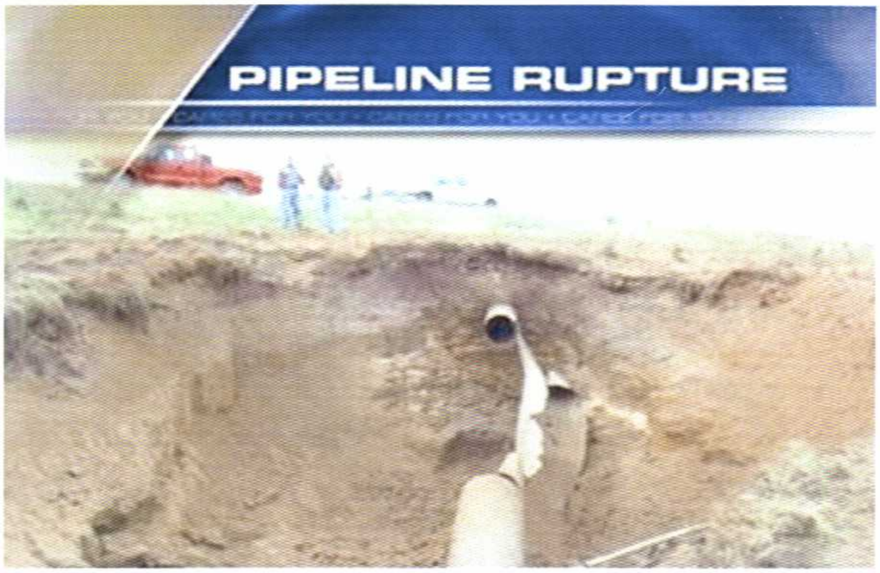


Is South Dakota Ready For High Pressure Crude Oil Pipelines?

Testimony Presented
October 31, 2007
by Curt Hohn Before the
S.D. Public Utilities Commission
In The Matter of Application HP 07-001
TransCanada-Keystone Pipeline

Photos: Pipeline failures at Whiteside County, IA, Oct. 15, 2007 (top photo) **TransCanada Pipeline south east of Grande Prairie, Dec 1, 2003** (middle & bottom photos)

"Thinner walled pipe means greater risk for South Dakota. Much of the steel pipe that will be installed will be made in China and India. Neither country can provide the level of inspection and quality control that U.S. steel pipe company's offer.

The PUC should require that all pipe installed in South Dakota be made in the USA and be of the same wall thickness or greater wall thickness than existing oil pipelines being operated, tested and inspected by the federal government in the United States of American.

Most of TransCanada's pipeline experience is with natural gas pipelines which are less likely to spill and damage soil or ground water. When crude oil pipes leak the oil spreads out into the soil and damages the groundwater aquifers.

Curt Hohn
WEB General Manager

EXHIBIT
WEB 7
12-10-07 cw
PENGAD 800-631-6989

Before the Public Utilities Commission of the State of South Dakota

IN THE MATTER OF THE APPLICATION BY TRANSCANADA KEYSTONE PIPELINE, LP FOR A PERMIT UNDER THE SOUTH DAKOTA ENERGY CONVERSION AND TRANSMISSION FACILITIES ACT TO CONSTRUCT THE KEYSTONE PIPELINE PROJECT	)))))))	HP 07-001 **DIRECT TESTIMONY OF CURT HOHN** October 31, 2007

My name is Curt Hohn. I'm the General Manager of WEB Water Development Association, Inc., with offices at 38462 U.S. Highway 12, P.O. Box 51, Aberdeen, South Dakota 57402-0051. I'm responsible for the overall leadership, operations, development and protection of the WEB water pipeline system which provides domestic water service and drinking water to a 17 county area, which includes 14 counties in South Dakota and 3 counties in North Dakota.

Professional Qualifications - Background

I have been involved in water resource development, management, water resource conservation, aquifer studies, and rural water system development since 1976. From 1976 through 1982, I served as the Manager of the Oahe Conservancy Sub-district, one of five districts established by the South Dakota Legislature for the purpose of regional water resource development. In that capacity, I worked with the South Dakota Geological Survey (SDGS) and United States Geological Survey (USGS) on ground water studies that were completed in the northeast area of South Dakota, including the counties of Marshall, Day, Clark, Brown, and Beadle, all of which would be crossed by the TransCanada-Keystone Pipeline as currently proposed. I have served as the General Manager of the WEB Water Development Association for 15 years, from 1983 through 1987 and again from 1997 to the present date. I have been involved in securing the necessary federal authorization and funding for the WEB project and have been involved in the management and over sight of much of its construction. From 1998 to 1999 I served as a contract facilities consultant for CBM Inc. I also served as the Division Administrator and Operations Manager for the Oregon General Services Department from 1989 to 1993 involved in building facilities construction and operations. As the Manager of Engineering and Technical Services for the Clackamas Water and Sanitary District from 1994 to 1997 I was involved in treatment plant and pipeline system development and construction for a fast growing urban growth area southeast of Portland, OR. I'm a graduate of Northern State University with a Bachelor of Science degree in business and public administration. I worked as plumber on large building and heating/cooling facility construction to put myself through college. I was born and raised in Aurora County, South Dakota near the town of Plankinton on a family farm which is still being operated by a member of my family.

WEB Water Development Association, Inc.

WEB Water Development owns and operates a regional water pipeline system which provides drinking water and domestic water to 8,000 farms and rural homes, 105 towns and bulk use customers, 5 ethanol plants, 2 electrical peaking power plants, 2 soybean processing plants, a 500,000 head livestock industry, and assorted industries in a 17 county area through a 6,800 mile pipeline system. Our primary source of water is the Missouri River at Lake Oahe Reservoir south of Mobridge, SD. The WEB water system was constructed in 1985 to 1990 to replace the deep artesian water wells, which prior to WEB were the main source of water for most of the area since statehood. The artesian water has high levels of sodium and TDS and fails to meet federal and state safe drinking water standards.

TransCanada-Keystone Impact On WEB

As proposed, the TransCanada- Keystone Pipeline would cross or parallel the WEB water pipeline system at 12 to 20 different locations in Day and Clark Counties, depending on the final route taken by the oil pipeline. The largest pipe being impacted is a 12 inch PVC mainline which provides the primary source of drinking water for 1,029 farms and rural homes, 8 towns and several lake resort areas in Day, Marshall and Clark Counties. One of the few sources of quality water in the area is the glacial drift area that makes up the James Aquifer and the Deep James Aquifer located along the west edge of Marshall, Day, and Clark Counties.

The route that TransCanada has selected for the proposed Keystone oil pipeline would cross through and over this aquifer, which is used by ranchers and farmers in the area for livestock and other uses. WEB is exploring the development of wells in groundwater aquifers near Mansfield, SD and Andover, SD to develop wells and install package water treatment plants to treat ground water, which will be blended with treated Missouri River water to help WEB meet peak water needs of our customer service area including value added plants that are building in the area.

Burden of Proof

Under South Dakota law, the applicant in this case, TransCanada, has the burden of proof as stated in SDCL 49;

> *SDCL 49-41B-22 Applicant's burden of proof. The applicant has the burden of proof to establish that:*
>
> *(1) The proposed facility will comply with all applicable laws and rules;*
>
> *(2) The facility will not pose a threat of serious injury to the environment nor to the social and economic condition of inhabitants or expected inhabitants in the siting area;*
>
> *(3) The facility will not substantially impair the health, safety or welfare of the inhabitants; and*
>
> *(4) The facility will not unduly interfere with the orderly development of the region with due consideration having been given the views of governing bodies of affected local units of government.*

The testimony presented in this document will address where we believe the permit application filed by TransCanada fails to meet burden of proof as required under state and federal law.

(1) The proposed facility will comply with all applicable laws & rules

The permit application and project plan presented by Canada-Keystone does not comply with state and federal laws and regulations.

Title 49: Transportation, Part 195 - Transportation of Hazardous Liquids By Pipeline: Federal regulations require that plans for crude oil pipelines provide protection for High Consequence Areas (HCA's) and Unusually Sensitive Areas (USA's) and Wellhead Protection Areas (WHPA) which has not been done by the applicant TransCanada. The permit applications filed with the U.S. State Department and the permit application filed with the SDPUC failed to recognize shallow aquifers being crossed in Marshall, Day, Clark and Beadle Counties and other counties. The applications also failed to recognize and mitigate for eight (8) rural water systems being crossed by the project.

Eminent Domain: The permit application does not comply with South Dakota eminent domain law SDCL 21-35, SDCL 49-41B, SDCL 46-8, SDCL 49-2, SDCL 49-7.

Common Carrier: TransCanada does not meet the test of a "common carrier". TransCanada has not secured the necessary permit from the South Dakota Public Utilities Commission and the necessary approvals. TransCanada has not obtained legislative approval, has not "Negotiated in good faith" as required under the law, and has secured easements through use of "harassment and willful or wanton misconduct and fraudulent means". TransCanada holds itself out as "a common carrier engaging in the business of transporting commodities for hire" when in fact the Keystone Pipeline is owned by a monopoly and will be used primarily to haul the oil products of the owners and investors of the pipeline, Conoco Phillips and EnCana Corp, a Calgary-based company specializing in recovery of oil sands bitumen. **(See Exhibit 1)** TransCanada-Keystone will move no oil products for anyone in South Dakota and will provide no direct benefit to the residents of South Dakota, which is essential in claiming common carrier status. We believe that TransCanada has violated state and federal law by filing condemnation and eminent domain against 18 South Dakota landowners, 15 landowners in Marshall County and 3 landowners in Day County. TransCanada has taken this action before the SDPUC has even held formal hearings or granted a permit and before the appeal of any such decision could be considered by a circuit court as is required by law and before a permit approval has been granted by U.S. government. TransCanada's permit and project plan does not comply with eminent domain laws of the state or the federal EIS approval process. The easement document TransCanada has used to secure signatures includes a clause that calls for "**one or more pipes**" to be placed in the easement right-of-way while the permit and project plan specifies one pipeline. **(See Exhibit 2)** An easement of this kind which is secured under duress or under the pressure or threat of condemnation, is not a valid document and amounts to an illegal taking which is a violation of state and federal law and a possible violation of the civil rights of the property owners involved.

James Bush of Britton, SD was working cattle when TransCanada's land agent dropped by and insisted that Bush stop what he was doing and sign the easement which he had just been given. Bush asked to set up an appointment at a later date. The next contact Jim had with TransCanada was when the sheriff delivered condemnation papers. An elderly lady (whose signed statement will be provided later) will testify that she was told by a TransCanada land agent that if she signed the easement "**we can bring the boys back from Iraq sooner"**. We will present signed statements and testimony from various landowners that TransCanada land agents have raised the threat of condemnation at the first meeting and virtually every meeting or contact. There has been no negotiation as required by state and federal law. Landowners were denied their requests to keep a copy of the easement to share with their attorney or family. If TransCanada, a private company from a foreign country, is allowed to take land and property by eminent domain and condemnation, then property rights are no longer safe in South Dakota and the United States of America. Under South Dakota law, the use of eminent domain (condemnation) is limited to state and local governments, power lines, rural water systems and railroads <u>that provide benefits to the communities they cross</u>. Taking of private land is done only after all other options have been exhausted. Even then, landowners have the right to appeal to locally elected boards and commissions for relief.

National Environmental Policy Act (NEPA): The project plan and testimony presented by TransCanada does not adequately address and compare the environmental and social impacts of the proposed route to various other alternate routes that could and should be considered, including the I-29 Alternate Route along the west road ditch of Interstate Highway 29 which was included as an alternate route in the permit application filed with the US State Department (See Exhibit 3). Or a route from Williston, ND south through the oil field area of western North Dakota and South Dakota which would place the pipe near the oil fields and provide a means for shipping oil out.

Further consideration should be given to these alternate routes by the PUC and federal government as part of the Final Environmental Impact Statement. By failing to seriously consider this and other alternatives, TransCanada is in violation of federal law. In their testimony, TransCanada claims "constructing any pipeline along a major highway will put workers at risk, require highway closures, increase safety impacts and costs, hamper development of commercial districts and trade one group of affected landowners for another". The WEB rural water system constructed miles of large ductile iron pipelines ranging in size from 30 inch and 24 inch pipe in the Highway 12 and Highway 281 road ditches without accident or injury. The pipeline has been operated safely for more than 20 years. Permits were granted by the South Dakota Department of Transportation **(See Exhibit 4).**

The State of South Dakota owns the highway road ditch along I-29 so very little private farm land would be needed to accommodate construction of the Keystone Pipeline. Road access for construction, operation and emergency response purposes would be better from a four lane interstate highway than a dirt road or gravel section line road that often has load restrictions and often are impassable in the winter and during the spring of the year. There is concern that Keystone with use the easement right-of-way they secure or condemn as a "corridor" for **more pipelines**. A representative of ConocoPhillips stated in a Houston news story that South Dakota and the Midwest will be a "corridor" for oil pipelines (more than one) and that by the year 2020 as much as 3,500,000 barrels of tar sands crude oil will be moved through pipelines in the USA (See Exhibit 1). To move that much crude oil will require SIX pipelines like TransCanada-Keystone. The state permit process and NEPA require that all connected and related issues be addressed in the project plans and that project plan plans be specific and detailed.

The National Environmental Policy Act (NEPA) requires that alternatives be reviewed and considered and that the public be given an opportunity for comment. In 2006, as part of their filing with the U.S. State Department, TransCanada present maps showing three pipeline routes that would have used the west ditch of Highway I-29. All three options would have passed by Elk Point, South Dakota, the location Hyperion has selected for a tars sands oil refinery. In the end, the route proposed for the Keystone Pipeline was shifted west so that it will run from Britton to Yankton, South Dakota. The citizens of South Dakota were never included in the decision process on site selection for the pipeline or the refinery. The oil industry in Canada and Texas made the decision, without consultation, which is a violation of federal law and state law. IF the SDPUC grants a permit for the Keystone Pipeline it should be limited to one pipeline.

If a serious review of this project has been done by any state agencies the reports should be released to the public. Alternate pipeline routes through western North Dakota and South Dakota where oil wells are located or installing the pipe in the wide I-29 road ditch was never seriously considered or studied. The Department of Environment and Natural Resources (DENR), GF&P, Health Department, Geological Survey, EPA, and Fish and Wildlife have all been silent. Federal agencies say it's a state issue and state agencies say its federal. If a farmer installs a 1,000 gallon fuel storage tank, the DENR would review the plans and require containment to protect groundwater and the environment. If it leaks the farmer will be fined or prosecuted. The TransCanada pipeline will move 24.8 million gallons of crude oil PER DAY through South Dakota (591,000 barrels) through 220 miles of high pressure thin walled pipe crossing aquifers, wetlands, streams and hundreds of public and private water lines. Risk Management Consultants, DNV, says that a pinhole leak could release **372,000 gallons of oil PER DAY** with no review by state agencies. If a farmer drains a wetland GF&P or USF&W would fine them. If a farmer's oil tanks leaks DENR would issue a fine and enforce the law. TransCanada, a private oil company from a foreign country, is allowed to threaten landowners with condemnation, trespass on private property, dig through wetlands, streams and aquifers, and add a new risk to our environment and no state agency gets involved.

Need & National Interest: TransCanada says their pipe is in the "national interest" and is needed to move Canadian tar sands oil south to Illinois and Texas. Yet, US oil refineries are running at less than full capacity. Canadian oil will compete with US energy supplies, including ethanol and wind energy here in the Midwest. TransCanada provides no direct benefit to South Dakota. Federal and state agencies, like the Fish and Wildlife Service, NRCS, and GF&P refuse to grant easements so the oil pipe can't cross government land or land with government easements. That forces the oil pipeline over on to private farm land. Apparently a high pressure crude oil pipe is in the "National Interest" so long as it's on private farm land and doesn't cross government lands.

Full Disclosure - Public Information: Documents TransCanada filed with the SDPUC in April in support of their permit application were all stamped "confidential" and not made available to the public. Even the table of contents was marked confidential. Only after formal complaints were filed by Dakotan's Concerned and others was part of the information made available months later. Those documents that were eventually released were not available until the Friday before the public meetings, too late for the 660 people who attended the meetings to review the documents. TransCanada did most of the talking at the four meetings leaving only limited time for questions and public input. Landowner lists were never made available by TransCanada. After complaints were filed, a list was released by the PUC but it was loaded with names of adjacent landowners so no one could really tell where the pipeline would go and who was impacted. One month before the

PUC hearings, a June 26th version of the pipeline route map is still not available to the public or the PUC as of Oct. 22, 2007.

(2) The facility will not pose a threat of serious injury to the environment nor to the social and economic condition of inhabitants or expected inhabitants in the siting area............................

At an operating pressure of 1,440 psi to 1,584 psi the thin walled pipe that TransCanada is proposing to construct and operate what will be highly pressurize vessel waiting to fail. At that pressure, TransCanada is asking South Dakota to accept an "unreasonable risk of a crude oil leak or spill occurring resulting in irreversible damage to 220 miles and thousands of acres of productive farmland, millions of acre feet of ground water, hundreds of creeks and streams, wetlands, and the groundwater aquifers, rivers, creeks, wetlands and private property in eastern South Dakota. Robert Jones, TransCanda VP was quoted in an April 29, 2007 Argus Leader news story saying "crude oil regularly moves between 1,400 to **2,000 psi, up from 1,000 psi for pipelines built in the 1950's**" (See Exhibit 5). TransCanada will increase the pressure on this pipeline to 2,000 psi to move more and more oil through South Dakota to increase their profits. It's the job of state and federal regulators to protect the resources and the safety of the people of South Dakota.

Thinner Wall Pipe: November 17, 2006, TransCanada applied for a "Special Permit" from the federal government to install a 30-inch pipeline with THINNER PIPE WALL THICKNESS than any other oil pipeline currently operating in the United States. They also asked for permission to run the pipe at a HIGHER OPERATING PRESSURE (11%). TransCanada received the permit approval on April 30, 2007 but didn't inform the SDPUC or the public until August 23, 2007, four months later. What's remarkable is TransCanada has **no track record of operating high-pressure crude oil pipelines**. Most of TransCanada's pipeline experience is with natural gas pipelines which are less like to spill and damage soil or ground water. When crude oil pipes leak the oil spreads out into the soil and damages the groundwater aquifers. Thinner walled pipe means greater risk for South Dakota. Allowing a company like TransCanada, with no oil pipeline experience, a permit of that kind is an insult to South Dakota and every state crossed. According to recent news reports, much of the steel pipe that will be installed will be made in China and India. Neither country can provide the level of inspection and quality control that U.S. steel pipe company's offer. China has had problems making toothpaste, dog food and children's toys. A news story dated 10/31/07 reported that the estimated **cost of the TransCanada-Keystone Pipeline has risen from $2.1 billion to $5.4 billion** because of steel and construction costs (See Exhibit 6) . **The PUC should require** that all pipe installed in South Dakota be made in the USA and be of the **same wall thickness or greater wall thickness** than existing oil pipelines being operated, tested and inspected by the federal government in the United States of American. If a private company from Canada wants to build a crude oil pipeline through South Dakota they should be required to meet the same standards as the oil companies they are competing with in this country.

49 CFR 195.106 (Thinner Pipe Wall – Higher Pressure): TransCanada's permit application filed with the SDPUC on April 27, 2007 requested a permit to build and operate a pipeline to move 18,270,000 gallons (**435,000 barrels**) of tar sands oil per day through South Dakota at a pressure of 1,400 psi. **Four months later**, on August 23, 2007, TransCanada informed the SDPUC that they had requested and received a "Special Permit" from Jeffery D. Wiese, Acting Associate Administrator for Pipeline Safety, on April 30, 2007 to increase the volume moved to 24,822,000 gallons (**591,000 barrels**) per day which represents a **36% increase** in pipeline flow. To accomplish this, TransCanada proposes to increase the operating pressure from the standard followed by other oil pipes in the USA of 72% of pipe design capacity to 80% of pipe design capacity. In testimony, TransCanada officials are now saying the pressure will be 1,440 psi and 24,822,000 gallons (591,000 barrels) per day, and that federal law allows them to **exceed the maximum operating pressure by 10%** as a result of "abnormal" operation (1,440 psi x 1.10 = **1,584 psi).** Once the Keystone Pipeline is built, TransCanada will be tempted to sell or lease the right-of way easement area to other pipelines and to "increase" the operating pressure to move even more oil at greater pressure and greater risk to South Dakota. Robert Jones, TransCanada Vice President was quoted in an Argus Leader news story dated April 29, 2007 saying that "crude oil regularly moves between 1,440 to **2,000 psi**, up from 1,000 psi for pipelines built in the 1950's" **(See Exhibit 6).** Operating a crude oil pipeline through South Dakota at any pressure beyond what is normally done by other oil pipeline operators in the USA will increase the level of risk to South Dakota and should be avoided for public safety reasons if nothing else. TransCanada has not told us what the Maximum Operation Pressure (MOP) will be at the lowest point of elevation between each pump station in South Dakota. There will be low elevation locations along the Keystone pipeline where the pressure on the pipeline will "exceed" the Maximum Operation Pressure. If so, then TransCanada should be required to install, as part of construction, pressure sensors devices which are tied into their computer SCADA system that monitors the project. The SDPUC and the communities crossed by this pipeline have a right to know where high pressure locations will be along the pipeline and what special construction measures, if any, will be taken to protect public safety and the environment. Other pipelines with thicker pipe wall and lower operating pressure have failed because of surges on the line caused by equipment malfunction and operator error.

Oil Leak Impacts

A report prepared by a risk management consultants (DNV), in support of TransCanada permit application confirms that the TransCanada-Keystone Pipeline **will leak within five to seven years** and that pinhole leaks on the pipeline that will not be detected by computer SCADA systems could result in **oil leaks as large as 372,330 gallons per day** that could continue to leak for **90 days before they are detected**. The Draft Environmental Impact Statement does not adequately address the impact that operational oil leaks on the TrandsCanada-Keystone Pipeline will have on aquifers, the environment, and the farm communities crossed by the project. The Draft EIS and the documents presented to the PUC address oil leaks that occur during construction from equipment and small spills and they do not adequately address the impact that oil leaks during pipeline operations will have on aquifers, the environment, and the rural communities that will be crossed by the project.

Higher Operating Pressure Means Greater Risk For South Dakota

The application that TransCanada filed with the U.S. State Department in 2006 and the South Dakota PUC in 2007 stated that the Keystone Pipeline would be operated at **72% of pipe design factor** and that the pressure would range from 1,400 psi to 1,700 psi. TransCanada recently released copies of a "***Special Permit***" it has received from the Pipeline and Hazardous Materials Safety Administration (PHMSA) to operate the TransCanada-Keystone pipeline at **80% of pipe design factor**, or about **11 % higher** than other oil pipelines currently operating oil pipelines in the United States **(See Exhibit 7).** Neither the project plans presented to the PUC or the Draft EIS presented to the State Department adequately addressed this change in pressure and what the associated changes in impact to the state will be. This increase in operating pressure increases the risk of pipe line leaks and failures and increases the risk of contamination of ground water, aquifers, farm land, grass lands, wetlands, wildlife habitat and the safety risk to the people of South Dakota living along the pipeline route. This pipeline will bring **a new risk** of environmental contamination to a remote rural area of South Dakota where no such risk exists now and will change the social and economic aspects of the area. In addition to the impact this higher operating pressure will have on the environment, we believe that it will increase the risk of oil leaks that could cause serious damage to miles of PVC rural water pipelines that the TransCanada-Keystone would be crossing in eastern South Dakota.

Proximity To Private Homes, HCA's and USA's

Federal 49 CFR 195 requires that oil pipelines be built to protect High Consequence Areas (HCA's) and Unusually Sensitive Areas (USA's) . The regulations include specific set back requirements: We reviewed the latest version of the TransCanada-Keystone Pipeline maps available on the SDPUC website on Oct. 30, 2007 and found the following;

		Sites With Less Than The Recommended Setback
Home or Private Dwelling	50 feet	1
Buildings Must Be Vacated During Pressure Test of The Pipeline	300 feet	16
Other Buildings	660 feet	53
Carlsbad, NM Standard	800 feet	78

(the number shown at right are cumulative)

The TransCanada-Keystone Oil Pipeline will be operated at **1,440 psi to 1,700 psi** (pounds per square inch) to deliver 24,822,000 gallons per day (591,000 barrels). In a news story in the *Argus Leader*, Robert Jones, VP for TransCanada was quoted as saying the operating pressure could safely be raised as high as 2,000 psi. In comparison, the 155 mile WEB water mainline built with ductile iron pipe operates at a peak pressure of 100 to 209 psi and delivers 8,000,000 gallons of water per peak day. A 30" crude oil pipeline pressurized at even 1,440 psi is a very serious and dangerous pressure vessel. The pipeline near Carlsbad, NM that failed in August 2000 was operating at 675 psi when 12 people were killed, including small children. According to NTSB there were 227 reported pipeline failures in the U.S. in 2000 with property damages of $197 million and 16 fatalities. As reported by the **National Transportation Safety Board (NSTB)**, a single pipeline accident..."*can injure hundreds of persons, affect thousands more, and cost millions of dollars in property damage, loss of work opportunity, community disruption, ecological damage, and insurance liability*"(7). According to the **Office of Pipeline Safety** (OPS) the most common cause of natural gas and liquid (oil) transmission pipeline accidents is corrosion (24%). Another less frequent category is seam weld failure on pipe, when the seam of the pipe splits open. Seam weld failure accounted for 4% to 5% of the failures and **30% of the property damage** according to a 2002 OPS report. The "*Distribution Pipeline Incident Summary by Cause Report*" issued by OPS concluded that... "*Outside force damage is a catchall term that includes (1) third party excavation damage, (2) excavation damage caused by the pipeline company itself, (3) landslides, (4) fire, (5) lightning, (6) snow, (7) wind, (8) motor vehicles and (9) vandalism.*" Explosions on large natural gas pipelines can kill people hundreds of feet away. **Spills from oil pipelines may extend miles away from the pipeline and often can never be fully cleaned up.** (See Bemidji, MN - 1979 Crude Oil Spill, USGS)

TransCanada's Lack of Oil Pipeline Experience:

At public meetings held in Aberdeen and Britton on May 10, 2007, TransCanada officials L.A. "Buster" Gray, Chief Engineer and Nichole Aitken, Stake Holder Relations Manager admitted to a group of landowners, farmers and local officials that TransCanada doesn't own or operate any crude oil pipelines. A recent search of TransCanada's official website found no oil pipeline listed among the facilities they own and operate. Companies with years of experience, like BP (British Petroleum), Exxon and others are having pipe failures and leaks like the one that dumped 200,000 gallons of crude oil into the ground near Prudhoe Bay, Alaska on March 3, 2003 and resulted in millions of dollars in fines (**See Exhibit 8**). It's a bad idea for the United States, the State of South Dakota and other Midwest states to allow the construction of a 30-inch high pressure crude oil pipeline by a foreign company which has no proven track record as a company in the operation of a high pressure thin walled oil pipeline.

The TransAlaska Pipeline, which is now called **Alyeska Pipeline** has had a history of oil leaks each of the 30 years that's been in operation from 1977 to 2007 (**See Exhibit 9**) http://www.alyeska-pipe.com/Pipelinefacts/PipelineOperations.html. The Draft Environmental Impact Statement does not adequately address the impact that high operating pressure will have on the environment and social impact it will have on the aquifers, the environment, the rural water pipeline systems, the communities and the states crossed by the TransCanada-Keystone Pipeline.

Groundwater & Aquifer Protection

The aquifers in eastern South Dakota that would be crossed by the TransCanada pipeline are protected by federal and state laws against contamination and pollution under the Clean Water Act, Source Water Protection and PHMSA regulations and requirements that apply to pipelines moving oil and hazardous liquids. There is no way that TransCanada can "prove" or guarantee South Dakota that the pipeline won't leak as required under SDCL. There are documented cases that prove that oil pipelines of this kind will fail and leak. Oil pipeline failure statistics gathered by the PHMSA confirm that oil pipes fail and leak (See Exhibit 10. The thousands of farms, rural homes, 8 rural water systems, and hundreds of towns that rely on aquifers as a their sole source of drinking water supply have a right to be protected under state and federal law. If the PUC and their staff grant the permit and allow the project to proceed as planned they will be approving the construction of a public nuisance. There is a real and immediate risk and danger that the Keystone Pipeline Project could fail within 7 to 12 years and dump toxic tar sands crude oil into the soil and into the environment. With welded pipe joints at every 40 feet resulting in 132 welded joints per mile, there could be a total of **29,040 welded joints** or more across South Dakota, each one a potential **risk of oil leakage and pollution** that wasn't there before Keystone came. There is a great risk that the pipe could fail during the life of the pipeline which would violate state and federal environmental laws. The oil, which will be warmed to 70 to 80 degrees, will pollute and contaminate shallow ground water and aquifers in eastern South Dakota, including those in Marshall, Day, and Clark Counties as well as other counties crossed through South Dakota. The Alyeska Pipeline has failed and leaked every year that it's been in operation. TransCanada has no history or track record operating high pressure oil pipelines as a company. What makes TransCanada think that they will have a better track record than British Petroleum (BP), Exxon, or other companies that have been in the oil pipeline business for years? Hydraulic testing of the pipeline with water once construction is completed will not eliminate leaks occurring after the pipeline is placed in operation. On the Northern Border Pipeline, which TransCanada is a partner on, there were more than 40 leaks on 31 miles of pipeline in Brown County alone according to statements made by the project foreman to landowners whose land was crossed by the pipeline.

Clean Water Act: There is a real and immediate risk and danger that if constructed as proposed, the Keystone Pipeline Project will leak and contaminate soil, water, wetlands, creeks and streams, and pollute air quality which would be a violation of the Clean Water Act and various state laws, permit requirements and regulations. The "***Frequency Volume Study"*** completed by DNV Risk Management Consultants states on page 19 of the report that a pin hole leak smaller than 1.5% of pipe volume in remote areas of the pipeline could release oil into the soil and the environment for as long as 90 days before being detected. At 591,000 barrels of oil volume per day, 1.5% would amount to 372,330 gallons of per day and or 33,509,700 million gallons over a 90-day period. Certainly more than enough oil to contaminate any aquifer, wetland, creek or stream including the James River and Missouri River which will be crossed. It will cause serious damage to shallow aquifers found in Marshall, Day and Clark Counties and other parts of the state. As proposed, the Keystone Pipeline Project route will cross one of the few sources of quality water and quantity in northeast South Dakota. The sandy soils in eastern Marshall, Day, Clark and Beadle Counties are recharged by snow melt and spring runoff from the Coteau Hills formation. According to a detailed report completed by the South Dakota Geological Survey, the aquifer ranges from 8 to 50 feet from the soil surface and offers a reliable water supply, even during extended dry conditions such as during the Great Depression. At times, the water in the aquifer comes to the surface in the form of springs. Incredibly, this is the location TransCanada has selected as the proposed route for the Keystone Pipeline.

According to USGS elevation maps, the land surface elevation between the Couteau Hills and the Keystone Pipeline route in Marshall and Day Counties drops off 450 feet in elevation. From the pipeline route the land elevation drops even further as the creeks and streams drain to the James River and a man made drainage canal (Crow Creek Drain) moves water through the area. The route selected will shallow aquifers which are used by rural residents, towns and rural water systems as their primary source of drinking water. **(See Exhibit 11)** TransCanada-Keystone Pipeline will be operated at 1,440 to 1,700 psi. At that pressure, there is a high risk if a crude oil leak or spill occurs that irreversible damage will be done to productive farm land and aquifers in eastern South Dakota. The carbon in the oil may move only a short distance from the location of the leak, but the chemicals in the crude oil, such as **Ethylenzen, Xylene, Benzene, Toluene, and Hydrogen Sulfide** are water soluble and will quickly move with the water and contaminate large areas of the aquifer.

The runoff from snow melt and spring and summer rains from the Coteau Hills in Marshall, and Clark Counties recharge the aquifers. Because of the elevation change, the runoff will "move" the crude oil spill and chemicals through the aquifer and down the natural drainages to the James River. The Brown-Day-Marshall (BDM) Rural Water System relies on the James Aquifer as its primary source of water. Five of the eight rural water systems that will be crossed by the project currently rely on groundwater aquifers. WEB has been exploring the development of wells in the aquifers located near Mansfield and Andover, SD to help meet the growing water needs of our service area.

The South Dakota Association of Rural Water Systems (SDARWS) has approved a draft resolution regarding the TransCanada-Keystone Pipeline, which will be finalized in early December and presented to the SDPUC as an addendum to this testimony. Once groundwater is contaminated by an oil spill it will never be the same again. The rural water systems and residents of South Dakota who rely on ground water aquifers for their supply have every right to expect that their water supply will be protected by the state and federal government.

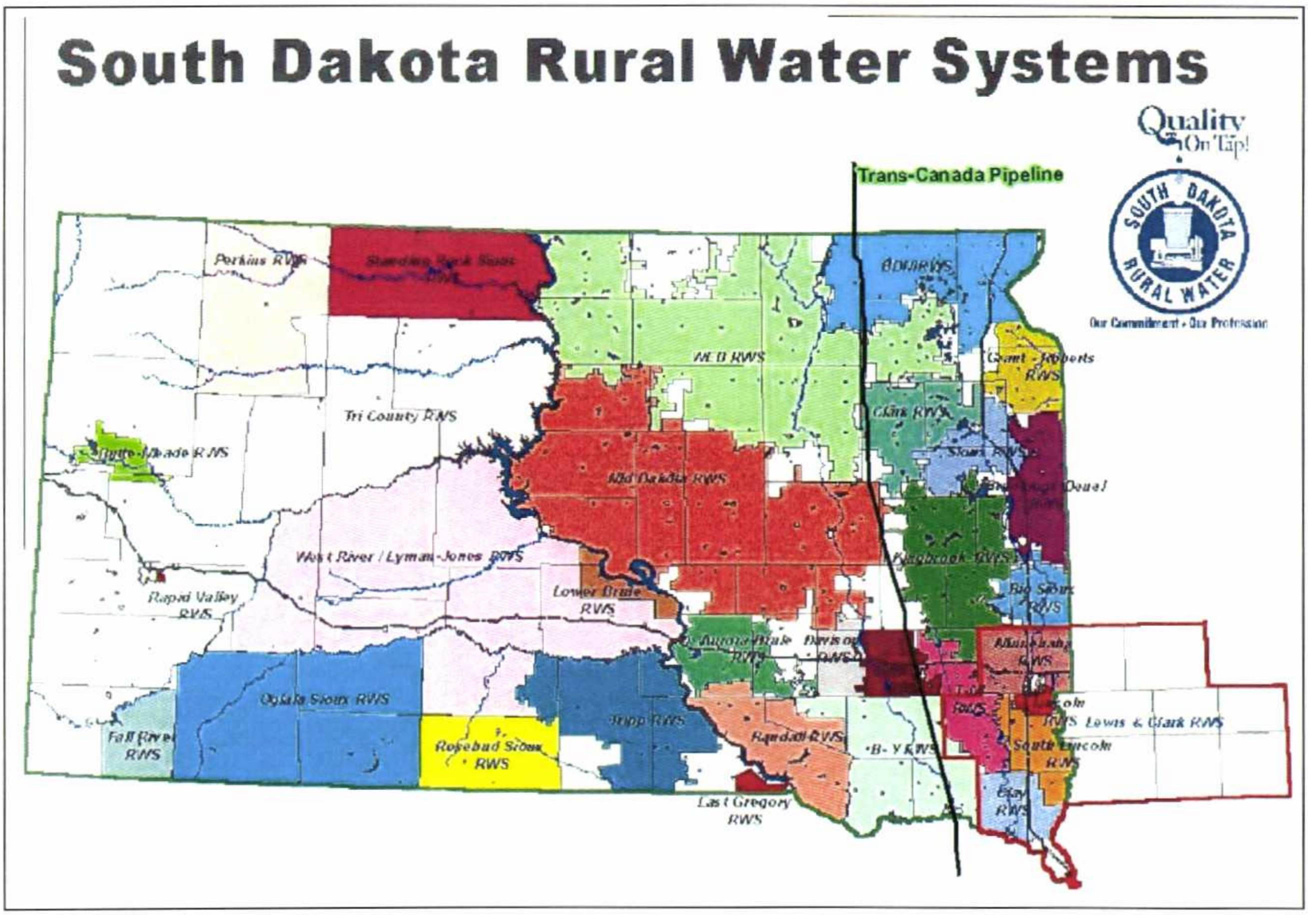
(3) The facility will not substantially impair the health, safety or welfare of the inhabitants

Native Grass & Protected Species: As currently proposed, the TransCanada-Keystone Oil Pipeline poses a threat of serious injury to the inhabitants, the environment, and the social and economic condition of inhabitants in the siting area; TransCanada-Keystone Pipeline has the potential of causing irreversible long term damage to native grass lands in every county crossed. Farm crop lands, wetlands, wildlife and the environment of the rural area crossed in eastern South Dakota will be forever changed. The construction and operation of the Keystone Pipeline will impact virgin native "Buffalo" grass which has been protected and conserved by landowners and their families since statehood and which if disturbed can never be replaced. The native grass provides an important source of feed for livestock during extended drought conditions. The Keystone Pipeline will impact species found in Marshall, Day, Clark and Beadle Counties, including the "*Dakota Skipper*" and the "*Western Prairie Fringed Orchid*" which are both on the federal endangered species list.

Rural Water Systems: The permit application filed with the U.S. State Department by TransCanada failed to acknowledge that the proposed oil pipeline would cross miles of rural water pipeline operated by eight (8) rural water systems in South Dakota. The permit application filed with the federal government by TransCanada in 2006 failed to identify the risk that could result in the event that a crude-oil spill came in contact with buried PVC water pipelines.

A study by Iowa State University, commissioned by the American Water Works Association (AWWA), confirmed that petroleum and crude-oil products can permeate through the rubber gasket of PVC water pipes, contaminating the drinking water being delivered to customers by municipal and rural water systems. How much PVC water pipeline will need to be replaced in the event of a large oil "spill" is not known at this time, nor is it known if TransCanada would be held responsible for the cost of replacement.

In their prefiled testimony, TransCanada questions whether tar sands oil will damage PVC water lines. WEB **challenges TransCanada to deliver a 42 gallon barrel of tar sands oil** to Iowa State University and the Water Resource Lab at SDSU so that independent tests can be run in t he light of day. We are not going to take the word of a witness who owes his/ her career and future to TransCanada.



The TransCanada Oil Pipeline route will cross eight rural water pipeline systems in South Dakota.

If the TransCanada-Keystone pipeline fails at or near the point where the crude oil pipeline crosses WEB's 12" PVC water mainline a crude-oil spill could damage the rubber pipe joint gaskets, permeate through the pipe wall, and contaminate the drinking water service of 1,029 rural hookups and 8 towns. If the SDPUC issues a permit it should include a condition that TransCanada be required to secure a permit from every rural water system and municipal water system crossed, which includes insurance coverage naming water system as an "additional insured" and a cash bond be deposited in a South Dakota bank to cover the impacts of any future oil "spills" or leaks during the operating life of the pipeline. The Draft EIS does not adequately address the protection provided under Title 49 CRF Part 95 to rural water systems and their aquifer water sources. The Draft EIS <u>fails to address</u> how the eight rural water pipeline systems crossed by the TransCanada Keystone pipeline (BDM Rural Water System, WEB Rural Water System, Clark Rural Water System, King-Brook Rural Water System, Mid-Dakota Rural Water System, Hanson Rural Water System, Turner-McCook Rural Water System and BonHomme-Yankton Rural Water System) will be protected and/or mitigated as required by federal law and Title 49 CRF Part 95.

Missouri River Crossing: The TransCanada-Keystone Oil Pipeline will cross the Missouri River near Yankton, South Dakota, upstream of a section of river which is the only portion of the Missouri River in South Dakota that remains in a natural scenic condition. The area is managed by the National Park Service and will require a permit from the U.S. Secretary of Interior. Constructing an oil pipe crossing under the Missouri River east of Yankton would be a major project and a major environmental concern. It would place the oil pipeline 22 miles upstream of Vermillion which is the location of the **Lewis & Clark Regional Water System intake wells.** The only thing standing between the Lewis and Clark wells along the Missouri River and the water soluble chemicals found in tar sands oil is river sand which will not block or filter out **Ethylene, Xylene, Benzene, Toluene, and Hydrogen Sulfide**. The Missouri River is a source of water for over half the population of South Dakota, including the City of Sioux Falls, once the Lewis & Clark water system is completed.

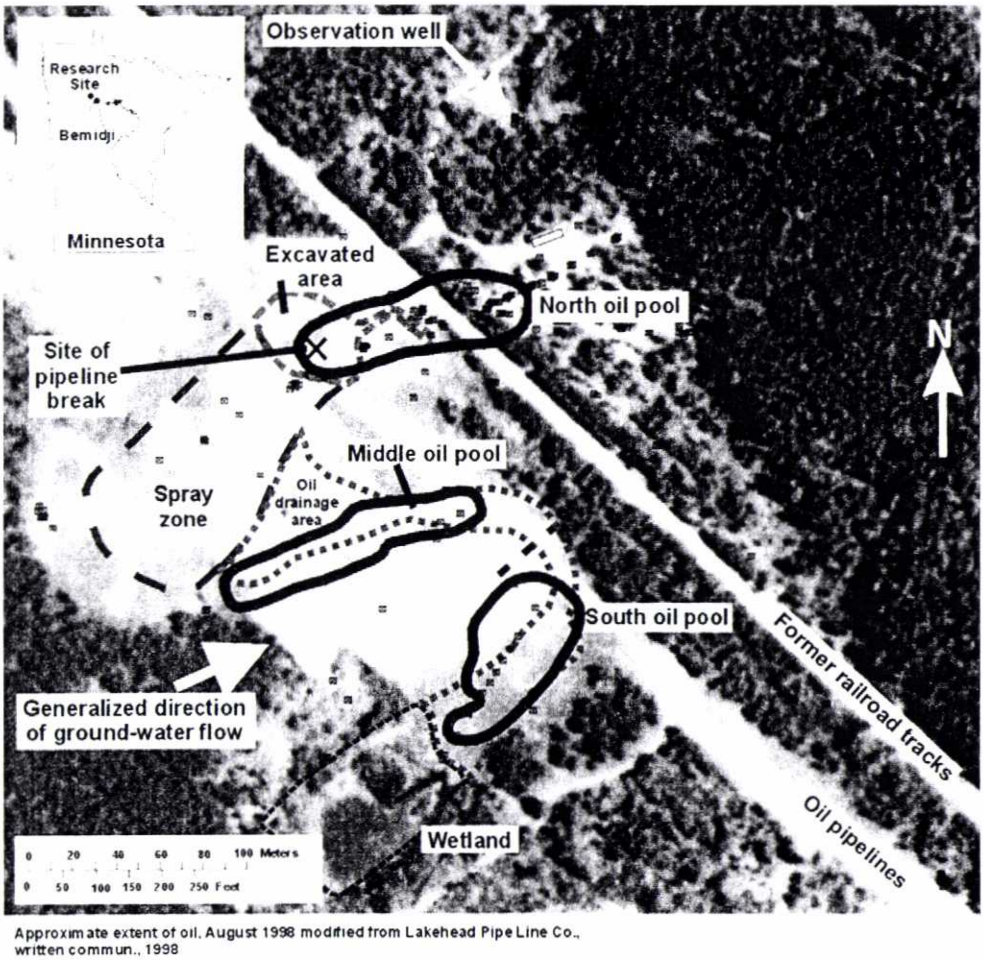
Oil Sands Makeup: TransCanada has refused to release the exact composition of the crude oil they plan to transport across North Dakota and South Dakota claiming it is "proprietary information". Below is a summary of information taken from the **Canadian Center for Occupational Health & Safety** (http://www.ccohs.ca). Among the many substances in crude-oil are chemicals such as **benzene, toluene, ethyl benzene, xylene and other lightweight chemical compounds**. These compounds are more water soluble and can disperse further and more rapidly in both surface and ground waters than other crude oil substances. These compounds pose a significant threat to water quality. For example, one teaspoon of benzene (0.005 ppm) can contaminate 260,660 gallons of water. The US-EPA enforceable water quality standard for drinking water allows no more that 0.005 ppm concentration of benzene in both surface water and groundwater. Benzene exposure can cause anemia or a decrease in blood platelets and may result in an increased risk of cancer. Toluene in excess of EPA standards can cause problems with the nervous system, kidneys and liver. Ethylbenzene can cause problems with the liver and kidneys. Xylene can cause damage to the nervous system.

An "***Oil Spill Frequency Volume Study*** " filed by TransCanada in 2006 acknowledged that oil spills do occur on oil pipelines. Release of crude oil can occur during transport through a pipeline and pose a significant risk of soil and water contamination surrounding the area of the spill. The Trans-Canada Study estimated that a 1,000 barrel (42,000 gallons) oil spill may occur anywhere along the TransCanada Keystone Pipeline once in 12 years; a 10,000 barrels (420,000 gallons) oil spill may occur once in 39 years; and a spill of more than 10,000 barrels might occur once in 50 years *(TC Pipeline Risk Assessment, pg 3-2)*. The projections are theoretical based on historical data of pipeline operation. The extent of environmental damage would depend on the location and quantity of the oil spill, the type of soil and water resources in the area of the spill, and the topography of the land area. In a study independent of the oil industry, the United States Geological Survey (USGS) estimated that an average of 83 crude-oil spills occurred in the United States during the three year period of 1994-1996, with each spilling about 50,000 barrels (2,100,000 gallons) of crude-oil. The British Petroleum (BP) pipeline failure and spill on March 3, 2003 at Prudhoe Bay, Alaska dumped 200,000 gallons of crude oil. BP is recognized as having years of oil pipeline operations experience, and they had a major pipe failure and oil spill. TransCanada doesn't even own or operate a crude oil pipeline and has no experience or track record operating a high pressure crude oil pipeline.

Oil Spill -Impact On Soils: According to the information filed by TransCanada with the U.S. State Department, the clean-up of a **84,000 gallon oil spill** (2,000 barrels) from the TransCanada pipeline spill could require the removal of up to the equivalent land area of **3 feet in depth over 400 acres** or about 2,001,277 cubic yards of soil *(Pipeline Risk Assessment, pg 4-4).*

The crude oil is extracted from Alberta oil sands, called "bitumen", is described as "black and thick oil". Crude-oil released into soils will disperse both vertically and horizontally. Much of the land area being crossed by the pipeline in under-laid with large quantities of sand, gravel and sandy soil.

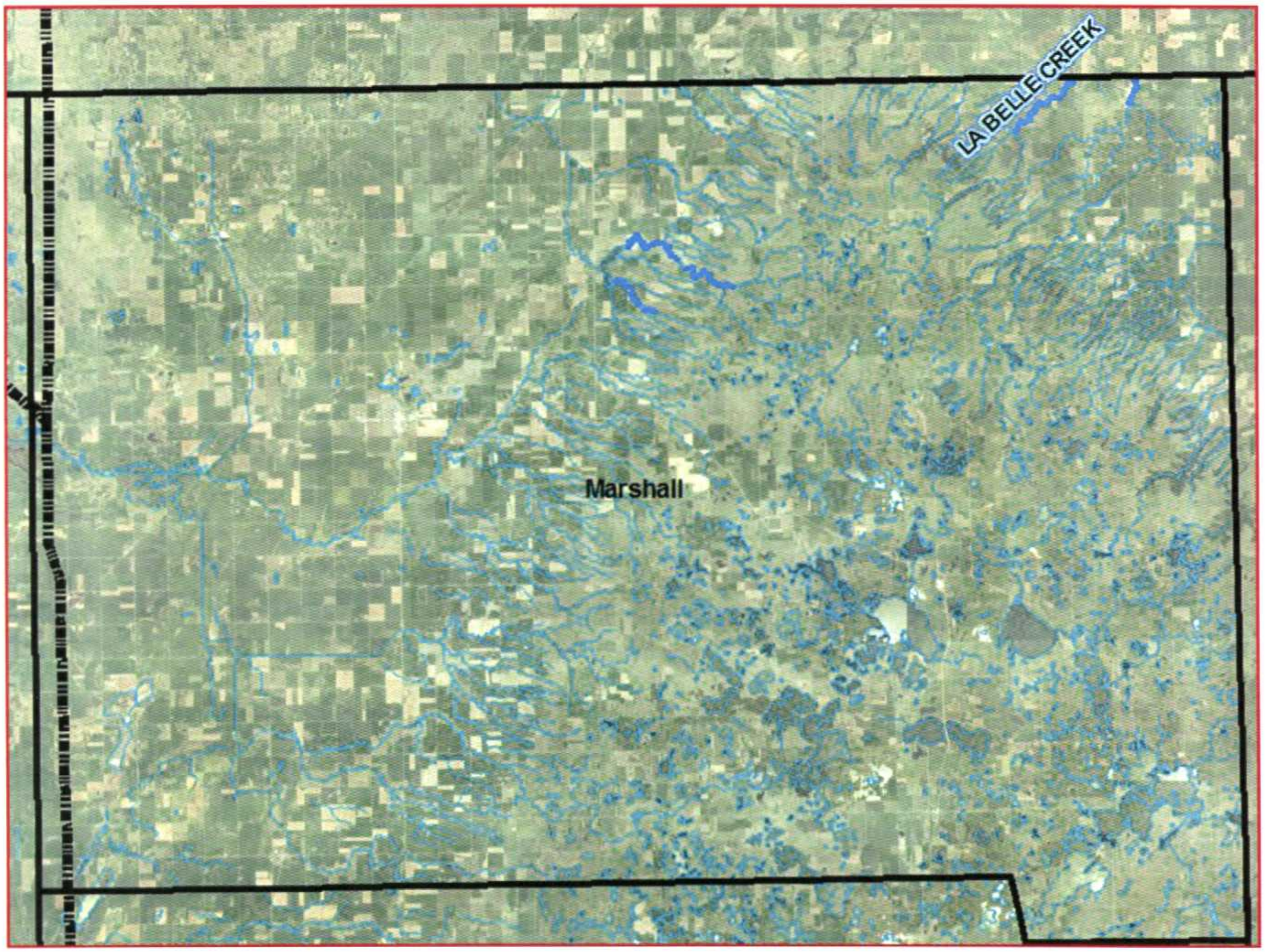
Sandy soils found throughout much of the TransCanada-Keystone Pipeline route would accommodate the dispersion of crude-oil. Soil moisture and run off due to snow melt and spring rains could also increase the dispersion of a crude-oil spill. TransCanada's application states that clean-up of soil contaminated by crude oil can require significant time, effort and cost. Required remedial actions may range from excavation and removal of contaminated soil to allow the contaminated soil to recover through natural environmental fate process (evaporation, biodegradation, etc). State and federal programs mandate notification and initiation of response actions "*in a timeframe and on a scale commensurate with the threats posed*" whatever that means *(TransCanada Construction Mitigation & Reclamation Plan, 2-50).* What about the loss of crop production, property values and future earnings to farmers as a result of contamination by an oil spill? A crude oil pipeline leak near Bemidji, MN in 1979 was never fully cleaned up and soils remain sterile 28 years later.



Features of the Bemidji, Minnesota crude-oil spill research site superimposed on a 1991 aerial photograph.

Risk Of Large Crude Oil Spill: The TransCanada-Keystone Oil Pipeline plan calls for a wide separation between mainline automated valves and manual valves. For example, the distance between the pump station at the North Dakota-South Dakota state line and the next pumping station near Ferney, SD is about 42 miles of 30 inch pipe which would hold about 156,660,000 gallons of crude-oil (3,728,571 barrels).

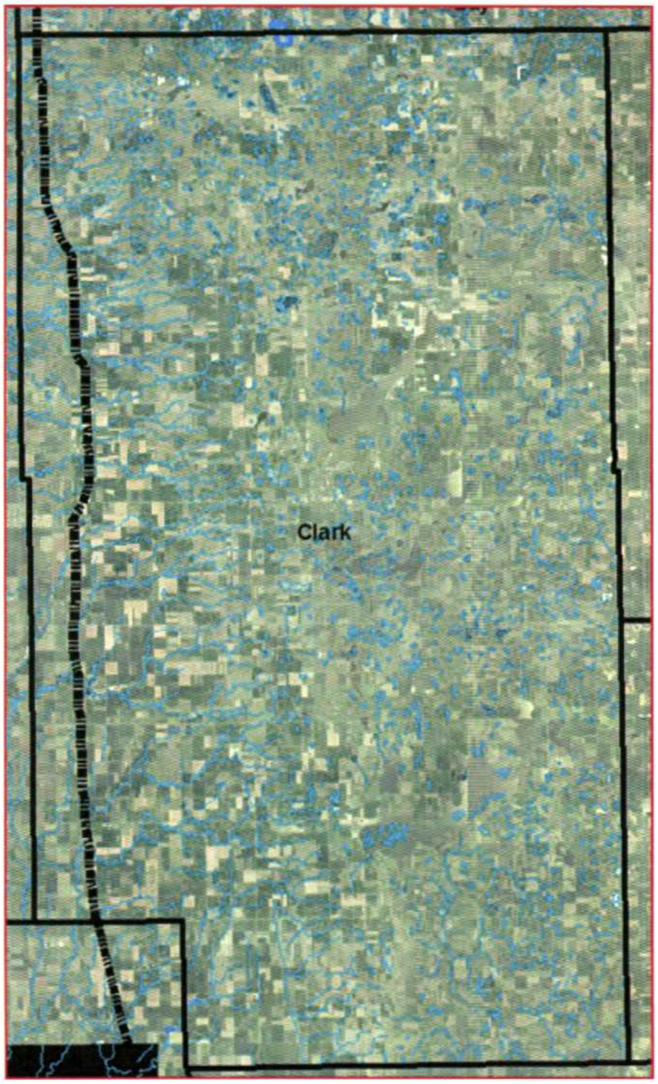
The distance between the Fernery pump station and the next pump station near Carpenter, SD is about 47 miles of 30 inch pipe which would hold about 175,312,000 gallons of crude oil (4,174,000 barrels). In addition to the 4 automated valves at compressor pump stations, the TransCanada-Keystone Pipeline will have 7 to 10 manually operated valves on the 220 miles of pipeline in South Dakota, with some valves being 20 to 30 miles apart. In the event of a major pipe failure, **there may not be time to reach manual valves** to stop the crude-oil from draining out of the pipeline and on to productive farm land or wetlands. Manually operated valves won't do much good if the TransCanada operations staff and contractors are hundreds of miles away in Alberta or Omaha. A pipe failure at a low elevation point on either the 42 mile reach between North Dakota and Ferney, SD or the 47 mile reach between Ferney and Carpenter, SD could result in a spill of millions of gallons of crude oil. In line check valves are being provided on either side of the Missouri River near Yankton to protect the river. Similar check valves will be needed in other areas of the pipeline route where elevation changes are great. By way of comparison, the 155 mile WEB water mainline has 31 manual isolation valves, with each valve located every 5 miles, and six pump stations and control points which are monitored and operated by a computerized SCADA system and operations staff dispatched out of Aberdeen, South Dakota. At a May 10, 2007 meeting a TransCanada official stated that their operational staff will be located in Omaha, NE and the SCADA control center will be located in Canada, hundreds of miles from South Dakota.



