BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE PETITION OF TRANSCANADA KEYSTONE PIPELINE, LP FOR ORDER ACCEPTING CERTIFICATION OF PERMIT ISSUED IN DOCKET HP09-001 TO CONSTRUCT THE KEYSTONE XL PIPELINE	))))))))	Docket 14-001 **TESTIMONY OF CINDY MEYERS**

Statement for the South Dakota Public Utilities Commission ("PUC")

My name is Cindy Myers, R.N. My address is 87925 468th Ave., PO Box 104, Stuart, NE 68780.

This testimony is submitted regarding Amended Conditions: 2, 34, 35, 36, 40, 46 and Finding of Facts: 41, 50, 107 of the Amended Final Decision and Order in HP 09-001.

Introduction

Benzene, a potent carcinogen, has increasingly become the most threatening of all environmental toxins. Cancer is primarily an environmental disease. Allowing one of the largest pipelines filled with the world's dirtiest oil, under the most extreme pressure to funnel benzene and other toxins into South Dakota is a major public health threat. The lifeblood of South Dakota, the Missouri River, which supplies water to over 50% of the state must be protected. The pristine High Plains Aquifer in Tripp County will have this mega toxic infrastructure immersed in water which supplies a municipal well and several private wells. Water protection and Medical Response Planning are not sufficiently considered for this project.

SDCL 49-41 B-22 states: The applicant for a facility construction permit has the burden of proof to establish that:

> "The facility will not substantially impair the health, safety or welfare of the inhabitants."

TransCanada Keystone Pipeline, LP ("TransCanada") has failed to meet this burden of proof. TransCanada has failed the most important condition of this application: the health, safety and welfare of South Dakotans. I ask the PUC to put aside economic benefits for a foreign company and instead think about what is in the best interest of the good people of South Dakota.

Testimony

As a Registered Nurse, I believe two issues are of paramount importance in ensuring the health, safety, and welfare of South Dakota's residents: (1) clean drinking water, and (2) medical preparedness. If the PUC approves the proposed KXL Pipeline, I believe the health, safety, and welfare of citizens will be impaired or at risk.

Toxicity

Benzene is a potent carcinogen. According to E.P.A. standards, the maximum contamination goal in water is zero. The allowable limit in drinking water is only 5 parts per billion! This is so dilute, you can't taste, see or smell this toxic amount in drinking water. It can only be discovered by testing. Therefore, it would be possible to drink benzene unknowingly. Benzene is a component of oil and the diluent used to thin heavy tar sands oil. We don't know the exact amount because this information is kept from the public by TransCanada, even though such minute amounts of benzene can have major adverse health effects.

NAPHTHA is the primary diluent for bitumen. It is a brew of chemicals, including benzene. Up to 50% of the tar sands product is diluent, meaning 10,000,00 gallons a day of this poison would be gushing through South Dakota daily through a 36 inch pipe under extremely high pressure. NAPHTHA is a known carcinogen, but also capable of causing birth defects and reproductive harm. Scientists and medical professionals in Utah are connecting benzene to a host of severe medical diagnoses, thinking benzene, toluene, and xylenes cross the placental barrier, resulting in dead babies and birth defects.

TransCanada admits: "Benzene can result in health impacts from short-term exposure or long-term exposure." But according to John Stansbury, Ph.D., Associate Professor of Environmental/Water Resources Engineering at U.N.L. , TransCanada has failed to adequately study benzene: "If the leak does go undetected for 90 days as the TransCanada document reports, a groundwater user could be exposed to unacceptable concentrations of benzene for a significant period of time. There should have been a human health risk assessment that would have estimated the increased risk of cancer, but there isn't any such assessment. They simply indicate that there could be a significant, undetected release of benzene which could be consumed by human receptors and leave it at that."

The 2010 permit clearly indicates concern about chemicals in the KXL product: BTEX (benzene, toluene, ethyl benzene, xylene). The 2010 permit directs: "At least forty-five days prior to construction, Keystone shall publish a notice in each newspaper of general circulation in each county through which the Project will be constructed advising landowners and public water supply systems of this condition."

Dr. Cleve Trimble is a Nebraska physician concerned about health impacts from the unknown chemical composition and the difficulty in providing treatment.

Aquifers

This massive toxic infrastructure is routed to go straight through the Ogallala Aquifer in Tripp County. This is a major health threat to people drinking from the several private wells and public water system drinking water from that source. Condition of Permit #35 states "The evidence in the record demonstrates that in some reaches of the Project in southern Tripp County, the High Plains Aquifer is present at or very near ground surface and is overlain by highly permeable sands permitting the uninhibited infiltration of contaminants." Residents are not even informed if they live in a "high consequence area" and risks associated with that designation.

I live where the first KXL route was to cross in Nebraska. That route was moved because of the high water table and sandy soil, similar to the situation in Tripp County which is also underlain by the Ogallala Aquifer. If this was reason to change the route in Nebraska, how come it is still acceptable in South Dakota?

Neither TransCanada nor SD have plans to do prophylactic analyses for the very potential undetected leaks, choosing only to do analyses "in the event of a release." TransCanada ran the route straight through the Ogallala Aquifer to get the shortest route to the Bakken Oil, telling me: "Meeting the proposed project's purpose and need, including the extent to which additional infrastructure (pipeline) is necessary to access Bakken crude oil." The priority here should be the people who drink water in Tripp County.

TransCanada admits other aquifers may not be identified until construction, implying that a thorough pre-evaluation of route has not been accomplished. Oil migrates deep into the ground. In the wheat field near Tioga, ND, 50 feet of soil was required to be removed to evacuate all the spilled oil.

Waterways

TransCanada plans to route KXL through major river valleys in South Dakota: Little Missouri, Cheyenne and White River. These waterways feed into the life blood of South Dakota, the Missouri River. Intakes from the Cheyenne and Missouri Rivers provide drinking water to many cities and reservations across the state, stretching from the Pine Ridge Reservation in western SD to Sioux Falls near the state's eastern border.

We know the tar sands spill into Michigan's Kalamazoo River spread several miles downstream. Visible oil from the 2011 Silvertip pipeline break into the Yellowstone River was found 70 miles downstream. An oil sheen was seen an estimated 100 miles downriver three days after the Jan 2012 pipeline break in the Yellowstone River near Glendive, MT. What we don't know and see is exactly how far and where the benzene plumes migrate to down the rivers.

Arden Davis and John Stansbury both estimate hundreds of miles. The Department of State's environmental study, relied on by South Dakota, only takes into consideration the impact of spills 10 miles downstream.

Waterway Crossing	Distance to Missouri River	Public Water Intake	Distance from KXL to Water Intake
Cheyenne River	89.5 miles	Cheyenne Reservation	50-60 miles, est.
Cheyenne River	89.5 miles	OSRWSS	89.5, est.
Cheyenne River	89.5 miles	Chamberlain	156 miles, est.
White River	82.4 miles	Yankton	222 miles, est
White River	82.4 miles	Sioux Falls	unknown location

Health Impact Assessment

The Commission's 2010 permit relies on the federal EIS, prepared by the Department of State.

SDCL 49-41 B-21:"Environmental impact statement. Prior to the issuance of a permit, the commission may prepare or require the preparation of an environmental impact statement that complies with the provisions of chapter 34A-9"

The federal EIS, required for a cross-border Presidential permit, is not sufficient to adequately address concerns pertinent to South Dakota, particularly health concerns

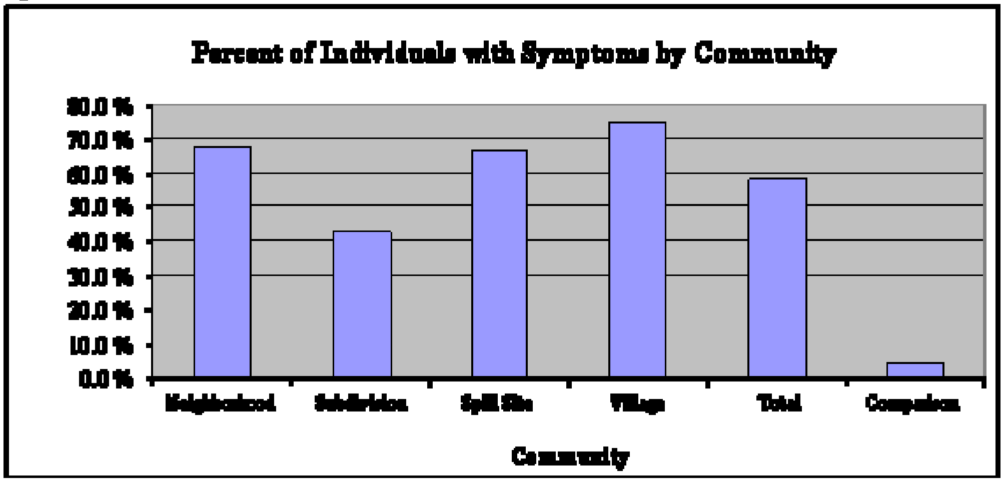
The FSEIS has several chapters. There are chapters exclusively for wildlife, fisheries and threatened and endangered species. There is even a chapter just about terrestrial vegetation, but….there is not even one chapter devoted to how KXL will impact people! The federal study does not include a health impact assessment and the state of SD did not do a health impact assessment.

Medical Preparedness

Tar sands oil spills into Michigan's Kalamazoo River and into the community of Mayflower, Arkansas have demonstrated that medical communities must be prepared to respond to major oil spills and the specifics of benzene toxicity. Emergency response is mentioned in the 2010 permit, implying a response plan for cleaning up spills, but this does not describe an emergency medical response plan.

Acute Health Effects of the Enbridge Oil Spill (Kalamazoo) Michigan Department of Health identified 320 (58%) of 550 individuals with adverse health effects from four community surveys along the impacted waterways.

Figure 3



TransCanada's pamphlet "Oil Pipeline for Emergency Responders", contains absolutely no information geared toward health care providers. It simply says to "Monitor for I-EL, H S and benzene if possible". What lay person knows what that means? Are first responders equipped to test for benzene in the air?

TransCanada declares "Public disclosure of the emergency response plan could commercially disadvantage keystone." Not preparing the medical community for tar sands oil spills could physically disadvantage South Dakotans.

TransCanada has not communicated with Indian Health Services or South Dakota health care facilities medical information such as specifics about tar sands oil product, KXL spill scenarios, and staff education and training for effective treatment of people exposed to benzene. Treating adverse health effects from massive benzene toxicity is not usual for most health professionals.

The "Draft" TransCanada-Keystone Emergency Response Plan in the FSEIS, Appendix Q does not include medical response planning, only a place to list the nearest hospital.

I visited with Kevin Schlosser, Emergency Management Coordinator
Avera McKennan in Sioux Falls (Assists Avera St. Mary's, Pierre, SD) He has not seen a Safety Data Sheet, SDS, describing chemicals involved in tar sands oil. He would like to know "What are we dealing with? What is the time-frame? When would it would reach us (in the water). I have not seen any of that. For decontamination purposes and for treating patients, we rely on a SDS. If they would provide a SDS, it would be kept in the Emergency Department to have readily available."

Kevin is not aware of education or training to prepare medical communities to affectively respond to major oil spills. TransCanada directed me to the FSEIS when I asked about an MSDS. The FSEIS gave samples of an MSDS, but stated they do not represent the actual product that would flow through the proposed Keystone XL pipeline. TransCanada has responded "TransCanada is not a medical provider and does not provide medical information. The local medical authority has jurisdiction during an incident or emergency."

Contamination of Public Water Intakes

GLENDIVE MONTANA, January 2015
"Breach in pipeline found; cancer-causing agent detected in water "
--- Billings Gazette

What happened in Glendive MT, could happen in SD. After an oil pipeline spilled miles upstream, benzene was found to be up to triple the mcl in the public water system. The residents weren't warned not to drink the water until two days later! Because water treatment plants do not remove benzene, water plants must be shut down.

Are Water Treatment Plants Prepared in SD?

I contacted three water treatment plants using Missouri River water. Two plants responded they were unaware of any emergency plan in response to a tar sands oil spill directly or indirectly affecting the Missouri. One plant stated the Bureau of Reclamation would notify them if an oil spill threatened the water supply. Another plant stated DNR usually sends out information, but "haven't heard a word from them" when asked what he knew about tar sands spillage into water. One plant thought benzene analysis was done quarterly and another plant thought benzene analysis was done yearly. The third plant did say a spill kit (for water analyses) is available for emergencies.

Dr. Madden Testimony

Testimonial analysis by Dr. Madden is woefully inadequate to meet SDCL 49-41 B-22. which requires the project must protect the health, safety and welfare of SD residents. He is not a medical doctor, but an economist

INDUSTRY	SOURCE OF ECONOMIC IMPACTS	DIRECTION OF IMPACT	NET IMPACT
HEALTH	Revenue	Positive	Positive
	Labor Costs	None Significant	
	Displacement of Traditional Users	None	

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Conclusion

Who is responsible for the health,safety and welfare of SD citizens? TransCanada responded these concerns were addressed by the commission, but the law clearly states the applicant is responsible.

SDCL 49-41 B-22 states: The applicant for a facility construction permit has the burden of proof to establish that:

“The facility will not substantially impair the health, safety or welfare of the inhabitants.”

TransCanada has not met the burden of proof establishing this project will not impair the health, safety or welfare of the good people of South Dakota and the many other US citizens living downstream.

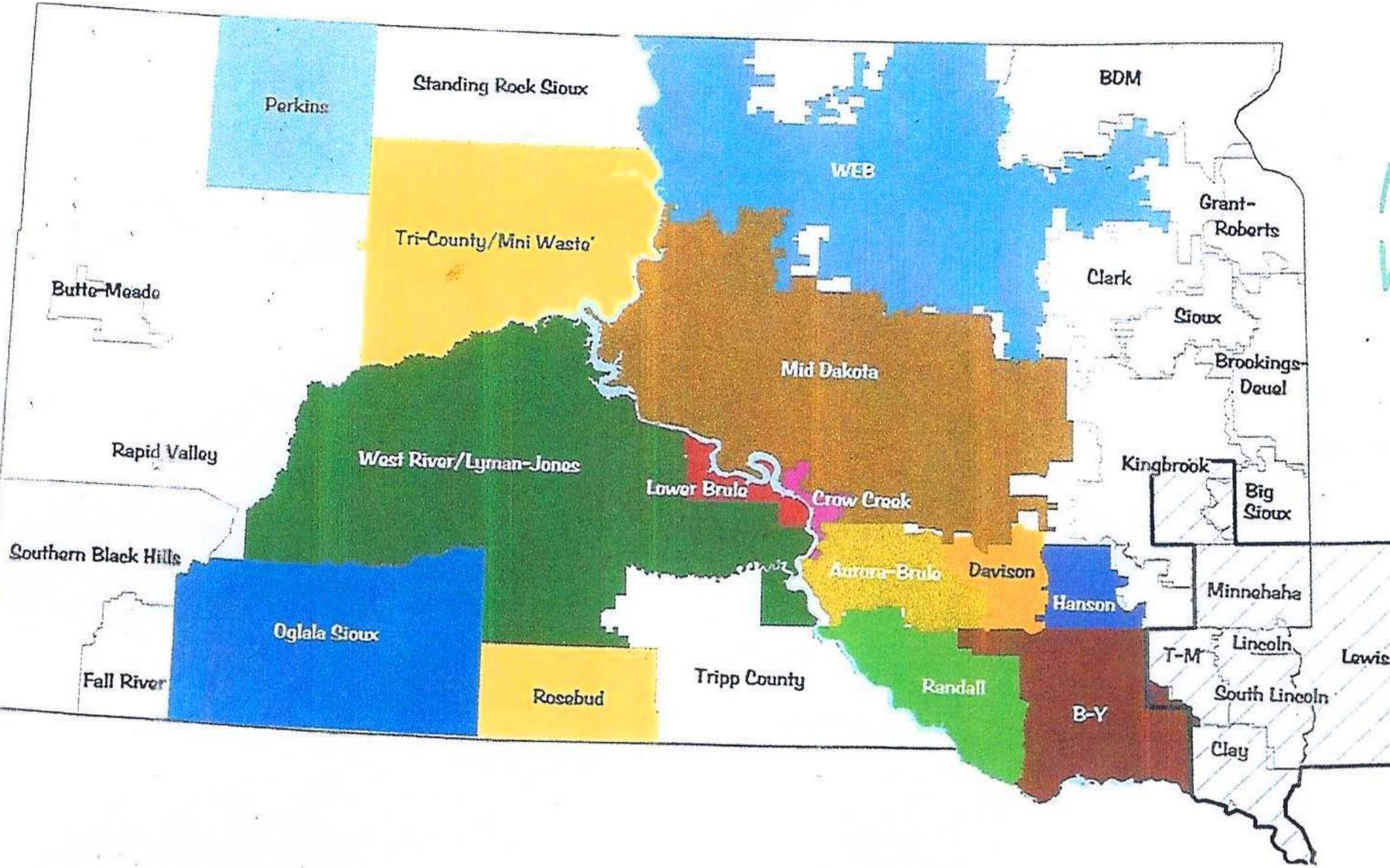
TransCanada affirmed to me “Keystone has not asserted that the project would have ‘no impact on the health, safety and welfare of SD’”.

____________________________________ April 2, 2015

CINDY MYERS, R.N.

Paul Seamans
April 2015

I have added up the counties populations of the rural water systems that rely on Missouri River water. It is hard to get an exact count because a lot of the water districts don't always follow county lines. I came up with an approximate 2010 census figure of 500,000 people that rely on Missouri River water. The 2010 census figures for South Dakota's population is 814,000. The percentage of South Dakota's population that gets their water from the Missouri would equal around 61%. The 2014 estimates have South Dakota's population at 853,000 and a large portion of that growth is in the Sioux Falls metro area so this figure would be closer to 64%. I think a person is real safe in saying that at least half of South Dakota relies on the Missouri River for their drinking water, in all actuality it is probably closer to two thirds.



Perkins
Standing Rock Sioux
BDM
WEB
Grant-
Roberts
Tri-County/Mini Waste'
Clark
Butte-Meade
Sioux
Mid Dakota
Brookings-
Deuel
Rapid Valley
West River/Lyman-Jones
Kingbrook
Lower Brule
Crow Creek
Big
Sioux
Southern Black Hills
Aurora-Brule
Davison
Hanson
Minnehaha
Oglala Sioux
Lincoln
T-M
Lewis
Fall River
Tripp County
Randall
Rosebud
South Lincoln
B-Y
Clay

029805

Analysis of Frequency, Magnitude and Consequence of Worst-Case spills from the Proposed Keystone XL Pipeline

John Stansbury, Ph.D., P.E.

Executive Summary

TransCanada is seeking U.S. regulatory approval to build the Keystone XL pipeline from Alberta, Canada to Texas. The pipeline will transport diluted bitumen (DilBit), a viscous, corrosive form of crude oil across Montana, South Dakota, Nebraska, Kansas, Oklahoma and Texas. As part of the regulatory process, the National Environmental Policy Act (NEPA) requires an assessment of the potential environmental impacts of a pipeline spill. The Clean Water Act (CWA) also requires TransCanada to estimate the potential worst-case discharge from a rupture of the pipeline and to pre-place adequate emergency equipment and personnel to respond to a worst-case discharge and any smaller spills. The Keystone XL environmental assessment documents (e.g., Draft Environmental Impact Assessment) as well as the environmental impacts documents for the previously built Keystone pipeline, can be found on the US State Department web site. It is widely recognized that the environmental assessment documents for the Keystone XL pipeline are inadequate, and that they do not properly evaluate the potential environmental impacts that may be caused by leaks from the pipeline (e.g., USEPA 2011a). The purpose of this paper is to present an independent assessment of the potential for leaks from the pipeline and the potential for environmental damage from those leaks.

The expected frequency of spills from the Keystone XL pipeline reported by TransCanada (DNV, 2006) was evaluated. According to TransCanada, significant spills (i.e., greater than 50 barrels (Bbls)) are expected to be very rare (0.00013 spills per year per mile, which would equate to 11 significant spills for the pipeline over a 50 year design life). However, TransCanada made several assumptions that are highly questionable in the calculation of these frequencies. The primary questionable assumptions are: (1) TransCanada ignored historical data that represents 23 percent of historical pipeline spills, and (2) TransCanada assumed that its pipeline would be constructed so well that it would have only half as many spills as the other pipelines in service (on top of the 23 percent missing data), even though they will operate the pipeline at higher temperatures and pressures and the crude oil that will be transported through the Keystone XL pipeline will be more corrosive than the conventional crude oil transported in existing pipelines. All of these factors tend to increase spill frequency; therefore, a more realistic assessment of expected frequency of significant spills is 0.00109 spills per year per mile (from the historical data (PHMSA, 2009)) resulting in 91 major spills over a 50-year design life of the pipeline.

The CWA requires that TransCanada estimate the “worst-case spill” from the proposed pipeline (ERP, 2009). TransCanada’s calculation of the worst-case spill from the proposed Keystone XL pipeline was not available at the time of this assessment, so an assessment of the methods used by TransCanada for the existing Keystone pipeline and a comparison of the results of those methods with the methods recommended in this analysis were made. The worst-case spill volume at the Hardisty Pumping Station on the Keystone (the original pipeline will be referred to as simply the Keystone pipeline while the proposed pipeline is the Keystone Xl pipeline) pipeline predicted using methods recommended in this analysis was 87,964 barrels

(Bbl), while the worst-case spill predicted using TransCanada's methods was 41,504 Bbl (ERP, 2009). The difference is a factor of more than 2 times. The primary difference between the two methods was the expected time to shut down the pumps and valves on the pipeline. TransCanada used 19 minutes (TransCanada states that it expects the time to be 11.5 minutes for the Keystone XL pipeline). Since a very similar pipeline recently experienced a spill (the Enbridge spill), and the time to finally shut down the pipeline was approximately 12 hours, and during those 12 hours the pipeline pumps were operated for at least 2 hours, it is clear that the assumption of 19 minutes or 11.5 minutes is not appropriate for the shut-down time for the worst-case spill analysis. Therefore, worst-case spill volumes are likely to be significantly larger than those estimated by TransCanada. The worst-case spill volumes from the Keystone XL pipeline for the Missouri, Yellowstone, and Platte River crossings were estimated by this analysis to be 122,867 Bbl, 165,416 Bbl, and 140,950 Bbl, respectively. In addition, this analysis estimated the worst-case spill for a subsurface release to groundwater in the Sandhills region of Nebraska to be 189,000 Bbl (7.9 million gallons).

Among numerous toxic chemicals that would be released in a spill, the benzene (a human carcinogen) released from the worst-case spill into a major river (e.g., Missouri River) could contaminate enough water to form a plume that could extend more than 450 miles at concentrations exceeding the Safe Drinking Water Act Maximum Contaminant Level (MCL) (i.e., safe concentration for drinking water). Therefore, serious impacts to drinking water intakes along the river would occur. Contaminants from a release at the Missouri or Yellowstone River crossings would enter Lake Sakakawea in North Dakota where they would adversely affect drinking water intakes, aquatic wildlife, and recreation. Contaminants from a spill at the Platte River crossing would travel downstream unabated into the Missouri River for several hundred miles and affect drinking water intakes for hundreds of thousands of people in cities like Lincoln, NE; Omaha, NE; Nebraska City, NE; St. Joseph, MO; and Kansas City, MO, as well as aquatic habitats and recreational activities. In addition, other constituents from the spill would pose serious risks to aquatic species in the river. The Missouri, Yellowstone, and Platte Rivers all provide habitat for threatened and endangered species including the pallid sturgeon, the interior least tern, and the piping plover. A major spill in one of these rivers could pose a significant threat to these species.

The benzene released by the worst-case spill to groundwater in the Sandhills region of Nebraska would be sufficient to contaminate 4.9 billion gallons of water at concentrations exceeding the safe drinking water levels. This water could form a plume 40 feet thick by 500 feet wide by 15 miles long. This plume, and other contaminant plumes from the spill, would pose serious health risks to people using that groundwater for drinking water and irrigation.

Introduction

TransCanada is seeking U.S. regulatory approval to build the Keystone XL pipeline from Alberta, Canada to Texas. The pipeline will transport diluted bitumen (DilBit), a viscous, corrosive form of crude oil across Montana, South Dakota, Nebraska, Kansas, Oklahoma, and Texas. As part of the regulatory process, TransCanada is required by the National Environmental Policy Act (NEPA) to evaluate the potential environmental impacts of a pipeline spill. The Clean Water Act (CWA) also requires TransCanada to estimate the potential worst-case discharge from a rupture of the pipeline and to pre-place adequate emergency equipment and personnel to respond to a worst-case discharge and any smaller spills. The Keystone XL environmental assessment documents (e.g., Draft Environmental Impact Assessment) as well as the environmental impacts documents for the previously built Keystone pipeline, can be found on the US State Department web site. It is widely recognized that the environmental assessment documents for the Keystone XL pipeline are inadequate, and that they do not properly evaluate the potential environmental impacts that may be caused by leaks from the pipeline (e.g., USEPA, 2011a). The purpose of this paper is to present an independent assessment of the potential for leaks from the pipeline and the potential for environmental damage from those leaks.

In addition to evaluating potential environmental damage from pipeline leaks, TransCanada is required by law to pre-position emergency equipment and personnel to respond to any potential spill. This paper does not address these requirements. However, an independent assessment of TransCanada's emergency response plans for the previously built Keystone pipeline was done by Plains Justice (Blackburn, 2010). This document clearly shows that the emergency response plan for the Keystone pipeline is woefully inadequate. Considering that the proposed Keystone XL pipeline will cross much more remote areas (e.g., central Montana, Sandhills region of Nebraska) than was crossed by the Keystone pipeline, there is little reason to believe that the emergency response plan for Keystone XL will be adequate.

Since spills from these pipelines will occur, and since they will be extremely difficult and expensive to clean up (likely tens to hundreds of millions of dollars), it is imperative that TransCanada be required to be bonded for these clean-up costs before any permits are granted. This proposed requirement is supported by the recent Enbridge spill, where a smaller crude-oil pipeline leak released crude oil into a tributary of the Kalamazoo River, and early clean-up costs, as reported in Enbridge's annual report, have exceeded $500 million (Enbridge, 2011).

Worst-Case Spill

One of the requirements of the CWA is to calculate the worst-case potential spill from the pipeline. An assessment of the potential worst-case spill from the Keystone pipeline was conducted by TransCanada; however, some of the methods and assumptions in that assessment are in question. The primary focus of this paper is to provide an independent assessment of the worst-case spill from the Keystone XL pipeline and to compare that to the assessment done by TransCanada.

<u>Spill frequency</u>

To support understanding of the potential impacts due to releases from the pipeline, an assessment of the likely frequency of spills from the pipeline is made. TransCanada calculated the likely frequency of a pipeline spill for the Keystone XL pipeline in the Draft Environmental Impact Statement (ENTRIX, 2010) using statistics from the Pipeline and Hazardous Materials Safety Administration (PHMSA). Nation-wide statistics from PHMSA for spills from crude oil pipelines show 0.00109 significant (i.e., greater than 50 Bbl) spills per mile of crude oil pipelines per year. When this rate is applied to the Keystone XL pipeline with a length of 1,673 miles, the expected frequency of spills is 1.82 spills per year (0.00109 spills/mi* 1,673 mi). Adjusting the nation-wide PHMSA data to only include data from the states through which the Keystone XL pipeline will pass results in a frequency of 3.86 spills per year for the pipeline length (ENTRIX, 2010).The state-specific data are more applicable to the Keystone location; however, the smaller state-specific data base might over-estimate spill frequency. Therefore, the frequency of 1.82 per year is adopted as the best available value for this assessment. Assuming a design life of 50 years for the pipeline, 1.82 spills per year results in 91expected significant spills (i.e., greater than 50 barrels) for the Keystone Pipeline project. According to the TransCanada Frequency-Volume Study of the Keystone Pipeline (DNV, 2006), 14 percent of the spills would likely result from a large hole (i.e., greater than 10 inches in diameter). Using the 14 percent value, the 91 expected spills during a 50-year lifetime for the pipeline would result in 13 major spills (i.e., from holes larger than 10 inches in the pipeline).

However, TransCanada diverged from historical data and modified the estimate of the expected frequency of spills from the pipeline (DNV, 2006). The company's primary rationale for reducing the frequency of spills from the pipeline was that modern pipelines are constructed with improved materials and methods. Therefore, TransCanada assumed that pipelines constructed with these new improved materials and methods are likely to experience fewer leaks. The revised expected frequency for spills was reported in the Frequency-Volume Study (DNV, 2006) to be 0.14 spills/year over the 1,070 miles from the Canadian border to Cushing, OK. This value was adjusted to 0.22 spills per year for the total 1,673 miles of pipeline, including the Gulf Coast Segment (ENTRIX, 2010). Using the 0.22 spills/year, TransCanada predicted 11 spills greater than 50 barrels would be expected over a 50-year project life.

This reduced frequency estimated by TransCanada is probably not appropriate for a couple of reasons. First, the study of the revised frequency ignored some of the historical spill data; i.e., the spill cause category of "other causes" in the historical spill data set (DNV, 2006). The "other causes" category was assigned for spills with no identified causes. Since this category represents 23 percent of the total spills, this is a significant and inappropriate reduction from the spill frequency data. In addition, the assumed reduction in spill frequency resulting from modern pipeline materials and methods is probably overstated for this pipeline. TransCanada used a reduction factor of 0.5 in comparison to historical data for this issue. That is, according to TransCanada, modern pipeline construction materials and methods would result in half as many spills as the historical data indicate. However, the PHSMA data used in the TransCanada report were from the most recent 10 years. Therefore, at least some of the pipelines in the analysis were modern pipelines. That is, the initial frequency estimate was calculated in part with data from modern pipelines; therefore, a 50 percent reduction of the frequency estimates is highly questionable based on the data set used. More importantly, DilBit, the type of crude oil to be transported through the Keystone XL pipeline will be significantly more corrosive and abrasive than the conventional crude oil transported in most of the pipelines used in the historical data set. The increased corrosion and abrasion are due to 15 – 20 times the acidity (Crandall, 2002), 5 – 10 times the sulfur content (Crandall, 2002), and much higher levels of abrasive sediments (NPRA, 2008) compared to conventional crude oil. In addition, the high viscosity of DilBit requires that the pipeline be operated at elevated temperatures (up to 158^{o}F for DilBit and ambient temperature for conventional oil) and pressures (up to 1440 psi for DilBit and 600 psi for conventional oil) compared to conventional crude oil pipelines (ENTRIX, 2010). Since corrosion and pressure are the two most common failure mechanisms resulting in crude oil releases from pipelines (DNV, 2006), increased corrosion and pressure will likely negate any reduced spill frequency due to improvement in materials and methods. Although pipeline technology has improved, new pipelines are subject to proportionally higher stress as companies use this improved technology to maximize pumping rates through increases in operational pressures and temperatures, rather than to use this improved technology to enhance safety margins.

Also, TransCanada relies heavily on “soft” technological improvements, such as computer control and monitoring technology, rather than only on “hard” improvements, such as improved pipe fabrication technology. Whereas “hard” technological improvements are built into pipelines, “soft” improvements require an ongoing commitment of monitoring and maintenance resources, which should not be assumed to be constant over the projected service life of the pipeline, and are also subject to an ongoing risk of error in judgment during operations. As demonstrated by the spill from Enbridge’s pipeline into the Kalamazoo River, as pipelines age maintenance costs increase, but pipeline company maintenance efforts may be insufficient to prevent major spills, especially if operators take increased risks to maintain return on investment. Moreover, TransCanada assumes that future economic conditions will allow it to commit the same level of maintenance resources from its first year to its last year of operation. Given future economic uncertainty, this is not a reasonable assumption. It is reasonable to assume that decades from now TransCanada or a future owner will likely fail to commit adequate maintenance resources, fail to comply with safety regulations, or take increased operational risks during periods of lower income. Overtime, PHMSA should assume that the risk of spill from the Keystone XL Pipeline will increase due to weakening of “soft” technological enhancements. Over the service life of the pipeline it is not reasonable to rely on TransCanada’s “soft” technological improvements to the same extent as built-in “hard” improvements.

The TransCanada spill frequency estimation consistently stated the frequency of spills in terms of spills per year per mile. This is a misleading way to state the risk or frequency of pipeline spills. Spill frequency estimates averaged per mile can be useful; e.g., for extrapolating frequency data across varying pipeline lengths. However, stating the spill frequency averaged per mile obfuscates the proper value to consider; i.e., the frequency of a spill somewhere along the length of the pipeline. Stating the spill frequency in terms of spills per mile is comparable to acknowledging that although some 33,000 deaths from automobile accidents occur annually in the U.S., the average annual fatality rate across 350 million people is only 0.000094; therefore, fatalities from automobile accidents are so rare as to be unimportant. In other words, it is of little importance to know the risk (frequency) of a release in any particular mile segment (frequency per mile); rather it is important to know the risk of a release from the pipeline. As shown above, the expected number of spills for the pipeline over the pipeline lifetime ranges between 11 and 91 spills, depending on the data and assumptions used.

In summary, there is no compelling evidence to reduce the frequency of spills because of modern materials and methods. The increased corrosiveness and erosiveness of the product being transported will likely cancel any gains due to materials and methods improvements and soft technological safeguards will likely become less effective over time. Moreover, the modified frequency stated by TransCanada should not have been reduced by omitting an important failure category. The frequency of spills should have been stated as frequency of spills across the pipeline length per year and per pipeline lifetime. Therefore, the best estimate for spill frequency is the value from the PHSMA historical data set resulting in 1.82 spills/yr or 91 significant spills over the pipeline lifetime. Table 1 compares the predicted number of spills over the lifetime of the pipeline computed from TransCanada's assumptions and from historical data.

Table 1: Predicted Number of Spills from Keystone XL Pipeline Over a 50-Year Lifetime.

	TransCanada Estimate	Estimates Using Historical Data
Spills per year per mile	0.00013[a]	0.00109[a]
Pipeline spills per year	0.22[b]	1.82[b]
Pipeline spills per 50-year lifetime	11[c]	91[c]
Pipeline spills from > 10 inch hole	1.54[d]	12.74[d]

(a) ENTRIX, 2010
(b) spills/year-mile *1673 miles
(c) spills/year* 50 years of pipeline lifetime
(d) spills/lifetime * 14percent spills from > 10 inch hole

Most Likely Spill Locations

Crude oil could be spilled from any part of the pipeline system that develops a weakness and fails. Likely failure points include welds, valve connections, and pumping stations. A vulnerable location of special interest along the pipeline system is near the side of a major stream where the pipeline is underground but at a relatively shallow depth. At these locations, the pipeline is susceptible to high rates of corrosion because it is below ground (DNV, 2006). Since the pipeline is below ground, small initial leaks due to corrosion-weakened pipe would potentially go undetected for extended periods of time (e.g., up to 90 days) (DNV, 2006) providing conditions for a catastrophic failure during a pressure spike. In these locations, pressures would be relatively high due to the low elevation near the river crossing. In addition, major leaks at these locations are likely to result in large volumes of crude oil reaching the river.

In addition to river crossings, areas with shallow groundwater overlain by pervious soils (such as the Sandhills region in Nebraska) where slow leaks could go undetected for long periods of time (e.g., up to 90 days) (DNV, 2006), pose risks of special concern.

