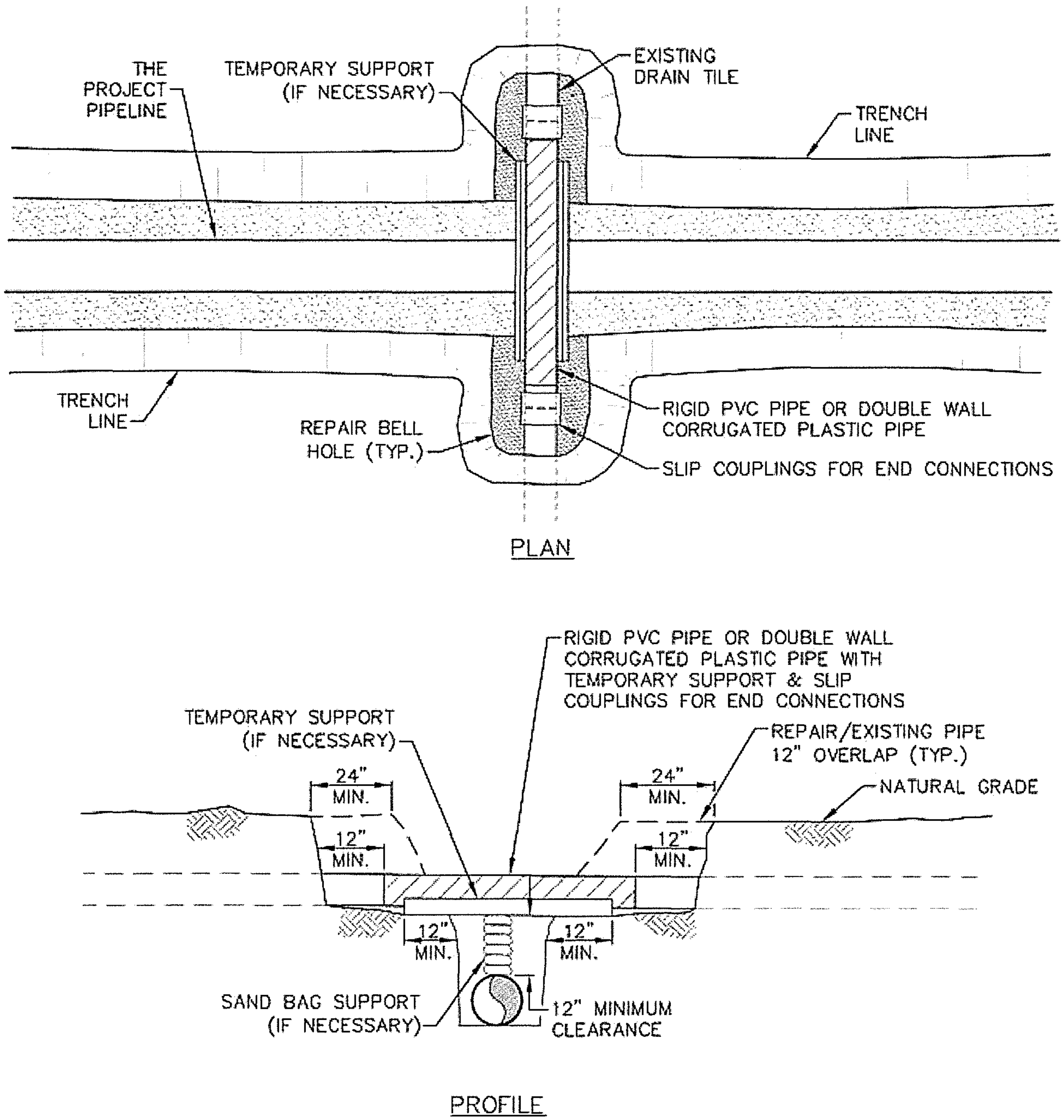

NOTES:

1. IMMEDIATELY REPAIR TILE IF WATER IS FLOWING THROUGH TILE AT TIME OF TRENCHING.
2. SCREEN ALL EXPOSED ENDS OF TILE LINES.

REVISIONS		
01	2008-11-04	UPDATED DRAWING NOTES
02	2010-10-11	REVISED TITLE BLOCK

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	FIA # 4359	CHAINAGE:	DISCIPLINE # 03
CHECKED BY: WSF	DESIGN CHECKER: RW	TITLE: DETAIL 28 DRAINAGE AND IRRIGATION TEMPORARY DRAIN TILE REPAIR
SCALE N.T.S.	DWG No 4359-03-ML-03-721	REV 02

TC_A4_BR.DWG 8.5X11

CADD DRAWING: DO NOT MAKE MANUAL REVISIONS

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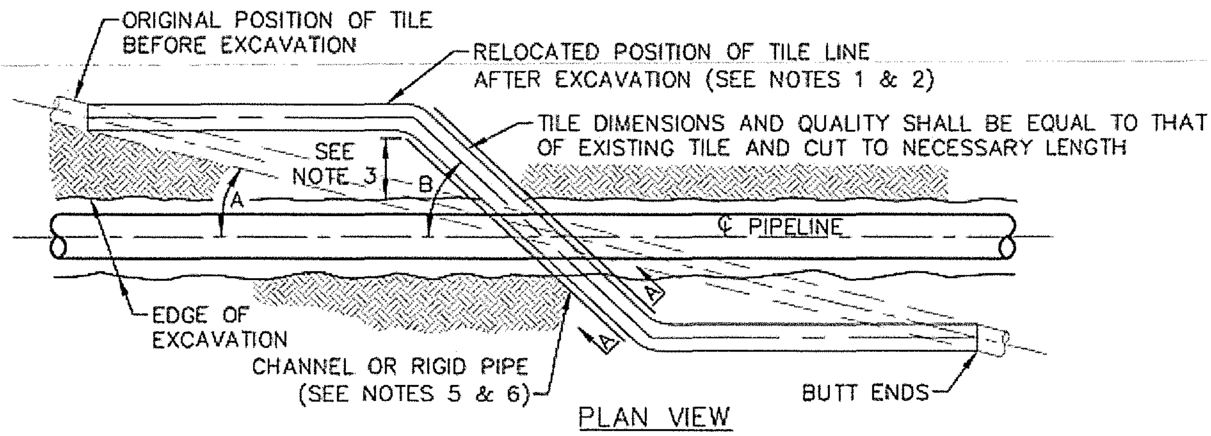
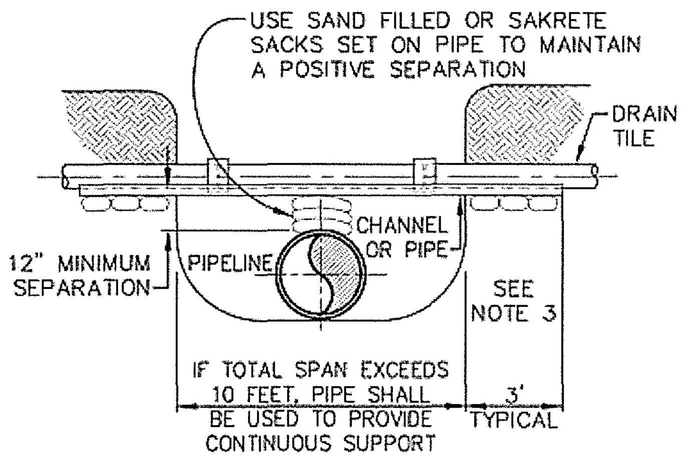
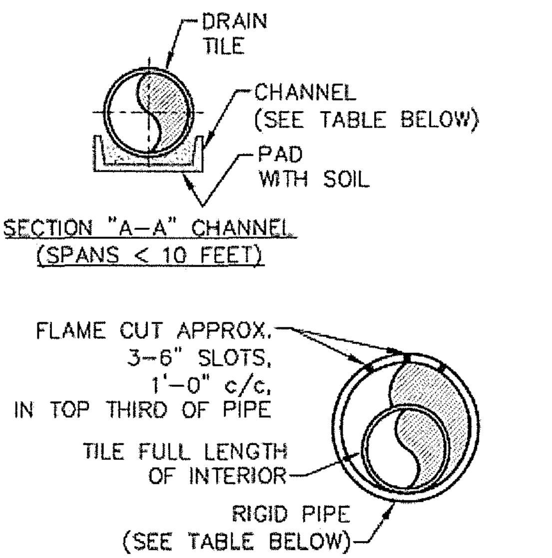


PLAN VIEW



SECTION "A-A" CHANNEL
(SPANS < 10 FEET)



END VIEWS

SECTION "A-A" RIGID PIPE
(SPANS > 10 FEET)

NOTES:

1. TILE REPAIR SHALL MAINTAIN ORIGINAL ALIGNMENT AND GRADIENT WHEN ANGLE "A", BETWEEN PIPELINE AND ORIGINAL TILE, IS MORE THAN 20 FEET UNLESS OTHERWISE DIRECTED BY THE PROJECT REPRESENTATIVE.
2. WHEN ANGLE "A" IS LESS THAN 20 FEET, UNLESS OTHERWISE DIRECTED BY COMPANY, ANGLE "B" SHALL BE 45° FOR USUAL WIDTHS OF TRENCH. FOR EXTRA WIDTHS, IT MAY BE GREATER AS DIRECTED BY THE PROJECT REPRESENTATIVE.
3. 3 FOOT MINIMUM LENGTH OF CHANNEL OR RIGID PIPE SHALL BE SUPPORTED BY UNDISTURBED SOIL, OR IF CROSSING IS NOT AT RIGHT ANGLES TO GAS PIPELINE, EQUIVALENT LENGTH PERPENDICULAR TO TRENCH. SHIM WITH SAKRETE, SAND BAGS OR CONCRETE BLOCKS TO UNDISTURBED SOIL FOR SUPPORT AND DRAINAGE GRADIENT MAINTENANCE (TYPICAL BOTH SIDES).
4. DRAINAGE TILE SHALL BE REPLACED SO THAT ITS FORMER GRADIENT AND ALIGNMENT ARE RESTORED.
5. DIAMETER OF RIGID PIPE SHALL BE OF ADEQUATE SIZE TO ALLOW FOR THE INSTALLATION OF THE TILE FOR THE FULL LENGTH OF THE RIGID PIPE.
6. OTHER METHODS OF SUPPORTING DRAIN TILE MAY BE USED IF THE ALTERNATE PROPOSED IS EQUIVALENT IN STRENGTH TO THE CHANNEL/PIPE SECTIONS SHOWN AND IF APPROVED BY THE PROJECT REPRESENTATIVE IN ADVANCE. SITE SPECIFIC ALTERNATE SUPPORT SYSTEM TO BE DEVELOPED BY THE PROJECT REPRESENTATIVE AND FURNISHED TO CONTRACTOR FOR SPANS IN EXCESS OF 20 FEET, TILE GREATER THAN 10 INCHES DIAMETER, AND FOR HEADER SYSTEMS.
7. ALL MATERIAL TO BE FURNISHED BY CONTRACTOR.
8. PRIOR TO REPAIRING TILE, CONTRACTOR SHALL PROBE INTO THE EXISTING TILE TO THE FULL WIDTH OF THE RIGHT-OF-WAY TO DETERMINE IF ADDITIONAL DAMAGE HAS OCCURRED. ALL DAMAGED/DISTURBED TILE SHALL BE REPAIRED AS NEAR AS PRACTICABLE TO ITS ORIGINAL OR BETTER CONDITION.
9. "NIGHT CAP" OPEN ENDS OF PIPE AND/OR DRAIN TILES IF REPAIRS ARE NOT COMPLETED BY END OF WORK DAY.

MINIMUM SUPPORT TABLE

TILE SIZE	CHANNEL SIZE	PIPE SIZE
3"	4" @ 5.4 #/FT.	4" STD. WT
4"-5"	5" @ 6.7 #/FT.	6" STD. WT
6"-9"	7" @ 9.8 #/FT.	8"-10" STD. WT
10"	10" @ 15.3 #/FT.	12" STD. WT

REVISIONS		
01	2008-11-04	UPDATED DRAWING NOTES
02	2010-10-11	REVISED TITLE BLOCK

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DESIGNER:	KEYSTONE XL PROJECT		
JMP (NAME) 2010-10-21 (DATE)	FIA # 4359	CHAINAGE:	DISCIPLINE # 03
	TITLE DETAIL 29 DRAINAGE AND IRRIGATION PERMANENT DRAIN TILE REPAIR		
CHECKED BY: WSF / DESIGN CHECKER: RW	SCALE N.T.S.	DWG No 4359-03-ML-03-722	REV 02

P7100

TC_A4_BR.DWG 8.5X11

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020489

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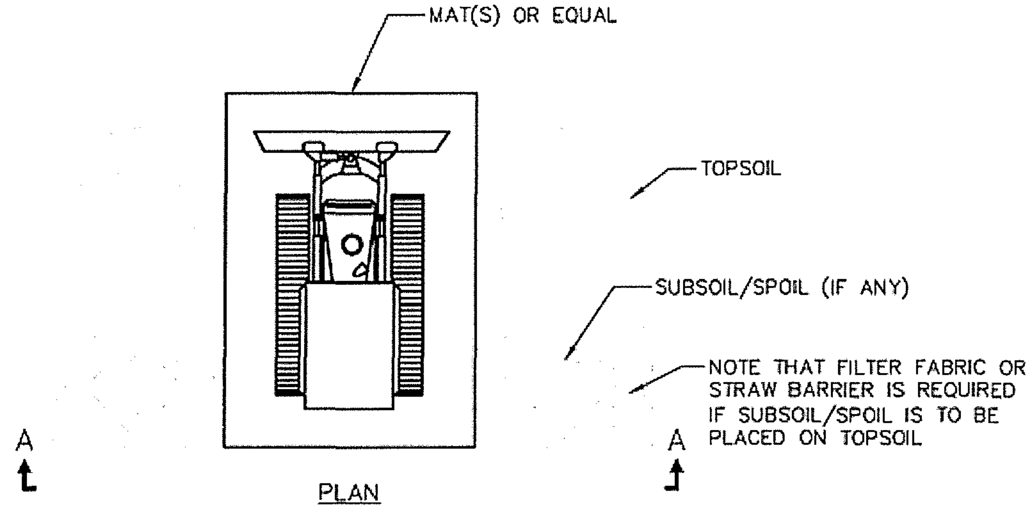
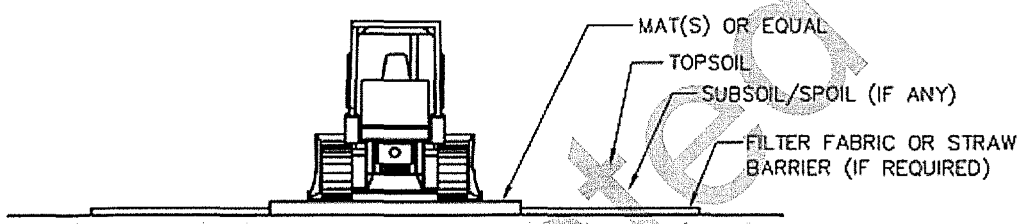


PLAN



SECTION A–A

CLEANING STATION NOTES:

1. ALL EQUIPMENT WILL BE REQUIRED TO BE CLEANED AT EQUIPMENT CLEANING STATIONS LOCATED AS SHOWN ON THE CONSTRUCTION DRAWINGS OR AS DIRECTED BY THE ENVIRONMENTAL INSPECTOR.
2. STOCKPILE TOPSOIL/SUBSOIL AS SHOWN OR IN ANY CONFIGURATION APPROVED BY THE ENVIRONMENTAL INSPECTOR.
3. SHOVELS OR OTHER HAND TOOLS AND/OR COMPRESSED AIR WILL BE USED TO REMOVE AS MUCH AS MUCH SOIL AS PRACTICAL FROM TRACKED EQUIPMENT. EFFORT WILL BE FOCUSED ON TRACKS AND BLADES.
4. IF CONDITIONS ARE MUDDY, WHEELED EQUIPMENT WILL ALSO BE CLEANED USING HAND TOOLS TO REMOVE EXCESS SOIL FROM TIRES AND WHEEL WELLS.
5. CLEANING WILL BE CONDUCTED ON CONSTRUCTION MATS OR OTHER RAISED SURFACE TO MINIMIZE REATTACHMENT OF SOIL THAT HAS BEEN PREVIOUSLY REMOVED.
6. MATS WILL BE CLEANED BETWEEN EACH PIECE OF EQUIPMENT.
7. SOIL COLLECTED DURING THE CLEANING PROCESS WILL BE STOCKPILED AT A CONVENIENT LOCATION NEAR THE CLEANING STATION AND DISPOSED OF IN AN ACCEPTABLE LAND FILL.
8. IF THE SOIL HAS A SIGNIFICANT COMPONENT OF SUBSOIL, IT WILL BE PLACED OVER THE BACKFILLED TRENCH OR IN THE ADJACENT SPOIL STORAGE AREA, AND SUBSEQUENTLY COVERED WITH TOPSOIL. IF THE LAND OWNER DIES NOT APPROVE OF ON–SITE DISPOSAL, THE SOIL WILL BE TAKEN TO AN APPROVED DISPOSAL SITE.
9. SOILS CONTAMINATED WITH OIL OR GREASE WILL BE REMOVED AND DISPOSED OF IN ACCORDANCE PROJECT SPCCC PLAN.

REVISIONS		
02	2010-10-11	REVISED TITLE BLOCK
01		REVISED LABELS

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DESIGNER: JMP (NAME)	2010-10-21 (DATE)	KEYSTONE XL PROJECT	
		FIA # 4359	CHAINAGE:	DISCIPLINE # 03
CHECKED BY: WSF	DESIGN CHECKER: RW	TITLE: DETAIL 30 EQUIPMENT CLEANING STATION DETAIL	
		SCALE N.T.S.	DWG No 4359-03-ML-05-713	REV 02

TC_A4_BR.DWG 8.5X11

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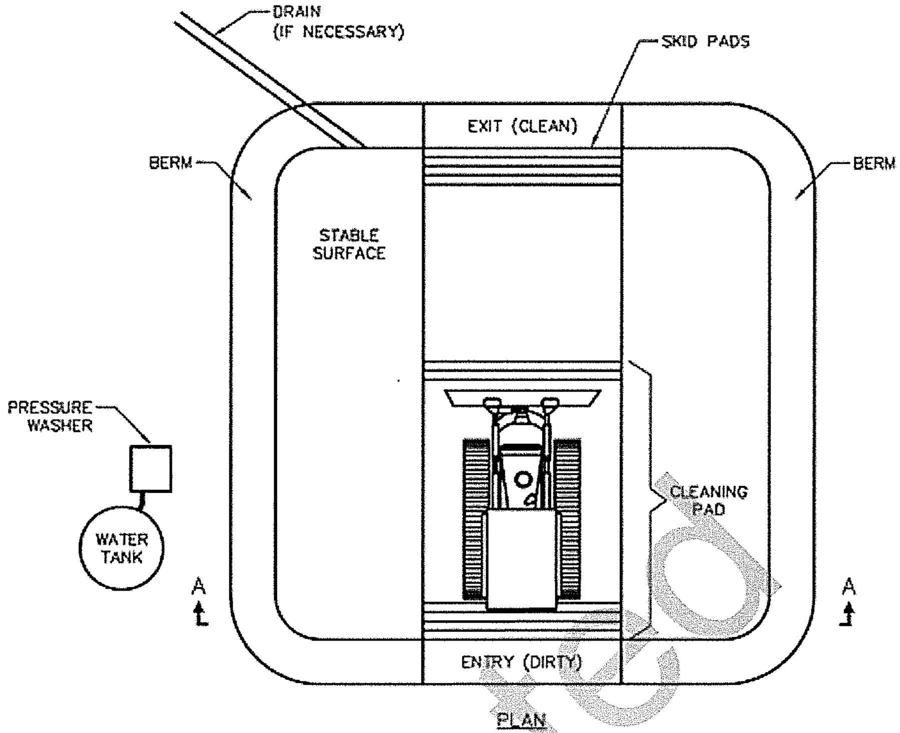
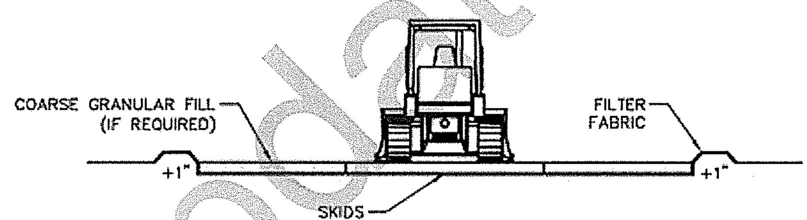


PLAN



SECTION A–A

WASH STATION NOTES:

1. ALL EQUIPMENT AND VEHICLES ARE REQUIRED TO BE CLEANED AT WASH STATION LOCATIONS SHOWN ON THE CONSTRUCTION DRAWINGS OR AS DIRECTED BY THE ENVIRONMENTAL INSPECTOR. WASH STATIONS WILL BE CONSTRUCTED BY THE CONTRACTOR. WASHINGS WILL BE CARRIED OUT UNDER THE SUPERVISION AND TO SATISFACTION OF THE ENVIRONMENTAL INSPECTOR.
2. WASH WATER USED FOR CLEANING WILL NOT BE ALLOWED TO ENTER ANY WATERBODY, WETLAND, OR IRRIGATION CANAL/DITCH. ANY SOILS CONTAMINATED BY PETROLEUM-BASED, OR OTHER UNDESIRABLE MATERIALS FROM WASH STATIONS WILL BE REMOVED.
3. THE SIZE OF STATION WILL BE ADEQUATE TO ACCOMMODATE THE MAXIMUM SIZE OF EQUIPMENT EXPECTED.
4. EQUIPMENT WILL CONSISTENTLY ENTER THE "DIRTY END" AND EXIT THE "CLEAN END."
5. STABLE DRAINAGE FROM THE SITE WILL BE PROVIDED (IF NECESSARY). NO DISCHARGE TO STREAMS OR WETLANDS WILL BE ALLOWED.
6. WASH STATIONS WILL BE EQUIPPED WITH SKID PADS OR WASH RACKS TO PREVENT SOIL FROM BEING CARRIED ON TRACKS OR TIRES AS EQUIPMENT AND VEHICLES EXIT THE WASH STATION. SKIDS ARE TO BE CLEANED EACH TIME A PIECE OF EQUIPMENT IS CLEANED.
7. GRAVEL FILL (IF REQUIRED) AND FILTER FABRIC WILL BE REMOVED AND DISPOSED OF IN AN ACCEPTABLE LAND FILL.
8. THE DEPRESSION WILL BE BACKFILLED WITH BERMED MATERIAL.
9. CLEANING SITES WILL BE MONITORED DURING THE POST CONSTRUCTION MONITORING PROGRAM AND WEEDS WILL BE CONTROLLED PER THE NOXIOUS WEED MANAGEMENT PLAN.

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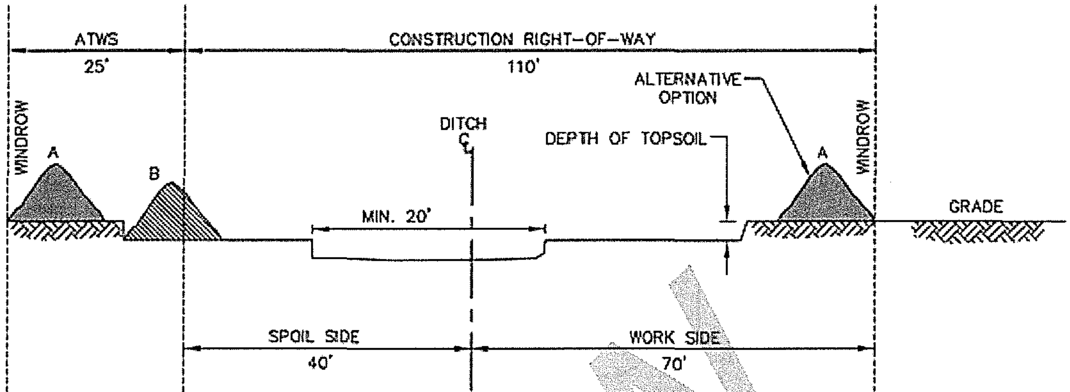
DESIGNER: JMP (NAME) 2010-10-21 (DATE)	KEYSTONE XL PROJECT	
	FIA # 4359	CHAINAGE:	DISCIPLINE # 03
CHECKED BY: WSF	DESIGN CHECKER: RW	TITLE: DETAIL 31 EQUIPMENT WASH STATION DETAIL
SCALE N.T.S.	DWG No 4359-03-ML-05-714	REV 02

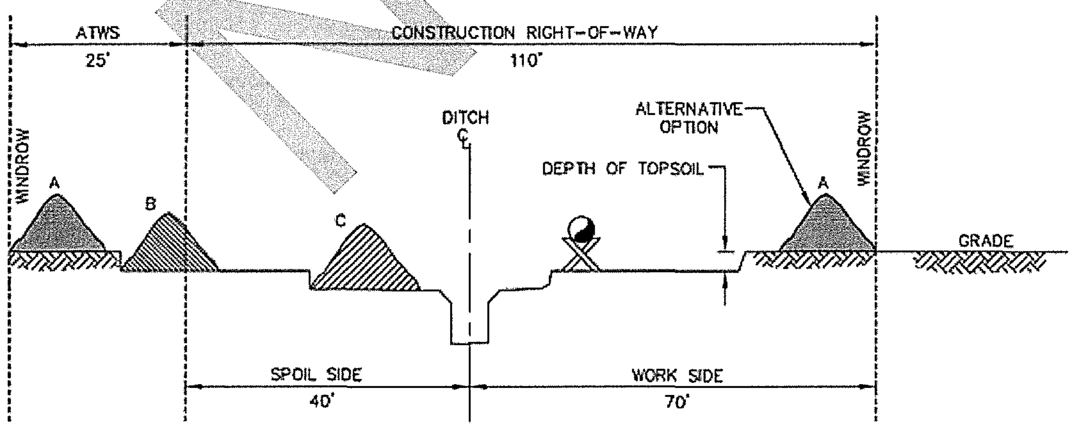
THESE ARE TYPICAL DRAWINGS; ACTUAL SITE CONDITIONS MAY VARY FROM THE SITE GRAPHICALLY REPRESENTED.

1. POTENTIAL LOCATIONS WHERE TRIPLE DITCH TOPSOIL CONSERVATION MAY BE COMPLETED ARE SHOWN ON THE ALIGNMENT SHEETS. KEYSTONE WILL DIRECT THE ACTUAL LOCATIONS WHERE TRIPLE DITCH WILL BE COMPLETED DURING, OR IMMEDIATELY PRIOR TO, TOPSOILING THE ROW. KEYSTONE MAY MODIFY TRIPLE DITCH PROCEDURES FROM THOSE DESCRIBED HERE TO ADDRESS SITE-SPECIFIC, OR SOIL-SPECIFIC, CONDITIONS.

2. STRIP TOPSOIL ("A" HORIZON) ACCORDING TO THE "A" HORIZON DEPTHS AND CONSTRUCTION DETAILS SHOWN ON CONSTRUCTION ALIGNMENT SHEETS. PLACE "A" HORIZON IN THE ADDITIONAL TEMPORARY WORKSPACE OR THE WINDROW WITHIN THE WORKING SIDE OF THE CONSTRUCTION RIGHT-OF-WAY. IN AREAS OF THICKER "A" HORIZON'S, "A" HORIZON MAY BE SPLIT TO BOTH SIDES OF THE RIGHT-OF-WAY.
REMOVE "B" HORIZON (2ND DITCH) TO DEPTHS SPECIFIED BY KEYSTONE AND STOCKPILE ON SPOIL SIDE. THE "B" HORIZON SHOULD BE REMOVED IN A STRIP AT LEAST 20 FEET WIDE OVER THE TRENCH TO ALLOW FOR STORAGE OF THE TRENCH SPOIL MATERIALS. MAINTAIN A MINIMUM OF 2 FEET BETWEEN "A" HORIZON AND "B" HORIZON STOCKPILES.



3. EXCAVATE TRENCH. ENSURE THE DIFFERENT SOIL HORIZONS ("B" HORIZON AND "C" HORIZON) ARE IN SEPARATE STOCKPILES. THE VISUAL DISTINCTION OF EACH PILE MUST BE POSSIBLE AT ALL TIMES. THE STOCKPILING SHALL ALLOW FOR RE-PLACEMENT OF THE SOIL HORIZONS BACK TO THEIR ORIGINAL SEQUENCE WITHOUT LOSS OF SOIL. MAINTAIN A MINIMUM OF 2 FEET BETWEEN "B" HORIZON AND "C" HORIZON STOCKPILES.



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03 2010-10-11 REVISED TITLE BLOCK

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DESIGNER: JMP (NAME) 2010-10-21 (DATE)	KEYSTONE XL PROJECT	
	FIA # 4359	CHAINAGE:	DISCIPLINE # 03
CHECKED BY: WSF	DESIGN CHECKER: RW	TITLE: DETAIL 67 TOPSOIL CONSERVATION DITCH & SPOIL STRIPPING TRIPLE DITCH
SCALE N.T.S.	DWG No 4359-03-ML-05-724	REV 03

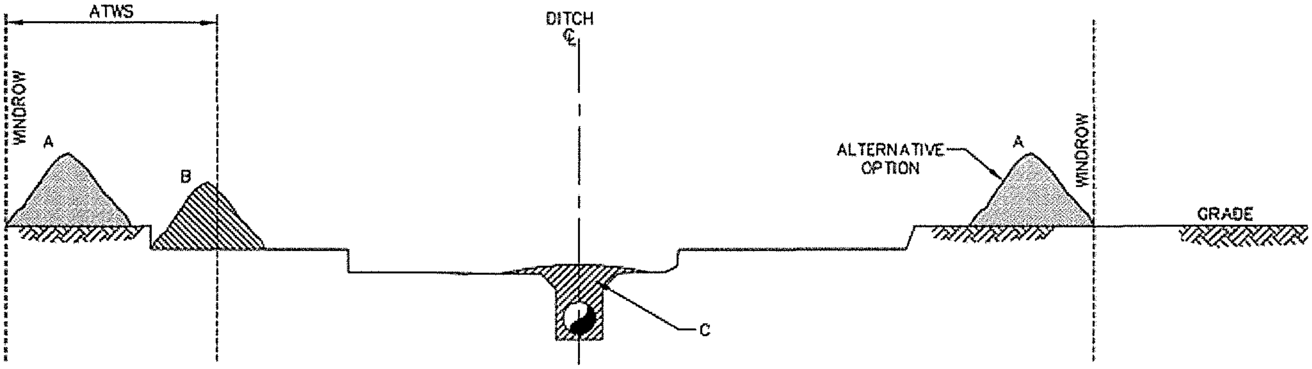
TC_A4_BR.DWG 8.5X11

CADD DRAWING: DO NOT MAKE MANUAL REVISIONS

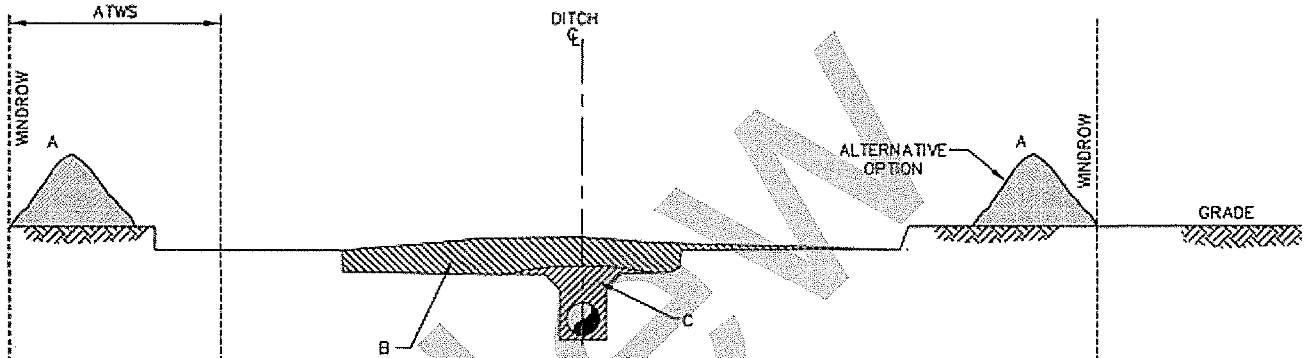
020492

THESE ARE TYPICAL DRAWINGS; ACTUAL SITE CONDITIONS MAY VARY FROM THE SITE GRAPHICALLY REPRESENTED.

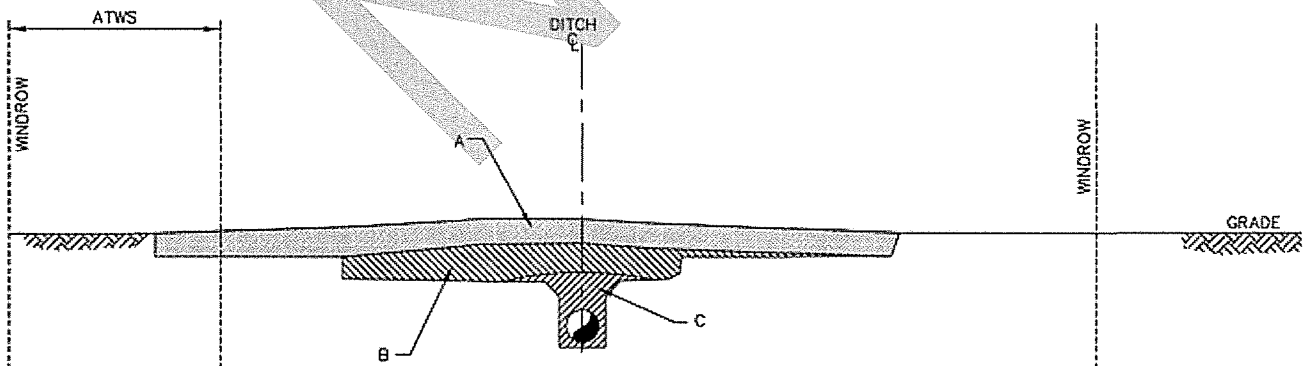
4. BACKFILL TRENCH AND COMPACT AS PER APPROVED PROCEDURE., PLACE THE SOIL HORIZONS BACK IN THEIR ORIGINAL SEQUENCE IN THE TRENCH.



5. RELIEVE AREAS OF COMPACTION AND FEATHER (B) MATERIAL EVENLY OVER STRIPPED AREA.



6. REPLACE "A" HORIZON PILE EVENLY OVER STRIPPED AREA.



New

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DESIGNER:		KEYSTONE XL PROJECT		
JMP (NAME)	2010-10-21 (DATE)	FIA # 4359	CHAINAGE:	DISCIPLINE # 03
		TITLE DETAIL 67A TOPSOIL CONSERVATION DITCH & SPOIL STRIPPING TRIPLE DITCH		
CHECKED BY: WSF	DESIGN CHECKER: RW	SCALE N.T.S.	DWG No 4359-03-ML-05-725	REV 03

TC_A4_BR.DWG 8.5X11

CADD DRAWING: DO NOT MAKE MANUAL REVISIONS

020493

020494

Finding Number	Amended Final Decision and Order	Update
	The Project	
14	The purpose of the Project is to transport incremental crude oil production from the Western Canadian Sedimentary Basin ("WCSB") to meet growing demand by refineries and markets in the United States ("U.S."). This supply will serve to replace U.S. reliance on less stable and less reliable sources of offshore crude oil. Ex TC-1, 1.1, p. 1; Ex TC-1, 3.0 p. 23; Ex TC-1, 3.4 p. 24.	The purpose of the Project is to transport incremental crude oil production from the Western Canadian Sedimentary Basin ("WCSB") and domestic production from the Williston Basin area to meet demand by refineries and markets in the United States ("U.S."). This supply will serve to replace U.S. reliance on less stable and less reliable sources of offshore crude oil and support the growth of crude oil production in the U.S. (See updated Findings 24-29)
15	The Project will consist of three segments: the Steele City Segment, the Gulf Coast Segment, and the Houston Lateral. From north to south, the Steele City Segment extends from Hardisty, Alberta, Canada, southeast to Steele City, Nebraska. The Gulf Coast Segment extends from Cushing, Oklahoma south to Nederland, in Jefferson County, Texas. The Houston Lateral extends from the Gulf Coast Segment in Liberty County, Texas southwest to Moore Junction, Harris County, Texas. It will interconnect with the northern and southern termini of the previously approved 298-mile-long, 36-inch-diameter Keystone Cushing Extension segment of the Keystone Pipeline Project. Ex TC-1,1.2, p. 1. Initially, the pipeline would have a nominal capacity to transport 700,000 barrels per day ("bpd"). Keystone could add additional pumping capacity to expand the nominal capacity to 900,000 bpd. Ex TC-1, 2.1.2, p. 8.	The Project will consist of the Steele City Segment. From north to south, the Steele City Segment extends from Hardisty, Alberta, Canada, southeast to Steele City, Nebraska. It will interconnect with the previously approved and constructed 298-mile-long, 36-inch-diameter Keystone Cushing Extension segment of the Keystone Pipeline System allowing crude oil to be delivered to Gulf Coast Refineries. The pipeline would have a maximum capacity to transport 830,000 barrels per day.
16	The Project is an approximately 1,707 mile pipeline with about 1,380, miles in the United States. The South Dakota portion of the pipeline will be approximately 314 miles in length and will extend from the Montana border in Harding County to the Nebraska border in Tripp County. The Project is proposed to cross the South Dakota counties of Harding, Butte, Perkins, Meade, Pennington, Haakon, Jones, Lyman and Tripp. Ex TC-1, 1.2 and 2.1.1, pp. 1 and 8. Detailed route maps are presented in Ex TC-1, Exhibits A and C, as updated in Ex TC-14.	The Project is an approximately 1202 mile pipeline with about 876 miles in the United States. The South Dakota portion of the pipeline will be approximately 315 miles in length and will extend from the Montana border in Harding County to the Nebraska border in Tripp County. The Project is proposed to cross the South Dakota counties of Harding, Butte, Perkins, Meade, Pennington, Haakon, Jones, Lyman and Tripp.
17	Construction of the Project is proposed to commence in May of 2011 and be completed in 2012. Construction in South Dakota will be conducted in five spreads, generally proceeding in a north to south direction. The Applicant expects to place the Project in service in 2012. This in-service date is consistent with the requirements of the Applicant's shippers who have made the contractual commitments that underpin the viability and need for the project. Ex TC-1, 1.4, pp. 1 and 4; TR 26.	Construction of the Project is proposed to commence when all necessary permits are obtained. Construction in South Dakota will be conducted in three or four spreads, generally proceeding in a north to south direction. The Applicant expects to place the Project in service when construction is completed.
18	The pipeline in South Dakota will extend from milepost 282.5 to milepost 597, approximately 314 miles. The pipeline will have a 36-inch nominal diameter and be constructed using API 5L X70 or X80 high-strength steel. An external fusion bonded epoxy ("FBE") coating will be applied to the pipeline and all buried facilities to protect against corrosion. Cathodic protection will be provided by impressed current The pipeline will have batching capabilities and will be able to transport products ranging from light crude oil to heavy crude oil. Ex TC-1, 2.2, 2.2.1, 6.5.2, pp. 8-9, 97 -98; Ex TC-8, ¶ 26.	The pipeline in South Dakota will extend from milepost 285.6 to milepost 600.9, approximately 315 miles. The pipeline will have a 36-inch nominal diameter and be constructed using API 5L X70M high-strength steel. An external fusion bonded epoxy ("FBE") coating will be applied to the pipeline and all buried facilities to protect against corrosion. Cathodic protection will be provided by impressed current. The pipeline will have batching capabilities and will be able to transport products ranging from light crude oil to heavy crude oil.
19	The pipeline will operate at a maximum operating pressure of 1,440 psig. For location specific low elevation segments close to the discharge of pump stations, the maximum operating pressure will be 1,600 psig. Pipe associated with these segments of 1,600 psig MOP are excluded from the Special Permit application and will have a design factor of 0.72 and pipe wall thickness of 0.572 inch (X-70) or 0.500 inch (X-80). All other segments in South Dakota will have a MOP of 1,440 psig. Ex TC-1, 2.2.1, p. 9.	At most locations, the pipeline will operate at a maximum operating pressure of 1,307 psig. For location specific low elevation segments close to the discharge of pump stations, the maximum operating pressure will be 1,600 psig. Pipe associated with these segments of 1,600 psig MOP will have a design factor of 0.72 and a nominal pipe wall thickness of 0.572 inch (X-70M). All other segments in South Dakota will have a MOP of 1,307 psig.

Finding Number	Amended Final Decision and Order	Update
20	The Project will have seven pump stations in South Dakota, located in Harding (2), Meade, Haakon, Jones and Tripp (2) Counties. TC-1, 2.2.2, p. 10. The pump stations will be electrically driven. Power lines required for providing power to pump stations will be permitted and constructed by local power providers, not by Keystone. Initially, three pumps will be installed at each station to meet the nominal design flow rate of 700,000 bpd. If future demand warrants, pumps may be added to the proposed pump stations for a total of up to five pumps per station, increasing nominal throughput to 900,000 bpd. No additional pump stations will be required to be constructed for this additional throughput. No tank facilities will be constructed in South Dakota. Ex TC-1, 2.1.2, p.8. Sixteen mainline valves will be located in South Dakota. Seven of these valves will be remotely controlled, in order to have the capability to isolate sections of line rapidly in the event of an emergency to minimize impacts or for operational or maintenance reasons. Ex TC-1, 2.2.3, pp. 10- 11.	The Project will have seven pump stations in South Dakota, located in Harding (2), Meade, Haakon, Jones and Tripp (2) Counties. TC-1, 2.2.2, p. 10. The pump stations will be electrically driven. Power lines required for providing power to pump stations will be permitted and constructed by local power providers, not by Keystone. Three to five pumps will be installed at each station to meet the maximum design flow rate of 830,000 bpd. No tank facilities will be constructed in South Dakota. Twenty mainline valves will be located in South Dakota. All of these valves will be remotely controlled, in order to have the capability to isolate sections of line rapidly in the event of an emergency to minimize impacts or for operational or maintenance reasons.
22	The Project will be designed, constructed, tested, and operated in accordance with all applicable requirements, including the U.S. Department of Transportation, Pipeline Hazardous Materials and Safety Administration (PHMSA) regulations set forth at 49 CFR Part 195, as modified by the Special Permit requested for the Project from PHMSA (see Finding 71). These federal regulations are intended to ensure adequate protection for the public and the environment and to prevent crude oil pipeline accidents and failures. Ex TC-1, 2.2, p. 8.	The Project will be designed, constructed, tested, and operated in accordance with all applicable requirements, including the U.S. Department of Transportation, Pipeline Hazardous Materials and Safety Administration (PHMSA) regulations set forth at 49 CFR Part 195, and the special conditions developed by PHMSA and set forth in Appendix Z to the Department of State ("DOS") January 2014 Final Supplemental Environmental Impact Statement ("Final SEIS"). These federal regulations and additional conditions are intended to ensure adequate protection for the public and the environment and to prevent crude oil pipeline accidents and failures.
23	The current estimated cost of the Keystone Project in South Dakota is $921.4 million. Ex TC-1, 1.3, p. 1.	The current estimated cost of the Keystone XL Project in South Dakota is $1.974 billion. The estimated cost of the South Dakota portion of the project has primarily increased due to the new technical requirements (for example, the 59 additional conditions set forth in the DOS Final SEIS), and inflation and additional costs (for example, increased project management; regulatory; and material storage and preservation costs) due to the projected six-year delay in starting construction.
	Demand for the Facility	
24	The transport of additional crude oil production from the WCSB is necessary to meet growing demand by refineries and markets in the U.S. The need for the project is dictated by a number of factors, including increasing WCSB crude oil supply combined with insufficient export pipeline capacity; increasing crude oil demand in the U.S. and decreasing domestic crude supply; the opportunity to reduce U.S. dependence on foreign off-shore oil through increased access to stable, secure Canadian crude oil supplies; and binding shipper commitments to utilize the Keystone Pipeline Project. Ex TC-1, 3.0, p. 23.	The June 29, 2010 order recites Findings of Fact demonstrating the strong demand for the Project. Given the dynamic nature of the crude oil market, there have been changes in the nature of this demand since 2010. As demonstrated below, however market demand for the Project remains strong today. The transport of additional crude oil production from the WCSB continues to be necessary to meet demand by refineries and markets in the U.S. The need for the project is driven by a number of factors, including increasing domestic U.S. and Canadian, crude oil production combined with insufficient pipeline capacity; an energy efficient and safe method to transport this growing production; the opportunity to reduce U.S dependence on foreign offshore crude oil through increased access to North American supplies; and binding shipper commitments to utilize the Keystone Pipeline System.
25	According to the U.S. Energy Information Administration ("EIA"), U.S. demand for petroleum products has increased by over 11 percent or 2,000,000 bpd over the past 10 years and is expected to increase further. The EIA estimates that total U.S. petroleum consumption will increase by approximately 10 million bpd over the next 10 years, representing average demand growth of about 100,000 bpd per year (EIA Annual Energy Outlook 2008). Ex TC-1, 3.2, pp. 23-24.	United States production of crude oil has increased significantly, from approximately 6.5 million barrels per day (bpd) in 2012, and is expected to peak at 9.6 million bpd by 2019. However, even with the domestic production growth, the U.S. is expected to remain a net importer of crude oil. According to the U.S. Energy Information Administration ("EIA"), U.S. demand for crude oil has held steady at approximately 15 million bpd and is expected to remain relatively stable into the future.[1]
26	At the same time, domestic U.S. crude oil supplies continue to decline. For example, over the past 10 years, domestic crude production in the United States has declined at an average rate of about 135,000 bpd per year, or 2% per year. Ex TC-1, 3.3, p. 24. Crude and refined petroleum product imports into the U.S. have increased by over 3.3 million bpd over the past 10 years. In 2007, the U.S. imported over 13.4 million bpd of crude oil and petroleum products or over 60 percent of total U.S. petroleum product	The rise in U.S. crude oil production, predominantly light crude, has replaced most foreign imports of light crude. However the demand persists for imported heavy crude oil by U.S. refineries that are optimally configured to process heavy crude slates.[2] The U.S. Gulf Coast continues to import approximately 3.5 million bpd of heavy and medium sour crude oil.[3]

[1] Energy Information Administration (EIA) Annual Energy Outlook 2014
[2] Id.
[3] Energy Information Administration – Company Level Imports

Finding Number	Amended Final Decision and Order	Update
	consumption. Canada is currently the largest supplier of imported crude oil and refined products to the U.S., supplying over 2.4 million bpd in 2007, representing over 11 percent of total U.S. petroleum product consumption (EIA 2007). Ex TC-1, 3.4, p.24.	
27	The Project will provide an opportunity for U.S. refiners in Petroleum Administration for Defense District III, the Gulf Coast region, to further diversify supply away from traditional offshore foreign crude supply and to obtain direct access to secure and growing Canadian crude supplies. Access to additional Canadian crude supply will also provide an opportunity for the U.S. to offset annual declines in domestic crude production and, specifically, to decrease its dependence on other foreign crude oil suppliers, such as Mexico and Venezuela, the top two heavy crude oil exporters into the U.S. Gulf Coast. Ex TC-1, 3.4, p. 24.	Canadian production of heavy crude oil continues to grow, the vast majority of which is currently exported to the United States to be processed by U.S. refineries. North American crude oil production growth and logistics constraints have contributed to significant discounts on the price of landlocked crude and led to growing volumes of crude shipped by rail in the United States and, more recently Canada. As the DOS Final SEIS makes clear, in the absence of new pipelines, crude oil will continue to be transported via rail at an increasing rate.[4] The North Dakota Pipeline Authority estimates that rail export volumes from the U.S. Williston Basin have increased from approximately 40,000 bpd in 2010 to over 700,000 bpd in early 2014. Over 60% of crude oil transported from the Williston Basin is delivered by rail.[5] The industry has also been making significant investments in increasing rail transport capacity for crude oil out of the Western Canadian Sedimentary Basin (WCSB).[6] In recent years, rail transport of crude oil in Canada has grown from approximately 10,000 bpd in 2010 to approximately 270,000 bpd by the end of 2013.[7] The DOS Final SEIS indicates that transportation of crude oil by pipeline is safer and less greenhouse gas intensive than crude oil transportation by rail.[8] The Project will provide an opportunity for U.S. refiners in Petroleum Administration for Defense District III, the Gulf Coast region, to further diversify supply away from traditional offshore foreign crude supply and to obtain direct access to secure and growing domestic crude supplies.
28	Reliable and safe transportation of crude oil will help ensure that U.S. energy needs are not subject to unstable political events. Established crude oil reserves in the WCSB are estimated at 179 billion barrels (CAPP 2008). Over 97 percent of WCSB crude oil supply is sourced from Canada's vast oil sands reserves located in northern Alberta. The Alberta Energy and Utilities Board estimates there are 175 billion barrels of established reserves recoverable from Canada's oil sands. Alberta has the second largest crude oil reserves in the world, second only to Saudi Arabia. Ex TC-1, 3.1, p. 23.	Reliable and safe transportation of crude oil will help ensure that U.S. energy needs are not subject to unstable political events. Of Canada's 173 billion barrels of oil reserves, 97% or 167 billion, barrels are located in the oil sands. In terms of overall oil reserves, Canada's 173 billion barrels is third only to Venezuela and Saudi Arabia.[9] Canada is the largest foreign supplier of crude oil to the U.S. and is likely to remain as such for the foreseeable future.[10]
29	Shippers have already committed to long-term binding contracts, enabling Keystone to proceed with regulatory applications and 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 and access to Canadian crude supplies. Ex TC-1, 3.5, p. 24.	Shippers have committed to long-term binding contracts, enabling Keystone to proceed with regulatory applications and 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 domestic and Canadian crude supplies. The DOS Final SEIS independently confirms the continuing strong market demand.[11]
	Environmental	
32	Table 6 to the Application summarizes the environmental impacts that Keystone's analysis indicates could be expected to remain after its Construction Mitigation and Reclamation Plan (CMR Plan) are implemented. Ex TC-1, pp. 31-37.	Table 6 is still applicable. The latest version of the CMR Plan is Rev4, April 2012. Attachment A to this Tracking Table is a redline version showing changes to the CMR Plan from Rev1 to the current Rev4. Overall changes to the CMR Plan were made to clarify language, provide additional detail related to construction procedures and incorporate lessons learned from previous pipeline construction, current right-of-way conditions and project requirements

[4] Final Supplemental Environmental Impact Statement, Keystone XL Pipeline Project, January 2014 at 1.4.3.2 and 1.4.3.3.
[5] North Dakota Pipeline Authority 2014 https://ndpipelines.files.wordpress.com/2012/04/nd-rail-estimate-april-2014.jpg
[6] Final Supplemental Environmental Impact Statement Keystone XL Pipeline Project, January 2014 at 1.4.1.3
[7] Transportation Safety Board of Canada http://www.tsb.gc.ca/eng/recommandations-recommendations/rail/2014/rec-r1401-r1403.asp
[8] Final Supplemental Environmental Impact Statement, Keystone XL Pipeline Project, January 2014, Chapter 5 and Errata Sheet at http://keystonepipeline-xl.state.gov/documents/organization/227464.pdf.
[9] Canadian Association of Petroleum Producers (CAPP) Crude Oil Forecast, Markets & Transportation June 2014
[10] EIA Annual Energy Outlook 2014
[11] Final Supplemental Environmental Impact Statement, Keystone XL Pipeline Project, January 2014 at 1.3.1 and 1.4.2.6

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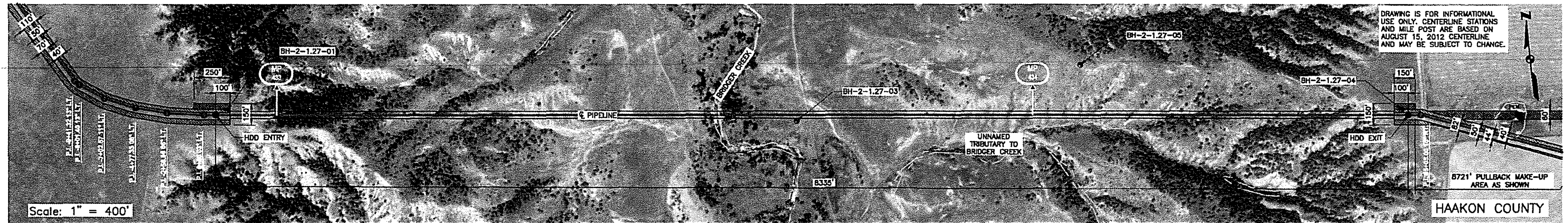
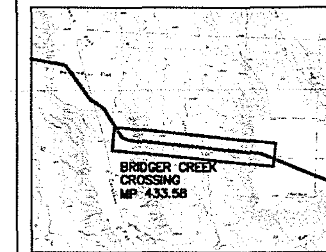
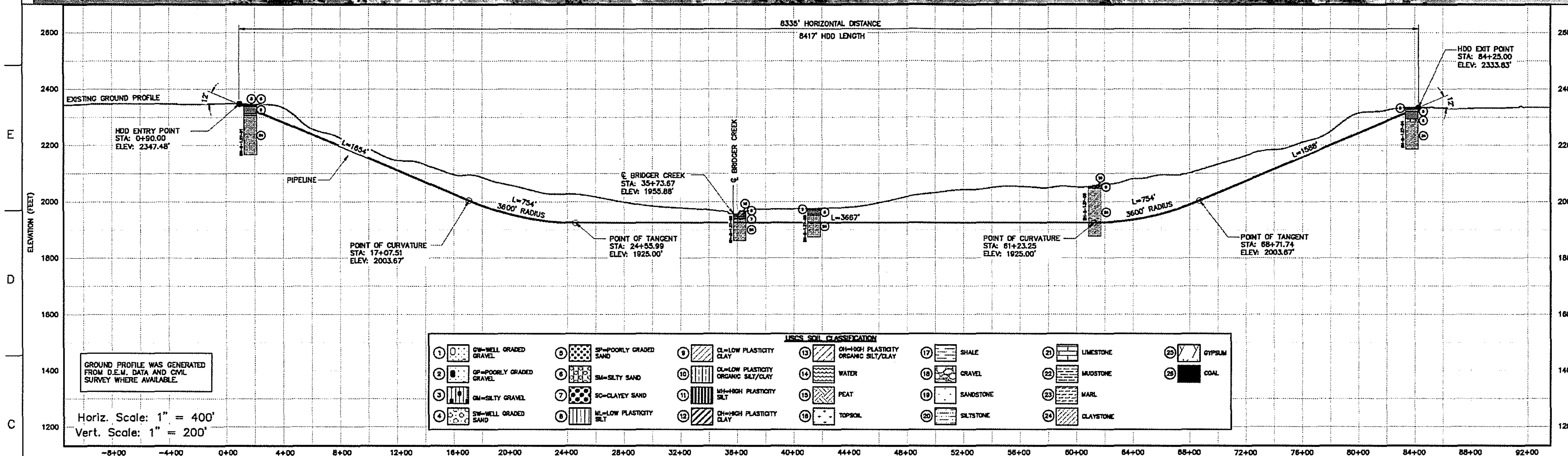
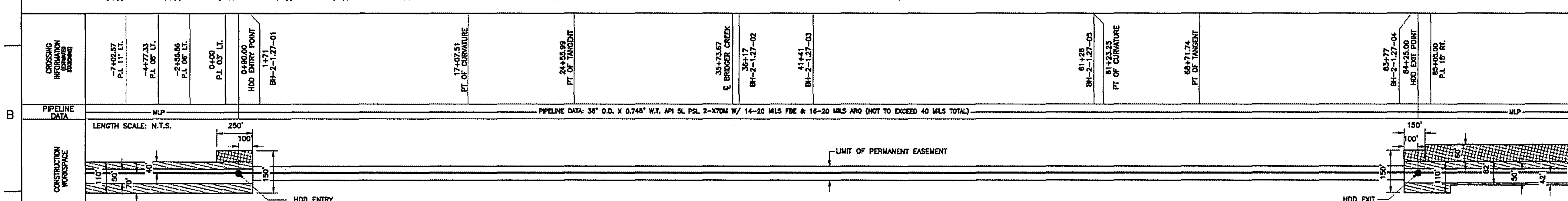
33	The pipeline will cross the Unglaciated Missouri Plateau. This physiographic province is characterized by a dissected plateau where river channels have incised into the landscape. Elevations range from just over 3,000 feet above mean sea level in the northwestern part of the state to around 1,800 feet above mean sea level in the White River valley. The major river valleys traversed include the Little Missouri River, Cheyenne River, and White River. Ex TC-1, 5.3.1, p. 30; Ex TC-4, ¶ 15. Exhibit A to the Application includes soil type maps and aerial photograph maps of the Keystone pipeline route in South Dakota that indicate topography, land uses, project mileposts and Section, Township, Range location descriptors. Ex TC-1, Exhibit A. Updated versions of these maps were received in evidence as Exhibit TC-14.	The soil type maps and aerial photograph maps of the Keystone pipeline route in South Dakota that indicate topography, land uses, project mileposts and Section, Township, Range location descriptors that were submitted in evidence as Exhibit TC-14 are still generally consistent in the description of the current Project route through South Dakota. Keystone will submit updated maps prior to the initiation of construction as required by Condition No. 6 of the Amended Final Decision and Order.
41	Fifteen perennial streams and rivers, 129 intermittent streams, 206 ephemeral streams and seven man-made ponds will be crossed during construction of the Project in South Dakota. Keystone will utilize horizontal directional drilling ("HDD") to cross the Little Missouri, Cheyenne and White River crossings. Keystone intends to use open-cut trenching at the other perennial streams and intermittent water bodies. The open cut wet method can cause the following impacts: 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. Alternative techniques include open cut dry flume, open cut dam-and-pump and horizontal directional drilling. Exhibit C to the Application contains a listing of all water body crossings and preliminary site-specific crossing plans for the HDD sites. Ex TC-14. Permitting of water body crossings, which is currently underway, will ultimately determine the construction method to be utilized. Keystone committed to mitigate water crossing impacts through implementation of procedures outlined in the CMR Plan. Ex TC-1, 5.4.1, pp. 45-46.	Fifteen perennial streams and rivers, 129 intermittent streams, and 206 ephemeral streams will be crossed during construction of the Project in South Dakota. No man-made ponds are crossed. Keystone will utilize horizontal directional drilling ("HDD") to cross the Little Missouri, Cheyenne, Bad, and White rivers, as well as Bridger Creek. Keystone intends to use open-cut trenching at other perennial streams and intermittent water bodies. The open cut wet method can cause the following impacts: 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. Alternative techniques include open cut dry flume, open cut dam-and-pump and horizontal directional drilling. To supplement Exhibit C to the Application, Attachment B to this Tracking Table contains the preliminary site-specific crossing plans for the two newly identified HDD crossings; Bad River and Bridger Creek.
50	The total length of Project pipe with the potential to affect a High Consequence Area ("HCA") is 34.3 miles. A spill that could affect an HCA would occur no more than once in 250 years. TC-12, ¶ 24.	The total length of Project pipe with the potential to affect a High Consequence Area ("HCA") is 19.9 miles. A spill that could affect an HCA would occur no more than once in 250 years.
54	Of the approximately 314-mile route in South Dakota, all but 21.5 miles is privately owned. 21.5 miles is state-owned and managed. The list is found in Table 14. No tribal or federal lands are crossed by the proposed route. Ex TC-1, 5.7.1, p. 75.	Of the approximately 315-mile route in South Dakota, all but 27.9 miles are privately owned. 1.7 miles are local government owned, and 26.3 miles are state-owned and managed. No tribal or federal lands are crossed by the route.
	Design and Construction	
60	Keystone has applied for a special permit ("Special Permit") from PHMSA authorizing Keystone to design, construct, and operate the Project at up to 80% of the steel pipe specified minimum yield strength at most locations. TC-1, 2.2, p. 8; TR 62. In Condition 2, the Commission requires Keystone to comply with all of the conditions of the Special Permit, if issued.	Keystone withdrew its request to PHMSA for a special permit ("Special Permit") on August 5, 2010. Keystone will implement 59 additional safety measures as set forth in the DOS Final SEIS, Appendix Z. These measures provide an enhanced level of safety equivalent to or greater than those that would have applied under the previously requested Special Permit.
61	TransCanada operates approximately 11,000 miles of pipelines in Canada with a 0.8 design factor and requested the Special Permit to ensure consistency across its system and to reduce costs. PHMSA has previously granted similar waivers adopting this modified design factor for natural gas pipelines and for the Keystone Pipeline. Ex TC-8, ¶¶ 13, 17.	[Finding 61 is no longer relevant as Keystone has withdrawn its request for a Special Permit].
62	The Special Permit is expected to exclude pipeline segments operating in (i) PHMSA defined HCAs described as high population areas and commercially navigable waterways in 49 CFR Section 195.450; (ii) pipeline segments operating at highway, railroad, and road crossings; (iii) piping located within pump stations, mainline valve assemblies, pigging facilities, and measurement facilities; and (iv) areas where the MOP is greater than 1,440 psig. Ex TC-8, ¶ 16.	[Finding 62 is no longer relevant as Keystone has withdrawn its request for a Special Permit.]
63	Application of the 0.8 design factor and API 5L PSL2 X70 high-strength steel pipe results in use of pipe with a 0.463 inch wall thickness, as compared with the 0.512 inch wall thickness under the otherwise applicable 0.72 design factor, a reduction in thickness of .050 inches. TR 61. PHMSA previously found that the issuance of a waiver is not inconsistent with pipeline safety and that the waiver will 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. Ex TC-8, ¶ 15.	The pipeline will operate at a maximum operating pressure of 1,307 psig. Use of API 5L X70 high-strength steel results in a 0.465 inch nominal pipe wall thickness. For location specific low elevation segments close to the discharge of pump stations, the maximum operating pressure will be 1,600 psig. Pipe associated with these segments of 1,600 psig MOP will have a design factor of 0.72 and a nominal pipe wall thickness of 0.572 inch (X-70M).

Finding Number	Amended Final Decision and Order	Update
68	TransCanada has thousands of miles of this particular grade of pipeline steel installed and in operation. TransCanada pioneered the use of FBE, which has been in use on its system for over 29 years. There have been no leaks on this type of pipe installed by TransCanada with the FBE coating and cathodic protection system during that time. When TransCanada has excavated pipe to validate FBE coating performance, there has been no evidence of external corrosion. Ex TC-8, ¶ 27.	TransCanada has thousands of miles of this particular grade of pipeline steel installed and in operation. TransCanada pioneered the use of FBE, which has been in use on its system for over 33 years. There have been no leaks on this type of pipe installed by TransCanada with the FBE coating and cathodic protection system during that time. When TransCanada has excavated pipe to validate FBE coating performance, there has been no evidence of external corrosion except for one instance where an adjacent foreign utility interfered with the cathodic protection system. No similar situations exist on the Project in South Dakota.
73	The Applicant has prepared a detailed CMR Plan that describes procedures for crossing cultivated lands, grasslands, including native grasslands, wetlands, streams and the procedures for restoring or reclaiming and monitoring those features crossed by the Project. The CMR Plan is a summary of the commitments that Keystone has made for environmental mitigation, restoration and post-construction monitoring and compliance related to the construction phase of the Project. Among these, Keystone will utilize construction techniques that will retain the original characteristics of the lands crossed as detailed in the CMR Plan. Keystone's thorough implementation of these procedures will minimize the impacts associated with the Project. A copy of the CMR Plan was filed as Exhibit B to Keystone's permit application and introduced into evidence as TC-1, Exhibit B.	Keystone has updated its CMR Plan since the Amended Final Decision and Order. Overall changes to the CMR Plan were made to clarify language, provide additional detail related to construction procedures and incorporate lessons learned from previous pipeline construction, current right-of-way conditions and project requirements. A redlined version of the CMR Plan showing changes since the version considered in 2010 is attached as Attachment A to this Tracking Table.
80	Keystone is in the process of preparing, in consultation with the area National Resource Conservation Service, construction/reclamation unit ("Con/Rec Unit') mapping to address differing construction and reclamation techniques for different soils conditions, slopes, vegetation, and land use along the pipeline route. This analysis and mapping results in the identification of segments called Con/Rec Units. Ex. TC-5; TC-16, DR 3-25.	In consultation with the area National Resource Conservation Service, Keystone has completed construction/reclamation unit ("Con/Rec Unit') mapping to address differing construction and reclamation techniques for different soils conditions, slopes, vegetation, and land use along the pipeline route.
83	Keystone will utilize HDD for the Little Missouri, Cheyenne and White River crossings, which will aid in minimizing impacts to important game and commercial fish species and special status species. Open-cut trenching, which can affect fisheries, will be used at other perennial streams. Keystone will use best practices to reduce or eliminate the impact of crossings at the perennial streams other than the Cheyenne and White Rivers. Ex TC-1 , 5.4.1, p. 46; 5.6.2, p. 72; TC-16, DR 3-39.	Keystone will utilize HDD for the Little Missouri, Cheyenne, Bad and White River crossings, as well as Bridger Creek, which will aid in minimizing impacts to important game and commercial fish species and special status species. Open-cut trenching, which can affect fisheries, will be used at other perennial streams. Keystone will use best practices to reduce or eliminate the impact of crossings at the perennial streams that are open cut.
	Operation and Maintenance	
90	The Keystone pipeline will be designed constructed, tested and operated in accordance with all applicable requirements, including the PHMSA regulations set forth at 49 CFR Parts 194 and 195, as modified by the Special Permit. These federal regulations are intended to ensure adequate protection for the public and the environment and to prevent crude oil pipeline accidents and failures. Ex TC-8, ¶ 2.	The Keystone pipeline will be designed constructed, tested and operated in accordance with all applicable requirements, including the PHMSA regulations set forth at 49 CFR Parts 194 and 195, and the 59 PHMSA Special Conditions as set forth in DOS Final SEIS, Appendix Z. These federal regulations and additional conditions are intended to ensure adequate protection for the public and the environment and to prevent crude oil pipeline accidents and failures.
	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.	[Keystone has withdrawn its Special Permit application but will comply with the 59 additional conditions set forth in the DOS Final SEIS, Appendix Z, which provide an enhanced level of safety equivalent to or greater than those that would have applied under the requested Special Permit.] The increased cost of the Project reflected in updated Finding 23 is likely to result in increased tax revenue to the affected counties.









ENVIRONMENTAL MITIGATION/RECLAMATION	
TOPSOIL SALVAGE METHOD	
STREAMS	
WETLANDS	
TIMING CONSTRAINTS	
MILEPOST	TO BE DETERMINED
MONITORING	
RECLAMATION	
SPECIAL CONSIDERATIONS	

INSTALLATION NOTES

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14) PIPELINE DATA: 36" O.D. X 0.618" W.T. API 5L PSL 2-X70M W/ 14-20 MILS FBE & 16-20 MILS ARO (NOT TO EXCEED 40 MILS TOTAL)

15) PIPELINE DATA: 36" O.D. X 0.465" W.T. API 5L PSL 2-X70M W/ 14-20 MILS FBE

LEGEND

- POINT OF INTERSECTION (P.I.)
- ENTRY OR EXIT POINT
- GEOTECHNICAL BOREHOLE
- POWERPOLE
- MLP — MAINLINE PIPE
- PIPELINE
- FOREIGN PIPELINE
- EDGE OF WATER
- PRIVATE ACCESS SHOO FLY ROAD
- COUNTY BOUNDARY
- WATER LEVEL
- USACOE CONSTRUCTION REFERENCE POINT
- WETLANDS
- PERMANENT EASEMENT
- TEMPORARY WORKSPACE
- ADDITIONAL TEMPORARY WORKSPACE

REFERENCE DRAWINGS

DRAWING No	TITLE
4367-03-ML-02-028	ALIGNMENT SHEET

REVISION / APPROVAL

REV No	DATE	DESCRIPTION	PROJECT CODE	DRAFTER	DRAFTING CHECKER	DESIGNER	DESIGN CHECKER	PROJECT MANAGER	COMPANY
A	2012-03-30	ISSUED FOR REVIEW	2095406	AH	YL	BS	REW	RG	EXP
B	2012-09-07	UPDATED CENTERLINE (2012-08-15)	2095406	JB	YL	BS	KM	RG	EXP

PROFESSIONAL ENGINEER/RPT: RAYMOND E. WALLACE, JR. PE SD - 10070

PERMIT/ ENG. APPROVAL

DATE

PRELIMINARY

REV. NO. | DATE | PERMIT NUMBER:

TransCanada
In business to deliver

exp Energy Services Inc.
t: +1.850.385.5441 | f: +1.850.385.5523
1300 Metropolitan Blvd
Tallahassee, FL 32308
USA
www.exp.com

exp.

KEYSTONE XL (NPS 36 2014) FAITH SECTION

FIA # 4367 | CHAINAGE: MP 433.58 | DISCIPLINE # 03

BRIDGER CREEK HDD INSTALLATION
KEYSTONE XL PROJECT
HAAKON COUNTY, SOUTH DAKOTA

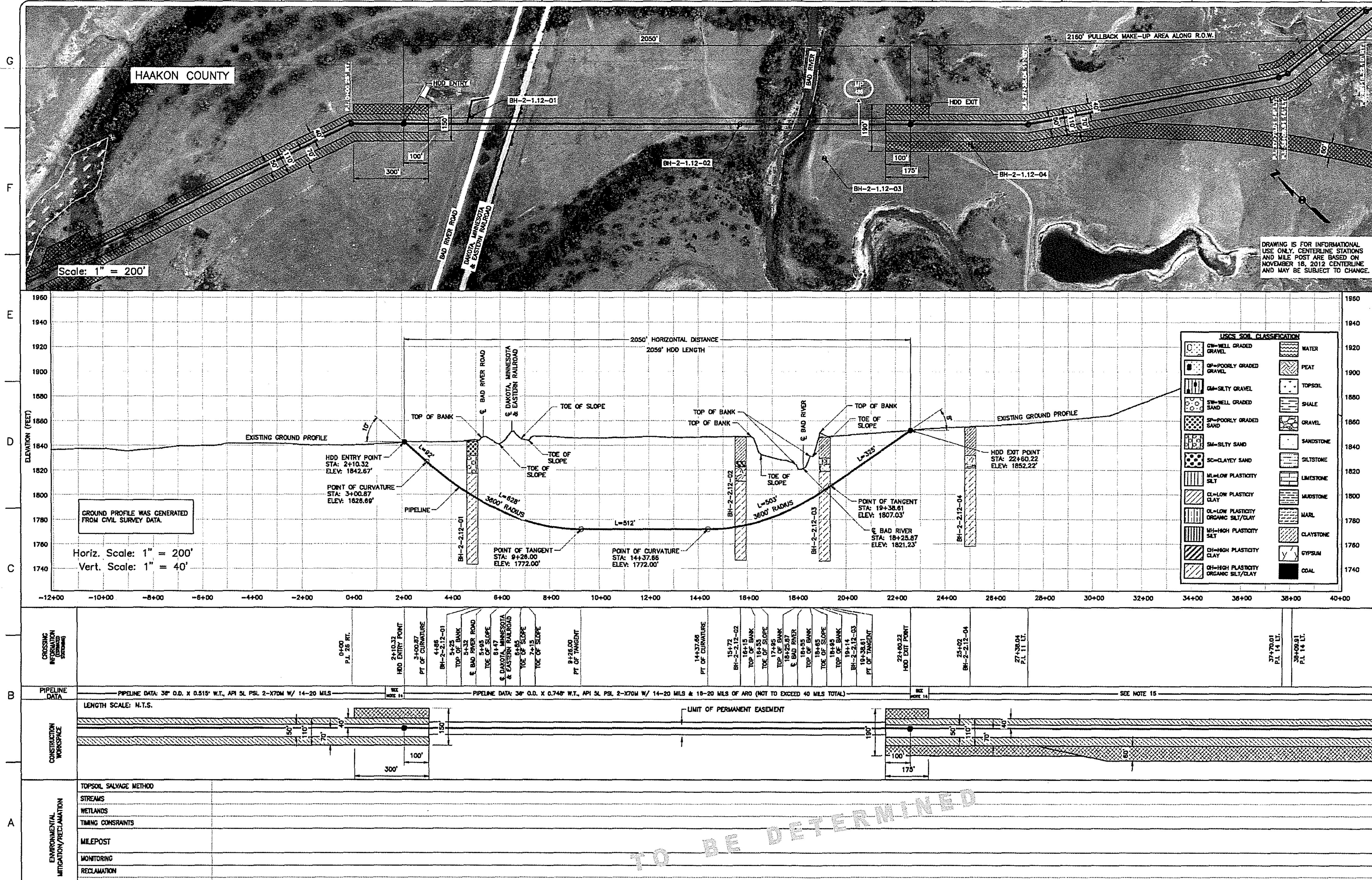
SCALE AS SHOWN | DRAWING No 4367-03-ML-03-003 | REV B

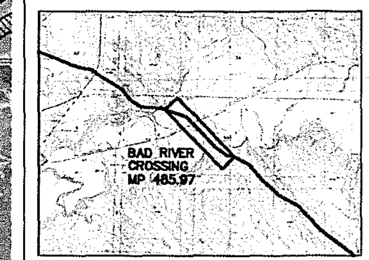
CADD DRAWING: DO NOT MAKE MANUAL REVISIONS

PLOTTED SIZE: ANSI D (22x34)

TC_UD_BR.DWG 22X34

020500





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14) PIPELINE DATA: 36" O.D. X 0.618" W.T., API 5L PSL 2-X70M W/14-20 MILS & 16-20 MILS ARO (NOT TO EXCEED 40 MILS TOTAL)

15) PIPELINE DATA: 36" O.D. X 0.465" W.T., API 5L PSL 2-X70M W/14-20 MILS FBE

LEGEND

POINT OF INTERSECTION (P.I.)
ENTRY OR EXIT POINT
GEOTECHNICAL BOREHOLE
POWERPOLE
MANLINE PIPE
PIPELINE
FOREIGN PIPELINE
EDGE OF WATER
PRIVATE ACCESS SHOO FLY ROAD
COUNTY BOUNDARY
WATER LEVEL
USACOE CONSTRUCTION REFERENCE POINT
WETLANDS
PERMANENT EASEMENT
TEMPORARY WORKSPACE
ADDITIONAL TEMPORARY WORKSPACE

REFERENCE DRAWINGS

DRAWING No	TITLE
4368-03-ML-02-027	ALIGNMENT SHEET
4368-03-ML-03-028	ALIGNMENT SHEET

REVISION / APPROVAL

REV No	DATE	DESCRIPTION	PROJECT CODE	DRAFTER	DRAFTING CHECKER	DESIGNER	DESIGN CHECKER	PROJECT MANAGER	COMPANY
A	2008-07-31	ISSUED FOR UNITED STATES DEPARTMENT OF STATE (2008-07-31 CL)	2095406	BM	JP	FP	REW	RG	EXP
B	2008-12-08	ISSUED FOR REVIEW (2008-12-01 CL)	2095406	BM	AH	FP	REW	RG	EXP
C	2011-07-06	UPDATED EASEMENTS	2095406	AH	AH	BS	REW	RG	EXP
D	2011-09-23	UPDATD CENTERLINE (2011-09-21 CL)	2095406	JB	AH	BS	REW	RG	EXP
E	2012-03-16	UPDATED CENTERLINE (2012-03-14 CL)	2095406	BM	AH	BS	REW	RG	EXP
F	2012-09-20	UPDATED CENTERLINE (2012-08-15 CL)	2095406	JB	AH	BS	KM	RG	EXP
G	2012-12-14	ISSUED FOR REVIEW	2095406	JB	AH	BS	KM	RG	EXP

PROFESSIONAL ENGINEER/RPT | PERMIT/ ENG. APPROVAL | DATE

PRELIMINARY

REV. NO. | DATE | PERMIT NUMBER:

TransCanada — In business to deliver

exp Energy Services Inc. — exp.

KEYSTONE XL (NPS 36 2014) HAAKON SECTION

FA # 4368 | CHAINAGE: MP 485.97 | DISCIPLINE # 03

BAD RIVER HDD INSTALLATION
KEYSTONE XL PROJECT
HAAKON COUNTY, SOUTH DAKOTA

SCALE AS SHOWN | DRAWING No 4368-03-ML-03-001 | REV G

TC_UD_BR.DWG 22X34

CADD DRAWING: DO NOT MAKE MANUAL REVISIONS

PLOTTED SIZE: ANSI D (22x34)

020501

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 DIRECT TESTIMONY OF COREY GOULET

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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 direct 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.

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3. Please state your professional qualifications and experience with pipeline operations.

Answer: My professional background is stated in my resume, a copy of which is attached as Exhibit A. I have a degree in mechanical engineering.

4. Are you responsible for portions of the Tracking Table of Changes attached as Appendix C to Keystone's certification petition?

Answer: Yes. I am individually or jointly responsible for the information provided with respect to Finding Numbers 14, 15, 16, 17, 18, 19, 20, 22, 23, and 107 related to the Project. In general, I can testify to the Project purpose; overall description; construction schedule; operating parameters; overall design; cost; and tax revenues.

5. Please summarize the updated information regarding Finding Number 14.

Answer: The Bakken Marketlink project was developed after Keystone's permit application in HP 09-001. The update to this finding reflects that the Project's purpose include transporting domestic production from the Williston Basin and supporting the growth of crude oil production in the United States.

6. Please summarize the updated information regarding Finding No. 15.

Answer: The Gulf Coast Segment of the original Keystone XL Project and the Houston Lateral were constructed as a stand-alone project. The update to this finding reflects that change, meaning that the Project consists of the Steele City Segment, from Hardisty, Alberta, Canada, to Steele City Nebraska, where it will interconnect with the Keystone Cushing Extension segment of the Keystone Pipeline. The Project's current design is based on a maximum capacity to transport 830,000 barrels per day.

7. Please summarize the updated information regarding Finding No. 16.

Answer: Because the Project is limited to the Steele City Segment, the mileage decreased to approximately 1202 miles, with 876 miles through Montana, South Dakota, and Nebraska. The mileage has changed slightly in South Dakota due to minor route variations made at the request of landowners or for engineering reasons. The right of way passes through the same counties as indicated in the Permit Application.

8. Please summarize the updated information regarding Finding No. 17.

Answer: Keystone does not currently have a construction schedule for the Project, pending issuance of the Presidential Permit. The Project's inservice date is uncertain for the same reason.

9. Please summarize the updated information regarding Finding No. 18.

Answer: Due to minor route variations, the mileage in South Dakota and the mileposts have changed slightly. The pipeline will be constructed using API 5L X70M high-strength steel, which was one of the design options presented in the original Permit Application. Keystone's final design determinations were made after TransCanada withdrew its application to PHMSA for a special permit and adopted 59 special conditions developed by PHMSA as set forth in Appendix Z to the Department of State Final Supplemental Environmental Impact Statement (FSEIS).

10. Please summarize the updated information regarding Finding No. 19.

Answer: This update reflects final design determinations based on the decision to withdraw the special permit application and the requirements of 49 CFR 195.106.

11. Please summarize the updated information regarding Finding No. 20.

Answer: This update reflects a change in the number of mainline valves in South Dakota from 16 to 20 due to PHMSA requirements. All of the valves will be remotely controlled for purposes of emergency response.

12. Please summarize the updated information regarding Finding No. 22.

Answer: The 59 special conditions are set forth in Appendix Z to the FSEIS. Keystone has committed to meet these conditions.

13. Please summarize the updated information regarding Finding No. 23.

Answer: The estimated cost of the Project in South Dakota increased to $1.974 billion due to new technical requirements, inflation, and additional costs due to the delay in receipt of federal approval and commencing construction.

14. Please summarize the updated information regarding Finding No. 107.

Answer: Although I am not a tax expert, the increased cost of the Project reflected in Finding No. 23 is likely to result in increased tax revenues to the affected counties. To the extent that tax revenues are an issue at the hearing, Keystone may present rebuttal testimony addressing tax issues from Steve Klekar, Manager, Property Taxation for TransCanada – US Pipelines.

15. Are you aware of any reason that Keystone cannot continue to meet the conditions on which the Permit was granted by the Commission?

Answer: No. As stated in the Certification that I signed, Keystone is or will be able to satisfy all of the conditions imposed by the Commission as part of its Amended Final Decision and Order dated June 29, 2010.

16. Does this conclude your prepared direct testimony?

Answer: Yes.

Dated this 1 day of April, 2015.

Corey Goulet

CERTIFICATE OF SERVICE

I hereby certify that on the 2nd day of April, 2015, I sent by United States first-class mail, postage prepaid, or e-mail transmission, a true and correct copy of the foregoing Direct Testimony of Corey Goulet, to the following:

Patricia Van Gerpen
Executive Director
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
patty.vangerpen@state.sd.us

Kristen Edwards
Staff Attorney
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
kristen.edwards@state.sd.us

Brian Rounds
Staff Analyst
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
brian.rounds@state.sd.us

Darren Kearney
Staff Analyst South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
darren.kearney@state.sd.us

Tony Rogers, Director
Rosebud Sioux Tribe - Tribal Utility Commission
153 South Main Street
Mission, SD 57555
tuc@rosebudsiouxtribe-nsn.gov

Cindy Myers, R.N.
PO Box 104
Stuart, NE 68780
csmyers77@hotmail.com

Jane Kleeb
1010 North Denver Avenue
Hastings, NE 68901
jane@boldnebraska.org

Byron T. Steskal
Diana L. Steskal
707 E. 2nd Street
Stuart, NE 68780
prairierose@nntc.net

Terry Frisch
Cheryl Frisch
47591 875th Road
Atkinson, NE 68713
tcfrisch@q.com

Arthur R. Tanderup
52343 857th Road
Neligh, NE 68756
atanderu@gmail.com

Lewis GrassRope
PO Box 61
Lower Brule, SD 57548
wisestar8@msn.com

Robert G. Allpress
46165 Badger Road
Naper, NE 68755
bobandnan2008@hotmail.com

Amy Schaffer
PO Box 114
Louisville, NE 68037
amyannschaffer@gmail.com

Benjamin D. Gotschall
6505 W. Davey Road
Raymond, NE 68428
ben@boldnebraska.org

Elizabeth Lone Eagle
PO Box 160
Howes, SD 57748
bethcbest@gmail.com

John H. Harter
28125 307th Avenue
Winner, SD 57580
johnharter11@yahoo.com

Peter Capossela
Peter Capossela, P.C.
Representing Standing Rock Sioux Tribe
PO Box 10643
Eugene, OR 97440
pcapossela@nu-world.com

Carolyn P. Smith
305 N. 3rd Street
Plainview, NE 68769
peachie_1234@yahoo.com

Jeff Jensen
14376 Laflin Road
Newell, SD 57760
jensen@sdplains.com

Louis T. (Tom) Genung
902 E. 7th Street
Hastings, NE 68901
tg64152@windstream.net

Nancy Hilding
6300 West Elm
Black Hawk, SD 57718
nhilshat@rapidnet.com

Paul F. Seamans
27893 249th Street
Draper, SD 57531
jacknife@goldenwest.net

Viola Waln
PO Box 937
Rosebud, SD 57570
walnranch@goldenwest.net

Wrexie Lainson Bardaglio
9748 Arden Road
Trumansburg, NY 14886
wrexie.bardaglio@gmail.com

Harold C. Frazier
Chairman, Cheyenne River Sioux Tribe
PO Box 590
Eagle Butte, SD 57625
haroldcfrazier@yahoo.com
mailto:kevinckeckler@yahoo.com

Jerry P. Jones
22584 US Hwy 14
Midland, SD 57552

Cody Jones
21648 US Hwy 14/63
Midland, SD 57552

Debbie J. Trapp
24952 US Hwy 14
Midland, SD 57552
mtdt@goldenwest.net

Gena M. Parkhurst
2825 Minnewsta Place
Rapid City, SD 57702
GMP66@hotmail.com

Joye Braun
PO Box 484
Eagle Butte, SD 57625
jmbraun57625@gmail.com

Duncan Meisel
350.org
20 Jay St., #1010
Brooklyn, NY 11201
duncan@350.org

The Yankton Sioux Tribe
Robert Flying Hawk, Chairman
PO Box 1153
Wagner, SD 57380
robertflyinghawk@gmail.com
Thomasina Real Bird
Attorney for Yankton Sioux Tribe
trealbird@ndnlaw.com

Bruce Ellison
Attorney for Dakota Rural Action
518 6th Street #6
Rapid City, SD 57701
belli4law@aol.com

Chastity Jewett
1321 Woodridge Drive
Rapid City, SD 57701
chasjewett@gmail.com

RoxAnn Boettcher
Boettcher Organics
86061 Edgewater Avenue
Bassett, NE 68714
boettcherann@abbnebraska.com

Bruce Boettcher
Boettcher Organics
86061 Edgewater Avenue
Bassett, NE 68714
boettcherann@abbnebraska.com

Bonny Kilmurry
47798 888 Road
Atkinson, NE 68713
bjkilmurry@gmail.com

Ronald Fees
17401 Fox Ridge Road
Opal, SD 57758

Robert P. Gough, Secretary
Intertribal Council on Utility Policy
PO Box 25
Rosebud, SD 57570
bobgough@intertribalCOUP.org

Tom BK Goldtooth
Indigenous Environmental Network (IEN)
PO Box 485
Bemidji, MN 56619
ien@igc.org

Dallas Goldtooth
38731 Res Hwy 1
Morton, MN 56270
goldtoothdallas@gmail.com

Gary F. Dorr
27853 292nd
Winner, SD 57580
gfdorr@gmail.com

Cyril Scott, President
Rosebud Sioux Tribe
PO Box 430
Rosebud, SD 57570
cscott@gwtc.net
ejantoine@hotmail.com

Paula Antoine
Sicangu Oyate Land Office Coordinator
Rosebud Sioux Tribe
PO Box 658
Rosebud, SD 57570
wopila@gwtc.net
paula.antoine@rosebudsiouxtribe-nsn.gov

Thomasina Real Bird
Representing Yankton Sioux Tribe
Fredericks Peebles & Morgan LLP
1900 Plaza Dr.
Louisville, CO 80027
trealbird@ndnlaw.com

Sabrina King
Dakota Rural Action
518 Sixth Street, #6
Rapid City, SD 57701
sabinra@dakotarural.org

Frank James
Dakota Rural Action
PO Box 549
Brookings, SD 57006
fejames@dakotarural.org

Robin S. Martinez
Dakota Rural Action
Martinez Madrigal & Machicao, LLC
616 West 26th Street
Kansas City, MO 64108
robin.martinez@martinezlaw.net

Tracey A. Zephier
Attorney for Cheyenne River Sioux Tribe
Fredericks Peebles & Morgan LLP
910 5th Street, Suite 104
Rapid City, SD 57701
tzephier@ndnlaw.com

Paul C. Blackburn
4145 20th Avenue South
Minneapolis, MN 55407
paul@paulblackburn.net

Matthew Rappold
Rappold Law Office
on behalf of Rosebud Sioux Tribe
PO Box 873
Rapid City, SD 57709
matt.rappold01@gmail.com

April D. McCart
Representing Dakota Rural Action
Certified Paralegal
Martinez Madrigal & Machicao, LLC
616 W. 26th Street
Kansas City, MO 64108
april.mccart@martinezlaw.net

Kimberly E. Craven
3560 Catalpa Way
Boulder, CO 80304
kimecraven@gmail.com

Joy Lashley
Administrative Assistant
SD Public Utilities Commission
joy.lashley@state.sd.us

Mary Turgeon Wynne
Rosebud Sioux Tribe - Tribal Utility Commission
153 S. Main Street
Mission, SD 57555
tuc@rosebudsiouxtribe-nsn.gov

Eric Antoine
Rosebud Sioux Tribe
PO Box 430
Rosebud, SD 57570
ejantoine@hotmail.com

WOODS, FULLER, SHULTZ & SMITH P.C.

By /s/ James E. Moore

William Taylor
James E. Moore
PO Box 5027
300 South Phillips Avenue, Suite 300
Sioux Falls, SD 57117-5027
Phone (605) 336-3890
Fax (605) 339-3357
Email James.Moore@woodsfuller.com
Attorneys for Applicant TransCanada

With more than 60 years' experience, TransCanada is a leader in the responsible development and reliable operation of North American energy infrastructure including natural gas and oil pipelines, power generation and gas storage facilities. TransCanada operates a network of natural gas pipelines that extends more than 68,500 kilometres (42,500 miles), tapping into virtually all major gas supply basins in North America. TransCanada is one of the continent's largest providers of gas storage and related services with more than 400 billion cubic feet of storage capacity. A growing independent power producer, TransCanada owns or has interests in over 11,800 megawatts of power generation in Canada and the United States. TransCanada is developing one of North America's largest oil delivery systems. TransCanada's common shares trade on the Toronto and New York stock exchanges under the symbol TRP. For more information visit: www.transcanada.com or check us out on Twitter @transcanada or http://blog.transcanada.com.

Corey Goulet

President, Keystone Projects

As President, Keystone Projects, Corey Goulet has overall accountability for the development and implementation of all phases of the Keystone Pipeline including securing land and permits, engineering, procurement, construction, commissioning, start-up and testing.

Prior to his current role, Mr. Goulet was Vice-President of the Facilities and Pipeline Projects department where he was responsible for leading the technical development and implementation of power plant, compression, metering and pipeline projects in Canada and the United States.

Mr. Goulet has 27 years of energy infrastructure experience. His experience is varied and has focused on the development, construction, operation and maintenance of natural gas, wind, hydro, nuclear and transmission power facilities; gas, oil and refined products pipelines; and oil and gas production facilities. He joined the company in 1998 as a manager in the international business unit where he was responsible for developing projects. Since that role, he has lead various departments including pipeline engineering, energy projects, and nuclear technical development.

Mr. Goulet is a former member of the Operations and System Integrity subcommittee for CSA Z662 Oil and Gas Pipeline Systems. In addition, he represented TransCanada for two years as a Board member, Executive Committee member, and Planning Committee member with the Pipeline Research Council International, Inc. (PRCI). Mr. Goulet has also been a Board member for two joint venture companies.

Born and raised near Edmonton, Alberta, he graduated with a Bachelor of Science in Mechanical Engineering (with Distinction) from the University of Alberta in 1985.

Biography (September 10, 2014)

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TransCanada
In business to deliver

KEYSTONE 1342
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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 DIRECT TESTIMONY OF DAVID DIAKOW

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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 direct testimony of David Diakow.

1. Please state your name and address for the record.

Answer: My name is David Diakow. 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 Vice President, Commercial, Liquids Pipelines, for TransCanada Pipelines. I am responsible for commercial activities for TransCanada's liquids pipeline business, including the Keystone XL Project.

3. Please state your professional qualifications and experience with pipeline operations.

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Answer: My professional background is stated in my resume, a copy of which is attached as Exhibit A. I have a bachelor's and master's degree in mechanical engineering, and a Master of Business Administration degree.

4. Are you responsible for portions of the Tracking Table of Changes attached as Appendix C to Keystone's certification petition?

Answer: Yes. I am individually or jointly responsible for the information provided with respect to Finding Numbers 24, 25, 26, 27, 28, and 29 related to the Project. In general, I can testify to demand for the Project.

5. Please summarize the updated information regarding Finding Number 24.

The crude oil market is dynamic. While the crude oil market has changed since 2010, demand for the Project remains strong. Keystone has binding shipper commitments for the Project. The need for the Project is driven by factors that include the need to transport safely and efficiently growing U.S. and Canadian crude oil production, insufficient pipeline capacity, and the opportunity to reduce U.S. dependence on foreign offshore crude oil through increased access to North American supplies. The continued demand for the Project is documented in the Department of State Final Supplemental Environmental Impact Statement (FSEIS), Section 1.4, Market Analysis.

6. Please summarize the updated information regarding Finding Number 25.

Answer: Since Keystone's petition for a permit was filed with the Commission in 2009, United States production of crude oil has increased significantly, from approximately 6.5 million barrels per day (bpd) in 2012, and is expected to peak at 9.6 million bpd by 2019. Even with this growth in domestic production, the United States is expected to remain a net importer of crude oil. Keystone reviews and relies on forecasts from the U.S. Energy Information Administration (EIA). According to the EIA, U.S. demand for crude oil has held steady at approximately 15 million bpd and is expected to remain relatively stable into the future. More information from the EIA forecasts is included in the FSEIS in Section 1.4. Keystone also relies on industry information available from the CAPP Crude Oil Forecast, Markets and Transportation June 2014, which Keystone produced in discovery in this proceeding.

7. Please summarize the updated information regarding Finding Number 26.

Answer: While domestic production of light crude oil has increased since 2009 and has replaced most foreign imports of light crude, demand persists for imported heavy crude oil by U.S. refineries that are optimally configured to process heavy crude slates. The U.S. Gulf Coast continues to import approximately 3.5 million bpd of heavy and medium sour crude oil. This demand is supported by Keystone's binding shipper commitments for the Keystone XL Project.

8. Please summarize the information regarding Finding Number 27.

Answer: Continued demand for imported heavy crude oil is also demonstrated by the fact that the vast majority of Canadian heavy crude oil production is currently exported to the United States to be processed by U.S. refineries. North American crude oil production growth and logistics constraints have contributed to significant discounts on the price of landlocked crude and led to growing volumes of crude shipped by rail in the United States. As the FSEIS makes clear, in the absence of new pipelines, crude oil will continue to be transported via rail at an increasing rate. The North Dakota Pipeline Authority estimates that rail export volumes from the U.S. Williston Basin have increased from approximately 40,000 bpd in 2010 to over 700,000 bpd in early 2014. Over 60% of crude oil transported from the Williston Basin is delivered by rail. The industry has also been making significant investments in increasing rail transport capacity for crude oil out of the Western Canadian Sedimentary Basin. In recent years, rail transport of crude oil in Canada has grown from approximately 10,000 bpd in 2010 to approximately 270,000 bpd by the end of 2013. Chapter 5 of the FSEIS (sections 5.0, 5.1, 5.2, and 5.3) indicates that transportation of crude oil by pipeline is safer and less greenhouse gas intensive than crude oil transportation by rail. Thus, the statement in Finding No. 27 remains true--that the project will provide an opportunity for U.S. refiners in Petroleum Administration for Defense District III, the Gulf Coast region, to further diversify supply away from traditional offshore foreign crude supply and to obtain direct access to secure and growing domestic crude supplies.

9. Please summarize the updated information regarding Finding No. 28.

Answer: The numbers vary slightly, but the overall fact remains the same. Reliable and safe transportation of crude oil will help ensure that U.S. energy needs are not subject to unstable political events. Canada has 173 billion barrels of oil reserves, 97% of which are located in the oil sands. Canada's reserves are third only to Venezuela and Saudi Arabia. Canada is the largest foreign supplier of crude oil to the United States and is likely to remain as such for the foreseeable future.

10. Please summarize the updated information regarding Finding No. 29.

Answer: Keystone's shippers have committed to long-term binding contracts, which 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 domestic and

Canadian crude supplies. The FSEIS independently confirms strong market demand for the Project.

11. Are you aware of any reason that Keystone cannot continue to meet the conditions on which the Permit was granted by the Commission?

Answer: No. I have reviewed the conditions contained in the Amended Final Decision and Order dated June 29, 2010. The changes discussed in Finding Nos. 24-29 related to demand do not affect Keystone's ability to meet the conditions on which the Permit was granted.

12. Does this conclude your prepared direct testimony?

Answer: Yes.

Dated this 24 day of March, 2015.

David Diakow

CERTIFICATE OF SERVICE

I hereby certify that on the 2nd day of April, 2015, I sent by United States first-class mail, postage prepaid, or e-mail transmission, a true and correct copy of the foregoing Direct Testimony of David Diakow, to the following:

Patricia Van Gerpen
Executive Director
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
patty.vangerpen@state.sd.us

Kristen Edwards
Staff Attorney
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
kristen.edwards@state.sd.us

Brian Rounds
Staff Analyst
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
brian.rounds@state.sd.us

Darren Kearney
Staff Analyst South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
darren.kearney@state.sd.us

Tony Rogers, Director
Rosebud Sioux Tribe - Tribal Utility Commission
153 South Main Street
Mission, SD 57555
tuc@rosebudsiouxtribe-nsn.gov

Cindy Myers, R.N.
PO Box 104
Stuart, NE 68780
csmyers77@hotmail.com

Jane Kleeb
1010 North Denver Avenue
Hastings, NE 68901
jane@boldnebraska.org

Byron T. Steskal
Diana L. Steskal
707 E. 2nd Street
Stuart, NE 68780
prairierose@nntc.net

Terry Frisch
Cheryl Frisch
47591 875th Road
Atkinson, NE 68713
tcfrisch@q.com

Arthur R. Tanderup
52343 857th Road
Neligh, NE 68756
atanderu@gmail.com

Lewis GrassRope
PO Box 61
Lower Brule, SD 57548
wisestar8@msn.com

Carolyn P. Smith
305 N. 3rd Street
Plainview, NE 68769
peachie_1234@yahoo.com

Robert G. Allpress
46165 Badger Road
Naper, NE 68755
bobandnan2008@hotmail.com

Amy Schaffer
PO Box 114
Louisville, NE 68037
amyannschaffer@gmail.com

Benjamin D. Gotschall
6505 W. Davey Road
Raymond, NE 68428
ben@boldnebraska.org

Elizabeth Lone Eagle
PO Box 160
Howes, SD 57748
bethcbest@gmail.com

John H. Harter
28125 307th Avenue
Winner, SD 57580
johnharter11@yahoo.com

Peter Capossela
Peter Capossela, P.C.
Representing Standing Rock Sioux Tribe
PO Box 10643
Eugene, OR 97440
pcapossela@nu-world.com

Jerry P. Jones
22584 US Hwy 14
Midland, SD 57552

Jeff Jensen
14376 Laflin Road
Newell, SD 57760
jensen@sdplains.com

Louis T. (Tom) Genung
902 E. 7th Street
Hastings, NE 68901
tg64152@windstream.net

Nancy Hilding
6300 West Elm
Black Hawk, SD 57718
nhilshat@rapidnet.com

Paul F. Seamans
27893 249th Street
Draper, SD 57531
jacknife@goldenwest.net

Viola Waln
PO Box 937
Rosebud, SD 57570
walnranch@goldenwest.net

Wrexie Lainson Bardaglio
9748 Arden Road
Trumansburg, NY 14886
wrexie.bardaglio@gmail.com

Harold C. Frazier
Chairman, Cheyenne River Sioux Tribe
PO Box 590
Eagle Butte, SD 57625
haroldcfrazier@yahoo.com
mailto:kevinckeckler@yahoo.com

Cody Jones
21648 US Hwy 14/63
Midland, SD 57552

Debbie J. Trapp
24952 US Hwy 14
Midland, SD 57552
mtdt@goldenwest.net

Gena M. Parkhurst
2825 Minnewsta Place
Rapid City, SD 57702
GMP66@hotmail.com

Joye Braun
PO Box 484
Eagle Butte, SD 57625
jmbraun57625@gmail.com

Duncan Meisel
350.org
20 Jay St., #1010
Brooklyn, NY 11201
duncan@350.org

The Yankton Sioux Tribe
Robert Flying Hawk, Chairman
PO Box 1153
Wagner, SD 57380
robertflyinghawk@gmail.com
Thomasina Real Bird
Attorney for Yankton Sioux Tribe
trealbird@ndnlaw.com

Bruce Ellison
Attorney for Dakota Rural Action
518 6th Street #6
Rapid City, SD 57701
belli4law@aol.com

Chastity Jewett
1321 Woodridge Drive
Rapid City, SD 57701
chasjewett@gmail.com

RoxAnn Boettcher
Boettcher Organics
86061 Edgewater Avenue
Bassett, NE 68714
boettcherann@abbnebraska.com

Bruce Boettcher
Boettcher Organics
86061 Edgewater Avenue
Bassett, NE 68714
boettcherann@abbnebraska.com

Bonny Kilmurry
47798 888 Road
Atkinson, NE 68713
bjkilmurry@gmail.com

Ronald Fees
17401 Fox Ridge Road
Opal, SD 57758

Robert P. Gough, Secretary
Intertribal Council on Utility Policy
PO Box 25
Rosebud, SD 57570
bobgough@intertribalCOUP.org

Tom BK Goldtooth
Indigenous Environmental Network (IEN)
PO Box 485
Bemidji, MN 56619
ien@igc.org

Dallas Goldtooth
38731 Res Hwy 1
Morton, MN 56270
goldtoothdallas@gmail.com

Gary F. Dorr
27853 292nd
Winner, SD 57580
gfdorr@gmail.com

Cyril Scott, President
Rosebud Sioux Tribe
PO Box 430
Rosebud, SD 57570
cscott@gwtc.net
ejantoine@hotmail.com

Paula Antoine
Sicangu Oyate Land Office Coordinator
Rosebud Sioux Tribe
PO Box 658
Rosebud, SD 57570
wopila@gwtc.net
paula.antoine@rosebudsiouxtribe-nsn.gov

Thomasina Real Bird
Representing Yankton Sioux Tribe
Fredericks Peebles & Morgan LLP
1900 Plaza Dr.
Louisville, CO 80027
trealbird@ndnlaw.com

Sabrina King
Dakota Rural Action
518 Sixth Street, #6
Rapid City, SD 57701
sabinra@dakotarural.org

Frank James
Dakota Rural Action
PO Box 549
Brookings, SD 57006
fejames@dakotarural.org

Robin S. Martinez
Dakota Rural Action
Martinez Madrigal & Machicao, LLC
616 West 26th Street
Kansas City, MO 64108
robin.martinez@martinezlaw.net

Tracey A. Zephier
Attorney for Cheyenne River Sioux Tribe
Fredericks Peebles & Morgan LLP
910 5th Street, Suite 104
Rapid City, SD 57701
tzephier@ndnlaw.com

Paul C. Blackburn
4145 20th Avenue South
Minneapolis, MN 55407
paul@paulblackburn.net

Matthew Rappold
Rappold Law Office
on behalf of Rosebud Sioux Tribe
PO Box 873
Rapid City, SD 57709
matt.rappold01@gmail.com

April D. McCart
Representing Dakota Rural Action
Certified Paralegal
Martinez Madrigal & Machicao, LLC
616 W. 26th Street
Kansas City, MO 64108
april.mccart@martinezlaw.net

Kimberly E. Craven
3560 Catalpa Way
Boulder, CO 80304
kimecraven@gmail.com

Joy Lashley
Administrative Assistant
SD Public Utilities Commission
joy.lashley@state.sd.us

Mary Turgeon Wynne
Rosebud Sioux Tribe - Tribal Utility Commission
153 S. Main Street
Mission, SD 57555
tuc@rosebudsiouxtribe-nsn.gov

Eric Antoine
Rosebud Sioux Tribe
PO Box 430
Rosebud, SD 57570
ejantoine@hotmail.com

WOODS, FULLER, SHULTZ & SMITH P.C.

By /s/ James E. Moore

William Taylor
James E. Moore
PO Box 5027
300 South Phillips Avenue, Suite 300
Sioux Falls, SD 57117-5027
Phone (605) 336-3890
Fax (605) 339-3357
Email James.Moore@woodsfuller.com
Attorneys for Applicant TransCanada

David Diakow
Vice President, Commercial, Liquids Pipelines
TransCanada Pipelines

David is currently responsible for commercial activities for TransCanada's liquids pipeline business, including strategy development, commercial regulatory management and commercial management of its operating assets, such as the Keystone Pipeline system, and including those in advanced stages of commercial development such as the Keystone XL project.

David has over 27 years of experience in the oil and gas industry, with 24 years at TransCanada. David has held management positions in engineering, major projects and business development with respect to natural gas and crude oil pipelines development in Canada and the U.S.

David graduated from the University of Saskatchewan in 1987 with a Bachelor of Science degree in Mechanical Engineering and also holds both a Master of Science degree in Mechanical Engineering (1994) and a Master of Business Administration degree (2002) from the University of Calgary.

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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 DIRECT TESTIMONY OF MEERA KOTHARI, P.ENG.

0-0-0-0-0-0-0-0-0-0-0-0-0-0-0-0-0-0-0-0-0-0-0-0-0-0-0

Pursuant to the Commission's Order Granting Motion to Define Issues and Setting Procedural Schedule, Petitioner TransCanada Keystone Pipeline, LP, offers the following direct testimony of Meera Kothari.

1. Please state your name and address for the record.

Answer: My name is Meera Kothari. My business address is 700 Louisiana Street, Houston, Texas 77002.

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 currently Manager, U.S. Business Development, Liquids Pipelines, for TransCanada, as well as Manager, Technical Services Pipeline Engineering for Keystone Oil Projects. I have oversight responsibility for design and engineering for the Keystone XL Pipeline Project.

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3. Please state your professional qualifications and experience with pipeline operations.

Answer: My professional background is stated in my resume, a copy of which is attached as Exhibit A. In general, I am a Professional Engineer, with a degree in mechanical and manufacturing engineering. Beginning in October, 2005, I served as the Lead Project Engineer for the Keystone Pipeline Project. I was the Project Manager for the Cushing Extension Pipeline Project from April 2010 to January 2011. I was the Reclamation Project Manager for the Cushing Extension Pipeline from January 2011 to November 2011. I have testified before the Commission in the permit proceedings concerning the Keystone Pipeline in Docket HP07-001 and concerning the Keystone XL Pipeline in Docket HP 09-001.

4. Are you responsible for portions of the Tracking Table of Changes attached as Appendix C to Keystone's certification petition?

Answer: Yes. I am individually or jointly responsible for the information provided with respect to Finding Numbers 60, 61, 62, 63, 68, 83, 90, and 107. In general, I can testify to design and construction of the Keystone XL Pipeline and PHMSA compliance.

5. Please summarize the updated information regarding Finding No. 60.

Answer: Since the Amended Final Order dated June 29, 2010, Keystone withdrew its request to PHMSA for a special permit ("Special Permit") on August 5, 2010. The decision was explained in a media advisory issued on August 5, 2010, a copy of which is attached as Exhibit B. As a result of the withdrawal, Keystone will implement 59 additional safety measures as set forth in Appendix Z to the Department of State Final Supplemental Environmental Impact

Statement. These measures provide an enhanced level of safety equivalent to or greater than those that would have applied under the previously requested Special Permit.

6. Please summarize the updated information regarding Finding No. 61.

Answer: This finding is no longer relevant as Keystone has withdrawn its request for a Special Permit.

7. Please summarize the updated information regarding Finding No. 62.

Answer: This finding is no longer relevant as Keystone has withdrawn its request for a Special Permit.

8. Please summarize the updated information regarding Finding No. 63.

Answer: As a result of withdrawing the Special Permit application, Keystone will build the Keystone XL Pipeline using the as-proposed high strength steel, API 5L grade X70M steel with a nominal wall thickness of 0.465 inches, but will operate the pipeline at a lower pressure of 1,307 psig to comply with internal pressure design requirements in accordance with federal code of regulation title 49 CFR 195.106. For location specific low elevation segments close to the discharge of pump stations, the maximum operating pressure will be 1,600 psig. Pipe associated with these segments of 1,600 psig MOP will have a design factor of 0.72 and a nominal pipe wall thickness of 0.572 inches (X-70M).

9. Please summarize the updated information regarding Finding No. 68.

Answer: This Finding was updated because TransCanada has four more years of experience in the use of FBE coated pipe. On one occasion when TransCanada excavated pipe to validate FBE coating performance, there was one instance in which an adjacent foreign utility interfered with the cathodic protection system in a shared utility corridor. The situation was remedied, and no similar situation could exist in South Dakota because there are no shared utility corridors.

10. Please summarize the updated information regarding Finding No. 83.

Answer: Keystone will use Horizontal Directional Drilling ("HDD") for the Bridger Creek and Bad River crossings, in addition to the Little Missouri, Cheyenne, and White River crossings. Attachment B to Keystone's Tracking Table of Changes contains the preliminary site-specific crossing plans for the HDD crossings of the Bad River and Bridger Creek.

11. Please summarize the updated information regarding Finding No. 90.

Answer: The updated information for this finding is based on the withdrawal of the Special Permit application. Keystone will comply with the 59 additional conditions as set forth in the FSEIS, Appendix Z, which provide an enhanced level of safety equivalent to or greater than those that would have applied under the Special Permit.

12. Please summarize the updated information regarding Finding No. 107.

Answer: To the extent that Finding No. 107 included reference to the Special Permit, Keystone has withdrawn its application, but will comply with the 59 additional conditions as set forth in the FSEIS, Appendix Z.

13. Are you aware of any reason that Keystone cannot continue to meet the conditions on which the Permit was granted by the Commission?

Answer: No. I have reviewed the conditions contained in the Amended Final Decision and Order dated June 29, 2010. The changes discussed in Finding Nos. 60, 61, 62, 63, 68, 83, 90, and 107 do not affect Keystone's ability to meet the conditions on which the Permit was granted.

14. Does this conclude your prepared direct testimony.

Answer: Yes.

Dated this 1 day of April, 2015.

Meera Kothari

Meera Kothari P.Eng.

CERTIFICATE OF SERVICE

I hereby certify that on the 2nd day of April, 2015, I sent by United States first-class mail, postage prepaid, or e-mail transmission, a true and correct copy of the foregoing Direct Testimony of Meera Kothari, P.Eng., to the following:

Patricia Van Gerpen
Executive Director
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
patty.vangerpen@state.sd.us

Kristen Edwards
Staff Attorney
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
kristen.edwards@state.sd.us

Brian Rounds
Staff Analyst
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
brian.rounds@state.sd.us

Darren Kearney
Staff Analyst South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
darren.kearney@state.sd.us

Tony Rogers, Director
Rosebud Sioux Tribe - Tribal Utility Commission
153 South Main Street
Mission, SD 57555
tuc@rosebudsiouxtribe-nsn.gov

Cindy Myers, R.N.
PO Box 104
Stuart, NE 68780
csmyers77@hotmail.com

Jane Kleeb
1010 North Denver Avenue
Hastings, NE 68901
jane@boldnebraska.org

Byron T. Steskal
Diana L. Steskal
707 E. 2nd Street
Stuart, NE 68780
prairierose@nntc.net

Terry Frisch
Cheryl Frisch
47591 875th Road
Atkinson, NE 68713
tcfrisch@q.com

Arthur R. Tanderup
52343 857th Road
Neligh, NE 68756
atanderu@gmail.com

Lewis GrassRope
PO Box 61
Lower Brule, SD 57548
wisestar8@msn.com

Robert G. Allpress
46165 Badger Road
Naper, NE 68755
bobandnan2008@hotmail.com

Amy Schaffer
PO Box 114
Louisville, NE 68037
amyannschaffer@gmail.com

Benjamin D. Gotschall
6505 W. Davey Road
Raymond, NE 68428
ben@boldnebraska.org

Elizabeth Lone Eagle
PO Box 160
Howes, SD 57748
bethcbest@gmail.com

John H. Harter
28125 307th Avenue
Winner, SD 57580
johnharter11@yahoo.com

Peter Capossela
Peter Capossela, P.C.
Representing Standing Rock Sioux Tribe
PO Box 10643
Eugene, OR 97440
pcapossela@nu-world.com

Carolyn P. Smith
305 N. 3rd Street
Plainview, NE 68769
peachie_1234@yahoo.com

Jeff Jensen
14376 Laflin Road
Newell, SD 57760
jensen@sdplains.com

Louis T. (Tom) Genung
902 E. 7th Street
Hastings, NE 68901
tg64152@windstream.net

Nancy Hilding
6300 West Elm
Black Hawk, SD 57718
nhilshat@rapidnet.com

Paul F. Seamans
27893 249th Street
Draper, SD 57531
jacknife@goldenwest.net

Viola Waln
PO Box 937
Rosebud, SD 57570
walnranch@goldenwest.net

Wrexie Lainson Bardaglio
9748 Arden Road
Trumansburg, NY 14886
wrexie.bardaglio@gmail.com

Harold C. Frazier
Chairman, Cheyenne River Sioux Tribe
PO Box 590
Eagle Butte, SD 57625
haroldcfrazier@yahoo.com
mailto:kevinckeckler@yahoo.com

Jerry P. Jones
22584 US Hwy 14
Midland, SD 57552

Cody Jones
21648 US Hwy 14/63
Midland, SD 57552

Debbie J. Trapp
24952 US Hwy 14
Midland, SD 57552
mtdt@goldenwest.net

Gena M. Parkhurst
2825 Minnewsta Place
Rapid City, SD 57702
GMP66@hotmail.com

Joye Braun
PO Box 484
Eagle Butte, SD 57625
jmbraun57625@gmail.com

Duncan Meisel
350.org
20 Jay St., #1010
Brooklyn, NY 11201
duncan@350.org

The Yankton Sioux Tribe
Robert Flying Hawk, Chairman
PO Box 1153
Wagner, SD 57380
robertflyinghawk@gmail.com
Thomasina Real Bird
Attorney for Yankton Sioux Tribe
trealbird@ndnlaw.com

Bruce Ellison
Attorney for Dakota Rural Action
518 6th Street #6
Rapid City, SD 57701
belli4law@aol.com

Chastity Jewett
1321 Woodridge Drive
Rapid City, SD 57701
chasjewett@gmail.com

RoxAnn Boettcher
Boettcher Organics
86061 Edgewater Avenue
Bassett, NE 68714
boettcherann@abbnebraska.com

Bruce Boettcher
Boettcher Organics
86061 Edgewater Avenue
Bassett, NE 68714
boettcherann@abbnebraska.com

Bonny Kilmurry
47798 888 Road
Atkinson, NE 68713
bjkilmurry@gmail.com

Ronald Fees
17401 Fox Ridge Road
Opal, SD 57758

Robert P. Gough, Secretary
Intertribal Council on Utility Policy
PO Box 25
Rosebud, SD 57570
bobgough@intertribalCOUP.org

Tom BK Goldtooth
Indigenous Environmental Network (IEN)
PO Box 485
Bemidji, MN 56619
ien@igc.org

Dallas Goldtooth
38731 Res Hwy 1
Morton, MN 56270
goldtoothdallas@gmail.com

Cyril Scott, President
Rosebud Sioux Tribe
PO Box 430
Rosebud, SD 57570
cscott@gwtc.net
ejantoine@hotmail.com

Thomasina Real Bird
Representing Yankton Sioux Tribe
Fredericks Peebles & Morgan LLP
1900 Plaza Dr.
Louisville, CO 80027
trealbird@ndnlaw.com

Frank James
Dakota Rural Action
PO Box 549
Brookings, SD 57006
fejames@dakotarural.org

Tracey A. Zephier
Attorney for Cheyenne River Sioux Tribe
Fredericks Peebles & Morgan LLP
910 5th Street, Suite 104
Rapid City, SD 57701
tzephier@ndnlaw.com

Matthew Rappold
Rappold Law Office
on behalf of Rosebud Sioux Tribe
PO Box 873
Rapid City, SD 57709
matt.rappold01@gmail.com

Gary F. Dorr
27853 292nd
Winner, SD 57580
gfdorr@gmail.com

Paula Antoine
Sicangu Oyate Land Office Coordinator
Rosebud Sioux Tribe
PO Box 658
Rosebud, SD 57570
wopila@gwtc.net
paula.antoine@rosebudsiouxtribe-nsn.gov

Sabrina King
Dakota Rural Action
518 Sixth Street, #6
Rapid City, SD 57701
sabinra@dakotarural.org

Robin S. Martinez
Dakota Rural Action
Martinez Madrigal & Machicao, LLC
616 West 26th Street
Kansas City, MO 64108
robin.martinez@martinezlaw.net

Paul C. Blackburn
4145 20th Avenue South
Minneapolis, MN 55407
paul@paulblackburn.net

April D. McCart
Representing Dakota Rural Action
Certified Paralegal
Martinez Madrigal & Machicao, LLC
616 W. 26th Street
Kansas City, MO 64108
april.mccart@martinezlaw.net

Kimberly E. Craven
3560 Catalpa Way
Boulder, CO 80304
kimecraven@gmail.com

Mary Turgeon Wynne
Rosebud Sioux Tribe - Tribal Utility Commission
153 S. Main Street
Mission, SD 57555
tuc@rosebudsiouxtribe-nsn.gov

Joy Lashley
Administrative Assistant
SD Public Utilities Commission
joy.lashley@state.sd.us

Eric Antoine
Rosebud Sioux Tribe
PO Box 430
Rosebud, SD 57570
ejantoine@hotmail.com

WOODS, FULLER, SHULTZ & SMITH P.C.

By /s/ James E. Moore
William Taylor
James E. Moore
PO Box 5027
300 South Phillips Avenue, Suite 300
Sioux Falls, SD 57117-5027
Phone (605) 336-3890
Fax (605) 339-3357
Email James.Moore@woodsfuller.com
Attorneys for Applicant TransCanada

Meera Kothari P.Eng.

Professional Experience

TransCanada Corp. Houston, TX October, 2014 – Present

Manager, U.S. Business Development, Liquids Pipelines

- Manage TransCanada's existing customer relationships, and develop new customers for future business opportunities.
- Market of capacity on TransCanada's existing oil pipeline system, and extending the reach of TransCanada's oil pipeline network through the development of transportation and terminalling opportunities.
- Perform market research and provide analysis supporting strategy development.
- Prepare business strategies and plans.
- Provide analytical and due diligence support.
- Prepare marketing material and proposals.
- Assist with development of key valuation assumptions and related analysis.
- Interact with key internal clients: Engineering, Supply Chain, Construction, Operations, Legal, Finance, Accounting, Tax, and Risk.
- Transition successful development projects to execution.

TransCanada Corp. Houston, TX October, 2012 – Present

Manager, Technical Services Pipeline Engineering for Keystone Oil Projects

- Guide, review and sign off on pipeline designs and facility interface designs for oil project portfolios worth up to $12B.
- Oversight of 8 engineering firms dealing with all facets of pipeline engineering (inclusive of specialty items such as routing, civil design, E&I, welding, ECA, coating, welding, NDE technology, stress analysis, cathodic protection design, AC mitigation design, risk and spill analysis, thermal modeling, etc.)
- Oversight of construction technical execution for a 860 km 36" pipeline project inclusive of mechanize and flux core welding, automated girth weld coating application, high risk HDDs applications (7500 ft+ in length), AUT/RTR nondestructive examination, automated inspection record capturing
- Performance management for team of 15 direct reports/10 contract staff (engineers, technologists, resident inspectors).
- Technical representative interfacing with construction contractors and major pipe/material suppliers.
- Preparation of permit applications, data responses and meetings with Canadian/US Federal and State agencies (NEB, PHMSA, Department of State, Bureau of Reclamation/Land Management ,etc.),

TransCanada Corp. Houston, TX November 2011 - October 2012

Technical Advisor, Keystone XL Pipeline Project

- Technical advisor during pipeline detail design phase, construction contractor bid process, material procurement, and preconstruction planning activities for 36" 2,798 km cross border pipeline project.