Black line is the approximate route of the TransCanada pipeline as it crosses streams and drainages in Marshall County, all of which contribute to the recharge of the aquifer and drain to the James River.

The black line at the left side of the map is the approximate route of the TransCanada pipeline as it crosses streams and drainages in Day County, all of which contribute to the recharge of the aquifer and drain to the James River.

If the TransCanada Keystone Pipeline fails and leaks the water from the drainage will carry the pollutants into the aquifer and to the James River.



The U.S. Office of Pipeline Safety requires that TransCanada-Keystone prepare and file an Emergency Response Plan (ERP). The TransCanada permit application filed with the U.S. State Department states last year stated that an Emergency Response Plan will be filed as a "supplemental" to the permit application. No plan has been made available as of Sept. 21, 2007. The Emergency Response Plan, which is required by law, should be filed with state and local government, fire departments, utilities and local emergency responders for review, comment and approval BEFORE consideration is given to any permits by the SD Public Utilities Commission or the U.S. State Department. The rural area where TransCanada is proposing to construct their oil pipeline has only volunteer fire departments without the equipment, training and man power to contain an oil leak or fight an oil fire like the one shown at the right.

Computer Monitoring Systems

TransCanada-Keystone says they will use two technology-based leak detection systems, which will include leak detection software SCADA (Supervisory Control and Data Acquisition) monitoring and volumetric balancing. Sensors and monitoring equipment will be located at pump stations and the data collected will be transmitted by satellite to the central control center in Canada (*TransCanada Construction & Reclamation Plan, 2-48).* The SCADA systems that TransCanada will be using will help monitor and operate the crude-oil pipeline and may help detect problems by sensing changes in pressure and flow rate. However, at the point the SCADA system senses a change in pressure or flow and shuts the automated valves off at the pump station, a major release or spill may have already occurred on the pipeline miles away from the pump station. Based on NTSB's reports on oil and gas line failures, and WEB's own experience, computer SCADA systems may detect major changes in pressure and flow but they don't necessarily detect small leaks that develop on pipelines, which over time can develop into a major leak or spill and contaminate soil and ground water for days, weeks or months before the leak is found. That is exactly what happened on March 3, 2005 with the BP crude oil pipeline failure at Prudhoe Bay, Alaska. This kind of leak causes more of a problem when the pipe is located in a remote isolated rural area. Because of the potentially severe consequences of a crude-oil spill, prevention is critically important and successful prevention requires regular testing of the pipeline's integrity, including internal corrosion. Internal inline inspection devices, known as "smart pig" may detect some defects in the pipe as they travel through the pipeline being moved by oil flow and pressure. It is not enough to cite oil industry construction standards and record keeping required by OPS. The Draft EIS should specifically address the impacts that tar sands crude oil will have on the environment and the health and safety of the residents who live along the pipeline and whose lives may come in contact with it.

Ground Water Aquifers

The groundwater aquifers in the path of the proposed pipeline route meet the test of HCA's (High Consequent Areas)" and USAs (Unusual Sensitive Areas) under Title 49 CRF Part 195. Section 195.6 speaks to the issue of groundwater and surface water sources, public water systems, and well head protection areas as sensitive areas. Under federal law, these aquifer resources must receive additional protection from high pressure oil pipelines like the TransCanada-Keystone Pipeline. As currently proposed, the TransCanada-Keystone Pipeline will cross numerous shallow aquifers which are the primary source of drinking water for rural homes, farms and towns in eastern South Dakota, including five of the eight rural water systems being crossed by the TransCanada-Keystone Pipeline. The aquifers have been identified by studies completed by the South Dakota Geological Survey and the USGS. Enclosed are maps and reports completed in Marshall County and Clark County, which are representative of studies completed in other South Dakota Counties. TransCanada made no mention of these water systems in their permit application. Very little mention was made in the Draft Environmental Impact Statement. TransCanada-Keystone Pipeline will be operated at a high operating pressure that could result in an increased number of oil leaks and will increase the risk of oil leaks that could cause serious damage to underground aquifers that would be crossed by the TransCanada-Keystone Pipeline in eastern South Dakota.

The Draft Environmental Impact Statement fails to address how groundwater aquifers in eastern South Dakota will be impacted by the construction and long term operation on the TransCanada-Keystone Pipeline. The Draft EIS must address how these underground water supplies are to be protected as required under federal law, including Title 49 CRF Part 95, et al, the Clean Water Act and other federal laws. TransCanada claims that shipping oil by pipe is safer than shipping the same oil by truck which is not true. The risk of an oil spill with a tanker truck is limited to volume of the tanker. Unlike the Keystone pipeline, an oil tanker is not under pressure. It would take 47 tankers trucks each pulling 8,000 gallons to equal just one day's oil leak of 372,000 gallons estimated in the DNV Frequency Volume Study. If the pipe leak went 90 days undetected as was estimated, the pill would equal 4,208 tanker trucks of 8,000 gallon each. An oil leak incident does far more damage than a tanker truck because the pipeline has an endless supply of oil.

The permit application information and testimony presented by TransCanada in support of the permit does not adequately address and compare the environmental and social impacts of the proposed route to various alternate routes, including the I-29 Corridor Alternate Route and the western route proposed by North Dakota. Further consideration should be given to the alternate routes in the Final Environmental Impact Statement. By failing to seriously consider this and other alternatives, TransCanada is in violation of federal law. An oil leak along I-29 would be observed and reported sooner than if the same leak were to develop along the remote area between Britton and Yankton, SD. The fire and emergency response teams would be able to access the area much easier from I-29 than from the gravel and dirt section line roads the pipeline would cross in Marshall, Day and Clark County and the rural area between Britton and Yankton.

The Pipeline Safety Improvement Act of 2002, which was signed into law on December 17, 2002, and codified at 49 U.S.C. 60109, provides protections and safe guards for communities crossed by gas and oil pipelines. As a primary source of drinking water for eastern South Dakota, rural water pipeline systems meet the test of being "**Highly Consequent Areas**" (HCA's) and **Unusually Sensitive Areas** (USA's) under Title 49 CRF Part 195. Section 195.6 speaks to the issue of groundwater and surface water sources, public water systems, and well head protection areas as sensitive areas. Under federal law, these rural water pipeline systems and their water sources must receive a higher level of protection from a high pressure oil pipeline like the TransCanada-Keystone Pipeline. Eight rural water pipeline systems will be crossed by the TransCanada-Keystone Pipeline in eastern South Dakota, including the WEB water systems. Of the eight rural water systems, five rely on ground water aquifer as their sole source of water. TransCanada-Keystone made no mention of these rural water systems in their application filed with DOS and the SDPUC. WEB raised the issue in written testimony we presented to the Department of State in the fall of 2006. We provided DOS with a map of South Dakota showing the relationship of the TransCanada-Keystone Pipeline to the location of rural water pipeline systems.

<u>**Groundwater Aquifers:**</u> The TransCanada-Keystone Pipeline will cross numerous aquifers in South Dakota, including the Oakes, Bramton, Tulare, Vermillion, Altamont, Floyd, and Lower James-Missouri aquifers. The depth to water in the Oakes Aquifer along the route of the pipeline in Marshall County is 10-15 feet in depth. The depth to the upper layer of water of the Altamont Aquifer near Raymond in Clark County varies from 10-35 feet. The same is true for ground water in the Carpenter area of Clark County. Near-surface groundwater occurs at various locations where the pipeline crosses small streams in northwestern Day County *(TransCanada Construction Mitigation & Reclamation Plan, pg 3.5-35)*. Much of the ground water in northwest and western Day County is within 4 feet of the surface according to the <u>*Day County Soils Survey*</u> completed by USDA-NRCS.

MP-257
Day Co.

The Coteau Hills, in the center of the photo above, snow melt and runoff from spring and summer rain recharge the aquifers in western Marshall, Day, and Clark Counties. The sandy soils at the base of the hills filter and retain the water as it recharges the shallow aquifer below. The potential for groundwater contamination is greater where the water table is relatively close to the surface, and where the soils overlying the aquifer are porous materials. Depending on the type of pipe failure, the volume of the spill, the depth of the groundwater and the soil conditions in the area, a crude oil spill could continue to move and contaminate an aquifer in a very short time. Crude-oil moving through gravel or sandy soils could reach and damage PVC water pipelines used by municipal water systems and rural water systems to deliver drinking water to towns, farms, rural homes, livestock hookups, ethanol plants and other customers. Five of the eight rural water systems crossed by TransCanada currently <u>rely</u> on groundwater wells (See Exhibit 12).

DNV Risk Management consultants say that the thin walled 30-inch high-pressured 1,700 psi oil pipeline will fail within the first 5 to 7 years. When that happens, TransCanada wants the oil leak in some remote back road area and not along a well-traveled highway like I-29. Small town local volunteer fire departments like Britton, Langford, Carpenter, Iroquois, Freeman, and Alexandria aren't equipped or trained to contain oil spills or fight crude oil fires where the fumes can cause cancer and damage to the lungs and vital organs. The DNV Report title "*Frequency Volume Study*" states that 53% of the leaks on the Keystone Pipeline will be from pinhole leaks that cannot be detected by the computer SCADA systems TransCanada will use to monitor and operate the system (See WEB Attachment # 4). The DNV report estimates that leaks smaller than 1.5% of the pipe volume flow will go undetected. At 591,000 barrels per day a 1.5% volume leak undetected could result in a leak of 8,864 barrels per day or the equivalent of 372,330 gallons per day. In prefiled testimony a TransCanada witness raised the unaccounted for pipe volume to 2% which at 591,000 barrels per day would amount to 496,440 gallons per day. The DNV report also states that oil lost to pin holes leaks could go undetected for as long as 90 days which could result in an oil leak totaling 33 million gallons to 44.7 million gallons. An oil leak of that size and magnitude could pollute and ruin an entire aquifer and rural community resulting in millions of dollars of damages.

Oil spill at Coffeyville, Kansas on July 2, 2007

Oil leak at Burnaby, BC on July 24, 2007

(4) The facility will not substantially interfere with the orderly development of the region with due consideration having been given the views of governing bodies of affected local units of government.

As currently proposed, the TransCanada-Keystone pipeline will restrict and limit development of WEB and other rural water systems by a new threat of risk over available ground water supplies. No serious consideration was given to alternative routes, including the **I-29 Corridor Alternative Route** which would offer less long term risk and environmental damage to South Dakota. The I-29 route would offer better access for construction, inspection, operations and emergency response. The larger towns along I-29, such as Watertown, Brookings and Sioux Falls, have full time fully equipped professional fire departments and emergency responders, with the equipment and staff to handle oil pipeline emergencies. The small communities along the proposed route do not. The people of South Dakota and the communities to be crossed by the pipeline were never included in the process for selecting a route. North Dakota government officials have asked that a route through western North Dakota be considered to allow crude oil in that part of the state to use the Keystone Pipeline to ship their product to market. The I-29 route and the western route proposed by North Dakota officials should be considered in the DEIS process. The TransCanada-Keystone Pipeline route, as currently proposed and routed, would unduly interfere with and restrict economic development in the counties that would be crossed. Aquifer ground water that is relied on by the community for livestock development, irrigation, housing development, industry, value added development and new home construction could be seriously impacted. Landowners who would have an oil pipeline through the center of their property or going at odd angles would not have the full use of their property. New farming practices have such as "no till" have increased production. Innovate uses of the land, such as fish farming, rice production, organic farming and wind farms are all possible for the landowner to explore. The Keystone Pipeline would limit and restrict that development. The I-29 Alternative Route, which would place the oil pipeline in state owned road right-of-way would have less impact on land use and communities and less impact on orderly development.

Taxes: TransCanada claims that they will pay $6.4 million in annual tax on the pipeline the first year it is built and sales and excise tax from the construction. County governments have been told they will benefit. A Britton School official was quoted in the Britton Journal as saying their school district would get very little of the taxes paid by Keystone. TransCanada has printed ads in papers and mailed out letters bragging about the taxes South Dakota will get if the oil pipeline is built.

Then a news story in the American News dated Sept. 28, 2007 written by Bob Mercer quotes TransCanada's Vice President Robert Jones as saying that **$13 million of the $18 million in sales and excise tax (75%) will be waived by the State**. (See Exhibit 13).

So, TransCanada will **REALLY ONLY PAY $4.5 million (25%) of the sales and excise tax they owe.** If a farmer builds a shop, or a business adds on to their business, or a home owner hires a contractor to shingle the roof, they all pay their share of South Dakota's sales and excise tax. **But private oil company from Canada gets 75% break. WHY?** There is no reason for South Dakota to give TransCanada a tax break, they were coming anyway. The SDPUC and the Legislature should ask the Revenue Department and the Auditor General to look into that.

Dated this **31st** day of **October, 2007**

Curt Hohn

Curt Hohn

Monday, October 22, 2007 Yankton Press & Dakotan
Story last updated at 11:30 pm on 10/21/2007

S.D. Sits At Crossroads Of Oil Projects

By: **Dirk Lammers**
Associated Press Writer
http://www.yankton.net/stories/102207/new_210741666.shtml

SIOUX FALLS -- As oil hovers around $90 a barrel, the race is on to more heavily tap into the world's second-largest oil reserve, and South Dakota -- a major ethanol producer that typically sits on the alternative side of the fuel industry -- is finding itself at the crossroads of two major oil projects. One is a 590,000-barrel-a-day pipeline with plans to deliver Canadian crude to Patoka, Ill. and Cushing, Okla. The other is a proposed refinery that would be the first new U.S. refinery location in more than 25 years. Supply for both projects would come from the Alberta oil sands of northern Canada, home to some 175 billion barrels of crude putting the region second only to Saudi Arabia in terms of the world's oil reserves.

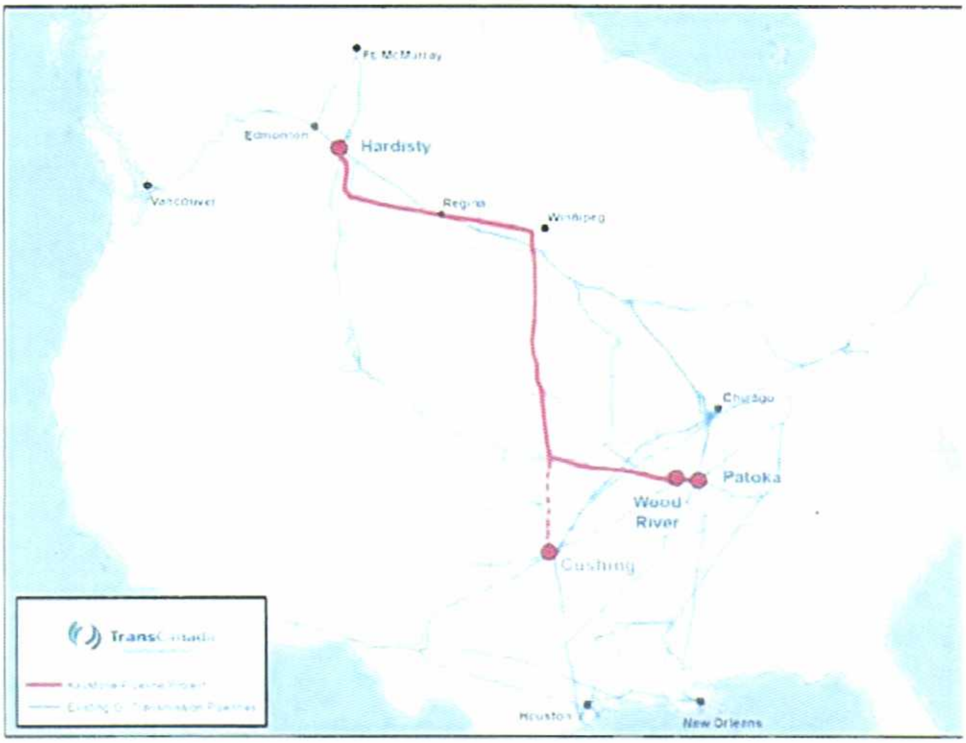
U.S. refiners are converting their plants to handle thicker Canadian crude, and pipeline specialists such as Calgary-based TransCanada Corp. are looking to connect supply with demand. TransCanada plans to begin construction this spring on the Keystone pipeline, a 2,148-mile route passing through the Dakotas, Nebraska, Kansas and Missouri. Robert Jones, a TransCanada vice president and director of the Keystone project, said transporting crude oil by rail or trucks is less environmentally friendly than moving it underground. New pipelines are critical infrastructure if North America is to achieve greater energy independence, he said. "The U.S. refiners have to do something to respond to increasing energy demands in the U.S.," Jones said. "So their choices are import more oil offshore from foreign sources or look to Canada and have a reliable source of crude oil to supply the refineries."

Jones said TransCanada already has firm long-term compacts on nearly 500,000 of the 590,000 barrels that will be transported along the route each day. That means passage along Keystone is nearly booked, and the line won't be able to supply South Dakota's other potential oil project -- the Hyperion Energy Center. Privately held Hyperion Resources of Dallas wants to build a 400,000-barrel-per-day oil refinery in either Elk Point -- which sits less than 50 miles from the planned Keystone route -- or another undisclosed Midwest location. The refinery would be built to handle Canadian crude, and the most obvious way to get it to a refinery is by pipeline, J.L. "Corky" Frank, a Hyperion project executive, told The Associated Press. "Our 400,000 barrels a day that we'd require for our refinery would probably be more than enough to justify a separate line, in and of itself, to serve this refinery as well as any other potential customers that were on that line," he said.

Frank said the U.S. needs more refining capacity, and building refineries inland to shield them from weather-related catastrophes such as hurricanes makes sense. The Hyperion Energy Center would produce ultra-low sulfur gasoline and diesel and be one of the most environmentally friendly in the world, he said. Its price tag has been estimated at between $8 billion and $10 billion, but Frank said the industry is changing daily, so the final cost could be

more or less. Frank said Hyperion is open to partnering with pipeline companies, producers and equity firms, but the company has yet to select a final site for the refinery and is keeping its options open.
"First thing you have to do before anybody wants to talk seriously about doing something is to have a site," Frank said. Throughout North America, companies are courting corporate partners to better tap into Canada's valuable resource.

TransCanada and Houston-based ConocoPhillips Co. signed an agreement in 2005 to use the Keystone pipeline to deliver crude to ConocoPhillips' Wood River, Ill. and Borger, Texas refineries, which are being expanded. The deal gives ConocoPhillips the right to up to a 50 percent ownership stake in the pipeline.



WEB Exhibit # 1-6

In January, ConocoPhillips signed an agreement with EnCana Corp., a Calgary-based company specializing in recovery of oil sands bitumen -- the thick, gooey crude that's found in that part of the world.

The deal gives EnCana a 50-percent stake in ConocoPhillips' Wood River and Borger refineries in the U.S. in exchange for a 50-percent stake in EnCana's Foster Creek and Christina Lake oil sands properties in northeast Alberta. Encana spokesman Alan Boras said it's a win-win for both companies. "For us, we got access to the capacity to turn heavy oil into gasoline and diesel that goes to the market," Boras said. "And for ConocoPhillips, it got access to additional reserves so that its refineries can run efficiently and have a secure supply of oil." Boras said the partnership removes some of the market's price volatility. Canadian oil recovery companies typically get **20 to 30 percent less for their oil** compared to lighter crude, and that differential can climb as high as 50 percent when supply exceeds demand.

With a 50-50 partnership, the upstream partner makes more money when the crude is selling for more, and the downstream partner reaps the benefits when the price is cheaper. "So it integrated the business, and as a result you protected yourself or removed that risk of the volatility of price, both on each side of the equation," he said. The transition from foreign oil to Canadian crude was highlighted in 2006, when two pipelines typically used to move oil from the Gulf Coast area to northern Midwest points were reversed. **ExxonMobil reversed one of its oil pipelines so it could bring Canadian oil already running to Patoka, Ill. down to Texas. And Enbridge Inc., a major Canadian pipeline company, reversed its Spearhead Pipeline so oil could flow from Chicago to a major industry hub in Cushing, Okla**., said Denise Hamsher, Enbridge's director of public and regulatory affairs in the U.S. "The economics being what they are, that secure supply is growing," Hamsher said.
Enbridge has several other major expansion projects in the works. One would expand its existing pipeline system, including pump station modifications in Alberta, Saskatchewan and Manitoba and new pipeline in Wisconsin and Illinois, to increase crude oil capacity to Midwest refineries and **beyond.** Another, called the Alberta Clipper, would construct a new crude oil pipeline from Alberta to Superior, Wis., to initially increase capacity to 450,000 barrels per day with potential growth to 800,000 barrels per day. **An additional pipeline running in the opposite direction along the same route would transport diluents -- light hydrocarbons used to thin Canadian crude so it can move through a pipeline -- up to Alberta.** Enbridge is teaming with ExxonMobil to assess the development of **a new pipeline project to transport crude from Patoka, Ill. to the Texas cities of Beaumont and Houston**. Other oil companies are also making moves in the industry: -- Houston-based energy company Marathon Oil Corp. is acquiring Western Oil Sands Inc. for $5.5 billion in a deal that would give the nation's fifth-largest refiner a 20-percent stake in the Athabasca Oil Sands Project. Shell Canada Ltd. and Chevron Canada Ltd. hold the remaining 60 percent and 20 percent stakes, respectively. Marathon stands to tap a net production of about 31,000 barrels of bitumen per day, increasing to more than 130,000 barrels per day by 2020. -- BP, which owns and operates a 600-mile long crude pipeline that moves oil from Oklahoma to Chicago, wants to reverse the line's flow if it can solicit enough long-term transport agreements. If demand warrants, the Viridian Pipeline could begin running north-south by the fourth quarter of 2009 with an immediate capacity of 100,000 barrels per day and potential for another 100,000 barrels, the company says.

AP researcher Rhonda Shafner in New York contributed to this report.

On the Net:
TransCanada Keystone Pipeline: http://www.transcanada.com/keystone/
Hyperion Energy Center: http://www.hyperionec.com/

WEB Exhibit # 1-c

Encana Corp.: http://www.encana.com/
ConocoPhillips Co.: http://www.conocophillips.com/
Enbridge Inc.: http://www.enbridge.com/
Post your comments

Conoco Has Big Plans for Alberta Oilsands, CEO Says

By Shawn McCarthy
20 Jul 2007 at 10:19 AM GMT-04:00 ***Resource Investor***

OTTAWA (CP) -- ConocoPhillips Co. [NYSE:COP] is prepared to spend billions of dollars on pipelines and refinery upgrades to allow it to process oilsands crude throughout its refinery network stretching to the U.S. Gulf Coast, the Globe and Mail reported on its website Thursday night.

Company chairman Jim Mulva said the extension of the pipeline network into the Gulf Coast would open a vast new market for Canadian oil sands producers and help ensure that oilsands projects that have already been proposed could go ahead.

The industry is worried, however, that federal and local governments on both sides of the border could create a regulatory logjam that would stall the planned investments.

Mulva said the rapid development of the Canadian oilsands is a key goal as the U.S. seeks to reduce its dependency on imported oil from outside North America, while still meeting rising gasoline demand at home. In a telephone news conference from Washington, Mulva said Conoco, the third-largest U.S. oil company, sees few hurdles in the way of the massive expansion of oilsands production, and is upgrading its fleet of refineries to handle the tarry crude.

* Last year, Houston-based Conoco and Calgary's EnCana Corp. [NYSE:ECA; TSX:ECA] joined forces to boost production in the oilsands, with Conoco gaining a 50% stake in oilsands projects such as Surmont and Christina Lake, while the Canadian company gained a 50% share in two of Conoco's refineries.

The two companies are already pouring in some US$5.3-billion to upgrade the Wood River refinery near St. Louis, and the Borger facility in northwest Texas to handle oilsands production. Now, Mulva said the company is considering extending pipelines and upgrading three refineries along the Gulf Coast to handle Canadian crude. Those facilities currently rely on declining U.S. production and imports from outside North America.

"We're considering projects that we can do to upgrade capacity to the extent that we need to handle this type of oil at our Gulf Coast refineries," Mulva said, adding that the Canadian crude would replace dwindling U.S. production there. U.S.-based energy economist James Williams said access to the Gulf Coast would help ensure robust markets for vastly expanded oilsands production, **which could reach 3.5 million barrels a day by 2020.** *

"There's no downside for Canada," he said. Not only would it provide a new market for

WEB Exhibit # 1.d

production, but, in doing so, it would reduce the price differential that now exists between oilsands crude output and the benchmark light U.S. The prospect of an expansion of the U.S. market for Canadian crude comes just a week after Chinese oil officials pulled the plug on their involvement in the Gateway pipeline project that would deliver oil sands crude to the West Coast for delivery to Asian markets.

Industry insiders have long acknowledged that the Gateway pipeline project faced huge hurdles, because Alberta producers have shown a clear preference for the U.S. market, and the route would have required right-of-way deals with scores of native bands. Mulva said Conoco and EnCana expect to eventually produce 400,000 barrels a day of crude from two major oil sands projects, and will be looking to book pipeline space now. He said the industry as a whole will need additional pipeline capacity for roughly one million barrels within about five years.

TransCanada Corp.[NYSE:TRP; TSX:TRP] is planning to build the Keystone pipeline, which would connect Alberta with southern Illinois, near the Wood River refinery, with an extension into Oklahoma. It would have a capacity of 435,000 barrels a day in the initial stage to open in 2009, and 590,000 barrels a day for the final phase, which would be completed in 2011.

Enbridge Inc. [NYSE:ENB; TSX:ENB], is proceeding with the Alberta Clipper line that would carry 450,000 barrels a day into the U.S. Midwest. New pipeline construction would be required to ship the Canadian crude to the Gulf Coast, which is the refining hub of the U.S.

Mulva said the industry will need **accelerated regulatory reviews and permits** to get the pipeline built in time to meet the market demand. David MacInnis, president of the Canadian Energy Pipeline Association, said the expansion of the network to the Gulf Coast would be a major boon to Alberta oilsands producers. But he said the regulatory hurdles remain significant and could delay projects if the various jurisdictions don't work together to expedite the reviews.

© *The Canadian Press 2007*

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WEB Exhibit # 1-e

LANDOWNER WARNING:

Don't sign this document before having a lawyer review it for you.
Look closely at Section 1, Section 5 and Section 8.

COPY

Tract No[redacted]

EASEMENT AND RIGHT-OF-WAY
AGREEMENT

For and in consideration of the sum of Ten Dollars ($10.00) paid in accordance with this Easement and Right-of-Way Agreement (this "**Agreement**"), the mutual promises of the parties herein and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged (collectively, the "**Consideration**"), [redacted], whose mailing address is [redacted] (hereinafter called "**Grantor**") does hereby grant, sell, convey and warrant unto TRANSCANADA KEYSTONE PIPELINE, LP., a Limited Partnership having its principal place of business at 450 – 1 Street SW, Calgary, Alberta, Canada, T2P 5H1, its successors and assigns (hereinafter called "**Grantee**"), a perpetual, permanent easement and right-of-way (the "**Easement**") for the purposes of surveying, laying, constructing, inspecting, maintaining, operating, repairing, replacing, altering, reconstructing, removing and abandoning in place one or more pipelines, together with all fittings, cathodic protection equipment, pipeline markers and all other equipment and appurtenances thereto, for the transportation of oil, natural gas, hydrocarbons, petroleum products and all by-products thereof, along routes convenient for Grantee's operations on, over, under, across and/or through a strip of land generally 50 feet in width, as more particularly described under the heading "Permanent Easement and Right-of-Way" in Exhibit A, which is attached hereto and made a part hereof (the "**Easement Area**") described as being situated in the County of Marshall, State of South Dakota, located on real property (the "**Property**"). [redacted] owned by Grantor, as more particularly described in Exhibit A attached hereto and made a part hereof (the "**Property**"). In addition, during the original construction of the pipeline(s), the easement and right-of-way granted hereunder shall also include the area described under the headings "Temporary Work Space" and "Additional Temporary Work Space" in Exhibit A hereto (the "**Temporary Work Space**").

Grantee may further define the location of the Easement Area by recording a "Notice of Location" referring to this instrument and setting forth a legal description of the Easement Area and the location of the pipelines contained therein, which description may be set forth by map attached to said Notice. A copy of said Notice shall be delivered to Grantor.

The aforesaid Easement is granted subject to the following terms, stipulations and conditions which are hereby covenanted and agreed to by Grantor. By acceptance of any of the benefits hereunder, Grantee shall be deemed to have agreed to be bound by the covenants applicable to Grantee hereunder.

1. The above recited Consideration is accepted by Grantor, and, subject to Paragraph 4, Paragraph 6 and Paragraph 8, below, Grantor (on behalf itself and its heirs, assigns, agents, successors in interest and any other person or entity taking through or under it) does hereby release, acquit, waive and forever discharge Grantee, and its successors and assigns, its parent, subsidiary and related companies and their officers, directors, employees, shareholders, agents, successors, assigns, attorneys, insurers, subcontractors, consultants, or any other person or entity taking through or under them, or any of them, of all and from all manner of action, causes of action, lawsuits, claims and demands of every kind and nature whatsoever, whether known or unknown and whether arising in law or in equity, that Grantor has or may have against Grantee (its successors and assigns) in connection with this Agreement.

WEB Exhibit # 2-a

2. Insofar as it may be practicable to do so, Grantee shall, unless otherwise requested by Grantor, strip the topsoil from the ditch line in the Easement Area only prior to construction and installation of any pipeline placed in the Easement Area. Following the construction and installation of each pipeline, the top soil will be replaced, to the extent feasible, as near as practicable to its original location and condition.

3. Except for above-ground piping facilities, such as mainline block valves, pump stations, etc., and except as otherwise stated in this Agreement, each pipeline shall be installed at a depth conforming with industry standards and the requirements of applicable laws.

4. Grantee shall have the right to remove all fences from the Easement Area and the Temporary Work Space, as required for purposes of construction of Grantee's pipeline(s) and Grantee shall repair all such fences promptly upon completion of construction on Grantor's Property to substantially the same condition as such fences were in prior to removal by Grantee.

5. Provided its use of the Property does not in any manner interfere with or prevent the exercise by Grantee of its rights hereunder, or create an actual or potential hazard to the pipeline(s) or its appurtenances, the undersigned Grantor, its successors, heirs or assigns, reserve all oil, gas and minerals on and under Property and the right to farm, graze and otherwise fully use and enjoy the Property; provided, however, that Grantee shall have the right hereafter to cut, keep clear and remove all trees, brush, shrubbery, structures and other obstructions or facilities in the Easement Area being conveyed that are deemed by Grantee to injure, endanger or interfere in any manner with the proper and efficient construction, use, inspection or maintenance of said pipeline(s), or fittings, cathodic protection equipment and other appurtenances thereto; and, provided, further, that Grantor shall not excavate or otherwise alter the ground elevation, construct any dam or otherwise create a water impoundment within or over the Easement Area without prior authorization of Grantee. Grantee shall have all privileges necessary or convenient for the full use of the rights herein granted, together with reasonable ingress and egress over and across that part of the Property located adjacent to the Easement Area and the Temporary Work Space.

COPY

6. Grantee agrees to pay all commercially reasonable costs and expenses relating to damages to crops, pasture, fences, structures, timber on the Property, or any other damages to the Property, resulting from Grantee's use of the Easement Area and the Temporary Work Space, except to the extent arising out of or relating to the negligence, recklessness or willful misconduct of Grantor or any of Grantor's invitees, licensees, agents or employees.

7. Any payment hereunder may be made or mailed to Grantor at the address shown above or to ____

____

____

who is hereby appointed agent and authorized to receive and receipt for same, and who is also appointed the true and lawful attorney in fact for Grantor. The agency and power of attorney granted by Grantor to its agent hereunder shall not be deemed revoked until written notice from Grantor has been received by Grantee.

8. Except as provided above with respect to limitations on damages, from and after the date of this Agreement, Grantee shall indemnify and hold harmless Grantor from any loss, damages, claims or actions resulting from Grantee's use of the Easement, except to the extent such loss, damage, claim or action results from the negligence or willful misconduct of Grantor, its invitees, licensees, agents or employees. Grantor shall indemnify and hold harmless Grantee from any loss, damages, claims or actions alleging injury to Grantor, its invitees, licensees, agents or employees who enter the Easement Area, except to the extent such loss, damage, claim or action results from the negligence or willful misconduct of Grantee.

9. All notices under this Agreement shall be in writing, addressed to the addresses first set forth above and be delivered by certified mail, postage prepaid, and return receipt requested, next business day delivery via a reputable national courier service, regular United States mail, facsimile, e-mail or hand delivery. A party may change its address for notice by giving notice of such change to the other party.

10. The undersigned hereby bind themselves, and their respective heirs, executors, administrators, successors and assigns, to warrant and forever defend this easement and right-of-way unto Grantee, its successors and assigns, against every person claiming or to claim the same, or any part thereof. The Easement granted hereby shall create a covenant and burden upon the Property and running therewith.

WEB Exhibit # 2b

11. Grantor and Grantee acknowledge that the actual location of the Easement Area may change because of various engineering factors and Grantor agrees to execute and deliver to Grantee, without additional compensation, and, where necessary, in recordable form, any additional documents needed to correct the legal description of the Easement Area to conform with the actual location of the pipeline(s). Said document, if required, will be prepared by Grantee at its expense.

12. It is agreed that this Agreement constitutes the entire agreement between the parties and that no other agreements have been made modifying, adding to or changing the terms of the same. This Agreement may not be abrogated, modified, rescinded or amended in whole or in part without the consent of Grantor and Grantee, in writing and executed by each of them, and duly recorded in the appropriate real property records.

13. The rights granted hereby to Grantee may be assigned by Grantee in whole or in part, in Grantee's sole discretion.

14. This Agreement shall be governed by the law of the State in which the Easement Area is situated.

15. This Agreement may be executed in counterparts, each of which shall be considered an original for all purposes; provided, however, that all such counterparts shall together constitute one and the same instrument.

IN WITNESS WHEREOF, Grantor has executed this Agreement as of the ________________ day of ________________, 200__.

COPY

GRANTOR:

Print: [redacted] ____________________

Sign: ______________________________

CORPORATE ACKNOWLEDGMENT

STATE OF South Dakota)
) SS
COUNTY OF Marshall)

Before me, a Notary Public in and for said County and State, on this ____ day of ____________________, 20 ___, personally appeared ____________________, to me known to be the identical person who Subscribed the name of the maker thereof to the foregoing instrument as its ____________________, and acknowledged to me that he executed the same as his free and voluntary act and deed and as the free and voluntary act and deed of such corporation for the uses and purposes therein set forth.

IN WITNESS WHEREOF, I have hereunto set my hand and official seal the day and year last above written.

My Commission expires:

____

____
NOTARY PUBLIC

ADDRESS

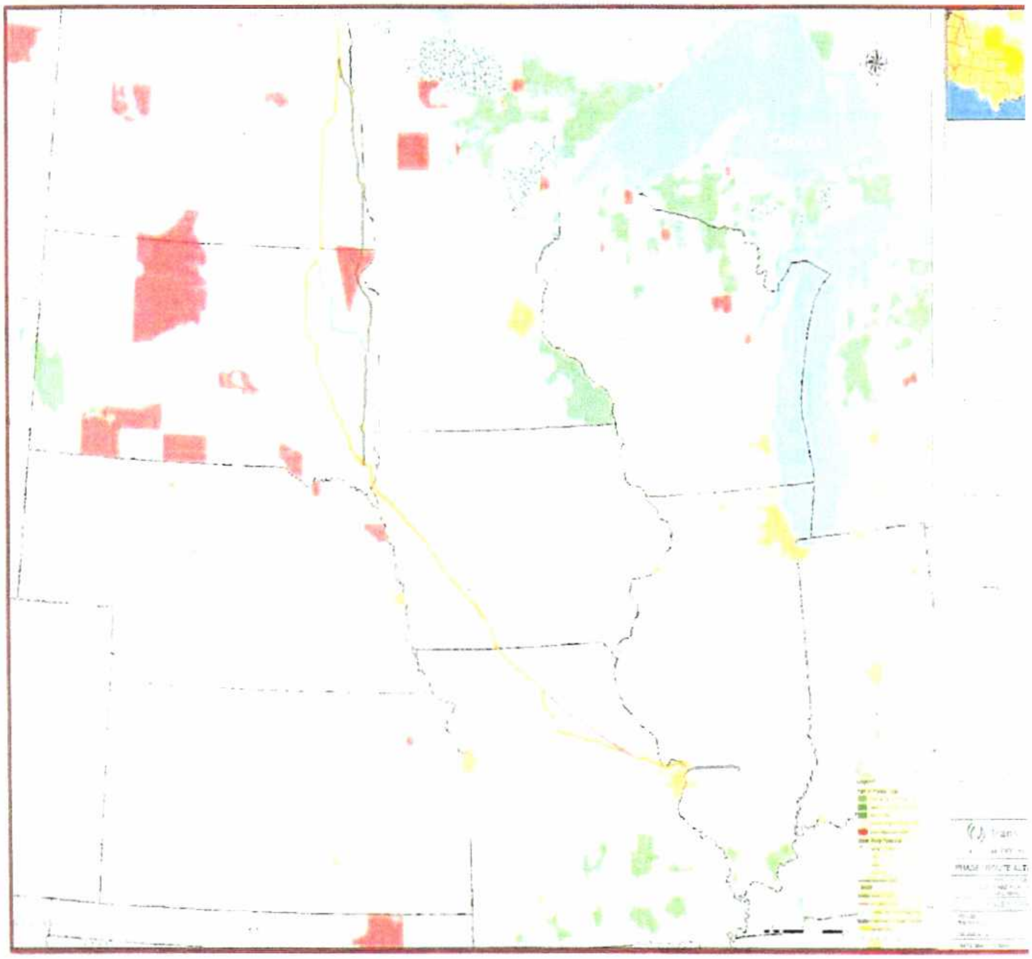
____

This Instrument Prepared by:

TRANSCANADA KEYSTONE PIPELINE, LP
450-1 Street SW
Calgary, Alberta, Canada
T2P 5H1

WEB Exhibit # 2-c

Interstate 29 - Alternate Route - TransCanada Oil Pipeline



WEB Exhibit # 3

DOT 241
(7-1-74)

Permit No. 84334

UTILITY PERMIT

Date: August 10, 1984

ISSUED TO:

WEB Water Development Association
Box 1911
Aberdeen, SD 57401

Project: 0122-376

Gentlemen:

The South Dakota Department of Transportation on August 10, 1984 has approved your request to occupy highway right-of-way as outlined in your application.

Therefore, permission is hereby granted, in accordance with the laws of the State of South Dakota relative thereto, to install 24 inches underground water pipe facilities within the highway right-of-way of US Highway Number(s) 12 in Walworth County, South Dakota, provided same is done at the expense of the permitee, under the supervision and to the satisfaction of the Area Engineer and according to Exhibits A, B, and ____ attached.

In the event it is deemed necessary by the South Dakota Department of Transportation to move or alter the line in any way due to maintenance or highway reconstruction within its present right-of-way width, the alteration will be accomplished by the owner without cost to the State.

Very truly yours,

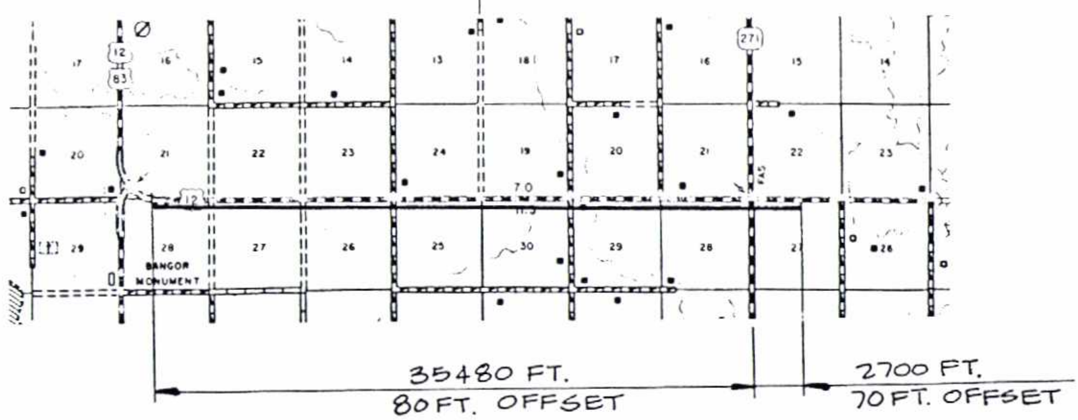
DEPARTMENT OF TRANSPORTATION
Operations Support
Pierre, South Dakota

Larry Snyder by RDE
Larry Snyder
Lease - Permit Engineer

LS:MT
cc: Records Center
File
Region Engineer
Area Engineer

WEB Exhibit # 4-a

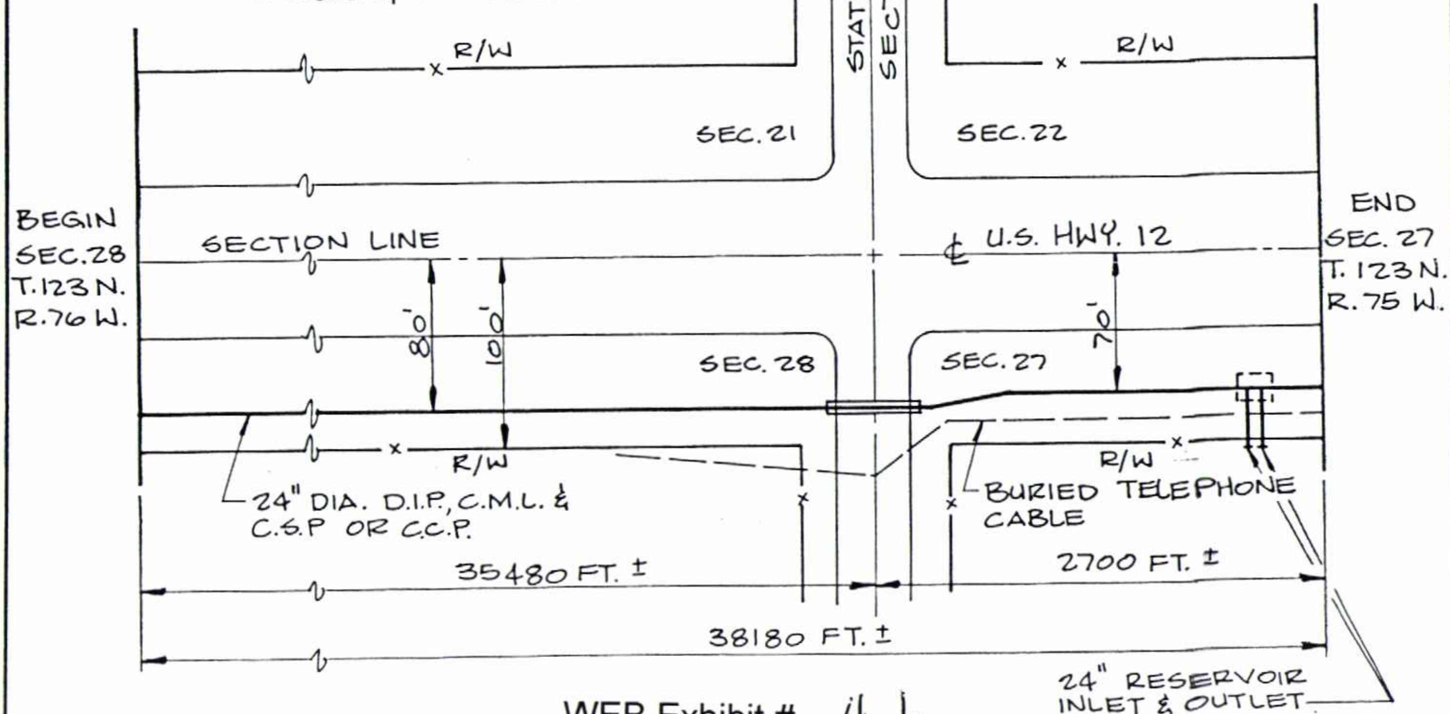
RECEIVED AUG 13 1984



LOCATION MAP

NOTE: PAVED DRIVEWAYS TO BE REPLACED IN KIND WHERE DISTURBED BY CONSTRUCTION. PAVED AREA SOUTH OF HWY 271 TO BE CROSSED BY BORING AND JACKING. CASING TO BE 60 FT. OF 36" DIA. STEEL PIPE. PIPELINE INCLUDES:

8-SERVICE CONNECTIONS
3-BLOWOFFS
2-AIR RELEASE VALVES
2-INLINE VALVES W/AIR RELEASES
13-ELECTROLYTIC MONITORING STATIONS WITH ASSOCIATED VAULTS & MANHOLES



WEB Exhibit # 4-b

EXHIBIT A

WEB WATER DEVELOPMENT ASSOCIATION, INC.

APPLICATION FOR PERMIT

ISSUED TO:

WEB Water Development Association
Box 1911
Aberdeen, SD 57401

You are hereby advised to notify the Mobridge Area Engineer,

William Bain at Mobridge

South Dakota; telephone number 605/845-3844

five working days prior to starting work covered by (Permit No.) 84334

dated August 10, 1984 on Project 0122-376

Please complete and send to Area Engineer as shown above.

To: William Bain, Area Engr., Dept. of Trans., P.O. Box 488, Mobridge, S.D. 57601

Permit No. 84334

Dated: August 10, 1984

Project No. 0122-376

Type of Installation 24 inches underground water pipe

Proposed Installation date __________

Submitted by __________

Title __________

Company __________

Address __________

WEB Exhibit # 4-c

DOT-200
(1-83)

SOUTH DAKOTA DEPARTMENT OF TRANSPORTATION
~~XXXXXXXXXXXXXXXXXXX~~

APPLICATION FOR UTILITY PERMIT

Highway No. 12 County Walworth Approximately 0 Mi. N S X E W

from U.S. Hwy. 12 (City or well defined point) for construction of potable water pipeline (type of utility facility)

Begin Section 28 Township 123N Range 76W End Section 27 Township 123N Range 75W

Intended usage or rating Domestic water supply

Cable size and type N/A

~~XXXXXX~~ pipe diameter 24-inch ductile iron, CML&C steel pipe, or concrete cylinder pipe

Maximum pipeline operating pressure 225 psi

Size and type of metal casing N/A

Minimum depth of cable or pipeline 72-inch

Method of installation Trenching (Boring and jacking 60 ft. only)

Approximate construction dates - Start November 1984 Finish November 1985

Special conditions

I, the undersigned, request permission to construct and maintain an utility facility on public right-of-way at the above location and as shown on the attached layout sheet and in accordance with provisions of Administrative Rule chapter 70:01:08 of the South Dakota Department of Transportation, ~~XXXXXXXXXXXXXXXXXX~~. In consideration for this permission, I agree to abide by all conditions as herein stated.

1. To furnish all materials, labor, incidentals and pay all costs involved with the construction and maintenance of the utility facility. To perform approved open cut trench operations in accordance with current DOT Open Cut Trench Policy. To restore any damaged portions of the roadway and right-of-way to equal or better conditions than existed prior to beginning work covered by this permit.
2. To provide protection to highway traffic during construction and maintenance by the use of proper signs, barricades, flagpersons and lights as prescribed in the "Manual of Uniform Traffic Control Devices".
3. To indemnify, hold and save harmless the State of South Dakota, its Department of Transportation, ~~XXXXXXXXXXXXXXXXXX~~ its Officers and Employees, from any and all suits, actions or claims of any kind or nature brought because of any injuries or damage received or sustained by any person or property on account of the use or occupancy of highway right-of-way designated in this application.

COMPANY WEB Water Development Association DATE 7-30-84

ADDRESS Box 1911, Aberdeen, SD 57401 Telephone (605)229-4749

BY: Curt Holm TITLE Project Coordinator

* * * To be completed by ~~XXXXXXXXXXXXXXXX~~ Dept. of Transportation * * *

Project (Const.) F044-3(2) Station 85± to 396± Milepost 214.1 to 221.5

Project (Maint.) 0122 Maintenance Unit 376

1. Prior to commencing construction and upon completion of work the applicant shall notify William Bain, Area Engineer at Mobridge, South Dakota

   Telephone 845-3844

2. Special Conditions:

3. Failure to construct and maintain the utility facility in accordance with the provisions of this permit will automatically render this permit null and void and constitute grounds for its removal and/or full restoration of the site at the applicant's expense.

Recommended: August 7, 19 84.

~~XXXXXXXXXXXXXX~~
PIERRE REGIONAL MANAGER

This permit to construct and maintain an utility facility is granted subject to all conditions as herein stated on this ______ day of __________________, 19______.

Utility Engineer

WEB Exhibit # 4-d

INSTRUCTIONS

APPLICANT:

1. Complete all items at top of form.

2. Prepare separate sheets showing details of the proposed installation. The drawings should include:

   a. Location of the facility in relation to the highway and the right-of-way line along with section lines, bridges and any other permanent features.

   b. Installations on bridges must include details of method of attachment.

   c. A North arrow.

   d. Any other pertinent information.

3. Sign and submit 2 copies of the request and 6 copies of the attachments to the district office for processing.

DIVISION OF HIGHWAYS:

District Engineer:

1. Review request and complete bottom portion of form.

2. If request is not recommended, return request to applicant stating reason for denial.

3. If request is recommended, forward request and all attachments to the Utility Engineer.

Utility Engineer:

1. Review request and if denied, return to applicant stating reason for denial with copy to District Engineer.

2. If request is granted, make and send copies of the permit and attachments as follows:

   a. 3 copies to District Engineer.

   b. 1 copy to applicant.

   c. Original to Record Center.

3. File 1 copy in Utility Office.

WEB Exhibit # 4-e

DOT 241
(3-1-85)

RECEIVED JUL - 2 1985
SD DOT [illegible]

Permit No. 85184

UTILITY PERMIT

Date: June 28, 1985

ISSUED TO:

WEB Water Development Association, Inc.
P.O. Box 51
Aberdeen, SD 57401

Project: 0122-155

Gentlemen:

The South Dakota Department of Transportation on June 28, 1985 has approved your request to occupy highway right-of-way as outlined in your application.

Therefore, permission is hereby granted, in accordance with the laws of the State of South Dakota relative thereto, to install 18 in. water line parallel installation facilities within the highway right-of-way of US Highway Number(s) 12 in Edmunds County, South Dakota, provided same is done at the expense of the permitee, under the supervision and to the satisfaction of the Area Engineer and according to Exhibits B, and A attached.

IN THE EVENT IT IS DEEMED NECESSARY BY THE SOUTH DAKOTA DEPARTMENT OF TRANSPORTATION TO MOVE OR ALTER THE LINE IN ANY WAY DUE TO MAINTENANCE OR HIGHWAY RECONSTRUCTION WITHIN ITS PRESENT RIGHT-OF-WAY WIDTH, THE ALTERATION WILL BE ACCOMPLISHED BY THE OWNER WITHOUT COST TO THE STATE.

Very truly yours,

DEPARTMENT OF TRANSPORTATION
Operations Support
Pierre, South Dakota

Robert D. Victor

Permit Engineer

BV:dg
cc: Records Center
File
Region Engineer
Area Engineer

WEB Exhibit # 4-f

ISSUED TO:

WEB Water Development Association, Inc.
P.O. Box 51
Aberdeen, SD 57401

You are hereby advised to notify the Aberdeen Area Engineer, Eugene Mattern at Aberdeen South Dakota; telephone number 605/622-2244 five working days prior to starting work covered by (Permit No.) 85184 dated June 28, 1985 on Project 0122-155

Please complete and send to Area Engineer as shown above.

To: Eugene Mattern, Area Engr., Dept. of Trans., P.O. Box 1767, Aberdeen, S.D. 57401

Permit No. 85184

Dated: June 28, 1985

Project No. 0122-155

Type of Installation 18 in. water line parallel installation

Proposed Installation date

Submitted by

Title

Company

Address

WEB Exhibit # 4-9

DOT-209
(2-84)

SOU. DAKOTA DEPARTMENT OF TRANSPORTATI(

APPLICATION FOR UTILITY PERMIT

Highway No. 12 County Edmunds Approximately 4.2 Mi. N S (E) W

from Roscoe (City or well defined point) for construction of Potable Water Pipeline (type of utility facility)

Begin Section 23 Township 123N Range 70N End Section 21 Township 123N Range 68W

Intended usage or rating Domestic Water Supply

Cable size and type N/A

Outside pipe diameter See Drawings (Attached)

Maximum pipeline operating pressure 225 P.S.I.

Size and type of metal casing N/A

Minimum depth of cable or pipeline 72 inches

Method of installation Trenching (Parallel Installation)

Approximate construction dates - Start August, 1985 Finish December, 1986

Special conditions

I, the undersigned, request permission to construct and maintain an utility facility on public right-of-way at the above location and as shown on the attached layout sheet and in accordance with provisions of Administrative Rule chapter 70:01:08 of the South Dakota Department of Transportation. In consideration for this permission, I agree to abide by all conditions as herein stated.