<u>Worst Case Spill Volume</u>

The volume of a spill is calculated in two parts: the pumping rate volume and the drain-down volume. The pumping rate volume is the volume of crude oil that is pumped from the leaking pipe during the time between the pipe failure and stoppage of the pumps. The time to shut down the pumps after a leak can be divided into two phases: the time to detect the leak, and the time to complete the shut-down process. The pumping rate volume also depends on the size of the hole in the pipe and the pressure in the pipe. The drain-down volume is the volume of crude oil that is released after the pumps are stopped, as the crude oil in the pipe at elevations above the leak drains out. The following sections explain how the pumping rate volume, the drain-down volume, and the total spill volume are calculated.

<u>Pumping Rate Volume</u>

The pumping rate volume is calculated as:

$$PRV = PR * (DT + SDT)$$

Where:

PRV = pumping rate volume (Bbl)

PR = pumping rate (Bbl/min)

DT = detection time (time required to detect and confirm a leak and order pipeline shut-down (min))

SDT = shut-down time (time required to shut down pumps and to close valves (min))

TransCanada's Frequency-Volume Study (DNV, 2006) states that detection of a leak in an underground pipeline section can range from 90 days for a leak less than 1.5 percent of the pipeline flow rate to 9 minutes for a leak of 50 percent of the pipeline flow rate. The 90-day time to detection is for a very slow leak that would not be detected by the automatic leak detection system. The 9 minute time to detection is for a leak that is large enough to be readily detected by the leak detection system. However, this time estimate is questionable because, as has been shown by experience, it is difficult for the leak detection system to distinguish between leaks and other transient pressure fluctuations in a pipeline transporting high viscosity materials such as DilBit. For example, in the Enbridge pipeline spill, signals from the leak detection system were misinterpreted, and up to 12 hours elapsed between the time of the leak and final pipeline shut-down (Hersman, 2010). During the 12-hour period between the initial alarm and the final shut-down, the pipeline pumps were operated intermittently for at least two hours. It should be noted that the location of the Enbridge spill was a populated area where field verification of the leak should have been quick and easy. Indeed, local residents called 911 complaining about petroleum odors (likely from the leak) 10 hours before the pipeline was shut down. In the case of the Keystone XL pipeline, leaks could occur in remote areas (e.g., central Montana, or the Sandhills region of Nebraska) where direct observation would only occur by sending an observer to the suspected site; this could take many hours.

TransCanada states that the time to complete the pipeline shut-down sequence is 2.5 minutes (ERP, 2009). Therefore, using TransCanada's time estimates, for a 1.5 percent leak, the total time between leak initiation and shut-down could be up to 90 days, and for a large (>50 percent) leak, the total time between leak initiation and shut-down would be 11.5 minutes (ERP, 2009).

However, given the difficulty for operators to distinguish between an actual leak and other pressure fluctuations, the shut-down time for the worst case volume calculation should not be considered to be less than 30 minutes for a leak greater than 50 percent of the pumping rate. This would allow for 4 alarms (5 minutes apart) to be evaluated by operators and a 5th alarm to cause the decision to shut down. In addition, the time to shut down the systems (pumps and valves) would require another 5 minutes. The assumption that the decision to shut the pipeline down can be made after a single alarm , as is suggested by TransCanada(ERP, 2009) is unreasonable considering the difficulty in distinguishing between a leak and a pressure anomaly. The ability to make the decision to shut down the pipeline after 5 alarms is likely a reasonable "best-case" assumption. However, this "best-case" does not describe the "worst case" conditions that are being assessed here. Rather, the worst case should consider confusing and confounding circumstances where a shut-down decision is not clear and where the leak site is remote and not verifiable in a short time period. The total time is then considered to be between 30 minutes (a best-case scenario) and 12 hours (the time for the Enbridge final shut-down) from leak initiation to shut-down. Considering that the Keystone XL pipeline will cross extremely remote areas and that verification of a leak could take many hours, a shut-down time of 2 hours (i.e., the time the pumps were operated during the Enbridge shutdown process) is a reasonable time for the worst-case analysis.

Therefore, for the worst-case spill for a large leak, a shut-down time of 2 hours is assumed. With a maximum pumping rate of 900,000 Bbl/d, and a shut-down time of 2 hours, the pumping rate volume is 75,000 Bbl (900,000 Bbl/d * 1 d/24 hr* 2 hr). This pumping rate volume (75,000 Bbl) is used in the calculation of the total worst-case spill volume for all high-rate leaks (i.e., greater than 50 percent flow-rate).

The worst-case spill for a small leak could occur where the pipeline is buried and in a remote location (such as central Montana or the Sandhills region of Nebraska), and where direct observation would be infrequent. According to TransCanada documents (DNV, 2006), a slow leak of less than 1.5 percent of the pumping rate could go undetected for up to 90 days. However, since pipeline inspections are scheduled every few weeks, it is likely that the oil would reach the surface and be detected before the entire 90 days elapsed. Assuming that the pipeline is buried at a depth of 10 feet and that the 1.5 percent leak (75,802 ft^3/d) is on the bottom of the pipe, oil would fill the pore spaces in the soil mostly in a downward direction, but it would also be forced upward toward the surface. Assuming that the oil initially fills a somewhat conical volume that extends twice as far below the pipeline as above it, the oil would emerge at the surface within about one day (volume of a cone 30 feet deep with a base diameter of 30 feet is 7,068 ft^3). Therefore, the leak would likely be detected in 14 days during the next inspection (assuming bi-weekly inspections). A 1.5 percent spill at a pumping rate of 900,000 Bbl/d over 14 days would result in a release of 189,000 Bbl (7.9 million gallons).

Table 2: Pumping Rate Volume for Various Sized Leaks

Leak as percent of Pumping Rate[(a)]	Detection and Shut-Down Time	Pumping Rate Volume[(d)]
<1.5percent	14 days[(b)]	189,000 Bbl
100percent	2 hours	75,000 Bbl
100percent	11.5 minutes[(c)]	7,188 Bbl

(a) Design pumping rate for Keystone XL = 900,000 Bbl/d. Calculation of worst-case spill requires 100 percent of pumping rate.

(b) Time between pipeline inspections.(DNV, 2006)

(c) TransCanada's assumed shut-down time (ERP, 2009)

Drain-Down Volume

The drain-down volume is the volume in the pipe between the leak and the nearest valve or the nearest high point. Some oil in locally isolated low spots will tend to remain in the pipe. TransCanada arbitrarily assigned a drain-down factor of 0.6 for the Keystone XL pipeline, meaning that 40 percent of the oil in the draining pipeline at elevations above the leak will be captured in low spots. However, since siphon effects will tend to move much of the oil even in local low spots, the 40 percent retention factor is likely too high for a worst-case analysis. PHMSA regulations require valves to be placed on either side of a major water crossing. If these valves are working, they should limit the amount of crude oil that drains from the pipeline to the amount that is between the valves. However, to calculate a worst case spill, the volume should be calculated assuming that at least some of the valves fail (recall the failures of the safety devices in the recent Gulf oil spill). If the valves fail, the drain-down volume would be limited by the major high elevation points on either side of the leak, with a reasonable adjustment for residual crude oil remaining in the pipeline. For this worst-case analysis, a reasonable estimate for residual crude oil remaining in the pipeline is assumed at 20percent of the total volume of oil at elevations above the leak. All of these parameters are site-specific; therefore, for this assessment, the worst case drain-down volumes will be calculated for several of the river crossings of the Keystone XL pipeline, including the Missouri, Yellowstone, and Platte Rivers.

The drain-down volume is calculated using:

$$DDV = PLDV * DF$$

Where:

DDV = Drain Down volume (Bbl)

PLDV = Pipeline Drain Volume (Bbl) (volume of pipeline either side of the leak to next valve or high elevation point)

DF = Drainage Factor (80percent)

<u>Worst-Case Release Calculation for the Missouri River Crossing</u>

The Missouri River crossing is located at mile post (MP) 89 along the Keystone XL pipeline. The upstream valve is located at MP84, and the downstream valve is located at MP 91. The river is at an elevation of 2,035 feet. Figure 1 shows the elevation profile of the crossing at the Missouri River. Since there are no major high elevations between the river and the valve at MP 84, it is likely that nearly all of the oil in the pipeline between the valve and a hypothetical leak at the river will be siphoned or drained via gravity. If the valve at MP 84 fails, all of the oil in the pipeline between that point and the next valve (MP 81.5) could drain since the pipeline rises gradually in elevation between MP 84 and MP 81 (elevation of 2,225 feet). If the valve on the downstream side of the crossing (MP 91) fails, oil in the pipeline up to the major high point at MP 93 could drain to the hypothetical leak at the river crossing.

There are several scenarios that could affect the drain-down volume. In the worst-case scenario both valves could fail, and the drain-down volume would then be the cross-sectional area of the pipe, times the length of pipeline draining times 80 percent. For this scenario, the length of pipe is 11.5 miles (MP 81.5 to MP 93). The cross-sectional area of the 36 inch pipe is 7.07 ft^2. Thus the drain-down volume is $3.43x10^5$ ft^3 (61,164 Bbls, 2.57 million gallons). However it is highly unlikely that both valves will fail at the same time.

A second scenario would occur if both valves operated correctly but the siphon effect removed the oil from the high point downstream of the valve at MP 84. Under this scenario, the length of drained pipe is 7 miles, and the resulting drain-down volume is $2.09x10^5$ ft^3 (37,230 Bbls, 1.56 million gallons).

A third scenario would occur if both valves operated correctly, and the siphon effect did not remove the oil between the high point at MP 86.5 and the valve at MP 84. In this scenario, the length of drained pipe is 4.5 miles (valve at MP 91 to the high point at MP 86.5), and the drain-down volume is $1.34x10^5$ ft^3 (23,934Bbls, 1.01 million gallons).

A fourth scenario would occur if one of the valves fails. To be conservative, the valve closest to the river will be the assumed failed valve. In this scenario, the drain-down distance would be 9 miles (between the valve at MP 84 and the high point at MP 93). The resulting drain-down volume would be 2.69 x 10^5 ft^3 (9 mi * 5,280 ft/mi * 7.07 ft^2 * 0.8) (47,867 Bbl, 2.01 million gallons).

While the first scenario is very unlikely, valve failure is a reasonable consideration in the worst-case spill analysis. So for the purposes of this analysis the fourth scenario, where one of the valves fails, is used to calculate the worst-case spill drain-down volume for the Missouri River crossing site. Therefore, using the fourth drain-down scenario, the drain-down volume is 47,867Bbls. Adding the pumping rate volume of 75,000 Bbl, the worst-case release volume for the Missouri River crossing is 122,867 Bbl (5.16 million gallons).

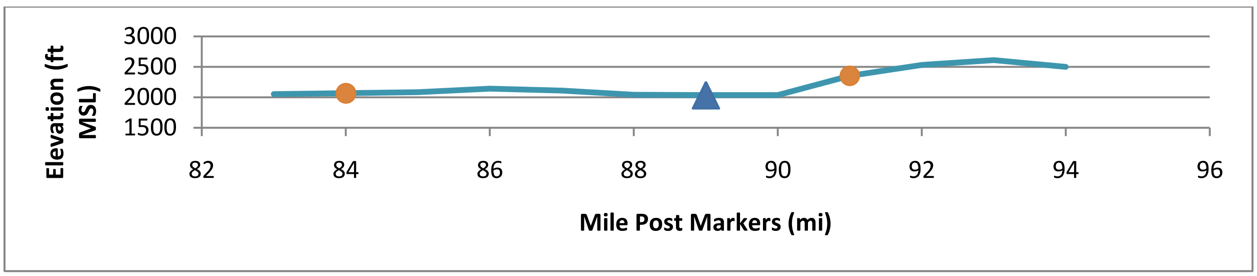


Figure 1: Horizontal profile of surface elevations at the Missouri River crossing. Note that the vertical axis is exaggerated compared to the horizontal axis. Solid circles show locations of pipeline valves. The solid triangle shows the location of the river crossing.

<u>Worst Case Release Volume Calculation for the Yellowstone River</u>

The crossing on the Yellowstone River is at MP 196.5 which is at an elevation of 2,125 feet. The closest upstream valve is at MP 194.5 at an elevation of 2,230 feet. The nearest major high point on the upstream side is at MP 183 at an elevation of 2,910 feet. The closest valve on the downstream side is at MP 200 at an elevation of 2,506 which is also the high point on the downstream side of the crossing. Figure 2 shows the elevation profile for the crossing at the Yellowstone River.

The first scenario for drain-down volume is if all valves work properly. The drain-down volume is 80 percent of the volume between the valves (the cross-sectional area of the pipe (7.07 ft^2) times the pipe length between the valves (5.5. miles)) which equals 1.64x10^5 ft^3 (29,252 Bbl, 1.23 million gallons).

Another scenario considers the volume if the valve at MP 194.5 does not work. In this case, the drain-down volume is the volume of the pipe between the two high elevations which are at MP 183 and MP 200 (17 miles). In this scenario the drain-down volume is 5.07x10^5 ft^3 (90,416 Bbl, 3.80 million gallons).Assuming failure of the valve at mile-post 194.5 is a reasonable assumption for conditions of the worst-case spill volume. The total worst-case volume is then

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the drain-down volume of 90,416 Bbl plus the pumping rate volume of 75,000 Bbl totaling 165,416 Bbl (6.95 million gallons).

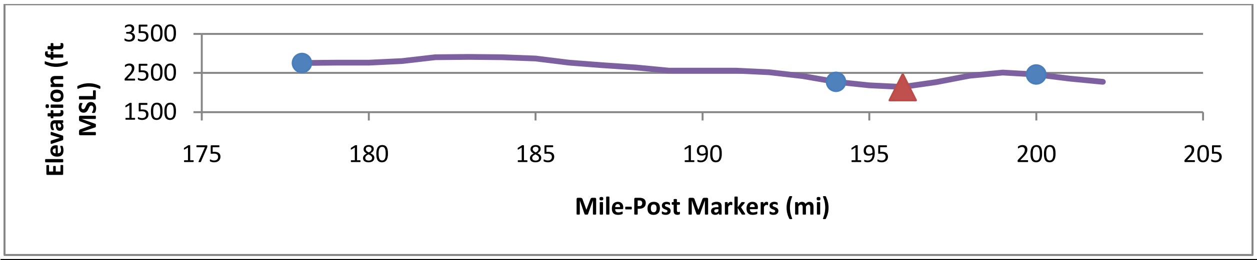


Figure 2: Horizontal profile of surface elevations at the Yellowstone River crossing. Note that the vertical axis is exaggerated compared to the horizontal axis. Solid circles show locations of pipeline valves. The solid triangle shows the location of the river crossing.

Worst-Case Release Volume Calculation for the Platte River, NE

The Keystone XL Pipeline is proposed to cross the Platte River in Nebraska at MP 756.5. There is an upstream valve at MP 747.6 and a downstream valve at MP 765. Figure 3 shows the elevation profile for the crossing at the Platte River. A reasonable worst-case spill scenario is to consider the valve at MP 765 (i.e., closest to the river) to fail. The drain-down volume would then be the pipeline volume between the high point at MP 760 and the valve at MP 747.6. The resulting drain-down volume would be 3.70×10^5 ft^3 (65,950 Bbl, 2.77 million gallons). Adding the pumping rate volume, the worst-case spill at the Platte River crossing would be 140,950 Bbl (5.92 million gallons).

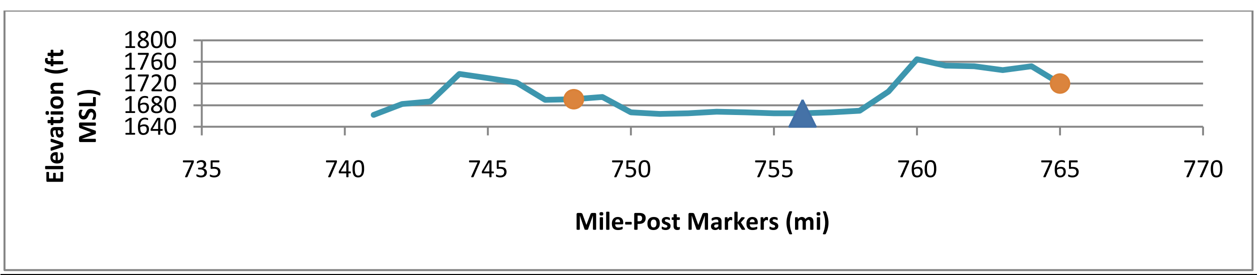


Figure 3: Horizontal profile of surface elevations at the Platte River crossing. Note that the vertical axis is exaggerated compared to the horizontal axis. Solid circles show locations of pipeline valves. The solid triangle shows the location of the river crossing.

Table 3: Worst-Case Spill Volume Estimates.

Location	Estimate from this analysis		
	Pumping Rate Volume (Bbl)	Drain Down Volume (Bbl)	Total Release (Bbl)
Groundwater	189,000[(a)]	NA	189,000
Missouri River	75,000[(b)]	47,867[(c)]	122,867
Yellowstone River	75,000[(b)]	90,416[(c)]	165,416
Platte River	75,000[(b)]	65,950[(c)]	140,950

(a) 900,000 Bbl/d (Keystone XL design pumping rate)* 1.5 percent leak * shut-down time of 14 days

(b) 900,000 Bbl/d (Keystone XL design pumping rate) * shut-down time of 2 hours

(c) Expected volume to drain from ruptured pipeline after pumps and valves closed

<u>Comparison to TransCanada methods</u>

TransCanada calculated the total Worst-Case Release Volume in a way that appears to be flawed. The worst-case volume was calculated from (ERP, 2009):

$$WCV = ALV + PRV$$

Where:

WCV = worst-case volume (Bbl)

ALV = adjusted line volume (Bbl)

PRV = pumping rate volume (Bbl) i.e., pumping rate (Bbl/min) * time to shut-down (min)

The adjusted line volume was calculated from:

$$ALV = (ILFV – PRV) * 0.60$$

Where:

ILFV = initial line fill volume (Bbl) i.e., the volume of the pipe between the leak and the nearest valve on both sides of the leak.

0.60 = drain-down factor where 60percent of the oil in the pipe will drain after shut-down.

For the Hardisty Pump Station/Regina Pump Station (Keystone pipeline) calculation, the ILFV was stated as 63,346 Bbl. The pumping rate was 662,400 Bbl/day, and the time to shut down was 19 minutes (10 minutes of evaluation of whether a leak had occurred and 9 minutes to shut down the system). This resulted in a PRV of 8,740 Bbl, and an ALV of 32,763 Bbl. The ALV plus the PRV resulted in a total release of 41,503 Bbl.

TransCanada does not explain how the initial line fill volume is calculated. They simply provide a value (ERP, 2009). For the Hardisty Pump Station/Regina Pump Station calculation, they state the value to be 63,346 Bbl. There is no way to verify this value. Whatever method was used, the value should be the pipeline volume between the leak and the high points of elevation on both sides of the leak. TransCanada then, in what appears to be a flawed process, subtracts the pumping rate volume from the initial line fill volume. It is not clear why this subtraction was done. Apparently, TransCanada considered that since the PRV would be pumped out of the pipeline during the leak discovery and shutdown time, that volume of oil would not be still in the pipeline during draining. However, even though the PRV would be removed from the pipeline during shutdown time, an equal amount would be pumped into the draining section. Therefore, the DDV should be calculated as simply the volume of the draining pipeline modified by the fraction of oil trapped in local low points. That is, the PRV should not have been subtracted from the ILFV. The result of subtracting the PRV from the ILFV was then multiplied by 0.60 to account for 40 percent of the oil in the pipe being caught in locally low spots in the pipeline and failing to drain out. Certainly some of the oil in the pipe will fail to drain, especially in locally low spots; however, considering siphon effects, it is very likely that nearly all of the oil will drain even through the locally low spots. Therefore, the 60 percent drain factor is likely to be a significant underestimate of the fraction of oil that will drain. For this worst case spill analysis, a drainage factor of 80 percent is a more reasonable assumption.

Table 4 shows the PRV, DDV, and total worst-case release estimates for the Hardisty Pumping Station on the original Keystone pipeline using methods recommended in this analysis and methods used by TransCanada (ERP, 2009). Note that the PRV values using the method of this paper are much larger than those using TransCanada's method because the assumed shut-down time is much shorter in TransCanada's method (19 minutes compared to 2 hours). The drain-down volumes used for both methods are the reported drain-down volumes from TransCanada's method because sufficient detail was not available in the TransCanada report (ERP, 2009) to allow a comparison of methods.

Table 4: Worst-Case spill volume estimate using the method recommended in this analysis and the method used by TransCanada for the Keystone Pipeline.

	Estimate from this Paper			TransCanada Estimate[a]		
	PRV (Bbl)	DDV (Bbl)	Total Release (Bbl)	PRV (Bbl)	DDV (Bbl)	Total Release (Bbl)
Hardisty Pumping Station	55,200[b]	32,764[c]	87,964	8,740[d]	32,764[c]	41,504

(a) ERP, 2009
(b) Pumping rate volume = 662,400 Bbl/d (Hardisty) * shut-down time of 2 hours
(c) Drain-down volume reported by TransCanada (ERP, 2009)
(d) Pumping rate = 662,400 Bbl/d * shut-down time of 19 min

Impacts from Worst-Case Spill

Impacts to the Air

The primary impacts to the air will be from benzene, hydrogen sulfide, and light molecular weight constituents of the DilBit. The DilBit will be pumped at high temperatures (up to 158^{o}F) and pressures (up to 1440 psi) causing these compounds to volatilize into the air at the site of the spill. The Occupational Health and Safety Agency (OSHA) acceptable concentration of benzene in the air for a workplace is 3.25 mg/m^3 (NIOSH, 1990) for short-term (8-hour) exposures. Since benzene is denser than air, it could accumulate in low-lying areas that are protected from the wind. Under these conditions, the benzene concentration could be above acceptable levels for inhalation. The basements of buildings located above groundwater plumes could also trap benzene gases that exceed safe levels. This could have serious consequences for the occupants of such a building, who may not be aware that a plume of benzene lies beneath the building.

Hydrogen sulfide is another toxic gas that could cause dangerous conditions at the site. The OSHA acceptable concentration for a workplace is 14 mg/m^3 for an 8-hour exposure and 21 mg/m^3 for even a momentary exposure (NIOSH, 1990). The concentrations of hydrogen sulfide in the air are expected to be above acceptable levels in areas near a spill site (Enbridge, 2010) and will likely be a serious health threat to emergency workers, remediation workers, and possibly to local residents.

In addition to toxicity effects, benzene, hydrogen sulfide, and the light molecular weight fractions of the oil could create explosive conditions as they volatilize from the spilled oil. Again, this risk will be greatest in areas that are protected from the wind and where concentrations could reach the explosive limits.

Impacts to Terrestrial Resources

The proposed pipeline will cross numerous types of terrestrial habitats (e.g., upland prairies, lowland prairies, woodlands, northern high plains, etc.) as it passes from Canada to Texas. Each of these habitats is unique in terms of its physical conditions (e.g., soils, climates), biological communities, and human communities. Because the physical, biological, and human conditions are so varied in these habitats, the potential impacts from a spill will be different for each type of habitat and location. Therefore, it is not possible to thoroughly assess the potential impacts to terrestrial habitats in this paper.

In general, a primary negative impact caused by a crude oil spill on land will be burial and smothering of plants and ground-dwelling animals. The spilled DilBit will form a very dense and thick layer over the ground that will kill essentially any organisms that are contacted. This effect will be localized to the immediate area of the spill, and most animals will be able to avoid contact with the oil. However, some animals may inadvertently contact the oil (e.g., birds landing in the oil) and be harmed or killed. In addition, the spill will release toxic constituents such as benzene, hydrogen sulfide, light molecular weight oil fractions, and polycyclic aromatic hydrocarbons (PAHs), all of which will have toxic effects on local wildlife. A significant concern arises when the pipeline crosses habitats of the numerous threatened or endangered species that are found along the pipeline route. Finally, the spill could affect human communities via exposures to the toxic constituents.

Impacts to Surface Water Resources

The primary constituents of concern in surface water are: benzene, PAHs, hydrogen sulfide, and bulk crude oil. The amounts of these constituents in the surface water are affected by several factors including: the concentration of the constituent in the crude oil, the solubility of the constituent, and the turbulence and velocity of the water. Constituents of special concern are benzene and certain PAHs because they are carcinogenic.

Benzene makes up 0.1 to 1.0 percent of DilBit crude oil (Shell Canada, 2008), and it is relatively soluble in water. The amount of benzene that will be dissolved in the water can be estimated from the octanol-water partition coefficient (a measure of how much of a contaminant will dissolve into the water) which is 131.8 for benzene (LaGrega et al., 2001). Using the octanol-water relationship, and assuming that the benzene concentration in the DilBit is 1 per cent(~$1x10^4$ mg/L), results in a benzene water concentration immediately at the oil/water interface of 75 mg/L ($1x10^4$ mg/L ÷ 131.8). This benzene concentration is 15,000 times the MCL for benzene of 0.005 mg/L. Since the temperature of the DilBit will be up to158^{o}F, the actual water concentration at the spill will likely be somewhat higher than this calculation, which is based on an octanol-water partition coefficient for ambient temperatures. The benzene concentration will decrease with distance from the oil/water interface. TransCanada's Risk Assessment calculated that the average (mixed) benzene concentration in surface water for a 10,000 Bbl spill in a 10,000 ft^3/sec stream would be 2.2 mg/L (ENTRIX, 2010); however, this calculated concentration assumes that all of the benzene would be released into the water within one hour (likely over-estimates resulting concentrations) and that the benzene is immediately mixed across the entire stream (under-estimates resulting concentrations). Note that 2.2 mg/L is 440 times the MCL for benzene. In most cases, the benzene will form a plume that travels downstream from the spill site. The concentration in the plume will gradually decrease as it moves farther from the spill site.

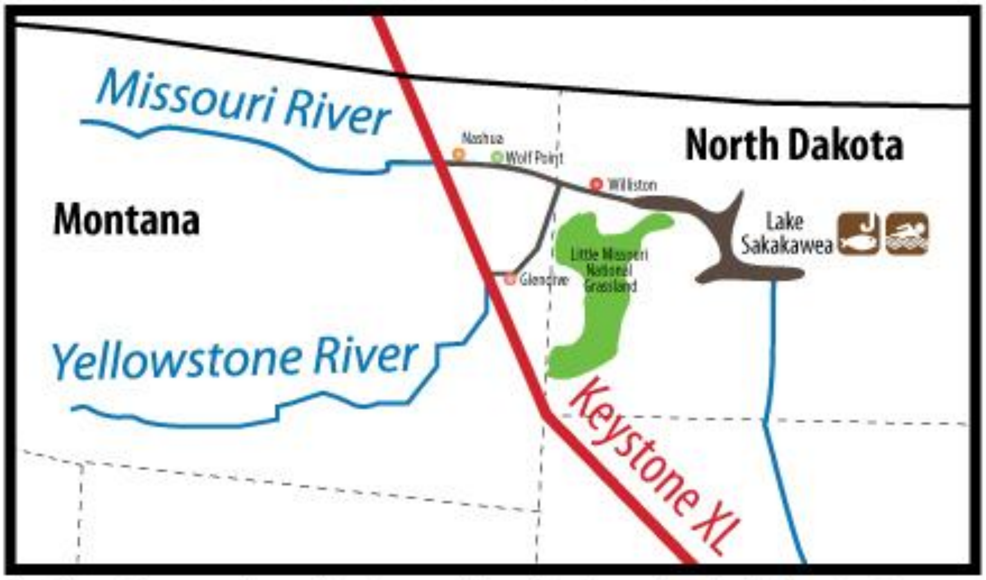
Besides human health risks from contaminated drinking water supplies, benzene also poses risks to aquatic species. The EPA Region III screening water concentration for benzene designed to be protective of aquatic biota is 0.370 mg/L (EPA, 2011b). The predicted benzene concentration at the oil/water interface is 75 mg/L which is 200 times higher than the screening concentration. Therefore, negative ecological impacts due to toxicity are expected, at least in localized areas where benzene is actively dissolving from the oil.

If a spill of 150,000 Bbl (i.e., in the range of predicted worst-case spill volumes) were to occur in a stream with a flow of 10,000 ft^3/sec and a velocity of 3 ft/sec (e.g., the Missouri River below Fort Peck dam has a flow of 9,225 cfs, and the Yellowstone River at Miles City, MT has a flow of 11,180 cfs (USGS, 2009)), the mass and resulting plume of the benzene in the water could be characterized as follows. Assuming that benzene makes up 1.0percent of the DilBit, 150,000 Bbl of DilBit would contain approximately $2.3x10^5$ Kg of benzene (150,000 Bbl * 42 gal/Bbl * 3.788 L/gal * 1 Kg/L * 0.01). If 80 percent of the benzene is lost via volatilization and product removal during and immediately after the spill, $4.77x10^4$ Kg of benzene would remain in the stream. This benzene would dissolve through time into the water from the DilBit mixture. To be released into the water, the benzene in the mass of crude would have to diffuse to the oil/water interface. Since the composition of DilBit is variable and since the thickness of the crude mass is case-specific (i.e., depends on turbulence, temperature, etc.), it is not possible to predict precisely the rate at which the benzene will diffuse to the oil/water interface; however, a reasonable assumption would be that 5percent of the benzene would reach the oil/water interface per day. If this assumption is too high, these calculations will over estimate the water concentrations but underestimate the duration of the negative impacts, and if it is too small, the opposite will be true. Assuming 5percent of the benzene is released into the water per day, over 2.3 million grams of benzene will be released to the water per day. This will result in a water concentration of 0.09 mg/L ($2.3x10^6$ g/d * sec/10,000 ft^3 * 1d/86,400 sec *1,000 mg/g * 35.3 ft^3/m^3 * 0.001 m^3/L) once the contaminant plume completely mixes across the entire width of the stream (several miles downstream of the spill). This concentration exceeds the MCL of 0.005 mg/L by 18.8 times. As the benzene plume migrates downstream, the concentration will decrease because of processes such as degradation and volatilization. Reported half-lifes of benzene in surface water range from 1 to 6 days (USEPA, 1986). Assuming a half-life of 3 days, a stream velocity of 3 ft/sec, and a tributary contribution of 20 cfs/mi (the measured value for the Missouri River downstream of the proposed crossing (USGS, 2009)), the plume would reach over 450 miles before its concentration would drop to the MCL and be safe for public water intakes. The plume length was modeled using a series of 10-mile long river reaches with first-order decay ($k=-0.231d^{-1}$) and increased flow of 200 cfs/10 mi reach.

Contaminants from a release at the Missouri or Yellowstone River crossing would enter Lake Sakakawea in North Dakota where they would adversely affect drinking water intakes, aquatic wildlife, and recreation. Contaminants from a spill at the Platte River crossing would travel downstream unabated into the Missouri River for several hundred miles affecting drinking water intakes for hundreds of thousands of people (e.g., Lincoln, NE; Omaha, NE; Nebraska City, NE; St. Joseph, MO; Kansas City, MO) as well as aquatic habitats and recreational activities. In addition, other constituents from the spill would pose serious risks to humans and to aquatic species in the river.

Map 1:

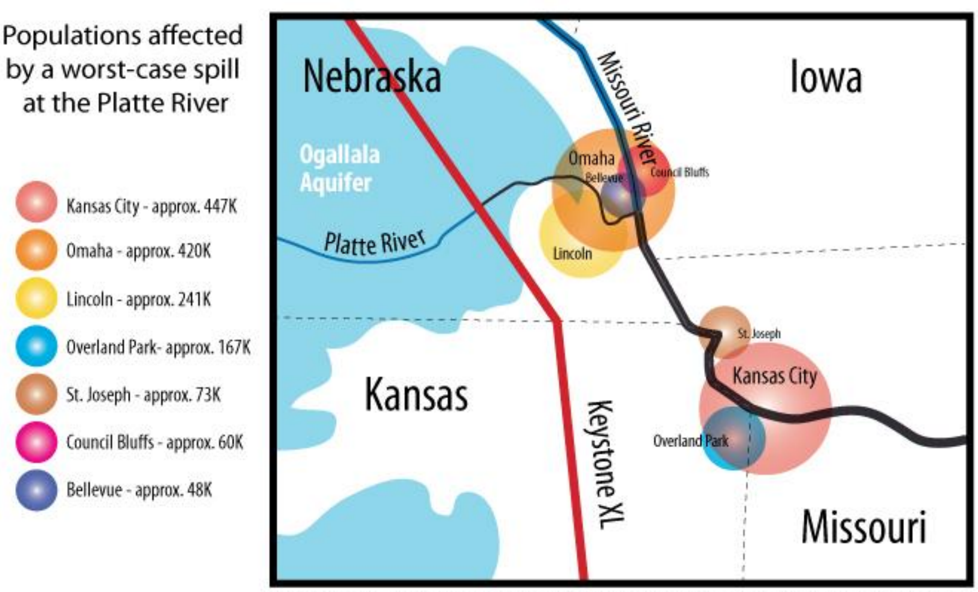
Worst-case spill at the Missouri River or Yellowstone River crossing.



A spill at either crossing could release millions of gallons of crude oil into the rivers and extending downstream as far as Lake Sakakawea, polluting drinking water, and threatening endangered species and recreation areas.

Map 2:

Populations affected by a worst-case spill at the Platte River



Population estimates based on available data from the U.S. Census Bureau, http://quickfacts.census.gov. Circles representing these cities are for illustrative purposes and are not to scale.

Of course other assumptions (e.g., shorter half-life) would give somewhat different results. For example, assuming that benzene makes up only 0.3 percent of DilBit and that 10 percent of the benzene is released per day, the calculated plume length would be reduced to around 200 miles. However, since the case-specific details are not known at this point, the precise impacts cannot be calculated; however, it has been clearly shown that if a worst-case spill occurs in a major stream, the impacts would be serious, far-reaching, and long-lasting, and claims to the contrary should be challenged.

The concentrations of PAHs (e.g., benz(a)pyrene) are not specified in the Material Safety Data Sheet(MSDS) for DilBit (Shell Canada, 2008). Also, the risk assessment done for the pipeline (ENSR, 2006) discusses the presence of PAHs, but doesn't detail specific concentrations. Therefore, this analysis will assume that PAHs make up 2 percent of DilBit, and that benz(a)pyrene (BaP) makes up one-tenth of the PAHs or 0.2 percent of the DilBit. This is likely an underestimate. PAHs are not as soluble or as mobile in surface water as is benzene. Much of the released PAH mass will sorb to sediments and remain closer to the location of the spill. However, they will be transported downstream with suspended solids and sediments, and the PAH fraction that does dissolve will form a plume and also be transported downstream. Since they are less soluble and mobile than benzene, PAHs pose less of a threat to municipal water intakes. Using the octanol-water coefficient for benz(a)pyrene (BaP) of 1.1×10^6 (LaGrega et al., 2001), the BaP concentration at the oil/water interface would be 0.0018 mg/L (1.8 µg/L). This concentration exceeds the MCL for BaP of 0.0002 mg/L by a factor of about ten; however, this concentration would be quickly reduced as the plume mixes in the stream. Therefore, based on the assumption that PAHs make up 2percent of the DilBit, drinking water is probably not significantly threatened from release of PAHs.

However, PAHs are toxic to aquatic organisms. The EPA Region III water quality criteria for benz(a)pyrene to protect aquatic species is 0.015 µg/L (EPA, 2011b). In addition, there are several other PAHs with water quality values to protect aquatic species (e.g., benzo(a)anthracene (0.018 µg/L), fluoranthene (0.04 µg/L), and naphthalene (1.1 µg/L)) that are likely to have concentrations that exceed water quality criteria in a major spill. Therefore, the estimated concentration of PAHs is approximately 100 times the allowable level for protection of aquatic life.