EXHIBIT A

TransCanada Corp. Houston, TX January 2011 - November 2011

Reclamation Project Manager, Cushing Extension Pipeline

- Management of ROW reclamation activities for 482 km pipeline.

TransCanada Corp. Houston, TX April 2010 - January 2011

Project Manager, Cushing Extension Pipeline Project

- Construction execution of $110M, 36" 171 km pipeline project in Kansas.
- Delivery of safety performance results and ensured management visibility on the construction site.
- Ensured the project was constructed with the approved design, plans, and standards; and in accordance with environmental regulations and all project permit conditions.
- Delivered within budget and on-time performance meeting project safety, environmental, and quality requirements.
- Ensured positive and professional relationships are enhanced and maintained with contractors, unions, landowners, communities, aboriginal , governmental and regulatory bodies.
- Facilitation of Board of Directors and External Stakeholder visits to the ROW.

TransCanada Corp. Calgary, AB October 2005 - April 2010

Lead Project Engineer, Keystone Pipeline Project

- Development and review of DBM, FEED, detail design, specifications, standards, procedures for new construction, pipeline change of service conversion and above ground facilities in accordance with applicable industry codes and standards (Canada & USA).
- Pipeline route planning, HCA development, integrity management plans, spill analysis.
- Construction technical support for design, coating, NDE (AUT/RTR), ECA, mechanized/manual welding, hydrostatic testing, In-Line Inspection (ILI), and materials.
- Commissioning support.
- Engineering and Integrity assessment for conversion of 864 km circa 1950, 34" gas pipeline to crude oil service in Canada. Converted without hydrotesting through the use of ultrasonic in-line inspection
- Engineering assessment for the design, construction and operation of 30"/36" 2,215 km crude pipeline at 80% SMYS in the USA. First liquid line to be granted a waiver in the US.
- Plan, review and ensure timely completion of regulatory baseline data collection, permit application preparation and submittal in Canada (NEB Section 74, Section 52, Section 58) and the US (NEPA and State).
- Preparation and analysis of project budgets & expansion cases.
- Generation of terms, conditions, scope, analysis and award and completion of project RFP for major materials and services.
- Expert witness testifying at multiple Department of State (DOS) hearings, State hearings, technical spokesperson at public consultation project open houses.
- Preparation of permit applications, data responses and meetings with Canadian/US Federal and State agencies (NEB, PHMSA, Department of State etc),

TransCanada Energy. Trois Rivières, Québec May 2005 - October 2005

Project Engineer, Becancour 500 MW Cogeneration Power Plant

- Development & implementation of inside battery limit/outside battery limit construction quality plan for $550M project.
- Witness point inspections and audit of equipment fabrication & equipment installation.
- Conducted plant hazard assessment recommendation close out.
- Validation of work package estimates for outside battery limit pipeline project bid award.
- Development hazardous material philosophy.

- RFP preparation for gas and chemical supply.
- Development of community investment risk matrix.
- French guided plant tours for various stakeholders.
- Preparation of monthly project status report, management presentations and HS&E statistics
- Analysis and validation of cost and schedule for various work packages
- Development of management operating system compliance tracking report

TransCanada Corp. Calgary, AB July 2001 - April 2005

Pipeline Integrity Engineer for Asset Reliability, Technical Support and Technology Management

- Technical specification support for new capital pipeline projects (coating, welding, materials, NDE).
- Engineering critical assessment for pipeline defect assessment, maintenance repair, pipeline pressure de-rating, unsupported pipe lengths, blasting/explosives, coating systems for 40,000 miles of operating pipeline.
- Urban development encroachments, foreign utility, road and vehicle crossing application review focused in the areas of integrity verification, stress analysis, population growth tracking for the purpose of code compliance and conflicts with facilities that may impact the ability to maintain integrity, access for maintenance purposes, emergency response accessibility and compatible land uses for 40,000 miles of operating pipeline.
- Failure analysis of in service pipe body leaks, pipeline ruptures and hydrostatic test failures
- Research & Development of SCC & MFL In-Line Inspection, NDT techniques, pipeline repair techniques, mainline and joint coating systems, welding of new materials.
- Risk analysis for new pipeline construction projects.
- Development of engineering & integrity budget and programs for due diligence and acquisitions.
- Development of commercial agreements & contracts with Provincial Governments, private developers and construction contracts for pipeline upgrade/rehabilitation project.
- Coordination of Facilities Integrity R&D Program reviews and budgeting cycles.
- Liaison with Regulators (National Energy Board, Transportation Safety Board and Alberta Energy and Utilities Board) with respect to integrity management issues and incidents.
- Providing direction during emergency maintenance activities to various groups within the organization.
- Developed annual integrity maintenance program using quantitative risk modeling software.
- Coordination of research & development projects for risk management, corrosion and SCC.
- Coordination of peer review team for evaluation of projects feasibility and cost management.
- Performed value/benefit analysis for integrity projects.
- Directing contractors & field technicians to perform technical tasks.

Education

Bachelor of Science (BSc) – Mechanical & Manufacturing Engineering, University of Calgary, AB May 2001

- Four (4) Summer Student Program Terms with Petro-Canada Oil & Gas Ltd performing data and technology architecture development for various projects: McKay River Bitumen Recovery Scheme, De-sulferization upgrade facility, transportation developments and Natural Gas Liquids (NGL) facilities June 1998 - May 2001

Special Skills

- **Team and Individual Leadership** – Can fully utilize the capabilities of direct reports to ensure effectiveness of own department. Empowers and motivates the team to set and achieve goals despite significant obstacles.
- **Project Management** – Utilize time management skills to meet deadlines for numerous major projects and demonstrated ability to engage and collaborate with team members effectively.
- **Communication & Collaboration** – Possess strong oral and written communication skills; able to research and present ideas effectively as shown through publications, speeches, and presentations.
- **Languages** – Write and speak fluent English and French

Publications & Industry

M. Kothari, S. Tappert, U. Strohmeier, J. Larios and D. Ronsky, "**Validation of EMAT In-Line Inspection Technology for SCC Management**," Proceedings of the International Pipeline Conference, Calgary, 2004.

R. Worthingham, M. Cetiner, M. Kothari, "**Field Trial of Coating Systems for Arctic Pipelines**," Proceedings of the International Pipeline Conference, Calgary, 2004.

Chair Person: **In-Line Inspection Session**, Banff Pipeline Integrity Workshop, Banff, 2005

Professional Member of APEGGA

TransCanada
In business to deliver

Media Advisory

Special Permit Application Withdrawn for Keystone Gulf Coast Expansion Pipeline

Calgary, Alberta – August 5, 2010 – TransCanada has withdrawn its request to the Pipeline and Hazardous Materials Safety Administration (PHMSA) for a special permit. The permit would have allowed TransCanada to operate the proposed Keystone XL pipeline at a slightly higher pressure than current federal regulations for oil pipelines in the United States, subject to building the pipeline using stronger steel and operating under additional safety conditions.

After listening to concerns from the public and various political leaders, TransCanada made the decision to withdraw the permit application. The company will build Keystone XL using the as-proposed stronger steel but will operate it at a lower level of pressure, consistent with current U.S. regulations.

The company recognizes it needs to take more steps to assure the public and stakeholders that the parameters of the special permit would result in a safer pipeline. The company will continue to establish an operating record which will demonstrate the strength and integrity of the Keystone Pipeline System, which has been granted a special permit.

Keystone XL will implement the additional safety measures that would have been required under the special permit. These measures offer an enhanced level of safety and would allow TransCanada to request a special permit in the future. These safety measures also will be consistent with those that have been implemented on the existing Keystone Pipeline. In issuing the special permit for Keystone, PHMSA concluded the permit would provide a level of safety equal to or greater than that provided if the pipeline were operated under the current standard.

Without the special permit, Keystone XL will meet all of its initial commercial commitments to serve Gulf Coast refineries. Keystone also will continue to work with U.S. producers in the Bakken and broader Williston Basin area to provide needed transport for growing production in Montana and the Dakotas.

The Keystone XL project received approval in March 2010 from both the South Dakota Public Utility Commission and the National Energy Board in Canada. Pending receipt of additional permits, construction is planned to begin in 2011.

When completed, the Keystone XL project will increase the commercial capacity of the overall Keystone Pipeline System from 590,000 barrels per day to approximately 1.1 million barrels per day. The $12 billion system is 83 percent subscribed with long-term, binding contracts that include commitments of 910,000 barrels per day for an average term of approximately 18 years.

Commercial operations of the first phase of the Keystone system began June 30. Construction of the extension from Steele City Nebraska to Cushing Oklahoma is one-third complete and the pipeline is expected to be operational in 2011.

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Keystone XL is a planned 1,959-mile (3,134-kilometre), 36-inch crude oil pipeline stretching from Hardisty, Alberta and moving southeast through Saskatchewan, Montana, South Dakota and Nebraska. It will connect with a portion of the Keystone Pipeline that will be built through Kansas to Cushing, Oklahoma and facilitate take away capacity from U.S. hubs located on the pipeline. The pipeline will then continue on through Oklahoma to a delivery point near existing terminals in Nederland, Texas to serve the Port Arthur, Texas marketplace.

To view a map of the proposed pipeline route, please visit the project web page at www.transcanada.com/keystone

With more than 50 years' experience, TransCanada is a leader in the responsible development and reliable operation of North American energy infrastructure including natural gas and oil pipelines, power generation and gas storage facilities. TransCanada's network of wholly owned natural gas pipelines extends more than 60,000 kilometres (37,000 miles), tapping into virtually all major gas supply basins in North America. TransCanada is one of the continent's largest providers of gas storage and related services with approximately 380 billion cubic feet of storage capacity. A growing independent power producer, TransCanada owns, or has interests in, over 11,700 megawatts of power generation in Canada and the United States. TransCanada is developing one of North America's largest oil delivery systems. TransCanada's common shares trade on the Toronto and New York stock exchanges under the symbol TRP. For more information visit: www.transcanada.com

TransCanada Forward-Looking Information

This news release may contain certain information that is forward looking and is subject to important risks and uncertainties. The words "anticipate", "expect", "believe", "may", "should", "estimate", "project", "outlook", "forecast" or other similar words are used to identify such forward-looking information. Forward-looking statements in this document are intended to provide TransCanada securityholders and potential investors with information regarding TransCanada and its subsidiaries, including management's assessment of TransCanada's and its subsidiaries' future financial and operations plans and outlook. Forward-looking statements in this document may include, among others, statements regarding the anticipated business prospects, projects and financial performance of TransCanada and its subsidiaries, expectations or projections about the future, and strategies and goals for growth and expansion. All forward-looking statements reflect TransCanada's beliefs and assumptions based on information available at the time the statements were made. Actual results or events may differ from those predicted in these forward-looking statements. Factors that could cause actual results or events to differ materially from current expectations include, among others, the ability of TransCanada to successfully implement its strategic initiatives and whether such strategic initiatives will yield the expected benefits, the operating performance of TransCanada's pipeline and energy assets, the availability and price of energy commodities, capacity payments, regulatory processes and decisions, changes in environmental and other laws and regulations, competitive factors in the pipeline and energy sectors, construction and completion of capital projects, labour, equipment and material costs, access to capital markets, interest and currency exchange rates, technological developments and economic conditions in North America. By its nature, forward looking information is subject to various risks and uncertainties, which could cause TransCanada's actual results and experience to differ materially from the anticipated results or expectations expressed. Additional information on these and other factors is available in the reports filed by TransCanada with Canadian securities regulators and with the U.S. Securities and Exchange Commission (SEC). Readers are cautioned to not place undue reliance on this forward looking information, which is given as of the date it is expressed in this news release or otherwise, and to not use future-oriented information or financial outlooks for anything other than their intended purpose. TransCanada undertakes no obligation to update publicly or revise any forward looking information, whether as a result of new information, future events or otherwise, except as required by law.

Media Enquiries:	Cecily Dobson/Terry Cunha	403.920.7859 800.608.7859
Investor & Analyst Enquiries:	David Moneta/ Terry Hook	403.920.7911 800.361.6522

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 DIRECT 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 direct testimony of Heidi Tillquist.

1. Please state your name and address for the record.

Answer: My name is Heidi Tillquist. My business address is Stantec Consulting Services Inc., 2950 E. Harmony Road, Suite 290, Fort Collins, CO 80528.

2. Please state your position and provide a description of your areas of responsibility with respect to the Keystone XL Project.

Answer: I am a contractor of Keystone. I am employed as an environmental toxicologist and Director of Oil & Gas Risk Management with Stantec Consulting Services Inc. I have provided environmental consulting services to Keystone with respect to the Keystone XL Project. I am responsible for evaluating risk posed by the Project to human and environmental resources.

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3. Please state your professional qualifications and experience with pipeline operations.

Answer: My professional background is stated in my resume, a copy of which is attached as Exhibit A. My education consists of a bachelor's degree in fishery and wildlife biology, and a master's degree in environmental toxicology. In general, I have over 25 years of experience in environmental consulting, including environmental toxicology and conducting environmental risk assessments and water quality assessment and analysis. I have previously testified before the Commission in the permit proceedings concerning the Keystone Pipeline in Docket HP 07-001 and concerning the Keystone XL Pipeline in Docket HP 09-001.

4. Are you responsible for portions of the Tracking Table of Changes attached as Appendix C to Keystone's certification petition?

Answer: Not directly. In general, I can testify to the risk assessments related to the Keystone XL Pipeline, including spill frequency. I am familiar with the design changes addressed in the Tracking Table as a result of Keystone's decision to withdraw its Special Permit application with PHMSA, as well as the minor route variations in South Dakota. The design and route changes have not affected the overall conclusion of the spill frequency analysis to which I testified in connection with the permit application. With respect to Finding No. 50, the minor route changes have caused slight changes resulting in a reduced probability of a spill occurring within High Consequence Areas. As a result, the statement that a spill that could affect an HCA would occur no more than once in 250 years would now be altered to no more than once in 460 years, based on 15.8 miles of HCAs crossed in South Dakota. The 2009 Keystone XL Risk

Assessment, which is Appendix P to the Final Supplemental Environmental Impact Statement, and its conclusions remain valid. .

5. Are you able to address issues related to worst case spill scenarios, environmental cleanup in the event of a spill, and the potential impacts to groundwater resources?

Answer. Yes. I participated in answering discovery in this proceeding with respect to all of these issues. While nothing with respect to these issues has changed since the Amended Final Decision and Order, I can answer questions at the hearing related to these issues.

6. Are you aware of any reason that Keystone cannot continue to meet the conditions on which the Permit was granted by the Commission?

Answer: No. I have reviewed the conditions contained in the Amended Final Decision and Order. With respect to risk assessment and environmental toxicology, the changes discussed in the Tracking Table do not affect Keystone's ability to meet the conditions on which the Permit was granted.

7. Does this conclude your prepared direct testimony?

Answer: Yes.

Dated this 31 day of March, 2015.

Heidi Tillquist

CERTIFICATE OF SERVICE

I hereby certify that on the 2nd day of April, 2015, I sent by United States first-class mail, postage prepaid, or e-mail transmission, a true and correct copy of the foregoing Direct Testimony of Heidi Tillquist, to the following:

Patricia Van Gerpen
Executive Director
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
patty.vangerpen@state.sd.us

Kristen Edwards
Staff Attorney
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
kristen.edwards@state.sd.us

Brian Rounds
Staff Analyst
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
brian.rounds@state.sd.us

Darren Kearney
Staff Analyst South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
darren.kearney@state.sd.us

Tony Rogers, Director
Rosebud Sioux Tribe - Tribal Utility Commission
153 South Main Street
Mission, SD 57555
tuc@rosebudsiouxtribe-nsn.gov

Cindy Myers, R.N.
PO Box 104
Stuart, NE 68780
csmyers77@hotmail.com

Jane Kleeb
1010 North Denver Avenue
Hastings, NE 68901
jane@boldnebraska.org

Byron T. Steskal
Diana L. Steskal
707 E. 2nd Street
Stuart, NE 68780
prairierose@nntc.net

Terry Frisch
Cheryl Frisch
47591 875th Road
Atkinson, NE 68713
tcfrisch@q.com

Arthur R. Tanderup
52343 857th Road
Neligh, NE 68756
atanderu@gmail.com

Lewis GrassRope
PO Box 61
Lower Brule, SD 57548
wisestar8@msn.com

Carolyn P. Smith
305 N. 3rd Street
Plainview, NE 68769
peachie_1234@yahoo.com

Robert G. Allpress
46165 Badger Road
Naper, NE 68755
bobandnan2008@hotmail.com

Amy Schaffer
PO Box 114
Louisville, NE 68037
amyannschaffer@gmail.com

Benjamin D. Gotschall
6505 W. Davey Road
Raymond, NE 68428
ben@boldnebraska.org

Elizabeth Lone Eagle
PO Box 160
Howes, SD 57748
bethcbest@gmail.com

John H. Harter
28125 307th Avenue
Winner, SD 57580
johnharter11@yahoo.com

Peter Capossela
Peter Capossela, P.C.
Representing Standing Rock Sioux Tribe
PO Box 10643
Eugene, OR 97440
pcapossela@nu-world.com

Jerry P. Jones
22584 US Hwy 14
Midland, SD 57552

Jeff Jensen
14376 Laflin Road
Newell, SD 57760
jensen@sdplains.com

Louis T. (Tom) Genung
902 E. 7th Street
Hastings, NE 68901
tg64152@windstream.net

Nancy Hilding
6300 West Elm
Black Hawk, SD 57718
nhilshat@rapidnet.com

Paul F. Seamans
27893 249th Street
Draper, SD 57531
jacknife@goldenwest.net

Viola Waln
PO Box 937
Rosebud, SD 57570
walnranch@goldenwest.net

Wrexie Lainson Bardaglio
9748 Arden Road
Trumansburg, NY 14886
wrexie.bardaglio@gmail.com

Harold C. Frazier
Chairman, Cheyenne River Sioux Tribe
PO Box 590
Eagle Butte, SD 57625
haroldcfrazier@yahoo.com
mailto:kevinckeckler@yahoo.com

Cody Jones
21648 US Hwy 14/63
Midland, SD 57552

Debbie J. Trapp
24952 US Hwy 14
Midland, SD 57552
mtdt@goldenwest.net

Gena M. Parkhurst
2825 Minnewsta Place
Rapid City, SD 57702
GMP66@hotmail.com

Joye Braun
PO Box 484
Eagle Butte, SD 57625
jmbraun57625@gmail.com

Duncan Meisel
350.org
20 Jay St., #1010
Brooklyn, NY 11201
duncan@350.org

The Yankton Sioux Tribe
Robert Flying Hawk, Chairman
PO Box 1153
Wagner, SD 57380
robertflyinghawk@gmail.com
Thomasina Real Bird
Attorney for Yankton Sioux Tribe
trealbird@ndnlaw.com

Bruce Ellison
Attorney for Dakota Rural Action
518 6th Street #6
Rapid City, SD 57701
belli4law@aol.com

Chastity Jewett
1321 Woodridge Drive
Rapid City, SD 57701
chasjewett@gmail.com

RoxAnn Boettcher
Boettcher Organics
86061 Edgewater Avenue
Bassett, NE 68714
boettcherann@abbnebraska.com

Bruce Boettcher
Boettcher Organics
86061 Edgewater Avenue
Bassett, NE 68714
boettcherann@abbnebraska.com

Bonny Kilmurry
47798 888 Road
Atkinson, NE 68713
bjkilmurry@gmail.com

Ronald Fees
17401 Fox Ridge Road
Opal, SD 57758

Robert P. Gough, Secretary
Intertribal Council on Utility Policy
PO Box 25
Rosebud, SD 57570
bobgough@intertribalCOUP.org

Tom BK Goldtooth
Indigenous Environmental Network (IEN)
PO Box 485
Bemidji, MN 56619
ien@igc.org

Dallas Goldtooth
38731 Res Hwy 1
Morton, MN 56270
goldtoothdallas@gmail.com

Gary F. Dorr
27853 292nd
Winner, SD 57580
gfdorr@gmail.com

Cyril Scott, President
Rosebud Sioux Tribe
PO Box 430
Rosebud, SD 57570
cscott@gwtc.net
ejantoine@hotmail.com

Paula Antoine
Sicangu Oyate Land Office Coordinator
Rosebud Sioux Tribe
PO Box 658
Rosebud, SD 57570
wopila@gwtc.net
paula.antoine@rosebudsiouxtribe-nsn.gov

Thomasina Real Bird
Representing Yankton Sioux Tribe
Fredericks Peebles & Morgan LLP
1900 Plaza Dr.
Louisville, CO 80027
trealbird@ndnlaw.com

Sabrina King
Dakota Rural Action
518 Sixth Street, #6
Rapid City, SD 57701
sabinra@dakotarural.org

Frank James
Dakota Rural Action
PO Box 549
Brookings, SD 57006
fejames@dakotarural.org

Robin S. Martinez
Dakota Rural Action
Martinez Madrigal & Machicao, LLC
616 West 26th Street
Kansas City, MO 64108
robin.martinez@martinezlaw.net

Tracey A. Zephier
Attorney for Cheyenne River Sioux Tribe
Fredericks Peebles & Morgan LLP
910 5th Street, Suite 104
Rapid City, SD 57701
tzephier@ndnlaw.com

Paul C. Blackburn
4145 20th Avenue South
Minneapolis, MN 55407
paul@paulblackburn.net

Matthew Rappold
Rappold Law Office
on behalf of Rosebud Sioux Tribe
PO Box 873
Rapid City, SD 57709
matt.rappold01@gmail.com

April D. McCart
Representing Dakota Rural Action
Certified Paralegal
Martinez Madrigal & Machicao, LLC
616 W. 26th Street
Kansas City, MO 64108
april.mccart@martinezlaw.net

Kimberly E. Craven
3560 Catalpa Way
Boulder, CO 80304
kimecraven@gmail.com

Joy Lashley
Administrative Assistant
SD Public Utilities Commission
joy.lashley@state.sd.us

Mary Turgeon Wynne
Rosebud Sioux Tribe - Tribal Utility Commission
153 S. Main Street
Mission, SD 57555
tuc@rosebudsiouxtribe-nsn.gov

Eric Antoine
Rosebud Sioux Tribe
PO Box 430
Rosebud, SD 57570
ejantoine@hotmail.com

WOODS, FULLER, SHULTZ & SMITH P.C.

By /s/ James E. Moore
William Taylor
James E. Moore
PO Box 5027
300 South Phillips Avenue, Suite 300
Sioux Falls, SD 57117-5027
Phone (605) 336-3890
Fax (605) 339-3357
Email James.Moore@woodsfuller.com
Attorneys for Applicant TransCanada

Heidi Tillquist

Stantec

Environmental Toxicologist/Senior Program Manager

Ms. Tillquist has over 24 years of experience in environmental consulting, including environmental permitting, environmental toxicology, environmental risk assessment, water quality assessment and analysis, fisheries and wildlife biology. She has evaluated risk and environmental consequences of contaminant releases in 28 states of the U.S. and 6 Canadian provinces. Ms. Tillquist routinely provides technical assistance in support of complicated environmental issues. She has successfully negotiated changes in surface water quality criteria for mining companies and has helped develop water quality criteria for several metals. She has managed numerous projects, such as environmental permitting and compliance for TransCanada's Keystone Pipeline Project and multiple third-party Environmental Impact Statements (EISs). Ms. Tillquist's work requires an in-depth understanding both the engineering and environmental aspects of pipeline projects. Ms. Tillquist breadth of knowledge and ability to effectively communicate between diverse stakeholders (project engineers, environmental staff, regulatory agencies) has resulted in collaborative efforts that focus on potential benefits, constraints and feasibility issues, and short- and long-term costs. Ms. Tillquist believes that development and environmental protection are not mutually exclusive, but are hallmarks of a well-designed and executed project. She has conducted multiple risk assessments for regulatory agencies and mining and the oil and gas industry and provides technical expertise regarding potential environmental impacts. Ms. Tillquist routinely provides expert witness support for issues related to environmental toxicology and risk assessment.

EDUCATION

MS, Environmental Toxicology, Colorado State University, Fort Collins, Colorado, 1992

BS, Fishery and Wildlife Biology, Colorado State University, Fort Collins, Colorado, 1987

REGISTRATIONS

Certified Wildlife Biologist #114667, The Wildlife Society

Certified Fisheries Professional #044814, American Fisheries Society

MEMBERSHIPS

Member, The Wildlife Society

Member, American Fisheries Society

Member, Society for Environmental Toxicology and Chemistry

PROJECT EXPERIENCE

Pipeline Projects

TransCanada, Energy East and Related Pipeline Projects, Alberta, Saskatchewan, Manitoba, Ontario, Quebec, and New Brunswick, Canada

Senior technical advisor, pipeline risk assessment lead. TransCanada proposes to repurpose an existing natural gas pipeline, construct new build pipeline and terminal facilities to transport various crude oils from Alberta to terminals in Quebec and New Brunswick. Ms. Tillquist and her staff evaluate risk for project components as part of the National Energy Board (NEB) filing. For each project, Stantec will i) identify high consequence areas, ii) assist engineers with valve siting, and iii) conduct a pipeline risk assessment that assesses failure frequency, probable spill volumes, and spill impacts to terrestrial, freshwater, and marine environments. After the final route is approved, Ms. Tillquist and her staff will conduct detailed flow path modeling to identify pipeline segments with the potential to impact High Consequence Areas per 49 CFR 195. Ms. Tillquist role on this project is to advise TransCanada, addressing and resolving substantive issues, helping to maintain consistency of analysis, and providing TransCanada with legacy information to facilitate and improve the overall project.

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Heidi Tillquist

Environmental Toxicologist/Senior Program Manager

Grand Rapids, Heartland, and Northern Courier Pipeline Projects, Alberta, Canada

Senior technical advisor, pipeline risk assessment lead. TransCanada and its affiliates propose to develop multiple pipeline projects in Alberta. For each project, Stantec will i) identify high consequence areas, ii) assist engineers with valve siting, iii) conduct a pipeline risk assessment that assesses failure frequency, probable spill volumes, range of environmental impacts, and mitigation, and iv) map groundwater vulnerability along the ROW. Ms. Tillquist role on this project is to advise TransCanada, addressing and resolving substantive issues, helping to maintain consistency of analysis, and providing TransCanada with legacy information to facilitate and improve the overall project.

TransCanada, Keystone XL Pipeline Project*, Montana, South Dakota, Nebraska, Oklahoma, Texas

Senior Technical Advisor and Lead Pipeline Risk Assessor for the project, attending numerous public meetings and providing expert witness testimony for public utility commissions in South Dakota as well as a variety of condemnation hearings. TransCanada proposed the construction and operation of a 36- inch crude oil pipeline from the Alberta oil sands into the U.S., terminating in the Gulf Coast region in Texas. The pipeline would have a nominal maximum throughput of 830,000 barrels per day. Within the U.S., the pipeline would cross portions of Montana, South Dakota, Nebraska, Oklahoma, and Texas. Because the project crosses the U.S.-Canada border, the Department of State is the lead federal agency. Ms. Tillquist was involved with TransCanada's Keystone XL crude oil pipeline since its initial design phase. Ms. Tillquist conducted an environmental risk assessment estimated spill frequency and spill volumes and the subsequent environmental consequences, particularly to sensitive areas. The risk analysis was used to support Keystone's Presidential Permit Application, various state permitting processes, and for refinement of the project design. As a result of this early interaction, Ms. Tillquist's risk assessment work helped control construction costs while reducing potential impacts of a spill, thereby reducing potential future environmental damages. Ms. Tillquist prepared the South Dakota Public Utilities Commission Application and participated in public meetings and hearings. She provided expert witness testimony in support of environmental and spill risk issues.

Hess Corporation, Hawkeye Pipelines, North Dakota

Senior technical advisor, PHMSA compliance lead, pipeline risk assessment lead. Hess proposes to construct several co-located pipelines to transport crude oil, natural gas liquids, and natural gas from the Bakken Formation. Stantec is leading the environmental permitting process. Ms. Tillquist role on this project is to advise, address, and resolve substantive issues, such as perceived risk associated with crossing of the Missouri River, tribal concerns, and PHMSA compliance.

Bureau of Land Management (BLM), BakkenLink Pipeline, North Dakota

PHMSA Compliance Lead/ Lead Risk Assessor. BakkenLink proposed to construct and operate a 12-inch crude oil pipeline from Frybery to Beaverlodge, North Dakota, with a 8-inch lateral to Belfield. Ms. Tillquist prepared a risk assessment that evaluated failure frequency and environmental consequences of a release, particularly to High Consequence Areas. The risk assessment was successfully used in the Environmental Assessment for the federal NEPA process. Ms. Tillquist also prepared BakkenLink's Emergency Response Plan which was reviewed and approved by PHMSA. Ms. Tillquist will provide technical support for BakkenLink with their Emergency Response Training exercises.

TransCanada, Keystone Pipeline System, US and Canada

Lead Pipeline Risk Assessor, PHMSA Compliance. Ms. Tillquist prepared hazard assessments for both new build and existing pipeline segments associated with the Keystone Pipeline System in the US and Canada. In Canada, Ms. Tillquist created a procedure to identify highly sensitive receptors, based on economic, public health, and ecological concerns. Using fate and transport analyses, segments of pipeline that were capable of potentially affecting the highly sensitive areas (Canada) or PHMSA-defined High Consequence Areas (US) were identified, risk quantified, and pipeline segments prioritized to facilitate operations and maintenance activities. The analysis incorporated both new build and existing infrastructure. Ms. Tillquist assisted TransCanada with PHMSA audits and provided technical responses to information requests. Ms. Tillquist documented legacy information regarding environmental compliance requirements. Ms. Tillquist coordinated with emergency response team. Provided updated to hazard assessments as required by federal regulations. Ms. Tillquist's work on this project continues with Stantec as the project continues to evolve.

* denotes projects completed with other firms

Heidi Tillquist

Environmental Toxicologist/Senior Program Manager

TransCanada, Keystone Crude Oil Pipeline Project*, North Dakota, South Dakota, Nebraska, Kansas, Missouri, Illinois, Canada

Environmental Permitting Project Manager and Pipeline Risk Assessor. As the Environmental Project Manager for the project, Ms. Tillquist was responsible for all environmental permitting and surveying within the U.S., including pre-construction siting and post-construction monitoring and compliance. Ms. Tillquist worked with TransCanada's Keystone crude oil pipeline since its initial design phase. As a result of this early interaction, route selection and intelligent valve placement helped control construction costs while reducing potential impacts of a spill, thereby reducing potential future environmental damages. Further, TransCanada successfully used Ms. Tillquist's environmental risk assessment to justify modification of the pipeline's design factor from 0.72 to 0.8 for the majority of the route. This modification reduced capital costs associated with the pipe by $50 million.

Texas Offshore Port System (TOPS)*, Texas

Lead Pipeline Risk Assessor, Senior Technical Advisor. The Texas Offshore Port System (TOPS) Project consisted of the construction and operation of a proposed deepwater port, receiving up to 1,700,000 barrels of crude oil per day and transporting the oil to a receiving terminal and transmission facility via 50 miles of on- and off-shore pipelines. Ms. Tillquist prepared a risk assessment document to support TOPS in permitting the project through the Maritime Administration and US Coast Guard. The document evaluated risk of a pipeline disruption and its potential environmental consequences. The report presented the results of a pipeline incident frequency and spill volume analysis based on TOPS' design and operations criteria and applies the resulting risk probabilities to an environmental consequence analysis, incorporating project-specific environmental data. Specifically, the report evaluated the risk of crude oil spills during pipeline operations, including contribution of natural hazards to spill risk, and the subsequent potential effects on humans and other sensitive resources, particularly High Consequence Areas, that include highly and other populated areas, municipal drinking water intakes (surface and groundwater), and/or ecologically sensitive areas.

Enterprise Products Company, Seaway Pipeline – Segment 7, Texas

Lead Pipeline Risk Assessor. The Seaway Pipeline - Segment 7 is a crude oil pipeline that will loop an existing- 30-inch pipeline for approximately 60 miles in length from Mont Belvieu to Nederland, Texas. Ms. Tillquist was hired as a subcontractor by Project Consulting Services, Inc. (PCS) to identify valve sites to ensure regulatory compliance and to minimize potential impacts to the environment, particularly to High Consequence Areas.

Enterprise Products Company, ATEX Express Pipeline*, Ohio, Indiana, Texas

Lead Pipeline Risk Assessor, Project Manager. The ATEX Express Pipeline (ATEX) is designed to transport ethane from the Marcellus and Utica shale regions in Pennsylvania, West Virginia and Ohio to the U.S. Gulf Coast. The approximately 1,230-mile, 16-inch diameter pipeline will have an initial capacity of 125,000 barrels per day of ethane and will deliver ethane to Enterprise's natural gas liquids storage complex at Mont Belvieu, Texas. Ms. Tillquist was hired as a subcontractor by Project Consulting Services, Inc. (PCS) to identify valve sites and perform a precursory HCA analysis for the purposes of selecting valve locations along Segment 3, approximately 117 miles in length through southwestern Ohio and southeastern Indiana, and Segment 6, approximately 55 miles in length through southeastern Texas.

Enterprise Products Company, Lone Star West Texas Pipeline and Laterals, Texas

Lead Pipeline Risk Assessor, Senior Technical Review. The Lone Star West Texas Pipeline and Laterals project will deliver natural gas liquids across Texas. As a subconsultant to Project Consulting Services, Inc., Ms. Tillquist was responsible for evaluating the placement of valve sites in relation to 1) federal pipeline regulations and 2) protection of environmental resources. Ms. Tillquist also provided senior technical review of a preliminary risk report.

* denotes projects completed with other firms

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Heidi Tillquist

Environmental Toxicologist/Senior Program Manager

FERC and BLM, Entrega Natural Gas Pipeline Environmental Impact Statement*, Colorado and Wyoming

Project Manager and Lead Pipeline Risk Assessor. Entrega Gas Pipeline Inc. (an affiliate of Encana Natural Gas) proposed to construct and operate a 328-mile 36- to 42-inch-diameter natural gas transmission pipeline. The pipeline transports up to 1.5 billion cubic feet per day of natural gas from the Piceance Basin in Colorado to interconnections in Wamsutter and near Cheyenne, Wyoming. As the Project Manager, Ms. Tillquist supervised the preparation of the EIS as a third-party contractor to the FERC (lead agency) and the BLM (cooperating agency). Major issues include potential impacts to threatened and endangered species (water depletion issues), noxious weed management, and socioeconomic impacts. Because Western Interstate Company (a subsidiary of El Paso Corporation) also proposed to build a large diameter pipeline from the Piceance Basin to Wamsutter, cumulative impacts were also an issue. The project was approved and construction completed in 2007.

BLM and USFS, ONEOK, Overland Pass Natural Gas Liquids Pipeline*, Wyoming, Colorado, and Kansas

Project Manager, Lead Pipeline Risk Assessor. ONEOK and Williams proposed to construct and operate a 760-mile transmission pipeline for transportation of up to 150,000 barrels per day of natural gas liquids from western Wyoming, through Colorado, to Conway, Kansas. As the Project Manager, Ms. Tillquist supervised the preparation of the EIS as a third-party contractor to the BLM (lead agency) and the U.S. Forest Service (cooperating agency). Major issues included potential impacts to cultural resources, threatened and endangered species, and fisheries impacts. The Final EIS was published in 2007, with the pipeline constructed and is currently in-service.

FERC, Piceance Basin Expansion Natural Gas Pipeline Environmental Impact Statement*, Wyoming and Colorado

Senior Technical Advisor. Wyoming Interstate Company (WIC, a subsidiary of El Paso Corporation) proposed to construct and operate a 141.7-mile 36-inch-diameter natural gas pipeline to transport up to 350 million cubic feet per day of natural gas from the Piceance Basin in Colorado to interconnections near Wamsutter, Wyoming. As The Senior Technical Advisor, Ms. Tillquist supervised staff in the preparation of the EIS (concurrent with the Entrega Pipeline EIS) as a third-party contractor to the Federal Energy Regulatory Commission, with the Bureau of Land Management as a cooperating agency. Major issues include potential impacts to threatened and endangered species (water depletion issues), noxious weed management, and socioeconomic impacts. Because Entrega Pipeline Company Inc. also proposed to build a large diameter pipeline from the Piceance Basin to Wamsutter, cumulative impacts also were an issue.

BLM, Inland Resources, Castle Peak and Eightmile Flat Oil Expansion Project*, Utah

Lead Pipeline Risk Assessor. Ms. Tillquist conducted a pipeline risk assessment, evaluating pipeline failure threats, mitigation, failure frequencies, and probable environmental impacts in the event of a failure. The BLM's Vernal Field Office commissioned the preparation of the EIS that examined potential impacts associated with a proposed expansion of oil field development operations in the Uintah Basin area of northeastern Utah. The study area covered approximately 110 sections or 65,500 acres. Inland proposed to expand its existing waterflood oil recovery operations by drilling up to 900 additional wells in the Castle Peak and Eightmile Flat areas of the greater Monument Butte-Myton Bench oil and gas production region. Important issues associated with this project included cumulative effects to raptor species in the Uintah Basin, air quality, and effects on sensitive species, such as the mountain plover and hookless cactus. A Biological Assessment for the U.S. Fish and Wildlife Service was prepared as part of the project permitting.

* *denotes projects completed with other firms*

Heidi Tillquist

Environmental Toxicologist/Senior Program Manager

BLM, Equilon/Shell Pipeline Company, New Mexico Products Pipeline Environmental Impact Statement*, New Mexico and Texas

Project manager, pipeline risk assessor. Shell proposed to convert and reverse the flow of an existing 406-mile crude oil pipeline to transport refined petroleum products (i.e., gasoline, diesel, jet fuel). System conversion also entailed the construction of two new pipeline extensions (about 100 miles total), pump stations, pressure reducing stations, miscellaneous facilities, and associated electrical transmission lines. The project would affect portions of New Mexico and Texas, involving many local, state, federal, and tribal jurisdictions. Due to public concern, a probabilistic risk assessment evaluated risk to humans and the environment that could result from an accidental release from the pipeline and its facilities. As a third-party contractor for the BLM, the Draft EIS in May 2003 and the Final EIS was completed in September 2003. Prior to the release of the Final EIS, Shell decided to put the project on hold.

FERC, Raton Basin 2005 Expansion*, Colorado, Kansas, New Mexico, Oklahoma

Technical support on pipeline risk issues and field surveys. For this 100-mile, six-loop project built in 2005, Ms. Tillquist supported Colorado Interstate Gas with the Federal Energy Regulatory Commission (FERC) NEPA Pre-filing Process (including agency and public scoping), preparation of the FERC certification application, state and federal environmental permitting, Environmental Assessment (EA) preparation, Biological Assessment/ Biological Evaluation preparation, and construction management. Ms. Tillquist also assisted with U.S. Fish and Wildlife Service Section 7 consultation, a Forest Service EA for crossing the Comanche National Grasslands, environmental compliance training, avian and mammal pre-construction clearing and biological monitoring during construction, and construction environmental inspection support.

FERC, Application for Line 2000 Converting a Crude Oil Pipeline to Natural Gas Pipeline, Texas, New Mexico, Arizona

Technical evaluation of pipeline reliability and public safety. Ms. Tillquist assisted with the preparation of El Paso Energy's Line 2000 application to the Federal Energy Regulatory Commission (FERC) for the conversion of an existing 800-mile crude oil pipeline to natural gas service. This conversion project affected lands within Texas, New Mexico, and Arizona. Ms. Tillquist's duties included the preparation of FERC resource reports, an applicant-prepared biological assessment, applicant-prepared environmental assessment, and Clean Water Act 404 permit. Ms. Tillquist's project management activities included project budgeting, coordinating office staff and field survey crews, and creation and maintenance of a database detailing over 300 construction sites and activities.

FERC and CSLC, Southern Trails Natural Gas Pipeline*, California, Arizona, Utah, and New Mexico

Project Manager. Responsible for personnel management and project budgeting in addition to technical writing responsibilities. Questar Natural Gas proposed to convert a 600-mile crude oil pipeline to a natural gas pipeline, referred to as the Southern Trails Pipeline. Construction resulting from the proposed extensions, reroutes, realignments, and replacements affected portions of California, Arizona, Utah, and New Mexico and involved many local, state, federal, and tribal jurisdictions. As Project Manager, Ms. Tillquist supervised staff in the preparation of this third-party Environmental Impact Statement/Environmental Impact Report (EIS/EIR) for the Federal Energy Regulatory Commission. As project coordinator, wrote several technical sections, and provided technical review of the EIS document. For the California Environmental Quality Act, a separate Environmental Impact and Mitigation Measures Summary was developed for the California State Lands Commission.

** denotes projects completed with other firms*

Heidi Tillquist

Environmental Toxicologist/Senior Program Manager

El Paso - Western Interstate Company, Kanda Natural Gas Lateral Pipeline Project*, Utah

Environmental Toxicologist and Lead Pipeline Risk Assessor. One of the most significant services that Ms. Tillquist provides is effective communication between oil and gas companies and federal regulating agencies. Ms. Tillquist has repeatedly demonstrated the ability to successfully work through difficult problems. On the Kanda Project, the U.S. Fish and Wildlife Service (USFWS) insisted that El Paso install emergency shutoff valves at the Green River to protect threatened and endangered fish species. The USFWS concerns revolved around the perceived toxicological threats from natural gas and the potential future conversion to hazardous liquids transportation. Ms. Tillquist prepared a white paper that detailed why the USFWS concerns were unjustified. The argument was successful: the USFWS withdrew its request for a valve at the site, thereby saving El Paso an estimated $250,000.

BLM, Natural Gas Liquid Pipeline Environmental Assessment*, Wyoming

Lead Pipeline Risk Assessor. Inland Resources plans to develop an area for natural gas liquids extraction. As part of the development, a new pipeline would be constructed which would cross a tributary to the Green River in Utah, which contains several endangered fish species. At the request of the BLM and potential hazard posed by the pipeline by evaluating the likelihood of a spill, attenuation rates, and dilution potential.

Additionally, cumulative risk from other natural gas liquid pipelines within the same drainage was also estimated. Based on the pipelines' location, volume of natural gas liquids, probability of failure, and likelihood of downstream transport, the assessment showed that no impacts to endangered fish species would be anticipated.

Spill & Resource Damage Evaluations

Emergency Spill Response, Confidential O&G Client, North Dakota

Deputy Incident Command/Lead Environmental Risk Assessor. Ms. Tillquist was on-site to within 6 hours of notification, responding to a well blowout near Watford City, North Dakota. Ms. Tillquist coordinated the environmental sampling and documentation. Crude oil and produced water was dispersed over a 5-square mile area during a winter blizzard. Stantec's emergency response team established and Incident Command Center and coordinated containment and cleanup with the US Environmental Protection Agency and North Dakota Department of Health. The site is stabilized, with closure anticipated after spring runoff. Due to the subzero temperatures, quantitative sampling of snow samples was conducted to determine the area where total petroleum hydrocarbons might exceed North Dakota soils standards after spring runoff. Salinity was also examined as a contaminant of concern since the blowout may have contained produced water. Stantec continues to work with North Dakota Department of Health and US Environmental Protection Agency to monitor the site during spring runoff and obtain site closure.

American Petroleum Institute (API), Fate and Effects of Oil Spills in Freshwater Environments*

Environmental Toxicologist, Technical Writing and Review. Ms. Tillquist assisted in the preparation of an API report describing the fate and effects of oil spills in freshwater environments. This report summarizes and documents potential environmental effects from inland oil spills into fresh surface waters. It identifies, describes, and compares the behavior, fate, and ecological implications of crude oil and petroleum products in inland waters. The document provides basic information necessary for the formulation of spill response strategies that are tailored to the specific chemical, physical, and ecological constraints of a given spill situation. The report describes the relevant features of various inland spill habitat types, discusses the chemical characteristics of oils and the fate processes that are dependent thereon, summarizes reported ecological and toxicological effects results both generally and with specific reference to distinct organism groupings, and, finally, in the context of case histories from past spills, highlights some of the considerations, difficulties, and elements of success of presently available spill response techniques.

* *denotes projects completed with other firms*

Heidi Tillquist

Environmental Toxicologist/Senior Program Manager

Toxicity Profile for Crude Oil*, Nationwide

Ms. Tillquist authored a report that reviewed the toxicity of crude oil to terrestrial and aquatic ecosystems. The intended audience of this report was BP field personnel that might be involved with accidental releases of crude oil into the environment. The document provided a general characterization of crude oil, its environmental fate, and potential effects to various environments.

Exxon Valdez Oil Spill*, Prince William Sound, Alaska

Ms. Tillquist provided technical support for Natural Resource Damage Claims filed against Exxon following the Exxon Valdez spill. Data were compiled from thousands of environmental samples, ranging from water and sediment to oiled wildlife. Ms. Tillquist provided technical support for expert witness testimony in support of Exxon. Specifically, Ms. Tillquist was responsible for assembling, synthesizing, and summarizing relevant literature on oils spills and their impacts to aquatic ecosystems.

Burlington Northern Santa Fe Railroad, Train Derailment Emergency Response Team, Crow Creek*, Cheyenne, Wyoming

Ms. Tillquist was a team member in an emergency response program to evaluate potential human health and environmental contamination. She participated in an emergency response call to evaluate potential aquatic effects on a train derailment at Crow Creek, Wyoming. Ms. Tillquist was responsible for coordinating activities with state and federal wildlife agencies regarding potential impacts on federally endangered Preble's meadow jumping mouse as well as to the local plain stream fishery. In the field, she was responsible for the sampling design and field sampling. After the event, she summarized the incident events and presented findings in a report to Burlington Northern Santa Fe Railway.

Evaluation of the Transredes Petroleum Product Spill*, Bolivia (Technical Advisor)

Ms. Tillquist provided technical support following a pipeline rupture on the Rio Desaguardero. The spatial extent and environmental effects of hydrocarbon contamination were evaluated by chemical analysis of environmental media and laboratory toxicity tests. These data were then used in a risk assessment to evaluate the potential risk to aquatic biota, terrestrial herbivores (cattle, sheep, and endangered vicunas), and human receptors.

Exxon Valdez Oil Spill*, Prince William Sound, Alaska

Technical Support. Ms. Tillquist provided technical support for Natural Resource Damage Claims filed against Exxon following the Exxon Valdez spill. Thousands of environmental samples were collected, analyzed, and catalogued, ranging from water and sediment to oiled wildlife. Ms. Tillquist was responsible for assembling synthesizing, and summarizing relevant literature on oils spills and their impacts to aquatic ecosystems in support of expert witness testimony in support of Exxon.

Oil and Gas Projects

Washington Ranch Natural Gas Field Storage Project*, New Mexico

Technical support evaluating public safety issues, including preparation of Resource Reports for the Federal Energy Regulatory Commission (FREC) application. El Paso proposed to construct a small natural gas storage field in southeastern New Mexico. The project consisted of several horizontal wells, tie-in pipelines, and access roads. Ms. Tillquist prepared several environmental Resource Reports in support of El Paso's successful Federal Energy Regulatory Commission (FERC) application.

Boehm Natural Gas Storage Field Project*, Colorado

Ms. Tillquist provided technical support evaluating public safety issues, including preparation of Resource Reports for the Federal Energy Regulatory Commission (FERC) application. El Paso proposed to construct a small natural gas storage field in southeastern Colorado. The project consisted of horizontal wells, tie-in pipelines, and access roads. The project was successfully permitted.

Raton Basin Expansion Project and Washington Ranch Natural Gas Field Storage Project*, Colorado, Kansas, Oklahoma, and New Mexico

Technical Review of Public Safety. Ms. Tillquist evaluated public safety issues associated with several El Paso projects, including Raton Basin and Washington Ranch. El Paso proposed to loop its existing Raton Basin natural gas pipeline system in Colorado, Kansas, and Oklahoma. The project would consist of several pipeline loops, laterals, metering stations, and access roads. In New Mexico, El Paso proposed to construct a small natural gas storage field in southeastern New Mexico. The project consisted of several horizontal wells, tie-in pipelines, and access roads. Ms. Tillquist prepared environmental Resource Reports in support of El Paso's successful FERC application.

* *denotes projects completed with other firms*

Heidi Tillquist

Environmental Toxicologist/Senior Program Manager

Pipeline and Facility Decommissioning Evaluation*, New Jersey, Pennsylvania

Project Manager. Ms. Tillquist was responsible for evaluating the condition of the pipeline and facilities and providing cost estimates for decommissioning the facilities, including regulatory compliance. Reliant owns a 10-mile pipeline that has been used to transport fuel oil #6 (historically) and fuel oil #2 (currently). The company also owns a related facility with breakout tanks and aboveground piping. Reliant was considering temporarily (1 to 3 years) suspending the transport of oil through the pipeline and facility and, perhaps, totally abandoning these assets. Alternatively, Reliant wanted the evaluation to include the potential for reactivating the pipeline after a temporary suspension. Ms. Tillquist and other staff evaluated the federal, state, and local regulatory that govern the temporary suspension, reactivation, and abandonment processes. Additionally, Ms. Tillquist and staff identified technical issues that would be associated with each process. Finally, Ms. Tillquist and staff provided Reliant with a range of anticipated costs associated with each of these activities.

Ecological Risk Assessment

Ecological Risk Assessment of Depleted Uranium*, Sonoran Desert and Chesapeake Bay, Arizona, Maryland

Co-investigator, assessing the environmental fate and distribution of depleted uranium in the Sonoran Desert, Yuma, Arizona, and the Chesapeake Bay, Aberdeen, Maryland. Ms. Tillquist collected biota, vegetation, water, soils, and sediments in the field from contaminated and uncontaminated sites. She also conducted toxicity tests to evaluate the toxicity of depleted uranium on kangaroo rats and freshwater and marine aquatic organisms. Ms. Tillquist compared concentrations of depleted uranium collected in the field to concentrations that caused toxicity in laboratory organisms.

Effects of Two-Stroke Outboard Motor Exhaust on Aquatic Biota*, California, Nevada

Ms. Tillquist conducted a systematic survey of the published literature and prepared a monograph summarizing and documenting the ecological effects from two-stroke outboard engine exhaust into the aquatic environment was produced. The document identified the major constituents of outboard exhaust, described the environmental fate of these constituents, and the detailed the toxicological implications. The ecological significance of two-stroke outboard engines was found to be primarily dependent on the water quality characteristics of the waterbody, the intensity of boat use, and the amount of pollution from other anthropogenic sources.

U.S. Army Corps of Engineers, Alaska District, Fort Richardson Post-wide Human Health and Ecological Risk Assessment*, Alaska

Ms. Tillquist provided technical support for the ecological risk assessment and toxicological evaluations for the project. Four ecological risk assessments have been conducted for various areas within the Fort Richardson post. This particular post-wide ecological risk assessment reviewed all previous assessments, identified data and assessment gaps, and re-assessed risk on a post-wide scale. During this process, Ms. Tillquist developed chemical profiles for more than 80 compounds that had been detected at Fort Richardson. Ms. Tillquist calculated exposure of various ecological receptors and compared with toxicity reference values established in the chemical profiles to evaluate the likelihood of risk. The evaluation suggested that potential risk exists to wildlife receptors from bioaccumulating contaminants in aquatic ecosystems. Subsequent field surveys were conducted to confirm or refute this possibility. Data from these surveys indicated that the level of contamination was not significantly impacting aquatic ecosystems. To further reduce potential ecological risk at the site, cooling water was rerouted around sensitive areas, providing a simple and inexpensive mitigation to eliminate further exposure.

Ecological Risk Assessment of US Navy Facilities, South Weymouth, Department of Defense*, Boston, Massachusetts

Ms. Tillquist conducted ecological risk assessments for the Navy's South Weymouth facility. Ms. Tillquist and other staff evaluated the potential risk to aquatic, wetland, and terrestrial receptors using a weight-of-evidence approach that included screening against benchmarks values, critical body residues, toxicity tests, quantitative field surveys, and food web exposure models.

Ecological Risk Evaluation of Dioxin's Effects on Wildlife*, Guam

Ms. Tillquist evaluated the toxicity of dioxin to terrestrial and aquatic receptors. In support of an ecological risk assessment, provided technical assessment of dioxin hazards and potentially toxic threshold values.

* *denotes projects completed with other firms*

Heidi Tillquist

Environmental Toxicologist/Senior Program Manager

Upper Clark Fork River Ecological Assessment*, Upper Clark Fork River, Montana

Ms. Tillquist provided technical support for the ecological risk assessment and toxicological evaluations. Terrestrial and aquatic screening-level ecological risk assessments were conducted by Ms. Tillquist to evaluate the potential effects of heavy metals on the Clark Fork River ecosystem. In cooperation with the U.S. Environmental Protection Agency (USEPA) Region VIII, developed food web exposure models and provided extensive chemical profile documentation to justify the selection of aquatic and terrestrial toxicity reference values for arsenic, cadmium, copper, lead, and zinc. Estimated exposure and risk using computer models. Ms. Tillquist submitted multiple documents to the USEPA in support of the advancement of science in the risk assessment process as rebuttals to the State of Montana's legal position.

Evaluation of 210 Chemicals: Physical Chemistry, Acute Toxicity, and Human Health Protection*, Nationwide

Ms. Tillquist co-authored a book and accompanying CD-ROM that describes the toxicity, physical chemistry, emergency response procedures, material handling procedures, and regulatory compliance information of 210 chemicals. Information was compiled from various computerized databases.

Evaluation of Chronic Effects to Aquatic Biota from Organochlorine Exposure, Rocky Mountain Arsenal*, Colorado

Ms. Tillquist was awarded grant as co-principal investigator to evaluate the sublethal effects of organochlorine pesticide exposure on fish via food web exposure at the Rocky Mountain Arsenal. Specifically, the project evaluated toxic effects using bioenergetic models and used field data to validate the model.

Environmental Assessments

Bureau of Land Management, Over the River™ Art Project Environmental Impact Statement and Event Management Plan*, Colorado

Lead Public Safety Risk Assessor. Ms. Tillquist evaluated public safety risks associated with the project, including boating accidents, emergency access, and sufficiency of emergency personnel and equipment. The artists, Christo and the late Jeanne-Claude, propose to drape curtains across the Arkansas River as a temporary form of art. Since the project would occur on federal lands, Ms. Tillquist helped prepare a draft EIS as a third-party consultant to the BLM's Royal Gorge Field Office. The project will take three years to construct, display, and disassemble, affecting more than 3,500 acres of land. Public concerns ranged from impacts to bighorn sheep, aesthetics, socio-economic impacts, and public safety and emergency access along the narrow road that parallels the river through the Arkansas River canyon. Ms. Tillquist prepared a semi-quantitative risk assessment on how the project could potentially impact public safety. The four-volume draft EIS evaluated several alternatives that reduced the size or duration of the exhibit. The Draft EIS was published in July 2010, with the Final EIS and Record of Decision issued in February 2011.

Environmental Assessment of Chatfield Reservoir Drawdown*, Denver, Colorado

Ms. Tillquist provided technical direction and analyzed impacts associated with potential drawdown. Denver Water proposed to construct and operate a pump station to convey raw water from Chatfield Reservoir to the municipal water supply system during drought conditions. Construction of the pump station and drawdown of the reservoir required the approval of the U.S. Army Corps of Engineers. The Environmental Assessment evaluated the potential impacts from several drawdown and refill scenarios. While the drawdown would affect recreational opportunities, water quality, and fish and wildlife habitat at the reservoir, the No Action alternative (no pump station, but high evaporative losses) also would substantially impact these same resources.

** denotes projects completed with other firms*

Heidi Tillquist

Environmental Toxicologist/Senior Program Manager

Pima County Wastewater District, Applicability of U.S. EPA Water Quality Criteria in the Arid West*, Arizona and Other Western States

Project Manager. Ms. Tillquist evaluated the applicability of national water quality criteria (AWQC) for the arid West, particularly for effluent-dominated systems. The evaluation process included the evaluation of four AWQC, looking at duration and frequency of exceedances, sensitivity of local biota, and speed of aquatic system recovery. Various AWQC-modifying procedures, such as the Recalculation Procedure and the Biotic Ligand Model, were reviewed to determine their appropriateness and usefulness for site-specific modification of the AWQC. Results of this project were published in a special publication, "Relevance of Ambient Water Quality Criteria for Ephemeral and Effluent-Dependent Watercourses of the Arid Western U.S.," by the Society of Environmental Toxicology and Analytical Chemistry.

State of Wyoming, Evaluation of the Effects of Water Depletion on Endangered Species, Litigation Support, North Platte River*, Wyoming and Nebraska

Ms. Tillquist was responsible for evaluating correlations between water levels, fish populations, and whooping crane and plover populations. The effects of North Platte water depletions on endangered whooping crane and plovers were contested in Federal Court. Both these species use the North Platte drainage during their seasonal migrations as a foraging and resting area. Ms. Tillquist provided a technical evaluation of whooping crane population trends and its relationship to discharge at Grand Island, Nebraska. Results indicated that while discharge rates can directly affect habitat suitability for cranes and forage fish for plovers, these factors have not had any measurable effect of whooping crane populations.

Programmatic Environmental Impact Statement for Herbicide Application throughout the Western U.S.*

Lead Technical Advisor for toxicological evaluations of herbicides and their environmental fate and persistence in the environment. Ms. Tillquist assisted in the preparation of a Programmatic EIS for the BLM that evaluated the application of nine herbicides on BLM-administered lands throughout the West. Ms. Tillquist developed an ecological risk assessment to evaluate exposure pathways and potential effects to multiple receptors, ranging from non-target plant species to aquatic biota and terrestrial wildlife species. The nine herbicides included bromacil, chlorsulfuron, diflufenzopyr, diquat, diuron, fluridone, imazapic, sulfmeturon methyl, and tebuthiuron. To evaluate the toxicity of these nine herbicides, Ms. Tillquist review, synthesized, and summarized information from the Environmental Protection Agency registration data and the peer-reviewed literature to develop toxicity benchmarks (toxicity reference values). These benchmark values were subsequently used in the ecological risk assessment and programmatic EIS.

Mining

Bureau of Land Management, Cameco Resources In-Situ Uranium Mine Environmental Impact Statement*, Gas Hills, Wyoming (Lead Public Safety Risk Assessor)

Cameco proposes to develop the Gas Hills In-situ Recovery Uranium Mine Project. The project area covers approximately 8,500 surface acres (approximately 13 square miles) of federal, state and private lands. The Bureau of Land Management's Lander Field Office is the lead agency for the environmental analysis. The Project is permitted by the Wyoming Department of Environmental Quality and is licensed by the U.S. Nuclear Regulatory Commission. Unlike conventional mining practices, in-situ removal mining methods utilize a solution consisting of oxygen and carbon dioxide or bicarbonate injected via conventional water wells into uranium ore-bearing rock formations in the subsurface. The solution dissolves the uranium ore from the rock formations into the circulating groundwater. The resultant uranium-bearing groundwater is recovered by pumping wells located adjacent to the injection wells. The groundwater containing uranium is then processed through an ion-exchange facility where the uranium is precipitated onto a resin bead media. The resin beads containing uranium would then be transported to the Cameco Smith Ranch-Highland facility for processing into uranium yellowcake. After the uranium has been removed, the resin bead media would be returned to the Project site for re-use. The distance one-way from the Gas Hills to Smith Ranch-Highland is approximately 140 road miles.

** denotes projects completed with other firms*

Heidi Tillquist

Environmental Toxicologist/Senior Program Manager

Beartrack Mine, NPDES Issues and Biological Opinion*, Napias Creek, Idaho

Ms. Tillquist was the project manager for a study that evaluated the toxicity of heavy metals to trout. Because of extremely low water hardness (less than 10 mg/L of $CaCO_3$), the permitted discharge of metals, particularly copper, were extremely low for this mine. Ms. Tillquist developed a site-specific sampling plan to collect the necessary data for the development of a site-specific translator value for the mine's National Pollutant Discharge Elimination System permit. Samples were collected using ultra-clean sampling techniques and were analyzed to detect metal concentrations at very low concentrations. Results from these analyses were used to develop a translator value, allowing the mine to continue to discharge effluent.

Water Quality Evaluation*, Nevada

Ms. Tillquist was the environmental toxicologist and risk assessor evaluating the impacts of selenium and mercury from a mine. The U.S. Fish and Wildlife Service (USFWS) expressed concerns that elevated concentrations of contaminants derived from the Big Springs Mine, particularly mercury and selenium, have affected or have the potential to affect aquatic biota in the North Fork of the Humboldt River. The USFWS concern was enhanced by the presence of endangered Lahontan cutthroat trout and other species of concern. Critically evaluated the USFWS-proposed field sampling plan and questioned whether the data that would be collected could credibly discern any adverse effects attributable to the Big Springs Mine from normal environmental variability. As a result of the critique, the USFWS revised its field sampling plan and entered into consultation with Independence Mining Co. regarding alternative approaches.

Atlanta Gold, National Pollutant Discharge Elimination System Permit*, Atlanta, Idaho

Project Manager. Mining operations in Atlanta, Idaho, have occurred since the 1870s. As a result of these activities, mine drainage is currently being released at 25 different locations. The primary contaminant of concern is arsenic. Atlanta Gold needs to obtain a National Pollutant Discharge Elimination System (NPDES) permit for these existing discharges. To expedite the NPDES process, the Environmental Protection Agency (EPA) Region 10 agreed to third-party preparation of the NPDES application, EPA Fact Sheet, and the EPA permit.

Mining Company, Evaluation of Dietary Metals Toxicity to Rainbow Trout*, Western U.S.

Ms. Tillquist conducted literature research to compile and synthesize data related to dietary metal exposure to trout. In some mining areas, metals concentrations in benthic macroinvertebrates are elevated compared to reference sites. Some scientists have expressed concern that trout may be exposed to potentially toxic levels of metals via dietary exposure. Ms. Tillquist analyzed the published literature and established concentrations of metals in the diets that are considered to have no observable adverse effects as well as the lowest concentration demonstrated to have an adverse effect on survival or growth. This information was presented at the 1999 Society of Environmental Toxicology and Analytical Chemistry.

Identification of Potential Habitat for the Endangered Lahontan Cutthroat Trout*, Walker River and Carson River, Nevada, California

Ms. Tillquist identified drainages within the Walker and Carson River basins that contain potential habitat for future restoration work for off-site mitigation for Lahontan cutthroat trout habitat. As a result of the project, suitable habitat was identified for the mining client, who subsequently purchased the property with its associated water rights and successfully conducted off-site habitat mitigation.

Electrical Power Generation and Transmission

Bureau of Indian Affairs and Williams Company, Wanapa Energy Center Environmental Impact Statement*, Hermiston and Umatilla, Oregon

Ms. Tillquist evaluated water rights and researched water laws applicable to the project, particularly those related to threatened anadromous salmon species. As a third-party contractor for the Bureau of Indian Affairs, Ms. Tillquist evaluated the potential impacts associated with the construction and operation of the Wanapa Energy Center, a power generating plant. Ms. Tillquist evaluated issues associated with water rights and laws pertaining to water withdrawal, given the presumption by Diamond Generating (developer) that the water rights to be used were "reserved" municipal water rights and that these city water rights predated the in-stream flow requirements for the Columbia River. Also, the amount of water withdrawn and the method used to withdraw water were evaluated to determine if they could have potential impacts on federally listed Pacific salmon. Finally, water quality issues were evaluated to assess potential impacts of the effluent water used to cool the power generating equipment and to predict effects to the environment from the discharged water into the environment.

** denotes projects completed with other firms*

Heidi Tillquist

Environmental Toxicologist/Senior Program Manager

Tri-State Generation and Transmission Association, Environmental Assessment and Alternative Evaluation*, New Mexico

Provided technical support, evaluated data, and prepared the majority of the environmental assessment and alternatives evaluation. Tri-State applied for financial assistance from the Rural Utilities Services (RUS) in order to construct a simple-cycle combustion turbine generating facility near Lordsburg, New Mexico. As part of the RUS application process, Ms. Tillquist developed an Alternatives Evaluation which evaluated alternative sites for the power plant. A Site Selection Study also was produced; RUS used this Site Selection Study as its Environmental Assessment (with public scoping).

Power Plant Application for Certificate*, San Bernardino County, California

Wildlife Toxicologist evaluating risk to endangered biota from nitrogen deposition. The U.S. Fish and Wildlife Service expressed concerns about the potential negative effects of supplemental atmospheric nitrogen deposition on native plant communities originating from the new Mountainview Power Plant. Ms. Tillquist evaluated the likelihood of changes in the vegetative communities based on their location, growth periods, and estimated amount of nitrogen deposition. Sensitivity to nitrogen enrichment was assessed. The analysis indicated that the amount of additional atmospheric nitrogen deposition was not appreciable, particularly when compared to the sizeable background concentrations in the Los Angeles Air Basin.

Solar Energy

Stirling Energy Systems (SES), LLC, SES Solar Two Project*, Imperial County, California (Lead Biologist)

SES submitted an application to the Bureau of Land Management (BLM) for development of the proposed SES Solar Two Project, a concentrated solar electrical generating facility capable of generating 750 megawatts (MW) of renewable power. The proposed SES Solar Two Project site is located on approximately 6,140 acres of federal land managed by the BLM and approximately 300 acres of privately owned land, in Imperial County, California. The project would consist of approximately 30,000 SunCatchers, with a total generating capacity of 750 MW. The proposed SES Solar Two Project also includes an electrical transmission line, water supply pipeline, and a site access road. A new 230-kV substation would be constructed on-site, connected to the existing San Diego Gas & Electric Imperial Valley Substation via a 10.3-mile, double-circuit, 230-kV transmission line. Just over 7.5 miles of the new line would be constructed off-site. An off-site 6-inch diameter water supply pipeline would be constructed 3.4 miles from the Westside Main Canal to the project boundary. The BLM and CEC have executed a Memorandum of Understanding concerning their intent to conduct a joint environmental review of the project in a single NEPA/CEQA process. Ms. Tillquist provided review and technical input to the BLM's and CEC's environmental analysis. Ms. Tillquist revised CEC's document under an extremely tight timeline to make the document compliant with BLM minimum standards. Major concerns included biological impacts to desert bighorn sheep and desert tortoise.

** denotes projects completed with other firms*

Heidi Tillquist

Environmental Toxicologist/Senior Program Manager

Bureau of Land Management and California Energy Commission, Ivanpah Solar Energy Projects*, San Bernardino County, California

Biological Lead, handling wildlife and special status species issues. BrightSource Energy, Inc. proposed the development three separate solar thermal power plants within a 3,600-acre project site located in the desert in San Bernardino County, California. When constructed, the 392-megawatt project will be the world's largest solar energy project, nearly doubling the amount of solar thermal electricity currently produced in the U.S. It also will be the largest fully solar-powered steam turbine. Ms. Tillquist also helped prepare a Supplemental and Final EIS as a third-party contractor to the BLM. Ms. Tillquist also worked cooperatively with the California Energy Commission (CEC) to ensure the CEC siting committee issued a proposed decision consistent with the BLM's Record of Decision. BrightSource's proprietary Luz Power Tower (LPT) technology enables the company to employ a low-impact environmental design. Instead of the extensive land grading and concrete pads, BrightSource mounts mirrors (heliostats) on individual poles that are placed directly into the ground, allowing the solar field to be built around the natural contours of the land and avoid areas of sensitive vegetation. This design also allows for vegetation to co-exist within the solar field. The Final EIS was published in July 2010 with construction in fall 2010.

Inhalation Toxicology

National Institute of Health, Retention and Clearance of Radioactive Particles from Intermediate Airways in Beagle Dogs, Lovelace Inhalation Toxicology Research Institute*, New Mexico

Ms. Tillquist was a summer intern who received a grant to examine the movement and retention of small inhaled particles within the intermediate airways of lungs. In the lung, particulate matter tends to be trapped either in the upper airways or deep within the lung. Little was known about the ability of the intermediate airways to clear or retain particulate matter. Based on a grant from the National Institutes of Health, Ms. Tillquist developed a new technique for exposing intermediate airways (bronchioles). Clearance and retention rates of various-sized particulate within the lung were evaluated by using particles labeled with radioactive cesium and strontium. In addition to this basic research, was involved in the post-operative performance evaluation of lung transplants, a relatively new surgical procedure. Finally, Ms. Tillquist acted as a technician for measurement of radioactive materials in various tissues and other matrices for a variety of other projects.

National Toxicology Program, Acute $Ni^{63}SO_4$ Inhalation Exposures in Mice and Rats, Lovelace Inhalation Toxicology Research Institute*, New Mexico

Ms. Tillquist was the lead technician responsible to several National Toxicology Program studies. As part of the National Toxicology Program's evaluation of nickel compounds, conducted acute aerosol exposures of laboratory animals (over 100 animals) in order to evaluate the metabolism of nickel. Radioactive nickel was used to trace metabolic pathways. This work required Level B laboratory conditions (respirators, protective clothing, shower-in/shower-out procedures) as well as constant monitoring for radiological contamination.

National Toxicology Program, Chronic NiO, $NiSO_4$, and Ni_3S_2 Inhalation Exposures in Rats and Mice, Lovelace Inhalation Toxicology Research Insitute*, New Mexico

Ms. Tillquist was the lead technician responsible to several National Toxicology Program studies. The National Toxicological Program (NTP) routinely evaluates the toxicity of compounds in the environment. Nickel compounds are used in a number of manufacturing processes. Ms. Tillquist was responsible for the supervision, monitoring, and laboratory measurements associated with three large inhalation toxicology studies (>3,500 animals) for the NTP. Ms. Tillquist ensured that staff followed Good Laboratory Practices (GLP procedures), maintained Quality Assurance of the associated data and other project-related paperwork. This work involved Level B laboratory conditions (respirators, protective clothing, shower-in/shower-out procedures).

** denotes projects completed with other firms*

Heidi Tillquist

Environmental Toxicologist/Senior Program Manager

Water Quality Assessments

Climax Mine, Evaluation of the Effects of Aqueous Aluminum on Aquatic Biota of Tenmile Creek*, Climax, Colorado

Ms. Tillquist evaluated eight years of fish and macroinvertebrate community data to determine if any temporal or spatial trends related to water quality, specifically aluminum, were apparent. Whole-effluent toxicity (WET) test results for this same period were summarized and, again, were correlated to aluminum concentrations. Finally, a review on the toxicity of aluminum to aquatic biota was written to summarize the state-of-the-science knowledge of aluminum toxicity in aquatic systems, which has changed dramatically since the ambient water quality criteria were developed for aluminum. Results showed that although aluminum concentrations were above national ambient water quality criteria and local background levels, concentrations of aluminum were not having any demonstrable effect on aquatic biota. Rather, patterns of improvement were observed in the biological data since 1995, coinciding with the implementation of significant changes in the water treatment procedures at the Climax water treatment facility. Moreover, laboratory WET testing showed no acute or chronic toxicity when aluminum was above ambient water quality criteria.

Beartrack Mine, Review of Biological Opinion on Chinook and Steelhead: Critique and Re-evaluation, Tributary of the Snake River*, Idaho

Ms. Tillquist conducted a systematic evaluation of water quality in a Snake River tributary to determine if salmonids would be adversely affected by metal concentrations. The National Marine Fisheries Service (NMFS) originally concluded in a Biological Opinion that the continued operation of the mine jeopardized the successful reintroduction of Chinook salmon into this watershed. This conclusion was based on water quality data, which occasionally exceeded the national ambient water quality criteria. Ms. Tillquist re-evaluated the water quality data using a more extensive dataset and conducted a broad, weight-of-evidence evaluation that evaluated aquatic community health. Temporal and spatial trends in water quality and fish and benthic macroinvertebrate community structure were examined to determine if any adverse effects exist which are attributable to the operation of the mine. Specifically, this assessment evaluated the likelihood of adverse effects to federally listed salmonids. This assessment found there was no evidence of adverse impacts from the operation of the mine. Furthermore, there were statistically significant indications that the aquatic community health (measured as density and diversity) has recently improved, perhaps due to the mining company's restoration of historic placer mining areas in the watershed. As a result, the NMFS was forced to recant its original position and revised their Biological Opinion to indicate a no jeopardy finding.

Aquatic Toxicity Assessment of Leachate from the Cortez Landfill Superfund Site, Delaware Water Gap*, Pennsylvania/ Delaware

Ms. Tillquist investigated leachate from a Superfund site into a National Park area. In the 1970s, barrels containing unknown contamination were illegally dumped in a landfill in New Jersey. By the late 1980s, material from these barrels was leaching into surrounding properties and into the Delaware River and the landfill was designated as a Superfund site. Notably, there was an increased prevalence of illness in the surrounding areas. This portion of the Delaware River was part of the Delaware River Gap National Park, administrated by the National Park Service. Through a grant from the National Park Service, assessed the aquatic toxicity of leachate entering the Delaware River using Microtox® and several routine aquatic toxicity tests.

Water Quality Criteria Evaluation*, Nationwide (Technical Lead)

Ms. Tillquist is providing support on toxicological data and associated environmental impacts. National water quality criteria promulgated by the U.S. Environmental Protection Agency (USEPA) are applicable over a normal range of water hardness. However, the validity of extrapolating criteria to unusually hard or soft waters is unknown. Ms. Tillquist conducted a literature evaluation to determine whether application of the USEPA's criteria for metals is appropriate. Additionally, Ms. Tillquist conducted a series of aquatic toxicity tests with copper in both hard and soft waters. Neither the literature evaluation nor the toxicity tests supported the extrapolation of criteria beyond these hardness limits.

** denotes projects completed with other firms*

Heidi Tillquist

Environmental Toxicologist/Senior Program Manager

Wildlife Biology

Biomonitoring of the Cache la Poudre River*, Colorado

Ms. Tillquist provided technical support for a long-term (i.e., over 10 years) biomonitoring project, fish community structure program. The study area encompassed the Poudre River in northern Colorado with the intent to evaluate if changes in water quality attributable to Eastman Kodak have negatively impacted the Cache la Poudre River ecosystem. Habitat was evaluated using U.S. Environmental Protection Agency's Rapid Bioassessment Protocol, while the fish community was assessed using the Index of Biotic Integrity. Large scale, long-term trends in the fish community appeared to be primarily affected by human disturbance activities such as channelization. Ms. Tillquist conducted fieldwork and analyzed data as part of an Index of Biotic Integrity assessment. Fish collected by electrofishing and seining were identified, weighed, measured, and examined for disease. Flow rates, habitat type, and habitat quality were quantitatively evaluated.

Survey of Fish Assemblage in the Headwaters of East Plum Creek*, Colorado

Ms. Tillquist conducted field surveys for fish in small streams on U.S. Air Force Academy lands. The Air Force Academy was evaluating the potential environmental impacts of increased training activities in undeveloped areas of the Academy's property. In conjunction with this assessment, conducted fish surveys in the intermittent portions of upper East Plum Creek. Electrofishing gear and seines were used to sample the creek and beaver ponds. No fish were found in these reaches.

Museum of Southwestern Biology, University of New Mexico, Field Surveys of Fish in Plain Streams of the Southwestern U.S.*, New Mexico, Texas, Colorado

Ms. Tillquist conducted field surveys for the collection and systematic identification of fish throughout New Mexico, Colorado, and Texas. Special emphasis was placed on the identification of new or existing endangered fish species. Through this work, the Rio Grande silvery minnow was identified and this species subsequently has been listed as an endangered species, largely due to the publication of this fieldwork. She helped curate specimens into the Museum of Southwestern Biology.

Carbon Dioxide Pipeline Project Environmental Assessment*, Wyoming (Project Wildlife Biologist)

Anadarko proposed to construct the 125-mile-long Salt Creek Carbon Dioxide Pipeline. Ms. Tillquist conducted sage-grouse, mountain plover, and raptor surveys. Data from these field reconnaissance surveys were used to assist with pipeline route selection and to identify areas with seasonal construction constraints. The pipeline has been successfully permitted and constructed.

Nesting Habitat Evaluation and Improvement for Threatened Dusky Canada Geese, Prince William Sound & Copper River Delta*, Cordova, Alaska

Ms. Tillquist evaluated areas on the Copper River Delta for their potential as nesting habitat for the endangered Dusky Canada goose. Once suitable sites were identified, artificial nesting structures and islands were constructed. Nesting success was documented through the breeding season to determine if artificial nesting structures were effective. Ms. Tillquist also participated in breeding waterfowl surveys and banded geese. She also evaluated and constructed in-stream habitat improvement structures for anadromous fish and collected water quality data.

** denotes projects completed with other firms*

Heidi Tillquist

Environmental Toxicologist/Senior Program Manager

PUBLICATIONS

Cooper, A. R., H. Tillquist, L. M. Overholt, and D. C. Jamison. Cooper's Acute Toxic Exposures (with CD-ROM). *CRC Press, Inc.*, 1996.

Ebinger, M. H., P. L. Kennedy, O. B. Myers, W. Clements, H. T. Bestgen [Tillquist], and R. J. Beckman. Long-term Fate of Depleted Uranium at Aberdeen and Yuma Proving Grounds, Phase II: Human Health and Ecological Risk Assessments. *Los Alamos National Laboratory, New Mexico. LA-13156-MS*, 1996.

Bestgen [Tillquist], H. T. Use of soil extracts as a culture and test medium for Ceriodaphnia dubia.. *Master's Thesis. Colorado State University, Fort Collins, Colorado*, 1992.

Nimmo, D. R., J. F. Karrish, H. T. Bestgen [Tillquist], T. A. Steidl-Pulley, M. J. Willox, T. L. Craig. The assessment of nonpoint sources of toxicity in National Park waters using biomonitoring techniques.. *Park Science*, 1992.

Wolff, R. K., H. Tillquist, B. A. Muggenburg, J. R. Harkema, and J. L. Mauderly. Deposition and clearance rate of radiolabeled particles from small ciliated airways in beagle dogs. *Journal of Aerosol Medicine 2(3):261-270.*, 1988.

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 DIRECT TESTIMONY OF JON SCHMIDT, PH.D.

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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 direct testimony of Jon Schmidt.

1. Please state your name and address for the record.

Answer: My name is Jon Schmidt. My business address is exp Energy Services, 1300 Metropolitan Boulevard, Suite 200, Tallahassee, FL 32308.

2. Please state your position and provide a description of your areas of responsibility with respect to the Keystone XL Project.

Answer: I am Vice President, Environmental & Regulatory Services in the Tallahassee office of exp Energy Services, Inc. I am the regulatory and permitting manager for the Keystone XL Pipeline Project, including the coordination of the Department of State EIS, DEIS, SEIS, FEIS, and FSEIS, the Section 9 Biological Opinion, NHPA Section 106 Programmatic

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Agreement, United States Army Corps of Engineers permitting, the Montana Facility Siting Act licensing, South Dakota PUC environmental filing, and other state and federal permitting.

3. Please state your professional qualifications and experience with pipeline operations.

Answer: My professional background is stated in my resume, a copy of which is attached as Exhibit A. My education consists of a bachelor's degree in marine biology, a master's degree in biological sciences, and a Ph.D. in biological sciences. In general, I have extensive experience in environmental management with respect to the pipeline industry, and have permitted over 30,000 miles of pipeline projects in most states in the United States over the last 28 years. I managed the regulatory and permitting tasks associated with the Keystone Pipeline, including associated compliance inspection during construction. I have testified before the Commission in the permit proceedings concerning the Keystone XL Pipeline in Docket HP 09-001.

4. Are you responsible for portions of the Tracking Table of Changes attached as Appendix C to Keystone's certification petition?

Answer: Yes. I am individually or jointly responsible for the information provided with respect to Finding Numbers 32, 33, 41, 50, 54, 73, and 80. In general, I can testify to environmental issues other than risk and spill response information; the CMR Plan; the Con/Rec Units and the use of horizontal directional drilling.

5. Please summarize the updated information regarding Finding No. 32.

Answer: The environmental impacts discussed in Table 6 of Keystone's permit application still apply. The CMR Plan has been updated. The last version is Rev4, which is attached in redlined form as Attachment A to Appendix C to Keystone's certification petition.

Overall changes to the CMR Plan were made to clarify language, provide additional detail related to construction procedures, and incorporate lessons learned from previous construction, current right-of-way conditions, and project requirements.

6. Please summarize the updated information regarding Finding No. 33.

Answer: Keystone previously submitted Exhibit TC-14 in connection with the hearing on its permit application. Exhibit TC-14 includes soil type maps and aerial photograph maps of the route in South Dakota, showing topography, land uses, project mileposts and location descriptors. Exhibit TC-14 is still generally consistent in the description of the current Project route through South Dakota. Keystone has disclosed in discovery maps of minor route variations made at the request of landowners or for engineering reasons. These maps will be marked as an exhibit at the hearing on Keystone's certification petition. In addition, Keystone will submit updated maps prior to the initiation of construction as required by Condition No. 6 of the Amended Final Decision and Order.

7. Please summarize the updated information regarding Finding No. 41.

Answer: Since the permit application, Keystone has decided to use horizontal directional drilling ("HDD") to cross the Bad River and Bridger Creek, in addition to the Little Missouri, Cheyenne, and White Rivers. Exhibit C to Keystone's permit application contains a listing of all water body crossings and preliminary site-specific crossing plans for the HDD sites. To supplement Exhibit C in Docket HP09-001, Attachment B to Keystone's Tracking Table of Changes in Docket HP14-001 contains the preliminary site-specific crossing plans for the HDD crossings of the Bad River and Bridger Creek.

8. Please summarize the updated information regarding Finding No. 50.

Answer: The total length of the Project pipe with the potential to affect a High Consequence Are ("HCA") is 14.9 miles. The reference to 19.9 miles in the Tracking Table was a typographical error. Since the Tracking Table was prepared, the Cheyenne River crossing was adjusted because of HDD access issues and for construction and engineering reasons, resulting in a slight increase in total HCA mileage. The current HCA mileage figure is 15.8 miles. The 15.8 miles are ecologically sensitive areas and do not encompass populated areas or drinking water areas.

9. Please summarize the updated information regarding Finding No. 54.

Answer: Because of minor route variations, the mileages in South Dakota have changed slightly. The route is approximately 315 miles in South Dakota. All but 27.9 miles of the route are privately owned. 1.7 miles are owned by local governments, and 26.3 miles are state owned and managed. No tribal or federal lands are crossed by the route in South Dakota.

10. Please summarize the updated information regarding Finding No. 73.

Answer: Keystone has updated its CMR Plan since the Amended Final Decision and Order. The changes are shown in a redlined version of the CMR Plan, which is Rev4, filed with the Commission as Attachment A to Appendix C to Keystone's certification petition.

11. Please summarize the updated information regarding Finding No. 80.

Answer: Since the Amended Final Decision and Order, Keystone has completed the construction/reclamation unit ("Con/Rec Unit") mapping in consultation with the National Resource Conservation Service. The Con/Rec Unit mapping is included as Appendix R to the FSEIS.

12. Are you aware of any reason that Keystone cannot continue to meet the conditions on which the Permit was granted by the Commission?

Answer: No. I have reviewed the conditions contained in the Amended Final Decision and Order dated June 29, 2010. The changes discussed in Finding Nos. 32, 33, 41, 50, 54, 73, and 80 do not affect Keystone's ability to meet the conditions on which the Permit was granted.

13. Does this conclude your prepared direct testimony?

Answer: Yes.

Dated this 30th day of March, 2015.

Jon Schmidt

CERTIFICATE OF SERVICE

I hereby certify that on the 2nd day of April, 2015, I sent by United States first-class mail, postage prepaid, or e-mail transmission, a true and correct copy of the foregoing Direct Testimony of Jon Schmidt, to the following:

Patricia Van Gerpen
Executive Director
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
patty.vangerpen@state.sd.us

Kristen Edwards
Staff Attorney
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
kristen.edwards@state.sd.us

Brian Rounds
Staff Analyst
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
brian.rounds@state.sd.us

Darren Kearney
Staff Analyst South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
darren.kearney@state.sd.us

Tony Rogers, Director
Rosebud Sioux Tribe - Tribal Utility Commission
153 South Main Street
Mission, SD 57555
tuc@rosebudsiouxtribe-nsn.gov

Cindy Myers, R.N.
PO Box 104
Stuart, NE 68780
csmyers77@hotmail.com

Jane Kleeb
1010 North Denver Avenue
Hastings, NE 68901
jane@boldnebraska.org

Byron T. Steskal
Diana L. Steskal
707 E. 2nd Street
Stuart, NE 68780
prairierose@nntc.net

Terry Frisch
Cheryl Frisch
47591 875th Road
Atkinson, NE 68713
tcfrisch@q.com

Arthur R. Tanderup
52343 857th Road
Neligh, NE 68756
atanderu@gmail.com

Lewis GrassRope
PO Box 61
Lower Brule, SD 57548
wisestar8@msn.com

Robert G. Allpress
46165 Badger Road
Naper, NE 68755
bobandnan2008@hotmail.com

Amy Schaffer
PO Box 114
Louisville, NE 68037
amyannschaffer@gmail.com

Benjamin D. Gotschall
6505 W. Davey Road
Raymond, NE 68428
ben@boldnebraska.org

Elizabeth Lone Eagle
PO Box 160
Howes, SD 57748
bethcbest@gmail.com

John H. Harter
28125 307th Avenue
Winner, SD 57580
johnharter11@yahoo.com

Peter Capossela
Peter Capossela, P.C.
Representing Standing Rock Sioux Tribe
PO Box 10643
Eugene, OR 97440
pcapossela@nu-world.com

Carolyn P. Smith
305 N. 3rd Street
Plainview, NE 68769
peachie_1234@yahoo.com

Jeff Jensen
14376 Laflin Road
Newell, SD 57760
jensen@sdplains.com

Louis T. (Tom) Genung
902 E. 7th Street
Hastings, NE 68901
tg64152@windstream.net

Nancy Hilding
6300 West Elm
Black Hawk, SD 57718
nhilshat@rapidnet.com

Paul F. Seamans
27893 249th Street
Draper, SD 57531
jacknife@goldenwest.net

Viola Waln
PO Box 937
Rosebud, SD 57570
walnranch@goldenwest.net

Wrexie Lainson Bardaglio
9748 Arden Road
Trumansburg, NY 14886
wrexie.bardaglio@gmail.com

Harold C. Frazier
Chairman, Cheyenne River Sioux Tribe
PO Box 590
Eagle Butte, SD 57625
haroldcfrazier@yahoo.com
mailto:kevinckeckler@yahoo.com

Jerry P. Jones
22584 US Hwy 14
Midland, SD 57552

Debbie J. Trapp
24952 US Hwy 14
Midland, SD 57552
mtdt@goldenwest.net

Duncan Meisel
350.org
20 Jay St., #1010
Brooklyn, NY 11201
duncan@350.org

Bruce Ellison
Attorney for Dakota Rural Action
518 6th Street #6
Rapid City, SD 57701
belli4law@aol.com

RoxAnn Boettcher
Boettcher Organics
86061 Edgewater Avenue
Bassett, NE 68714
boettcherann@abbnebraska.com

Bonny Kilmurry
47798 888 Road
Atkinson, NE 68713
bjkilmurry@gmail.com

Robert P. Gough, Secretary
Intertribal Council on Utility Policy
PO Box 25
Rosebud, SD 57570
bobgough@intertribalCOUP.org

Cody Jones
21648 US Hwy 14/63
Midland, SD 57552

Gena M. Parkhurst
2825 Minnewsta Place
Rapid City, SD 57702
GMP66@hotmail.com

Joye Braun
PO Box 484
Eagle Butte, SD 57625
jmbraun57625@gmail.com

The Yankton Sioux Tribe
Robert Flying Hawk, Chairman
PO Box 1153
Wagner, SD 57380
robertflyinghawk@gmail.com
Thomasina Real Bird
Attorney for Yankton Sioux Tribe
trealbird@ndnlaw.com

Chastity Jewett
1321 Woodridge Drive
Rapid City, SD 57701
chasjewett@gmail.com

Bruce Boettcher
Boettcher Organics
86061 Edgewater Avenue
Bassett, NE 68714
boettcherann@abbnebraska.com

Ronald Fees
17401 Fox Ridge Road
Opal, SD 57758

Tom BK Goldtooth
Indigenous Environmental Network (IEN)
PO Box 485
Bemidji, MN 56619
ien@igc.org

Dallas Goldtooth
38731 Res Hwy 1
Morton, MN 56270
goldtoothdallas@gmail.com

Gary F. Dorr
27853 292nd
Winner, SD 57580
gfdorr@gmail.com

Cyril Scott, President
Rosebud Sioux Tribe
PO Box 430
Rosebud, SD 57570
cscott@gwtc.net
ejantoine@hotmail.com

Paula Antoine
Sicangu Oyate Land Office Coordinator
Rosebud Sioux Tribe
PO Box 658
Rosebud, SD 57570
wopila@gwtc.net
paula.antoine@rosebudsiouxtribe-nsn.gov

Thomasina Real Bird
Representing Yankton Sioux Tribe
Fredericks Peebles & Morgan LLP
1900 Plaza Dr.
Louisville, CO 80027
trealbird@ndnlaw.com

Sabrina King
Dakota Rural Action
518 Sixth Street, #6
Rapid City, SD 57701
sabinra@dakotarural.org

Frank James
Dakota Rural Action
PO Box 549
Brookings, SD 57006
fejames@dakotarural.org

Robin S. Martinez
Dakota Rural Action
Martinez Madrigal & Machicao, LLC
616 West 26th Street
Kansas City, MO 64108
robin.martinez@martinezlaw.net

Tracey A. Zephier
Attorney for Cheyenne River Sioux Tribe
Fredericks Peebles & Morgan LLP
910 5th Street, Suite 104
Rapid City, SD 57701
tzephier@ndnlaw.com

Paul C. Blackburn
4145 20th Avenue South
Minneapolis, MN 55407
paul@paulblackburn.net

Matthew Rappold
Rappold Law Office
on behalf of Rosebud Sioux Tribe
PO Box 873
Rapid City, SD 57709
matt.rappold01@gmail.com

April D. McCart
Representing Dakota Rural Action
Certified Paralegal
Martinez Madrigal & Machicao, LLC
616 W. 26th Street
Kansas City, MO 64108
april.mccart@martinezlaw.net

Kimberly E. Craven
3560 Catalpa Way
Boulder, CO 80304
kimecraven@gmail.com

Mary Turgeon Wynne
Rosebud Sioux Tribe - Tribal Utility Commission
153 S. Main Street
Mission, SD 57555
tuc@rosebudsiouxtribe-nsn.gov

Joy Lashley
Administrative Assistant
SD Public Utilities Commission
joy.lashley@state.sd.us

Eric Antoine
Rosebud Sioux Tribe
PO Box 430
Rosebud, SD 57570
ejantoine@hotmail.com

WOODS, FULLER, SHULTZ & SMITH P.C.

By /s/ James E. Moore

William Taylor
James E. Moore
PO Box 5027
300 South Phillips Avenue, Suite 300
Sioux Falls, SD 57117-5027
Phone (605) 336-3890
Fax (605) 339-3357
Email James.Moore@woodsfuller.com
Attorneys for Applicant TransCanada

Jon Schmidt, PhD

Vice President, Environmental & Regulatory

+1.850.385.5441 | jon.schmidt@exp.com

Education & Training

- PhD, Biological Sciences, Florida State University
- M.S., Biological Sciences, University of Bridgeport
- B.S., Marine Biology, University of Massachusetts - Dartmouth

Overview

Jon A. Schmidt is currently the Vice President, Environmental & Regulatory Services in the Tallahassee office of **exp** Energy Services Inc. He joined **exp** in May of 2009.

Mr. Schmidt has extensive experience in environmental management, particularly with respect to the pipeline industry including: environmental regulatory strategy development and project planning, project management, environmental surveys, permitting, and environmental inspection. In over 25 years, he has permitted over 30,000 miles of pipeline projects in most states in the US for mid-stream pipeline companies, gas distributors, and producers. He has also permitted LNG facilities, refined products, natural gas, and crude oil pipelines and terminals throughout the US. This included the management of the regulatory and permitting tasks associated with the 7-state, 1,385 mile Keystone pipeline and associated compliance inspection during construction.

Currently, Jon is the regulatory and permitting manager for work for the 6-state, 1,300 mile Keystone XL Pipeline Project, including the coordination of the Department of State EIS, DEIS, SEIS, FEIS and now SFEIS, the Section 9 Biological Opinion, NHPA Section 106 Programmatic Agreement with over 60 parties, USACE permitting across 7 USACE Districts, Montana Facility Siting Act licensing, South Dakota Public Utilities Commission certification and other state and federal permitting. Jon is also working with the Alaska Pipeline Project in developing the FERC filing strategy and overall environmental program for the re-designed pipeline and LNG project.

Prior to joining **exp,** Mr. Schmidt had a wide variety of experience in the midstream energy industry, including work on international pipeline projects.

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Jon Schmidt, PhD– *Continued*

Vice President, Environmental & Regulatory

+1.850.385.5441 | jon.schmidt@exp.com

Project Experience

- **TransCanada/ExxonMobil Development Company as Alaska Pipeline Project (APP), 754 mile, Alaska Pipeline Project, Alaska.**
  Employment: 2010-2012
  Jon served as a member of the company Environment, Regulatory, and Land (ERL) management team for TransCanada and ExxonMobil to direct consulting firms conducting the environmental field surveys, agency consultations, and development of the FERC application for the proposed APP. His role focused on developing and implementing a regulatory strategy lined up with the commercial realities of the project. Jon directed consultants on the scope and efforts required for field surveys, the Resource Reports, and agency meetings and pre-filing activities. He wrote an overarching permitting roadmap and strategy, individual agency permitting plans, and helped implement through agency meetings and workshops to address and resolve timing and level of detail issues with the Alaskan agencies.

- **Keystone XL Pipeline, Montana, South Dakota, Nebraska, Kansas, Oklahoma, and Texas.**
  Employment: 2010
  For the expansion of the Keystone pipeline, Jon served as the overall environmental manager reporting directly to TransCanada. Keystone XL is a 36-inch 1,375 mile crude oil pipeline to the Gulf Coast of the US. Jon's role was similar to that on the Keystone project, but with overall responsibility for environmental compliance. He managed several firms that carried out the field surveys, report writing, and permit application preparation.

- **Keystone Pipeline, North Dakota, South Dakota, Nebraska, Kansas, Oklahoma, Missouri, and Illinois.**
  Employment: 2006-2012
  Was overall account manager and project director for AECOM as they served as environmental management contractor for Trow Engineering Consultants, owner's engineer for the TransCanada Keystone Project. Keystone is an approximate 1,300 mile crude oil pipeline. Jon was responsible for the overall environmental regulatory strategy for the Department of State Presidential Permit application and EIS process. This effort entailed the coordination with the USACE across multiple districts, multiple USFWS field offices, the NRCS, the South Dakota PUC, North Dakota PSC, and multiple state agencies in each state. Jon's role also included senior review on the multiple filings that were made to the agencies, consultation coordination and meetings, and negotiation of permit conditions, and a Conservation Agreement with the USFWS for Migratory Bird Treaty Act mitigation. Jon was also pivotal in negotiating the USACE permitting to be a NWP for all states crossed and mitigation projects to cover compensation in all states crossed.

- **ConocoPhillips Company, Environmental Services for Licensing of Proposed Beacon Port Liquid Natural Gas Facility, Gulf of Mexico.**
  Employment: 2004
  - Project Director, ConocoPhillips Company contracted ENSR to assist with the licensing of its proposed Beacon Port liquid natural gas facility in the northern Gulf of Mexico. ENSR's services included: 1) developing the environmental report for the deepwater port (DWP) license application to the Maritime Administration (MARAD) and the U.S. Coast Guard (USCG), and 2) managing the development of the entire DWP license application per the DWP Act of 1974, as amended.

Jon Schmidt, PhD– *Continued*
Vice President, Environmental & Regulatory
+1.850.385.5441 | jon.schmidt@exp.com

- Related services included: 1) regulatory outreach, 2) biological impact assessment, 3) water discharge modeling, 4) air emissions modeling, 5) Environmental Protection Agency permitting (air and water discharges), U.S. Army Corps of Engineers permitting, 5) wetland surveys, 6) threatened and endangered species surveys, and 7) development and coordination of a biological sampling plan, among other services. ENSR continues to support ConocoPhillips Company in its efforts to develop Beacon Port.

- **AES Ocean Express Pipeline Third Party Environmental Impact Statement.**
  Employment: 2004
  Served as Project Director for the Environmental Impact Statement (EIS) prepared for the AES Ocean Express pipeline project from the Economic Exclusion Zone (EEZ) to Broward County, Florida. This project ties into a pipeline and LNG facility to be built in the Bahamas. ENSR's role is to serve as the Federal Energy Regulatory Commission's (FERC's) extended staff in preparing the EIS. To date, a PDEIS has been drafted for regulatory review by the MMS, NMFS, FERC, and the USACE.

- **Ingleside Energy Center and San Patricio Pipeline, Oxy Energy Ventures, Corpus Christi, Texas.**
  Employment: 2003-2005
  Jon served as the Project Manager overseeing the preparation of the FERC filing for a new LNG regas facility collocated with Occidental's chemical plant and power plant near Corpus Christi, Texas. Jon coordinated the field surveys required for the facility location, the marine studies to accommodate the dredging of a new berth and pier, as well as studies along the 80+ mile pipeline from the facility to the interstate pipeline grid. Jon worked with Oxy's energy services staff to utilize waste heat from the power plant for regasification, air modeling and coordination with the plant's existing air permits, and coordination of the NHPA 106 and Section 7 ESA consultation required for the FERC application.

- **Bayou Casotte Energy LLC, Casotte Landing Natural Gas Import Terminal, Pascagoula, Mississippi.**
  Employment: 2003-2005
  Jon acted as Project Director for the FERC licensing and permitting of a liquefied natural gas import terminal adjacent to Chevron's Pascagoula refinery at Moss Point, Mississippi. The FERC filing covered the regasification facilities, air modeling and permitting, USACE permitting and dredge disposal studies, and the water use permitting for hydrotesting the LNG storage tanks. Because the site location and required dredging impacted the Gulf Sturgeon, a Section 7 ESA consultation was required to complete the EIS.

- **Cypress Pipeline Project, 166 mile Natural Gas Pipeline, Coastal Georgia and Florida**
  Employment: 2002-2004
  Project Director for permitting the Cypress Project, which included route analysis, agency consultation, FERC Environmental Report preparation, wetland delineation report to USACE and FERC, Environmental Resource Permit application to the state of Florida, and specialized field surveys for Gopher Tortoises.

Jon Schmidt, PhD– *Continued*

Vice President, Environmental & Regulatory

+1.850.385.5441 | jon.schmidt@exp.com

- **ConocoPhillips Company, Environmental Services for Licensing of Proposed Compass Port Natural Gas Facility, Gulf of Mexico.**
  Employment: 2002-2004
  Project Manager, ConocoPhillips Company contracted ENSR to assist with the licensing of its proposed Compass Port liquid natural gas facility in the northern Gulf of Mexico. ENSR's services included: 1) developing the environmental report for the deepwater port (DWP) license application to the Maritime Administration (MARAD) and the U.S. Coast Guard (USCG), 2) developing the environmental report for the Certificate of Public Convenience and Necessity with the Federal Energy Regulatory Commission (FERC), and 3) managing the development of the entire DWP license application in accordance with the DWP Act of 1974, as amended. Related services included: 1) management of the regulatory Team Permitting process, 2) biological impact assessment, 3) water discharge modeling, 4) air emissions modeling, 5) Environmental Protection Agency permitting (air and water discharges), U.S. Army Corps of Engineers permitting, 6) wetland surveys, 7) threatened and endangered species surveys, and 8) development and coordination of a biological sampling plan, among other services. ENSR continues to support ConocoPhillips Company in its efforts to develop Compass Port.

- **Elba Island LNG Import Terminal Reactivation, Southern LNG Inc.—An El Paso Company, Georgia.**
  Employment: 1999-2001
  Project Director for the successful 1999–2000 certification for reactivation of the Elba Island Import Terminal.

- **Gulfstream Natural Gas System, Environmental Management of Pipeline Construction Project, Gulf of Mexico, Mississippi, Alabama, Florida.**
  Employment: 1998-2001
  Project Director for siting, routing, field surveys, and permitting for 775-mile pipeline construction project. To-date, the project has involved the coordination of over 100 regulatory agencies, and over 15 public meetings with landowners, the general public and over 30 environmental groups. Led the Team Permitting (Florida) and FERC coordination aspects on behalf of the client. Included assessing project impacts to live bottom (reefs) in the Gulf of Mexico and impacts to threaten and endangered marine turtles and mammals.

- **Destin Pipeline Company, LLC (Southern Natural Gas Affiliate), Destin Pipeline Project - Construction of Natural Gas Pipeline, Gulf of Mexico to Clarke County, Mississippi.**
  Employment: 1996-1998
  Project Manager for environmental aspects of construction project which included the installation of 206 miles of 36-in outside- diameter (OD) and 30-in OD pipeline, installation of 2.4 miles of 16-in OD pipeline in Mississippi, installation of four meter stations,construction of a platform in the Gulf of Mexico, and construction of two new compressor stations in Mississippi. Tasks included Alternatives Analysis for selection of a preferred route, environmental surveys, permitting, and on-site environmental inspection.

Jon Schmidt, PhD– *Continued*

Vice President, Environmental & Regulatory

+1.850.385.5441 | jon.schmidt@exp.com

- **Blue Atlantic Transmission System, Environmental Management of Pipeline Project, Nova Scotia Canada to New York.**
  Employment: 1996
  Project Director for the siting, routing, field surveys, regulatory permitting and meetings, and FERC filing for a 850+ mile large diameter pipeline from Nova Scotia into the New York marketplace. The project has involved meeting with all the New England state regulatory bodies, the FERC, NMFS, USACE, MMS, and NOAA to discuss routing and field survey requirements. Most of the offshore field surveys have been completed to date.

- **Etowah LNG Company, LLC, Etowah LNG Peakshaving Facility and Pipeline Construction Project, Polk County, Georgia.**
  Employment: 1995
  Project Director for all environmental aspects of project related to construction of a new 2.5-billion cubic ft. liquefied natural gas peakshaving facility and 12.49 miles of 12.75-in OD natural gas pipeline. Directed team responsible for: preparation ofFERC 7(c) filing and Biological Survey Report; conducting biological field surveys of the jurisdiction and non- jurisdictional facilities (including wetlands, species of concern, and surveys for construction constraints); assisting in the siting of the Etowah Pipeline; preparing Land Disturbing Activity; permitting for the construction of the jurisdictional facilities; preparing the application to the USACE for Section 404 permit; coordinating with surveyors to quickly complete field surveys; and performing agency consultations and negotiations.

- **TransCanada/ANR partnership, 800+ mile SunShine Pipeline Project, Florida, and Alabama.**
  Employment: 1994
  Technical Project Manager. Managed the technical team to put together the state of Florida Siting Application as well as directed the effort for the FERC ER. Managed the technical efforts and data analysis for the cultural resource and biological surveys using GPS/GIS. Participated in the 36 public meetings and coordinated with 80 regulatory agencies from local, regional, state and federal agencies to coordinate comments and simplify licensing/permitting conditions. Put together a regulatory and technical Mitigation Task Force to constructively deal with the impact to over 1,000 wetland crossings.

- **TransContinental Pipe Line Company, Southeast Mainline Looping Project, Alabama, Georgia, and North Carolina.**
  Employment: 1994
  Directed the biological field survey efforts, FERC ER preparation, and provided support to TransContinental for FERC interrogatories.

- **Viking Voyageur Pipeline Company, Viking Voyageur Pipeline Project, Minnesota, Wisconsin, and Illinois.**
  Employment: 1993
  Project Director for 800+-mile project which included providing siting, biological and cultural resource field surveys, FERC ER preparation, and permitting support and coordination for the joint TransCanada and NSP Power project.

Jon Schmidt, PhD– *Continued*
Vice President, Environmental & Regulatory
+1.850.385.5441 | jon.schmidt@exp.com

- **ANR, LSP Power Project, Mississippi.**
  Employment: 1992
  Project includes the field surveys, permitting and FERC ER preparation for the 12-mile lateral.

- **Southern Natural Gas Company, Southern Natural Zone III Expansion Project, Alabama, and Georgia**
  Employment: 1991-1994
  Project director for the Southern Natural Zone III Expansion Project (27 miles looping in 3 states with compression), FERC Section 7(c) Environmental Report (ER), field Surveys, permitting, and environmental inspector's manual preparation.

- **Florida Power Corporation, Environmental Master Services Agreement, Florida.**
  Employment: 1991-1993
  Projects included jurisdictional wetland delineations at the Higgins Power Plant, waste water monitoring at the Montincello facility.

- **ANR Pipeline Company, Patterson Looping Project, Gulf of Mexico, and Louisiana.**
  Employment: 1991
  Project director for 37-mile project which included FERC ER preparation, federal and state permitting, and agency negotiation.

- **Southern Natural Gas Company, Approximately Fifteen 7(c) Projects Totaling 600 Linear Miles, LA, MI, AL, GA, TN, SC, NC, FL, and Gulf of Mexico.**
  Employment: 1990-1992
  Project Manager and Director providing air permitting, contamination assessment, audit and environmental inspection services for regulated facilities.

- **US Navy, Environmental Assessments, Puerto Rico, Florida, and Atlantic Seaboard.**
  Employment: 1990
  Project manager for several US Navy EAs which were completed for proposed facilities or Navy actions. Projects included the Camp Pendleton Warfare Training facilities, the Naval Warfare Training Facilities on Isla Pincros, Puerto Rico, and the ecological risk assessment at the Naval Air Training Center in Pensacola, Florida. Managed the efforts to conduct a siting alternatives analysis study along the Atlantic seaboard for the shock testing for the new class of submarine, the Sea Wolf. Project utilized satellite imagery to create databases and a GIS to manage the information. Required to assess impacts of underwater detonation of explosives to marine mammals and endangered species.

Jon Schmidt, PhD– *Continued*
Vice President, Environmental & Regulatory
+1.850.385.5441 | jon.schmidt@exp.com

- **Chandeleur Pipeline Company, Chandeleur Destin Extension Project and Chandeleur Expansion Project, Mississippi, and Gulf of Mexico, and Louisiana.**
  Employment: 1990
  Project director for Chandeleur Destin Extension project (4 miles) and Chandeleur Expansion project (30 miles). ENSR provided field survey, FERC ER preparation and permitting support until the project was removed from consideration by Chandeleur.

- **Discovery Pipeline Company LLC, Discovery Pipeline Project, Gulf of Mexico, and Louisiana.**
  Employment: 1990
  Project manager for 80-mile project where ENSR was asked to provide a fast track ER for filing with the FERC and support to Discovery through the FERC review and certification process.

- **Southern Natural Gas Company, Southern Natural East Tennessee Expansion Project, Alabama, Georgia, and Tennessee.**
  Employment: 1989-1991
  Project Director for the project. On a fast track basis, ENSR conducted biological field surveys, completed the FERC ER and survey reports, agency consultation for filing with the FERC and sate and federal agencies in 45 days. Completed all permitting and construction implementation plans. Provided EIS and managed environmental inspection.

- **Southern Natural Gas Company, North Alabama Pipeline Project, Alabama.**
  Employment: 1989
  Project Manager for Southern Natural's 122-mile North Alabama pipeline project in Tuscaloosa, Fayette, Walker, Cullman, Morgan, and Madison counties, Alabama. Project involves route alternatives analysis, FERC 7(c) ER, field surveys using GPS/GIS, and public meeting/FERC support through the EIS process, permitting, and agency negotiation. Currently providing EIS and inspection services.

- **Tenneco, Tenneco West-East Pipeline Project, Louisiana, and Mississippi.**
  Employment: 1989
  Project management involved preparation of the ER for a 225-mile project, management of the biological and cultural resource surveys in Tennessee's Vicksburg field office, and coordination with state and federal agencies and FERC.

Jon Schmidt, PhD- *Continued*

Vice President, Environmental & Regulatory

+1.850.385.5441 | jon.schmidt@exp.com

International

- **TransCanada Pipelines, Colombia.**
  Employment: 1997
  For TransCanada's first pipeline project in Colombia, Jon served as the technical reviewer and in-country consultant coordinator between the local environmental consulting firms and TCPL's project staff. He helped the locals develop the scope of work for the EIA with the regulators, oversaw implementation, and assisted in impact assessment development to ensure permitting conditions could be implemented in the field by TCPL.

- **ENSR (now AECOM) – Senior Vice President**
  Employment: 1996 – 2009
  Responsibilities included: Part of senior management team at ENSR/AECOM that oversaw all of the company's consulting services related to pipelines and LNG facilities. This included ensuring that staff resources were available across the country and around the world to support key clients on all pipeline and LNG projects. Jon was also account manager for TransCanada, El Paso, and ConocoPhillips while overseeing the company's mid-stream services line.

- **PDVSA, eastern Venezuela.**
  Employment: 1996
  Working with Willbros Engineers, Jon served as the project manager for a routing and feasibility study for the Caripito-Guiria oil pipeline project in the Orinocho River basin. This project involved siting a new oil pipeline from interior E & P locations, across virgin tropical wetland forests, to the coast for PDVSA to build a new oil refinery and shipping facilities to export this new source of crude. Working with local environmental and engineering firms, Jon oversaw the route development, aerial reconnaissance, and report preparation. He participated with Willbros in presenting the study's results to the PDVSA management.

- **Endesa, Chile.**
  Employment: 1993
  For two separate projects on the Bio-Bio River, Jon served first as a task leader for an Environmental Impact Assessment (EIA) to the International Finance Corporation (IFC) for a hydro-electric dam, the first in a series of 5 to be built on this Clase VI river. This project was the first Category A EIA to be reviewed and approved by the IFC. On a subsequent project, Jon was the project manager for a downstream impact and flow study related to the EIA. Issues and concerns related to the operations of the dam resulted in this additional study where Jon had to coordinate and manage local University professors specializing in endemic fish species, hydrologists, modelers, and riverine ecologists coupled with E & E's ecological and modeling staff. He managed his work efforts from Santiago Chile and served as the principal negotiator between Endesa and the IFC on flow conditions for dam operations.

- **Ecology and Environment Inc. – Senior Environmental Scientist.**
  Employment: 1987 – 1996
  Responsibilities included: Served as project manager and project director on energy related projects throughout the US and overseas. Specialties included marine impact assessments and NEPA document preparation for energy projects.

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 REBUTTAL 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

1. State your name and occupation.

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 engineering 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 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 and

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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. My resume is attached as Exhibit A.

3. Did you provide direct testimony in this proceeding?

Answer: No.

4. To whose testimony are you responding to in your rebuttal?

Answer: I am responding to the direct testimony of Evan Vokes. During the entirety of his employment with TransCanada, Mr. Vokes worked in an engineering group which I led.

5. Mr. Vokes states his opinion that the current management of TransCanada is a very significant technical threat to the safety of pipelines, including the proposed KXL pipeline. Please comment on the focus of TransCanada's management on pipeline safety, with respect to the operations and engineering function.

Answer: TransCanada's management is fully focused on pipeline safety as our highest priority. We are a recognized leader in the industry in developing and implementing safe construction and operations practices. Management review of the suitability, adequacy, and effectiveness of our pipeline integrity and protection programs occurs at every level of oversight at TransCanada. The senior governance structures for each of the management systems provide the highest level of management governance, overseeing the strategic aspects of management review and direction setting.

TransCanada builds safety and compliance into every aspect of our operations - starting with design and continuing through construction and operation of our pipelines. Not only is this the right thing to do, but there is no benefit to TransCanada, financial or otherwise, of cutting corners on safety or compliance. TransCanada's success, from a business perspective, depends on building safe, reliable pipelines that service North America's energy needs on a long-term basis. TransCanada will not compromise safety - period.

Contrary to Mr. Vokes' comments, TransCanada does not profit from cutting prudently incurred safety-related expenses. From a business standpoint, we are paid to safely move products on behalf of our customers. If our systems are not designed properly or do not work reliably, that impacts our bottom line. It just makes good business sense to do things right from the beginning. We deliver critical energy products that we all rely on every day and the public, our regulators, and our shareholders expect us to do our jobs as safely as possible.

One of the primary tools for ensuring safety and compliance is the implementation of robust and rigorous quality management systems (QMS) for pipeline design and construction. The quality management system includes various checks and balances to ensure all pipelines are constructed in compliance with regulatory requirements, codes, and internal company specifications.

Pipeline projects are complex undertakings and there are many factors that may lead to issues during the lifecycle of a pipeline, but the quality management system operates to identify issues or non-conformances. Non-conformances are situations where code or internal specifications are not met in the initial construction. Should non-conformances occur, they are identified and corrective actions are developed and implemented prior to a pipeline being placed into service. The quality management system is comprised of a series of processes that apply to engineering design, procurement, and construction of pipelines. These processes include:

- Engineering design reviews;
- Specifications for materials, welding, and non-destructive examination (NDE);
- Qualification of suppliers and services;
- Inspection requirements and training for manufacturing, fabrication, and construction;
- Engineering reviews and audits of construction; and,
- Lessons learned and continuous improvement.

The quality, safety and inspection standards that TransCanada adheres to during construction are among the best in the world. Prior to putting a pipeline into service, non-destructive examination is carried out on all welds. Hydrostatic pressure testing is conducted at pressures well in excess of design operating pressures to prove the integrity of the pipeline. In-line inspection tools, known as smart pigs, are then used to measure and test for any defects in the pipe. Any anomalies that do not meet acceptance criteria are cut out and replaced prior to operations.

This department was fully and adequately staffed during Mr. Vokes' tenure with TransCanada. Moreover, since Mr. Vokes' departure in 2012, over 1,500 new employees have been hired into the TransCanada Operations and Engineering department, which is reflective of the Company's growth. Specifically, 241 net new permanent hires have been made in the Engineering and Asset Reliability team. The Materials Engineering department (which Mr. Vokes refers to as the Engineering Specialist department) currently employs 31 employees whose primary purpose is to support projects and ensure our standards are followed.

6. Can you discuss Mr. Vokes' position and responsibilities while at TransCanada?

Answer: In 2007, Mr. Vokes was hired on as an Engineer-in-Training (EIT). He worked in the welding team along with senior engineers and technologists. In the Province of Alberta, an engineer must have four years of suitable work experience under the supervision of a professional engineer before being eligible for professional engineering status (P.Eng.). As an EIT, Mr. Vokes worked under the guidance and supervision of a senior professional engineer. In July, 2009, Mr. Vokes received his P.Eng. He was then promoted to a junior engineer position. As a P.Eng., Mr. Vokes was moved into the Non-Destructive Examination (NDE) area. He worked under the guidance of a senior NDE technologist. In both the welding area and the non-destructive examination area, Mr. Vokes was responsible for identifying issues and addressing non-conforming work as a standard part of the quality control process.

7. **Mr. Vokes alleges that a rupture on the North Central Corridor Buffalo West pipeline was the result of cost/schedule decisions made by project managers, and specifically that the materials involved were understrength. Can you comment on that allegation?**

Answer: The failure was not caused by cost and schedule decision or by understrength materials. To the best of my knowledge and based on a good faith inquiry, TransCanada did not falsify any documents in this regard. TransCanada's finding is that the cause of this natural gas pipeline failure was a set of issues unique to this pipeline, its design, and operating temperature. These conditions are not directly relevant to the Keystone XL Project, but we do incorporate the learnings from all failures and quality issues into future projects and operations.

8. **Mr. Vokes alleges that substandard fittings are in service in the US and an equal number in Canada on the Keystone system. Can you comment on that allegation?**

Answer: All fittings in service on the Keystone system in Canada and the US are safe for continued operation of the pipeline. Every fitting in service has successfully undergone a hydrostatic pressure test to a pressure significantly higher than the maximum operating pressure.

Fittings were ordered stronger than required to meet the intended design. Because certain fittings came with less strength than ordered, TransCanada conducted an extensive engineering assessment to ensure the fittings were acceptable for design and operations, which included mechanical testing, stress analysis, and proof testing. TransCanada also applied composite reinforcement to specific fittings in consultation with PHMSA.

Both the National Energy Board and PHMSA have been heavily involved and engaged throughout this process. PHMSA initiated an independent third party engineering review of TransCanada's engineering assessment and the review confirmed the fittings within the pump stations meet burst pressure requirements, stress analysis requirements, and the design requirements for the maximum operating pressure (MOP) of the Pipeline. TransCanada would not be operating the system if we could not prove it was safe for operation.

9. **Mr. Vokes alleges that on the Keystone Phase II or Cushing Extension project, TransCanada engineers were forced into allowing the project to permit substandard inspection techniques on girth welds. Can you comment on that allegation?**

Answer: Keystone engineers specified industry-accepted non-destructive examination practices in accordance with federal code requirements, Company specifications, and industry standards. Full time third-party auditors also were employed during construction activities to verify the inspection techniques being applied and the results of those inspections.

10. **Mr. Vokes alleges that there was a problem with the original design of the Keystone pump stations and that inspectors were penalized for a practice of "contractor self-inspection." Can you comment on that allegation?**

Answer: Keystone has safely transported almost one billion barrels of crude oil since 2010, thus validating the original design of the pump stations. I am not aware that TransCanada has penalized any inspectors for a practice of "contractor self-inspection." In fact, TransCanada requires Contractors to implement a quality management plan because we believe it is imperative that contractors take responsibility for the quality of their work. Requiring the contractor to implement a quality management plan, however, is just one of part of TransCanada's larger, multi-layer quality management program, which also includes inspection by TransCanada.

11. **Mr. Vokes alleges a "salt induced microcracking" problem with pipe ordered for the Keystone XL pipeline. Can you comment on that allegation?**

Answer: There is no phenomenon known as "salt induced microcracking" in the pipeline industry. Salt on the surface of the bare pipe can cause disbondment of the coating during the application process. Because of this, the pipe is cleaned prior to coating application, both in the mill and in the field, in order to remove any contaminants. Furthermore, the pipe is inspected through the use of a "holiday" detector, which identifies any gaps in the coating, both in the mill upon completion of coating application, and prior to the pipe being placed into the ground, to verify that no coating disbondment has occurred. An above-ground close interval cathodic protection survey is performed on the pipeline after it has been lowered into the trench and backfilled to determine if there are any areas of coating disbondment as required by PHMSA special condition requirements.