1. To furnish all materials, labor, incidentals and pay all costs involved with the construction and maintenance of the utility facility. To perform approved open cut trench operations in accordance with current DOT Open Cut Trench Policy. To restore any damaged portions of the roadway and right-of-way to equal or better conditions than existed prior to beginning work covered by this permit.
2. To provide protection to highway traffic during construction and maintenance by the use of proper signs, barricades, flagpersons and lights as prescribed in the "Manual of Uniform Traffic Control Devices".
3. To indemnify, hold and save harmless the State of South Dakota, its Department of Transportation, its Officers and Employees, from any and all suits, actions or claims of any kind or nature brought because of any injuries or damage received or sustained by any person or property on account of the use or occupancy of highway right-of-way designated in this application.

COMPANY WEB Water Development Assoc., Inc. DATE 6-8-85

ADDRESS P.O. Box 51 Aberdeen, SD 57401 Telephone (605) 229-4749

BY: Curt Hohn TITLE Project Coordinator

* * * To be completed by Department of Transportation * * *

Project (Const.) Station Milepost 262+ to 252+

Project (Maint.) 0122-155 Maintenance Unit 155

1. Prior to commencing construction and upon completion of work the applicant shall notify Eugene Mattern, Area Engineer, SD DOT at Aberdeen, SD 57401
Telephone 622-2244
2. Special Conditions: See attached sheet
3. Failure to construct and maintain the utility facility in accordance with the provisions of this permit will automatically render this permit null and void and constitute grounds for its removal and/or full restoration of the site at the applicant's expense.

Recommended: 6-21, 1985. [signature]
Region Manager

This permit to construct and maintain an utility facility is granted subject to all conditions as herein stated on this 28 day of June, 1985.

Robert D. Victor
Utility Engineer

WEB Exhibit # 4-h EXHIBIT B

Special Conditions

(1) Traffic into and out of the ditches shall be from approaches as much as possible during construction and maintenance phases.

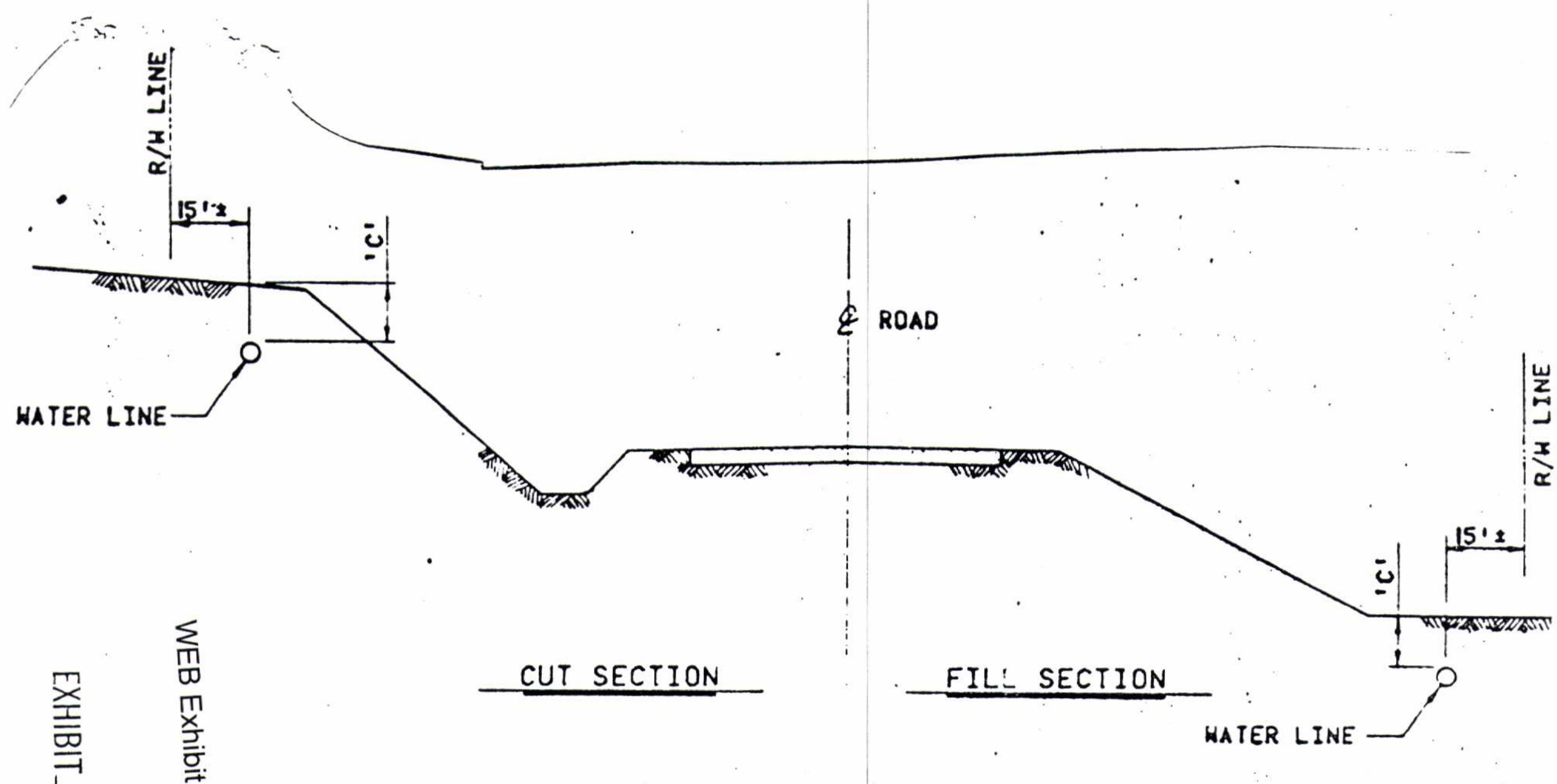
(2) Equipment and materials will not be allowed within 42' of the highway centerline except when absolutely necessary.

(3) The Area Engineer is to be notified when the work is completed so a finals inspection can be made.

(4) A copy of the as built plans will be furnished to the DOT by the WEB Water Development Association on completion of the work.

(5) Placement of Markers on the pipeline shall be in accordance with the DOT Right-Of-Way Encroachment Rules.

WEB Exhibit # 4-i



TYPICAL LINE INSTALLATION IN ROAD RIGHT OF WAY

NO SCALE

WEB Exhibit # 4-j

EXHIBIT A

PROJECT: WEB Water Development Assoc. Inc 3-1A

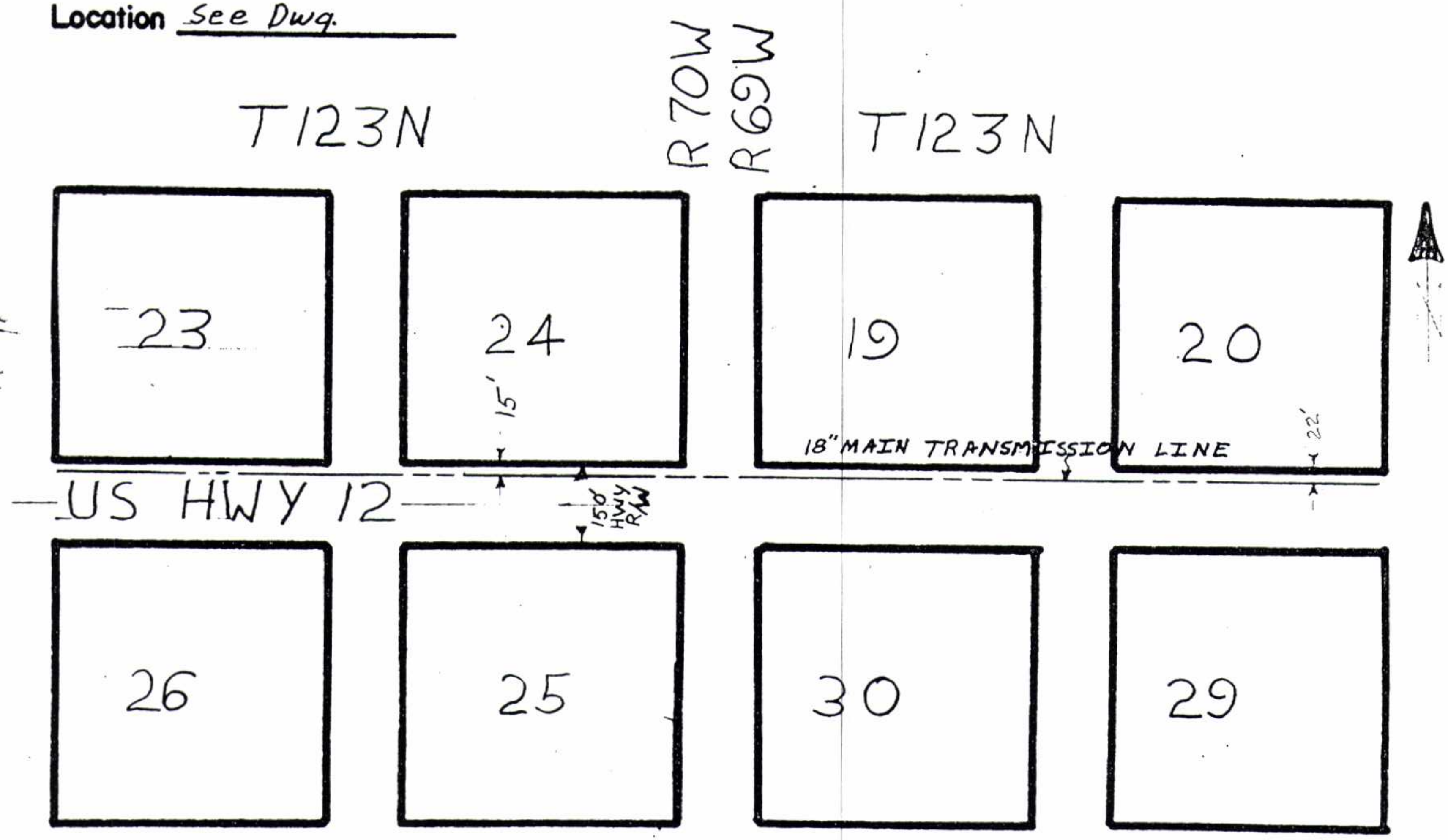
Highway No. 12

County Edmunds

Crossing No. Parallel Installation Within Highway R/W

Carrier Size 18"

Location See Dwg.

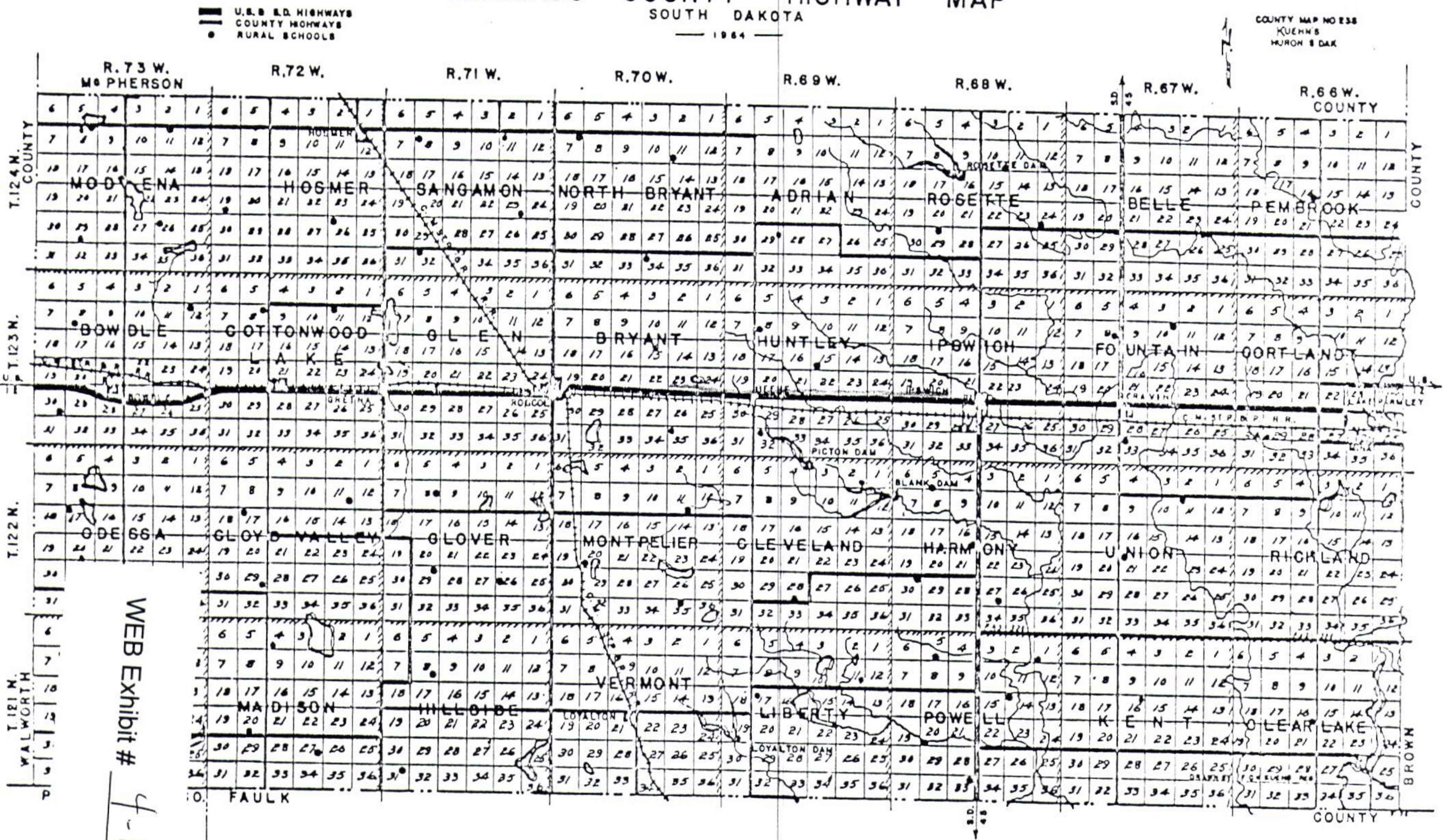


No Scale

WEB Exhibit # 4-K

Location of Parallel Installation

EDMUNDS COUNTY HIGHWAY MAP
SOUTH DAKOTA
— 1964 —



WEB Exhibit # 4-6

4

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Argus Leader

, April 29, 2007 | SIOUX FALLS, SOUTH DAKOTA | ☆☆ $1.50

MEET THE SCHOOL BOARD CANDIDATES

▶ Seven Sioux Falls residents seek two seats in the May 15 school board election. Read about them inside today's edition and learn more of their views Monday. **FULL PAGE REPORT: PAGE 5A**

Oil pipeline on fast track

Firm hopes to pump 435,000 barrels per day under S.D. by 2009

Curt Hohn: Has concerns about the oil pipeline's safety.

Bob Sheedy: Says Trans-Canada has an impeccable safety record.

BY PETER HARRIMAN
pharrima@argusleader.com

For South Dakotans used to seeing large projects such as the Dakota Minnesota & Eastern Railroad expansion toil for years to gain regulatory approval and fight legal challenges, a proposed oil pipeline through eastern South Dakota appears to be moving at astonishing speed.

"In my estimation, this thing is on as fast a track as I've ever seen," said John Davidson of the Living River Group of the South Dakota Sierra Club chapter, about the Keystone pipeline, a plan by utility giant TransCanada to send 435,000 barrels of crude oil per day by 2009 under South Dakota. The oil would move through a 30-inch pipe pressurized at 1,400 pounds per square inch.

Many see it as steady progress. But at least one official with some insight into pipelines is raising concerns about potential leaks.

Curt Hohn, general manager of the WEB Water Development Association in northeastern South Dakota and North Dakota, is in charge of a 6,200-mile network of underground

See **PIPELINE**, Page 6A

@ARGUS LEADER.COM

See Dave Mingo, Yankton development director, talk about TransCanada's Keystone Pipeline.

WEB Exhibit # 5-a

Pipeline: So far, criticism has been minimal

Continued from 1A

pipes and valves carrying an environmentally safe product: water. At 200 psi, WEB Water's pipeline is pressurized considerably less than TransCanada's oil pipeline would be.

Hohn might be a lonely critic amid the many supporters of the project, but he is trying to rally support for sharp scrutiny of the TransCanada plan. He is raising questions about whether a huge, high-pressure daily pulse of crude oil an average of 4 feet under South Dakota's productive farmland, range and wetlands is really all that safe.

"Even in the best laid pipelines, the pipes fail," Hohn said.

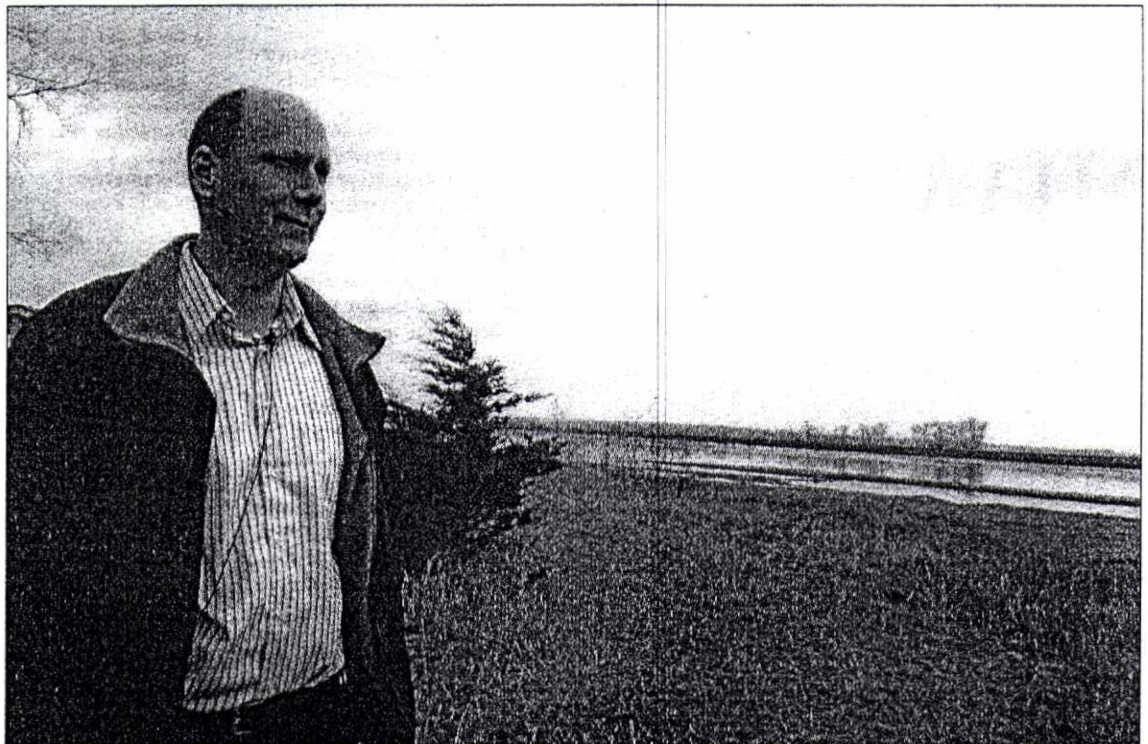
Across South Dakota, the TransCanada project is designed to have shutoff valves about 20 miles apart remotely monitored and operated by a computer system in Canada. The WEB system has valves every two miles to isolate breaks in the line and minimize spills, Hohn said.

Awaiting approval

TransCanada's $2.1 billion Keystone pipeline was announced as a proposal in early 2005. Its total length of 1,830 miles will reach from vast oil reserves in the sandy soil underlying Alberta to an oil storage and pipeline hub near Patoka, Ill. Spur lines also will connect with pipelines leading to refineries in Cushing, Okla., Wood River, Ill., and the Gulf Coast.

On Feb. 12, the Canadian National Energy Board approved the project. The U.S. State Department is preparing an Environmental Impact Statement to secure a Presidential Permit. An array of federal and state agencies are assisting in the preparation of the Environmental Impact Statement and other permitting issues. No pipe will be laid in South Dakota until the permitting is completed.

Many experts laud TransCanada's

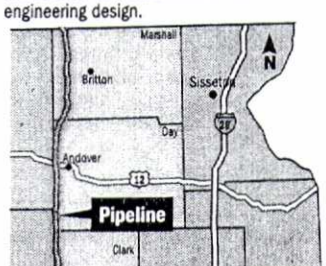


LARA NEEL / ARGUS LEADER

Yankton community development director Dave Mingo talks about the Missouri River at Paddle Wheel Point. Mingo said pipeline plans mean his city is looking as far as 70 years out to make sure the pipeline doesn't affect growth.

Proposed Keystone pipeline

This map is the proposed Keystone pipeline route through South Dakota as of April 7. This route will continue to be refined based on consultation with stakeholders and engineering design.



Hohn might look askance at the proposed distance between Keystone's isolation valves. However, Jones said spacing them about every 20 miles "is suitable for the environment we're going through." In areas of higher population, there would be more.

Furthermore, Jones said corrosion and leaks that plague the BP pipeline in Alaska probably won't affect Keystone because much of the water and sulphur mixed with crude oil that has degraded the BP pipeline will be removed before Alberta crude oil enters the Keystone network.

TransCanada is building Keystone

Dakota's interests.

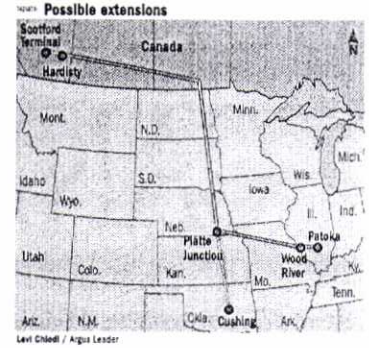
Mitch Krebs, Gov. Mike Rounds' spokesman, said Rounds is relying on the state agencies but is keeping abreast of Keystone's permitting issues. Rounds also continues to support the approximately $310 million economic benefit from pipeline construction and the $6.5 million in annual taxes Keystone will bring to South Dakota, Krebs said.

Wildlife worries

The State Department oversees Keystone's federal permit process, but agencies more familiar to South

TransCanada's proposed Keystone pipeline project route

Possible extensions



Levi Chiledi / Argus Leader

ment during pipeline construction.

Planning future growth

A straight blue line on a map offers a graphic illustration of the challenge Keystone will cause Yankton. The line is the planned Keystone route, and it borders a vacant plain on Yankton's southeast where the city is expected to add industrial development.

"It's a wall," said Dave Mingo, Yankton's community development director.

TransCanada has been willing to run the pipeline deeper so it won't interfere with the city's plans to eventually bring utilities to the area, but the pipeline "has forced us to look maybe as far as 70 years out as far as infrastructure planning is concerned. Typically, we would look no more than 20 years out," Mingo said. "If we don't let them know now, when the pipeline ends up in the ground, we would be designing around them rather than them designing around us."

The pipeline route also crosses under 70 acres of recreational trail, prairie and shoreline associated with the city's visitor center. South Dakota currently has no crude oil pipelines and only three carrying refined petroleum products. One of them is already located here: The Kaneb line carrying

WEB Exhibit # 5-6

[redacted]ill co[redacted]with[redacted]es l[redacted] to refineries in Cushing, Okla., Wood River, Ill., and the Gulf Coast.

On Feb. 12, the Canadian National Energy Board approved the project. The U.S. State Department is preparing an Environmental Impact Statement to secure a Presidential Permit. An array of federal and state agencies are assisting in the preparation of the Environmental Impact Statement and other permitting issues. No pipe will be laid in South Dakota until the permitting is completed.

Many experts laud TransCanada's track record and business practices.

Chuck Hamel is an ardent watchdog of oil pipelines who has drawn attention to the failings of the British Petroleum pipeline at Prudhoe Bay in Alaska.

"As long as it is done right and operated correctly, I don't see a problem. They've got crude oil lines all over the world," he said. Furthermore, "the Canadians have done very well. I've never heard a bad thing about TransCanada."

Bob Sheedy, a writer from Roblin, Manitoba, who works with the Manitoba government to develop trout fisheries in prairie lakes, says TransCanada "has an impeccable safety record."

Robert Jones, TransCanada's vice president and director of the Keystone pipeline, says a combination of high-grade steel and welding, monitoring technology and forethought about picking the Keystone route make it safe.

"We try and avoid sensitive areas, state and national parks. We don't cross any aboriginal lands.

"We try to stay away from major metropolitan areas. We don't want to run this thing down Main Street," he said.

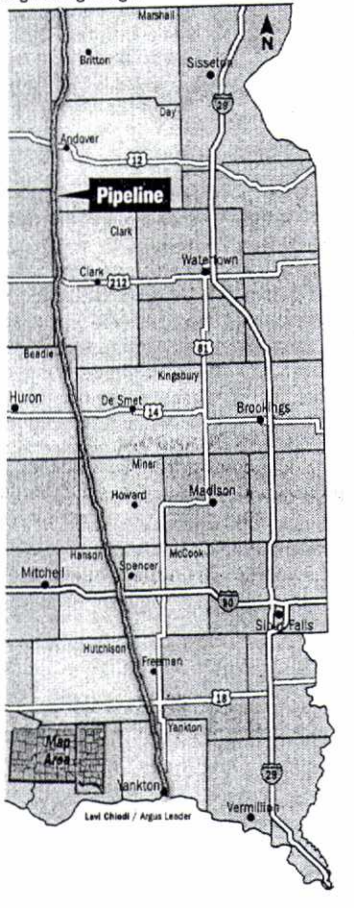
The pipeline will be buried an average depth of 4 feet. It will not interfere with farming activity and municipal utilities, Jones said. In comparison, the Lewis & Clark water pipeline is being buried an average of 6 feet underground for many of those same reasons, Lewis & Clark Rural Water director Troy Larson said.

Leak prevention

Hohn's concerns about pipeline pressure notwithstanding, crude oil regularly moves between 1,400 and

[redacted]

[redacted]p is th[redacted]ed Key[redacted]peline route through South Dakota as of April 7. This route will continue to be refined based on consultation with stakeholders and engineering design.



2,000 psi, Jones said. It's up from 1,000 psi for pipelines built in the 1950s. This reflects improved quality of steel and welding. "We try to test 100 percent of our welds, so when we put it in the ground, we never have to look at it again," Jones said.

In TransCanada's modern oil pipelines, in-line computerized inspections detect dents, corrosion and other anomalies before they become leaks. And pipeline pressures are monitored. If there is any sudden change, pump stations are shut down, and the line is isolated to minimize damage from leaking oil.

pose[redacted]ance[redacted]een[redacted]one's isolation valves. However, Jones said spacing them about every 20 miles "is suitable for the environment we're going through." In areas of higher population, there would be more.

Furthermore, Jones said corrosion and leaks that plague the BP pipeline in Alaska probably won't affect Keystone because much of the water and sulphur mixed with crude oil that has degraded the BP pipeline will be removed before Alberta crude oil enters the Keystone network.

TransCanada is building Keystone itself, but oil giant ConocoPhillips has an opportunity to become a partner, Jones said. Whether it does will not affect TransCanada's management of Keystone and ongoing commitment to maintain it, Jones said.

PUC permit

Jones said the project is moving along at a responsible pace.

"We've done all the consultation and all the surveys. We've selected the route. We've talked to all the different stakeholders. We've filed evidence with the Department of State," he said. A draft Environmental Impact Statement is due out in June, and TransCanada next will file for a state permit with the Public Utilities Commission.

The draft Environmental Impact Statement and PUC request might present opportunities for Keystone opponents to mount challenges. To date, criticism of the project is minimal. "If there's a concern, it's the lack of a forum to seriously raise" potential environmental issues associated with the pipeline, Davidson said.

TransCanada seems to be skillfully driving the regulatory process.

"At this point, it really appears they are taking in everyone's concerns," said Kara Van Bockern, PUC lawyer. She calls the relationship between TransCanada and the myriad federal, state and local agencies "a very harmonious state of affairs."

She also said when TransCanada files for a state permit, the PUC and the Department of Environment and Natural Resources will have sufficient statutory clout to look out for South

[redacted]itch[redacted]. Go[redacted]e R[redacted] spokesman, said Rounds is relying on the state agencies but is keeping abreast of Keystone's permitting issues. Rounds also continues to support the approximately $310 million economic benefit from pipeline construction and the $6.5 million in annual taxes Keystone will bring to South Dakota, Krebs said.

Wildlife worries

The State Department oversees Keystone's federal permit process, but agencies more familiar to South Dakotans, such as the U.S. Fish and Wildlife Service and Army Corps of Engineers, are shaping the project.

"It's almost impossible to build a project of this scale and scope without crossing some of the easements we have," said Jack Lalor, assistant manager of the USFWS Tewaukon National Wildlife Refuge, who is working on wetlands issues associated with Keystone. The Corps, under the Clean Water Act, is responsible for ensuring that Keystone does not degrade water quality, and it has to approve Keystone's crossing of the Missouri River at Paddle Wheel Point in Yankton.

The USFWS is largely concerned that Keystone does not disturb valuable habitat for threatened and endangered species and that building the pipeline does not permanently harm wetlands the pipe will pass under. Tom Tornow, who heads the USFWS Madison wetlands district, said the pipeline "will be crossing some critical habitat for Topeka shiners," a federally designated endangered species, and construction is expected to result in a one-year disturbance in nesting for wetland birds.

Lalor said TransCanada has been amenable to a USFWS request to reroute Keystone away from the Hecla sand hills that drain into Waubay and the Sand Lake Wildlife Refuge, and the agency is taking inventory of other areas with rare plants and animals that might be affected by a pipeline.

Most of the wetland soils that would be disturbed by construction "recover nicely" Lalor said, and Jones added that TransCanada in the past decade has made "real advances" in soil manage-

str[redacted]plan[redacted]s con[redacted]. Typically, we would look no more than 2[illegible] years out," Mingo said. "If we don't let them know now, when the pipeline ends up in the ground, we would be designing around them rather than them designing around us."

The pipeline route also crosses under 70 acres of recreational trail, prairie and shoreline associated with the city's visitor center. South Dakota currently has no crude oil pipelines and only three carrying refined petroleum products. One of them is already located here: The Kaneb line carrying vehicle fuels crosses the Missouri at Paddle Wheel Point. The Corps of Engineers will require Keystone to use the same crossing. Mingo says in the 15 years he has worked for Yankton, there have been no problems with the Kaneb pipeline.

According to the U.S. Energy Information Administration, Kaneb, Williams and Amoco have refined petroleum products pipelines in South Dakota. After Sept. 11, the National Pipeline Mapping System no longer makes its maps available to the public.

As Keystone gets closer to securing regulatory approval, Hohn at WEB Water questions whether TransCanada will have sufficient staff in the U.S. to maintain the pipeline. Will TransCanada post bonds with state or local governments to establish a mitigation fund if Keystone leaks, or will landowners have to fight for restitution? If crude oil escapes the pipeline at 1,400 psi, could friction start a fire? If so, who will fight it?

Hohn also points to a pipeline rupture near Bemidji, Minn., in 1979 that spilled 10,700 barrels of crude oil. Despite cleanup efforts, about 110,000 gallons remain in the soil and water table and are migrating toward a nearby lake. Is this South Dakota's fate?

While the draft Environmental Impact Statement might prompt such inquiry, so far, Hohn seems to be a lone voice asking questions.

The loudest voice talking about Keystone might belong to Jones. He said this: "A pipeline is by far the safest way to move hydrocarbon products."

Reach reporter Peter Harriman at 575-3615.

WEB Exhibit # 5-c

PIPELINE

TransCan's Keystone costs soar

DAVID EBNER

October 31, 2007

CALGARY -- The cost estimate of a planned new pipeline to move raw oil sands production to the United States has almost doubled, **TransCanada Corp.** says.

The Calgary-based pipeline and power-generation company said yesterday its proposed Keystone pipeline will cost $5.2-billion (U.S.), up from an estimate of $2.8-billion four months ago.

TransCanada is a natural gas pipeline company trying to break into the oil-transportation business. It would be taking on archrival **Enbridge Inc.**, the No. 1 mover of oil."Even with the cost increases, we're still very, very competitive," Russ Girling, president of TransCanada's pipeline business, said during a conference call yesterday to discuss quarterly earnings.

The Keystone pipeline, which could be moving oil in late 2009, would connect a major hub near Edmonton with two refining centres in southern Illinois. There would also be another connection with Cushing, Okla. In total, Keystone could carry 590,000 barrels of oil a day.

Groups such as the Canadian Energy & Paperworkers Union have said the pipeline would effectively ship 18,000 high-value domestic jobs "down the pipeline" to the United States, and they want the federal cabinet to stop the project.

The massive jump in Keystone's price tag is due to design changes, as well as high costs for steel and workers, and overall inflation, TransCanada said.

Canadian regulatory approval has been secured to move 435,000 barrels per day on Keystone, and TransCanada said yesterday it will request approval for 590,000 barrels. It still needs approval for Keystone in the United States.

Calgary-based Enbridge already moves upward of two million barrels a day between Alberta and Chicago and further south.

The company is looking to add 450,000 barrels per day of new capacity on a planned new pipeline called Alberta Clipper, which would run alongside its main line from Alberta to Wisconsin, with additional connections beyond. TRANSCANADA CORP. (TRP)

WEB Exhibit # 6

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BRENT A. WILBUR 1949-2006
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605 224-6289

August 23, 2007

Writer's E-mail: koenecke@magt.com

Patricia Van Gerpen, Executive Director
South Dakota Public Utilities Commission
500 E. Capitol
Pierre, SD 57501

Re: 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 Pipeline Project; HP 07-001. Informational Submittal

Our File: 5057

Dear Ms. Van Gerpen:

TransCanada Keystone Pipeline, LP (Keystone) hereby provides, as an informational submittal in connection with its application for a permit under the South Dakota Energy Conversion and Transmission Facilities Act, a copy of the "Special Permit" granted to Keystone by the United States Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA).

The federal pipeline safety regulations require that the formula used by pipeline operators to establish maximum operating pressure use the design factor contained in 49 C.F.R. § 195.106. The formula specifies a design factor of 0.72 for onshore pipelines. Under the federal Pipeline Safety Act, PHMSA may grant a waiver of any regulatory requirement if the agency finds that granting the waiver "is not inconsistent with pipeline safety." 49 U.S.C. § 60118. On November 17, 2006, Keystone filed a request for waiver of 49 C.F.R. § 195.106, seeking permission to use an 0.80 design factor, in lieu of a 0.72 design factor, for the Mainline and Cushing Extension portions of the Keystone Pipeline project.

PHMSA undertook an extensive, detailed technical review of Keystone's request. PHMSA also engaged outside experts in the field of steel pipeline fracture mechanics, leak detection and SCADA systems to assist in the review of Keystone's application. PHMSA publicly noticed Keystone's application and incorporated the concerns expressed in public comment into its review. As a result of its review, PHMSA issued the attached Special Permit allowing Keystone to design, construct and operate its crude oil pipeline project using a design

WEB Exhibit # 7-a

factor and operating stress level of 80 percent of the steel pipe's specified minimum strength (SMYS) in most areas.

In issuing the Special Permit, PHMSA found specifically that allowing Keystone to operate at 80 percent of SMYS is not inconsistent with pipeline safety and that it "will provide a level of safety equal to or greater than that which would be provided if the pipelines were operated under existing regulations." The Special Permit contains 51 conditions that Keystone must comply with, addressing areas such as steel properties, manufacturing standards, fracture control, quality control, puncture resistance, hydrostatic testing, pipe coating, overpressure control, welding procedures, depth of cover, SCADA, leak detection, pigging, corrosion monitoring, pipeline markers, in-line inspection, damage prevention program, reporting, and other areas. Failure to comply with any condition may result in revocation of the Special Permit. In addition, the Special Permit is not applicable to certain sensitive areas including commercially navigable high consequence areas, high population high consequence areas, highway, railroad and road crossings, and pipeline located within pump stations, mainline valve assemblies, pigging facilities, and measurement facilities. Issuance of the Special Permit was based on PHMSA's determinations that the aggregate affect of Keystone's actions and PHMSA's conditions provide for more inspections and oversight than would occur on pipelines installed under the existing regulations, and that PHMSA's conditions require Keystone to more closely inspect and monitor its pipeline over its operational life than similar pipelines installed without a Special Permit.

The PHMSA Special Permit does not materially change Keystone's application before the Public Service Commission. Specifically, issuance of the Special Permit will not result in an increase in Keystone's maximum allowable operating pressure of 1,440 psig.

While compliance with the federal pipeline safety regulations is a matter subject to PHMSA's jurisdiction, Keystone appreciates the PUC's interest in the Special Permit and trusts this informational submittal is helpful to the Commission.

Respectfully submitted,

MAY, ADAM, GERDES & THOMPSON LLP

BRETT KOENECKE

BK:lar

WEB Exhibit # 7-6

U.S. Department
of Transportation

Pipeline and Hazardous Materials Safety Administration

400 Seventh Street, S.W.
Washington, D.C. 20590

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

APR 30 2007

Mr. Robert Jones
Vice President
TransCanada Keystone Pipeline, LP
450 1st Street, SW
Calgary, Alberta, T2P 5H1
Canada

Dear Mr. Jones:

On November 17, 2006 you wrote to the Pipeline and Hazardous Materials Safety Administration (PHMSA) requesting a waiver of compliance from PHMSA's pipeline safety regulation 49 CFR 195.106 for two pipelines. The regulation specifies the design factor used in the design pressure formula to establish the maximum operating pressure for a hazardous liquid pipeline.

The PHMSA is granting this waiver through the enclosed special permit. This special permit will allow TransCanada Keystone Pipeline, LP (Keystone) to establish a maximum operating pressure for two pipelines using a 0.80 design factor in lieu of 0.72, with conditions and limitations. The proposed pipelines covered by this special permit are the 1,025-mile, 30-inch, mainline from the Canadian border at Cavalier County, North Dakota, to Wood River, Illinois; and, the 291-mile, 36-inch, Cushing Extension from Jefferson County, Nebraska, to Cushing (Marion County), Oklahoma. The special permit provides some relief from the Federal pipeline safety regulations for Keystone while ensuring that pipeline safety is not compromised.

If necessary, my staff would be pleased to discuss this special permit or any other regulatory matter with you. Florence Hamn, Director, Office of Regulations (202-366-4595) would be pleased to assist you.

Sincerely,

Jeffrey D. Wiese
Acting Associate Administrator
for Pipeline Safety

Enclosure

WEB Exhibit # 7-C

DEPARTMENT OF TRANSPORTATION

PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION (PHMSA)

SPECIAL PERMIT

Docket Number:	PHMSA-2006-26617
Pipeline Operator:	TransCanada Keystone Pipeline, L.P.
Date Requested:	November 17, 2006
Code Section(s):	49 CFR 195.106

Grant of Special Permit:

Based on the findings set forth below, the Pipeline and Hazardous Materials Safety Administration (PHMSA) grants this special permit to TransCanada Keystone Pipeline, L.P. (Keystone). This special permit allows Keystone to design, construct and operate two new crude oil pipelines using a design factor and operating stress level of 80 percent of the steel pipe's specified minimum yield strength (SMYS) in rural areas. The current regulations in 49 CFR 195.106 limit the design factor and operating stress level for hazardous liquids pipelines to 72 percent of SMYS. This special permit is subject to the conditions set forth below.

Except for the non-covered portions of the pipelines described below, this special permit covers two proposed pipelines in the United States:

- The 1,025-mile, 30-inch, Mainline from the Canadian border at Cavalier County, North Dakota, traversing the States of South Dakota, Nebraska, Kansas and Missouri, to Wood River, Illinois; and
- The 291-mile, 36-inch, Cushing Extension from Jefferson County, Nebraska, through Kansas, to Cushing (Marion County), Oklahoma.

This special permit does not cover certain portions of the Mainline and Cushing Extension pipelines. These non-covered portions are the following:

- Pipeline segments operating in high consequence areas (HCAs) described as commercially navigable waterways in 49 CFR 195.450;
- Pipeline segments operating in HCAs described as high population areas in 49 CFR 195.450;

WEB Exhibit # 7-C

- Pipeline segments operating at highway, railroad and road crossings; and
- Piping located within pump stations, mainline valve assemblies, pigging facilities and measurement facilities.

For the purpose of this special permit, the "special permit area" means the area consisting of the entire pipeline right-of-way for those segments of the pipeline that will operate above 72 percent of SMYS.

Findings:

PHMSA finds that granting this special permit to Keystone to operate two new crude oil pipelines at a pressure corresponding to a hoop stress of up to 80 percent SMYS is not inconsistent with pipeline safety. Doing so will provide a level of safety equal to, or greater than, that which would be provided if the pipelines were operated under existing regulations. We do so because the special permit analysis shows the following:

- Keystone's special permit application describes actions for the life cycle of each proposed pipeline addressing pipe and material quality, construction quality control, pre-in service strength testing, the Supervisory Control and Data Acquisition (SCADA) system inclusive of leak detection, operations and maintenance and integrity management. The aggregate affect of these actions and PHMSA's conditions provide for more inspections and oversight than would occur on pipelines installed under existing regulations; and
- The conditions contained in this special permit grant require Keystone to more closely inspect and monitor the pipelines over its operational life than similar pipelines installed without a special permit.

Conditions:

The grant of this special permit is subject to the following conditions:

1) Steel Properties: The skelp/plate must be micro alloyed, fine grain, fully killed steel with calcium treatment and continuous casting.
2) Manufacturing Standards: The pipe must be manufactured according to American Petroleum Institute Specification 5L, *Specification for Line Pipe* (API 5L), product

WEB Exhibit # 7-d

specification level 2 (PSL 2), supplementary requirements (SR) for maximum operating pressures and minimum operating temperatures. Pipe carbon equivalents must be at or below 0.23 percent based on the material chemistry parameter (Pcm) formula.

3) Transportation Standards: The pipe delivered by rail car must be transported according to the API Recommended Practice 5L1, *Recommended Practice for Railroad Transportation of Line Pipe* (API 5L1).

4) Fracture Control: API 5L and other specifications and standards address the steel pipe toughness properties needed to resist crack initiation. Keystone must institute an overall fracture control plan addressing steel pipe properties necessary to resist crack initiation and propagation. The plan must include acceptable Charpy Impact and Drop Weight Tear Test values, which are measures of a steel pipeline's toughness and resistance to fracture. The fracture control plan, which must be submitted to PHMSA headquarters, must be in accordance with API 5L, Appendix F and must include the following tests:

   a) SR 5A - Fracture Toughness Testing for Shear Area: Test results must indicate at least 85 percent minimum average shear area for all X-70 heats and 80 percent minimum shear area for all X-80 heats with a minimum result of 80 percent shear area for any single test. The test results must also ensure a ductile fracture;

   b) SR 5B – Fracture Toughness Testing for Absorbed Energy; and

   c) SR 6 – Fracture Toughness Testing by Drop Weight Tear Test: Test results must be at least 80 percent of the average shear area for all heats with a minimum result of 60 percent of the shear area for any single test. The test results must also ensure a ductile fracture.

The above fracture initiation, propagation and arrest plan must account for the entire range of pipeline operating temperatures, pressures and product compositions planned for the pipeline diameter, grade and operating stress levels, including maximum pressures and minimum temperatures for start up and shut down conditions associated with the special permit area. If the fracture control plan for the pipe in the special permit area does not meet these specifications, Keystone must submit to PHMSA headquarters an alternative plan providing an acceptable method to resist crack initiation, crack propagation and to arrest ductile fractures in the special permit area.

5) Steel Plate Quality Control: The steel mill and/or pipe rolling mill must incorporate a comprehensive plate/coil mill and pipe mill inspection program to check for defects and

inclusions that could affect the pipe quality. This program must include a plate or rolled pipe (body and all ends) ultrasonic testing (UT) inspection program per ASTM A578 to check for imperfections such as laminations. An inspection protocol for centerline segregation evaluation using a test method referred to as slab macro-etching must be employed to check for inclusions that may form as the steel plate cools after it has been cast. A minimum of one macro-etch or a suitable alternative test must be performed from the first or second heat (manufacturing run) of each sequence (approximately four heats) and graded on the Mannesmann scale or equivalent. Test results with a Mannesmann scale rating of one or two out of a possible five scale are acceptable.

6) Pipe Seam Quality Control: A quality assurance program must be instituted for pipe weld seams. The pipe weld seam tests must meet the minimum requirements for tensile strength in API 5L for the appropriate pipe grade properties. A pipe weld seam hardness test using the Vickers hardness testing of a cross-section from the weld seam must be performed on one length of pipe from each heat. The maximum weld seam and heat affected zone hardness must be a maximum of 280 Vickers hardness (Hv10). The hardness tests must include a minimum of two readings for each heat affected zone, two readings in the weld metal and two readings in each section of pipe base metal for a total of 10 readings. The pipe weld seam must be 100 percent UT inspected after expansion and hydrostatic testing per APL 5L.

7) Monitoring for Seam Fatigue from Transportation: Keystone must inspect the double submerged arc welded pipe seams of the delivered pipe using properly calibrated manual or automatic UT techniques. For each lay down area, a minimum of one pipe section from the bottom layer of pipes of the first five rail car shipments from each pipe mill must be inspected. The entire longitudinal weld seam must be tested and the results appropriately documented. For helical seam submerged arc welded pipe, Keystone must test and document the weld seam in the area along the transportation bearing surfaces and all other exposed weld areas during the test. Each pipe section test record must be traceable to the pipe section tested. PHMSA headquarters must be notified of any flaws that exceeded specifications and needed to be removed. Keystone's findings will determine if PHMSA will require the testing program be expanded to include a larger sampling population for seam defects originating during pipeline transportation.

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8) Puncture Resistance: Steel pipe must be puncture resistant to an excavator weighing up to 65 tons with a general purpose tooth size of 3.54 inches by 0.137 inches. Puncture resistance will be calculated based on industry established calculations such as the Pipeline Research Council International's *Reliability Based Prevention of Mechanical Damage to Pipelines* calculation method.

9) Mill Hydrostatic Test: The pipe must be subjected to a mill hydrostatic test pressure of 95 percent of SMYS or greater for 10 seconds. Any mill hydrostatic test failures must be reported to PHMSA headquarters with the reason for the test failure.

10) Pipe Coating: The application of a corrosion resistant coating to the steel pipe must be subject to a coating application quality control program. The program must address pipe surface cleanliness standards, blast cleaning, application temperature control, adhesion, cathodic disbondment, moisture permeation, bending, minimum coating thickness, coating imperfections and coating repair.

11) Field Coating: Keystone must implement a field girth weld joint coating application specification and quality standards to ensure pipe surface cleanliness, application temperature control, adhesion quality, cathodic disbondment, moisture permeation, bending, minimum coating thickness, holiday detection and repair quality must be implemented in field conditions. Field joint coatings must be non-shielding to cathodic protection (CP). Field coating applicators must use valid coating procedures and be trained to use these procedures. Keystone will perform follow-up tests on field-applied coating to confirm adequate adhesion to metal and mill coating.

12) Coatings for Trenchless Installation: Coatings used for directional bore, slick bore and other trenchless installation methods must resist abrasions and other damages that may occur due to rocks and other obstructions encountered in this installation technique.

13) Bends Quality: Certification records of factory induction bends and/or factory weld bends must be obtained and retained. All bends, flanges and fittings must have carbon equivalents (CE) equal to or below 0.42 or a pre-heat procedure must be applied prior to welding for CE above 0.42.

14) Fittings: All pressure rated fittings and components (including flanges, valves, gaskets, pressure vessels and pumps) must be rated for a pressure rating commensurate with the MOP of the pipeline.

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15) Design Factor - Pipelines: Pipe installed under this special permit may use a 0.80 design factor. Pipe installed in pump stations, road crossings, railroad crossings, launcher/receiver fabrications, population HCAs and navigable waters must comply with the design factor in 49 CFR 195.106. If portions of the pipeline become population HCAs during the operational life of the pipeline, Keystone will apply to PHMSA headquarters for a special permit for the affected pipeline sections.
16) Temperature Control: The pipeline operating temperatures must be less than 150 degrees Fahrenheit.
17) Overpressure Protection Control: Mainline pipeline overpressure protection must be limited to a maximum of 110 percent MOP consistent with 49 CFR 195.406(b).
18) Construction Plans and Schedule: The construction plans, schedule and specifications must be submitted to the appropriate PHMSA regional office for review within two months of the anticipated construction start date. Subsequent plans and schedule revisions must also be submitted to the PHMSA regional office.
19) Welding Procedures: The appropriate PHMSA regional office must be notified within 14 days of the beginning of welding procedure qualification activities. Automated or manual welding procedure documentation must be submitted to the same PHMSA regional office for review. For X-80 pipe, Keystone must conform to revised procedures contained in the 20th edition of API Standard 1104, *Welding of Pipelines and Related Facilities* (API 1104), Appendix A, or by an alternative procedure approved by PHMSA headquarters.
20) Depth of Cover: The soil cover must be maintained at a minimum depth of 48 inches in all areas except consolidated rock. In areas where conditions prevent the maintenance of 42 inches of cover, Keystone must employ additional protective measures to alert the public and excavators to the presence of the pipeline. The additional measures shall include placing warning tape and additional pipeline markers along the affected pipeline segment. In areas where the pipeline is susceptible to threats from chisel plowing or other activities, the top of the pipeline must be installed at least one foot below the deepest penetration above the pipeline. If routine patrols indicate the possible loss of cover over the pipeline, Keystone must perform a depth of cover study and replace cover as necessary to meet the minimum depth of cover requirements specified herein. If the replacement of cover is impractical or not possible, Keystone must install other protective measures including warning tape and closely spaced signs.

WEB Exhibit # 7-h

21) Construction Quality: A construction quality assurance plan for quality standards and controls must be maintained throughout the construction phase with respect to: inspection, pipe hauling and stringing, field bending, welding, non-destructive examination (NDE) of girth welds, field joint coating, pipeline coating integrity tests, lowering of the pipeline in the ditch, padding materials to protect the pipeline, backfilling, alternating current (AC) interference mitigation and CP systems. All girth welds must be NDE by radiography or alternative means. The NDE examiner must have all current required certifications.

22) Interference Currents Control: Control of induced alternating current from parallel electric transmission lines and other interference issues that may affect the pipeline must be incorporated into the design of the pipeline and addressed during the construction phase. Issues identified and not originally addressed in the design phase must be brought to PHMSA headquarters' attention. An induced AC program to protect the pipeline from corrosion caused by stray currents must be in place and functioning within six months after placing the pipeline in service.

23) Test Level: The pre-in service hydrostatic test must be to a pressure producing a hoop stress of 100 percent SMYS and 1.25 X MOP in areas to operate to 80 percent SMYS. The hydrostatic test results from each test after completion of each pipeline must be submitted to PHMSA headquarters.

24) Assessment of Test Failures: Any pipe failure occurring during the pre-in service hydrostatic test must undergo a root cause failure analysis to include a metallurgical examination of the failed pipe. The results of this examination must preclude a systemic pipeline material issue and the results must be reported to PHMSA headquarters and the appropriate PHMSA regional office.

25) Supervisory Control and Data Acquisition (SCADA) System: A SCADA system to provide remote monitoring and control of the entire pipeline system must be employed.

26) SCADA System – General:

   a) Scan rate shall be fast enough to minimize overpressure conditions (overpressure control system), provide very responsive abnormal operation indications to controllers and detect small leaks within technology limitations;

   b) Must meet the requirements of regulations developed as a result of the findings of the National Transportation Safety Board, *Supervisory Control and Data Acquisition (SCADA) in Liquid Pipelines,* Safety Study, NTSB/SS-05/02 specifically including:

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- Operator displays shall adhere to guidance provided in API Recommended Practice 1165, *Recommended Practice for Pipeline SCADA Display* (API RP 1165)
- Operators must have a policy for the review/audit of alarms for false alarm reduction and near miss or lessons learned criteria
- SCADA controller training shall include simulator for controller recognition of abnormal operating conditions, in particular leak events
- See item 27b below on fatigue management
- Install computer-based leak detection system on all lines unless an engineering analysis determines that such a system is not necessary

c) Develop and implement shift change procedures for controllers;

d) Verify point-to-point display screens and SCADA system inputs before placing the line in service;

e) Implement individual controller log-in provisions;

f) Establish and maintain a secure operating control room environment;

g) Establish controls to functionally test the pipeline in an off-line mode prior to beginning the line fill and placing the pipeline in service; and

h) Provide SCADA computer process load information tracking.

27) SCADA – Alarm Management: Alarm Management Policy and Procedures shall address:

a) Alarm priorities determination;

b) Controllers' authority and responsibility;

c) Clear alarm and event descriptors that are understood by controllers;

d) Number of alarms;

e) Potential systemic system issues;

f) Unnecessary alarms;

g) Controllers' performance regarding alarm or event response;

h) Alarm indication of abnormal operating conditions (AOCs);

i) Combination AOCs or sequential alarms and events; and

j) Workload concerns.

28) SCADA – Leak Detection System (LDS): The LDS Plan shall include provisions for:

a) Implementing applicable provisions in API Recommended Practice 1130, *Computational Pipeline Monitoring for Liquid Pipelines* (API RP 1130), as appropriate;

b) Addressing the following leak detection system testing and validation issues:
   - Routine testing to ensure degradation has not affected functionality
   - Validation of the ability of the LDS to detect small leaks and modification of the LDS as necessary to enhance its accuracy to detect small leaks
   - Conduct a risk analysis of pipeline segments to identify additional actions that would enhance public safety or environmental protection

c) Developing data validation plan (ensure input data to SCADA is valid);

d) Defining leak detection criteria in the following areas:
   - Minimum size of leak to be detected regardless of pipeline operating conditions including slack and transient conditions
   - Leak location accuracy for various pipeline conditions
   - Response time for various pipeline conditions

e) Providing redundancy plans for hardware and software and a periodic test requirement for equipment to be used live (also applies to SCADA equipment).

29) SCADA – Pipeline Model and Simulator: The Thermal-Hydraulic Pipeline Model/ Simulator including pressure control system shall include a Model Validation/Verification Plan.