Hydrogen sulfide is very volatile, and much of it will likely volatilize to the air during a major spill. However, some of the hydrogen sulfide will dissolve into the surface water and cause toxic effects to the aquatic biota. The EPA Region III screening water concentration protective of aquatic species is 2.0 µg/L. Since the hydrogen sulfide will quickly volatilize, it is expected that these toxic effects will be limited to areas near the spill.

Bitumen, which makes up most of the DilBit, is more dense than water, so it will sink to the bottom and smother any aquatic plants or sediment-dwelling organisms. These effects will be limited to the immediate area of the spill and are expected to pose a significant risk primarily if the stream is the habitat to threatened or endangered species. Since the Missouri, Yellowstone, and Platte Rivers all provide habitat to threatened and endangered species, including the pallid sturgeon, interior least tern, and piping plover, these impacts should be considered potentially significant.

Table 5: Benzene Plume Development for Spill of 150,000 Bbl into a 10,000 cfs Stream.

	Estimate From This Analysis
Spill Volume	150,000 Bbl
Stream Discharge	10,000 cfs
Fully Mixed Concentration[(a)]	0.09 mg/L
Ratio of Concentration to MCL [(b)]	18.8
Length of Plume > MCL [(c)]	450 miles
Duration of Release to Water [(d)]	20 days

(a) mg/sec benzene release to stream ÷ L/sec of flow (10,000 cfs = 283,286 L/sec)
(b) fully mixed concentration ÷ 0.005 mg/L
(c) assumes half-life of 3 d; velocity of 3 ft/sec;
(d) assumes 5percent of benzene is released from DilBit mass per day

Impacts to Groundwater Resources

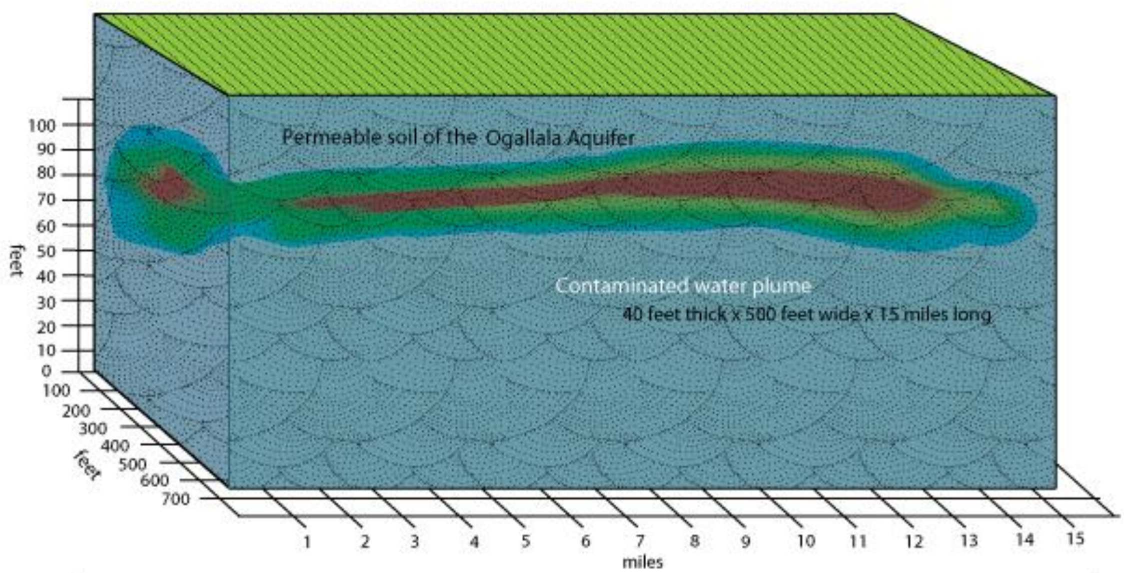
The primary constituent of concern for a spill into groundwater is benzene. Since DilBit is very viscous, the bulk crude oil will not likely migrate through the soil to groundwater in large quantities. However, if a small, underground leak remains undetected for an extended period of time, a large amount of benzene will be released with the DilBit. The released benzene could then be transported to groundwater via infiltrating rainwater. According to a TransCanada publication “Frequency-Volume Study of Keystone Pipeline” (DNV, 2006), a leak of 1.5 percent of total flow could remain undetected for 90 days. For this analysis, the discovery and shut-down time is assumed to be 14 days which corresponds to the time between pipeline inspections. At the design flow rate of 900,000 Bbl/d, a 1.5 percent leak would release 189,000 Bbl (7.9 million gallons) of DilBit in 14 days. Since DilBit is 0.1 to 1.0 percent benzene, this would result in a release of up to 79,380 gallons of benzene.

A spill of the magnitude of 189,000 Bbl of DilBit would occupy approximately $2.65\text{x}10^6$ cubic feet of subsurface sands with a porosity of 0.4 (189,000 Bbl * 5.61 ft^3/Bbl ÷ 0.4). Assuming that theDilBit mass occupies a somewhat cylindrical volume and that the aquifer is 20 feet below the pipeline, the DilBit would spread to an area approximately 335 feet in diameter (335 feet diameter X 30 feet high). A reasonable worst-case 100-year, 24-hour storm would deposit 6 inches of rainwater on the site. In the Sandhills of Nebraska, nearly all of this water would infiltrate. Six inches of water infiltrating onto a contaminated area of $8.8\text{x}10^4$ ft^2 (335 feet diameter) results in $4.4\text{x}10^4$ cubic feet of water ($8.8\text{x}10^4$ ft^2 * 0.5 ft infiltrating water) contacting the DilBit. Using the octanol-water partition coefficient of 131.8 (LaGrega et al., 2001), the benzene concentration in the infiltrating water would be approximately 75 mg/L.

The 4.4×10^4 cubic feet of water at a concentration of 75 mg/L equates to 9.35×10^7 milligrams of benzene. Thus, this storm would transport 9.35×10^7 milligrams of benzene to the groundwater. Once in the groundwater, the benzene plume would migrate down-gradient, potentially to down-gradient water supplies or basements where it could pose a cancer risk to residents. The 9.35×10^7 milligrams of benzene in the groundwater, if evenly distributed (not likely) could pollute 1.9×10^{10} Liters (4.9×10^9 gallons) of groundwater at the MCL, enough water to form a plume 40 feet thick by 500 feet wide by more than 15 miles long (assuming porosity of 0.4) at the MCL. These plume dimensions are given for illustrative purposes only. The actual dimensions of a groundwater plume cannot be determined with the available information. Of course, the benzene would not be evenly distributed; however, the plume would still be many miles long. In addition, future storms would transport additional benzene to the groundwater increasing the size of the plume.

Figure 4:

Worst-case spill above the Nebraska Sandhills.



A spill over 14 days, releasing 7.9 million gallons of crude oil could contaminate 4.9 billion gallons of water and form a plume 40 feet thick by 500 feet wide by 15 miles long. By comparison:

The length of the plume is equal to 264 football fields.
Manhattan is 13.4 miles long.
The volume of the plume (1,584,000,000 feet^3) is equal to that of 19,631 Olympic sized pools.

The worst-case site for such a spill is in the Sandhills region of Nebraska. The Sandhills are ancient sand dunes that have been stabilized by grasses. Because of their very permeable geology, nearly 100 percent of the annual rainfall infiltrates to a very shallow aquifer, often less than 20 feet below the surface. This aquifer is the well-known Ogallala Aquifer that is one of the most productive and important aquifers in the world.

Table 6: Benzene Plume from a189,000 Bbl Spill to Groundwater.

Volume of released DilBit (Bbl)	189,000
Volume of benzene in spill (gal)	79,380
Mass of benzene dissolved in groundwater (mg)	9.35×10^{7}
Volume of contaminated water > MCL (gal)	4.9×10^{9}
Equivalent plume dimensions	40 feet X 500 feet X 15 miles

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Emailed 02-26-2015 to me by Dr. John Stansbury

Excerpts he had taken from his study:

a. TransCanada's Risk Assessment calculated that the average (mixed) benzene concentration in surface water for a 10,000 Bbl spill in a 10,000 ft3/sec stream would be 2.2 mg/L (ENTRIX, 2010); however, this calculated concentration assumes that all of the benzene would be released into the water within one hour (likely over-estimates resulting concentrations) and that the benzene is immediately mixed across the entire stream (under-estimates resulting concentrations). Note that 2.2 mg/L is 440 times the MCL for benzene. Beyond admitting that the concentration will be unacceptable, and therefore, pose a human health risk, there is no further analysis. There should have been a human health risk assessment that would have estimated the increased risk of cancer, but there isn't any such assessment. They simply state that the concentration will be unacceptable and leave it at that.

b. Stansbury (not TransCanada) estimates benzo(a)pyrene (BaP) concentration at the oil/water interface of a major spill into a stream would be 1.8 µg/L. The EPA Region III water quality criteria for benz(a)pyrene to protect aquatic species is 0.015 µg/L (EPA, 2011b). In addition, there are several other PAHs with water quality values to protect aquatic species (e.g., benzo(a)anthracene (0.018 µg/L), fluoranthene (0.04 µg/L), and naphthalene (1.1 µg/L)) that are likely to have concentrations that exceed water quality criteria in a major spill. Therefore, the estimated concentration of PAHs is approximately 100 times the allowable level for protection of aquatic life. Note that the reason Stansbury's estimate is used here is that TransCanada failed to assess even the potential concentrations of PAHs let alone assess the potential health and environmental risks posed by the release of these chemicals.

c. According to a TransCanada publication "Frequency-Volume Study of Keystone Pipeline" (DNV, 2006), a leak of 1.5 percent of total flow could remain undetected for 90 days. For this analysis, the discovery and shut-down time is assumed to be 14 days which corresponds to the time between pipeline inspections. At the design flow rate of 900,000 Bbl/d, a 1.5 percent leak would release 189,000 Bbl (7.9 million gallons) of DilBit in 14 days. Since DilBit is 0.1 to 1.0 percent benzene, this would result in a release of up to 79,380 gallons of benzene into the groundwater. If the leak does go undetected for 90 days as the TransCanada document reports, a groundwater user could be exposed to unacceptable concentrations of benzene for a significant period of time. There should have been a human health risk assessment that would have estimated the increased risk of cancer, but there isn't any such assessment. They simply indicate that there could be a significant, undetected release of benzene which could be consumed by human receptors and leave it at that. Note, be careful using my "estimate" of a groundwater plume dimensions. As it states in my report, this is not a prediction of a plume size, it is only the dimensions that a plume could have for the predicted amount of released benzene – the actual plume size would depend on a lot of site-specific conditions.

Tar Sands Pipeline Primer with Dr. John Stansbury

Youtube video interview

<iframe width="560" height="315" src="https://www.youtube.com/embed/9Dw7a7YSnH0" frameborder="0" allowfullscreen></iframe>

https://youtu.be/9Dw7a7YSnH0

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE PETITION OF TRANSCANADA KEYSTONE PIPELINE, LP FOR ORDER ACCEPTING CERTIFICATION OF PERMIT ISSUED IN DOCKET HP09-001 TO CONSTRUCT THE KEYSTONE XL PIPELINE	)	Docket 14-001 **TESTIMONY OF DR. ARDEN D. DAVIS, Ph.D., P.E., ON BEHALF OF DAKOTA RURAL ACTION**

My name is Arden D. Davis, Ph.D., P.E. My address is 1014 Milwaukee Street, Rapid City, South Dakota 57701.

This testimony is submitted regarding Findings of Fact 12(2)-(3), 20, 22, 33-34, 36, 37, 40-41, 43-53, 64, 77, 79, 82, 86, 94-95, 98-99, 101-104, 110, 113, and Amended Conditions: 22, 34-35, 37 of the Amended Final Decision and Order in HP 09-001.

Professional Qualifications and Background

I have been involved in the fields of ground water and environmental contamination since 1978. I hold a B.A. degree in Geology from the University of Minnesota, and M.S. and Ph.D. degrees in Geological Engineering from South Dakota School of Mines and Technology. I am a registered professional engineer in South Dakota (no. 4663). Since 1985, I have taught courses in ground water, ground-water contamination, geological engineering, and environmental pollution at South Dakota School of Mines and Technology. I have also presented expert witness testimony in numerous cases, and have assisted the State of South Dakota in ground-water contamination problems, including the Williams Pipe Line / Hayward Elementary School site in Sioux Falls.

Potential Impact of Keystone XL Pipeline on Water Resources in South Dakota

A crude-oil or diluted bitumen leak could have devastating effects on ground-water supplies, surface water, and environmental resources in South Dakota. The proposed Keystone XL Pipeline would cross the recharge areas of several shallow aquifers in the western part of the State, including the Ogallala aquifer and Sand Hills type material, especially in Tripp County. Other shallow aquifers that would be crossed by the proposed pipeline route are terrace gravel aquifers, eolian (wind-blown) aquifer materials, alluvial aquifers, and the Fox Hills aquifer.

The proposed pipeline also would have major stream crossings at water courses such as the Little Missouri River, the Grand River and its tributaries, the Moreau River, the Cheyenne River upstream from Oahe Reservoir, the Bad River, and the White River. These drainages have associated alluvial aquifers beneath and adjacent to the rivers, and dissolved hydrocarbon contaminants could be transported downgradient in surface water, in ground water within the aquifers, or both.

The proposed route is shown on Figure 1 (from U.S. Dept. of State, 2014) and would cross the western part of South Dakota in a northwest-to-southeast trend. The South Dakota state geologic map is shown on Figure 2, with the proposed route superimposed.

In Harding County, in the extreme northwestern part of South Dakota, the route would cross the Little Missouri River (Figure 3) and the Grand River (Figure 4). The Hell Creek Formation (shown as K_h on Figure 3 and Figure 4) contains bentonitic shale and is exposed in the river valleys at these crossings. The Little Missouri River flows northward into North Dakota, where it eventually joins the Missouri River. The Grand River flows generally eastward and joins the Missouri River in north-central South Dakota.

In Harding County the proposed route would cross permeable wind-blown deposits, shown as Q_e on Figure 4. These wind-blown deposits of silt and sand recharge from rainfall and snowmelt, and they are capable of supplying water to shallow wells in the area. The proposed route also would cross the Fox Hills aquifer (shown as K_{fh} on Figure 4) in Harding County. This sandstone aquifer is one of the most important ground-water reservoirs in northwestern South Dakota and supplies drinking water to public supplies for the City of Buffalo as well as a standby well for the City of Lemmon.

In Butte County the proposed route would cross the North Fork of the Moreau River (Figure 4), and in Perkins County the route would cross the Moreau River (Figure 4), which flows eastward and joins the Missouri River in north-central South Dakota.

In Meade County the proposed route would cross Cherry Creek and Red Owl Creek, as well as a large expanse of the exposed recharge area of the Fox Hills Formation (see Figure 5). As mentioned above, the Fox Hills aquifer is a major aquifer in northwestern South Dakota.

Near the border of Meade, Haakon, and Pennington counties, the proposed route would cross the Cheyenne River (Figure 6). This part of the Cheyenne River watershed is downstream from the Belle Fourche River, which drains the northern Black Hills, and the main branch of the Cheyenne, which drains the southern and eastern Black Hills. At this site, the Cheyenne River has gathered the surface-water drainage from the entire Black Hills. From here downstream, the Cheyenne River flows into the Oahe Reservoir on the Missouri River. The Pierre Shale (shown as K_p), which contains bentonite, is exposed along steep sides of the Cheyenne River valley and is prone to slope failures in western South Dakota. The proposed route also would cross the Bad River near Midland in Haakon County (Figure 7), where Pierre Shale also is exposed along the valley sides.

South of the Cheyenne River in Haakon County, the proposed route would cross permeable Quaternary terrace gravels (shown as Q_t on Figure 6) and wind-blown deposits (Q_e on Figure 6). The terrace gravels are stream-bed deposits of former flood plains. Both the terrace gravels and wind-blown deposits are permeable and are recharged by precipitation. In places they are capable of supplying water to wells, springs, and seeps, as well as providing soil moisture for trees and other vegetation.

In Jones and Lyman counties, the proposed pipeline route would cross permeable wind-blown deposits (shown as Q_e on Figure 8) and also would cross Quaternary terrace deposits north of the White River (shown as Q_t on Figure 8). The terrace deposits in this area have a shallow water table and are recharged by rainfall and snowmelt, which provide water for springs and seeps at the heads of streams that drain southward toward the White River. The shallow water table also supports small lakes, ponds, and wetlands in the area.

The proposed pipeline route would cross the White River at the border of Lyman and Tripp counties (Figure 8). The Pierre Shale is exposed in the White River valley at this location and is a concern because of potential slope failures.

In Tripp County, near the southeastern end of the proposed pipeline in South Dakota, the route would cross the Ogallala aquifer (shown as T_o on Figure 9). It also would cross wind-blown Sand Hills type material (shown as Q_e) above the Ogallala aquifer. According to Martin et al. (2004) the wind-blown material shown as Q_e on the South Dakota state geologic map includes the Sand Hills Formation. The hydrologic situation is similar to the Sand Hills of Nebraska, which form a permeable recharge zone above the Ogallala aquifer and therefore deserve consideration for special protection as a high-consequence area. As noted by Stansbury (2011), areas with shallow ground water that are overlain by permeable soils, such as Sand Hills type material, pose risks of special concern because leaks could go undetected for long periods of time

Contaminants and Potential Problems

The proposed Keystone XL pipeline would transport crude oil and diluted bitumen. As noted by Stansbury (2011), diluted bitumen is more corrosive than conventional crude oil transported in existing pipelines. Crude oil and diluted bitumen contain hydrocarbons, including benzene, toluene, ethylbenzene, and xylene. Benzene is of particular note because its maximum contaminant level (MCL) in drinking water is 5 parts per billion. Benzene is known to produce leukemia in humans. It has been identified as a human carcinogen by the Occupational Safety and Health Administration and the National Toxicology Program.

Benzene is soluble in water and can be transported downgradient toward receptors such as public water-supply wells, private wells, and springs or seeps. In certain cases, benzene can be transported more than 500 or 1000 feet downgradient in aquifers, according to records of agencies such as the South Dakota Geological Survey, the South Dakota Department of Environment and Natural Resources, and the South Dakota Petroleum Release Compensation Fund. For example, a benzene contaminant plume from a leaking tank at the Williams Pipe Line / Hayward Elementary School site in Sioux Falls, South Dakota, was documented to have traveled about 800 feet downgradient from the tank (Iles et al., 1988). Because of benzene's solubility and its allowable limit of only 5 parts per billion in drinking water, a pipeline leak could contaminate a large volume of surface water or ground water in shallow aquifers of western South Dakota.

Leaks from pipelines have occurred in the past in South Dakota and have threatened ground-water supplies. These include a pipeline spill from Williams Pipe Line Company near water-supply wells for the City of Sioux Falls, and a large spill north of the City of Sioux Falls on glacial till near the Big Sioux aquifer. Reports of these are available in the files of the South Dakota Department of Environment and Natural Resources. A spill of more than 840,000 gallons in 2010 at Marshall, Michigan, caused extensive environmental damage and polluted the Kalamazoo River. The rupture and subsequent investigation resulted in new recommendations for pipeline safety from the National Transportation Safety Board. Two recent pipeline ruptures along the Yellowstone River in Montana were particularly serious and caused serious environmental problems. One, in 2011 near Laurel, Montana, resulted in the discharge of about 63,000 gallons of crude oil. The second, in 2015, released about 30,000 gallons of crude oil and contaminated the public drinking water supply of the City of Glendive, Montana.

A major concern involves the stability of steep slopes where the Pierre Shale or other bentonite-bearing shales are exposed, particularly along the breaks of major rivers, including the Cheyenne River, the White River, the Bad River, the Little Missouri River, the Grand River, and the Moreau River. Expansive clays such as bentonite are a particular concern because they can absorb large amounts of water during wet periods, leading to instability and potential failure. Slope failures are common along these river valleys, and could cause ruptures and serious leaks from the proposed pipeline. Additional safeguards for pipeline integrity should be undertaken in such locations. Leaks in these areas potentially could result in surface-water contamination downstream toward the Missouri River and its reservoirs

A report for TransCanada by DNV Consulting (Appendix A: Frequency-Volume Study of Keystone Pipeline), dated May 1, 2006, indicates on page 19, Table 5-2, that a leak rate of less than 1.5% could go undetected for 90 days for below-ground pipe. Page 20, Figure 5-1, of the same report indicates a leak detection and verification time of 138 min (2.3 hours) for a leak rate of 1.5%. The leak rate for this detection time is approximately 200 barrels per hour (BPH). This potentially could result in a leak of about 19,000 gallons (2.3 hr x 200 barrels/hr x 42 gallons/barrel). It appears, therefore, that larger volumes of oil could leak over a longer time (e.g., 90 days), if the leak rate is less than 1.5%. A leak of 19,000 gallons or greater could contaminate a large volume of ground-water supplies because of the solubility of crude oil components such as benzene and other volatile hydrocarbons.

The Final Supplemental Environmental Impact Statement for the Keystone XL Project (U.S. Department of State, 2014) stated that spill volumes from larger-diameter pipelines tend to be larger than those from smaller-diameter pipelines. It also stated that the primary releases causes, aside from failure of components such as valves, are outside forces and corrosion. In addition, the spill size and impact, for medium to large spills, are more sensitive to response time than for small spills. In other cases, smaller leaks might not be detected (U.S. Department of State, 2014).

The executive summary of the Final Environmental Impact Statement (U.S. Department of State, 2011) stated, "Although the leak detection system would be in place, some leaks might not be detected by the system. For example, a pinhole leak could be undetected for days or a few weeks if the release volume rate were small and in a remote area." The executive summary also stated, "In spite of the safety measures included in the design, construction, and operation of the proposed Project, spills are likely to occur during operation over the lifetime of the proposed Project. Crude oil could be released from the pipeline, pump stations, or valve stations." In addition, the executive summary mentioned 14 spills since 2010 from the existing Keystone pipeline system, including a spill of 21,000 gallons in North Dakota.

Stansbury (2011) stated concerns about questionable assumptions and calculations by TransCanada of expected frequency of spills from the proposed Keystone XL Pipeline. He noted that the pipeline would operate at higher temperatures and pressures than existing pipelines, and that the crude oil that would be transported in the Keystone XL Pipeline will be more corrosive than conventional crude oil. These factors would tend to increase spill frequency. Stansbury (2011) also stated that worst-case spill volumes from the proposed Keystone XL Pipeline are likely to be significantly larger than those estimated by TransCanada.

The Final Supplemental Environmental Impact Statement (U.S. Department of State, 2014) noted, "For all spills, especially those that reached water resources, the response time between initiation of the spill event and arrival of the response contractors would influence the potential magnitude of impacts to environmental resources." If a pipeline leak goes undetected and a spill of crude oil reaches a major water course such as the Cheyenne River, it could potentially be transported many miles downstream during high-velocity flows at certain times of the year. For example, the Cheyenne River can have a velocity of 7½ to 8 feet per second at times of high discharges (Dawdy, 1961). A river velocity of 8 feet per second is equivalent to about 5½ miles per hour. If a leak is undetected and a spill reaches the river under these conditions, it could potentially be transported about 60 miles downstream in 12 hours. If a leak cannot be controlled or is undetected for 24 hours, it could be transported about 120 miles downstream. This raises concerns about emergency response and mobilization in such a situation. For example, the straight-line distance is about 40 miles from the proposed pipeline route's crossing of the Cheyenne River to the Oahe Reservoir. This is in a remote, sparsely populated area. Assuming a channel sinuosity of about 2 to 2.5 for this reach of the Cheyenne River, the river's actual distance would be about 80 to 100 miles from this crossing to the Missouri River's reservoir. Thus, if a release occurred at this crossing and it could not be controlled or went undetected for 12 to 24 hours, petroleum contaminants could reach the Missouri River, potentially affecting water supplies and surface-water users, and causing environmental damage.

Summary

The Keystone XL Pipeline, as currently proposed, would cross shallow aquifers including the Ogallala aquifer, Sand Hills type aquifer material, terrace gravel aquifers, wind-blown aquifer materials, alluvial aquifers along rivers, and the Fox Hills aquifer. Spills in these aquifers could pose serious health risks to ground-water users. The proposed route also would have river crossings at water courses that include the Cheyenne River upstream from Oahe Reservoir, the White River, and the Bad River, and other streams. The sides of these river valleys are vulnerable to large slope failures, especially where bentonite-containing shales are exposed, which potentially could cause pipeline rupture. At these river crossings and downstream, the proposed pipeline poses serious risks and could have devastating effects on surface water and associated environmental resources, potentially affecting water supplies and surface-water users.

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I hereby affirm under penalty of perjury that the above testimony is true and correct.

Arden D. Davis

ARDEN D. DAVIS

April 2, 2015
(date)

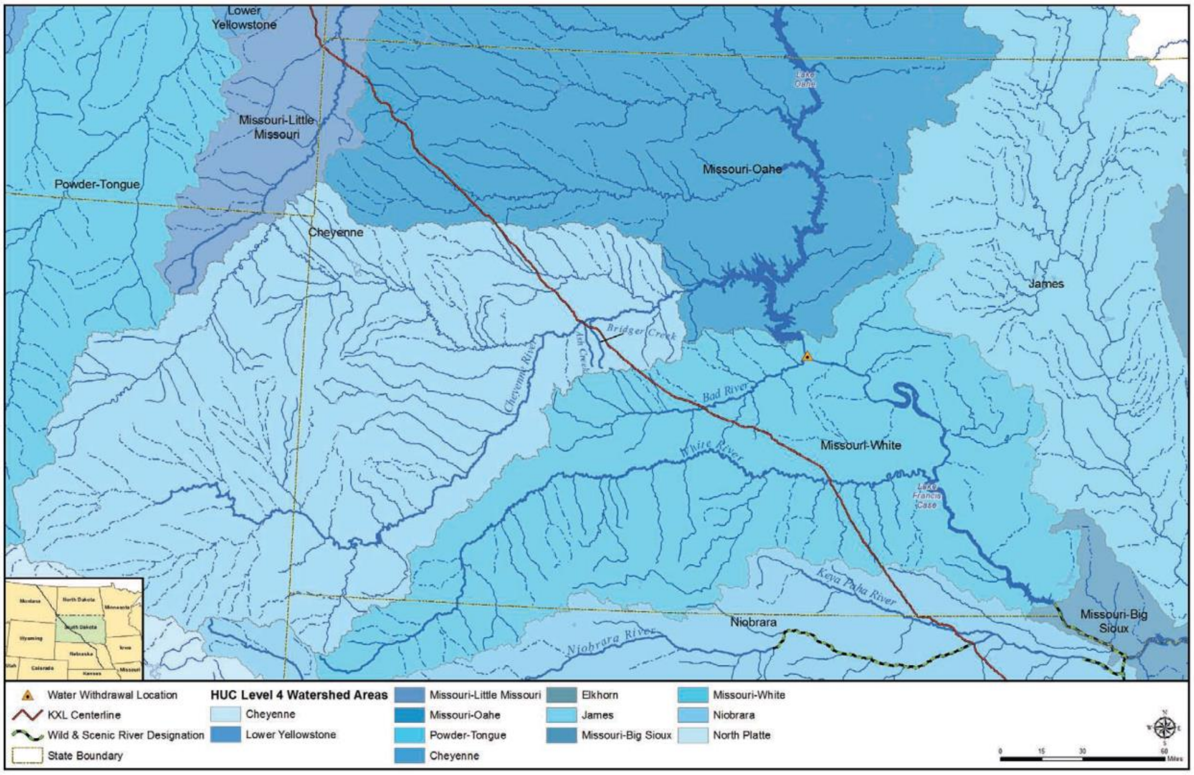


Figure 1. Water crossings of the proposed Keystone XL Pipeline in western South Dakota (from U.S. Dept. of State, 2014, p. 3.3-39.

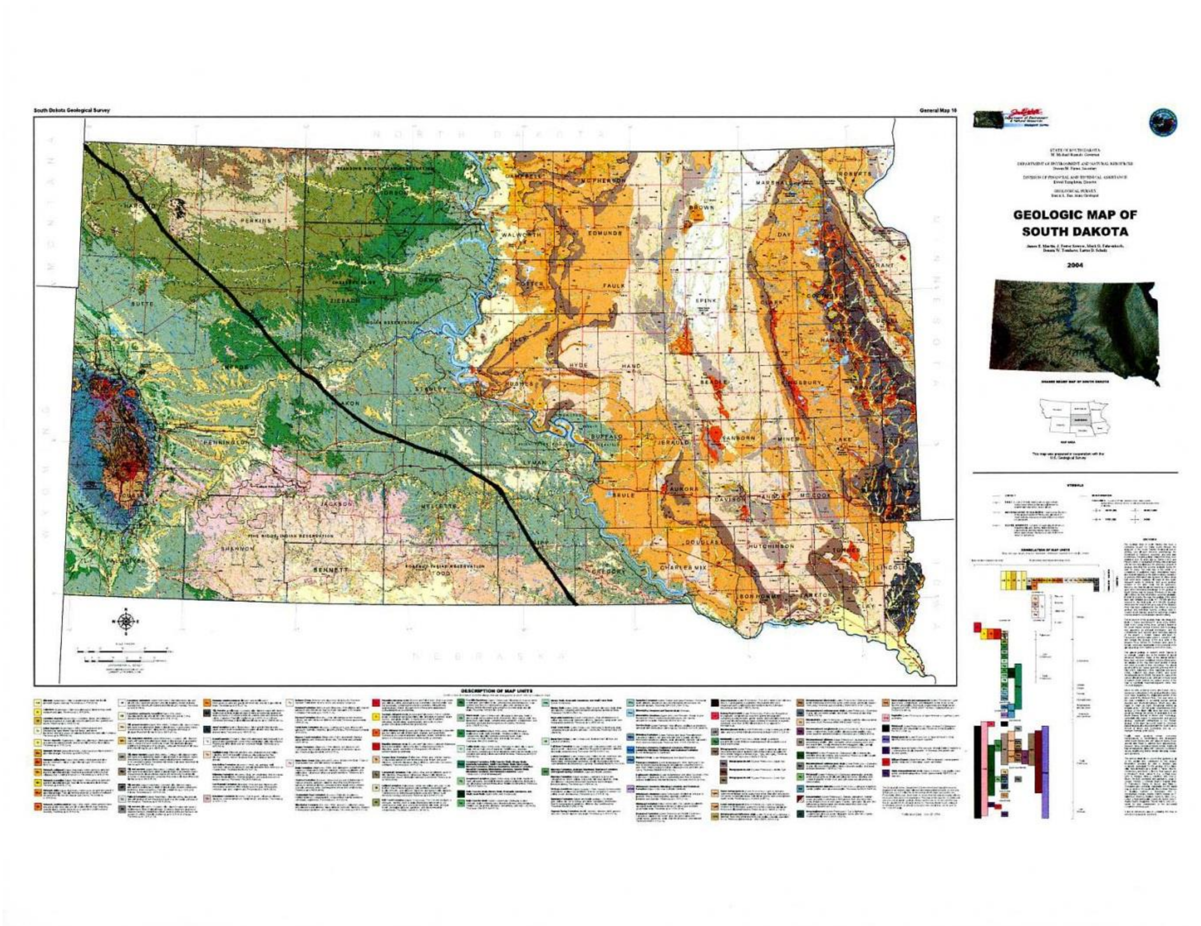


Figure 2. South Dakota geologic map (from Martin et al., 2004) with proposed Keystone XL route superimposed.

South Dakota Geological Survey

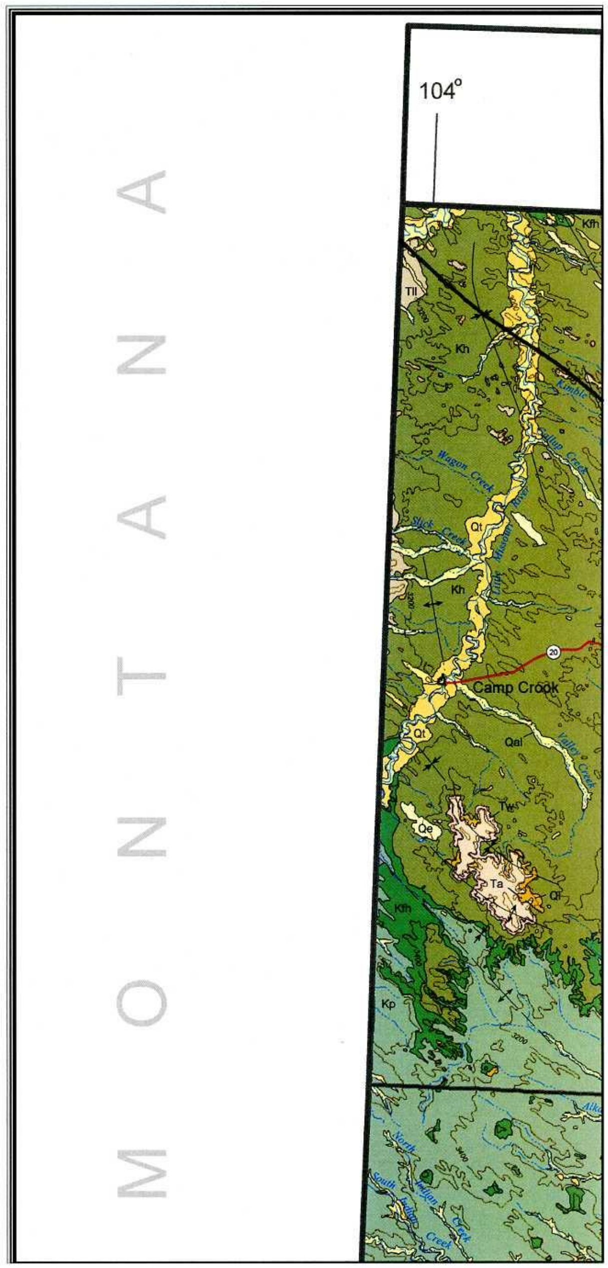


Figure 3. Part of the South Dakota geologic map (from Martin et al., 2004) in the northwestern part of Harding County, with proposed Keystone XL route superimposed.