12. **Mr. Vokes alleges that certain anomalies on the Gulf Coast section of the Keystone pipeline were the result of construction contractors not following the code of construction and inspectors not enforcing the rules. Can you comment on those allegations?**

Answer: TransCanada conducts various inspections throughout a project, including inspections after hydrostatic pressure testing. These inspections were effective in finding anomalies on the Keystone Gulf Coast pipeline. Coating damage and pipe body dents were all identified and repaired prior to any oil product being introduced into the pipeline and at no time posed a threat to the safety of the pipeline or to the environment. .

13. **Mr. Vokes alleges that on the Gulf Coast project there were extensive problems including pipe falling or ready to fall off skids, heavy equipment marks consistent with collisions with pipe, serious coating damage from pipe being mishandled, repair coatings not correctly applied, and pipe on top of large rocks. Can you comment on those allegations?**

Answer: As I have indicated, the purpose of TransCanada's multi-layer inspection system is to identify and remediate events or occurrences that do not meet our stringent construction standards. If there were instances of the issues cited by Mr. Vokes, they would have been identified and addressed by these inspections. Indeed, as I have testified, the Keystone pipeline system has safely transported almost one billion barrels of crude oil since 2010, thus demonstrating the efficacy of our quality management system.

14. **Mr. Vokes alleges numerous quality failings on the Bison Pipeline project. Can you comment on those allegations?**

Answer: The Bison pipeline experienced a failure six months after being placed in service. The failure was caused by a back-hoe strike that was unreported. PHMSA had extensive involvement during the failure investigation and repair program. TransCanada conducted high resolution in-line inspections of the Bison pipeline, pipeline excavations, and an above ground close interval cathodic protection survey, and addressed all indications found to PHMSA's satisfaction. The Bison pipeline is in full operation. Other than at this one location, TransCanada did not find any other indications of external damage or other issues with the safe operation of the pipeline. As a result of this failure, increased numbers of inspectors and enhanced inspector training have been instituted on future projects.

15. **Mr. Vokes alleges that managers at TransCanada sanction unsafe construction practices to the benefit of cost and schedule. Can you comment on that allegation?**

Answer: As I have described, TransCanada employs a project management system based on industry best practices for quality management and project management to deliver large-scale construction projects. TransCanada is a leader in the use of advanced construction practices. This is demonstrated by our voluntary commitment to adopt special conditions related to the design, construction and operations of the Keystone XL project that are above the requirements in the applicable federal regulations and industry standards. In view of the extensive internal and external checks on construction practices, cost and schedule concerns do not override adherence to safe construction practices. Contrary to Mr. Vokes assertion, TransCanada's business does not benefit from unsafe pipeline construction or operations. Pipelines that are unsafe cannot be operated and shippers will not move products through pipelines that are not reliable.

16. **Does this conclude your testimony?**

Answer: Yes it does.

Dated this 15 day of June, 2014.

Dan King

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 Dan King, to the following:

Patricia Van Gerpen
Executive Director
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
patty.vangerpen@state.sd.us

Kristen Edwards
Staff Attorney
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
kristen.edwards@state.sd.us

Brian Rounds
Staff Analyst
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
brian.rounds@state.sd.us

Darren Kearney
Staff Analyst South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
darren.kearney@state.sd.us

Tony Rogers, Director
Rosebud Sioux Tribe - Tribal Utility Commission
153 South Main Street
Mission, SD 57555
tuc@rosebudsiouxtribe-nsn.gov

Cindy Myers, R.N.
PO Box 104
Stuart, NE 68780
csmyers77@hotmail.com

Jane Kleeb
1010 North Denver Avenue
Hastings, NE 68901
jane@boldnebraska.org

Byron T. Steskal
Diana L. Steskal
707 E. 2nd Street
Stuart, NE 68780
prairierose@nntc.net

Terry Frisch
Cheryl Frisch
47591 875th Road
Atkinson, NE 68713
tcfrisch@q.com

Arthur R. Tanderup
52343 857th Road
Neligh, NE 68756
atanderu@gmail.com

Lewis GrassRope
PO Box 61
Lower Brule, SD 57548
wisestar8@msn.com

Carolyn P. Smith
305 N. 3rd Street
Plainview, NE 68769
peachie_1234@yahoo.com

Robert G. Allpress
46165 Badger Road
Naper, NE 68755
bobandnan2008@hotmail.com

Amy Schaffer
PO Box 114
Louisville, NE 68037
amyannschaffer@gmail.com

Louis T. (Tom) Genung
902 E. 7th Street
Hastings, NE 68901
tg64152@windstream.net

Benjamin D. Gotschall
6505 W. Davey Road
Raymond, NE 68428
ben@boldnebraska.org

Nancy Hilding
6300 West Elm
Black Hawk, SD 57718
nhilshat@rapidnet.com

Elizabeth Lone Eagle
PO Box 160
Howes, SD 57748
bethcbest@gmail.com

Paul F. Seamans
27893 249th Street
Draper, SD 57531
jacknife@goldenwest.net

John H. Harter
28125 307th Avenue
Winner, SD 57580
johnharter11@yahoo.com

Viola Waln
PO Box 937
Rosebud, SD 57570
walnranch@goldenwest.net

Peter Capossela
Peter Capossela, P.C.
Representing Standing Rock Sioux Tribe
PO Box 10643
Eugene, OR 97440
pcapossela@nu-world.com

Wrexie Lainson Bardaglio
9748 Arden Road
Trumansburg, NY 14886
wrexie.bardaglio@gmail.com

Travis Clark
Fredericks Peebles & Morgan LLP
Suite 104, 910 5th St.
Rapid City, SD 57701
tclark@ndnlaw.com

Harold C. Frazier
Chairman, Cheyenne River Sioux Tribe
PO Box 590
Eagle Butte, SD 57625
haroldcfrazier@yahoo.com
mailto:kevinckeckler@yahoo.com

{01958978.1}

Jerry P. Jones
22584 US Hwy 14
Midland, SD 57552

Cody Jones
21648 US Hwy 14/63
Midland, SD 57552

Debbie J. Trapp
24952 US Hwy 14
Midland, SD 57552
mtdt@goldenwest.net

Gena M. Parkhurst
2825 Minnewsta Place
Rapid City, SD 57702
GMP66@hotmail.com

Jennifer S. Baker
Representing Yankton Sioux Tribe
Fredericks Peebles & Morgan LLP
1900 Plaza Dr.
Louisville, CO 80027
jbaker@ndnlaw.com

Joye Braun
PO Box 484
Eagle Butte, SD 57625
jmbraun57625@gmail.com

Duncan Meisel
350.org
20 Jay St., #1010
Brooklyn, NY 11201
duncan@350.org

The Yankton Sioux Tribe
Robert Flying Hawk, Chairman
PO Box 1153
Wagner, SD 57380
robertflyinghawk@gmail.com
Thomasina Real Bird
Attorney for Yankton Sioux Tribe
trealbird@ndnlaw.com

Bruce Ellison
Attorney for Dakota Rural Action
518 6th Street #6
Rapid City, SD 57701
belli4law@aol.com

Chastity Jewett
1321 Woodridge Drive
Rapid City, SD 57701
chasjewett@gmail.com

RoxAnn Boettcher
Boettcher Organics
86061 Edgewater Avenue
Bassett, NE 68714
boettcherann@abbnebraska.com

Bruce Boettcher
Boettcher Organics
86061 Edgewater Avenue
Bassett, NE 68714
boettcherann@abbnebraska.com

Bonny Kilmurry
47798 888 Road
Atkinson, NE 68713
bjkilmurry@gmail.com

Ronald Fees
17401 Fox Ridge Road
Opal, SD 57758

Robert P. Gough, Secretary
Intertribal Council on Utility Policy
PO Box 25
Rosebud, SD 57570
bobgough@intertribalCOUP.org

Tom BK Goldtooth
Indigenous Environmental Network (IEN)
PO Box 485
Bemidji, MN 56619
ien@igc.org

Dallas Goldtooth
38731 Res Hwy 1
Morton, MN 56270
goldtoothdallas@gmail.com

Gary F. Dorr
27853 292nd
Winner, SD 57580
gfdorr@gmail.com

Cyril Scott, President
Rosebud Sioux Tribe
PO Box 430
Rosebud, SD 57570
cscott@gwtc.net
ejantoine@hotmail.com

Paula Antoine
Sicangu Oyate Land Office Coordinator
Rosebud Sioux Tribe
PO Box 658
Rosebud, SD 57570
wopila@gwtc.net
paula.antoine@rosebudsiouxtribe-nsn.gov

Thomasina Real Bird
Representing Yankton Sioux Tribe
Fredericks Peebles & Morgan LLP
1900 Plaza Dr.
Louisville, CO 80027
trealbird@ndnlaw.com

Sabrina King
Dakota Rural Action
518 Sixth Street, #6
Rapid City, SD 57701
sabinra@dakotarural.org

Frank James
Dakota Rural Action
PO Box 549
Brookings, SD 57006
fejames@dakotarural.org

Robin S. Martinez
Dakota Rural Action
Martinez Madrigal & Machicao, LLC
616 West 26th Street
Kansas City, MO 64108
robin.martinez@martinezlaw.net

Tracey A. Zephier
Attorney for Cheyenne River Sioux Tribe
Fredericks Peebles & Morgan LLP
910 5th Street, Suite 104
Rapid City, SD 57701
tzephier@ndnlaw.com

Paul C. Blackburn
4145 20th Avenue South
Minneapolis, MN 55407
paul@paulblackburn.net

Matthew Rappold
Rappold Law Office
on behalf of Rosebud Sioux Tribe
PO Box 873
Rapid City, SD 57709
matt.rappold01@gmail.com

April D. McCart
Representing Dakota Rural Action
Certified Paralegal
Martinez Madrigal & Machicao, LLC
616 W. 26th Street
Kansas City, MO 64108
april.mccart@martinezlaw.net

Kimberly E. Craven
3560 Catalpa Way
Boulder, CO 80304
kimecraven@gmail.com

Joy Lashley
Administrative Assistant
SD Public Utilities Commission
joy.lashley@state.sd.us

Mary Turgeon Wynne
Rosebud Sioux Tribe - Tribal Utility Commission
153 S. Main Street
Mission, SD 57555
tuc@rosebudsiouxtribe-nsn.gov

Eric Antoine
Rosebud Sioux Tribe
PO Box 430
Rosebud, SD 57570
ejantoine@hotmail.com

WOODS, FULLER, SHULTZ & SMITH P.C.

By /s/ James E. Moore

William Taylor
James E. Moore
PO Box 5027
300 South Phillips Avenue, Suite 300
Sioux Falls, SD 57117-5027
Phone (605) 336-3890
Fax (605) 339-3357
Email James.Moore@woodsfuller.com
Attorneys for Applicant TransCanada

RESUME FOR DAN KING

EDUCATION: Bachelor of Science in Electrical Engineering, Minor in Computer Engineering, University of Calgary, 1983
Ivey Executive Program, Ivey School of Business, University of Western Ontario, 1997

EXPERIENCE SUMMARY: Over thirty years of experience in the design, construction, maintenance, project and program management of pipeline and energy facilities in Canada and overseas. Experience includes:
- leadership of TransCanada's central engineering group
- leadership of Pipe Integrity planning for 42,000k pipeline system
- front line and senior level management of several different multi-disciplinary teams.
- program management of the implementation of a receipt point specific pricing system for the NGTL pipeline system.
- wide variety of project and program management activities
- Development, design and commissioning work on the instrumentation and control systems for pipeline facilities.

EXPERIENCE: **TransCanada & Predecesor Companies**

2009 to Present **Vice President – Engineering & Asset Reliability**
Leadership of engineering and asset reliability for O&E operations as well as broader engineering, operations and major project support services including engineering governance, risk management and specialized core technical support

2005 to 2009 **Director – Engineering**
Management of the Engineering department. Accountable for the reliability of all TransCanada's operated physical assets including pipeline, power and other energy assets. Provide engineering standards, owner engineering functions and engineering expertise to the corporation. Leadership for 12 managers, strategy and goal setting for the department, reorganization and other change initiatives.

2003 to 2005 **Director – Pipe Engineering**
Management of the Pipe Engineering department. Accountable for the development, implementation, standards and technical support for the pipeline integrity program at TransCanada. Leadership for 3 managers, strategy and goal setting for the department, reorganization and outsourcing of certain activities.

2000 to 2003 **Manager – Program Development – Pipe Engineering**
Management of a multidisciplinary group accountable for the development of the pipe integrity program for TransCanada. The group uses extensive quantitative risk management techniques to develop a $65 to $100 million per year program to ensure the safety of the pipeline system. Includes the management and planning activities for a staff of approximately 25 engineers and technologists, dealing extensively with regulators and other third parties.

1999 to 2000 **Manager – Materials, Standards and Technology**
Management of a services group accountable for: materials testing and failure analysis, Engineering Standards and Procedures management, Technology Program Management (R&D). Includes the management and planning activities for a staff of approximately 25 engineers and technologists executing a program of approximately $10 Million annually.

'998 to 1999	**Program Manager - Products & Pricing Implementation** **Customer Interface - Rates and Revenues** Responsible for developing and managing the program to implement the business process and computer system changes necessary to support the major change in Nova Gas Transmission's service and pricing offerings to customers. This change involves moving from the "Postage Stamp" toll to receipt point specific tolls.
1983 to 1998	**Various Positions** Various line and leadership roles of increasing responsibility in the design, construction, commissioning and operations of natural gas and liquid pipeline facilities in Canada and overseas.

PROFESSIONAL ASSOCIATIONS:

- Association of Professional Engineers and Geoscientists of Alberta
- Institute of Electrical and Electronic Engineers
- ASME International

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 PIPELINE	: : : : :	HP 14-001 REBUTTAL TESTIMONY OF F. J. (RICK) PERKINS

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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 F. J. (Rick) Perkins.

1. Please state your name and occupation.

Answer: Rick Perkins. I am the Project Manager-Logistics and Services for the TransCanada Keystone XL Pipeline project. I am employed by TransCanada.

2. Whose testimony are you rebutting?

Answer: Faith Spotted Eagle.

3. Are construction workforce camps to be utilized during the construction of the KXL pipeline part of your area of responsibility?

Answer: Yes.

4. Will there be any workforce camps in South Dakota during the construction of the Keystone XL pipeline?

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Answer: Yes, three camps, one located near Buffalo in Harding County, one near Howes in northern Meade County, and one near Colome in Tripp County.

5. Will Keystone operate the camps?

Answer: No, the camps will be operated by Target Logistics, a company that specializes in the development and in the operation of workforce camps worldwide.

6. Tell the Commission about Target Logistics' experience in operating workforce camps.

Answer: Target Logistics is highly experienced in operating workforce camps, both civilian and military. It has operated workforce camps throughout the nation and internationally for years.

7. Describe the camps for the Commission.

Answer: The workforce camps are constructed on property that is leased for that purpose. Keystone has leased sites for the three South Dakota workforce camps. Each camp is constructed employing purpose built modular units. The modular living units contain rooms much like small motel rooms, each occupied by a project employee. Other modular support units contain a commissary style store that sells a wide range of necessities, a kitchen and dining complex, medical facilities, recreational facilities, laundry facilities, administrative offices; other modular units contain support facilities. The camp will be entirely removed at the conclusion of camp operation. Target Logistics supplies the modular units, custom built to Keystone's specifications.

8. What is the capacity of the camps?

Answer: Typically the camps will be constructed to accommodate a peak capacity of 1,200 persons. During the run up to the peak of construction, occupancy will ramp up over time. We expect occupancy during the height of construction to peak at about 1,200 and to ramp down as construction activities are completed.

9. How long do you expect the camps to remain open?

Answer: Approximately 18 months from the beginning of camp construction until the camp is closed and all facilities removed.

10. Describe the typical employee who will live in the camps.

Answer: The camps will be populated by pipeline construction workers and construction support personal. Pipeline construction workers, often called "pipeliners," are typically union employees, hired by our construction contractors. Most are career pipeliners, who make their living constructing cross-country pipelines. Skill sets run from common laborers to equipment operators through highly skilled specialty welders, inspectors, and a wide variety of specialist technicians and support personnel. Typically, a superintendent for one of our contractors has a core group of key employees that he hires for each project; usually all are acquainted, and work on projects as they develop. Pipeliners as a group are hard-working, used to long work hours, highly responsible, and well compensated. Many have college degrees and years of experience in the business of constructing pipelines. The average age of camp occupants will be in the early 40s.

In addition, Target Logistics employees who operate the workforce camps will live in the camps.

11. How do construction workers get from the camp to the job site?

Answer: Pipeline construction is accomplished in construction "spreads". A "spread" is considered the labor and equipment required to construct the pipeline in a given geographic area, typically a distance of from fifty to one-hundred miles long. Many of the pipeline construction workers are transported to and from the pipeline construction location each day in work buses provided by the pipeline construction contractor. This is done to reduce highway traffic congestion.

12. Are there behavior codes imposed on occupants of the camps?

Answer: Target Logistics will have strict behavior codes that apply to all persons living in the camp. If a resident violates the terms of the behavior code, their residency in the camp could be terminated. Because camp lodging will be provided to all camp residents at Keystone's expense; the loss of camp residency privileges is a major cost benefit to the worker and a major good behavior motivator. Therefore, we anticipate no discipline problems in the camps.

13. How are the behavior codes enforced?

Answer: Each camp will have a security team provided by Target Logistics. The security team enforces the rules of conduct that govern the camps. There is very little occasion to enforce the behavior codes in the camps. Most workers put in 10 hour days, plus travel time from the camp to the construction and return, and accordingly have little extra time or energy to involve themselves in behavior that is in violation of the occupancy rules.

14. Is local law enforcement engaged for the camps?

Answer: Target Logistics will provide 24-7 camp security using its own security officers. Local law enforcement will be engaged if needed within the camps; however, that is not anticipated. Keystone has already conducted preliminary discussions with local law enforcement agencies and has indicated that when necessary, it will augment the cost of additional law enforcement personnel required as a result of the workforce camp.

15. Have you obtained local government approval for the camps?

Answer: Keystone has obtained a conditional use permit from Harding County for the construction and operation of the camp near Buffalo. A conditional use permit for operation of the camp to be constructed in Meade County is not required; however an occupancy permit for work force camp will be obtained prior to operation of the camp. Tripp County does not have a zoning ordinance or a conditional use permit requirement for the camp planned for near Colome.

16. Is your professional resume attached and marked Exhibit A?

Answer: Yes.

Dated this 25th day of June, 2015.

F. J. (Rick) Perkins

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 Direct Testimony of F. J. (Rick) Perkins, to the following:

Patricia Van Gerpen
Executive Director
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
patty.vangerpen@state.sd.us

Kristen Edwards
Staff Attorney
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
kristen.edwards@state.sd.us

Brian Rounds
Staff Analyst
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
brian.rounds@state.sd.us

Darren Kearney
Staff Analyst South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
darren.kearney@state.sd.us

Tony Rogers, Director
Rosebud Sioux Tribe - Tribal Utility Commission
153 South Main Street
Mission, SD 57555
tuc@rosebudsiouxtribe-nsn.gov

Cindy Myers, R.N.
PO Box 104
Stuart, NE 68780
csmyers77@hotmail.com

Jane Kleeb
1010 North Denver Avenue
Hastings, NE 68901
jane@boldnebraska.org

Byron T. Steskal
Diana L. Steskal
707 E. 2nd Street
Stuart, NE 68780
prairierose@nntc.net

Terry Frisch
Cheryl Frisch
47591 875th Road
Atkinson, NE 68713
tcfrisch@q.com

Arthur R. Tanderup
52343 857th Road
Neligh, NE 68756
atanderu@gmail.com

Lewis GrassRope
PO Box 61
Lower Brule, SD 57548
wisestar8@msn.com

Carolyn P. Smith
305 N. 3rd Street
Plainview, NE 68769
peachie_1234@yahoo.com

{01971871.1}

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Robert G. Allpress
46165 Badger Road
Naper, NE 68755
bobandnan2008@hotmail.com

Amy Schaffer
PO Box 114
Louisville, NE 68037
amyannschaffer@gmail.com

Louis T. (Tom) Genung
902 E. 7th Street
Hastings, NE 68901
tg64152@windstream.net

Benjamin D. Gotschall
6505 W. Davey Road
Raymond, NE 68428
ben@boldnebraska.org

Nancy Hilding
6300 West Elm
Black Hawk, SD 57718
nhilshat@rapidnet.com

Elizabeth Lone Eagle
PO Box 160
Howes, SD 57748
bethcbest@gmail.com

Paul F. Seamans
27893 249th Street
Draper, SD 57531
jacknife@goldenwest.net

John H. Harter
28125 307th Avenue
Winner, SD 57580
johnharter11@yahoo.com

Viola Waln
PO Box 937
Rosebud, SD 57570
walnranch@goldenwest.net

Peter Capossela
Peter Capossela, P.C.
Representing Standing Rock Sioux Tribe
PO Box 10643
Eugene, OR 97440
pcapossela@nu-world.com

Wrexie Lainson Bardaglio
9748 Arden Road
Trumansburg, NY 14886
wrexie.bardaglio@gmail.com

Travis Clark
Fredericks Peebles & Morgan LLP
Suite 104, 910 5th St.
Rapid City, SD 57701
tclark@ndnlaw.com

Harold C. Frazier
Chairman, Cheyenne River Sioux Tribe
PO Box 590
Eagle Butte, SD 57625
haroldcfrazier@yahoo.com
mailto:kevinckeckler@yahoo.com

Jerry P. Jones
22584 US Hwy 14
Midland, SD 57552

Cody Jones
21648 US Hwy 14/63
Midland, SD 57552

Debbie J. Trapp
24952 US Hwy 14
Midland, SD 57552
mtdt@goldenwest.net

Gena M. Parkhurst
2825 Minnewsta Place
Rapid City, SD 57702
GMP66@hotmail.com

Jennifer S. Baker
Representing Yankton Sioux Tribe
Fredericks Peebles & Morgan LLP
1900 Plaza Dr.
Louisville, CO 80027
jbaker@ndnlaw.com

Joye Braun
PO Box 484
Eagle Butte, SD 57625
jmbraun57625@gmail.com

Duncan Meisel
350.org
20 Jay St., #1010
Brooklyn, NY 11201
duncan@350.org

The Yankton Sioux Tribe
Robert Flying Hawk, Chairman
PO Box 1153
Wagner, SD 57380
robertflyinghawk@gmail.com
Thomasina Real Bird
Attorney for Yankton Sioux Tribe
trealbird@ndnlaw.com

Bruce Ellison
Attorney for Dakota Rural Action
518 6th Street #6
Rapid City, SD 57701
belli4law@aol.com

Chastity Jewett
1321 Woodridge Drive
Rapid City, SD 57701
chasjewett@gmail.com

RoxAnn Boettcher
Boettcher Organics
86061 Edgewater Avenue
Bassett, NE 68714
boettcherann@abbnebraska.com

Bruce Boettcher
Boettcher Organics
86061 Edgewater Avenue
Bassett, NE 68714
boettcherann@abbnebraska.com

Bonny Kilmurry
47798 888 Road
Atkinson, NE 68713
bjkilmurry@gmail.com

Ronald Fees
17401 Fox Ridge Road
Opal, SD 57758

Robert P. Gough, Secretary
Intertribal Council on Utility Policy
PO Box 25
Rosebud, SD 57570
bobgough@intertribalCOUP.org

Tom BK Goldtooth
Indigenous Environmental Network (IEN)
PO Box 485
Bemidji, MN 56619
ien@igc.org

Dallas Goldtooth
38731 Res Hwy 1
Morton, MN 56270
goldtoothdallas@gmail.com

Gary F. Dorr
27853 292nd
Winner, SD 57580
gfdorr@gmail.com

Cyril Scott, President
Rosebud Sioux Tribe
PO Box 430
Rosebud, SD 57570
cscott@gwtc.net
ejantoine@hotmail.com

Paula Antoine
Sicangu Oyate Land Office Coordinator
Rosebud Sioux Tribe
PO Box 658
Rosebud, SD 57570
wopila@gwtc.net
paula.antoine@rosebudsiouxtribe-nsn.gov

Thomasina Real Bird
Representing Yankton Sioux Tribe
Fredericks Peebles & Morgan LLP
1900 Plaza Dr.
Louisville, CO 80027
trealbird@ndnlaw.com

Sabrina King
Dakota Rural Action
518 Sixth Street, #6
Rapid City, SD 57701
sabinra@dakotarural.org

Frank James
Dakota Rural Action
PO Box 549
Brookings, SD 57006
fejames@dakotarural.org

Robin S. Martinez
Dakota Rural Action
Martinez Madrigal & Machicao, LLC
616 West 26th Street
Kansas City, MO 64108
robin.martinez@martinezlaw.net

Tracey A. Zephier
Attorney for Cheyenne River Sioux Tribe
Fredericks Peebles & Morgan LLP
910 5th Street, Suite 104
Rapid City, SD 57701
tzephier@ndnlaw.com

Paul C. Blackburn
4145 20th Avenue South
Minneapolis, MN 55407
paul@paulblackburn.net

Matthew Rappold
Rappold Law Office
on behalf of Rosebud Sioux Tribe
PO Box 873
Rapid City, SD 57709
matt.rappold01@gmail.com

April D. McCart
Representing Dakota Rural Action
Certified Paralegal
Martinez Madrigal & Machicao, LLC
616 W. 26th Street
Kansas City, MO 64108
april.mccart@martinezlaw.net

Kimberly E. Craven
3560 Catalpa Way
Boulder, CO 80304
kimecraven@gmail.com

Joy Lashley
Administrative Assistant
SD Public Utilities Commission
joy.lashley@state.sd.us

Mary Turgeon Wynne
Rosebud Sioux Tribe - Tribal Utility Commission
153 S. Main Street
Mission, SD 57555
tuc@rosebudsiouxtribe-nsn.gov

Eric Antoine
Rosebud Sioux Tribe
PO Box 430
Rosebud, SD 57570
ejantoine@hotmail.com

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WOODS, FULLER, SHULTZ & SMITH P.C.

By /s/ James E. Moore

William Taylor
James E. Moore
PO Box 5027
300 South Phillips Avenue, Suite 300
Sioux Falls, SD 57117-5027
Phone (605) 336-3890
Fax (605) 339-3357
Email James.Moore@woodsfuller.com
Attorneys for Applicant TransCanada

F.J. (Rick) Perkins

5401 Rampart #275, Houston, TX 77081 Work: (832) 320-5915 Cell: (402) 350-1281

email: Rick_Perkins@TransCanada.com

CAREER EXPERIENCE OVERVIEW

- 25 Years - Service contract development for onshore and offshore pipeline, process plant, and compressor station engineering, construction, and other project support activities
- 6 Years - International Offshore Project Materials Management (Purchasing and Logistics)
- 7 Years - Onshore exploration and production administrative budgeting and forecasting, office and fleet management
- 3 Years – Project Management

SIGNIFICANT CAREER ACCOMPLISHMENTS

- As a Buyer, Purchasing Manager, and Contracts Manager, I have participated in the development and installation of 5 major offshore platforms in the Java Sea in Indonesia, the development and installation of over 3,000 miles of large diameter pipeline and over 500,000 horsepower of pipeline compression in the United States.

WORK HISTORY

May/2012 - Present **TransCanada/Keystone XL Project – Houston, TX – responsible for project workforce camp development, project pipe logistics and pipe preservation activities, project aviation requirements, and project field office development.**
Title – Project Manager – Services & Logistics

2010–May/2012 **TransCanada USA Operations, Inc. – Houston, TX - currently manage the service contracting requirements in the U.S. for all of TransCanada operating pipeline entities**
Title – Supply Chain Management - Manager – U.S. Services

2007 to Sept 2010 **TransCanada USA Operations, Inc. – Omaha, NE - supported various TransCanada pipelines with the purchasing and contract requirements for major pipeline and compression projects in the United States**
Title - Sr. Contract Analyst

2005 to 2007 **ONEOK Partners GP, LLC - supported Northern Border Pipeline Company, Viking Gas Transmission Co, Guardian Pipeline LLC, and Midwestern Gas Transmission Co with their contract requirements for major pipeline and compression projects in the United States**
Title - Sr. Contract Analyst

2002- 2005 **EL PASO CORPORATION - supported ANR Pipeline Co. and Tennessee Gas Transmission Co. with the contract requirements for major pipeline and compressor projects, both onshore and offshore**
Title – Principal Procurement Specialist

1989 – 2002 **Enron Engineering and Construction Co. (supported all Enron pipeline entities with the contract requirements for all major pipeline and compression projects in the U.S.)**
Title: Contracts Manager – Major Projects

1987 – 1989 **Enron Gas Processing Company**
Title: Sr. Administrative Specialist

1980 – 1987 **Lear Petroleum Corp**
Title: Division Administrative Manager

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1975 – 1980	**Natomas International Corp.** **(parent company of "Independent Indonesian American Petroleum Company")** **Title: Buyer/Purchasing Manager**
1973 – 1975	**Ingersoll Rand Corp.** **Title: Regional Corporate Expediter**
1971 – 1973	**Missouri Pacific Railroad** **(now part of Union Pacific Railroad)** **Assistant Terminal Manager**

EDUCATION
BBA, University of Houston, 1971
CM, American Society of Transportation & Logistics
Airline Transport Pilot, Flight Instructor

HEALTH
Excellent, non-smoker.

REFERENCES – Personal and Professional
Furnished upon request.

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	HP 14-001 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 testimonies of Richard Kuprewicz of Accufacts Inc., Ian Goodman and Brigid Rowan of The Goodman Group, Ltd., and Arden Davis, Ph.D., P.E.

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4. Kuprewicz (p. 4) and Goodman and Rowan (p. 22, 23, 24, 25, 34, 35, and 50) question the use of historical incident databases to conduct the 2009 Keystone XL Risk Assessment included as part of the Department of State Final Supplemental Environmental Impact Statement (FSEIS). Can you comment on the use of historical incident databases, such as the PHMSA database, as industry practice? Additionally, please explain how the PHMSA database was used to determine risk as part of the permitting process for the Keystone XL pipeline.

Answer: During the environmental permitting process, Keystone elected to provide an estimate of failure frequencies and range of probable spill volumes based on historical data since no operational data is available for the proposed project. These statistics are then combined with environmental data to assess the reasonable range of environmental impacts that may occur in the event of a release.

The PHMSA database was used in the development of the 2009 Keystone XL Risk Assessment. While future events cannot be known with absolute certainty, historic incident frequencies are an appropriate basis on which to estimate the number of events that might occur over a period of time. The 2009 Keystone XL Risk Assessment was developed as a part of the State Department's environmental review under the National Environmental Policy Act (NEPA) during its permitting process. The purpose of this Risk Assessment is to provide a conservative range of anticipated effects from the operation of the Project that is sufficient for the purposes of federal permitting requirements. Additionally, the 2009 Keystone XL Risk Assessment provides a preliminary evaluation of potential risk during the pipeline's design phase and provides an initial basis for emergency response planning.

A two-year independent review of Keystone XL's design and the 2009 Keystone XL Risk Assessment was conducted by Battelle Memorial Institute (Battelle) and E^{x}ponent Inc. (E^{x}ponent) under the direction of the US Department of State (DOS), Pipeline and Hazardous Materials Safety Administration (PHMSA), and the US Environmental Protection Agency (USEPA) to address concerns raised by the USEPA in the NEPA review of the proposed project. Battelle (2013) concluded that "*because historic data provide a sound basis to assess risk from a historic perspective, it is customary to do such analysis based on the historic record. As stated in the [2009] Keystone [XL] Risk Assessment, the Project is being weighed relative to the US portion of the system; therefore, their assessment focused exclusively on the US database, which is maintained by the PHMSA…As has been noted by Keystone, all data available were used with the exception of information involving terminals and tanks, with a rationale noted for that decision. As needed, gaps were bridged or adjustments were made in the context of judgment, which has been a usual practice since risk analysis emerged in the early 1990s as a viable assessment under the auspices of a joint industry-government task force…Much of what has been done is usual and consistent with industry practices as part of the procedure for obtaining PHMSA approval to commission a pipeline.* ***However, the Risk Assessment presented does go beyond the process typically followed for the National Environmental Policy Act (NEPA) stage of the Federal process*** [emphasis added]" (Battelle 2013).

5. Kuprewicz (p. 4) and Goodman and Rowan (p. 23, 25, 50, and 52) suggest that PHMSA data have significantly changed since the 2009 Keystone XL Risk Assessment due to the "recent growth in North America crude oil production, the accompanying increase in terrestrial transport of more hazardous non-conventional crudes, as well as the unfortunate advent of very large spills." Based on your analysis, has the PHMSA incident

database significantly changed such that the findings and conclusions of the 2009 Keystone XL Risk Assessment are no longer valid?

Answer: No. For consistency, the values presented in this testimony are based on the same database used for the 2009 Keystone XL Risk Assessment. Nonetheless, the risk statistics presented in the 2009 Keystone XL Risk Assessment are highly comparable with current PHMSA data. Recent high profile spill events remain extremely uncommon and are not representative of the majority of spills. Spill volume data continue to reflect a highly skewed distribution, with the spill distribution for very large spills decreasing by one tenth of one percent (i.e., spills greater than 10,000 barrels now account for 0.4% of all spills, as compared to 0.5% of all spills as reported in 2009 Keystone XL Risk Assessment).

6. Goodman (p. 23) states "[m]ost of the data is provided by industry, which tends to underreport spills, particularly the serious ones, which are of greatest concern." Please comment on this assertion.

Answer: Goodman's assertion that operators do not comply is contrary to federal regulations is unsupported by data. Since 2002, pipeline operators are required by federal regulations (49 CFR Sections 195.50 and 195.54) to file accident reports for a release of 5 gallons or more. Failure to report incidents constitutes a noncompliance violation and PHMSA can impose fines and other punitive measures. PHMSA regularly audits pipeline operators for compliance. Questions regarding compliance with incident reporting are identified on two separate auditing forms provided by PHMSA. These forms allow operators to conduct internal audits to ensure compliance and provide companies with the minimum documentation that they will be required to produce during an audit.

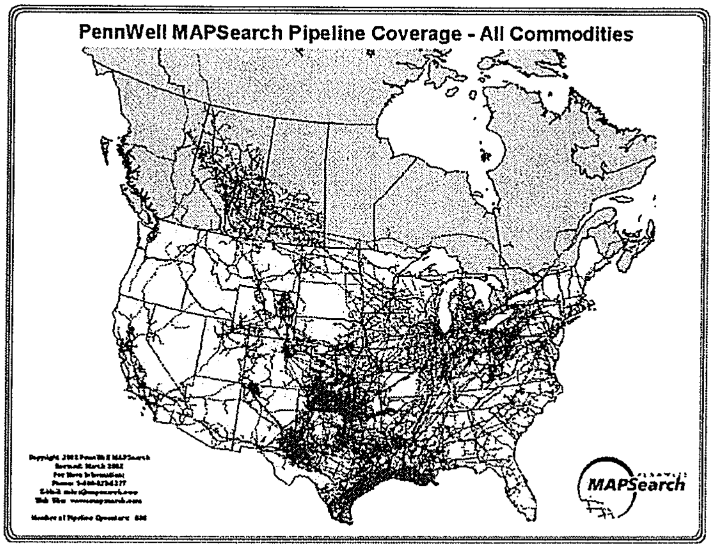
7. Kuprewicz (p. 5) suggests that a "true risk assessment" should be conducted using "specific pipeline" information. Goodman and Rowan (p. 22, 23, 24, and 25) also suggest that a similar site-specific risk assessment using "the elevation profile and other key information" be conducted. Can you comment on these suggestions?

Answer: As described above, the 2009 Keystone XL Risk Assessment was prepared as part of the environmental permitting process and evaluated all "specific pipeline" information identified by Kuprewicz and Goodman and Rowan.

8. Can you comment on the appropriateness of the PHMSA database for determining risk in areas that are "unique" (e.g., areas of reported high landslide risk as mentioned in testimonies of Kuprewicz [p. 2 and 4] and Goodman and Rowan [p. 22])?

Answer: The PHMSA incident database contains historical incident data for approximately 200,000 miles of liquid pipelines. The extent of US liquid pipelines is shown on Figure 1. These pipelines routinely cross discrete areas of high landslide risk, slope instability, soils with high clay content, and other landscape features. Thus, it is reasonable to use the PHMSA database to estimate incident frequencies for a pipeline that crosses several states for permitting purposes.

Figure 1. Pipelines in North America



While geological hazards are addressed at a macro-scale in the 2009 Keystone XL Risk Assessment, actual routing, design, engineering, and operations incorporate site-specific information and analyses to account for terrain, including slope stability issues.

9. Kuprewicz (p. 6) states, "[l]andslides are most likely to be associated with high water/rain events (e.g., flash floods) where rivers and streams will be at higher flow." Can you comment on that assertion?

Answer: While landslides may be associated with high water/rain events, pipeline failures caused by flooding are not associated with landslides. Instead, pipeline failures caused by flooding are almost always due to the loss of cover caused by either vertical scour or lateral stream migration.

While flooding only causes a small fraction of pipeline failures (0.52%) with a median spill volume of 97.0 barrels (PHMSA 2008), under federal regulations (49 CFR Section 195), Keystone's Integrity Management Program is required to monitor and reduce risks from a number of threats, including outside forces due to flooding.

Pipeline failures at river crossings are highly uncommon and almost always are associated with loss of depth of cover. According to the PHMSA Report to US Congress (2012), during the 21-year span between 1991 and 2012, only 20 accidents involving water crossings occurred. "*A depletion of cover, sometimes in the waterway and other times in new channels cut by floodwaters, was a factor in 16 accidents. The dynamic and unique nature of rivers and flood plains was a factor in each accident. These 16 accidents are 0.3 percent of all reported hazardous liquid accidents and 0.5 percent of the hazardous liquid significant incidents*" (PHMSA 2012). A "significant release" is defined by PHMSA as a release of 50 barrels or more, fire, explosion, injury resulting in hospitalization, fatality, or damages of $50,000 or more of cost incurred by operator (PHMSA 2015). PHMSA promulgated 49 CFR Section 195 to establish minimum pipeline safety standards for hazardous liquid pipeline systems. Regulations relevant to depth of cover are found in two subparts: Construction, and Operation and Maintenance.

As part of the 59 Special Conditions developed by PHMSA and set forth in Appendix Z to the State Department's FSEIS, Keystone has committed to a depth of cover of 48 inches in most locations, which exceeds federal regulatory standards. Additionally, as part of the 59 PHMSA Special Conditions, Keystone is required to maintain that depth of cover for the life of the Project.

10. Kuprewicz (p. 6) states that landslides are the "most likely event that could cause rupture" for the Keystone XL pipeline in South Dakota. Goodman and Rowan (p. 28) state that the worst case scenario for the Keystone XL pipeline is "a full bore rupture…caused by a breakaway landslide in areas of steep elevation change." Is the risk of

landslides/ground movement expected to be a leading cause of pipeline failure along the route in South Dakota?

Answer: No. The relevant historical data indicate that the overall probability of an incident related to landslides is very low and unlikely to be the leading cause of pipeline incidents for Keystone XL. Earth movement accounts for approximately 0.56% of pipeline incidents (PHMSA 2008). This is corroborated by Goodman and Rowan on page 27 of their testimony. The majority of earth movement incidents result in relatively small releases, with 50% resulting in releases of 43.5 barrels or less (PHMSA 2008).

11. Kuprewicz (p. 2) and Goodman and Rowan (p. 10 and 36) claim that a rupture would result in substantial volumes of oil being released along terrain in South Dakota. Please comment on the probability of a large volume spill occurring along the route.

Answer: Based on the PHMSA dataset, the probability of a 10,000 barrel spill at any 1-mile segment along the Keystone XL pipeline in South Dakota is equivalent to 1 spill every 1.5 million years. The occurrence intervals for a range of spill volumes, including greater than 10,000 barrels, are shown in Table 1.

Table 1 Occurrence Intervals by Spill Volume

	Occurrence Interval (years) by Spill Volume				
Crossing Distance	**All spills**	**3 bbl**	**100 bbl**	**1,000 bbl**	**10,000 bbl**
1 mile	7,407	14,599	48,662	145,985	1,459,854

Source: PHMSA 2008.

Based on the PHMSA pipeline incident database (2002 to 2009), only 3.8% and 3.2% of spills affected surface water or groundwater resources, respectively, and most of those water resources were not drinking water resources. Only 0.16% of spills actually affect drinking water resources. Consequently, the possibility of a spill occurring and affecting drinking water is very remote.

12. Kuprewicz (p. 2) claims that there would be a "remarkably low amount of released oil that will actually be recovered in the event of a spill." Please comment on the fate of released crude oil in the environment in the event of a spill.

Answer: Crude oil released into the environment undergoes weathering (i.e., the loss and degradation of petroleum products). Using ADIOS2, an environmental fate model for crude oil spills, approximately 20 to 60% of the crude oil evaporates within the first 12 hours following a spill. For Western Canadian Select, approximately 20% evaporates in the first 12 hours, consistent with other heavy conventional crude oils. In addition, according to the PHMSA database, approximately 50% of crude oil released is recovered. Therefore, the vast majority of crude oil either evaporates or is recovered following an incident.

13. Goodman and Rowan (p. 28 and 29) claim that "[i]n light the Line 6B spill, there is now substantial evidence that dilbit can sink in water making a dilbit spill to water significantly more difficult to clean up." Please comment on this assertion.

Answer: On July 25, 2012, Enbridge's 6B pipeline failed near Marshall, Michigan, and released over 20,000 barrels of oil into Talmadge Creek. At the time of the accident, Enbridge's 6B pipeline was transporting Cold Lake diluted bitumen. An API of 10 is equivalent to water, which means any oil with an API above 10 will float on water while any with an API below 10 will sink (Petroleum 2015). Keystone's diluted bitumen has an API gravity of 16. In comparison, the API gravities of Western Canadian Select and Bakken crude are 20.6 and 52.9, respectively (Crude Monitor 2013, Shafizadeh 2010). Cold Lake's API value is lower than most diluted bitumen crude oils but is greater than 10 and, therefore, it was expected to float on the water's surface. According to the US Environmental Protection Agency (DOS 2014, USFWS et al. 2015) and PHMSA's on-site coordinator (J. Hess, personal communication, January 2013), the oil did float initially, as expected.

It has been suggested that the type of oil contributed to the severity of the spill and its impacts. Recent evaluations of diluted bitumen (Battelle 2012, Been 2011, National Academy of Sciences [NAS] 2013) found no significant differences in the physical or chemical properties of diluted bitumen and other heavy crude oils. Copies of these reports have been attached as Exhibits 1 through 3 of my testimony.

The behavior of the crude oil in the Kalamazoo spill was similar to that expected for other heavy crude oils; it was not unique. Extenuating factors (flood conditions and emergency response times) allowed time for the crude to weather prior to cleanup. As the oil weathered with time (i.e., light end hydrocarbons evaporated), the remaining oil became heavier until the API gravity was less than 10 and portions of the oil slick became submerged. This process was exacerbated by heavy turbulence caused when the oil passed over an overflow dam and flooding that caused sediment, rocks, debris, and water to become incorporated into the crude oil, forming a heavier-than-water emulsion. The resulting submerged oil formed globules that were transported downstream.

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

Crude Monitor. 2013. Western Canadian Select. Website accessed 24 Jan 2013. Website: http://crudemonitor.ca/crude.php?acr=WCS.

National Academy of Sciences (NAS). 2013. Special Report 311: Effect of Diluted Bitumen on Crude Oil Transmission Pipelines. 110 pp.

Petroleum. 2015. API Gravity. Internet website: http://www.petroleum.co.uk/api. Accessed on May 27, 2015.

Shafizadeh, A. (2010, June 10). Bakken [Powerpoint slides]. Retrieved from Crude Oil Quality Association website: http://www.coqa-inc.org/06102010_Shafizadeh.pdf

US Fish and Wildlife Service (USFWS), Nottawaseppi Huron Band of the Potawatomi Tribe, Match-E-Be-Nash-She-Wish Band of the Pottawatomi Indians. 2015. Draft Damage Assessment and Restoration Plan/Environmental Assessment for the July 25-26, 2010 Enbridge Line 6B Oil Discharges near Marshall, MI. May 2015.

14. Following up on Goodman and Rowan's discussion of the Kalamazoo spill (p. 23), can you discuss key differences between Enbridge Line 6B and the proposed Keystone XL pipeline that affect the risk posed by each pipeline.

Answer: A major failure comparable to Enbridge's 6B failure at Kalamazoo is highly unlikely for the Keystone XL pipeline for the following key reasons: i) the quality of the pipe and longitudinal seam welding procedures; ii) corrosion protection systems; iii) the use of in-line inspection tools; and iv) other key materials and construction procedures.

Pipeline manufacturing processes and regulatory standards have evolved and improving technologies have resulted in demonstrable improvements in pipeline safety performance. The Enbridge Line 6B pipeline was constructed in 1969 when there were different pipe materials and manufacturing processes than today. The Keystone XL pipeline will be manufactured with much higher quality and stronger steel that helps reduce the impacts of external forces, such as excavation and flooding damage.

Federal pipeline regulations have evolved over time and pipeline operators are now required to manage their pipelines actively to reduce the possibility of incidents. Keystone has agreed to implement an additional 59 PHMSA Special Conditions identified in the FSEIS. The State Department, in consultation with PHMSA, has determined that incorporation of the 59 PHMSA Special 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 HCAs, as defined in 49 CFR 195.450*" (DOS 2014).

15. Goodman and Rowan (p. 38 and 52) state, "a slow and undiscovered leak is likely to be the more serious threat to the Ogallala Aquifer and RST water resources." Kuprewicz (p. 7 and 8, respectively) states, "leaks are probably the most likely risk of concern to the water wells" and that leaks "could migrate underground possibly delaying discovery." Please comment on the subsurface movement of groundwater plumes and the potential impacts on these specific groundwater resources.

Answer: The proposition that a leak could go undetected for a long period of time that could release thousands of barrels is not realistic. The independent Battelle review (2013) concurred with the conclusions in the 2009 Keystone XL Risk Assessment that a small leak going undetected indefinitely is unlikely. Battelle (2013) estimated that crude oil from a small "pin hole" leak (28 bbl/day) would theoretically reach the ground surface in no more than a few months.

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 almost always are small. The data used in the 2009 Risk Assessment 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 demonstrate that the theory of a leak going undetected for months to years resulting in a release of tens of thousands of barrels is not reasonable or realistic.

In the event of a release, crude oil would spread through the interstitial spaces between soil particles. Often the oil will remain in the trench where soils are less consolidated compared to the adjacent soils as well as move to the soil's surface. Crude oil adheres to soil particles and has very limited mobility. If crude oil was not removed from the environment and crude oil came into contact with groundwater, soluble constituents could begin to form a groundwater plume. Plume formation takes months to years to occur due to the limited subsurface movement of petroleum hydrocarbons. Newell and Connor (1998) summarized the results of four nationwide studies looking at groundwater plumes from petroleum hydrocarbon contamination. The results show that the subsurface movement of petroleum hydrocarbons is very limited, moving 312 feet or less in 90 percent of the cases. Additional studies support this plume transport distance. Copies of these reports have been attached as Exhibits 4 through 9 of my testimony.

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.

16. Goodman and Rowan (p. 32, 37, and 52) also identify groundwater resources associated with the Ogallala Aquifer in Tripp County as being a high value resource. How is Keystone addressing groundwater vulnerability in this region?

Answer: The High Plains Aquifer area in southern Tripp County has been identified as a hydrological 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.

17. Kuprewicz (p. 3 and 6) states, "[i]t is my understanding that much of the state gets its water from the Missouri River so the impact on the state's overall water supply should the pipeline rupture and threaten this resource needs to be properly evaluated." Please comment on this as it relates to spill distance to this resource and possible impacts.

Answer: The Missouri River is not crossed by the Keystone XL pipeline and is located at least 82 river miles downstream from the Keystone XL pipeline at the closest point. The White River represents the shortest downstream flow path from the pipeline to the Missouri River. The 82-mile distance far exceeds the maximum transport distance observed in even catastrophic pipeline failures during flood conditions. Three major rivers that are tributaries to the Missouri River will be crossed using HDD, thereby reducing the possibility of i) stream scour resulting in pipeline failure and ii) a pipeline release entering the waterbody due to the amount of overburden. All water crossings were evaluated using a vertical and horizontal scour analysis based on a 100-year flood event and the depth of crossings adjusted accordingly.

Most historic spill incidents are relatively small, are contained in close proximity to the origin of the spill, are cleaned up immediately, and never reach flowing surface water. Most spills would not move significant distances downstream and still be detectable. Under exceptional circumstances, there have been cases where large volume spills have resulted in crude oil being detected miles downstream. Examination of exceptional spill events (e.g., spills into the Coffeyville and Kalamazoo rivers) illustrate that contamination typically does not travel more than 20 miles downstream, with the maximum observed distance of 30 miles. Following a 10,000 barrel release in 2007 from the Coffeyville 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 reports that contamination has been documented in localized areas within 30 miles of the spill's origin. I concur with Kuprewicz's conclusion on p. 3 and reiterated on p. 7 that the risks to the two RST water supply line crossings and the Cheyenne River are not significant.

18. Kuprewicz (p. 6) states, "[t]he steepness of the terrain also indicates that a rupture release will result in considerable surface migration, either over the ground surface or via

river transport should a rupture release reach a river that crosses the pipeline." Please comment on river and overland ground transport distances of diluted bitumen.

Answer: Refer to my response to Question 17 for case studies regarding downstream transport distances following large spills. Maximum overland transport distances were calculated using a GIS-based analysis and pipeline product parameters (e.g., transport temperature, dynamic viscosity, and 25,000-barrel spill). Overland transport distances for diluted bitumen are summarized in Table 2.

Table 2 Overland Transport Distances

Slope (%)	Miles of Route	Transport Distance (feet)
Herbaceous Land		
0-20	297	35-218
20-25	13	244
25-30	3	267
30-35	1	289
>35	1	345
Barren Land		
0-20	297	103-655
20-25	13	732
25-30	3	802
30-35	1	866
>35	1	1,035

19. Goodman and Rowan (p. 22 and 24) raise concerns as to whether sufficient attention is being given to these sensitive areas in terms of pipeline safety and oil spill response planning. Please comment on protection of High Consequence Areas.

Answer: Keystone's evaluation of potential impacts to HCAs has been quantified in a confidential appendix for federal agencies. This preliminary analysis is not required by regulation, but assists regulators with understanding the possibility of an incident and its potential impacts. The 2009 Keystone XL Risk Assessment is not intended to replace the more detailed Engineering Assessment required by federal pipeline safety regulations as identified in

49 CFR Section 195.452 and Section 195 Appendix C. That analysis is subject to audit and review by PHMSA, which has regulatory authority over interstate pipelines, including the Keystone XL pipeline.

20. Kuprewicz (p. 7) claims that, in his experience, pipeline incidents are often due to a failure "to incorporate some degree of challenge or reality check to assure spill risk was really low." Please comment on this assertion.

Answer: Key features of Keystone's operational program, where applicable, include the incorporation of industry best practices and participation in industry conferences and forums to exchange ideas and information, as well as involvement with industry research and development programs. Keystone had adopted many of the PHMSA Special Conditions into the Keystone XL pipeline long before they were mandated by regulators. It has been my personal experience that Keystone strives to meet or exceed pipeline safety requirements and often leads the industry in adopting more stringent safety requirements.

The types of errors Kuprewicz refers to can be minimized by independent third-party review of Keystone's policies and practices. In addition to the regulator auditing conducted by PHMSA, the design basis and risk assessment process were reviewed by independent, third-party contractors (Battelle and E^x^ponent) during a two-year review process that was conducted on behalf of the DOS to address similar concerns expressed by the USEPA. Battelle concluded that the 2009 Keystone XL Risk Assessment was appropriate for the permitting process and that the design of the Project meets or exceeds current regulatory requirements. If approved, the Keystone XL pipeline will be required to meet more stringent requirements than any other pipeline built to date. Thus, the review recommended by Kuprewicz has already been conducted.

21. 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.

22. 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.

23. 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).

24. 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.

25. 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.

26. 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.

27. 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.

28. 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.

29. 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.

30. 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).

31. 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.

32. 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.

Dated this 25 day of June, 2015.

Heidi Tillquist

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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:

Patricia Van Gerpen
Executive Director
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
patty.vangerpen@state.sd.us

Brian Rounds
Staff Analyst
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
brian.rounds@state.sd.us

Tony Rogers, Director
Rosebud Sioux Tribe - Tribal Utility Commission
153 South Main Street
Mission, SD 57555
tuc@rosebudsiouxtribe-nsn.gov

Jane Kleeb
1010 North Denver Avenue
Hastings, NE 68901
jane@boldnebraska.org

Terry Frisch
Cheryl Frisch
47591 875th Road
Atkinson, NE 68713
tcfrisch@q.com

Lewis GrassRope
PO Box 61
Lower Brule, SD 57548
wisestar8@msn.com

Robert G. Allpress
46165 Badger Road
Naper, NE 68755
bobandnan2008@hotmail.com

Kristen Edwards
Staff Attorney
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
kristen.edwards@state.sd.us

Darren Kearney
Staff Analyst South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
darren.kearney@state.sd.us

Cindy Myers, R.N.
PO Box 104
Stuart, NE 68780
csmyers77@hotmail.com

Byron T. Steskal
Diana L. Steskal
707 E. 2nd Street
Stuart, NE 68780
prairierose@nntc.net

Arthur R. Tanderup
52343 857th Road
Neligh, NE 68756
atanderu@gmail.com

Carolyn P. Smith
305 N. 3rd Street
Plainview, NE 68769
peachie_1234@yahoo.com

Amy Schaffer
PO Box 114
Louisville, NE 68037
amyannschaffer@gmail.com
Benjamin D. Gotschall
6505 W. Davey Road
Raymond, NE 68428
ben@boldnebraska.org
Elizabeth Lone Eagle
PO Box 160
Howes, SD 57748
bethcbest@gmail.com
John H. Harter
28125 307th Avenue
Winner, SD 57580
johnharter11@yahoo.com
Peter Capossela
Peter Capossela, P.C.
Representing Standing Rock Sioux Tribe
PO Box 10643
Eugene, OR 97440
pcapossela@nu-world.com
Travis Clark
Fredericks Peebles & Morgan LLP
Suite 104, 910 5th St.
Rapid City, SD 57701
tclark@ndnlaw.com

Jerry P. Jones
22584 US Hwy 14
Midland, SD 57552
Debbie J. Trapp
24952 US Hwy 14
Midland, SD 57552
mtdt@goldenwest.net

Jennifer S. Baker
Representing Yankton Sioux Tribe
Fredericks Peebles & Morgan LLP
1900 Plaza Dr.
Louisville, CO 80027
jbaker@ndnlaw.com

Louis T. (Tom) Genung
902 E. 7th Street
Hastings, NE 68901
tg64152@windstream.net
Nancy Hilding
6300 West Elm
Black Hawk, SD 57718
nhilshat@rapidnet.com
Paul F. Seamans
27893 249th Street
Draper, SD 57531
jacknife@goldenwest.net
Viola Waln
PO Box 937
Rosebud, SD 57570
walnranch@goldenwest.net
Wrexie Lainson Bardaglio
9748 Arden Road
Trumansburg, NY 14886
wrexie.bardaglio@gmail.com

Harold C. Frazier
Chairman, Cheyenne River Sioux Tribe
PO Box 590
Eagle Butte, SD 57625
haroldcfrazier@yahoo.com
mailto:kevinckeckler@yahoo.com
Cody Jones
21648 US Hwy 14/63
Midland, SD 57552
Gena M. Parkhurst
2825 Minnewsta Place
Rapid City, SD 57702
GMP66@hotmail.com

Joye Braun
PO Box 484
Eagle Butte, SD 57625
jmbraun57625@gmail.com

Duncan Meisel
350.org
20 Jay St., #1010
Brooklyn, NY 11201
duncan@350.org

Bruce Ellison
Attorney for Dakota Rural Action
518 6th Street #6
Rapid City, SD 57701
belli4law@aol.com
RoxAnn Boettcher
Boettcher Organics
86061 Edgewater Avenue
Bassett, NE 68714
boettcherann@abbnebraska.com
Bonny Kilmurry
47798 888 Road
Atkinson, NE 68713
bjkilmurry@gmail.com
Robert P. Gough, Secretary
Intertribal Council on Utility Policy
PO Box 25
Rosebud, SD 57570
bobgough@intertribalCOUP.org
Dallas Goldtooth
38731 Res Hwy 1
Morton, MN 56270
goldtoothdallas@gmail.com
Cyril Scott, President
Rosebud Sioux Tribe
PO Box 430
Rosebud, SD 57570
cscott@gwtc.net
ejantoine@hotmail.com

Thomasina Real Bird
Representing Yankton Sioux Tribe
Fredericks Peebles & Morgan LLP
1900 Plaza Dr.
Louisville, CO 80027
trealbird@ndnlaw.com

The Yankton Sioux Tribe
Robert Flying Hawk, Chairman
PO Box 1153
Wagner, SD 57380
robertflyinghawk@gmail.com
Thomasina Real Bird
Attorney for Yankton Sioux Tribe
trealbird@ndnlaw.com
Chastity Jewett
1321 Woodridge Drive
Rapid City, SD 57701
chasjewett@gmail.com

Bruce Boettcher
Boettcher Organics
86061 Edgewater Avenue
Bassett, NE 68714
boettcherann@abbnebraska.com
Ronald Fees
17401 Fox Ridge Road
Opal, SD 57758

Tom BK Goldtooth
Indigenous Environmental Network (IEN)
PO Box 485
Bemidji, MN 56619
ien@igc.org
Gary F. Dorr
27853 292nd
Winner, SD 57580
gfdorr@gmail.com
Paula Antoine
Sicangu Oyate Land Office Coordinator
Rosebud Sioux Tribe
PO Box 658
Rosebud, SD 57570
wopila@gwtc.net
paula.antoine@rosebudsiouxtribe-nsn.gov
Sabrina King
Dakota Rural Action
518 Sixth Street, #6
Rapid City, SD 57701
sabinra@dakotarural.org

Frank James
Dakota Rural Action
PO Box 549
Brookings, SD 57006
fejames@dakotarural.org

Tracey A. Zephier
Attorney for Cheyenne River Sioux Tribe
Fredericks Peebles & Morgan LLP
910 5th Street, Suite 104
Rapid City, SD 57701
tzephier@ndnlaw.com
Matthew Rappold
Rappold Law Office
on behalf of Rosebud Sioux Tribe
PO Box 873
Rapid City, SD 57709
matt.rappold01@gmail.com

Kimberly E. Craven
3560 Catalpa Way
Boulder, CO 80304
kimecraven@gmail.com
Mary Turgeon Wynne
Rosebud Sioux Tribe - Tribal Utility Commission
153 S. Main Street
Mission, SD 57555
tuc@rosebudsiouxtribe-nsn.gov

Robin S. Martinez
Dakota Rural Action
Martinez Madrigal & Machicao, LLC
616 West 26th Street
Kansas City, MO 64108
robin.martinez@martinezlaw.net
Paul C. Blackburn
4145 20th Avenue South
Minneapolis, MN 55407
paul@paulblackburn.net

April D. McCart
Representing Dakota Rural Action
Certified Paralegal
Martinez Madrigal & Machicao, LLC
616 W. 26th Street
Kansas City, MO 64108
april.mccart@martinezlaw.net
Joy Lashley
Administrative Assistant
SD Public Utilities Commission
joy.lashley@state.sd.us
Eric Antoine
Rosebud Sioux Tribe
PO Box 430
Rosebud, SD 57570
ejantoine@hotmail.com

WOODS, FULLER, SHULTZ & SMITH P.C.

By /s/ James E. Moore
William Taylor
James E. Moore
PO Box 5027
300 South Phillips Avenue, Suite 300
Sioux Falls, SD 57117-5027
Phone (605) 336-3890
Fax (605) 339-3357
Email James.Moore@woodsfuller.com
Attorneys for Applicant TransCanada

Exhibit 1: Diluted Bitumen-Derived Crude Oil: Relative Pipeline Impacts (Battelle 2012)

Exhibit 2: Comparison of the Corrosivity to Dilbit and Conventional Crude (Been 2011)

Exhibit 3: Effects of Diluted Bitumen on Crude Oil Pipelines (National Academy of Sciences 2013)

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Exhibit 6: Review of Quantitative Surveys of the Length and Stability of MTBE. TBA, and Benzene Plumes in Groundwater at UST Sites (Connor et al. 2015).

Exhibit 7: Characteristics of Dissolved Petroleum Hydrocarbon Plumes: Results from Four Studies (Newell and Connor 1998)

Exhibit 8: A comparison of benzene and toluene plume lengths for sites contaminated with regular vs. ethanol-amended gasoline (Ruiz-Aguilar et al. 2003)

Exhibit 9: Evaluation of the impact of fuel hydrocarbons and oxygenates on groundwater resources (Shih et al. 2004)

Exhibit 10: Leukemia Risk Associated With Low-Level Benzene Exposure (Glass et al. 2003)

Exhibit 11: United States Department of State 12.1: Keystone XL Project, Risk Analysis (Kothari, Bajnok, Tillquist)

Final Report

Diluted Bitumen-Derived Crude Oil: Relative Pipeline Impacts

Battelle Memorial Institute
505 King Avenue
Columbus, OH 43201

By
Barry Hindin
Brian Leis

July 20, 2012

EXHIBIT
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Executive Summary

This report evaluated the claim made that dilbit is more corrosive than other crudes. This evaluation was benchmarked against conventional and/or sour crude, and was based on the existing literature on crude and dilbit properties and characteristics, data on pipeline integrity and results of engineering assays of pipe that has been transporting dilbit, with such outcomes supplemented by interviews of industry engineering experts from operators with pipelines transporting dilbit.

It was found that the literature on this topic concludes that "the characteristics of dilbit are not unique and are comparable to conventional crude oils." The relative measure of similarity developed in this project did not indicate that crude oil derived from diluted bitumen is significantly more corrosive than any other oil, and that the dilbit oils likely have corrosivities close to the heavy sour conventional oils. In addition to this relative outcome, the experience of operators transporting dilbit does not indicate it behaves differently from typical crudes. That view can be supported with images of the inside of such pipelines, which appear no different after many years of service than those shipping conventional crude and data reported to PHMSA that no releases from pipelines transporting Canadian crudes and caused by internal corrosion occurred from 2002 to early 2011.

Similarity of Dilbit Relative to Conventional Crude Oils

Introduction

Following a brief discussion of factors that affect internal corrosion independent of the type of crude involved, this section evaluates the first of the above-noted claims that dilbit is more corrosive as compared to conventional crude oil. This evaluation is based on available data and a review of published literature: no laboratory experiments were conducted as part of this evaluation. This section draws extensively from one of the most comprehensive yet concise reviews of the corrosivity of dilbit as compared to conventional crude oil, which was developed by Alberta Innovates Energy and Environmental Solutions.[iii][1] Use is also made of the references cited in that report, with the related analysis developed as part of this project founded on basic corrosion science and electrochemistry.

Some Generic Factors that Affect Internal Corrosion

While the focus of this section is to evaluate dilbit relative to other crudes transported by pipeline, for the sake of completeness it is appropriate to briefly note that other factors more strongly influence if and where internal corrosion can occur, and its rate. Among some of the more important factors are the presence of solids like sand, and the design of the line as it influences the flow regime, which depends on the speed of flow and the "dropout" of liquid-phase water and its transport in the line along with solids. The presence of abrasive solids like sand in crude depends on the source of the crude and any prior processing, with sand being found in many sources of crude. As such solids are not unique to dilbit, they are not addressed as part of this comparison. Moreover, existing tariffs include limits on the water and solids content, where the combined total is usually limited to 0.5 weight percent. In regard to factors that are controlled by pipeline design it is important to note that pipelines transporting products that have the potential to cause internal corrosion are designed for turbulent flow, which limits liquid water and its dropout from the product stream. Because this and related aspects are design issues, and common to transported crudes rather than unique to dilbit, these and other such aspects that are not unique to dilbit are not addressed in the comparison that follows.

Approach to Compare and Contrast Crude Types

The approach used to compare the corrosivity of dilbit to conventional crude oil was to examine the factors that would most affect the corrosivity of oil in pipelines. These factors, based on fundamental electrochemical considerations, include oxygen content, water content, effect of Microbiologically Influenced Corrosion (MIC), underdeposit corrosion, and temperature. In addition to the relative outcomes of this analytical approach, input from operators that transport dilbit was assessed to determine an absolute metric of corrosion susceptibility.

Regarding the analytical assessment, other pipeline oil parameters such as total sulfur, sediment, and salt contents were used to derive a relative index of oil similarity. The "average" similarity of conventional oil was defined as a value of 1.0. Based on a consideration of how the common factors varied for dilbit and other oils compared to a conventional crude oil, a similarity index was defined as the ratio of the similarity of dilbit to a conventional Canadian heavy sour crude. A similarity index greater than 1.0 indicated that the oil was may be more corrosive than conventional crude, whereas an index value less than 1.0 indicated that the oil was likely less

[1] Superscript Roman numerals refer to the list of references compiled at the end of this report.

corrosive than conventional crude. The properties of the Canadian oils that were used for comparison were obtained from the on-line data available from Crude Quality Inc. (CQI)[iv] and Enbridge 2010 Crude Characteristics.[v] Data from crude oils from Colombia[vi] and Mexico[vii] were also included.

Results

Almost all corrosion processes in metals are electrochemical in nature. When electrochemical processes occur, there is only one anodic reaction that occurs on metals, namely

$$M \rightarrow M^{+n} + ne \qquad [1]$$

where M stands for a metal and n is the number of valence electrons. In the case of pipeline steel, the predominant metal in the steel alloy is iron. For most anodic reactions in steel exposed to an aqueous phase at ambient temperature, Eqn. 1 becomes,

$$Fe \rightarrow Fe^{+2} + 2e \qquad [2]$$

For every anodic reaction there must be at least one cathodic reaction, otherwise the corrosion process cannot proceed. Corrosion inhibitors are used to interfere with either the anodic or cathodic reaction or both in the attempt to minimize the corrosion reaction rate.

The following paragraphs review the role that water content, oxygen content, temperature, MIC, sulfur, underdeposit corrosion, total acid number (TAN), and salt concentration have on the interior corrosion of pipelines.

Water Content

For corrosion to occur, an electrolyte needs to be present. In oil pipelines, in the presence of sludge, the predominant electrolyte is water. While pure water is not a good electrolyte, the water in oil pipelines is sufficiently contaminated with dissolved solids and salts that it will serve as a good electrolyte. The amount of water that is typically present in any transmission oil pipeline will be quite low, as required by the basic sediment and water (BS&W) limitation of 0.5 volume percent[iii]. Moreover, this value is significantly less than what is considered the critical water concentration of greater than 10 percent,[viii] and water that is present must be the continuous phase of any water and oil emulsion.

The necessary condition for water to participate in the corrosion of the interior steel wall of a pipe is that water exists in the oil-in-water (O/W) condition rather than the non-corrosive water-in-oil (W/O) condition[ix]. The water layer on the surface of the pipe wall will be very thin. Unfortunately specific information on water-dropout for the examined crude oils was not available. Moreover, the pH of the water phase, which is an important parameter for determining the corrosivity of the water phase to steel, was also not available in the examined data.

Oxygen and other Gas Content

Oxygen content plays a major role in the corrosion reaction of steel. In neutral and alkaline pH solutions the predominant cathodic reaction involving reduction of oxygen is given by

$$O_2 + 2H_2O + 4e \rightarrow 4OH^- \qquad [3]$$

Combining the anodic reaction for iron given in Eqn. 2 with the cathodic reaction in Eqn. 3, yields,

$$Fe^{+2} + 2OH^- \rightarrow Fe(OH)_2\downarrow \qquad [4a]$$

The reaction product in this case is the relatively insoluble ferrous hydroxide. Ferrous hydroxide can also occur from the reaction of ferrous sulfate with hydroxide ions yielding sulfate ions.

$$FeSO_4 + 2OH^- \rightarrow Fe(OH)_2 + SO_4^{2-} \quad [4b]$$

Sulfate ions, however, were experimentally found to not have an effect on pitting corrosion rate on steel.[ix]

In the absence of oxygen, ferrous hydroxide can be further oxidized by the hydrogen ions in water to form magnetite (Fe_3O_4), which is more stable than many other iron oxides and provides a protective coating to the underlying steel surface.

$$3\ Fe(OH)_2 \rightarrow Fe_3O_4 + H_2 + 2\ H_2O \quad [5]$$

The corrosion of iron can also occur in acid solutions (pH below 7) in the absence of oxygen.

Other gases such as hydrogen sulfide (sour gas) can directly react with steel to form iron sulfide without the presence of oxygen and carbon dioxide (sweet gas) can also play a role in some corrosion reactions with pipeline steel. However, these presence or absence of these gases have not been reported in the evaluated crude oils and are therefore were not considered.

Temperature

It is not clear what the typical operating temperatures of the dilbit pipelines are compared to the conventional crude oil pipelines operating temperatures below 180 F are not expected to contribute to corrosivity of the oil. In addition, there are several factors that would temper the expected increase in corrosion rate as temperature increases. The major mitigating factor is the decrease in oxygen solubility in the water phase of the oil with increasing temperature. When additional constituents are in the water such as salts, the solubility will decrease further. On the other hand, the oxygen solubility increases with pressure. A higher pressure pipeline can have higher oxygen solubility in its water phase than a lower pressure pipeline.

Microbiologically Influenced Corrosion and Underdeposit Corrosion

MIC is most often associated with the presence of sludge, which plays a dominant role in underdeposit corrosion. Bacteria responsible for MIC in pipelines include sulfate reducing bacteria (SRB), heterotrophic aerobic bacteria (HAB), and acid producing bacteria (APB).[x] These bacteria are found in a wide variety of oil pipelines including those carrying conventional crude oil and dilbit.

Sulfur Content

The organic sulfur content of the oils at ambient temperature were found to either have no effect or actually decreased the corrosion rate of steel.[xi] The reported values for sulfur in oil, however, are the total sulfur concentrations that include both organic and inorganic forms of sulfur such as sulfates and sulfides. The presence of sulfate reducing bacteria can lead to pitting attack of the interior pipeline wall. Consequently, the sulfur parameter was included in the similarity index.

Sediment and Sludge

While the amount of sediment and sludge present in the oil may or may not be related to the amount of underdeposit corrosion, there are several variables associated with these parameters that need to be considered. These include the particulate size and distribution of sludge particles, the waxiness or oiliness of the deposits, and the velocity and turbulence of the deposits[xii]. The presence of MIC is also associated with sediments. For these reasons, the concentration of sediment was included in the similarity index.

Total Acid Number

The total acid numbers (TAN) for pipeline oils are associated with the presence of naphthenic acids. This parameter is important in determining the crude oils corrosivity at high temperatures encountered in crude oil distillation columns in refineries but not at ambient temperatures of 35 F to 75 F of oil transport in pipelines. The temperature range where the TAN is important is from 430 F to 750 F[xiii]. Because TAN is "not necessarily reflective of the corrosivity of crude oil,"[iii] it was excluded from the similarity index.

Salt Concentration

Chlorides and other halides are usually associated with the corrosive species in most salts but "it has been shown that high salinity brines in contact with oil did not affect the corrosion rate."[iii] However, this parameter was included in the similarity index because the ubiquitous nature of these constituents in the oils.

Nickel and Vanadium Content

The low-concentration presence of these metals in the pipeline oil will not play any role in the corrosion of steel pipelines and therefore was not included in the similarity index.

Pipeline Oil Similarity Index

There have been several attempts to arrive at a corrosivity index for pipelines with the most extensive one being based on a scoring method using points and a parameter weighting scheme.[xiv] However, because the common properties reported for pipeline oil have not been shown to be directly related to the interior corrosion of the pipeline steel, a similarity index scheme is used in this report that is based solely on published properties of the oil rather than the entire pipeline infrastructure and simply uses equal weighting for three oil parameters. These parameters include the sulfur content, sediment concentration, and the salt concentration. The selection of these parameters does not imply that they are responsible for any corrosion in the pipeline but are simply being used as a basis for comparison of one oil to another. The rationale for this approach is that if similar properties are found for dilbit oils compared to conventional crude that have not exhibited corrosivity, then the dilbit would also be expected to be equally non-corrosive. As a basis for comparison, the heavy sour conventional crude oil designated Western Canadian Blend (WCB) was chosen.

The pipeline oil similarity index (POSI) is calculated as follows:

$$POSI = \frac{\frac{Sulfur\ (wt\%)}{3.16} + \frac{Sediment\ (ppmw)}{294} + \frac{Salt\ (ptb)}{71.5}}{} \qquad [6]$$

where the values in the denominator for each factor is for WCB; the POSI for WCB, therefore would be 1.0.

Table 1 shows the POSI values calculated for a variety of heavy sour conventional, heavy sour dilbit, heavy sour synbit, heavy sour dilsynbit, medium sour, and light sour crude oils.

Table 1. List of Crude Oil Types and Their Associated Pipeline Similarity Index Based on Eqn. 6.

Country	Crude Type	Crude Name	Crude Code	POSI
Canada	Heavy Sour - Conventional	Bow River North	CAN A	0.82
		Bow River South	CAN B	0.62
		Fosterton	CAN C	0.63
		Lloyd Blend	CAN D	1.02
		Lloyd Kerrobert	CAN E	0.92
		Smiley-Coleville	CAN F	0.66
		Western Canadian Blend	Control (WCB)	1.00
	Heavy Sour - Dilbit	Access Western Blend	Dilbit A	0.69
		Cold Lake	Dilbit B	0.65
		Peace River Heavy	Dilbit C	0.81
		Seal Heavy	Dilbit D	0.79
		Statoil Cheecham Blend	Dilbit E	0.64
		Wabasca Heavy	Dilbit F	0.70
		Western Canadian Select	Dilbit G	1.01
	Heavy Sour - Synbit	Long Lake Heavy	Synbit A	0.59
		Surmount Heavy Blend	Synbit B	0.53
	Heavy Sour - Dilsynbit	Albian Heavy Synthetic	Dilsynbit	1.21
	Medium Sour	Midale	CAN Med Sour A	0.89
		Mixed Sour Blend	CAN Med Sour B	0.63
		Sour High Edmonton	CAN Med Sour C	0.55
	Light Sour	Light Sour Blend	Light Sour	1.09
Mexico	Heavy Sour	Maya	Maya	2.60
Mexico	Medium Sour	Isthmus	Isthmus	0.69
Colombia	Heavy Sour	Rubiales Oil Field	Rubiales	1.26

Figures 1 to 4 are bar charts of the data listed in Table 1. The red horizontal line in the charts at a POSI of 1.0 represents the similarity of the control oil, namely, the Western Canadian Blend conventional crude.

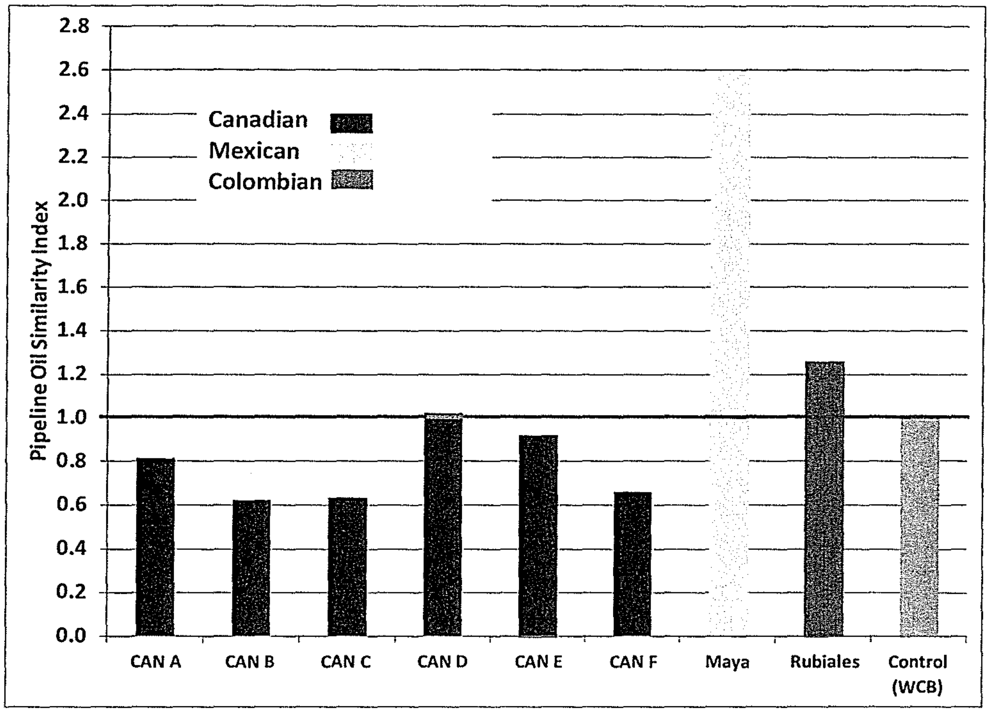

Figure 1. Pipeline oil similarity indices for heavy sour conventional crude oils.

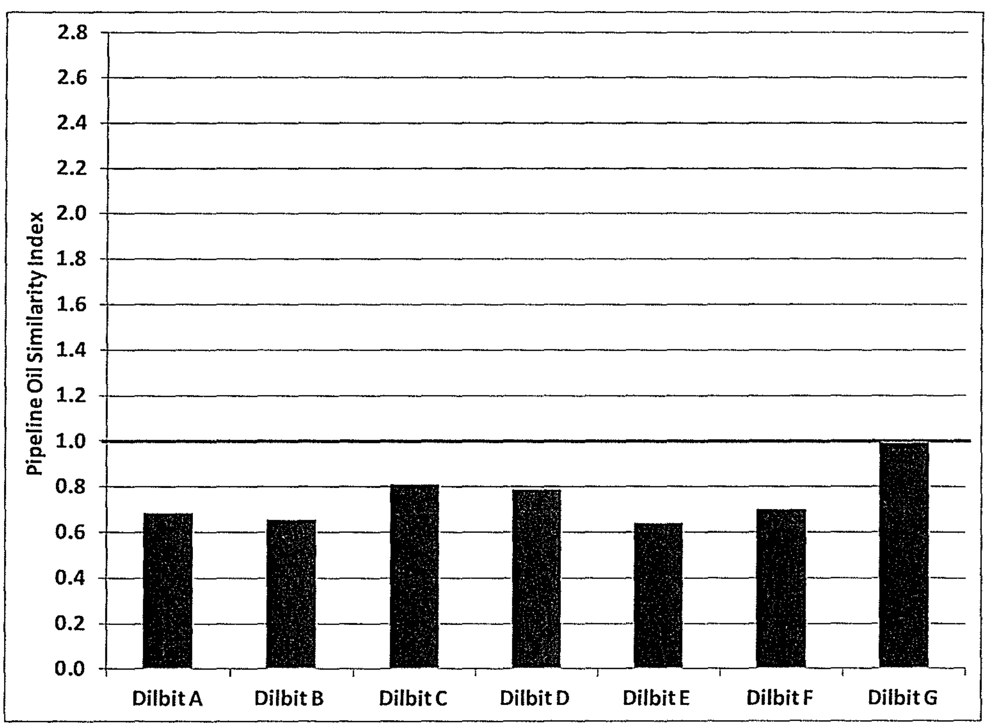

Figure 2. Pipeline oil similarity indices for Canadian heavy sour dilbit crude oils.

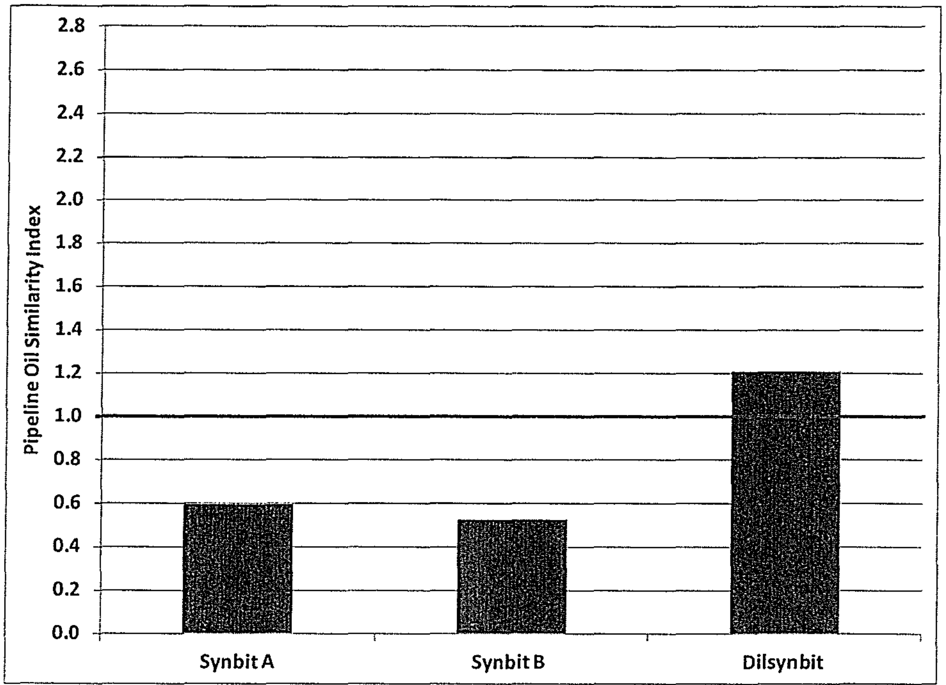

Figure 3. Pipeline oil similarity indices for Canadian heavy sour synbit and dilsynbit crude oils.

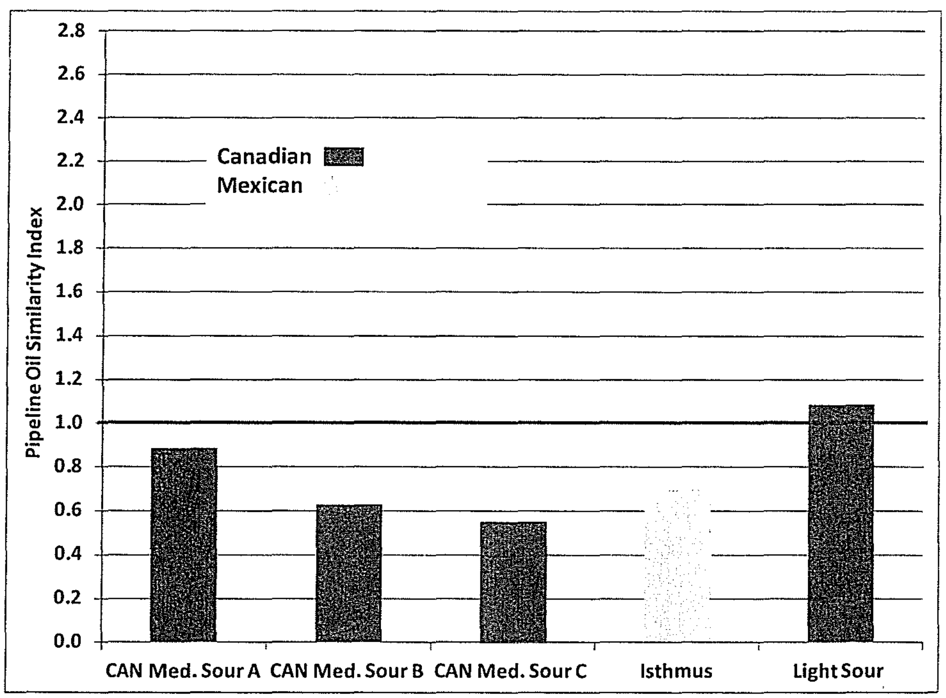

Figure 4. Pipeline oil similarity indices for medium and light sour crude oils.

In Figure 1, the POSI of the Mexican heavy sour conventional crude oil is significantly greater than the Canadian and Colombian crude oils, and the POSI values of all Canadian heavy sours are also less than the Colombian crude oil. Six of the seven heavy sour dilbit crude oils had POSI values less than the control and the seventh dilbit crude oil had the same value as the control (Figure 2). The POSI for the heavy sour synbit and dilsynbit crude oils were either slightly greater or less than the control (Figure 3). All of the medium sour crude oils had POSI values less than the control and the light sour Canadian oil was only slightly greater than the control (Figure 4).

Conclusions and Recommendations

The selection of a Pipeline Oil Similarity Index (POSI) to compare the similarities of various crude oils to one another revealed that the heavy sour dilbit crude oils were either less than or had the same similarity than a typical North American heavy sour conventional crude oil. More striking was the relatively high POSI value of the selected Mexican heavy sour crude, which was greater than any of the other oils randomly chosen for comparison. The key question that is left unanswered is what significance are the POSI values in terms of actual pipeline corrosion.

While choosing a different conventional crude oil as a control will yield different POSI values, the general approach is reasonable from a corrosion engineering consideration for calculating the relative corrosiveness of pipeline oils. While it is clear that the POSI approach does not indicate that crude oil derived by diluted bitumen is more corrosive than any other oil it also shows that the dilbit oils in particular likely have corrosivities close to or less than other heavy sour conventional oils commonly used in North America. In other words, based on the information available, diluted bitumen poses no more of a corrosion risk to pipelines than conventional crudes.

Further insight into similarity follows from absolute metrics of the extent of metal loss due to corrosion for pipelines that transport dilbit as well as conventional crudes. Dialog with operators clearly indicates operational experience with dilbit shows that it does not behave any differently than typical crudes. That dialog is supported by images of the inside of pipelines transporting dilbit, which appear no different than shipping conventional crude after many years of service. This observation is consistent with literature on this topic[i], which concludes that "the characteristics of dilbit are not unique and are comparable to conventional crude oils."

Should there be interest in corrosivity as quantified by the POSI approach, it is recommended that it be further refined to perhaps introduce additional weighting factors to capture the fact that some parameters are anticipated to have a greater affect on pipeline oil's corrosivity than others. Such refinement will likely require collection of additional field data specifically relevant to similarity of pipeline oil, and possibly also benchmark experiments.

Summary and Conclusions

This report evaluated the claim that dilbit is more corrosive than currently transported crudes. This evaluation was made benchmarked against conventional and/or sour crude, and based on the existing literature on crude and dilbit properties and characteristics, data on pipeline integrity and results of engineering assays of pipe that has been transporting dilbit, with such outcomes supplemented to a limited extent by interviews of industry engineering experts from operators with pipelines transporting dilbit.

Major conclusions at a high-level follow:

- Literature on this topic concludes that "the characteristics of dilbit are not unique and are comparable to conventional crude oils."
- The relative measure of similarity developed in this project did not indicate that one oil is significantly more corrosive than any other oil, and that the dilbit oils likely have corrosivities close to the heavy sour conventional oils.
- In addition to this relative outcome, the experience of operators transporting dilbit does not indicate it behaves differently from typical crudes. This view can be supported with images of the inside of such pipelines, which appear no different after many years of service than those shipping conventional crude.

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Alberta Innovates Technology Futures

Alberta Innovates Energy and Environment Solutions

Comparison of the Corrosivity of Dilbit and Conventional Crude

Prepared for:
Dr. John Zhou

Alberta Innovates Energy and Environment Solutions

Prepared by:
Jenny Been, PEng, Ph.D., PMP

Corrosion Engineering, Advanced Materials, AITF

Reviewed by:
John Wolodko, PEng, Ph.D.

Advanced Materials, AITF

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2480002

EXHIBIT
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3.

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 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 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

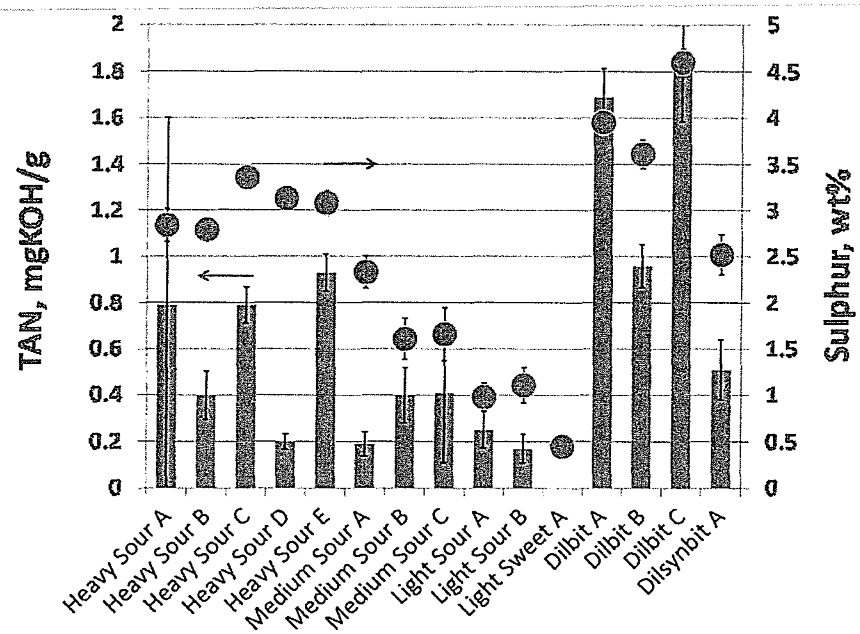


Figure 1a Properties of various conventional crudes and dilbits in Western Alberta illustrating acidity and sulphur contents. The data were obtained from Crude Quality Inc.'s website crudemonitor.ca [10]. Error bars represent the standard deviation over five years of data.

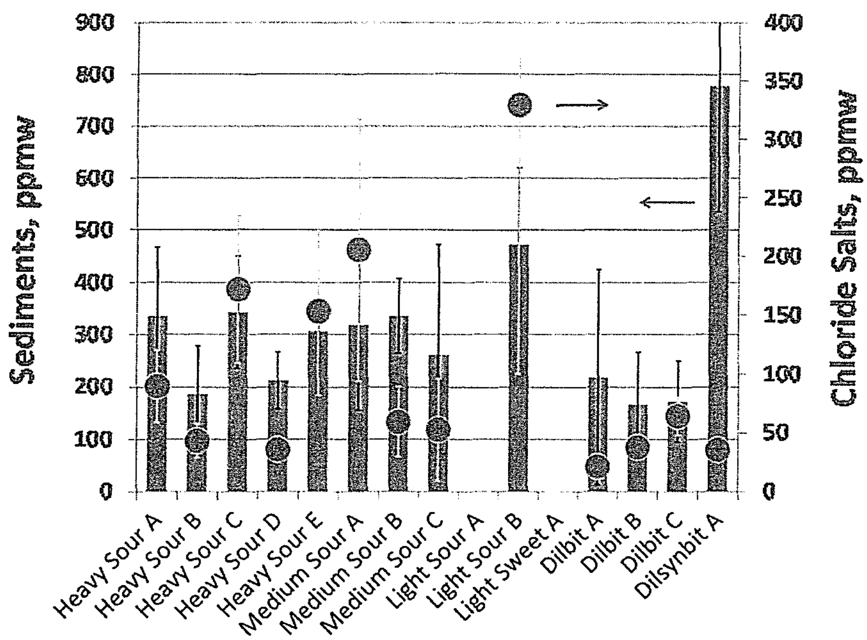


Figure 1b Properties of various conventional crudes and dilbits in Western Alberta illustrating the content of sediments and chloride salts. The data were obtained from Crude Quality Inc.'s website crudemonitor.ca [10]. Error bars represent the standard deviation over five years of data.

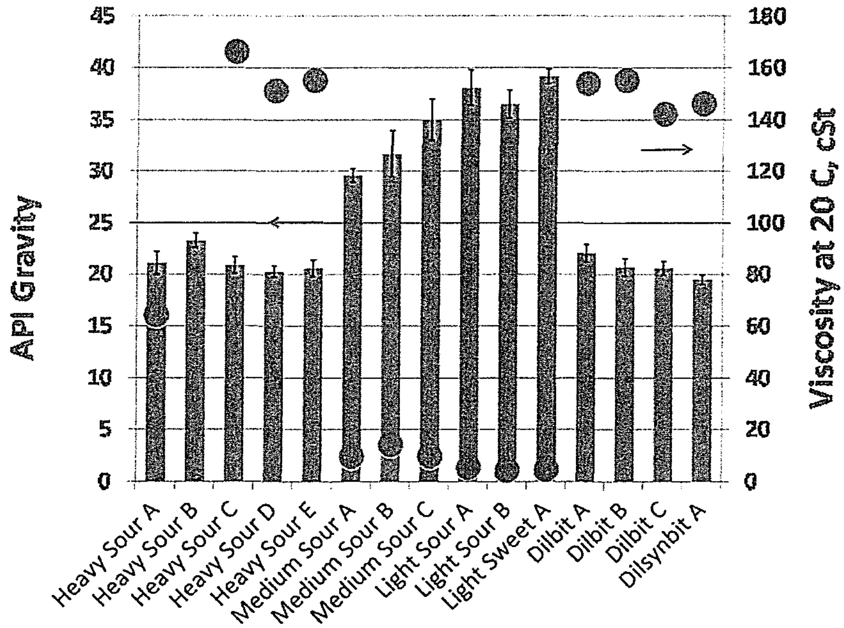


Figure 1c Properties of various conventional crudes and dilbits in Western Alberta illustrating the degree of API gravity and viscosity (after ref [11]). The API gravity data were obtained from Crude Quality Inc.'s website crudemonitor.ca [10]. Error bars represent the standard deviation over five years of data. One representative set of viscosity data is plotted.

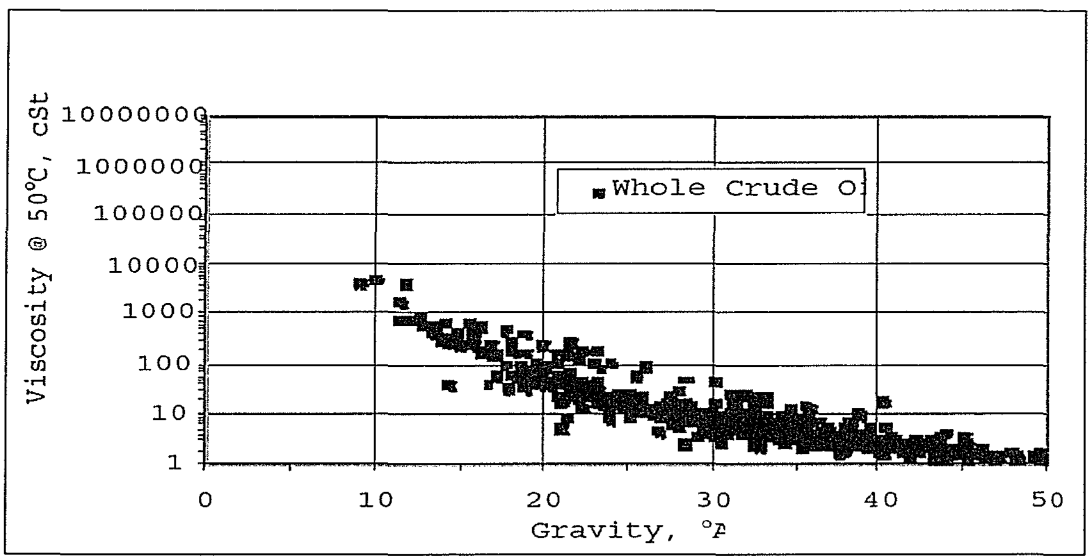


Figure 1d The gravity-viscosity relationship of conventional crude oils (after ref [17]).

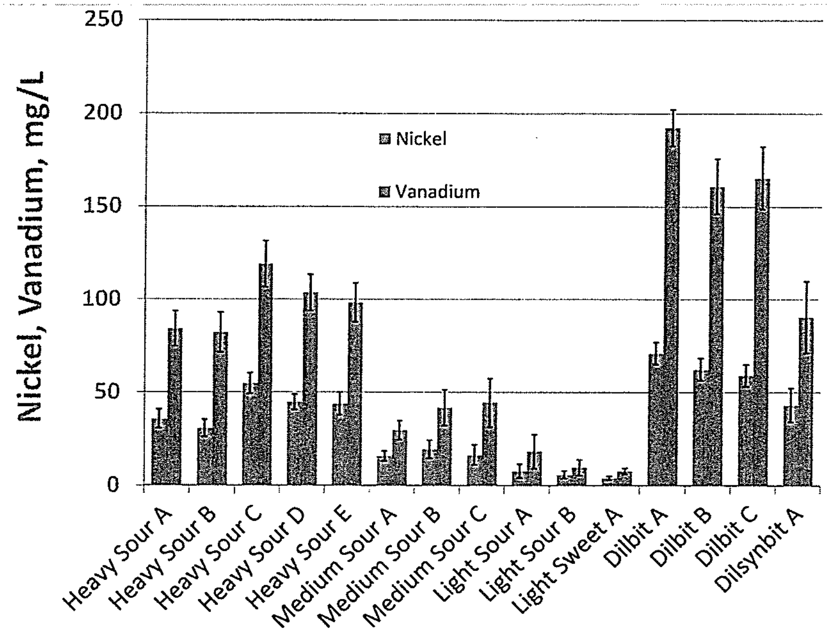


Figure 1e Properties of various conventional crudes and dilbits in Western Alberta illustrating heavy metal concentrations. The data for were obtained from Crude Quality Inc.'s website crudemonitor.ca [10]. Error bars represent the standard deviation over five years of data.

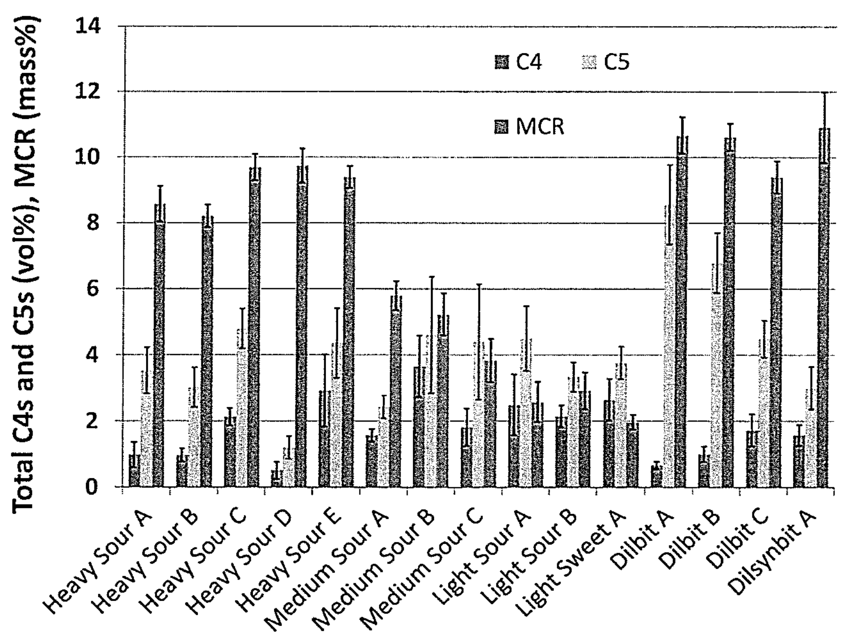


Figure 1f Properties of various conventional crudes and dilbits in Western Alberta illustrating fractions of light carbons and Micro Carbon Residue (MCR). The data were obtained from Crude Quality Inc.'s website crudemonitor.ca [10]. Error bars represent the standard deviation over five years of data.

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 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.

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.

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].

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].

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].

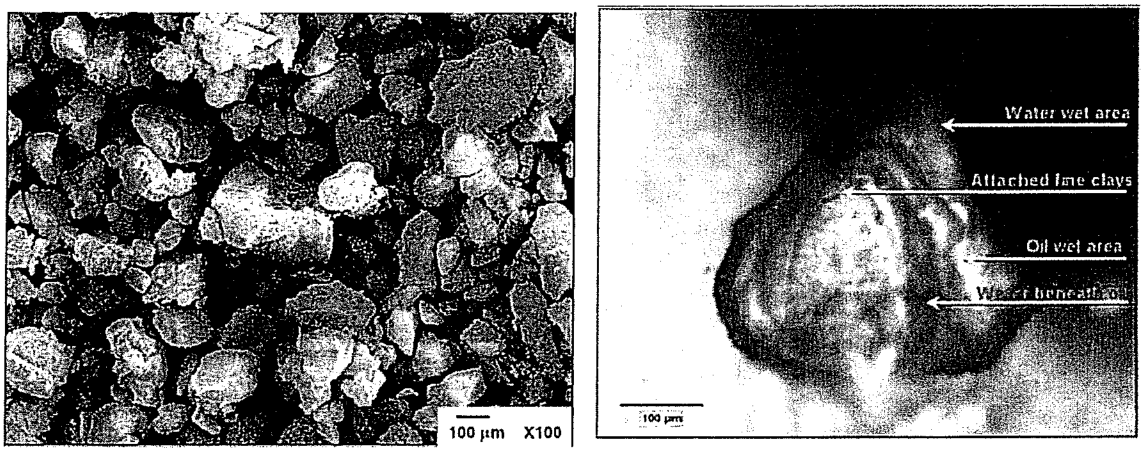
Figure 1b did not indicate a much higher content of sediments for the dilbit crudes compared to the conventional crudes, except for dilsynbit A. The data, however, only indicates the total amount of sediments and does not provide information on the size distribution. It is unknown how the solids in the 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.

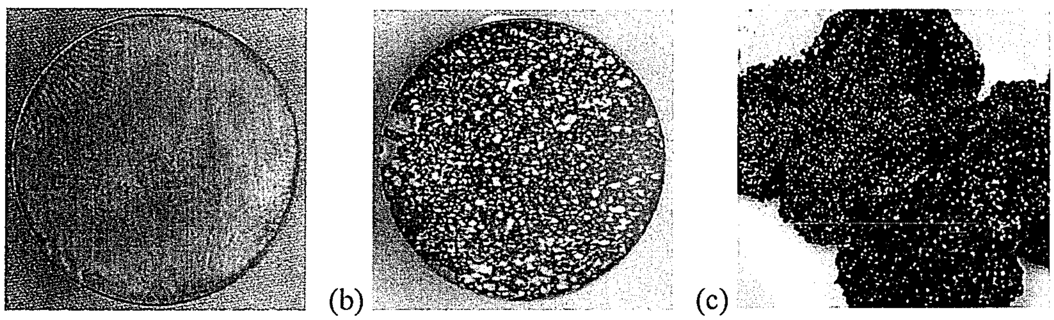
7.5 Underdeposit corrosion

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.



(a) (b)

Figure 2 Micrograph of (a) washed sludge solids and (b) a large solid (from [47])



(a) (b) (c)

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.

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 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

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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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

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NATIONAL RESEARCH COUNCIL
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NOTICE: The project that is the subject of this report was approved by the Governing Board of the National Research Council, whose members are drawn from the councils of the National Academy of Sciences, the National Academy of Engineering, and the Institute of Medicine. The members of the committee responsible for the report were chosen for their special competencies and with regard for appropriate balance.

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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020700

Committee for a Study of Pipeline Transportation of Diluted Bitumen

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Claudia Sauls, Senior Program Assistant, Transportation Research Board

020701

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.

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,

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.

Contents

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.

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.

1

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.

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.

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

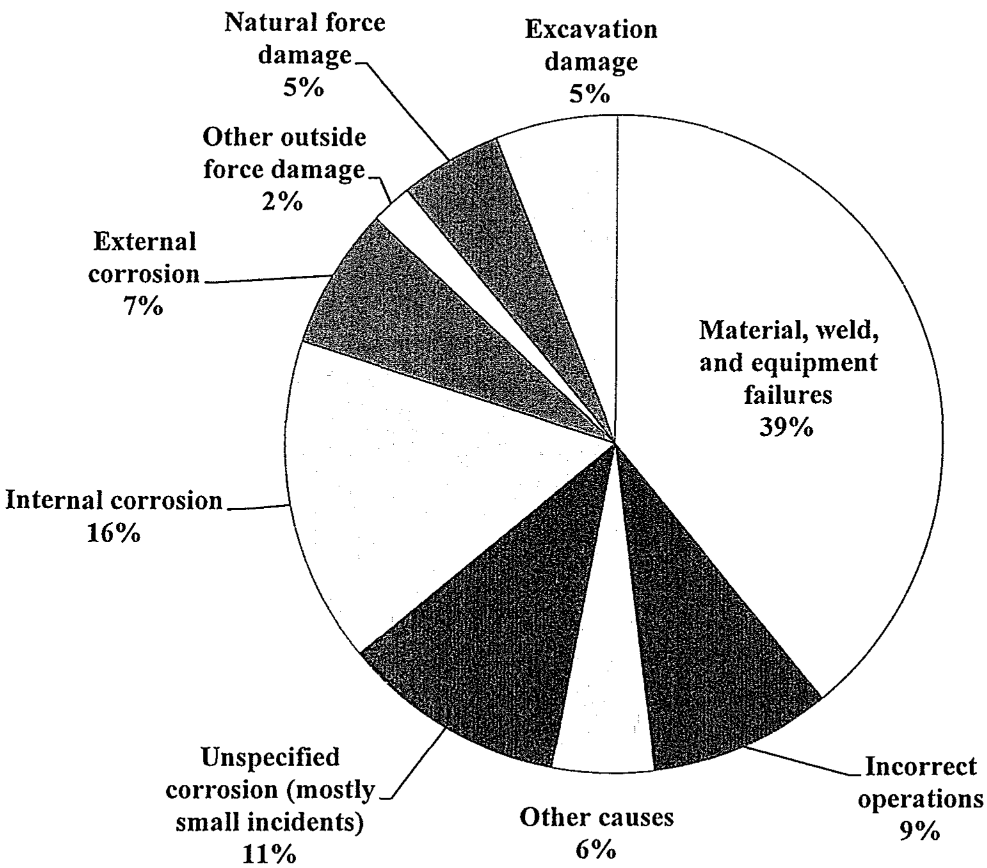

FIGURE 1-1 Causes of crude oil pipeline releases reported to PHMSA, 2002 to 2011. (Source: Incident data provided to committee by PHMSA Office of Pipeline Safety during presentations on October 23, 2012. http://onlinepubs.trb.org/onlinepubs/dilbit/Keener102312.pdf.)

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

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[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.

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,

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[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

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[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).

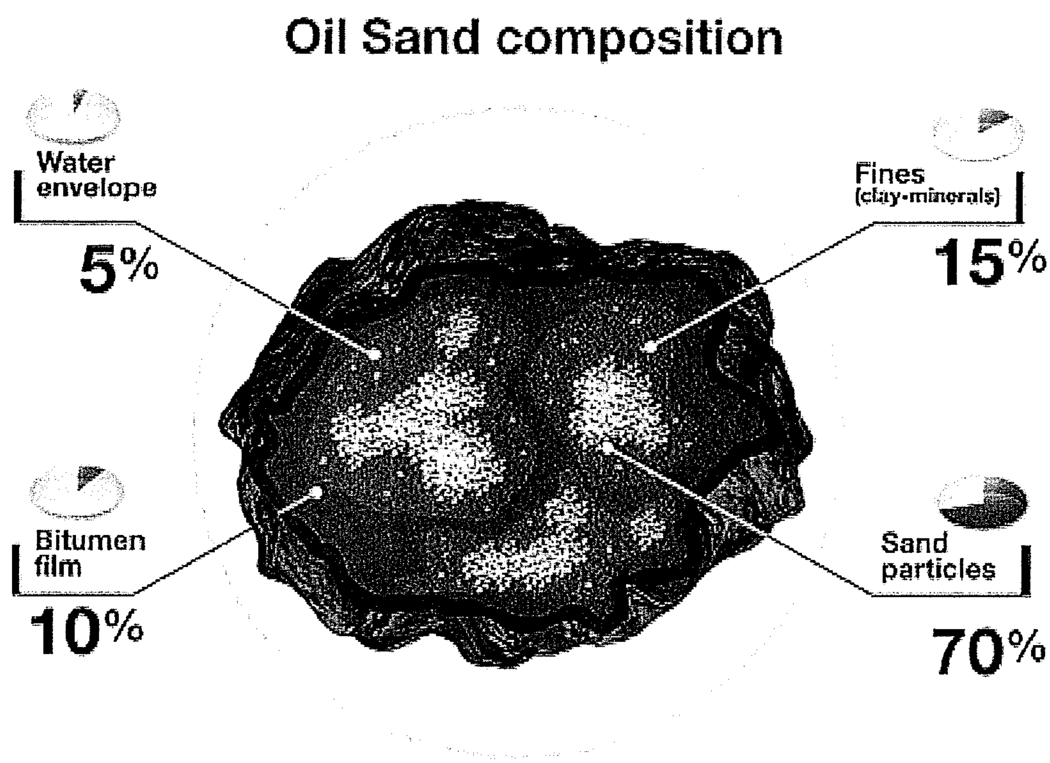

FIGURE 3-1 Composition of oil sands.

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).

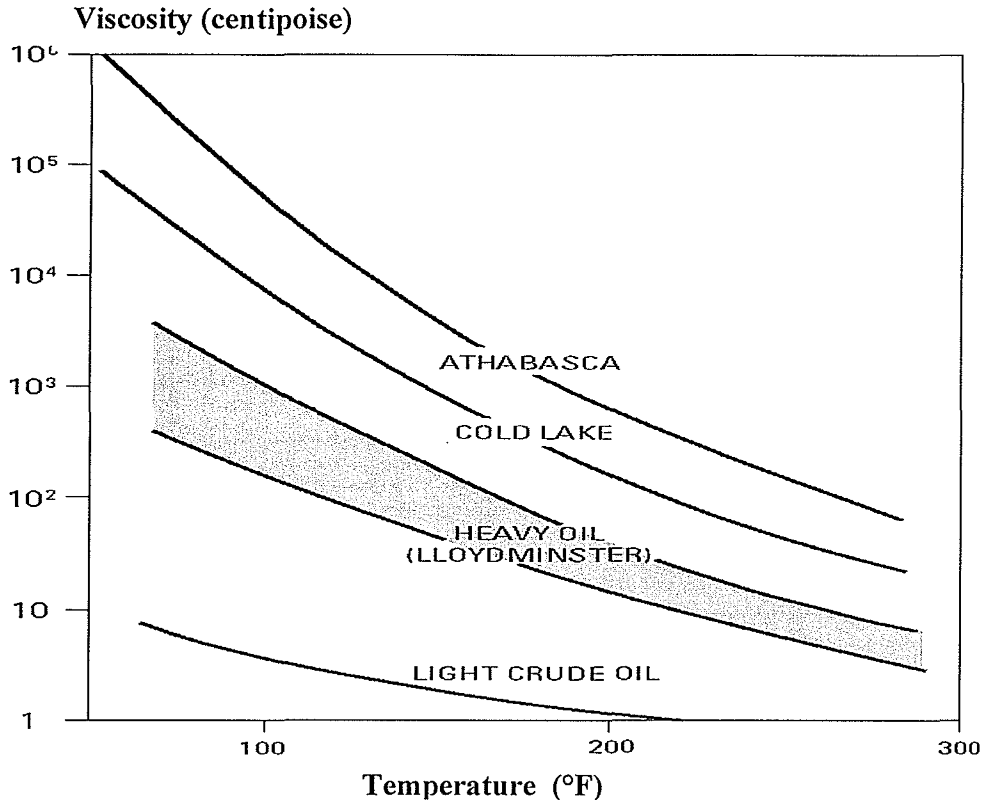

FIGURE 3-2 Response of crude oil viscosity to changes in temperature (Raicar and Procter 1984; WEC 2010, 126).

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.

[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.

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[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).

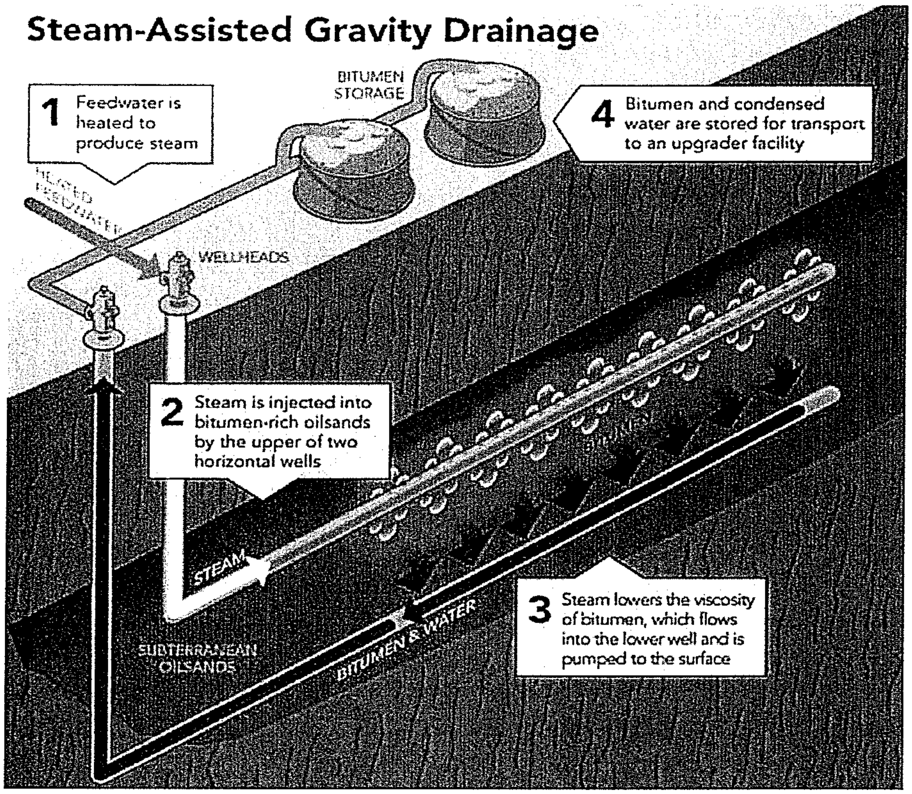

FIGURE 3-3 Bitumen recovered using SAGD (ERCB 2012b).

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.

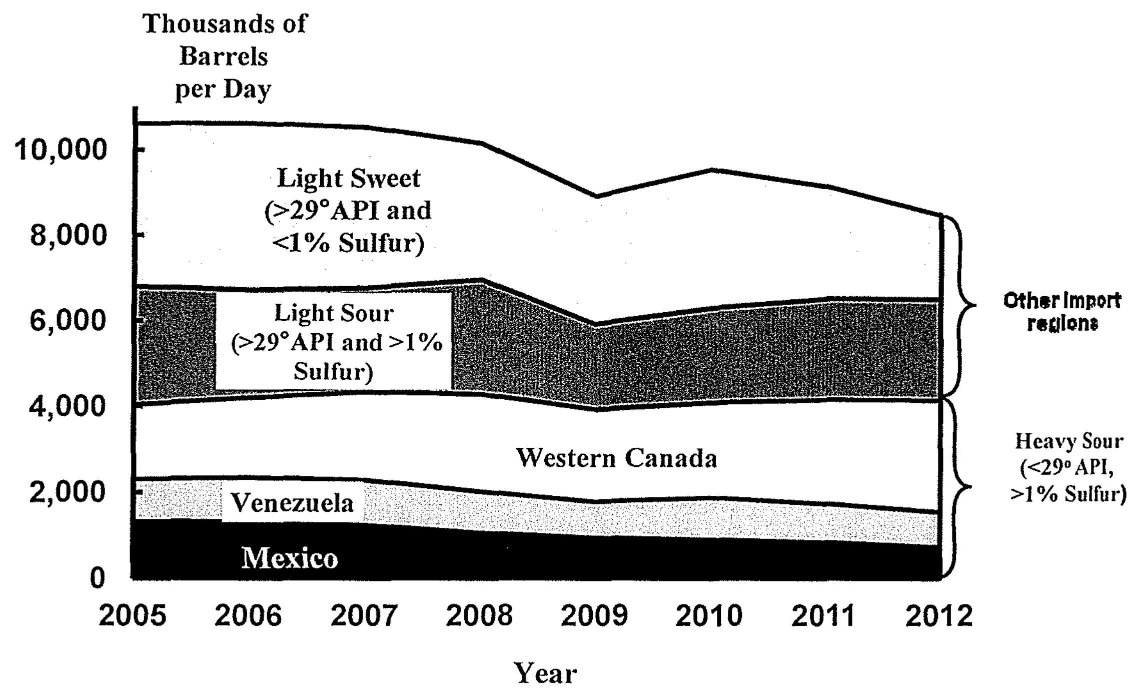

FIGURE 3-4 Annual U.S. crude oil imports by grade and origin. [Chart is derived from January 31, 2012, presentation to the committee by G. Houlton. Source data on crude oil imports were obtained from the Energy Information Administration, U.S. Department of Energy (http://www.eia.gov/countries/cab.cfm?fips=CA).]

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.

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).

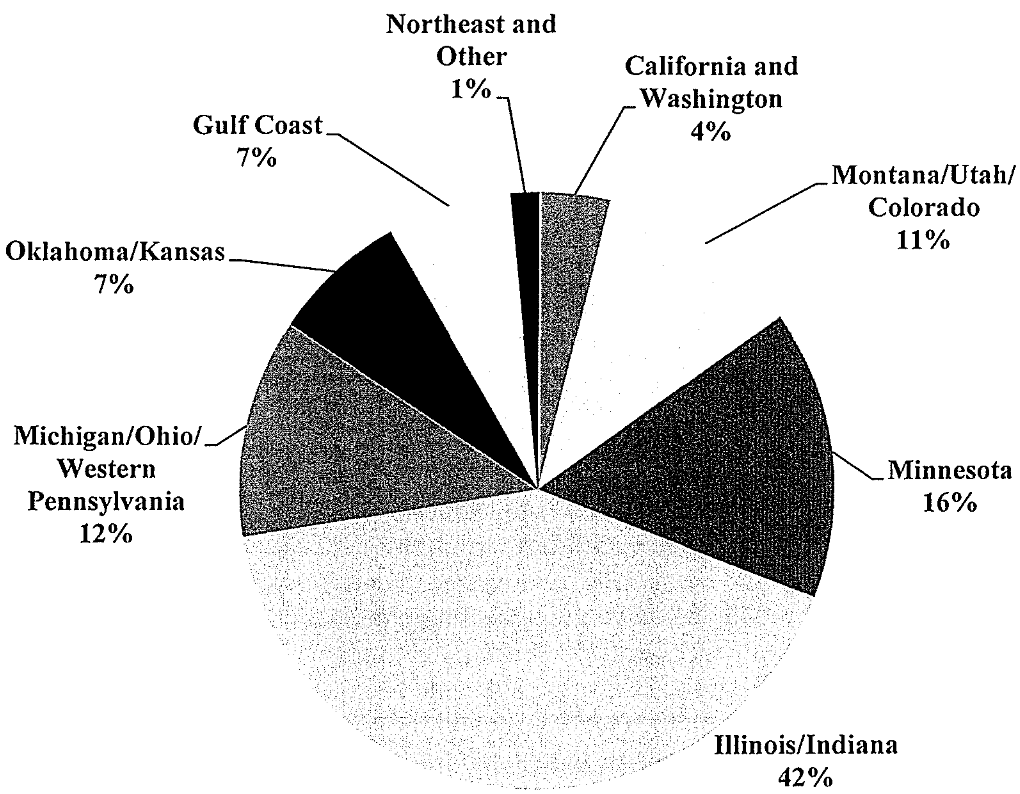

FIGURE 3-5 U.S. refinery destinations for Canadian heavy crude oil imports in 2011. [Source: National Energy Board fact sheet "Disposition of Heavy Crude Oil and Imports" (http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/sttstc/crdlndptrlmprdct/dspstnfdmstccrdlndmprts-eng.html#s1).]