30) SCADA – Training: The training and qualification plan (including simulator training) for controllers shall:

a) Emphasize procedures for detecting and mitigating leaks;

b) Include a fatigue management plan and implementation of a shift rotation schedule that minimizes possible fatigue concerns;

c) Define controller maximum hours of service limitations;

d) Meet the requirements of regulations developed as a result of the guidance provided in the American Society of Mechanical Engineers Standard B31Q, *Pipeline Personnel Qualification Standard* (ASME B31Q), September 2006 for developing qualification program plans;

e) Include and implement a full training simulator capable of replaying near miss or lesson learned scenarios for training purposes;

f) Implement tabletop exercises periodically that allow controllers to provide feedback to the exercises, participate in exercise scenario development and actively participate in the exercise;

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g) Include field visits for controllers accompanied by field personnel who will respond to call-outs for that specific facility location;

h) Provide facility specifics in regard to the position certain equipment devices will default to upon power loss;

i) Include color blind and hearing provisions and testing if these are required to identify alarm priority or equipment status;

j) Training components for task specific abnormal operating conditions and generic abnormal operating conditions;

k) If controllers are required to respond to "800" calls, include a training program conveying proper procedures for responding to emergency calls, notification of other pipeline operators in the area when affecting a common pipeline corridor and education on the types of communications supplied to emergency responders and the public using API Recommended Practice 1162, *Public Awareness Programs for Pipeline Operators* (API RP 1162);

l) Implement on-the-job training component intervals established by performance review to include thorough documentation of all items covered during oral communication instruction; and

m) Implement a substantiated qualification program for re-qualification intervals addressing program requirements for circumstances resulting in disqualification, procedure documentation for maximum controller absences before a period of review, shadowing, retraining, and addressing interim performance verification measures between re-qualification intervals.

31) SCADA – Calibration and Maintenance: The calibration and maintenance plan for the instrumentation and SCADA system shall be developed using guidance provided in API 1130. Instrumentation repairs shall be tracked and documentation provided regarding prioritization of these repairs. Controller log notes shall periodically be reviewed for concerns regarding mechanical problems. This information will be tracked and prioritized.

32) SCADA – Leak Detection Manual: The Leak Detection Manual shall be prepared using guidance provided in Canadian Standards Association, *Oil and Gas Pipeline Systems*, CSA Z662-03, Annex E, Section E.5.2, Leak Detection Manual.

33) Mainline Valve Control: Mainline valves located on either side of a pipeline segment containing an HCA where personnel response time to the valve exceeds one hour must be

remotely controlled by the SCADA system. The SCADA system must be capable of opening and closing the valve and monitoring the valve position, upstream pressure and downstream pressure.

34) Pipeline Inspection: The pipeline must be capable of passing in line inspection (ILI) tools. All headers and other segments covered under this special permit that do not allow the passage of an ILI device must have a corrosion mitigation plan.

35) Internal Corrosion: Keystone shall limit sediment and water (S&W) to 0.5 percent by volume and report S&W testing results to PHMSA in the 180-day and annual reports. Keystone shall also report upset conditions causing S&W level excursions above the limit. This report shall also contain remedial measures Keystone has taken to prevent a recurrence of excursions above the S&W limits. Keystone must run cleaning pigs twice in the first full year of operation and as necessary in succeeding years based on the analysis of oil constituents, weight loss coupons located in areas with the greatest internal corrosion threat and other internal corrosion threats. Keystone will send their analyses and further actions, if any, to PHMSA.

36) Cathodic Protection (CP): The initial CP system must be operational within six months of placing a pipeline segment in service.

37) Interference Current Surveys: Interference surveys must be performed within six months of placing the pipeline in service to ensure compliance with applicable NACE International Standard Recommended Practices 0169 and 0177 (NACE RP 0169 and NACE RP 0177) for interference current levels. If interference currents are found, Keystone will determine if there have been any adverse affects to the pipeline and mitigate the affects as necessary. Keystone will report the results of any negative finding and the associated mitigative efforts to the appropriate PHMSA regional office.

38) Corrosion Surveys: Corrosion surveys of the affected pipeline must be completed within six months of placing the respective CP system(s) in operation to ensure adequate external corrosion protection per NACE RP 0169. The survey will also address the proper number and location of CP test stations as well as AC interference mitigation and AC grounding programs per NACE RP 0177. At least one CP test station must be located within each HCA with a maximum spacing between test stations of one-half mile within the HCA. If placement of a test station within an HCA is impractical, the test station must be placed at the nearest practical location. If any annual test station reading fails to meet 49 CFR 195,

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Subpart H requirements, remedial actions must occur within six months. Remedial actions must include a close interval survey on each side of the affected test station and all modifications to the CP system necessary to ensure adequate external corrosion control.

39) Initial Close Interval Survey (CIS) - Initial: A CIS must be performed on the pipeline within two years of the pipeline in-service date. The CIS results must be integrated with the baseline ILI to determine whether further action is needed.

40) Pipeline Markers: Keystone must employ line-of-sight markings on the pipeline in the special permit area except in agricultural areas or large water crossings such as lakes where line of sight markers are impractical. The marking of pipelines is also subject to Federal Energy Regulatory Commission orders or environmental permits and local restrictions. Additional markers must be placed along the pipeline in areas where the pipeline is buried less than 42 inches.

41) Monitoring of Ground Movement: An effective monitoring/mitigation plan must be in place to monitor for and mitigate issues of unstable soil and ground movement.

42) Initial In-Line Inspection (ILI): Keystone must perform a baseline ILI in association with the construction of the pipeline using a high-resolution Magnetic Flux Leakage (MFL) tool to be completed within three years of placing a pipeline segment in service. The high-resolution MFL tool must be capable of gouge detection. Keystone must perform a baseline geometry tool run after completion of the hydrostatic strength test and backfill of the pipeline, but no later than six months after placing the pipeline in service under a special permit. The ILI data summary sheets and planned digs with associated ILI tool readings will be sent to the PHMSA regional office. The PHMSA regional office will be given at least 14 days notice before confirmation digs are executed on site. The dimensional data and other characteristics extracted from these digs will be shared with the PHMSA regional office. Keystone will also compare dimensional data and other characteristics extracted from the digs and compare them with ILI tool data. If there are large variations between dig data and ILI tool data, Keystone will submit PHMSA a plan on further actions, inclusive of more digs, to calibrate their analysis and remediation process.

43) Future ILI: Future ILI inspection must be performed on the entire pipeline subject to the special permit, on a frequency consistent with 49 CFR 195.452(j)(3), assessment intervals,

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or on a frequency determined by fatigue studies based on actual operating conditions, inclusive of flaw and corrosion growth models.

44) Verification of Reassessment Interval: Keystone must submit a new fatigue analysis to validate the pipeline reassessment interval annually for the first five years after placing the pipeline subject to this special permit in service. The analysis must be performed on the segment experiencing the most severe historical pressure cycling conditions using actual pipeline pressure data.

45) Two years after the pipeline in-service date, Keystone will use all data gathered on pipeline section experiencing the most pressure cycles to determine effect on flaw growth that passed manufacturing standards and installation specifications. This study will be performed by an independent party agreed to by Keystone and PHMSA headquarters. Furthermore, this study will be shared with PHMSA headquarters as soon as practical after its completion, preferably before baseline assessment begins. These findings will determine if an ultrasonic crack detection tool must be launched in that pipeline section to confirm crack growth with Keystone's crack growth predictive models.

46) Direct Assessment Plan: Headers, mainline valve bypasses and other sections covered by this special permit that cannot accommodate ILI tools must be part of a Direct Assessment (DA) plan or other acceptable integrity monitoring method using External and Internal Corrosion Direct Assessment criteria (ECDA/ICDA).

47) Damage Prevention Program: The Common Ground Alliance (CGA) damage prevention best practices applicable to pipelines must be incorporated into the Keystone's damage prevention program.

48) Anomaly Evaluation and Repair: Anomaly evaluations and repairs in the special permit area must be performed based upon the following:

a) Immediate Repair Conditions: Follow 195.452(h)(4)(i) except designate the calculated remaining strength failure pressure ratio (FPR) = < 1.16;

b) 60-Day Conditions: No changes to 195.452(h)(4)(ii);

c) 180-Day Conditions: Follow 195.452(H)(4)(iii) with exceptions for the following conditions which must be scheduled for repair within 180 days:

- Calculated FPR = < 1.32
- Areas of general corrosion with predicted metal loss greater than 40 percent

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- Predicted metal loss is greater than 40 percent of nominal wall that is located at a crossing of another pipeline
- Gouge or groove greater than 8 percent of nominal wall

d) Each anomaly not repaired under the immediate repair requirements must have a corrosion growth rate and ILI tool tolerance assigned per the Integrity Management Program (IMP) to determine the maximum re-inspection interval.

e) Anomaly Assessment Methods: Keystone must confirm the remaining strength (R-STRENG) effective area, R-STRENG - 0.85dL and ASME B31G assessment methods are valid for the pipe diameter, wall thickness, grade, operating pressure, operating stress level and operating temperature. Keystone must also use the most conservative method until confirmation of the proper method is made to PHMSA headquarters.

f) Flow Stress: Remaining strength calculations for X-80 pipe must use a flow stress equal to the average of the ultimate (tensile) strength and the SMYS.

g) Dents: For initial construction and the initial geometry tool run, any dent with a depth greater than 2 percent of the nominal pipe diameter must be removed unless the dent is repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. For the purposes of this condition, a "dent" is a depression that produces a gross disturbance in the curvature of the pipe wall without reducing the pipe wall thickness. The depth of the dent is measured as the gap between the lowest point of the dent and the prolongation of the original contour of the pipe.

49) Reporting - Immediate: Keystone must notify the appropriate PHMSA regional office within 24 hours of any non-reportable leaks originating in the pipe body in the special permit area.

50) Reporting – 180 Day: Within 180 days of the pipeline in-service date under a special permit, Keystone shall report on its compliance with special permit conditions to PHMSA headquarters and the appropriate regional office. The report must also include pipeline operating pressure data, including all pressures and pressure cycles versus time. The data format must include both raw data in a tabular format and a graphical format. Any alternative formats must be approved by PHMSA headquarters.

51) Annual Reporting: Following approval of the special permit, Keystone must annually report the following:

a) The results of any ILI or direct assessment results performed within the special permit area during the previous year;

b) The results of all internal corrosion management programs including the results of:
   - S&W analyses
   - Report of processing plant upset conditions where elevated levels of S&W are introduced into the pipeline
   - Corrosion inhibitor and biocide injection
   - Internal cleaning program
   - Wall loss coupon tests

c) Any new integrity threats identified within the special permit area during the previous year;

d) Any encroachment in the special permit area, including the number of new residences or public gathering areas;

e) Any HCA changes in the special permit area during the previous year;

f) Any reportable incidents associated with the special permit area that occurred during the previous year;

g) Any leaks on the pipeline in the special permit area that occurred during the previous year;

h) A list of all repairs on the pipeline in the special permit area during the previous year;

i) On-going damage prevention initiatives on the pipeline in the special permit area and a discussion of their success or failure;

j) Any changes in procedures used to assess and/or monitor the pipeline operating under this special permit;

k) Any company mergers, acquisitions, transfers of assets, or other events affecting the regulatory responsibility of the company operating the pipeline to which this special permit applies; and

l) A report of pipeline operating pressure data to include all pressures and pressure cycles versus time. The data format must include both raw data in a tabular format and a graphical format. Any alternative formats must be approved by PHMSA headquarters.

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Limitations:

Should Keystone fail to comply with any conditions of this special permit, or should PHMSA determine this special permit is no longer appropriate or that this special permit is inconsistent with pipeline safety, PHMSA may revoke this special permit and require Keystone to comply with the regulatory requirements in 49 CFR 195.106.

Background and process:

The Keystone Pipeline is a 1,845-mile international and interstate crude oil pipeline project developed by TransCanada Keystone Pipeline L.P., a wholly owned subsidiary of TransCanada Pipelines Limited. The Keystone Pipeline will transport a nominal capacity of 435,000 barrels per day of crude oil from western Canada's sedimentary basin producing areas in Alberta to refineries in the United States. Keystone indicates it has filed an application with the U.S. Department of State for a Presidential Permit for the Keystone Pipeline since the project involves construction, operation and maintenance of facilities for the importation of petroleum from a foreign country. Keystone anticipates receiving all necessary government approvals by November 2007 and beginning construction in late 2007. The targeted in-service date is during the fourth quarter of 2009.

The existing regulations in 49 CFR 195.106 provide the method used by pipeline operators to establish the MOP of a proposed pipeline by using the design formula contained in that section. The formula incorporates a design factor, also called a de-rating factor, which is fixed at 0.72 for an onshore pipeline. Keystone requests the use of a 0.80 design factor in the formula instead of 0.72 design factor.

PHMSA previously granted waivers to four natural gas pipeline operators to operate certain pipelines at a hoop stresses up to 80 percent SMYS. The Keystone pipeline project represents the first request by an operator in the United States for approval to design and operate a hazardous liquid (crude oil) pipeline beyond the existing regulatory maximum level. Canadian standards already allow operators to design and operate hazardous liquids pipelines at 80 percent SMYS.

On January 15, March 27, and April 17, 2006, PHMSA conducted technical meetings to learn more about the technical merits of Keystone's proposal to operate at 80 percent SMYS and to

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answer questions posed by internal and external subject matter experts. The meetings resulted in numerous technical information requests and deliverables, to which Keystone satisfactorily responded.

PHMSA also secured the services of experts in the field of steel pipeline fracture mechanics, leak detection and SCADA systems to assist in the review of appropriate areas of Keystone's application. The experts' reports are included in the public docket.

On February 8, 2007, PHMSA posted a notice of this special permit request in the Federal Register (FR) (72 FR 6042). In the same FR notice we informed the public that we have changed the name granting such a request to a special permit. The request letter, the FR notice, supplemental information and all other pertinent documents are available for review under Docket Number PHMSA-2006-26617, in the DOT's Document Management System.

Two comments were received and posted to the public docket concerning the Keystone pipeline project request for a special permit. One commenter listed a number of recommended and relevant conditions for hazardous liquid pipelines to operate at 80 percent SMYS. The conditions developed by PHMSA and incorporated into the grant of special permit include the concerns of the commenter. The second commenter did not provide substantive comments relevant to the special permit request.

AUTHORITY: 49 U.S.C. 60118(c) and 49 CFR 1.53.

Issued in Washington, DC on APR 30 2007.

Jeffrey D. Wiese,

Acting Associate Administrator for Pipeline Safety.

WEB Exhibit # 7-5

BP fined $20 million for pipeline corrosion

SPILLS ON SLOPE: Company had been on probation before the leaks.

By WESLEY LOY
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Published: October 26, 2007
Last Modified: October 27, 2007 at 01:10 AM

BP will plead guilty to a federal misdemeanor and pay $20 million in criminal penalties for last year's Prudhoe Bay oil spills, which prosecutors said were the result of the company's knowing neglect of corroding pipelines.

Story

Prosecutors said BP managers failed to heed "many red flags and warning signs" that key pipelines within the nation's largest oil field were going bad, with one of them leaking an estimated 201,000 gallons of oil onto the tundra and a frozen pond in March 2006, the largest oil spill ever on the North Slope.

Another leak the following August forced a temporary shutdown of half the field, driving up the price of oil on world markets and adding fuel to a federal criminal investigation that already was under way.

BP's pending plea in the Prudhoe case was among three major criminal and civil settlements the London-based company reached Thursday with federal authorities.

BP agreed to pay $50 million and plead guilty to a felony for its 2005 Texas refinery explosion that killed 15 and injured more than 170 people, and it was penalized $303 million in connection with price manipulation of the Lower 48 propane market. In addition, a federal grand jury in Chicago on Thursday indicted four former BP employees on charges of conspiring to manipulate and corner the propane market.

Federal and state authorities said Thursday that BP didn't spend the money necessary to maintain Prudhoe pipes. BP runs the field and shares costs with other owners Conoco Phillips, Exxon Mobil and Chevron.

WEB Exhibit # 8a

"As a result of BP's criminal negligence, corroded pipelines leaked crude oil into one of the nation's most fragile ecosystems," said Granta Nakayama, assistant administrator for enforcement with the U.S. Environmental Protection Agency, which helped investigate the case with the FBI and other agencies.

"Global companies like BP, with their experience, capabilities and financial resources, have no excuse for committing environmental crimes," he said.

"BP cut corners with disastrous consequences and is being held to account," said Ronald Tenpas, a ranking assistant U.S. attorney general.

STATE PROBE CONTINUES

In a statement, BP America president Bob Malone said the March spill "revealed a significant gap in our corrosion management program -- a gap that existed because our approach to assessing and managing corrosion risk in these lines was not robust or systematic enough."

In the Alaska case, BP will pay a $12 million federal criminal fine, $4 million in criminal restitution to the state, and $4 million for Arctic research. BP's local subsidiary, BP Exploration (Alaska) Inc., also will go on probation for three years, a 28-page plea agreement says.

BP Alaska will plead guilty in late November to one misdemeanor count of negligently discharging oil in violation of the federal Clean Water Act.

The charge pertains only to the March oil spill. BP was not charged with the second spill in August, which was much smaller, because the company "was prompt in detecting and containing this leak," the plea agreement says.

Nelson Cohen, U.S. attorney for Alaska, and state Attorney General Talis Colberg said BP's plea to the misdemeanor will wrap up the criminal aspect of the Prudhoe spills for both the federal and state governments.

However, they said authorities still can seek criminal prosecution of BP employees or contractors and can pursue civil penalties against BP Alaska.

Colberg acknowledged the state has a civil investigation ongoing, but he declined to provide details.

In the past, state officials including Colberg's predecessor, former Attorney General David Marquez, said that the state might seek what could be a multimillion-dollar civil fine against BP, and that the state also would review whether it lost money due to interrupted production of millions of barrels of oil during the partial Prudhoe shutdown.

BP'S CRIMINAL RECORD

The guilty plea will mark the second time in eight years that BP Alaska will have been convicted of a federal environmental crime in Alaska.

In 1999, the company pleaded guilty to one felony count in connection with the illegal dumping of nearly 1,000 gallons of hazardous waste by one of its drilling contractors in BP's Endicott oil field. BP paid $15.5 million in penalties and was placed on probation for five years.

Because that probation period had ended, BP was not in violation as a result of last year's pipeline leaks, Cohen said.

The pipe that leaked the 201,000 gallons had been neglected since 1998, prosecutors said.

That was the last time BP ran a cleaning or testing device called a pig through the steel pipe, which is part of a key network of Prudhoe trunk lines that funnel oil into the 800-mile trans-Alaska pipeline.

After the March 2006 spill, a grand jury began investigating. Prosecutors said BP cooperated by supplying millions of documents, explaining technical details, and sawing out a section of the leaky pipeline for examination as evidence.

Investigators found a 6-inch layer of hardened sediment caked to the bottom of the pipe section.

WEB Exhibit # 8-c

Cohen said the sludge helped breed acidic bacteria and corrosion that ultimately ate an almond-sized hole through the line, allowing a slow leak that released 201,000 gallons before a BP worker who was driving nearby smelled oil that had oozed beneath snow blanketing the tundra.

SAVING MONEY

BP executives and spokesmen have said they were surprised that corrosion developed in the large trunk lines, which unlike many other pipes don't carry much water mixed with the oil.

But BP knew that sediment was collecting in the pipes, that the changing nature of the oil and its slow flow could encourage corrosion, and that leak-detection technology wouldn't work well unless the pipelines were periodically cleaned.

Saving money was a factor, prosecutors said.

"BP didn't spend money that it should have spent," Cohen said.

He said the $20 million in penalties likely is the largest dollar punishment ever for an environmental misdemeanor in Alaska.

BP said Thursday work is under way to replace 16 miles of corroded Prudhoe pipelines and the roughly $250 million job will be done next year.

The company said it "promptly and thoroughly cleaned up" the spills and "no lasting harm to the surrounding environment is expected."

The larger spill covered 2 acres and it could take up to a decade for the tundra vegetation to return to normal, state environmental officials said Thursday.

Other changes have occurred at BP Alaska since last year's corrosion crisis. The company now has a new president and a new Prudhoe Bay field manager, and it has beefed up its anticorrosion unit.

Federal pipeline regulators also have intensified scrutiny of the pipelines that leaked.

WEB Exhibit # 8-C2

Among other details to emerge Thursday:

• The plea agreement forbids BP from deducting the $20 million in penalties from its state or federal taxes.

• BP can shorten its three-year probation to one year if it promptly replaces bad pipes and meets other conditions.

Find Wesley Loy online at **adn.com/contact/wloy** or call 257-4590. Daily News reporter Erika Bolstad contributed to this story.

MORE

AT A GLANCE: See the terms of BP's penalties in Alaska and the Lower 48.

JUNEAU: Will the BP fine prompt legislators to tighten deductions on state oil taxes?

BP agreement

IN ALASKA

The U.S. Justice Department's criminal investigation focused on Prudhoe Bay oil spills last year, particularly 201,000 gallons spilled from a pipeline, the largest North Slope oil spill ever. BP Exploration (Alaska) Inc. will:

Plead guilty to a misdemeanor violation of the Clean Water Act.

Serve three years of probation.

Pay a $12 million criminal fine.

Pay $4 million criminal restitution to the state.

Pay $4 million for research on Alaska's Arctic.

IN TEXAS

WEB Exhibit # 8-C3

The criminal investigation concerned a 2005 explosion at a BP refinery that killed 15 workers and injured more than 170 others. BP Products North America Inc. will:

Plead guilty to violating the Clean Water Act, a felony.

Serve three years of probation.

Pay a $50 million criminal fine.

PROPANE MARKET

The criminal investigation centered on a conspiracy to manipulate the Lower 48 propane market:

BP America Inc. is charged with violating the Commodity Exchange Act, mail fraud and wire fraud. But federal prosecutors will not prosecute the case for three years if BP cooperates with an ongoing investigation and with an independent monitor.

Four ex-employees were indicted Thursday by a federal grand jury in Chicago on charges of conspiring to manipulate and corner the propane market.

BP will pay $303 million in criminal and civil fines and restitution.

http://www.adn.com/news/alaska/story/9407569p-9320306c.html

WEB Exhibit # 8-c4

"I think it's fair to say that the (Whiting) refinery doesn't have the breadth of problems that Texas City had," said Carter, the deputy Indiana labor commissioner.

After the Texas City explosion, BP paid a $21 million fine, the largest in the 35-year history of the federal Occupational Safety and Health Administration.

Last week, the company agreed to plead guilty to a felony and pay an additional $50 million criminal fine stemming from federal Clean Air Act violations tied to the explosion.

WEB Exhibit # 8-e

THE INDIANAPOLIS STAR
INDYSTAR.COM

7:44 AM October 30, 2007

BP refinery safety violations revealed

Associated Press
October 30, 2007

WHITING, Ind. – A 5-month investigation of BP's Whiting refinery following a deadly explosion at a Texas refinery owned by BP found untested fire hoses, broken equipment and outdated safety procedures, The Times of Munster reported.

While significant, state officials say the violations at the Whiting refinery largely pale in comparison to the problems uncovered at BP's Texas City refinery, where a March 2005 explosion killed 15 people and injured more than 170 others.

The Indiana Occupational Safety and Health Administration, or IOSHA, finished its lengthy review of the Whiting refinery -- the nation's fourth largest -- last year, finding more than a dozen serious safety hazards and leveling $384,250 in fines.

The Times, which first reported the fines last month, recently obtained state inspection records detailing the hazards cited at the refinery.

Those records show that the refinery's most critical violations centered on problems with pressure gauges and rupture disks -- a type of relief valve that constricts pipeline flow to prevent surges that can cause a fire or explosion.

In one area, a unit in which gasoline octane is boosted, inspectors found two malfunctioning gauges and a blown rupture disk that had not been replaced.

State inspectors also cited the Whiting refinery for failing to update written maintenance and safety procedures. In several cases, the refinery was more than a year behind on self-inspection deadlines for various types of equipment.

In one case, a structural integrity test that was supposed to have been performed seven years earlier remained unfulfilled when the state's review began in May 2006.

The violations yielded 13 fines ranging from $2,125 to $70,000 that totaled $384,250.

"We've levied bigger, but not very often," said Jeff Carter, a deputy commissioner for the Indiana Department of Labor.

BP spokesman Tom Keilman said the Whiting refinery has corrected all of the safety hazards cited by IOSHA and is working with the state agency to resolve the fines. If the two sides do not reach an agreement by February, the case will go before an administrative hearing panel.

"The Whiting refinery has had a solid record on safety performance, showing continuous safety improvement over the past several years," he said.

Although the violations at the Whiting refinery are significant, state officials say the problems uncovered at BP's Texas City refinery are largely much more significant.

State inspectors classified five of the Whiting violations as knowing, or willful, the most severe category of workplace hazard under federal safety guidelines.

At BP's Texas City refinery, however, investigators found 301 willful violations in the wake of the March 2005 blast that killed 15 people and injured more than 170 others.

WEB Exhibit # 8-d

"We regret that our monitoring of these lines did not meet the expectations of the State of Alaska and the U.S. government," Malone said. "Since this incident we have worked with state and federal regulators to ensure the safe, reliable operation of critical Prudhoe Bay pipelines which deliver processed oil to the Trans Alaska Pipeline."

Following the March spill, BPXA said they worked with the U.S. Department of Transportation to make periodic maintenance and smart pigging part of BPXA's oil transit line corrosion inspection, monitoring and inhibition program.

BPXA said replacement of the 16-mile Prudhoe Bay oil transit line system will be completed in 2008. BPXA began construction of the $250 million project in early 2007.

During the investigation the United States obtained a section of pipe where the March 2006 leak occurred. Approximately six inches of sediment were found on the bottom of the thirty-four-inch-diameter pipe. When sediment builds up in a pipeline it forms an environment in which acid-producing bacteria can thrive undisturbed by the flow of oil and chemicals intended to protect the pipe from corrosion. The acid produced by these bacteria can cause corrosion, which causes pits or, if unchecked, holes in the wall of the pipe.

Knowing this the Justice Department said, BPXA should have cleaned the OTLs with a piece of equipment called a maintenance (or cleaning) pig and inspected the pipes for corrosion with a smart pig-- an inspection tool able to make a complete evaluation of a pipeline's integrity. A maintenance pig would have disturbed the bacteria and cleared out the stagnant water and sediment that harbor the acid-producing bacteria. A smart pig would have provided a clear picture of the corrosion activity that was occurring in both areas where leaks eventually occurred.

The case was prosecuted by Trial Attorneys J. Ronald Sutcliffe and Christopher J. Costantini of the Environmental Crimes Section of the

Department of Justice and Assistant U.S. Attorney Andrea T. Steward and Special Assistant U.S. Attorney Daniel Cheyette of the U.S. Attorney's Office for the District of Alaska.

The case was investigated by the EPA's Criminal Investigation Division and the FBI with assistance from and the Department of Transportation's Office of Inspector General. Technical assistance was provided by the Pipeline and Hazardous Materials Safety Administration and the Alaska Department of Environmental Conservation.

Sources of News:

U.S. Department of Justice
http://www.usdoj.gov

British Petroleum
http://www.bp.com/

WEB Exhibit # 8-9

Alyeska pipeline

Pipeline Quick Facts

- The Trans-Alaska Pipeline System was designed and constructed to move oil from the North Slope of Alaska to the northern most ice- free port- Valdez, Alaska.
- Length: 800 miles.
- Diameter: 48 inches.
- Crosses three mountain ranges and over 800 rivers and streams.
- Cost to build: $8 billion in 1977, largest privately funded construction project at that time.
- Construction began on March 27, 1975 and was completed on May 31, 1977.
- First oil moved through the pipeline on June 20, 1977.
- Over 14 billion barrels have moved through the Trans Alaska Pipeline System.
- First tanker to carry crude oil from Valdez: ARCO Juneau, August 1, 1977.
- Tankers loaded at Valdez: 16,781 through March 2001.
- Storage tanks in Valdez- 18 with total storage capacity of 9.1 million barrels total.
- The mission of Alyeska's Ship Escort Response Vessel System is to safely escort tankers through Prince William Sound.

Last updated May 7, 2004

Basic information

- Maximum daily throughput — 2.136 million bbl., avg. (With 11 pump stations operating). Rates exceeding 1,440,000 bbl./day assume drag reduction agent (DRA) injection.
- Maximum daily throughput — 2000 (with 7 pump stations operating) — .99 million bbl., avg. Rates exceeding 1,000,000 bbl./day assume DRA injection
- Fuel required for all operations (fuel oil equivalent) — 210,000 gal/day (also see fuel requirements under Pump Stations, and Marine Terminal).
- Pressure —
    - Design, maximum — 1,180 psi
    - Operating, maximum — 1,180 psi
- Pump Station facilities in original design — 12 pump stations with 4 pumps each.
- Pump Stations operating, Nov. 1, 1998 — 7: PS 1, 3, 4, 5, 7, 9, 12. PS 5 is a relief station only. PS 11 is a security site. PS 8 placed in standby June 30, 1996. PS 10 placed in standby July 1, 1996. PS 2 placed in standby July 1, 1997. PS 6 placed in standby August 8, 1997.

Control system

- Basic function — Provides instantaneous monitoring, control of

WEB Exhibit # 9-a

all significant aspects of operation, and pipeline leak detection. Operators in the Operations Control Center (OCC) at the Marine Terminal monitor the system 24 hours a day and control oil movement through the pipeline and loading of tankers.

- Computer type — Data general MV/20000 and various PCs
- Location — Computer hardware and controllers' consoles are located in the Operations Control Center at the Marine Terminal.

Points monitored —
  - Pipeline —
    3,047 Input points
    352 Control points
  - Marine Terminal —
    1,074 Input points
    461 Control points
- Remote data acquisition units —
  - Pipeline — 14 (each Pump Station, plus the North Pole Metering facility and Petro Star Refinery)
  - Marine Terminal — 24
  - Metering — 14
- Software programming functions —
  - Data acquisition and control
  - Alarm and data processing and display
  - Hydraulic modeling
  - Leak detection
  - Historical archiving and reporting
  - Seismic evaluation

Drag Reduction Agent (DRA)

Definition — A long chain hydrocarbon polymer injected into the oil to reduce the energy loss due to turbulence in the oil.

Chronology

- **1979 —**
  - **Apr 1** — First test of DRA in TAPS at PS 1
  - **Jul 1** — (6 p.m.) — Injection initiated at PS 1
  - **Aug 19** — Initiated at PS 6
  - **Oct 15** — Initiated at PS 4
  - **Oct 22** — Discontinued at PS 1 (PS2 on line)
  - **Nov 1** — Initiated at PS 10
- **1980 — Nov 5** — Discontinued at PS 6 (PS7 on line)
- **1985 — Jan 6** — Initiated at MP 203 (in support of MP 200 Reroute Project)
- **1987 — Sep 11** — Initiated at PS 1
- **1987 — Sep 11** — Initiated at PS 7
- **1990 — Dec 18** — Installed at PS 8

WEB Exhibit # 9-b

- **1991 — Oct 3 —** Demobed MP203 (declining throughput)
- **1992 — Summer —** Installed at PS6
- **1992 — Oct 1** — Decommissioned at PS7 (declining throughput)
- **1993 — June** — Test run at PS6
- **1994 — April** — Test run at PS6
- **1995 — Nov 1 —** Initiated at PS6 (PS7 shutdown for maintenance, three months)
- **1996 — Jun 15 —** Installed at PS7 and PS9
  - **Jul 1 —** Initiated at PS7 and PS9 (PS8 and PS10 placed in standby)
- **1997 — Summer** — Installed and initiated at PS1 and MP238 (PS2 and PS6 placed in standby)
- **1999/2000** — Testing new DRA suspension technology at MP238 and PS9

  WEB Attachment 6A

- **2001 — Jun - Oct,** Used to bypass PS 12

- **2002 — Sep - Dec,** Used to bypass PS 12
  DRA Test Beds installed south of PS 9 at MP 554.74, MP 568.82, MP 602.66, MP 649.4, MP 709.48

Major mainline pipe repairs

- **1977 —**
  - **Jul 7** — MP 489.12 — approx. 20 ft. south of north block valve at PS 8; damage to 30° elbow and pipe from injection of super cooled nitrogen ahead of oil front during oil-in. Replaced with new elbow and two 6-ft. pups. Pipe reburied.
  - **Jul 8** — MP 489.24 — pump building at PS 8 destroyed in an explosion and fire; the pipeline was undamaged. The pump building was replaced, and recommissioned Mar. 7, 1978.
  - **September** – MP 388.00 — north of Lost Creek; two bullet indentations. Covered with 48-in. dia., 3-ft. welded split sleeve.
- **1978 —**
  - **February** – MP 457.53 — Steele Creek; 1-in. dia. hole (sabotage). Covered with 48-in. dia., 22-1/2 in. bolted split sleeve; subsequently covered with welded sleeve.
- **1979 —**
  - **June** – MP 166.43 — north side Atigun Pass; hairline crack caused by buckle. Covered with 56-in. dia., 6-ft. welded split sleeve; 19 steel supports installed. Pipe reburied.
  - **June** – MP 734.16 — 1 mi. north of PS 12; hairline crack caused by buckle in pipe. Covered with 56-in. dia., 6.1-ft. welded split sleeve; 7 steel supports installed. Pipe reburied.
  - **September** – MP 157.62 to MP 157.65 — instrument

WEB Exhibit # 9-c

pig ("Super Pig") lodged in line at check valve 29. Stopple and bypass installed, valve bonnet lifted, pig removed. Pipe reburied.
    - **October** – MP 166.41 — north side Atigun Pass; buckled pipe. Covered with 56-in. dia., 6-ft. welded split sleeve. Pipe reburied.
- **1980 —**
    - **April** – MP 449.96 — indentation, possibly from bullet. Covered with 48-in. dia., 18-in. welded split sleeve.
    - **May** – MP 159.70 — construction damage from backhoe during monitor rod installation. Covered with 48-in. dia., 3.6-ft. welded split sleeve. Pipe reburied.
    - **June** – MP 416.00 — approx. 2 mi. south of PS 7; pipe settlement. Approx. 430-ft. excavation; 8 steel supports installed. Pipe not reburied.
    - **August** – MP 752.00 — flash flood, 900 ft. of overburden washed out; no damage. Pipe reburied.
    - **November** – MP 720.00 — pipe settlement. Approx. 200-ft. excavation; pipe lifted, concrete slurry added beneath pipe. Pipe reburied.
- **1982 —**
    - **April** – MP 168.40 — south side Atigun Pass; pipe settlement. Approx. 300-ft. excavation; concrete slurry added beneath pipe. Pipe reburied.
    -
    - **August** – MP 166.03 — north side Atigun Pass; pipe buckle. Covered with 56-in. dia., 6.5-ft. welded split sleeve. Pipe reburied.
- **1983 —**
    - **March** – MP 730.29 — pipe settlement. Approx. 102-ft. excavation; 9 concrete river weights removed, concrete slurry added beneath pipe. Pipe reburied.

      April – MP 200.24 — Dietrich River channel; pipe buckle. River channel redirected temporarily; approx. 125-ft. excavation; 56-in. dia., 6-ft. welded split sleeve installed; 5 specially designed steel supports installed. Pipe reburied.
    - **October** – MP 45.97 — pipe settlement. Approx. 200-ft. excavation; concrete slurry added beneath pipe. Pipe reburied.
- **1984 —**
    - **March** – removal of stuck scraper pig at CV4 and relocation of pig trap from PS 5 to PS4.
    - **November** – removal of stuck pig at PS 10.
- **1985 —**
    - **January** – MP 200 temporary bypass tie-in, pipe settlement.
    - **April** – MP 200 final tie-in of 48-inch permanent

WEB Exhibit # 9-d

reroute. (404.7 ft. added to total pipeline length in MP 200 reroute, Apr 22, 1985) Reroute due to pipe settlement.

- **1986 —**
    - **Oct 10** — Steele Creek; permanent welded sleeve installed over bolted split sleeve.
    - **Nov 18** — replaced damaged "Tee" at PS 10; "Tee" damaged by stuck scraper pig.
- **1987 —**
    - **Sep 29** — replaced 234 ft. of buckled pipe, MP 166.41 — 166.43, Atigun Pass.
    - **Aug 25** — mechanical damage covered with 3 ft. welded sleeve.
- **1989** — total of 30 sleeves installed for corrosion repairs.
- **1990** — total of 86 sleeves installed for corrosion repairs.
    - **Nov 23** – dent covered by 6 ft. welded sleeve.
    - **Dec 3** – mechanical damage covered with bolted clamp, later covered with a split tee (part of Atigun Floodplain Pipe Replacement Project).
- **1991** — total 18 sleeves installed for corrosion repairs.
    - **Mar 8** – mechanical damage covered by 4 ft. welded sleeve, MP 779.47.
    - **Apr 6** – mechanical damage covered by 4 ft. welded sleeve, MP 756.80.
    - **September** – Atigun Floodplain Pipe Replacement Project completed, MP157-165.5. Permanent reroute of 8.5 miles of main line pipe. Replacement due to corrosion.
- **1993 — Jun 6** – mechanical damage covered by 3 ft. welded sleeve, MP775.
- **1994 —**
    - **Jul 22 —** CV9 Bypass spool replacement and drain line repair.
    - **Jul 20 —** CV86 bypass and drain line repair.
    - **Sep 30 —**CV74 drain line repair.
    -
- **1995**
    - **Mar 15 —** Replace actuator on CV55.
    - **Jun 8—** Replace actuator on CV89.
    - **Jul 14 —** RGV system leak repair.
    - **Sep 15 —** Extended Chena Hot Springs Road casing.
- **1996**
    - **Apr 25 —** Replace bypass line on CV92.
- **1997**
    - **Feb 8 —**Install "armadillo" sleeve at Wilbur Creek. Repair due to corrosion.
    - **Jun 20 —** Mechanical damage covered by 2.5 ft. welded sleeve, MP 775.75.
    - **Oct 9 —** Corrosion repair covered by 4.8 ft. welded sleeve, MP 799.68.

WEB Exhibit # 9e

- **1998**
  - **Sep 25** — Replaced RGV 80 and and repaired CV122.
  - **Mar 19** — Constructed and started Tanker Vapor Control System at Valdez Marine Terminal.
- **1999**
  - **Apr 26** — Total of 2 sleeves installed for corrosion repair at MP 652.
  - **Sep 11** — Replaced RGV 60.
- **2000**
  - **May 26** — Completed reset and repair of tripped anchors at MP 170, a result of the collapse of vapor pocket after pipeline restart.
  - **June 1** — mechanical damage cover by two 2 ft. welded sleeves, MP 710.76.
  - **Sep 16** — Replaced CKV 74 and M-2 valve at PS 9.
- **2001**
  - **Sep 22** — Pipeline shutdown for mainline valve maintenance and integrity test, and performance evaluation of two 48-inch mainline remote gate valves.
  - **Oct 4** — MP 400, bullet hole repaired with hydraulic clamp. Clamp later replace with Thor plug.
- **2002**
  - **Jul 25** — Pipeline shutdown to replace RGV 39.
  - **Nov** — MP 588, repaired or replaced damaged shoes and VSM crossbeams from 7.9 earthquake on November 3.

Shutdowns

- 1977 —
  - **Aug 2** — equipment malfunction — 40 min.
  - **Aug 15** — PS 9 sump overflow — 110 hrs., 11 min.
  - **Sep 20** — equipment malfunction — 59 min.
  - **Oct 9** — producer shutdown — 4 hrs., 14 min.

- **1978 —**
  - **Jan 5** — equipment malfunction — 1 hr.
  - **Jan 10** — equipment malfunction — 4 hrs.
  - **Jan 16** — equipment malfunction — 4 hrs., 22 min.
  - **Jan 17** — equipment malfunction — 3 hrs., 41 min.
  - **Feb 15** — sabotage, Steele Creek — 21 hrs., 31 min.
  - **May 6** — equipment malfunction — 7 hrs., 18 min.
  - **May 30** — equipment malfunction — 2 hrs., 22 min.

WEB Exhibit # 9f

- Sep 4 — equipment malfunction — 3 hrs.
  - **Dec 17** — equipment malfunction — 2 hrs., 8 min.
- **1979 —**
  - **Jun 10** — Atigun Pass leak — 53 hrs., 37 min.
- **1980 —**
  - **May 12** — PS 10 crude tank valve leak — 3 hrs., 37 min.
  - **Oct 17** — scheduled maintenance — 5 hrs., 16 min.
- **1981 —**
  - **Jan 1** — check valve 23 leak — 15 hrs., 38 min.
- **Feb 8** — equipment malfunction — 3 hrs., 54 min.

- **1982 —**
  - **Jun 7** — equipment malfunction — 2 hrs., 48 min.
  - **Dec 22** — equipment malfunction — 12 hrs.
- **1983** — 0 hrs. (no shutdowns)
- **1984 —**
  - **Mar 20** — Scraper pig stuck at check valve 4 — 18 hrs./PS 4 Trap relocation, 57 hrs., 40 min.
  - **Jun 17** — equipment malfunction — 1 hr., 7 min.
  - **Oct 5** — producer maintenance — 5 hrs.
- **1985 —**
  - **Jan 21** — MP 200 bypass tie in — 66 hrs.
  - **Apr 22** — MP 200 final reroute tie-in of 48-in. pipe — 20 hrs., 40 min. (404.7 ft. added to total pipeline length in MP 200 reroute, Apr. 22, 1985).
  - **Jun 26** — equipment malfunction — 42 min.
  - **October** – removed stuck pig at PS 10.
  - **Nov 9** — **PS 1 explosion and fire — 10 hrs., 15 min.**
- **1986 —**
  - **Sep 26** — removed scraper pig at PS 10 — 31 hrs., 50 min.
  - **Nov 18** — replaced "Tee" at PS 10 — 16 hrs., 54 min.
- **1987 —**
  - **Sept 29** — Atigun Pass pipe replacement — 24 hrs., 6 min.
- **1988** — 0 hrs. (no shutdowns)
- **1989 —**
  - **Feb 26** — total power failure; PS 1- hr., 31 min.; PS 1 block line - 32 min.
  - **Oct 20** — repair corroded pipe at MP 144.2-5 hr., 16 min.
- **1990 —**
  - **Mar 21** — PS 3, broken nipple valve 320 - 4 hr., 10 min.
  - **Jun 12** — PS 1, valve D2 pipe replacement - 12 hr., 39 min.
  - **Jun 12** — PS 9 isolated station, valve M2 leak- 1 hr., 34 min.
  - **Nov 20** — Corrosion repair, welding at MP 157.87 - 3hr., 17 min.
  - **Dec 15** — high inventory and power failure at Valdez Terminal - 1 hr., 42 min.

WEB Exhibit # 9-9

- 1991 — 0 hrs. (no shutdowns)
- **1992 —**
  - **Aug 7** — uncommanded closure of RGV 73, electric short - 1 hr., 49 min.
  - **Oct 7** — segment 11 RGV intransit indication - 35 min.
  - **Oct 16** — segment 11 RGV intransit indication - 7 min.
- **1993 —**
  - **May 20** — PS3 isolated gas building, broken fitting - 9 min.
  - **Jun 22** — RGV 98A false intransit indication, MLR2 project work - 38 min.
  - **Oct 29** — loss of communication with segment 12 RGV's - 20 min.
- **1994 —**
  - **Jan 24** — Isolate station at PS10 caused by leaking nipple on 26" yard check valve — 1 hr., 26 min.
  - **Feb 14** — Isolate gas building at PS1, faulty gas detector — 24 Min.
  - **Apr 15** — Replace 002 valve at Valdez and troubleshoot segement 4 RGVs — 24 hrs., 28 min.
  - **Apr 18** — Work on PS4 Systronics Master Panel — 7 hrs., 57 min.
  - **Jun 8** — Communications failure with RGV73, failed power converter — 1 hr.
    Jun 12 — Communications failure with RGV69, battery failure — 36 min.
  - **Oct 15** — Communications failure with RGV40 — 2 hrs., 20 min.
- **1995**
  - **Feb 22** — PS9 shutdown by high pressure shutdown switch — 19 min.
  - **Jun 16** — Communications failure to Segment 4 RGVs, RGVs 31-35 closed — 2 hrs., 25 min.
  - **Jul 10** — RGV 118 intransitt indication — 1 hr.,41 min.
  - **Jul 10** — Communications failure to Segment 10, RGV 95 — 29 min.
  - **Jul 11** — Communications failure with RGV 95 — 1 hr., 30 min.
  - **Sep 11** — Scheduled maintenance — 15 hrs., 45 min.
  - **Sep 12** — Completion of scheduled PS2 maintenance — 4 hrs., 51 min.
  - **Sep 18** — Communications failure with RGV 37 — 1 hr., 42 min.
  - **Nov 7** — Fire alarm in PS10 pump house building — 12 min.
- **1996**
  - **Feb 17** — Communications failure with RGV 113 — 2 hrs., 7 min.

WEB Exhibit # 9-h

- **May 6** — Scheduled maintenance — 21 hrs., 45 min.
- **May 7** — PS8 valve seal repair, repair leaking PS4 M2 valve body drain valve — 7 hrs., 17 min.
- **Jul 12** — Scheduled maintenance, preparations for PS8 and PS10 standby — 10 hrs., 25 min.
- **Aug 1** — Scheduled maintenance as part of ramping down PS8 and PS10 — 8hrs., 40 min.
- **Aug 6** — scheduled maintenance as a part of ramping down PS8 and PS10 — 11 hrs., 2 min.

- **1997**
  - **Jan 12** — Communications failure with RGV 124 — 3 hrs., 24 min.
  - **Jan 13** — Communications failure at RGV 62, 65, 7 67 — 13 min.
  - **Jun 1** — False RGV indication at RGV 32-34, Segment 4 — 2 hrs., 9 min.
  - **Jun 26** — Communications failure with RGVs in Segment 12 — 5 hrs., 44 min.
  - **Jul 1** — Communications failure with RGV 31-33 — 1 hr., 45 min.
  - **Aug 1** — Scheduled maintenance for PS2 & PS6 ramp-down preparation— 17 hrs., 49 min.
  - **Aug 8** — Placed PS6 in standby — 19 hrs., 29 min.
  - **Aug 12** — False transit indication, PS11, M-1 valve — 25 min.
  - **Sep 19** — false tranisit indication, RGV 103 — 14 min.
  - **Nov 8** — Communications failure, RGV 45 — 1 hr., 17 min.
- **1998**
  - **May 18** — PS1 in-rush vapor test and vibration test of VMT incoming relief piping — 5 hrs., 9 min.
  - **Aug 5** — Segment 10 RGVs in invalid status — 24 min.
  - **Aug 14** — Communications failure, Segment 10 — 5 hrs., 4min.
  - **Sep 25** — Valve maintenance, replaced RGV 80 and repaired CKV 122 — 28 hrs., 40 min.
  - **Nov 15** — Communications failure to Segment 4 RGVs, relay failure — 3 hrs., 23 min.
- **1999**
  - **Feb 15** — Communications failure at RGV 60 — 15 mins.
  - **Feb 17** — Communications failure at RGV 105 — 1 hr., 25 mins.
  - **Feb 23** — Communications failure at RGV 32, battery failure — 2 hrs., 15 mins.
  - **Mar 20** — Communications failure at RGV 80 — 1 hr., 07 mins.
  - **Mar 25** — Communications failure at RGV 102 — 1

WEB Exhibit # 9-i

hr., 57 mins.

Apr 3 — Communications failure at RGV 91 — 26 mins.

- **Apr 11** — Communications failure at RGV 69 — 56 mins.
- **Jun 8** — Communications failure with all Segment 4 RGVs — 1 hr., 13 mins.
- **Jun 17** — Communications failure at RGV 91 — 34 mins.
- **Jul 5** — Communications failure at RGV 43 — 34 mins.
- **Jul 5** — Maintenance at Tea Lake, repeater loss of communication to segment 4 RGVs — 1 hr., 52 mins.
- **Sep 11** — Valve maintenance, replaced RGV 60, tested 46 mainline valves and completed 165 other maintenance tasks — 25 hrs., 49 mins.
- **Oct 16** — Communications failure at RGV 67 — 1 hr., 10 mins.
- **Nov 9** — Communications failure at RGV 53 — 26 mins.
- **Nov 13** — Planned maintenance amd autologic testing — 8 hrs., 6 mins.
- **Dec 8** — False fire alarm is PS1 booster pump building — 2 hrs., 34 mins.
- **Dec 23** — Communications failure with RGVs 62 & 67 — 36 mins.
- **Dec 25** — Communications failure at RGV 121 — 4 hrs., 16 mins.

- **2000**
  - **Feb 10** — communications failure at RGV 42 — 1hr., 24 mins.
  - **Apr 17** — PS 4 unintended stop flow / close RGV initiated due to invalid state transmitted from RGV 35A while troubleshooting power failure — 1hr., 26 mins.
  - **Apr 22** — Loss of visibility of PS 11M-1 — 43 mins.
  - **Aug 28** — communications failure at RGV 121A, battery failure — 1hr., 39 mins.

WEB Attachment 6A

  - **Sept. 16** — Planned line-wide maintenance shutdown — 29hrs., 39 mins.
  - **Oct 7** — Planned line-wide shutdown for valve leak tests — 7 hrs., 31 mins.
- **2001**
  - **Feb 26** — PS 5 false fire alarm - 1 hr., 24 mins.
  - **Apr 3** — Communications failure at RGV 32 - 2 hrs., 59 mins.
  - **Apr 18** — Work on PS 4 Systronics Master Panel - 6 hrs., 38 mins.

WEB Exhibit # 9-j

- **Jun 25** — Automatic controls activated during planned failover of Scada Host Computer - 1 hr., 10 mins.
- **Aug 16** — Communications failure at RGV 60 - 1 hr., 30 mins.
- **Aug 26** — Communications failure at RGV 123 - 58 mins.
- **Sep 5** — Communications failure at RGV 124 - 2 hrs., 59 mins.
- **Sep 22** — Planned maintenance shutdown - 21 hrs., 4 mins.
- **Oct 4** — Bullet puncture at MP 400 - 60 hrs., 30 mins.
- **Oct 18** — PS 4 false fire alarm indicator - 1 hr., 57 mins.
- **Oct 28** — Backbone communication system disruption - 4 hrs., 5 mins.
- **Nov 1** — Communications failure at RGV 44 - 2 hrs., 48 mins.
- **Dec 20** — Communications failure at RGV 44 - 2 hrs., 30 mins.

- **2002**
  - **Jan 5** — Segment 10 to 11 RGVs closed due to Copper Valley Electric Association power failure - 2 hrs., 6 mins.
  - **May 9** — Communications failure at RGV 108 - 1 hr., 10 mins.
  - **Jun 11** — Communications failure at RGV 97 - 2 hrs.
  - **Jul 27** — Planned maintenance shutdown - 29 hours., 57 mins.
  - **Sep 16** — Seismic system testing - 35 mins.
  - **Oct 12** — Planned maintenance at PS 4 - 3 hrs., 20 mins.
  - **Nov 3** — 7.9 earthquake at MP 588 - 66 hrs., 33 mins.
  - **Nov 27** — Communications failure in segment 4 - 1 hr., 49 mins.