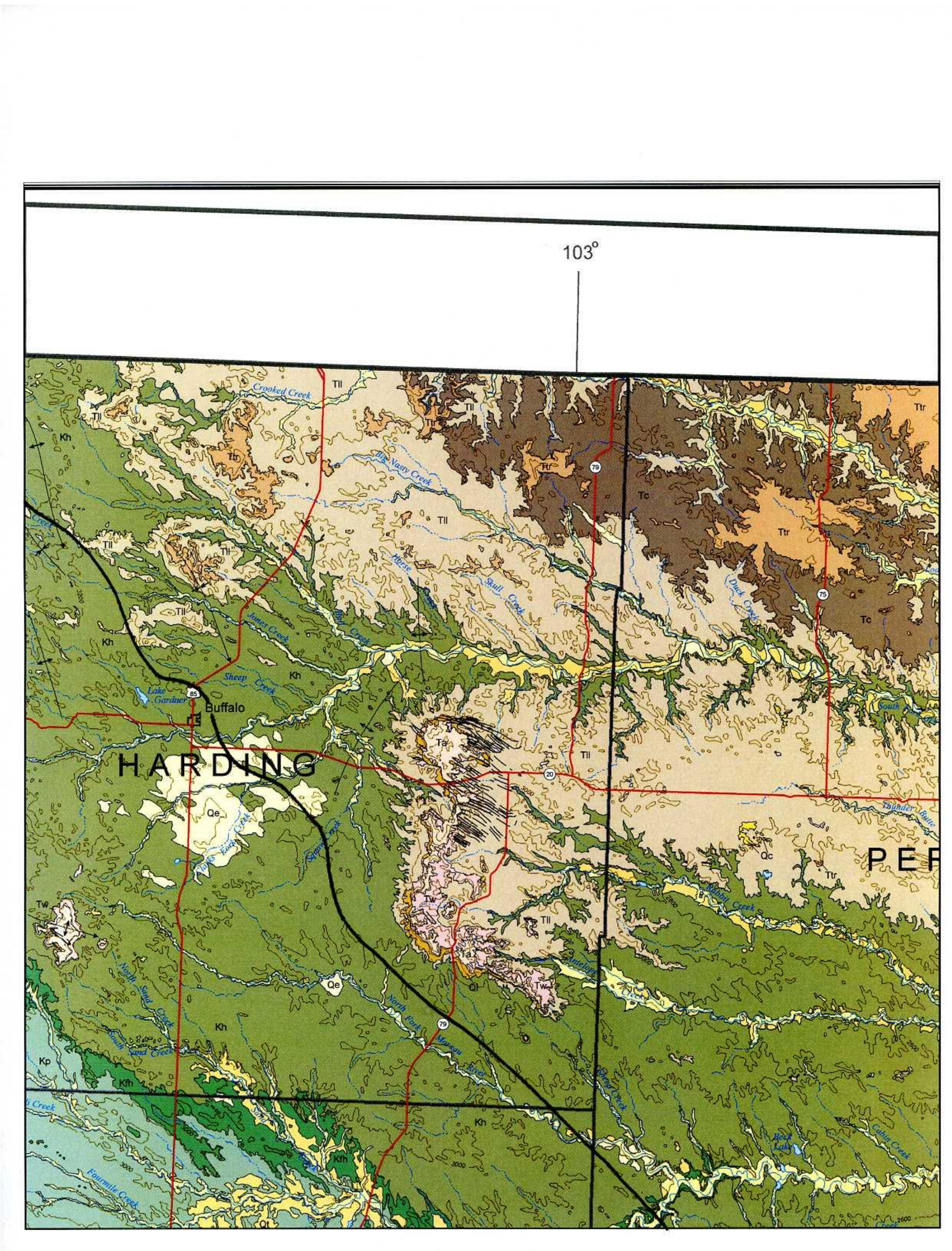


Figure 4. Part of the South Dakota geologic map (from Martin et al., 2004) in Harding and Perkins counties, with proposed Keystone XL route superimposed. The area shown as Q_e south and southeast of Buffalo is mapped as eolian (wind-blown) deposits.

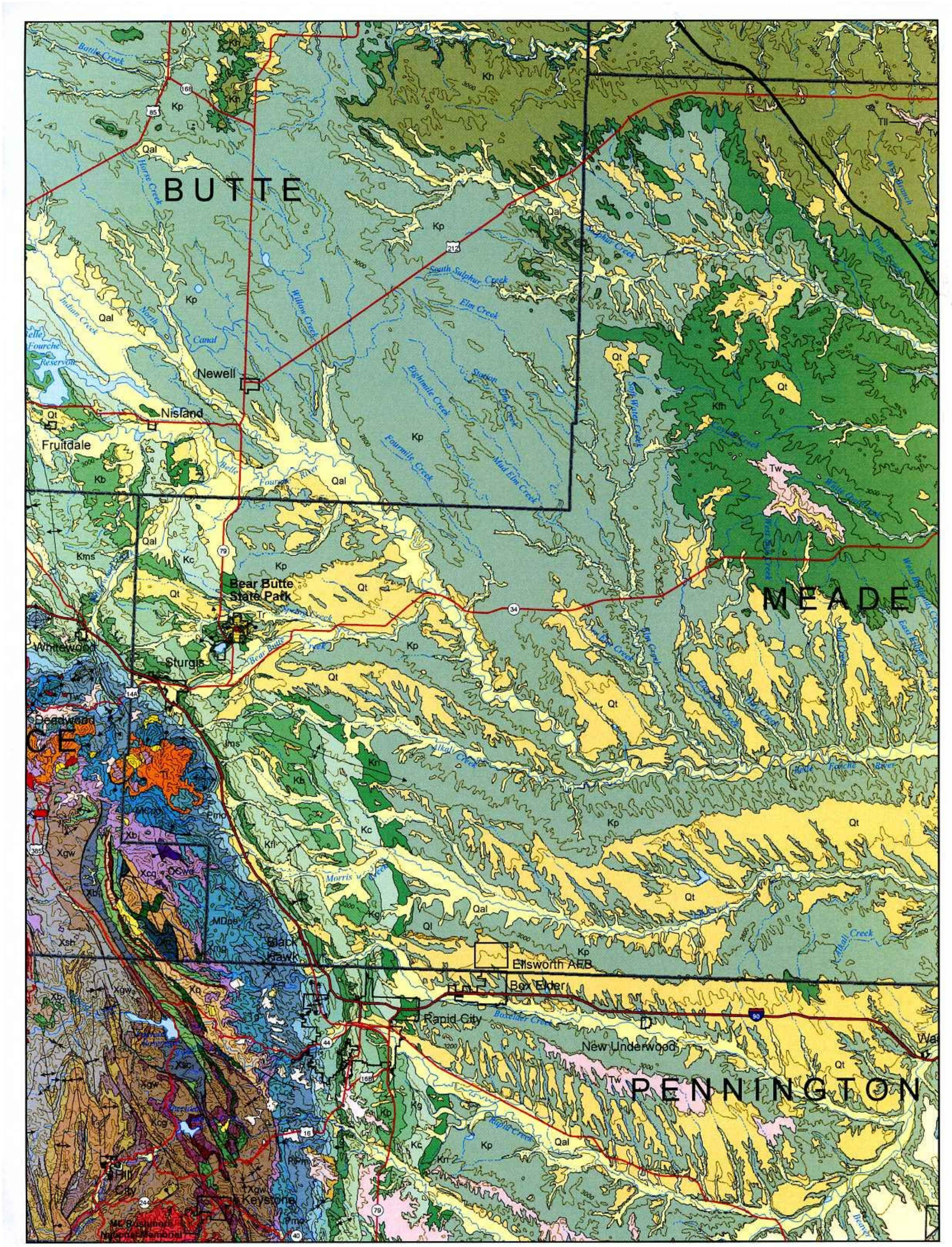


Figure 5. Part of the South Dakota geologic map (from Martin et al., 2004) in Perkins and Meade counties, with proposed Keystone XL route superimposed. The area shown as K_{fh} is mapped as the Fox Hills Formation.

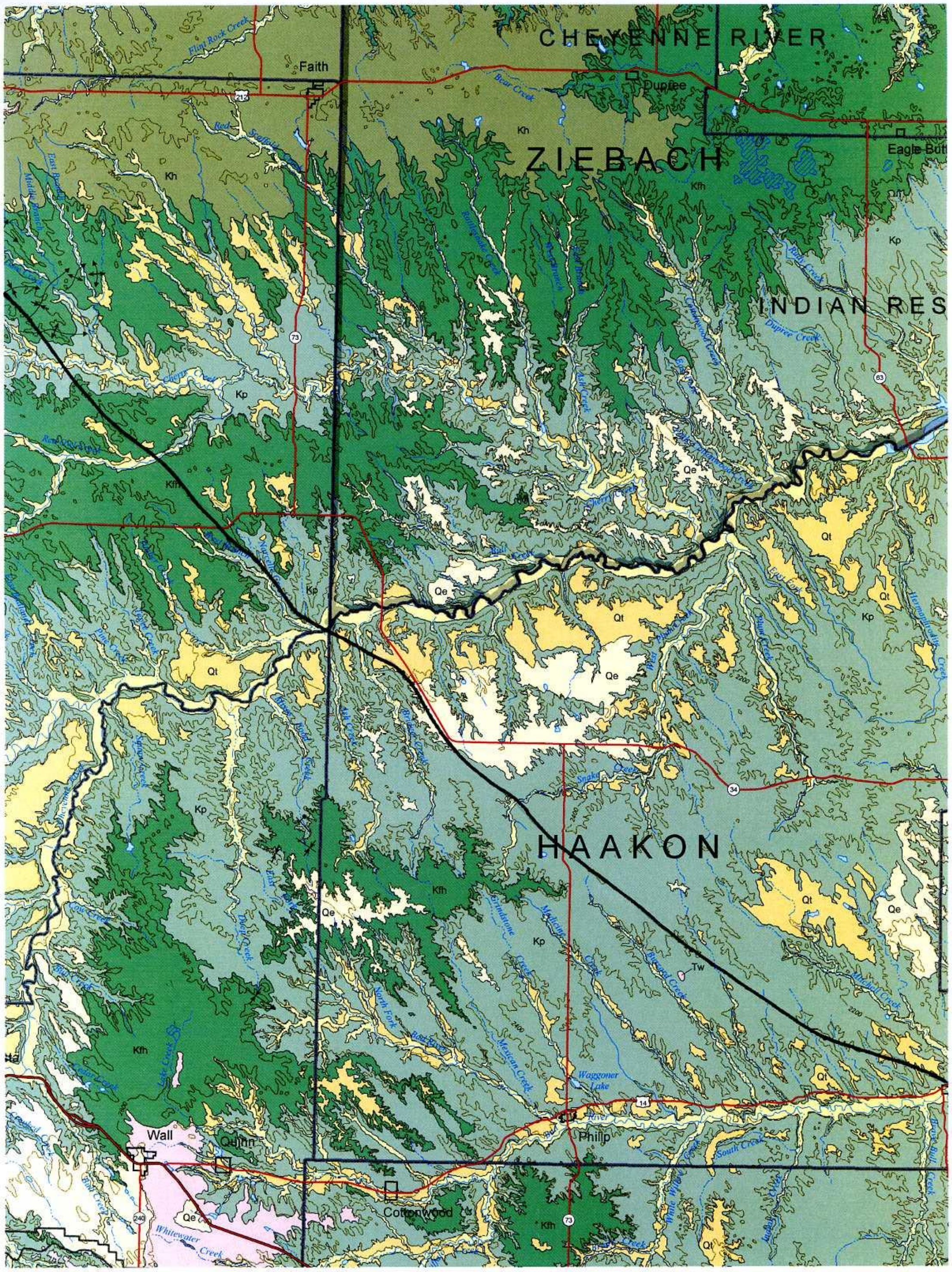


Figure 6. Part of the South Dakota geologic map (from Martin et al., 2004) in Meade and Haakon counties, with proposed Keystone XL route superimposed. The route would cross the Cheyenne River near the border of Meade and Haakon counties. The area mapped as Q_t refers to terrace deposits of streams in former flood plains.

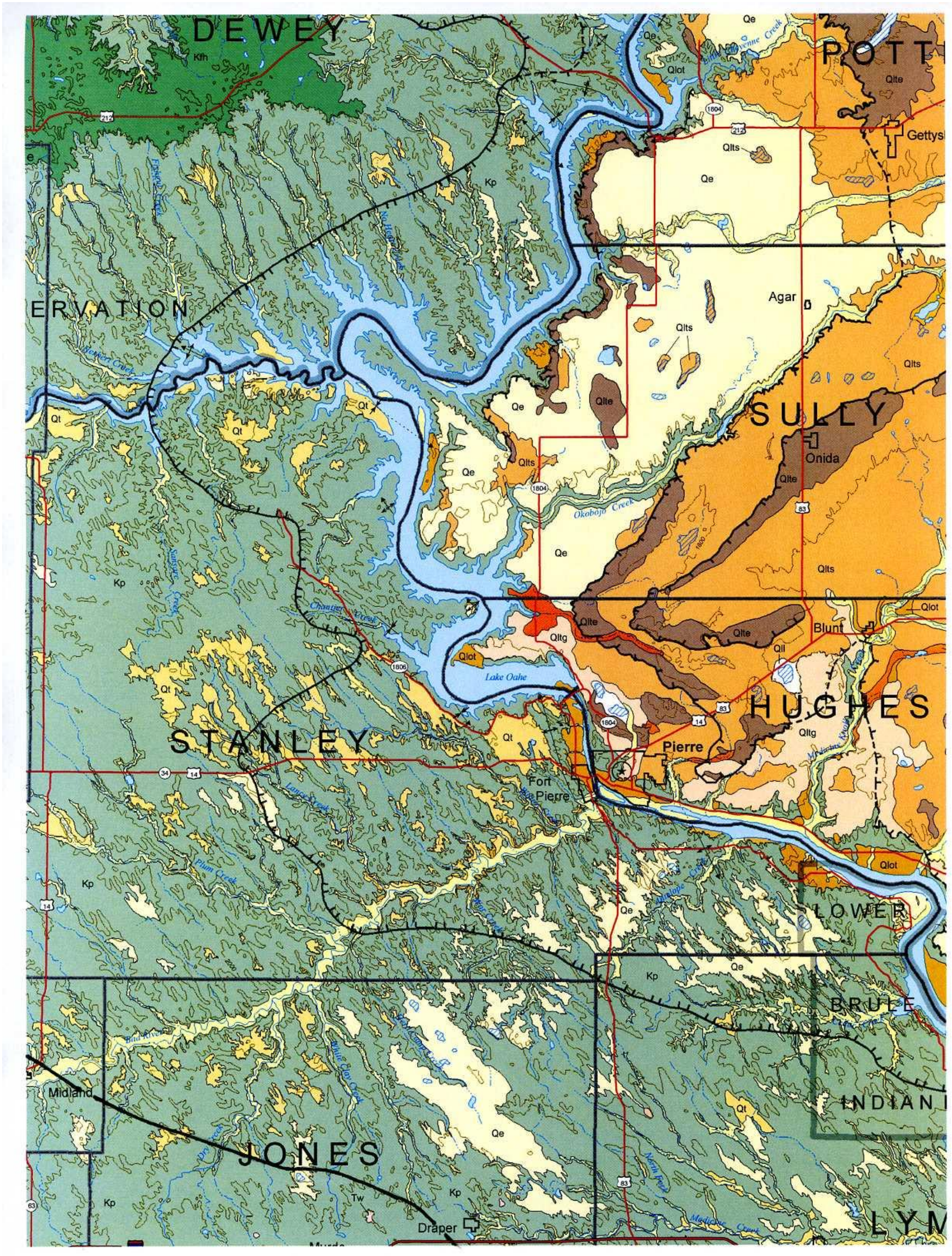


Figure 7. Part of the South Dakota geologic map (from Martin et al., 2004) in Haakon and Jones counties, with proposed Keystone XL route superimposed.

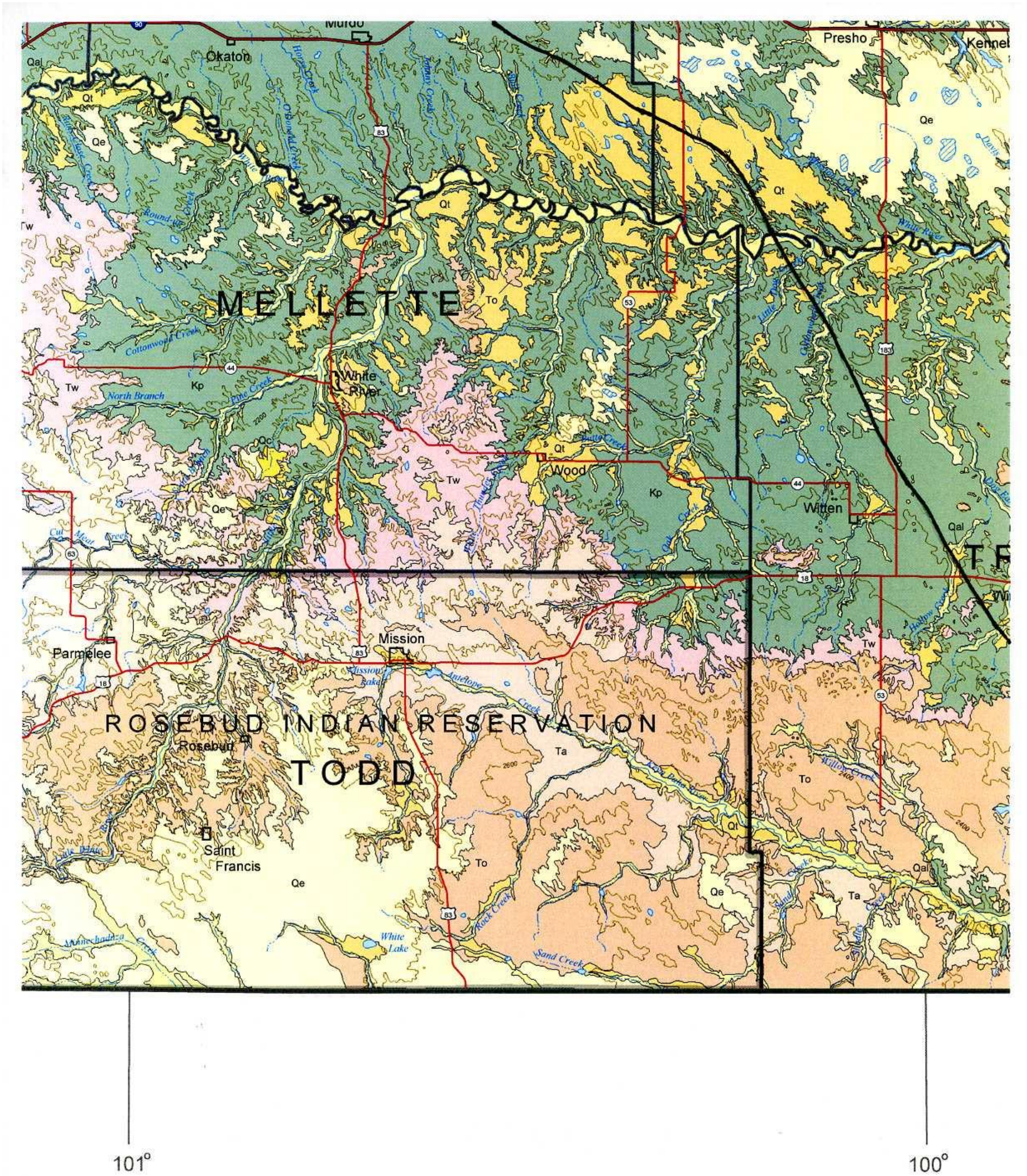


Figure 8. Part of the South Dakota geologic map (from Martin et al., 2004) in Jones, Lyman, and Tripp counties, with proposed Keystone XL route superimposed. The area mapped as Q_t shows terrace deposits of streams in former flood plains.

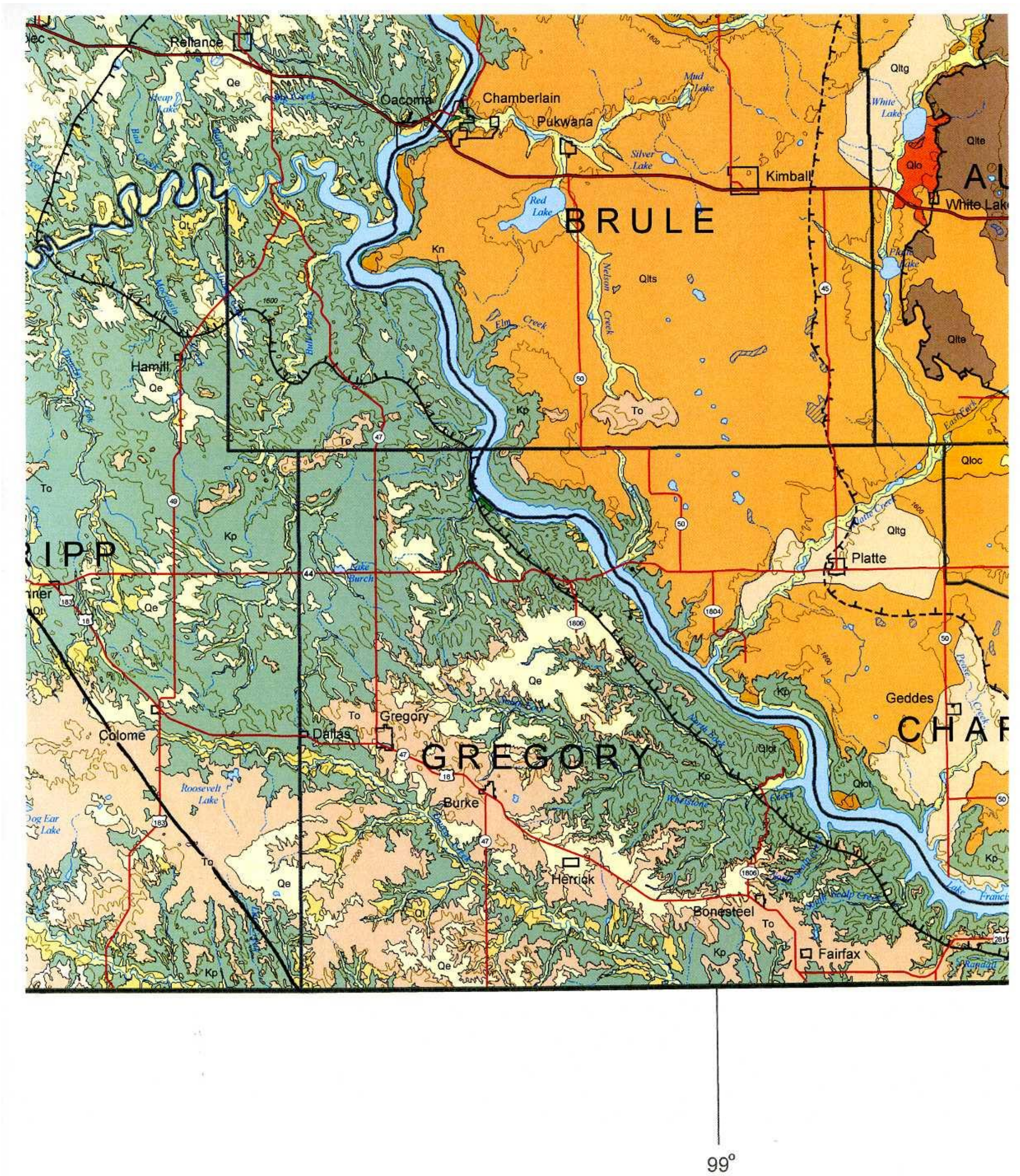


Figure 9. Part of the South Dakota geologic map (from Martin et al., 2004) in Tripp County, with proposed Keystone XL route superimposed. The area mapped as T_o shows the Ogallala aquifer. The areas mapped as Q_e show eolian (wind-blown) deposits, including Sand Hills type material.

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

KEYSTONE XL PROJECT
DOCKET HP09-001

PREFILED TESTIMONY OF MICHAEL K. MADDEN
ON BEHALF OF THE COMMISSION STAFF
SEPTEMBER 2009

BEFORE THE PUBLIC UTILITIES COMMISSION STATE OF SOUTH DAKOTA

PREFILED TESTIMONY OF MICHAEL K. MADDEN

Q: Please state your name and business address.

A: Michael K. Madden, 63 Langdon Road, Buffalo, Wyoming 82834.

Q: Describe your educational background.

A: I received my Bachelor of Science Degree in 1965 from South Dakota State University with a major in Economics and a minor in Mathematics. I received my Doctorate with a major in Economics and minor in Statistics from Iowa State University in 1970.

Q: What is your employment history?

A: I served as Assistant Professor of Economics at the University of Wyoming from 1968 to 1972, Associate Professor of Economics at South Dakota State University from 1972 to 1975 and Associate Professor, Professor and Assistant Dean at the University of South Dakota from 1975 to 1999. From 1999 until 2003, I served as Dean of Graduate Studies at National American University in Rapid City. During all of this time, I also devoted significant time to private consulting activities.

Q: By whom are you now employed?

A: Since retiring from the academic field, I am now self-employed as a business and economic consultant. During the last three years, I have served as a Wyoming State Representative of Johnson and Sheridan Counties.

Q: What work experience have you had that is relevant to your research on this project?

A: I have conducted economic impact and feasibility studies for nearly three decades in South Dakota. Industries in which I have performed these analyses include electric power, mining, agriculture, health, banking and tourism.

Q. On whose behalf was this testimony prepared?

A. This testimony was prepared on behalf of the Staff of the South Dakota Public Utilities Commission (Staff).

Q: What is the purpose of your testimony?

A: My purpose in providing this testimony is to report my findings regarding various socioeconomic impacts that can be expected in connection with the construction and operation of the proposed Keystone XL hydrocarbon pipeline. The study I am preparing in providing a basis for this testimony will be entitled "Assessment of Socioeconomic Impacts Associated with Keystone XL."

Q: Which socioeconomic areas are you studying?

A: The retail sectors that are similar to those impacted by the travel industry, such as eating and drinking establishments, lodging and general retail trade. Other business sectors that are examined include health, agriculture and housing. Social services, such as emergency ambulance services, police and fire protection and transportation are also being examined.

Q: What methodology are you employing?

A: A primary basis of the analysis involves an examination of changes in socioeconomic factors that has occurred and is presently occurring during the construction cycle of the first Keystone Pipeline in eastern South Dakota. In economic sectors for which data is available, I am examining changes in business volume from secondary sources. This information is being supplemented by field interviews with representatives of key community business organizations and providers of social services. Since the same company is involved with both projects at nearly the same span of time, it is expected that reliable results for Keystone XL will be obtained. In addition, much useful information will by synthesized from the Wyoming Industrial Siting Council and the Wyoming Pipeline Authority. Both of these organizations have had detailed experience with dozens of pipeline projects in the state of Wyoming.

Q: Is the study complete?

A: No, the study could not be finalized until the specific communities which were impacted most from the first Keystone pipeline could be determined and until the bulk of these community impacts had transpired. I will, therefore, substantiate the findings relayed below prior to the hearing through the submission of the aforementioned report. However, some preliminary findings have emerged.

Q: Summarize the findings that have been determined to this point.

A: The source and direction of impacts within the industries studied are summarized below.

Industry	Source of Economic Impacts	Direction of Impact	Net Impact
Leisure Travel	Revenue	Positive	Positive
	Labor Costs	None Significant	
	Displacement of Traditional Users	Somewhat Negative	
Health	Revenue	Positive	Positive
	Labor Costs	None Significant	
	Displacement of Traditional Users	None	
Law Enforcement	Volume	Somewhat Positive	Moderate Negative
	Labor Costs	None	
Emergency Services	Volume	None	None Significant
	Labor Costs	None	
Fire Services	Volume	None	None Significant
	Labor Costs	None	
Agriculture	Revenue	None	None Significant
	Labor Costs	None Significant	
Retail	Revenue	Positive	Positive

	Labor Costs	Negative	
	Displacement of Traditional Users	None	
Housing	Revenue	Positive	Positive
	Displacement/Rent Increases	Minor	

Most sectors are impacted by changes in gross revenues. Agriculture does not appear to have been impacted, but adjoining landowners may have benefited slightly by access fees.

Labor expense for farmers has not noticeably increased due to increased competition from pipeline businesses. Labor costs are not expected to rise in the Keystone XL project because of increased unit labor competition of the moderate amount of local labor demanded and because of the short-term character of the positions that will be available. On balance, most sectors are projected to experience an economic benefit because increases in revenues will exceed increased labor expenses.

Displacement of traditional leisure travelers in Western South Dakota by construction workers demanding the same goods and services is likely to be limited to the summer season. Any potential impacts are likely to be mitigated because of the intent on the part of the company to utilize temporary worker camps in two or three communities in close proximity to the project. Murdo, the community with potentially the largest tourism impact, will have specifically been addressed by the company by providing workers for the area a temporary worker camp near Winner. Any impacts to that community will occur in 2011 and is therefore expected to be minor.

Moderately increased revenue is expected to be the primary economic impact accruing to the health industry in connection with the project.

The retail sector is projected to experience moderate growth in revenue. Retail businesses providing goods that are directly bought by construction workers will experience the largest growth. Other businesses will see revenues grow through indirect spending. Providers of fuel and other supplies directly required by the project itself will experience increased revenues, with moderate increases in labor requirements. An increased demand for labor created by the construction of the pipeline will induce higher local wages. Generally, sectors providing goods and services directly to the project will experience the highest growth in demand for labor, but will probably not significantly increase wage rates due to the short-term nature of the growth in business volume.

Because of its unique nature, the need for housing has the potential to generate negative community impacts in towns such as Buffalo, Belle Fourche, Philip, Murdo and Winner. Any substantial increase in temporary housing demand may produce increased competition seen by local tenants as competition from temporary construction workers, earning higher than average wages, takes place. This, in turn, may produce undesirable economic consequences in the long run if displaced tenants choose to leave the area permanently.

The project plan however, provides a mitigation of these impacts by the operation of large construction camps in the vicinity of Union Center and Winner. It is important that these worker camps be a part of the company commitment to help ease the load on local housing stocks.

Q: How else can the possible negative remaining impact on the housing market be mitigated?

A: If adequate sized worker camps providing board and room to temporary workers are provided, there is probably nothing else that needs to be done. Any remaining capacity shortcomings to the worker camps can be supplemented by:

- Bus transportation could be provided for workers from larger and more distant communities such as Rapid City, Pierre or Chamberlain to the job site. This policy would mitigate the otherwise added cost of transportation to and from work for those living in more distant communities.
- Agreements could be negotiated with area motels guaranteeing a minimum quantity and price of lodging rooms throughout the region. These agreements could be negotiated with consideration given to geographic dispersion and to available capacity throughout annual cycles.

Q: Aside from your study to substantiate your conclusions, does this conclude your testimony?

A: Yes

3.3 WATER RESOURCES

3.3.1 Introduction

This section discusses water resources in the proposed Project area. The description of water resources is based on information provided in the 2011 Final Environmental Impact Statement (Final EIS) as well as new circumstances or information relevant to environmental concerns that have become available since the publication of the Final EIS, including the proposed major reroute in Nebraska and numerous minor (less than 1 mile) route modifications in Montana and South Dakota. The information provided here builds on the information provided in the Final EIS as well as the 2013 Draft Supplemental EIS and, in many instances, replicates that information with relatively minor changes and updates: other information is entirely new or substantially altered from that presented in the Final EIS.

Specifically, the following information, data, methods, and/or analyses have been substantially updated from the 2011 document:

- Well data (depth, hydrogeology, and water quality) near the proposed Project area in Montana and South Dakota were added.
- Tribal lands are considered in the Surface Water sections.
- Major proposed route modifications in much of Nebraska necessitated new data collection and analysis including wells locations, water depths, water quality, and hydrogeologic (aquifer) analysis.
- The number and type of stream crossings and stream crossing methods have changed due to route modifications as well as updated field survey information provided by TransCanada Keystone Pipeline, LP (Keystone). The stream crossing assessment was comprised of a desktop analysis based on National Hydrography Dataset (NHD) information and supplemented by Keystone field survey descriptions where available.
- Based on the limitations of the data used in the desktop analysis, the intermittent and ephemeral stream categories were combined and assessed as intermittent streams, and no distinction between these categories was maintained. This document separates makes the distinction between ephemeral and intermittent streams.
- State and federally designated or mapped floodplain areas were assessed in Montana, South Dakota, and Nebraska from publicly available map data. Not all counties along the proposed Project route are mapped. Project locations that intersected mapped floodplains were listed.
- Floodplains for the Cheyenne, Little Missouri, and Bad River in South Dakota were identified in a desktop analysis that included effective floodplain areas regardless of designation.
- The number and depth of reported wells within one mile of the proposed pipeline route have been identified.
- A detailed discussion of the aquifers and aquifer properties was added.
- A major new alignment in the sand hills portion of Nebraska and an assessment of existing conditions associated with the new alignment were added.

- A cross-section showing the general relationship of geologic and hydrologic units was added;
- Maps showing well locations and depths by state were added.
- Tables on the well information by route mile were updated and new tables were added.

The following information, data, methods, and/or analyses have been substantially updated from the 2013 Draft Supplemental EIS:

- Well data details were added or updated along the alignment route including Geographic Information System map coordinates for each registered well;
- A discussion of stream crossing methodology was expanded, including boring techniques.
- Specific discussions of spill potential and potential effects have been moved to Sections 4.3, Water Resources, and 4.13, Potential Releases.
- Additional discussion of Wild and Scenic Rivers Act designated segments has been added.
- Route modifications included a relocation of the Niobrara River crossing. This crossing is located between designated Wild and Scenic River segments managed by the National Park Service. Portions of the Missouri River watershed that could be affected by proposed Project's construction activities, operations, or potential releases have been included in this analysis.
- Water distribution system crossing criteria supplied by the U.S. Bureau of Reclamation (BOR), specifically as it relates to the Mni Wiconi water line crossed by the proposed project was added.
- BOR facility locations listed by approximate milepost (MP) as crossed by the proposed Project were added.
- In response to public and agency comments, text has been revised throughout the section where necessary.

Summary

The proposed Project would cross several primary groundwater aquifers[1] and regional aquitards[2] in the Project area. The aquifers encountered within the Project area range from large regional aquifers present in multiple states to shallow alluvial aquifers related to stream sediment, aeolian, and loess deposits[3]. The primary groundwater aquifers within the Project area include the Great Plains Aquifer (GPA), the Western Interior Plains Aquifer (WIPA), the Northern Great Plains Aquifer System (NGPAS), the Northern High Plains Aquifer (NHPAQ), and multiple unnamed alluvial aquifers. Within the Project area, the pipeline crosses approximately 25 miles of alluvial aquifers underlain by aquitards, 226 miles of the NGPAS, and 294 miles of the NHPAQ (190 miles of which are combined NHPAQ and alluvial aquifers).

[1] An aquifer is a geological formation, groups of formations, or part of a formation that is capable of yielding a significant amount of water to a well or spring.
[2] An aquitard is a confining bed that retards but does not prevent the flow of water to or from an adjacent aquifer.
[3] Loess is a blanket deposit of buff-colored calcareous silt, homogeneous, nonstratified, weakly coherent, porous, and friable (easily crumbled); it is thought to be from windblown dust of Pleistocene in age.

Depth to first groundwater within the Project corridor is reported to range from zero feet deep to over 300 feet deep. Water bearing zones with reported water depths of less than 50 feet below ground surface (bgs) and within 1 mile of the proposed Project corridor were identified for potential groundwater quality impacts from pipeline construction and operations. Based on available well records, approximately 250 to 300 miles of the proposed Project corridor have reported groundwater depths of less than 50 feet bgs. Deeper aquifers below 300 feet or that are saline were excluded from evaluation except where groundwater extraction activities occur.

Federal, state, and local databases were searched to compile groundwater information from domestic, irrigation, and public water supply well data. Agency-sponsored water quality information as well as available databases indicated that water within the proposed Project area contains moderate to high levels of total dissolved solids (TDS), dissolved carbonates, and nitrates. The primary source of TDS is attributed to saline intrusions[4] from deeper aquifers while the elevated nitrate concentration is attributed to soil characteristics and agricultural activities.

The proposed Project route would cross approximately 1,073 surface waterbodies; of those, 14 are planned for crossing with the horizontal directional drill (HDD) construction method. In addition to HDD pipeline installations, for some waterbody crossings the Project would use variations of open trench pipeline installations to protect habitats and aquatic species that depend on flowing surface water. Some waterbodies that the proposed Project encounters would require site-specific design and permitting based on protected conditions or areas that were determined to be of high consequence. The Pipeline and Hazardous Materials Safety Administration identifies High Consequence Areas for hazardous liquid pipelines. These designations focus on populated areas, drinking water sources, and unusually sensitive ecological resources. These are specific locations where a spill could have the most significant adverse consequences. Once identified, pipeline operators are required to devote additional focus, efforts, and analysis in High Consequence Areas to ensure the integrity of pipelines.