[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).

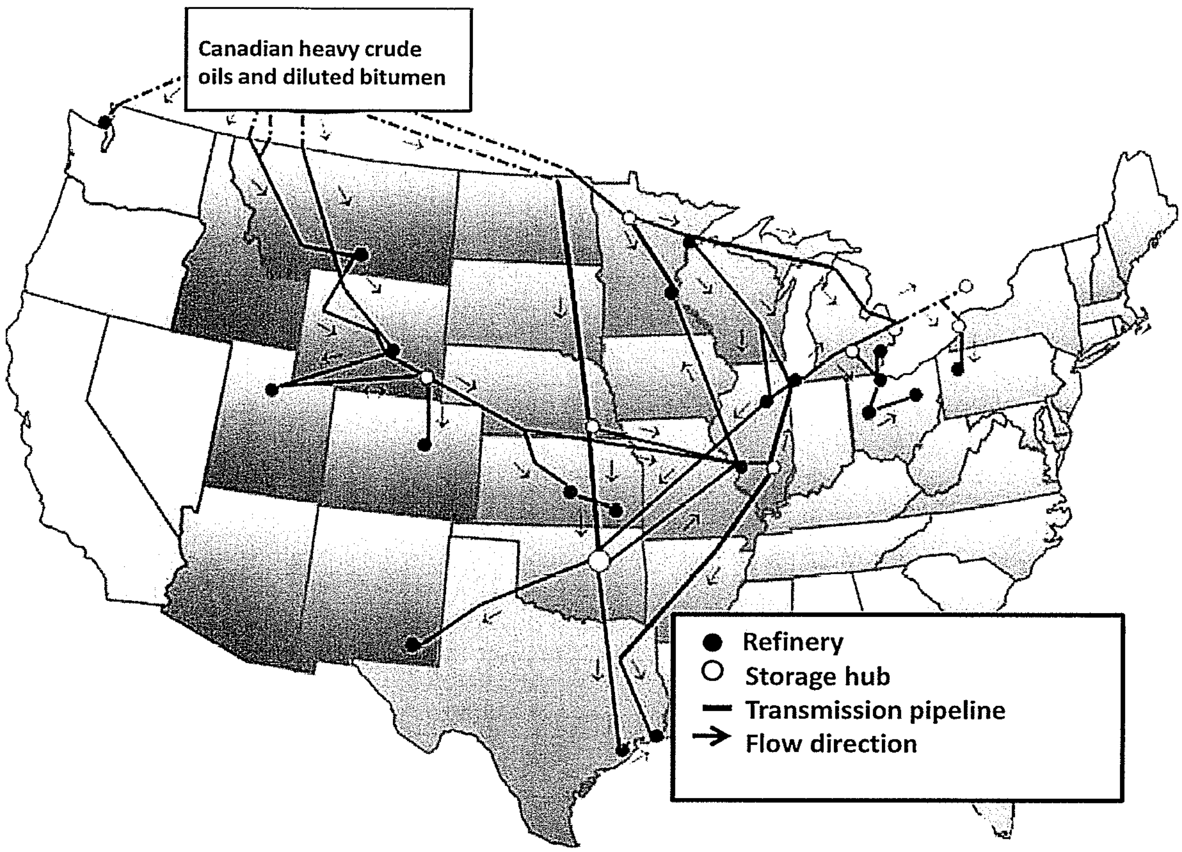

FIGURE 3-6 Main pipeline corridors moving Canadian crude oil to U.S. refineries.

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

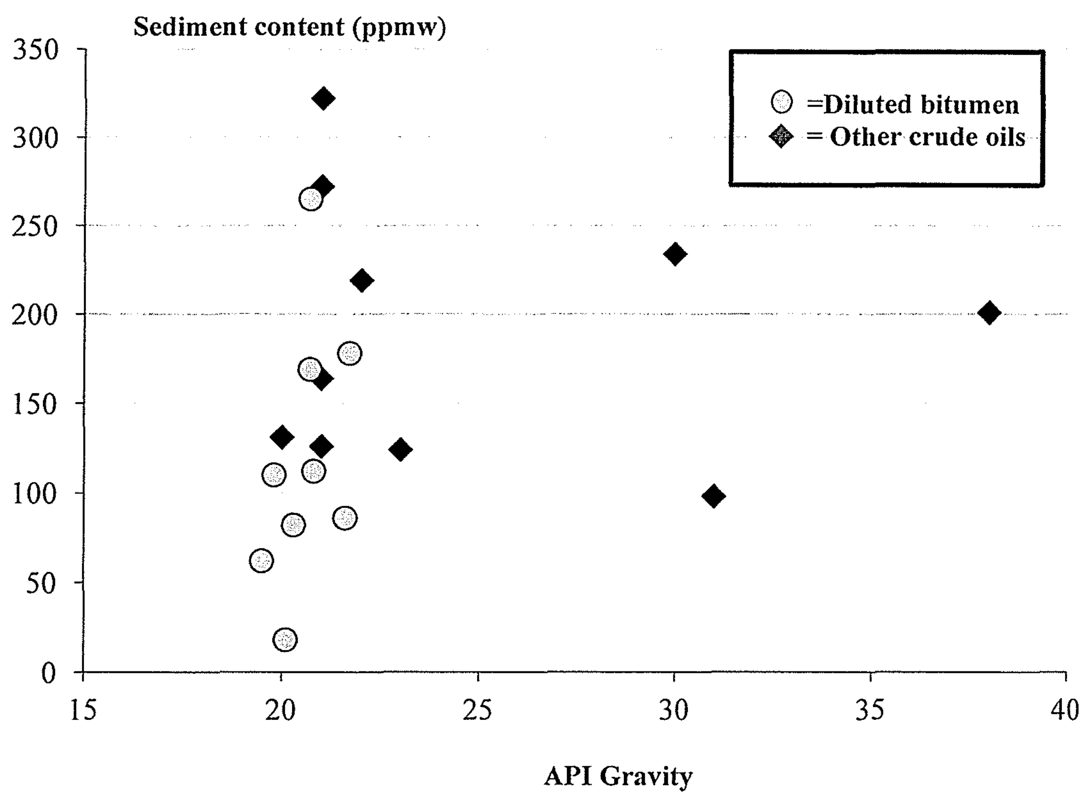

FIGURE 3-7 Average sediment content for nine diluted bitumen blends and 10 light, medium, and heavy Canadian crude oils. [Data obtained from CrudeMonitor.com by Crude Quality, Inc. (http://www.crudemonitor.ca/condensate.php?acr=SLD; http://www.crudemonitor.ca/crude.php?acr=SYN). Accessed March 1, 2013.]

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

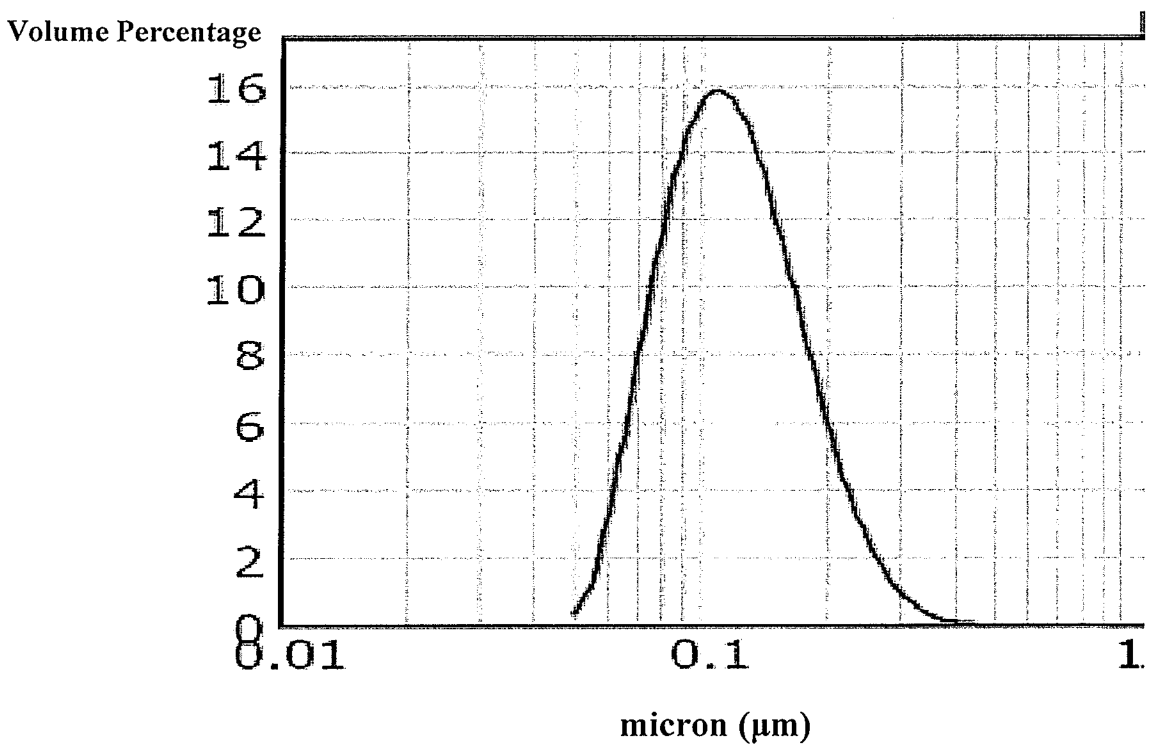

FIGURE 3-8 Particle size distribution of solids in diluted bitumen. (Source: McIntyre et al. 2012.)

[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.

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.

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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).

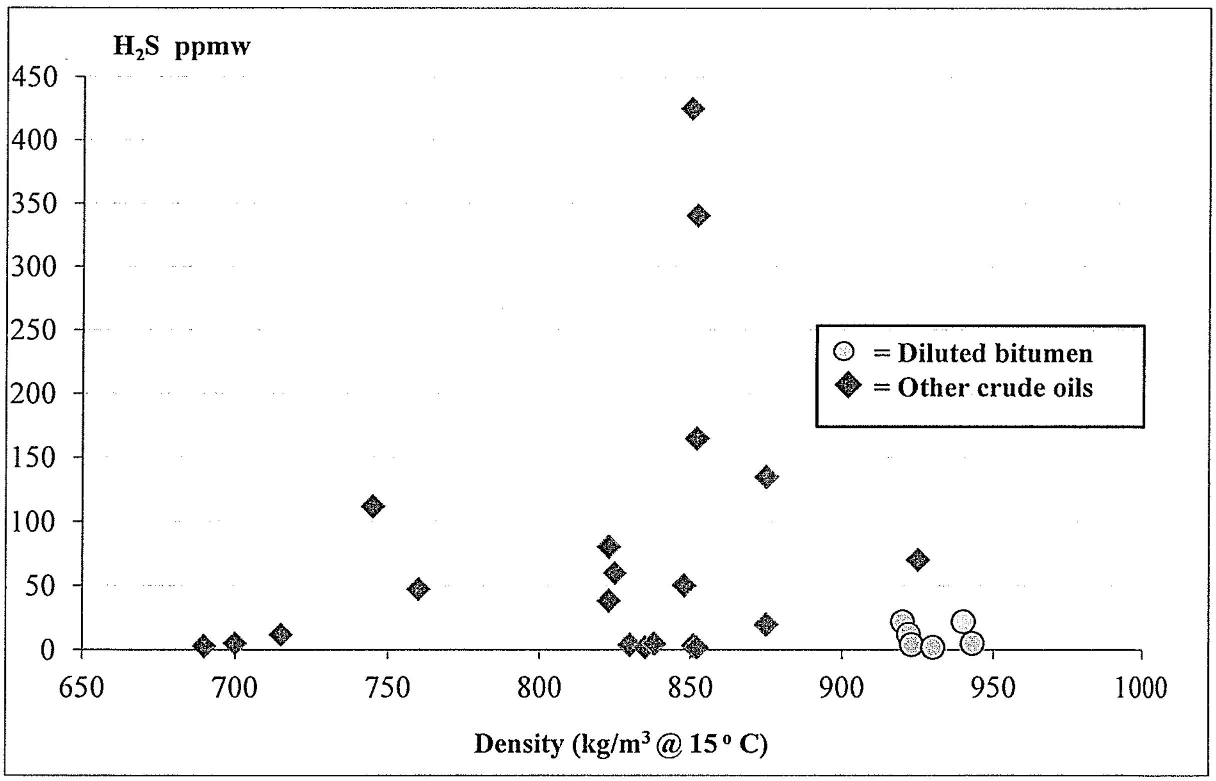

FIGURE 3-9 H_2S content of diluted bitumen and other crude oils. (H_2S is measured in liquid phase by using ASTM Test Method 5263. H_2S remains in a liquid state in pipelines because the partial pressures of operating pipelines are below the bubble point.) (Data submitted to the committee on November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

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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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.

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

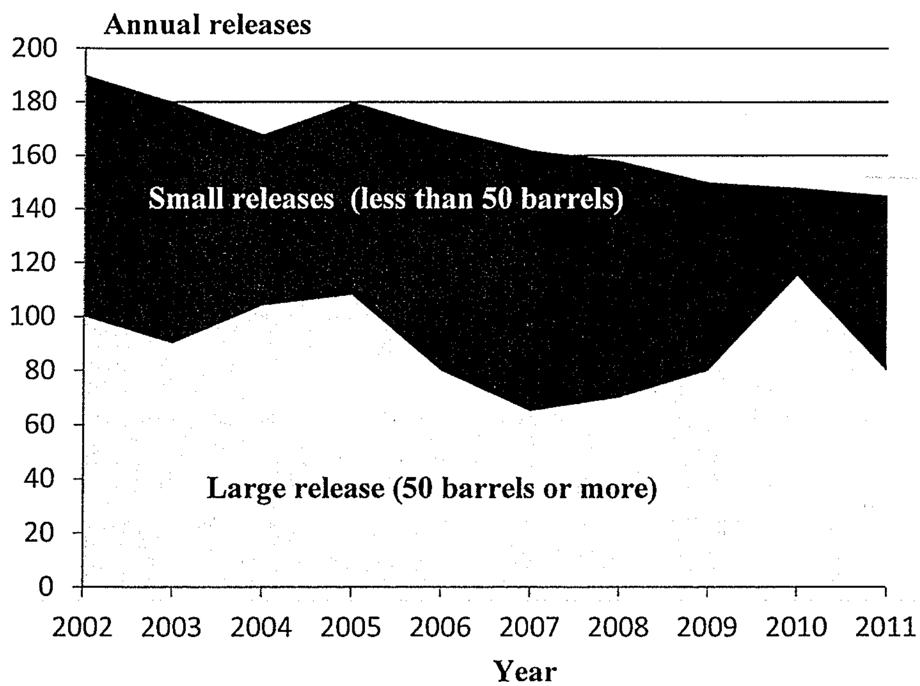

FIGURE 4-1 Crude oil pipeline incidents reported to PHMSA, 2002 to 2011. (Incident data were provided to the committee by PHMSA during the October 23, 2012, committee meeting.)

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

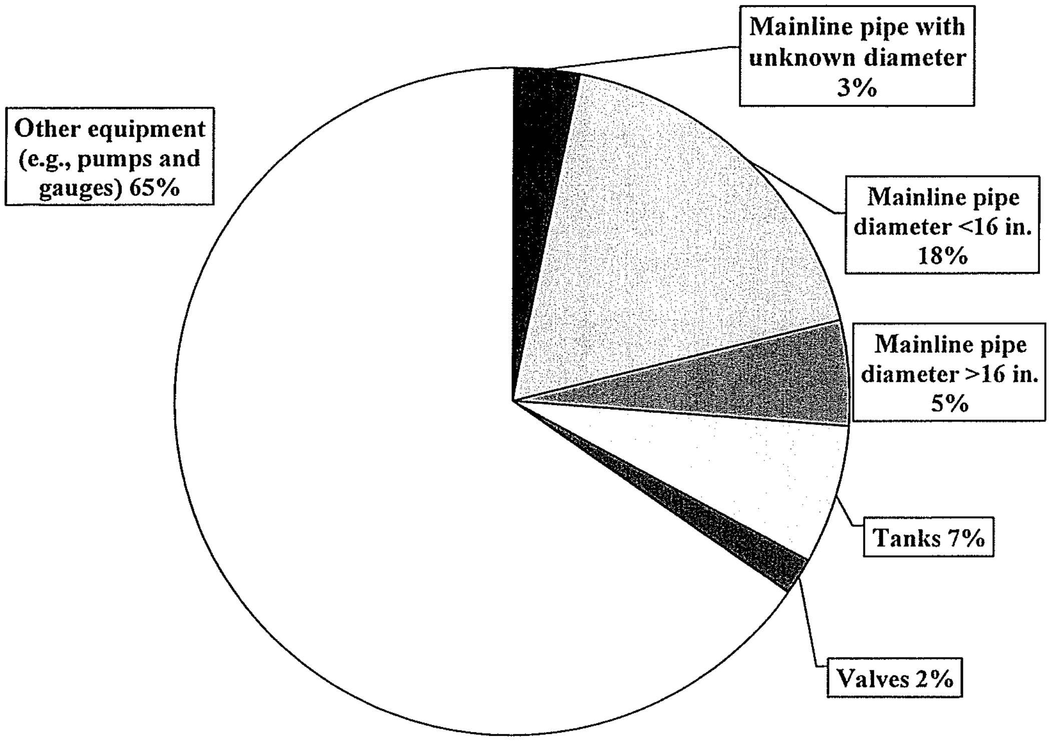

FIGURE 4-2 Crude oil pipeline incidents reported to PHMSA by system component involved, 2002 to 2012. [Data were obtained from analysis of PHMSA data from the Environmental Impact Statement of TransCanada XL permit application (U.S. Department of State 2013, Volume IV, Appendix K).]

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.

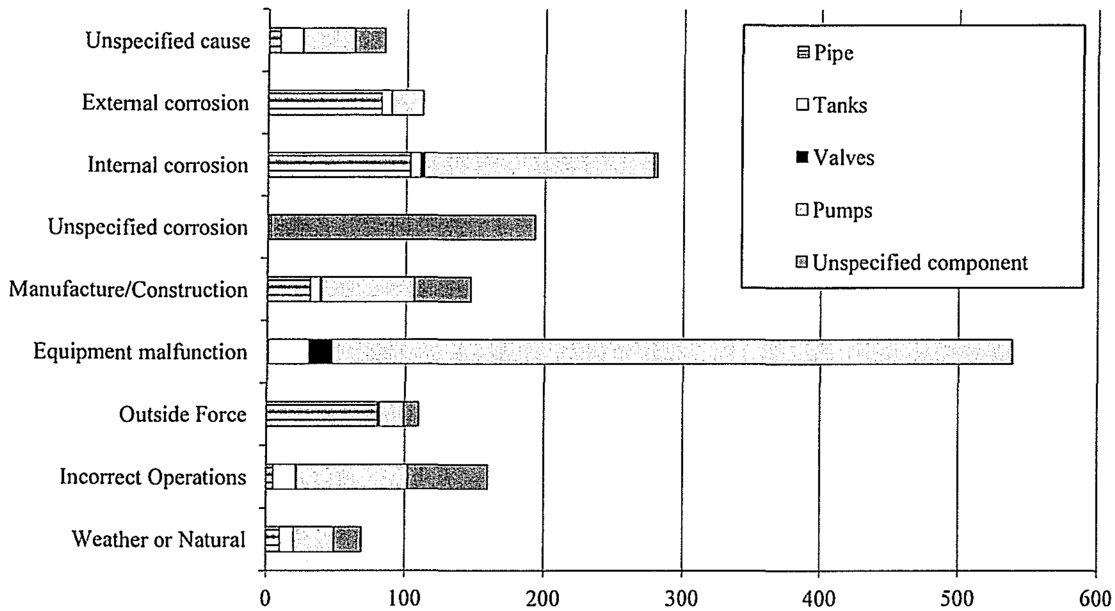

FIGURE 4-3 Crude oil pipeline incident reports to PHMSA by cause of release and system component involved, 2002 to 2012. (Source: U.S. Department of State 2013, Volume IV, Appendix K.)

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.

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

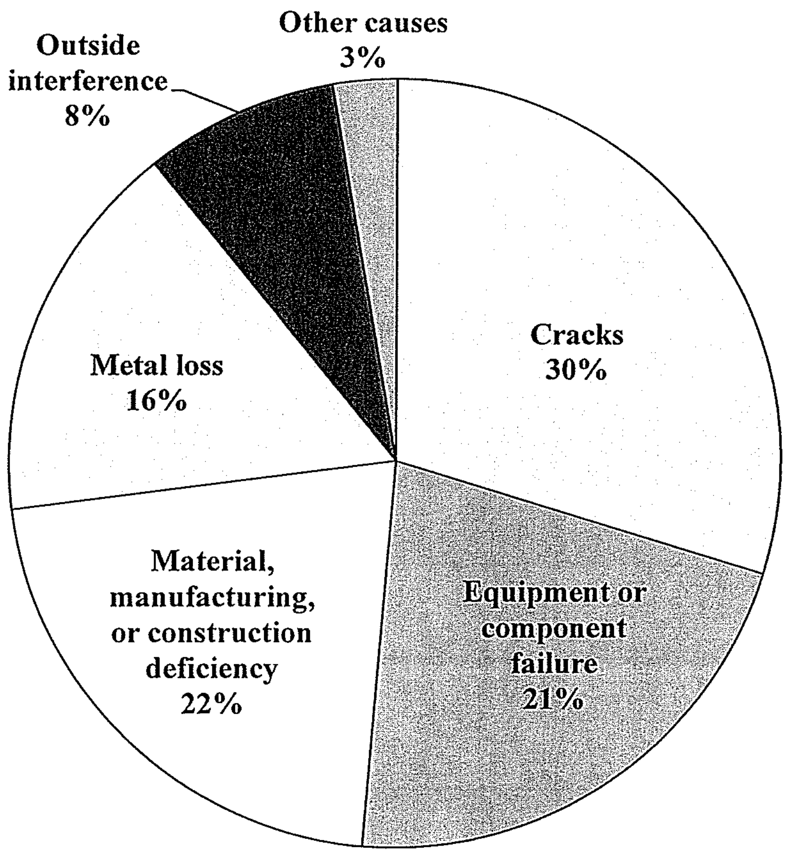

FIGURE 4-4 Causes of crude oil transmission pipeline incidents reported to NEB, 2004 to 2011. (Source: TSB 2012, Table 5.)

[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.

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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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.

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.

- *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.

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 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.

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[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

[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 (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 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.

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 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.

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.

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.

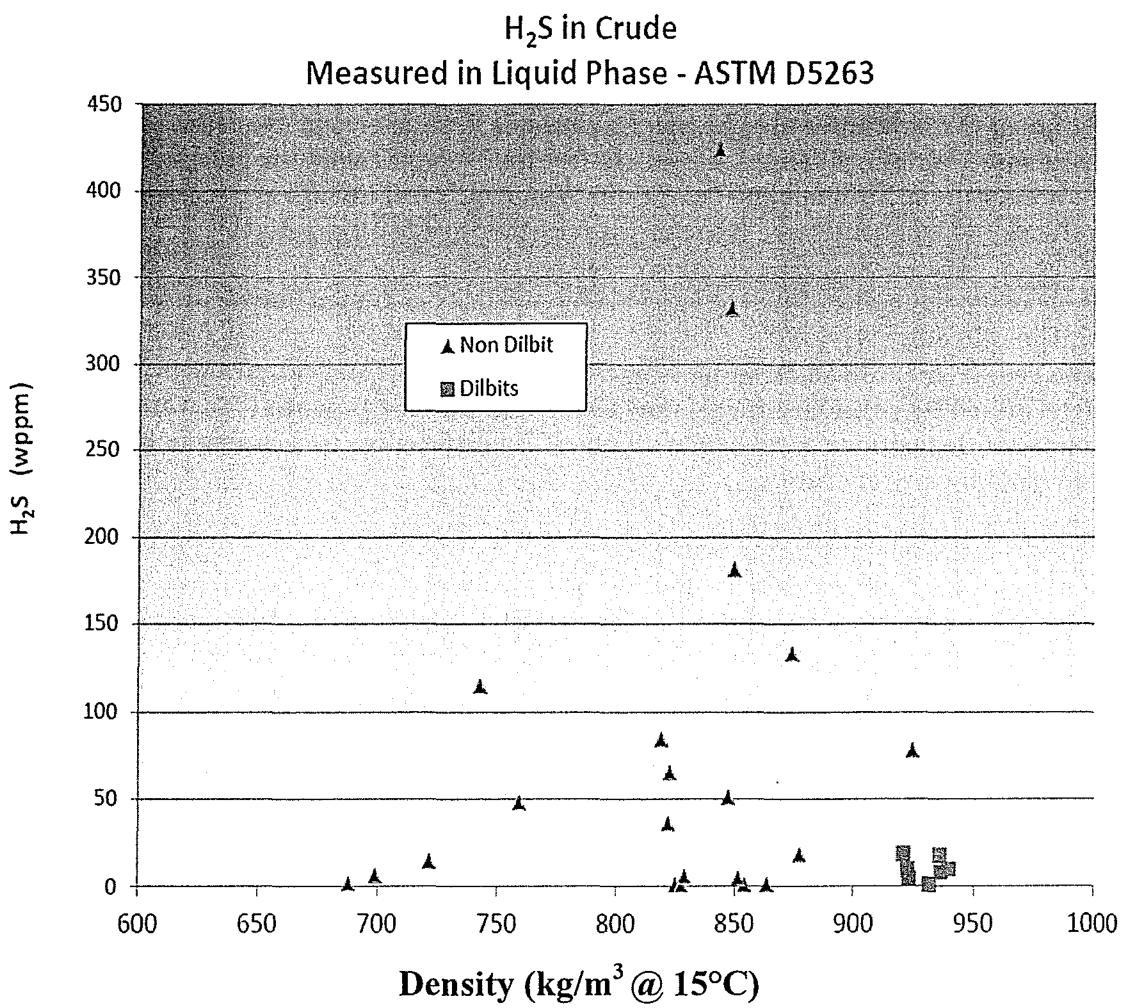

FIGURE A-1 Supplemental information on H_2S content.

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.

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

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 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

by Hedeff I. Essaid[1,2], Barbara A. Bekins[2], William N. Herkelrath[2], and Geoffrey N. Delin[3]

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

[1]Corresponding author: U.S. Geological Survey, 345 Middlefield Rd., Menlo Park, CA 94025; (650) 329-4581; fax: (650) 329-4463; hiessaid@usgs.gov

[2]U.S. Geological Survey, 345 Middlefield Rd., Menlo Park, CA 94025.

[3]U.S. Geological Survey, Denver Federal Center, Bldg. 53, Lakewood, CO 80225.

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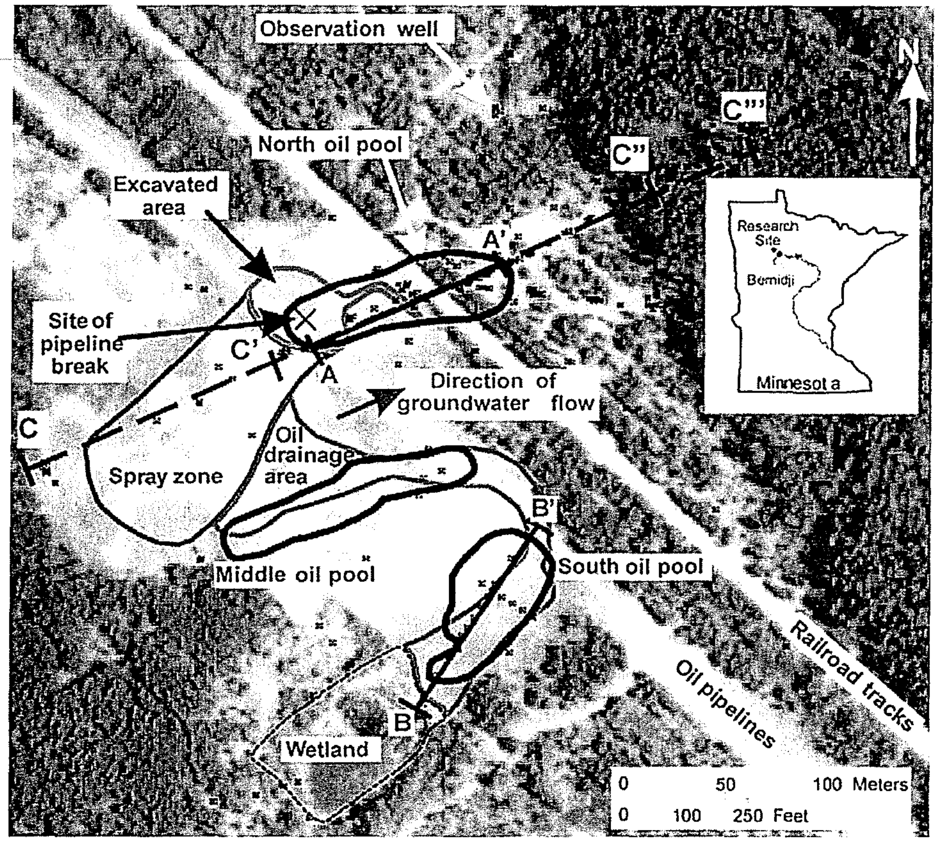

Figure 1. Aerial view of the Bemidji, Minnesota, crude-oil spill research site showing the site of the pipeline break, surface area impacted by oil spill, approximate extent of north, middle, and south oil pools floating on the water table, general direction of groundwater flow, and locations of cross 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,

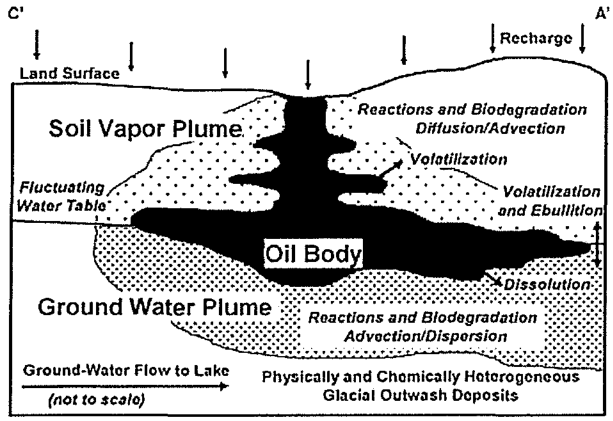

Figure 2. Generalized vertical cross section illustrating the fate and transport of spilled hydrocarbons in the subsurface (modified from Delin et al. 1998). Hydrocarbons infiltrate the subsurface as a separate oil phase, resulting in a residual oil source in the unsaturated zone and an oil body floating 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

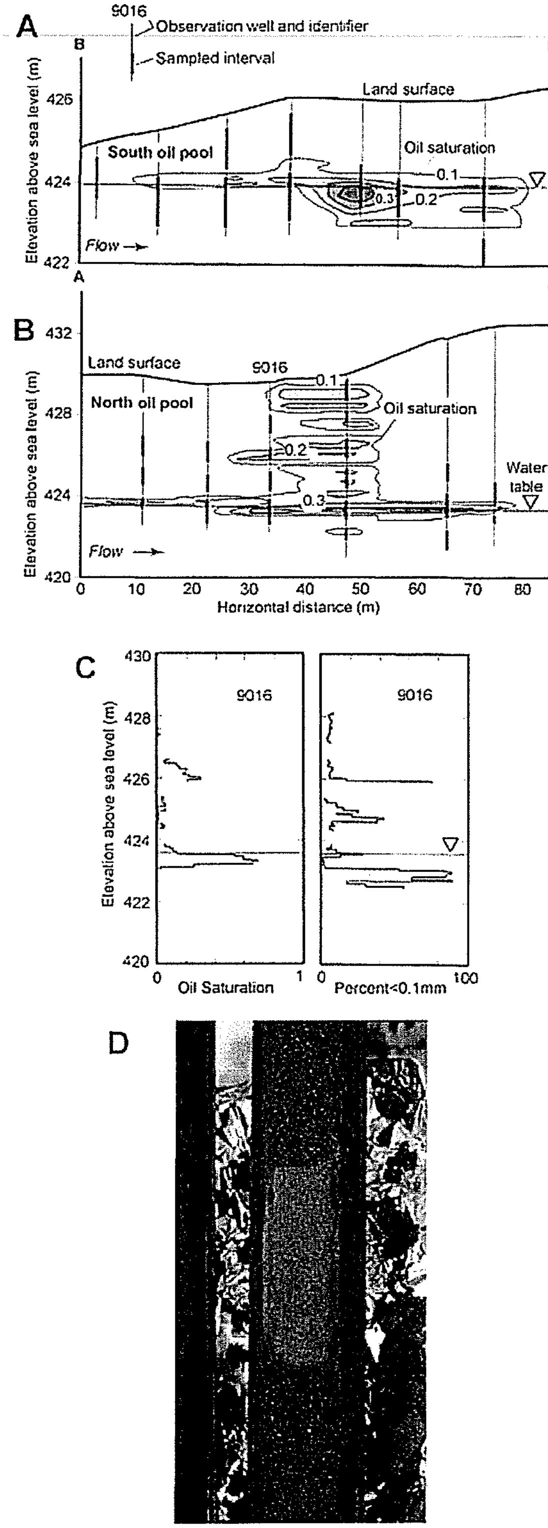

Figure 3. Oil-phase distribution at the Bemidji site (modified from Essaid et al. 1993; Dillard et al. 1997): (A) oil saturation (volume of oil/volume of pore space) distribution at the south pool; (B) oil-saturation distribution at the north pool; (C) oil saturation and percent grain size smaller than 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).

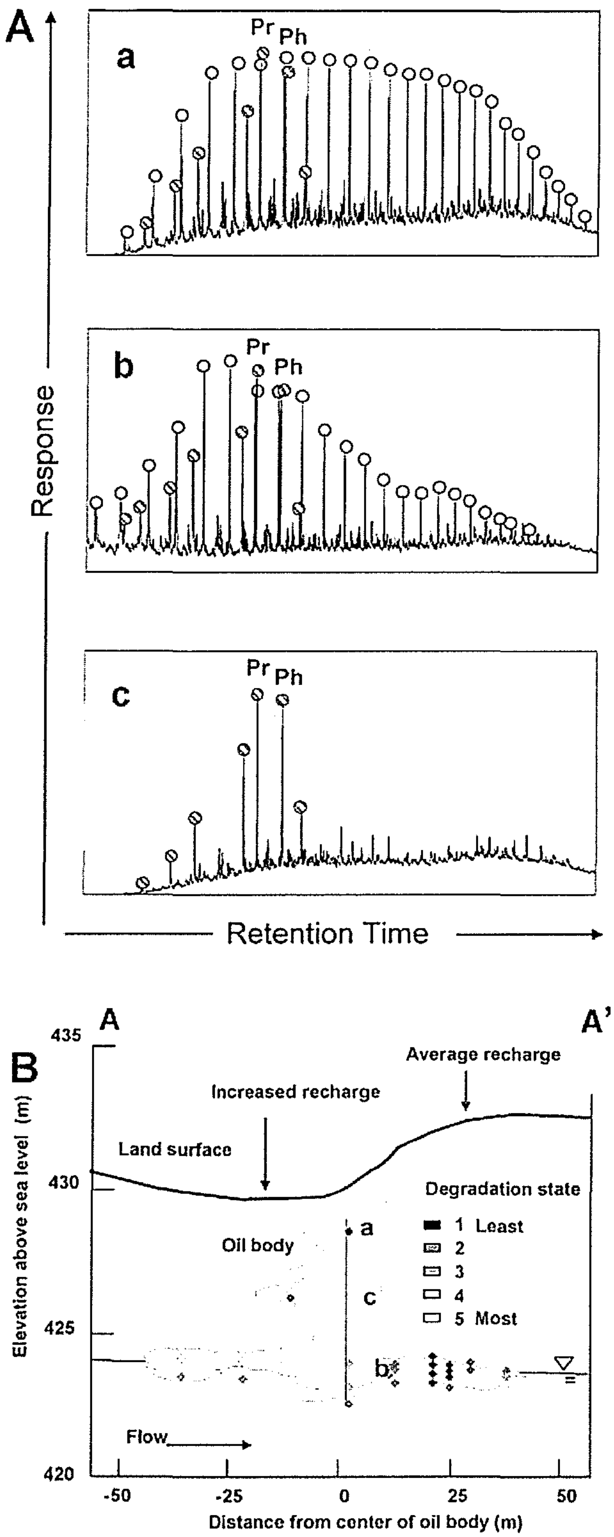

Figure 4. Evaluation of oil-phase degradation (from Bekins et al. 2005a): (A) ion chromatograms for oil samples with varying degrees of degradation (open circles are *n*-alkanes, black circles are isoprenoids) (a) relative undegraded sample with *n*-alkane concentrations greater than isoprenoids, (b) 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

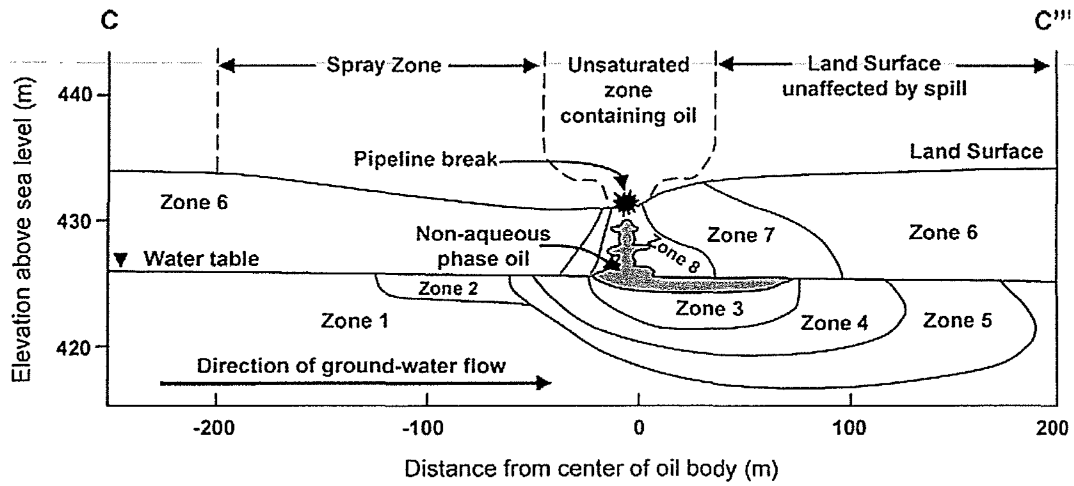

Figure 5. Subsurface geochemical zones identified at the north oil pool site (modified from Baedecker et al. 1993 and Delin et al. 1998). Zones are described in the accompanying text.

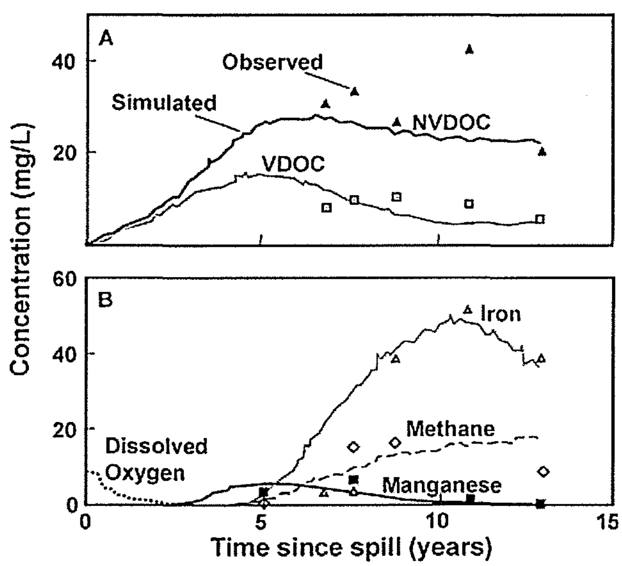

Figure 6. Observed (symbols) and simulated (lines) concentrations approximately 40-m downgradient from the center of the oil body, in the anoxic zone of the groundwater plume showing progression of terminal electron-accepting processes from aerobic degradation to manganese reduction, iron reduction, 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,

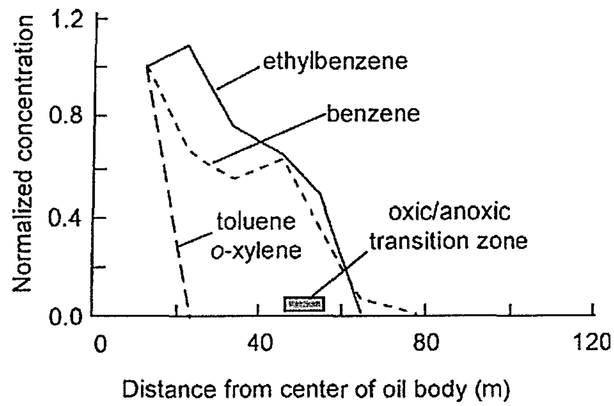

Figure 7. Groundwater concentrations of selected alkylbenzene compounds at the north pool, showing the effect of selective structure-dependent biodegradation of hydrocarbon compounds on persistence in the plume (modified from Eganhouse et al. 1996).

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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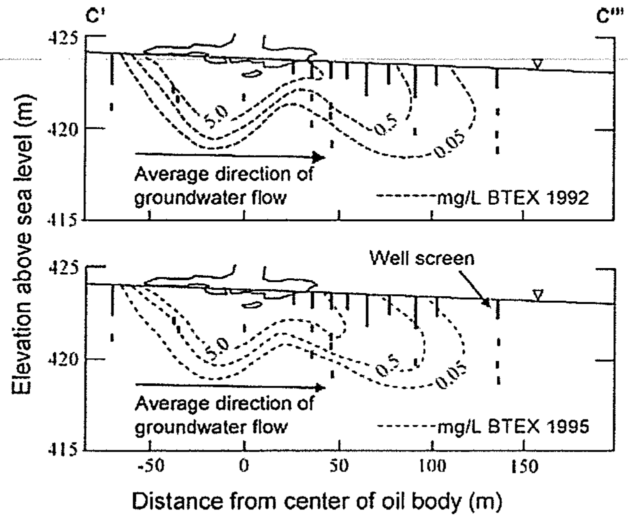

Figure 8. BTEX concentrations measured in wells (screened intervals shown as bars) in the groundwater plume for 1992 and 1995 showing that the extent of BTEX has remained relatively constant. However, the high concentration area in the core of the plume expanded as Fe^{3+} became depleted and conditions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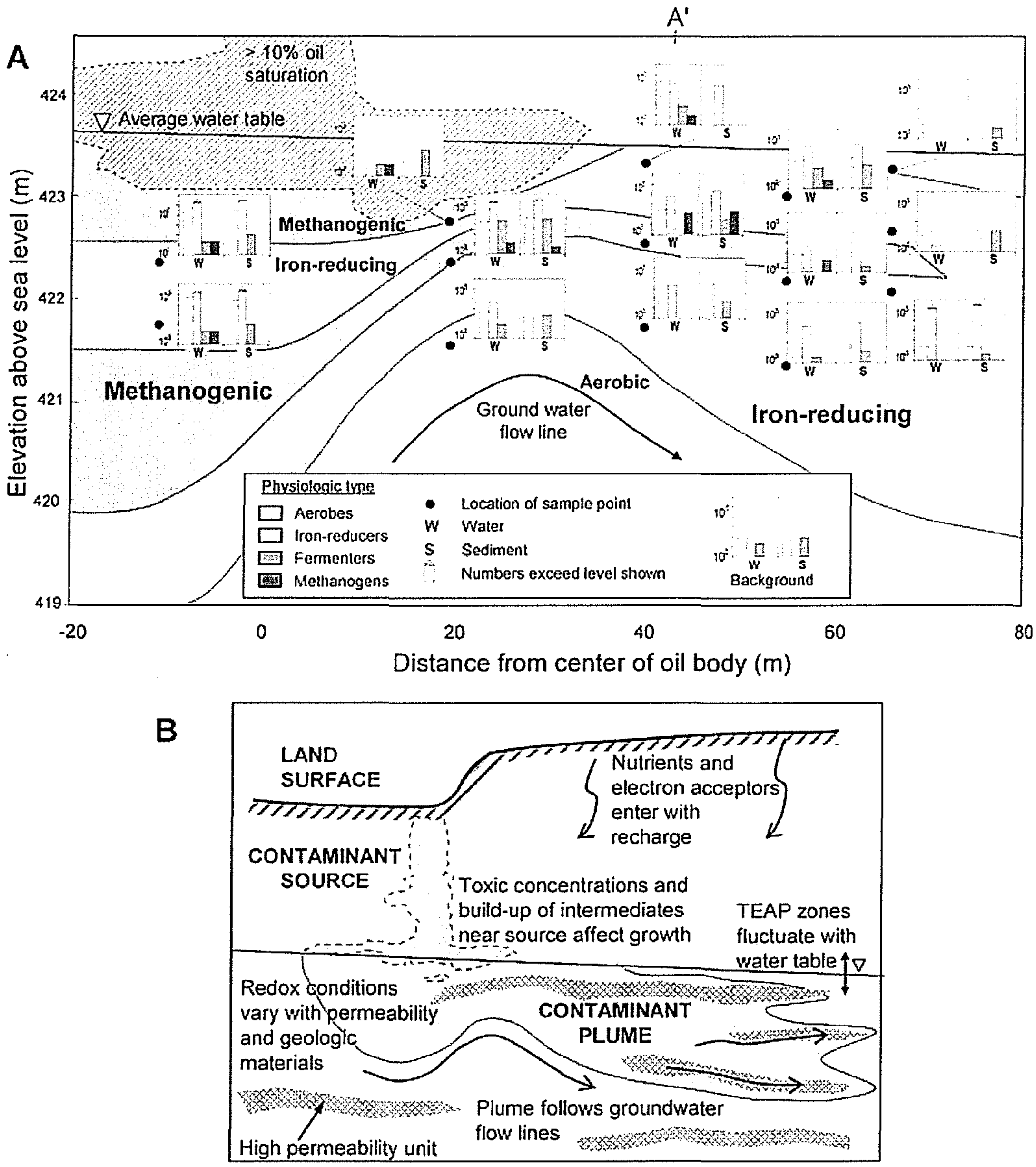

Figure 9. The influence of subsurface hydrologic and geochemical conditions on microbial populations in the hydrocarbon plume: (A) distributions of aerobes, iron reducers, methanogens, and heterotrophic fermenters in water and sediment within the north pool anaerobic plume (from Bekins et al. 1999); (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.

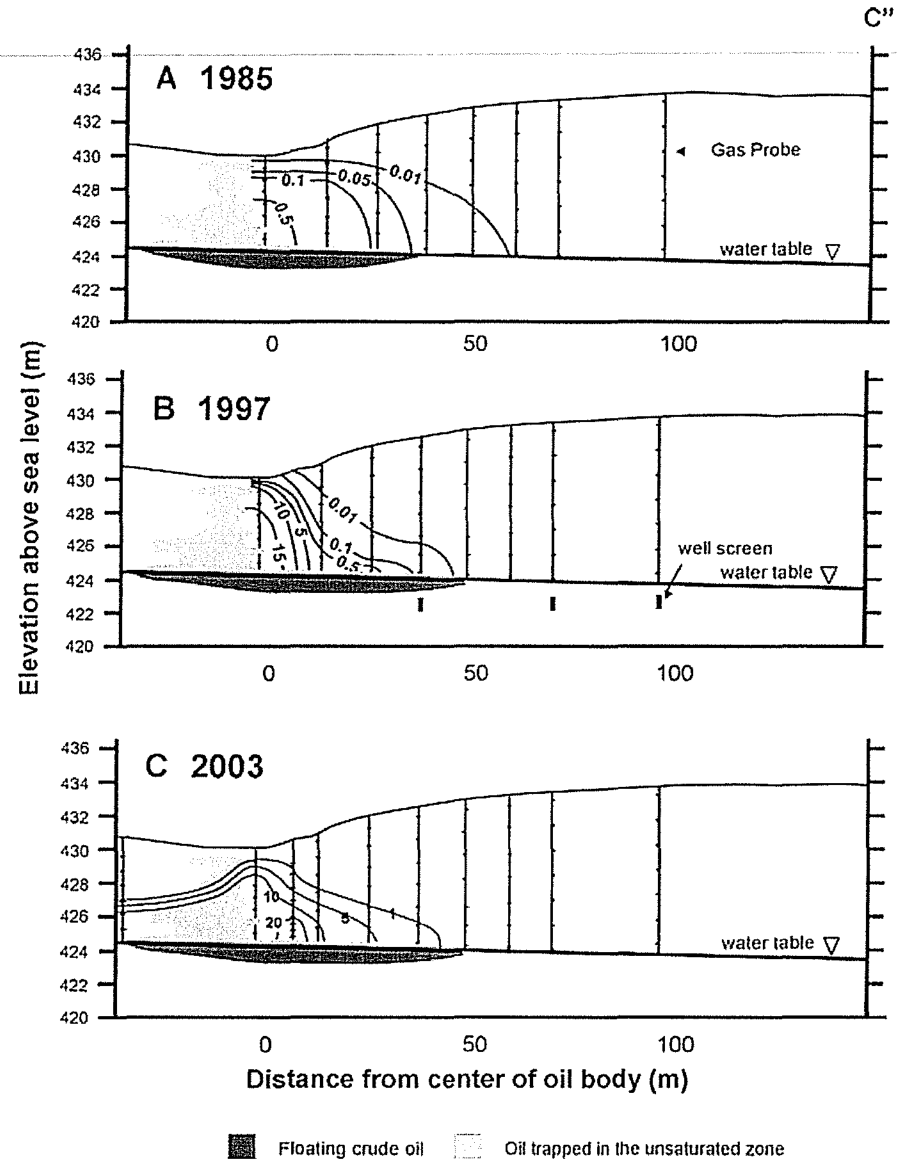

Figure 10. Unsaturated zone methane gas concentrations showing the increase with time as the plume became more methanogenic: (A) 1985 (modified from Hult and Grabbe 1988); (B) 1997 (from Chaplin et al. 2000); and (C) 2003 (modified from Amos et al. 2005).

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 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

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

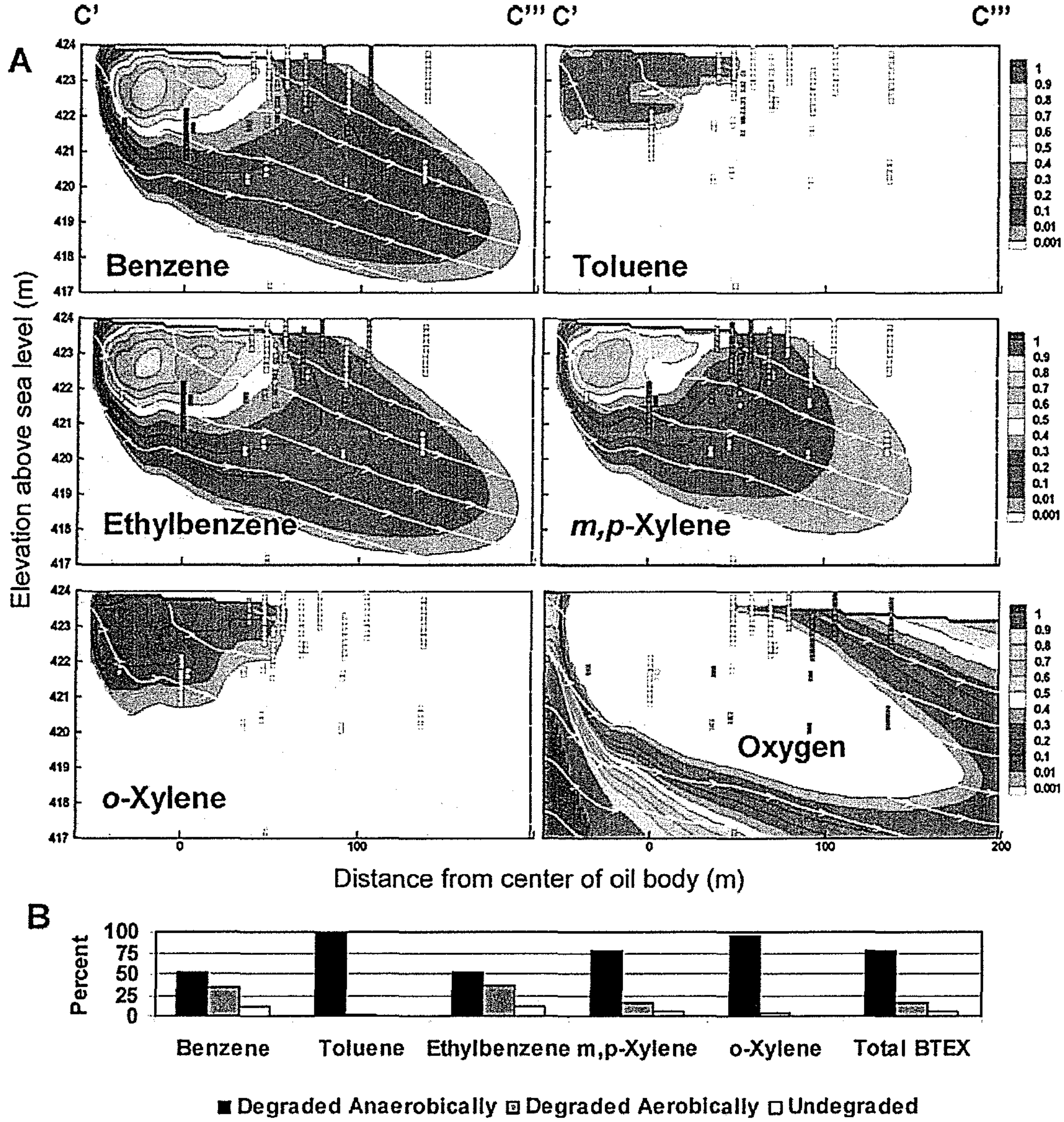

Figure 11. (A) The 1993 distribution of observed (boxes) and simulated (contours) BTEX and oxygen normalized concentrations showing that hydrocarbons with anaerobic degradation rates greater than their dissolution rate have limited plume extent (toluene and *o*-xylene), whereas compounds with anaerobic 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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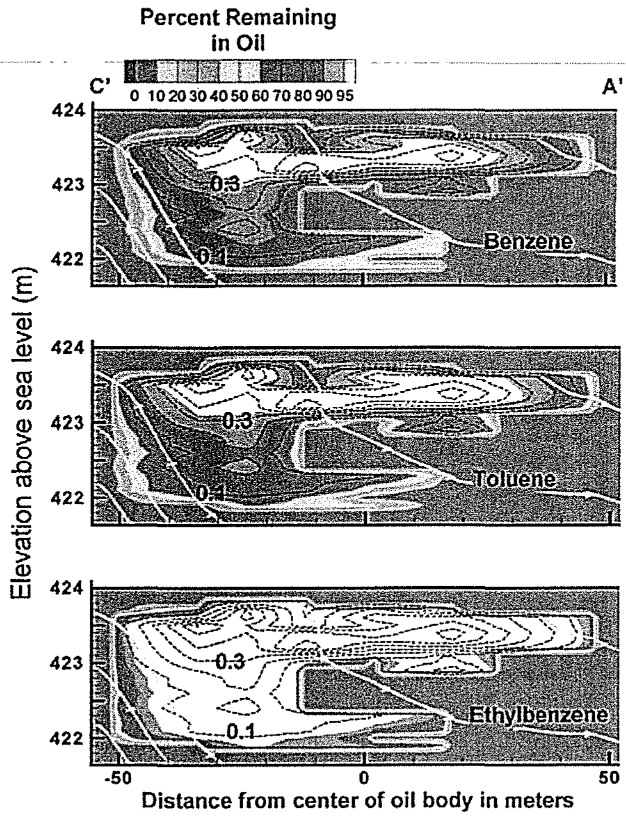

Figure 12. Simulated percent of benzene, toluene, and ethylbenzene remaining in the oil phase (relative to the initial amount in the oil body) after 18 years of dissolution and biodegradation. Dashed contours represent oil saturation and gray lines represent flow paths (from Essaid et al. 2003).

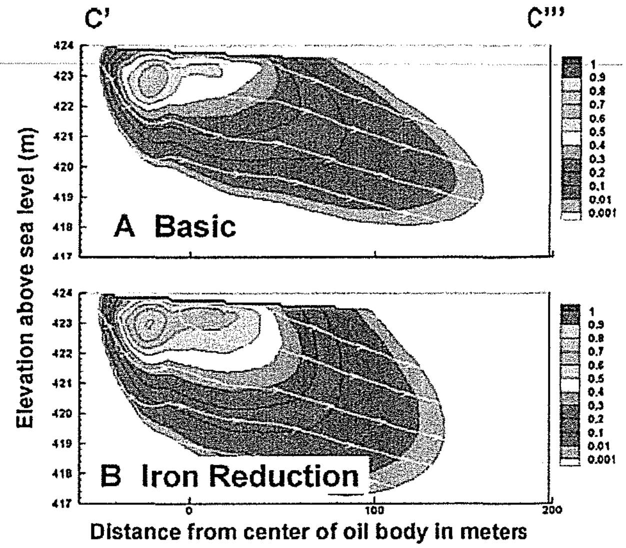

Figure 13. Predicted groundwater benzene concentration 50 years after the spill for the case of (A) a first-order anaerobic benzene biodegradation rate that is uniform in time and (B) a first-order anaerobic biodegradation rate that becomes zero when Fe^{3+} is depleted (from Essaid et al. 2003). The 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, 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 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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EXHIBIT
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.**

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

[1]Environmental Engineer, GSI Environmental Inc., Houston, Texas (corresponding author). E-mail: rkamath@gsi-net.com
[2]President, GSI Environmental Inc., Houston, Texas.
[3]Vice-President, GSI Environmental Inc., Houston, Texas.
[4]Environmental Scientist, GSI Environmental Inc., Houston, Texas.
[5]Environmental Engineer, GSI Environmental Inc., Houston, Texas.
[6]Stanford Univ., Stanford, California.
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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 $\mu g/L$ for benzene, 10 $\mu g/L$ for MTBE, and 12 $\mu g/L$ for TBA. For benzene, the remediation goal corresponds to the federal maximum contaminant level (MCL) for drinking water (5 $\mu g/L$), (EPA 2009). For MTBE, the value corresponds to the New York State Department of Environmental Conservation (NYSDEC) groundwater standard for MTBE (10 $\mu g/L$), (NYSDEC 2008) and for TBA, the value corresponds to the California drinking water action goal (12 $\mu g/L$) (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

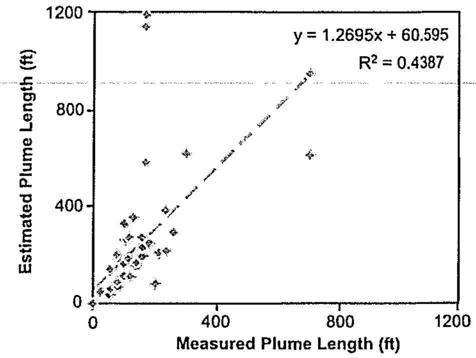

Fig. 1. Correlation between estimated ersus measured plume lengths at 30 UST sites with well-delineated MTBE, benzene, and TBA plumes

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.

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

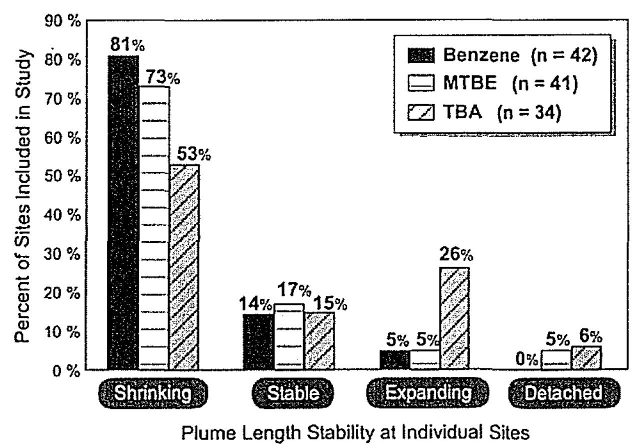

Fig. 2. Results of groundwater plume stability evaluation at individual sites

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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

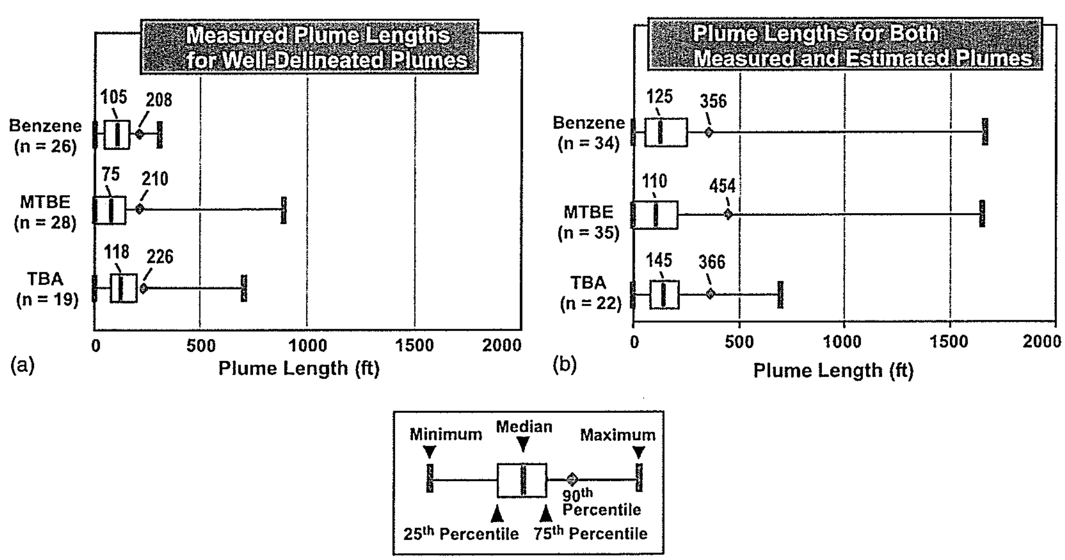

Fig. 3. Distribution of (a) measured plume lengths for well-delineated plumes; (b) measured and estimated plume lengths for all plumes

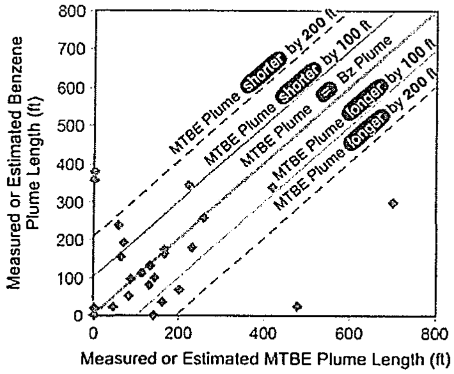

Fig. 4. Comparison of measured or estimated plume lengths for benzene versus MTBE

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%

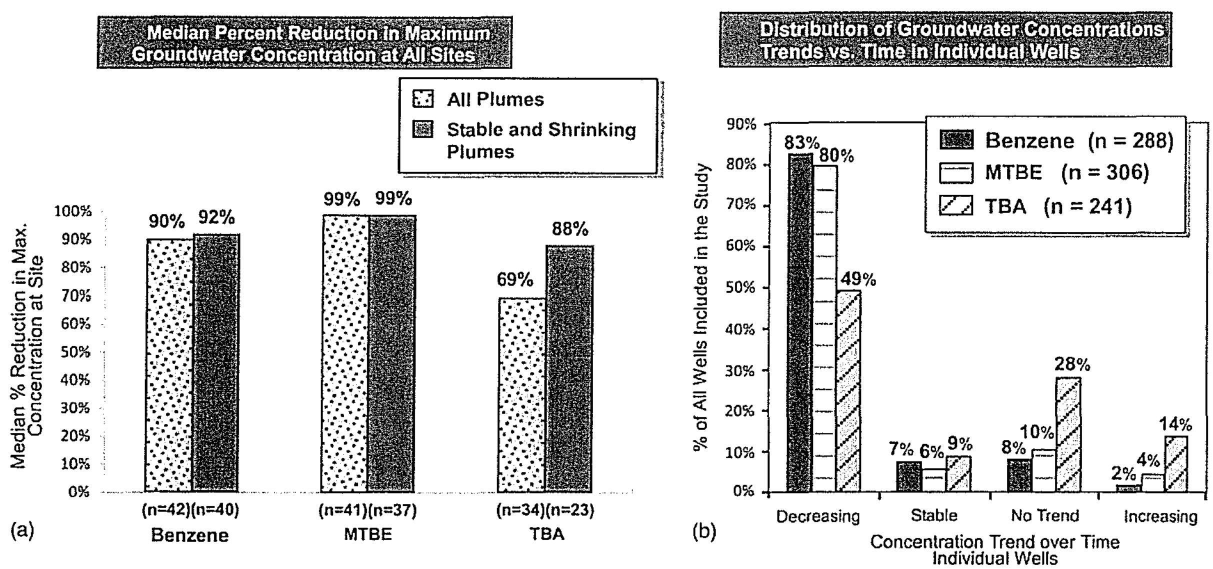

Fig. 5. Concentration Trends: (a) Median percent reduction in maximum groundwater concentration at all sites; (b) distribution of groundwater concentrations trends versus time in individual wells (Both stable plumes and no trend plumes have a Mann-Kendall result of "no trend." However, for our evaluation, 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 $\mu g/L$ for benzene and 10 $\mu g/L$ 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 $\mu g/L$) 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)

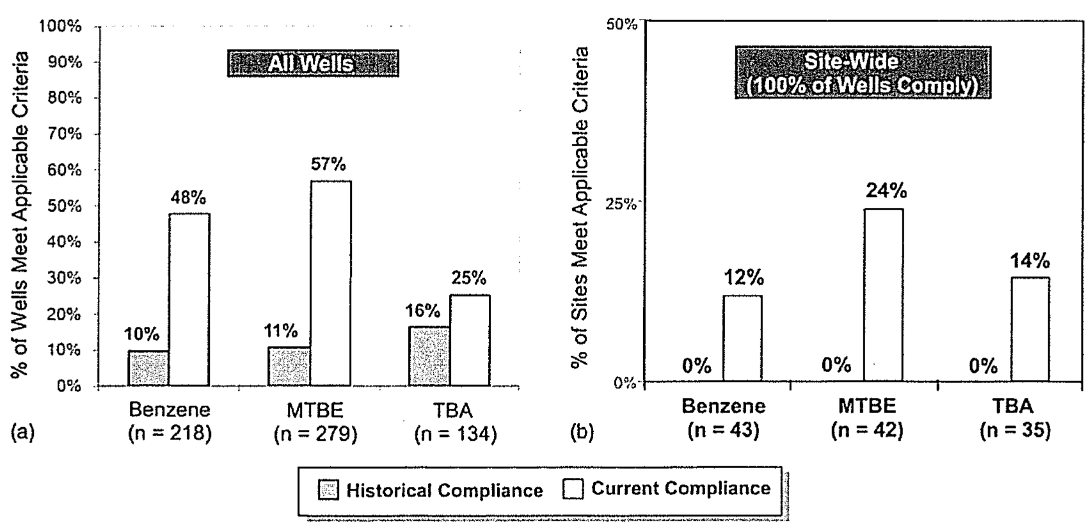

Fig. 6. Comparison of historical versus current compliance with remediation goals

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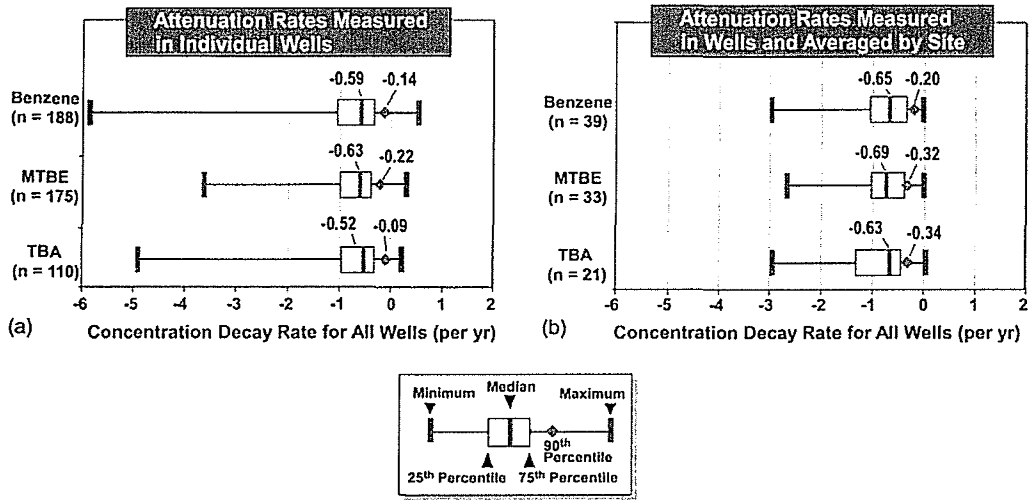

Fig. 7. Comparison of point attenuation rates for benzene, MTBE, and TBA at sites with stable or shrinking plumes

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.

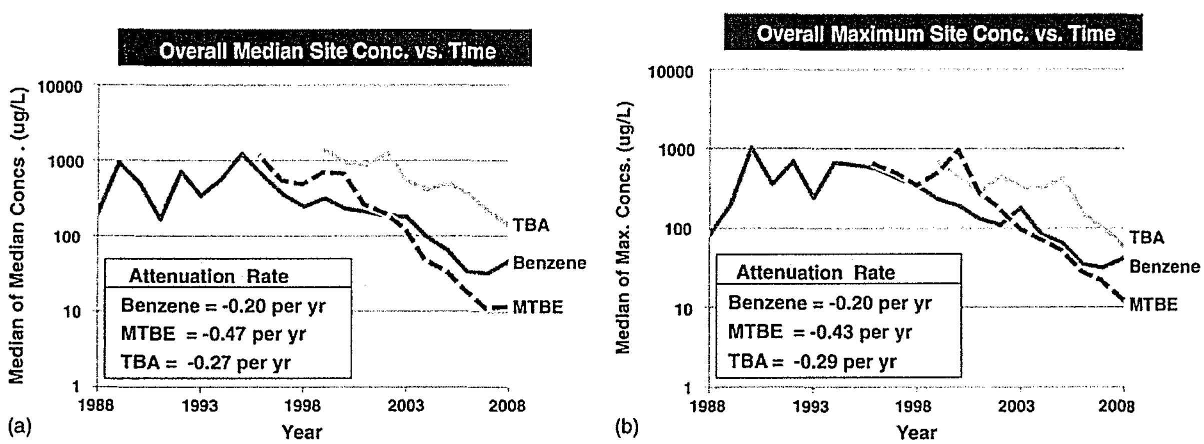

Fig. 8. Trend in site-wide median and maximum plume Concentrations versus time

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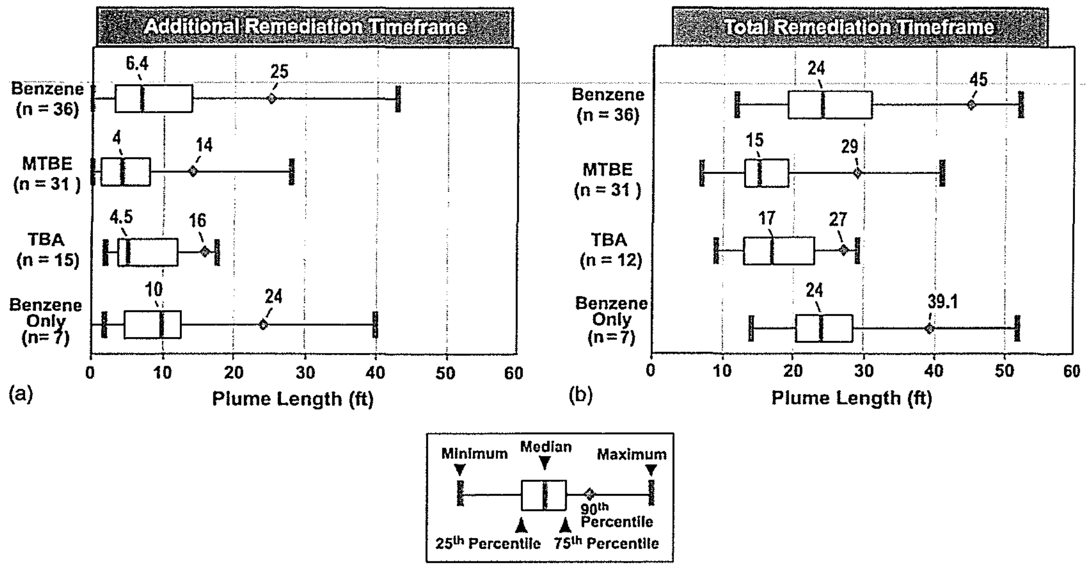

Fig. 9. Time to Remediation for Sites with Stable or Shrinking Plumes ("Benzene Only" refers to those sites where only benzene, not MTBE or TBA, exceeded the applicable remediation goal.)

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	Prior studies, 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 Paper/

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

[1]Corresponding author: GSI Environmental Inc., Houston, TX 77098; 713-522-6300; fax: 713-522-8010; jaconnor@gsi-net.com

[2]GSI Environmental Inc., Houston, TX 77098.

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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

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	Plume Stability Condition Evaluated? 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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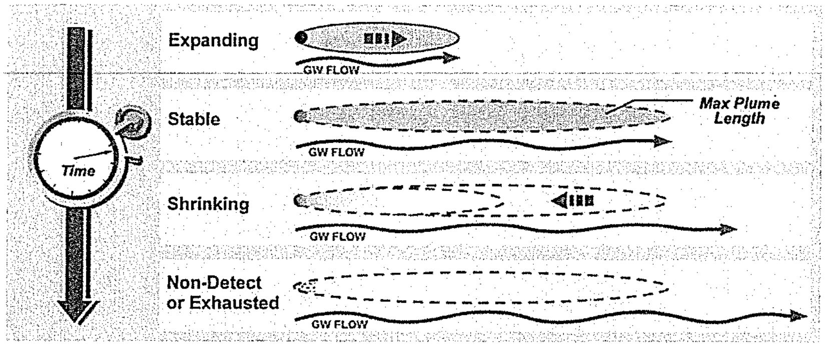

Figure 1. Schematic of groundwater plume stages at a typical UST site following termination of a spill or leak.

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 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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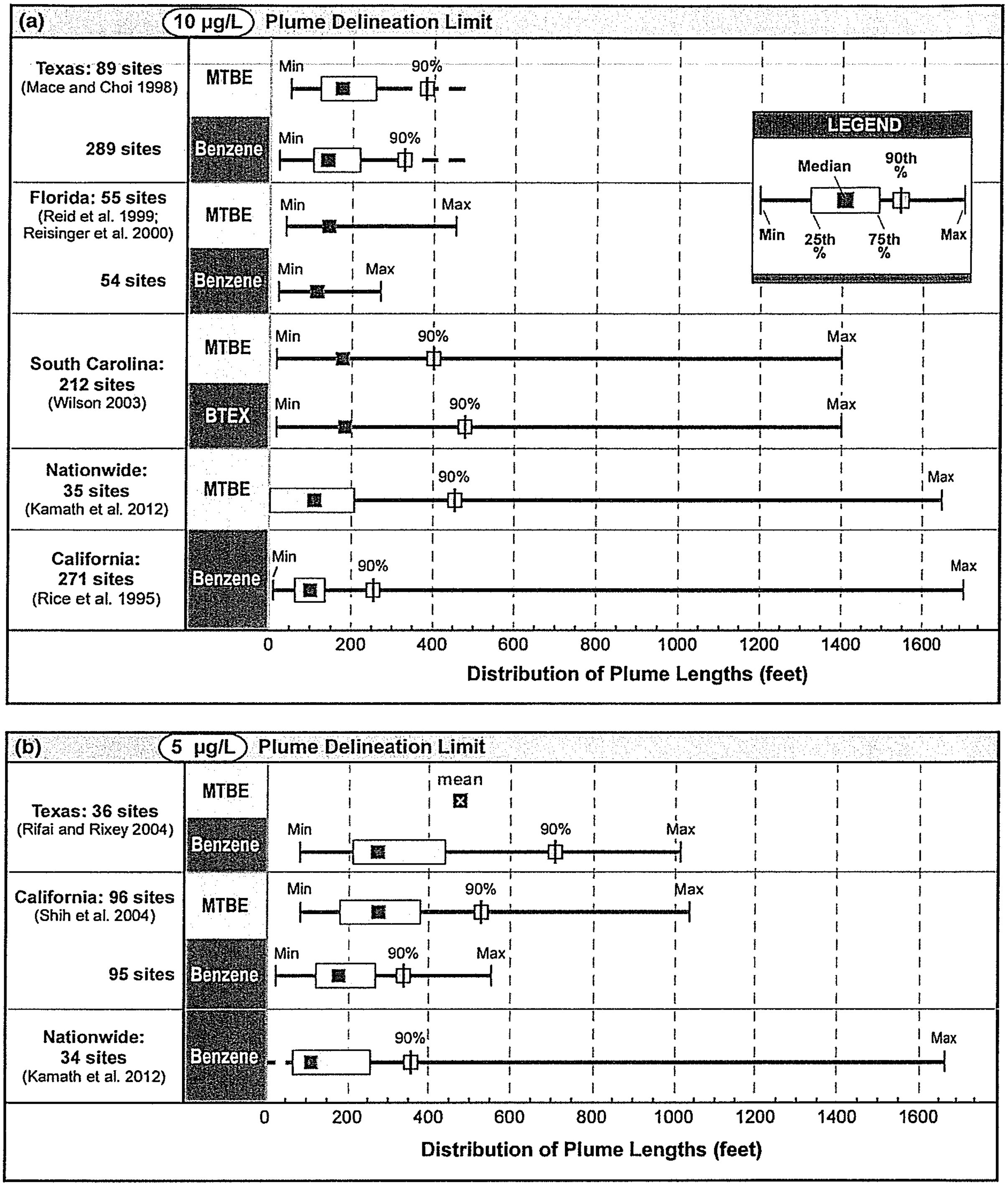

Figure 2. Summary of surveys of plume lengths in groundwater: MTBE versus benzene.

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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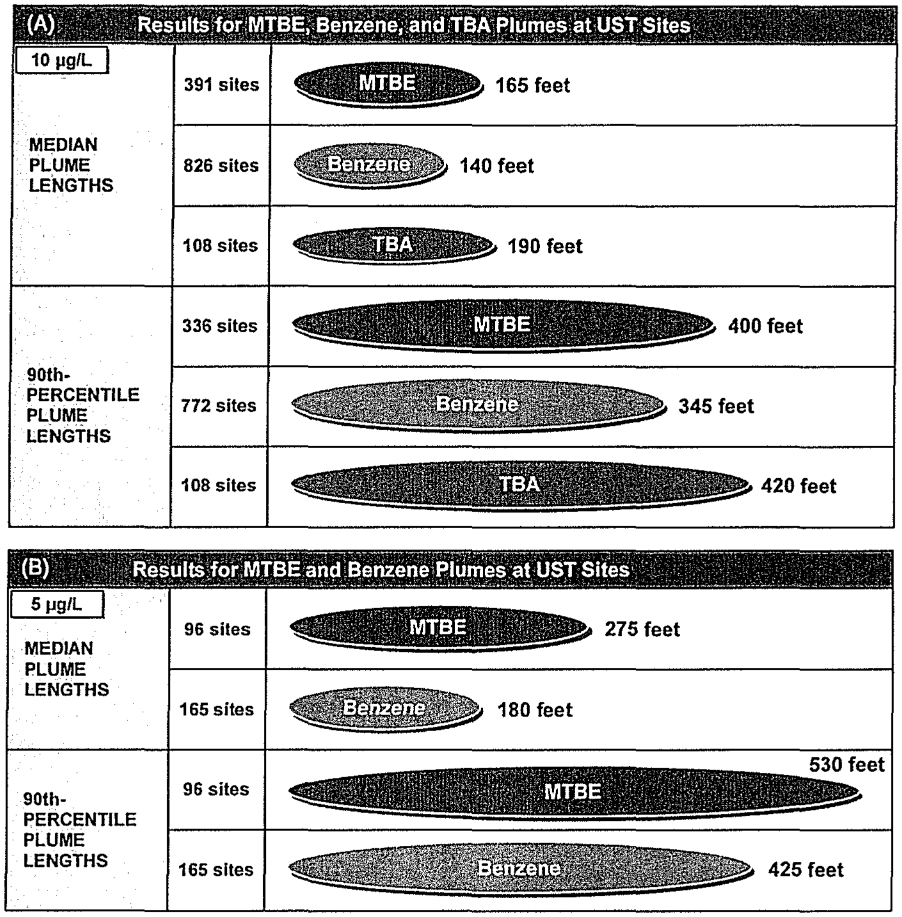

Figure 3. Weighted means of median lengths and 90th percentile lengths of MTBE, TBA, and benzene plumes. (A) Weighted means of plume lengths defined by 10 μg/L concentration limit. (B) Weighted means of plume lengths defined by 5 μg/L concentration limit. Lengths are estimated as the weighted mean of 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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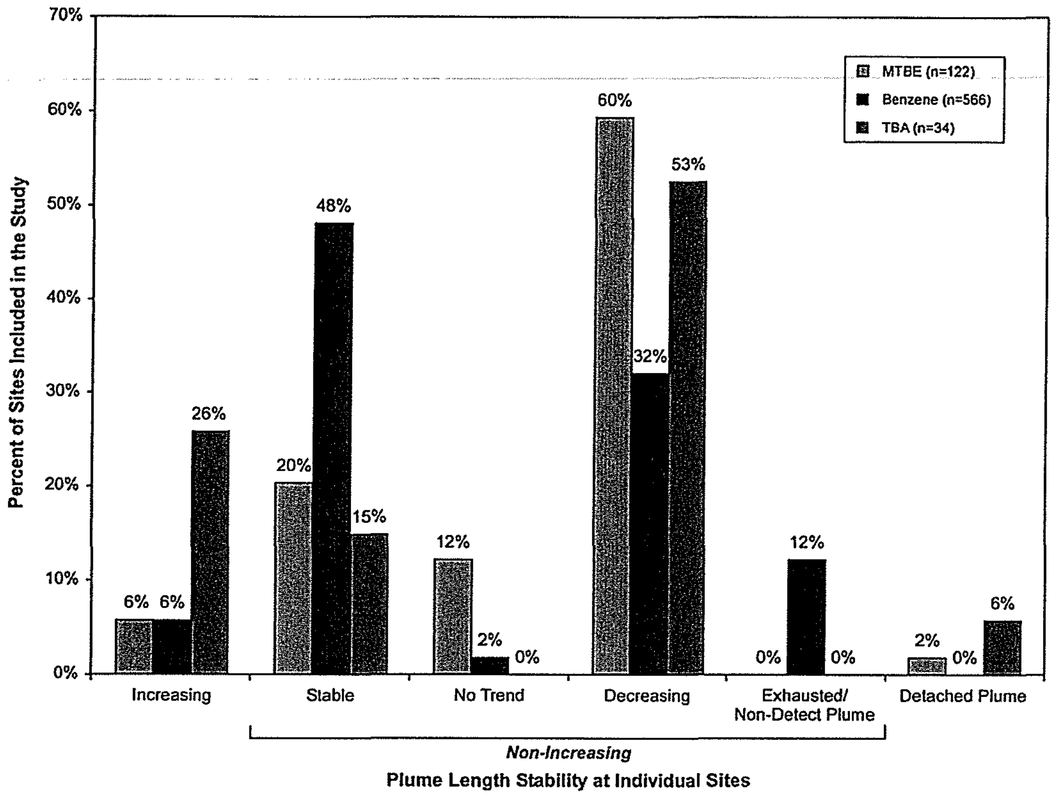

Figure 4. Comparison of plume length stability conditions for MTBE, benzene, and TBA plumes at UST sites. Data have been compiled for MTBE, benzene, and TBA plumes in groundwater underlying UST sites across the nation (see Table S2 for studies used to compile these stability percentages).

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

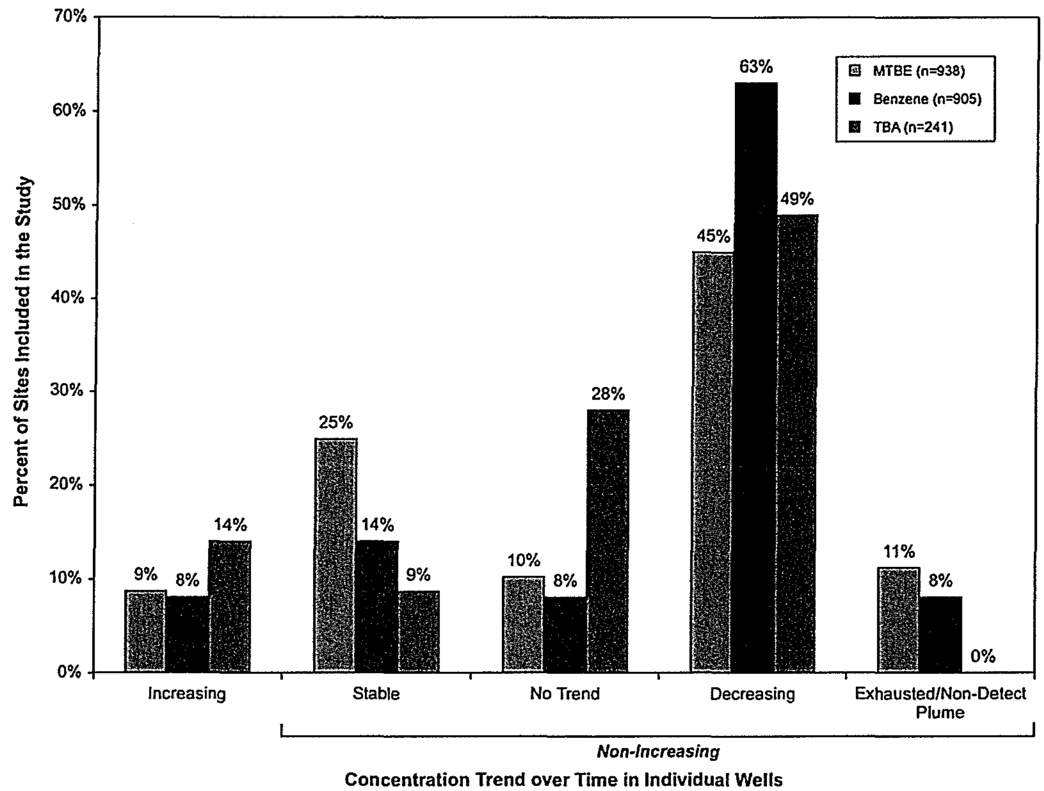

Figure 5. Comparison of concentration versus time trends for MTBE, benzene, and TBA in monitoring wells at UST sites. Data have been compiled for MTBE, benzene, and TBA concentration trends in groundwater underlying UST sites across the nation (see Table S3 for studies used to compile these concentration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

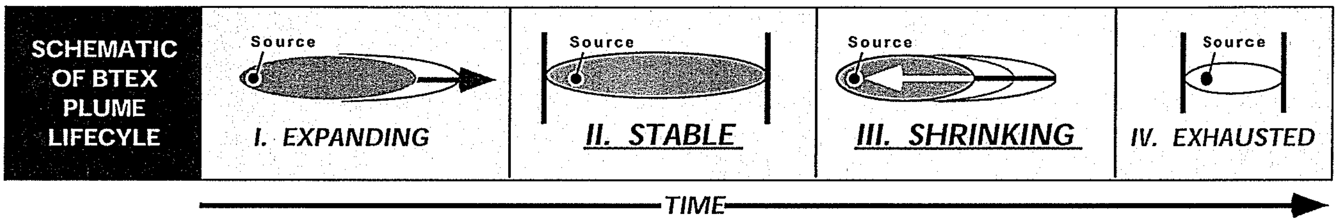
C.J. Newell and J.A. Connor, Groundwater Services, Inc.

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

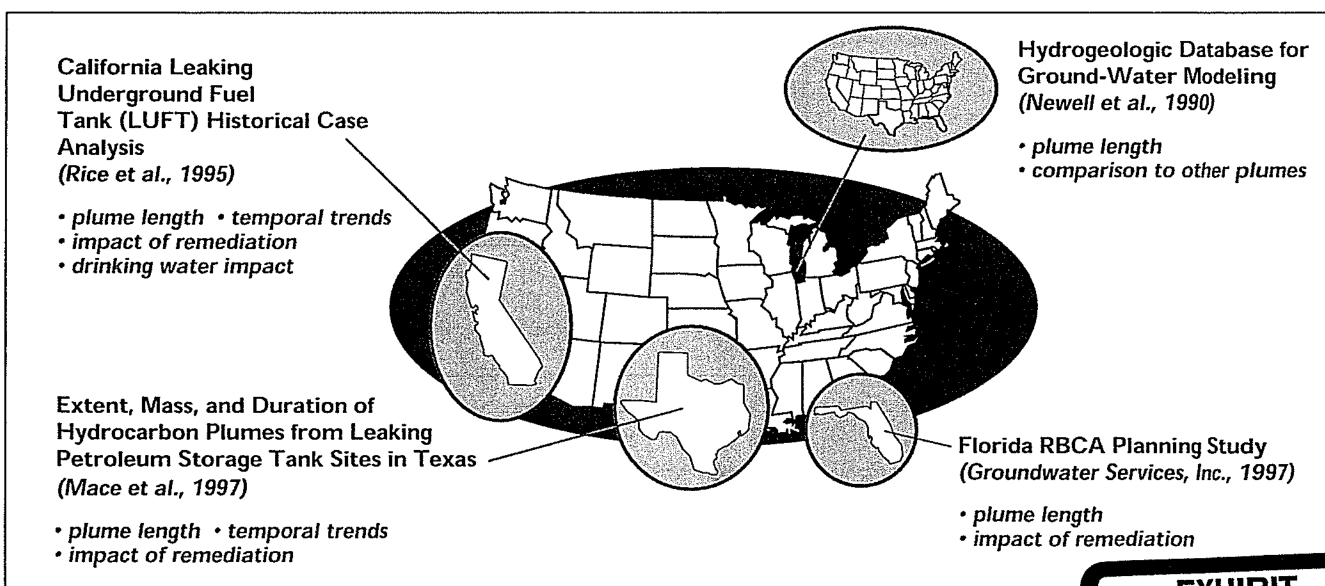
This bulletin summarizes information from four separate multi-site plume studies. Each study involved detailed analysis of data from a large number of sites (primarily underground storage tank facilities) to identify the key characteristics of groundwater contaminant plumes caused by petroleum hydrocarbon 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



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.

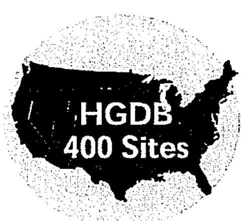
KEY RESULTS: Most benzene plumes (75%) are less than 250 ft long and have either stabilized or are decreasing in length and concentration. The median plume length was 181 ft. Only 14% are increasing in concentration, and only 3% are increasing in length. The length of a benzene plume cannot be predicted 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.

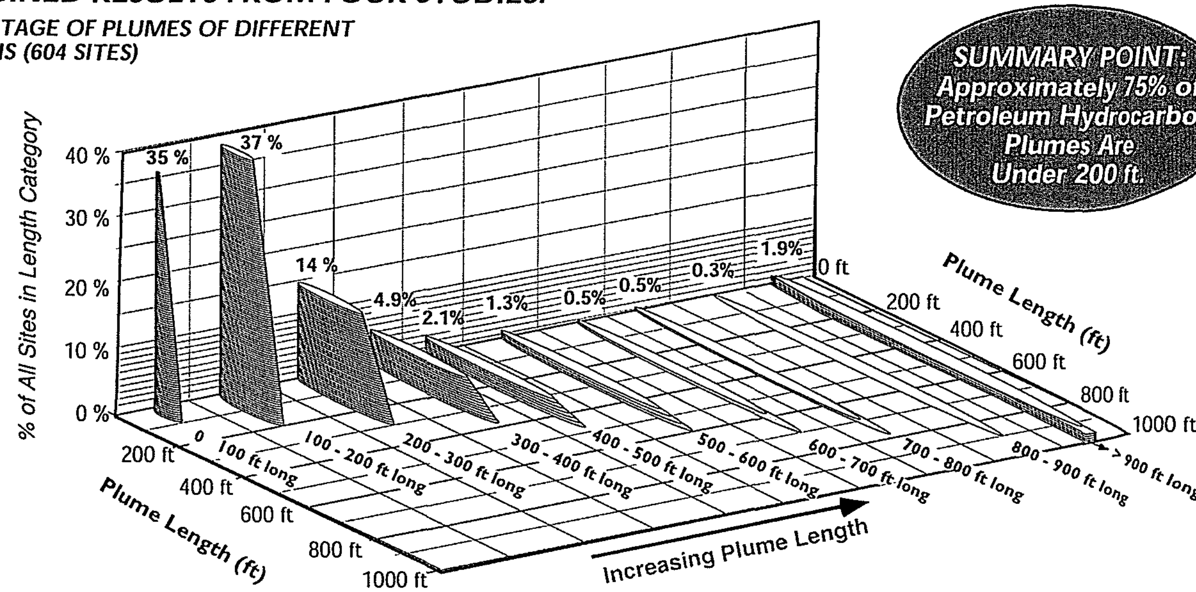
APPROACH: Hydrogeologic and chemical information from 400 site investigations across the U.S. was obtained in a national survey of National Ground Water Association members conducted in 1990. This 400-site database (available in spreadsheet form from the API Information Specialist, ehs@api.org) includes 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.

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

FLORIDA

74 Sites

HGDB

SUMMARY - ALL SITES		Summary (California)		Summary (Texas)		Summary (Florida)		Summary (HGDB)	
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

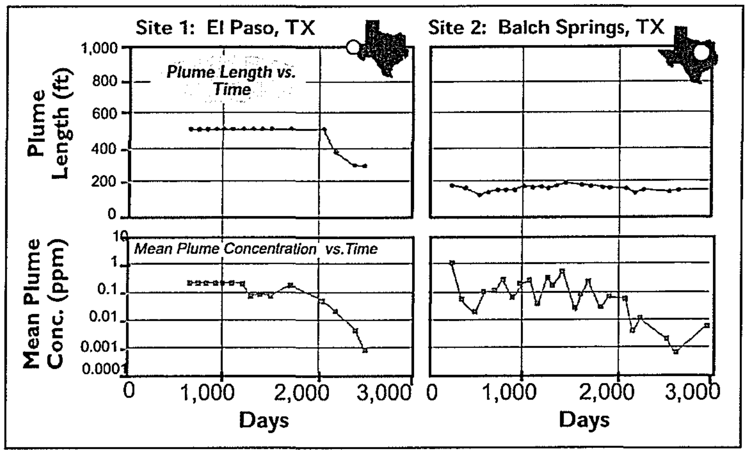
• LOCATION OF SITES:	CALIFORNIA	TEXAS	FLORIDA	ENTIRE U.S.
• Plume constituent(s):	Benzene	Benzene	Benzene, BTEX	Mostly benzene, BTEX constituents
• Plume Delineation Limit:	10 ppb	10 ppb	1 - 50 ppb	Not reported; probably analytical detection limit.
• Types of Sites:	UST sites with affected groundwater. 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)

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.



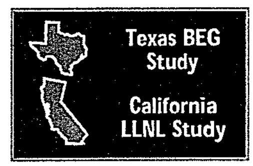
Plume stability trends were determined as follows:

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.

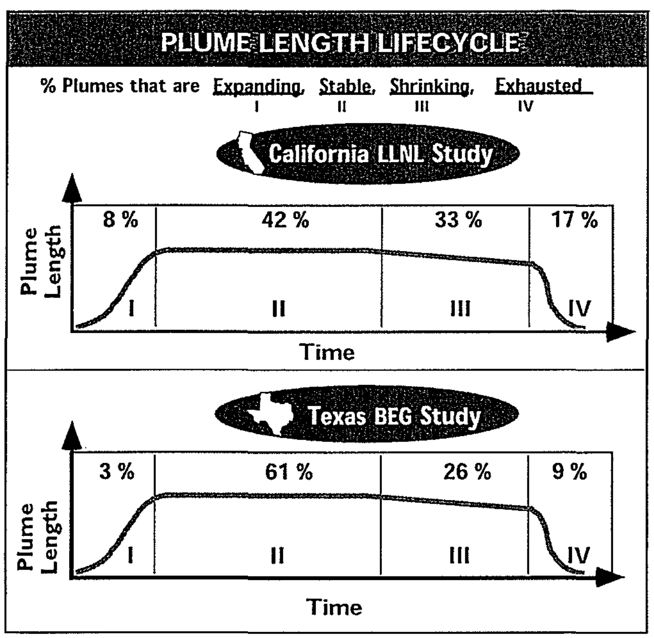
KEY RESULTS

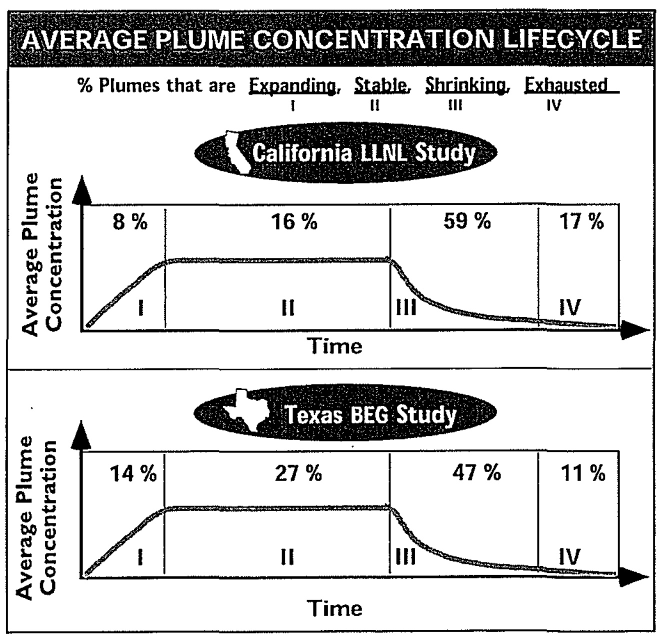


Based on the observed trends, the studies grouped the plumes into four categories:

- ***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.

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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)

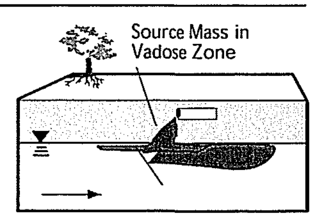
% OF PLUMES THAT ARE:

	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)



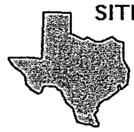
"..soil removal would not significantly affect groundwater remediation requirements." (pg. 21)

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

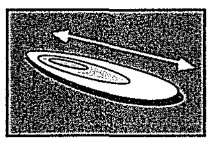


The Texas study (Mace et al., 1997) concluded that **plume length could not be predicted** by the following variables:

- *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 the 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 %**

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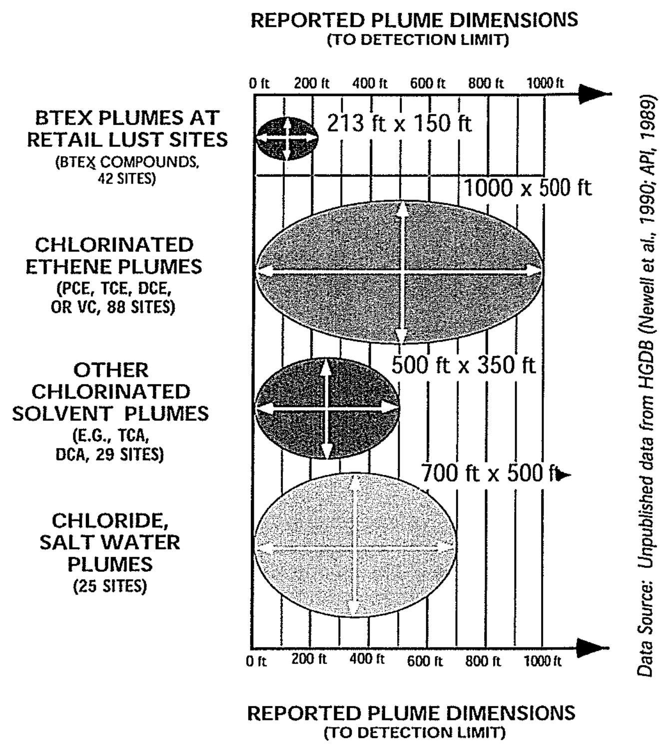
HOW ARE BTEX PLUMES DIFFERENT FROM OTHER PLUMES?

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 biodegradable 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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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
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Publ *4551*, Treatment of Gasoline-Contaminated Groundwater Through Surface Application: Laboratory Experiments, July 1994
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Publ *4552*, Treatment of Gasoline-Contaminated Groundwater through Surface Application: A Prototype Field Study, July 1994
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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

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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-

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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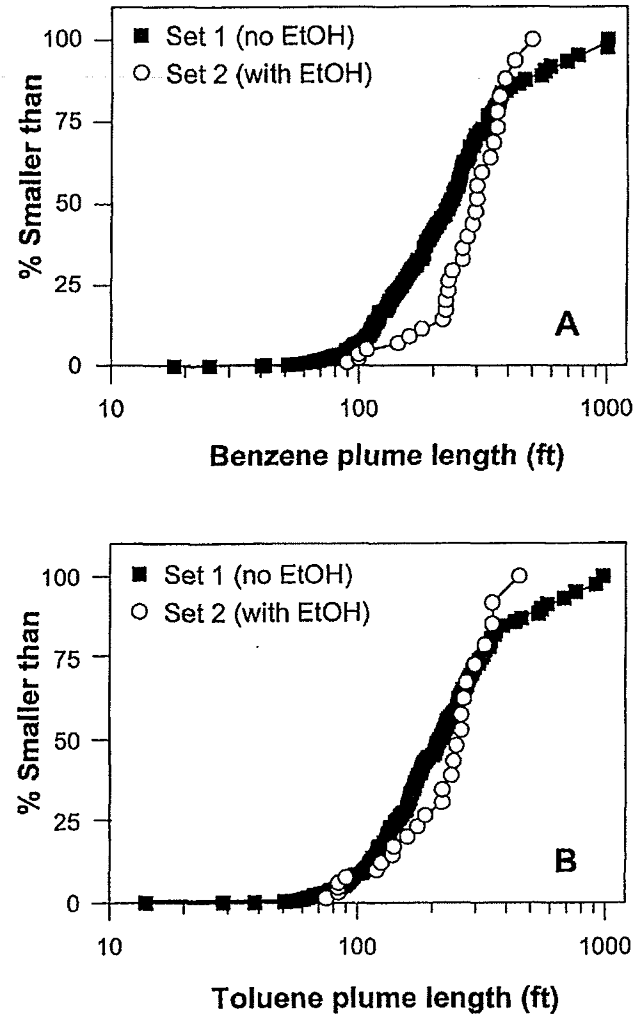

Figure 1. Cumulative distribution of (a) benzene and (b) toluene plume lengths for set 1 (Iowa data, without ethanol) and set 2 (Kansas data, with ethanol).

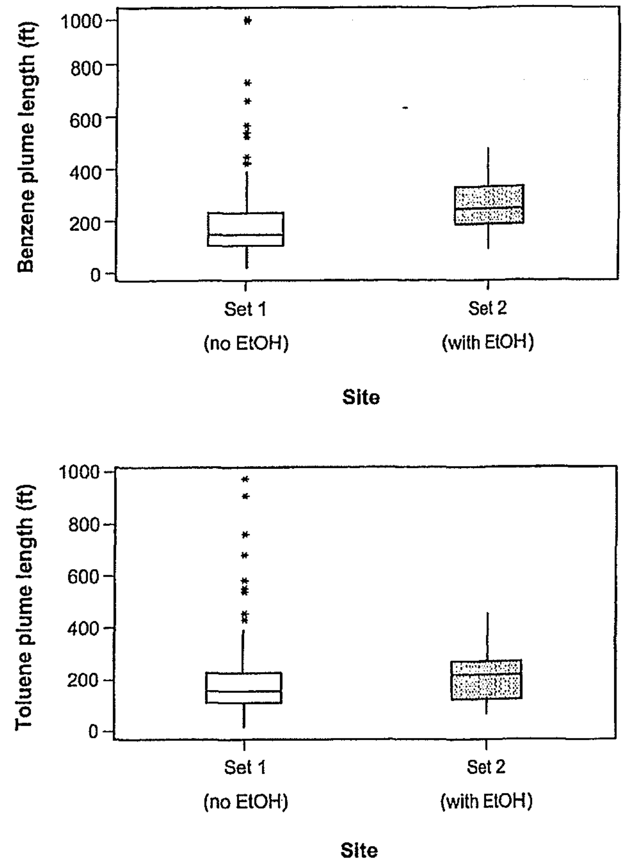

Figure 2. Box plots of the benzene and toluene plume length data. The line across the box represents the median. The bottom and top of the box represent the first and third quartiles (Q1 and Q3). The whiskers extend to the lowest and highest observations inside the region defined by Q1 −1.5(Q3-Q1) and 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	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.

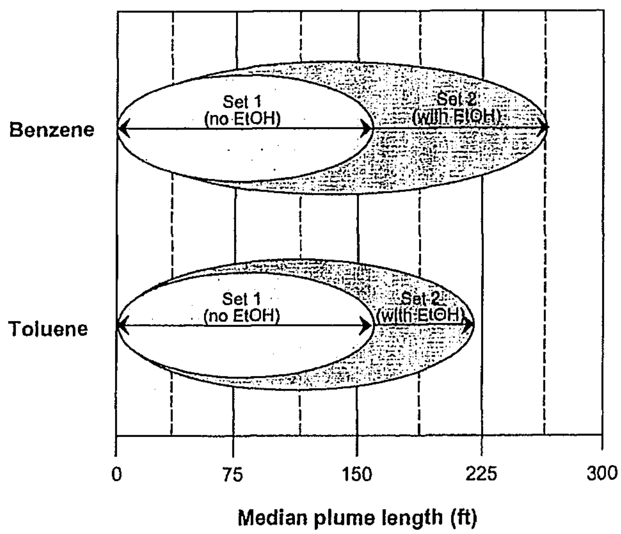

Figure 3. Median length of set 1 (Iowa data, without ethanol) versus set 2 plumes (Kansas data, with ethanol). The difference was significantly different for benzene ($p < 0.001$), but not for toluene ($p = 0.073$), as established by a Kruskal-Wallis test.

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)	Benzene Plume Length 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, 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.

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Biographical Sketches

Graciela Ruiz-Aguilar *is a post-doctoral fellow in the Department of Civil and Environmental Engineering at the University of Iowa, where she is conducting research on the anaerobic bioremediation of BTEX-ethanol mixtures. She has a Ph.D. in biotechnology and bioengineering from the Instituto Politecnico Nacional-CINVESTAV, in Mexico City, Mexico. Her studies focused on fungal technologies for PCB degradation*

Kirk T. O'Reilly *is a senior environmental specialist with ChevronTexaco's Energy Research and Technology Co. He has a B.S. in biological science from the University of California, Irvine, an M.S. in biology from Portland State University, and a Ph.D. in biochemistry from the University of Idaho. He has 16 years experience investigating the microbial and chemical aspects of the natural attenuation and active remediation of impacted ground water. Since 1996 his research has focused on oxygenate-related issues.*

Pedro J. Alvarez *is a professor in the Department of Civil and Environmental Engineering at the University of Iowa, where he also serves as associate director for the Center for Biocatalysis and Bioprocessing. He has a B. Eng. in civil engineering from McGill University, and an M.S. and a Ph.D. in environmental engineering from the University of Michigan. His research interests are related to the implications and applications of biological treatment processes to remove hazardous substances from contaminated ground water, waste water and soil. He is a P.E. and a Diplomate of the American Academy of Environmental Engineers.*

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Evaluation of the Impact of Fuel Hydrocarbons and Oxygenates on Groundwater Resources

TOM SHIH,*,†,‡ YUE RONG,‡
THOMAS HARMON,§ AND MEL SUFFET†

Environmental Science and Engineering Program, University of California at Los Angeles, 46-081 CHS, Box 951771, Los Angeles, California 90095-1772, Department of Civil and Environmental Engineering, University of California at Los Angeles, 5732 G BH, Box 951593, Los Angeles, California 90095-1593, and California Environmental Protection Agency, Regional Water Quality Control Board, 320 4th Street, Suite 200, Los Angeles, California 90013

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

* Corresponding author phone: (213) 576-6729; fax: (213) 576-6700; e-mail: Tshih@ucla.edu.

† Environmental Science and Engineering Program, University of California at Los Angeles.

‡ California Environmental Protection Agency.

§ Department of Civil and Environmental Engineering, University of California at Los Angeles.

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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 μg L^{-1} for benzene and ether oxygenates to 10 μg L^{-1} for TBA, and to 100 μg 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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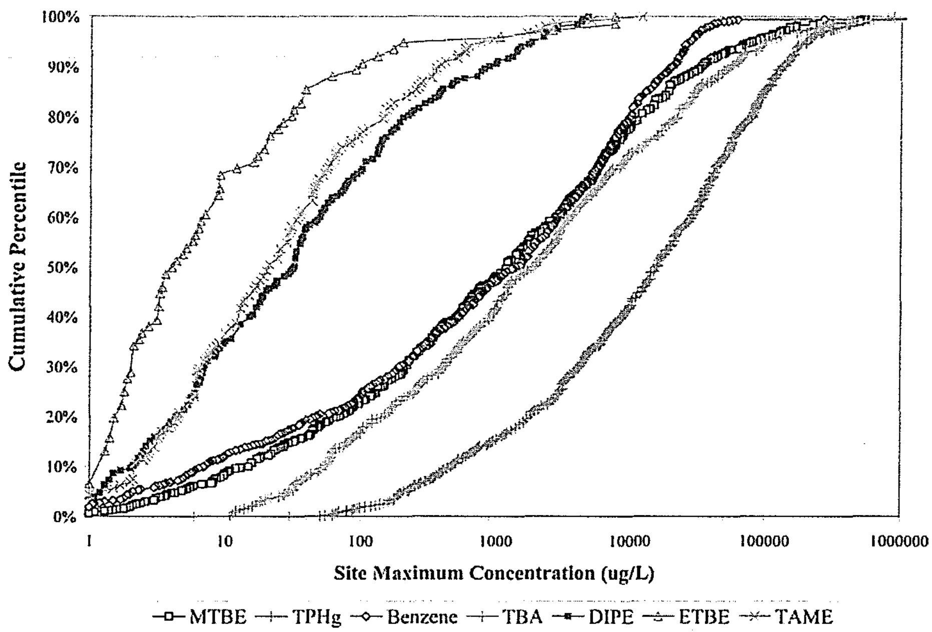

FIGURE 1. Plot of cumulative percentile of site maximum concentration for FHCs (TPH_G and benzene) and oxygenates (MTBE, TBA, DIPE, ETBE, and TAME).

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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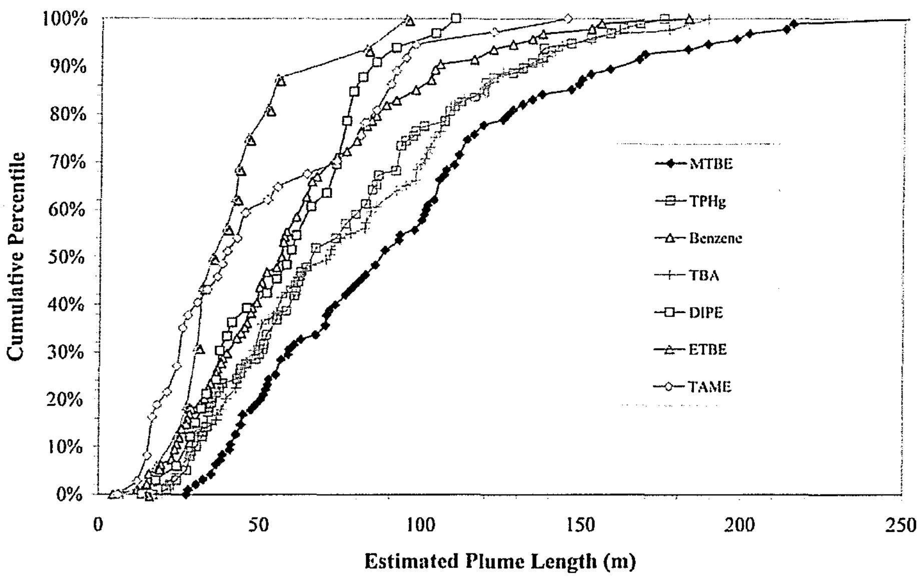

FIGURE 2. Plot of plume length cumulative percentile for FHCs (TPH_G and benzene) and oxygenates (MTBE, TBA, DIPE, ETBE, and TAME). Note: benzene, ether oxygenate, TBA, and TPH_G plume lengths were defined to 5, 5, 10, and 100 $\mu g\ L^{-1}$ dissolved concentration contours, respectively.

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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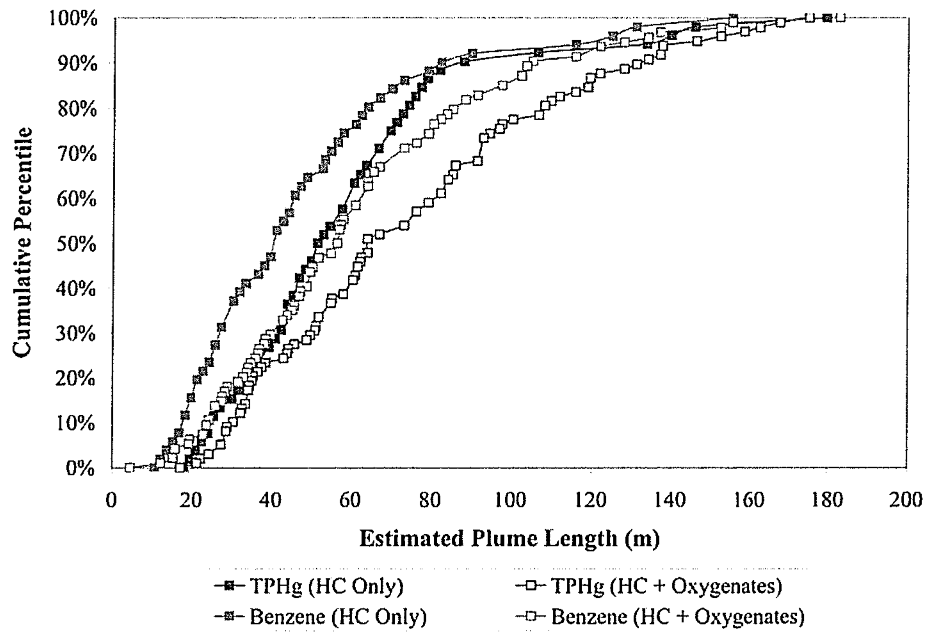

FIGURE 3. Comparison of TPH_G and benzene plume lengths at "hydrocarbons only" versus at "hydrocarbons and oxygenates" LUFT sites. TPH_G and benzene plume lengths were defined to 100 and 5 $\mu g\ L^{-1}$ dissolved concentration contours, respectively.

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.

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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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EXHIBIT
10

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

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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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From the *Department of Epidemiology and Preventive Medicine, Central and Eastern Clinical School, The Alfred Hospital, Commercial Road, Melbourne, Victoria, Australia; the †Occupational Hygiene Unit, Faculty of Science and Technology, Deakin University, Geelong, Victoria, Australia; the ‡School of Health Sciences, Deakin University, Burwood, Victoria, Australia; the §School of Population Public Health, University of Western Australia, Crawley, Perth, Western Australia, Australia; the ¶School of Dental Science, The University of Melbourne, Melbourne, Victoria, Australia; and the #Department of General Practice and Public Health, The University of Melbourne, Carlton, Victoria, Australia.

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Correspondence: Deborah C. Glass, Department of Epidemiology and Preventive Medicine, Central and Eastern Clinical School, The Alfred Hospital, Commercial Road, Melbourne, Victoria 3004, Australia. E-mail: deborah.glass@med.monash.edu.au.

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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.

TABLE 1. Type of Cancer by Highest Level of Evidence for the Diagnosis

		Highest Level of Evidence				
Type of Lympho-hematopoietic Cancer	**ICD-9 Code**	**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 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.

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.

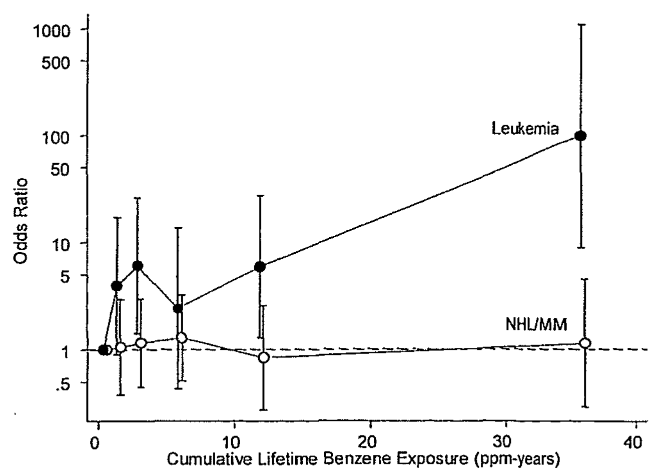

FIGURE 1. Leukemia and Non-Hodgkin Lymphoma/Multiple Myeloma (NHL/MM) odds ratios by geometric benzene exposure groups (ppm-years) displayed at the midpoint of the exposure group. (Circles indicate odds ratios; vertical lines depict confidence intervals).

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.

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 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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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

Prepared By: Meera Kothari, Jesse Bajnok & Heidi Tillquist

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

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.

Prepared By: Meera Kothari, Jesse Bajnok & Heidi Tillquist

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.

Prepared By: Meera Kothari, Jesse Bajnok & Heidi Tillquist

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).**

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.

Prepared By: Meera Kothari, Jesse Bajnok & Heidi Tillquist

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).**

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.