Leaks

Record of system crude oil leaks and spills of 100 bbl. or more on land or water*

	Location	bbl.	Cause
1977			

WEB Exhibit # 9-K

July 8	PS 8	300	Explosion
July 19	CV7	1,800	Construction damage
1978			
Feb 15	Steele Creek	16,000	Sabotage
1979			
June 10	Atigun Pass	1,500	Pipe settlement, hairline crack
June 15	MP 734	4,000	Pipe settlement, hairline crack
1980			
Feb 11	Terminal/V746	3,200	Leaking valve, east tank farm
May 12	PS 10	238	Tank valve
1981			
Jan 1	CV 23	1,500	Drain connection failure
1989			
Jan 3	*Thompson Pass*	1,700	Hull crack
March 24	*Exxon Valdez*	260,000	Vessel ran aground
1996			
April 20	CV 92	880	Loose thread fitting on buried piping
2001			
Oct 4	MP 400	6,800	Bullet Hole

System crude oil leaked or spilled* by year, number and amount

WEB Exhibit # 9-L

Year	*No.*	*Amount*
1977	34	93,778 gal/2,232 bbls
1978	24	672,576 gal/16,013 bbls
1979	43	233,800 gal/5,566 bbls
1980	55	149,495 gal/3,531 bbls
1981	32	63,371 gal/1,508 bbls
1982	30	1,653 gal/39 bbls
1983	17	174 gal/4 bbls
1984	32	3,260 gal/77 bbls
1985	31	1,138 gal/27 bbls
1986	40	1,607 gal/38 bbls
1987	37	172 gal/4 bbls
1988	35	600 gal/14 bbls
1989	26	10,572,207 gal/258,855 bbls
1990	31	277 gal/6 bbls
1991	54	460 gal/11 bbls
1992	55	822 gal/19 bbls
1993	65	361 gal/8 bbls
1994	44	13,610 gal/324 bbls
1995	06	90 gal/2 bbls
1996	12	34,185 gal/814 bbls
1997	05	80 gal/2 bbls
1998	05	22 gal/0.5 bbls
1999	08	16 gal/0.39 bbls
2000	06	165 gal/4 bbls
2001	15	287,980 gal/6,856 bbls
2002	09	16 gal/.39 bbls

Last updated June 23, 2004

WEB Exhibit # 9-m

PHMSA OFFICE OF PIPELINE SAFETY
HAZARDOUS LIQUID PIPELINE OPERATORS
ACCIDENT SUMMARY STATISTICS BY YEAR
1/1/1986 - 07/31/2007

Year	No. of Accidents	Fatalities	Injuries	Property Damage	Gross Loss (Bbls)	Net Loss (Bbls)
1986	210	4	32	$16,077,846	282,791	220,317
1987	237	3	20	$13,140,434	395,854	312,794
1988	193	2	19	$32,414,912	198,397	114,251
1989	163	3	38	$8,813,604	201,758	121,179
1990	180	3	7	$15,720,422	124,277	54,663
1991	216	0	9	$37,788,944	200,567	55,774
1992	212	5	38	$39,146,062	137,065	68,810
1993	229	0	10	$28,873,651	116,802	57,559
1994	245	1	7(1)	$62,166,058	164,387	114,002
1995	188	3	11	$32,518,689	110,237	53,113
1996	194	5	13	$85,136,315	160,316	100,949
1997	171	0	5	$55,186,642	195,549	103,129
1998	153	2	6	$63,308,923	149,500	60,791
1999	167	4	20	$86,355,560	167,230	104,487
2000	146	1	4	$180,155,745	108,652	56,953
2001	130	0	10	$25,346,751	98,348	77,456
2002	147	1	0	$47,410,656	95,642	77,269
2003	131	0	5	$49,981,280	80,112	50,523
2004	144	5	16	$146,333,176	88,237	68,558
2005	138	2	2	$102,623,201	137,017	45,814
2006	110	0	2	$55,063,317	136,033	53,788
2007	60	0	2	$20,471,574	55,927	40,768
Totals (2)	**3764**	**44**	**276(1)**	**$1,204,033,762**	**3,404,699**	**2,012,947**

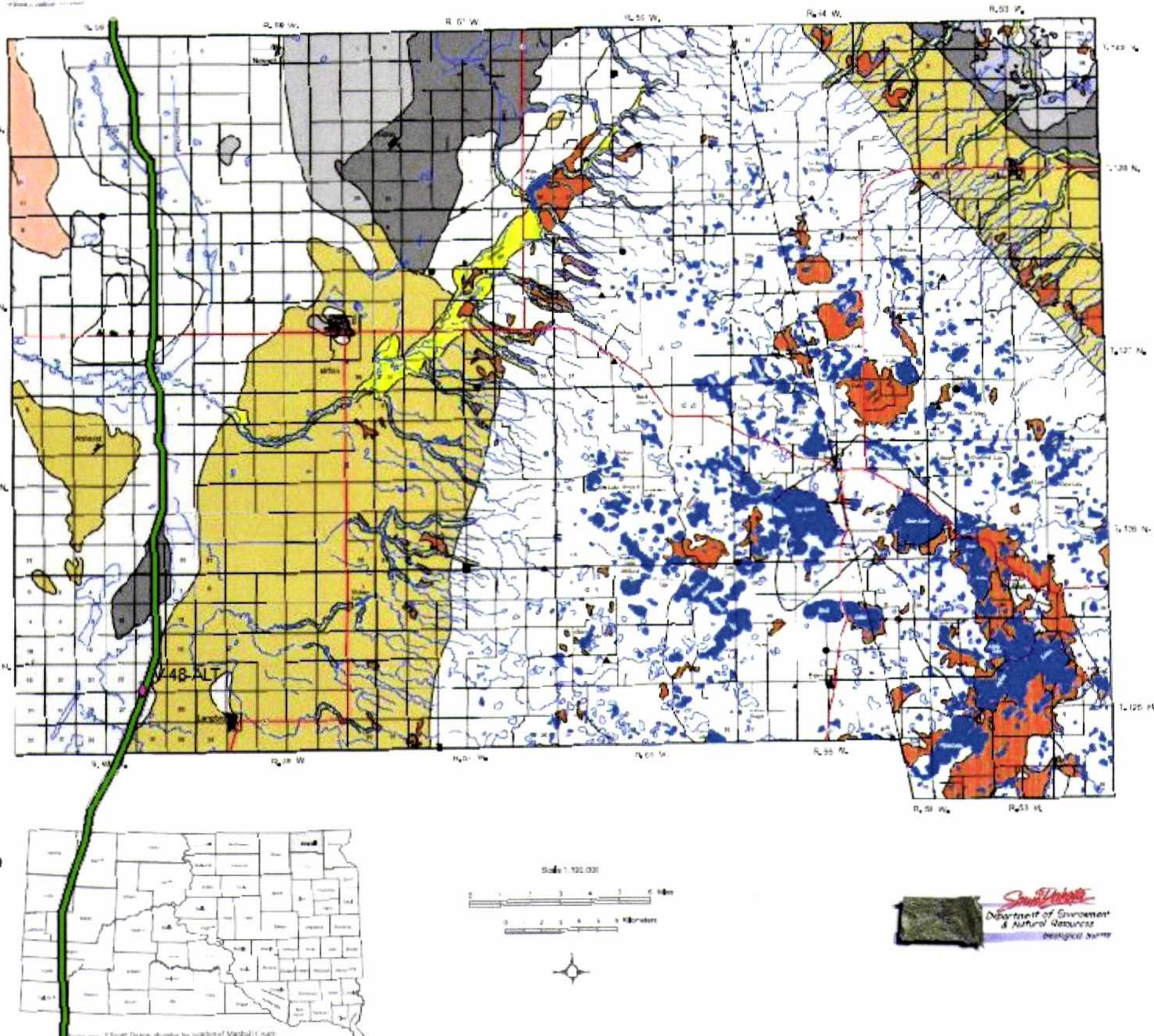
Historical totals may change as PHMSA receives supplemental information on incidents.

3,404,699 barrels of oil lost x 42 gallons per barrel = **142,997,358 gallons /oil leaks ~~in 2007~~** ck 22 years

WEB Exhibit # 10

First Occurrence of Aquifer Materials in Marshall County, South Dakota

Department of Environment and Natural Resources
Division of Financial and Technical Assistance
Geological Survey
Aquifer Materials Map 3
Ann R. Jensen, 2001



Explanation

First occurrence is generally less than or equal to 50 feet below land surface

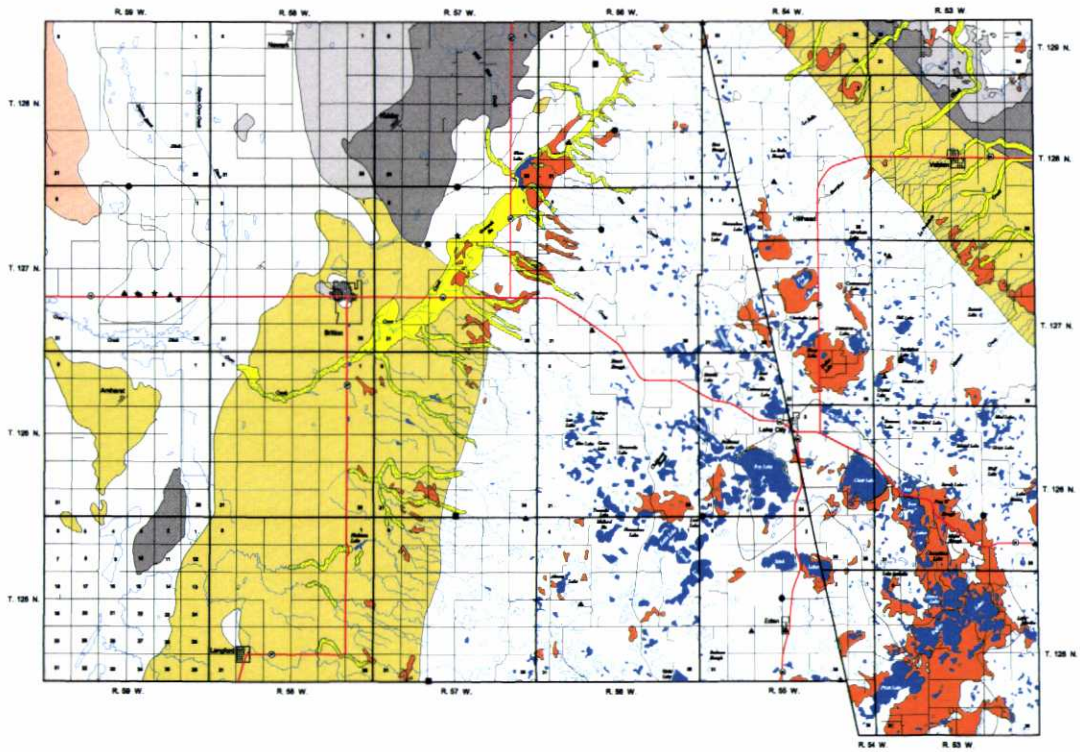
First occurrence is generally greater than 50 feet and less than or equal to 100 feet below land surface

First occurrence is generally greater than 100 feet below land surface

11-a

First Occurrence of Aquifer Materials in Marshall County, South Dakota

Department of Environment and Natural Resources
Division of Financial and Technical Assistance
Geological Survey
Aquifer Materials Map 3
Ann R. Jensen, 2001



Index map of South Dakota showing the location of Marshall County

Scale 1:100,000

0 1 2 3 4 5 6 Miles

0 1 2 3 4 5 6 Kilometers

Explanation

This map is intended for use as a tool to aid in identifying areas underlain by aquifer material. The aquifer materials shown on this map are categorized below. This map does not show individual aquifers. There may be more than one type of aquifer material present in an area. However, only the aquifer material that would be first encountered is shown. Within the boundaries of any given map unit, there may be localized areas where aquifer material is absent. The thickness and permeability of aquifer material may vary significantly. Also, no attempt was made to distinguish between saturated and unsaturated material. Therefore, not all of the areas defined on this map may be an aquifer. Site specific information should always be examined when making land management or water development decisions.

First occurrence is generally less than or equal to 50 feet below land surface

- **Alluvium:** Consists of clay and silt with minor amounts of sand and gravel
- **Eolian Sand:** Windblown, occurs at land surface
- **Sand and Gravel:** First occurrence is generally at land surface
- **Sand and Gravel:** First occurrence is generally below land surface. May not be uniform in depth and thickness and may be discontinuous in lateral extent

First occurrence is generally greater than 50 feet and less than or equal to 100 feet below land surface

- **Sand and Gravel:** May not be uniform in depth and thickness and may be discontinuous in lateral extent

First occurrence is generally greater than 100 feet below land surface

- **Sand and Gravel:** May not be uniform in depth and thickness and may be discontinuous in lateral extent
- **Dakota Formation:** Consists of interbedded siltstone, sandstone and shale

Area where aquifer material may be present in glacial deposits overlying the bedrock, but insufficient data are available to delineate mappable units. Data points have been plotted to show availability of information. Dakota Formation underlies this entire area.

- ● Data point where the first occurrence of aquifer material is generally less than or equal to 50 feet below land surface
- ■ Data point where the first occurrence of aquifer material is generally greater than 50 feet and less than or equal to 100 feet below land surface
- ▲ Data point where the first occurrence of aquifer material is generally greater than 100 feet below land surface
- ★ Data point which shows no aquifer material between land surface and the bedrock surface

Major highway
Road
Township boundary
River or stream
Lake
Slough or intermittent lake

For township section numbering system, see T. 125 N., R. 59 W.

This map was developed from lithologic logs and published reports. The major sources of information were:

Koch, N.C., 1975, *Major aquifers and sand and gravel resources in Marshall County, South Dakota*: South Dakota Geological Survey Water-Information Pamphlet 1, 9 p.

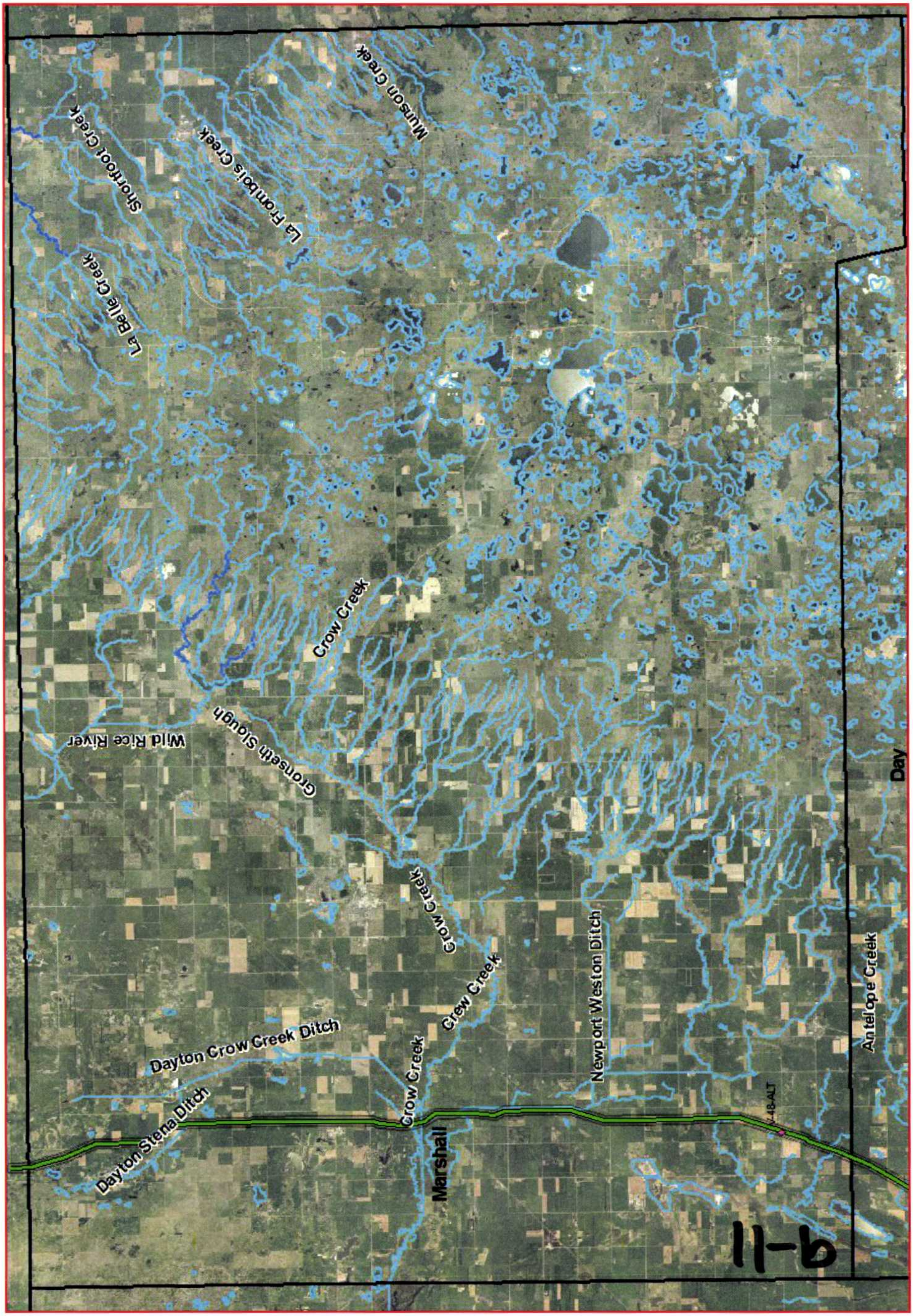
Koch, N.C., 1975, *Geology and water resources of Marshall County, South Dakota, Part I: Geology and water resources*: South Dakota Geological Survey Bulletin 23, 76 p.

South Dakota Geological Survey, Lithologic logs database.

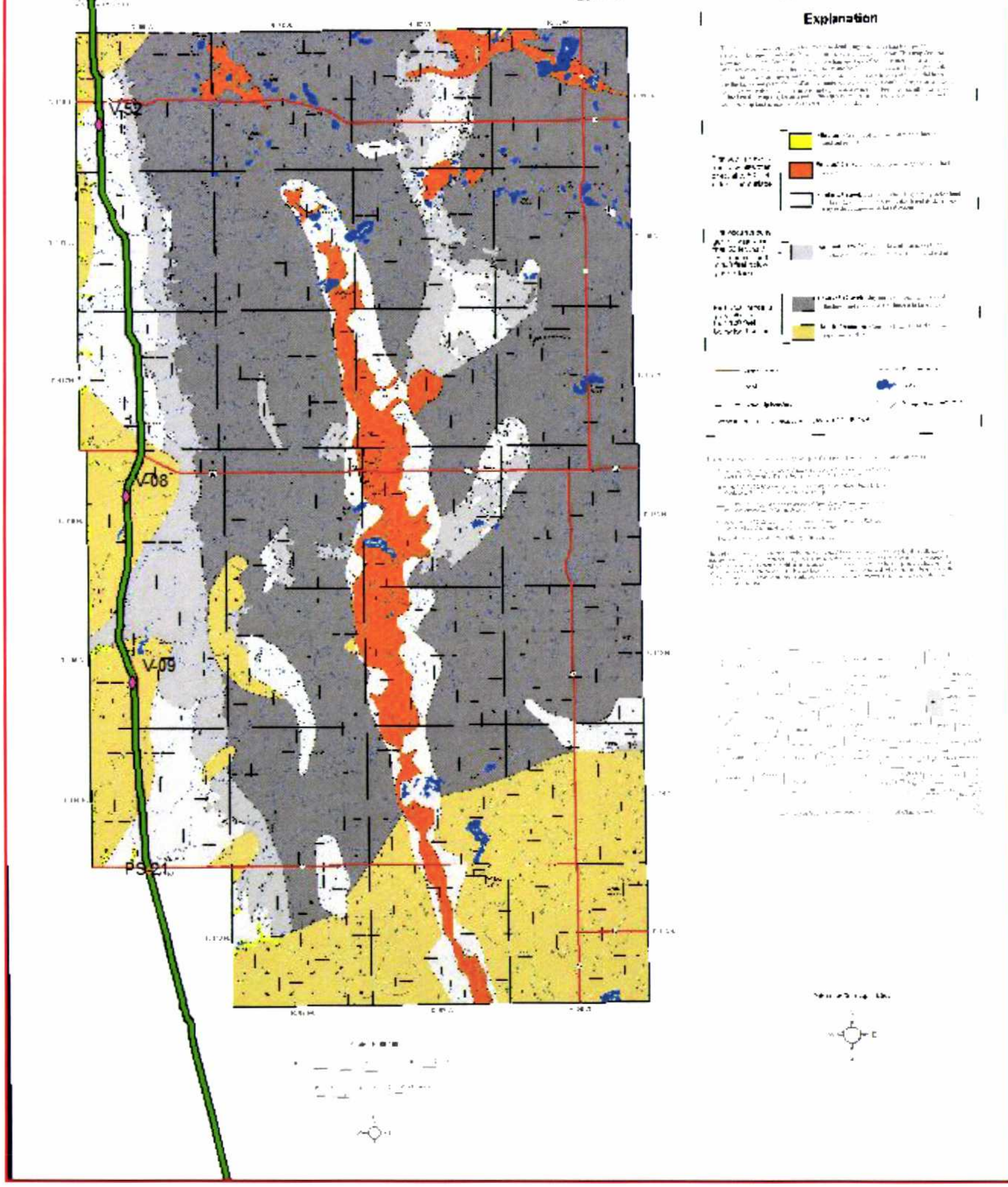
The Geological Survey, Department of Environment and Natural Resources, engages in an ongoing data collection and interpretation process. An outcome of that process is to reflect those interpretations on maps such as this one. Reasonable efforts have been made to ensure that this map accurately reflects the source data used in its preparation. This map is data specific. As additional data become available, geologic interpretations may be revised and the map may be updated by the Geological Survey. This map should not be enlarged or otherwise used in an attempt to interpret more detail than can be seen at the 1:100,000 scale.

Publication Date: April 9, 2001

WEB Exhibit # 11a1


Munson Creek
Shortfoot Creek
La Frombois Creek
La Bella Creek
Crow Creek
Wild Rice River
Gronseth Slough
Day
Crow Creek
Crew Creek
Newport Weston Ditch
Antelope Creek
Dayton Crow Creek Ditch
Crow Creek
Dayton Stena Ditch
Marshall
11-b

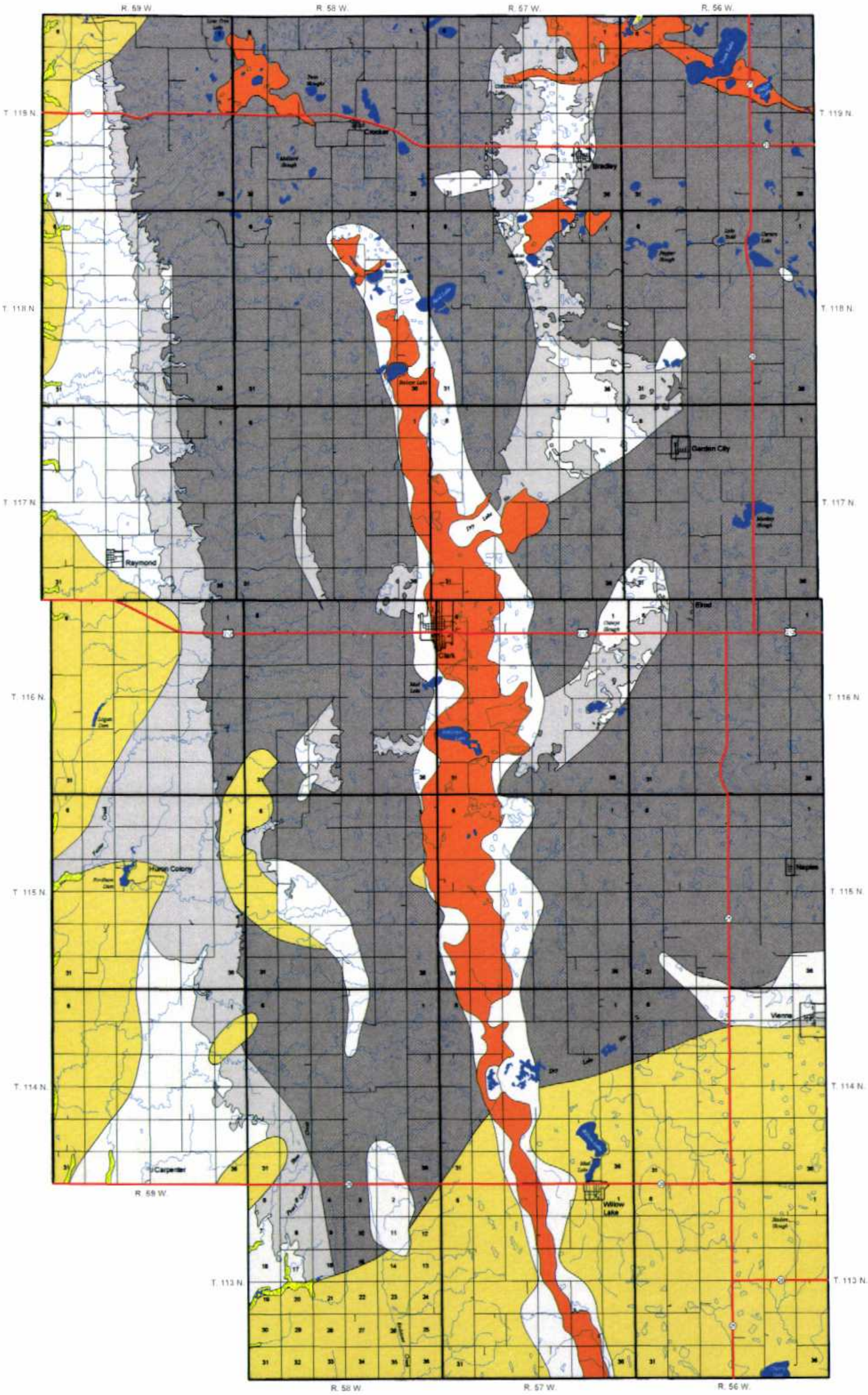
First Occurrence of Aquifer Materials in Clark County, South Dakota



11-C

First Occurrence of Aquifer Materials in Clark County, South Dakota

Department of Environment and Natural Resources
Division of Financial and Technical Assistance
Geological Survey
Aquifer Materials Map 2
Ann R. Jensen, 2001



Scale 1:100,000

Explanation

First occurrence is generally less than or equal to 50 feet below land surface

- **Alluvium:**
- **Sand and Gravel:**
- **Sand and Gravel:**

First occurrence is generally greater than 50 feet and less than or equal to 100 feet below land surface

- **Sand and Gravel:**

First occurrence is generally greater than 100 feet below land surface

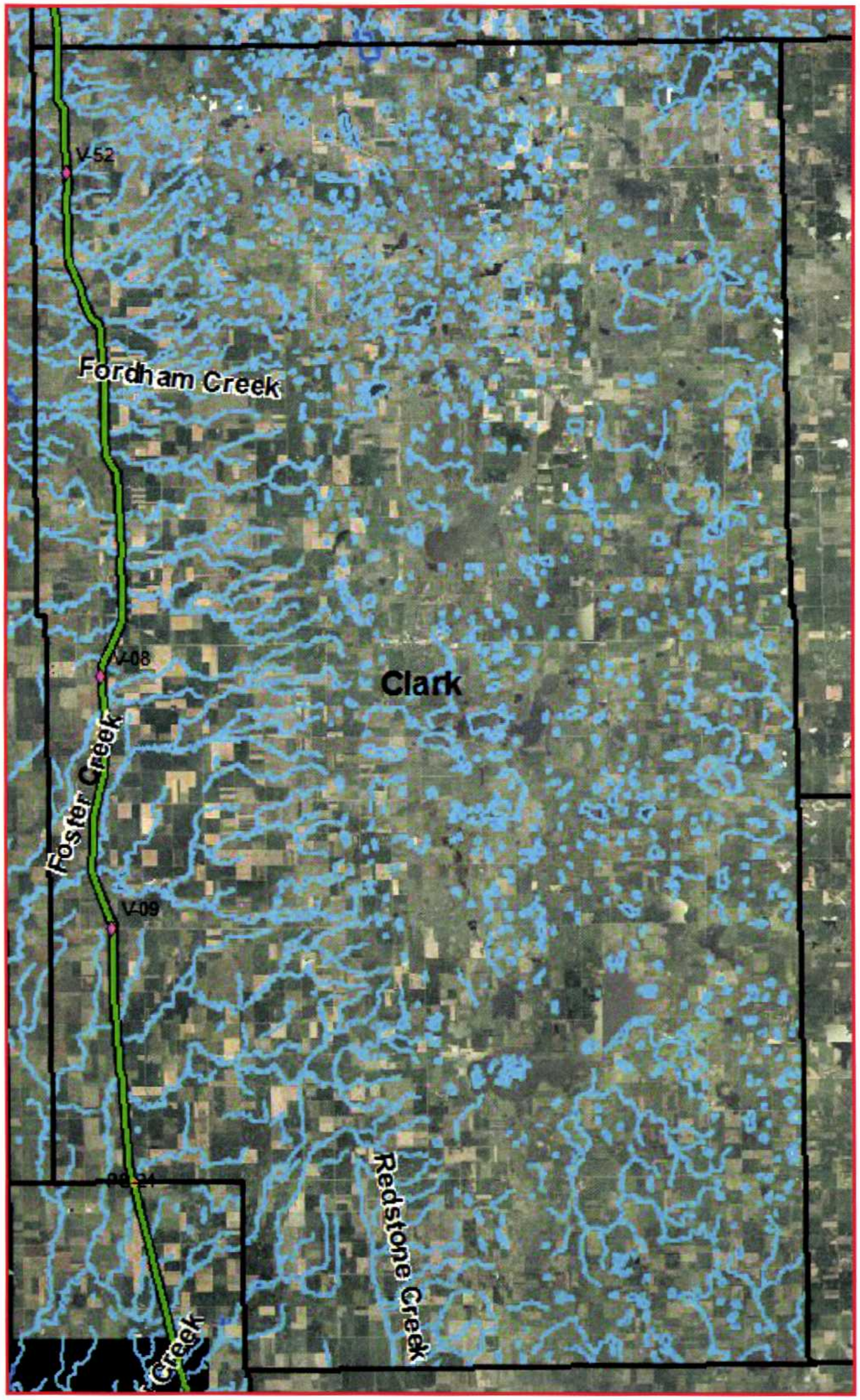
- **Sand and Gravel:**
- **Dakota Formation:**

Major highway
Road
Township boundary
River or stream
Lake
Slough or intermittent lake

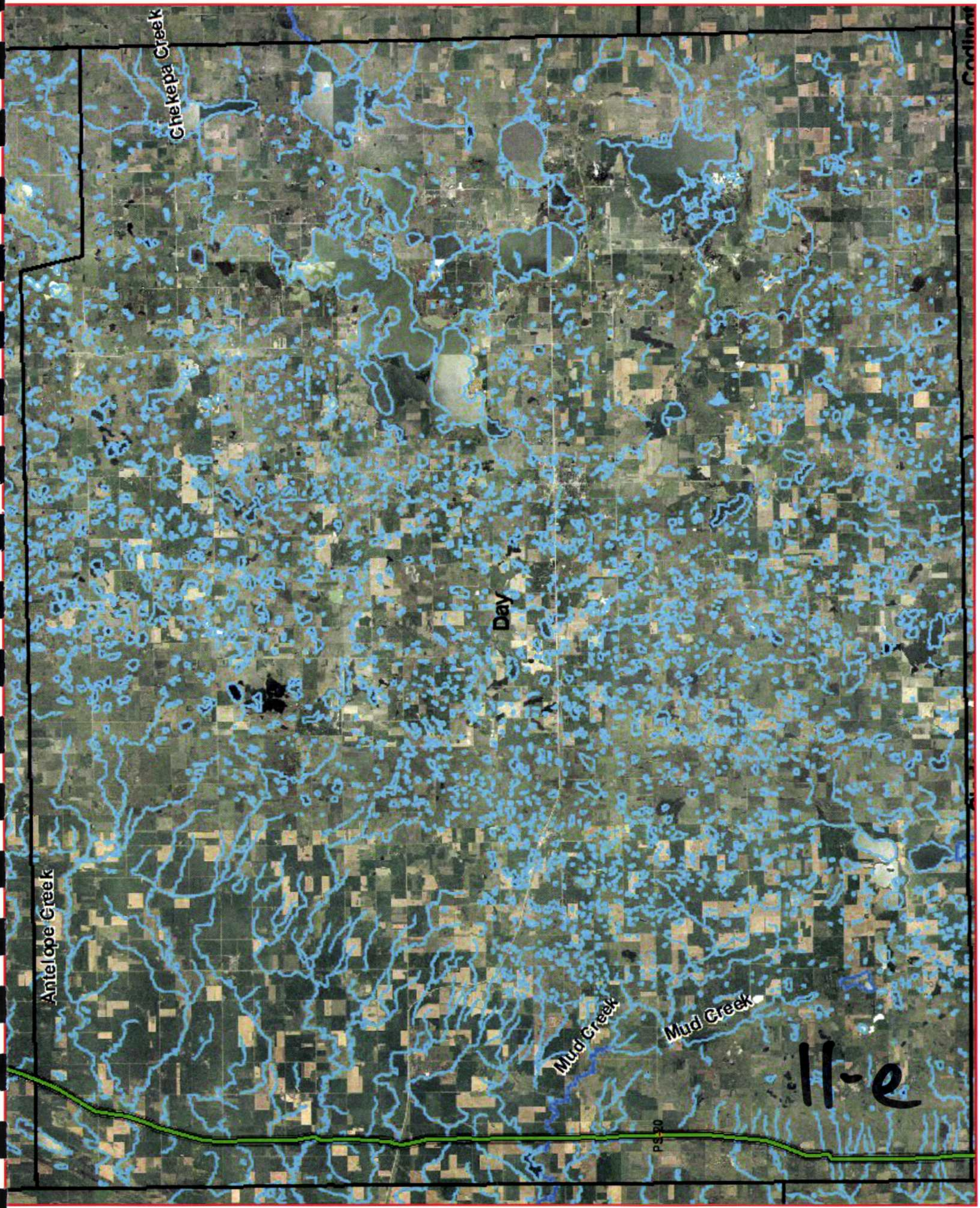
For township section numbering system, see T. 113 N., R. 58 W.

Publication Date: April 3, 2001

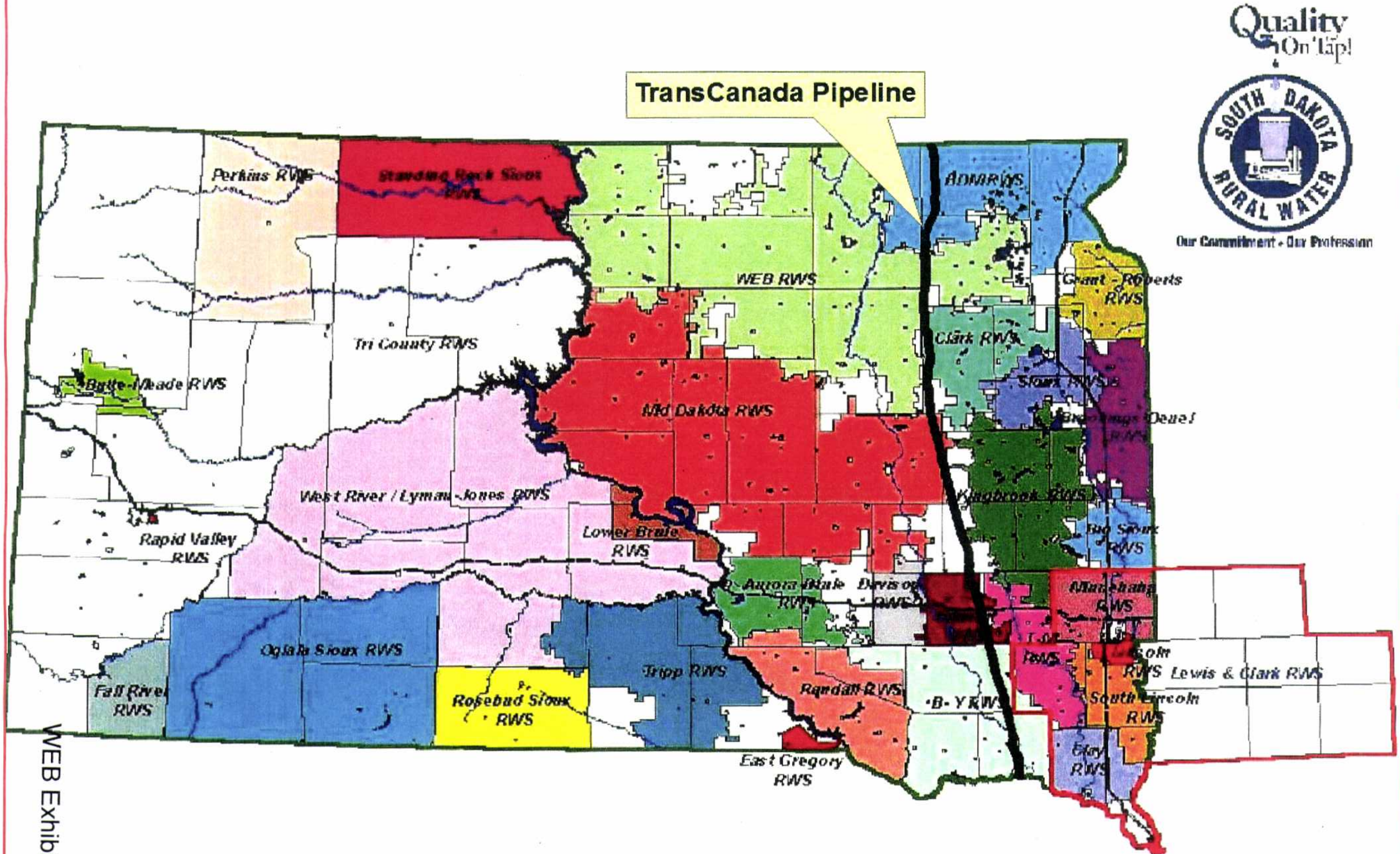
11C1


V-52
Fordham Creek
V-08
Clark
Foster Creek
V-09
Redstone Creek
Creek

11-d


Chekepa Creek
Day
Antelope Creek
Mud Creek
Mud Creek
11-e

South Dakota Rural Water Systems



WEB Exhibit # 12

Official: Pipeline, refinery not linked

By Bob Mercer
American News Correspondent

PIERRE — The Keystone crude-oil pipeline that TransCanada wants to build through South Dakota is not intended to serve the Hyperion oil refinery project proposed near Elk Point, according to sworn testimony filed with the state Public Utilities Commission.

Robert Jones, vice president for TransCanada Pipelines, said Keystone has firm contracts to deliver 495,000 barrels per day to customers at Wood River and Patoka, Ill., and Cushing, Okla.

"Hyperion is not included as a firm shipper. Keystone has not negotiated any shipping contracts or connection contracts with the proposed Hyperion project or any other proposed refinery," Jones said in his prefiled testimony.

Jones said there are sufficient commitments to lead TransCanada to increase the pipeline's capacity to 591,000 barrels per day.

"Keystone is not dependent on the construction of the Hyperion

See **OIL,** *Page 10A*

Oil: Cost estimated at $300 million

Continued *from Page 1A*

refinery or any other proposed refinery," he added.

Opponents of the pipeline have charged that TransCanada and Hyperion are linked.

The PUC will have a hearing in December on whether to grant TransCanada the necessary state permit to construct the pipeline through South Dakota. The 220-mile route would cross 10 counties.

Interstate 29: A project consultant said TransCanada never considered running the pipeline down the Interstate 29 corridor because such a route wouldn't be allowed for safety reasons.

The consultant, Michael Troski, said TransCanada also rejected the option of running the pipeline on property adjacent to I-29 because that route would need to loop around interchanges, overpasses and residential and commercial areas of development.

Opponents have urged the project be relocated from the James River Valley to the I-29 corridor.

Jones in his testimony said Keystone will have three full-time employees in South Dakota after construction is complete, along with 50 to 60 part-time contractual positions.

TransCanada wants to start construction in 2008 and have the project in operation by late 2009.

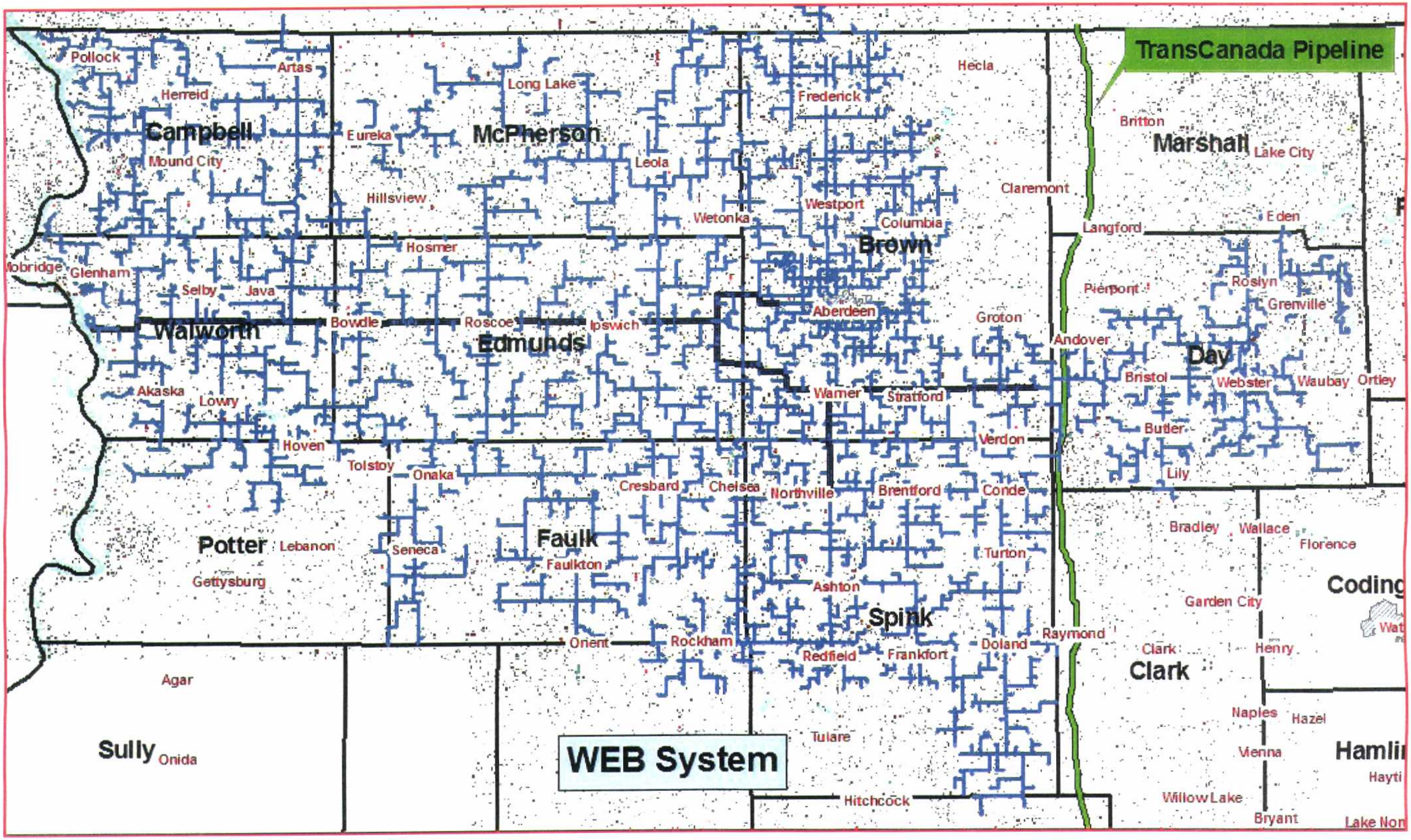
Cost, tax revenue: Jones said the estimated cost of construction in South Dakota is $300 million. He said sales and use taxes would normally be about $18 million, but a state law allows a 75 percent refund that would result in TransCanada paying about $4.5 million.

He expects the pipeline to generate about $6.5 million in taxes in the first year after construction.

The pre-filed testimony from TransCanada officials is the first step in the process leading up to the December hearing. Opponents will pre-file their testimony next, followed by rebuttals from each side.

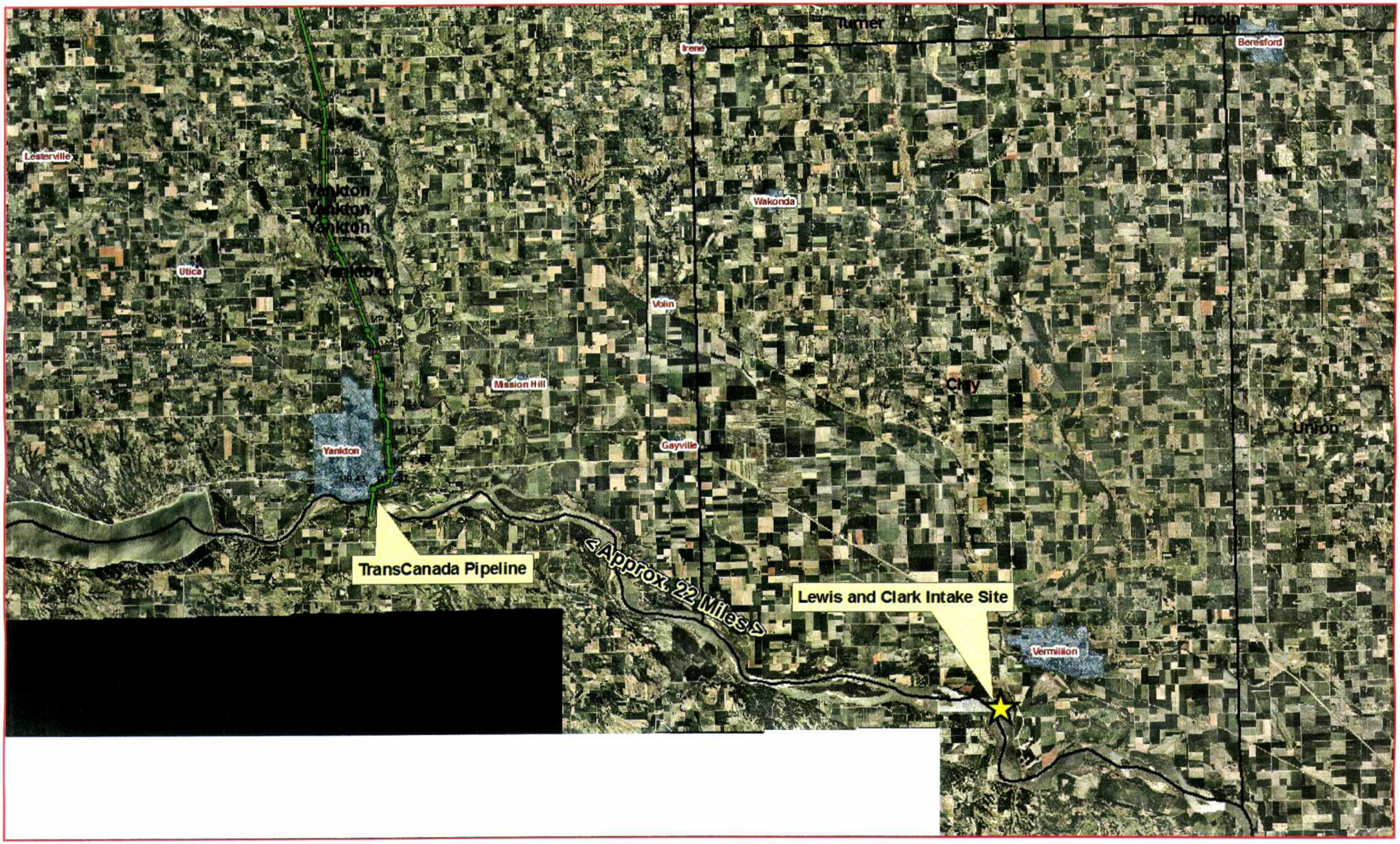
The purpose of the pre-filed testimony is to allow the three PUC members to better consider the written statements and to accelerate the hearing process.

WEB Exhibit # 13


TransCanada Pipeline
WEB System
Campbell
McPherson
Brown
Marshall
Day
Walworth
Edmunds
Potter
Faulk
Spink
Clark
Sully
Hamlin
Pollock
Artas
Herreid
Mound City
Eureka
Long Lake
Leola
Hillsview
Frederick
Hecla
Westport
Wetonka
Columbia
Claremont
Britton
Lake City
Eden
Langford
Glenham
Selby
Java
Hosmer
Bowdle
Roscoe
Ipswich
Aberdeen
Groton
Pierpont
Roslyn
Grenville
Andover
Bristol
Webster
Waubay
Ortley
Akaska
Lowry
Hoven
Tolstoy
Onaka
Warner
Stratford
Verdon
Butler
Lily
Cresbard
Chelsea
Northville
Brentford
Conde
Bradley
Wallace
Florence
Lebanon
Gettysburg
Seneca
Faulkton
Turton
Ashton
Garden City
Orient
Rockham
Redfield
Frankfort
Doland
Raymond
Clark
Henry
Agar
Onida
Tulare
Naples
Hazel
Vienna
Hayti
Willow Lake
Hitchcock
Bryant

14

15


Turner
Lincoln
Irene
Beresford
Lesterville
Yankton
Wakonda
Utica
Volin
Mission Hill
Clay
Union
Yankton
Gayville
TransCanada Pipeline
< Approx. 22 Miles >
Lewis and Clark Intake Site
Vermillion

[redacted]

Dakota Skipper
Hesperia dacotae


Photo by ©Robert Dana

Dakota skippers are found only in high quality prairies.

The Dakota skipper is a small butterfly with a 1-inch wingspan. Like other skippers, they have a thick body and a faster and more powerful flight than most butterflies. The upper side of the male's wings range from tawny-orange to brown with a prominent mark on the forewing; the lower surface is dusty yellow-orange. The upper side of the female's wing is darker brown with tawny-orange spots and a few white spots on the margin of the forewing; the lower side is gray-brown with a faint white spot band across the middle of the wing. Dakota skipper pupae are reddish-brown and the larvae (caterpillars) are light brown with a black collar and dark brown head.

Official Status
The Dakota skipper is a candidate for listing under the Endangered Species Act. Candidate species are those for which the U.S. Fish and Wildlife Service (Service) has sufficient information to list as threatened or endangered. To determine the order in which it proposes species for listing, the Service assigns listing priority numbers to candidate species based on the magnitude and immediacy of threats and the species' taxonomic distinctiveness. Listing priority numbers range from 1 (high priority) to 12 (low priority). Dakota skipper has a listing priority number of 11. Candidate species receive no legal protection under the Endangered Species Act (Act) - that is, there are no legal prohibitions under the federal Endangered Species Act against taking candidate species. The Fish and Wildlife Service works to implement conservation actions for candidate species that may eliminate the need to list the species as threatened or endangered.

Range
Scientists have recorded Dakota skippers from northeast Illinois to southern Saskatchewan. Their historical range is not known precisely because extensive destruction of native prairie preceded widespread biological surveys in central North America. Dakota skippers now occur no further east than western Minnesota and scientists presume that the species no longer exists in Illinois and Iowa. Although it likely occurred throughout a relatively unbroken and vast area of grassland in the north-central U.S. and south-central Canada, it now occurs only in scattered remnants of high-quality native prairie. Its current distribution straddles the border between tallgrass and mixed grass prairie ecoregions. The most significant remaining populations of Dakota skippers occur in western Minnesota, northeastern South Dakota, north-central North Dakota, and southern Manitoba.

Habitat
Dakota skipper occurs in two types of habitat. The first is relatively flat and moist native bluestem prairie in which three species of wildflowers are usually present and in flower when Dakota skippers are in their adult (flight) stage - wood lily (*Lilium philadelphicum*), harebell (*Campanula rotundifolia*), and smooth camas (*Zygadenus elegans*). The second habitat type is upland (dry) prairie that is often on ridges and hillsides. Bluestem grasses and needlegrasses dominate these habitats and three wildflowers are typically present in high quality sites that are suitable for Dakota skipper: pale purple (*Echinacea pallida*) and upright (*E. angustifolia*) coneflowers and blanketflower (*Gaillardia sp.*).

Ecology and Life History
Dakota skippers have four basic life stages - egg, larva, pupa, and adult. During the brief adult (flight) period in June and July, female Dakota skippers lay eggs on the underside of leaves approximately 1-2 inches above the ground. These eggs take about 10 days to hatch into larvae. After hatching, the pale-brown larvae build shelters at or below the ground surface and emerge at night to feed on grass leaves until late summer or early fall when they become dormant. They overwinter as mid-stage larvae in shelters at or just below ground level, typically in the bases of native bunchgrasses. The larvae emerge to continue development the following spring. Pupation takes about 10 days and occurs primarily in June. Males emerge as adults about five days before females. Maximum life span as adults is about

three weeks. This brief period is the only time during which Dakota skippers can reproduce.

If they attain maximum longevity of about three weeks and if adequate sources of nectar are available, females may lay up to about 250 eggs. Nectar provides Dakota skipper with both water and food and is crucial for the survival of both sexes during the flight period. Dakota skippers appear to prefer plants, such as purple coneflowers (*Echinacea spp.*), whose nectar cannot be obtained by insect species that do not have a relatively long, slender feeding tube (proboscis). In the absence of preferred plants, Dakota skippers attempt to obtain sufficient nectar from less preferred species.

Reasons for current status

Dakota skipper populations have declined historically due to widespread conversion of native prairie for agriculture and other uses. This has left remaining Dakota skipper populations isolated from one another in relatively small areas of remnant native prairie. States and Canadian provinces in the original range of Dakota skipper have each lost 85%-99% of their historical tallgrass prairie and 72%-99.9% of their historical mixed-grass prairie. This has left isolated fragments of native prairie, only some of which are suitable for Dakota skippers. Dakota skippers are sensitive to several types of artificial and natural disturbances and are almost always absent from remnant prairies that are overgrazed or otherwise degraded. Because of this sensitivity, the historical persistence of Dakota skippers may have depended on the vastness of the prairie and the availability of immigrants to repopulate areas in which the species had been eliminated by disturbances, such as fire or intensive bison grazing. Because the remaining populations of Dakota skipper are now largely isolated from one another, immigrating butterflies cannot reestablish populations made extinct by grazing, weed invasion, fire, or other causes. Even if they persist at such isolated sites, the lack of interaction with other populations reduces genetic diversity and may result in a reduced ability to adapt to environmental changes.

Although some species that depended on native prairie possessed adaptations that have allowed them to successfully occupy the types of habitat that occur in a modern agricultural landscape, Dakota skippers need high-quality native prairie habitats. In addition, many of the habitats where the species persists are threatened by over-grazing, conversion to cultivated agriculture, inappropriate fire management and herbicide use, woody plant invasion, road construction, gravel mining, invasive plant species, and, in some areas, historically high water levels. These factors threaten Dakota skipper populations on both public and private land. Although the threats are numerous, there are opportunities to address them and to effectively conserve the species. Dakota skippers and their native prairie habitat are dependent on some type of periodical disturbance; otherwise it would become shrubby or forested. Therefore, grazing, fire, or mowing, or a combination of these practices, are necessary for the species to persist. Because these practices may also eliminate populations, however, the methods by which they are implemented are crucial to the survival of the species.

What's being done to conserve Dakota skipper?

The Service and the states have been working with private landowners and other partners in North Dakota, South Dakota, and Minnesota to conserve the Dakota skipper's native prairie habitat. With cooperation from landowners, we are able to survey for and study Dakota skippers and have entered into cooperative agreements to conserve the species. The conservation of Dakota skipper depends on private landowners. Excluding lands owned by conservation organizations, such as The Nature Conservancy, approximately 50 percent of all known populations are on private lands. Public agencies are actively seeking private landowners who are willing to sell easements or secure conservation agreements that would facilitate land management practices that are conducive to the conservation of Dakota skipper and other native prairie species. These easements often simply ensure the continued implementation of existing land uses that are compatible with prairie conservation.

On public lands and other conservation areas, land managers are using prescribed fire and other land management techniques to conserve Dakota skippers and their native prairie habitats. Fire is a natural component of prairie habitats, but Dakota skippers are vulnerable to fire at virtually all life stages and likely depended historically on repopulation from unburned areas to persist. Therefore, many land managers are ensuring that only a small proportion of Dakota skipper habitat is burned in any given year and are only burning as frequently as is necessary to achieve specific objectives, such as preventing succession from grassland to shrubs or trees. Finally, research is ongoing to better understand the effects of livestock grazing on Dakota skippers and surveys for the species are ongoing to locate populations that are yet undiscovered.

How can I find out more about Dakota skippers?