Figure 3.3.1-1 provides a summary of waterbodies crossed by the proposed Project for each state[5]. These are separated by waterbody categories (Perennial, Intermittent, Canals and Other). Waterbodies categorized as other include manmade seasonal impoundments and ponds.

[4] Saline intrusion is a marine geologic deposit that can contain high concentrations of salt, which can leach into groundwater that comes in contact with the rocks. This water cannot be used by animals or crops without treatment and therefore is not used. This high salt (saline) water is typically below geologic deposits that contain usable groundwater.

[5] In addition to the planned pipeline, the additional supporting infrastructure for the proposed Project (a pipe yard and a rail siding in North Dakota and two pumps stations in Kansas) are not anticipated to impact surface waterbodies; therefore North Dakota and Kanas have no entries in the waterbody summaries or tables in this section.

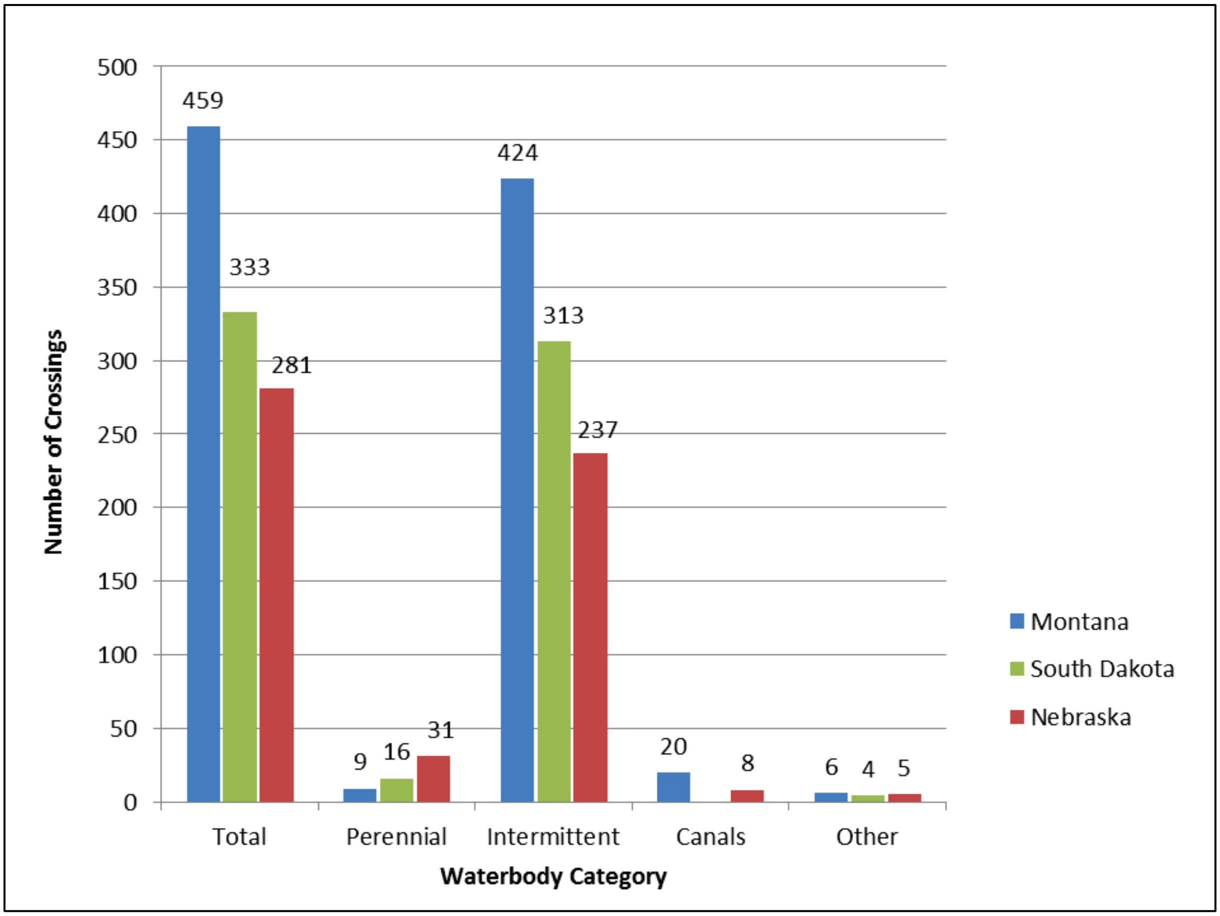


Figure 3.3.1-1 Waterbodies Crossed by Category

The affected environment assessment for waterbodies is based on several different surface water condition criteria including perennial versus intermittent, impaired versus not impaired, and multiple use classifications. For the purposes of the Final Supplemental EIS and based on limitations of the desktop level of investigation, intermittent and ephemeral waterbodies are assessed as a single category of stream. The U.S. Army Corps of Engineers nationwide permit program has the following definitions of these waterbodies:

- An intermittent stream has flowing water during certain times of the year, when groundwater provides water for stream flow. During dry periods, intermittent streams may not have flowing water. Runoff from rainfall is a supplemental source of water for stream flow.
- An ephemeral stream has flowing water only during, and for a short duration after, precipitation events in a typical year. Ephemeral stream beds are located above the water table year-round. Groundwater is not a source of water for the stream. Runoff from rainfall is the primary source of water for stream flow.
- An impaired waterbody is one that is polluted to the point where it does not meet its designated use. For example, a waterbody designated for swimming could become impaired if pollution increased to the point where it was not desirable or safe for people to swim. A

lake designated for aquatic life could become impaired if it became polluted to the point where certain types of fish that used to thrive there could no longer live. As a waterbody becomes impaired, the existing aquatic ecosystem changes for the worse, fish or wildlife habitat is degraded, and in extreme cases, public health may be threatened. These impaired waterbodies along proposed Project route have been assessed to determine any effects that could be incurred by the proposed Project construction or operation.

State-designated uses and water quality assessments have been reviewed to fully assess the waterbodies potentially affected by the proposed Project. Figure 3.3.1-2 provides a summary of the designated uses for waterbodies crossed by the proposed Project by state.

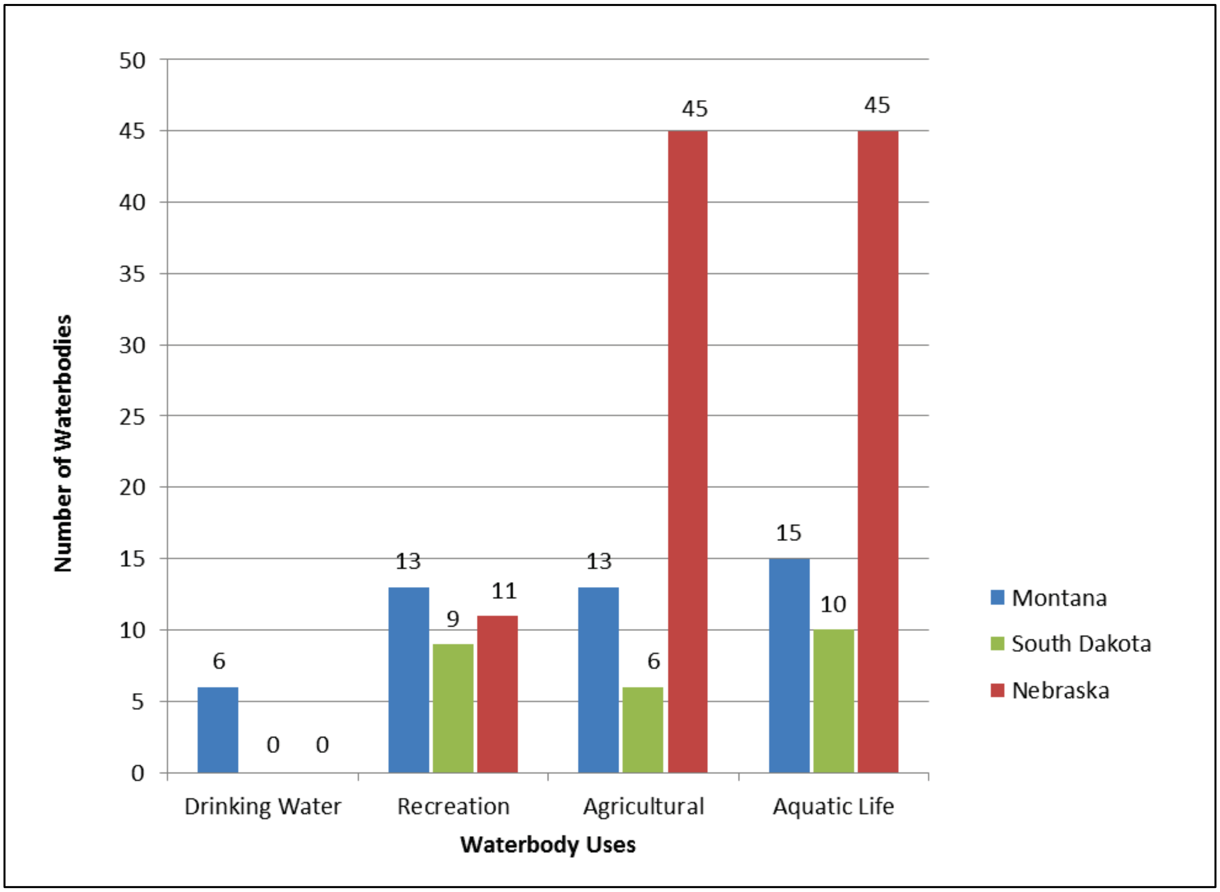


Figure 3.3.1-2 Waterbodies Crossed with Designated Uses

Primarily due to the changes in geography and latitude over the extent of the project, significant variations in the types and sizes of affected waterbodies would be encountered by the proposed Project.

Connected actions that would be constructed in areas similar to the proposed Project route include the Bakken Marketlink Project, the Big Bend to Witten 230-kilovolt (kV) Transmission Line, and electrical distribution lines and substations. The preliminary Bakken Marketlink route would cross seven intermittent waterbodies as well as the Sandstone Creek, a perennial waterbody (see Figure 2.1.12-3 for a map of the preliminary route). This connected action is not expected to impact the beneficial uses for Sandstone Creek, which are listed in the Montana Department of Environmental Quality (MDEQ) Final Water Quality Integrated Report (MDEQ 2012). The surface water resource and groundwater conditions for the connected actions are expected to be similar to the surface water resource and groundwater conditions discussed for the proposed Project route.

3.3.2 Groundwater

3.3.2.1 Hydrogeologic Setting

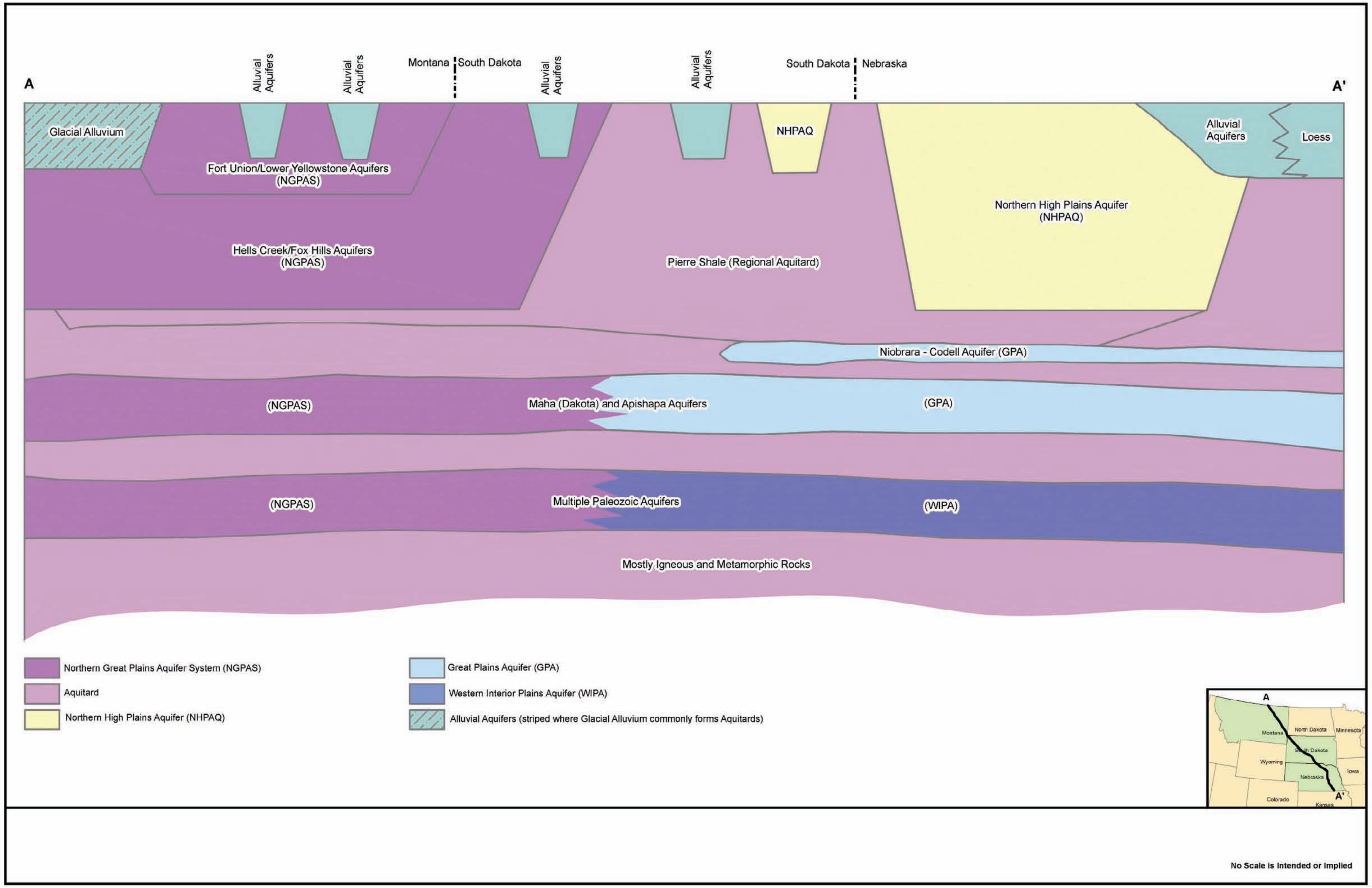
Groundwater resources are a primary source of irrigation and potable water along much of the proposed pipeline route. Several primary groundwater aquifers and aquifer groups underlie the proposed Project area, including the following:

- Alluvial aquifers
- NHPAQ
- GPA
- NGPAS
- WIPA

Each of these aquifers is described in the following subsections. To establish a context and better understanding of the specific conditions along the proposed pipeline route, the regional large-scale groundwater conditions and interactions of these aquifers and aquifer groups are described (see Figure 3.3.2-1).

Alluvial Aquifers

Alluvial aquifers along the proposed pipeline route typically consist of sediments deposited in stream valleys. In some areas of Nebraska crossed by the proposed route, the alluvial aquifer deposits also include aeolian (dune and sheet deposits) sands and loess (windblown silt deposits). These unconsolidated deposits range from a few feet to hundreds of feet thick. They are typically related to continental glaciation deposits in the proposed Project area, and are typically reworked sediments derived from local formations throughout the central portion of the proposed route (Miller and Appel 1997, University of Nebraska 1998).



Sources: Whitehead 1996, Miller and Appel 1997, Esri 2013

Figure 3.3.2-1 Schematic Hydrogeologic Cross-Section along Proposed Pipeline Route

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Groundwater in the alluvial aquifers is characteristically shallow (less than 50 feet bgs) and often unconfined. Wells completed in the alluvial deposits in the proposed Project area are typically less than 100 feet deep and have yields that range from one to several thousand gallons per minute (gpm) (Whitehead 1996). As would be expected given the range of observed well yields, the aquifer characteristics that measure the amount of groundwater and how easily it flows (transmissivity, storativity, and hydraulic conductivity[6]) of these deposits vary widely across the study area as well as locally. Table 3.3-1 contains information on general aquifer well yields for units along the proposed Project route. Unconsolidated alluvial aquifers are a primary source of groundwater for irrigation, domestic, commercial, and/or industrial use throughout much of the proposed Project area.

Table 3.3-1 Groundwater Yield Estimates by Aquifer

Aquifer	Regional Aquifer Group(s)[a]	State	Range of Yield[b]
Judith River Formation	NGPAS	MT	5-20
Missouri River Alluvium	AA	MT	5-300
Hells Creek/Fox Hills	NGPAS	MT	5-20
Fox Hills	NGPAS	MT	5-20
Fort Union	NGPAS	MT	15-25
Yellowstone R. Alluvium	AA	MT	50-500
Hells Creek/Fox Hills	NGPAS	SD	5-20
Ogallala Formation	NHPAQ	SD	0-50
Pleistocene River Terrace	AA	SD	250-750
White River Alluvium	AA	SD	1-30
Ogallala Formation	NHPAQ	NE	250-750
Sand Hills Unit	NHPAQ/AA	NE	100-1,000
Ogallala Formation	NHPAQ	NE	250-750
Platte River Unit	NHPAQ/AA	NE	5-500
Eastern Nebraska Unit	NHPAQ/AA	NE	5-250

Sources: Based on available well data from Nebraska Department of Natural Resources (NDNR) 2012, South Dakota Department of Environment and Natural Resources (SDDENR) 2012a, and Montana Bureau of Mines and Geology 2012

[a] NGPAS = Northern Great Plains Aquifer System; AA = Alluvial aquifer; NHPAQ = Northern High Plains Aquifer
[b] Yields are reported at gallons per minute.

The proposed Project would include two proposed pump stations in Kansas, both of which would be situated upon alluvial aquifers. The pump station in Clay County is located within the alluvium of the Republican River, and the pump station in Butler County is situated on the alluvium associated with the East Branch of the Whitewater River.

The stream valley alluvial aquifers in eastern Kansas consist mostly of Holocene and Pleistocene sand and gravel deposits with an average thickness of 90 to 100 feet, but locally can be as much as 160 feet thick. The saturated thickness within these alluvial aquifers is typically 50 to 80 feet, and aquifer conditions are usually unconfined. Well yields of up to 3,000 gpm are reported from

[6] *Transmissivity* is a volumetric measure of the rate of horizontal groundwater flow through an aquifer, generally equal to the product of the aquifer hydraulic conductivity and the aquifer saturated thickness. *Storativity* is a volumetric measure of the rate of groundwater extraction from an aquifer corresponding to a given decrease in the fluid level within the aquifer per unit area of the aquifer. *Hydraulic conductivity* is a velocity measure of rate of fluid flow through a porous soil or rock material under a hydraulic gradient (slope of fluid surface) of distances of 1 vertical :1 horizontal.

stream valley alluvial aquifers in Kansas, and transmissivity values range from 8,000 to 80,000 square feet per day (Whitehead 1996).

Northern High Plains Aquifer

The NHPAQ extends across portions of eight states from southern South Dakota to the Texas panhandle, and is an important groundwater resource across nearly the entire overlying area. The NHPAQ stores approximately 3.25 billion acre-feet of groundwater, and provides water to over 170,000 wells. The NHPAQ in the vicinity of the proposed Project consists of Tertiary rocks of the Ogallala Formation, Arikaree Group, and Brule Formation, as well as overlying and associated alluvial sediments. The Ogallala Formation is present beneath portions of the proposed Project area in southern South Dakota and Nebraska where the formation is primarily underlain by the Pierre Shale, a regional confining layer. The Arikaree Group and Brule Formation are not present directly beneath the proposed Project area. In southern South Dakota and Nebraska, the NHPAQ system is typically described to include groundwater-bearing Quaternary and recent aeolian, fluvial, and glacial alluvium overlying and adjacent to the Ogallala Formation; therefore, descriptions of the NHPAQ conditions overlap somewhat with the alluvial aquifers described above (Gutentag et al. 1984).

The Ogallala Formation consists primarily of unconsolidated to semi-consolidated gravel, sand, silt, and clay deposited by an extensive network of easterly flowing rivers and streams that drained the ancestral Rocky Mountains. Depth to groundwater in the Ogallala Formation in the proposed pipeline area ranges from near the surface to greater than 200 feet bgs. Thickness of the water-bearing units in this formation can be up to 900 feet or more, but are typically much thinner in the formation’s easternmost portions crossed by the proposed pipeline route, where saturated thicknesses of more than 300 feet are uncommon. Typical recharge rates to the Ogallala Formation and associated alluvial aquifers range from 0.5 to 5 inches per year along the proposed route, with the highest recharge rates in the areas of the aquifer associated with the Sand Hills Unit. Groundwater generally flows toward the east at an average of 1 foot per day (Gutentag et al. 1984). Transmissivity of the Ogallala Formation in the Project corridor typically ranges from approximately 2,000 to 10,000 square feet per day (University of Nebraska 1998).

Where present, the Ogallala Formation and associated alluvial aquifers are a primary source of groundwater for agricultural, domestic, commercial/industrial, and potable use along much of the proposed Project area in southern South Dakota and Nebraska.

Great Plains Aquifer

The GPA consists of sedimentary rocks deposited in the Cretaceous Period across much of Nebraska, Kansas, Colorado, and smaller parts of New Mexico, Oklahoma, Texas, South Dakota, and Wyoming (Miller and Appel 1997). The two primary sub-units of the aquifer are the Maha and Apishapa aquifers, which both consist of loosely cemented, fine- to medium-grained sandstone separated by a shale confining unit. A less extensive aquifer system, the Niobrara/Codell aquifer sub-unit, is present in the study area and is stratigraphically within the GPA. Along the proposed route, the GPA lies underneath the NHPAQ, including the Ogallala formation (Figure 3.3.2-1).

Of the two primary sub-units, only the Maha aquifer (Dakota Sandstone) is present beneath the proposed Project area across southern South Dakota and Nebraska. Rocks and conditions that correlate to both aquifer sub-units are present beneath the proposed Project area north of the

Nebraska-South Dakota border. Across that area, however, the depth to water, high dissolved solids content (salinity), and other water quality issues typically make the aquifer sub-units unsuitable for irrigation or potable use. Also within Nebraska, much of the GPA has limited use because of high salinity, except where the formations that compose the aquifer are near the surface in the eastern portion of the state.

The formation thickness of the Maha aquifer sub-unit is approximately 600 feet beneath Keya Paha County, Nebraska, and generally decreases along the proposed route to less than 200 feet in thickness at Steele City, Nebraska (Miller and Appel 1997). Depth to the top of the Maha is reported as 1,000 feet bgs or less along the proposed route; the Dakota Sandstone is near the surface in the southern portion of the proposed Project area in Nebraska, but typically covered with alluvium. Transmissivity of the Maha aquifer beneath the proposed Project area is estimated to range from greater than 1,000 to over 10,000 square feet per day.

The Niobrara/Codell aquifer sub-unit is a regional groundwater aquifer that stratigraphically falls within the GPA system and is present across much of Nebraska and southern South Dakota. The aquifer is present in Late Cretaceous sandy chalk, limestone, shale, and sandstone rocks overlying the Maha aquifer sub-unit. Water quality in this aquifer is generally better than the underlying Maha, but is still somewhat saline across much of the aquifer extent. In scattered areas where water quality is good, however, the aquifer is used as a minor source of domestic, municipal, and irrigation water (Korus and Joeckel 2011).

Recharge of the GPA across most of the proposed Project area in Nebraska may be from groundwater in the overlying Ogallala Formation; however, in the areas of downward hydraulic gradient between the Ogallala and the GPA that the proposed route would cross, the GPA is typically saline and not used for groundwater withdrawal (Miller and Appel 1997). Additionally, most of the NHPAQ in the area is underlain by the Pierre Shale, which forms an aquitard that limits hydraulic connectivity between the NHPAQ and GPA across most of the area where the two aquifers are present along the proposed route.

Where the GPA is present beneath the proposed Project area, no wells were identified that extract groundwater from this aquifer within 1 mile of the proposed Project corridor centerline based on a review of available water well logs for Nebraska and South Dakota.

Western Interior Plains Aquifer

The WIPA consists of Mississippian to Cambrian Age dolomite, limestone, and sandstone across most of Kansas, eastern Nebraska, and parts of Missouri (Miller and Appel 1997). In eastern Montana and South Dakota, this sequence grades laterally into the NGPAS and is typically deeply buried and contains very saline water, except in areas where uplift brings the formations close to the surface, such as the vicinity of the Black Hills. There are no such uplift areas present within the proposed Project area, and the WIPA lies underneath the GPA (Figure 3.3.2-1).

Along the proposed pipeline route in eastern Nebraska, the aquifer thickness is approximately 1,500 feet at Steele City, Nebraska, generally decreasing to the north and pinching out[7] a few miles south of the South Dakota border in Keya Paha County (Miller and Appel 1997). Little, if

[7] A pinch-out is the termination or end of a stratum of geologic material that narrows or thins progressively in a given direction until it disappears and the rocks it once separated are in contact.

any, water is withdrawn from the WIPA in Nebraska in the vicinity of the proposed pipeline area because the aquifer is deeply buried (at least several hundred feet bgs) and very saline (Korus and Joeckel 2011).

Where the WIPA is present beneath the proposed Project area, no wells that extract groundwater from this aquifer were identified within 1 mile of the proposed Project corridor centerline. In addition, the WIPA is separated from the overlying GPA by aquitards that limit hydraulic connectivity between the WIPA and GPA across the proposed Project area.

Northern Great Plains Aquifer System

The NGPAS in eastern Montana, northern Wyoming, western North Dakota, and northwestern South Dakota consists of early Cenozoic, Mesozoic, and Paleozoic rocks, some of which, further to the southeast, are subdivided into the GPA and WIPA (Whitehead 1996). This aquifer system also includes Tertiary and Late Cretaceous rocks that do not have correlative aquifer units in southern South Dakota and Nebraska. Although several separate aquifers and intervening aquitards are present within the NGPAS, the separate aquifers share similar conditions and exhibit at least some degree of hydraulic connectivity on a local and regional scale.

The Tertiary and Late Cretaceous formations that are included in the NGPAS (Fort Union Group, Hell Creek Formation, and Fox Hills Sandstone) are present at or near the surface across most of the proposed Project area through northwestern South Dakota and Montana (Whitehead 1996). Beneath these Tertiary formations and exposed at the surface along the eastern and western periphery of those rocks units, Early Cretaceous rocks of the Inyan Kara Group, the next deepest primary aquifer in the NGPAS, are present. Paleozoic rocks containing aquifers similar to or directly correlated to those in the WIPA are present beneath the Inyan Kara Group; however, these rocks do not approach the surface in the vicinity of the proposed Project area.

The thickness of the rock units comprising the NGPAS are tens of thousands of feet thick in aggregate, and individual water-bearing units can be several thousand feet thick. For example, the Fort Union Formation is up to 3,600 feet thick in the Powder River Basin. Similarly, aquitard units between the aquifer units are of variable thickness and are commonly absent in some areas.

Regional groundwater recharge into the NGPAS is typically from water infiltration at higher altitudes, along the shallow dip of the NGPAS aquifers, and then upward into overlying aquifer units (Whitehead 1996). Local recharge does occur through precipitation migration into Tertiary rocks and downward into the underlying older aquifers. Groundwater in the aquifer system typically moves from the highest elevations in the southern and western portions of the system toward the northeast in the Williston Basin (western North Dakota) and to the north in the Powder River Basin (northeastern Wyoming and southeastern Montana). Net groundwater flow between aquifer units is typically upward across the NGPAS. Groundwater quality is commonly slightly to very saline in the aquifer system’s Early Cretaceous portions, and is commonly at least slightly saline in the Late Cretaceous and Tertiary aquifers. The salinity in these aquifers is related to recharge from the underlying saline Paleozoic aquifer units.

Although the salinity in the groundwater from the uppermost NGPAS aquifer units makes the groundwater unsuitable for irrigation, the Tertiary and Late Cretaceous aquifers are commonly used for livestock watering and domestic and municipal water supply in western North Dakota and eastern Montana, including areas in the vicinity of the proposed Project corridor (Whitehead 1996).

Regarding the planned pipe yard[8] and rail siding in Bowman County, North Dakota, groundwater is located within the Lower Tertiary Fort Union Formation, which consists of sandstone and shale beds within interbedded coal in some areas. This unit is part of the NGPAS, and extends into Montana where the proposed Project area crosses the unit. Wells extracting groundwater from this unit in North Dakota are typically greater than 300 feet deep and yield up to 100 gallons per minute (Whitehead 1996).

3.3.2.2 Proposed Pipeline Area Hydrogeologic Conditions

This section includes a summary of the shallow groundwater encountered along the proposed pipeline area, followed by a more detailed summary of specific hydrogeologic conditions and major aquifers encountered along the pipeline area organized by state, including the following descriptions:

- Key aquifers;
- Nearby public water supply wells and private water wells;
- Depth to groundwater; and
- Water quality.

Deeper aquifers are excluded from evaluation except in areas where there may be potential groundwater quality impacts to those aquifers from pipeline construction or operation. The proposed project does not cross any sole-source aquifers (as designated by U.S. Environmental Protection Agency [USEPA] Region 8 [USEPA 2012]); however, the aquifers crossed potentially do represent up to 65 percent of potable water in Montana, up to 50 percent in South Dakota, and up to 83 percent in Nebraska. The NHPAQ in the vicinity of the proposed Project includes the Ogallala Formation and overlying and adjacent alluvial sediments. In total, the NHPAQ stores approximately 3.25 billion acre-feet of water, 66 percent of which is within Nebraska. Groundwater from the aquifer is extensively extracted for potable use, irrigation, livestock watering, and industrial use, including in the vicinity of the proposed Project (Gutentag et al. 1984). Water bearing zones less than 50 feet bgs were identified where possible by examining available well data obtained from each state for wells situated along the proposed pipeline area. These data typically include static water level and depth of wells within 1 mile of the proposed Project corridor centerline. The results of this evaluation are presented in Table 3.3-2.

[8] The pipe yard and rail siding would be a storage area used for equipment and material during pipeline construction.

Table 3.3-2 Water-Bearing Zones Less than 50 Feet Below Ground Surface Beneath the Proposed Pipeline Right-of-Way

State/County	Approximate Milepost (MP) or Range[a]	Approximate Depth to Groundwater (feet bgs[b])	Formation/Aquifer	Regional Aquifer Group[c]
Montana				
Phillips	2	8	Cretaceous Bearpaw Shale	NGPAS
Phillips	6	0	Cretaceous Bearpaw Shale	NGPAS
Phillips/Valley	25-26	<50	Frenchman Creek alluvium	AA
Valley	27	0-45	Late-Cretaceous Judith River Formation	NGPAS
Valley	38-41	0-9	Rock Creek glacial/alluvial sediments	AA
Valley	47	6	Late-Cretaceous Judith River Formation	NGPAS
Valley	55-57	40-43	Late-Cretaceous Bearpaw Shale and Buggy Creek alluvium	NGPAS
Valley	66-72	7-63	Cherry Creek glacial/alluvial sediments	AA
Valley	77-85	10-40	Porcupine Creek and Milk River alluvium	AA
Valley	88	7-22	Milk River/Missouri River alluvial sediments	AA
McCone	94	15	Late-Cretaceous Fox Hills Formation	NGPAS
McCone	99	26	Late-Cretaceous Hell Creek Formation	NGPAS
McCone	109	0	Late-Cretaceous Hell Creek Formation	NGPAS
McCone	119	20-30	Fort Union sands and Flying V Creek alluvium	NGPAS/AA
McCone	122-123	<50	Figure Eight Creek alluvium	AA
McCone	133-153	10-45	Fort Union sands; Redwater River alluvium; Buffalo Springs Creek alluvium; glacial drift	NGPAS/AA
Dawson	159-160	10-50	Fort Union sands	NGPAS
Dawson	166-180	10-45	Clear Creek alluvium	AA
Dawson	186-195	4-38	Clear Creek alluvium; Yellowstone River alluvium	AA
Prairie	201-205	0-15	Cabin Creek alluvium	AA
Prairie	209-214	18-40	Alluvium of merging creeks	AA
Fallon	227	<50	Dry Fork Creek alluvium	AA
Fallon	231-234	0	Glacial drift/alluvium	AA
Fallon	235-238	18-45	River alluvium of Dry Creek and its tributaries	AA
Fallon	242-250	5-26	Sandstone Creek and Butte Creek alluvium	AA
Fallon	257-262	0-37	Hidden Water Creek; Little Beaver Creek alluvium	AA
Fallon	264-272	0	Mud Creek and Soda Creek alluvium	AA
Fallon	275-279	0	North and South Coal Bank Creek alluvium	AA
Fallon	281-282	<50	Box Elder Creek alluvium	AA

State/County	Approximate Milepost (MP) or Range[a]	Approximate Depth to Groundwater (feet bgs[b])	Formation/Aquifer	Regional Aquifer Group[c]
South Dakota				
Harding	289-290	<50	Shaw Creek alluvium	AA
Harding	291-292	<50	Little Missouri River alluvium	AA
Harding	298-301	<50	Various creeks -alluvium	AA
Harding	304-306	<50	Jones Creek alluvium	AA
Harding	317-319	15-40	South Fork Grand River alluvium	AA
Harding	322-324	<50	Buffalo Creek/Clarks Fork Creek alluvium	AA
Harding	329	<50	West Squaw Creek alluvium	AA
Harding	339	20	Red Butte Creek alluvium	AA
Harding/Butte	351-355	<50	North Fork Moreau River alluvium	AA
Meade	380-387	15-45	Tertiary or alluvial	NGPAS/AA
Meade	390-394	25	Tertiary or alluvial	NGPAS/AA
Meade	399	18	Sulphur Creek alluvium	AA
Meade	403-404	14-44	Spring Creek alluvium	AA
Meade	407-408	14	Red Owl Creek alluvium	AA
Meade	411	3	Narcelle Creek alluvium	AA
Meade	425	5	Cheyenne River alluvium	AA
Pennington/ Haakon	432-437	<50	Alluvial	AA
Haakon	442	12	Alluvial	AA
Haakon	475	37	Alluvial	AA
Haakon	478-481	14-25	Bad River alluvium	AA
Jones	518-519	6	Alluvial	AA
Lyman	535-536	6	White River alluvium	AA
Tripp[d]	539	23	Ogallala Formation	NHPAQ
Tripp[d]	561-564	3-9	Ogallala Formation	NHPAQ
Tripp[d]	570 -595	6-25	Ogallala Formation	NHPAQ
Nebraska *North Central Tableland Groundwater Region[e]*				
Keya Paha	614-617	20-50	Keya Paha River alluvium	AA
Boyd	617-622	20-50	Keya Paha River alluvium	AA
Boyd	623-626	20-50	Various creeks—alluvial	AA
Holt	626-627	20-50	Various creeks—alluvial	AA
Holt	628-632	20-50	Tablelands alluvium	NHPAQ/AA
Holt	632-633	10-15	Various creeks—alluvial	AA
Holt	633	15-20	Various creeks—alluvial	AA
Holt	633-634	20-50	Tablelands alluvium	NHPAQ/AA
Holt	634.5	15-20	Tablelands alluvium	NHPAQ/AA
Holt	635.5-637	20-50	Tablelands alluvium	NHPAQ/AA
Holt	637-638	20-50	Tablelands alluvium	NHPAQ/AA
Holt	638.5	15-20	Tablelands alluvium	NHPAQ/AA
Holt	638.5-641	10-15	Tablelands alluvium	NHPAQ/AA
Holt	641.5	15-20	Tablelands alluvium	NHPAQ/AA
Holt	641.5-650	20-50	Tablelands alluvium	NHPAQ/AA
North Central Tableland/Sand Hills Groundwater Region[e]				
Holt	651	20-50	Tablelands alluvium	NHPAQ/AA

State/County	Approximate Milepost (MP) or Range[a]	Approximate Depth to Groundwater (feet bgs[b])	Formation/Aquifer	Regional Aquifer Group[c]
Sand Hills Groundwater Region[e]				
Holt	651.5-655	20-50	Tablelands alluvium	NHPAQ/AA
Holt	655-657	20-50	Tablelands alluvium	NHPAQ/AA
Holt	657-658	20-50	Tablelands alluvium	NHPAQ/AA
Holt	658.5	15-20	Tablelands alluvium	NHPAQ/AA
Holt	658.5-659	15-20	Tablelands alluvium	NHPAQ/AA
Holt	659.5	15-20	Tablelands alluvium	NHPAQ/AA
Holt	659.5-660	20-50	Tablelands alluvium	NHPAQ/AA
Holt	660-661	20-50	Tablelands alluvium	NHPAQ/AA
Holt	661-663	20-50	Tablelands alluvium	NHPAQ/AA
Holt	663-665	20-50	Various creeks - alluvial	AA
Holt	665-666	20-50	Various creeks - alluvial	AA
Holt	666-667	15-20	Tablelands alluvium	NHPAQ/AA
Holt	667.5	20-50	Tablelands alluvium	NHPAQ/AA
Holt	667.5-672	20-50	Tablelands alluvium	NHPAQ/AA
Holt	676-677	20-50	Tablelands alluvium	NHPAQ/AA
Antelope	680-682	20-50	Tablelands alluvium	NHPAQ/AA
East Central Dissected Plains Groundwater Region[e]				
Antelope	710-718	20-50	Tablelands alluvium/Elk Horn River alluvium	NHPAQ/AA
Boone	742-745	20-50	Various creeks—alluvial	AA
Boone	745-746	20-50	Tablelands alluvium	NHPAQ/AA
Boone	747-749	20-50	Tablelands alluvium/various creeks alluvium	NHPAQ/AA
Platte River Valley Groundwater Region[e]				
Nance	761-762	20-50	Loup River alluvium	AA
Nance	762-763	15-20	Loup River alluvium/various river alluvium	AA
Nance	763-765	5-10	Loup/Platte River alluvium	AA
Nance	765-766	5-10	Loup/Platte River alluvium	AA
Nance	766.5	10-15	Loup/Platte River alluvium	AA
Nance	767	5-10	Loup/Platte River alluvium	AA
Merrick	767.5	5-10	Loup/Platte River alluvium	AA
Merrick	767.5-771.5	10-15	Loup/Platte River alluvium	AA
Merrick	771.5-774	5-10	Loup/Platte River alluvium	AA
Merrick	774-775	10-15	Platte River alluvium	AA
Polk	775.5	10-15	Platte River alluvium	AA
Polk	778	20-50	Platte River alluvium	AA
Southeast Nebraska Glacial Drift Groundwater Region[e]				
Saline	840-844	20-50	Glacial drift alluvium	AA

Sources: Based on available well data from NDNR 2012, SDDENR 2012a, and Montana Bureau of Mines and Geology 2012

[a] MPs for the proposed Project start at 0.0 at the Canada/Montana border, and increase toward the south along the pipeline route.
[b] bgs = below ground surface.
[c] AA = Alluvial aquifer; NHPAQ = Northern High Plains Aquifer; NGPAS = Northern Great Plains Aquifer System.
[d] MP distances are approximate.
[e] State Groundwater Regions from University of Nebraska 1998.