Prepared By: Meera Kothari, Jesse Bajnok & Heidi Tillquist

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 HP 14-001 REBUTTAL TESTIMONY OF JON SCHMIDT

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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 Jon Schmidt.

1. State your name and occupation.

Answer: My name is Jon Schmidt. I am employed as Vice President, Environmental and Regulatory Services, Energy Services, by exp Energy Services, a consultant for the Keystone XL Project.

2. Did you provide direct testimony in this proceeding?

Answer: Yes.

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3. To whose testimony are you responding in rebuttal?

Answer: I am responding to the direct testimony of Doug Crow Ghost and Carlyle Ducheneaux.

4. On pages 2-4 of his testimony, Crow Ghost discusses the Winters Doctrine. Will construction of the Keystone Pipeline affect the water rights of the Tribe under this doctrine?

Answer: Keystone has not applied yet for temporary water use permits. Current South Dakota administrative code (ARSD 46:5:40:1) indicates that "no temporary permit may be issued if the permit interferes with or adversely affects prior appropriations or vested rights." Thus, there are administrative protections for the Tribe's claimed water rights. The proposed temporary water uses will not interfere with long-standing water rights in any of the rivers proposed for withdrawal.

5. On page 5 of his testimony, Crow Ghost states that the Little Missouri River, the Cheyenne River, the North Fork of the Morean River, the Bad River, and the White River have been potentially impacted by long-term drought. If Keystone withdraws water from these river systems, is it possible that downstream water users, including Tribal water users and non-Indian farmers and ranchers, will not have adequate water supplies?

Answer: As discussed above, the permitting process will address that issue. In addition, Keystone's primary use of water during construction is for hydrostatic testing. Water used in hydrostatic testing is returned to the water source.

6. On page 6 of his testimony, Crow Ghost discusses the effect of construction on water quality. Will construction of the Keystone Pipeline affect water quality, specifically referencing the North Fork of the Grand River and the Little Missouri River?

Answer: The Project will not cross the North Fork of the Grand River, and therefore will not release any sediment contamination in the river through handling or construction. The Project will also cross the Little Missouri River using the HDD construction method, thereby avoiding any impacts to the river sediments, and thereby avoiding release of potential contaminants in the river.

7. If drought conditions exist during the period of time when Keystone requires water for dust control or hydrostatic testing, how will Keystone obtain adequate water supplies?

Answer: If drought conditions were to exist such that insufficient unappropriated water was available in quantities required by Keystone, Keystone would seek alternate sources of water, which could include use of existing water wells, drilling new water wells, reuse of water from upstream tested sections as appropriate, or use of municipal supply. Additionally, Keystone could use alternate dust abatement methods such as magnesium chloride to reduce the amount of water needed. Lastly, if no alternate solutions were feasible Keystone would delay its testing program.

8. In question 8 of his testimony, Carlyle Ducheneaux states that the soils in and around the Cheyenne River and its tributaries are contaminated by previous polluters. Will construction of the Keystone XL Pipeline disrupt these contaminated sediments?

Answer: The Cheyenne River will be crossed using HDD construction techniques, which do not result in the disturbance or release of potential contaminants from existing river bed sediments or cause significant disturbance of soils in the area of the river.

9. In questions 12 and 13 of his direct testimony, Ducheneaux addresses the likelihood of pipeline failure due to sloughing of river banks and the fact that the banks of the Cheyenne River are highly susceptible to collapse. Will the construction of the Keystone XL Pipeline cause sloughing, erosion, or collapse of these river banks?

Answer: The Cheyenne River will be crossed using HDD construction techniques. There will be no impact to the river banks and bluffs that could lead to sloughing of the banks into the river. With respect to tributaries that are crossed using the open cut construction technique, Keystone will mitigate bank and bluff sloughing by various stabilization means such as installation of rip-rap, geotextile material or re-sloping of the banks, all of which are addressed in the CMR Plan.

Dated this 4 day of June, 2015.

Jon Schmidt

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 Jon Schmidt, to the following:

Patricia Van Gerpen
Executive Director
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
patty.vangerpen@state.sd.us

Kristen Edwards
Staff Attorney
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
kristen.edwards@state.sd.us

Brian Rounds
Staff Analyst
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
brian.rounds@state.sd.us

Darren Kearney
Staff Analyst South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
darren.kearney@state.sd.us

Tony Rogers, Director
Rosebud Sioux Tribe - Tribal Utility Commission
153 South Main Street
Mission, SD 57555
tuc@rosebudsiouxtribe-nsn.gov

Cindy Myers, R.N.
PO Box 104
Stuart, NE 68780
csmyers77@hotmail.com

Jane Kleeb
1010 North Denver Avenue
Hastings, NE 68901
jane@boldnebraska.org

Byron T. Steskal
Diana L. Steskal
707 E. 2nd Street
Stuart, NE 68780
prairierose@nntc.net

Terry Frisch
Cheryl Frisch
47591 875th Road
Atkinson, NE 68713
tcfrisch@q.com

Arthur R. Tanderup
52343 857th Road
Neligh, NE 68756
atanderu@gmail.com

Lewis GrassRope
PO Box 61
Lower Brule, SD 57548
wisestar8@msn.com

Robert G. Allpress
46165 Badger Road
Naper, NE 68755
bobandnan2008@hotmail.com

Amy Schaffer
PO Box 114
Louisville, NE 68037
amyannschaffer@gmail.com

Benjamin D. Gotschall
6505 W. Davey Road
Raymond, NE 68428
ben@boldnebraska.org

Elizabeth Lone Eagle
PO Box 160
Howes, SD 57748
bethcbest@gmail.com

John H. Harter
28125 307th Avenue
Winner, SD 57580
johnharter11@yahoo.com

Peter Capossela
Peter Capossela, P.C.
Representing Standing Rock Sioux Tribe
PO Box 10643
Eugene, OR 97440
pcapossela@nu-world.com

Travis Clark
Fredericks Peebles & Morgan LLP
Suite 104, 910 5th St.
Rapid City, SD 57701
tclark@ndnlaw.com

Carolyn P. Smith
305 N. 3rd Street
Plainview, NE 68769
peachie_1234@yahoo.com

Louis T. (Tom) Genung
902 E. 7th Street
Hastings, NE 68901
tg64152@windstream.net

Nancy Hilding
6300 West Elm
Black Hawk, SD 57718
nhilshat@rapidnet.com

Paul F. Seamans
27893 249th Street
Draper, SD 57531
jacknife@goldenwest.net

Viola Waln
PO Box 937
Rosebud, SD 57570
walnranch@goldenwest.net

Wrexie Lainson Bardaglio
9748 Arden Road
Trumansburg, NY 14886
wrexie.bardaglio@gmail.com

Harold C. Frazier
Chairman, Cheyenne River Sioux Tribe
PO Box 590
Eagle Butte, SD 57625
haroldcfrazier@yahoo.com
mailto:kevinckeckler@yahoo.com

Jerry P. Jones
22584 US Hwy 14
Midland, SD 57552

Debbie J. Trapp
24952 US Hwy 14
Midland, SD 57552
mtdt@goldenwest.net

Jennifer S. Baker
Representing Yankton Sioux Tribe
Fredericks Peebles & Morgan LLP
1900 Plaza Dr.
Louisville, CO 80027
jbaker@ndnlaw.com

Duncan Meisel
350.org
20 Jay St., #1010
Brooklyn, NY 11201
duncan@350.org

Cody Jones
21648 US Hwy 14/63
Midland, SD 57552

Gena M. Parkhurst
2825 Minnewsta Place
Rapid City, SD 57702
GMP66@hotmail.com

Joye Braun
PO Box 484
Eagle Butte, SD 57625
jmbraun57625@gmail.com

The Yankton Sioux Tribe
Robert Flying Hawk, Chairman
PO Box 1153
Wagner, SD 57380
robertflyinghawk@gmail.com
Thomasina Real Bird
Attorney for Yankton Sioux Tribe
trealbird@ndnlaw.com

Bruce Ellison
Attorney for Dakota Rural Action
518 6th Street #6
Rapid City, SD 57701
belli4law@aol.com

Chastity Jewett
1321 Woodridge Drive
Rapid City, SD 57701
chasjewett@gmail.com

RoxAnn Boettcher
Boettcher Organics
86061 Edgewater Avenue
Bassett, NE 68714
boettcherann@abbnebraska.com

Bruce Boettcher
Boettcher Organics
86061 Edgewater Avenue
Bassett, NE 68714
boettcherann@abbnebraska.com

Bonny Kilmurry
47798 888 Road
Atkinson, NE 68713
bjkilmurry@gmail.com

Ronald Fees
17401 Fox Ridge Road
Opal, SD 57758

Robert P. Gough, Secretary
Intertribal Council on Utility Policy
PO Box 25
Rosebud, SD 57570
bobgough@intertribalCOUP.org

Tom BK Goldtooth
Indigenous Environmental Network (IEN)
PO Box 485
Bemidji, MN 56619
ien@igc.org

Dallas Goldtooth
38731 Res Hwy 1
Morton, MN 56270
goldtoothdallas@gmail.com

Gary F. Dorr
27853 292nd
Winner, SD 57580
gfdorr@gmail.com

Cyril Scott, President
Rosebud Sioux Tribe
PO Box 430
Rosebud, SD 57570
cscott@gwtc.net
ejantoine@hotmail.com

Paula Antoine
Sicangu Oyate Land Office Coordinator
Rosebud Sioux Tribe
PO Box 658
Rosebud, SD 57570
wopila@gwtc.net
paula.antoine@rosebudsiouxtribe-nsn.gov

Thomasina Real Bird
Representing Yankton Sioux Tribe
Fredericks Peebles & Morgan LLP
1900 Plaza Dr.
Louisville, CO 80027
trealbird@ndnlaw.com

Sabrina King
Dakota Rural Action
518 Sixth Street, #6
Rapid City, SD 57701
sabinra@dakotarural.org

Frank James
Dakota Rural Action
PO Box 549
Brookings, SD 57006
fejames@dakotarural.org

Robin S. Martinez
Dakota Rural Action
Martinez Madrigal & Machicao, LLC
616 West 26th Street
Kansas City, MO 64108
robin.martinez@martinezlaw.net

Tracey A. Zephier
Attorney for Cheyenne River Sioux Tribe
Fredericks Peebles & Morgan LLP
910 5th Street, Suite 104
Rapid City, SD 57701
tzephier@ndnlaw.com

Paul C. Blackburn
4145 20th Avenue South
Minneapolis, MN 55407
paul@paulblackburn.net

Matthew Rappold
Rappold Law Office
on behalf of Rosebud Sioux Tribe
PO Box 873
Rapid City, SD 57709
matt.rappold01@gmail.com

April D. McCart
Representing Dakota Rural Action
Certified Paralegal
Martinez Madrigal & Machicao, LLC
616 W. 26th Street
Kansas City, MO 64108
april.mccart@martinezlaw.net

Kimberly E. Craven
3560 Catalpa Way
Boulder, CO 80304
kimecraven@gmail.com

Joy Lashley
Administrative Assistant
SD Public Utilities Commission
joy.lashley@state.sd.us

Mary Turgeon Wynne
Rosebud Sioux Tribe - Tribal Utility Commission
153 S. Main Street
Mission, SD 57555
tuc@rosebudsiouxtribe-nsn.gov

Eric Antoine
Rosebud Sioux Tribe
PO Box 430
Rosebud, SD 57570
ejantoine@hotmail.com

WOODS, FULLER, SHULTZ & SMITH P.C.

By /s/ James E. Moore

William Taylor
James E. Moore
PO Box 5027
300 South Phillips Avenue, Suite 300
Sioux Falls, SD 57117-5027
Phone (605) 336-3890
Fax (605) 339-3357
Email James.Moore@woodsfuller.com
Attorneys for Applicant 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	: : : : :	HP 14-001 REBUTTAL TESTIMONY OF COREY GOULET

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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 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.

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3. Have you provided direct testimony in this proceeding?

Answer: Yes, I have.

4. Which witnesses' direct testimony are you responding to in your rebuttal testimony?

Answer: I am responding to portions of the direct testimony of Cindy Myers, Sue Sibson, Diana Steskal, and Paul Seamans.

5. Cindy Myers testified that the Materials Safety Data Sheets (MDSD) provided in the State Department's Final Supplemental Environmental Impact Statement do not reflect the actual product that would flow through the proposed pipeline. Can you comment on that point?

Answer: The MSDS's provided in the Final Supplemental EIS represent the range of the different types of crude oil that would be transported through the proposed pipeline. Importantly, in the event of a release from the pipeline, the MSDS for the particular product or products involved in the release would be provided to responders and state and local officials within minutes.

6. Has TransCanada tested its ability to provide the applicable MSDS to responders and officials in the event of a release?

Answer: Yes we have. During its evaluation of the proposed pipeline reroute in Nebraska, the Nebraska Department of Environmental Quality (NDEQ) required TransCanada to demonstrate that ability. Accordingly, the NDEQ required TransCanada to conduct a test that is reported in its January 2013 Final Evaluation Report.

This emergency response exercise was conducted on the existing Keystone pipeline. Representatives of NDEQ and the Nebraska Emergency Management Agency (NEMA) attended the exercise at the TransCanada Regional Emergency Operations Center (EOC) in Omaha, Nebraska. The scenario chosen for the exercise was a landowner performing excavation work without first calling 811 to determine the location of any utilities on the property. The hypothetical landowner struck the pipeline, smelled and saw oil flowing into the trench, and called TransCanada's toll-free emergency line to report the incident. NDEQ randomly selected the simulated spill location and provided it at the start of the exercise.

The exercise facilitator, playing the role of the toll-free emergency line operator, began the exercise by calling the TransCanada Operations Control Centre (OCC) in Calgary and reporting the third-party excavation damage to the pipeline. The controller at the OCC stated that he had observed indications of a product release and that he was shutting down the line and contacting the nearest TransCanada on-scene responder to drive to the location of the spill. The Regional EOC in Omaha was activated, along with the Corporate EOC in Calgary. The Regional EOC Manager requested that the OCC email an MSDS for the batch of crude oil in the pipeline at the point of the third-party strike. The OCC controller stated that the location of the strike was near the interface of two batches of oil and sent an MSDS for each batch to the Regional EOC Manager, the Regional EOC Logistics Manager, and the TransCanada on-scene responder.

NDEQ and the other exercise observers reviewed the two MSDSs. Seventeen minutes after the exercise began, the Regional EOC Logistics Manager emailed the two safety data sheets to NEMA, the Wayne County Sheriff, the Wayne County Local Emergency Planning Committee (LEPC), and the PSAP (public safety answering point, or 911), successfully completing the exercise. According to the NDEQ's Final Evaluation report, "the exercise demonstrated that Keystone could provide an MSDS for the exact material being transported in the pipeline at the time of a hypothetical spill in a reasonable length of time."

7. Have you reviewed the direct testimony of Sue Sibson and Diana Steskal?

Answer: Yes I have. They both raise concerns with respect to our reclamation efforts on the Sibson property after the construction of the first Keystone Pipeline.

8. Can you comment on the concerns that they raise?

Answer: I have not personally viewed the property in question but I have reviewed the photos provided in Ms. Sibson's testimony. I understand the stated concerns that our reclamation efforts to date have not been to the Sibsons' satisfaction. I reiterate our commitment to continue working with the Sibsons to address these concerns and to achieve reclamation success equivalent to similar off-right-of-way property. In addition, I reiterate our commitment to compensate landowners for demonstrated damages to property that result from our construction activities.

9. Mr. Seamans testified that TransCanada overstated the estimated tax benefits to the counties along the route of the proposed pipeline. Can you comment on that testimony?

Answer: Yes. At the time of its 2009 application, and again at the 2009 hearing, TransCanada estimated the tax impacts of the KXL project in good faith, employing estimated construction costs. TransCanada does not control the assessed valuation determined by the Department of Revenue or the methodology the Department employs. To date, the actual taxes levied on the first Keystone Pipeline have been less than our estimates. Nonetheless, the taxes paid by Keystone, and the taxes expected on the Keystone XL Pipeline, are substantial, and represent a significant benefit to the counties and school districts that host the pipeline. For 2014, Keystone will pay real property taxes totaling slightly more than $4,300,000 in the ten counties transited by the first Keystone Pipeline. The 2014 taxes paid on the first Keystone Pipeline will represent about 3.4% of the total real property taxes collected in the ten counties crossed by the pipeline.

10. Does this conclude your prepared rebuttal testimony?

Answer: Yes.

Dated this 24 day of June, 2015.

Corey Goulet

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 Corey Goulet, to the following:

Patricia Van Gerpen
Executive Director
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
patty.vangerpen@state.sd.us

Kristen Edwards
Staff Attorney
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
kristen.edwards@state.sd.us

Brian Rounds
Staff Analyst
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
brian.rounds@state.sd.us

Darren Kearney
Staff Analyst South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
darren.kearney@state.sd.us

Tony Rogers, Director
Rosebud Sioux Tribe - Tribal Utility Commission
153 South Main Street
Mission, SD 57555
tuc@rosebudsiouxtribe-nsn.gov

Cindy Myers, R.N.
PO Box 104
Stuart, NE 68780
csmyers77@hotmail.com

Jane Kleeb
1010 North Denver Avenue
Hastings, NE 68901
jane@boldnebraska.org

Byron T. Steskal
Diana L. Steskal
707 E. 2nd Street
Stuart, NE 68780
prairierose@nntc.net

Terry Frisch
Cheryl Frisch
47591 875th Road
Atkinson, NE 68713
tcfrisch@q.com

Arthur R. Tanderup
52343 857th Road
Neligh, NE 68756
atanderu@gmail.com

Lewis GrassRope
PO Box 61
Lower Brule, SD 57548
wisestar8@msn.com

Carolyn P. Smith
305 N. 3rd Street
Plainview, NE 68769
peachie_1234@yahoo.com

Robert G. Allpress
46165 Badger Road
Naper, NE 68755
bobandnan2008@hotmail.com

Amy Schaffer
PO Box 114
Louisville, NE 68037
amyannschaffer@gmail.com

Louis T. (Tom) Genung
902 E. 7th Street
Hastings, NE 68901
tg64152@windstream.net

Benjamin D. Gotschall
6505 W. Davey Road
Raymond, NE 68428
ben@boldnebraska.org

Nancy Hilding
6300 West Elm
Black Hawk, SD 57718
nhilshat@rapidnet.com

Elizabeth Lone Eagle
PO Box 160
Howes, SD 57748
bethcbest@gmail.com

Paul F. Seamans
27893 249th Street
Draper, SD 57531
jacknife@goldenwest.net

John H. Harter
28125 307th Avenue
Winner, SD 57580
johnharter11@yahoo.com

Viola Waln
PO Box 937
Rosebud, SD 57570
walnranch@goldenwest.net

Peter Capossela
Peter Capossela, P.C.
Representing Standing Rock Sioux Tribe
PO Box 10643
Eugene, OR 97440
pcapossela@nu-world.com

Wrexie Lainson Bardaglio
9748 Arden Road
Trumansburg, NY 14886
wrexie.bardaglio@gmail.com

Travis Clark
Fredericks Peebles & Morgan LLP
Suite 104, 910 5th St.
Rapid City, SD 57701
tclark@ndnlaw.com

Harold C. Frazier
Chairman, Cheyenne River Sioux Tribe
PO Box 590
Eagle Butte, SD 57625
haroldcfrazier@yahoo.com
mailto:kevinckeckler@yahoo.com

Jerry P. Jones
22584 US Hwy 14
Midland, SD 57552

Cody Jones
21648 US Hwy 14/63
Midland, SD 57552

Debbie J. Trapp
24952 US Hwy 14
Midland, SD 57552
mtdt@goldenwest.net

Gena M. Parkhurst
2825 Minnewsta Place
Rapid City, SD 57702
GMP66@hotmail.com

Jennifer S. Baker
Representing Yankton Sioux Tribe
Fredericks Peebles & Morgan LLP
1900 Plaza Dr.
Louisville, CO 80027
jbaker@ndnlaw.com

Joye Braun
PO Box 484
Eagle Butte, SD 57625
jmbraun57625@gmail.com

Duncan Meisel
350.org
20 Jay St., #1010
Brooklyn, NY 11201
duncan@350.org

The Yankton Sioux Tribe
Robert Flying Hawk, Chairman
PO Box 1153
Wagner, SD 57380
robertflyinghawk@gmail.com
Thomasina Real Bird
Attorney for Yankton Sioux Tribe
trealbird@ndnlaw.com

Bruce Ellison
Attorney for Dakota Rural Action
518 6th Street #6
Rapid City, SD 57701
belli4law@aol.com

Chastity Jewett
1321 Woodridge Drive
Rapid City, SD 57701
chasjewett@gmail.com

RoxAnn Boettcher
Boettcher Organics
86061 Edgewater Avenue
Bassett, NE 68714
boettcherann@abbnebraska.com

Bruce Boettcher
Boettcher Organics
86061 Edgewater Avenue
Bassett, NE 68714
boettcherann@abbnebraska.com

Bonny Kilmurry
47798 888 Road
Atkinson, NE 68713
bjkilmurry@gmail.com

Ronald Fees
17401 Fox Ridge Road
Opal, SD 57758

Robert P. Gough, Secretary
Intertribal Council on Utility Policy
PO Box 25
Rosebud, SD 57570
bobgough@intertribalCOUP.org

Tom BK Goldtooth
Indigenous Environmental Network (IEN)
PO Box 485
Bemidji, MN 56619
ien@igc.org

Dallas Goldtooth
38731 Res Hwy 1
Morton, MN 56270
goldtoothdallas@gmail.com

Gary F. Dorr
27853 292nd
Winner, SD 57580
gfdorr@gmail.com

Cyril Scott, President
Rosebud Sioux Tribe
PO Box 430
Rosebud, SD 57570
cscott@gwtc.net
ejantoine@hotmail.com

Paula Antoine
Sicangu Oyate Land Office Coordinator
Rosebud Sioux Tribe
PO Box 658
Rosebud, SD 57570
wopila@gwtc.net
paula.antoine@rosebudsiouxtribe-nsn.gov

Thomasina Real Bird
Representing Yankton Sioux Tribe
Fredericks Peebles & Morgan LLP
1900 Plaza Dr.
Louisville, CO 80027
trealbird@ndnlaw.com

Sabrina King
Dakota Rural Action
518 Sixth Street, #6
Rapid City, SD 57701
sabinra@dakotarural.org

Frank James
Dakota Rural Action
PO Box 549
Brookings, SD 57006
fejames@dakotarural.org

Robin S. Martinez
Dakota Rural Action
Martinez Madrigal & Machicao, LLC
616 West 26th Street
Kansas City, MO 64108
robin.martinez@martinezlaw.net

Tracey A. Zephier
Attorney for Cheyenne River Sioux Tribe
Fredericks Peebles & Morgan LLP
910 5th Street, Suite 104
Rapid City, SD 57701
tzephier@ndnlaw.com

Paul C. Blackburn
4145 20th Avenue South
Minneapolis, MN 55407
paul@paulblackburn.net

Matthew Rappold
Rappold Law Office
on behalf of Rosebud Sioux Tribe
PO Box 873
Rapid City, SD 57709
matt.rappold01@gmail.com

April D. McCart
Representing Dakota Rural Action
Certified Paralegal
Martinez Madrigal & Machicao, LLC
616 W. 26th Street
Kansas City, MO 64108
april.mccart@martinezlaw.net

Kimberly E. Craven
3560 Catalpa Way
Boulder, CO 80304
kimecraven@gmail.com

Joy Lashley
Administrative Assistant
SD Public Utilities Commission
joy.lashley@state.sd.us

Mary Turgeon Wynne
Rosebud Sioux Tribe - Tribal Utility Commission
153 S. Main Street
Mission, SD 57555
tuc@rosebudsiouxtribe-nsn.gov

Eric Antoine
Rosebud Sioux Tribe
PO Box 430
Rosebud, SD 57570
ejantoine@hotmail.com

WOODS, FULLER, SHULTZ & SMITH P.C.

By /s/ James E. Moore
William Taylor
James E. Moore
PO Box 5027
300 South Phillips Avenue, Suite 300
Sioux Falls, SD 57117-5027
Phone (605) 336-3890
Fax (605) 339-3357
Email James.Moore@woodsfuller.com
Attorneys for Applicant TransCanada

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

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

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	: : : : :	HP 14-001 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 testimonies of Richard Kuprewicz, Ian Goodman, and Dr. Arden Davis.

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4. Mr. Kuprewicz's testimony states "The proposed routing in South Dakota is in areas of steep elevation changes." Do you agree with this statement?

Answer: No. The alignment through South Dakota totals approximately 315 miles in length. The vast majority of this alignment has generally flat (i.e., low sloping) to moderate topographic relief, with some buttes and badlands. The State Department's Final Supplemental January 2014 Environmental Impact Statement defines areas of incline greater than 20% as "steep." A desktop review was performed at my direction by independent engineering experts in this field using aerial photographs, video documentation of the alignment, publicly available topographic information, and LiDAR data, based on the most conservative assumptions. The review concluded that a maximum of approximately 18 miles or 5% of the alignment could traverse terrain with slopes greater than 20%.

Percent Slope	Approximate Distance (miles)
20-25%	13
25-30%	3
30-35%	1
>35%	1

Areas of steep slopes are located in isolated areas along the entire alignment and are generally more prevalent in the vicinity of the larger river crossings. I would note that a 20% slope does not present significant construction challenges in light of the mitigation measures and techniques discussed in the response to Question 7.

5. Can you comment on the USGS map that is attached as Exhibit 4 to Ian Goodman's testimony?

Answer: The USGS Landslide Overview Map of the Conterminous United States was published in 1982 at a scale of 1:7,500,000 in the USGS Professional Paper 1183 (USGS 1982), and then subsequently updated in digital format in 1997 in the USGS Open-File Report 97-289 (USGS 1997). The map depicts potential landslide hazard areas across a wide area of South Dakota. This map is intended for geographic display and analysis at the national level and for reviewing possible hazards at large regional scales. This map was used initially as publicly available data in the early phases of planning and design for the KXL project. Subsequent project routing review, design work and field visits were completed to refine and optimize the alignment, in particular at targeted, steeper topographic areas and at larger river crossings, such as the Cheyenne River (MP 430), the Bad River (MP 486), and the White River (MP 541).

6. Is that map appropriate for identification of landslide risk on a site specific basis?

Answer: No, it is not appropriate given the scale of the map (1:7,000,000). As cited on the USGS website for the landslide map (http://landslides.usgs.gov/hazards/nationalmap/) "because the map is highly generalized, owing to the small scale and the scarcity of precise landslide information for much of the country, it is unsuitable for local planning or actual site selection."

7. Mr. Kuprewicz's testifies that "geo-hazard risk cannot be appropriately mitigated by pipeline design or construction techniques." Do you agree with that statement?

Answer: No, this statement is not accurate. Pipelines are routinely constructed and operated in challenging terrain throughout North America, as well as internationally in similar terrain and geologic conditions. In particular, the standard of practice for pipeline construction and the practice of geotechnical engineering and geologic hazards assessment and mitigation specifically addressing landslide hazards are well understood and applicable to the kinds of terrain, topography, and geologic conditions encountered along the KXL alignment through South Dakota.

Geo-hazard risk is addressed through routing, pipeline design and mitigative construction techniques. To the extent necessary and practicable during the routing process, Keystone avoided areas of potential geo-hazard risk. Beyond that, mitigation addressing landslide hazards may include one or more design and construction measures including, but not limited to, the following, many of which are included in the Project's construction plans and Construction and Mitigation Reclamation Plan (CMRP):

- Installing the pipeline beneath landslide (deep burial)
- Engineering of the backfill around or within landslide areas
- Installation of engineered structures to protect the pipeline
- Installation of strain gauges on the pipeline to monitor and track potential strain accumulation in the pipeline
- Installation of geodetic monitoring stations to track potential changes in ground movement
- Installation of other below ground monitoring to track potential changes in ground conditions
- Removal of the landslide through excavation
- Targeted site management and diversion of surface water around landslide sites
- Mitigation of surface erosion by armoring or otherwise stabilizing surface soils
- Targeted site management of sources of water along the trench excavation
- Targeted mitigation of seeps, springs, or other subsurface water encountered along the disturbed ROW
- Reduction in surcharge on landslide areas
- Installation of deformable backfill around the pipeline
- Special in-line monitoring of pipeline parameters
- Completion of regular visual monitoring of site to observe and identify potential changes.

8. Mr. Kuprewicz testifies that Keystone should have determined worst case discharge based on a capacity of 922,000 B/SD. Can you comment on that assertion?

Answer: As required by federal regulation at 49 CFR 194.105, operators must use the maximum capacity to complete worst case discharge calculations. Keystone used the maximum pipeline throughput capacity of 1,000,000 barrels per day in determining worst case discharge.

9. Mr. Kuprewicz's testifies that "(r)eliability can be improved only if proper transient dynamics have been incorporated into a rupture detection alarming system, and procedures are in place that require shutdown and isolation of pipeline segments along the system where a rupture may be suspected." Has a transient analysis been performed and incorporated into the procedures required to shut down and isolate the pipeline?

Answer: Yes, a transient analysis has been performed and incorporated in the design of the pipeline and Computational Pipeline Monitoring (CPM) leak detection system in accordance with PHMSA Special Condition 27 and API 1130.

10. Mr. Kuprewicz's testifies that "further information is warranted to clarify how much of this terrain identified as High Landslide Hazard Area is really at risk to such massive abnormal loading forces." What is the total mileage of high risk landslide hazard along the pipeline route in South Dakota?

Answer: Based on Keystone's detailed engineering analysis approximately 0.5% of the alignment intersects potential landslide hazards. This number may further decrease with site reconnaissance to finalize the Project's construction plans. Taking a more conservative perspective, and looking for potential landslide hazards that may occur within approximately 200 feet (to either side) of the alignment but that do not actually intersect the alignment, the area of additional potential landslide risk only increases by approximately an additional 1.5%. These additional areas of potential landslides identified along the alignment may or may not pose a hazard to the pipeline (e.g., depending on direction of movement, activity level, depth of landslide, etc.); thus, this additional approximately 1.5% is a conservative estimate intended to capture the full potential landslide hazard, and will likely decrease in actual number once the Project's construction plans are finalized. The combined potential of landslide hazards that intersect, or are within approximately 200 feet of, the alignment through South Dakota that were identified did not appear to have the potential to generate "massive abnormal loading" conditions, and can be mitigated through standard pipeline design and construction practices or through the use of targeted mitigation measures.

11. Kuprewicz (p. 6) claims that the proposed Keystone "valving is seriously inadequate…in a location of considerable elevation changes." Please comment on this assertion.

Answer: A two-year independent review of Keystone XL's design and the 2009 Keystone XL Risk Assessment was conducted by Battelle Memorial Institute (Battelle) and E^{x}ponent Inc. (E^{x}ponent) under the direction of the US Department of State (DOS), Pipeline and Hazardous Materials Safety Administration (PHMSA), and the US Environmental Protection Agency (USEPA) to address concerns raised by the USEPA in the NEPA review of the Project. With respect to Keystone's valve placement, Battelle concluded that "*[t]he model and the process that were used to ensure that valves are placed to minimize the total outflow from a break appear to be correct and should be continued to be used*" (Battelle 2013).

12. 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 25 day of June, 2015.

Meera Kothari

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 Meera Kothari, to the following:

Patricia Van Gerpen
Executive Director
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
patty.vangerpen@state.sd.us

Brian Rounds
Staff Analyst
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
brian.rounds@state.sd.us

Tony Rogers, Director
Rosebud Sioux Tribe - Tribal Utility Commission
153 South Main Street
Mission, SD 57555
tuc@rosebudsiouxtribe-nsn.gov

Jane Kleeb
1010 North Denver Avenue
Hastings, NE 68901
jane@boldnebraska.org

Terry Frisch
Cheryl Frisch
47591 875th Road
Atkinson, NE 68713
tcfrisch@q.com

Lewis GrassRope
PO Box 61
Lower Brule, SD 57548
wisestar8@msn.com

Robert G. Allpress
46165 Badger Road
Naper, NE 68755
bobandnan2008@hotmail.com

Kristen Edwards
Staff Attorney
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
kristen.edwards@state.sd.us

Darren Kearney
Staff Analyst South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
darren.kearney@state.sd.us

Cindy Myers, R.N.
PO Box 104
Stuart, NE 68780
csmyers77@hotmail.com

Byron T. Steskal
Diana L. Steskal
707 E. 2nd Street
Stuart, NE 68780
prairierose@nntc.net

Arthur R. Tanderup
52343 857th Road
Neligh, NE 68756
atanderu@gmail.com

Carolyn P. Smith
305 N. 3rd Street
Plainview, NE 68769
peachie_1234@yahoo.com

Amy Schaffer
PO Box 114
Louisville, NE 68037
amyannschaffer@gmail.com
Benjamin D. Gotschall
6505 W. Davey Road
Raymond, NE 68428
ben@boldnebraska.org
Elizabeth Lone Eagle
PO Box 160
Howes, SD 57748
bethcbest@gmail.com
John H. Harter
28125 307th Avenue
Winner, SD 57580
johnharter11@yahoo.com
Peter Capossela
Peter Capossela, P.C.
Representing Standing Rock Sioux Tribe
PO Box 10643
Eugene, OR 97440
pcapossela@nu-world.com
Travis Clark
Fredericks Peebles & Morgan LLP
Suite 104, 910 5th St.
Rapid City, SD 57701
tclark@ndnlaw.com

Jerry P. Jones
22584 US Hwy 14
Midland, SD 57552
Debbie J. Trapp
24952 US Hwy 14
Midland, SD 57552
mtdt@goldenwest.net

Jennifer S. Baker
Representing Yankton Sioux Tribe
Fredericks Peebles & Morgan LLP
1900 Plaza Dr.
Louisville, CO 80027
jbaker@ndnlaw.com

Louis T. (Tom) Genung
902 E. 7th Street
Hastings, NE 68901
tg64152@windstream.net
Nancy Hilding
6300 West Elm
Black Hawk, SD 57718
nhilshat@rapidnet.com
Paul F. Seamans
27893 249th Street
Draper, SD 57531
jacknife@goldenwest.net
Viola Waln
PO Box 937
Rosebud, SD 57570
walnranch@goldenwest.net
Wrexie Lainson Bardaglio
9748 Arden Road
Trumansburg, NY 14886
wrexie.bardaglio@gmail.com

Harold C. Frazier
Chairman, Cheyenne River Sioux Tribe
PO Box 590
Eagle Butte, SD 57625
haroldcfrazier@yahoo.com
mailto:kevinckeckler@yahoo.com
Cody Jones
21648 US Hwy 14/63
Midland, SD 57552
Gena M. Parkhurst
2825 Minnewsta Place
Rapid City, SD 57702
GMP66@hotmail.com

Joye Braun
PO Box 484
Eagle Butte, SD 57625
jmbraun57625@gmail.com

Duncan Meisel
350.org
20 Jay St., #1010
Brooklyn, NY 11201
duncan@350.org

Bruce Ellison
Attorney for Dakota Rural Action
518 6th Street #6
Rapid City, SD 57701
belli4law@aol.com

RoxAnn Boettcher
Boettcher Organics
86061 Edgewater Avenue
Bassett, NE 68714
boettcherann@abbnebraska.com

Bonny Kilmurry
47798 888 Road
Atkinson, NE 68713
bjkilmurry@gmail.com

Robert P. Gough, Secretary
Intertribal Council on Utility Policy
PO Box 25
Rosebud, SD 57570
bobgough@intertribalCOUP.org

Dallas Goldtooth
38731 Res Hwy 1
Morton, MN 56270
goldtoothdallas@gmail.com

Cyril Scott, President
Rosebud Sioux Tribe
PO Box 430
Rosebud, SD 57570
cscott@gwtc.net
ejantoine@hotmail.com

Thomasina Real Bird
Representing Yankton Sioux Tribe
Fredericks Peebles & Morgan LLP
1900 Plaza Dr.
Louisville, CO 80027
trealbird@ndnlaw.com

The Yankton Sioux Tribe
Robert Flying Hawk, Chairman
PO Box 1153
Wagner, SD 57380
robertflyinghawk@gmail.com

Thomasina Real Bird
Attorney for Yankton Sioux Tribe
trealbird@ndnlaw.com

Chastity Jewett
1321 Woodridge Drive
Rapid City, SD 57701
chasjewett@gmail.com

Bruce Boettcher
Boettcher Organics
86061 Edgewater Avenue
Bassett, NE 68714
boettcherann@abbnebraska.com

Ronald Fees
17401 Fox Ridge Road
Opal, SD 57758

Tom BK Goldtooth
Indigenous Environmental Network (IEN)
PO Box 485
Bemidji, MN 56619
ien@igc.org

Gary F. Dorr
27853 292nd
Winner, SD 57580
gfdorr@gmail.com

Paula Antoine
Sicangu Oyate Land Office Coordinator
Rosebud Sioux Tribe
PO Box 658
Rosebud, SD 57570
wopila@gwtc.net
paula.antoine@rosebudsiouxtribe-nsn.gov

Sabrina King
Dakota Rural Action
518 Sixth Street, #6
Rapid City, SD 57701
sabinra@dakotarural.org

Frank James
Dakota Rural Action
PO Box 549
Brookings, SD 57006
fejames@dakotarural.org

Tracey A. Zephier
Attorney for Cheyenne River Sioux Tribe
Fredericks Peebles & Morgan LLP
910 5th Street, Suite 104
Rapid City, SD 57701
tzephier@ndnlaw.com
Matthew Rappold
Rappold Law Office
on behalf of Rosebud Sioux Tribe
PO Box 873
Rapid City, SD 57709
matt.rappold01@gmail.com

Kimberly E. Craven
3560 Catalpa Way
Boulder, CO 80304
kimecraven@gmail.com
Mary Turgeon Wynne
Rosebud Sioux Tribe - Tribal Utility Commission
153 S. Main Street
Mission, SD 57555
tuc@rosebudsiouxtribe-nsn.gov

Robin S. Martinez
Dakota Rural Action
Martinez Madrigal & Machicao, LLC
616 West 26th Street
Kansas City, MO 64108
robin.martinez@martinezlaw.net
Paul C. Blackburn
4145 20th Avenue South
Minneapolis, MN 55407
paul@paulblackburn.net

April D. McCart
Representing Dakota Rural Action
Certified Paralegal
Martinez Madrigal & Machicao, LLC
616 W. 26th Street
Kansas City, MO 64108
april.mccart@martinezlaw.net
Joy Lashley
Administrative Assistant
SD Public Utilities Commission
joy.lashley@state.sd.us
Eric Antoine
Rosebud Sioux Tribe
PO Box 430
Rosebud, SD 57570
ejantoine@hotmail.com

WOODS, FULLER, SHULTZ & SMITH P.C.

By /s/ James E. Moore
William Taylor
James E. Moore
PO Box 5027
300 South Phillips Avenue, Suite 300
Sioux Falls, SD 57117-5027
Phone (605) 336-3890
Fax (605) 339-3357
Email James.Moore@woodsfuller.com
Attorneys for Applicant TransCanada

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

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

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	: : : : :	HP 14-001 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.

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EXHIBIT
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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 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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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:

Patricia Van Gerpen
Executive Director
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
patty.vangerpen@state.sd.us

Kristen Edwards
Staff Attorney
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
kristen.edwards@state.sd.us

Brian Rounds
Staff Analyst
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
brian.rounds@state.sd.us

Darren Kearney
Staff Analyst South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501
darren.kearney@state.sd.us

Tony Rogers, Director
Rosebud Sioux Tribe - Tribal Utility Commission
153 South Main Street
Mission, SD 57555
tuc@rosebudsiouxtribe-nsn.gov

Cindy Myers, R.N.
PO Box 104
Stuart, NE 68780
csmyers77@hotmail.com

Jane Kleeb
1010 North Denver Avenue
Hastings, NE 68901
jane@boldnebraska.org

Byron T. Steskal
Diana L. Steskal
707 E. 2nd Street
Stuart, NE 68780
prairierose@nntc.net

Terry Frisch
Cheryl Frisch
47591 875th Road
Atkinson, NE 68713
tcfrisch@q.com

Arthur R. Tanderup
52343 857th Road
Neligh, NE 68756
atanderu@gmail.com

Lewis GrassRope
PO Box 61
Lower Brule, SD 57548
wisestar8@msn.com

Carolyn P. Smith
305 N. 3rd Street
Plainview, NE 68769
peachie_1234@yahoo.com

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Robert G. Allpress
46165 Badger Road
Naper, NE 68755
bobandnan2008@hotmail.com
Amy Schaffer
PO Box 114
Louisville, NE 68037
amyannschaffer@gmail.com
Benjamin D. Gotschall
6505 W. Davey Road
Raymond, NE 68428
ben@boldnebraska.org
Elizabeth Lone Eagle
PO Box 160
Howes, SD 57748
bethcbest@gmail.com
John H. Harter
28125 307th Avenue
Winner, SD 57580
johnharter11@yahoo.com
Peter Capossela
Peter Capossela, P.C.
Representing Standing Rock Sioux Tribe
PO Box 10643
Eugene, OR 97440
pcapossela@nu-world.com
Travis Clark
Fredericks Peebles & Morgan LLP
Suite 104, 910 5th St.
Rapid City, SD 57701
tclark@ndnlaw.com

Jerry P. Jones
22584 US Hwy 14
Midland, SD 57552
Debbie J. Trapp
24952 US Hwy 14
Midland, SD 57552
mtdt@goldenwest.net

Louis T. (Tom) Genung
902 E. 7th Street
Hastings, NE 68901
tg64152@windstream.net
Nancy Hilding
6300 West Elm
Black Hawk, SD 57718
nhilshat@rapidnet.com
Paul F. Seamans
27893 249th Street
Draper, SD 57531
jacknife@goldenwest.net
Viola Waln
PO Box 937
Rosebud, SD 57570
walnranch@goldenwest.net
Wrexie Lainson Bardaglio
9748 Arden Road
Trumansburg, NY 14886
wrexie.bardaglio@gmail.com

Harold C. Frazier
Chairman, Cheyenne River Sioux Tribe
PO Box 590
Eagle Butte, SD 57625
haroldcfrazier@yahoo.com
mailto:kevinckeckler@yahoo.com
Cody Jones
21648 US Hwy 14/63
Midland, SD 57552
Gena M. Parkhurst
2825 Minnewsta Place
Rapid City, SD 57702
GMP66@hotmail.com

Jennifer S. Baker
Representing Yankton Sioux Tribe
Fredericks Peebles & Morgan LLP
1900 Plaza Dr.
Louisville, CO 80027
jbaker@ndnlaw.com

Joye Braun
PO Box 484
Eagle Butte, SD 57625
jmbraun57625@gmail.com

Duncan Meisel
350.org
20 Jay St., #1010
Brooklyn, NY 11201
duncan@350.org

The Yankton Sioux Tribe
Robert Flying Hawk, Chairman
PO Box 1153
Wagner, SD 57380
robertflyinghawk@gmail.com

Thomasina Real Bird
Attorney for Yankton Sioux Tribe
trealbird@ndnlaw.com

Bruce Ellison
Attorney for Dakota Rural Action
518 6th Street #6
Rapid City, SD 57701
belli4law@aol.com

Chastity Jewett
1321 Woodridge Drive
Rapid City, SD 57701
chasjewett@gmail.com

RoxAnn Boettcher
Boettcher Organics
86061 Edgewater Avenue
Bassett, NE 68714
boettcherann@abbnebraska.com

Bruce Boettcher
Boettcher Organics
86061 Edgewater Avenue
Bassett, NE 68714
boettcherann@abbnebraska.com

Bonny Kilmurry
47798 888 Road
Atkinson, NE 68713
bjkilmurry@gmail.com

Ronald Fees
17401 Fox Ridge Road
Opal, SD 57758

Robert P. Gough, Secretary
Intertribal Council on Utility Policy
PO Box 25
Rosebud, SD 57570
bobgough@intertribalCOUP.org

Tom BK Goldtooth
Indigenous Environmental Network (IEN)
PO Box 485
Bemidji, MN 56619
ien@igc.org

Dallas Goldtooth
38731 Res Hwy 1
Morton, MN 56270
goldtoothdallas@gmail.com

Gary F. Dorr
27853 292nd
Winner, SD 57580
gfdorr@gmail.com

Cyril Scott, President
Rosebud Sioux Tribe
PO Box 430
Rosebud, SD 57570
cscott@gwtc.net
ejantoine@hotmail.com

Thomasina Real Bird
Representing Yankton Sioux Tribe
Fredericks Peebles & Morgan LLP
1900 Plaza Dr.
Louisville, CO 80027
trealbird@ndnlaw.com

Frank James
Dakota Rural Action
PO Box 549
Brookings, SD 57006
fejames@dakotarural.org

Tracey A. Zephier
Attorney for Cheyenne River Sioux Tribe
Fredericks Peebles & Morgan LLP
910 5th Street, Suite 104
Rapid City, SD 57701
tzephier@ndnlaw.com

Matthew Rappold
Rappold Law Office
on behalf of Rosebud Sioux Tribe
PO Box 873
Rapid City, SD 57709
matt.rappold01@gmail.com

Kimberly E. Craven
3560 Catalpa Way
Boulder, CO 80304
kimecraven@gmail.com

Mary Turgeon Wynne
Rosebud Sioux Tribe - Tribal Utility Commission
153 S. Main Street
Mission, SD 57555
tuc@rosebudsiouxtribe-nsn.gov

Paula Antoine
Sicangu Oyate Land Office Coordinator
Rosebud Sioux Tribe
PO Box 658
Rosebud, SD 57570
wopila@gwtc.net
paula.antoine@rosebudsiouxtribe-nsn.gov

Sabrina King
Dakota Rural Action
518 Sixth Street, #6
Rapid City, SD 57701
sabinra@dakotarural.org

Robin S. Martinez
Dakota Rural Action
Martinez Madrigal & Machicao, LLC
616 West 26th Street
Kansas City, MO 64108
robin.martinez@martinezlaw.net

Paul C. Blackburn
4145 20th Avenue South
Minneapolis, MN 55407
paul@paulblackburn.net

April D. McCart
Representing Dakota Rural Action
Certified Paralegal
Martinez Madrigal & Machicao, LLC
616 W. 26th Street
Kansas City, MO 64108
april.mccart@martinezlaw.net

Joy Lashley
Administrative Assistant
SD Public Utilities Commission
joy.lashley@state.sd.us

Eric Antoine
Rosebud Sioux Tribe
PO Box 430
Rosebud, SD 57570
ejantoine@hotmail.com

WOODS, FULLER, SHULTZ & SMITH P.C.

By /s/ James E. Moore
William Taylor
James E. Moore
PO Box 5027
300 South Phillips Avenue, Suite 300
Sioux Falls, SD 57117-5027
Phone (605) 336-3890
Fax (605) 339-3357
Email James.Moore@woodsfuller.com
Attorneys for Applicant TransCanada

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

- 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*

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

- ~ 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

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.

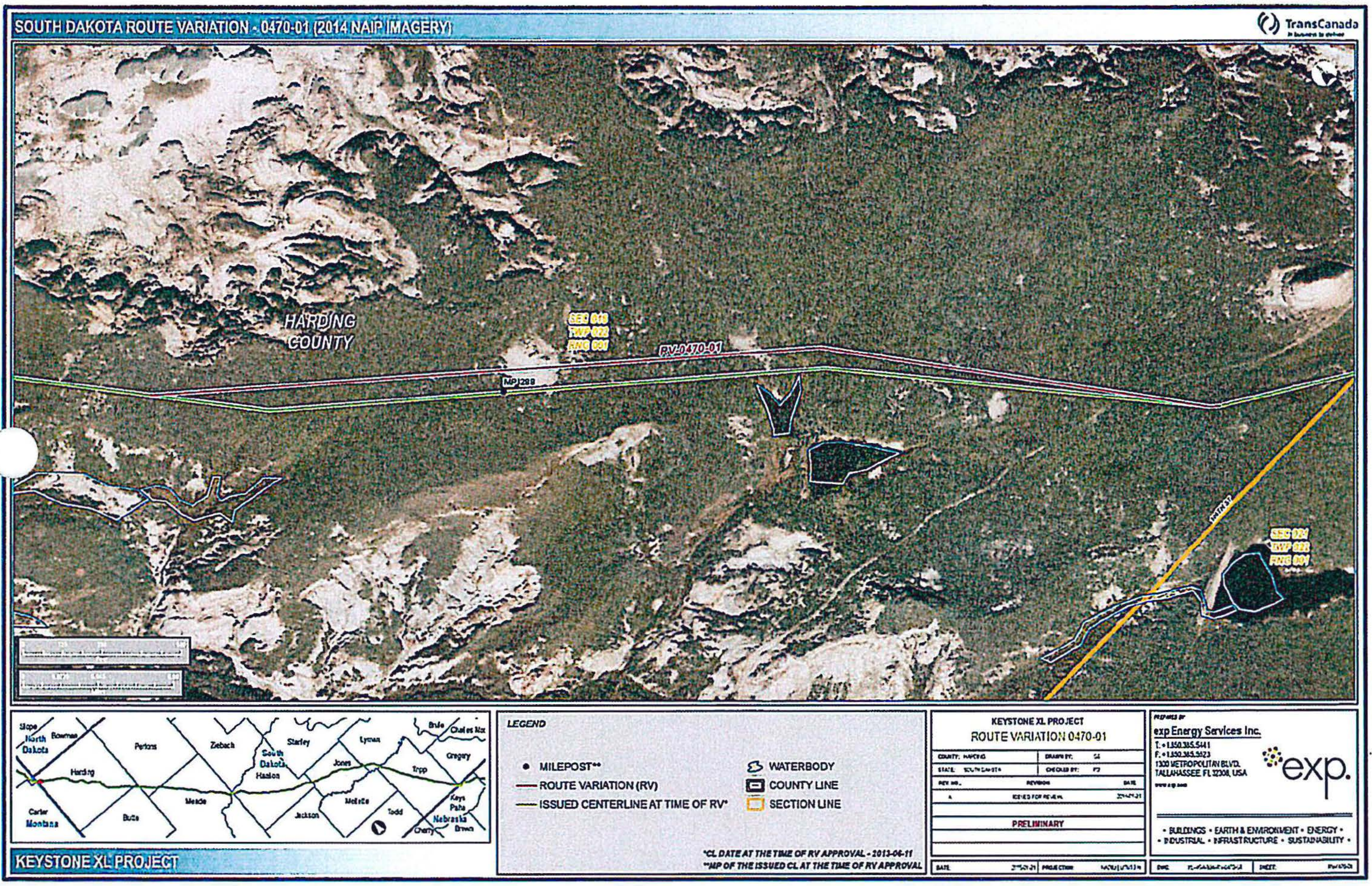

EXHIBIT
2013

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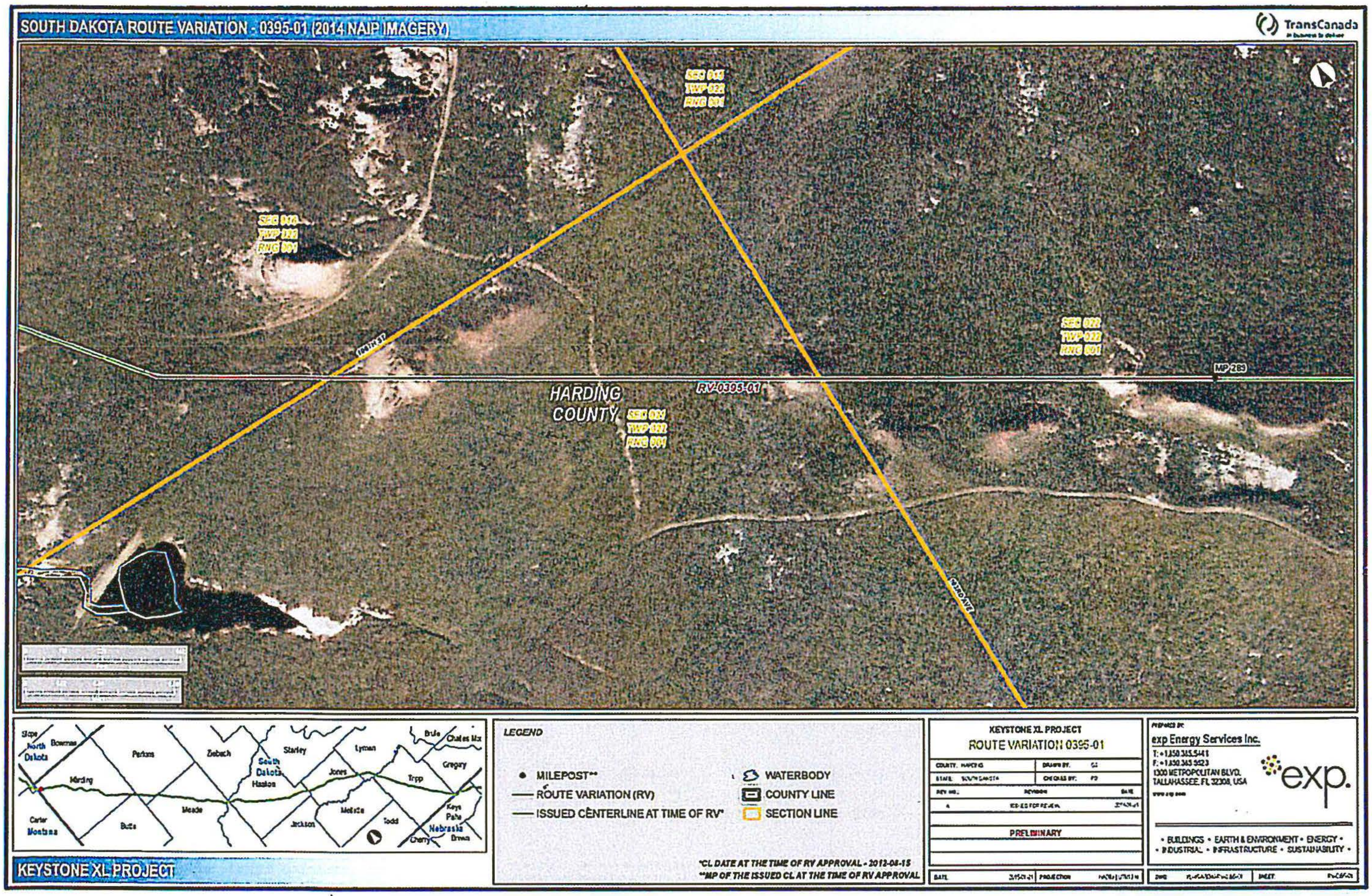

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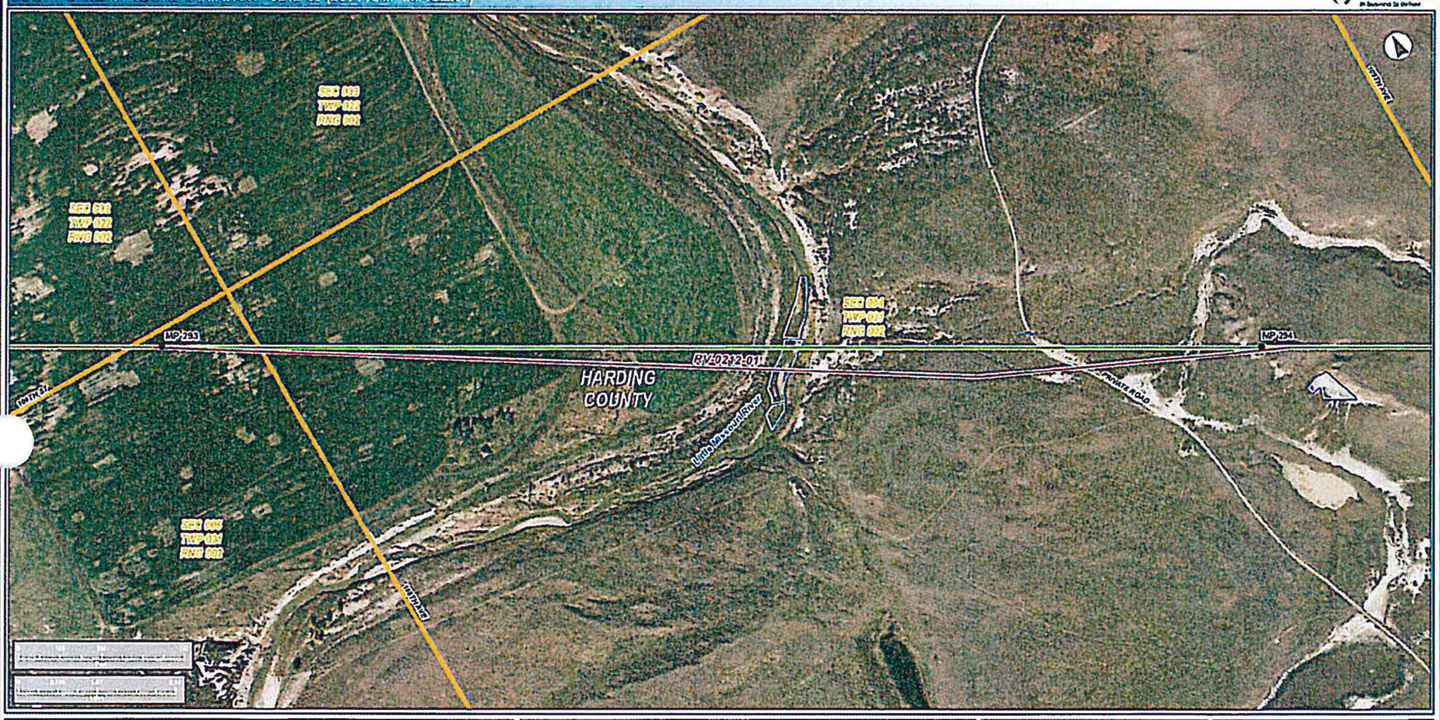
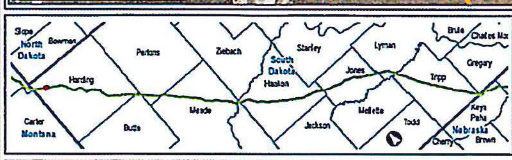
SOUTH DAKOTA ROUTE VARIATION - 0212-01 (2014 NAIP IMAGERY)

TransCanada





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 0212-01

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.

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KEYSTONE 0472

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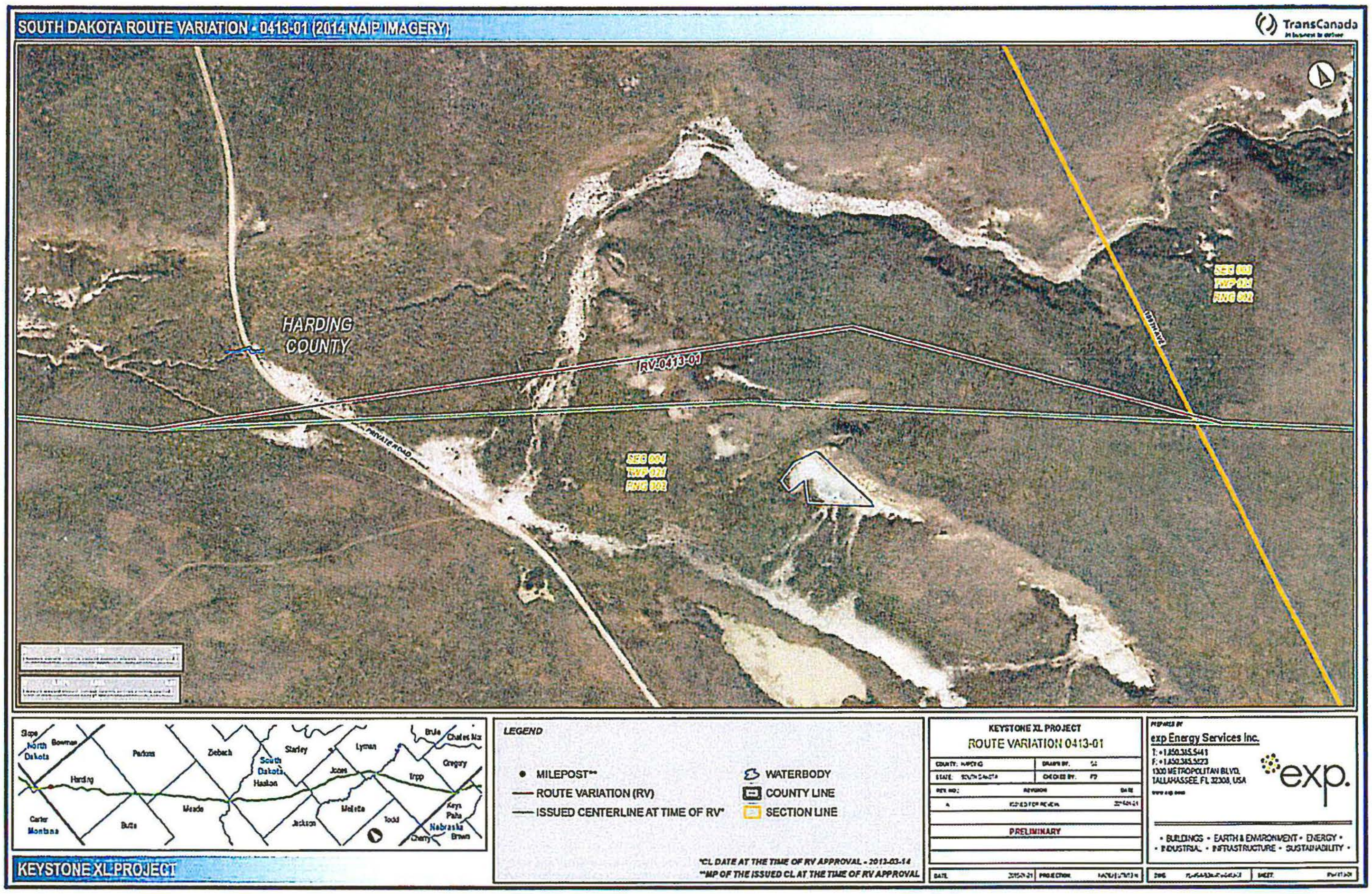

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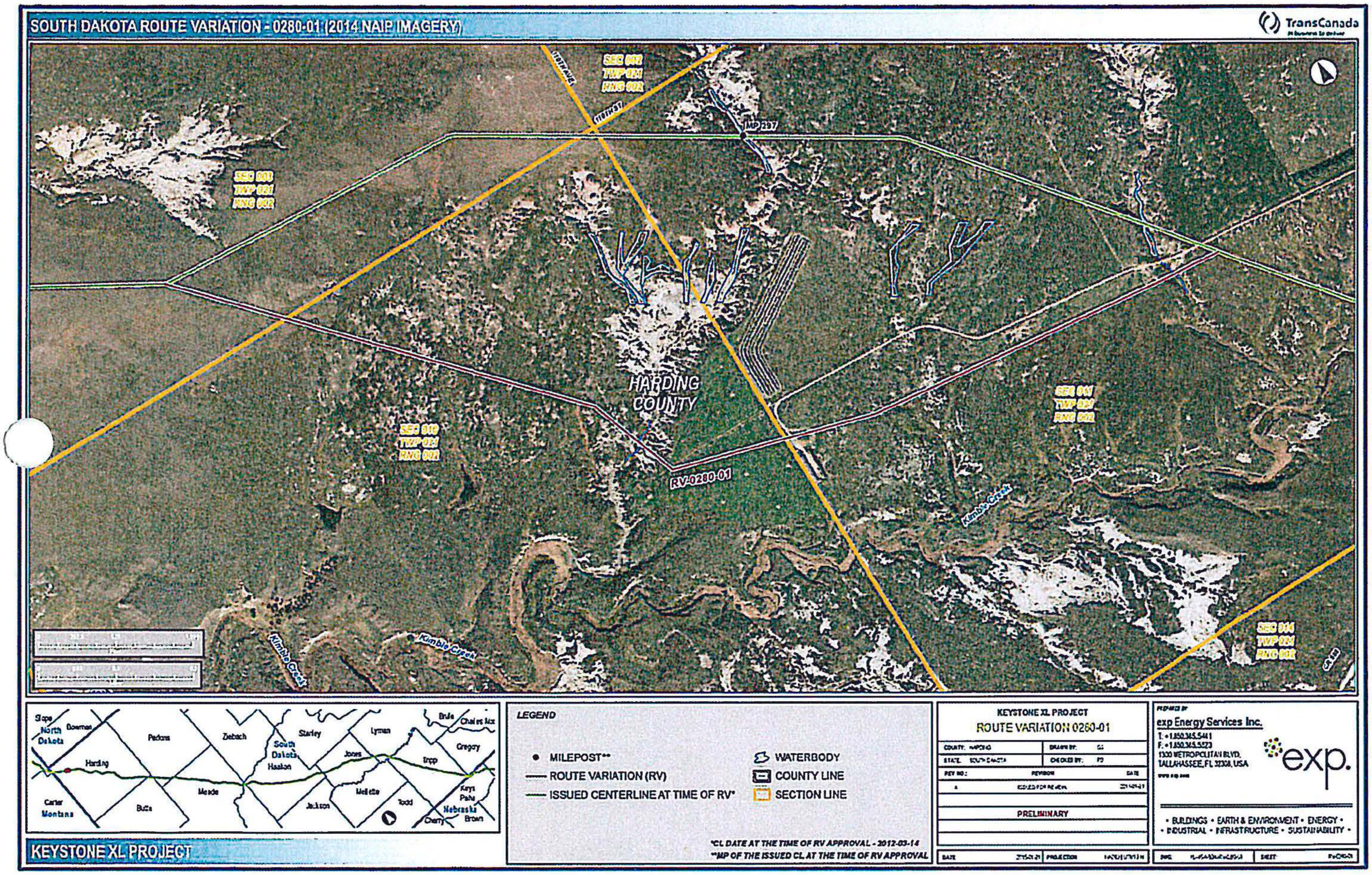

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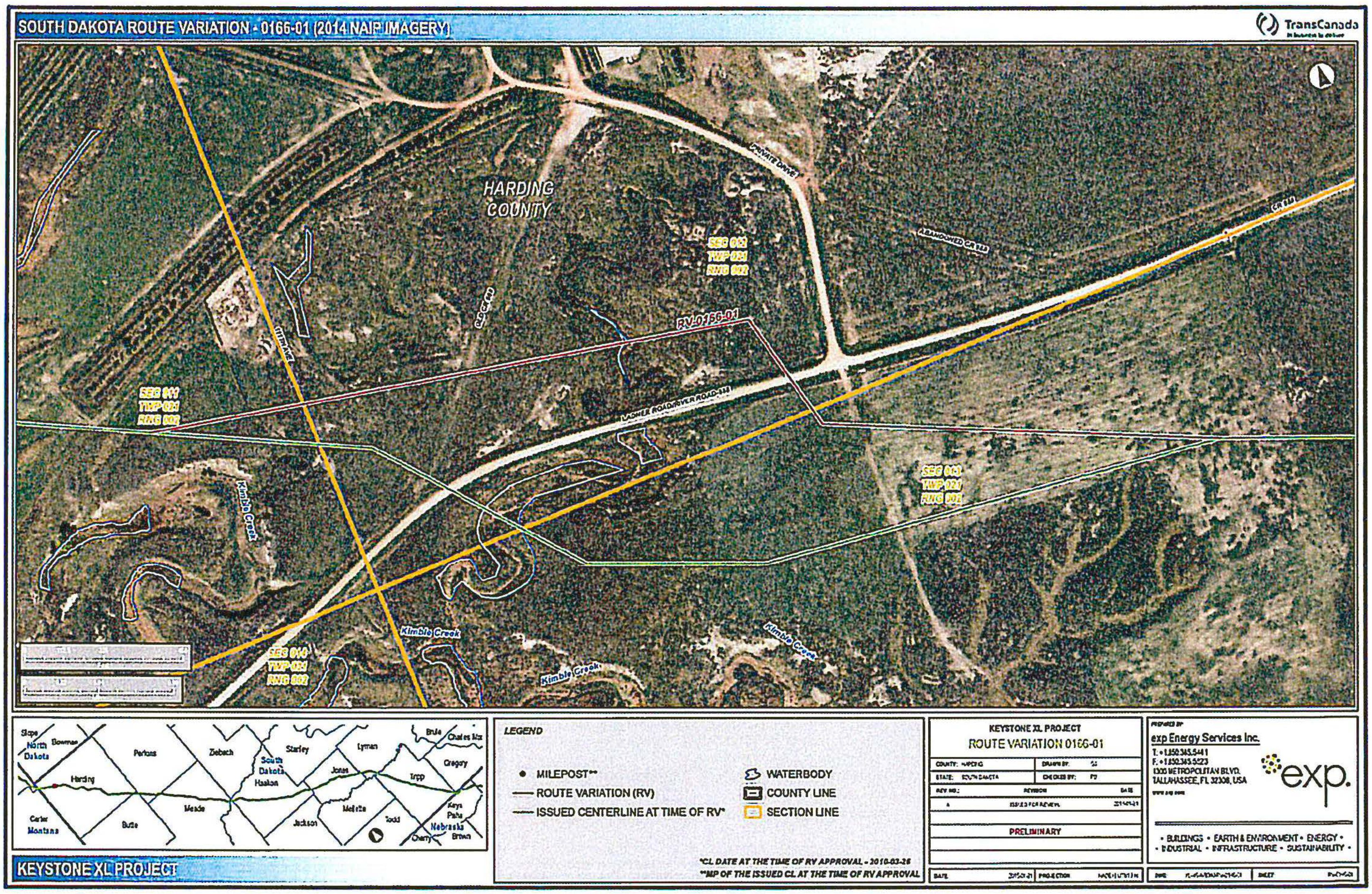
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HARDING COUNTY
PRIVATE DRIVE
ABANDONED CR 844
CR 844
RV-0166-01
LADNER ROAD/RIVER ROAD-844
Kimble Creek
Kimble Creek
Kimble Creek
Kimble Creek
Slope
North Dakota
Bowman
Perkins
Ziebach
Stanley
Lyman
Brule
Charles Mix
Harding
South Dakota
Haakon
Jones
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 - 2010-03-26
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0166-01
PRELIMINARY
exp Energy Services Inc.
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
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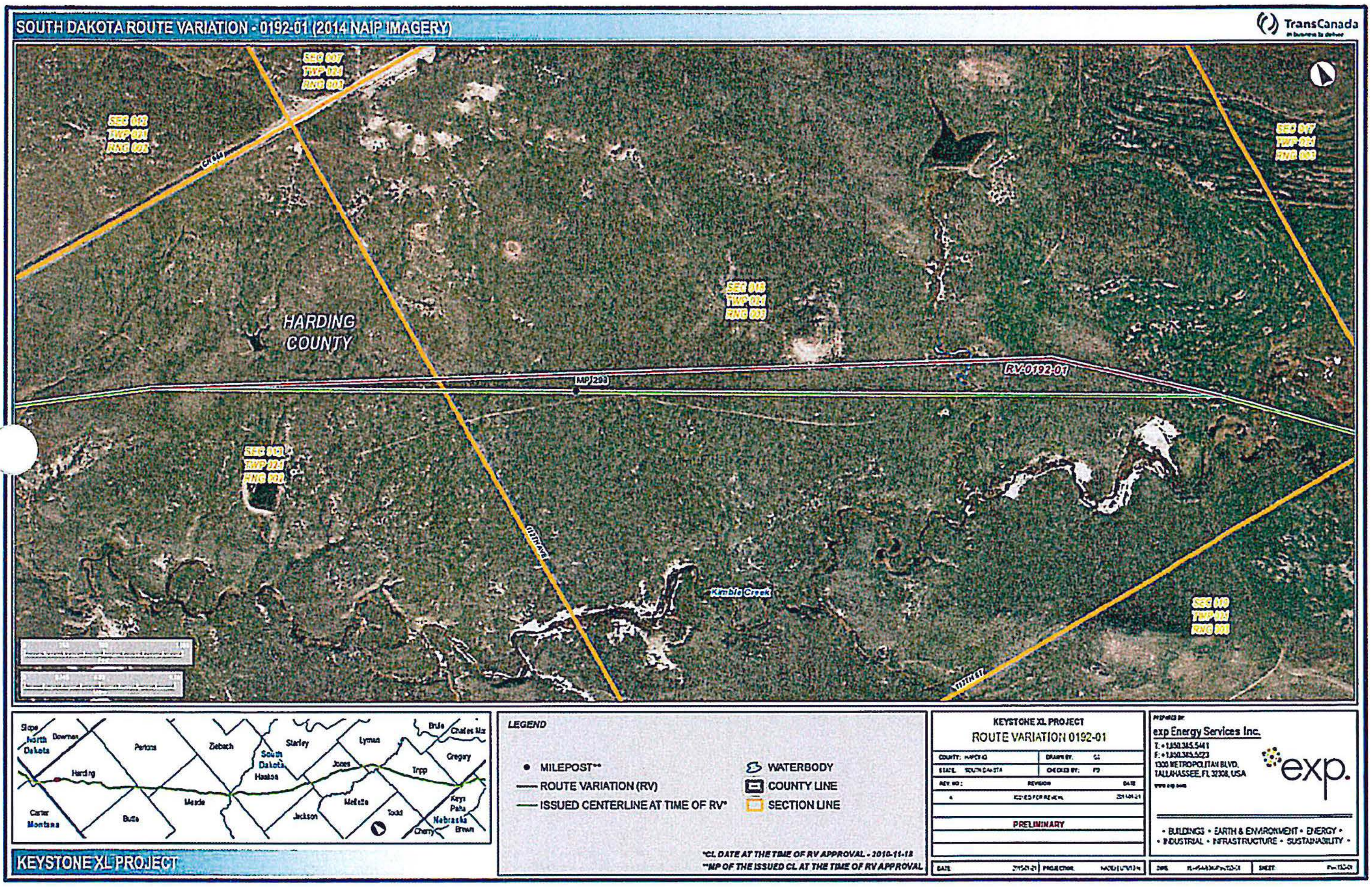
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •



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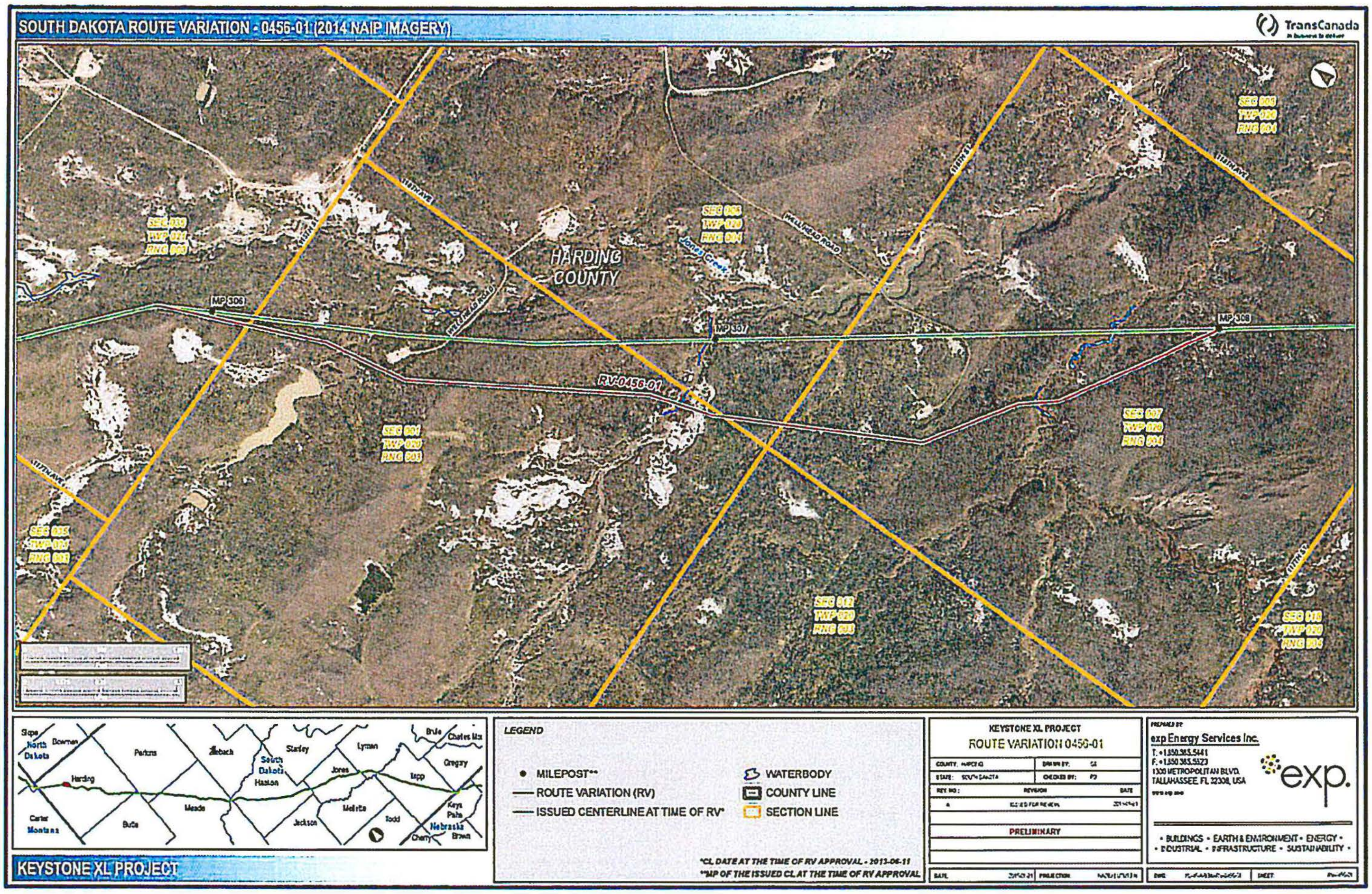

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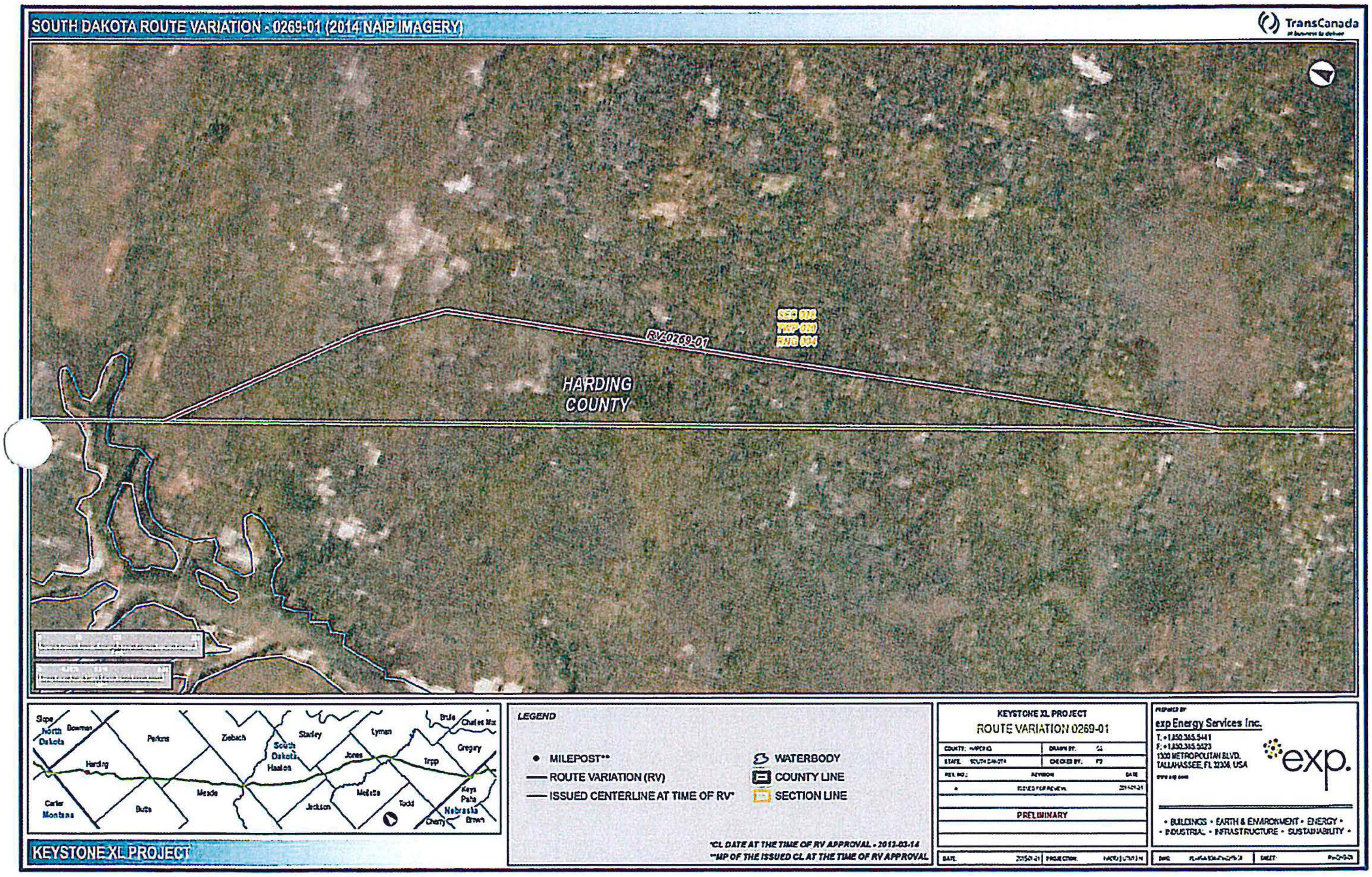

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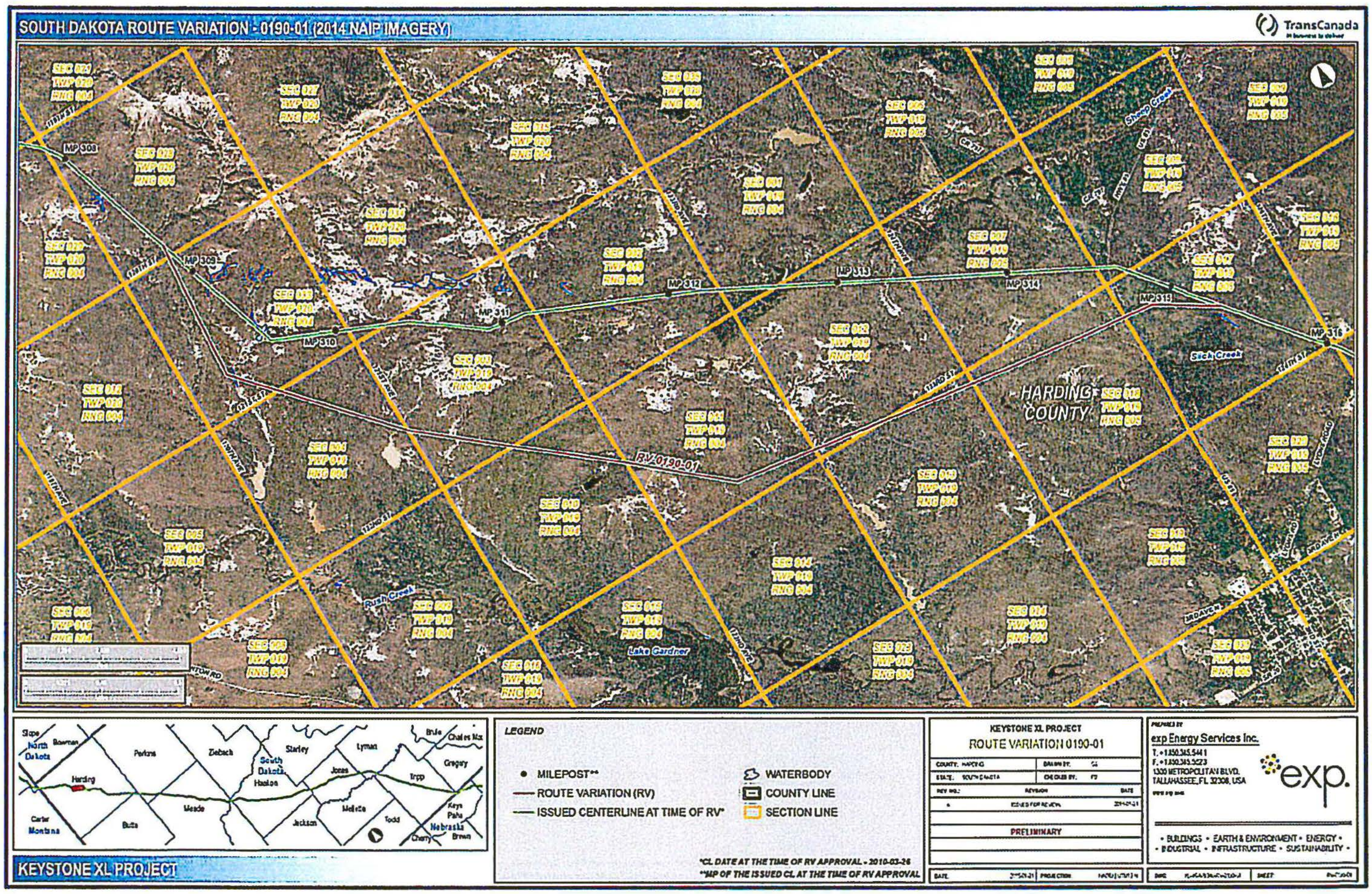

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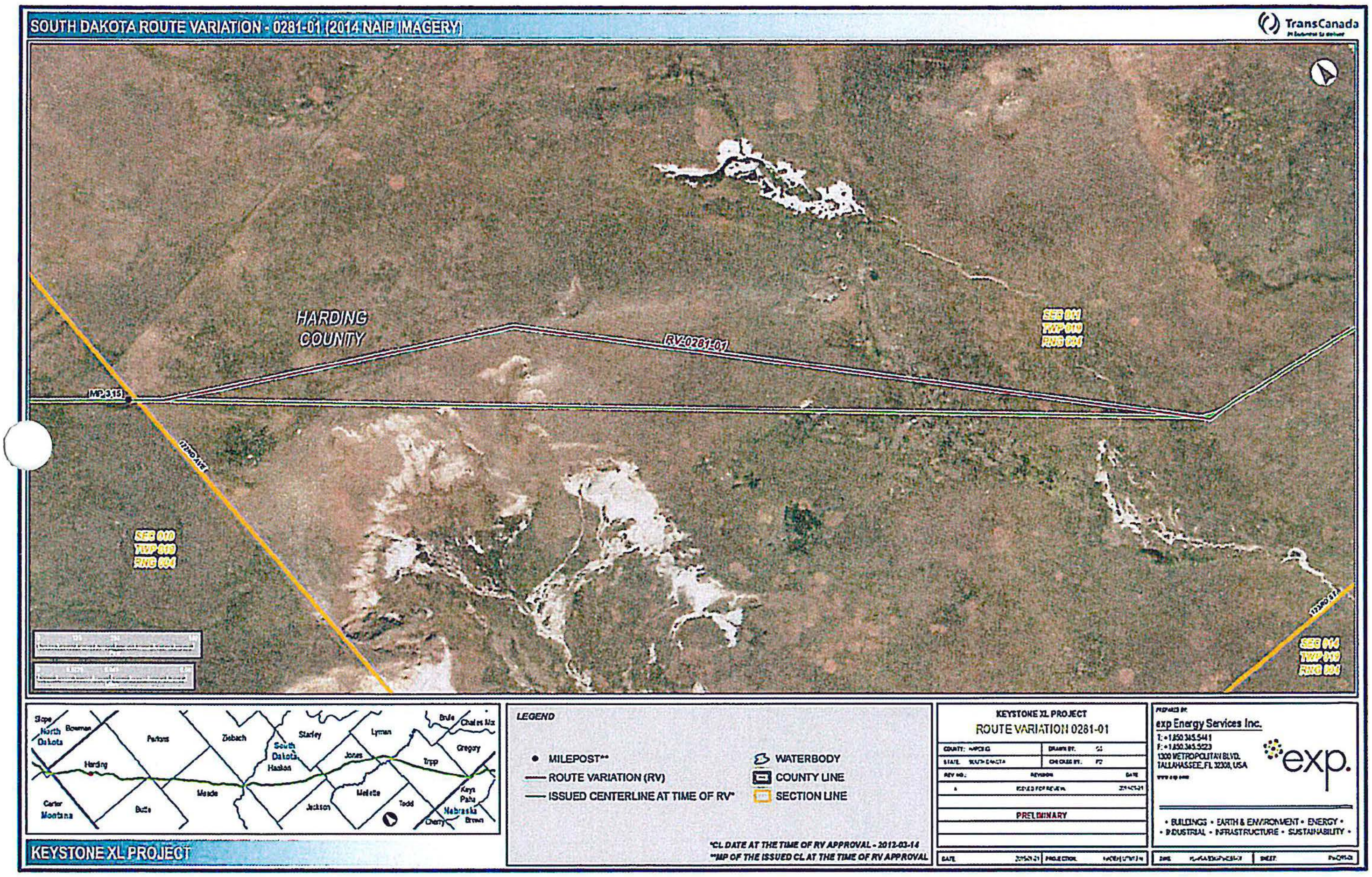

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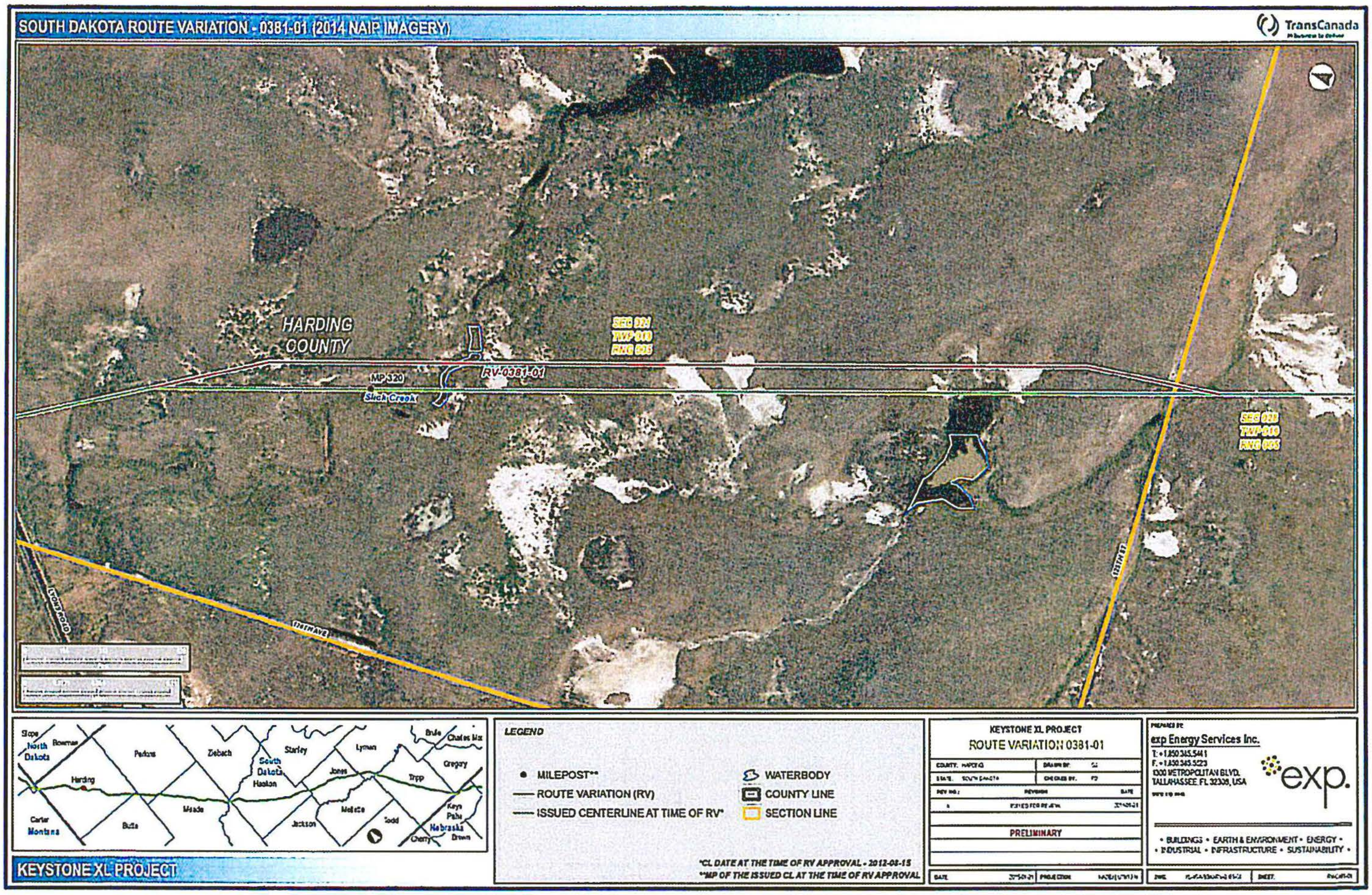

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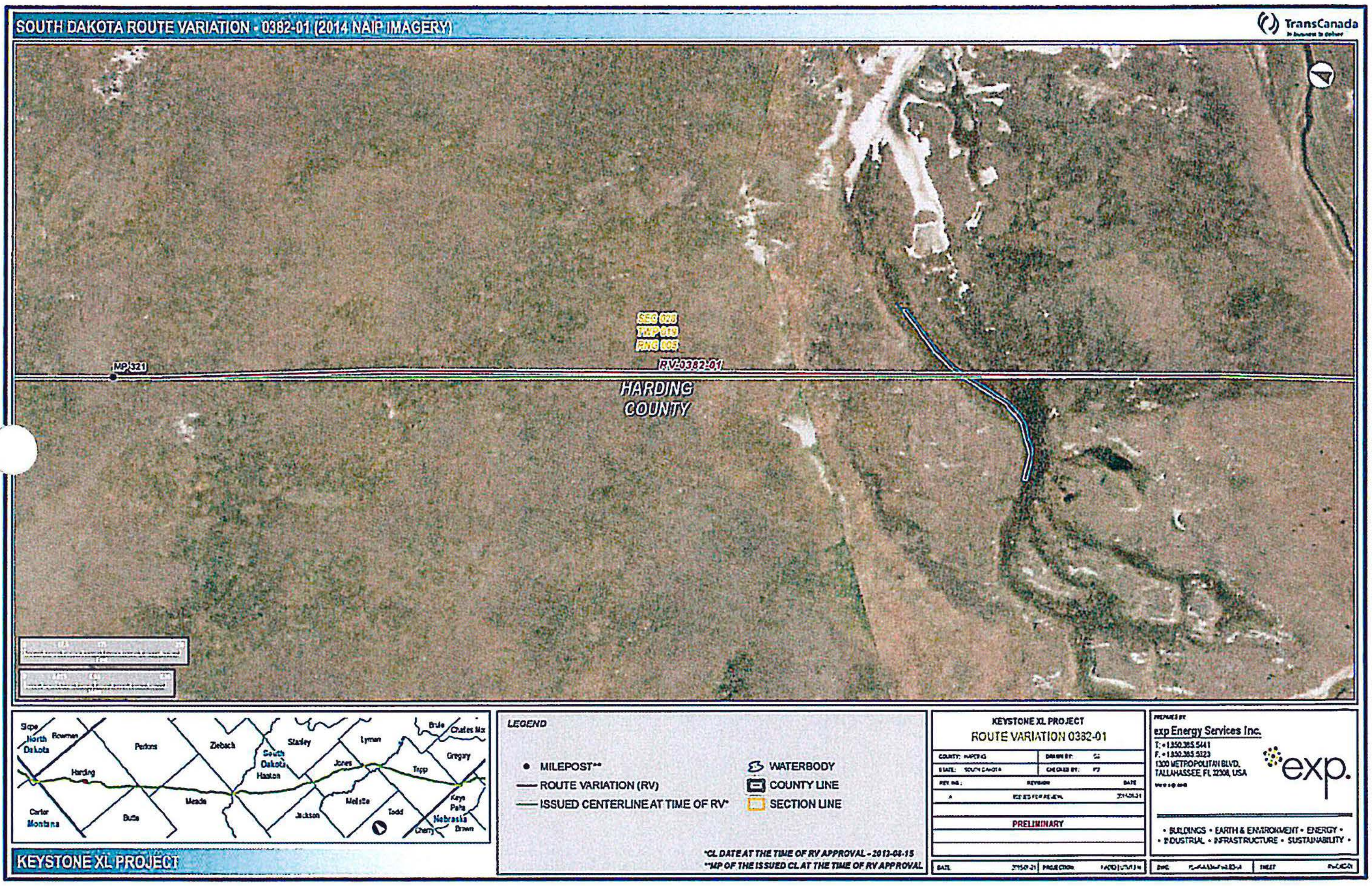

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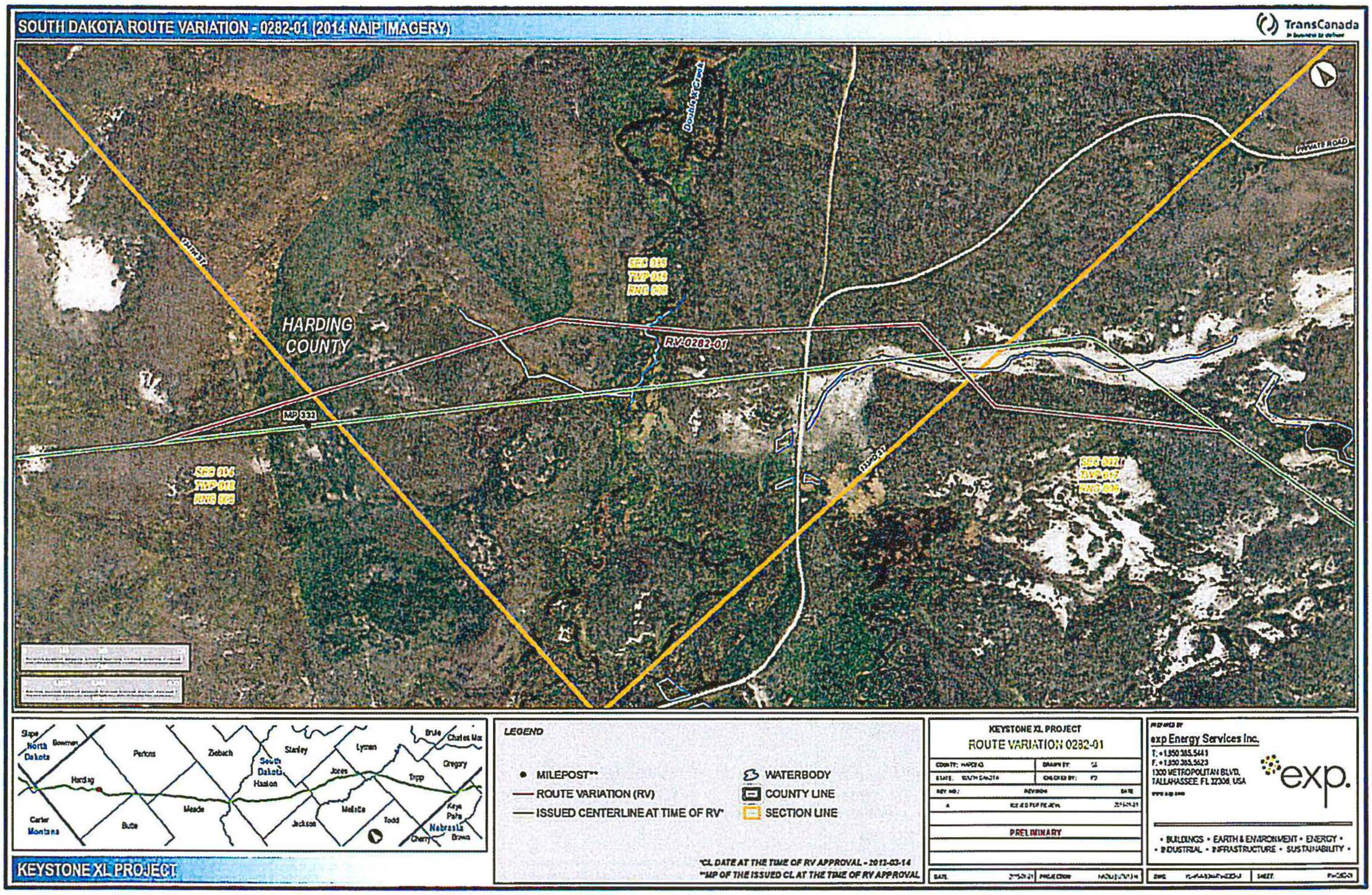

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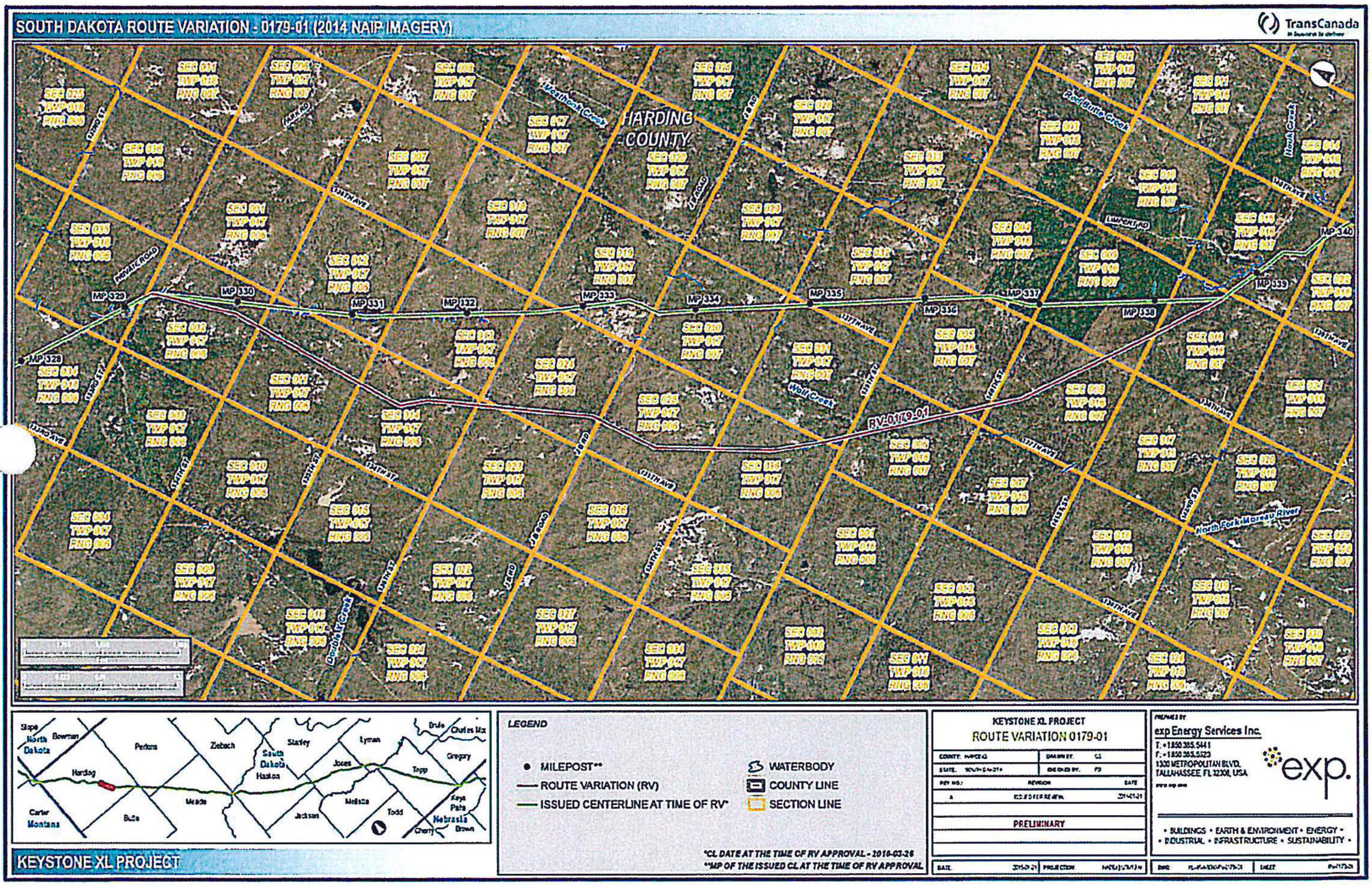

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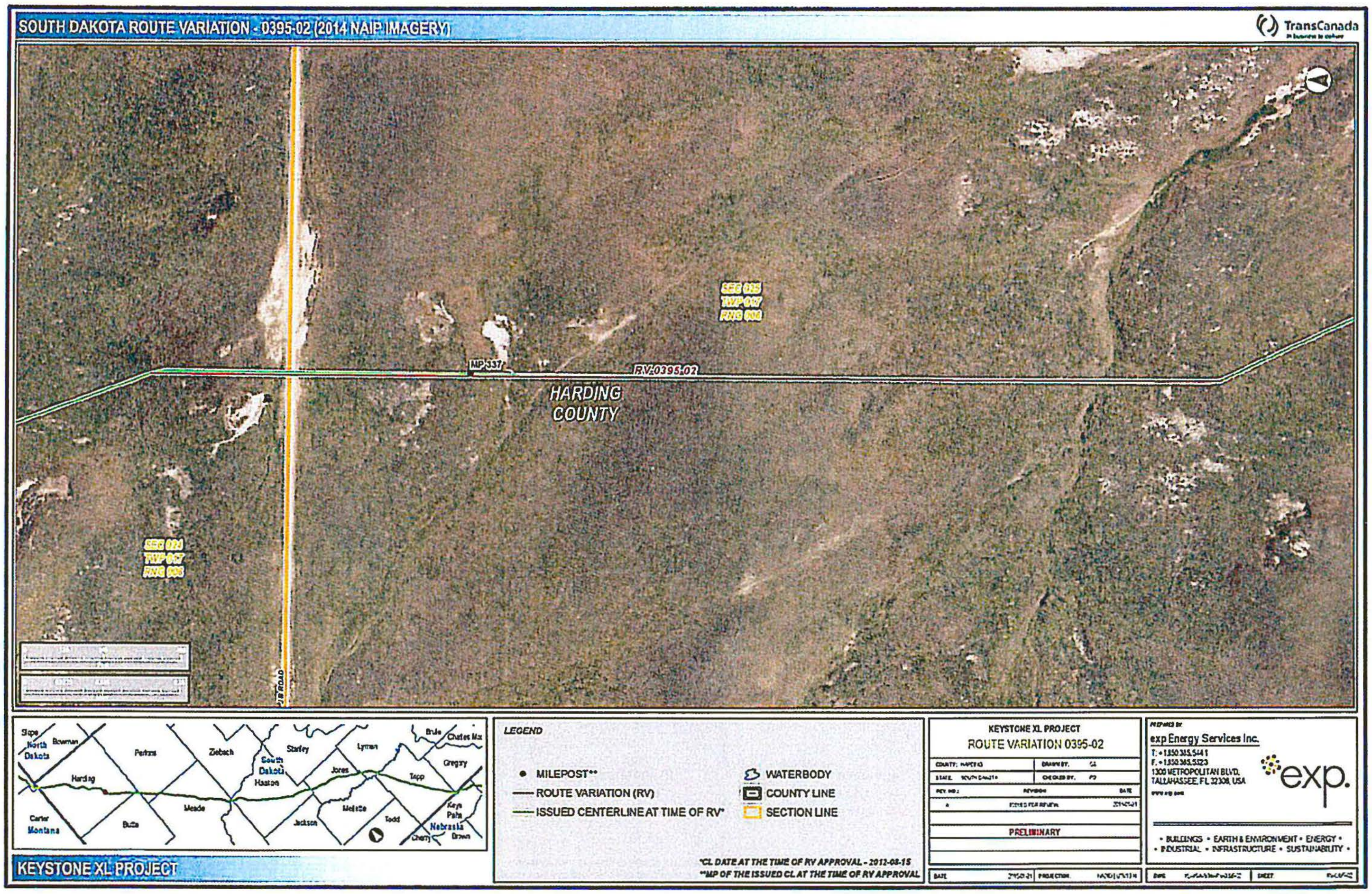

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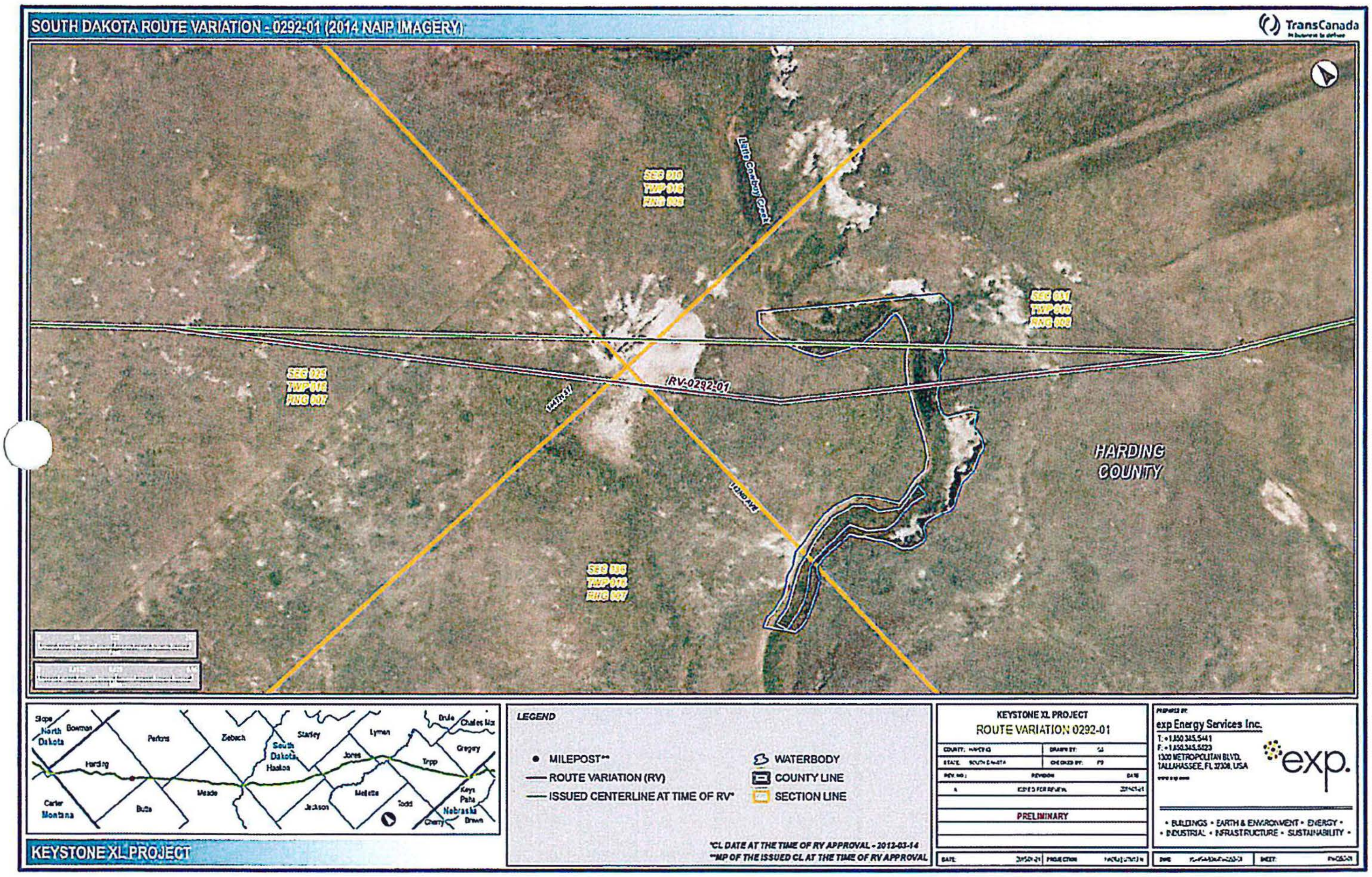
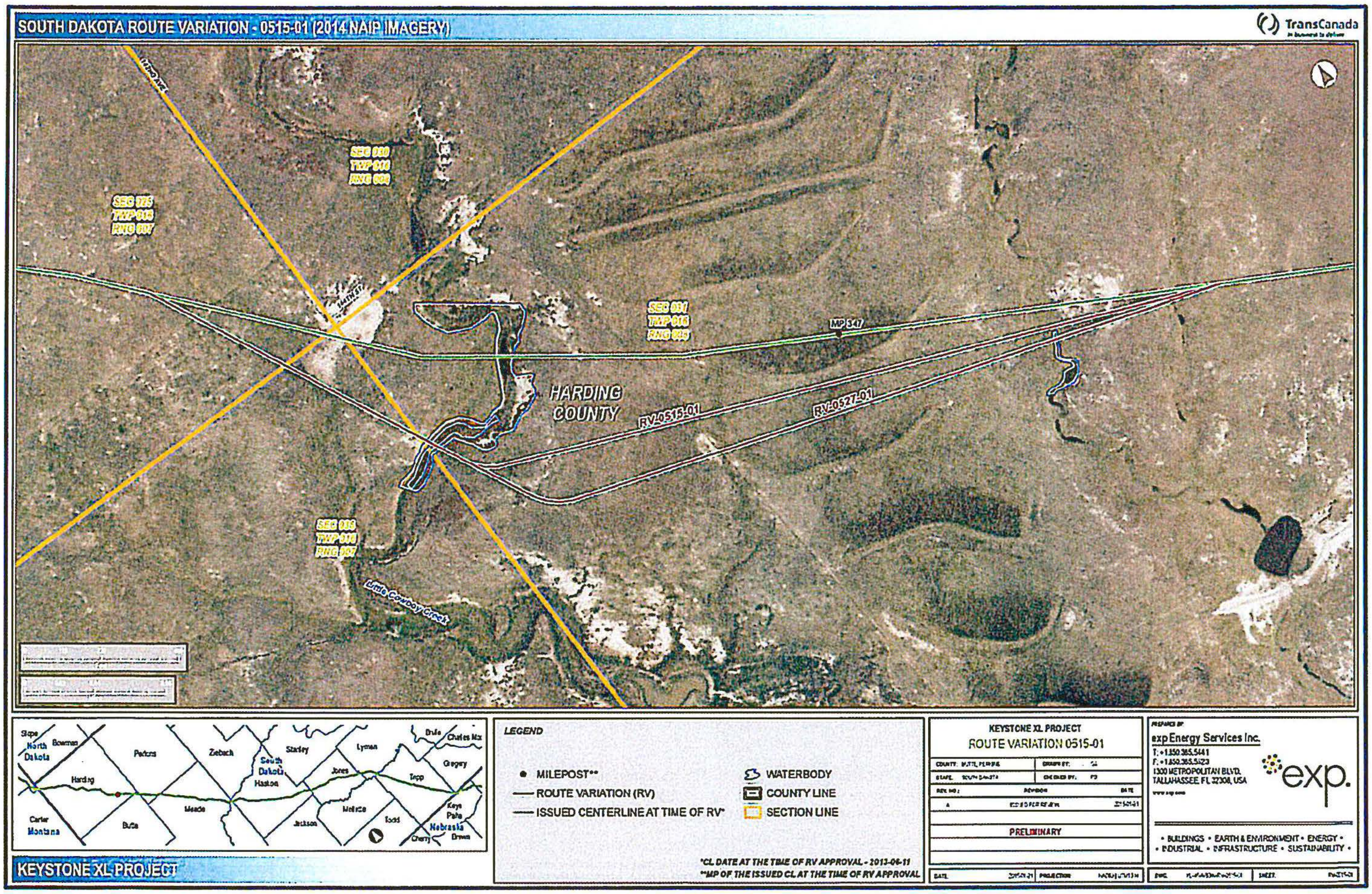


SOUTH DAKOTA ROUTE VARIATION - 0292-01 (2014 NAIP IMAGERY)
TransCanada
Little Crow Creek
RV-0292-01
HARDING COUNTY
North Dakota
Bowman
Slope
Perkins
Ziebach
Stanley
Lyman
Brule
Charles Mix
Harding
South Dakota
Haakon
Jones
Tripp
Gregory
Carter
Montana
Butte
Meade
Jackson
Mellette
Todd
Keya Paha
Nebraska
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 0292-01
PRELIMINARY
exp Energy Services Inc.
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •



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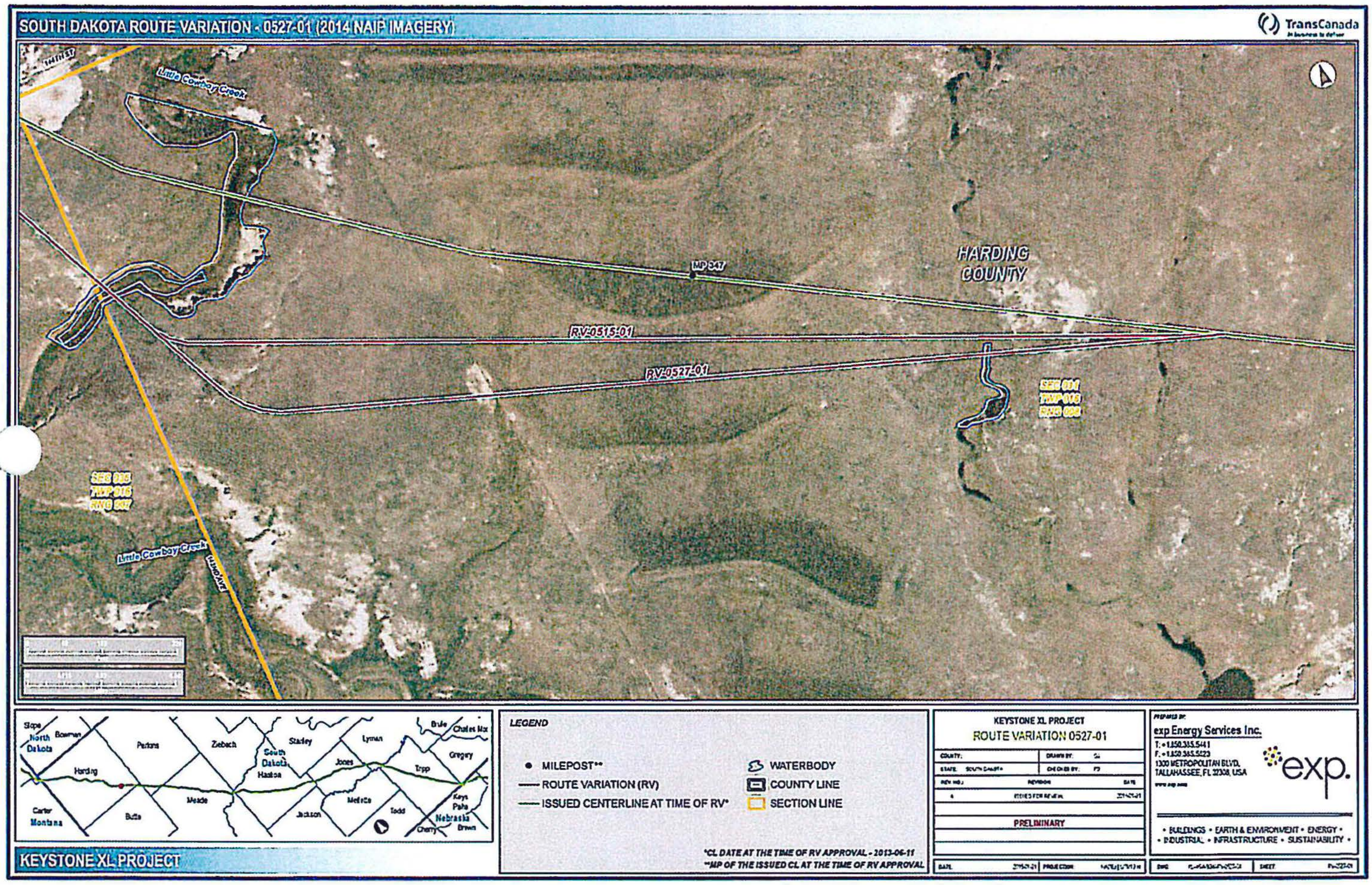