For more information on Dakota skippers and ongoing conservation efforts, visit the Service's website at http://midwest.fws.gov/endangered/ or contact one of the following offices:

In Minnesota:
U.S. Fish and Wildlife Service
4101 E. 80th St.
Bloomington, MN 55425
Phone: 612) 725-3548 ext. 206
Email: Phil_Delphey@fws.gov

In North Dakota:
U.S. Fish and Wildlife Service
3425 Miriam Avenue
Bismarck, ND 58501
Phone: (701) 250-4481
Email: Carol_Aron@fws.gov

In South Dakota:
U.S. Fish and Wildlife Service
420 South Garfield Ave., Suite 400
Pierre, SD 57501
Phone: (605) 224-8693
Email: Charlene_Bessken@fws.gov

References:

U.S. Fish and Wildlife Service. 2002. *Status Assessment and Conservation Guidelines, Dakota skipper.*

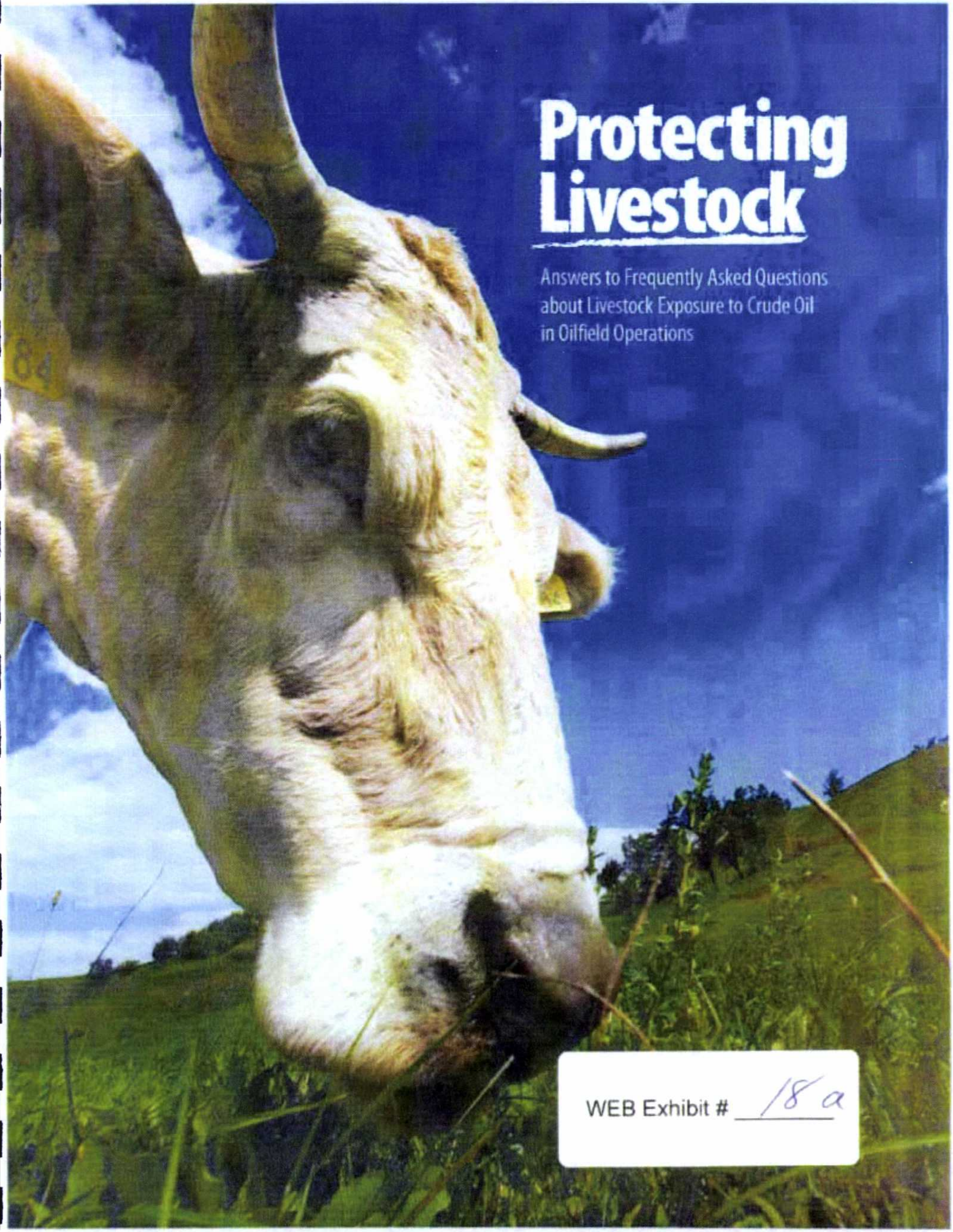
April 2007

WEB Exhibit # 16a

WEB Exhibit # 17

Protecting Livestock

Answers to Frequently Asked Questions about Livestock Exposure to Crude Oil in Oilfield Operations



WEB Exhibit # 18 a

Introduction

Livestock may be exposed to accidental releases of petroleum hydrocarbons at or near oil and natural gas exploration and production sites. Under certain circumstances, it may be necessary to evaluate the *risk* posed to livestock.

In *Risk-Based Screening Levels for the Protection of Livestock Exposed to Petroleum Hydrocarbons* by Pattanayek and DeShields [2004], and referred to herein as "API (2004)," API developed toxicity values and screening guidelines for evaluating risks to livestock from exposure to petroleum hydrocarbons. The report addressed how to: (1) determine whether livestock should be included in a risk evaluation and (2) estimate risks of petroleum hydrocarbon exposures to livestock.

This booklet summarizes the key results of API (2004), describing ways livestock might be significantly exposed to petroleum hydrocarbons via a conceptual site model, and outlines how to make a screening level determination of whether or not livestock are at risk from the exposure.

Screening levels for livestock protection have been developed by other agencies (e.g., Canadian Council of Ministers of the Environment [CCME] and Alberta Environment). These values are either region-specific or cover limited constituents of petroleum hydrocarbons. API (2004) used a more generalized approach to develop conservative screening levels for petroleum hydrocarbons. The screening levels can be used to characterize risks to livestock across a variety of conditions. API (2004) describes the differences among API, CCME, and Alberta Environment and also provides an uncertainty analysis of the API approach.

A glossary provided on page 14 describes terms shown in italic throughout this booklet.

Conceptual Site Models

This booklet refers to the use of a **conceptual site model (CSM)** to identify potential sources, exposure pathways, and receptors. CSMs may be graphical or text-based; at a minimum, however, CSMs must identify a complete or potentially complete linkage between a source and a receptor to be considered in a risk assessment:

SOURCE $\xrightarrow{\text{PATHWAY}}$ RECEPTOR

If a complete exposure pathway is not indicated by the CSM then further assessment is not necessary. If the linkage leads to an insignificant exposure, i.e. source concentrations less than the *risk-based screening levels (RBSLs)* for soil or water, the assessment indicates no unacceptable risk to the receptor. If constituent values are greater than RBSLs, further actions are taken to protect the receptor. The path forward could include a site-specific risk assessment, source treatment, source removal, source isolation, or land-use change.

WEB Exhibit # 186

Figure 1
Aerial view of a site with primary and secondary contaminant sources

What type(s) of animals are considered livestock?

API (2004) addresses dairy cattle, beef cattle, calves, sheep, goats, camels, and horses as receptors; therefore, they are considered livestock in this document. These are animals that forage in pasture areas. Species that are raised in more confined and controlled conditions, such as chickens or pigs, have less chance of exposure to petroleum hydrocarbons. Other species, such as llamas and oxen, could also be evaluated by following the approach outlined in API (2004). (Also, see text box: "Can Livestock RBSLs be Used for Wildlife?" on page 8).

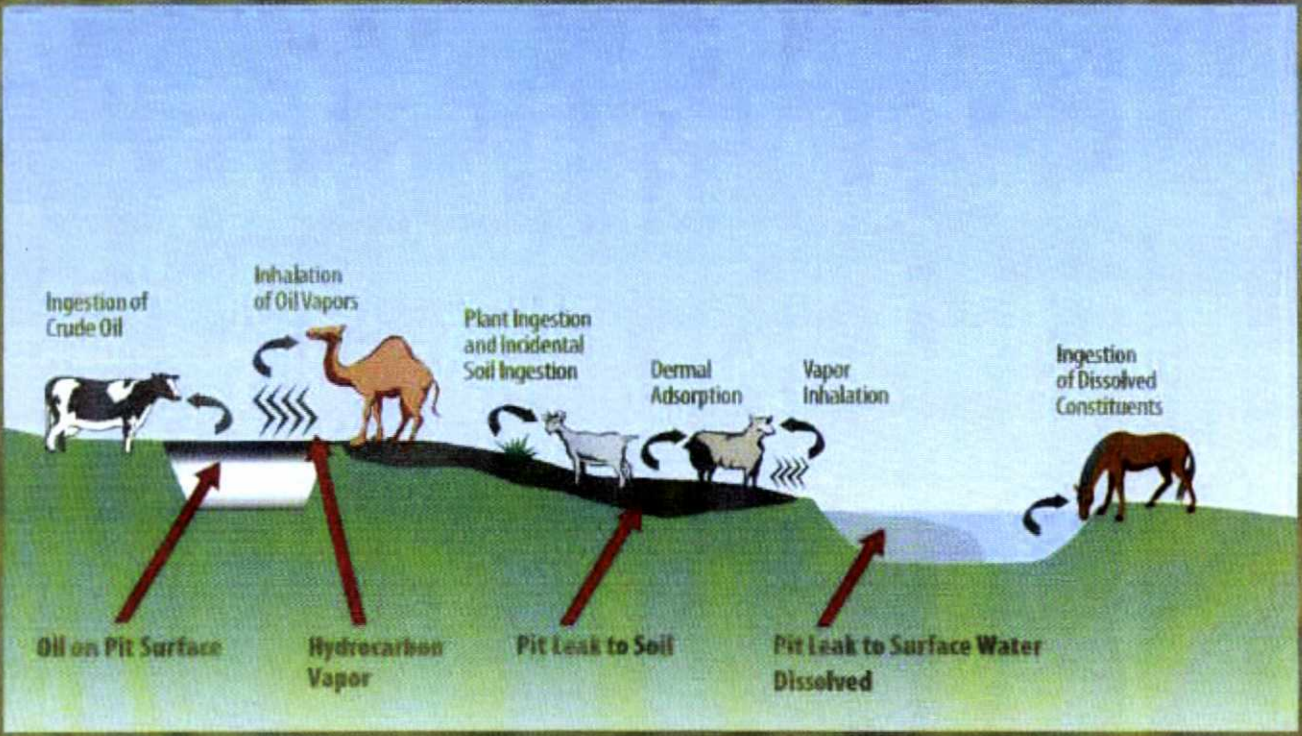
How are livestock typically exposed to crude oil?

Crude oil may be released to soil or water through accidental leaks and spills from primary sources such as equipment, pipelines, storage vessels, and transport vehicles. The resulting secondary sources are pools of crude oil, oil mixed in soil, dissolved constituents in water, and vapors in air (Figure 1).

Livestock can be exposed to petroleum hydrocarbons through incidental soil ingestion, water ingestion, direct ingestion of crude oil, inhalation, skin contact (dermal absorption), and indirectly through ingestion of contaminated plants (Figure 2). Based on information available in the scientific literature, the significant *exposure pathways* are incidental soil ingestion, water ingestion, and direct petroleum ingestion.

WEB Exhibit # 18-c

Figure 2
Potential source, pathways, and receptors addressed in API (2004)



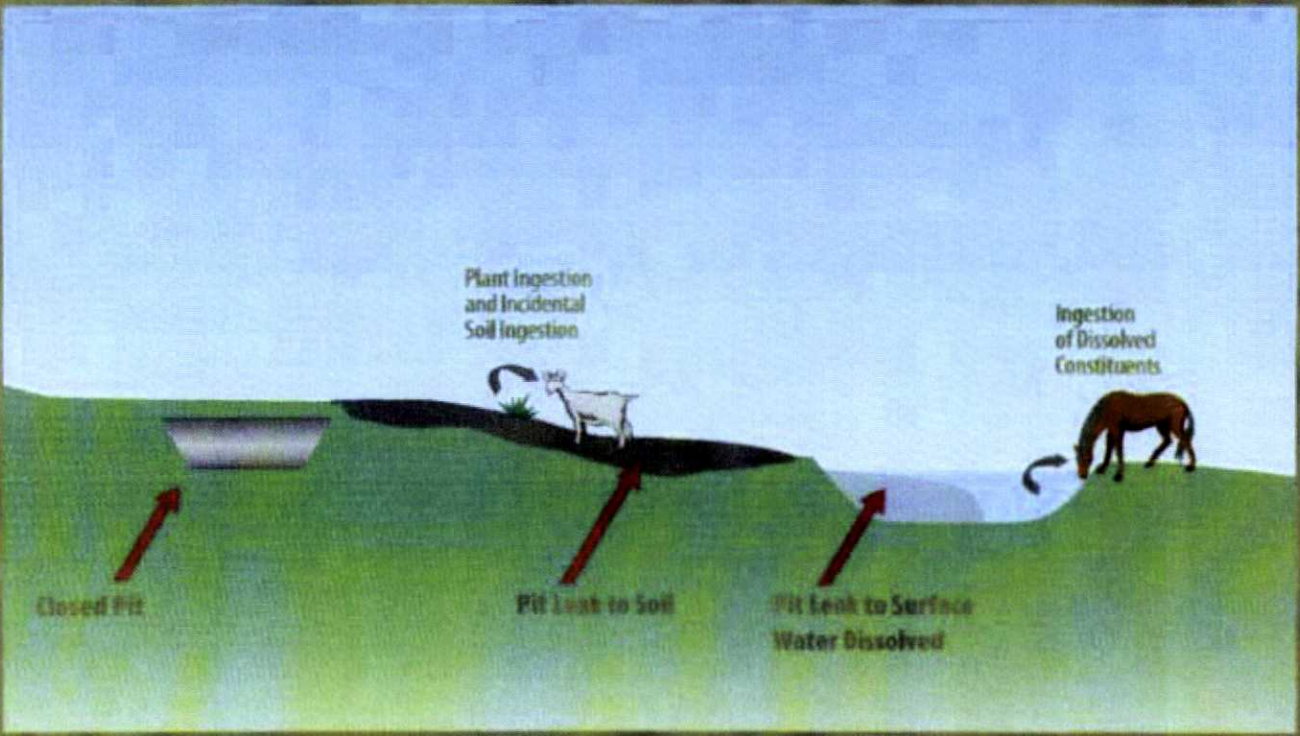
Livestock may consume soil inadvertently during grazing (Zach and Mayoh 1984; CCME 2000) or may intentionally ingest salty-tasting soil (Coppock *et* al. 1995). According to the CCME (2000), most of the petroleum hydrocarbon exposure in cattle is a result of contaminated surface-soil ingestion.

Chronic exposure through drinking water can be a significant exposure pathway for livestock (CCME 2000). The amount of water ingested by cattle varies according to age, physiological status (growth, fattening, pregnancy, lactation), diet composition, breed, size, and, for all animals, temperature (Agriculture and Agri-Food Canada 2001; National Research Council [NRC] 1988).

Cattle may directly ingest crude oil and other petroleum compounds because of curiosity (particularly young calves; Edwards 1985), i.e., drinking from pools created by piping failures (Edwards and Zinn 1979; Coppock et al. 1995; CCME 2000). Oil and natural gas industry guidance (API 1997) and many regulatory agencies (e.g., the Railroad Commission of Texas, 1993) stress the importance of removing free oil from the soil surface to prevent animal exposure.

WEB Exhibit # 18-d

Figure 3
Example conceptual site model showing significant exposure pathways at a site



How do I determine if livestock are at risk at a site?

The best way to start is to develop a *conceptual site model* (CSM). The CSM identifies complete and potentially complete exposure pathways (Fig. 3). If a complete significant pathway(s) does not exist for exposure of livestock to petroleum hydrocarbons, a screening-level risk evaluation for livestock is not necessary. By definition, if there is no significant exposure to a potentially toxic compound, there is no likelihood of significant unacceptable risk to the receptor from that compound.

If a significant exposure pathway exists, further screening-level assessment may be appropriate. A screening-level risk assessment uses a conservative approach to characterize potential risk to livestock exposed to petroleum hydrocarbons at a site. In short, concentrations of petroleum hydrocarbons in soil in milligrams per kilogram (mg/kg) and water in milligrams per liter (mg/L) at a site can be compared to *risk-based screening levels (RBSLs)* protective of livestock shown in Table 1.

WEB Exhibit # 18-e

Table 1
Risk-Based Screening Levels for Livestock
(Note: Depending on the composition of the oil, some RBSLs may exceed water solubility limits, therefore indicating that contaminated water cannot present a health risk unless free oil is present on the water.)

Livestock	Drinking Water Risk-Based Screening Levels (RBSLs; mg/L)						
	Crude Oil	Benzene	Toluene	Ethylbenzene	Xylene	LMW[1] PAH	HMW[2] PAH
Dairy Cattle	1,200	32.4	202	26.4	162	4.53	0.907
Beef Cattle	1,110	31.4	196	25.6	157	4.40	0.880
Calves	293	14.3	89.5	11.7	71.7	2.01	0.402
Sheep	855	40.5	253	33.1	203	5.68	1.14
Goats	622	34.8	217	28.4	174	4.87	0.974
Camels	7,670	202	1,260	165	1,000	28.3	5.65
Horses	2,760	74.3	464	60.6	371	10.4	2.08

Livestock	Soil Risk-Based Screening Levels (RBSLs; mg/kg)						
	Crude Oil	Benzene	Toluene	Ethylbenzene	Xylene	LMW PAH	HMW PAH
Dairy Cattle	47,200	1,270	7,950	1,040	6,370	178	35.7
Beef Cattle	44,900	1,270	7,900	1,030	6,330	177	35.5
Calves	44,900	2,200	13,700	1,790	11,000	308	61.5
Sheep	20,100	953	5,950	778	4,770	133	26.7
Goats	17,600	982	6,130	802	4,910	138	27.5
Camels	69,500	1,830	11,400	1,490	9,140	256	51.2
Horses	28,100	756	4,720	617	3,780	106	21.2

[1] Low molecular weight polycyclic aromatic hydrocarbons (LMW PAHs) are defined as PAHs with less than or equal to 3 rings.

[2] High molecular weight polycyclic aromatic hydrocarbons (HMW PAHs) PAHs are defined as PAHs with greater than or equal to 4 rings.

WEB Exhibit # 18 f

In general, what are livestock RBSLs and how are they developed?

RBSLs are threshold concentrations in soil and water, at or below which little-to-no likelihood of significant unacceptable risks to livestock are expected. API (2004) developed soil and drinking water RBSLs for crude oil, benzene, toluene, ethylbenzene, and xylenes (BTEX), low molecular weight polycyclic aromatic hydrocarbons (LMW PAHs), and high molecular weight polycyclic aromatic hydrocarbons (HMW PAHs) (see Table 1).

RBSLs for animals such as livestock are generally developed based on a risk assessment model integrating livestock exposures and toxicity values (i.e., *toxicity reference values* or TRVs). A description of how RBSLs were determined is provided on page 10 **"How are livestock RBSLs calculated?"** and covered in detail in API (2004).

How do I use RBSLs?

To use the RBSLs, site data are first evaluated to quantify the *Exposure Point Concentration* (EPC) to which livestock may be exposed under reasonable maximum exposure (RME) conditions. EPCs are concentrations of chemicals in site media (e.g., soil, water) to which livestock may be exposed. EPC can be calculated using USEPA guidelines (Section 6.5 of EPA 1989; EPA 2002) which outline the statistical methods that can be used and the considerations involved in choosing the appropriate statistical representation of exposure. The RME scenario represents an upper-bound estimate of exposure. As livestock generally graze over large areas, appropriate EPCs for the RME scenario could be the mean of the site data or the 95 percent upper confidence limit (95% UCL) of the mean concentration. According to the USEPA (EPA 1989), estimates of the RME EPC necessarily involve the use of professional judgment.

Next, soil or water EPCs for petroleum hydrocarbons can be compared to the media-specific and receptor-specific RBSLs (i.e., soil or drinking water) in Table 1 (see Example 1). If EPCs do not exceed RBSLs, then little to no likelihood of significant unacceptable risks can be expected. Conversely, if EPCs exceed RBSLs then a potential for unacceptable risks to livestock may be present and further assessment may be necessary.

WEB Exhibit # 18-g

Example 1
Application of RBSLs

Figure 3 is a graphical CSM for a site contaminated with weathered crude oil from previous exploration and production activities.
Analysis of the soil and groundwater provided upper confidence limit (UCL) constituent concentrations as shown in Tables A-1 and A-2, respectively.

Table A-1
Comparing UCL Water Sample Analytical Result with RBSLs for Livestock Drinking Water

	Results Compared with Drinking Water RBSLs (mg/L)						
	Crude Oil	Benzene	Toluene	Ethylbenzene	Xylene	LMW PAH	HMW PAH
H_2O Sample	122	0.051	0.023	0.003	0.003	ND (0.001)	ND (0.001)
Goat RBSL	622	34.8	217	28.4	174	4.87	0.974
Horse RBSL	2,760	74.3	464	60.6	371	10.4	2.08
ND = Non-detect No Exceedances							

Table A-2
Comparing UCL Soil Sample Analytical Result with RBSLs for Livestock Soil Ingestion

	Results Compared with Soil RBSLs (mg/kg)						
	Crude Oil	Benzene	Toluene	Ethylbenzene	Xylene	LMW PAH	HMW PAH
Soil Sample	**25,600**	256	521	108	470	51	**33.0**
Goat RBSL	17,600	982	6,130	802	4,910	138	27.5
Horse RBSL	28,100	756	4,720	617	3,780	106	21.2
Exceedances are bold							

No further action is required for the drinking water exposure pathway because RBSLs were not exceeded.

The soil ingestion exposure pathway RBSL for crude oil was exceeded for horses and for HMW PAHs for goats and horses.

These results must be considered in the next step of decision-making. Exceeding a RBSL does not mean cleanup is required.
It indicates that further risk assessment or some form of exposure mitigation is necessary.

WEB Exhibit # 18-h

Are livestock petroleum hydrocarbon RBSLs applicable to all types of crude oil releases?

In a screening-level risk assessment for any crude oil release, the RBSLs developed in API (2004) can be directly compared to crude oil concentrations, generally expressed as total petroleum hydrocarbon (TPH), at that site. TRVs for crude oil used to calculate the RBSLs were developed based on whole fresh, unweathered crude oil. TRVs and RBSLs for unweathered crude oil can be used for evaluating fresh spills and can be considered conservative screening values for weathered crude oil.

How can I obtain site-specific RBSLs?

The RBSLs developed for petroleum hydrocarbons in API (2004) were based on a generalized approach using conservative exposure parameters to characterize risks for a variety of livestock across a variety of conditions. However, site-specific RBSLs (also known as site-specific target levels or SSTLs) can be developed by substituting known site-specific site use factors (SUF) or exposure parameters (such as body weights, or ingestion rates for soil and water) in a subsequent evaluation if there is a need to refine the conservative assumptions used to calculate the RBSLs. Example 2 on the next page illustrates this procedure.

Can Livestock RBSLs be Used for Wildlife?

The RBSLs reported in API (2004) were developed specifically for the protection of livestock; therefore, they cannot be used directly for wildlife. However, a similar approach could be used to develop RBSLs for mammalian wildlife using wildlife-specific exposure parameters and body weight-scaled TRVs.

Livestock RBSLs for most of the individual petroleum hydrocarbons (i.e., BTEX and PAHs) were developed based on traditional laboratory mammalian toxicity studies as BTEX and PAH toxicity studies were not available for livestock. Toxicity values derived from small laboratory mammals were extrapolated, based on weight considerations, to a dose that would be protective of livestock. Crude oil toxicity studies were available for livestock, and therefore, crude oil TRV and RBSLs were developed based on a cow study by Stober (1962).

If toxicity values are not available for a specific wildlife mammal, then available mammalian toxicological data can be used along with appropriate exposure parameters and TRVs to develop RBSLs for the species in question.

WEB Exhibit # 18-i

Example 2
SSTL Calculation

The previous example (Example 1) indicated that the soil ingestion exposure pathway RBSL for crude oil was exceeded for horses and for HMW PAHs for goats and horses. In this example, the development of a site-specific site use factor (SUF) is used to illustrate the calculation of site-specific target levels (SSTLs). The SUF represents the fraction of the exposure area for the receptor represented by the contamination area. API (2004) assumes a SUF of 1, i.e., the contaminated area is as large as the effective grazing area. In reality, only a portion of a total grazing area would be contaminated.

A field survey indicates that only 0.25 acre of these livestock's 2-acre range is affected by petroleum-related activities. Thus, the SUF is 0.125 instead of the default value of 1. Using the equations on page 10, **"How are livestock RBSLs calculated?"**, SSTLs are determined using the site-specific SUF (i.e., RBSLs divided by the SUF). Likewise, other justifiable changes to default parameters could be used to calculate SSTLs.

Table B-1
Comparing UCL Soil Sample Analytical Result with Livestock Soil Ingestion SSTLs

	Results Compared with Soil SSTLs (mg/kg)						
	Crude Oil	Benzene	Toluene	Ethylbenzene	Xylene	LMW PAH	HMW PAH
Soil Sample	25,600	256	521	108	470	51	33
Goat RBSL	141,000	7,860	49,000	6,420	39,300	1,100	220
Horse RBSL	225,000	6,050	37,800	4,940	30,300	848	170
No Exceedances							

No further action is required for the livestock incidental soil ingestion exposure pathway because the SSTLs were not exceeded.

What if chemicals other than hydrocarbons (including BTEX and PAHs) are released?

This report focused on whole crude oil and its toxicologically important constituents (i.e., benzene, toluene, ethylbenzene, toluene [BTEX], and polycyclic aromatic hydrocarbons [PAHs]). Other chemicals, such as metals, can also be present in crude oil but are generally not found at high enough concentrations to provide a significant human health and ecological risk (Magaw et al., 1999).

Thus, metals were not addressed in API (2004). However, risks to livestock from metal exposure can be evaluated using a similar approach to that described on page 10 **"How are Livestock RBSLs Calculated?"** Toxicity values and RBSLs can be developed for metals to estimate potential risks to livestock using a similar approach to that described for petroleum hydrocarbons in API (2004).

WEB Exhibit # 18-j

How are Livestock RBSLs Calculated?

Livestock screening levels are risk-based and are developed based on the standard hazard quotient (HQ) equation used for estimating risks to human health and other ecological receptors (EPA 1997).

$$HQ = \frac{Dose}{TRV} \qquad \text{(Equation 1a)}$$

where:

TRV = Toxicity reference value in milligrams per kilogram body weight per day (mg/kg-bw/day)
Dose = estimated daily dose of petroleum related hydrocarbons from ingestion (mg/kg-bw/day); and calculated using the following equation:

$$\frac{[(IRsoil \times Csoil) + (IRwater \times Cwater)] \times SUF}{BW} \qquad \text{(Equation 1b)}$$

where:

IR_{soil} = amount of soil incidentally ingested per day in dry weight (kg/day)
IR_{water} = amount of water ingested per day (L/day)
C_{soil} = concentration of constituent in soil or sediment (mg/kg dry weight)
C_{water} = concentration of constituent in water (mg/L)
SUF = site use factor (unitless)
BW = body weight (kg)

Substituting Equation 1b for "Dose" in Equation 1a:

$$HQ = \frac{[(IRsoil \times Csoil) + (IRwater \times Cwater)] \times SUF}{BW \times TRV} \qquad \text{(Equation 1c)}$$

or

$$HQ = \frac{(IR \times C) \times SUF}{BW \times TRV} \qquad \text{(Equation 1d)}$$

To calculate RBSLs for a single medium (i.e., drinking water or soil), Equation 1d should be rearranged as shown in Equations 2a and 2b. Instead of estimating a HQ associated with a chemical concentration in water or soil and using the toxicity and exposure assumptions presented in Table 1 of the technical background report (API 2004), Equations 2a and 2b estimate a protective drinking water or soil concentration associated with a target HQ of 1.

Assuming target HQ = 1, SUF = 1, and rearranging Equation 1d, "C" becomes defined as the corresponding RBSL.

WEB Exhibit # 18 - K

Drinking-water RBSLs for livestock were calculated using the following equation:

$$dwRBSL = \frac{1 \times BW \times TRV}{IRwater} \qquad \text{(Equation 2a)}$$

where:

1	=	target hazard quotient; unitless
dwRBSL	=	drinking water RBSL in milligrams per liter (mg/L)
IR_{water}	=	water ingestion rate in liters per day (L/day); to be conservative, the summer IRwater value from Table 1 is used
BW	=	Body weight in kilograms (kg)
TRV	=	Toxicity reference value in milligrams per kilogram body weight per day (mg/kg-bw/day)

Incidental soil ingestion RBSLs for livestock were calculated using the following equation:

$$soilRBSL = \frac{1 \times BW \times TRV}{IRsoil} \qquad \text{(Equation 2b)}$$

where:

1	=	target hazard quotient; unitless
soilRBSL	=	soil RBSL in milligrams per kilogram dry weight (mg/kg)
IR_{soil}	=	soil ingestion rate in kilograms per day (kg/day)
BW	=	body weight in kilograms (kg)
TRV	=	toxicity reference value in milligrams per kilogram body weight per day (mg/kg-bw/day)

The TRVs developed in API (2004) are summarized as follows:

	Soil Risk-Based Screening Levels (RBSLs; mg/kg)						
Livestock	Crude Oil	Benzene	Toluene	Ethylbenzene	Xylene	LMW PAH	HMW PAH
Dairy Cattle	211	5.70	35.6	4.65	28.5	0.798	0.160
Beef Cattle	211	5.95	37.1	4.86	29.8	0.833	0.167
Calves	211	10.30	64.5	8.43	51.7	1.450	0.289
Sheep	211	10.00	62.5	8.17	50.1	1.400	0.280
Goats	211	11.80	73.6	9.62	58.9	1.650	0.330
Camels	211	5.55	34.6	4.53	27.8	0.777	0.155
Horses	211	5.67	35.4	4.63	28.4	0.794	0.159

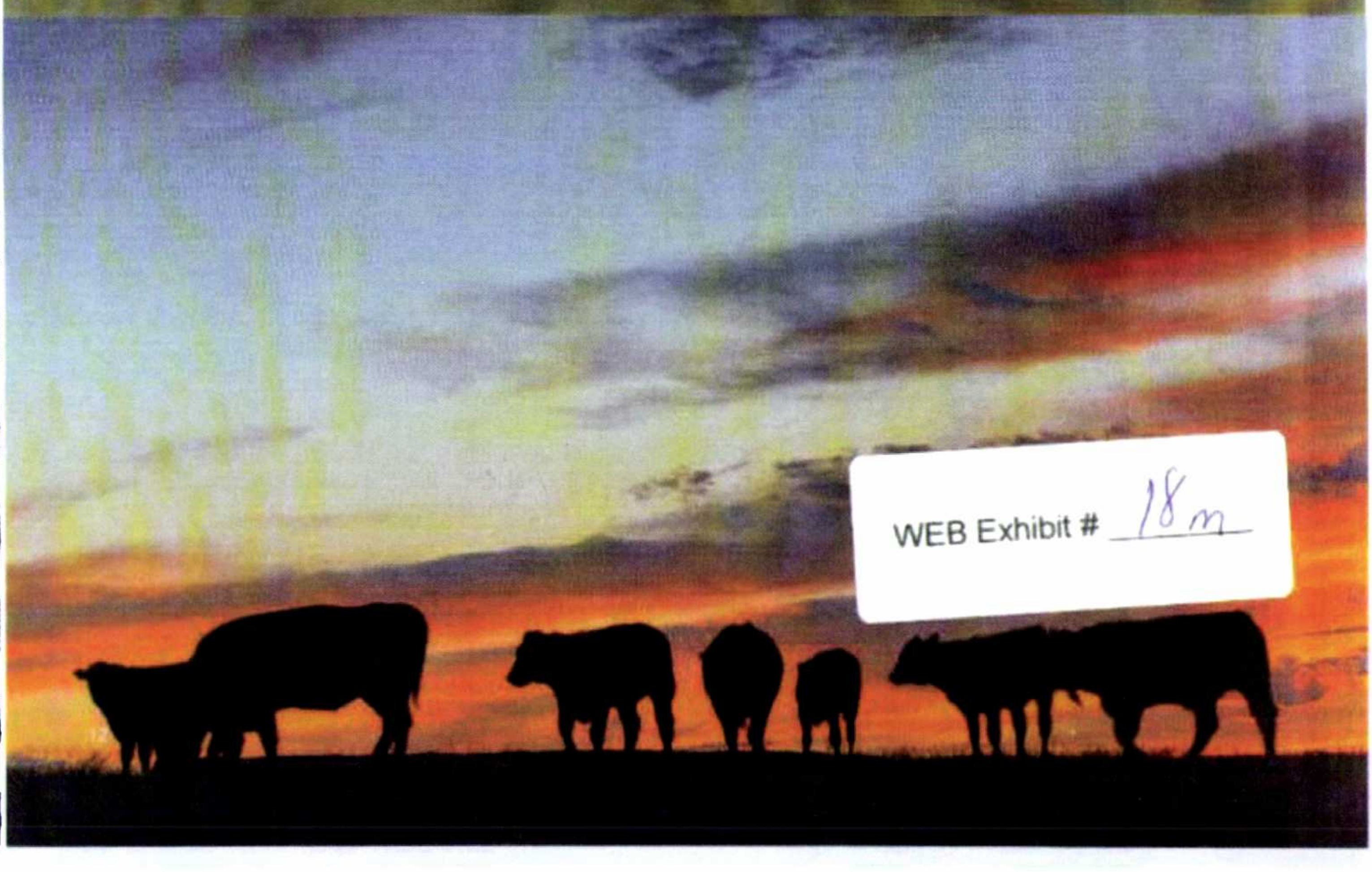
WEB Exhibit # 18 b

How do livestock RBSLs compare to human health RBSLs?

The toxicity values and guidelines for crude oil developed by API (2004) for soil ingestion in livestock are comparable to the recommended human health RBSLs for sites affected with crude oils. The suggested RBSLs for human residential and non-residential scenarios are the 95th percentile values (for all exposure pathways) of 2,800 mg/kg and 41,300 mg/kg, respectively (McMillen et al., 2001). Similarly, a comparable TPH screening level of 10,000 parts per million (ppm) is generally accepted as protective of plants (Hamilton et al., 1999).

How do API livestock RBSLs differ from levels calculated by other groups?

TRVs, drinking water and soil screening levels for the protection of livestock exposed to petroleum compounds have been developed by two agencies, the Canadian Council of Ministers of the Environment (CCME) and Alberta Environment. Differences between calculated API and Canadian screening levels result from selection of constituents and guidelines considered, calculation errors, and the Canadian agencies' use of uncertainty, "protection," and "allocation" factors. Differences among the Canadian guidelines (including constituents and guidelines considered) and their limitations are described in the text box "CCME Canada-Wide Standards (CWS; CCME 2000) and Alberta Environment (2001)."



WEB Exhibit # 18m

CCME Canada-Wide Standards (CWS; CCME 2000) and Alberta Environment (2001)

The Canada-Wide Standards for petroleum hydrocarbons present TRVs (referred to as Daily Threshold Effects Dose" or DTED) and drinking water RBSLs (referred to as "ReferenceConcentration" or RfC) for only whole oil and four fractions of crude oil (CCME 2000). These guidelines present levels that CCME considers protective under four generic land uses: agricultural, residential, commercial, and industrial. TRVs for livestock were developed based on Stober (1962), in an approach similar to that used by API. CCME and API used a similar approach to calculate drinking water RBSLs as well. However, a calculation error by CCME resulted in an order of magnitude, lower drinking-water screening level than that developed by API.

Alberta Environment set water RBSLs (referred to as "watering guidelines") and soil RBSLs (referred to as "soil quality guidelines" or SQG) for petroleum hydrocarbons (crude oil fractions and BTEX) considered to be protective of livestock health (Alberta Environment 2001*a*; 2001*b*). Crude oil TRVs for livestock were adopted from CCME. For BTEX, TRVs were developed using an approach similar to that described in API (2004). Soil and water RBSLs reflect exposure parameters and "other" protection factors specific to Alberta.

CCME and Alberta Environment toxicity values and guidelines are presented in Table 8 of API (2004).

Differences between the CCME and Alberta Environment and the API approach as well as limitations to these approaches are summarized below:

Differences/Limitations	CCME Canada Wide Standards	Alberta Environment
TRV Development	TRVs for whole oil and four crude oil fractions were developed.	Crude oil TRVs were adopted from CCME. BTEX TRVs were developed.
Chemical Constituents	Only drinking water screening levels for whole oil and four crude oil fractions were developed for one livestock receptor (cattle).	Added soil and drinking water screening levels for BTEX and PAHs and soil screening levels for crude oil for one livestock receptor (cattle).
Uncertainty and Other Factors	An allocation factor (AF) of 0.2 was used to adjust toxicity values to account for multiple exposure pathways and media (air, soil, water, food, and consumer products), whereas the guideline values are for single pathways. The AF of 0.2 assumed that livestock can be equally exposed by all five potentially complete exposure pathways. However, dermal and inhalation pathways are expected to be minor. Additionally, not all sites will have both water and soil exposures. This likely results in an overly conservative RBSL.	In addition to the use of an AF of 0.2, a protection factor of 0.75 was used to prevent livestock from being exposed to more than 75% of the TRV. This is likely overly conservative.
Fractionation Approach	The fractionation approach used by CCME is not necessarily applicable or appropriate at all sites. *	The fractionation approach used by CCME and carried over by Alberta Environment is not necessarily applicable or appropriate at all sites.*
Additional Guidelines Developed	None	Two types of water quality guidelines were developed: *exposure point guidelines* for water to which receptors are actually exposed and *groundwater quality guidelines* to assess acceptable concentrations of chemicals in groundwater were also developed using fate and transport models.
Mathematical Errors	There was an order of magnitude error in calculating the RfC value by CCME; the RfC value should actually be 231 mg/L instead of 23 mg/L (this error was acknowledged by CCME; personal communication with Ted Nason September 10, 2002).	The error in the CCME RfC calculation is propagated in the Alberta Environment document.

* In this report, a toxicity value was developed for whole (i.e. fresh) crude oil. As fresh crude oil is more toxic than weathered oil, these values can be considered conservative screening values for weathered products.

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WEB Exhibit # 18N

Glossary

Chronic exposure: A long-term contact between a receptor and a chemical that could result in a sub-lethal or permanent adverse effect.

Conceptual site model (CSM): A written description and/or visual representation of predicted relationships between receptors and the chemicals and/or stressors to which they may be exposed.

Exposure pathway: How a receptor comes in contact with a chemical and/or media.

Exposure point concentrations (EPC): The concentration of a chemical that a receptor is exposed to over a chronic exposure period.

Hazard quotient (HQ): The chemical-specific ratio of the dose to the toxicity value.

Receptor: The species, population, community, habitat, etc. that may be exposed to a chemical.

Risk: The likelihood of a harmful effect to a receptor based on the existence and magnitude of a hazard and exposure of the receptor to the hazard.

Risk assessment: A method to evaluate the potential adverse effects of chemicals or other stressors on receptors.

Risk-based screening levels (RBSLs): Chemical-specific concentrations in environmental media that are considered protective of health. Usually they are derived from the generally accepted risk equations by specifying an acceptable target risk level and rearranging the equations to determine the chemical concentration in the environmental medium of interest that achieves this risk level.

Site-specific target levels (SSTLs): RBSLs calculated using site-specific values rather than generally accepted defaults.

Toxicity reference value (TRV): A dose of a chemical at or above which a toxic response occurs in the receptor.

WEB Exhibit # 18-O

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WEB Exhibit # 18-9

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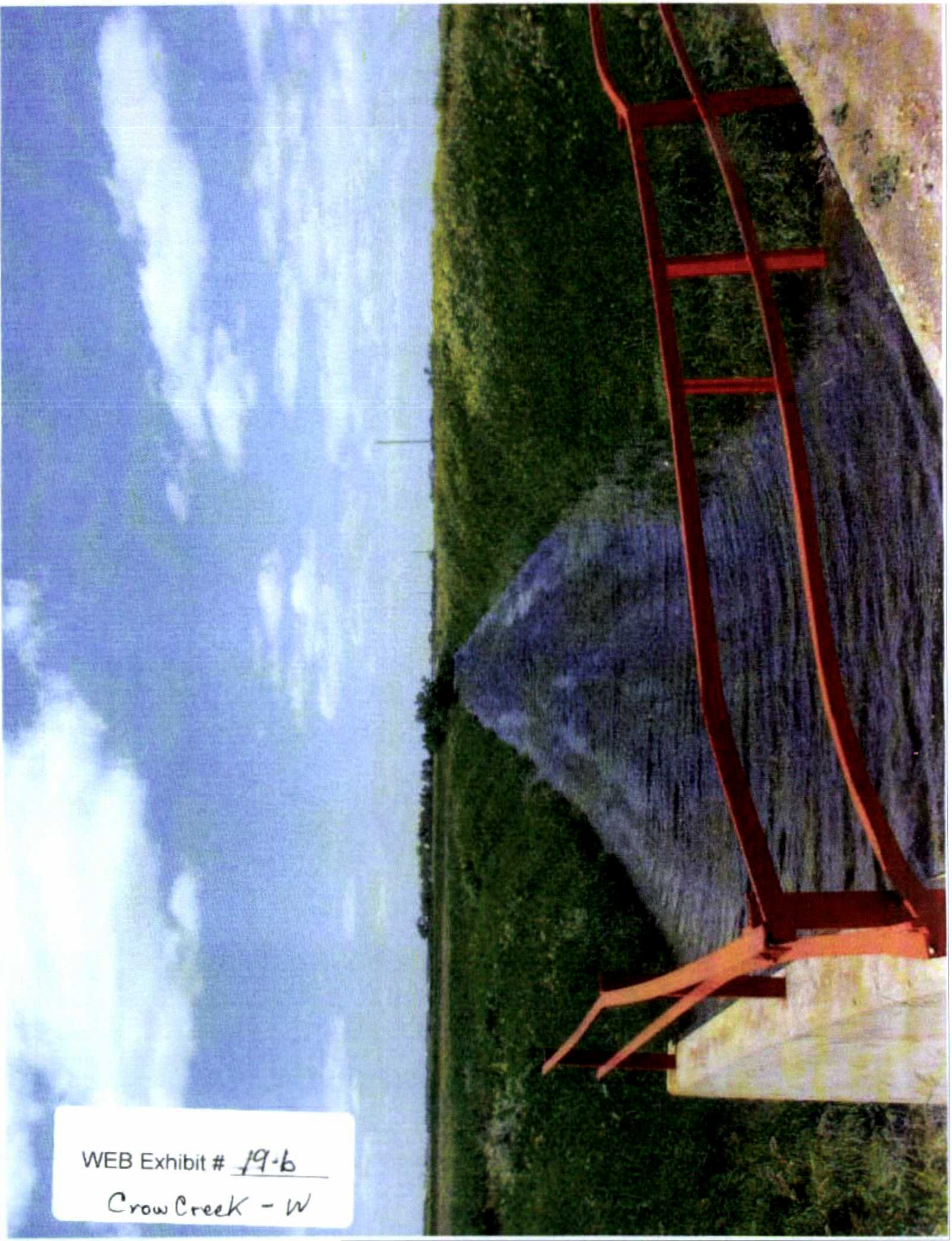
WEB Exhibit # 19

WEB Exhibit # 19 a



WEB Exhibit # 19-b
Crow Creek - W

WEB Exhibit # 19-c

Crow Creek Drain - N

American News

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Our Voice

TransCanada should slow down process

Slow down and give us some respect.

This is our message to TransCanada officials.

TransCanada wants to build a 1,830-mile pipeline that would haul crude oil from Hardisty, Alberta, Canada, to Patoka, Ill., and, eventually, Cushing, Okla. The $2.1 billion project would cut through the very western parts of Marshall and Day counties in northeast South Dakota. TransCanada wants to start work next year and have the pipeline finished by late 2009.

In July, we said the proposed TransCanada pipeline was a good idea and that it deserved public support. Our reasoning went something like this: Though in the wide spectrum of things one new pipeline is a small piece of the modern oil industry picture, we should remember that building a new pipeline is one way of increasing the infrastructure of the U.S. oil industry and decreasing our reliance on Mideast oil.

We also said that there were concerns ranging from environmental to quality of life and many, many areas in between. We hoped that the concerns would be thoroughly addressed and resolved.

That didn't happen. Instead, TransCanada began pushing its plan through the state like the proverbial bull in the china closet.

Though we still support the overall purpose of the project, we have a problem with the way it is being implemented — and the way in which state and company officials are handling it.

First, company officials announced that TransCanada would be using a different type of pipeline than was originally planned; a less expensive, thinner pipe — with a slightly lower safety factor.

Company officials claim there are never any problems, and that citizens shouldn't worry. Well, pat answers that include words like "never" and "always" have a tendency to throw up red flags — and they should.

This is all perfectly legal and as been approved by the federal Pipeline and Hazardous Materials Safety Administration, but it still begs the question: Why? Was South Dakota chosen because we are a rural, relatively poor, sparsely populated state that wouldn't put up too much of a fight?

Here's another concern: State officials have been uncharacteristically quiet about this whole process — and not nearly as protective of the interests of this state's citizens and environment as they should be. We are not aware of a single state official who publicly questioned the lower quality pipe.

And then there is the issue of eminent domain. South Dakota hasn't even officially approved the pipeline yet, and TransCanada is already pushing eminent domain lawsuits on landowners who are reluctant to give permanent easements for the pipeline to go under their land.

Many South Dakotans would like to see TransCanada pursue the I-29 bypass option. But a project consultant said TransCanada never considered running the pipeline down the Interstate 29 corridor because such a route wouldn't be allowed for safety reasons.

So we are just supposed to ignore safety considerations, sign the easements and pray everything goes OK, because TransCanada says so? We think not.

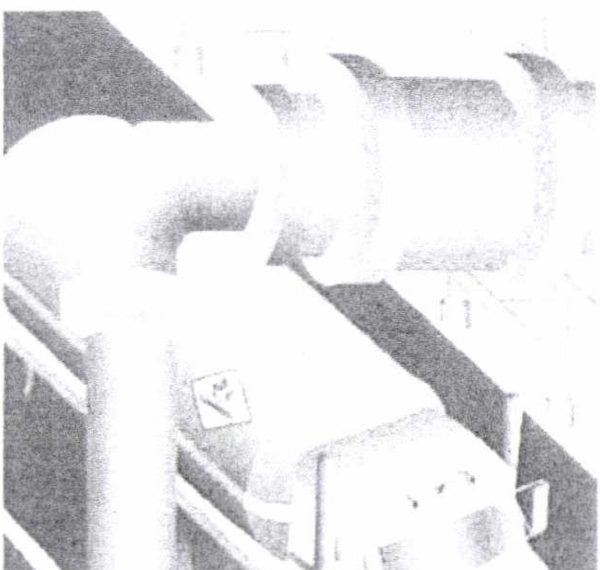
Maybe what TransCanada really needs right now is a good public relations firm to address the issues, not lawyers to file lawsuits.

And what South Dakotans need right now are state officials who are willing to step up to the plate to make sure the state's interests are protected.

South Dakotans need — and deserve — more respect and consideration than this company is giving. South Dakotans also need — and deserve — more support and advocacy than we are getting from our state officials.

WEB Exhibit # 20

Rupture of Enbridge Pipeline and Release of Crude Oil near Cohasset, Minnesota July 4, 2002



Pipeline Accident Report

NTSB/PAR-04/01

PB2004-916501
Notation 7514A

WEB Exhibit # 21

Pipeline Accident Report

Rupture of Enbridge Pipeline and Release of Crude Oil near Cohasset, Minnesota July 4, 2002

WEB Exhibit # 21 A

NTSB/PAR-04/01
PB2004-916501
Notation 7514A
Adopted June 23, 2004

National Transportation Safety Board
490 L'Enfant Plaza, S.W.
Washington, D.C. 20594

BY THE NATIONAL TRANSPORTATION SAFETY BOARD

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Vice Chairman

JOHN J. GOGLIA
Member

CAROL J. CARMODY
Member

RICHARD F. HEALING
Member

Adopted: June 23, 2004

WEB Exhibit # 21B

Chairman Ellen Engleman Conners did not participate in the adoption of this report.

Executive Summary

About 2:12 a.m., central daylight time, on July 4, 2002, a 34-inch-diameter steel pipeline owned and operated by Enbridge Pipelines, LLC ruptured in a marsh west of Cohasset, Minnesota. Approximately 6,000 barrels (252,000 gallons) of crude oil were released from the pipeline as a result of the rupture. The cost of the accident was reported to the Research and Special Programs Administration Office of Pipeline Safety to be approximately $5.6 million. No deaths or injuries resulted from the release.

The National Transportation Safety Board determines that the probable cause of the July 4, 2002, pipeline rupture near Cohasset, Minnesota, was inadequate loading of the pipe for transportation that allowed a fatigue crack to initiate along the seam of the longitudinal weld during transit. After the pipe was installed, the fatigue crack grew with pressure cycle stresses until the crack reached a critical size and the pipe ruptured.

The following safety issues were identified during this investigation:

- The effectiveness and application of line pipe transportation standards.
- The adequacy of Federal requirements for pipeline integrity management programs.

As a result of its investigation of this accident, the Safety Board issues safety recommendations to the Research and Special Programs Administration, the American Society of Mechanical Engineers, and the American Petroleum Institute.

WEB Exhibit # 21C

Factual Information

Accident Synopsis

About 2:12 a.m., central daylight time, on July 4, 2002, a 34-inch-diameter steel pipeline owned and operated by Enbridge Pipelines (Lakehead), LLC[1] ruptured in a marsh west of Cohasset, Minnesota. (See figure 1.) Approximately 6,000 barrels (252,000 gallons) of crude oil were released from the pipeline as a result of the rupture. No deaths or injuries resulted from the release.

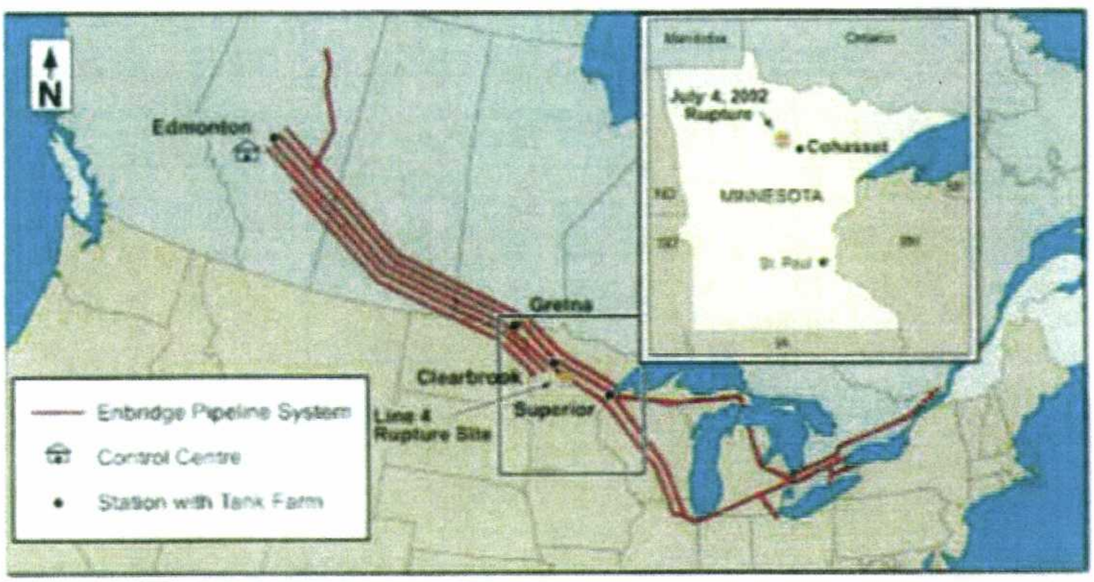

Figure 1. Enbridge pipeline system.

Accident Narrative

The crude oil pipeline involved in the accident originated at Edmonton, Alberta, Canada, and terminated at Superior Terminal in Superior, Wisconsin. The 34-inch-diameter pipeline, designated line no. 4 at the time of the accident, was operated by pipeline controllers in the Enbridge control center in Edmonton using a supervisory control and data acquisition (SCADA) system.[2] About 2:12 a.m. on July 4, 2002, the

[1] Enbridge Pipelines (Lakehead), LLC is the operator of the pipeline system formerly named Lakehead Pipe Line Company.

[2] Pipeline controllers use a computer-based SCADA system to remotely monitor and control movement of oil through pipelines. The system makes it possible to monitor operating parameters critical to pipeline operations, such as flow rates, pressures, equipment status, control valve positions, and alarms indicating abnormal conditions.

WEB Exhibit # 22

controller operating the line observed a SCADA system indication of a loss of suction and discharge pressure at the Deer River pump station. (See figure 2.) At 2:13 a.m., the Floodwood pump station suction pressures began dropping, and then audible and visual alarms were received for an invalid suction pressure. The controller initially suspected an inaccurate pressure transmitter at Floodwood, because the suction pressure had gone to zero. Subsequently, he noticed that the discharge pressure for Floodwood was also dropping and realized that he had an abnormal condition. The controller showed the shift coordinator the situation, and, suspecting a possible leak, they agreed at 2:14 a.m. to shut the pipeline down. At 2:15: a.m., the controller initiated closure of the pipeline injection valve at the Clearbrook Terminal and began shutting down pumps and remotely closed valves to isolate the suspected leak. The upstream valve at Deer River and the downstream sectionalizing valve at milepost (MP) 1017.9 were remotely closed by 2:21 a.m., which isolated the ruptured section. All remotely controlled valves on the pipeline from Clearbrook to Superior Terminal were closed by 2:32 a.m.