Information on groundwater occurrence, depth to groundwater, and groundwater use (wells) along the proposed pipeline area has been collected and summarized in this section to provide context for understanding potential impacts to groundwater quality that may occur during the construction and operation phases of the proposed Project. The analysis of local aquifer and groundwater use along the proposed Project area includes information on the likely occurrence of relatively shallow potable groundwater and water wells within 1 mile of the proposed Project corridor centerline. This information was compiled using publicly available and searchable databases maintained by water resource agencies within each of the affected states.

The databases were searched for domestic, irrigation, and public water supply well data. The analysis of impacts on water supplies for human consumption also applies to water intakes for industrial and municipal use. Data accessed included well location, well total depth, and depth to first water (if available) or static water level. Because the screened intervals of the wells (depth at which the screen is placed) are not typically recorded in the well data obtained from the states, it is not possible in all cases to correlate static water level to likely depth to first water. In other words, it could not be determined whether the aquifers tapped by the individual wells are confined or unconfined. To provide the most conservative well data evaluation, groundwater in each of the aquifers intercepted by the wells is considered present under unconfined conditions; therefore, depth to water measured in the wells is assumed to be equal to the depth of first water.

Water well data compiled within 1 mile of the proposed Project corridor centerline are shown in Figures 3.3.2-2, 3.3.2-3, and 3.3.2-4, respectively. Given the available data limitations and variations in data quality from state to state, the following five general categories that relate well depth and reported water levels (first water or static water level) to likely water depth were created. Water wells without recorded total depths or depth to water were excluded for use in generating the following categories:

- Category A: Very shallow water depth likely with reported water level less than or equal to 10 feet bgs and total well depth less than or equal to 50 feet bgs;
- Category B: Shallow water depth likely with reported water level between 10 and 50 feet bgs and total well depth less than or equal to 50 feet bgs;
- Category C: Water depth unclear, but potentially very shallow because reported water level is less than or equal to 10 feet bgs and total well depth is greater than 50 feet bgs (reported water level could indicate very shallow water depth if well screened in upper 50 feet or deep water depth if well screened at deeper interval under artesian conditions);
- Category D: Water depth unclear, but potentially shallow because reported water level is between 10 and 50 feet bgs and total well depth is greater than 50 feet bgs (reported water level could indicate shallow water depth if well screened in upper 50 feet or deep water depth if well screened at deeper interval under artesian conditions); and
- Category E: Deep water depth likely with reported water level greater than 50 feet bgs and total well depth greater than 50 feet bgs.

The following subsections present, by state, more detailed information on key shallow aquifers that the proposed Project area would cross, a summary of wells near the proposed Project area, additional information on depth to groundwater, and a summary of water quality in the shallow aquifers.

Montana

Key Aquifers

The bedrock aquifers beneath the proposed Project area in Montana are part of the NGPAS (Whitehead 1996). Along the proposed Project area in Montana, most aquifers used for water supply consist of unconsolidated fluvial and/or glacial alluvial aquifers, and Tertiary- and Late Cretaceous-aged aquifers of the NGPAS. Figure 3.3.2-2 shows the distribution of these aquifers in the study area of Montana.

In Phillips and Valley counties in northern Montana, up to 100 feet of relatively impermeable glacial till acts as a confining layer above the Cretaceous-aged Bearpaw Shale, Judith River Formation, and Clagett Formation (Whitehead 1996). Well data indicate groundwater in the Bearpaw Shale, where present, is typically shallow-to-moderate depth (0 to 45 feet bgs) and no information regarding well yields is presented. The water table in the Judith River Formation is present at approximately 150 to 500 feet bgs in this area and wells from the formation typically yield 5 to 20 gpm (see Table 3.3-1). Additionally, the glacial till contains local permeable zones of coarse glacial outwash less than 50 feet bgs that provide irrigation water. Most groundwater use in Valley County comes from shallow alluvial aquifers along major river drainages such as the Milk River and Missouri River (Whitehead 1996).

In McCone County, the proposed pipeline area crosses the Late Cretaceous Hells Creek/Fox Hills aquifer and the Tertiary Fort Union aquifer. Permeable sandstones of the Hells Creek/Fox Hills aquifer yield 5 to 20 gpm; most wells are drilled to depths of 150 to 500 feet bgs (Whitehead 1996). The Tertiary Fort Union aquifer consists of interbedded sandstones, mudstones, shale, and coal seams. Water-bearing zones are found in the sandstone layers and the aquifer is confined in most areas. Well yields are typically 15 to 25 gpm; most wells are drilled to depths of 50 to 300 feet bgs (Lobmeyer 1985); water depths typically range from 100 to 150 feet bgs (Swenson and Durum 1955).

Beneath the proposed pipeline area in Dawson, Prairie, and Fallon counties lies the Lower Yellowstone aquifer system which contains groundwater in the Tertiary Fort Union Formation. The Lower Yellowstone aquifer system is a shallow bedrock aquifer that is used as a groundwater resource in these three counties. The Yellowstone River contains abundant alluvial material along its banks, which contain shallow aquifers within the unconsolidated alluvium that are often used for water supply. Well yields in these shallow alluvial aquifers along the Yellowstone River range from 50 to 500 gpm (see Table 3.3-1) (LaRocque 1966). Additionally, shallow alluvial aquifers are also present at stream crossings including Clear Creek, Cracker Box/Timber Creek, Cabin Creek, Sandstone Creek, and Butte Creek.

Nearby Public Water Supply Wells and Private Water Wells

No public water supply (PWS) wells or source water protection areas (SWPA) are located within 1 mile of the proposed Project corridor in Montana. A total of six private water wells are located within approximately 100 feet of the proposed Project corridor within McCone, Dawson, Prairie, and Fallon counties. All identified wells within 1 mile of the proposed Project corridor in Montana are included on Figure 3.3.2-2.

Sources: Montana Bureau of Mines and Geology 2012, Esri 2013

Figure 3.3.2-2 Montana Water Wells Within 1 Mile of Proposed Pipeline Route

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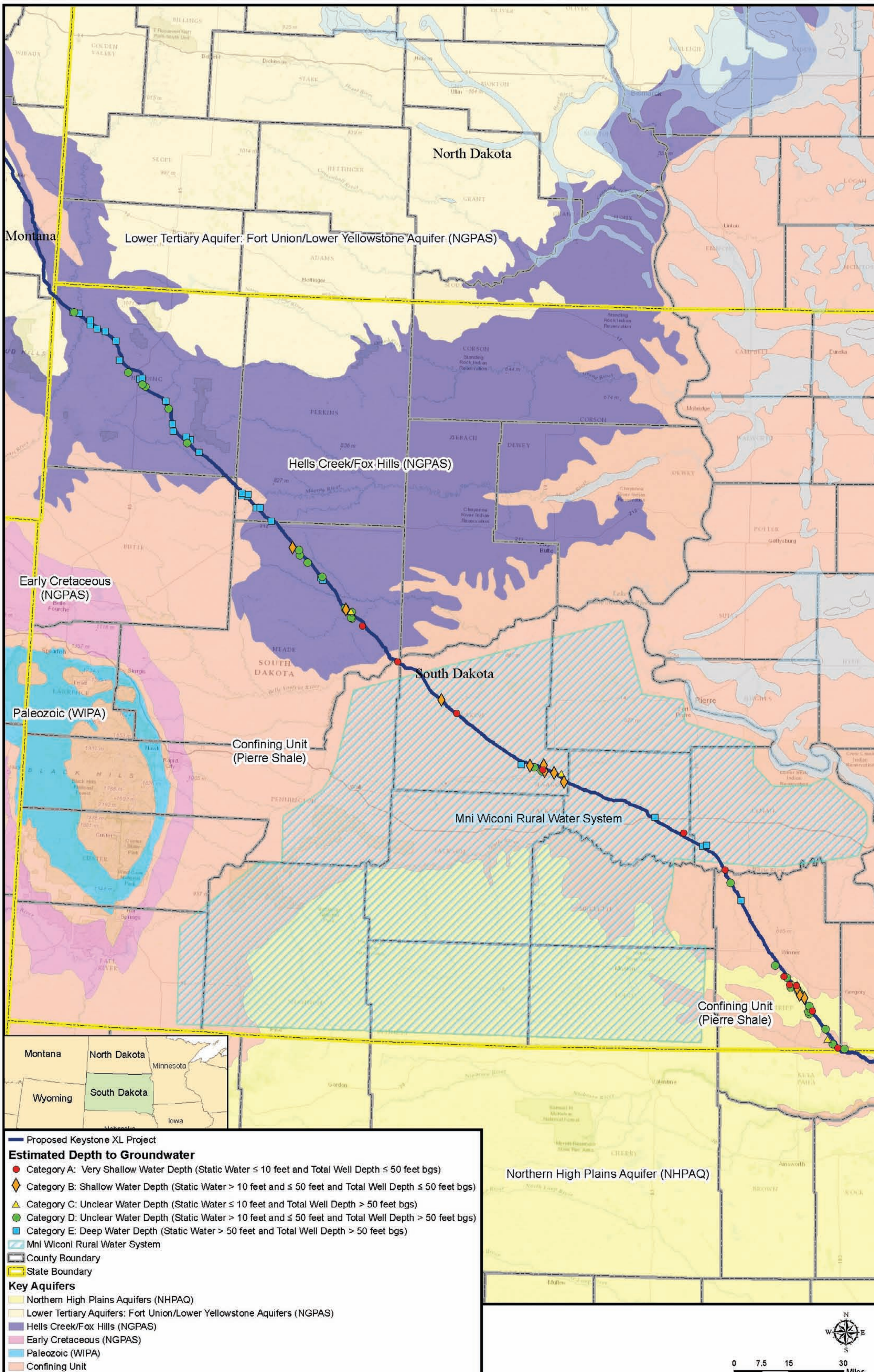

Sources: SDDENR 2012a, Esri 2013

Figure 3.3.2-3 South Dakota Water Wells Within 1 Mile of Proposed Pipeline Route

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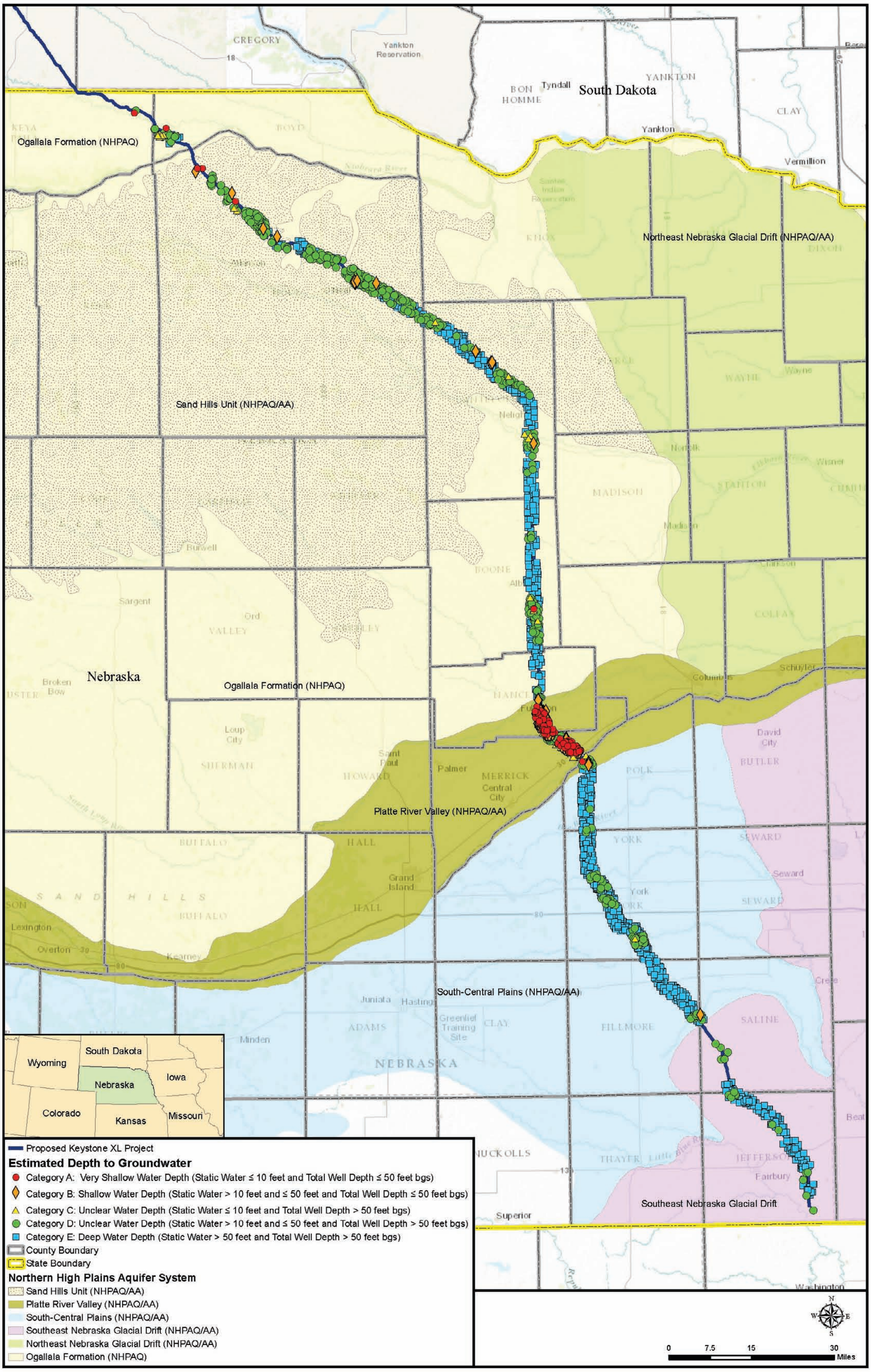

Sources: Nebraska Department of Natural Resources 2012a, Esri 2013

Figure 3.3.2-4 Nebraska Water Wells Within 1 Mile of Proposed Pipeline Route

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Depth to Groundwater

Depths to groundwater reported on well logs for well locations within 1 mile of the proposed Project corridor in Montana are provided in Figure 3.3.2-2. The number of wells within 1 mile of the proposed Project corridor by groundwater depth category is as follows:

- Category A (very shallow)—118
- Category B (shallow)—52
- Category C (unclear but potentially very shallow)—114
- Category D (unclear but potentially shallow)—101
- Category E (deep)—138

Water Quality

Available water quality information for several aquifers present along the proposed Project area in Montana is included in Table 3.3-3. Available studies and reports indicate that water within these aquifers exhibits moderate to high TDS concentrations that are typically related to high salinity and dissolved carbonates. The overall upward gradient and resulting upward movement of groundwater from deeper, more saline aquifers into the overlying aquifers is a primary source of TDS in shallow groundwater in the proposed Project area in Montana. In general, aquifer systems that are deep and occur in older rock formations have high TDS.

Table 3.3-3 Groundwater Quality of Select Subsurface Aquifers

Aquifer	Regional Aquifer Group[a]	State	County	Total Dissolved Solids (mg/L)[b,c]	Other Water Quality Information
Judith River Formation	NGPAS	MT	Phillips, Valley	500-10,000	Sodium chloride rich in Valley County
Missouri River Alluvium	AA	MT	Valley	800-2,700	Not available
Hells Creek/Fox Hills	NGPAS	MT	McCone	500-1,800	Sodium bicarbonate rich
Fox Hills	NGPAS	MT	Dawson, Prairie, Fallon	500-2,500	Sodium bicarbonate rich
Fort Union	NGPAS	MT	McCone, Dawson, Prairie, Fallon	500-5,000	Sodium bicarbonate rich
Yellowstone R. Alluvium	AA	MT	Dawson, Prairie, Fallon	1,000-1,500	Calcium bicarbonate rich
Hells Creek/Fox Hills	NGPAS	SD	Harding, Perkins, Meade	1,000-3,000	Sodium bicarbonate rich
Ogallala Formation	NHPAQ	SD	Tripp	<500	Sodium bicarbonate rich
Pleistocene River Terrace	AA	SD	Tripp	30-4,000	Not available
White River Alluvium	AA	SD	Tripp	287-688	Sodium bicarbonate rich
Ogallala Formation	NHPAQ	NE	Keya Paha	100-250	Not available

Aquifer	Regional Aquifer Group[a]	State	County	Total Dissolved Solids (mg/L)[b,c]	Other Water Quality Information
Sand Hills Unit	NHPAQ/ AA	NE	Rock-Greeley	<500	Not available
Ogallala Formation	NHPAQ	NE	Greeley-Nance	<500	Not available
Platte River Unit	NHPAQ/ AA	NE	Merrick	<500	Not available
Eastern Nebraska Unit	NHPAQ/ AA	NE	Merrick-Jefferson	<500	Not available

Sources: Lobmeyer 1985, Swenson and Drum 1955, Smith et al. 2000, LaRocque 1966, Whitehead 1996, Rich 2005, Hammond 1994, Cripe and Barari 1978, Newport and Krieger 1959, Stanton and Qi 2007

[a] NGPAS = Northern Great Plains Aquifer System; AA = Alluvial aquifer; NHPAQ = Northern High Plains Aquifer
[b] mg/L = milligrams per liter
[c] Total Dissolved Solids are classified as a secondary contaminant by the Environmental Protection Agency with a non-mandatory standard of 500 mg/L.

South Dakota

Key Aquifers

In northwestern South Dakota, bedrock aquifers beneath the proposed Project area are part of the NGPAS (Whitehead 1996), and along the southern border with Nebraska, the proposed Project area passes through an area underlain by the Ogallala Formation of the NHPAQ. The distribution of key aquifers in South Dakota is shown in Figure 3.3.2-3. These aquifers include the Late Cretaceous Fox Hills and Hells Creek aquifers in Harding, Perkins, and Meade counties. The town of Bison uses groundwater from the Fox Hills aquifer to meet water supply demands.

These municipal wells are 565 to 867 feet deep and yield up to 50 gpm (Steece 1981). Shallow alluvial aquifers are also present at stream crossings including the Little Missouri River, South Fork Grand River, Clarks Fork Creek, Moreau River, Sulphur Creek, Red Owl Creek, Narcelle Creek, and Cheyenne River.

In Haakon, Jones, and Lyman counties, major water-producing aquifers are not present, as the proposed Project through this area is underlain by the aquitard-forming rocks of the Late Cretaceous Pierre Shale, and groundwater below the Pierre shale in the rocks of the NGPAS and the GPA is typically very saline. In this area, the floodplains of the Bad River and the White River contain shallow alluvial aquifers that are used for water supply.

Beneath a short segment of the proposed Project area in Tripp County, groundwater is present within the Ogallala Formation of the NHPAQ and in Pleistocene-aged river terrace aquifers (Whitehead 1996). Tertiary-aged aquifers in the vicinity also include Brule and Arikaree Formations, but the proposed Project area does not cross these formations. The Ogallala Formation's depth to groundwater is typically 10 to 70 feet bgs (Hammond 1994) in this area with wells yielding 250 to 750 gpm (see Table 3.3-1).

Nearby Public Water Supply Wells and Private Water Wells

One PWS well (associated with the Colome SWPA) is identified within 1 mile of the proposed Project corridor in Tripp County. This PWS well is screened at a relatively shallow depth (reportedly less than 54 feet bgs) within the Tertiary Ogallala Formation. The proposed Project area would pass through the Colome SWPA in Tripp County. No private water wells are located within approximately 100 feet of the proposed Project corridor in South Dakota. All identified wells within 1 mile of the proposed Project corridor in South Dakota are included on Figure 3.3.2-3.

The Mni Wiconi Rural Water Supply System (MWRWSS) brings surface water from the Missouri River to the Pine Ridge Indian Reservation and other parts of western South Dakota. This project consists of hundreds of shallow municipal and private wells in southwestern South Dakota, some of which are near or within the proposed Project area (see Figure 3.3.2-3). The MWRWSS operates a water intake on the Missouri River to provide potable water to the MWRWSS and to replace the poor water quality of shallow wells within the area. Those individuals on the Pine Ridge Reservation that are not connected to the MWRWSS will likely be served by community water systems or individual wells. The MWRWSS is discussed in more detail in Section 3.3.3.2, South Dakota Surface Water.

Depth to Groundwater

Depths to groundwater reported on well logs for well locations within 1 mile of the proposed Project corridor in South Dakota are provided in Figure 3.3.2-3. The number of wells within 1 mile of the proposed Project corridor by groundwater depth category is as follows:

- Category A (very shallow)—11
- Category B (shallow)—12
- Category C (unclear but potentially very shallow)—1
- Category D (unclear but potentially shallow)—51
- Category E (deep)—30

Water Quality

Available water quality information for several aquifers present along the proposed Project area in South Dakota is shown in Table 3.3-3. Available studies and reports indicate that, in general, water within the NGPAS aquifers and some younger aquifer areas exhibit moderate levels of TDS. The overall upward gradient of groundwater from deeper, more saline aquifers into the upper aquifers is a primary source of TDS in the shallow groundwater in the proposed Project area in South Dakota. In the area of the MWRWSS where the NHPAQ is present as the Ogallala Formation or Quaternary alluvium, elevated concentrations of nitrate are common in shallow groundwater. Hammond (1994) reports nitrate concentrations up to 67.3 milligrams per liter (mg/L) in wells near the proposed Project area. The USEPA Maximum Contaminant Level for nitrate in drinking water is 10 mg/L. A primary driver in the development of the MWRWSS was to provide alternate water sources to areas with groundwater quality concerns (BOR [undated]). Where the NHPAQ or outlying smaller alluvial aquifers are not present, groundwater yields are typically low because the area is underlain by the fine-grained Pierre Shale.

Nebraska

Key Aquifers

Much of the proposed Project area in Nebraska overlies the NHPAQ system, which supplies 78 percent of the public water supply and 83 percent of irrigation water in Nebraska (Emmons and Bowman 2000). In Nebraska, the NHPAQ system includes six main hydrogeologic units, including the Tertiary Brule Formation, Arikaree Group, and Ogallala Formation, and Quaternary/Recent alluvium of the Eastern Nebraska Unit, the Platte River Valley Unit, and the Sand Hills Unit. The distribution of these aquifers in the proposed Project area is illustrated on Figure 3.3.2-4. The proposed Project would extend 274 linear miles through areas underlain by the NHPAQ system. The pipeline would immediately overlie 98 miles of the Eastern Nebraska Unit, 88 miles of the Ogallala Formation, 16 miles of the Platte River Valley Unit, and 72 miles of the Sand Hills Unit (see Figure 3.3.2-4).

In the High Plains Aquifer, which includes the NHPAQ system, hydraulic conductivity (a measurement of the rate of movement of water through a porous medium such as an aquifer at a hydraulic gradient of 1:1) ranges from 25 to 100 feet per day (ft/d) and averages 60 ft/d (Weeks et al. 1988). In general, groundwater in the High Plains Aquifer flows from west to east at a velocity (which also takes into account the hydraulic gradient, i.e., slope of the water table) of 1 ft/d (Luckey et al. 1986). The slope of the water (gradient) table will locally and regionally impact the rate that water (conductivity) will move through the aquifers, resulting in wide variation in the groundwater velocities. Should a spill or release reach groundwater, groundwater velocities will be an important consideration in determining when and if wells or springs will be impacted.

The soils of the Sand Hills Unit of the NHPAQ system are derived primarily from aeolian dune sands and are characterized by very low organic and clay/silt fractions. According to the U.S. Geological Survey (USGS), the hydraulic conductivity of the NHPAQ is relatively low, particularly in the Sand Hills north of the Platte River (Gutentag et al. 1984, Luckey et al. 1986). The aquifer material in this region is composed mainly of fine sands and silts with low hydraulic conductivity that underlie the typically unsaturated dune sands (Luckey et al. 1986).

Hydraulic conductivity estimates for the Sand Hills Unit of the NHPAQ system are variable, with a high of 50 ft/d (Gutentag et al. 1984) and a low of 10 ft/d (Bleed and Flowerday 1998). Assuming an average groundwater gradient of 0.002 in the eastern portion of the Sand Hills Unit of the NHPAQ system in Nebraska (from Bleed and Flowerday 1998), and assuming the maximum estimated hydraulic conductivity of 50 ft/d, the groundwater flow velocity in that portion of the NHPAQ system averages around 0.1 ft/d. Hydraulic conductivity is a specific property of each aquifer and describes how easily groundwater can move through an aquifer's available pore space. Groundwater flow velocity is dependent on the gradient of the groundwater table within the aquifer and takes both this gradient or slope of the water table and hydraulic conductivity specific to the aquifer to determine the speed by which groundwater is moving through the aquifer (i.e., velocity equals hydraulic conductivity times the gradient).

Along the proposed Project area south of the Sand Hills Unit, much of the soils originate in part from glacial loess and drift deposits. The fine-grained loess deposits can be as thick as 200 feet and can locally restrict water flow where fractures are absent (Stanton and Qi 2007, Johnson 1960).

Certain areas within the Ogallala Formation of the NHPAQ system contain soils or lithologic zones that inhibit downward migration (Gurdak et al. 2009). In these areas, transport of dissolved chemicals from the land surface to the water table is slower, taking decades to centuries (Gurdak et al. 2009). Even in these areas, however, localized preferential flow paths do exist that could enable dissolved chemicals to move at an increased rate through the unsaturated zone to the water table. These units with lower permeability are more likely to be present beneath topographic depressions where precipitation or surface water collects as a result of the lower infiltration rates through these units. These areas within the Ogallala Formation of the NHPAQ system consist of geologic units composed of unconsolidated sand, gravel, clay, and silt along with layers of calcium carbonate and siliceous cementation (Stanton and Qi 2007). According to the USGS water quality report, a zone of post-deposition cementation is present in many of these areas near the top of the Ogallala Formation, creating an erosion-resistant ledge. The Ogallala Formation also contains localized ash beds. These cementation zones and ash layers would serve as localized aquitards within the Ogallala Formation and would tend to inhibit vertical migration.

The water quality in the NHPAQ system is suitable for drinking and as irrigation water, but impacts from farming operations are present in areas of shallow groundwater (Stanton and Qi 2007). In areas where crop irrigation occurs and shallow groundwater is present, elevated levels of fertilizers, pesticides, and herbicides, including nitrate and atrazine, have been reported. Concentrations of these constituents are generally higher in the near-surface groundwater (Stanton and Qi 2007).

In Keya Paha County (northern Nebraska), wells yielding 100 to 250 gpm (see Table 3.3-1) are reported drawing from the NHPAQ and alluvial aquifers present in the Keya Paha and Niobrara River valleys (Newport and Krieger 1959). The Niobrara River, which receives groundwater recharge from surrounding aquifers, is also used as a source of irrigation and municipal water supply.

In Boyd County, the proposed pipeline area is underlain by the Ogallala Formation, the aquitard Pierre Shale, and alluvial aquifers present in the Keya Paha and Niobrara River valleys. In northern Holt County and through most of Nance County, the proposed pipeline area is again underlain by the NHPAQ system (Sand Hills Unit over the Ogallala Formation). The Sand Hills Unit typically has a water table aquifer and a depth to groundwater of less than 30 feet bgs (Stanton and Qi 2007), as is reflected in the shallow aquifer inventory in Table 3.3-2. Alluvial aquifers are also present along the Elkhorn River and tributaries of the Loup River and in areas of the Sand Hills Unit, which in this area consists of mixed aeolian and fluvial deposits mantling the upper Ogallala Formation.

In southernmost Nance County, the proposed pipeline area is underlain by undivided Tertiary and Quaternary/Recent alluvial sediments of the NHPAQ system (Eastern Nebraska Unit). At the Nance/Merrick County line, the proposed pipeline area enters the Platte River alluvium, which includes alluvium accumulated in the valleys of the Platte and Loup Rivers, used for irrigation, domestic, and municipal water supply in the area.

The proposed pipeline route exits the Platte River alluvium in Polk County and re-enters the Eastern Nebraska Unit of the NHPAQ system, which is used for irrigation, domestic, and municipal water supply. The public water supply for Hordville, approximately 7 miles west of the proposed pipeline route, comes from wells screened within this aquifer at depths ranging from 160 to 262 feet bgs (Keech 1962).

From York to Jefferson counties, the depth to groundwater averages 80 feet bgs within the Eastern Nebraska Unit of the NHPAQ system (Stanton and Qi 2007). Additionally, the proposed pipeline area crosses alluvial aquifers along Beaver Creek, the West Fork of the Big Blue River, and the alluvial floodplain of the South Fork Turkey Creek.

Nearby Public Water Supply Wells and Private Water Wells

A total of 38 known PWS wells are present within 1 mile of the proposed pipeline area in Boone, York, Fillmore, Saline, and Jefferson counties. The nine SWPAs within 1 mile of the proposed pipeline area include those for the towns of St. Edward, Bradshaw, York, McCool Junction, Exeter, Western, Jansen, and Steele City, and the Rock Creek State Park. The only SWPA traversed by the proposed pipeline area in Nebraska is in Steele City, Jefferson County. A total of 14 private water wells are located within approximately 100 feet of the proposed Project corridor within Antelope, Polk, York, Fillmore, and Jefferson counties. All identified wells within 1 mile of the proposed Project corridor in Nebraska are included on Figure 3.3.2-4.

The Clarks wellhead protection area along the Platte River is described as containing 30 feet or less of shallow alluvial materials in the Platte River valley. This thin alluvial material is underlain by the Pierre Shale which acts as a confining layer for the wellhead protection area. The proposed Project is approximately 3.5 miles downgradient of the wellhead protection area.

A previous proposed Project alignment intersected the SWPA for the town of Western, Nebraska. The Western Alternative was developed to avoid the wellhead protection area near the city of Western, and the current proposed Project alignment is now located at least 0.5 mile upgradient of the Western SWPA near the city of Western.

Depth to Groundwater

Depths to groundwater reported on well logs for existing well locations within 1 mile of the proposed Project corridor in Nebraska are provided in Figure 3.3.2-4. The number of wells within 1 mile of the proposed Project corridor by groundwater depth category is as follows:

- Category A (very shallow)—296
- Category B (shallow)—93
- Category C (unclear but potentially very shallow)—114
- Category D (unclear but potentially shallow)—612
- Category E (deep)—1,283

Additionally, a USGS analysis suggests that depth to groundwater in the NHPAQ system can be variable, with depths observed ranging from 0 to 272 feet bgs (Stanton and Qi 2007). However, the median depths to groundwater in the NHPAQ units that would be crossed by the proposed Project area in Nebraska are listed for each formation:

- Ogallala Formation—110 feet bgs
- Eastern Nebraska Unit—79 feet bgs
- Sand Hills Unit—20 feet bgs
- Platte River Valley Unit—5 feet bgs

The well locations where estimated groundwater depth falls within Categories A and C can be used to estimate the distance along the proposed Project area in Nebraska where water depths less than or equal to 10 feet bgs could be encountered. These data suggest that approximately 16 miles of the proposed Project area in Nebraska could encounter groundwater at depths less than or equal to 10 feet bgs (see Figure 3.3.2-4). Most of these areas are present in the Sand Hills Unit and the Platte River Valley Unit and overlie the deeper Ogallala Formation.

Water Quality

Available water quality information for several aquifers present along the proposed Project area in Nebraska is included in Table 3.3-3. Available studies and reports indicate that, in general, water within the NHPAQ and alluvial aquifers in the state exhibit low concentrations of TDS, making the water in the shallow aquifers generally suitable for irrigation, potable, and industrial uses. Groundwater in deeper aquifers in Nebraska (GPA and WIPA) is typically moderately to highly saline and generally is not extracted for use in the vicinity of the proposed Project area.

Of the over 96,000 groundwater quality samples collected from Nebraska wells between 1974 to 2010, 33 percent contained over 10 mg/L nitrate (the federal drinking water standard), and 15 percent of the samples contained over 20 mg/L nitrate. Sample 2007 data distribution indicate that groundwater in wells along much of the proposed Project area in Nebraska contains nitrate at concentrations greater than 10 mg/L (Nebraska Department of Environmental Quality [NDEQ] 2011).