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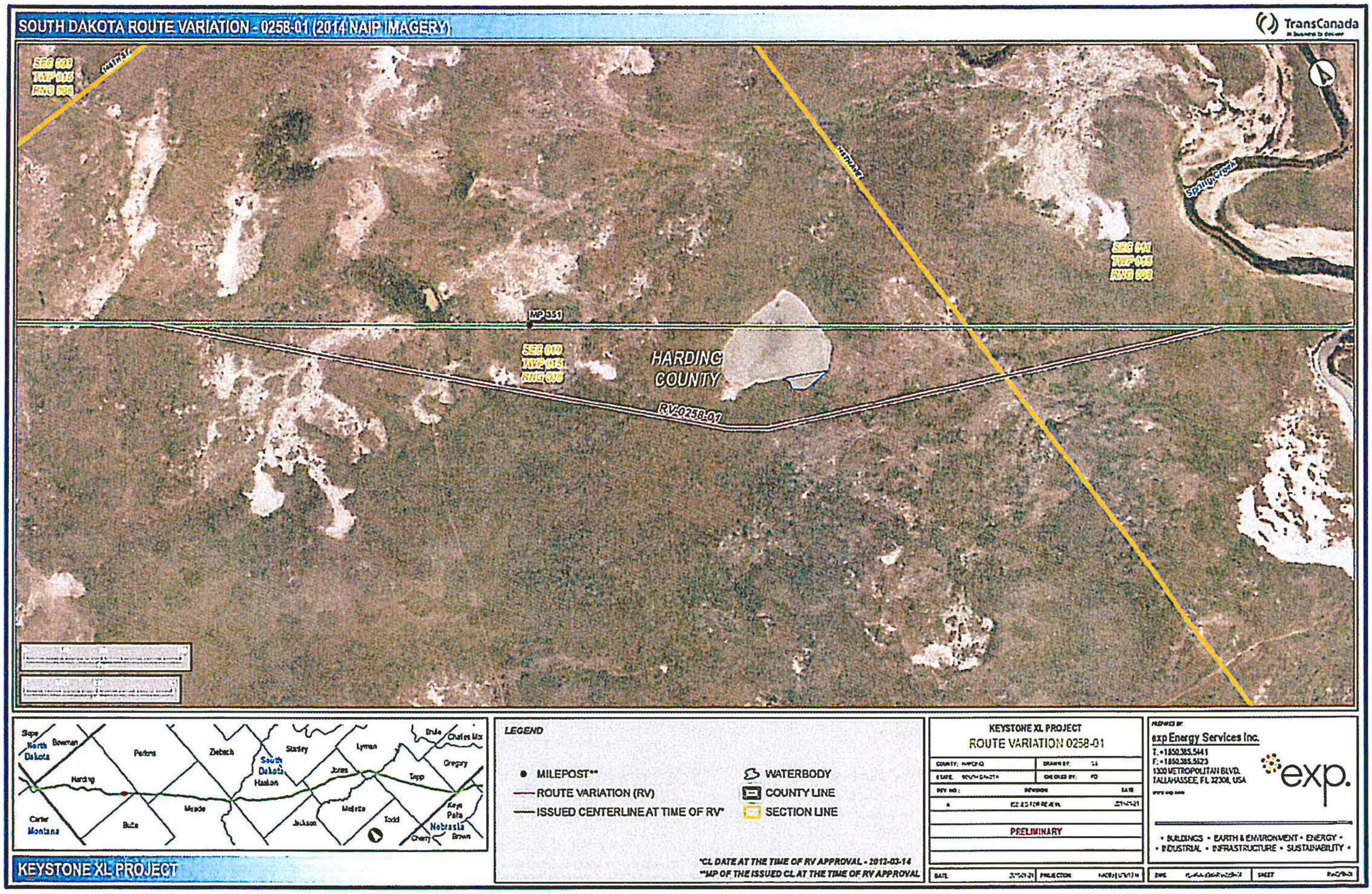

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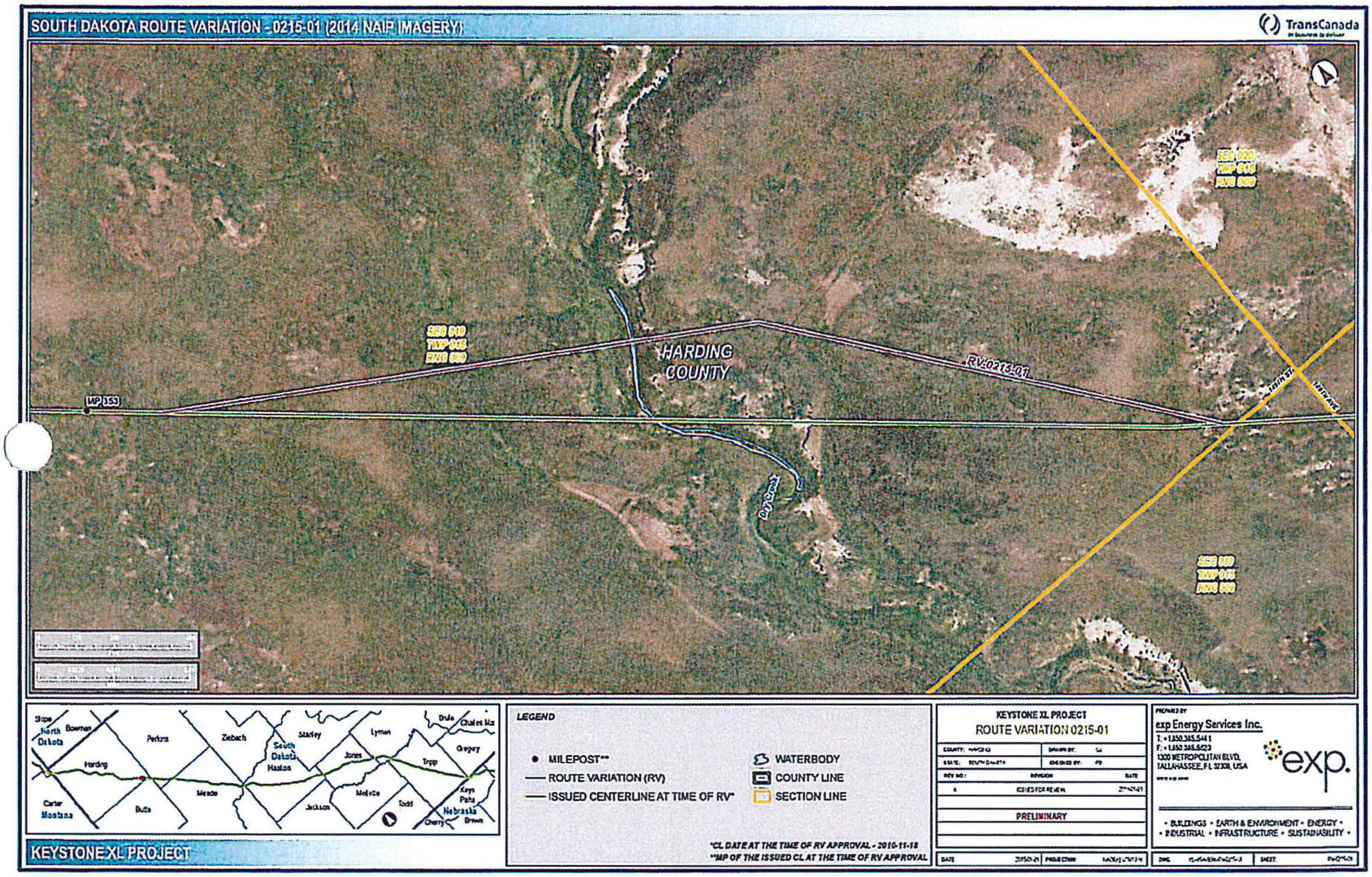

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TransCanada
HARDING
COUNTY
RV-0215-01
MP 353
Dry Creek
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South Dakota
Montana
Nebraska
Slope
Bowman
Perkins
Ziebach
Stanley
Lyman
Brule
Charles Mix
Gregory
Harding
Haakon
Jones
Tripp
Meade
Carter
Butte
Jackson
Mellette
Todd
Keya Paha
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
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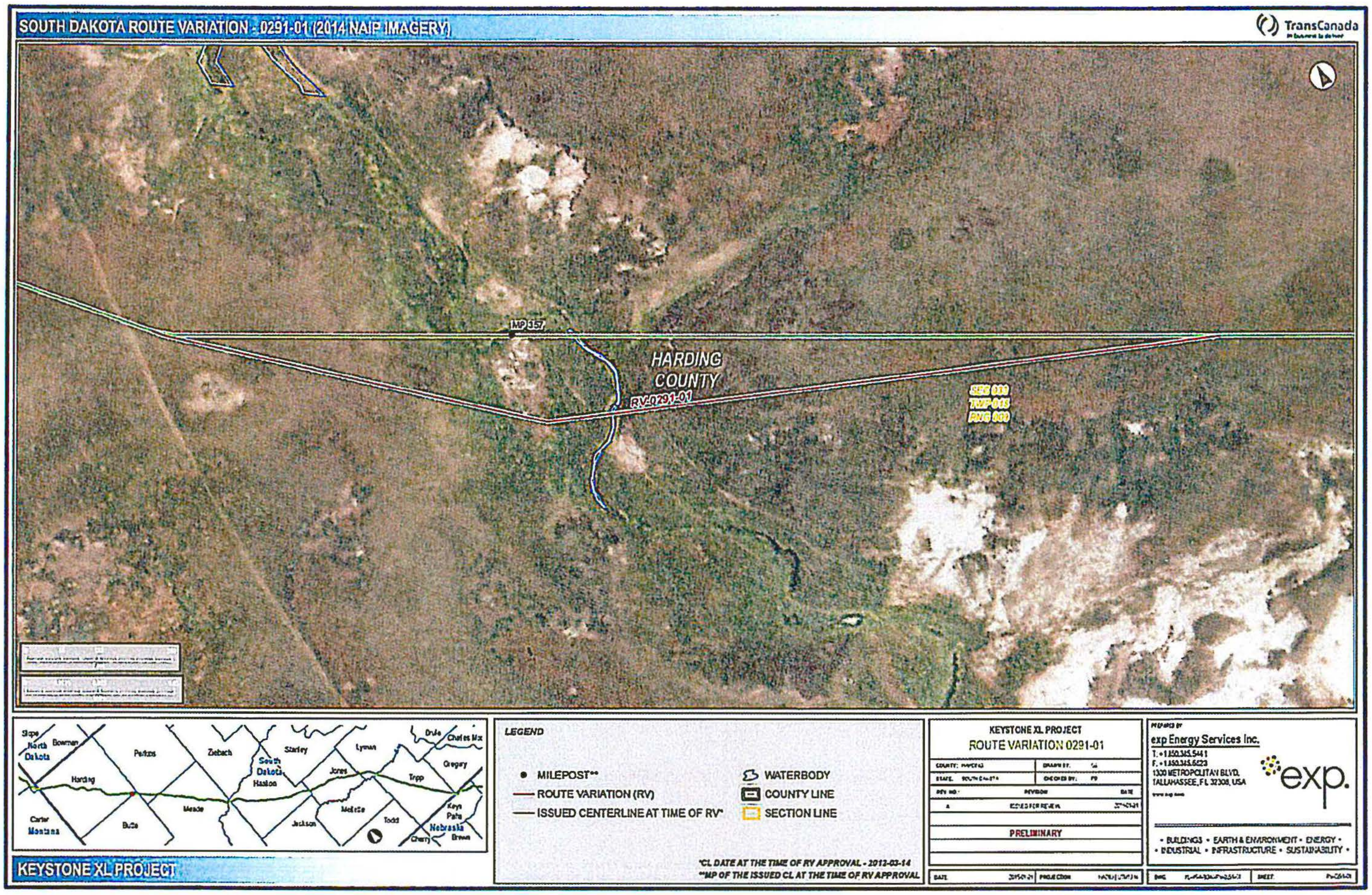
KEYSTONE XL PROJECT
ROUTE VARIATION 0215-01
COUNTY:
STATE: SOUTH DAKOTA
DRAWN BY:
CHECKED BY:
REV NO.:
REVISION
DATE
ISSUED FOR REVIEW
PRELIMINARY
DATE
PROJECTION
PREPARED BY
exp Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5423
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
DWG.
SHEET



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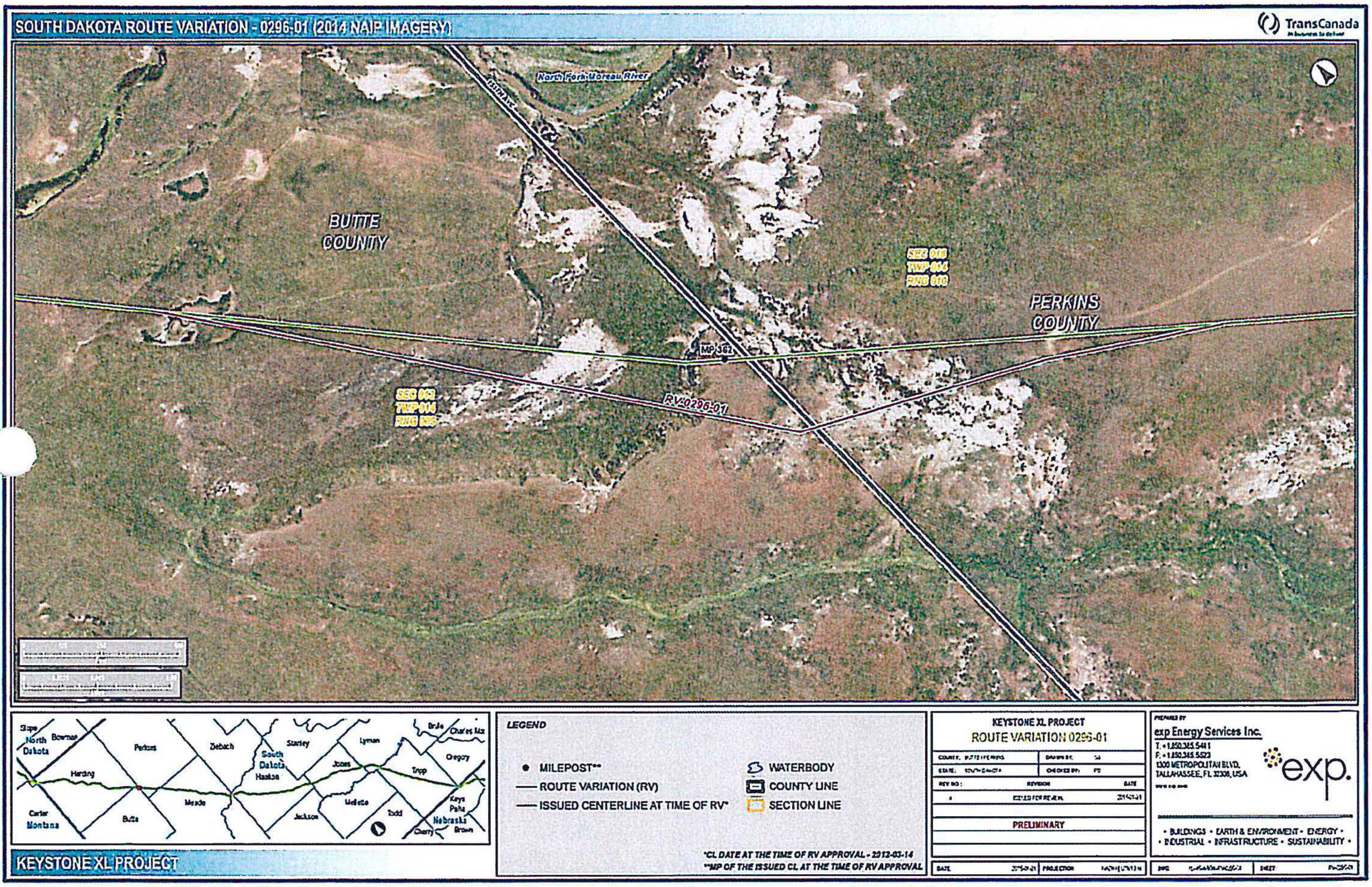

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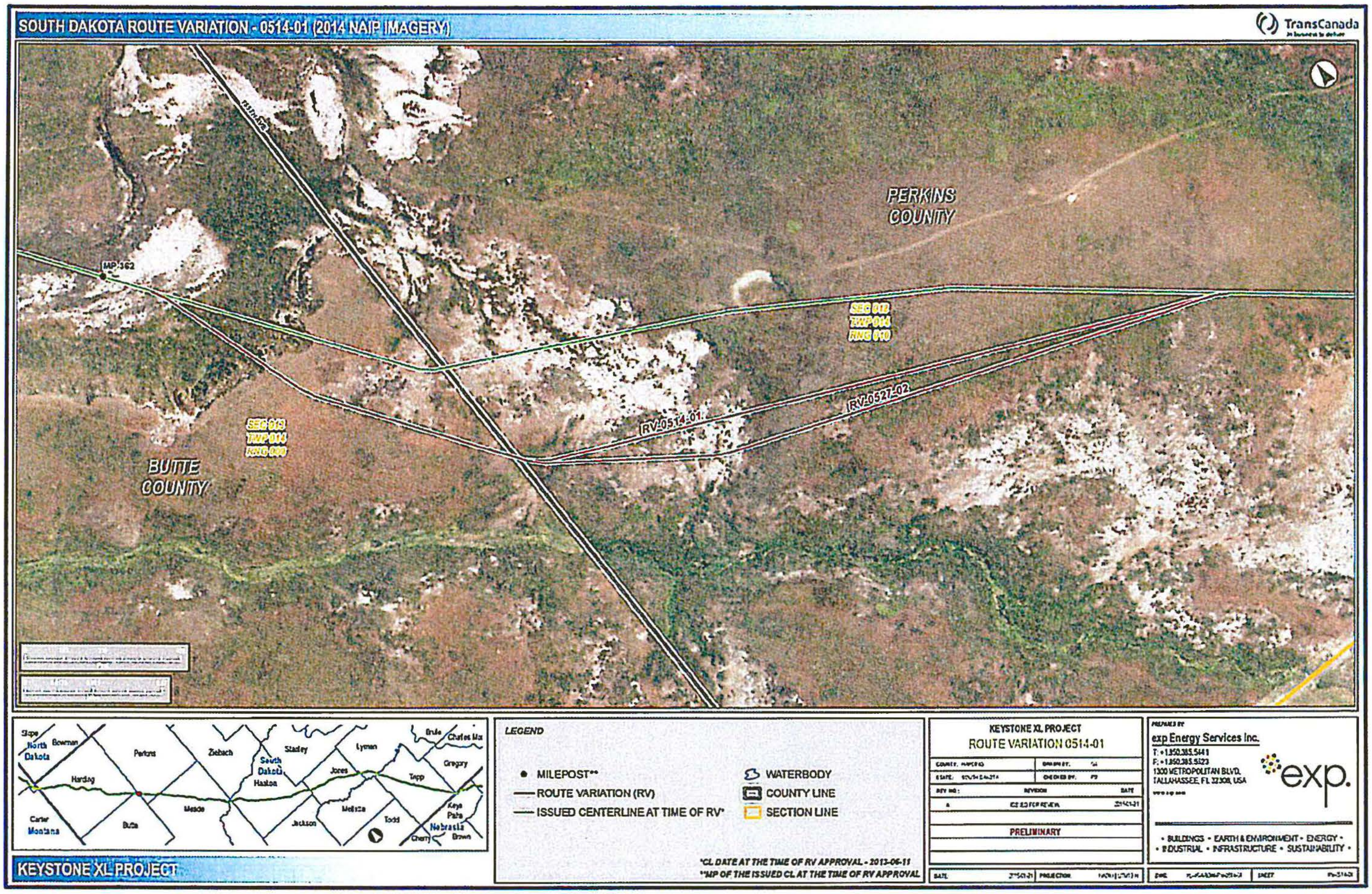

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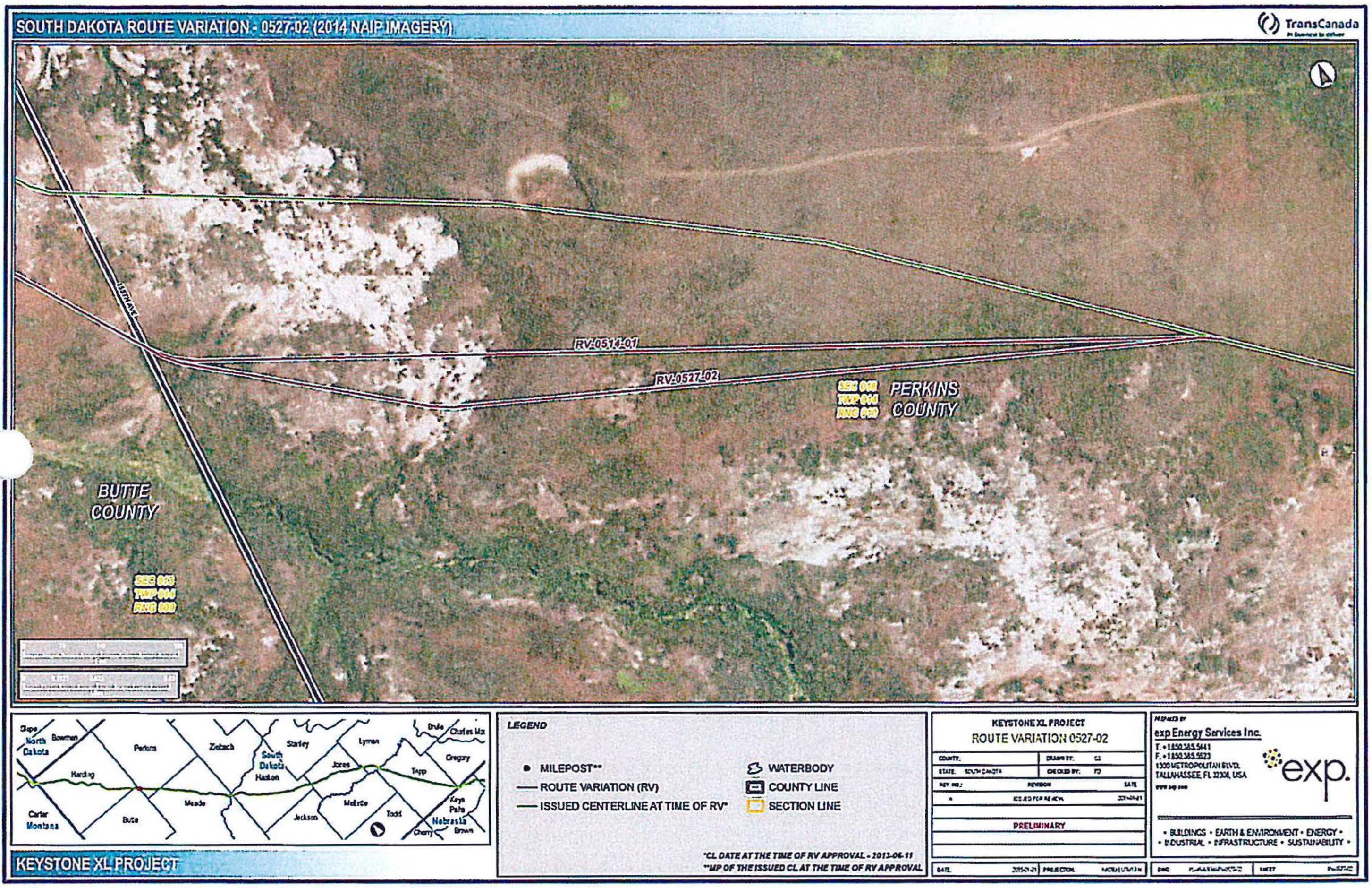

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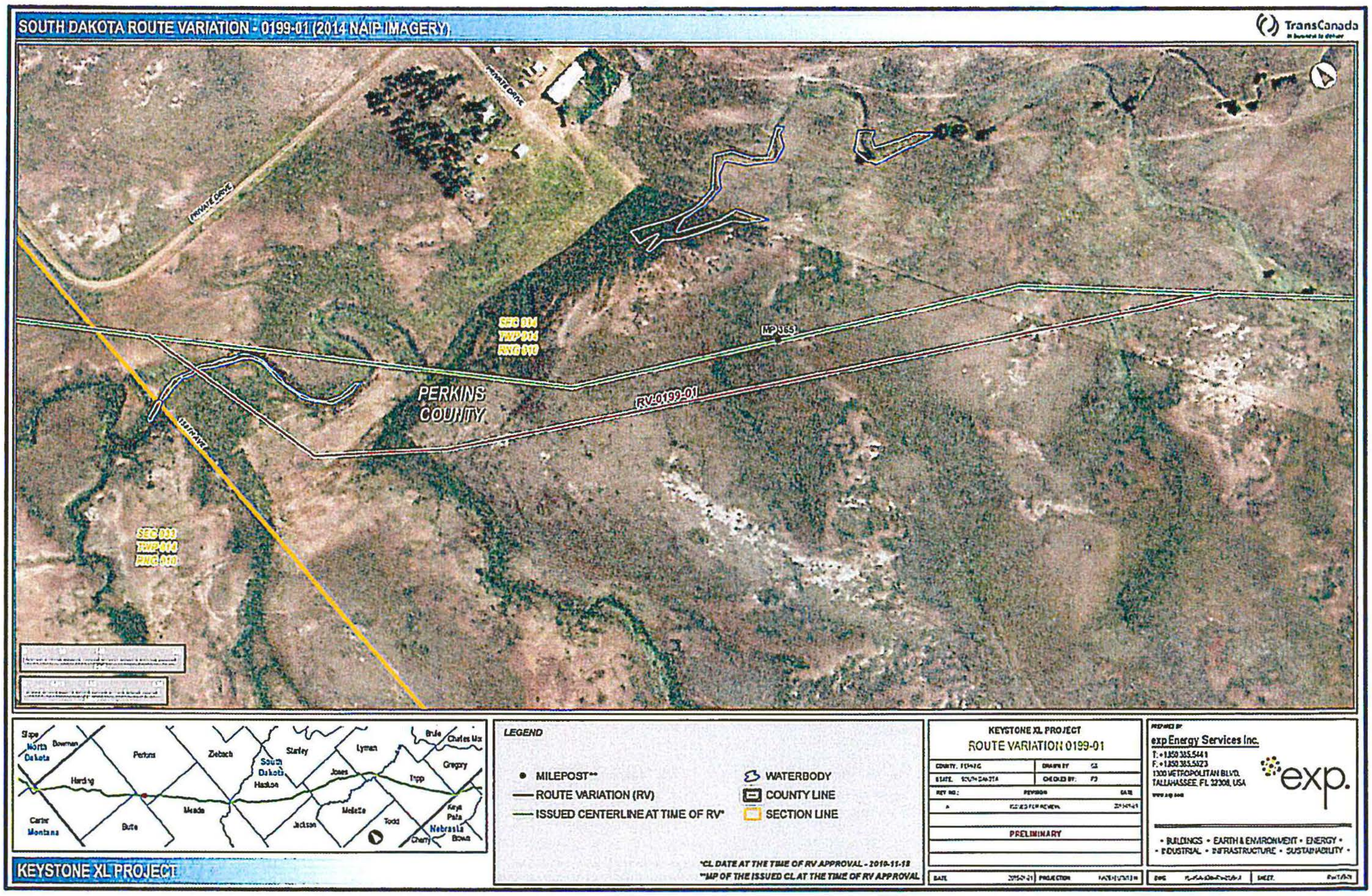

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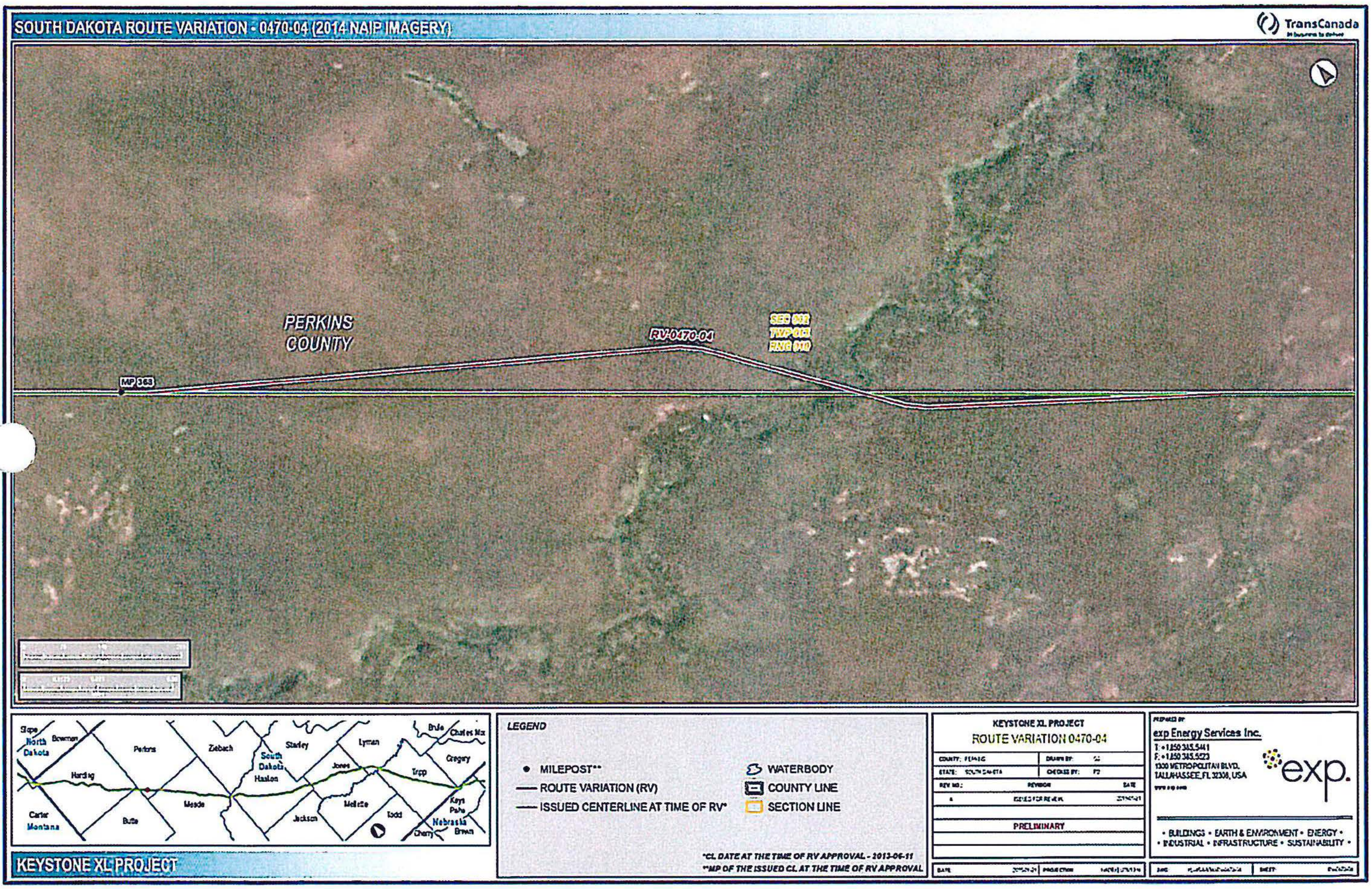

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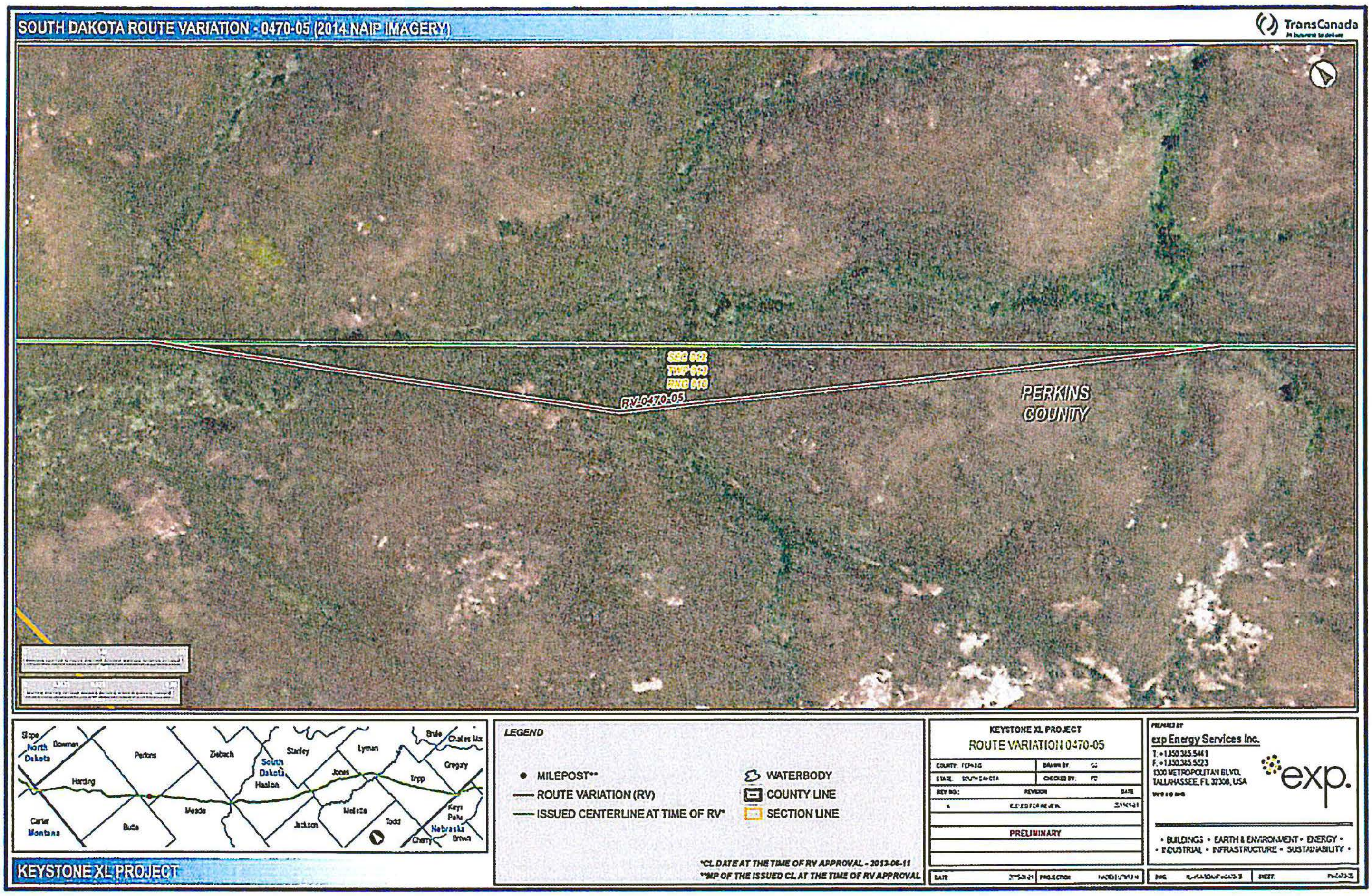

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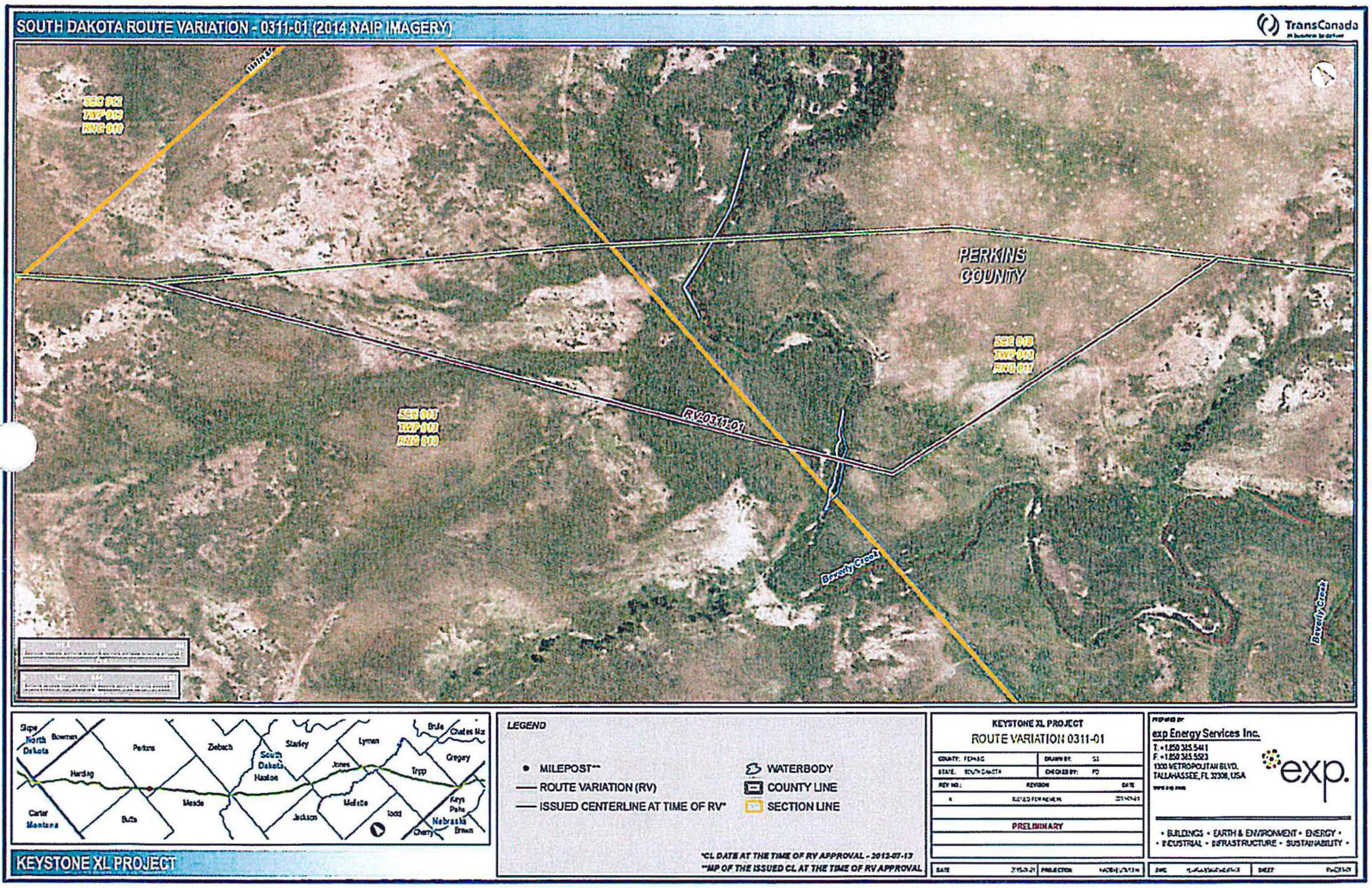

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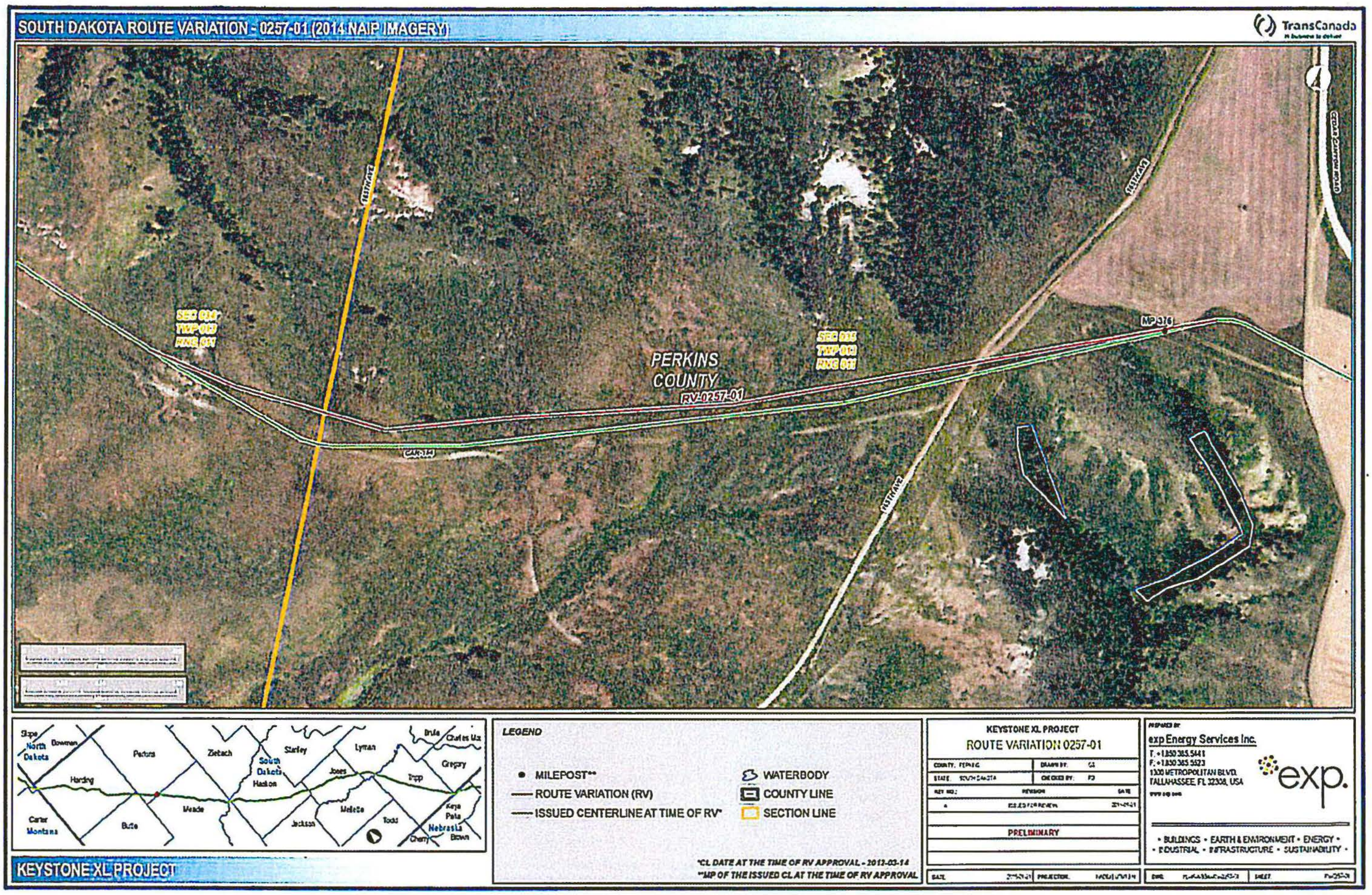

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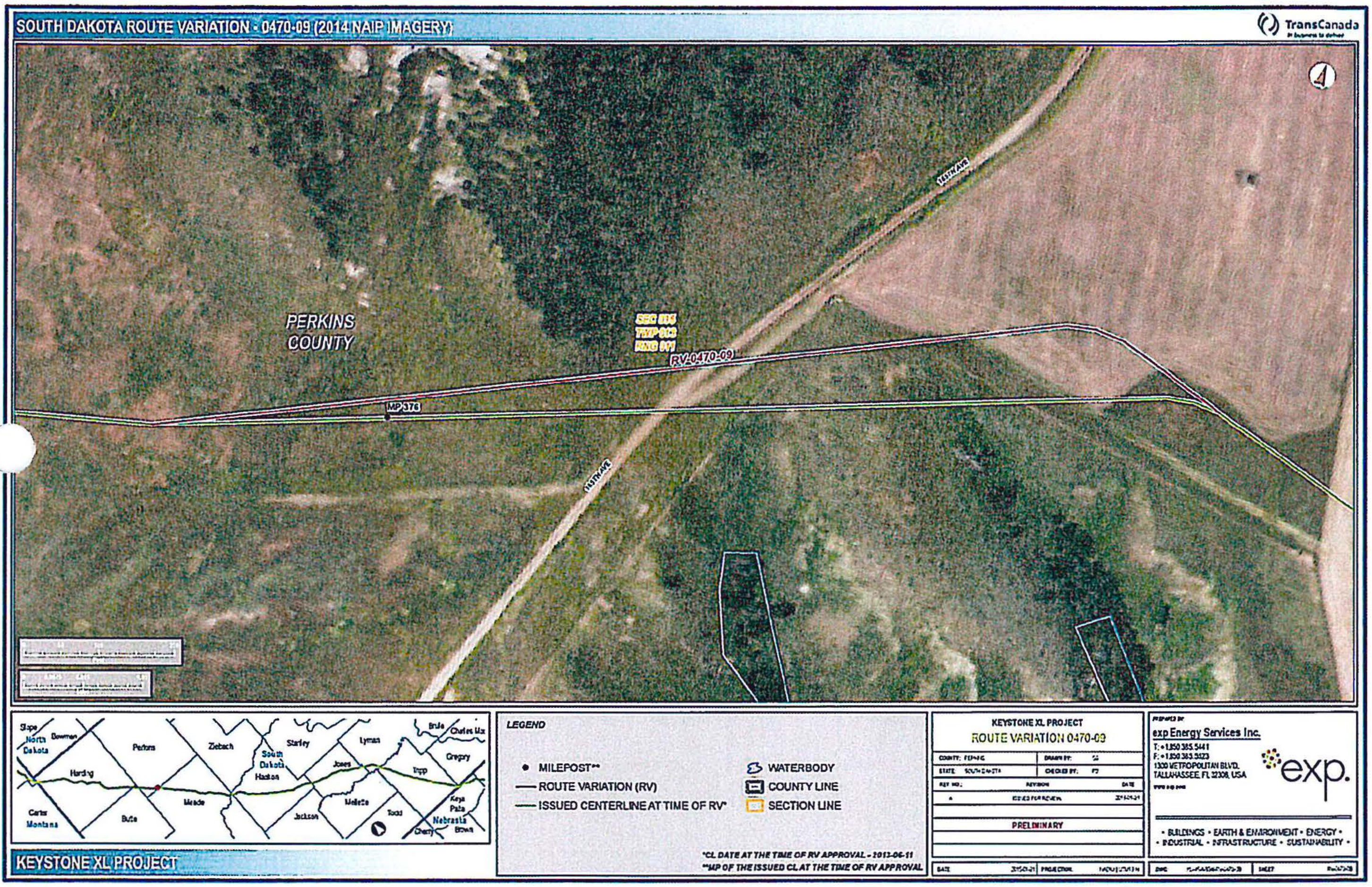

SOUTH DAKOTA ROUTE VARIATION - 0470-09 (2014 NAIP IMAGERY)
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PERKINS COUNTY
RV-0470-09
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Slope
Bowman
North Dakota
Harding
Perkins
Ziebach
Stanley
Lyman
Brule
Charles Mix
South Dakota
Haakon
Jones
Tripp
Gregory
Meade
Jackson
Mellette
Todd
Keya Paha
Nebraska
Cherry
Brown
Carter
Montana
Butte
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: +1.850.385.5423
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
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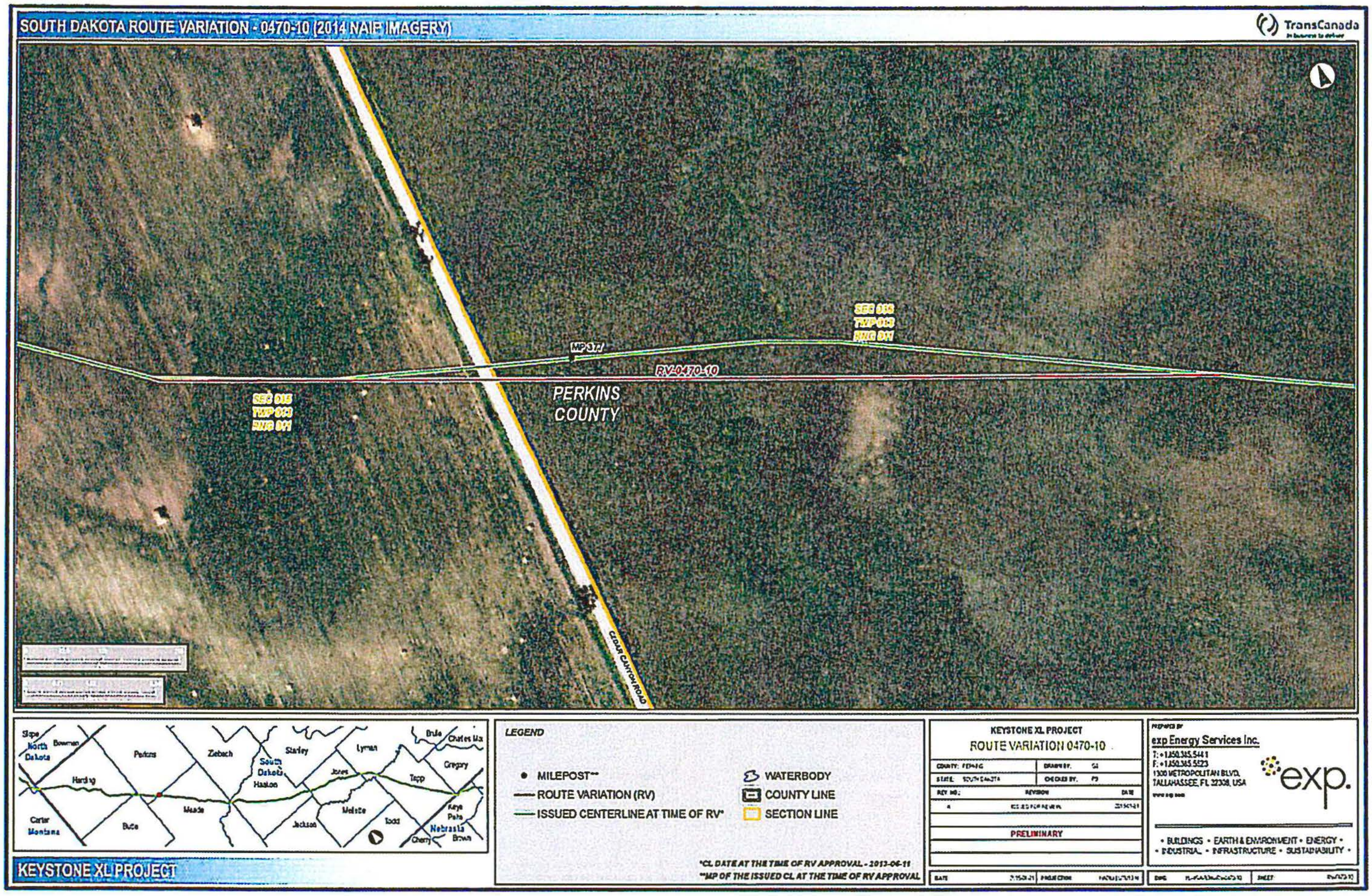
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •



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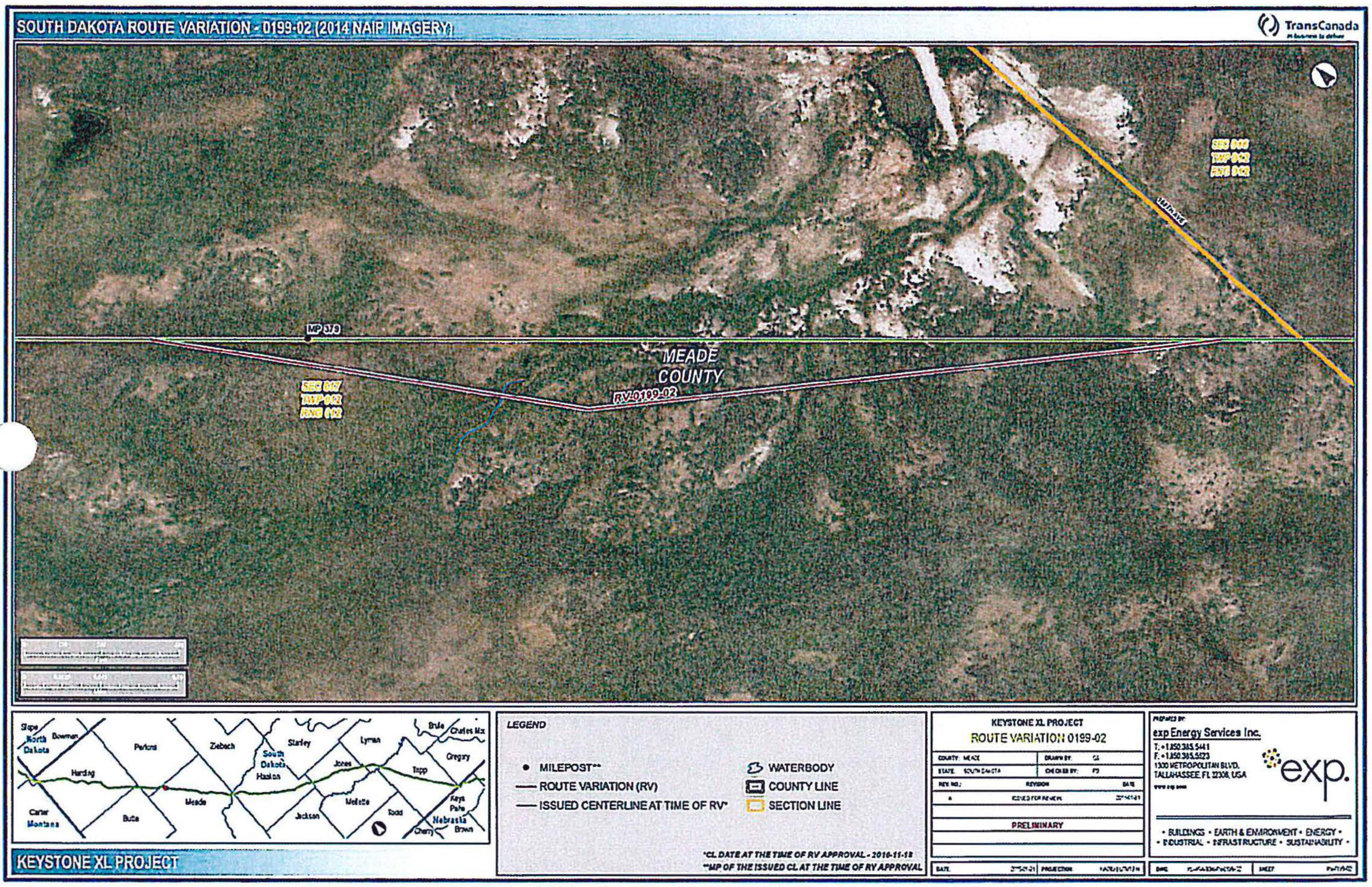

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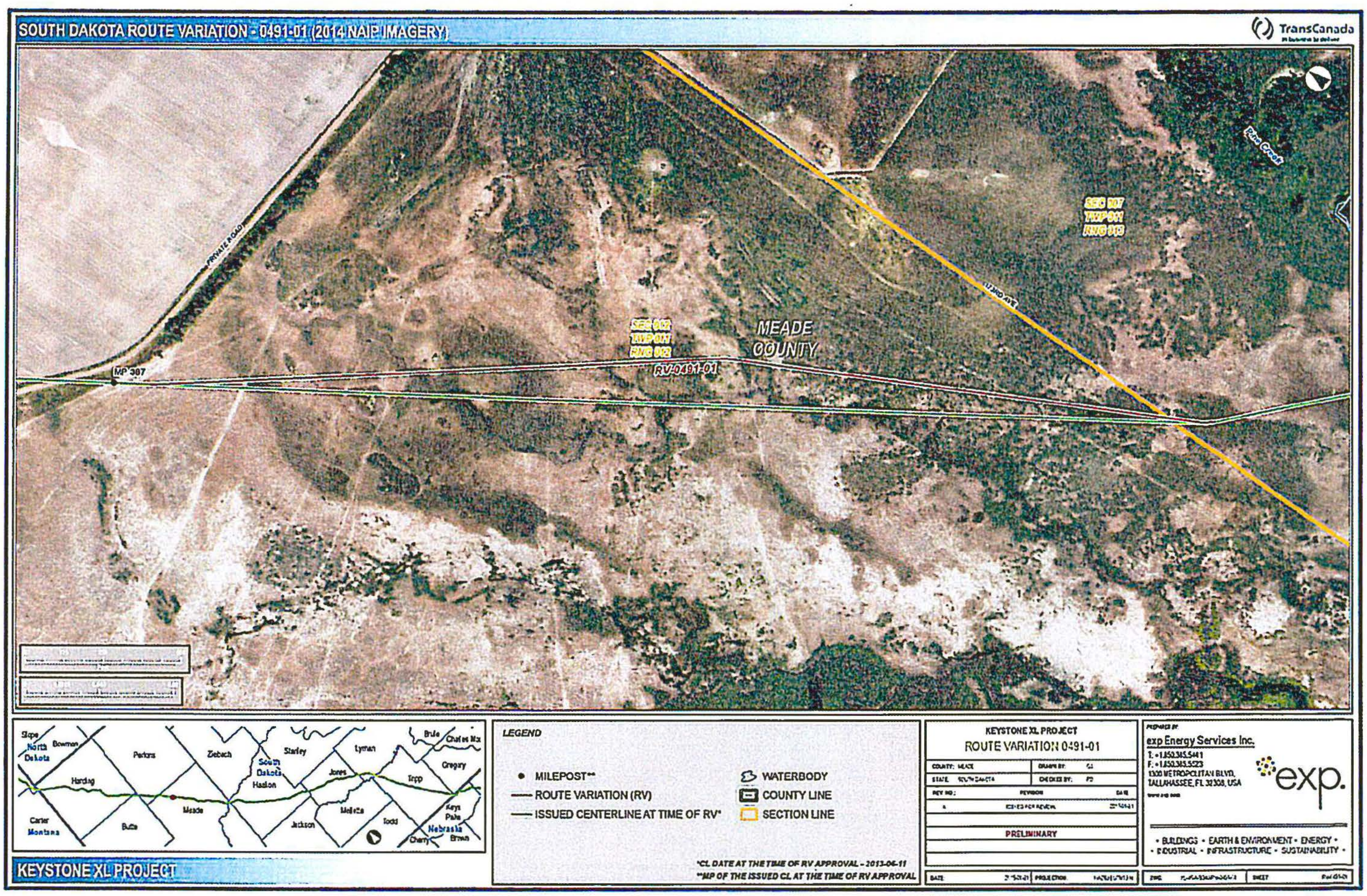

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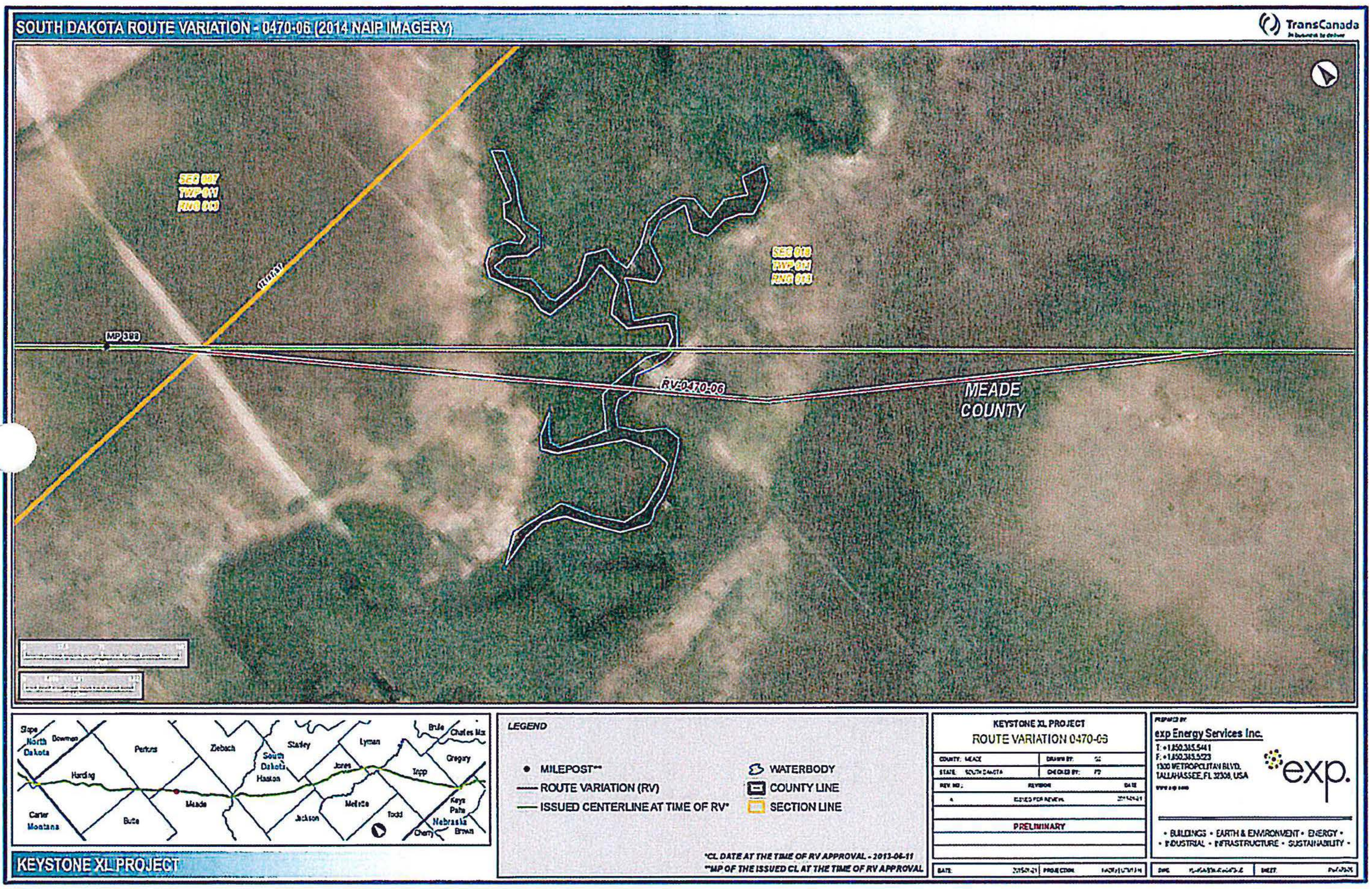

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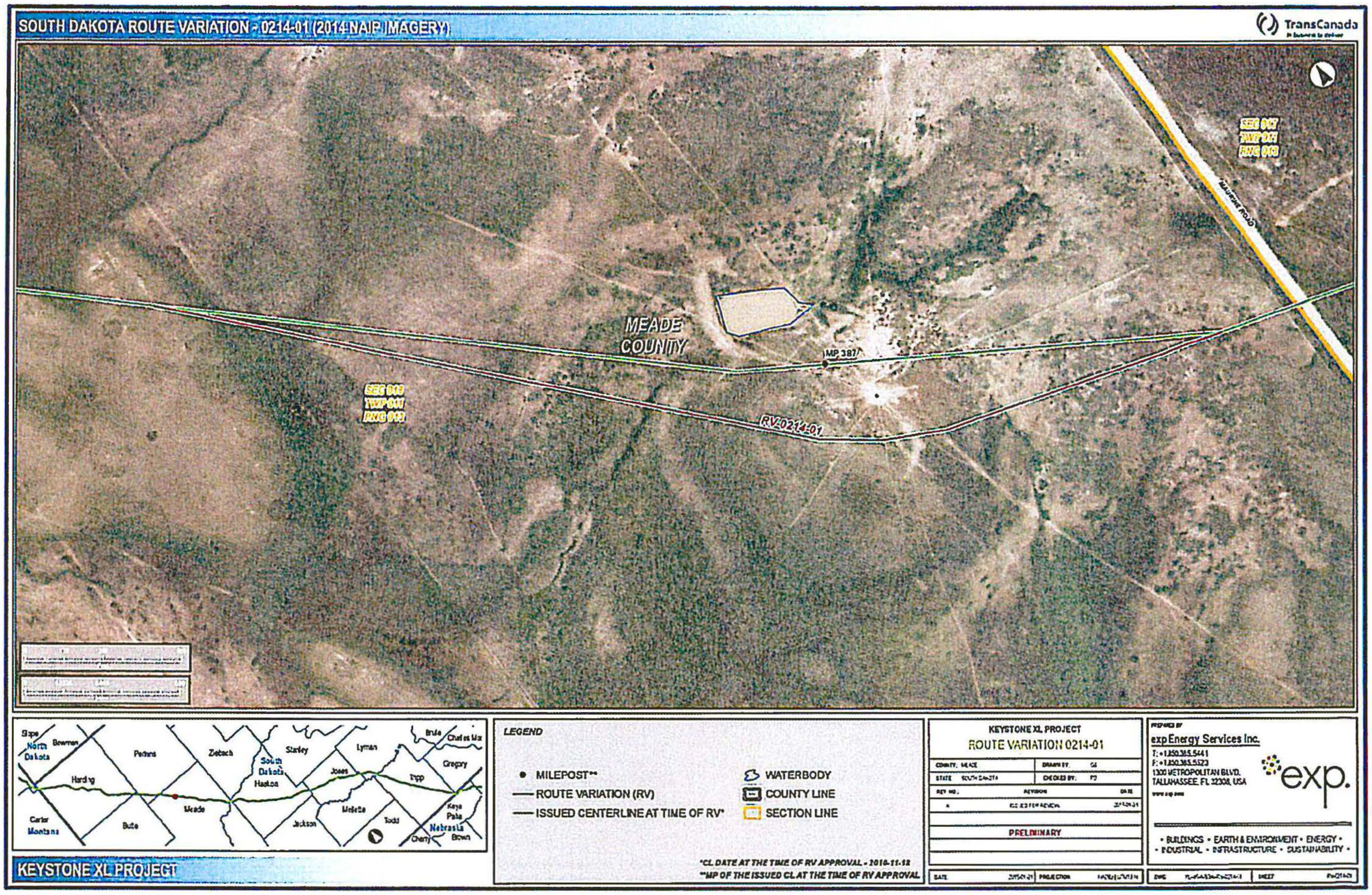

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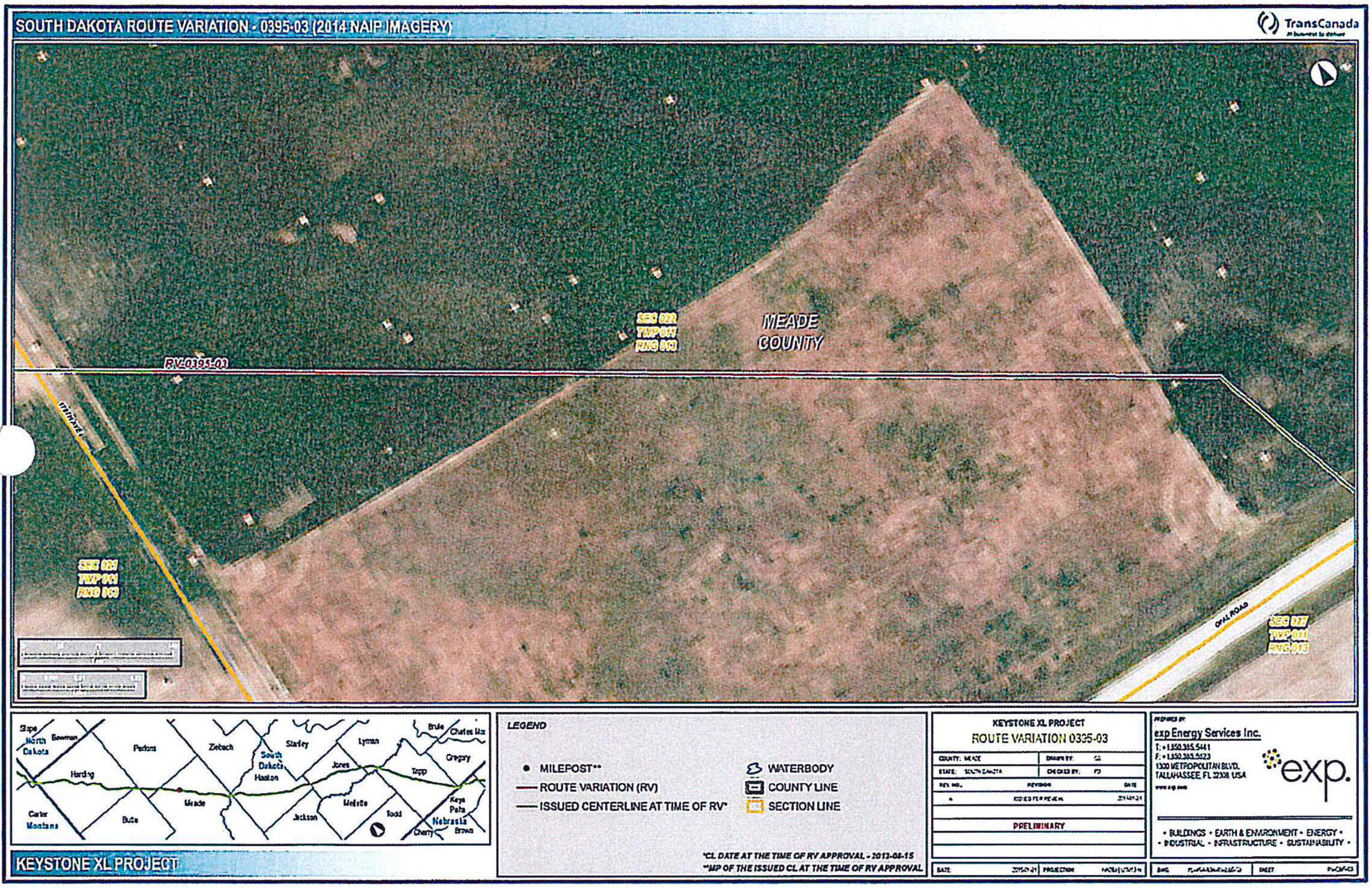

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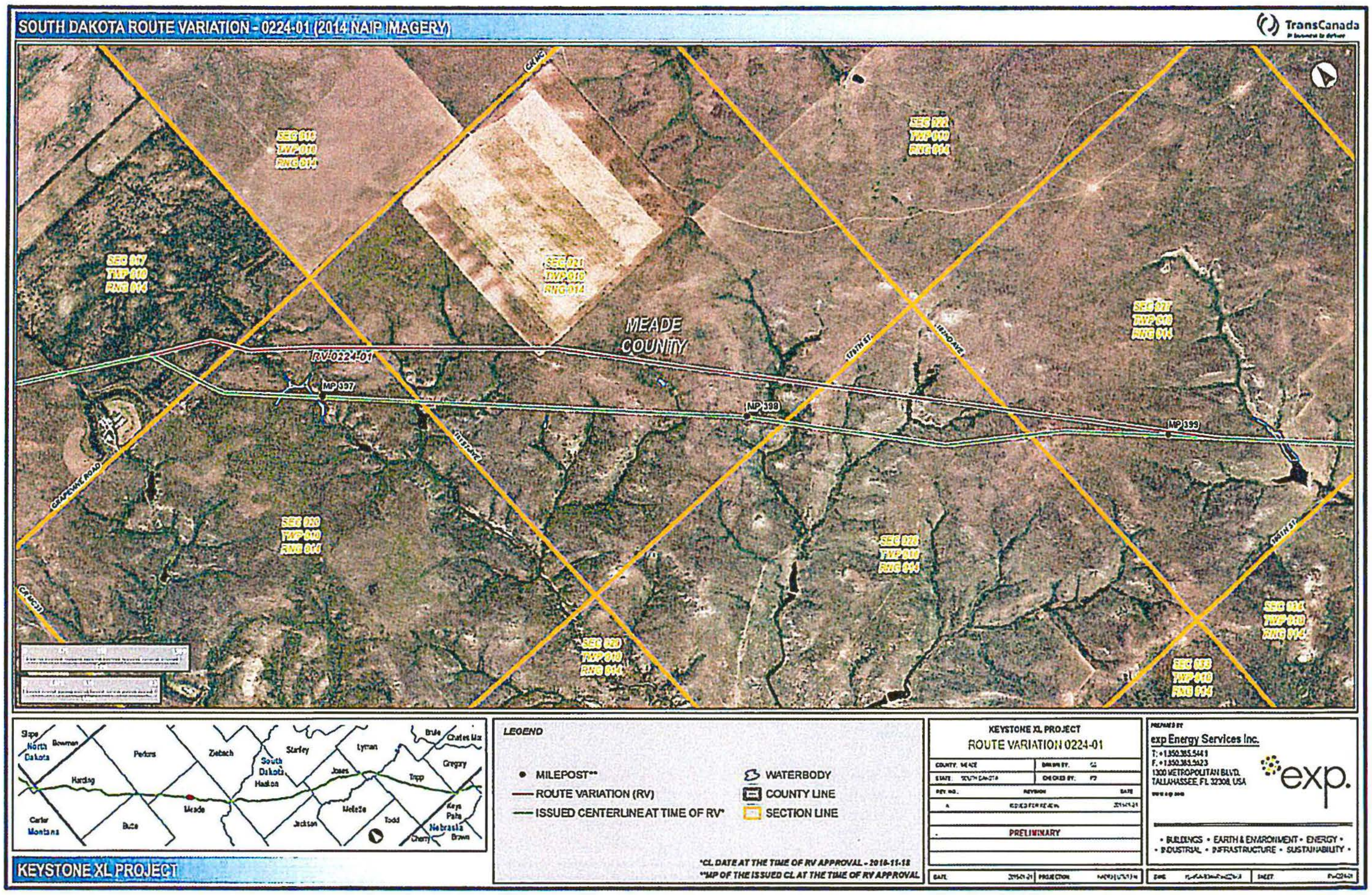

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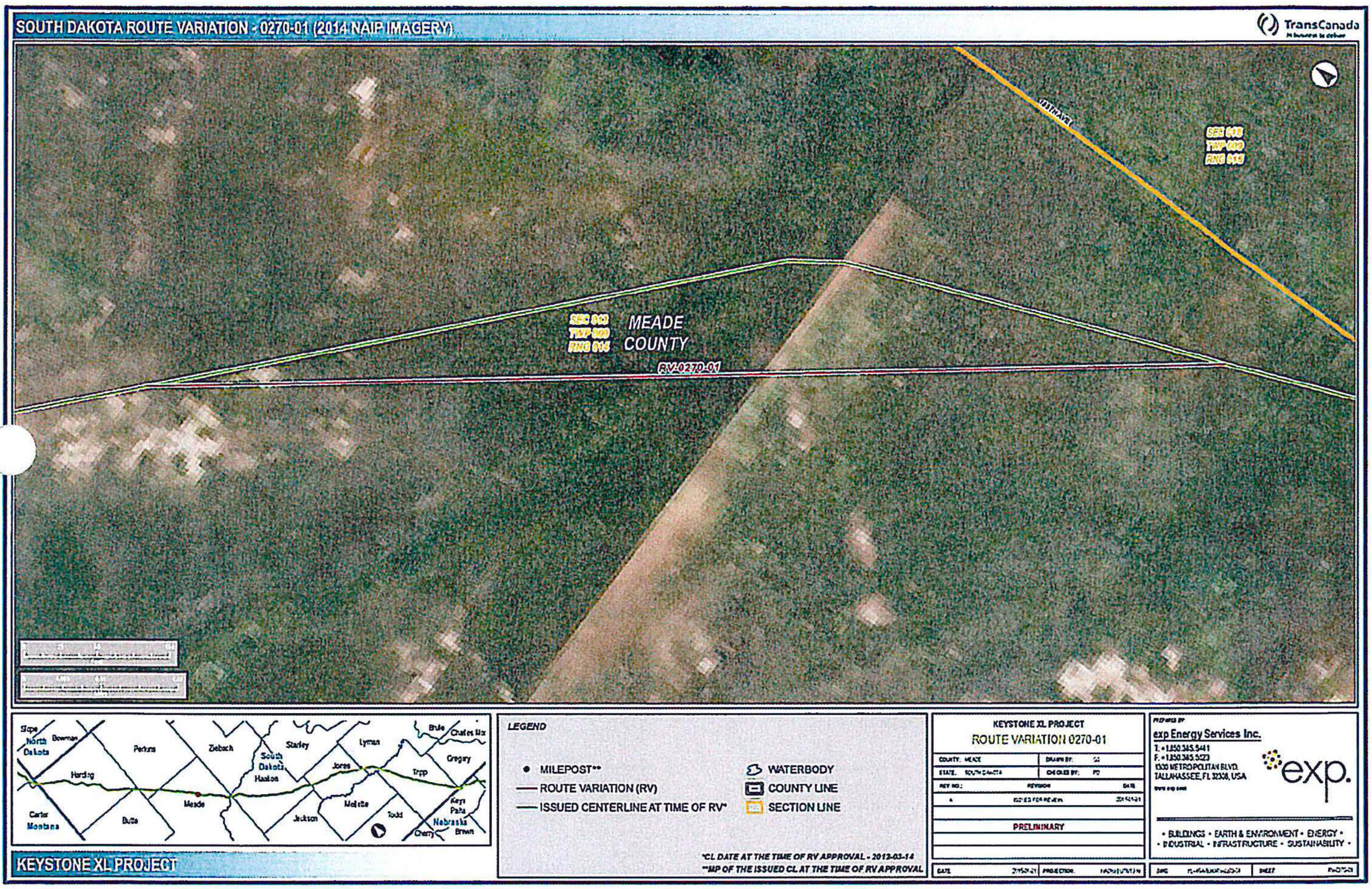

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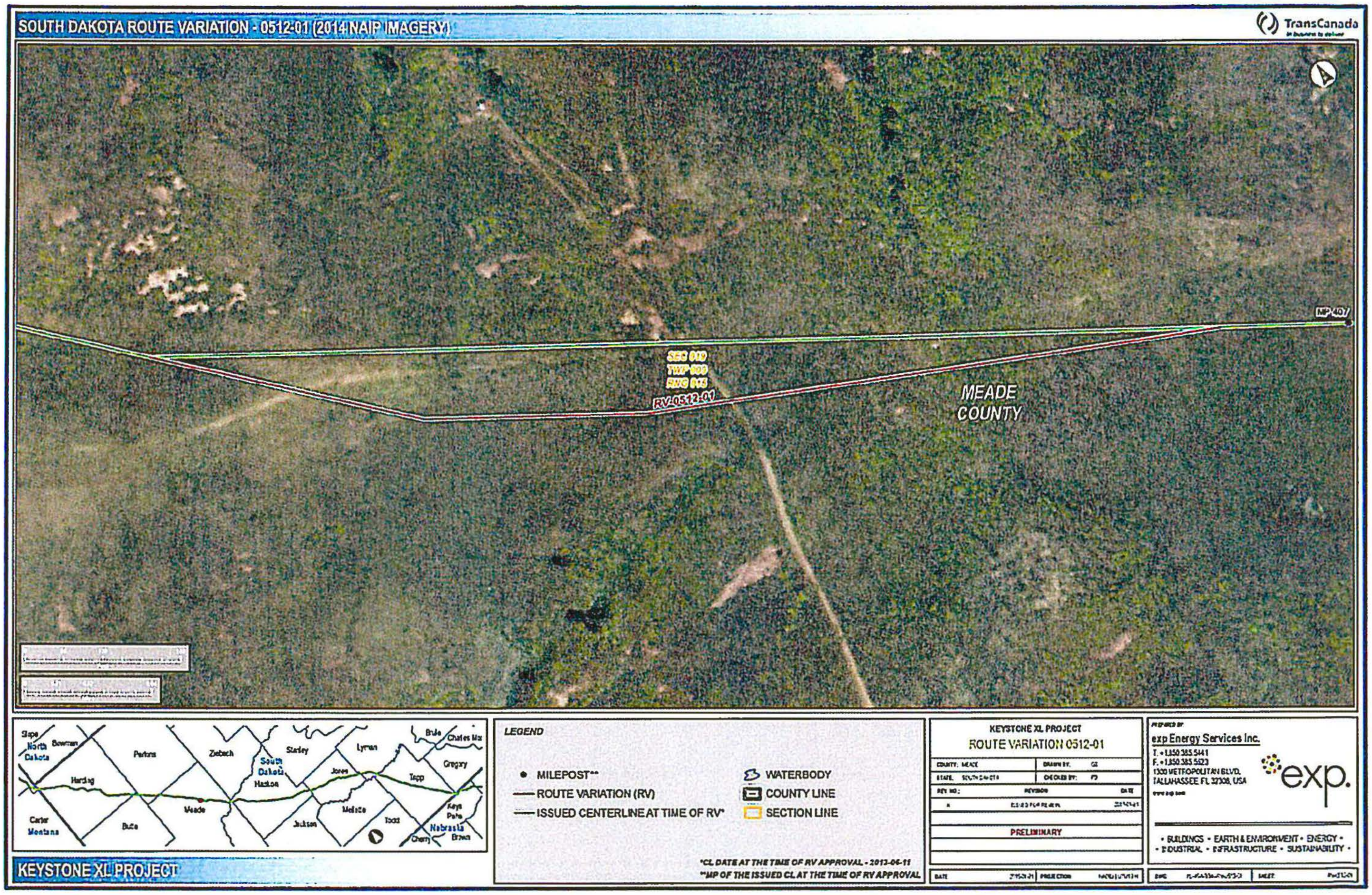

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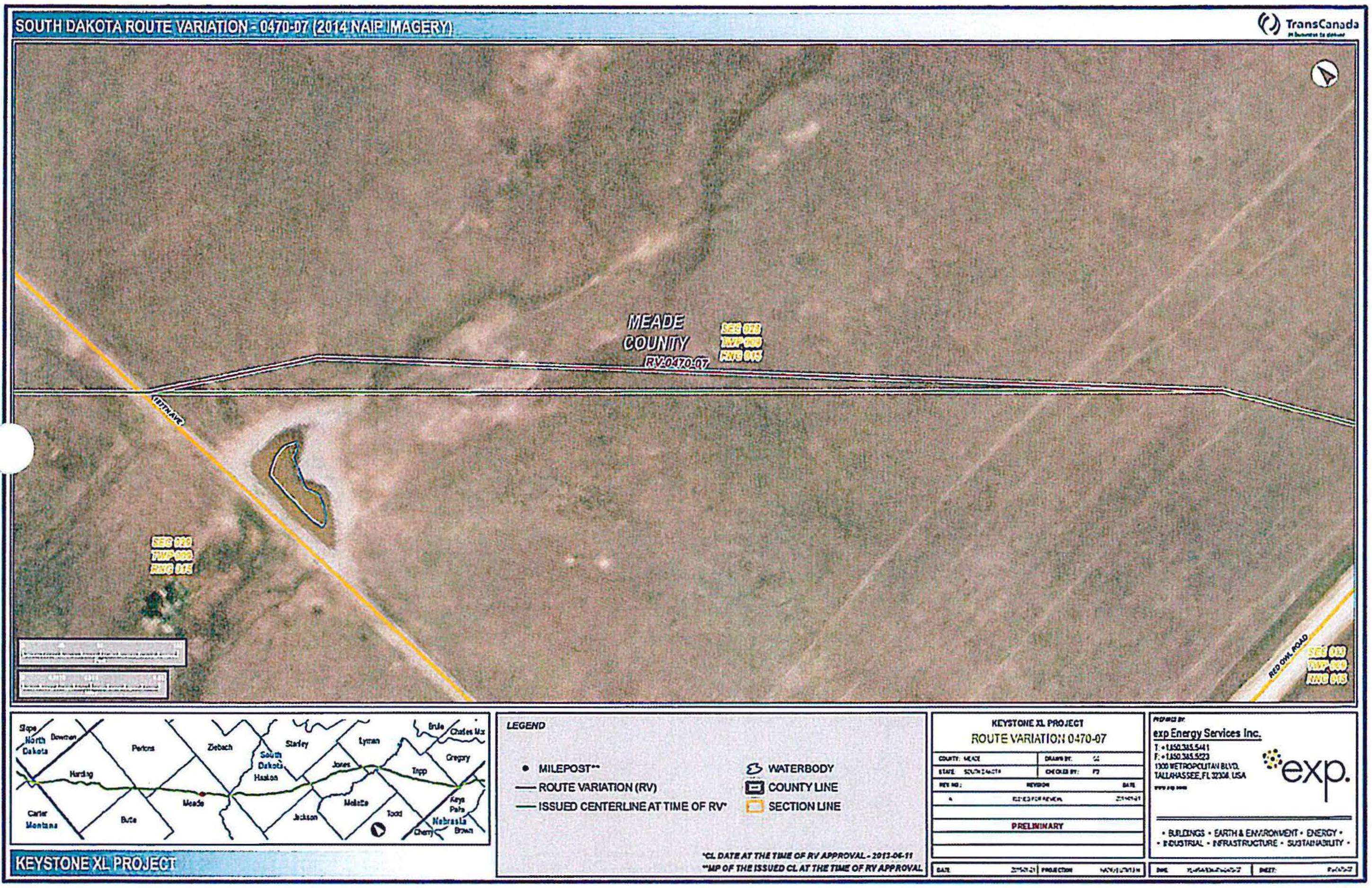

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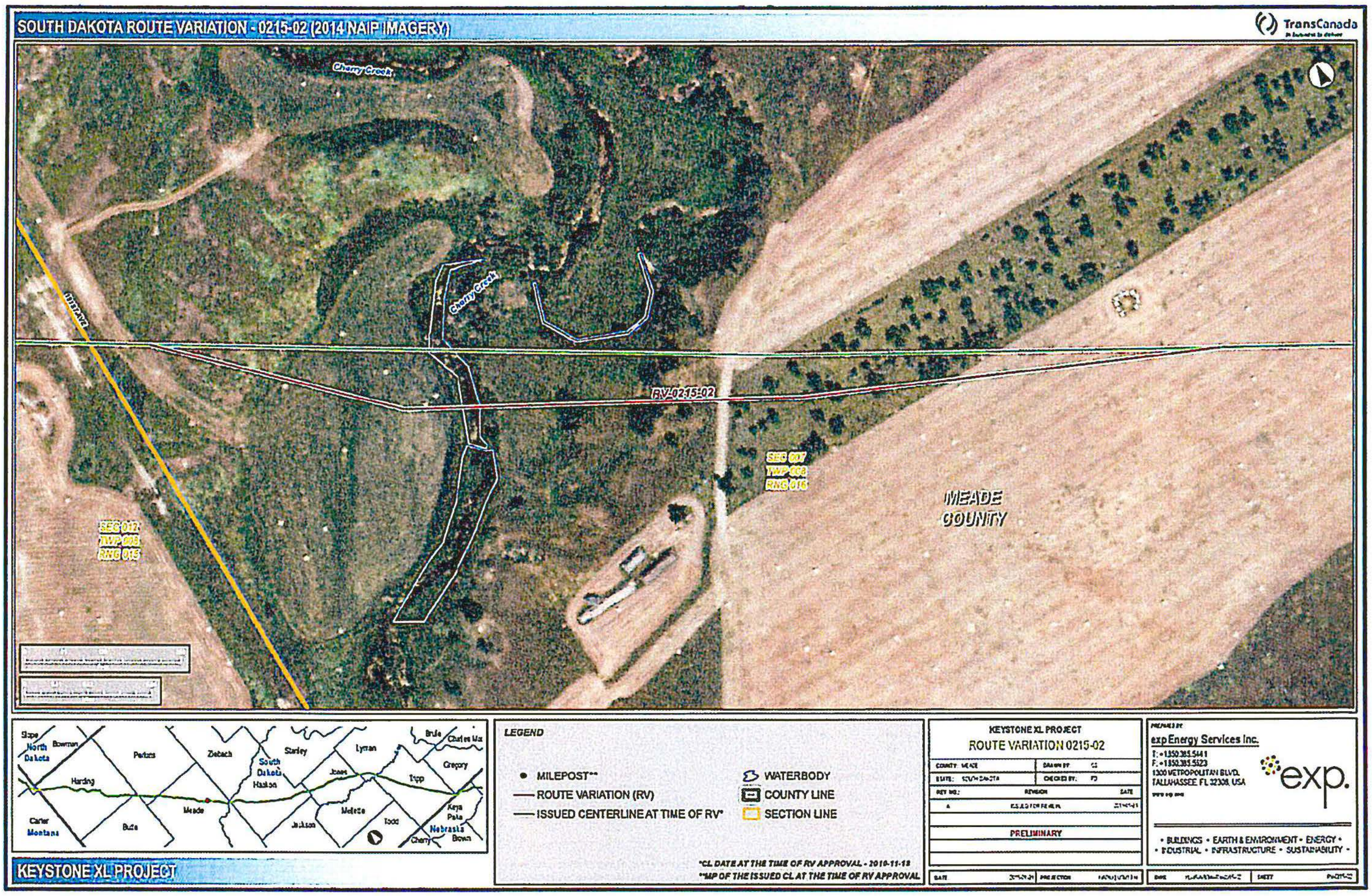

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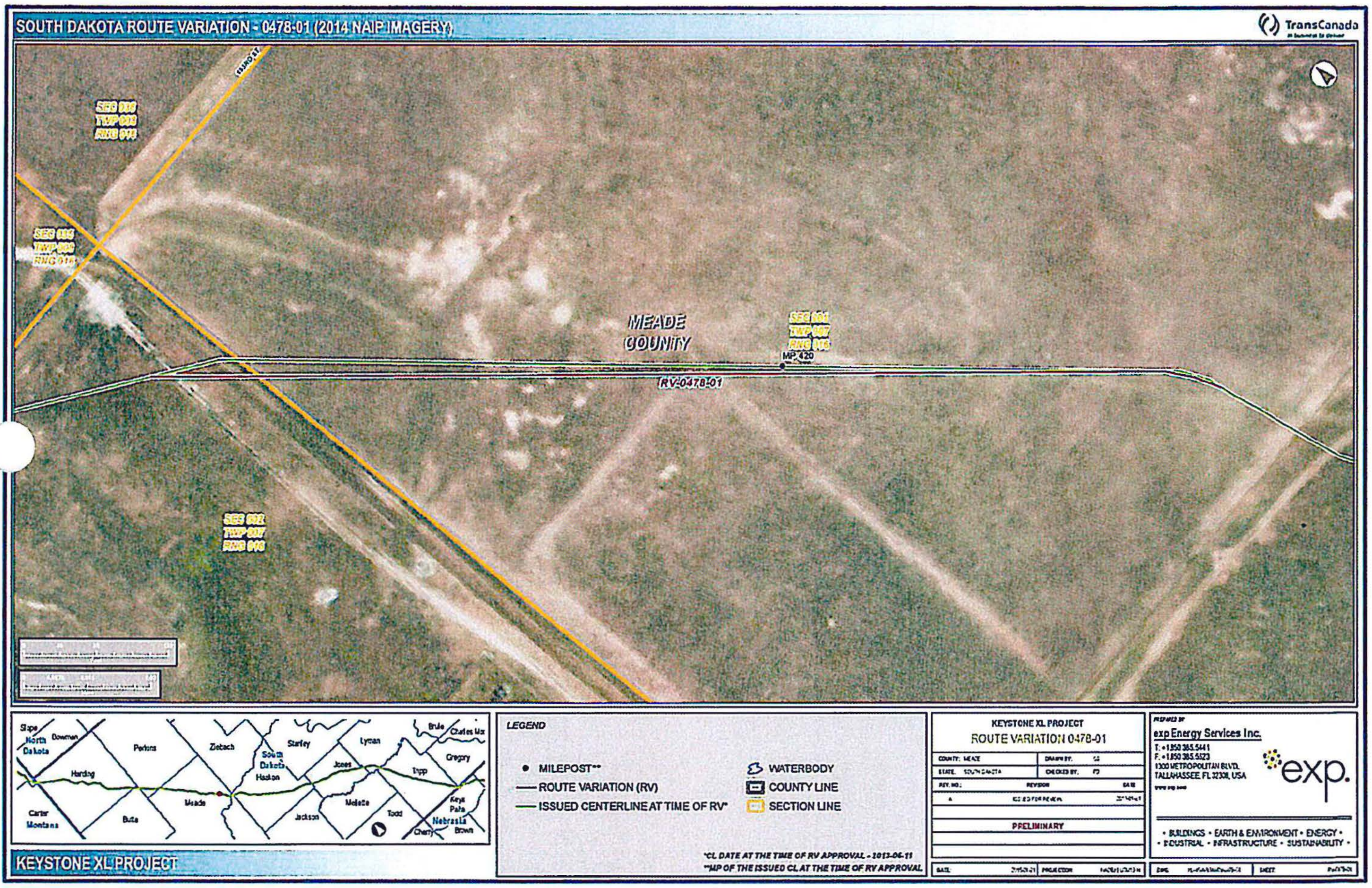

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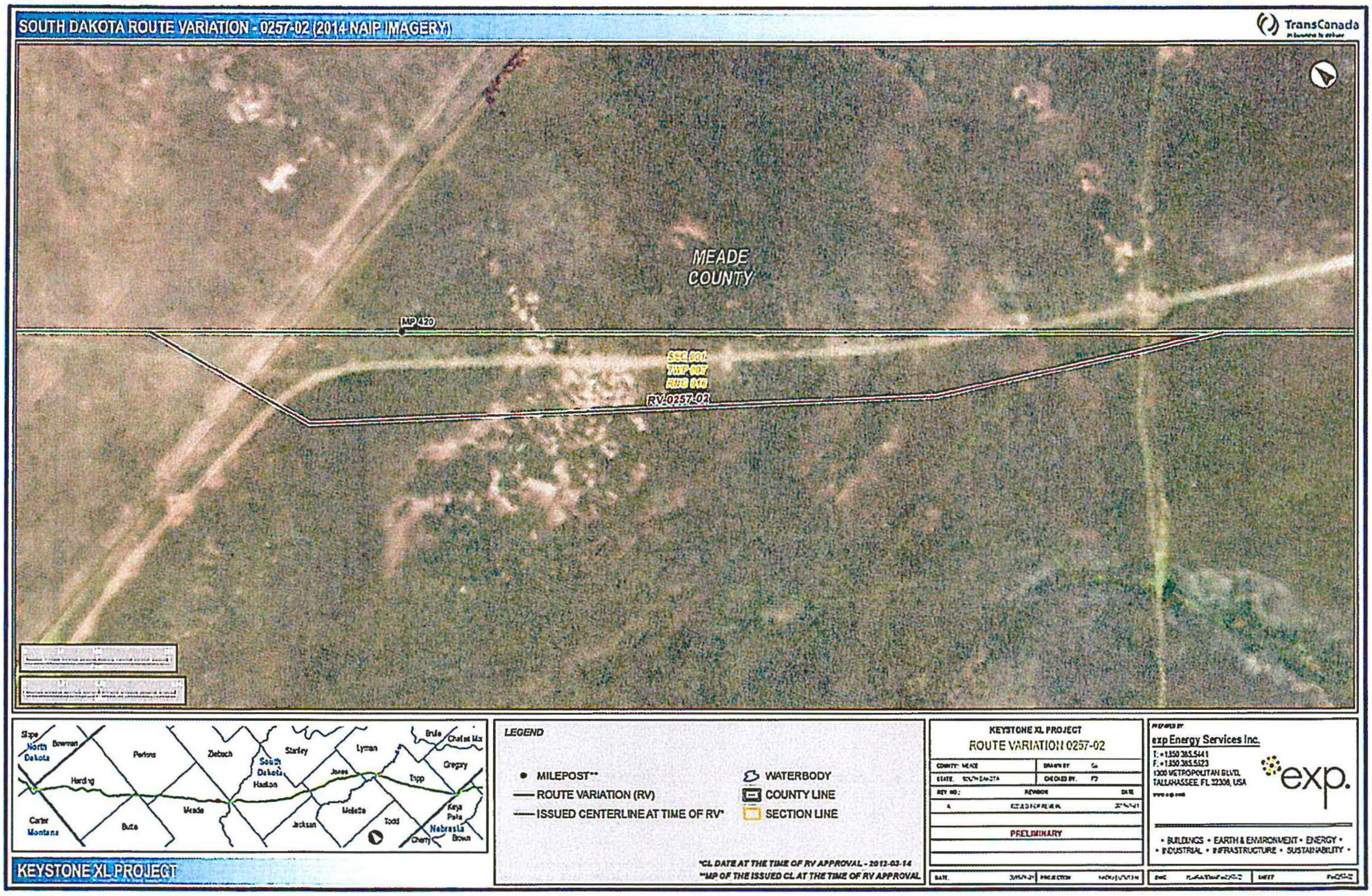

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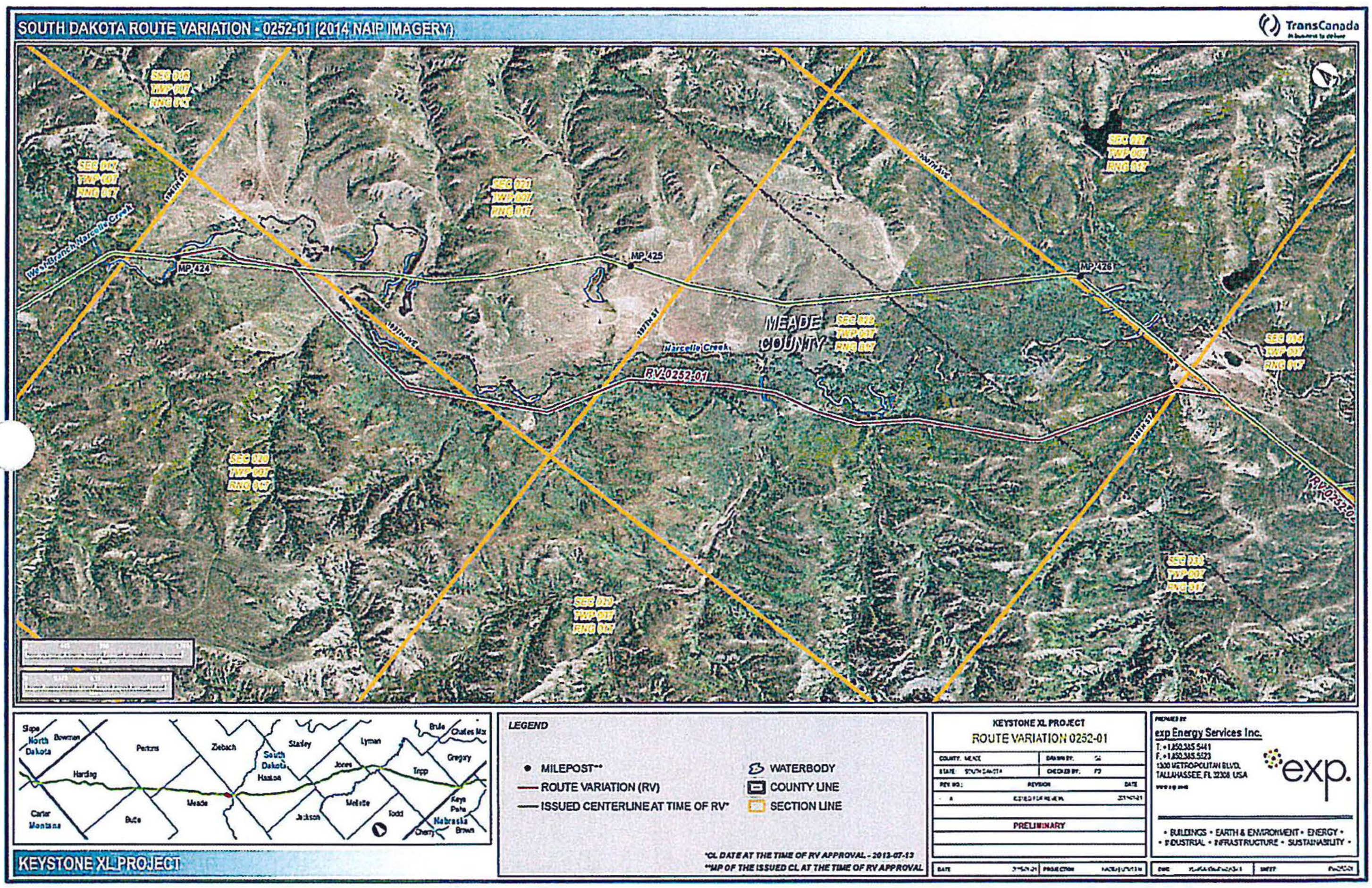

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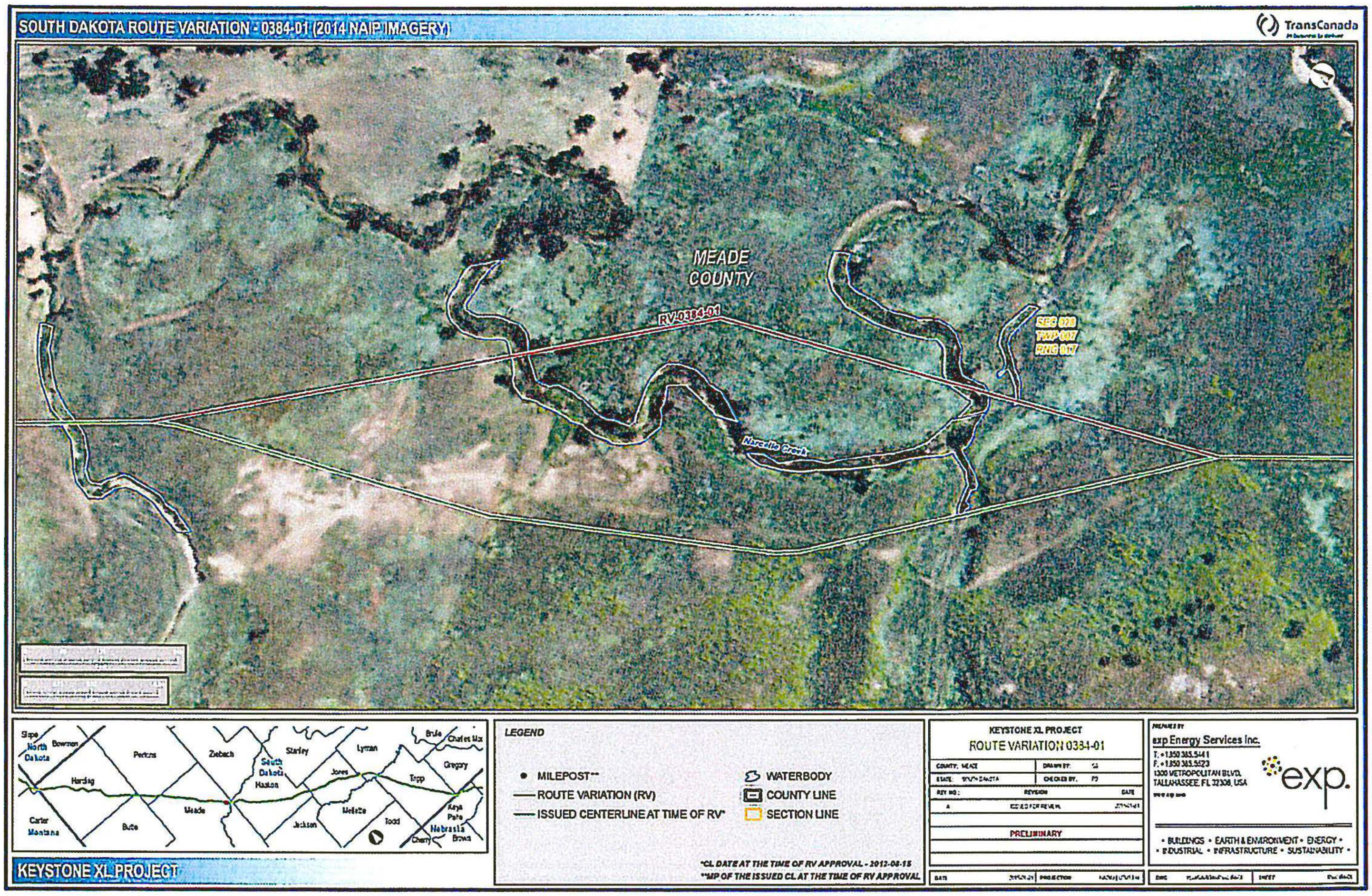

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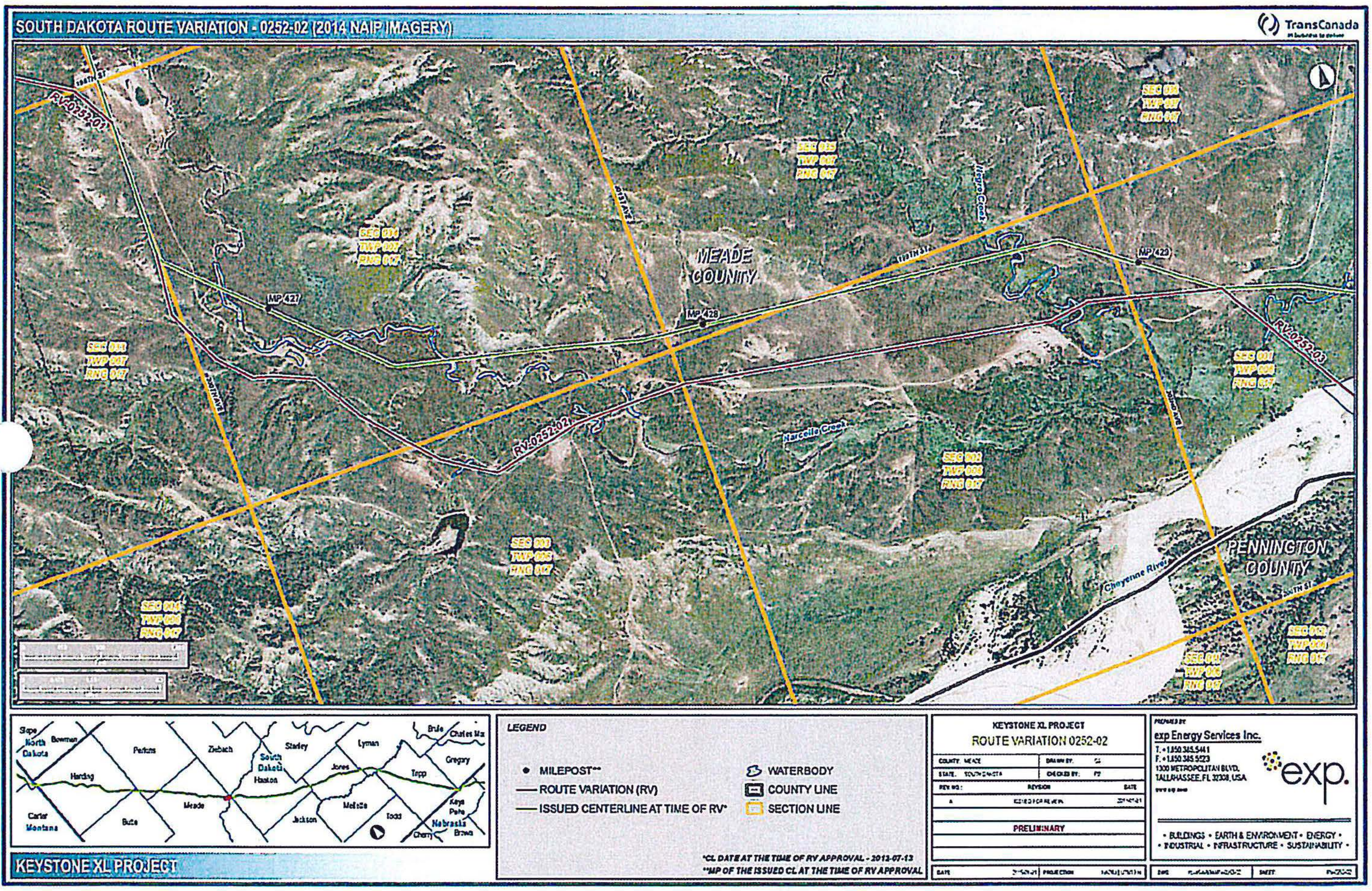

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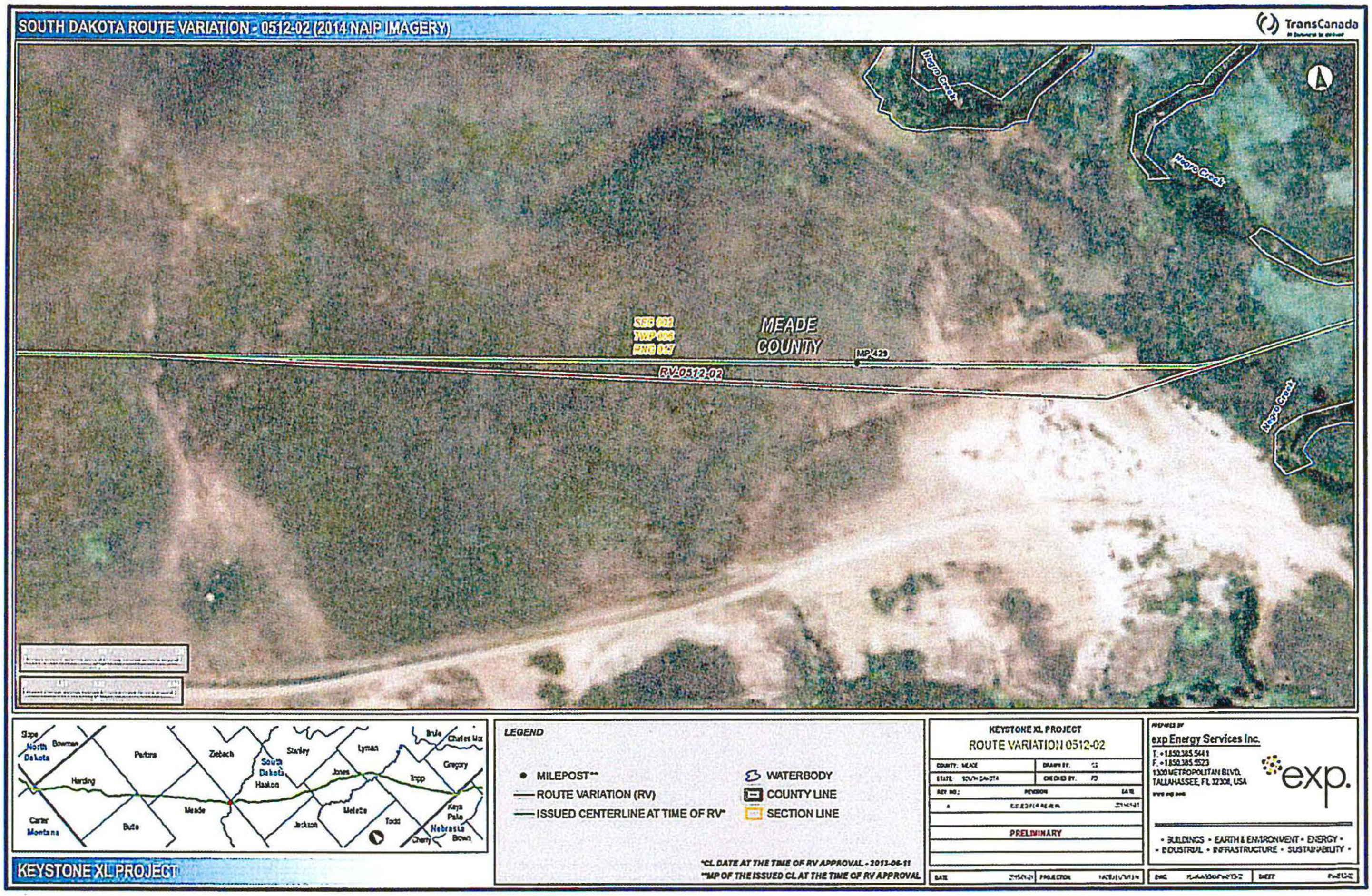

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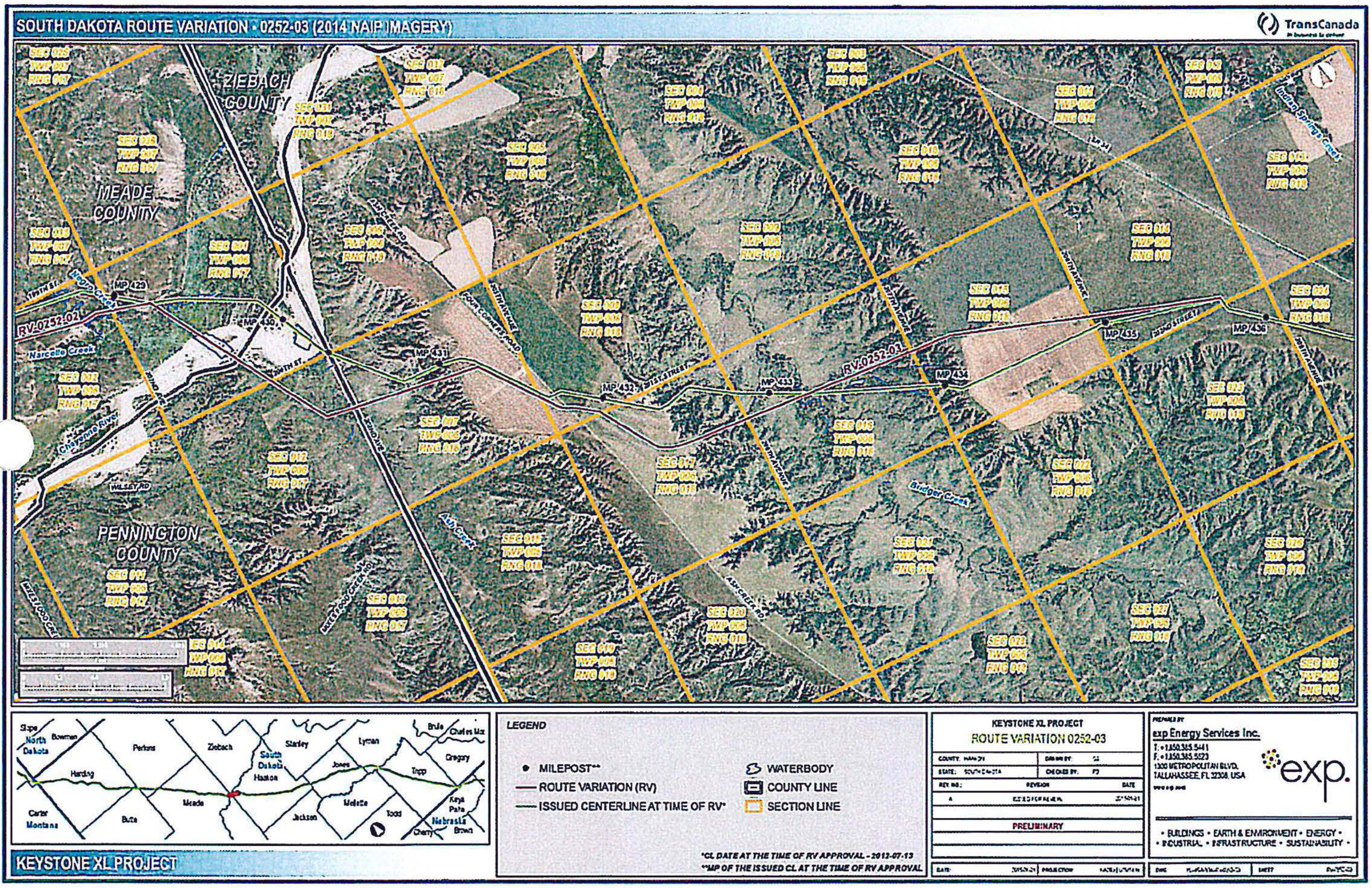
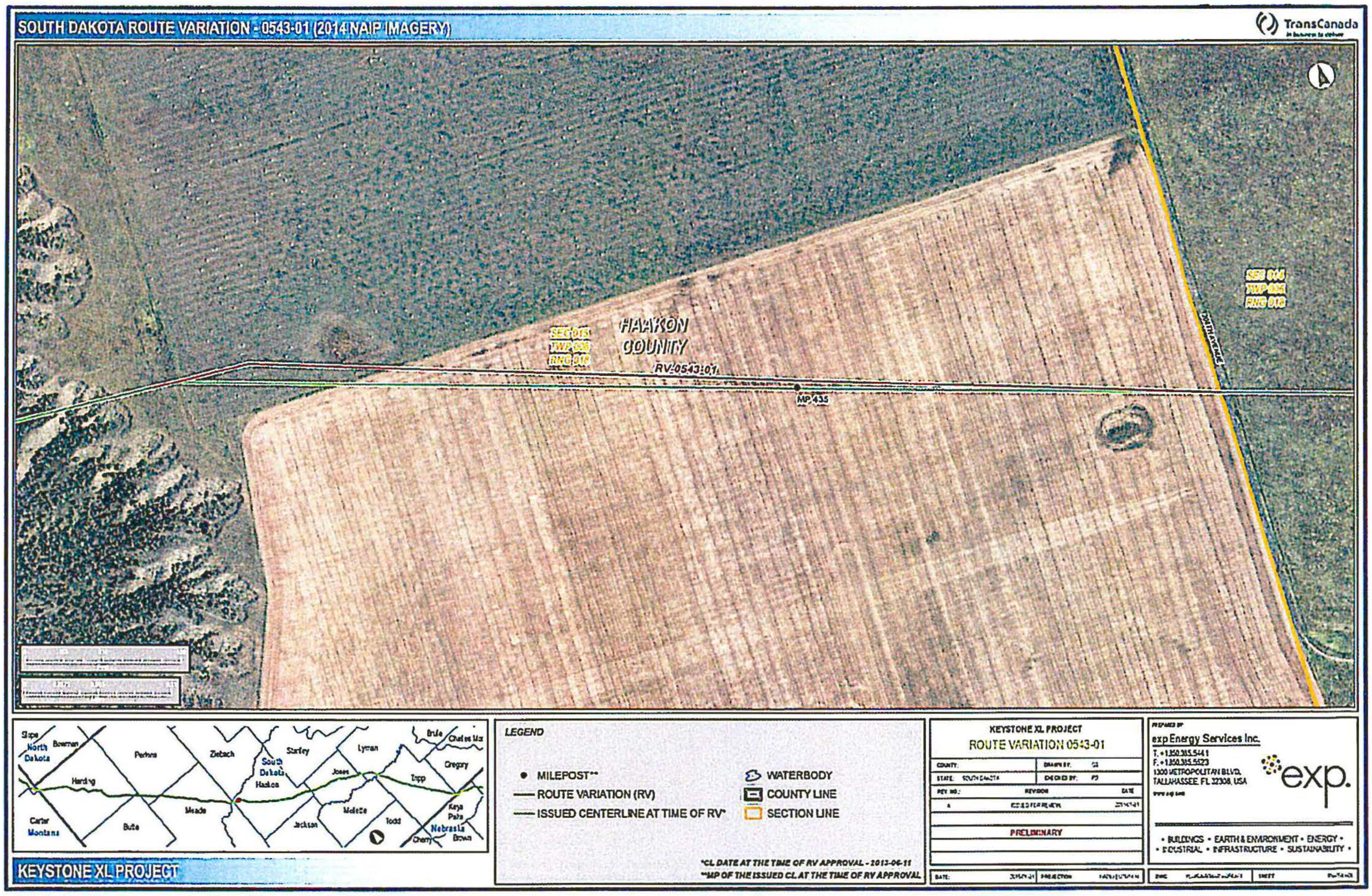