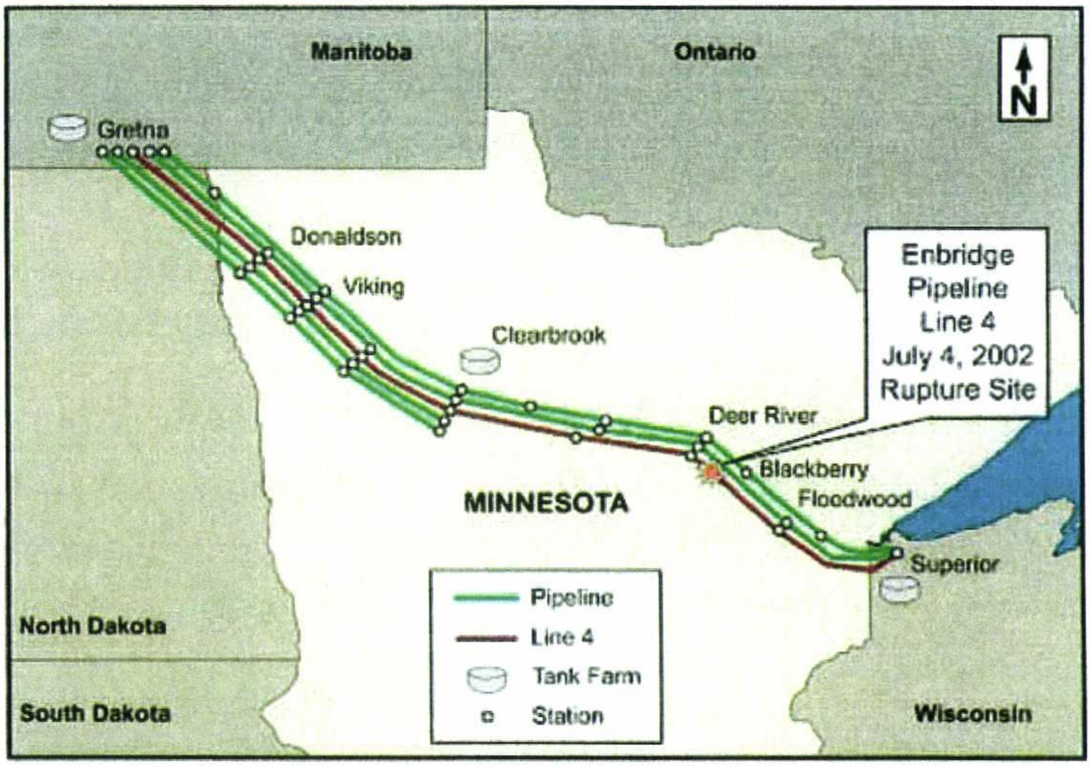

Figure 2. Enbridge pipeline facilities and rupture site.

About 2:25 a.m., the Enbridge control center notified the Deer River and Floodwood police departments of the suspected leak, and about 2:30 a.m., Enbridge field personnel were notified. About 5:20 a.m., Enbridge field personnel dispatched to investigate along the pipeline right-of-way detected the odor of crude oil in a marshy area near Blackwater Creek and manually closed the closest valve to the failure. This valve was near MP 1007.32, about 4 1/2 miles downstream (east) of the rupture

WEB Exhibit # 23

At 7:00 a.m., after Enbridge field employees verified the release, Enbridge notified the National Response Center of a crude oil leak in the company's 34-inch pipeline. This notification indicated that an unknown amount of crude oil had been released. The pipe was found to have ruptured at MP 1002.73, about 7 miles downstream of the Deer River pump station. The company then contacted local, State, and Federal officials, as well as Enbridge spill response contractors, who proceeded to the spill site. Enbridge also had right-of-way representatives contact landowners in the vicinity of the spill. At 12:09 p.m., Enbridge called the National Response Center again and updated the spill volume to 6,000 barrels of crude oil. At the time of the accident, Enbridge had not designated the area where the rupture occurred as a high-consequence area[3] based on the criteria defined in 49 *Code of Federal Regulations* (CFR) Part 195, "Transportation of Hazardous Liquids by Pipelines."

Emergency Response

Booms were placed in Blackwater Creek as a precaution to prevent crude oil from moving away from the spill site toward nearby waterways, including the Mississippi River. Enbridge started building a 1/4-mile-long road along the right-of-way to the spill site using wood mats. With heavy rain forecast, responders were concerned that the crude oil might spread farther and contaminate the Mississippi River. The unified command for the accident response was established and included the Cohasset Fire Department, Enbridge, the Minnesota Pollution Control Agency, the Minnesota Department of Emergency Management, and the Forestry Division of the Minnesota Department of Natural Resources.

The unified command decided that the best way to prevent the crude from entering nearby waterways was to perform a controlled burn. As a precaution, the command designated 12 homes in the local area to be evacuated, and seven residents were evacuated. Later in the afternoon, the Minnesota Department of Natural Resources coated the spill's perimeter with chemical fire retardant from tanker planes. After the chemical was placed, flares were shot into the crude oil to ignite the oil.

The controlled burn was ignited about 4:45 p.m. (See figure 3.) The burn created a smoke plume about 1 mile high and 5 miles long. (See figure 4.) The controlled burn lasted until about 5:00 p.m. the next day, July 5. While they monitored the fire, Enbridge personnel, firefighters, and environment authorities also monitored the spill perimeter to ensure that no crude was getting into area waterways. Reportedly, no free-flowing product reached any of the boomed areas.

[3] *High-consequence area* refers to commercially navigable waterways, high population areas, concentrated population areas, or unusually sensitive areas that might be affected by an accident involving the pipeline in that area. Title 49 CFR 195.450, 195.452, and 195.6 contain the criteria for designating an area a high-consequence area for hazardous liquid pipelines.

WEB Exhibit # 24

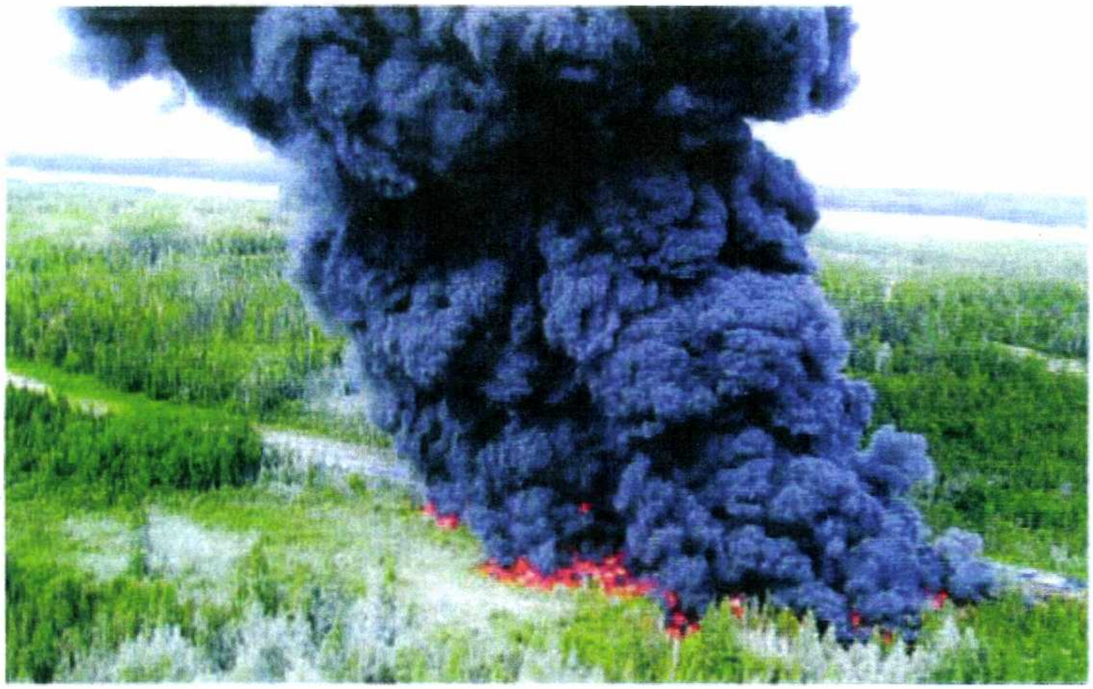

Figure 3. Controlled burn surrounded by white fire retardant.

Figure 4. Smoke plume 1 mile high and 5 miles long.

WEB Exhibit # 25

inch of the 0.297-inch measured wall thickness.[7] Measurement and testing of the pipe showed that it met thickness and strength requirements. The pipe fracture beyond the fatigue crack contained features typical of overstress fracture.

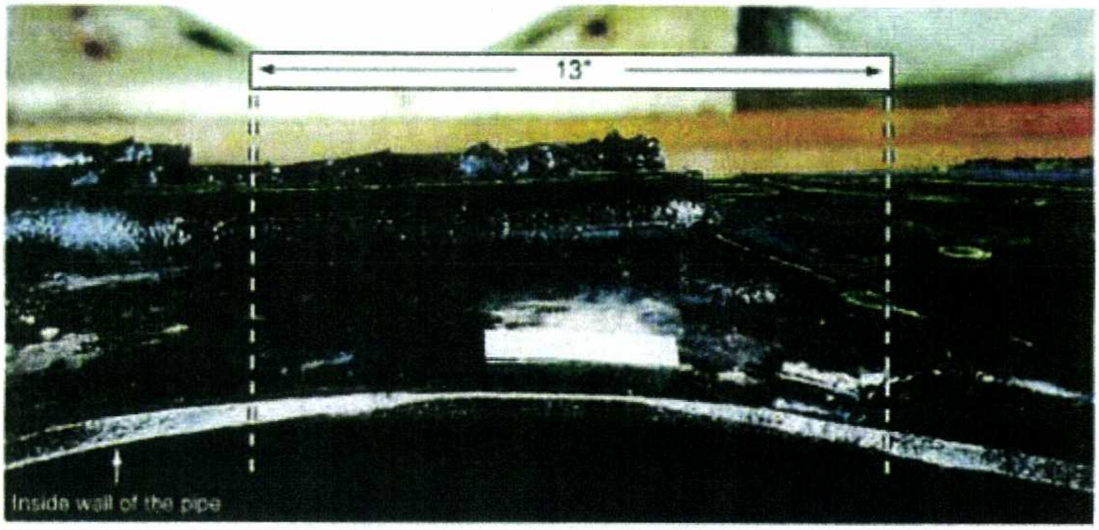

Figure 6. View of top fracture surface of 13-inch-long crack, showing penetration nearly through pipe wall in center.

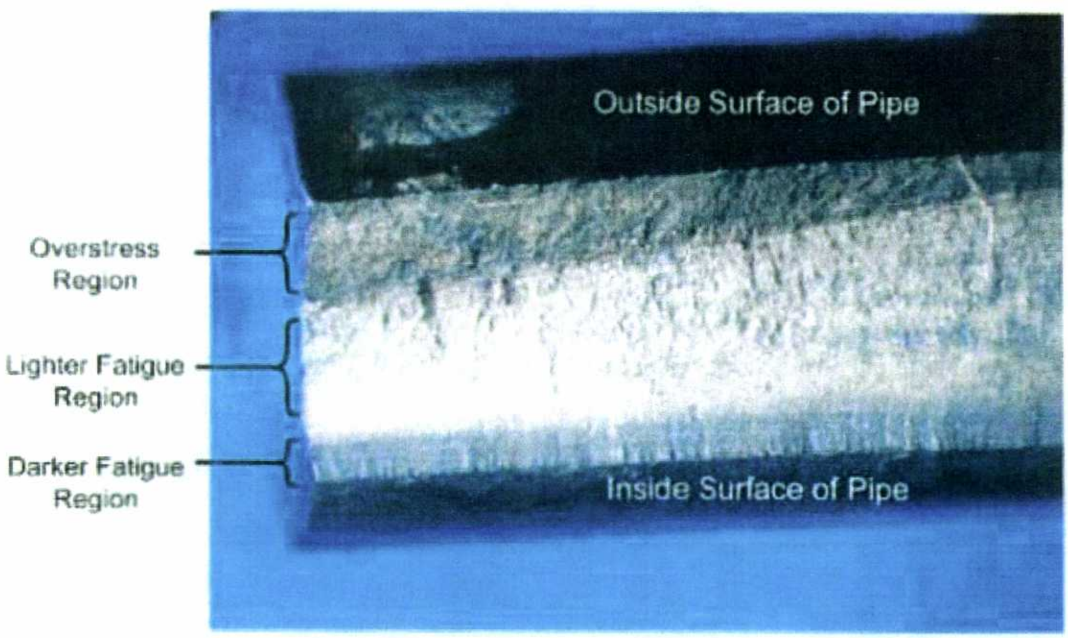

Figure 7. Face of fracture in accident pipe.

[7] The 0.297-inch measured wall thickness is within the allowable range for a pipe with 0.312-inch specified nominal wall thickness.

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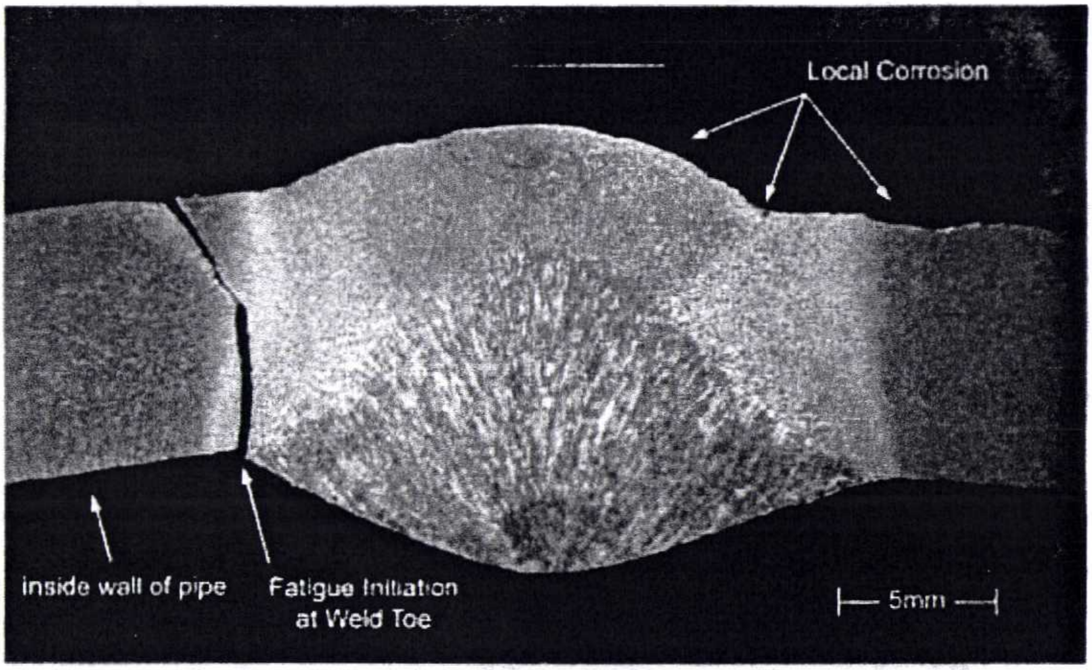

Figure 8. Fatigue initiating at toe of weld on interior surface of pipe.

Preaccident Events

Fatigue Cracking in Enbridge Pipe Manufactured by U.S. Steel

Enbridge's 34-inch U.S. Steel DSAW pipe had a documented history of longitudinal seam weld failures due to fatigue cracks. Metallurgical analysis reports of longitudinal seam weld failures in Enbridge's U.S. Steel pipe in 1974, 1979, 1982, 1986, 1989, and 1991 identified the causes as fatigue cracking at the toe of the weld. Enbridge's 34-inch pipeline system also used A.O. Smith flash-welded pipe, Canadian Phoenix electric resistance welded pipe, and Kaiser Steel submerged arc welded (SAW) pipe. All of the longitudinal seam weld failures caused by fatigue cracks in this pipeline have occurred in pipe manufactured by U.S. Steel.

Operational Reliability Assessments of the Pipeline

After the 1991 pipe rupture at the toe of the weld in the 34-inch pipeline resulted in the release of 40,500 barrels (1,701,000 gallons) of crude oil, Enbridge signed a consent order with RSPA's Office of Pipeline Safety to conduct an operational reliability assessment of the 34-inch pipeline from Gretna, Manitoba, Canada, to Superior, Wisconsin. The assessment was to include a review of pipeline operating conditions and an analysis of the previous pipe failures. The operator was also required to restrict

WEB Exhibit # 27

The D/t ratios that could lead to fatigue cracking during transportation were changed in the 1990 edition of API RP 5L1. The ratio was reduced from 70:1 to 50:1 because fatigue cracking had been reported in pipe with D/t ratios lower than 70:1. The latest edition of API RP 5L1, issued in July 2002, also states that pipe with D/t ratios well below 50:1 may suffer fatigue in transit under some circumstances.

No statistics on transportation damage were specifically tracked before RSPA instituted a change in 2002 to gather more detailed accident statistics. However, RSPA is now gathering information on whether an accident is caused by pipe damage sustained during transportation and whether the failure is a longitudinal tear or crack.

Railroad Transportation of Accident Pipe

The section of pipeline where the rupture occurred was constructed in 1967. The Enbridge 1966 purchase specification for the pipe included a requirement that pipe loading details be provided subject to its approval. In its quotation, U.S. Steel provided a diagram for railroad car loading (see figure 9), which Enbridge subsequently approved. The railcar loading instructions consisted of a drawing with notes specifying the blocking supports and banding to be used under and around the pipe and the required positioning of the longitudinal weld. U.S. Steel also noted in its specifications that the purchaser would spot-check railcar loadings at the mill before transportation. U.S. Steel transported the pipe by railcar to its storage facility near the mill, where it was unloaded and stored. Later, U.S. Steel loaded the pipe for transportation by rail. Finally, the pipe was loaded on trucks for transportation to the construction sites.[17] Enbridge had arranged with Moody Engineering Company (Moody) to inspect the manufacturing of the pipe. The handling and loading of the pipe for transportation from the mill to storage was a part of that inspection. These activities were summarized in Moody's final report. The Moody report indicates that the pipe was periodically inspected at a nearby storage facility to ensure that the pipe was being handled and unloaded with care. The report indicates that the pipe was accepted for shipment subject to the operator's shipping instructions. U.S. Steel did not document inspections of pipe loading. No records were found to indicate that the engineering company or the pipeline operator inspected the loading of the pipe on railroad cars for transportation from the U.S. Steel storage facility.

[17] Records related to the production activities at U.S. Steel's McKeesport pipe mill were destroyed several years ago after the mill was closed for a period of time.

WEB Exhibit # 28

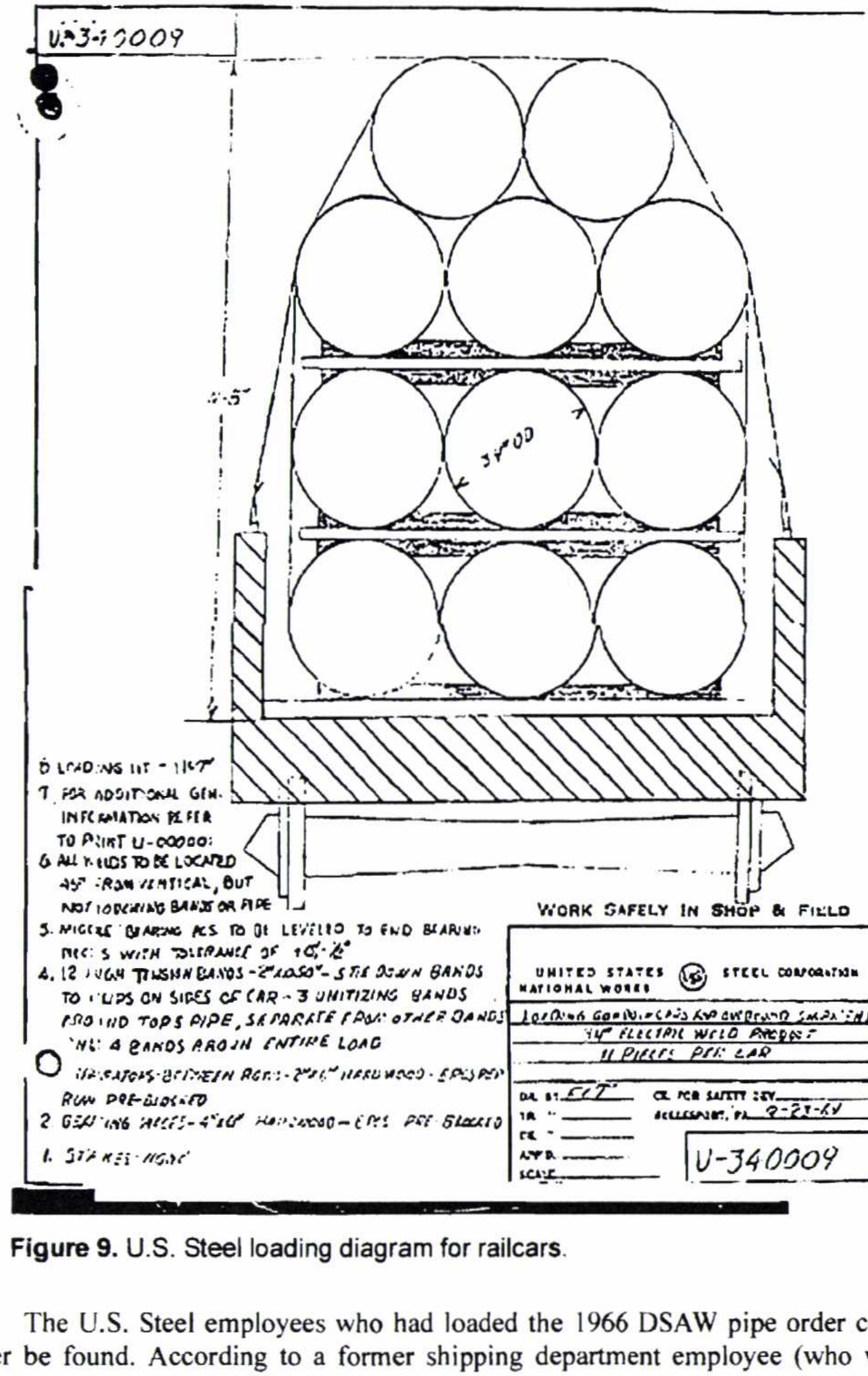

Figure 9. U.S. Steel loading diagram for railcars.

The U.S. Steel employees who had loaded the 1966 DSAW pipe order could no longer be found. According to a former shipping department employee (who was not present at the time of the Enbridge pipe loading), a typical pipe loading practice before and after this pipe order was to position the longitudinal weld at the 2, 4, 8, or 10 o'clock position so the pipe weld would not touch lumber, bands, or other pipe. If a 40-foot joint

WEB Exhibit # 29

of pipe was not loaded in this position, it was to be rotated as necessary to attain one of these positions. Except for the loading diagram, there were no written procedures for loading pipe, nor did U.S. Steel use checklists or other methods to confirm that the pipe was loaded according to specifications.

U.S. Steel does not currently manufacture DSAW or SAW pipe. U.S. Steel Tubular Products does produce seamless and electric resistance weld pipe, and the current loading procedures for the pipe are described in the company's *Pack, Mark, and Load Manual.* The procedures to be used for each order are entered into the order entry system from the purchase order and are designated on the mill order sent to the production mill. All pipe manufactured to API standards and destined for railroad transportation from the pipe mill is to be loaded to the requirements of the Association of American Railroads' *Open Top Loading Rules Manual*[18] and the supplementary recommended practices in API RP 5L1. Any additional transportation requirements are referenced in the mill order for the shipping department personnel and, if applicable, are attached to the mill order. A preproduction meeting is held at the mill to review the order and shipment requirements.

At pipe mills currently producing tubular products for U.S. Steel, shipping department workers are trained in the department's standard operating procedures. The group leader in the loading area discusses the loading requirements for each order with the crew. A load tally sheet is created that shows the length of each pipe joint with the referenced heat number for the material. The yard foreman checks the railcars periodically to confirm that the pipe is loaded according to the written requirements.

Before 1991, Enbridge specified that the manner of loading pipe for rail transportation should be provided in the pipe manufacturer's quotation, which was subject to Enbridge's approval. Currently Enbridge includes the use of API RP 5L1 in its specification for purchase of pipe transported by rail from a pipe mill. Enbridge also inspects the pipe during loading at the pipe mill to confirm that the requirements of API RP 5L1 are being met.

Safety Board Materials Laboratory Study

The Safety Board performed a finite element study of the U.S. Steel loading practice to determine the static stresses in pipe loaded for rail transportation. The study showed that the peak circumferential tensile stresses would have been highly localized to the areas in contact with the bearing and separator strips and that the stresses would have occurred at the inner surface of the pipe.

The length of the fatigue crack in this accident was similar to the length over which the peak circumferential tensile stress was predicted in the finite element model, and the fatigue crack initiated at the inner surface of the pipe. The finite element model

[18] The Association of American Railroads' *Open Top Loading Rules Manual* includes Section 1, General Rules Manual for Loading all Commodities, and Section 2, Loading Metal Products Including Pipe.

WEB Exhibit # 30

indicated that the circumferential tensile stresses decreased rapidly away from the bearing or separator strips. Aligning the welded seams at 45° to the vertical results in very small levels of circumferential tensile stress at the welds during transport. (See figure 10.) The results of the finite element model also indicate that aligning the welds at the 2, 4, 8, or 10 o'clock positions instead of exactly 45° from vertical does not increase the stress levels significantly.

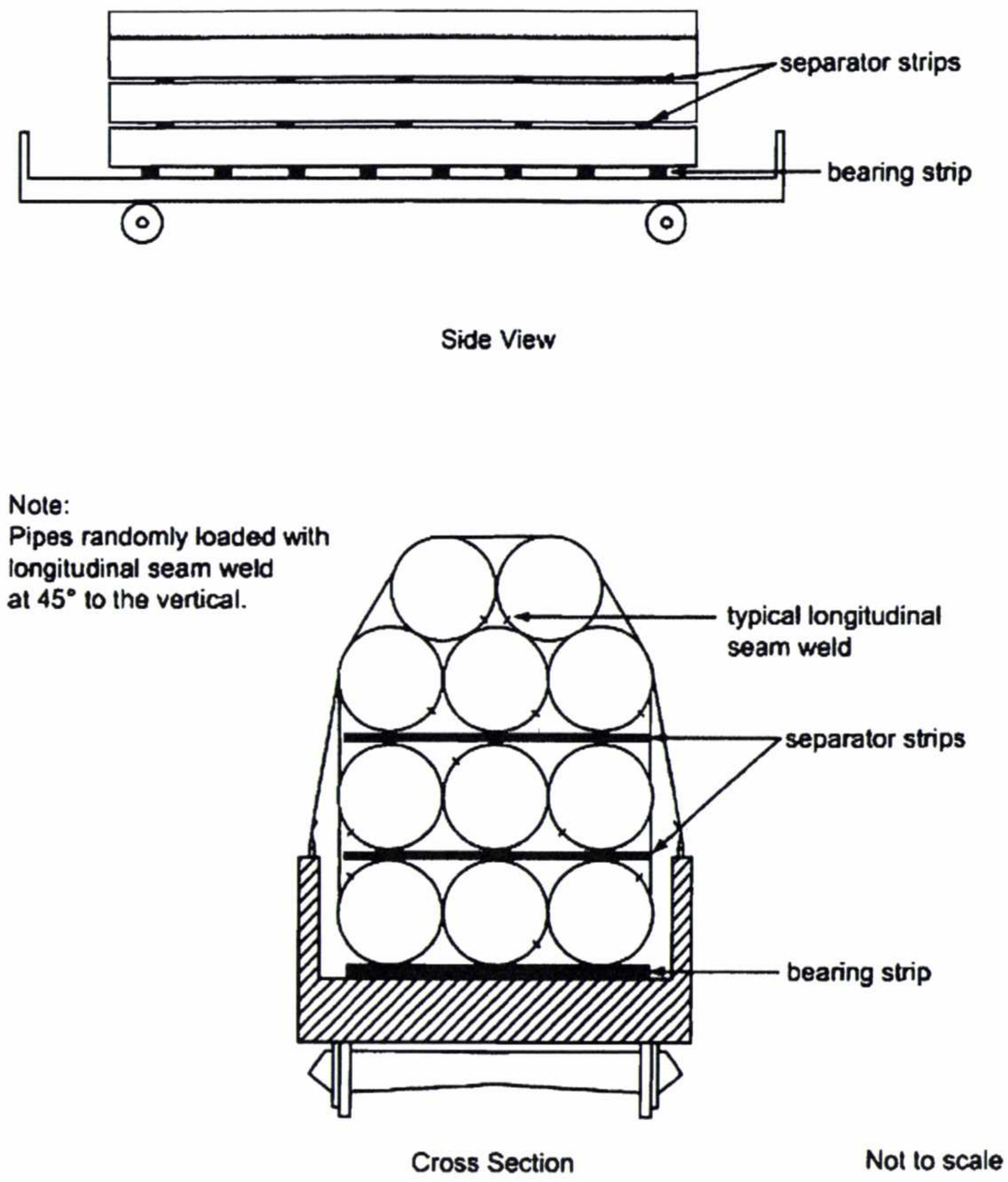

Figure 10. Typical pipe configuration on railroad car.

WEB Exhibit # 31

The Safety Board also studied API loading practices for rail transportation to determine the static stresses in pipe loaded for transportation. API RP 5L1 provides an equation for calculating the peak circumferential tensile stress in a pipe at a bearing strip as a function of the geometry of the loading. API RP 5L1 does not indicate the source of the equation. The purpose of this equation is to calculate the number of flat bearing strips needed to keep the stress below a specified level. The stress determined from the finite element model was compared to the stress calculated by the equation from API RP 5L1 under the same conditions. For a 40-foot-long, 34-inch-diameter, 0.300-inch-wall thickness pipe, the comparison indicates that the equation from API RP 5L1 underestimates the peak circumferential tensile stress by a factor of approximately 2.

The API has also published guidelines for loading pipe for transport onboard marine vessels, API RP 5LW, *Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessels*. API RP 5LW also includes an equation for calculating the peak circumferential tensile stress in a stack of pipe supported by bearing strips. However, this equation differs significantly from the API RP 5L1 equation, and no source is given for the equation. The stress determined from the finite element model was also compared to the stress calculated by the equation from API RP 5LW under the same conditions. For a 40-foot-long, 34-inch-diameter, 0.300-inch-wall thickness pipe, the comparison indicates that the equation from API RP 5LW also underestimates the peak circumferential tensile stress by a factor of approximately 2.

The Safety Board also evaluated the pipe movement attributed to the nearby excavation on February 5, 2002. The pipeline moved down and laterally a maximum of 18 inches. The deflection of the pipe led primarily to longitudinal tension and compression stresses that would not have affected the fatigue crack (oriented on a plane radially outward along the welded seam). Circumferential tensile stresses and shear stresses associated with the pipe deflection were calculated to be in the range of 1 to 10 psi in comparison to the circumferential tensile stress of 29,750 psi caused by the internal pressure of the oil in the pipe at the time of the rupture.

RSPA Postaccident Corrective Action Order

On July 5, 2002, RSPA issued to Enbridge a corrective action order that required the pipeline operator to conduct a detailed metallurgical analysis of the July 4 failure to determine the cause and contributing factors. The corrective action order also prohibited Enbridge from operating the pipeline until it had submitted a return-to-service plan, which was to incorporate a program to verify the integrity of the 34-inch pipeline from the Deer River Pump Station to Superior Terminal. The plan was to include, if relevant, an in-line inspection survey using a technologically appropriate tool capable of assessing the type of failure that had occurred, including the detection of longitudinal cracks, and remedial action. If relevant, the return-to-service plan was to include an evaluation of the pipeline coating system, a hydrostatic pressure test of the line segment, and a review of all available pipeline data and records.

WEB Exhibit # 32

Conclusions

Findings

1. Enbridge's pipeline control center personnel responded in a timely manner to the indications of a pipeline leak.

2. After storage, the accident pipe was likely inadequately loaded for transportation, which led to the initiation of fatigue cracking along a longitudinal seam weld before the pipe was placed in service.

3. After installation the preexisting fatigue crack grew with pressure cycle stresses until the crack reached a critical size and the pipe ruptured.

4. The American Petroleum Institute recommended practice 5L1, *Recommended Practice for Railroad Transportation of Line Pipe,* and American Petroleum Institute recommended practice 5LW, *Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessels,* may significantly underestimate the stresses in the pipe at the bearing or separator strips.

5. Hydrostatic pressure testing of a pipeline is insufficient to expose all transportation fatigue cracks that may eventually cause pipe failure.

6. There is a potential risk of pipe damage due to fatigue crack initiation during marine vessel transportation of pipe, similar to the risk during rail transportation, for both hazardous liquid and natural gas pipelines.

7. The absence of industry loading standards for truck transportation of pipe might create risks to the integrity of both natural gas and hazardous liquid pipelines.

8. The Elastic Wave in-line inspection conducted before the accident recorded an indication at the point where the pipe eventually failed; however, preaccident and postaccident interpretations of the recorded data found that the indication did not meet the feature selection criteria to identify it as a crack.

Probable Cause

The National Transportation Safety Board determines that the probable cause of the July 4, 2002, pipeline rupture near Cohasset, Minnesota, was inadequate loading of the pipe for transportation that allowed a fatigue crack to initiate along the seam of the longitudinal weld during transit. After the pipe was installed, the fatigue crack grew with pressure cycle stresses until the crack reached a critical size and the pipe ruptured.

WEB Exhibit # 33A

Recommendations

As a result of its investigation of the July 4, 2002, pipeline rupture near Cohasset, Minnesota, the National Transportation Safety Board makes the following safety recommendations:

To the Research and Special Programs Administration:

Remove the exemption in 49 *Code of Federal Regulations* 192.65 (b) that permits pipe to be placed in natural gas service after pressure testing when the pipe cannot be verified to have been transported in accordance with the American Petroleum Institute recommended practice 5L1. (P-04-01)

Amend 49 *Code of Federal Regulations* to require that natural gas pipeline operators (Part 192) and hazardous liquid pipeline operators (Part 195) follow the American Petroleum Institute recommended practice 5LW for transportation of pipe on marine vessels. (P-04-02)

Evaluate the need for a truck transportation standard to prevent damage to pipe, and, if needed, develop the standard and incorporate it in 49 *Code of Federal Regulations* Parts 192 and 195 for both natural gas and hazardous liquid line pipe. (P-04-03)

To the American Society of Mechanical Engineers:

Amend American Society of Mechanical Engineers B31.8, *Gas Transmission and Distribution Piping Systems*, section 816, to remove the provision that pressure testing may be used to verify the integrity of pipe that may not have been transported in accordance with the American Petroleum Institute recommended practices for transportation of pipe by railroad or marine vessels. (P-04-04)

Amend American Society of Mechanical Engineers B31.4, *Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids*, section 434.4, to require the use of the American Petroleum Institute recommended practice 5LW for marine transport of pipe. (P-04-05)

To the American Petroleum Institute:

Review the equations in American Petroleum Institute recommended practice 5L1, *Recommended Practice for Railroad Transportation of Line Pipe*, and American Petroleum Institute recommended practice 5LW, *Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessels*, for calculating the static load stresses at the bearing or separator strips and revise the recommended practices based on that review. (P-04-06)

WEB Exhibit # 33 B

Recommendations

As a result of its investigation of the July 4, 2002, pipeline rupture near Cohasset, Minnesota, the National Transportation Safety Board makes the following safety recommendations:

To the Research and Special Programs Administration:

Remove the exemption in 49 *Code of Federal Regulations* 192.65 (b) that permits pipe to be placed in natural gas service after pressure testing when the pipe cannot be verified to have been transported in accordance with the American Petroleum Institute recommended practice 5L1. (P-04-01)

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To the American Society of Mechanical Engineers:

Amend American Society of Mechanical Engineers B31.8, *Gas Transmission and Distribution Piping Systems*, section 816, to remove the provision that pressure

WEB Exhibit # 34

DRAFT
To Be Finalized 12/6/07

Draft Resolution
TransCanada-Keystone Pipeline

9/6/07

Whereas, on April 19, 2006 TransCanada Pipeline Limited of Calgary, Alberta, Canada filed an application on behalf of TransCanada-Keystone Pipeline LLC with the U.S. State Department for a Presidential permit to cross the border and build a 1,078 mile 30-inch buried steel pipeline for the purpose of moving crude oil from the oil sands area of Hardisty, Canada through North Dakota and South Dakota to refineries in Illinois, Oklahoma and eventually Texas, and

Whereas, on April 27, 2007 TransCanada Pipelines Limited of Calgary, Alberta, Canada filed an application with the South Dakota Public Utilities Commission (SDPUC) for a permit to construct and operate the TransCanada-Keystone Pipeline LLC, 220 miles 30-inch buried steel pipeline for the purpose of moving crude oil from the oil sands area of Hardisty, Canada through North Dakota and South Dakota to refineries in Illinois, Oklahoma and eventually Texas, and

Whereas, as currently planned, the TransCanada-Keystone Pipeline route will cross the service areas of seven (7) rural water systems in South Dakota, including: Brown-Day-Marshall RWS, WEB RWS, Clark RWS, KingBrook RWS, Mid-Dakota RWS, Hanson RWS, and B-Y RWS and could impact water systems which draw water supply from the Missouri River downstream of Yankton, SD; all of which provide quality drinking water to towns, farms, homes, businesses, dairies, schools, and ethanol plants in eastern South Dakota, and if the oil line is extended to the oil refinery being proposed at Elk Point, SD a branch pipeline could cross the Clay RWS, and

Whereas, based on information filed with the South Dakota PUC and the U.S. State Department, as currently designed, the TransCanada-Keystone Pipeline will operate at pressures ranging from 1,400 psi to 1,700 psi and will transport 435,000 to 591,000 barrels of oil per day, which at 42 gallons per barrel equals 18,270,000 to 24,822,000 gallons of crude oil per day, and that the crude oil will be heated up to 80 degrees so that the thick crude can be pumped and moved through the pipeline, and will contain Benzene, Hydrogen Sulfide, Toluene and other chemicals and elements which are consider toxic and pollutants by the US Environmental Protection Agency if released into

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the environment, which are elements rural water systems test for as part of the Safe Drinking Water Act requirements, and

Whereas, on August 23, 2007 TransCanada Pipeline informed the SDPUC and interveners that April 30, 2007 TransCanada had secured a "Special Permit" from the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA) to operate the Keystone Pipeline at pressures 11% higher than other oil pipelines in the U.S.A. The special permit allows TransCanada to operate the Keystone Pipeline at 80% of the pipes design factor while other oil pipelines in the U.S.A. that have operated at 72% or less of pipe design factor and which even at lower operating pressures than TransCanada is proposing, have had some history of leaks and pipeline failures, including the TransAlaska Pipeline which had a leak or leaks every year for the 25 years of operation, and (80 – 72 = 8 : 72 = 11%)

Whereas, during public information meetings held in 2007, TransCanada-Keystone engineers stated that in order to secure the more than 1,078 miles of steel pipe needed to construct the TransCanada-Keystone Pipeline in 2008 so that it will operational in 2009, that some of the steel pipe will be purchased from manufacturing companies located in China and that TransCanada will attempt to have their own inspectors inspect the pipe during the manufacturing and shipping process, and that the pipe wall thickness proposed by TransCanada-Keystone will be 0.375 inch thick, and a thicker walled pipe would provide greater safety and protection for South Dakota , and

Whereas, when asked in public meetings about liability and cleanup of oil spills TransCanada-Keystone officials have said that if for any reason TransCanada doesn't cleanup an oil spill the U.S. federal government would take charge and cleanup the site as part of the "super fund" program, and

Whereas, in the event of a petroleum spill or oil leak on this high pressure crude oil pipeline, it is very likely that the crude oil will come in contact with the PVC plastic pipelines that are used by all rural water systems, and that such contact will do damage to PVC water lines and oil products could enter the pipelines and pollute and contaminate drinking water supplies, as confirmed by an

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engineering study completed by Iowa State University, commissioned by the AWWA (American Water Works Association); and

Whereas, pages 1 and 19 of a report dated May 1, 2006, prepared by DNV Consultants, a risk consultant for TransCanada, filed with the SDPUC shows that oil leaks of less than 1.5% pipe volume may not be noticed or detected by the SCADA computer control systems TransCanada will be using and may not be found for as long as 90 days, which could result in oil leaks of 369,847 gallons per day (8,806 barrels per day) which figures out to 11 million gallons of crude oil per month or 33 million gallons of crude oil over 3 months, and

Whereas, the TransCanada-Keystone Pipeline is routed through and across aquifers identified by groundwater studies completed by the SD Geological Survey and the US Geological Survey, and through and across <u>shallow aquifers</u> located in Marshall, Day, Clark, Beadle and other counties of South Dakota, and

Whereas, a leak or oil spill from a high pressure oil pipeline like TransCanada-Keystone Pipeline could pollute and damage underground aquifers that are the only reliable water source and water supply for farms, towns and rural water systems, and

Whereas, the TransCanada-Keystone Pipeline is proposing to cross the Missouri River immediately south of Yankton, SD which if it were to leak or fail could impact the scenic designated section of the Missouri River and could impact or increase the risk of impact to water quality of that stretch of the river which serves as an indirect water source for the Lewis & Clark Regional Water System which supplies water to Sioux Falls, SD and a number of rural water systems, cities and towns in south eastern South Dakota, northwest Iowa, and southwest Minnesota; and

Whereas, land acquisition agents have been contacting the 660 landowners along the proposed 220 mile pipeline route in South Dakota, asking for a 100 ft easement which includes wording asking for "<u>one or more pipelines</u>", often cutting across or through the middle of quarter sections or half sections of farm land and not going along the fence line or quarter line, and TransCanada is offering a one time payment ranging from $1,700 to $2,600 per acre (in Marshall and Day County)

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depending on land use, which figures out to around $34 to $52 per acre over 50 years, and cash rent in the area currently runs around $100 to $140 per acre per year and doesn't carry with it the liability or risk of an oil leak that a high pressure oil pipeline like TransCanada-Keystone places on the land, and

Whereas, even though the SDPUC has scheduled formal hearings on the permit application starting on December 3, 2007 and may not reach a decision until as late as April 27, 2008, and even thought the U.S. State Department is conducting an Environmental Impact Statement (EIS) review required by federal law and for which written comments are due September 31, 2007 and a final report is expected to be issued in early 2008; on **August 23, 2007 TransCanada sent letters** to landowners along the proposed Keystone Pipeline route informing them that if they didn't sign TransCanada's easement and accept their easement payment offer by August 31, 2007, that TransCanada **would proceed with eminent domain and condemnation** of privately owned lands, even though no permit has yet been issued by the SD PUC, and TransCanada has no right or authority under South Dakota law to claim the right of "eminent domain" until such time as a permit has been issue and the deadline for appeals in Circuit Court have passed; and

Whereas, while counties, cities, utilities and rural water systems in South Dakota that serve the community have the right of eminent domain as a last resort, they use it sparingly and landowners can appeal to local boards of directors and commissions for relief or negotiation, which is not an option available to landowners in the case of TransCanada which is a private investor owned foreign oil company located in Calgary, Alberta, Canada, and

Therefore, Be It Resolved, that the South Dakota Association of Rural Water Systems (SDARWS) does hereby urge the SD Public Utilities Commission, Department of Environment and Natural Resources, South Dakota Legislature, the Governor, the Attorney General of South Dakota, and the South Dakota Congressional Delegation to protect rural water systems, ground water supplies and communities they serve by imposing conditions on any permit issued to Keystone Pipeline that will assure every protection possible under federal and state laws against oil leaks and "spills" and in the event of an oil leak or spill, that TransCanada-Keystone Pipeline LLC, TransCanada Pipeline LP, TransCanada Corporation, Conoco-Phillips and other investors be held financially and legally

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liable for all costs incurred to South Dakota landowners, communities, counties and rural water systems, and

Further, that SDARWS would ask for a pipe wall thickness greater than the 0.375 inch being proposed by TransCanada-Keystone, up to as much as 0.75 inch wall thickness when crossing through shallow aquifer areas, rural water systems and near schools, creeks, rivers, homes, road crossing and highway systems, and

Further, that one of the conditions imposed on the permit by the SD Public Utilities Commission and the State of South Dakota be a fee or tariff on each barrel of oil that passes through South Dakota on the TransCanada-Keystone Pipeline in the amount of $0.15 per barrel which would amount to $23,816,250 per year at 435,000 barrels per day and $32,357,250 per year at 591,000 barrels per day. That high quality and accurate metering device be installed at TransCanada's expense where the pipeline enters the state at the North Dakota Line and leaves the state at Yankton, SD, which will be monitored and maintained by the SD Revenue Department which will be charged with collection of the fee or tariff with the funds collected to be placed in an interest bearing reserve fund to be used to cover the cost of oil spill cleanup, damage to private property, impact to groundwater supplies, impacts to rural water systems, and other costs related to the operating on the TransCanada-Keystone Pipeline, and

Further, that the PUC, the Governor, Attorney General and the SD Congressional Delegation are hereby asked to send letters to TransCanada Pipeline LP and TransCanada-Keystone Pipeline LLC admonishing that they stop threatening condemnation when they don't yet have the authority or right under the law to do so, and stop all land acquisition until after the PUC hearing process and the EIS process have been completed and a permit decision has been made and the process has been allowed to run its course, including any appeals, and that they be asked to negotiate in good faith with South Dakota landowners, farmers and taxpayers, and

Further, that in the interest of the publics right to know, that the SDARWS ask the SD PUC to release all information filed on April 27, 2007 and filed since that date as part of the TransCanada-Keystone Pipeline permit application and that the PUC hearings process be delayed at least 90

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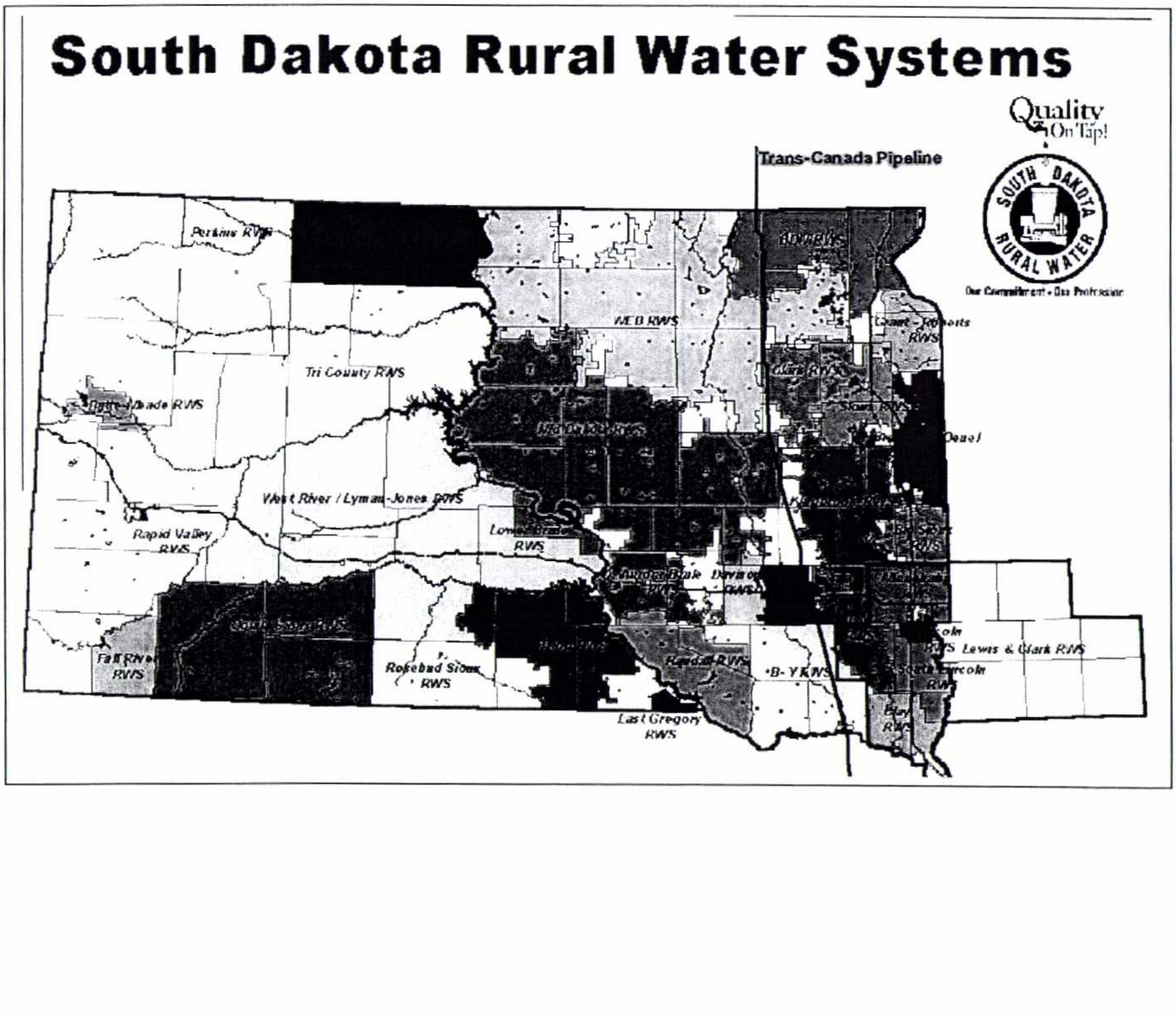
days because of the delay TransCanada caused in release of this information, to give the people of South Dakota time to review the information filed and that the information be placed on file with the County Auditor of each county crossed by the proposed project and that the SDPUC hold hearings out along the pipeline route at Yankton, Alexandria, Clark and Britton to make it easier and less costly for landowners, farmers and the public to participate in the formal hearing process, and

Now therefore, be it resolved that SDARWS has serious reservations and concerns with the TransCanada-Keystone Pipeline and asks that state approvals be withheld and decision reserved until such time as the issues raised herein have been resolved to the satisfaction of the rural water systems and communities that would be crossed by the TransCanada-Keystone Pipeline.



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The Athabasca Oil Sands in Alberta, Canada.

The **Athabasca Oil Sands** are a large deposit of oil-rich bitumen located in northern Alberta, Canada. **These oil sands consist of a mixture of crude bitumen (a semi-solid form of crude oil), silica sand, clay minerals, and water.** The Athabasca deposit is the largest of three oil sands deposits in Alberta, along with the Peace River and Cold Lake deposits. Together, these oil sand deposits cover about 141 000 km² of sparsely populated boreal forest and muskeg (peat bogs). The Athabasca oil sands are named after the Athabasca River which cuts through the heart of the deposit, and traces of the heavy oil are readily observed on the river banks. Historically, the bitumen was used by the indigenous Cree and Dene Aboriginal peoples to waterproof their canoes. The oil deposits are located within the boundaries of Treaty 8, and several First Nations of the area are involved with the sands. The oil sands were first seen by Europeans in 1788.

The key characteristic of the Athabasca deposit is that it is the only one shallow enough to be suitable for surface mining. About 10% of the Athabasca oil sands are covered by less than 75 metres (250 feet) of overburden. The mineable area as defined by the Alberta government covers 37 contiguous townships (about 3400 square kilometres or 1300 square miles) north of the city of Fort McMurray. The overburden consists of 1 to 3 metres of water-logged muskeg on top of 0 to 75 metres of clay and barren sand, while the underlying oil sands are typically 40 to 60 metres thick and sit on top of relatively flat limestone rock. As a result of the easy accessibility, the world's first oil sands mine was started by Great Canadian Oil Sands (now Suncor) back in 1967. The Syncrude mine (the biggest mine in the world) followed in 1978, and the Albian Sands mine (operated by Shell Canada) in 2003. All three of these mines are associated with bitumen upgraders that convert the unusable bitumen into synthetic crude oil for shipment to refineries in Canada and the United States.

The Athabasca oil sands are primarily located in and around the city of Fort McMurray which was still, in the late 1950s, primarily a wilderness outpost of a few hundred people whose main economic activities included fur trapping and salt mining. Since the energy crisis of the 1970s, Fort McMurray has been transformed into a boomtown of 80,000 people struggling to provide services and housing for migrant workers, many of them from Eastern Canada, especially Newfoundland.

Contents

[hide]

[edit] Estimated oil reserves

Alberta Government calculates that about 28 billion cubic metres (174 billion barrels) of crude bitumen are economically recoverable from the three Alberta oil sands areas at current prices using current technology. This is equivalent to about 10% of the estimated 1,700 and 2,500 billion barrels of bitumen in place.[1]. Alberta estimates that the Athabasca deposits alone contain 5.6 billion cubic metres (35 billion barrels) of surface mineable bitumen and 15.6 billion cubic metres (98 billion barrels) of bitumen recoverable by in-situ methods. These estimates of Canada's oil reserves caused some astonishment when they were first published but are now largely accepted by the international community. This volume places Canadian proven oil reserves second in the world behind those of Saudi Arabia.

The method of calculating economically recoverable reserves that produced these estimates was adopted because conventional methods of accounting for reserves gave increasingly meaningless numbers. They made it appear that Alberta was running out of oil at a time when rapid increases in oil sands production were more than offsetting declines in conventional oil, and in fact most of Alberta's oil production is now non-conventional oil. Conventional estimates of oil reserves are really calculations of the geological risk of drilling for oil, but in the oil sands there is very little geological risk because they outcrop on the surface and are extremely easy to find. One risk is economic risk of low oil prices and with the oil price increases of 2004-2006, this economic risk evaporated.

The Alberta estimates in some ways are extremely conservative, since they assume a recovery rate of around 20% of bitumen in place, whereas oil companies using the new steam assisted gravity drainage method of extracting bitumen report that they can recover over 60% with little effort. These much higher recovery rates probably mean that the ultimate production could be several times as high as the already very large government estimates.

At rate of production projected for 2015, about 3 million barrels per day, the Athabasca oil sands reserves would last over 400 years. [2] However, production cannot increase to those levels without a huge influx of workers into northern Alberta, which by 2006 was already occurring. This need created a severe labor shortage in Alberta, which by 2007 drove unemployment rates in Alberta and adjacent British Columbia to the lowest levels in history. Even as far away as the Atlantic Provinces, where workers were leaving to work in Alberta, unemployment rates fell to levels not seen for over 100 years.[3] These manpower limitations imply that, while Alberta is capable of being a major player on the world oil market for the rest of this century, it does not have enough population to replace the Middle East as the main source of American, European and Asian supply.[citation needed]

The Venezuelan Orinoco tar sands site may contain more oil sands than Athabasca (see tar sands article). However, while the Orinoco deposits are less viscous and more easily produced using conventional techniques (the Venezuelan government prefers to call them "extra-heavy oil"), they are too deep to access by surface mining.

Minesite at Syncrude's Mildred Lake plant

[edit] Economics

Despite the large reserves, the cost of extracting the oil from the sand has historically made production of the oil sands unprofitable - the cost of selling the extracted crude would not cover the direct costs of recovery; labour to mine the sands and fuel to extract the crude.

In mid-2006, the National Energy Board of Canada estimated the operating cost of a new mining operation in the Athabasca oil sands to be $9 to $12 per barrel, while the cost of an in-situ SAGD operation (using dual horizontal wells) would be $10 to $14 per barrel. This compares to operating costs for conventional oil wells which can range from less than $1 per barrel in Iraq and Saudi Arabia to $6 and up in the United States and Canada.