3.3.3 Surface Water

This section describes the streams and rivers the proposed Project would cross by state, including their water quality use classifications and impairments. Surface water features classified as either open water or riverine are addressed in the wetlands portion of this Final Supplemental EIS document (see Sections 3.4 and 4.4, Wetlands). Additionally, waterbodies within 10 miles[9] downstream of waterbody crossings along the proposed route are documented in Appendix D, Waterbody Crossing Tables and Required Crossing Criteria for Reclamation Facilities, for reference, as are surface drinking water supplies within 1 mile of the proposed pipeline right-of-way (ROW). Potential impacts due to ancillary features such as access roads or valve locations are described by state. A pipe yard and rail siding in North Dakota would not impact any surface water features. Spill modeling criteria for spills to surface water and related to the distance a plume may travel from the spill source are discussed in Section 4.13.3.2, Spill Propagation. This distance could be affected by the local environmental conditions present in the area surrounding the leak (e.g., if a leak occurred at the top of a hill, it could flow over a greater distance and affect more resources). Maximum buffer zones (i.e., the estimated maximum distance that oil from a spill would be expected to travel) were developed for surface waterbodies (10 miles) and stream crossings (500 feet); additional reference regarding spill propagation is available in Appendix P, Risk Assessments.

The proposed pipeline improvements include two proposed pump stations in Kansas. Analysis of preliminary facility locations indicated no significant or impaired waterbodies would be affected.

[9] Based on the analysis and modeling provided in Section 4.13, Potential Releases, a crude oil plume migration is very unlikely to travel more than 10 miles from the spill source.

3.3.3.1 Montana Surface Water

The proposed pipeline ROW would traverse a physiographic region commonly referred to as the northern Great Plains Province, which includes a glaciated section of the Missouri Plateau and is characterized by generally treeless, gently rolling terrain broken by buttes and a network of young perennial[10] and intermittent[11] streams, and small isolated mountain ranges (Wiken et al. 2011). North of the Missouri River, the proposed pipeline route traverses the southern extent of glaciation by continental ice sheets associated with the late Wisconsin stage approximately 35,000 to 11,150 years ago (Fullerton et al. 2004). The relatively young glacial terrain is characterized by ground and frontal moraines and a mosaic of small lakes (kettles) and prairie potholes. Moving southward past Fort Peck Reservoir through McCone County marks the beginning of the non-glaciated portion of the Missouri Plateau. Here, the terrain consists of more deeply entrenched stream networks cutting through mostly older sedimentary formations of the late Cretaceous and Tertiary period.

In eastern Montana, the wettest month of the year is typically June. Flooding occurs primarily in May and June when the effects of rains are multiplied by runoff from snow melt in the mountains (USGS 2012c). Flooding is sometimes caused by ice jam blockage or gorging in the winter; flash floods, triggered by large convective thunderstorms in the summer, are also typical in the area.

Waterbodies Crossed

There are 459 waterbody crossings along the proposed pipeline route in Montana, as presented in Appendix D, Waterbody Crossing Tables and Required Crossing Criteria for Reclamation Facilities, Table 1. Of the 459 crossings, nine are perennial streams, 424 are intermittent streams, 20 are canals, and six waterbodies are identified as either artificial or natural lakes, ponds, or reservoirs. Based on stream width, adjacent topography, adjacent infrastructure, best management practices, permitting, and sensitive environmental areas, four HDD constructed crossings are proposed to avoid disturbing the waterbodies listed below:

- Frenchman River in Phillips County (also known as Frenchman Creek) (approximately 135 feet wide, MP 25);
- Milk River in Valley County (approximately 100 feet wide, MP 83);
- Missouri River in Valley and McCone counties (approximately 1,000 feet wide, MP 90); and
- Yellowstone River in Dawson County; this HDD crossing includes a man-made channel tributary (30 feet), and a Yellowstone River side channel (75 feet) combined with the main Yellowstone River channel (approximately 780 feet wide, MP 198).

The remaining 454 waterbodies would be crossed using one of several non-HDD methods described in the Construction, Mitigation, and Reclamation Plan (CMRP) (see Appendix G). The crossing method for each waterbody would be depicted on construction drawings, but would ultimately be determined in consultation with MDEQ and other agencies and be based on site-

[10] A perennial stream, river, pond, or lake exhibits continuous flow in its stream bed or a volume of open water including a frozen surface all year round during periods of normal precipitation.
[11] An intermittent or seasonal stream, river, pond, or lake exists for longer periods, but not year-round and may be influenced by groundwater contributions.

specific conditions at the time of crossing. Qualified individuals,[12] including geologists or engineers, would provide modeling and analysis on behalf of the applicant and on behalf of reviewing agencies during the permitting process to ensure proper identification of channel migration zones and to further aid in selecting the appropriate crossing method, burial depth, and seasonal timing. In addition to the 459 waterbodies crossed by the proposed pipeline, six waterbodies are within the ROW but not crossed by the pipeline. Figure 3.3.3-1 illustrates the major watersheds in Montana and significant river and stream waterbodies within those watersheds that are crossed by the proposed Project. Wild and Scenic River-designated segments are shown as well.

Generally all flowing waterbodies in watersheds crossed by the proposed Project flow into or are entirely in the United States. There are transboundary watersheds that flow from headwaters in Montana through Canada and eventually back to Montana or flow from headwaters in Canada into Montana. These waterbodies are significantly upstream from and not impacted by the proposed Project. From MP 0 to MP 1, the proposed Project parallels an intermittent stream (USGS stream ID# 10050011009778) that turns east-northeast and flows into the Canadian province of Alberta. This stream is protected by the U.S./Canada Boundary Waters Treaty of 1909, Article IV. Additionally this stream is anticipated to be at low risk of spill impact from the detailed analysis of spill risk to intermittent streams based on modeling of spills to surface water and estimates of the distance a potential plume may travel from the spill source (see Section 4.13.3.2, Spill Propagation).

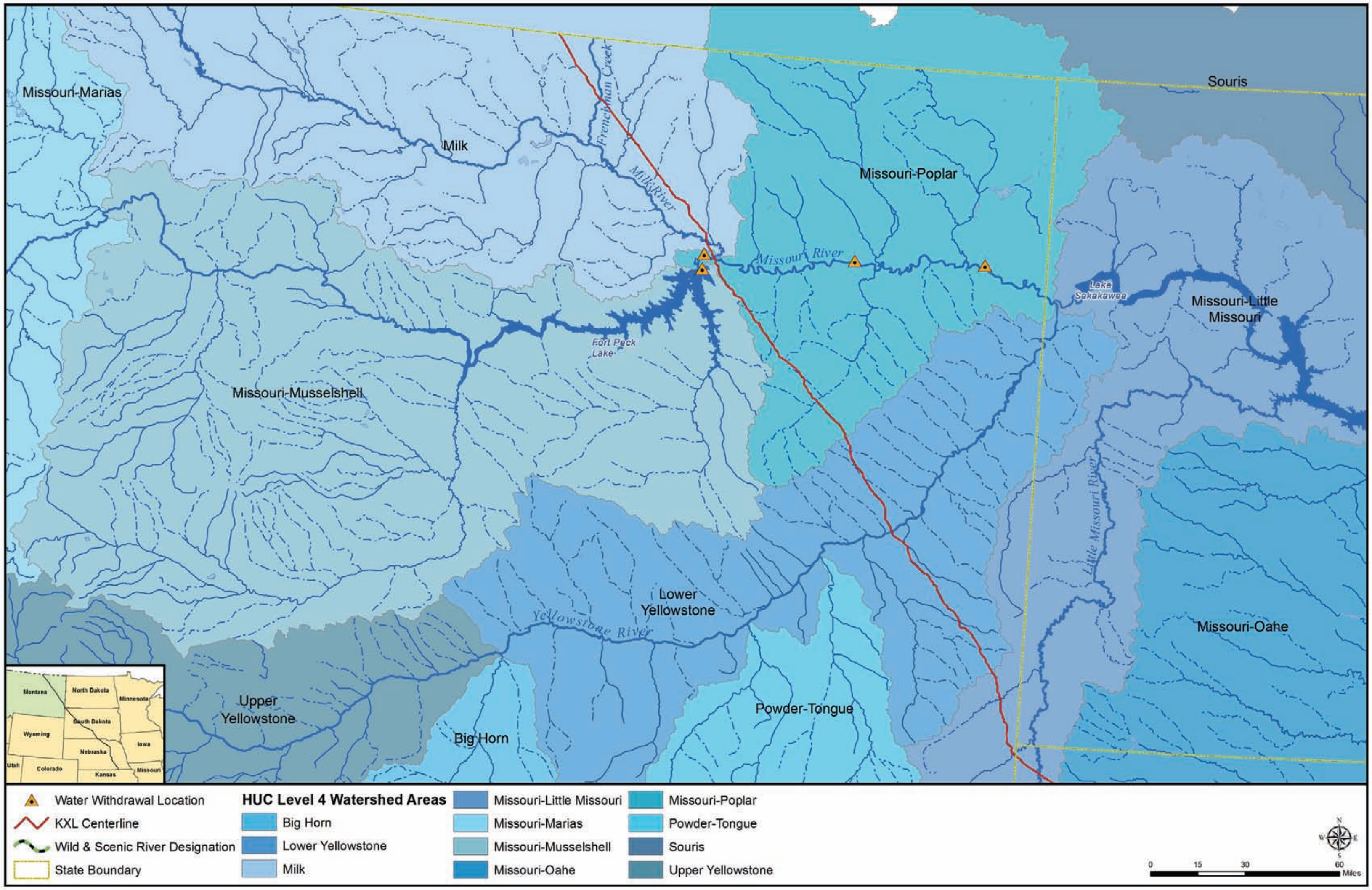
Several route variations have been proposed to either reduce impacts at a crossing or to address landowner concerns. These route variations include crossings of federally managed water distribution systems. There are six proposed BOR facility crossings anticipated for the project in Montana. Three are associated with the Milk River Project in Valley County near MP 85:

- Vandalia South Canal—Section 12, Township 27N, Range 41E (MP 86);
- Vandalia South Canal, Main Drain No. VW22—Section 12 T27N, R41E (MP 85); and
- Vandalia South Canal, Toe Drain for Lateral V-235—Section 12 T27N, R41E (MP 85).

Three are associated with the Buffalo Rapids Project in Dawson County near MP 196 and MP 197:

- Glendive Main Canal, Buffalo Rapids Unit—Section 10 Township 13N, Range 53E (MP 196);
- Glendive Main Canal, Buffalo Rapids Unit, Drain Ditch—Section 14 T13N, R53E (MP 197); and
- Glendive Main Canal, Buffalo Rapids Unit, Lateral 4.7—Section 14 T13N, R53E (MP 197).

[12] The definition of qualified personnel is in 29 CFR 1926.32(l): *Qualified* means one who, by possession of a recognized degree, certificate, or professional standing, or who by extensive knowledge, training, and experience, has successfully demonstrated his ability to solve or resolve problems relating to the subject matter, the work, or the project.



Sources: Esri 2013, USGS 2012b, MDEQ 2013, USGS 2013

Figure 3.3.3-1 Montana Watersheds Crossed by the Proposed Project Route

These facilities were reserved by the federal government by 1890 Canal Act easements (see Appendix D, Waterbody Crossing Tables and Required Crossing Criteria for Reclamation Facilities). For these crossings, Keystone would apply general design requirements consistent with BOR facility crossing criteria as specified in Appendix G, CMRP. The BOR's revised *TransCanada Keystone XL Pipeline: Required Crossing Criteria for Reclamation Facilities* document dated April 2013 is included in Appendix D, Waterbody Crossing Tables and Required Crossing Criteria for Reclamation Facilities.

Waterbodies Classifications

The proposed pipeline ROW would cross a number of streams and rivers with state water quality use descriptions based on their surface water classification or on waterbody type. There are 15 waterbodies with *Surface Water Classifications* or *Use Attainment Assessments* for the proposed route in Montana. Table 3.3-4 presents the names of these waterbodies, organized by county from north to south, and includes their state water quality use designations and use attainment assessment values (MDEQ 2012). The State of Montana has set its water quality standards as a means to define the water quality necessary to protect the defined water uses and to prevent degradation of the water resource. The primary goal is to prevent and remove pollutants; however, Montana has additional protections that are intended to prevent adverse hydrologic effects to the waters of the state.

Table 3.3-4 Streams and Rivers Crossed by Proposed Pipeline in Montana with State Water Quality Designations or Use Designations

Waterbody Name	County	Use Class Description	Use Attainment Assessment[a,b,c]			
			AqL	AG	DW	Rec
Frenchman River	Phillips	Drinking Water; Recreation; Warm Water Non-Salmonid Fishes and associated Aquatic Life; Agricultural/Industrial	P	P	F	P
Rock Creek	Valley	Non-Salmonid	ND	ND	ND	ND
Willow Creek	Valley	Non-Salmonid	ND	ND	ND	ND
Buggy Creek	Valley	Drinking Water; Recreation; Warm Water Non-Salmonid Fishes and associated Aquatic Life; Agricultural/Industrial	P	F	F	F
Cherry Creek	Valley	Drinking Water; Recreation; Warm Water Non-Salmonid Fishes and associated Aquatic Life; Agricultural/Industrial	F	F	F	F
Milk River	Valley	Drinking Water; Recreation; Warm Water Non-Salmonid Fishes and associated Aquatic Life; Agricultural/Industrial	ND	F	N	N
Missouri River	Valley	Drinking Water; Recreation; Cold Water Salmonid Fishes and associated Aquatic Life; Agricultural/Industrial	P	F	F	F
Middle Fork Prairie Elk Creek	McCone	Recreation; Warm Water Non-Salmonid Fishes and associated Aquatic Life; Agricultural/ Industrial; Degradation Prohibited	P	ND	ND	ND
East Fork Prairie Elk Creek	McCone	Recreation; Warm Water Non-Salmonid Fishes and associated Aquatic Life; Agricultural/ Industrial; Degradation Prohibited	P	ND	ND	ND
Redwater River	McCone	Recreation; Warm Water Non-Salmonid Fishes and associated Aquatic Life; Agricultural/ Industrial; Degradation Prohibited	P	ND	ND	F

Waterbody Name	County	Use Class Description	Use Attainment Assessment[a,b,c]			
			AqL	AG	DW	Rec
Yellowstone River	Dawson	Drinking Water; Recreation; Warm Water Non-Salmonid Fishes and associated Aquatic Life; Agricultural/Industrial	P	F	ND	ND
Pennel Creek	Fallon	Recreation; Warm Water Non-Salmonid Fishes and associated Aquatic Life; Agricultural/ Industrial; Degradation Prohibited	P	ND	ND	F
Sandstone Creek	Fallon	Recreation; Warm Water Non-Salmonid Fishes and associated Aquatic Life; Agricultural/Industrial; Degradation Prohibited	P	ND	ND	F
Little Beaver Creek	Fallon	Recreation; Warm Water Non-Salmonid Fishes and associated Aquatic Life; Agricultural/ Industrial; Degradation Prohibited	ND	ND	ND	ND
Boxelder Creek	Fallon	Recreation; Warm Water Non-Salmonid Fishes and associated Aquatic Life; Agricultural/ Industrial; Degradation Prohibited	ND	ND	ND	ND

Sources: USGS 2012, MDEQ 2012

[a] F = Full Support; P = Partial Support; N = Not Supporting; ND = No Data
[b] Where the Montana 2012 Integrated Report Appendix A contains a value of X and where there are no entries or blank columns, this table denotes those conditions as ND = No Data.
[c] AqL = Aquatic Life; AG = Agriculture; DW = Drinking Water; Rec = Recreation

Impaired or Contaminated Waterbodies

Contamination or impairments have been documented in nine sensitive or protected waterbodies that would be crossed by the proposed pipeline in Montana (see Appendix D, Waterbody Crossing Tables and Required Crossing Criteria for Reclamation Facilities, Table 4). Contamination in these waterbodies includes at least one of the following parameters of concern: iron, *E. coli*, lead, mercury, nitrogen (total), phosphorus (total), total Kjeldahl[13] nitrogen (TKN), TDS, dissolved solids, nitrate/nitrite (nitrite + nitrate as N). Impairments in these waterbodies include: temperature, hydrostructure flow regulation or modification, fish-passage barriers, alteration in stream-side or littoral[14] vegetative cover, chlorophyll-a, low flow alteration, and physical substrate habitat alteration. See Table 3.3-5.

Table 3.3-5 Impaired or Contaminated Waterbodies in Montana

Waterbody Name	Parameters of Concern
Middle Fork Prairie Elk Creek	Alteration in stream-side or littoral vegetative covers, nitrogen (total), phosphorus (total), physical substrate habitat alterations, TKN
East Fork Prairie Elk Creek	Alteration in stream-side or littoral vegetative covers, nitrogen (total), phosphorus (total), physical substrate habitat alterations, TKN
Missouri River	Alteration in stream-side or littoral vegetative covers, other flow regime alterations, temperature, water

[13] TKN is the sum of organic nitrogen, ammonia, and ammonium in the chemical analysis of soil or water as determined with the Kjeldahl method of analysis. This measurement is a required metric in regulatory reporting.
[14] Defined for lake shore environments as the vegetated zone that extends from the maximum water surface elevation to shoreline areas that are permanently submerged. Littoral vegetation is typically defined as emergent and anchored to the benthic strata, effective in preventing erosion.

Waterbody Name	Parameters of Concern
Frenchman River	Alteration in stream-side or littoral, vegetative covers, chlorophyll-a, low-flow alterations
Milk River	*E. coli*, lead, mercury
Yellowstone River	Fish-passage barrier
Buggy Creek	Iron
Sandstone Creek	Nitrate/nitrite (nitrite + nitrate as N), nitrogen (total)
Pennel Creek	TDS

Sources: USGS 2012a, MDEQ 2012

Water Supplies

Along the proposed pipeline ROW in Montana, municipal water supplies are largely obtained from groundwater sources and are described in Section 3.3.2, Groundwater. No intake or diversion sources for municipal surface water supplies are known to be located within 1 mile of the proposed Project ROW.

The Fort Peck Assiniboine & Sioux Rural Water Supply System (ASRWSS) operates a surface water withdrawal from the Missouri River near Poplar, Montana. The diversion is approximately 77 river miles downstream of the proposed Project crossing of the Missouri River, and it supplies raw water to the ASRWSS water treatment plant in Poplar. This system provides potable water to the Fort Peck Indian Reservation through the ASRWSS and to the residents of portions of Valley, Daniels, Sheridan, and Roosevelt counties through the Dry Prairie Rural Water Association. The ASRWSS replaces previous groundwater supplies that are no longer in use. The proposed pipeline ROW does not cross any ASRWSS-related infrastructure. The Fort Peck-Montana Compact indicates that multiple water rights and withdrawals are allotted on the Missouri River in Montana`.

There are 178 lakes, ponds, or reservoirs, located within 10 miles downstream of a proposed water crossing in Montana, which have the potential for one or all of the following uses: recreation, livestock watering, or agricultural water supply (see Appendix D, Waterbody Crossing Tables and Required Crossing Criteria for Reclamation Facilities, Table 7). Named waterbodies with a surface area in excess of 10 acres and within the 10-mile downstream range include Lindsay Reservoir and Salsbery Reservoir. Additionally, there are four waterbodies that are unnamed on the NHD with surface areas of 10 acres or larger within the 10-mile downstream range.

3.3.3.2 South Dakota Surface Water

The proposed pipeline ROW traverses the non-glaciated Missouri Plateau physiographic region of South Dakota, which is characterized by rolling plains of shale and sandstone interrupted by occasional buttes. The rolling surface of the non-glaciated Missouri Plateau has many low scarps (very steep slopes often created by erosion), indicating a geologically old landscape, in contrast to a mantle of glacial till and geologically young landscapes to the north. Some areas resemble dissected, badland terrain and deeply entrenched river breaks (Hogan 1995). Streams are mostly ephemeral[15] and intermittent with a few larger perennial rivers that cross the region from the

[15] An ephemeral stream, river, pond, or lake is that which only flows or is present for a short period following precipitation or snowmelt.

western mountains (Malo 1997). Many small impoundments along intermittent streams store surface runoff and are used for stock water and/or irrigation water and control. Non-regulated streams and rivers maintain a high sediment load of fine-grained alluvium. Natural surface water flows have been altered by man-made structures creating a significant change in the surface water characteristics. These changes may affect stream bank and bed conditions on which various habitats are based. Flooding occurs primarily in May and June, but peak flows may occur between March and July on many streams depending on seasonal fluctuations in snowpack, precipitation, temperature, and subsequent snow melt (USGS 2012b).

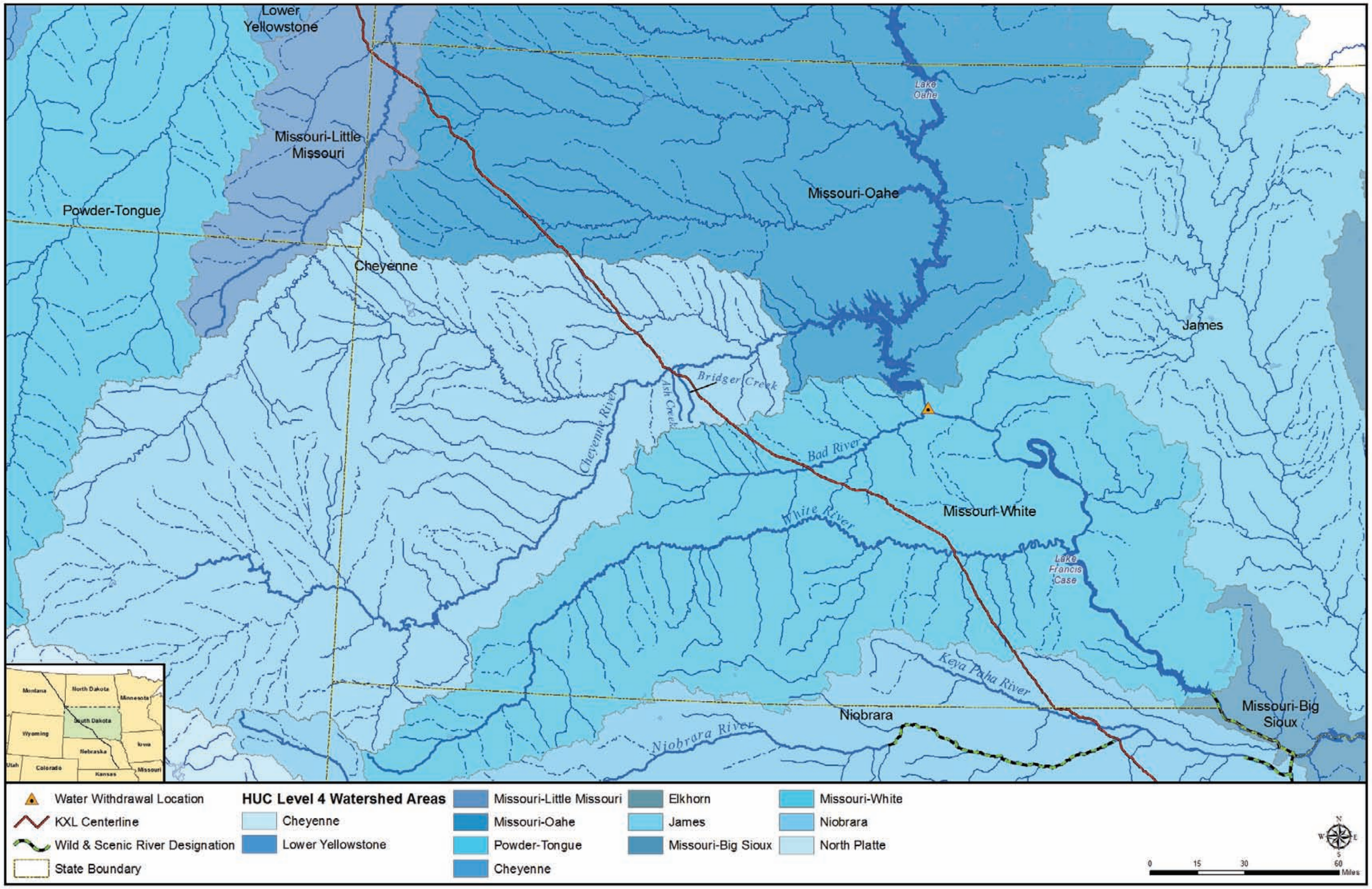
Waterbodies Crossed

There are 333 waterbody crossings along the proposed Project route in South Dakota, which includes 16 perennial streams, 313 intermittent streams, and four man-made impoundments (Appendix D, Waterbody Crossing Tables and Required Crossing Criteria for Reclamation Facilities, Table 3). Based on stream width, adjacent topography, adjacent infrastructure, best management practices, permitting, and sensitive environmental areas, five waterbodies in South Dakota would be crossed using the HDD method:

- Little Missouri River in Harding County (approximately 385 feet wide, MP 295);
- Cheyenne River in Meade and Pennington counties (approximately 1,600 feet wide, MP 430);
- Bridger Creek in Haakon County (approximately 75 feet wide, MP 434);
- Bad River in Haakon County (approximately 145 feet, MP 486); and
- White River in Lyman and Tripp counties (approximately 500 feet wide, MP 541).

The remaining 328 waterbodies would be crossed using one of several non-HDD methods described in the CMRP (see Appendix G). The crossing method for each waterbody would be depicted on construction drawings, but would ultimately be determined in consultation with the South Dakota Department of Environment and Natural Resources (SDDENR) and other agencies and be based upon site-specific conditions at the time of crossing. Qualified individuals would be involved in the permitting process to ensure proper identification of channel migration zones to further aid in selecting the appropriate crossing method, burial depth, and seasonal timing. In addition to the 333 waterbodies crossed by the centerline of the proposed Project, three waterbodies are present within the ROW for which there is no inlet or outlet indicated by the NHD; these may be potholes[16] or other similar features. Figure 3.3.3-2 illustrates the major watersheds in South Dakota and significant river and stream waterbodies within those watersheds that are crossed by the proposed Project. Wild and Scenic River-designated segments are shown as well.

[16] Potholes, also referred to as kettles, are fluvioglacial landforms resulting from blocks of ice calving from the front of a receding glacier and becoming partially to wholly buried by glacial outwash sediment. Typically these depressions fill with water on a seasonal or intermittent cycle.



Sources: USGS 2012b and 2013, Esri 2013

Figure 3.3.3-2 South Dakota Watersheds Crossed by the Proposed Project Route

The Final EIS stated that BOR water canal crossings would include one crossing in Haakon County near MP 467 and one in Jones County near MP 510 (see Appendix D, Waterbody Crossing Tables and Required Crossing Criteria for Reclamation Facilities). According to the data sources used to prepare this Final Supplemental EIS (USGS 2012), no artificial surface waterbodies would be intersected by the proposed Project for these counties. The BOR supplied a letter and revised the *TransCanada Keystone XL Pipeline: Required Crossing Criteria for Reclamation Facilities* document (dated April 2013), which is included in Appendix D, Waterbody Crossing Tables and Required Crossing Criteria for Reclamation Facilities. In the South Core Pipeline Crossing Criteria of that revision, BOR indicates a Mni Wiconi Core Pipeline crossing in Jones County. Further clarification supplied by BOR lists a total of two BOR pipeline crossings by the proposed Project that would be necessary in South Dakota:

- Oglala Sioux Rural Water System, North Coreline—Section 8 Township 2N, Range 23E (MP 472); and
- Oglala Sioux Rural Water System, South Coreline—Section 36 Township 1S, Range 29E (MP 515).

These facilities are managed by BOR through easements held in trust. Prior to construction, Keystone would consult with the canal owner/operator regarding the crossing of any canal infrastructure. Keystone would apply general design requirements consistent with canal owner/operator facility crossing criteria for all canal crossings as specified in Appendix G, CMRP.

Waterbodies Classifications

The proposed pipeline would cross 10 streams and rivers with state water quality use descriptions based on their surface water classification or waterbody type. Table 3.3-6 presents the names of these waterbodies, organized by county from north to south, and includes their state water quality designations.

Table 3.3-6 Streams and Rivers Crossed by the Proposed Pipeline in South Dakota with State Water Quality Designations or Use Designations

Waterbody Name	County	Designated Use	Use Support
Little Missouri River	Harding	Fish/Wildlife Propagation, Recreation, Stock, Irrigation Waters; Limited Contact Recreation; Warm Water Semipermanent Fish Life	Full; Full; Full; Non-supporting
South Fork Grand River	Harding	Fish/Wildlife Propagation, Recreation, Stock, Irrigation Waters; Limited Contact Recreation; Warm Water Semipermanent Fish Life	Full; Non-supporting; Full; Full
Clarks Fork Creek	Harding	Warm water Marginal Fish Life Propagation Waters; Limited Contact Recreation Waters.	Not Assessed
North Fork Moreau River	Butte	Warm water Marginal Fish Life Propagation Waters; Limited Contact Recreation Waters.	Not Assessed

Waterbody Name	County	Designated Use	Use Support
South Fork Moreau River	Perkins	Fish/Wildlife Propagation, Recreation, Stock, Irrigation Waters; Limited Contact Recreation; Warm water Marginal Fish Life	Non-supporting; Non-supporting; Full; Full
Pine Creek	Meade	Warm water Marginal Fish Life Propagation Waters; Limited Contact Recreation Waters	Not Assessed
Cheyenne River	Meade	Fish/Wildlife Propagation, Recreation, Stock; Immersion Recreation; Irrigation Waters; Limited Contact Recreation; Warm water Permanent Fish Life.	Full; Non-supporting; Full; Non-supporting; Non-supporting
Bad River	Haakon	Warm water Marginal Fish Life Propagation Waters; Limited Contact Recreation Waters	Not Assessed
Williams Creek	Jones	Fish/Wildlife Propagation, Recreation, Stock, Irrigation Waters	Insufficient Data; Insufficient Data
White River	Tripp	Fish/Wildlife propagation, Recreation, Stock; Irrigation Waters; Limited Contact Recreation; Warm water Semi-permanent Fish Life	Full; Full; Non-supporting Full

Sources: USGS 2012d, SDDENR 2012b

In addition to the streams listed in this Table 3.3-6, all streams in South Dakota are assigned the beneficial uses of fish and wildlife propagation, recreation, and stock watering (SDDENR 2012b).

Impaired or Contaminated Waterbodies

Contamination or impairment has been documented in five of these sensitive or protected waterbodies in South Dakota. Table 3.3-7 provides the names of the waterbodies and the contaminant or impairment (see also Appendix D, Waterbody Crossing Tables and Required Crossing Criteria for Reclamation Facilities, Table 6). Contamination or impairment in these waterbodies includes unacceptable levels of at least one of the following parameters: total suspended solids, total dissolved solids, salinity, specific conductance, *E. coli,* and fecal coliform.

Table 3.3-7 Impaired or Contaminated Waterbodies in South Dakota

Waterbody Name	Impairment
Little Missouri River	Suspended Solids
South Fork Grand River	Salinity and Specific Conductance
South Fork Moreau River	Total Dissolved Solids, Specific Conductance
Cheyenne River	*E. Coli* and Fecal Coliform, Total Suspended Solids
White River	*E. Coli*

Sources: USGS 2012d, SDDENR 2012b

Water Supplies

Along the proposed ROW in South Dakota, municipal water supplies are largely obtained from groundwater sources and are described in Section 3.3.2, Groundwater. No intake or diversion sources for municipal surface water supplies are known to be located within 1 mile of the proposed Project ROW.

The MWRWSS withdraws surface water from the Missouri River in Pierre, South Dakota, to provide potable water to the MWRWSS for rural water users in southwestern South Dakota. The BOR holds easements and is responsible for the protection of Indian trust assets, with which Mni Wiconi infrastructure is associated. The proposed pipeline ROW would cross Mni Wiconi water distribution infrastructure at various locations within the MWRWSS. BOR, in conjunction with its tribal partners, has specific requirements and conditions for energy pipeline crossings. Prior to construction, Keystone would consult with the water system owner/operator regarding the crossing of any water system infrastructure. Keystone would apply general design requirements consistent with BOR facility or infrastructure interfaces and crossings.

The MWRWSS intake withdraws water from the Missouri River in Pierre, South Dakota. The proposed Project route would cross several tributaries to the Missouri River with the potential to affect the Missouri River. The Cheyenne River crossing is approximately 57 river miles upstream of Lake Oahe, a reservoir on the Missouri River, and approximately 110 river miles upstream of Pierre. The Bad River crossing is approximately 44 river miles upstream of the Missouri River confluence. Spills or releases into surface waters could travel through these tributary systems and could potentially result in impacts to affect the Missouri River, aquatic habitats, as well as the MWRWSS.

Waterbodies and reservoirs located within 10 miles downstream of a proposed water crossing in South Dakota have the potential for one or all of the following uses: recreation, livestock watering, or agricultural water supply are summarized in Appendix D, Waterbody Crossing Tables and Required Crossing Criteria for Reclamation Facilities, Table 9. The larger of these waterbodies (those greater than 10 acres) include Lake Gardner and 18 other reservoirs that are unnamed on the USGS 2012 NHD. The analysis identified approximately 304 additional waterbodies located within 10 miles downstream of a proposed crossing that were less than 10 acres.

3.3.3.3 Nebraska Surface Water

The proposed pipeline ROW would enter north-central Nebraska near the edge of the northern NDEQ-identified Sand Hills Region and the northern High Plains, which are subdivisions of the Great Plains province. The High Plains are remnants of a former fluviatile (produced by rivers) plane that stretched from the Rocky Mountains to the Central Lowlands physiographic province to the east (Leighty 2001). Streams are typically overloaded with fine-grained sediment, mostly silt and sand with smaller quantities of gravel. Nebraska's rivers of the central High Plains typically flow through broad, flat valleys and deposit and rework sediments forming dynamic and unstable braided channel and transient depositional bars within relatively flat and broad valleys (Wiken et al. 2011). In northern and central Nebraska, the formation of sand dunes has taken place during the later stages of physiographic evolution. Sand dunes occur in many places in the High Plains, but mostly on the leeward sides of rivers, which derive their sand from the braided channels of local and adjacent stream channels. During periods of low water, the surface soils become dry and winds are capable of entraining and transporting loess to adjacent uplands (Leighty 2001).

The proposed pipeline would cross five major river basins in Nebraska: Niobrara, Elkhorn, Loup, Middle Platte, and the Kansas. Some of these basins may have either fully or over appropriated surface water supplies. There may be additional restrictions on surface water withdrawals for water use in the proposed Project's temporary potable water systems associated with construction camps, construction applications, and pipeline testing, all of which may require permitting.