SOUTH DAKOTA ROUTE VARIATION - 0252-03 (2014 NAIP IMAGERY)
TransCanada
ZIEBACH COUNTY
MEADE COUNTY
PENNINGTON COUNTY
RV-0252-01
MP 429
MP 430
MP 431
MP 432
MP 433
MP 434
MP 435
MP 436
Narcelle Creek
Cheyenne River
Ash Creek
Badger Creek
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME 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 0252-03
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 •
North Dakota
South Dakota
Nebraska
Montana
Harding
Perkins
Ziebach
Meade
Haakon
Stanley
Jones
Lyman
Tripp
Mellette
Jackson
Butte
Gregory
Todd
KEYSTONE XL PROJECT



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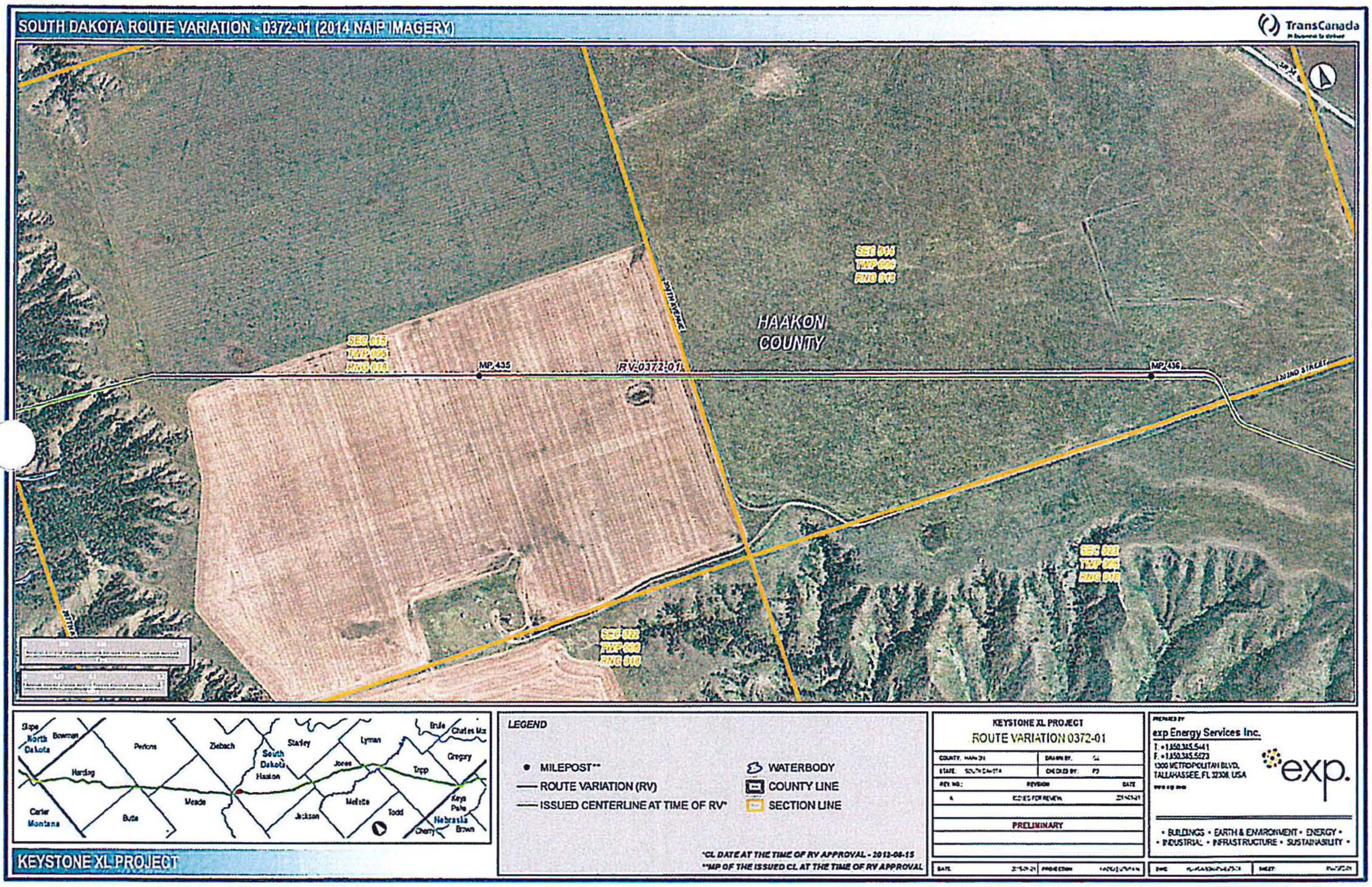

KEYSTONE 0520

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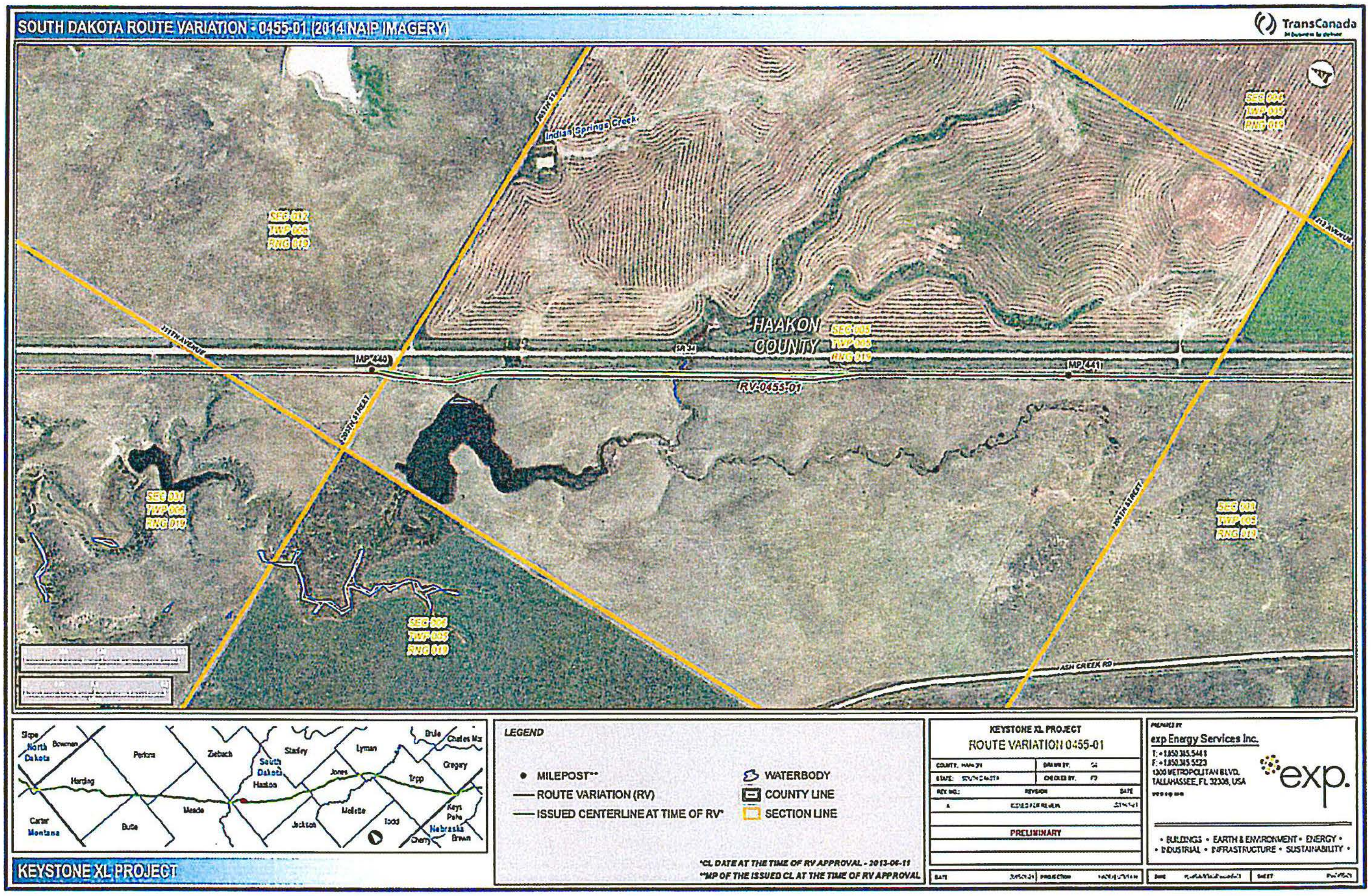

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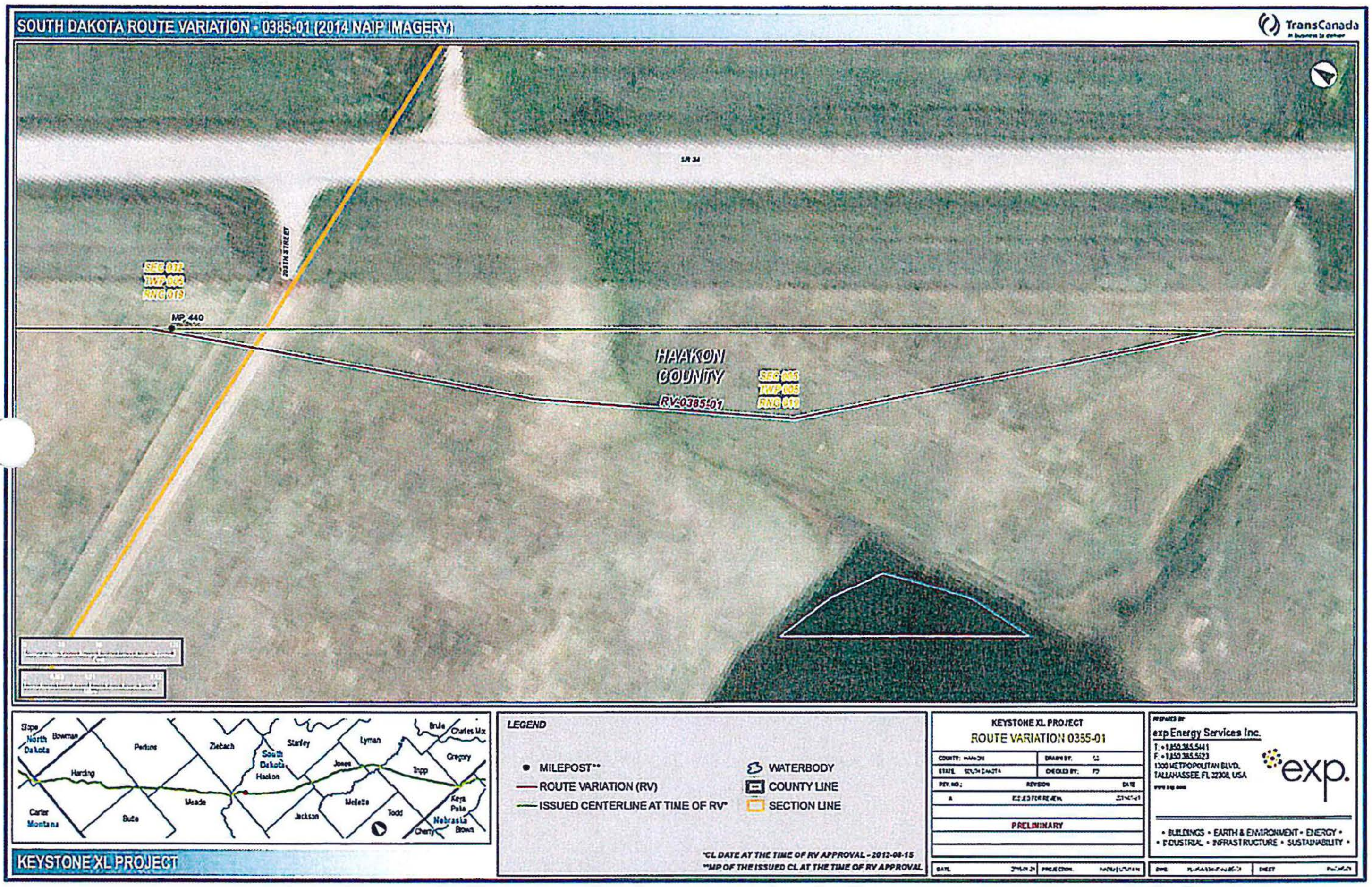

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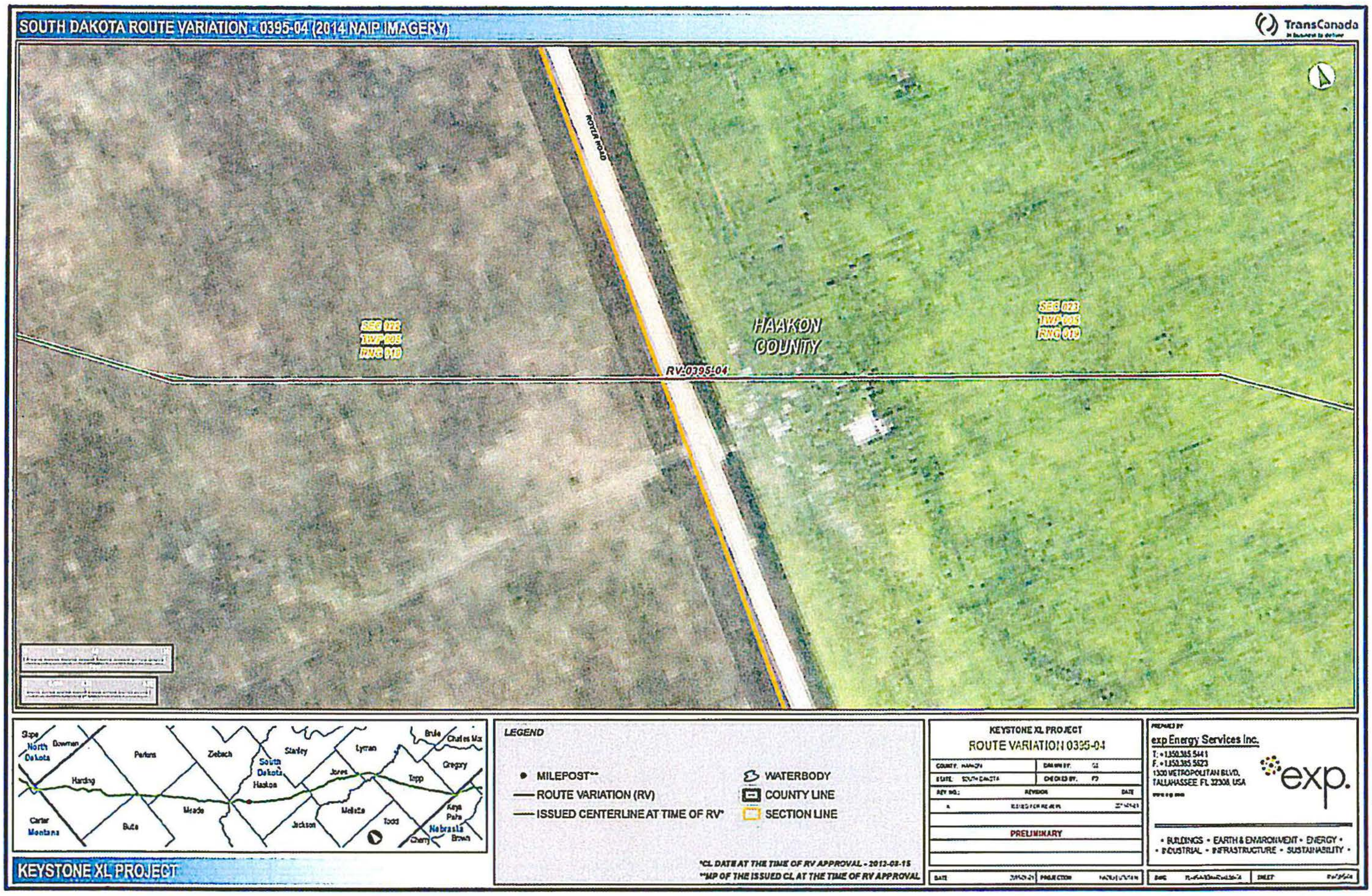

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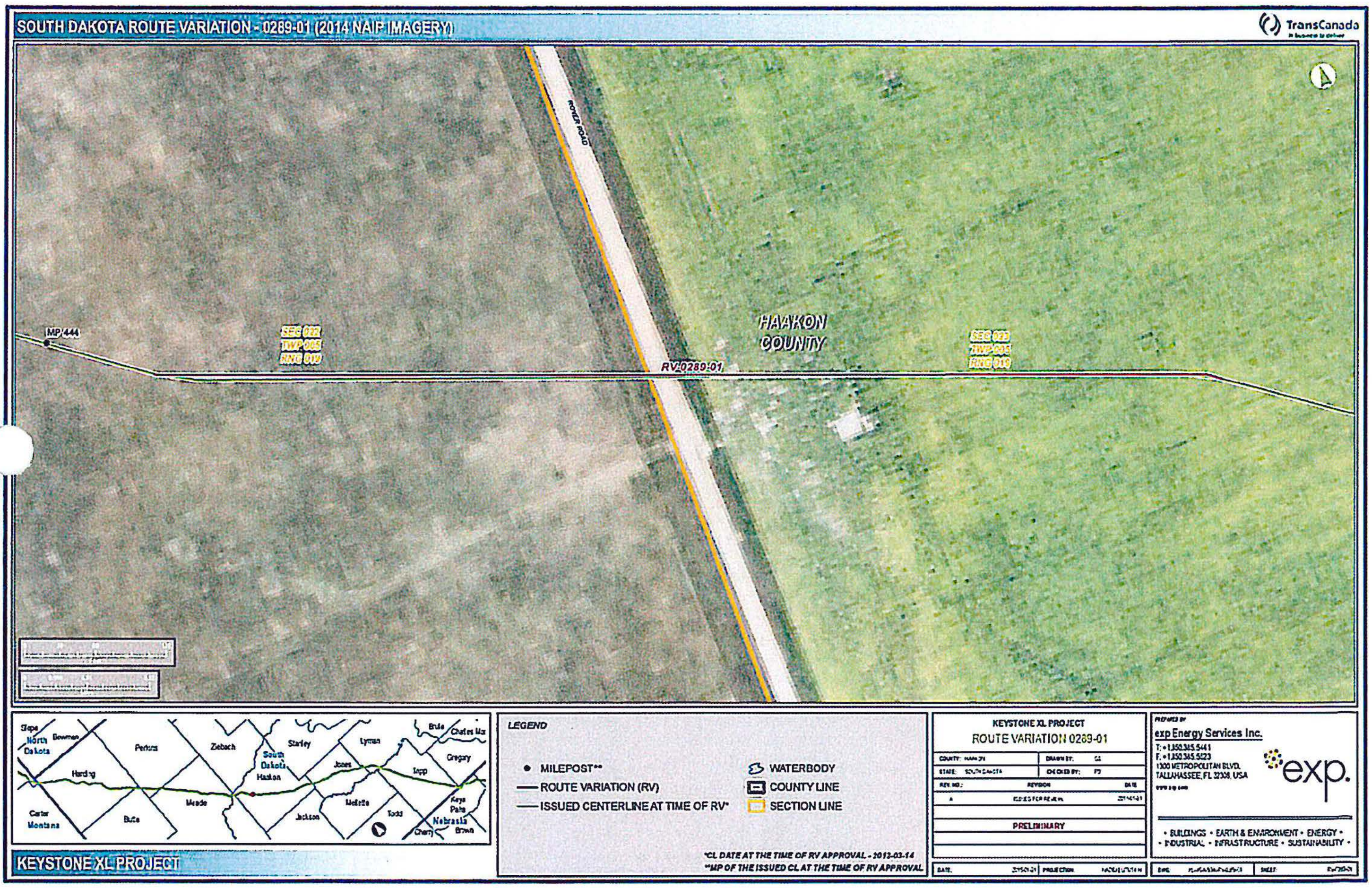

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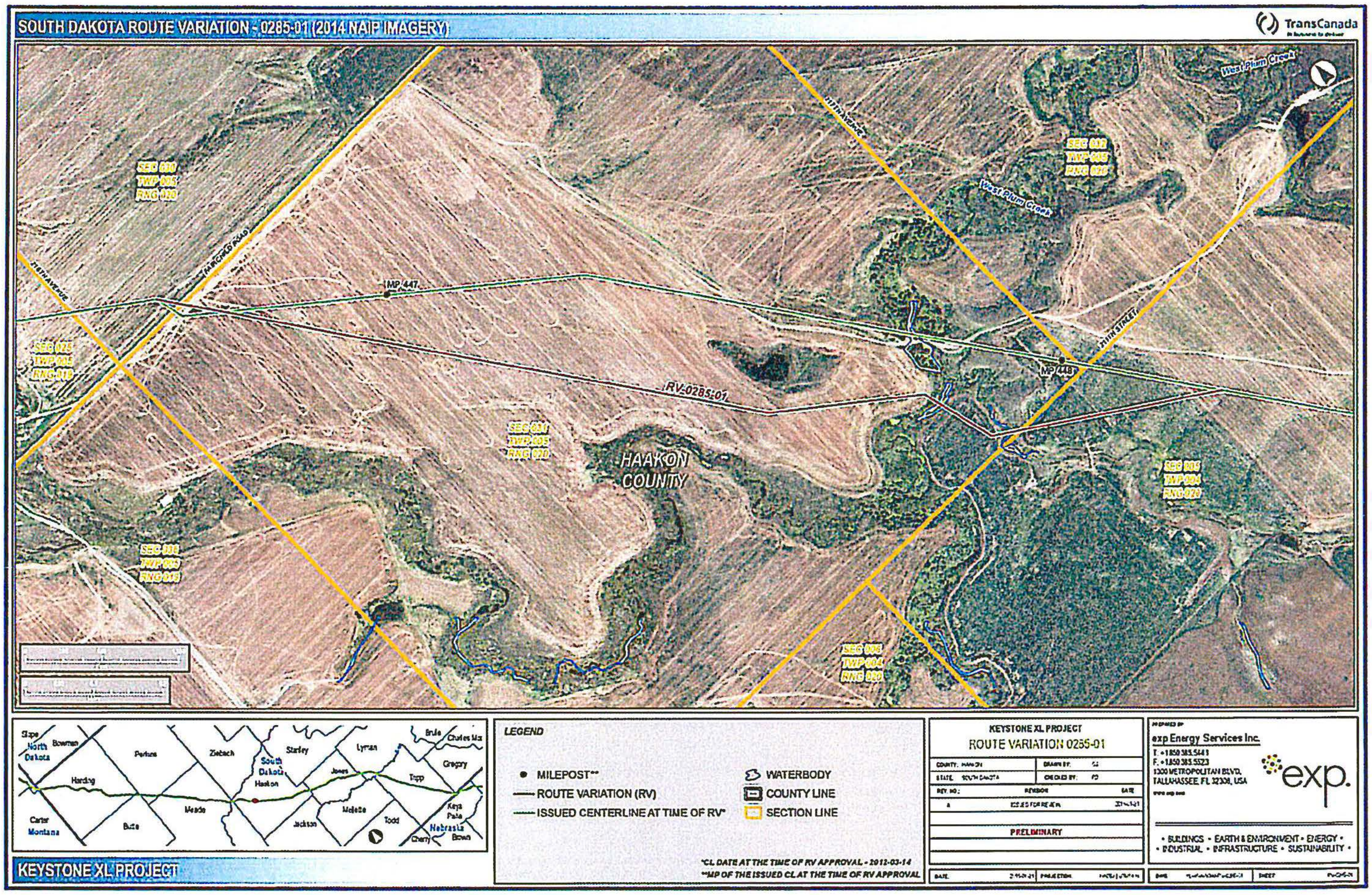

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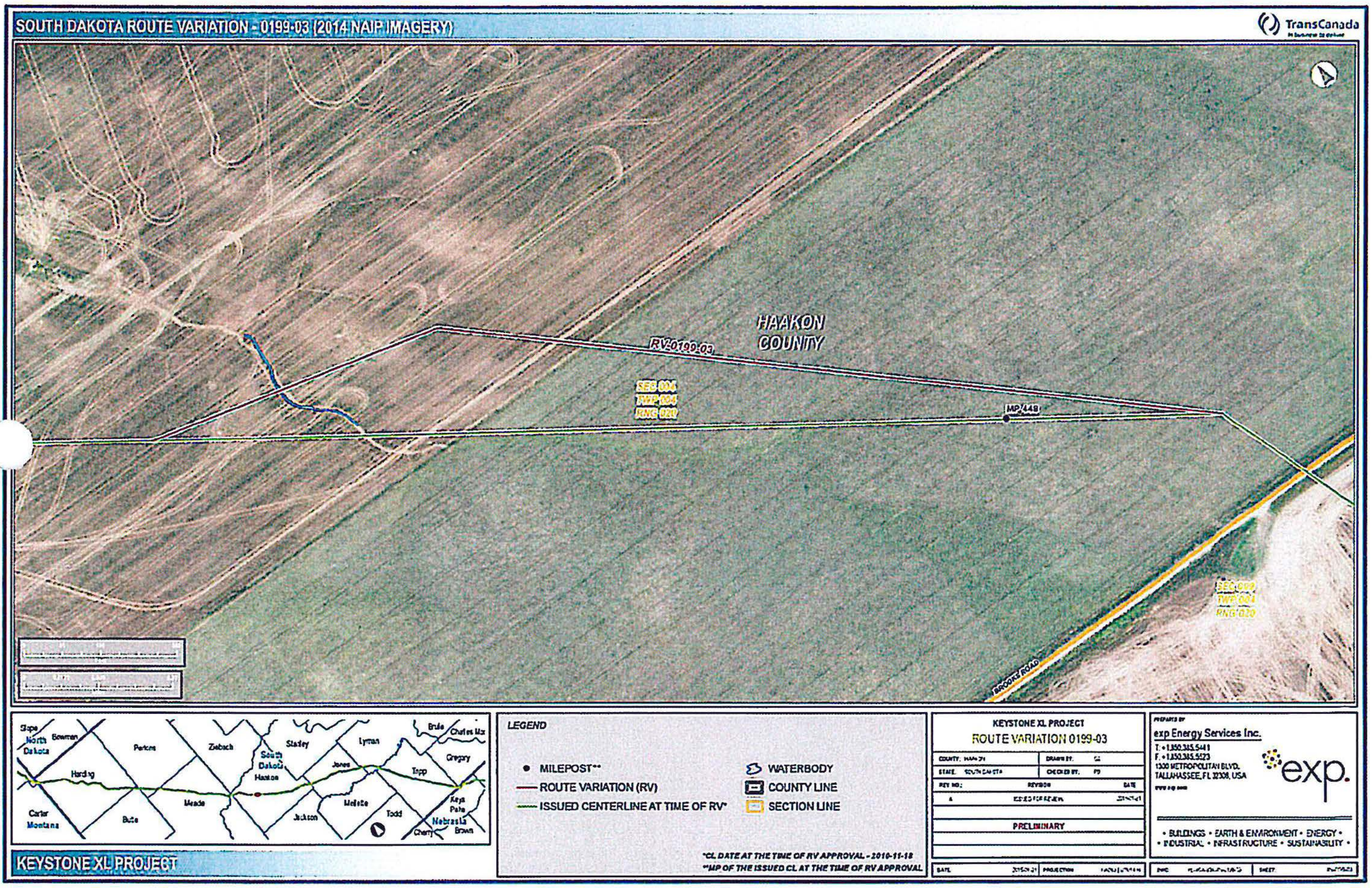

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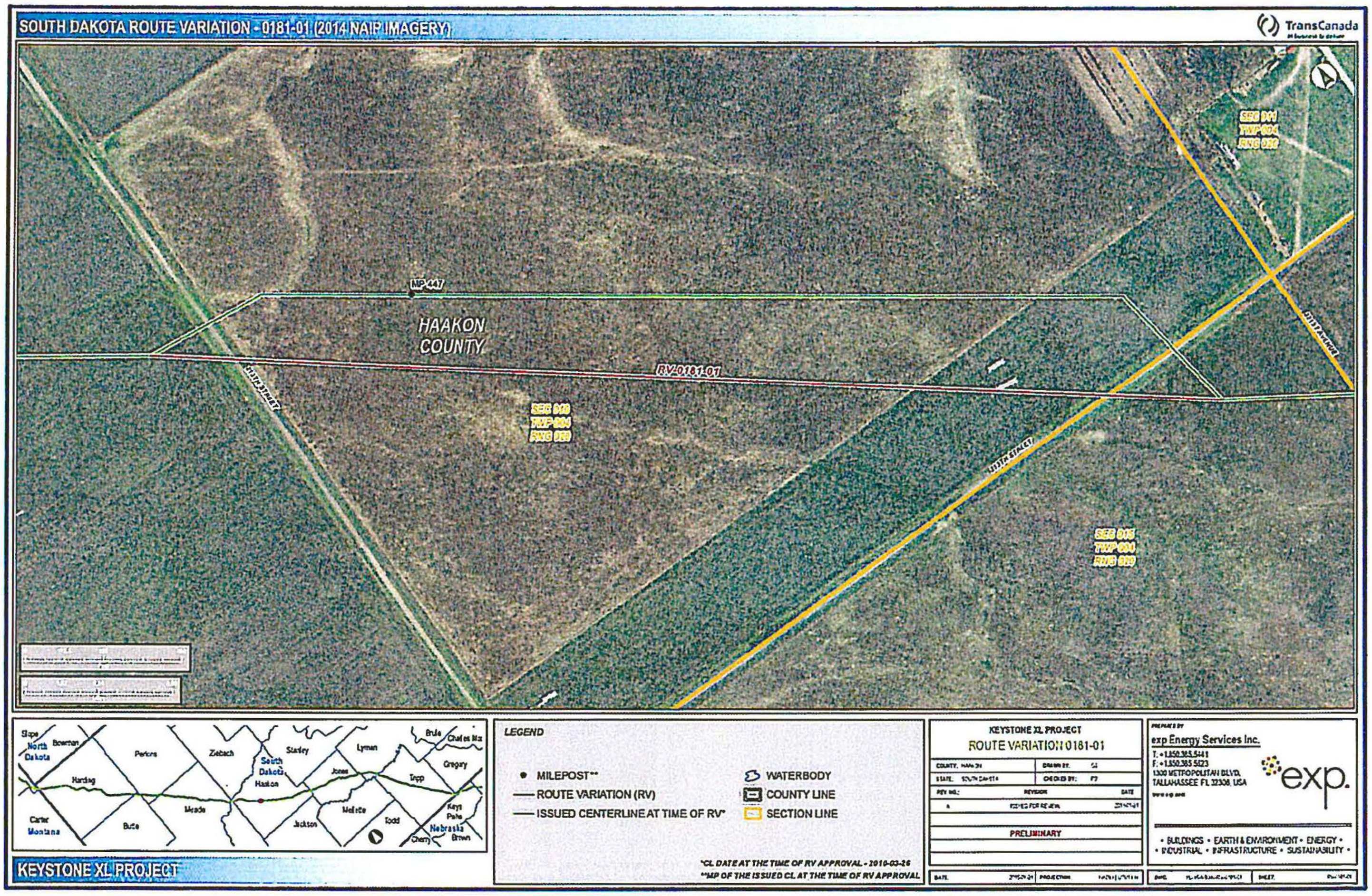

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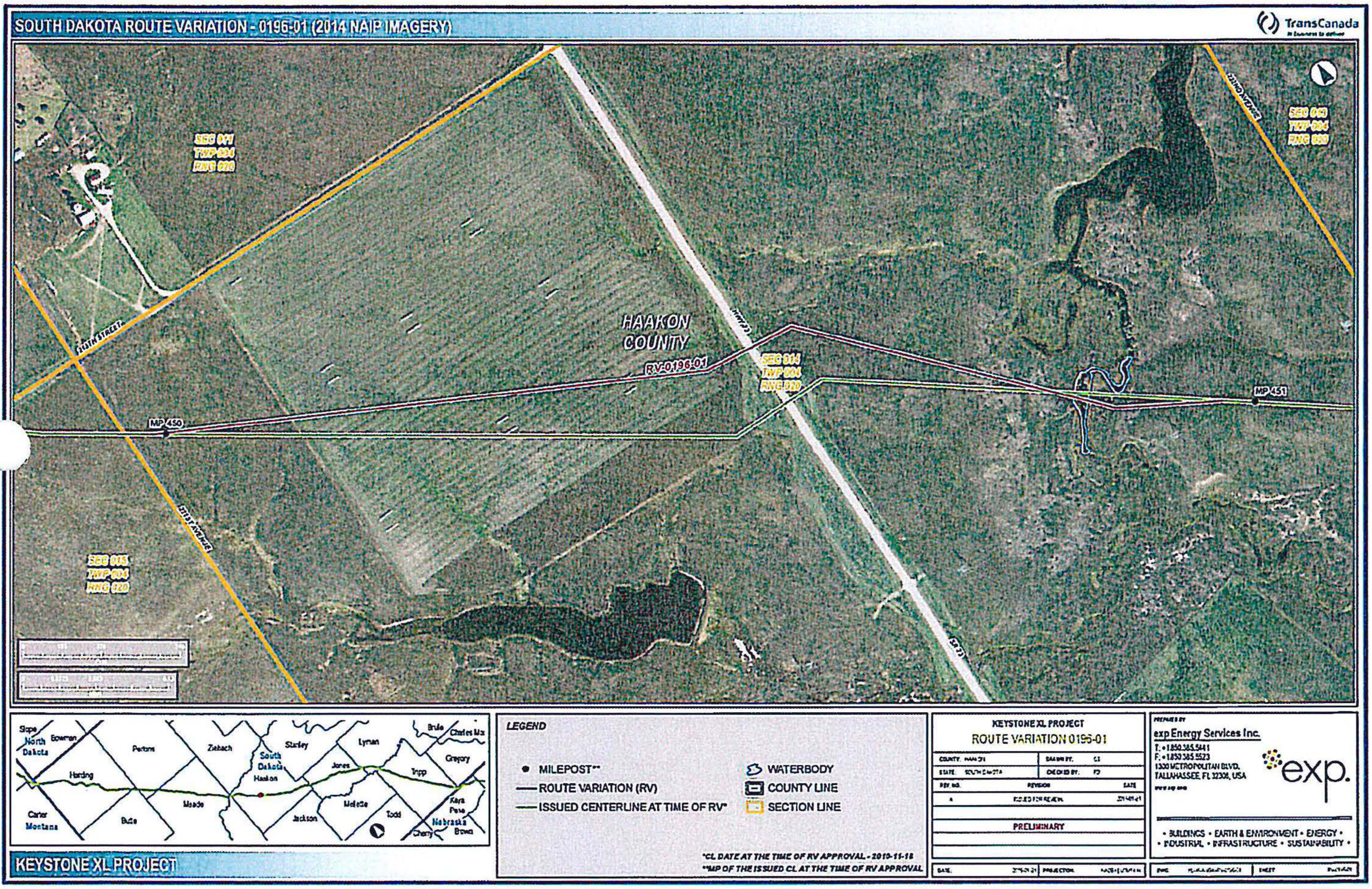

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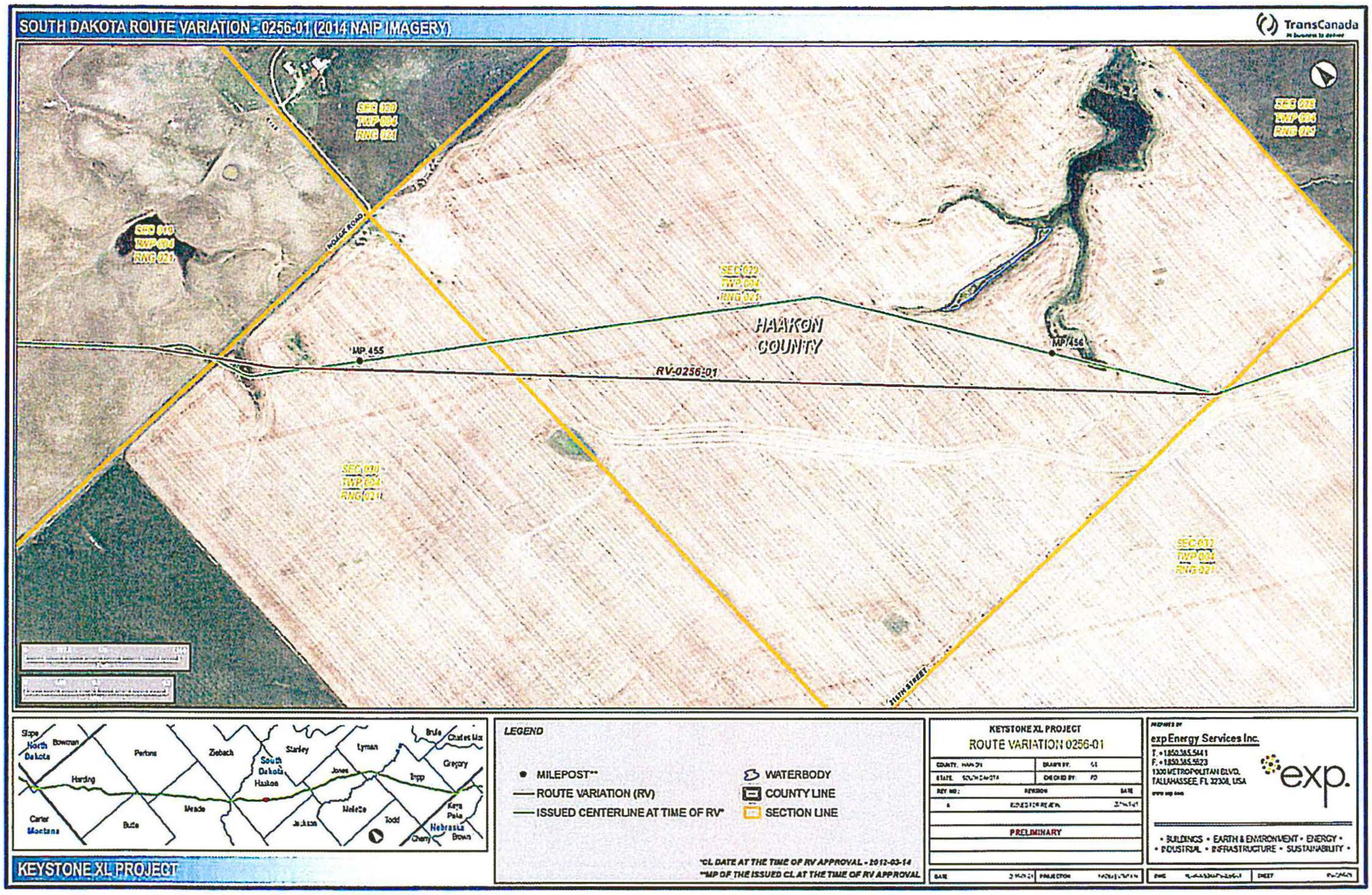

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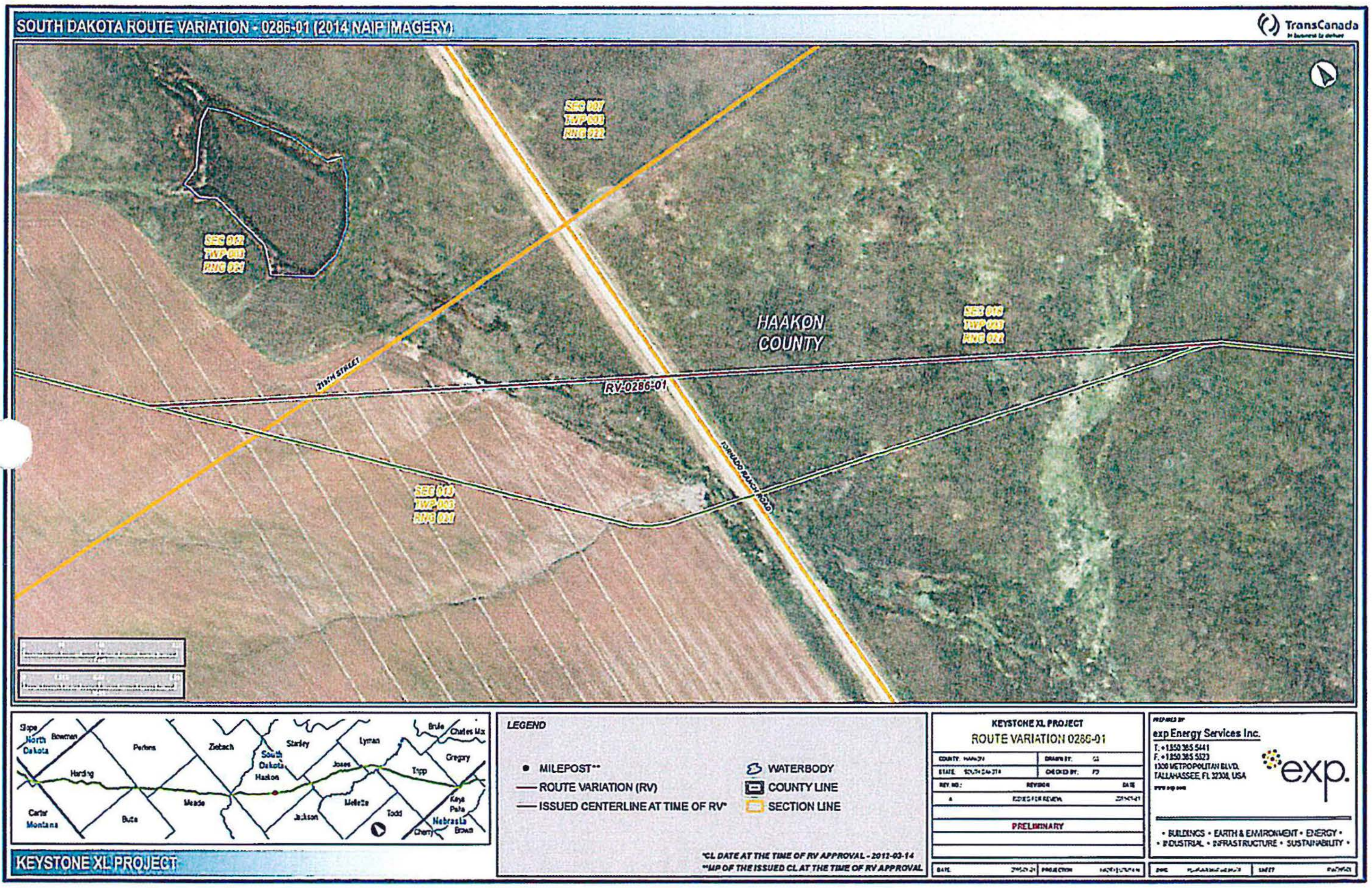

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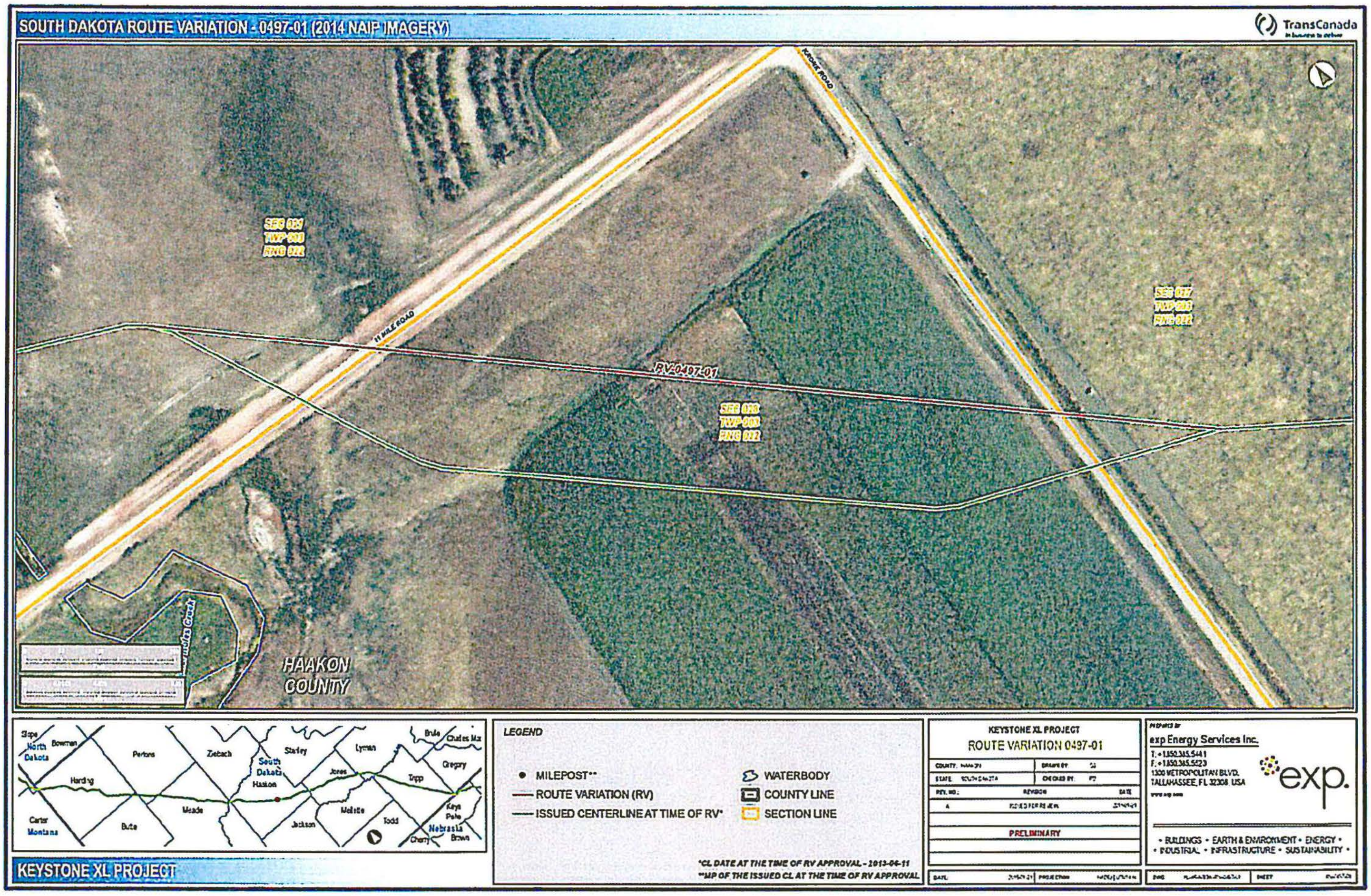

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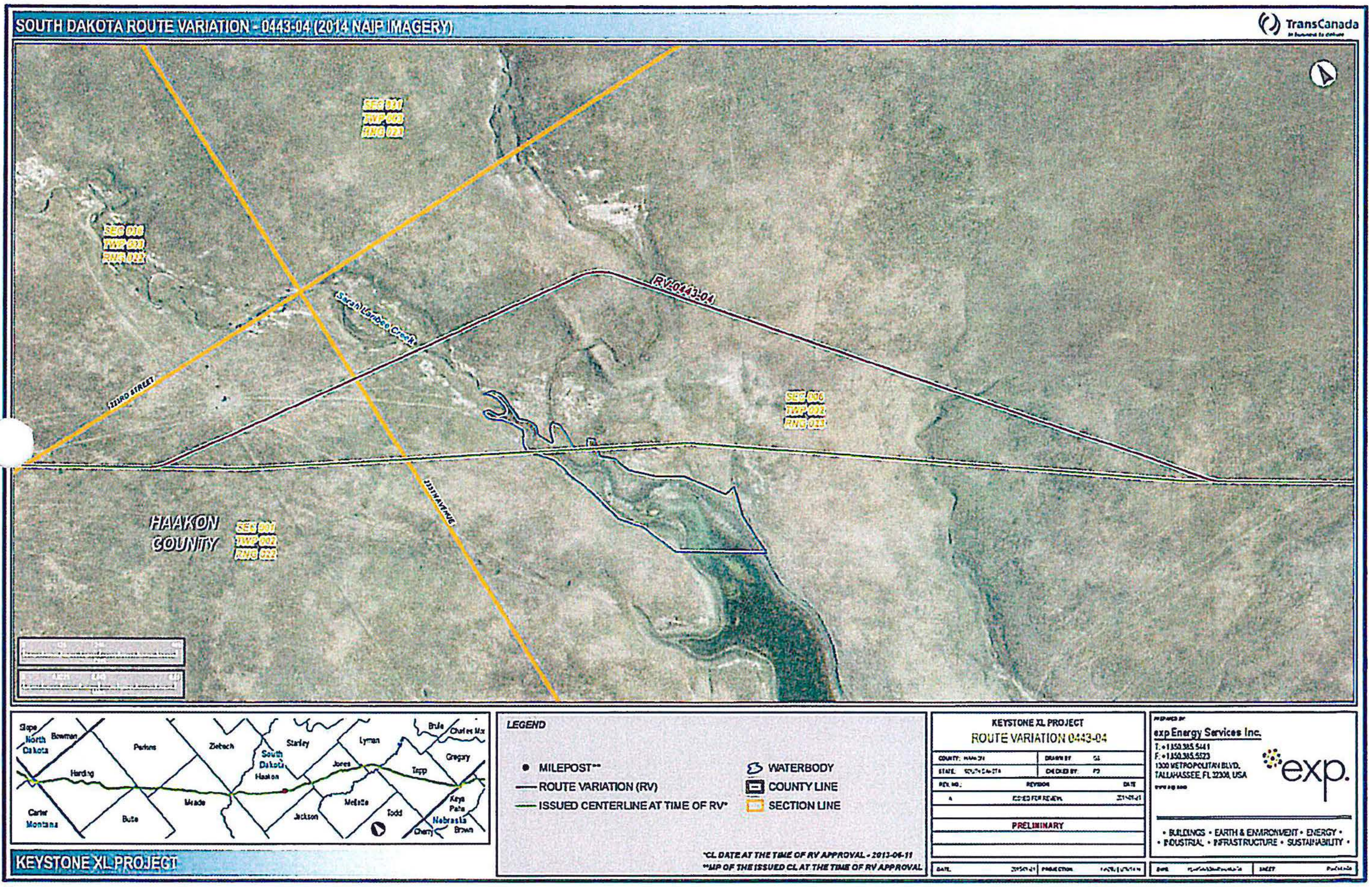

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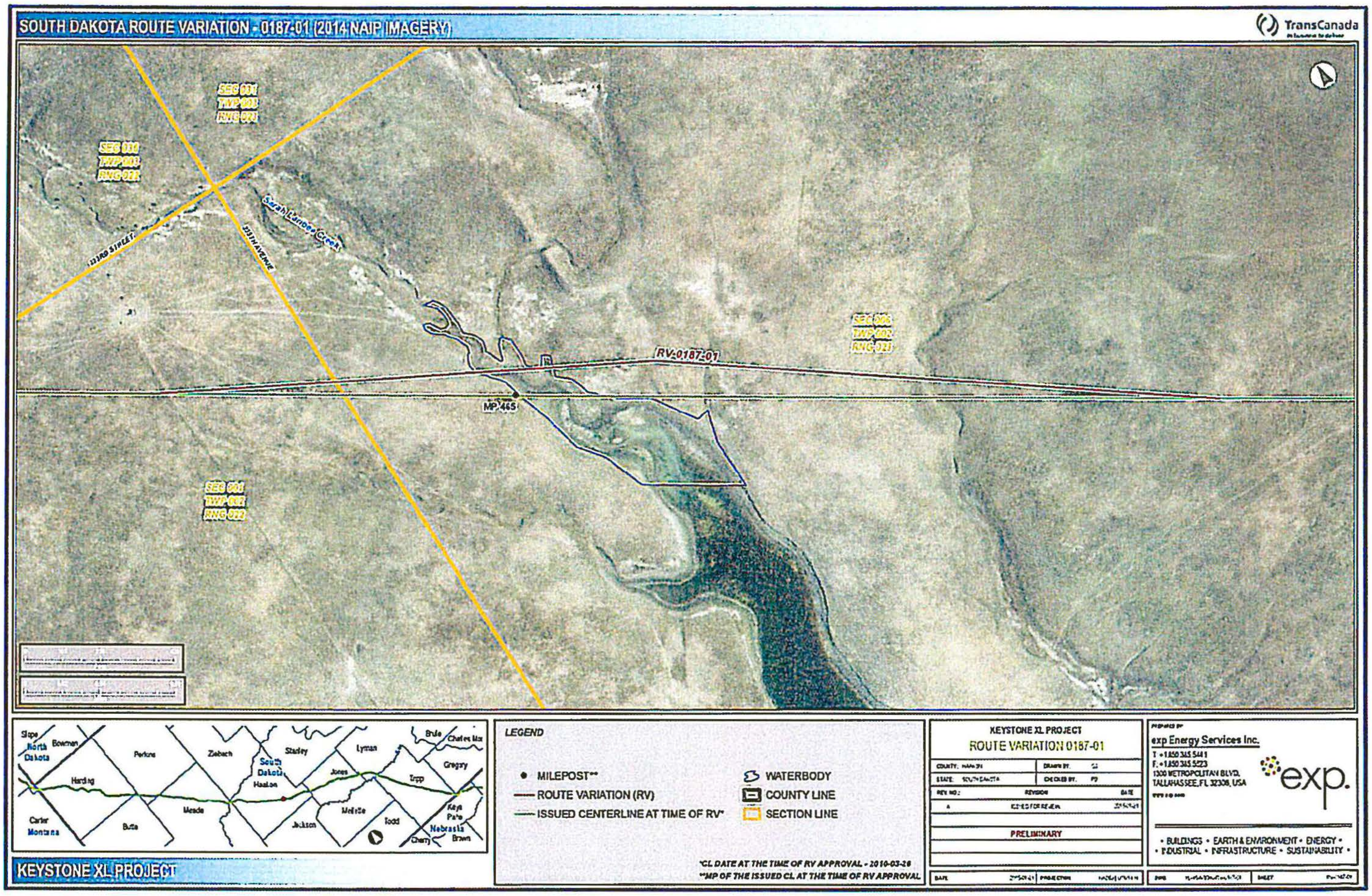

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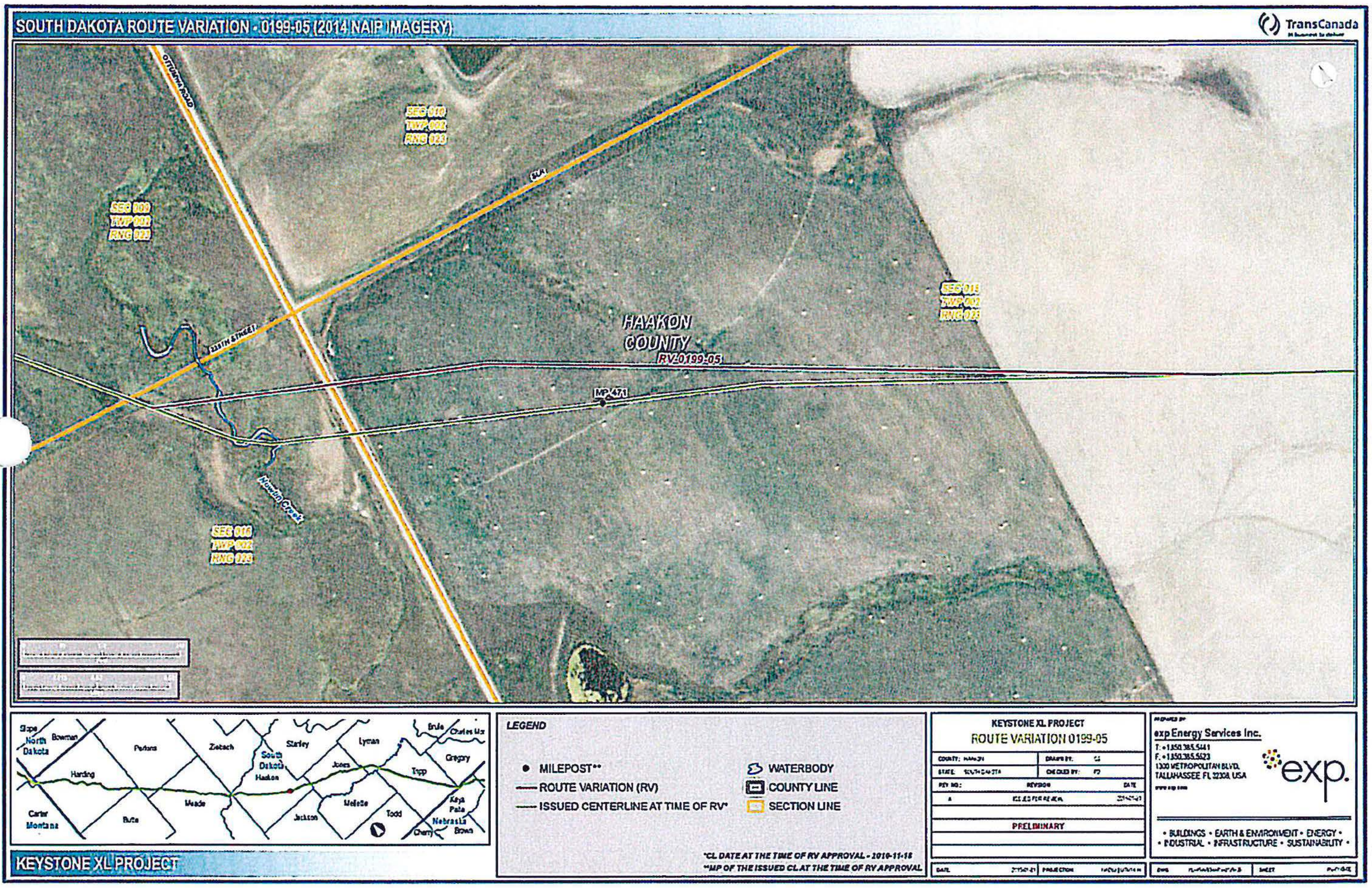

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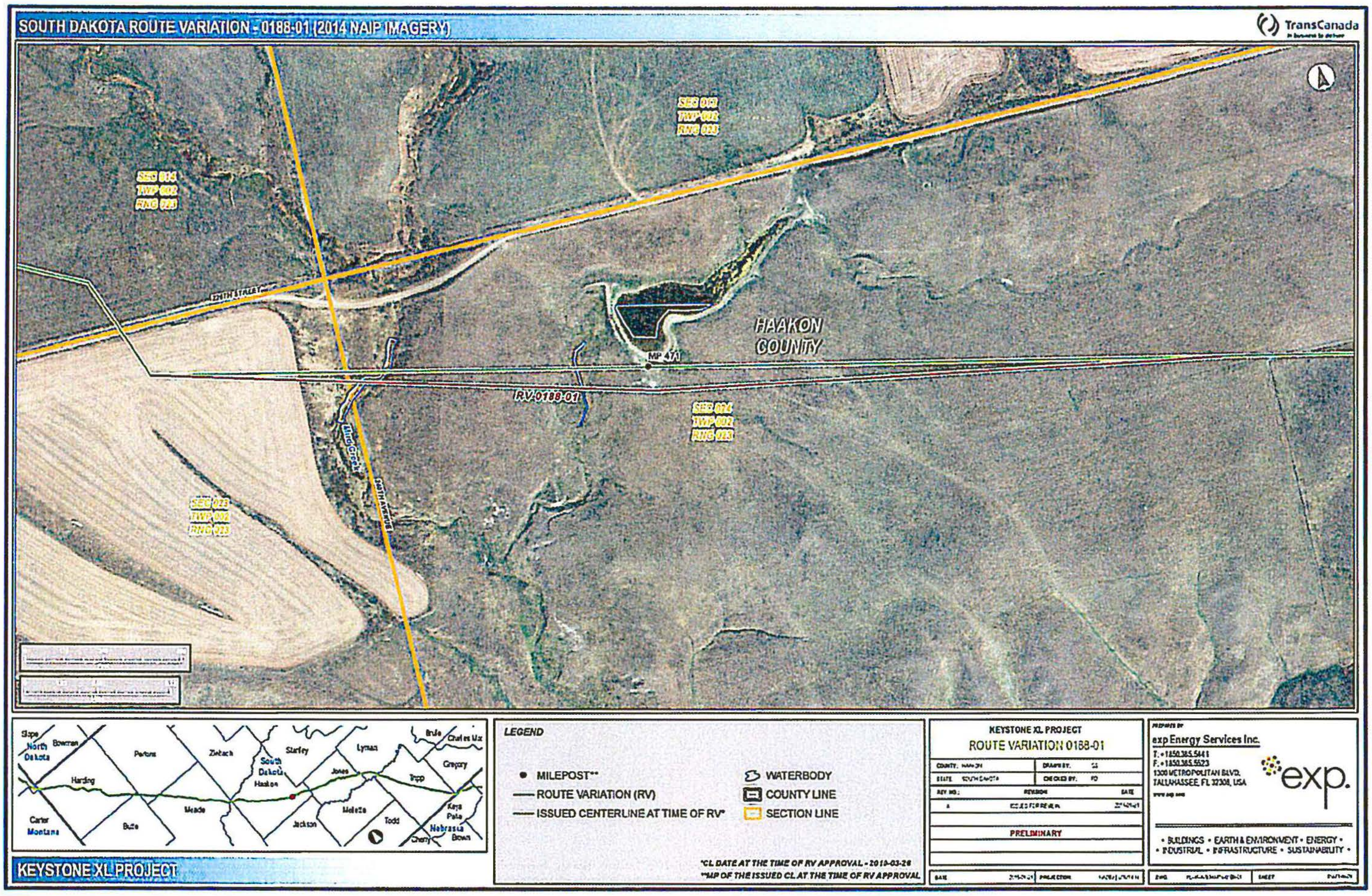

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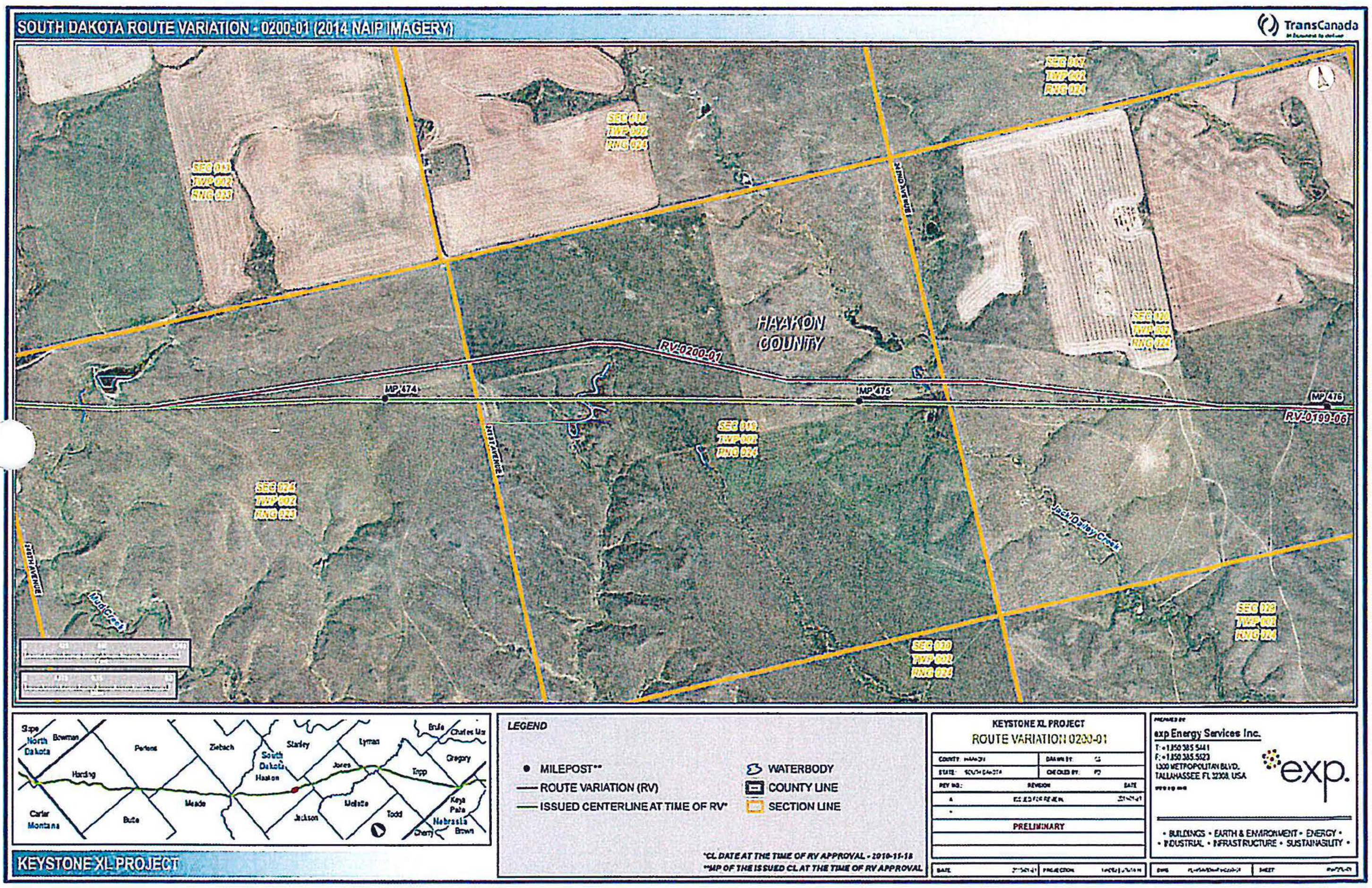

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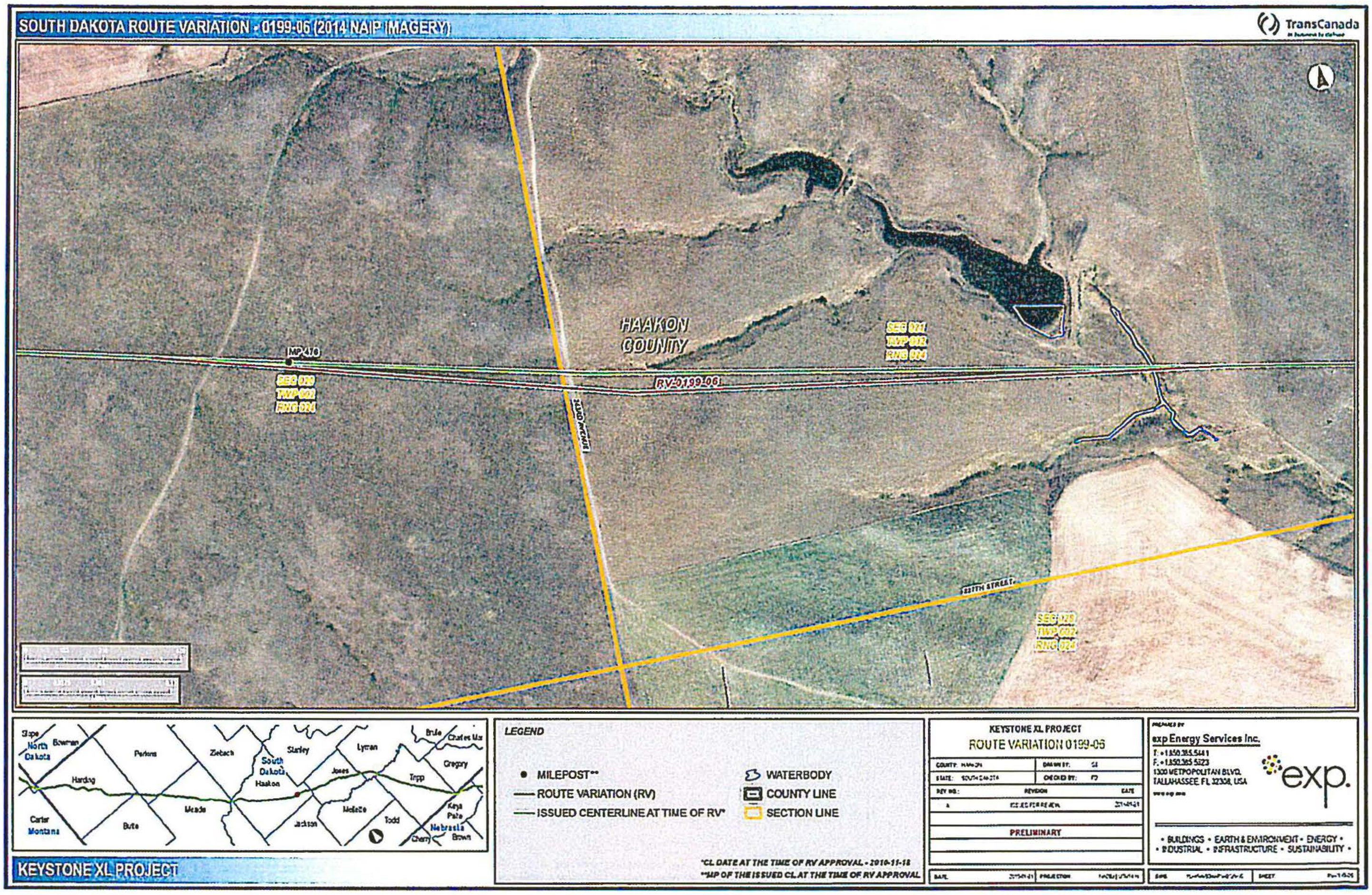

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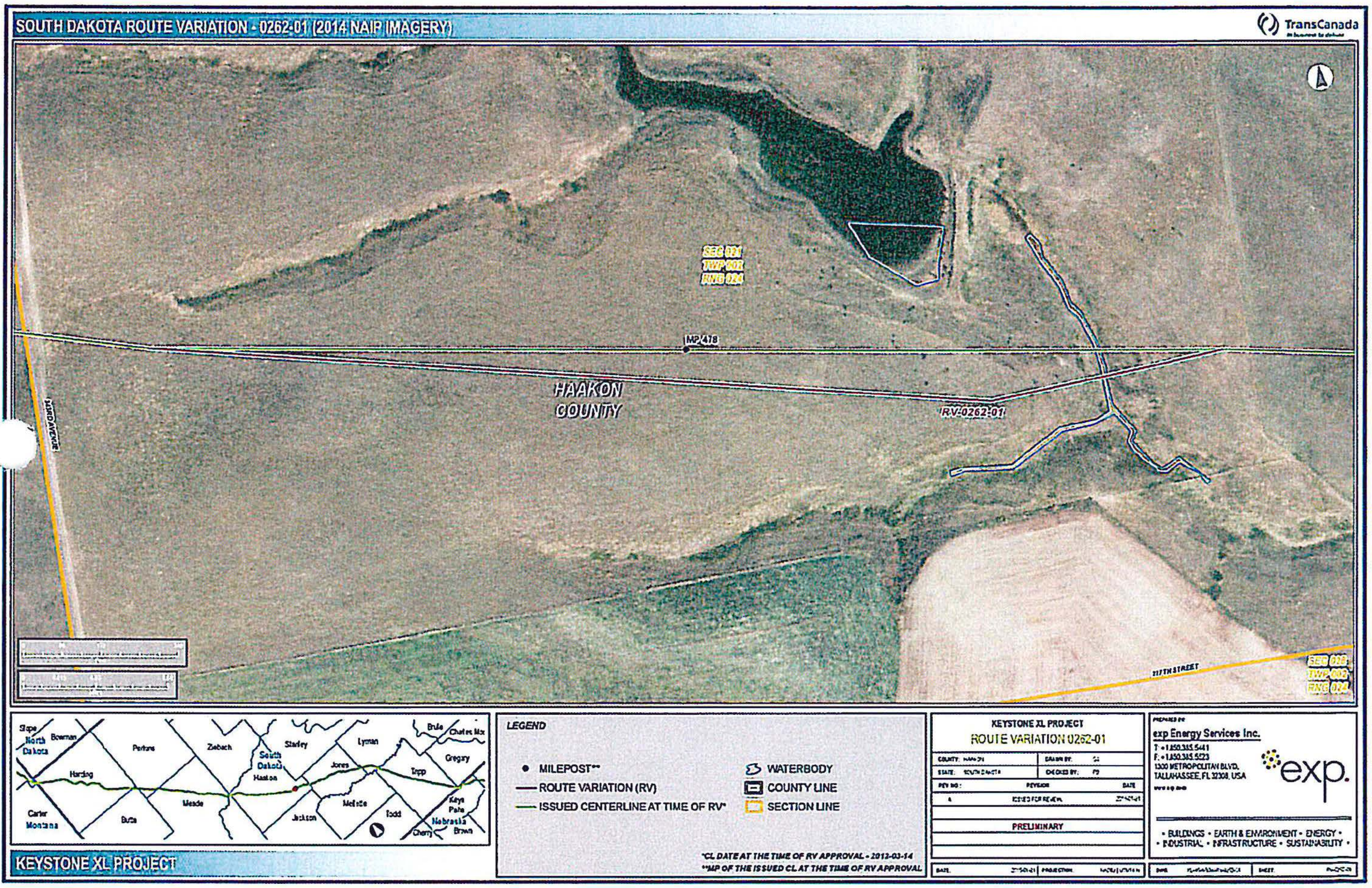

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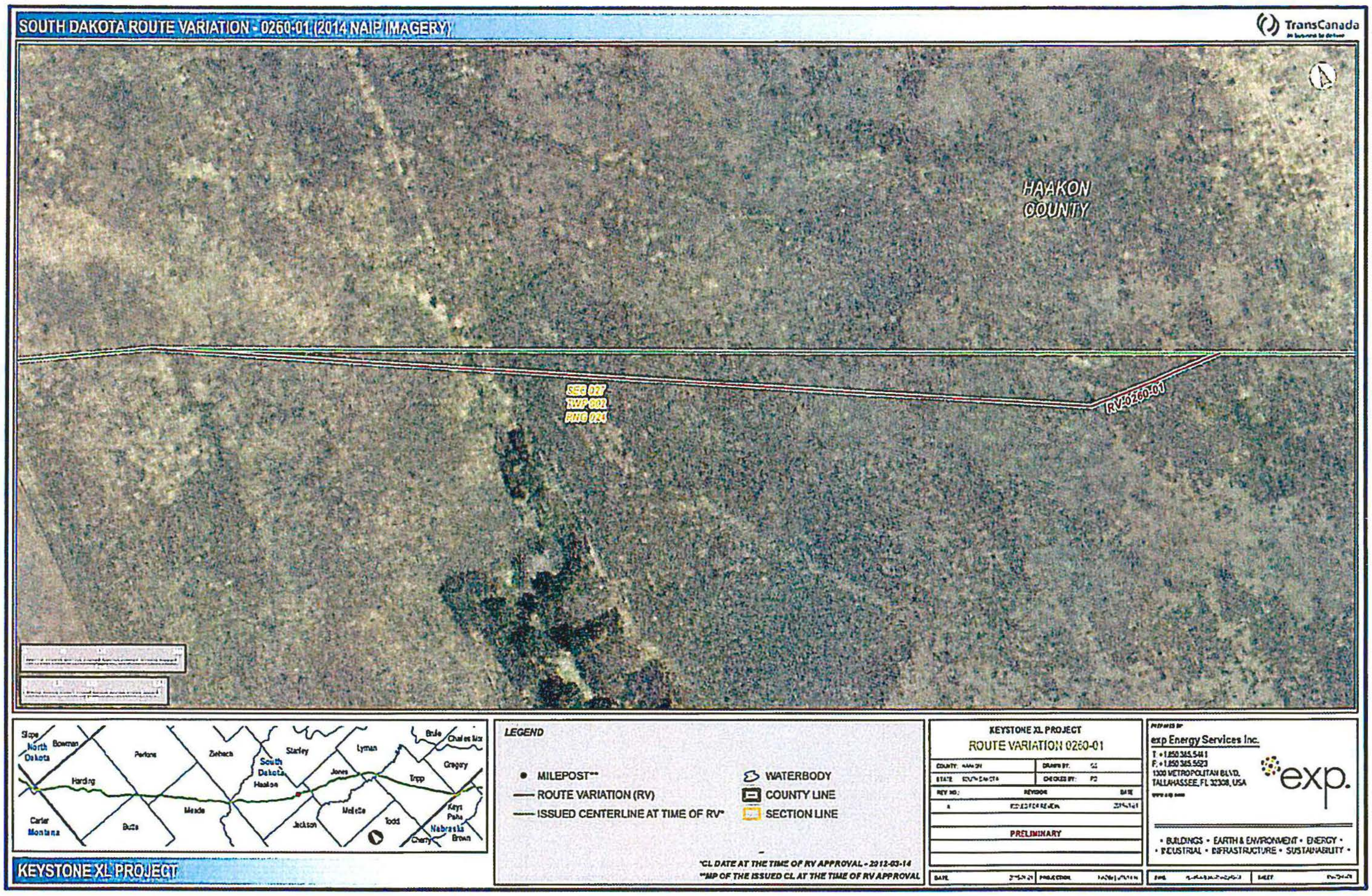

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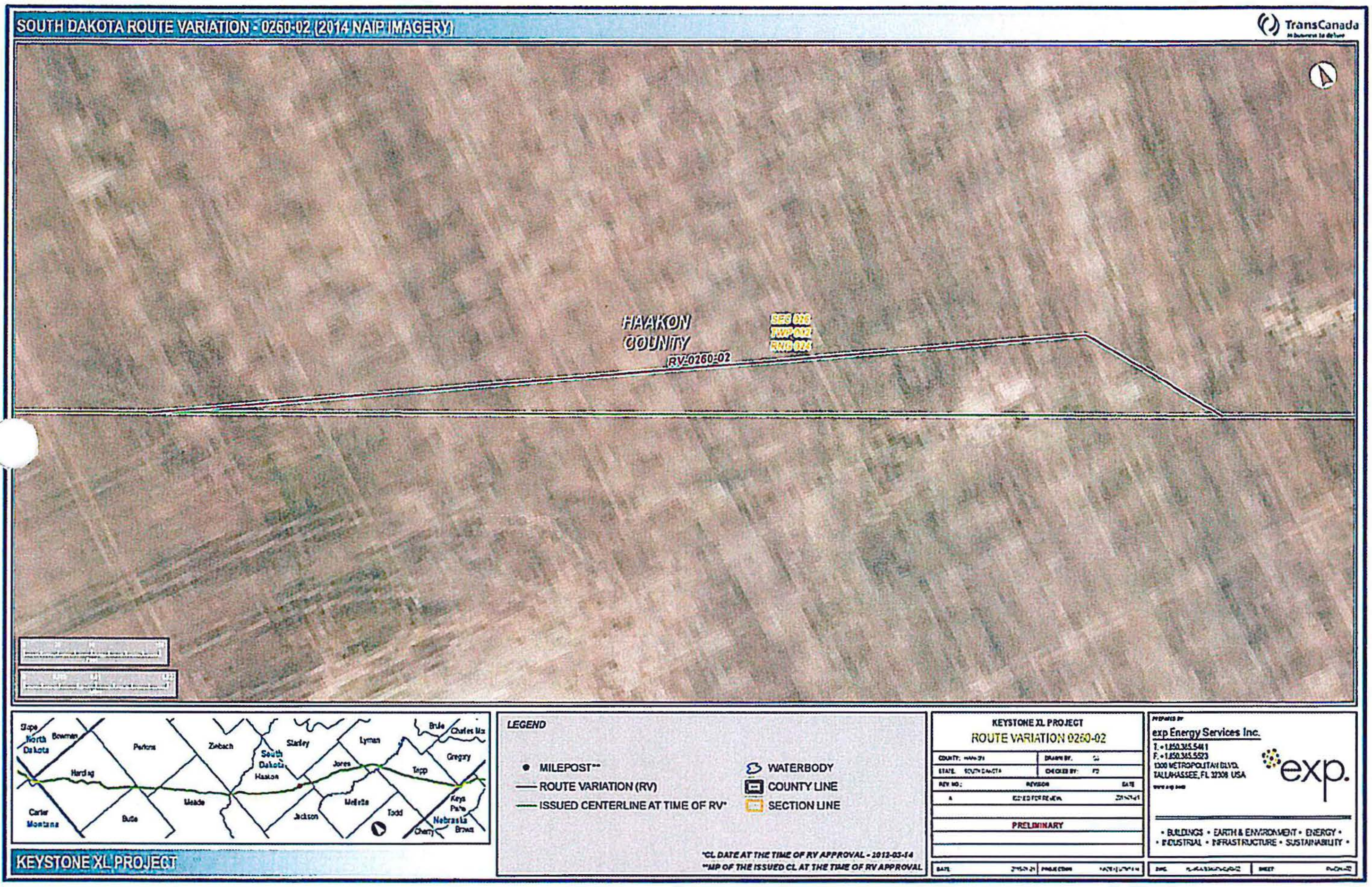

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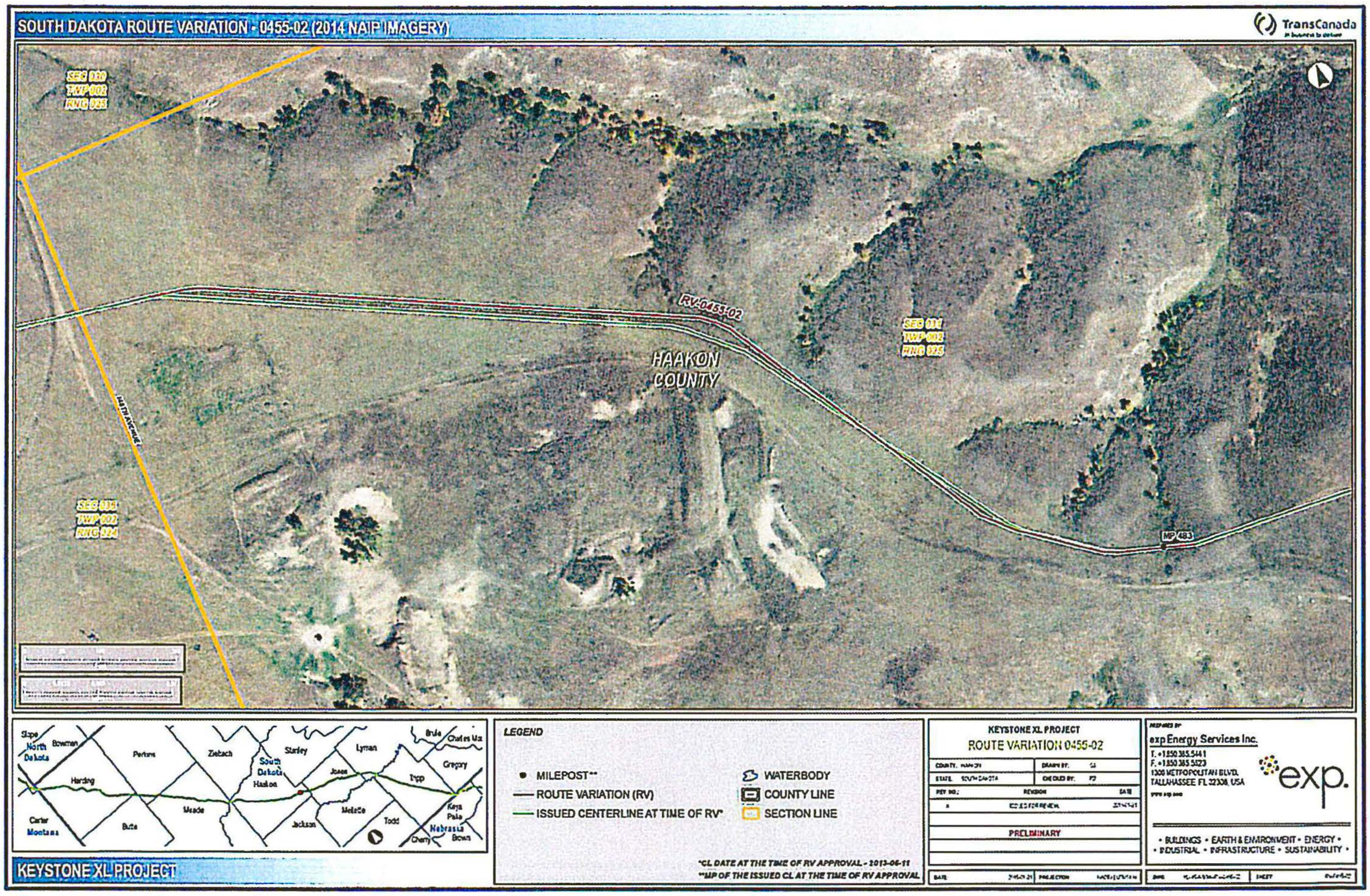

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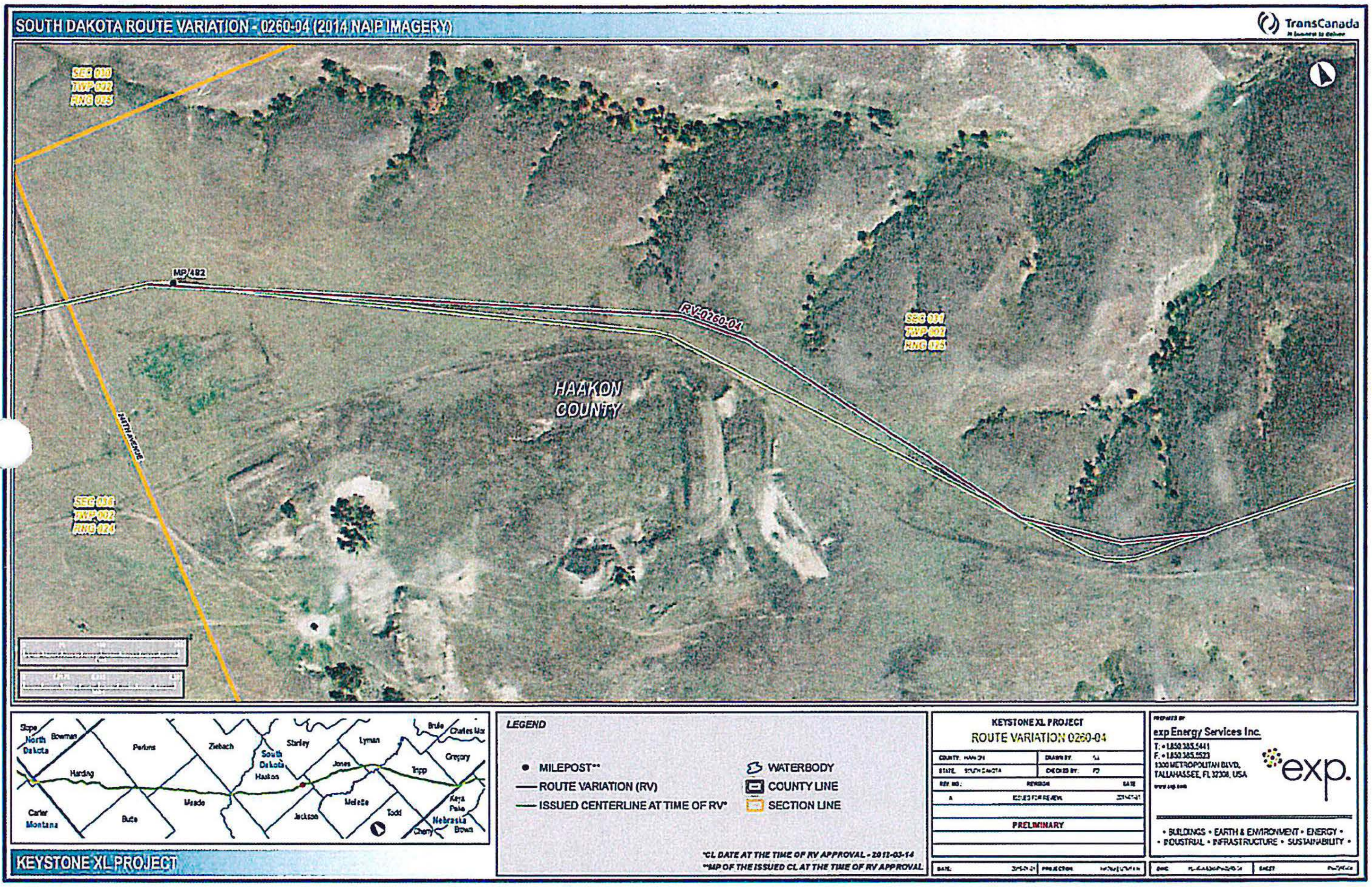

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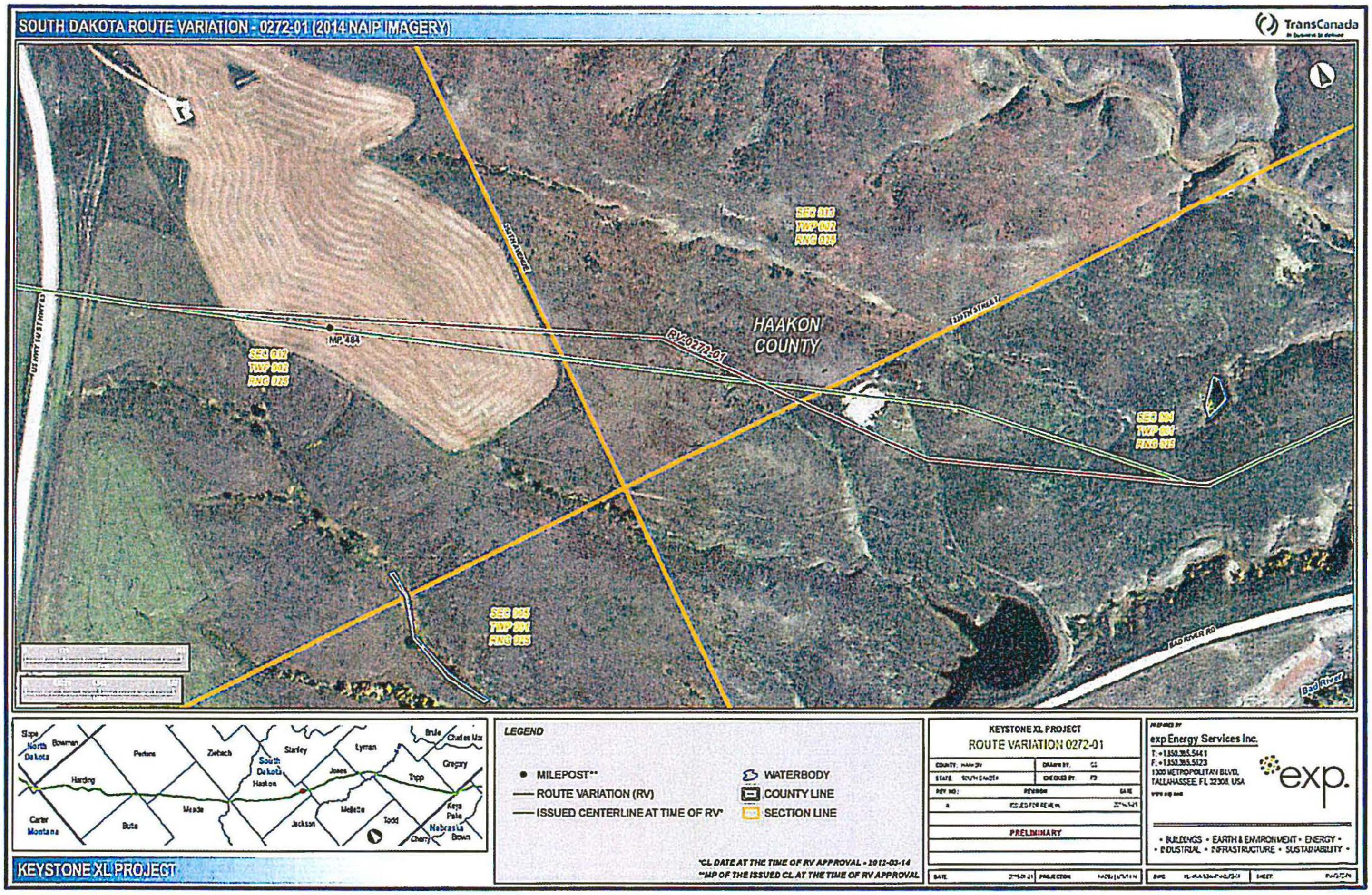

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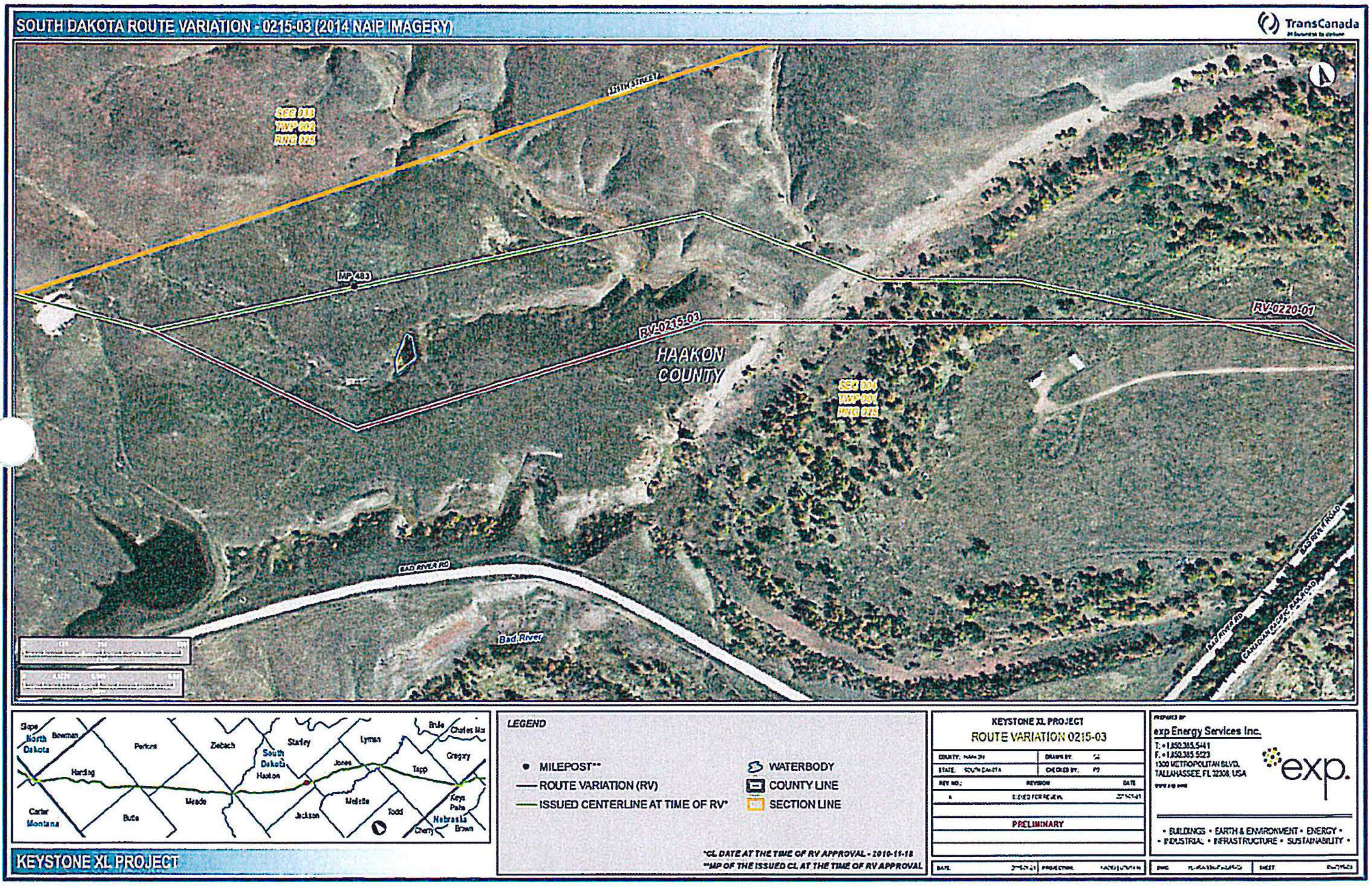

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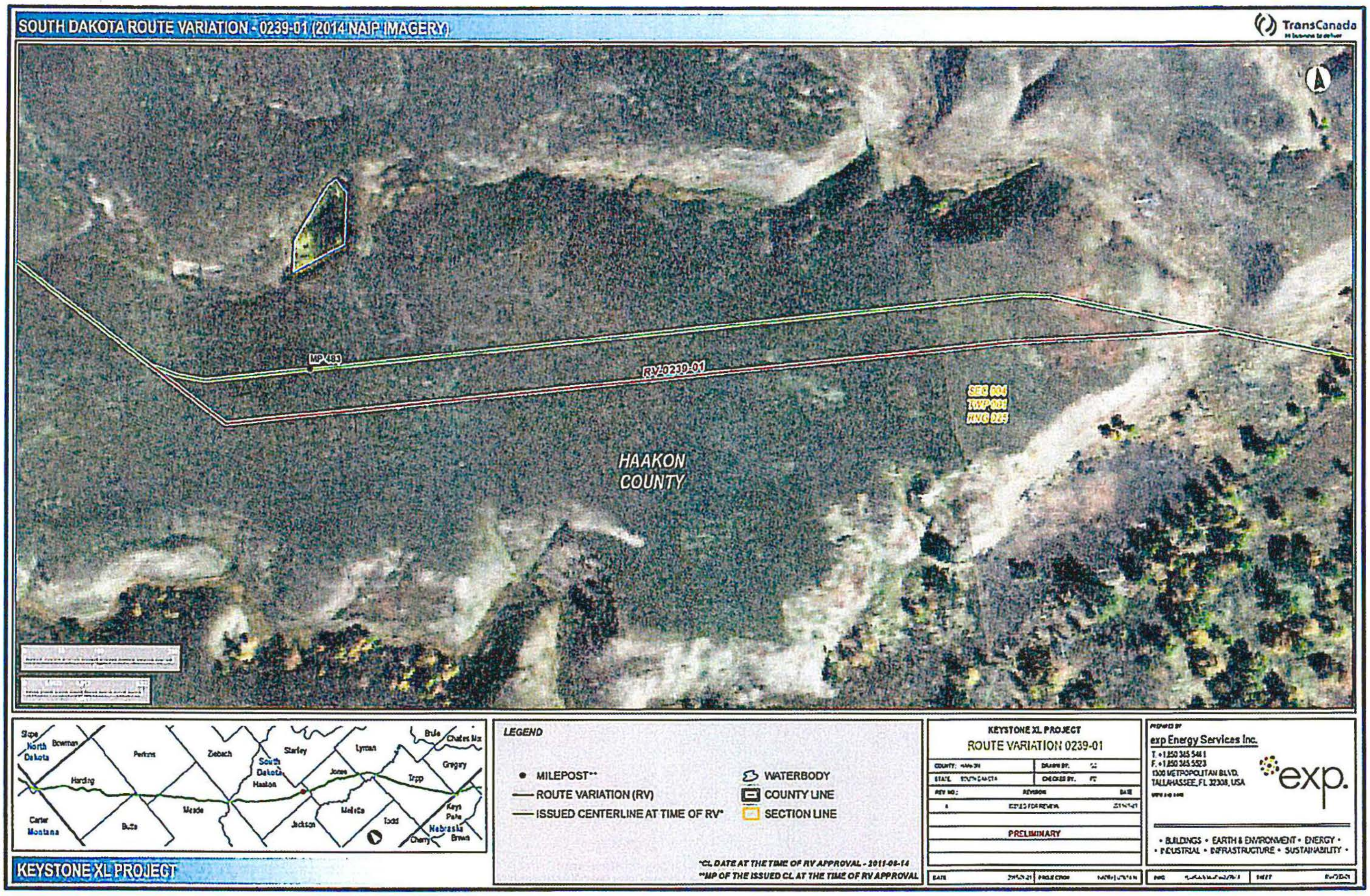

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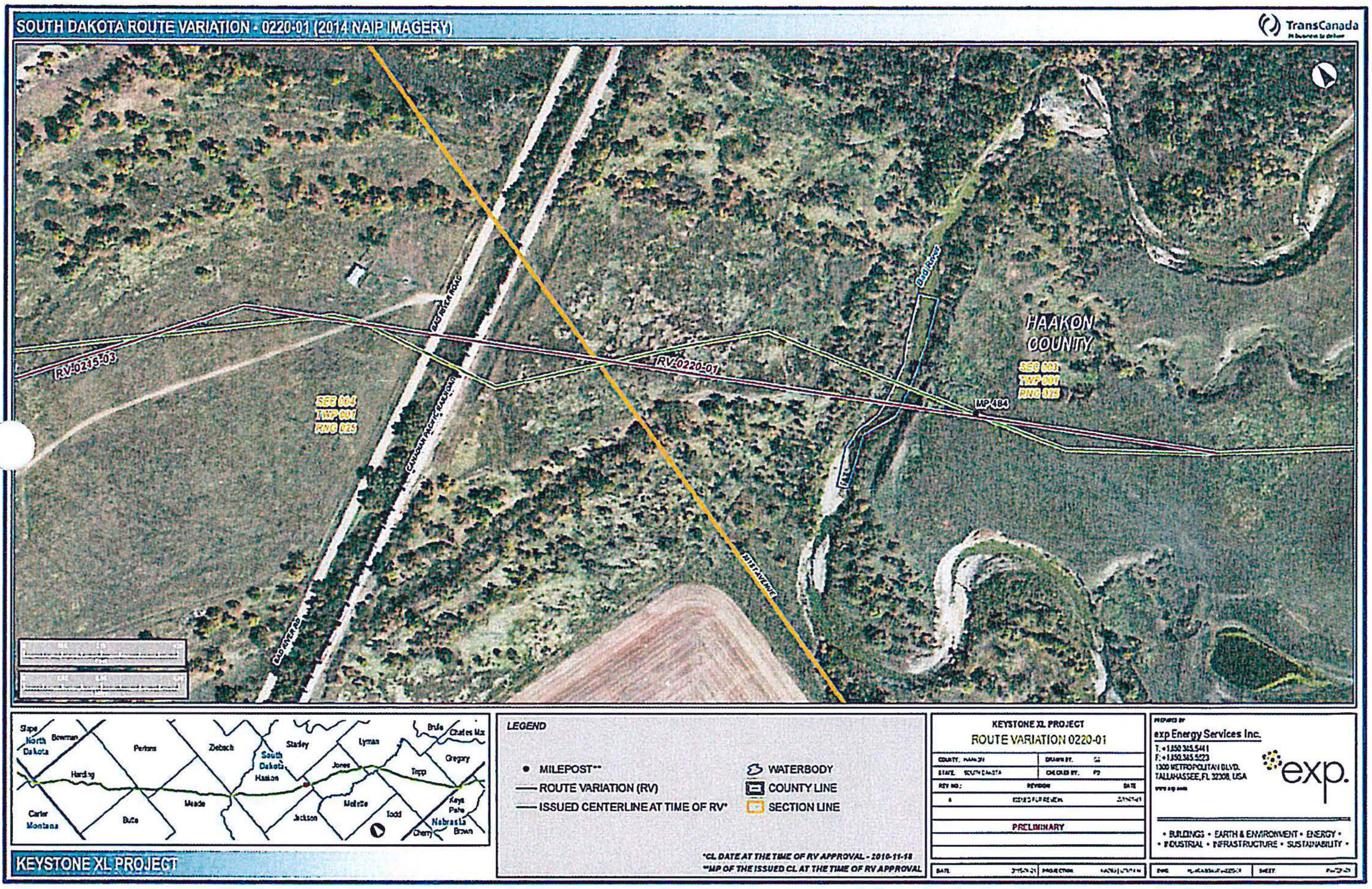

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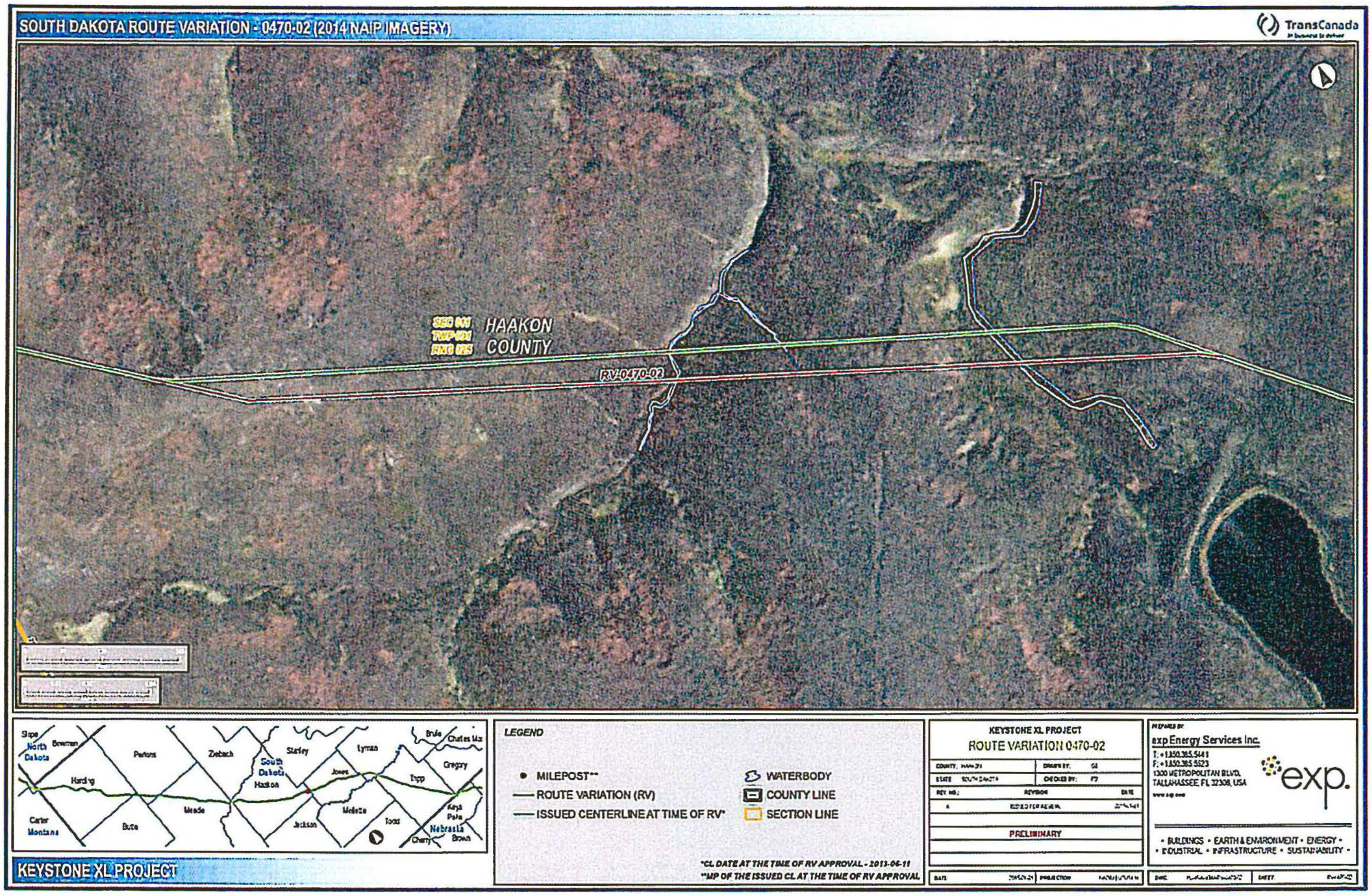

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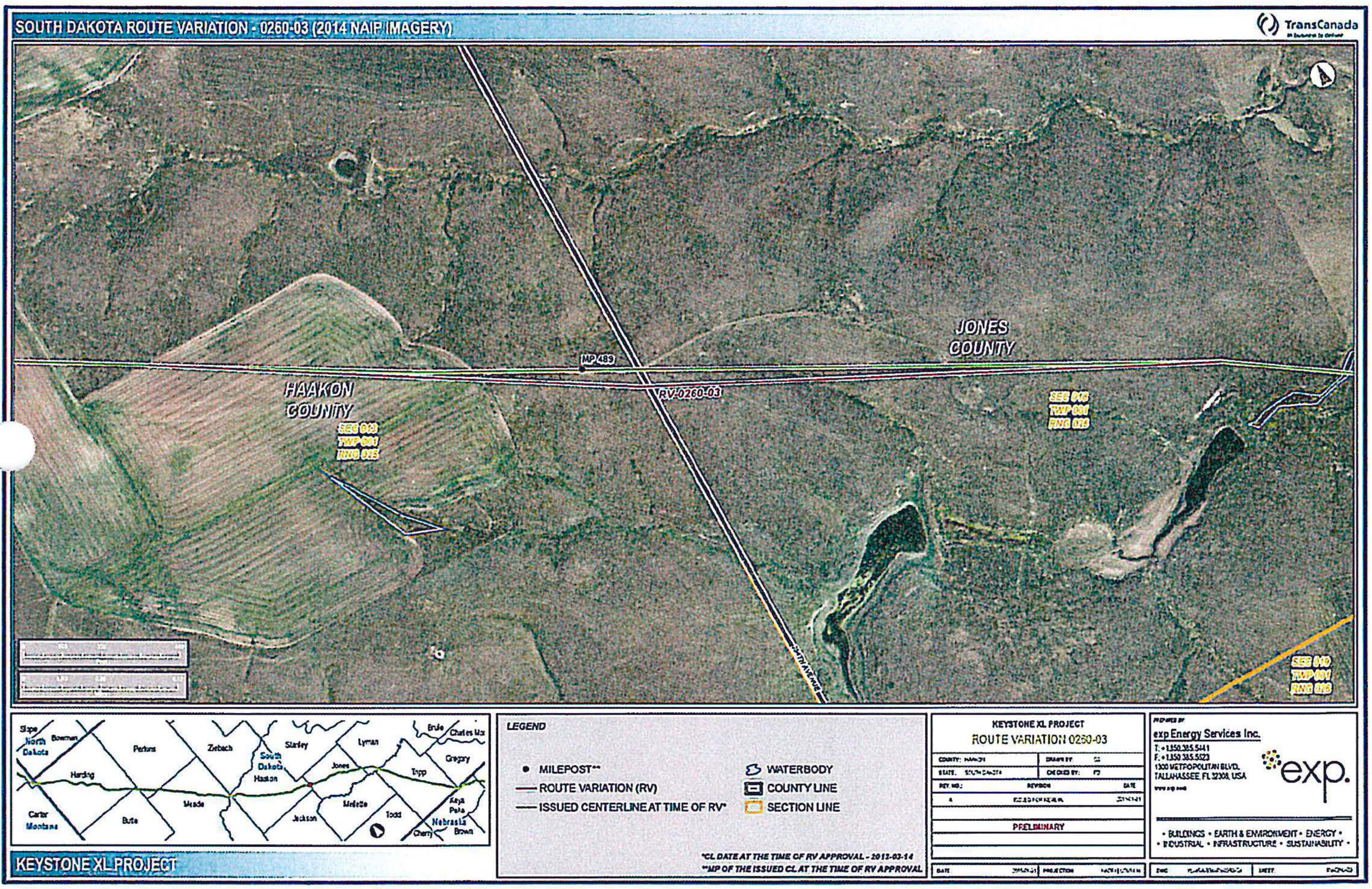

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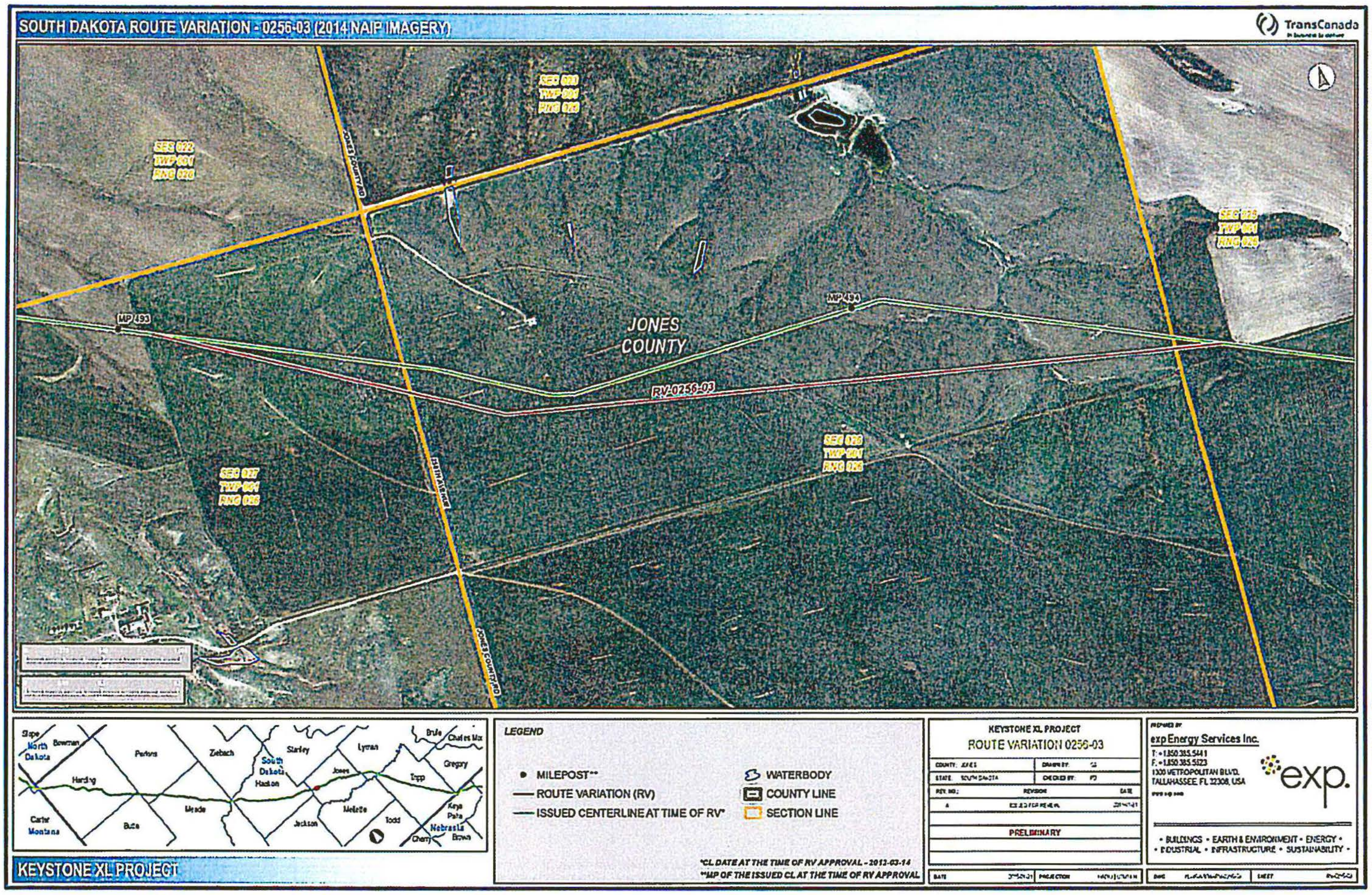

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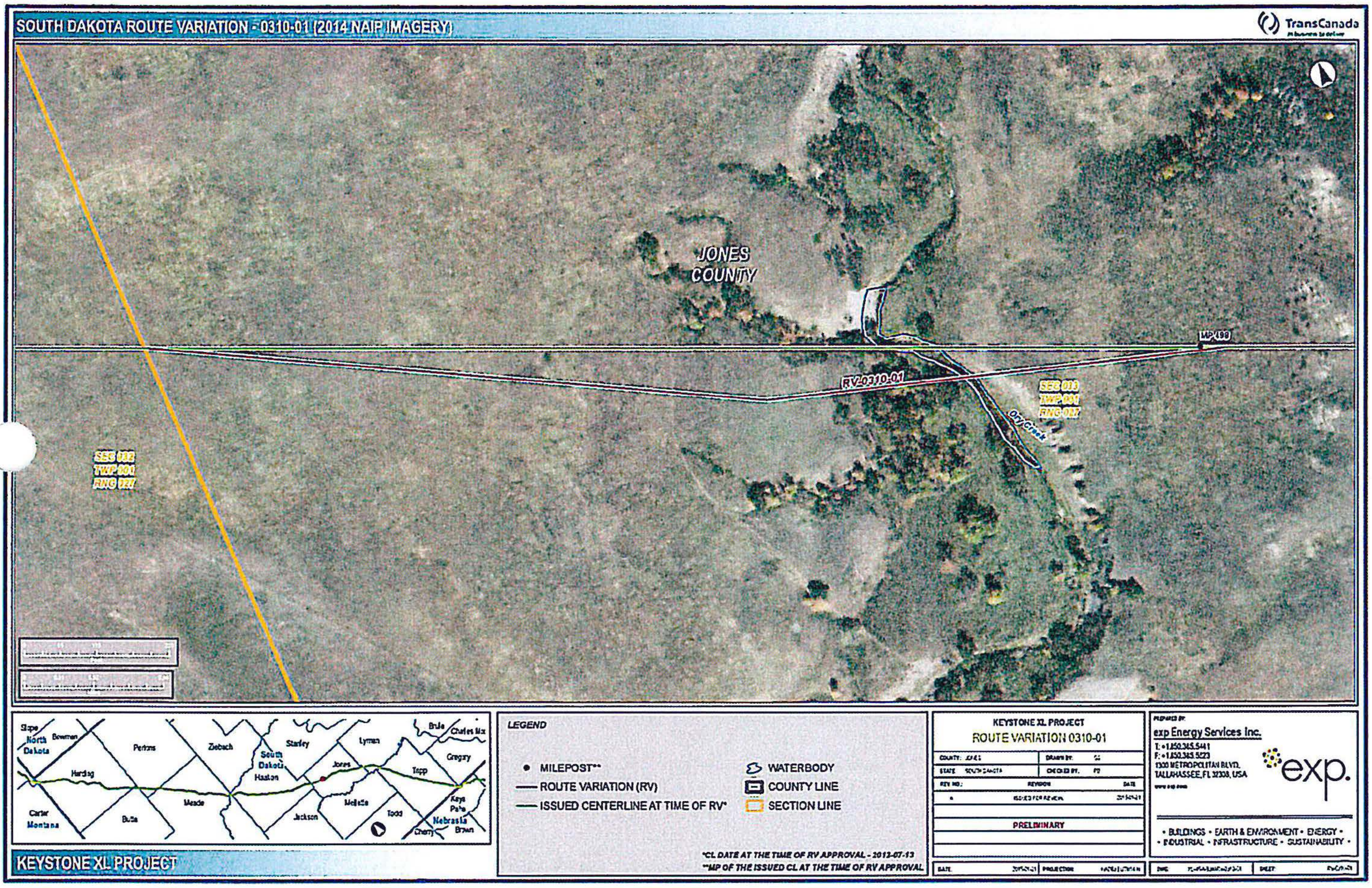