In addition, the capital cost of the equipment, such as the huge machines required to mine the sands and the dump trucks used to haul it to processing make capital costs a major consideration in starting production. The NEB estimates that capital costs raise the total cost of production to $18 to $20 per barrel for a new mining operation and $18 to $22 per barrel for a SAGD operation. This does not include the cost of upgrading the crude bitumen to synthetic crude oil, which makes the final costs $36 to $40 per barrel for a new mining operation.

Therefore, although high crude prices make the cost of production very attractive, sudden drops in price leaves producers unable to recover their enormous capital costs - although the companies are well financed and can tolerate long periods of low prices since the capital has already been spent and they can almost always cover incremental operating costs.

However, the development of commercial production is made easier by the fact that exploration costs are virtually nil. Such costs are a major factor when assessing the economics of drilling in a traditional oil field. The location of the oil deposits in the tar sands are well known and an estimate of recovery costs can usually be made easily. Most important, the oil sands are in a politically stable area - there is not another region in the world with energy deposits of this magnitude where it would be less likely that these expensive installations would be confiscated by a hostile national government, or be endangered by a war or revolution.

As a result of the Oil price increases of 2004-2006, the economics of oil sands have improved dramatically. At a world price of $50 per barrel, the NEB estimates an integrated mining operation would make a rate return of 16 to 23 percent, while a SAGD operation would return 16 to 27 percent. Prices in 2006 have been considerably higher than that. As a result, capital expenditures in the oil sands announced for the period 2006 to 2015 exceed $100 billion, which is twice the amount projected as recently as 2004. However, due to an acute labour shortage which has developed in Alberta, it is not likely that all these projects can be completed.

At present the area around Fort McMurray, Alberta, has seen the most effect from the increased activity in the oil sands. However, although jobs are plentiful, housing is in short supply and expensive. People seeking work often arrive in the area without arranging accommodation, driving up the price of temporary accommodation. The area is isolated, with only a two-lane road connecting it to the rest of the province, and there is pressure on the government of Alberta to improve road links as well as hospitals and other infrastructure.[4]

Despite the best efforts of companies to move as much of the construction work as possible out of the Fort McMurray area, and even out of Alberta, the shortage of skilled workers is spreading to the rest of the province.[5]. Even without the oil sands, the Alberta economy would be very strong, but development of the oil sands has resulted in the strongest period of economic growth ever recorded by a Canadian province and driven Alberta's unemployment rates to the lowest levels in history.[6]

[edit] Oil Sands Production

The Athabasca oil sands first came to the attention of European fur traders in 1719 when Wa-pa-su, a Cree trader, brought a sample of the oil sands to the Hudson's Bay Company post at Fort Churchill. In 1778, fur trader Peter Pond became the first white man to see the outcroppings along the Athabasca River and he noted that the native people used it to waterproof their canoes. In 1883, C. Hoffman of the Geological Survey of Canada tried separating the bitumen from oil sand with the use of water, and reported that it separated readily. However, it was nearly a century before extracting it became commercially viable. Dr. Karl Clark of the University of Alberta, perfected a steam separation process for the tar sands in 1926.

Commercial production of oil from the Athabasca oil sands began in 1967, when Great Canadian Oil Sands (now Suncor) opened its first mine, producing 30,000 barrels per day of synthetic crude oil. Development was inhibited by declining world oil prices, and the second mine, operated by the Syncrude consortium, did not begin operating until 1978, after the 1973 oil crisis sparked investor interest. However, the price of oil subsided afterwards, and although the 1979 energy crisis caused oil prices to peak again, introduction of the National Energy Program by Pierre Trudeau caused the oil companies and the Alberta government under Premier Peter Lougheed to pull the plug on new developments. Once more, prices declined to very low levels, causing considerable retrenchment in the oil industry, and the third mine, operated by Shell Canada, did not begin operating until 2003. However, with Oil price increases of 2004-2006, the existing mines have been greatly expanded and new ones are being planned.

According to the Alberta Energy and Utilities Board, production of crude bitumen in the Athabasca oil sands was as follows:

2005 Production	m^3/day	bbl/day
Suncor Mine	31,000	195,000
Syncrude Mine	41,700	262,000
Shell Canada Mine	26,800	169,000
In Situ Projects	21,300	134,000

TOTAL	120,800	760,000

This was despite a major fire at the Suncor operation, a major turnaround at Syncrude, and operational problems at the Shell operation. Combined oil production in all three Alberta oil sands areas was 169,100 m3/day or 1,065,000 barrels per day

With planned projects coming on stream, by 2010 oil sands production is projected to reach 2 million barrels per day or about two thirds of Canadian production. By 2015 Canadian oil production may reach 4 million barrels per day, of which only 15% will be conventional crude oil. The Canadian Association of Petroleum Producers predicts that by 2020 Canadian oil production will reach 4.8 million barrels per day, of which only about 10% will be conventional light or medium crude oil, and most of the rest will be crude bitumen and synthetic crude oil from the Athabasca oil sands.

[edit] Extraction of oil

See main article on Oil sands extraction

The original process of extraction used at the oil sands was developed by Dr. Karl Clark, working with the Research Council of Alberta in the 1920s.[7] Historically (since the 1960s), the oil sands have been mined in huge open pit mines and extracted from the sand by variations of the Clark water-based extraction process, which separates aerated bitumen from the other oil sand components in gravity settling vessels. More recently, new in-situ methods have been developed to extract bitumen from deep deposits by injecting steam to heat the sands and reduce the bitumen viscosity so that it can be pumped out like conventional crude oil.

The standard extraction process also requires huge amounts of natural gas. Currently, the oil sands industry uses about 4% of the Western Canada Sedimentary Basin natural gas production. By 2015, this may increase by a factor of 2.5 times.[8]

According to the National Energy Board, it requires about 0.4 million cubic feet of natural gas to produce one barrel of synthetic crude oil, which is the energy equivalent of 6 million cubic feet of gas, so the process produces a substantial net gain in energy. That being the case, it is likely that in the short term exports of natural gas to the United States will be reduced to provide fuel to the oil sands plants. In the long term, however, oil upgraders will likely turn to bitumen gasification to generate their own fuel. In much the same way the bitumen can be converted into synthetic crude oil, it can also be converted to synthetic natural gas.

In-situ extraction on a commercial scale is just beginning. A project nearing completion, the Long Lake Project,[9] is designed to provide its own fuel, by on-site cracking of the bitumen mined.[10] It is supposed to start extracting bitumen in 2006, and "upgrading" of bitumen to liquid oil in 2007, producing 60,000 bbl/day of usable oil. If it works, the natural gas problem becomes less of an issue and the problem of disposing of tailings disappears.

[edit] Geopolitical importance

The Athabasca Oil Sands are now featured prominently in international trade talks, with energy rivals China, India and the United States negotiating with Canada for a bigger share of the oil sands' rapidly increasing output. Output at the oil sands is expected to quadruple between 2005 and 2015, reaching 4 million bbl/day, increasing their political and economic importance. Although most of the oil sands production is currently exported to the United States, that could change.

An agreement has been signed between PetroChina and Enbridge to build a 400,000 barrel-per-day pipeline from Edmonton, Alberta to the west-coast port of Kitimat, British Columbia to export synthetic crude oil from the oil sands to China and elsewhere in the Pacific, plus a 150,000-barrel-per-day pipeline running the other way to import condensate to dilute the bitumen so it will flow. Sinopec, China's largest refining and chemical company, and China National Petroleum Corporation have bought or are planning to buy shares in major oil sands development.

India has announced plans to invest $1 billion in the Athabasca Oil Sands in 2006. As many as four different Indian oil companies, such as Oil and Natural Gas Corporation and Indian Oil Corporation, are involved.[11]

[edit] Indigenous peoples of the area

Indigenous peoples of the area include the Fort McKay First Nation and the Fort McMurray First Nation. The oil sands themselves are located within the boundaries of Treaty 8, signed in 1899. The Fort McKay First Nation has formed several companies to service the oil sands industry, and will be developing a mine on their territory.[12] However, support within the First Nation for such development is not unanimous.

[edit] Environmental impacts

Some critics contend that government and industry measures taken to minimize environmental and health risks posed by large-scale mining operations are inadequate, potentially causing damage to the natural environment.

The open-pit mining of the Athabasca oils sands destroys the boreal forest and muskeg, as well as changing the natural landscape. The Alberta government does not require companies to restore the land to "original condition" but only to "equivalent land capability". This means that the ability of the land to support various land uses after reclamation is similar to what existed, but that the individual land uses will not necessarily be identical.[13] Since the government considers agricultural land to be equivalent to forest land, oil sands companies have reclaimed mined land to use as pasture for buffalo, rather than restoring it to the original boreal forest and muskeg.

For every barrel of synthetic oil produced in Alberta, more than 80 kg of greenhouse gases are released into the atmosphere and between 2 and 4 barrels of waste water are dumped into tailing ponds that have replaced about 50 km² of forest. The forecast growth in synthetic oil production in Alberta also threatens Canada's international commitments. In ratifying the Kyoto Protocol, Canada agreed to reduce, by 2012, its greenhouse gas emissions by 6% with respect to [1990]. In 2002, Canada's total greenhouse gas emissions had increased by 24% since 1990.

"A cubic metre of oil, mined from the tar sands, needs two to 4.5 cubic metres of water. Approved oil sands mining operations -- not the in situ kind that extract oil from tar sands far below the surface -- will take twice the annual water needs of the City of Calgary. The water will come from the Athabasca River, from which 359-million cubic metres will be diverted."[14] However, the Athabasca River is much bigger than the small rivers that flow through Calgary, and current oil sands water license allocations are only for about 1% of the flow of the river.[15] The Alberta government sets strict limits on how much water oil sands companies can remove from the Athabasca River, and during low-flow conditions orders them to reduce their withdrawals.[16]

Ranked as the world's eighth largest emitter of greenhouse gases[17], Canada is a relatively large emitter given its population. The United States, which has not signed the Kyoto Protocol, is the world's largest emitter at a fluctuating 25% of the total. China is the second largest emitter at 20%, but as a developing country is exempt from controls. Its economy has been growing rapidly, and as a result the International Energy Agency expects it to exceed the U.S. as the world's largest emitter of carbon dioxide by about 2008. Other developing countries in Asia and Africa have also been increasing their emissions rapidly. However, it is developed nations that are responsible for the vast majority of historic emissions which are now causing climate change. Most European countries have missed their reduction targets, as is Canada. Against this background, Canada's developments in the oil sands are regrettable given the urgent need to reduce global emissions and meet Canada's Kyoto commitments.

[edit] Oil sand companies

There are currently three large oil sands mining operations in the area run by Syncrude Canada Limited, Suncor Energy and Albian Sands owned by Shell Canada, Chevron, and Western Oil Sands Ltd.

Major producing or planned developments in the Athabasca Oil Sands include the following projects:[18]

- Suncor Energy's Steepbank and millennium mines currently produce 263,000 barrels per day and its Firebag in-situ project produces 35,000 bpd. It intends to spend $3.2 billion to expand its mining operations to 400,000 bpd and its in-situ production to 140,000 bpd by 2008.
- Syncrude's Mildred Lake and Aurora mines currently can produce 360,000 bpd.
- Shell Canada currently operated its Muskeg River mine producing 155,000 bpd and the Scotford Upgrader at Fort Saskatchewan, Alberta. Shell intends to open its new Jackpine mine and expand total production to 500,000 bpd over the next few years.
- Nexen's in-situ Long Lake SAGD project is on schedule to produce 70,000 bpd by late 2007, with plans to expand it to 240,000 bpd over the next 10 years.
- CNRL's $8 billion Horizon in-situ project is planned to produce 110,000 bpd on startup in 2008 and grow to 300,000 bpd by 2010.
- Total S.A.'s subsidiary Deer Creek Energy is operating a SAGD project on its Joslyn lease, producing 10,000 bpd. It intends on constructing its mine by 2010 to expand its production by 100,000 bpd.
- Imperial Oil's $5 to $8 billion Kearl Oil Sands Project is projected to start construction in 2008 and produce 100,000 bpd by 2010. Imperial also operates a 160,000 bpd in-situ operation in the Cold Lake oil sands region.
- Synenco Energy and SinoCanada Petroleum Corp., a subsidiary of Sinopec, China's largest oil refiner, have agreed to create the $3.5 billion Northern Lights mine, projected to produce 100,000 bpd by 2009.

etc.

Country/Region	Lowest estimate	Highest estimate
North America	50.7	222.9
Canada	16.5	178.8
United States	21.3	29.3
Mexico	12.9	14.8
Central & South America	76	401.1

Venezuela	52.4	361.2
Brazil	10.6	11.2
Western Europe	16.2	17.3
United Kingdom	4.1	4.5
Norway	7.7	8.0
Eastern Europe & Former USSR	79.2	121.9
Russia	60	72.4
Kazakhstan	9	39.6
Middle East	708.3	733.9
Iran	125.8	132.7
Iraq	115	115
Kuwait	99	101.5
Qatar	15.2	15.2
Saudi Arabia[1]	261.9	264.3
UAE	69.9	97.8
Africa	100.8	113.8

Algeria	11.4	11.8
Libya	33.6	39.1
Nigeria	35.3	35.9
Asia **and** Oceania	36.2	39.8
China	15.4	16.0
Australia	1.5	4
India	4.9	5.6
Indonesia	4.3	4.3
World **total**	1082	1650.7

[1]This reserve number cannot be verified.

[edit] See also

- Canadian Centre for Energy Information
- History of the petroleum industry in Canada, part two
- Mackenzie Valley Pipeline

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17. ^ Reuters Top 50 countries by greenhouse gas emissions
18. ^ projects Oilsands Discovery - Oil Sands Projects

[edit] External links

- Hugh McCullum, Fuelling Fortress America: A Report on the Athabasca Tar Sands and U.S. Demands for Canada's Energy (The Parkland Institute)--Executive SummaryDownload report
- Oil Sands History - Syncrude Canada
- Oil Sands Discovery Centre - Fort McMurray Tourism
- The Trillion-Barrel Tar Pit - Article from December 2004 Wired.
- Oil Sands Review - Sister publication to Oilweek Magazine
- Alberta's Oil Sands - Alberta Department of Energy
- Alberta's Reserves 2005 and Supply/Demand Outlook 2006-2015 - Alberta Energy and Utilities Board
- Canada's Oil Sands - Opportunities and Challenges to 2015: An Update - June 2006 - National Energy Board of Canada
- Oilsands overview- Canadian Centre for Energy Information
- Alberta Plan Fails to Protect Athabasca River

Coordinates: 57.02° N 111.65° W

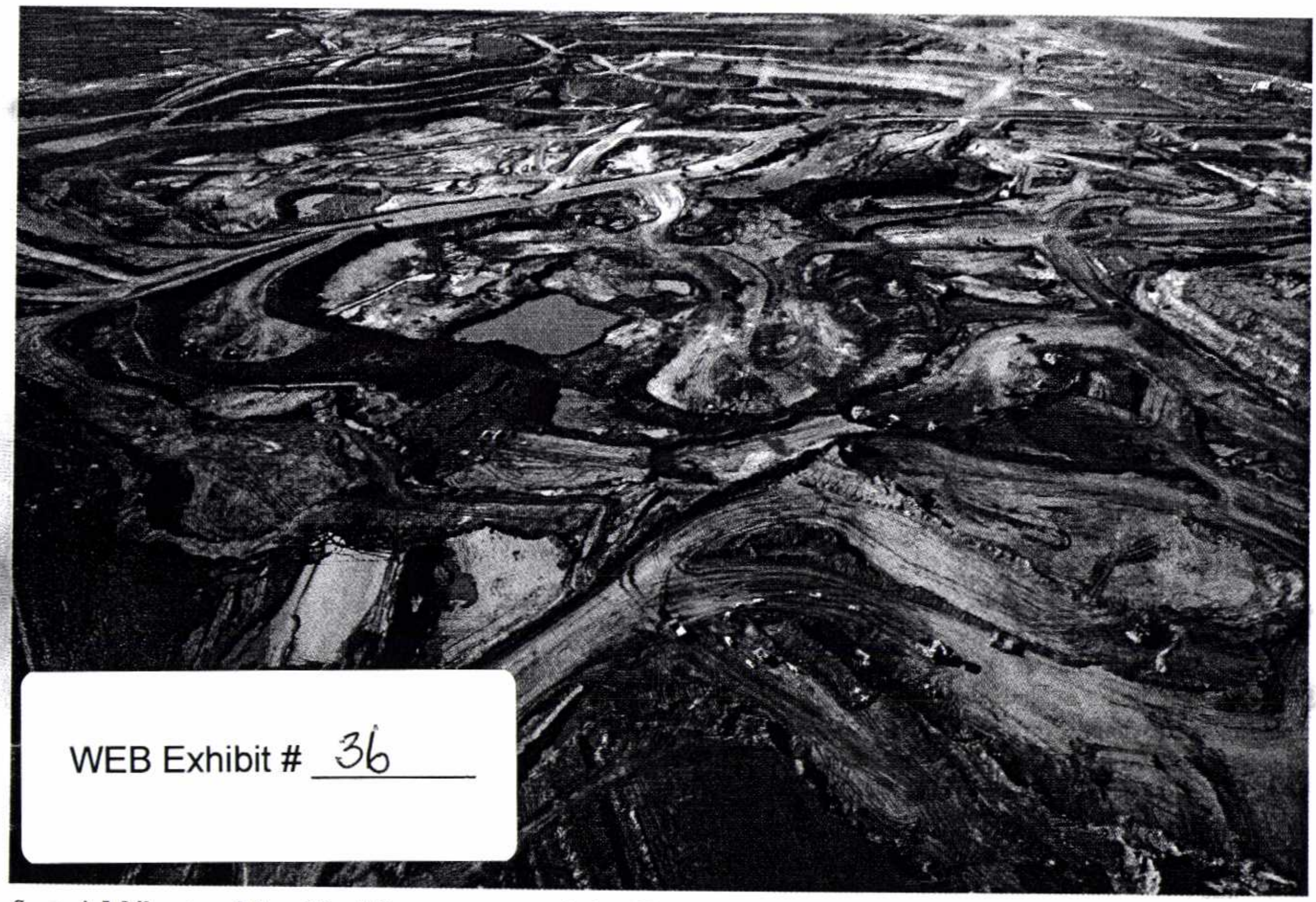
WEB Exhibit # 35

ANNALS OF ECOLOGY

UNCONVENTIONAL CRUDE

Canada's synthetic-fuels boom.

BY ELIZABETH KOLBERT



WEB Exhibit # 36

Suncor's Millennium Mine. The shift to new sources of oil could significantly increase greenhouse-gas emissions.

JIRI REZAC/POLARIS

The town of Fort McMurray occupies a set of irregularly spaced hillsides on either side of the Athabasca River, in northern Alberta. It has a dozen check-cashing joints, a roughly equal number of hotels, and a gaming center called the Boomtown Casino. It also has a museum, which is devoted to the region's most important resource, the Alberta tar sands. Exhibits include an eight-foot-long rotor, half of a hundred-and-fifty-ton truck, and a pump of Brobdingnagian proportions. Near the entrance to the museum sits a black mound covered by a clear plastic dome. A sign invites visitors to scratch around in the mound with a little retractable rake, then lift up a flap and take a sniff. Tar sands look like dirt and smell like diesel fuel.

The tar sands begin near the border of Saskatchewan, around the latitude of Edmonton, and extend, in three major deposits, north and west almost to British Columbia. All in all, they cover—or, more accurately, underlie—some fifty-seven thousand square miles, an area roughly the size of Florida. It is believed that they were pushed into their present location seventy million years ago by the uplift of the Rocky Mountains.

For the most part, the tar sands consist of quartzite, clay, and water. The other ingredient—the "tar"—is a mixture of very heavy hydrocarbons known as bitumen. Bitumen can be used as a sealant—supposedly the word "mummy" is derived from the term in ancient Persian—and as a paving material. With the right technology, it can also be converted into a form of petroleum known as synthetic crude.

There are two ways to assess the world's oil supply. One is to consider only conventional reserves—the sort of oil that comes gushing out of the ground. Estimates of conventional reserves vary widely, but most analyses suggest that their output will begin to decline sometime in the next few decades (if it hasn't already)—a development that so-called "peak oilers" predict will lead to a variety of gruesome consequences, including blackouts, food shortages, and general economic collapse. The second way is to look beyond conventional reserves to unconventional ones, like the tar sands.

It is estimated that there is enough bitumen in Alberta to yield 1.7 trillion barrels of synthetic crude. Assuming that only ten per cent of this is actually recoverable, it still represents the second-largest oil reserve in the world, after Saudi Arabia's, and more oil than is contained in the reserves of Kuwait, Norway, and Russia put together. Unconventional crude can be found in many other parts of the globe besides Canada; these include eastern Venezuela, which is home to a huge tar-sandslike deposit called the Faja Petrolífera del Orinoco, and portions of Colorado, Utah, and Wyoming, where there's a thick layer of oil shale known as the Green River Formation. Even coal can be converted into liquid fuel. During the Second World War, the Nazis employed a technique called the Fischer-Tropsch process; the same process is now in use in several countries, most notably South Africa, which invested heavily in coal-to-liquids technology during the apartheid era. Build enough coal-to-liquids plants and places like Montana and West Virginia could one day become major petroleum producers.

In Fort McMurray, what might be called the world's first unconventional oil boom is already under way. Since 2002, Shell, ConocoPhillips, Chevron, and Imperial Oil, which is primarily owned by ExxonMobil, have all received approval to construct major projects in the tar sands; Total has announced its intention to follow suit. Over the next five years, investment in the Fort McMurray area is expected to amount to more than seventy-five billion dollars. Residents of the town have taken to calling it Fort McMoney.

Thanks in large part to what's happening in the tar sands—output now tops a million barrels a day—Canada has become America's No. 1 source of imported oil; the country supplies the United States with more petroleum than all of the nations of the Persian Gulf combined. (If you have bought gas recently in Colorado, Ohio, or Indiana—states where tar-sands oil is refined—you are probably driving around with a piece of northern Alberta in your tank.) By 2010, the tar sands' yield is expected to double, and by 2015 to triple. Crude from the tar sands and other unconventional sources could keep oil flowing well into the middle of the century, and perhaps beyond. Depending on how you look at things, this is either a heartening prospect or a terrifying one.

The company that has been producing oil from the tar sands the longest is known as Suncor. (Suncor used to be a part of Sun Oil, now Sunoco, but today it is owned and operated independently.) One day this summer, I went to take a tour of its operations, which sprawl across several hundred square miles. I was picked up at the entrance to the site by a grandmotherly guide named Gloria Jackson, and together we went to fetch another Suncor official, named Darin Zandee. "There's no blasts today, so that's good," Zandee said, referring to the charges that are periodically set off to loosen the sands. We drove up to a lookout, from which we could see, spread before us, Suncor's newest mine, the Millennium. Rings of jet-black earthworks were scattered across an enormous pit, an arrangement that might have been based on a blueprint from the Inferno.

The Millennium Mine opened in 2002. Suncor expects to continue to pull tar sands out of it for the next twenty-five years. By then the pit, which is now roughly two miles in diameter, will be six miles across. We drove over the edge of the mine and slowly made our way down to the bottom. There a huge, Mike Mulligan-esque shovel was standing idle. Its bucket hung in midair, steel teeth glinting. Zandee said that to lift one of the teeth would require thirty men—"That gives you a sense of the scale." A gargantuan truck rumbled by. Zandee estimated that it was carrying about three hundred tons. "That's some of our smaller equipment," he said. The largest truck in the mine—the Caterpillar 797B—can haul more than four hundred tons. It has twelve-foot-tall tires, and its cab sits twenty-one feet off the ground. Driving one, I was told, is like trying to steer a house while peering out the window of the upstairs bathroom.

At the Millennium, the tar sands start at a depth of roughly a hundred feet and extend down in a more or less continuous layer, known as the "feed," for about a hundred and fifty feet. Before mining begins, everything above the feed—trees, bushes, grass, soil, rocks, wildlife—gets scooped up and carted away. (The material is delicately referred to as "overburden.") Below the tar sands, there's a thick layer of limestone, the remains of an ancient ocean that once covered Alberta. Suncor mines some of the limestone, too, and uses it to shore up the roads in the pit. What with the overburden and the tar sands and the limestone, Zandee said, "We try to move a million tons a day." He pointed out a truck in the distance that was dumping a load of tar sands onto what looked like a large platform. The platform was actually a grate, through

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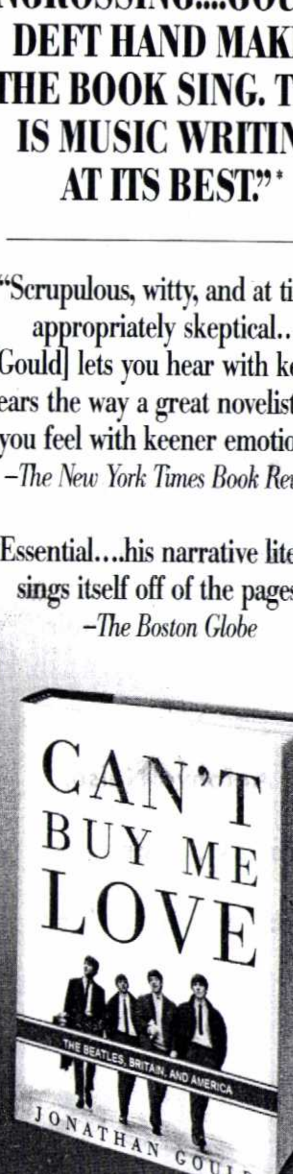

WEB Exhibit # 36

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Antonya Nelson reads a short story by Mavis Gallant

WEB Exhibit # 36

which the sands were being fed into a giant tank of hot water.

In any given load of sands, only about ten per cent is bitumen; to produce synthetic crude, the other ninety per cent has to be separated out. In the hot-water tank, the sands get spun around; the liberated bitumen is then siphoned off. For every barrel of synthetic crude that Suncor eventually produces, forty-five hundred pounds of tar sands have to be dug up and separated.

We made our way out of the pit and headed on, following the bitumen to its next stop, the upgrader. Along the way, we passed a murky expanse of water with oily scum on the surface. A few dozen scarecrow-like creatures, fixed to empty barrels, were bobbing on top. This, Gloria Jackson explained, was a tailings pond; it held water that had been used in the separation process and was too contaminated with mercury and other toxins to be released back into the Athabasca. (Suncor has nine such ponds, which collectively cover an area of eleven square miles.) The scarecrows, known as "bitu-men," were supposed to discourage birds from landing on the pond and poisoning themselves. Every minute or so, a dull boom filled the air. This was the sound of a propane cannon, another bird-intimidation device.

The primary difference between bitumen and ordinary crude is the size of the hydrocarbon molecules: in liquid oil, these molecules contain between five and twenty carbon atoms, while in bitumen they contain more than twenty. (At room temperature, pure bitumen is so viscous that it will not flow.) The main job of the upgrader is to break down the oversized hydrocarbons into smaller units. We drove along roads with names like Sulphur Street and Diesel Alley and pulled up to a huge refinery-like complex that covered several square blocks. There were dozens of smokestacks and tanks, and more pipes than could possibly be counted. Jackson explained that somewhere inside this maze the bitumen would be "cracked," at a temperature of nearly nine hundred degrees. After that, in the form of synthetic crude, it would be piped to specially outfitted refineries, either in the United States or Canada, to be converted largely into transportation fuels—gasoline for cars, diesel for trucks, and jet fuel for planes. (Suncor owns a refinery near Denver that processes tar-sands oil.) I had told Jackson that I had twin boys at home, and at the end of the tour she handed me two yellow Matchbox-size versions of the 797B.

American accounts usually give the start of the oil age as 1859, the year that a former railroad conductor named Edwin L. Drake drilled his first successful well, near Titusville, Pennsylvania. Canadian accounts go back a year earlier, to 1858, when a businessman named James Miller Williams decided to dig a well for drinking water outside the town of Bear Creek, Ontario. Instead of water, he struck oil.

Efforts to extract oil from the tar sands soon followed. Entrepreneurs and con men sunk dozens of wells around Fort McMurray in the second half of the nineteenth century. (One enterprising German immigrant who claimed to have struck oil apparently poured the stuff down the hole himself.) Eventually, it became clear that there was no oil, and attention turned to mining the bitumen. In 1930, a former farmer named Robert Fitzsimmons set up the first commercial separation plant in the tar sands; in 1938, Fitzsimmons had to flee Canada to avoid his creditors.

In 1956, an American geologist, Manley Natland, came up with the idea of streamlining the process by using atom bombs. Natland reasoned that "thermal devices" could be lowered into the limestone beneath the tar sands and exploded. This would create cavities into which the bitumen, heated to more than a thousand degrees, would flow and from which it could then be collected. The idea was taken seriously at the highest levels in both Ottawa and Washington—the United States Atomic Energy Commission even agreed to supply a bomb to test Natland's theory—but it was never implemented. (Beginning in the mid-nineteen-sixties, the Soviet Union actually tried the experiment, setting off half a dozen nuclear explosions to stimulate conventional oil production; production increased, but, unfortunately, much of the oil turned out to be radioactive.)

The technology for removing bitumen from the tar sands is probably still best described as a work in progress. Where the feed lies closest to the surface, as, for example, at the Suncor site, the bitumen is strip-mined and then separated. But most of the tar sands lie too deep to be mined profitably. In these zones, a method known as in-situ extraction is used. In-situ extraction is based on much the same principle as Natland's scheme, minus the atom bombs. Typically, two horizontal wells are drilled into the sands, one above the other. High-pressure steam is injected into the top well; eventually, the tar sands grow hot enough—nearly four hundred degrees—that bitumen begins to flow into the bottom well. The technical name for this process is Steam Assisted Gravity Drainage, or SAGD (pronounced "sag-dee").

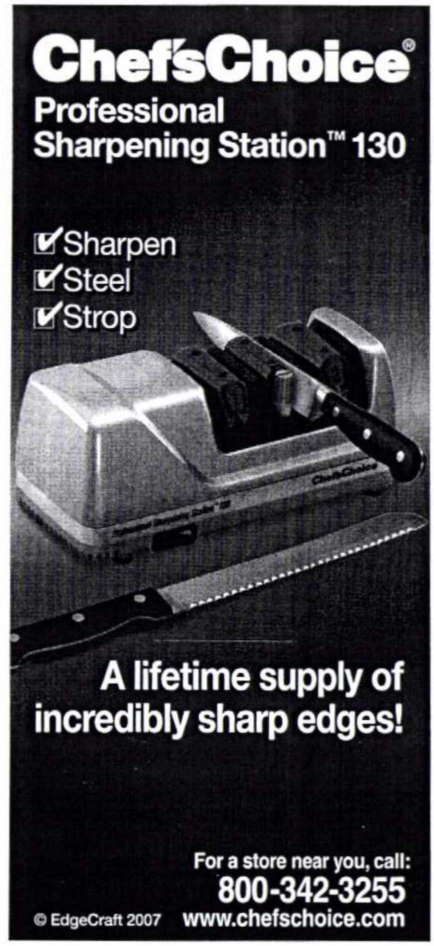
Whichever method is used, a great deal of energy is required. To produce a barrel of synthetic crude through mining takes roughly eight hundred and ten megajoules, which is the energy content of about an eighth of a barrel of oil. To produce a barrel of synthetic crude through SAGD takes more than sixteen hundred megajoules, which is the energy content of more than a quarter of a barrel of oil. This means that, for every three barrels extracted via SAGD, one has, in effect, been consumed.

Tar-sands oil itself could, in principle, be used to power the operations; in fact, most of the energy used to generate the steam for SAGD, as well as to run all the upgraders and separators, now comes from natural gas. It is estimated that by 2012 tar-sands operations will consume two billion cubic feet of natural gas a day, or enough to heat all the homes in Canada. Such is the demand for natural gas around Fort McMurray that a consortium of companies, including Shell Canada and Imperial Oil, has proposed building a seven-hundred-and-fifty-mile pipeline from the Arctic Ocean through the largely undisturbed wilderness of the Mackenzie River Valley and down into northern Alberta. The proposal, which has been challenged by native and environmental groups, has yet to receive regulatory approval; meanwhile, a variety of other plans have been floated. As it happens, while I was visiting Fort McMurray a company called the Energy Alberta Corporation filed an application to build a pair of nuclear reactors four hundred miles west of town. Early reports stated that the company already had a "large industrial off-taker" lined up to buy nearly three-quarters of the twenty-two hundred megawatts that the reactors would generate. Energy Alberta would not disclose the identity of this "off-taker"; in the local press it seemed to be taken for granted that the power would be going to the tar sands.

There are several reasons that companies like Chevron and ExxonMobil are now rushing to develop the tar sands, the most obvious being that it's increasingly profitable to do so. Converting the sands into synthetic crude costs around thirty dollars a barrel; last week, the price of a barrel of oil on the New York Mercantile Exchange was over ninety dollars. Other synthetic fuels require more elaborate processing, and are commensurately more costly to produce; converting coal into oil, for example, requires gasifying the coal under intense pressure and heat, then condensing it into a liquid. To extract oil from shale, meanwhile, involves basically rewriting geological history. (Shell has been experimenting with a process that involves baking the shale with electric heaters until it reaches a temperature of nearly seven hundred degrees while, at the same time, freezing the area around it.) If the price of oil remains above ninety dollars—many analysts expect it to hit a hundred dollars a barrel soon—then these and other unconventional forms of fuel can also be developed at a profit, and, all other things being equal, they will be.

No matter how it is carried out, oil extraction is a destructive business. Conventional oil wells require pipelines and drill pads and roads for heavy equipment; all of these fragment (or destroy) the landscape. The flaring of natural gas, which often accompanies oil production, produces an array of air pollutants, and leaks and spills release toxins ranging from volatile chemicals, like benzene (a known carcinogen), to much heavier compounds, like benzopyrene (another known carcinogen). With unconventional oil, the damage tends to be higher all around—more land gets disturbed, more pollutants are produced, and more opportunities arise for contamination. And then there are the greenhouse gases.

Alex Farrell is a professor in the Energy



WEB Exhibit # 36

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and Resources Group at the University of California at Berkeley who studies the impacts of unconventional oil. A few years ago, Farrell realized that all the major climate models were based on the same faulty premise: they assumed that in the future increased oil demand would be met with increased supplies of conventional crude. Together with a graduate student named Adam Brandt, Farrell decided to try to come up with projections that more accurately reflected reality. For their calculations, the two assumed that where there was a gap between demand and conventional supply it would be filled with synthetic fuels, first with tar-sands oil and later with oil from coal and shale. (According to high-end estimates, coal and oil shale could together yield some ten trillion barrels of unconventional crude.) They then calculated what the impact would be on global carbon-dioxide levels.

"All unconventional forms of oil are worse for greenhouse-gas emissions than petroleum," Farrell told me. "And it's pretty easy to understand why. It's not so hard to turn liquid petroleum into liquid fuels. Turning a solid material like coal into a liquid—it sounds hard to do, and it *is* hard to do. And that extra effort shows up in higher energy consumption and higher water use and higher emissions." In the case of tar-sands oil, total greenhouse-gas emissions per barrel—which is to say, the carbon dioxide produced in creating the oil and then burning it—are between fifteen and forty per cent higher than those from conventional oil. In the case of coal-to-liquids, or C.T.L., total emissions are almost two times as high as with conventional oil, and for oil shale they can be more than twice as high.

"Let's take coal-to-liquids," Farrell said. "You're talking about nearly doubling the greenhouse-gas emissions. Think about this—we're talking about a world in which over-all greenhouse-gas emissions should start to go down, and this is a technology that doubles emissions. They don't go together too well, do they?" Farrell and Brandt found that the shift to unconventional oil could add somewhere between fifty and four hundred gigatons of carbon to the atmosphere by 2100.

"The environment and climate change are what are called 'externalities,'" Farrell continued. "And at the moment we don't have effective ways of including these externalities in market transactions of any sort. Until we do, the market won't solve them, since by definition they're external to the market. They're a social good—government has to step up and say, 'We're going to take this into account.'"

One way that a government could take greenhouse-gas emissions into account would be to tax them. This would encourage producers of unconventional fuels to cut their emissions, by, for example, employing "carbon capture and storage" technologies. Ideally, it would also prompt entrepreneurs to develop alternatives to oil, like biofuels. Many analyses, though, suggest that, to have an appreciable effect on the oil sector, carbon taxes would have to be quite high—in the neighborhood of two dollars on a gallon of gasoline—precisely because today there are no readily available substitutes for gas or diesel or jet fuel. Farrell favors federal fuel standards, which would function somewhat like vehicle-efficiency standards, requiring oil companies to achieve a certain emissions target across all the products that they sell. (This target could be adjusted over time, much as auto-efficiency standards were ratcheted up during the seventies and eighties.) California is now in the process of drawing up such a plan—the California Low Carbon Fuel Standard is supposed to take effect on January 1, 2010—and several bills have been introduced in Congress that would impose such standards nationally.

At the same time, there is a great deal of support in Washington for measures that would, in effect, subsidize high-carbon fuels. One such measure, the Coal-to-Liquid Fuel Promotion Act, introduced earlier this year by Senators Jim Bunning, of Kentucky, and Barack Obama, of Illinois, would encourage companies to invest in C.T.L. plants by providing tax incentives and federal loan guarantees. (Although C.T.L. would be profitable at today's oil prices, building the plants requires large capital investments, which are considered risky as long as there's a chance that oil prices will fall.)

"If companies could lay off the risk of oil prices dropping below forty dollars a barrel, there would be enormous investment in this," Farrell told me. "But, when policies are proposed to promote C.T.L., I think the question to ask is, Is this an industry we want to start now?"

The Athabasca River flows north, into Lake Athabasca, which spans the Alberta-Saskatchewan border. In the winter, it is possible to drive the hundred and fifty miles from Fort McMurray to the lake on an ice road. (Because of rising temperatures, the number of days that the road is passable has been steadily shrinking.) In the summer, the only way to make the trip is by boat or by prop plane. One day when I was visiting Alberta, I flew up to a village on the edge of the lake, Fort Chipewyan, in a six-seat Cessna. As the plane gained altitude, I could see the vast black pits of the tar-sands mines that surround Fort McMurray. Farther north, the pits gave way to regularly spaced square-shaped clearings in the trees—signs of preparation for in-situ operations. Finally, these, too, gave way, and below was nothing but the wild green of the boreal forest. (Spread over 1.4 billion acres, Canada's boreal forest is considered one of the largest still intact ecosystems on the planet.)

Fort Chipewyan, which was founded in the seventeen-eighties as a trading post, is a native village; about half its twelve hundred or so residents are Mikisew Cree, and the other half are Athabasca Chipewyan. It has a few hundred houses, a post office, and two churches—one Anglican and one Catholic—both perched near the edge of the lake. To a certain extent, Fort Chip, as it is known locally, has shared in the tar-sands boom; many residents of the village work construction jobs in Fort McMurray and return home only on their days off. At the same time, there's a good deal of concern in the village about what is happening. A peculiarly high number of cases of a rare cancer have been reported in town; this has prompted speculation that toxins from the tailings ponds are working their way downriver into the lake, which provides the village with drinking water as well as with staples like whitefish and pike. Meanwhile, both the Chipewyan and the Cree consider many of the tracts that the Alberta government has leased to oil companies to be their ancestral lands. The week before I visited Fort Chip, there was a rally at the local community center, calling for a moratorium on new projects.

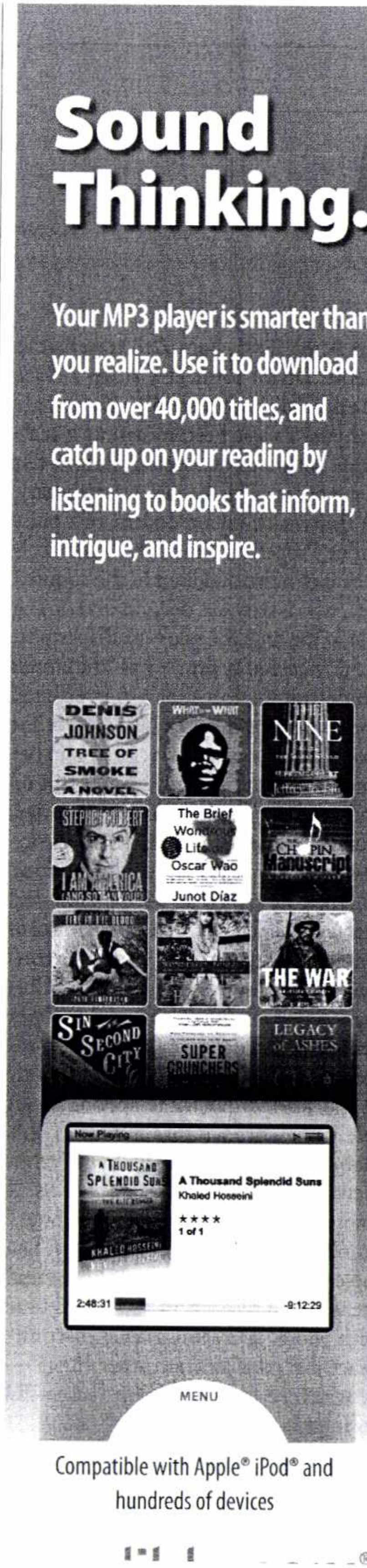
"It's sad to see this thing destroyed, you know," Ray Ladouceur, a fisherman I met, said. We were standing by the lake, which is more than two hundred miles long. It was a still afternoon, and billowy white clouds were reflected in the water. "A lot of the fish are getting—I might as well say it—scabby.

"I don't know what we have to do to try to prevent them from destroying any more," he said, referring to the oil companies. "They try to say they can clean it. There's no way. It'll take a thousand years before it flushes itself out, and I think I'll be too damn old for that."

Over the past year or so, opposition to new tar-sands projects has been steadily growing. Around Fort McMurray, the emphasis is on local impacts; town officials have fought recent expansion proposals by several oil companies on the ground that there's already a shortage of housing and hospital beds in the area. In the rest of Canada, the focus is on the destruction of the boreal forest and the implications for the climate. Canada, in contrast to the United States, was an early signatory to the Kyoto Protocol, but it will be all but impossible for the country to meet its CO_2-reduction goals, in part because of the tar sands. (A recent Toronto *Globe & Mail* op-ed piece on emissions from the sands was titled "The Gassy Elephant in Our Living Room.") The former Canadian Environment Minister Charles Caccia has compared the country's position on greenhouse gases—pledging to reduce emissions on the one hand while increasing tar-sands production on the other—to "attempting to ride two horses galloping in opposite directions."

Meanwhile, development in northern Alberta continues unabated. All the applications opposed by Fort McMurray officials were ultimately approved, and just a few months ago an American company, Hyperion Resources, announced plans to build the first new oil refinery in this country in thirty years, to handle increasing volumes of tar-sands crude. Stéphane Dion, the leader of Canada's Liberal Party (which is currently out of power), has said, "There is no environmental minister on earth who can stop the oil from coming out of the sand, because the money is too big."

When I first landed at Fort Chip's tiny airport, the place was deserted. When I returned there for the flight back, I found a few dozen people standing on the tarmac. The crowd, I was told, was waiting for a corpse; a village elder had died the previous day in a hospital in Fort McMurray, and his body was being brought home. Everyone was quiet as the casket was carried out of the plane and then loaded onto the back of a pickup truck. As soon as the crowd dispersed, I and three other passengers climbed into the Cessna, and two minutes later we took off. Below was the wilderness, then the perfectly square clearings in the trees, and, finally, as we headed into Fort McMurray, the vast pits and the black ponds, with the bitu-men bobbing on top. ♦



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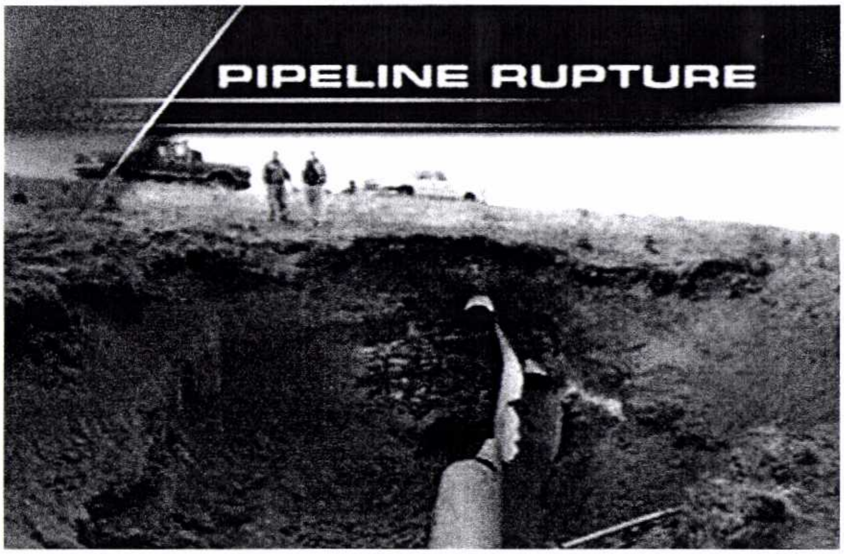

Is South Dakota Ready For High Pressure Crude Oil Pipelines?

Testimony Presented
October 31, 2007
by Curt Hohn Before the
S.D. Public Utilities Commission
In The Matter of Application HP 07-001
TransCanada-Keystone Pipeline

Photos: Pipeline failures at Whiteside County, IA, Oct. 15, 2007 (top photo) **TransCanada Pipeline south east of Grande Prairie, Dec 1, 2003** (middle & bottom photos)

"Thinner walled pipe means greater risk for South Dakota. Much of the steel pipe that will be installed will be made in China and India. Neither country can provide the level of inspection and quality control that U.S. steel pipe company's offer.

The PUC should require that all pipe installed in South Dakota be made in the USA and be of the same wall thickness or greater wall thickness than existing oil pipelines being operated, tested and inspected by the federal government in the United States of American.

Most of TransCanada's pipeline experience is with natural gas pipelines which are less likely to spill and damage soil or ground water. When crude oil pipes leak the oil spreads out into the soil and damages the groundwater aquifers.

Curt Hohn
WEB General Manager

WEB Exhibit # 37

Why not a bond for a crude oil pipeline?

Saturday, July 21, 2007 3B

Board expands gold mine's bond

Black Hills operation affected

By Bob Mercer
American News Correspondent

PIERRE — The state Board of Minerals and Environment decided Thursday to increase the environmental-protection bonds for the Wharf Resources gold mine in the northern Black Hills.

Wharf's reclamation bond, intended to cover the costs of restoring the land if the company doesn't, was raised $236,000. The new total is $10,966,400.

The company's cyanide-spill bond was raised by $31,000 to the maximum $500,000 allowed under South Dakota.

Wharf uses a leach-pad process, where piles of ore are treated with cyanide solution that separates the gold for recovery. A pond system is used as part of the solution processing.

Wharf's expansions of two of its four leach pads, and the accompanying increase in the amount of solution being used, were the main reasons for the bonding increases.

"When we reviewed the plans, the ponds were all adequately sized to contain the extra solution," Eric Holm, a natural resources engineer for the state's mining and minerals program, told the board.

Wharf made a series of small expansions in 2006 and this year, designed to prolong the mine's life into mid-2010.

Wharf is the last remaining large-scale gold mine operating in South Dakota. Wharf mined nearly 3.3 million tons of ore in 2006 and produced 63,039 ounces of gold and 184,444 ounces of silver worth an estimated combined value of $40 million.

For its processing system, Wharf withdrew more than 42 million gallons of groundwater and used in excess of 330 tons of cyanide.

In addition to its cyanide and reclamation bonds, Wharf also has a third financial guarantee, known as a postclosure bond, to protect against any long-term environmental effects after mining has ceased and the site is reclaimed. Wharf's amount for that is $8,120,700.

WEB Exhibit # 38

TransCanada-Keystone Oil Will Sell For <u>$38 Million to $58 Million Per Day</u> They Should Treat Landowners Fairly And Pay For Any Leaks Or Property Damage

Below is a list of things that WEB believes the SD Public Utilities Commission, Governor Rounds and the South Dakota Legislature <u>Can Do</u>, IF they are willing to provide a <u>reasonable measure of protection</u> for South Dakota landowners and rural water systems.

1. **Increase Pipe Wall Thickness:** TransCanada-Keystone could design their high pressure oil pipeline with **<u>wall thickness of 0.78 inch instead of 0.33 inch</u>** <u>thick</u> whenever this high pressure crude-oil pipeline route comes near **a town, school, home, farm, business, park, rural water system or other public areas**. With profits TransCanada and the oil industry are making on $99 a barrel oil and $3.00 gas they can well afford to do things right in South Dakota.

2. **Reserve Fund**: As part of their permit application approval, **South Dakota should collect a <u>fee on all oil that flows through the state through the TransCanada-Keystone Pipeline</u> on a per-barrel basis to help cover the costs associated with spills, accidents, fires, environmental impacts, clean-up, and property damage.** A $0.15 per barrel toll on 590,000 barrels per day would generate $88,500 per day or $32.3 million per year. If TransCanada has a leak that damages the aquifer that the BDM Rural Water System relies on it could cost over $22 million to bring in water from WEB or some other alternate source. If the WEB water lines serving Day County are contaminated by an oil spill, it would cost of $11.5 million to replace the system. If productive farm land crossed by the pipeline is damaged by an oil spill the fund would be available to reimburse the landowner for their loss. O**il selling for $65 per barrel will generate $38.5 million per day ($14 billion/year) in sales for TransCanada and their partners and investors.** Oil **selling for $99 per barrel will generate $58.5 million per day ($21.4 billion/year) in sales for TransCanada and their partners and investors.**

3. **No Eminent Domain:** South Dakota should not allow a **private company from a foreign country** to condemn and take the property of US citizens and South Dakota taxpayers by eminent domain. TransCanada-Keystone should be <u>required</u> to secure all easements from **willing sellers** without the threat of condemnation hanging over the landowners head. Condemnation of privately owned land should be discouraged and should be done only as a last resort and then only after all other alternatives and options have been exhausted. To assure that this happens, the PUC or the Governor and Legislature should establish a **process where landowners can appeal without having to go to court.** No land should be taken during this process. Rural water systems have installed thousands of miles of water lines using voluntary negotiated easements, without the use or threat of forced condemnation. Out-of-state out –of-country oil companies should be required to do the same. **No land acquisition activity should be allowed to begin until <u>after</u> a permit has been granted by the PUC and the legal appeal process has run its course.**

5. **Liability For Oil Spills, Cleanup & Damages:** TransCanada-Keystone should be <u>required</u> to reimburse landowners, adjacent property owners, water utilities, county government, township government and public lands and resources for any damage or impacts caused by an oil spill, pipeline construction or pipeline operations. Crop damage should be paid each year for the life of the pipeline because the heated oil will reduce crop. **This should be included as a condition of any permit issued by PUC.**

WEB Exhibit # 39

6. **Liability Insurance Coverage**: TransCanada-Keystone should be required to provide **proof of liability insurance coverage and a certificate of insurance** naming the State of South Dakota, counties, rural water systems, townships, utilities and individual landowners crossed by the pipeline as "**additional insured**" on the policy. The insurance policy should cover the operating life of the crude-oil pipeline, which is estimated by TransCanada at 50 years or more and should obligate all partners involved in the crude-oil pipeline, including LLC and LP.

7. **Post A Cash Bond:** South Dakota currently requires the owners of Homes take Gold Mine to post a cash bond to cover the costs of environmental impacts (See Exhibit 38). TransCanada and it's partners should be required to do the same thing. By **posting a bond or cash payment** with the State of South Dakota, the Public Utilities Commission and/or the Department of Environment and Natural Resources could be used to cover the cost of clean-up of any oil spills or leaks that may occur during the 50-year life of the TransCanada-Keystone Oil Pipeline. The permit application TransCanada filed with the federal government predicts that there will be oil leaks and pipe failure in 5 to 7 years (*Pipeline Risk Assessment pg 3-2 and DNV—Frequency Volume Study, May 2006). The "Frequency Volume Study"* prepared by DNV Consulting, risk management consultants hired by TransCanada, states that 53% of the oil leaks could be pinhole leaks and that the monitoring systems **will not detect leaks of 1.5% pipeline volume which means 370,000 gallons per day** of oil could leak from the system and not be detected for days, months or even up to 90 days according to the DNV report. (See DNV Report Filed on the PUC website)

8. **Dispute Arbitration:** The South Dakota Legislature should give the Public Utilities Commission or some other state agency the authority and responsibility to **arbitrate or mediate easement acquisition disputes** in an effort to reach reasonable settlement before TransCanada or other oil and gas pipelines are allowed to use South Dakota eminent domain laws to condemn land held in private ownership. The process should include independent appraisers using methods to determine fair compensation for temporary and permanent right-of-way easements including loss of crop production, loss of groundwater supplies, and other costs. Some states that have more experience will oil pipelines use special commissions made up of landowners in the community. The rights of private property owners along the pipeline route in South Dakota should not be left to the mercy of professional land acquisition agents sent in to the state by a foreign oil company.

9. **Strengthen Oil Pipeline Safety Laws:** The South Dakota Legislature should strengthen South Dakota laws and establishing a process for evaluating damage to land, water and resources by a gas or oil spill and a method and process for determining compensation for property damage caused by a gas or crude oil spill. The plan should include an administrative appeals process available to landowners and property owners who are not satisfied with the result of negotiations with TransCanada-Keystone or other gas and oil pipeline builders and operators. The process should be at no cost to the landowner.

10. **Require Prior Engineering Plan Review & Approval**: The Department of Environment and Natural Resources (DENR) must approve construction plans for livestock feedlot lagoons, fuel storage containment and for all water and sewer systems before they are built in South Dakota. Why not the same requirement for high pressure crude-oil and gas pipelines? The Legislature should require that oil and gas pipeline companies crossing South Dakota present detailed construction plans stamped by engineers licensed to do business in South Dakota to the Department of Environment and Natural Resources for prior review and approval before any easements are secured and most certainly before any permits are approved by the PUC or any other agency.

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TransCanada-Keystone Oil Will Sell For <u>$38 Million to $58 Million Per Day</u> They Should Treat Landowners Fairly And Pay For Any Leaks Or Property Damage

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