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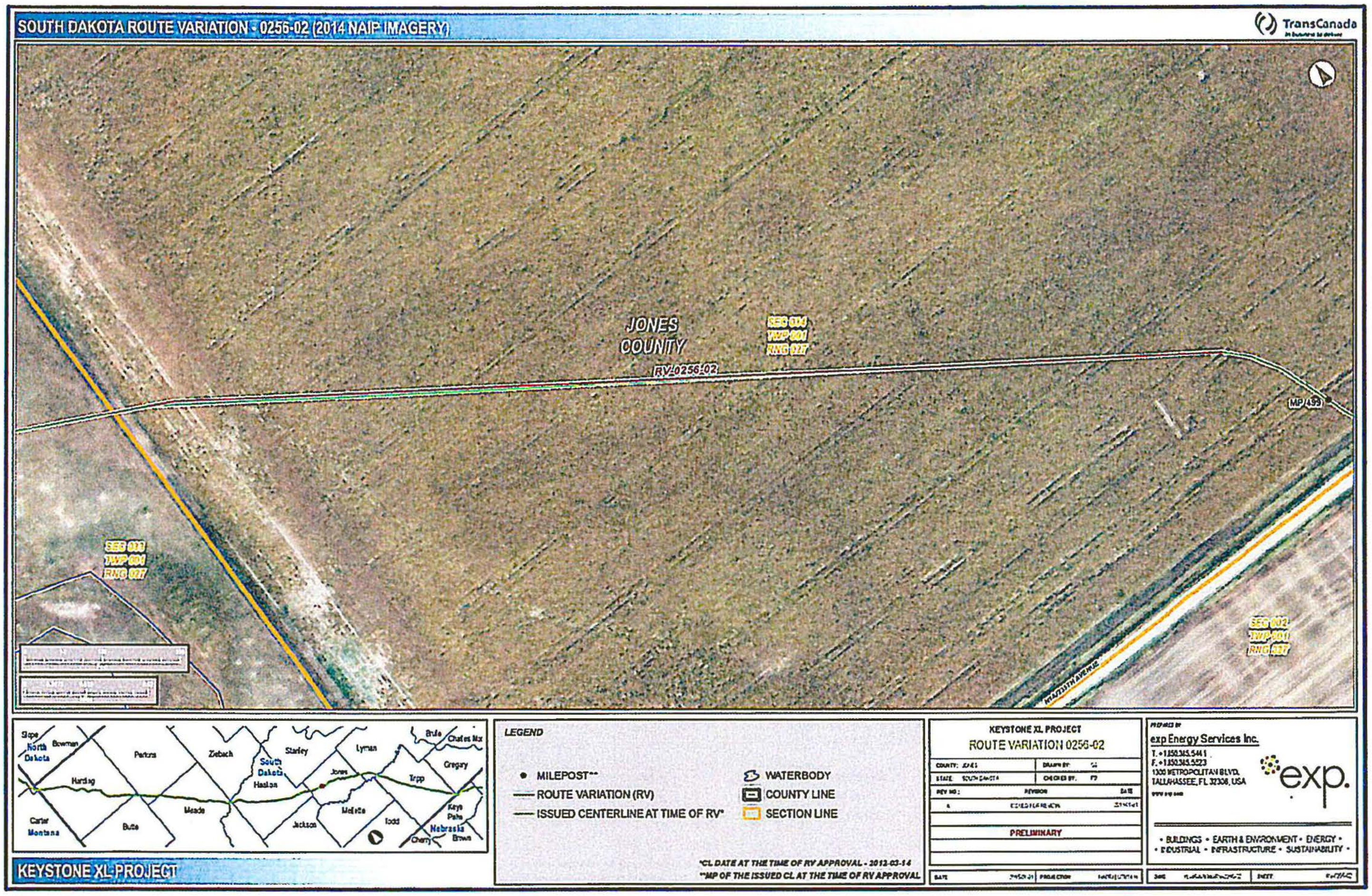

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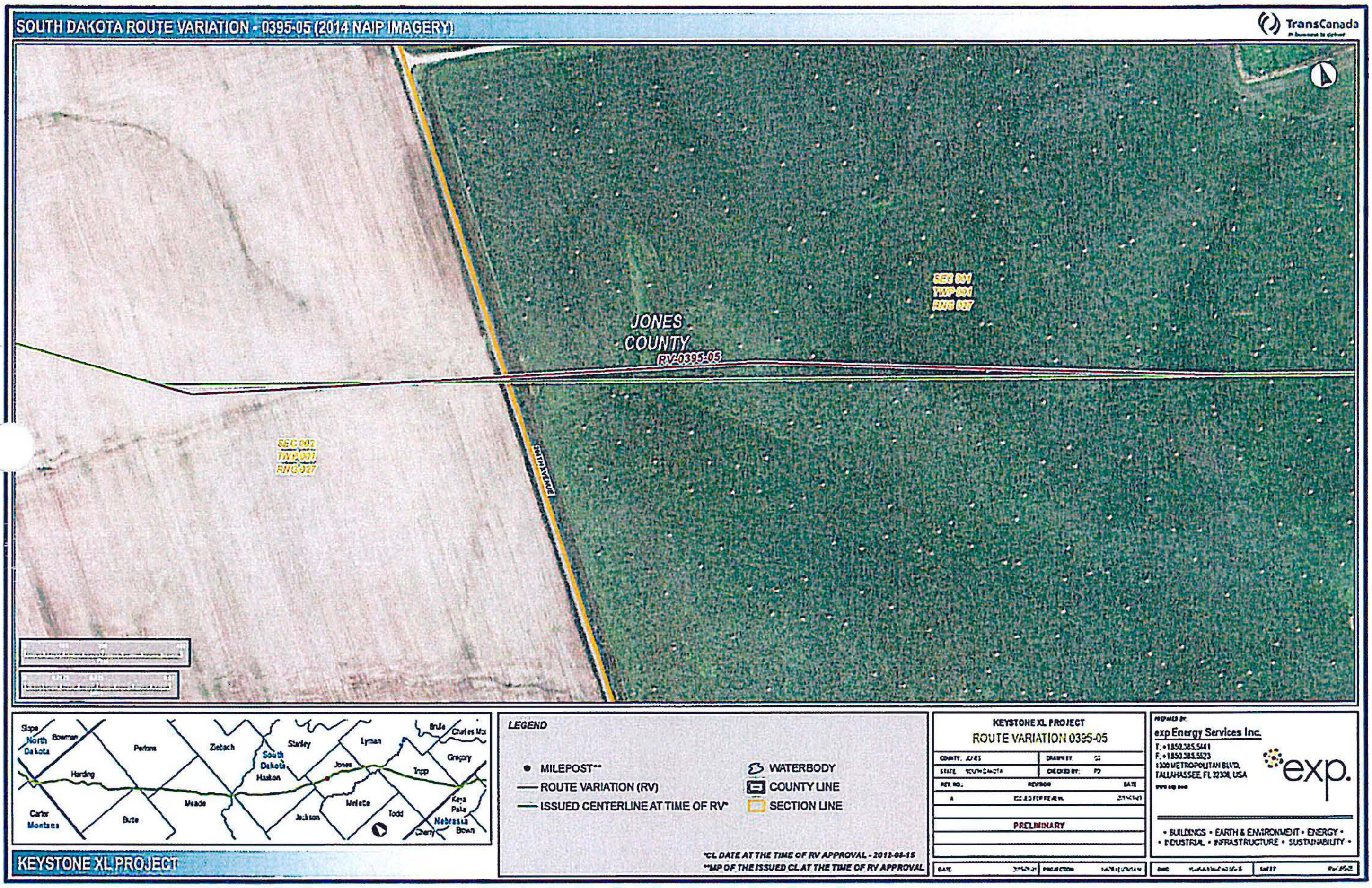

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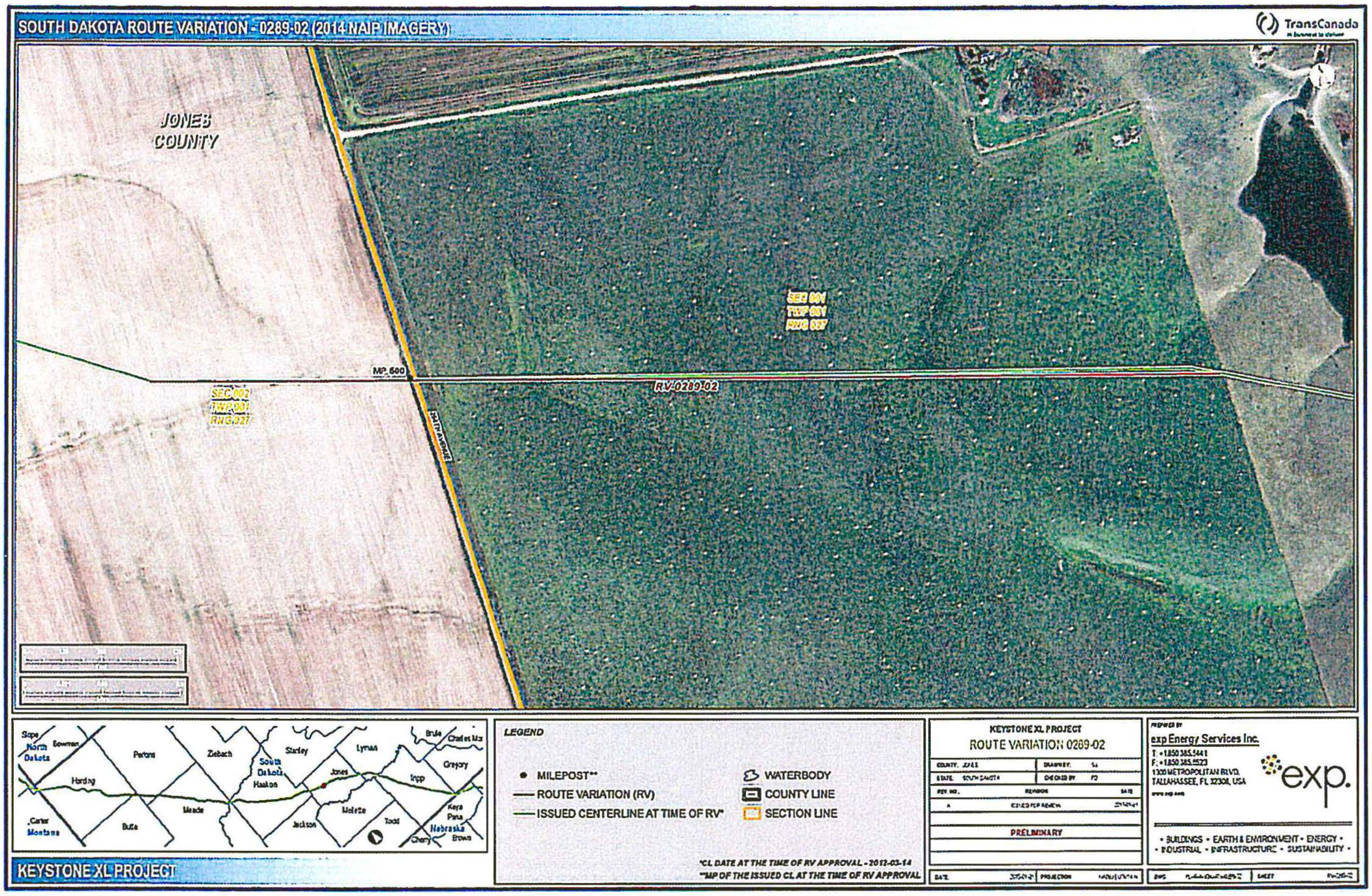

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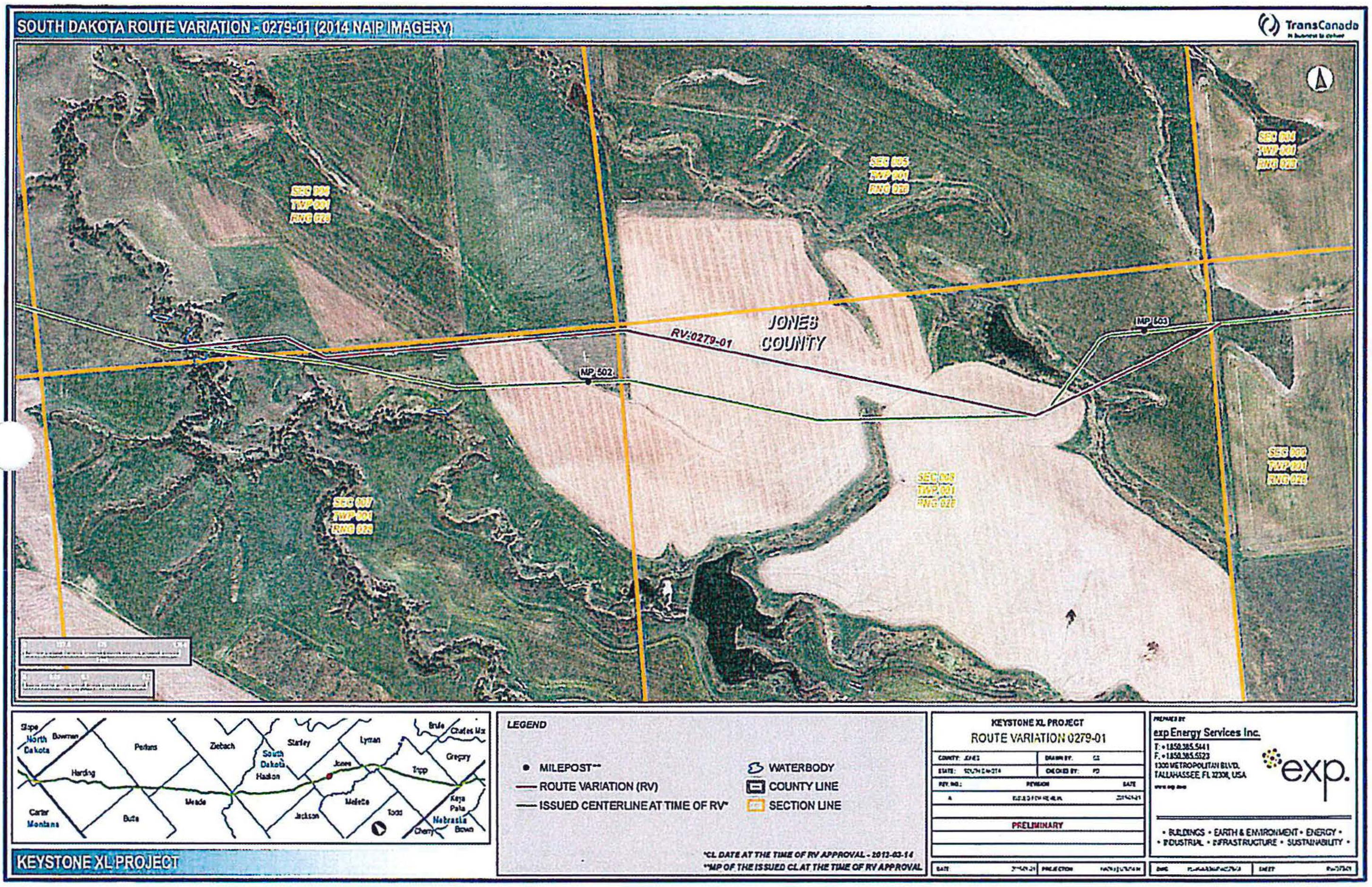

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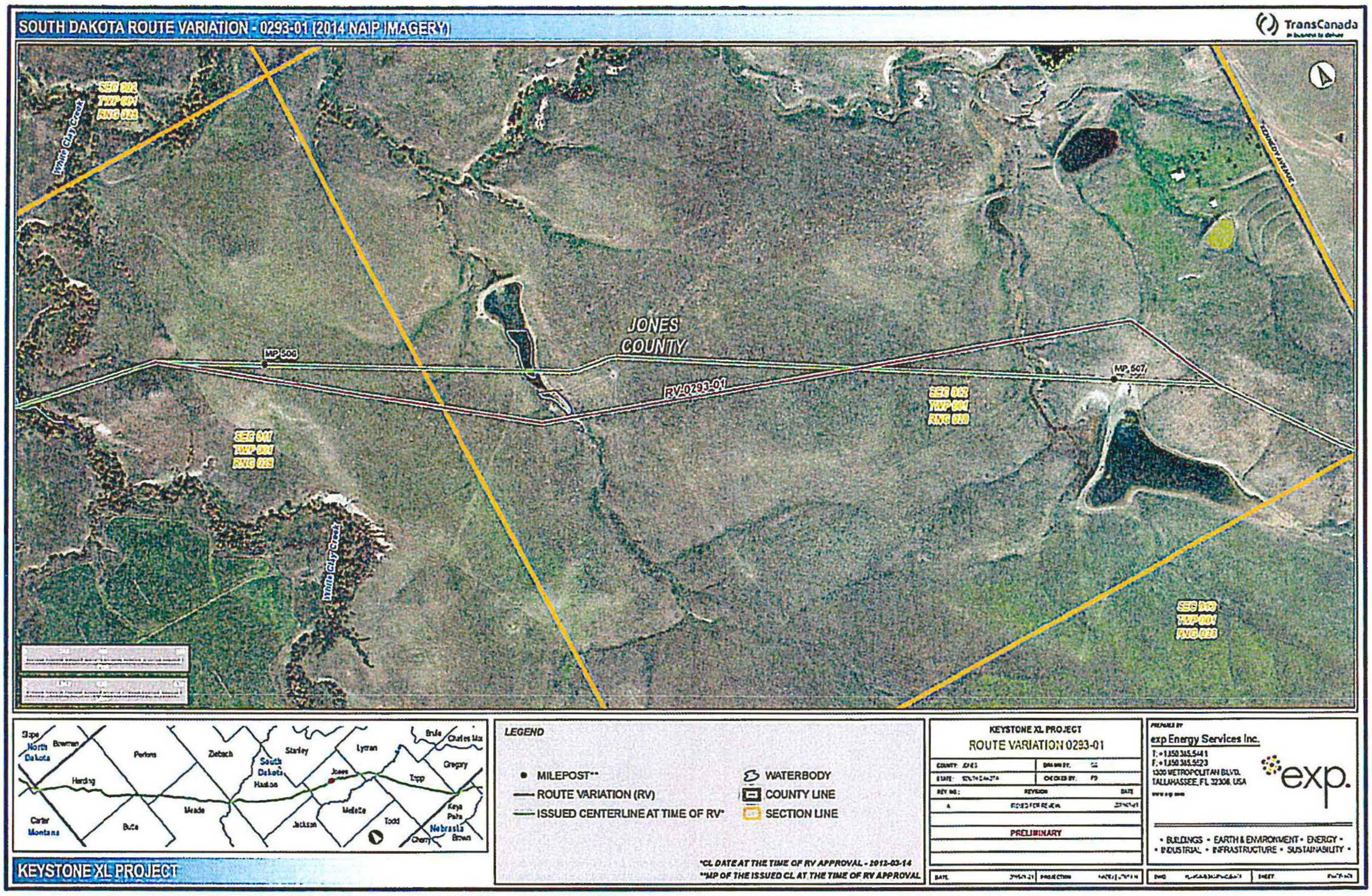

KEYSTONE 0555

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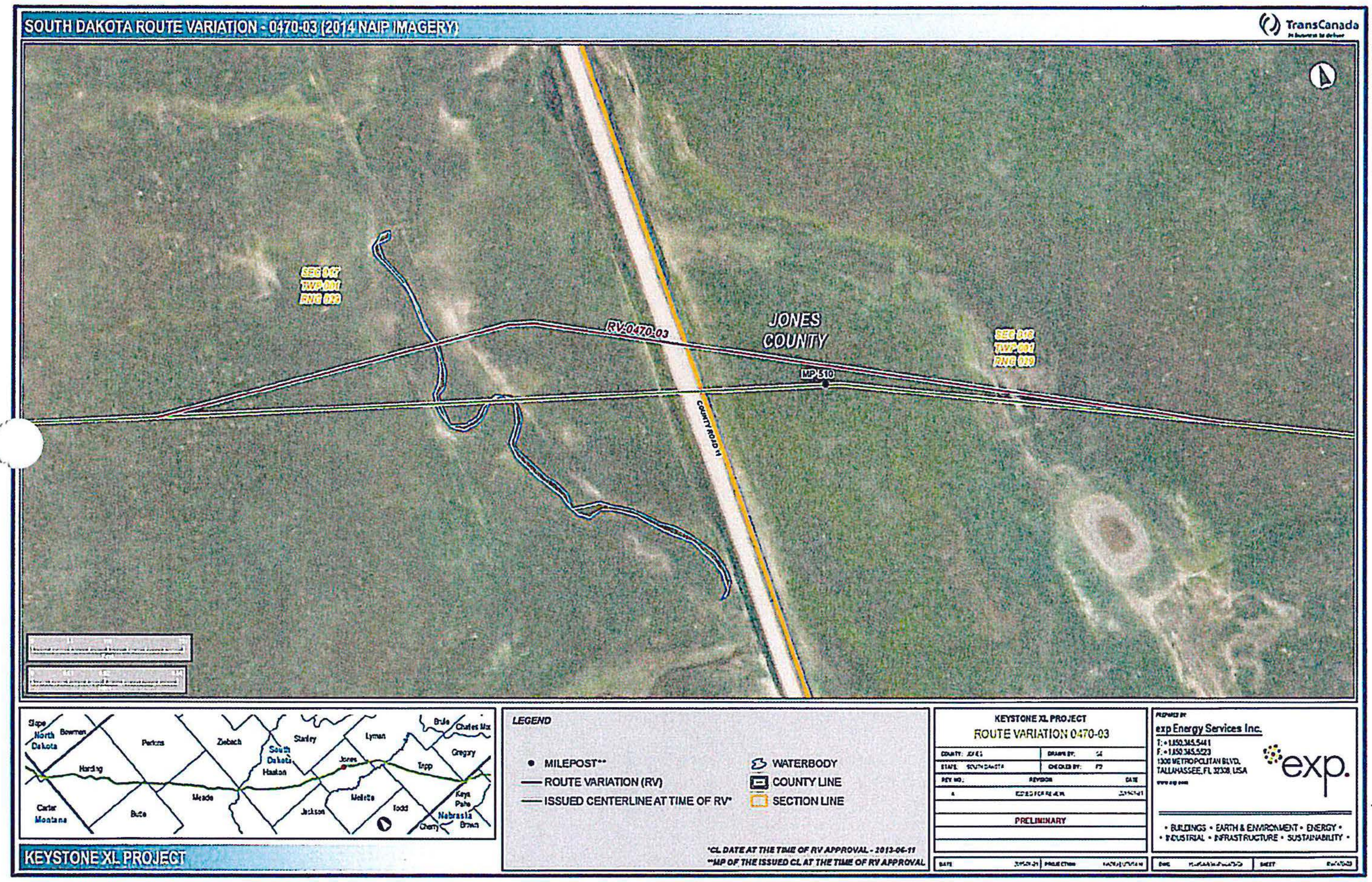
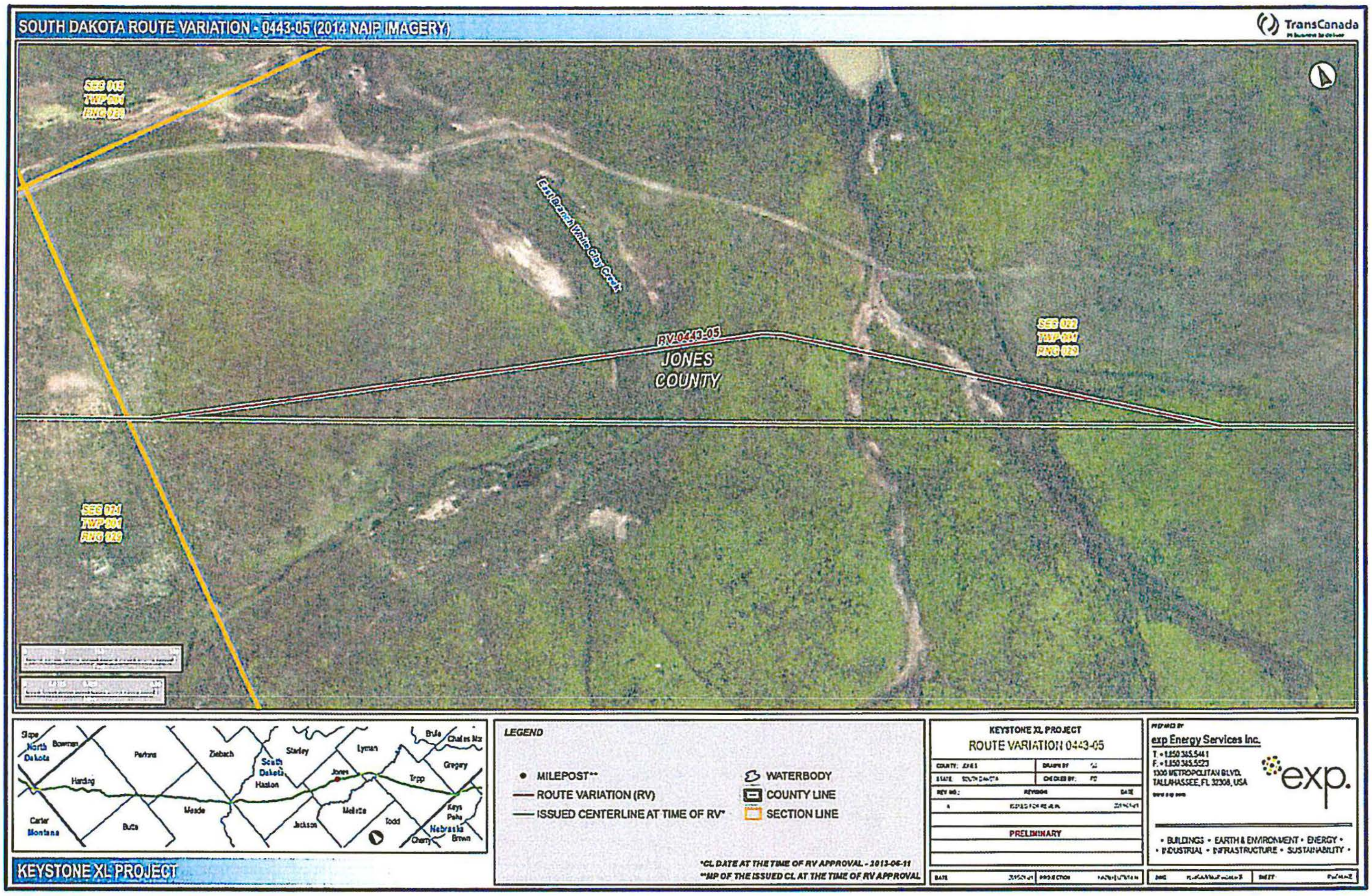


SOUTH DAKOTA ROUTE VARIATION - 0470-03 (2014 NAIP IMAGERY)
TransCanada
JONES COUNTY
RV-0470-03
MP 510
COUNTY ROAD 11
KEYSTONE XL PROJECT
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 2013-06-11
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0470-03
PRELIMINARY
exp Energy Services Inc.
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •



KEYSTONE 0557

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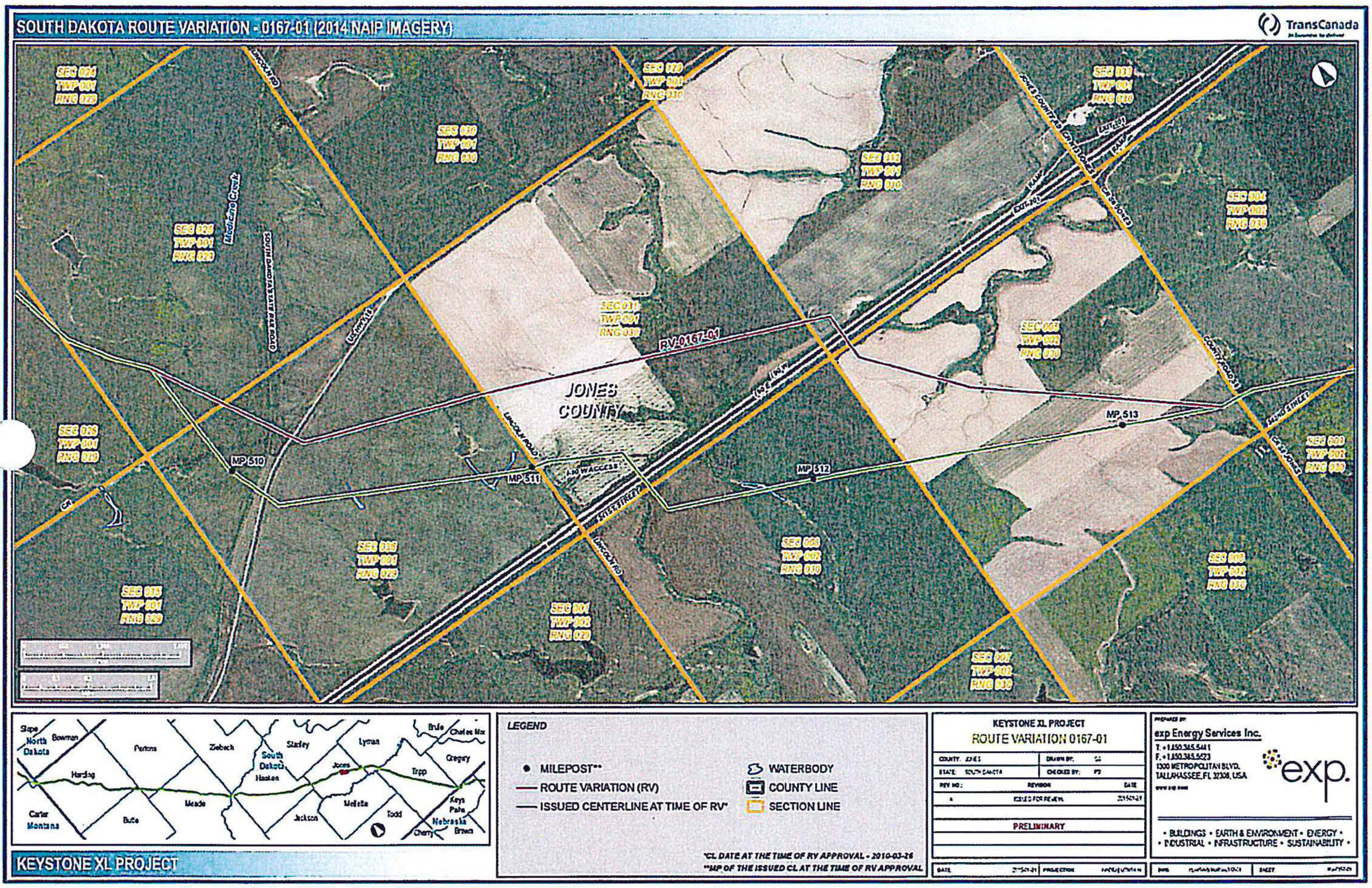

KEYSTONE 0558

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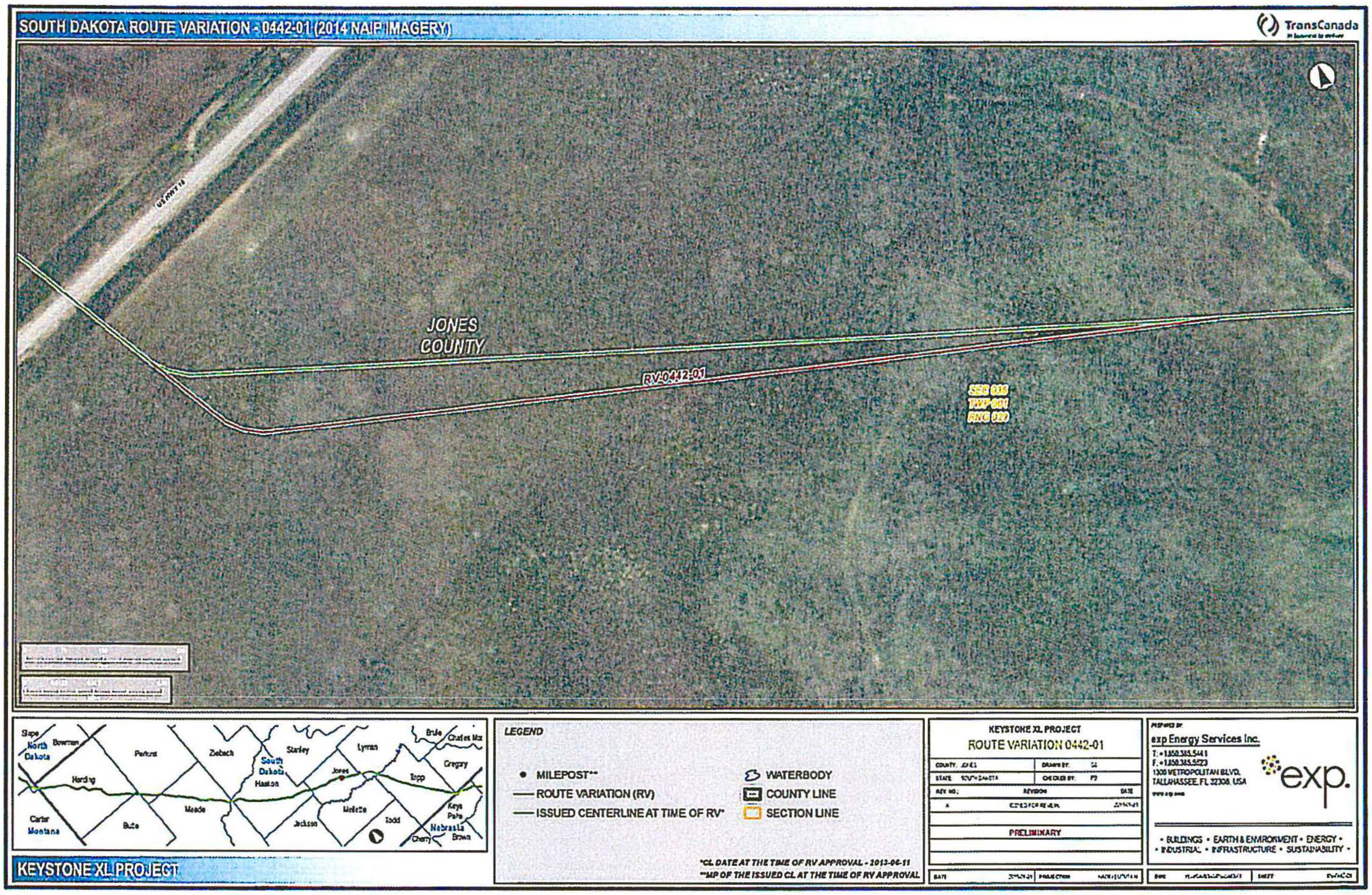

KEYSTONE 0559

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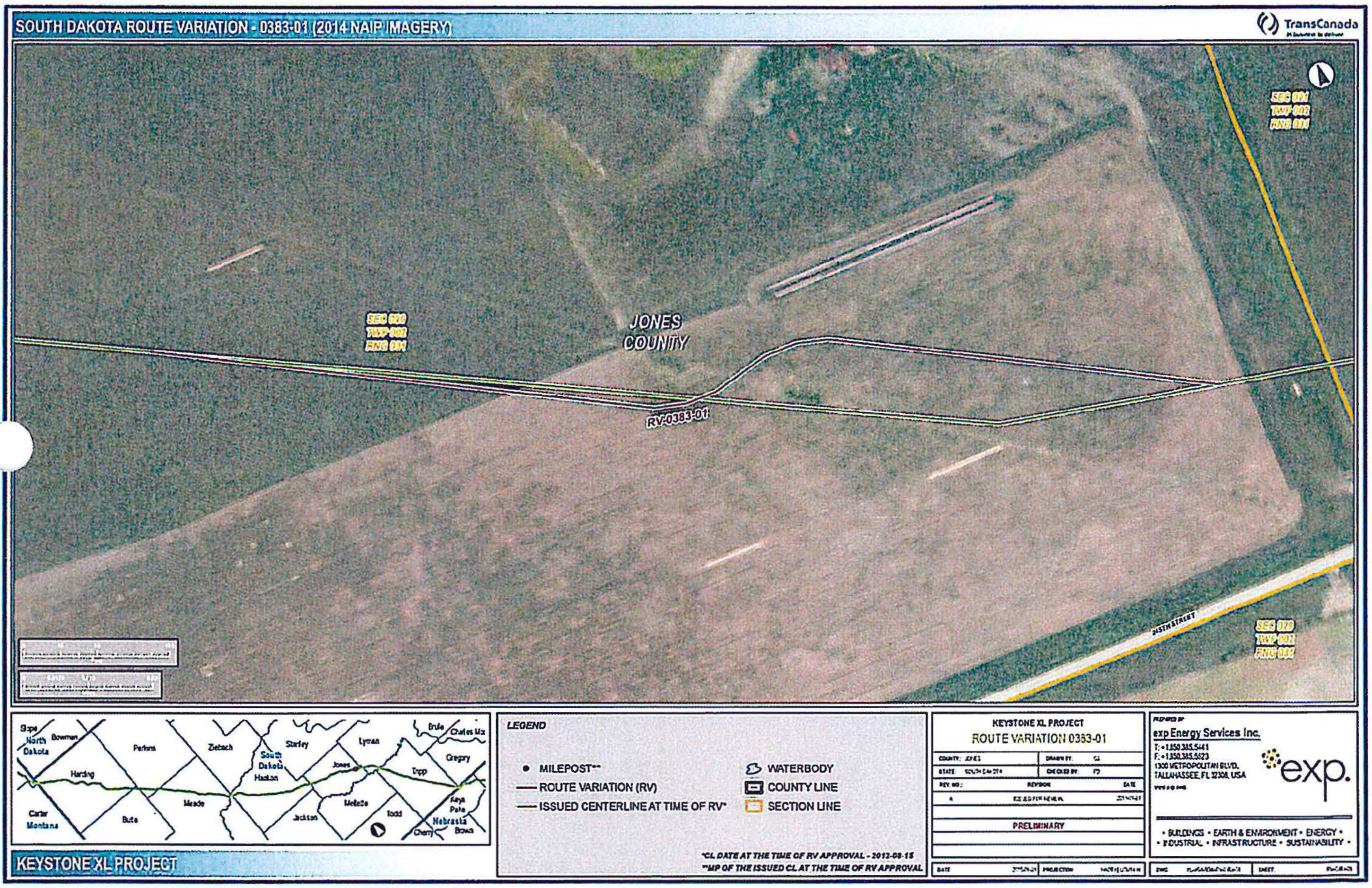

KEYSTONE 0560

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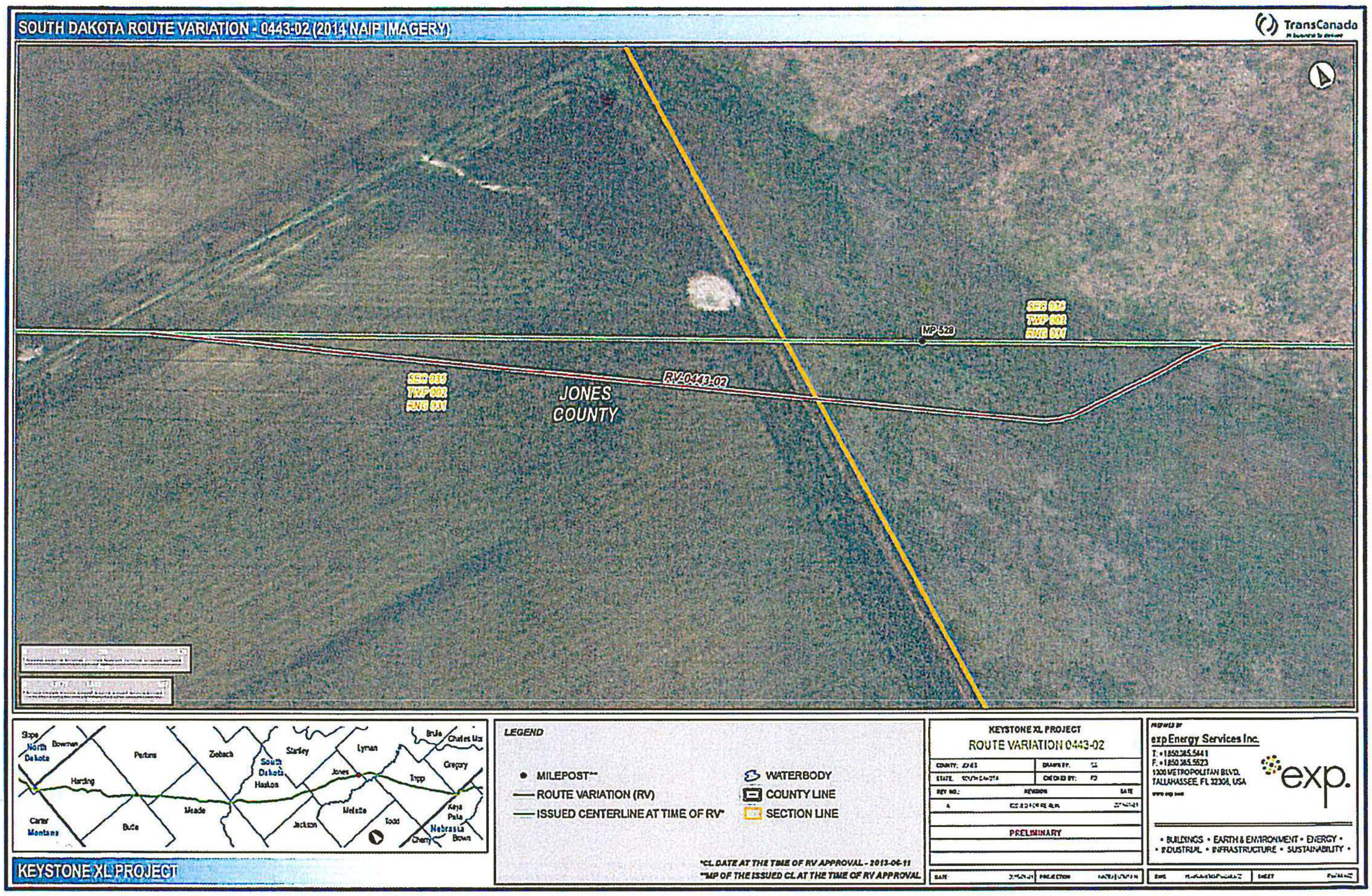

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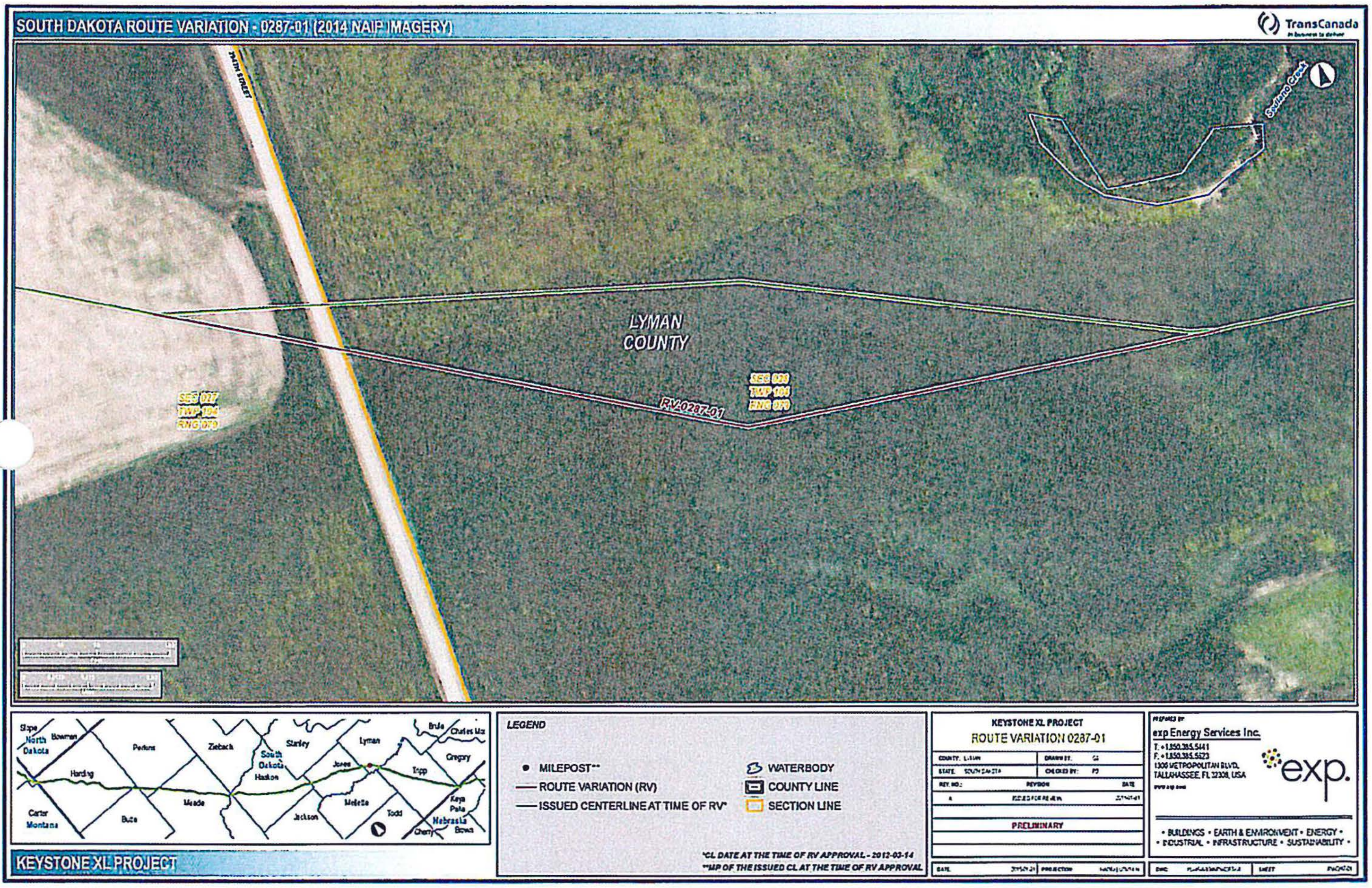

KEYSTONE 0562

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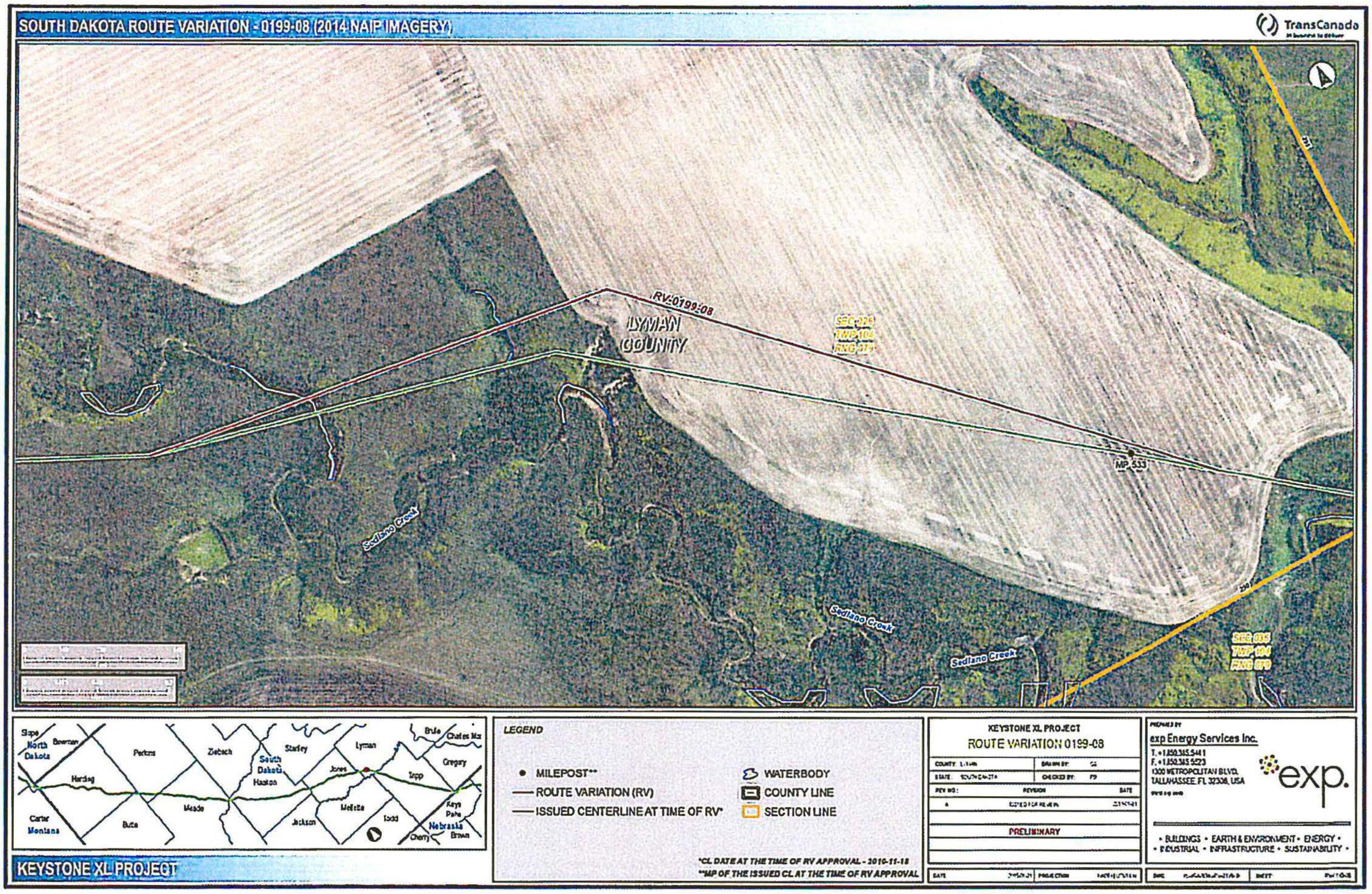

KEYSTONE 0563

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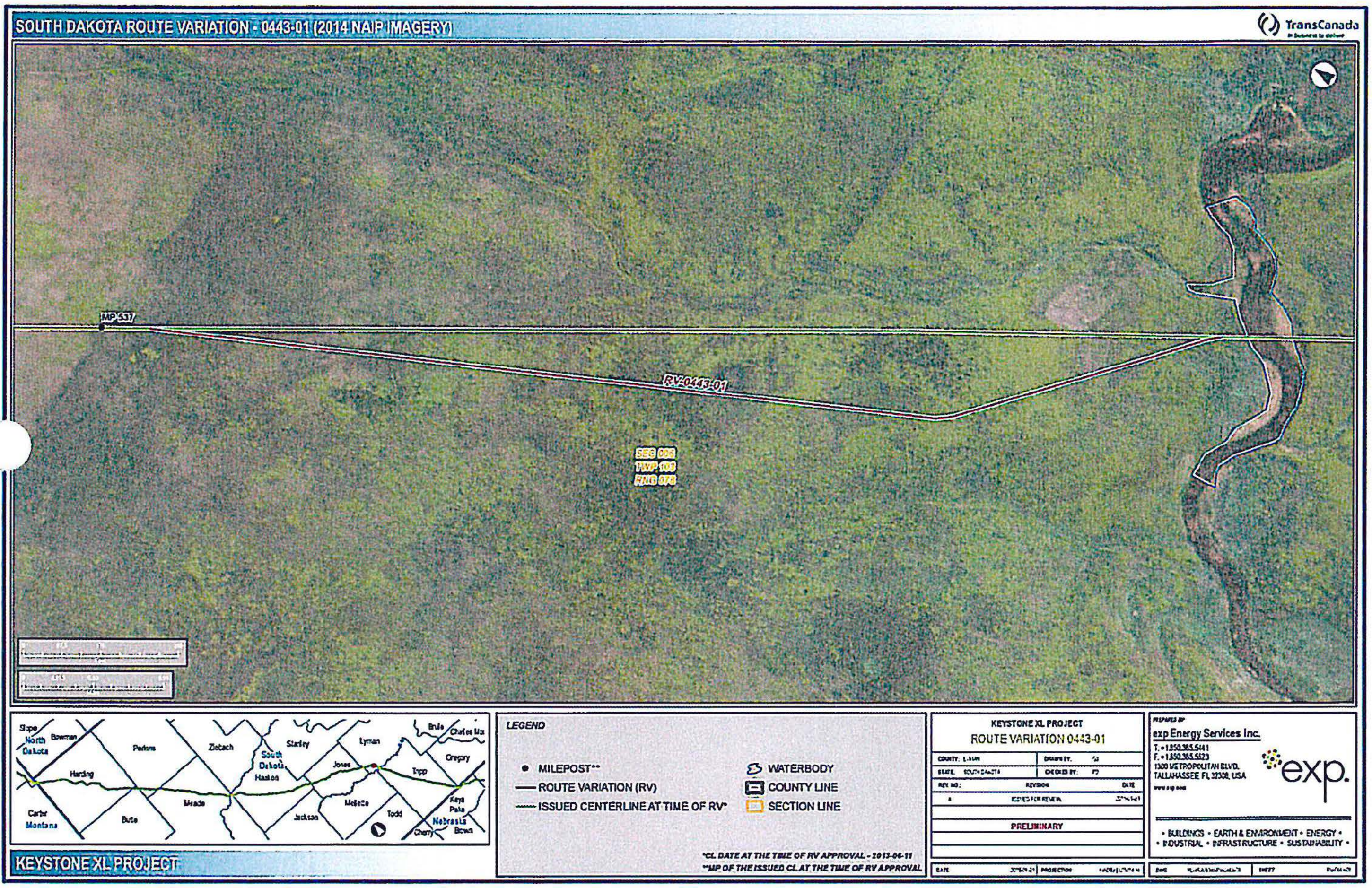

KEYSTONE 0564

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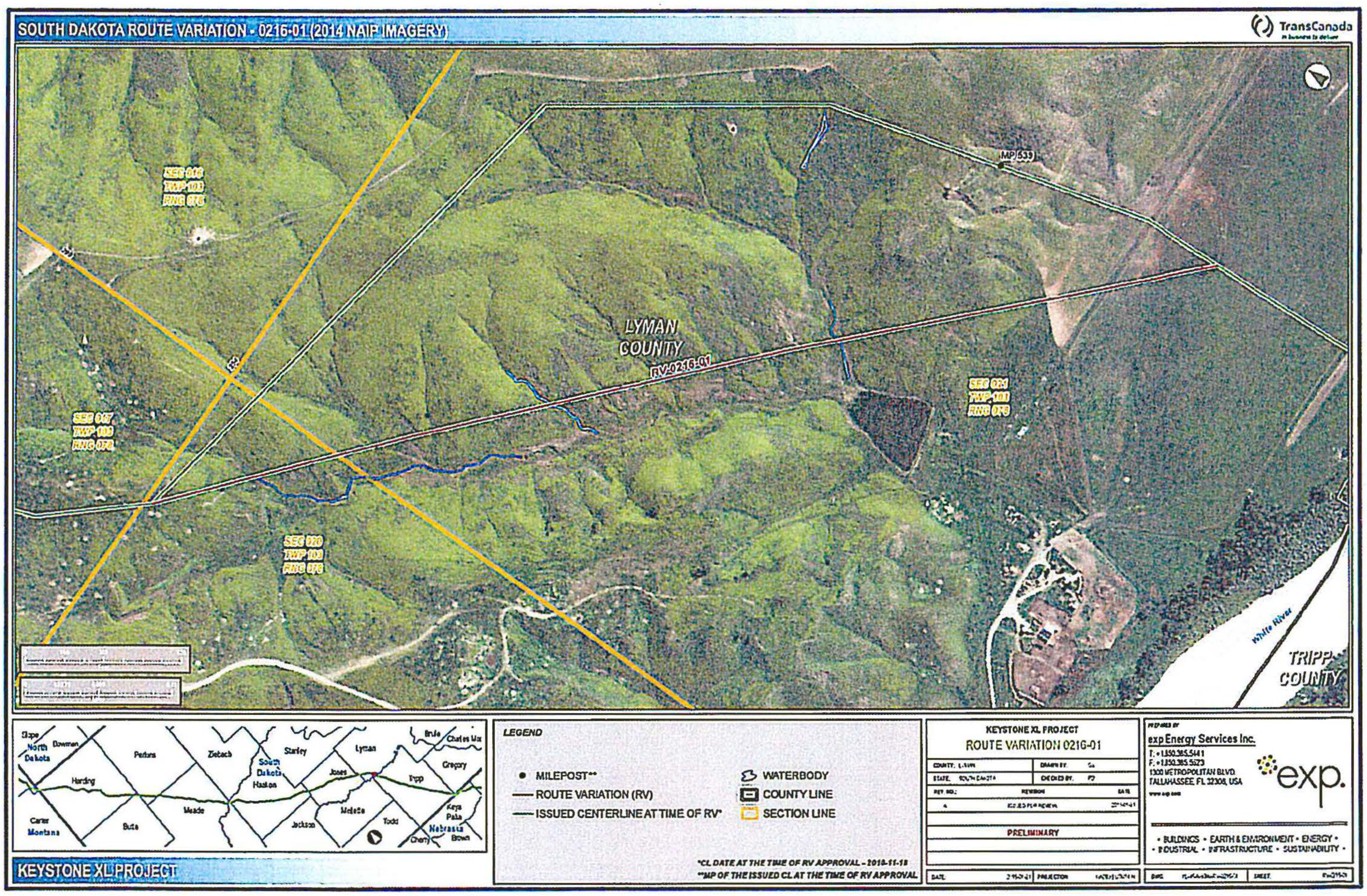

KEYSTONE 0565

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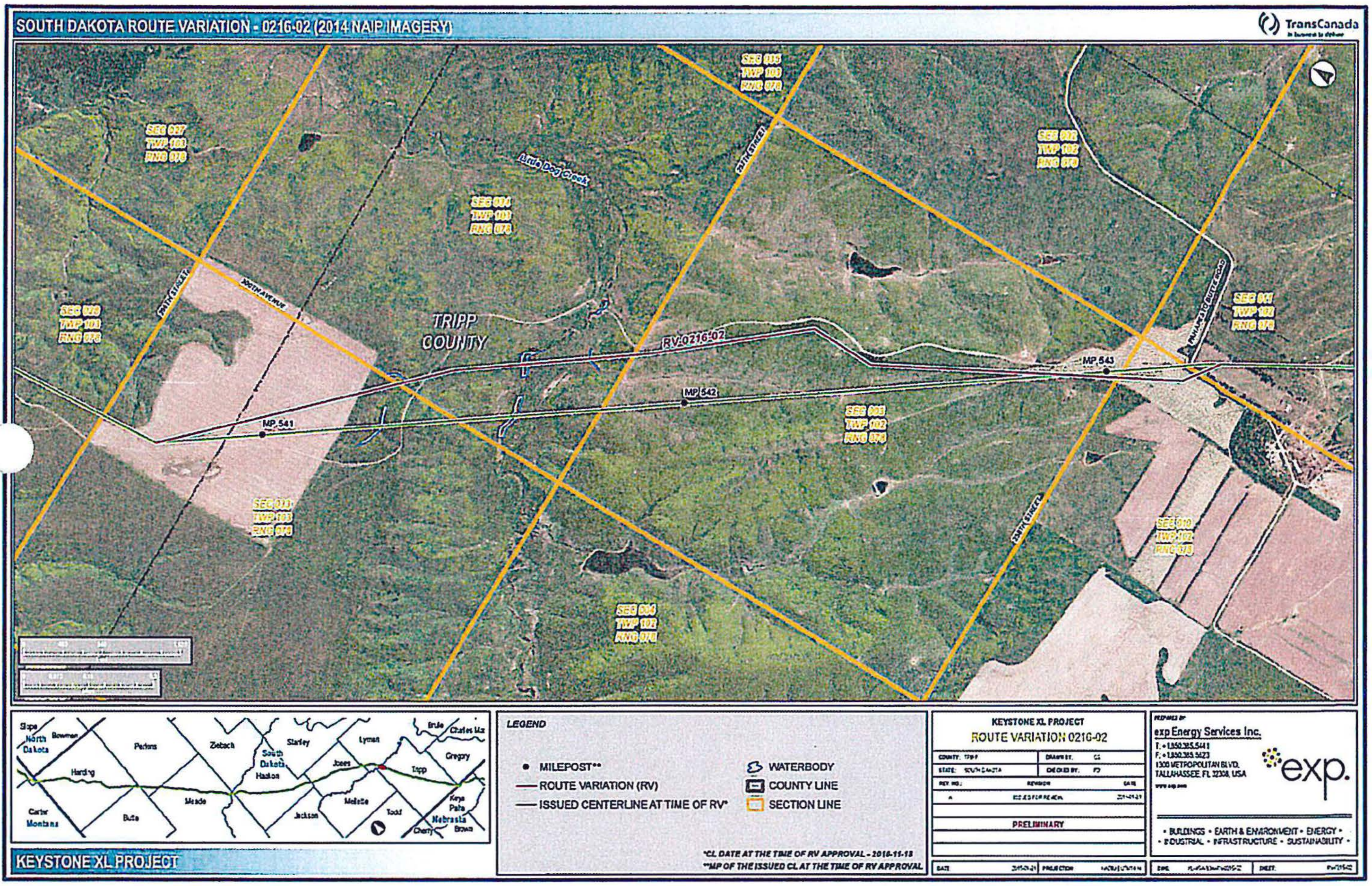

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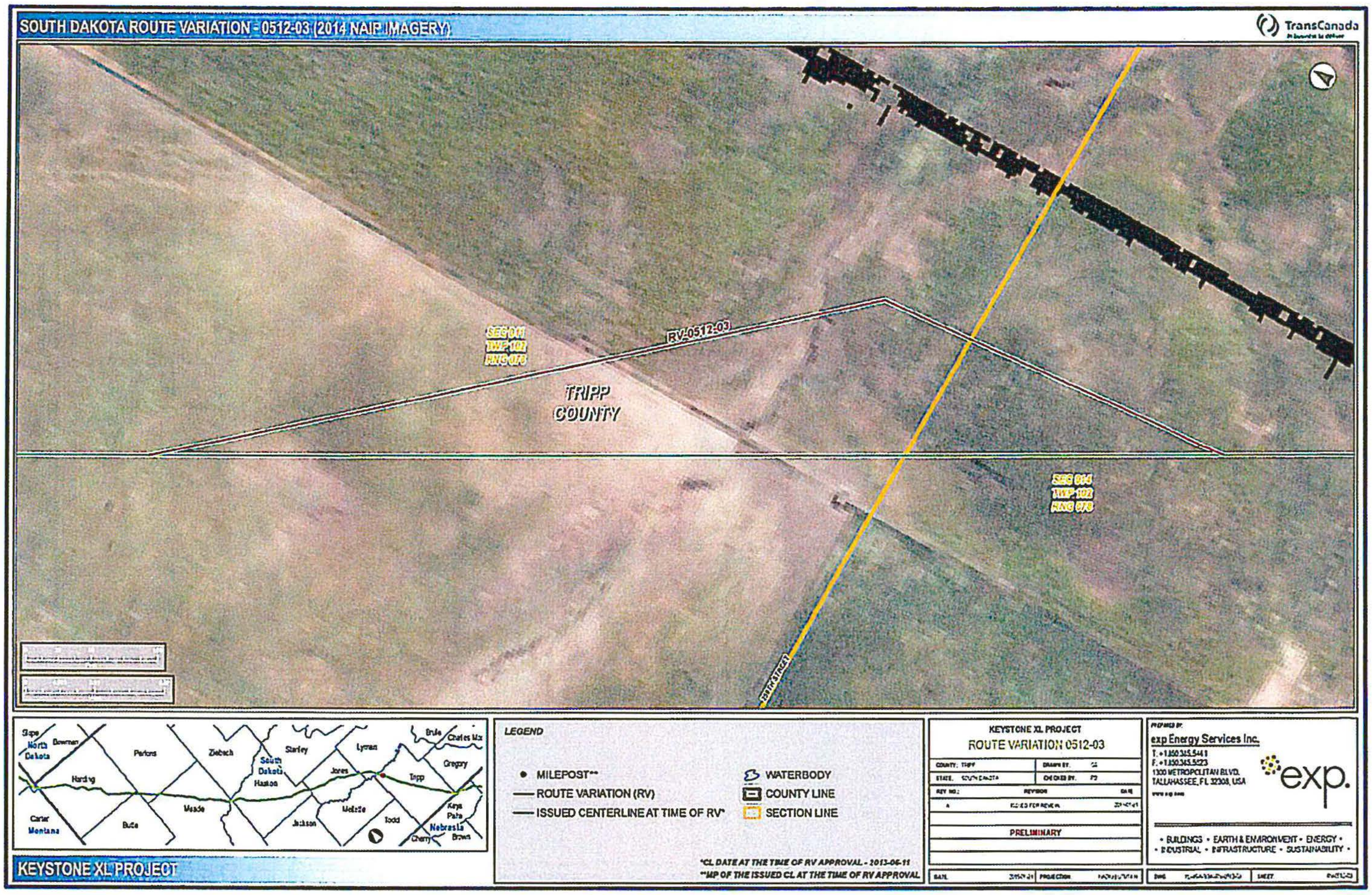
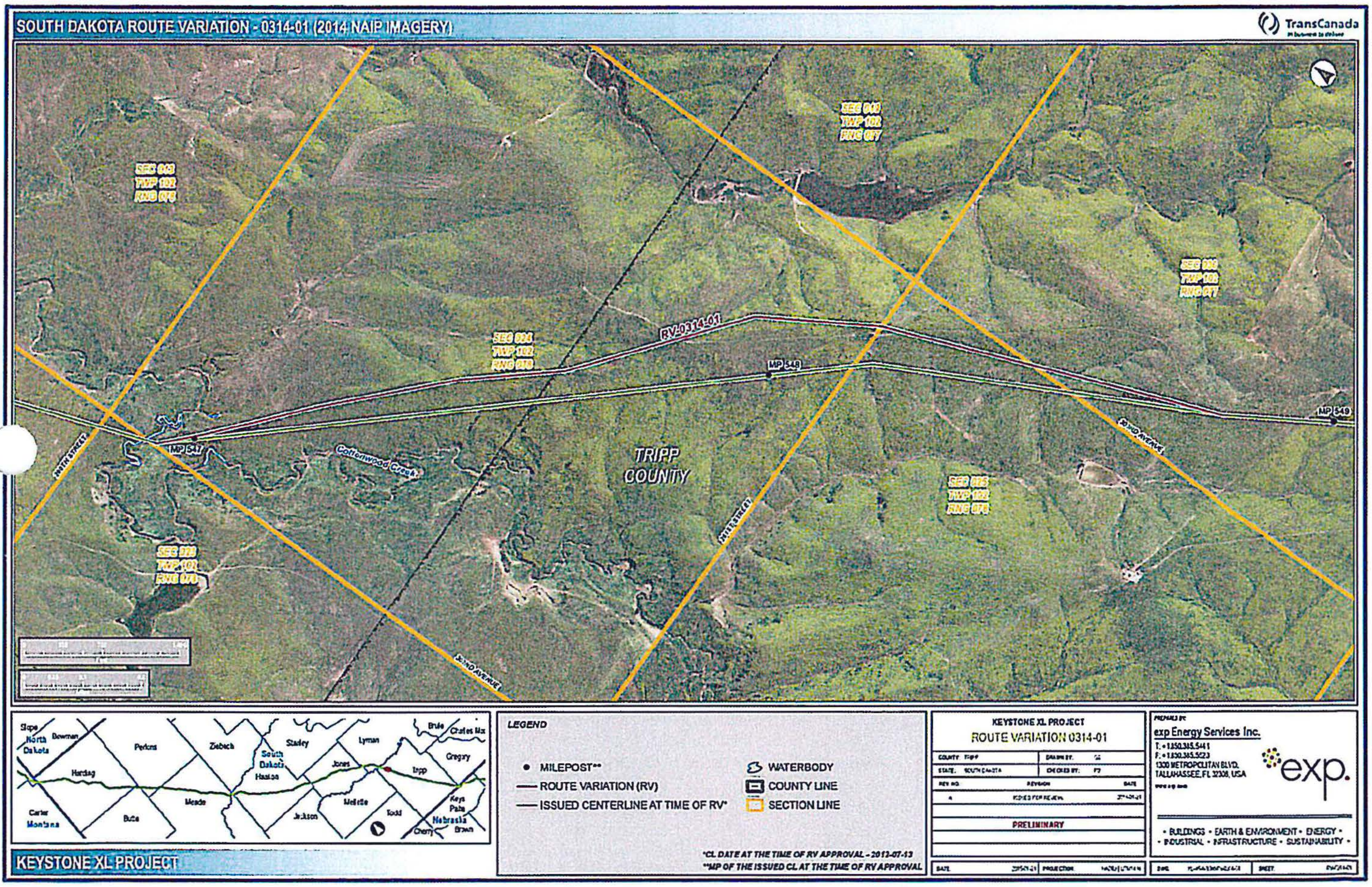

SOUTH DAKOTA ROUTE VARIATION - 0512-03 (2014 NAIP IMAGERY)
TransCanada
RV-0512-03
TRIPP
COUNTY
Slope
North Dakota
Bowman
Perkins
Ziebach
Stanley
Lyman
Brule
Charles Mix
Harding
South Dakota
Haakon
Jones
Tripp
Gregory
Carter
Montana
Butte
Meade
Jackson
Mellette
Todd
Keya Paha
Nebraska
Cherry
Brown
LEGEND
MILEPOST**
ROUTE VARIATION (RV)
ISSUED CENTERLINE AT TIME OF RV*
WATERBODY
COUNTY LINE
SECTION LINE
*CL DATE AT THE TIME OF RV APPROVAL - 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.
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •
KEYSTONE XL PROJECT



KEYSTONE 0568

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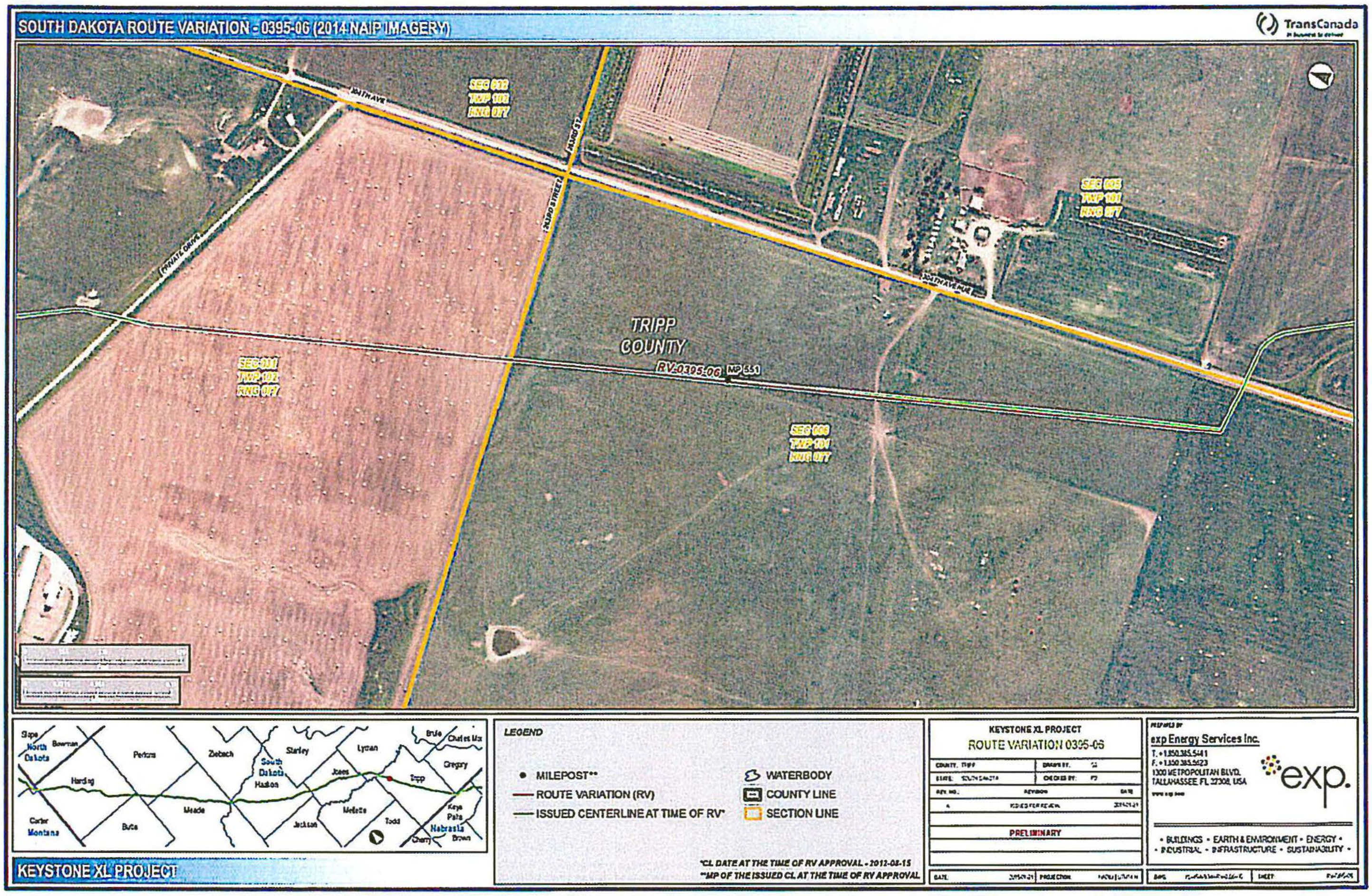

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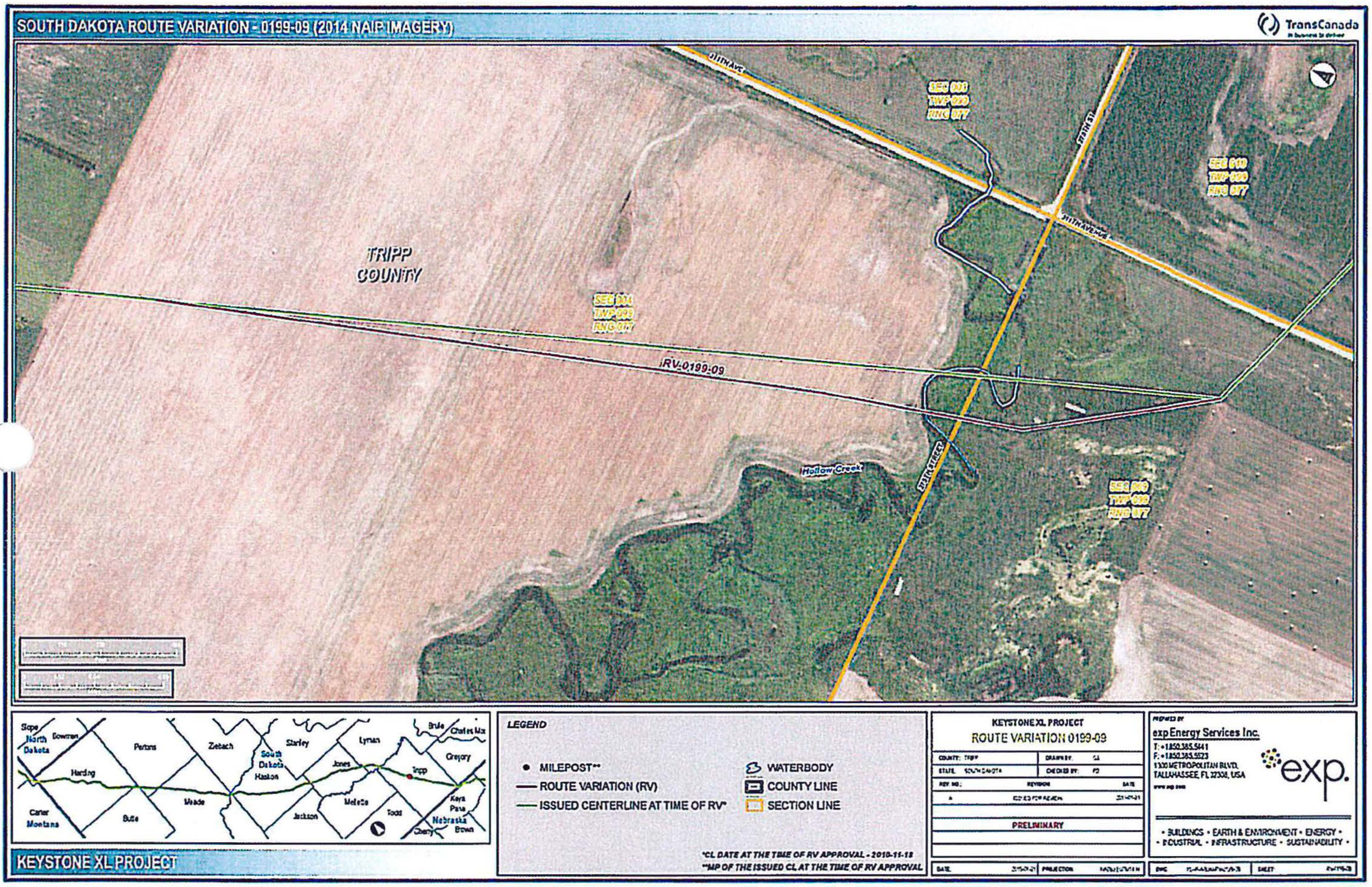

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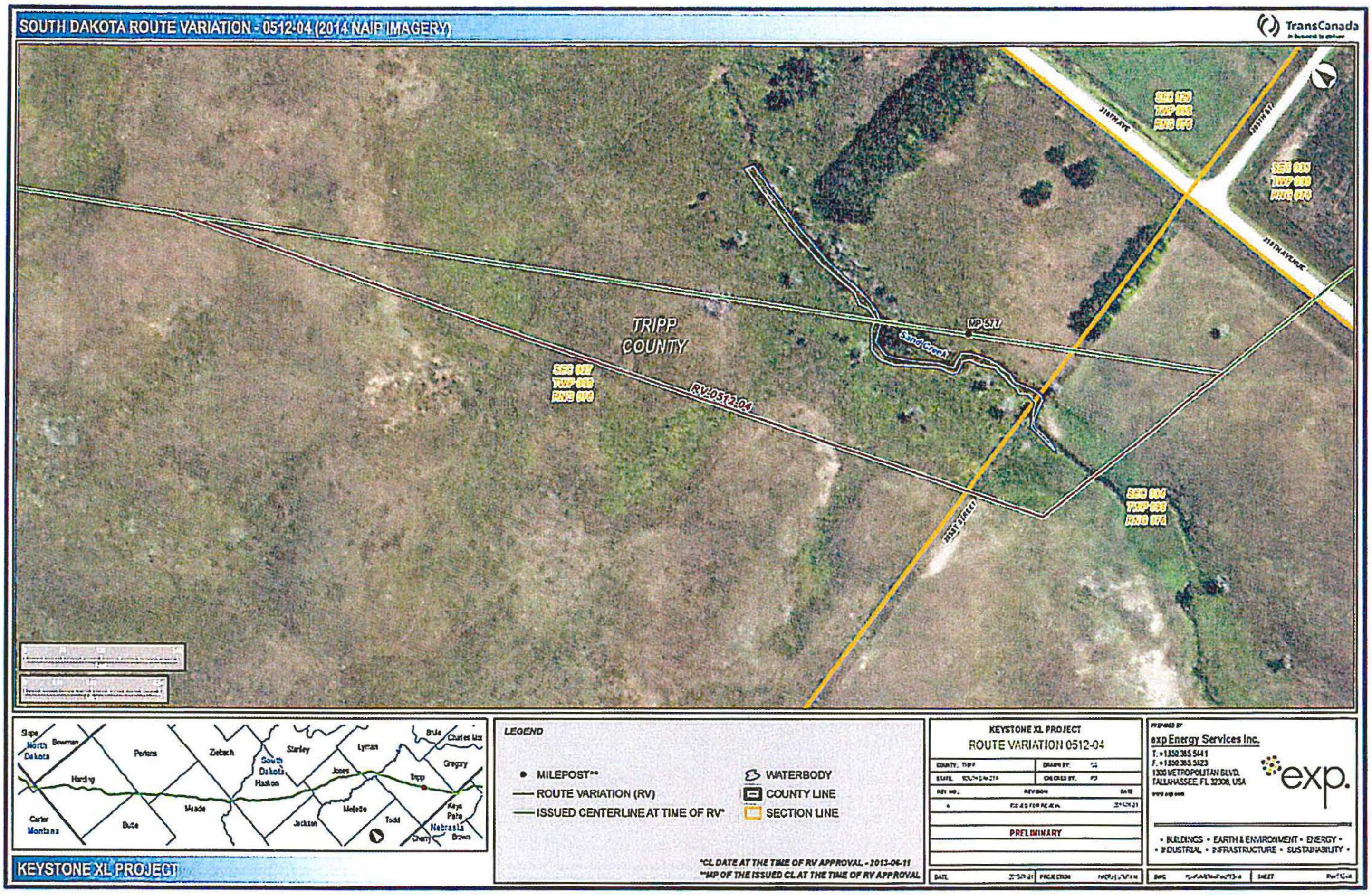

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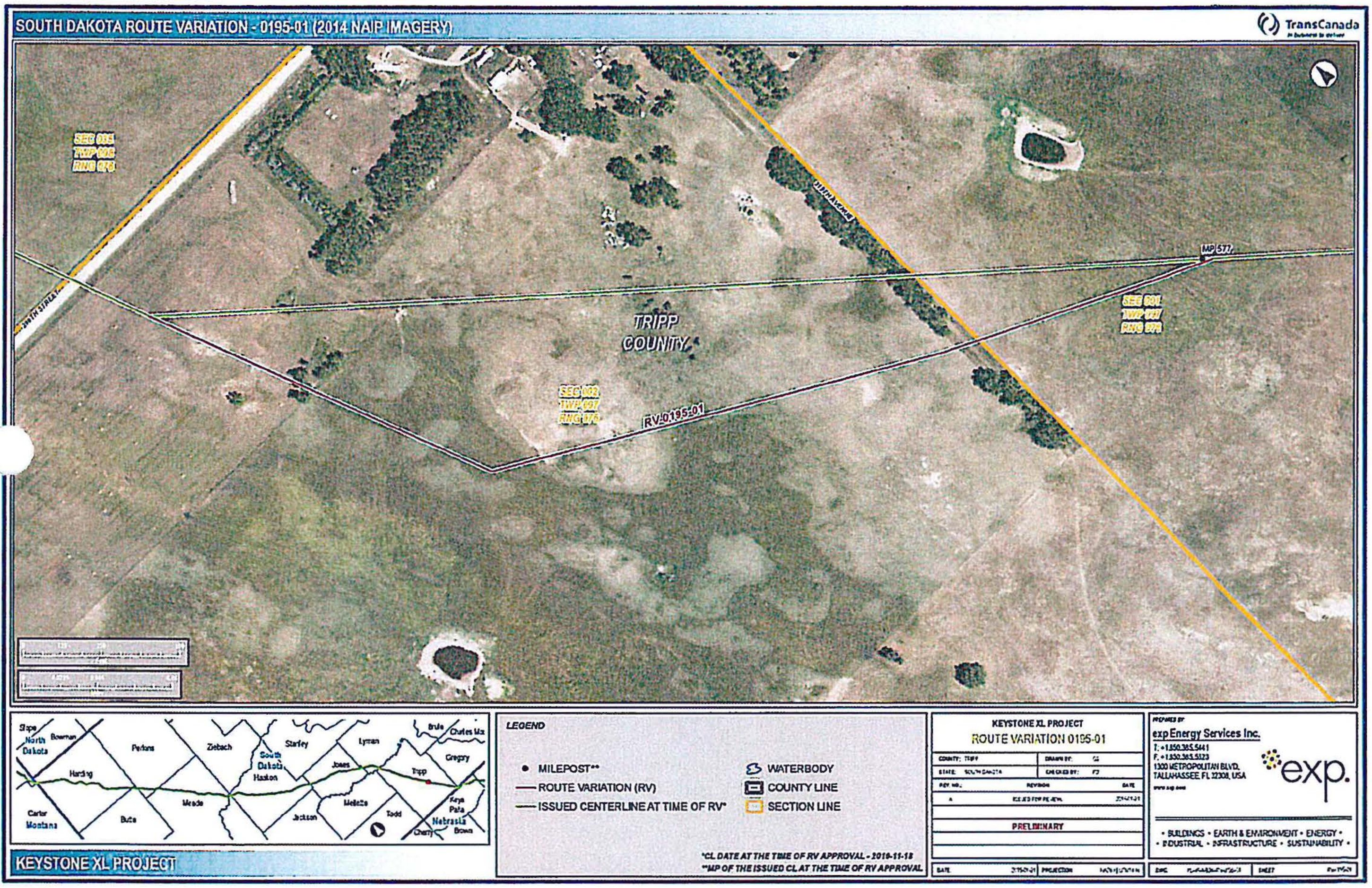

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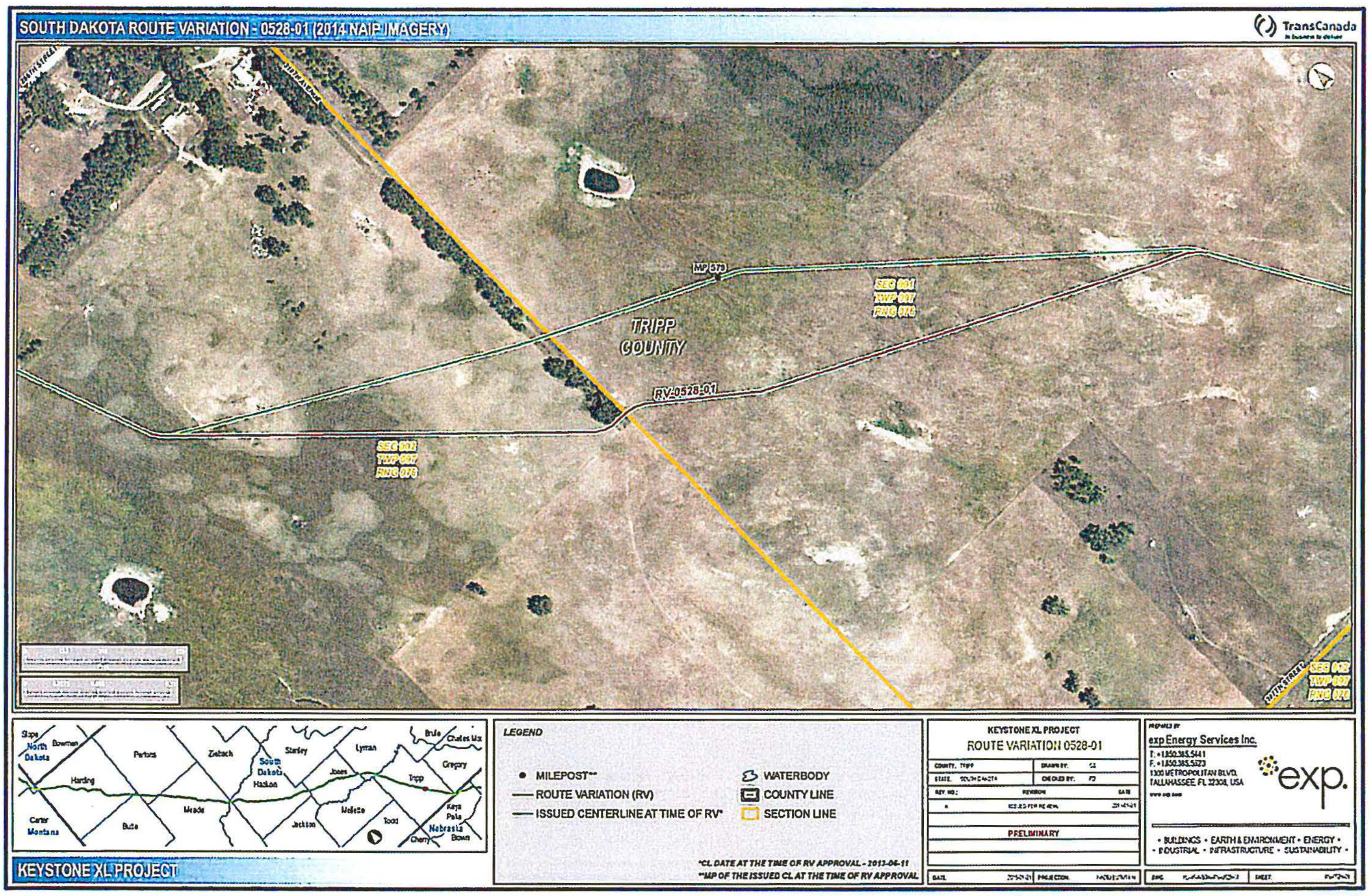
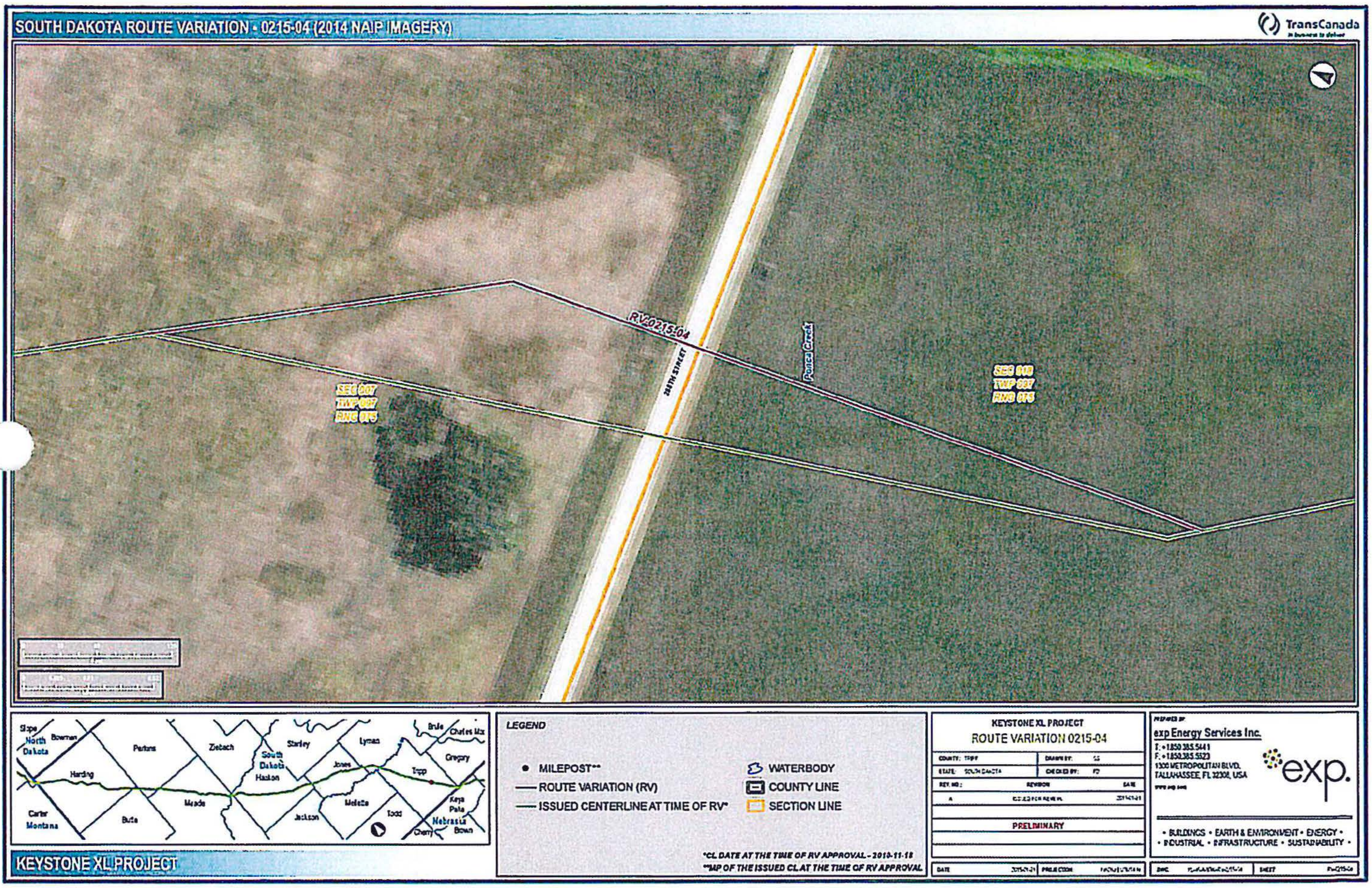
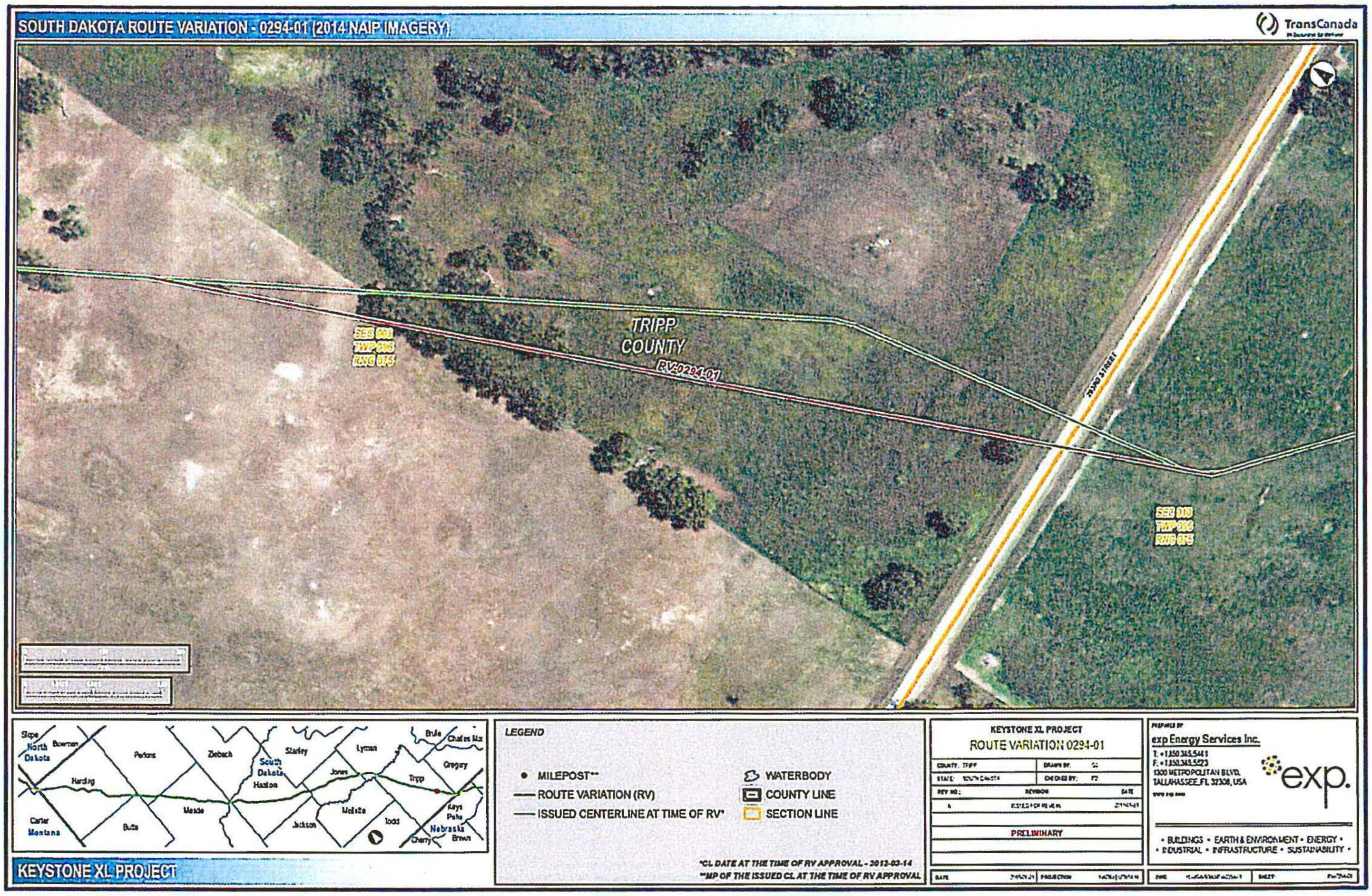


SOUTH DAKOTA ROUTE VARIATION - 0528-01 (2014 NAIP IMAGERY)
TransCanada
MP 573
TRIPP COUNTY
RV-0528-01
KEYSTONE XL PROJECT
Slope
North Dakota
Bowman
Perkins
Ziebach
Stanley
Lyman
Brule
Charles Mix
South Dakota
Haakon
Jones
Gregory
Harding
Tripp
Carter
Montana
Butte
Meade
Mellette
Todd
Keya Paha
Nebraska
Jackson
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 - 2013-06-11
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0528-01
PRELIMINARY
exp Energy Services Inc.
1300 METROPOLITAN BLVD.
TALLAHASSEE, FL 32308, USA
exp.
• BUILDINGS • EARTH & ENVIRONMENT • ENERGY •
• INDUSTRIAL • INFRASTRUCTURE • SUSTAINABILITY •



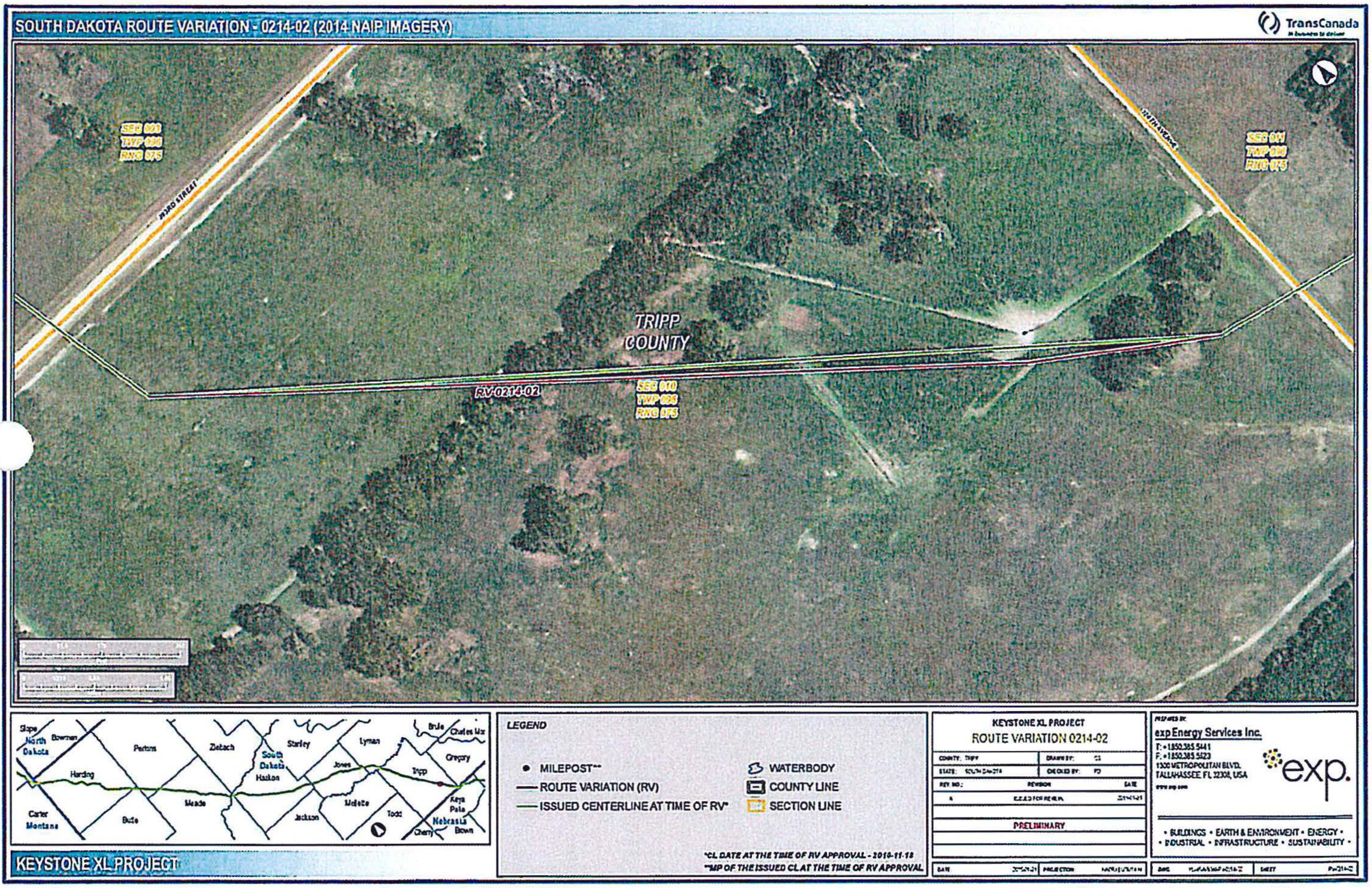
KEYSTONE 0574

021059



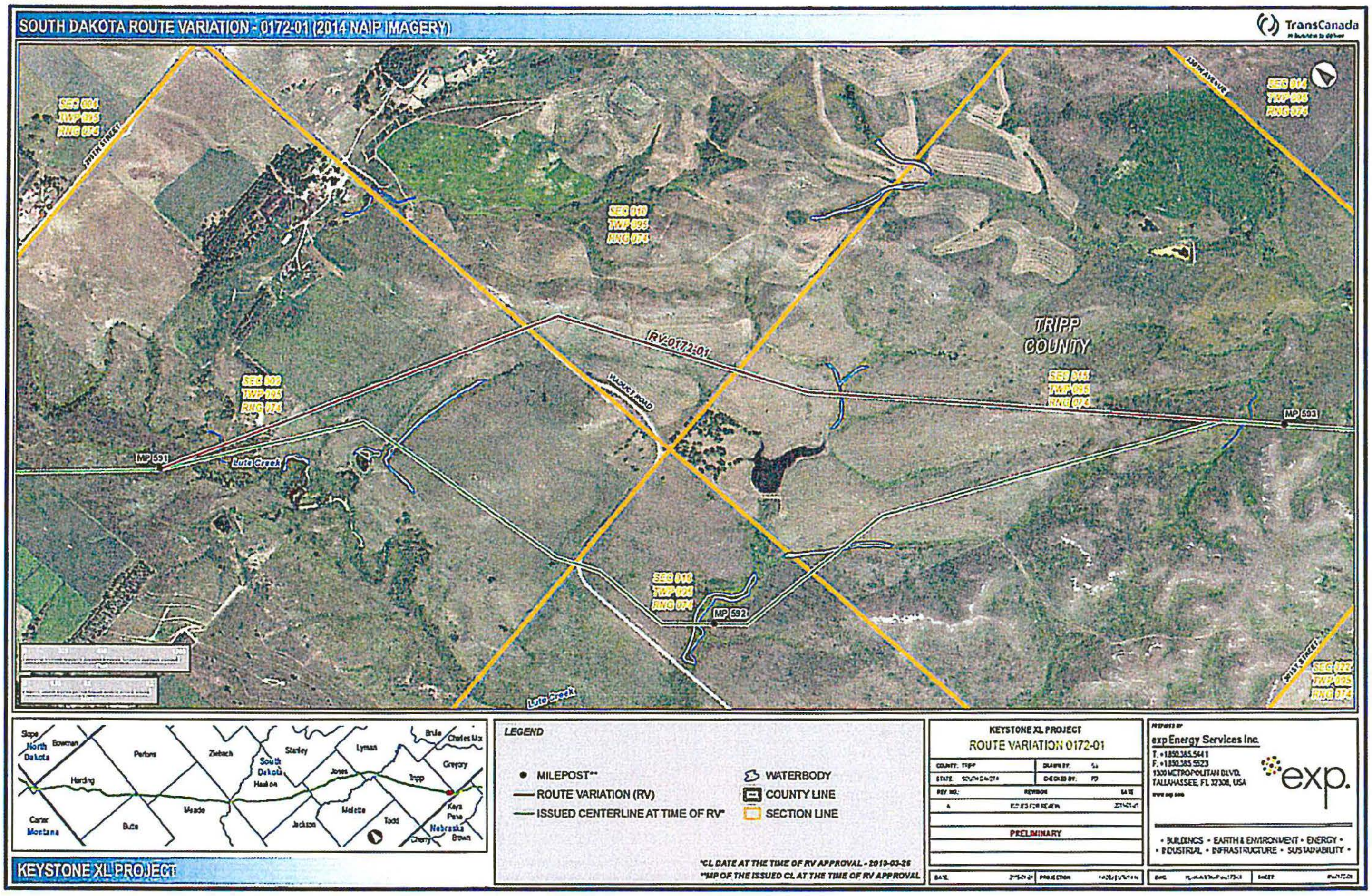
KEYSTONE 0575

021060



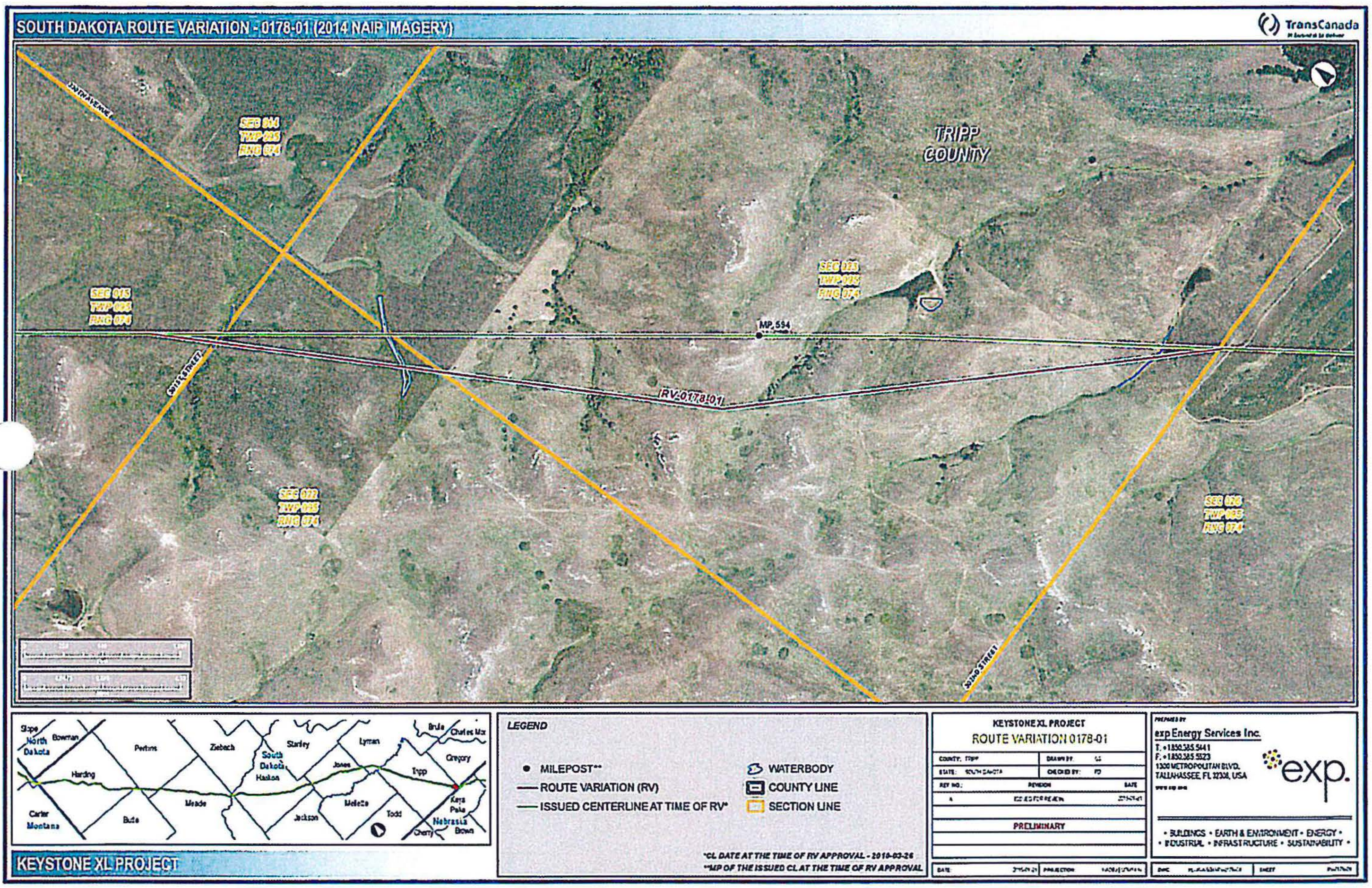
KEYSTONE 0576

021061

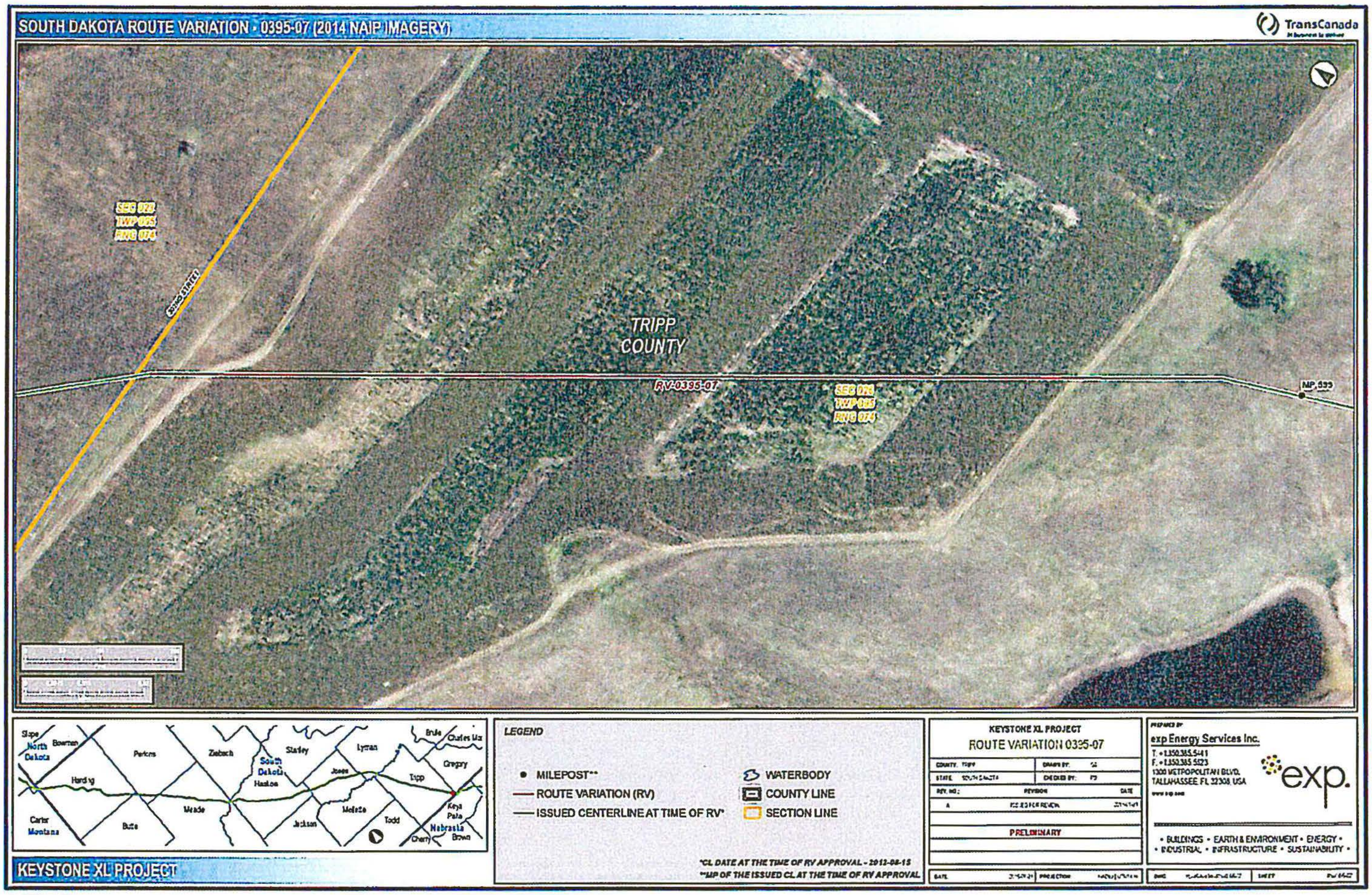


KEYSTONE 0577

021062

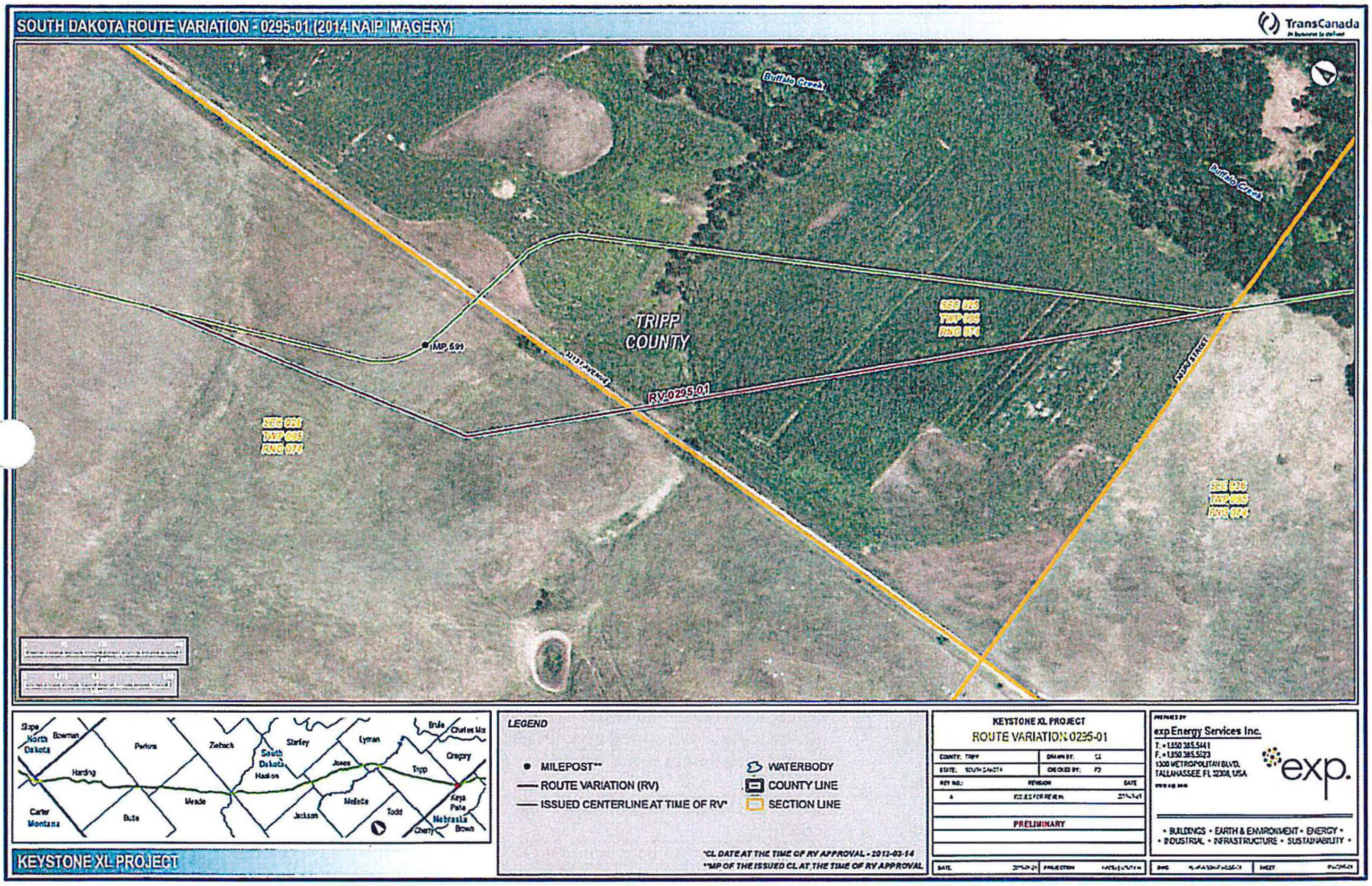


SOUTH DAKOTA ROUTE VARIATION - 0178-01 (2014 NAIP IMAGERY)
TransCanada
TRIPP COUNTY
MP 594
RV-0178-01
302ND STREET
Slope
North Dakota
Bowman
Harding
Perkins
Ziebach
Stanley
Lyman
Brule
Charles Mix
Gregory
South Dakota
Haakon
Jones
Tripp
Carter
Montana
Butte
Meade
Jackson
Mellette
Todd
Keya Paha
Nebraska
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 - 2019-03-26
**MP OF THE ISSUED CL AT THE TIME OF RV APPROVAL
KEYSTONE XL PROJECT
ROUTE VARIATION 0178-01
COUNTY: TRIPP
STATE: SOUTH DAKOTA
DRAWN BY:
CHECKED BY:
REV NO.:
REVISION
DATE
PRELIMINARY
DATE
PROJECTION
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 •
DWG
SHEET



KEYSTONE 0579

021064



KEYSTONE 0580

021065

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.

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.