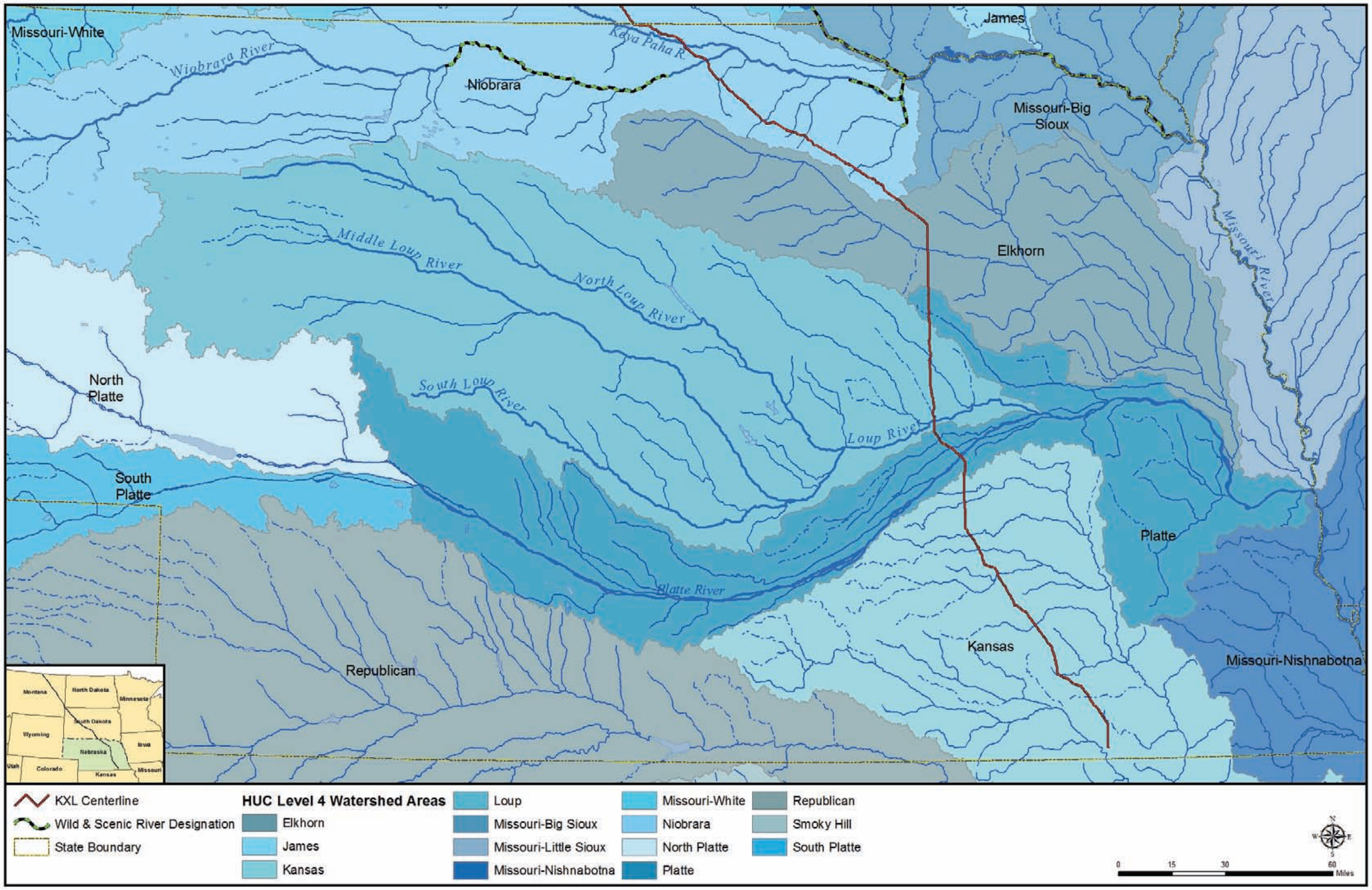
Similar to Montana and South Dakota, flooding in Nebraska typically occurs during spring (April-June); however, ice jams, rapid snowmelt, and intense rainfall have all contributed to major flooding in the recent past (USGS 2012d). Blockage of channels by ice jams in some of the larger braided rivers such as the Elkhorn and Platte are triggered by relatively abrupt weather changes in mid or late winter (Mason and Joeckel 2007), and have the potential to cause significant lateral channel migration.

Waterbodies Crossed

There are 281 waterbody crossings along the proposed Project route in Nebraska, including 31 perennial streams, 237 intermittent streams, eight canals, and five artificial or natural lakes, ponds, or reservoirs (Appendix D, Waterbody Crossing Tables and Required Crossing Criteria for Reclamation Facilities, Table 2). Based on stream width, adjacent topography, adjacent infrastructure, best management practices, permitting, and sensitive environmental areas, five rivers in Nebraska would be crossed using the HDD method:

- Keya Paha River in Boyd County (approximately 300 feet wide, MP 618);
- Niobrara River in Boyd and Holt counties (approximately 1,250 feet wide, MP 626);
- Elkhorn River in Antelope County (approximately 775 feet wide, MP 713);
- Loup River in Nance County (approximately 1,200 feet wide, MP 762); and
- Platte River in Merrick County (approximately 2,000 feet wide, MP 775).

The remaining 276 waterbodies would be crossed using one of several non-HDD methods described in the CMRP (see Appendix G). The crossing method for each waterbody would be depicted on construction drawings but would ultimately be determined based on site-specific conditions at the time of the crossing. Qualified individuals would be involved in the permitting process to ensure proper identification of channel migration zones to further aid in selecting the appropriate crossing method. In addition to the 281 waterbodies crossed by the centerline of the proposed pipeline, there are seven waterbodies within the ROW that would not be crossed by the proposed pipeline. Figure 3.3.3-3 illustrates the major watersheds in Nebraska and significant river and stream waterbodies within those watersheds that are crossed by the proposed Project. Wild and Scenic River-designated segments are shown as well.



Sources: USGS 2012b and 2013, Esri 2013

Figure 3.3.3-3 Nebraska Watersheds Crossed by the Proposed Project Route

Waterbodies Classifications

The proposed pipeline would cross a number of streams and rivers with state water quality use designations based on their surface water classification or by waterbody type. There are 40 classified streams that would be crossed by the proposed pipeline in Nebraska. Table 3.3-8 presents the names of these waterbodies, organized by county from north to south, and includes their state water quality designations.

Table 3.3-8 Streams and Rivers Crossed by Proposed Pipeline in Nebraska with State Water Quality Designations or Use Designations

Waterbody Name	County	Designated Use	Use Support/Attainment[a]
Unnamed Tributary to Buffalo Creek	Keya Paha	Warm Water Aquatic Life (Class B); Agricultural Water Supply—Class A; Aesthetics	No Data; No Data; No Data
Dry Creek	Keya Paha	Warm Water Aquatic Life (Class B); Agricultural Water Supply—Class A; Aesthetics	No Data; No Data; No Data
Wolf Creek	Keya Paha	Cold Water Aquatic Life (Class B); Agricultural Water Supply—Class A; Aesthetics	No Data; No Data; No Data
Spotted Tail Creek	Keya Paha	Cold Water Aquatic Life (Class B); Agricultural Water Supply—Class A; Aesthetics	No Data; No Data; No Data
Alkali Creek	Keya Paha	Warm Water Aquatic Life (Class B); Agricultural Water Supply—Class A; Aesthetics	No Data; No Data; No Data
Keya Paha River	Boyd	Primary contact Recreation; Warm Water Aquatic Live (Class A); Agricultural Water Supply; Aesthetics	Impaired; Supported; Supported; Supported
Big Creek	Boyd	Cold Water Aquatic Life (Class B); Agricultural Water Supply—Class A; Aesthetics	No Data; No Data; No Data
Niobrara River	Holt	Primary Contact Recreation; Warm Water Aquatic Live (Class A*); Agricultural Water Supply; Aesthetics	Impaired; Supported; Supported; Supported
Beaver Creek	Holt	Cold Water Aquatic Life (Class B); Agricultural Water Supply—Class A; Aesthetics	No Data; No Data; No Data
Big Sandy Creek	Holt	Primary Contact Recreation; Warm Water Aquatic Life (Class A); Agricultural Water Supply; Aesthetics	No Data; No Data; No Data; No Data
Unnamed Tributary to Brush Creek	Holt	Cold Water Aquatic Life (Class B); Agricultural Water Supply—Class A; Aesthetics	No Data; No Data; No Data
Brush Creek	Holt	Cold Water Aquatic Life (Class B); Agricultural Water Supply—Class A; Aesthetics	No Data; No Data; No Data

Waterbody Name	County	Designated Use	Use Support/Attainment[a]
North Branch Eagle Creek	Holt	Primary Contact Recreation; Cold Water Aquatic Life (Class B); Agricultural Water Supply; Aesthetics	No Data; No Data; No Data; No Data
Middle Branch Eagle Creek	Holt	Primary Contact Recreation; Cold Water Aquatic Life (Class B); Agricultural Water Supply—Class A; Aesthetics	No Data; Supported; No Data; No Data
East Branch Eagle Creek	Holt	Cold Water Aquatic Life (Class B); Agricultural Water Supply—Class A; Aesthetics	No Data; No Data; No Data
Honey Creek	Holt	Warm Water Aquatic Life (Class B); Agricultural Water Supply—Class A; Aesthetics	No Data; No Data; No Data
Blackbird Creek	Holt	Warm Water Aquatic Life (Class B); Agricultural Water Supply—Class A; Aesthetics	No Data; No Data; No Data
Redbird Creek	Holt	Warm Water Aquatic Life (Class B); Agricultural Water Supply—Class A; Aesthetics	No Data; No Data; No Data
Unnamed Tributary to Redbird Creek	Holt	Warm Water Aquatic Life (Class B); Agricultural Water Supply—Class A; Aesthetics	No Data; No Data; No Data
Middle Branch Verdigre Creek	Holt	Cold Water Aquatic Life (Class B); Agricultural Water Supply—Class A; Aesthetics	No Data; No Data; No Data
South Branch Verdigre Creek	Holt	Primary Contact Recreation; Cold Water Aquatic Life (Class B); Agricultural Water Supply; Aesthetics	No Data; No Data; No Data; No Data
Big Springs Creek	Antelope	Cold Water Aquatic Life (Class B); Agricultural Water Supply—Class A; Aesthetics	No Data; No Data; No Data
Unnamed Tributary to Big Springs Creek	Antelope	Warm Water Aquatic Life (Class B); Agricultural Water Supply—Class A; Aesthetics	No Data; No Data; No Data
Hathoway Slough	Antelope	Warm Water Aquatic Life (Class B); Agricultural Water Supply—Class A; Aesthetics	No Data; No Data; No Data
Al Hopkins Creek	Antelope	Warm Water Aquatic Life (Class B); Agricultural Water Supply—Class A; Aesthetics	No Data; No Data; No Data
Elkhorn River	Antelope	Primary Contact Recreation; Warm Water Aquatic Life (Class A); Agricultural Water Supply; Aesthetics	Impaired; Supported; Supported; Supported
Ives Creek	Antelope	Warm Water Aquatic Life (Class B); Agricultural Water Supply—Class A; Aesthetics	No Data; No Data; No Data
Beaver Creek	Boone	Primary Contact Recreation; Warm Water Aquatic Life (Class A); Agricultural Water Supply—Class A; Aesthetics	Impaired; Impaired; Supported; Supported

Waterbody Name	County	Designated Use	Use Support/Attainment[a]
Bogus Creek	Boone	Warm Water Aquatic Life (Class B); Agricultural Water Supply—Class A; Aesthetics	No Data; No Data; No Data
Plum Creek	Nance	Warm Water Aquatic Life (Class B); Agricultural Water Supply—Class A; Aesthetics	No Data; No Data; No Data
Loup River	Nance	Primary Contact Recreation; Warm Water Aquatic Life (Class A); Agricultural Water Supply—Class A; Aesthetics	Impaired; Supported; Supported; Supported
Prairie Creek	Nance	Warm Water Aquatic Life (Class B); Agricultural Water Supply—Class A; Aesthetics	Impaired; Supported; Supported
Platte River	Polk	Primary Contact Recreation; Warm Water Aquatic Life (Class A*); Agricultural Water Supply—Class A; Aesthetics	Supported; Supported; Supported; Supported
Big Blue River	Polk	Warm Water Aquatic Life (Class B); Agricultural Water Supply—Class A; Aesthetics	Impaired; Supported; Supported
Lincoln Creek	York	Warm Water Aquatic Life (Class B); Agricultural Water Supply—Class A; Aesthetics	Impaired; No Data; No Data
Beaver Creek	York	Warm Water Aquatic Life (Class B); Agricultural Water Supply—Class A; Aesthetics	Impaired; No Data; No Data
West Fork Big Blue River	York	Primary Contact Recreation; Warm Water Aquatic Life (Class A); Agricultural Water Supply—Class A; Aesthetics	Impaired; Impaired; Supported; Supported
Turkey Creek	Fillmore	Warm Water Aquatic Life (Class B); Agricultural Water Supply—Class A; Aesthetics	Supported; No Data; No Data
South Fork Swan Creek	Jefferson	Warm Water Aquatic Life (Class B); Agricultural Water Supply—Class A; Aesthetics	Supported; No Data; No Data
Cub Creek	Jefferson	Warm Water Aquatic Life (Class A); Agricultural Water Supply—Class A; Aesthetics	Supported; No Data; No Data

Sources: USGS 2012c, NDEQ 2012a and 2012b

[a] The “No Data” designation in this table represents NDEQ surface water assessment outcomes of Not Assessed for assigned beneficial uses as defined in Section 4.0 of the NDEQ 2012 Water Quality Integrated Report.

Impaired or Contaminated Waterbodies

Contamination or impairment has been documented in 2012 Water Quality Integrated Report, NDEQ, Water Quality Division, April 1, 2012, for 10 of these sensitive or protected waterbodies that would be crossed by the proposed pipeline in Nebraska. Table 3.3-9 provides the names of the waterbodies and the contaminant or impairment (see also Appendix D, Waterbody Crossing Tables and Required Crossing Criteria for Reclamation Facilities, Table 5). Contamination in these waterbodies includes unacceptable levels of at least one of the following parameters:

E. coli, dissolved oxygen, and atrazine. In some cases, the listed impairment is an impaired aquatic community.

Table 3.3-9 Impaired or Contaminated Waterbodies in Nebraska

Waterbody Name	Impairment
Keya Paha River	E. coli
Niobrara River	E. coli
Elkhorn River	E. coli
Beaver Creek	E. coli
Loup River	E. coli
Prairie Creek	Low dissolved oxygen
Big Blue River	Low dissolved oxygen, atrazine
Lincoln Creek	Impaired aquatic community
Beaver Creek	Impaired aquatic community
West Fork Big Blue River	*E. coli*, May–June atrazine, impaired aquatic community

Sources: USGS 2012c, NDEQ 2012a and 2012b

Additionally, the proposed Project would cross the central Platte River using the HDD method at MP 775. Activities associated with project in that area include water withdrawal for drilling fluids and hydrostatic testing. Water withdrawals from the Platte River would have the potential to adversely affect the river ecosystem through flow depletions. The state of Nebraska in cooperation with the U.S. Fish and Wildlife Service (USFWS) has developed plans to manage water depletions in conjunction with Section 7 Endangered Species Act consultations (USFWS 2009a). Water withdrawals that qualify as temporary uses such as hydrostatic testing would likely be consistent with the Platte River species depletions consultations *de minimus* threshold as provided by USFWS (USFWS 2009). The *de minimus* text states “temporary withdrawals of water (e.g., for hydrostatic pipeline testing) that return all the water to the same drainage basin within 30 days' time are considered to have no effect, and do not require consultation.”

The NDEQ has indicated Keystone would in many cases need to secure a surface water right from Nebraska Department of Natural Resources (NDNR) to withdraw water for construction from sources along the pipeline alignment. These permits or water rights for specific use locations, purposes, and/or quantity and may include seasonal stipulations. A number of river basins or portions of rivers in Nebraska have been identified by NDNR as being either fully appropriated or over-appropriated. In these locations Keystone would need to comply with any plan or program implemented to protect existing water uses in the affected basins.

In an effort to avoid or minimize impacts to sensitive waterbodies, Keystone has conducted consultations with the cooperating agencies during the proposed Project’s planning phase. Additional consultation may be required in accordance with additional regulatory and permitting review during the final design and permitting phases.

Water Supplies

Along the proposed pipeline route in Nebraska, municipal water supplies are largely obtained from groundwater and are described in Section 3.3.2, Groundwater. No intake or diversion sources for municipal surface water supplies are known to be located within 1 mile of the proposed Project ROW.

Waterbodies and reservoirs located within 10 miles downstream of a proposed water crossing in Nebraska have the potential for one or all of the following uses: recreation, livestock watering, or agricultural water supply are summarized in Appendix D, Waterbody Crossing Tables and Required Crossing Criteria for Reclamation Facilities, Table 8. The larger of these waterbodies (those greater than 10 acres) include Cub Creek Reservoir 14C, Cub Creek Reservoir 13C, Recharge Lake, Big Indian Creek Reservoir 8-E, Big Indian Creek Reservoir 10-A, and six unnamed reservoirs (unnamed according to the USGS 2012 NHD [USGS 2012b]). The analysis identified an additional 68 waterbodies or reservoirs located within 10 miles downstream of a proposed crossing that were less than 10 acres in size.

3.3.4 Floodplains

Floodplains are areas of land adjacent to rivers and streams that convey overflows during flood events. Floodwater energy is dissipated as flows spread out over a floodplain, and significant storage of floodwaters can occur through infiltration and surficial storage in localized depressions on a floodplain. Floodplains form where overbank floodwaters spread out laterally and deposit fine-grained sediments. The combination of rich soils, proximity to water, riparian forests, and the dynamic reworking of sediments during floods creates a diverse landscape with high habitat quality. Floodplains typically support a complex mosaic of wetland, riparian, and woodland habitats that are spatially and temporally dynamic.

Changing climatic and land use patterns in much of the west-central United States has resulted in region-wide incision of many stream systems. Stream systems cutting channels deeper into the surrounding floodplain cause high floodplain terraces to form along valley margins. These floodplain terraces are common along the proposed pipeline route and receive floodwaters less frequently than the low floodplains adjacent to the streams.

From a policy perspective, the Federal Emergency Management Agency (FEMA) defines floodplain as being any land area susceptible to being inundated by water from any source (FEMA 2012a). FEMA prepares Flood Insurance Rate Maps (FIRMs) that delineate flood hazard areas, such as floodplains, for communities. These maps are used to administer floodplain regulations and to reduce flood damage. Typically, these maps indicate the locations of 100-year floodplains, which are areas with a 1 percent chance of flooding occurring in any single year.

Executive Order 11988, Floodplain Management, states that actions by federal agencies are to avoid to the extent possible the long- and short-term adverse impacts associated with the occupancy and modification of floodplain development wherever there is a practicable alternative. Each agency is to provide leadership and shall take action to reduce the risk of flood loss, to minimize the impact of floods on human safety, health, and welfare, and to restore and preserve the natural and beneficial values served by floodplains in carrying out its responsibilities for the following:

- Acquiring, managing, and disposing of federal lands and facilities;
- Providing federally undertaken, financed, or assisted construction and improvements; and
- Conducting federal activities and programs affecting land use, including but not limited to water and related land resources planning, regulating, and licensing activities.

Both state-administered and FEMA-designated floodplains as well as some undesignated floodplain areas, crossed by the proposed route in Montana, South Dakota, and Nebraska are listed in Tables 3.3-10, 3.3-11, and 3.3-12, respectively. The proposed route crosses 12 floodplains in Montana, while four are crossed in South Dakota, and 74 are crossed in Nebraska. Significant portions of the proposed route do not have FEMA or state emergency management mapping of floodplains. Pump Station 24 in Nance County Nebraska may be inaccessible during periods of flood. Most if not all access roads to Pump Station 24 cross significant flood plain areas associated with the Loup River and Prairie Creek systems; if both are experiencing flood events, Pump Station 24 could be inaccessible.

Table 3.3-10 Designated Floodplain Areas Crossed by the Proposed Pipeline Route in Montana

County	Approximate MPs	Waterbody Associated with Floodplain
Valley	59	Grass Coulee Creek
Valley	60	Spring Creek
Valley	62	Morgan Creek
Valley	60	Cherry Creek
Valley	68	Foss Coulee
Valley	70	Spring Coulee
Valley	70	Hawk Coulee
Valley	72	East Fork Cherry Creek
Valley	83-86	Milk River
Valley/McCone	90-91	Missouri River
McCone	148-149	Redwater River
Dawson	197-198	Yellowstone River

Sources: FEMA 2012b, 2011 Final EIS Table 3.3.1.3-1 (for Redwater River and Yellowstone River).

Note: Due to rounding, some waterbodies may be listed with the same milepost.

Table 3.3-11 Designated[a] Floodplain Areas Crossed by the Proposed Pipeline Route in South Dakota

County	Approximate MPs	Waterbody Associated with Floodplain
Harding	295	Little Missouri River
Meade/Pennington	430	Cheyenne River
Haakon	486	Bad River
Lyman/Tripp	541-542	White River

Source: FEMA 2012b

[a] The proposed pipeline does not cross any South Dakota state, county, or FEMA-designated floodplains. Floodplains listed denote those identified in the 2011 Final EIS and are updated with current proposed Project MP data.

Table 3.3-12 Designated Floodplain Areas Crossed by the Proposed Pipeline Route in Nebraska

County[a]	Approximate MPs	Waterbody Associated with Floodplain
Boyd	618	Keya Paha River
Boyd	621	Big Creek
Boyd	626	Niobrara
Antelope	683	Big Springs Creek
Antelope	685	Unnamed Tributary to Big Springs Creek
Antelope	708	Al Hopkins Creek
Antelope	713-714	Elkhorn River

County[a]	Approximate MPs	Waterbody Associated with Floodplain
Antelope	719	Saint Clair Creek
Boone	725	North Shell Creek
Boone	730	Unnamed Tributary to Shell Creek
Boone	731	Shell Creek
Boone	731	Unnamed Tributary to Shell Creek
Boone	731	Unnamed Tributary to Shell Creek
Boone	733	Unnamed Tributary to Shell Creek
Boone	736	Unnamed Tributary to Vorhees Creek
Boone	737	Vorhees Creek
Boone	738	Unnamed Tributary to Vorhees Creek
Boone	739	Unnamed Tributary to Vorhees Creek
Boone	739	Unnamed Tributary to Vorhees Creek
Boone	739	Unnamed Tributary to Vorhees Creek
Boone	740	Unnamed Tributary to Vorhees Creek
Boone	740	Vorhees Creek
Boone	741	Unnamed Tributary to Vorhees Creek
Boone	744	Beaver Creek
Boone	745	Unnamed Beaver Creek
Boone	746	Unnamed Beaver Creek
Boone	748-749	Bogus Creek
Boone	749	Unnamed Tributary to Bogus Creek
Boone	750-751	Unnamed Tributary to Bogus Creek
Nance	753	Unnamed Tributary to Skeedee Creek
Nance	760	Plumb Creek
Nance	760	Unnamed Tributary to Plumb Creek
Nance	761-762	Loup River
Nance	765-766	Unnamed Tributary to Prairie Creek
Nance	766	Prairie Creek
Nance	766-767	Prairie Creek
Merrick	768-769	Prairie Creek
Merrick	770-774	Silver Creek
Merrick	775	Platte River
Polk	775-776	Platte River
Polk	777	Unnamed Tributary to Platte River
Polk	785	Unnamed Tributary to Prairie Creek
Polk	786	Prairie Creek
Polk/York	789	Big Blue River
York	798	Lincoln Creek
York	801-802	Unnamed Tributary to Beaver Creek
York	803	Beaver Creek
York	810	Unnamed Tributary to West Fork Big Blue River
York	810	Unnamed Tributary to West Fork Big Blue River
York	811	Unnamed Tributary to West Fork Big Blue River
York	813	West Fork Big Blue River
Fillmore	818	Indian Creek
Fillmore	828	Unnamed Tributary to Turkey Creek
Fillmore	831	Unnamed Tributary to Turkey Creek
Fillmore	831-832	Turkey Creek
Saline	833	Unnamed Tributary to Turkey Creek
Saline	836	Unnamed Tributary to North Fork Swan Creek
Saline	837	Unnamed Tributary North Fork Swan Creek
Saline	837	Unnamed Tributary North Fork Swan Creek

County[a]	Approximate MPs	Waterbody Associated with Floodplain
Saline	838	Unnamed Tributary North Fork Swan Creek
Saline	839	Unnamed Tributary North Fork Swan Creek
Saline	840	Unnamed Tributary North Fork Swan Creek
Saline	845	Unnamed Tributary South Fork Swan Creek
Saline	846	Unnamed Tributary South Fork Swan Creek
Jefferson	848	Unnamed Tributary South Fork Swan Creek
Jefferson	848	South Fork Swan Creek
Jefferson	853	Unnamed Tributary South Fork Swan Creek
Jefferson	853	Unnamed Tributary South Fork Swan Creek
Jefferson	859	Cub Creek
Jefferson	860	Unnamed Tributary to Cub Creek
Jefferson	860	Unnamed Tributary to Cub Creek
Jefferson	861	Unnamed Tributary to Cub Creek
Jefferson	869	Unnamed Tributary to Big Indian Creek
Jefferson	871	Unnamed Tributary to Big Indian Creek

Sources: FEMA 2012b, NDNR 2012b, FIRM maps provided by Jefferson County floodplain administrator

[a] Holt County does not have any FIRMs (based on conversation with Holt Colt Planning and Zoning Officer).
Note: Due to rounding, some waterbodies may be listed with the same milepost.

The U.S. Department of the Interior (DOI), through the National Wild and Scenic River System, has a duty to protect designated river environments. The DOI has noted several potential impacts due to floodplain activities of the proposed Project. In an effort to avoid or minimize impacts to DOI assets, it is recommended that National Park Service criteria relating to Wild and Scenic Rivers be considered when designing crossings of tributaries to and upstream of the Niobrara National Scenic River and Missouri National Recreational River segments (DOI 2012). Based on resource protection requirements in the Wild and Scenic Rivers Act and related Presidential Directives, the U.S. Army Corps of Engineers and other federal agencies will, as part of their normal environmental review process, consult with the National Park Service prior to taking actions that could effectively foreclose wild, scenic, or recreational river status on rivers in the inventory.

3.3.5 Connected Actions[17]

There are three connected actions of the proposed Project, including:

- Bakken Marketlink Project;
- Big Bend to Witten 230-kilovolt Transmission Line; and
- Electrical Distribution Lines and Substations.

These connected actions would be constructed in areas similar to the proposed Project. Further discussion regarding connected actions and water resources is provided in Section 4.3.5, Connected Actions.

[17] Connected actions are those that 1) automatically trigger other actions which may require environmental impact statements, 2) cannot or will not proceed unless other actions are taken previously or simultaneously, 3) are interdependent parts of a larger action and depend on the larger action for their justification.

3.3.5.1 Bakken Marketlink Project

Construction and operation of the Bakken Marketlink Project would consist of a 16-inch pipeline approximately 5 miles in length, additional piping, booster pumps, meter manifolds, and two 250,000-barrel tanks that would be used to store crude from connecting third-party pipelines and terminals. The Bakken Marketlink Project facilities would be located within private land currently used as pastureland and hayfields.

3.3.5.2 Big Bend to Witten 230-kV Transmission Line

The Big Bend to Witten 230-kV Transmission Project is located in Lyman and Tripp counties in south-central South Dakota. The project would consist of replacing the existing Big Bend-Fort Thompson No. 2 230-kV Transmission Line Turning Structure on the south side of the Big Bend Dam on Lake Sharpe; constructing a new double-circuit 230-kV transmission line for approximately 1 mile southwest of the dam; and constructing a new Lower Brule Substation south of the dam. The existing Witten Substation would be expanded immediately to the northeast to accommodate the new 230-kV connection.

3.3.5.3 Electrical Distribution Lines and Substations

Multiple private power companies or cooperatives would construct distribution lines to deliver power to 20 pump stations located along the length of the pipeline in the United States. These distribution lines would range in length from approximately 0.1-mile to 62 miles, with the average being 13 miles long, and are estimated to extend about 377 miles combined. The distribution lines would range in capacity from 69 kV to 240 kV, but the majority would have a capacity of 115 kV. The lines would be strung on a single-pole and/or on H-frame wood poles.

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3.13 POTENTIAL RELEASES

3.13.1 Introduction

This section addresses the potential for releases of oil products or crude oil that could occur during construction and operation of the proposed Project. The purpose of this section is to discuss the types of threats to pipeline and tank integrity (failure to contain oil as designed) and construction equipment that could result in such a release and identify the receptors that could be affected by a release. The description of potential releases is based on information provided in the 2011 Final Environmental Impact Statement (Final EIS) and the 2013 Draft Supplemental EIS, as well as new circumstances or information relevant to environmental concerns that have become available since the publication of the Final EIS, including the proposed reroute in Nebraska. The information that is provided here builds on the information provided in the Final EIS and, in many instances, replicates that information with relatively minor changes and updates; other information is entirely new or substantially altered.

Specifically, the following information, data, methods, and/or analyses have been substantially updated in this section from the 2011 document:

- The discussion on the characteristics of diluted bitumen (dilbit) has been further developed.
- The descriptions of dilbit, synthetic crude oil (SCO), and Bakken shale oil have been further developed.
- A comparison has been made between the characteristics of crude oil from around the world.
- The discussion on threats to pipeline integrity, including corrosion and security, has been expanded.
- The discussion on spill volume distribution has been revised based on Pipeline and Hazardous Material Safety Administration (PHMSA) data.

The following information, data, methods, and/or analyses have been substantially updated from the 2013 Draft Supplemental EIS:

- The discussion of Facility Response Plan (FRP)/Emergency Response Plan (ERP) and other relevant document approvals has been updated.
- The discussion of the Oil Spill Liability Trust Fund and the obligations and liabilities of responsible parties has been expanded.
- The discussion of crude oils and their behavior when released to surface water (e.g., sinking) has been expanded.
- Additional recent references on dilbit characteristics have been incorporated.
- The discussion of human health exposure to crude oil has been expanded.
- The discussion on Safety and Risk Analysis has been expanded.
- A discussion of industry standards and practices in reducing the potential for spills has been added.

- New information on dilbit corrosivity from the National Academy of Sciences (NAS) has been added.
- The general characteristics of the types of crude oil that could be transported by the proposed Project have been updated.
- The discussion on dilbit and diluent characteristics and composition has been expanded.
- A discussion on changes to dilbit characteristics during a release event has been added.
- Integrity threat definitions have been clarified.
- The discussion of pipeline security, standard security measures, and policies and procedures to address intentional damage has been expanded.
- In response to public and agency comments, text has been revised throughout the section where necessary.

For the combined risk of potential releases and environmental impacts from a spill, an Independent Engineering Assessment was prepared by Battelle Memorial Institute (Leis et al. 2013), and a third-party consultant Environmental Review of the TransCanada Keystone XL was prepared by E^{x}ponent (E^{x}ponent 2013).

Summary

The proposed Project could potentially release hazardous products during construction and crude oil during operations if damage were to occur to the pipeline or its associated components. A release over a period of time is considered a leak. If a leak enters the environment, it is considered a spill. In general, causes of releases for oil pipelines include:

- External corrosion (i.e., the metal of the pipeline reacts with the environment, causing the pipeline to rust on the outside of the pipe, similar to rust on a car);
- Internal corrosion (i.e., same as external corrosion, except the metal reacts with the contents inside the pipeline);
- Stress corrosion cracking (i.e., pressure and temperature changes cause the pipeline to expand and contract, which compromises the pipeline coating and renders the pipeline susceptible to corrosion, subsequently resulting in the development and progression of cracks in the pipeline);
- Manufacturing (e.g., defects in the original characteristics of the pipe, such as low-strength material or substandard threading, which result in compromised integrity of the pipe);
- Construction (e.g., a defect in the welding of the pipe);
- Equipment (e.g., unusual wear and tear of pipeline components, such as valves);
- Third-party damage (e.g., a backhoe digging nearby strikes the pipe);
- Incorrect operations (i.e., human error made by pipeline operators); and
- Weather-related and other natural forces (e.g., flooding contributes to stream bank erosion that exposes the pipe or a landslide ruptures the pipe).

The magnitude of an oil spill impact would be influenced by the type of receptors that might be exposed to the oil. The two primary types of receptors are High Consequence Areas (HCAs), as defined by the U.S. Department of Transportation (USDOT), and other resources that could be affected by a spill. An HCA is defined as a High Population Area (HPA), Other Populated Area (OPA), Commercially Navigable Waterway (CNW), or Unusually Sensitive Area, such as a sole-source drinking water supply. Other resources include soils, sediments, terrestrial vegetation, wildlife, water resources, cultural resources, and socioeconomic resources.

Three hypothetical spill volumes were developed for this Final Supplemental EIS and were based on PHMSA historic data:

- *Small*—up to 50 barrels[1] (bbl) (2,100 gallons); 79 percent of relevant PHMSA reported incidents[2] are small;
- *Medium*—greater than 50 bbl (2,100 gallons) to 1,000 bbl (42,000 gallons); 17 percent of relevant PHMSA-reported incidents are medium; and
- *Large*—greater than 1,000 bbl (42,000 gallons); 4 percent of relevant PHMSA reported incidents are large.

TransCanada Keystone Pipeline, LP (Keystone) has prepared written procedures to address response actions to prevent and control a spill event. These procedures are provided in Appendix I, Spill Prevention, Control, and Countermeasure (SPCC) Plan and ERP.

The Oil Spill Liability Trust Fund may be utilized should federal intervention be required to ensure rapid and effective response to oil spills. Section 1001(32)(B) of the Oil Pollution Act of 1990 (OPA 90) states that in the case of an onshore facility, any person owning or operating the facility is the responsible party. If there were an accidental release that could affect surface water, no matter what the reason, Keystone would be liable for all costs associated with cleanup and restoration, as well as other compensations, up to a maximum of $350 million, per OPA 90 (U.S. Department of Homeland Security 2012). However, this statutory $350 million liability limit does not apply where the incident was directly caused by 1) gross negligence or willful misconduct or 2) the violation of an applicable federal safety construction or operating regulation by Keystone or a person acting pursuant to a contractual relationship with Keystone. This topic is discussed further in Section 4.13.5.2, Safety and Spill Response, in subsection Spill Liability and Responsibility.

The behavior of crude oils released to flowing water or other surface water features depends on the streamflow and response time to the spill. As with any crude oil, key components of oil would evaporate and biodegrade over time, resulting in a weathered oil that could potentially sink (U.S. Environmental Protection Agency [USEPA] 1999). In flowing water systems, sinking oil could be transported downstream without the obvious surface oiling of stream banks. Sinking oil could be deposited in river or stream bottoms and become a continual source of oil as changing water flows released the deposited oil. Methods to detect submerged oil include sediment sampling in streams and rivers and the use of sonar or remote and diver-operated

[1] One barrel equals 42 U.S. gallons.
[2] The terms *incident* and *accident* can be used interchangeably or with specified definitions in various agency reports and databases. For the purposes of this report, the term *incident* has been selected for consistency.

underwater video detection systems in still waterbodies such as lakes and ponds. This topic is discussed further throughout Section 4.13, Potential Releases.

The combined implementation of industry standards and practices would aid in reducing the potential for spill incidents associated with the proposed Project. The standards were developed by the National Association of Corrosion Engineers (NACE), International and American Society of Mechanical Engineers (ASME), and other industry leaders. The U.S. Department of State (the Department), in consultation with PHMSA, has determined that these standards and practices, combined with PHMSA regulatory requirements and the set of proposed Project-specific Special Conditions developed by PHMSA, would result in a degree of safety over any other typically constructed domestic oil pipeline system under current code and a degree of safety along the entire length of the proposed pipeline system, similar to that required in HCAs as defined in 49 Code of Federal Regulations (CFR) 195.450. Appendix B, Potential Releases and Pipeline Safety, describes how each of the Special Conditions increases public safety over and above the applicable current CFR requirements (see Section 4.13.5.1, PHMSA Special Conditions).

An FRP, which would include the proposed Project-specific ERP, would be prepared and submitted to PHMSA prior to initiating operation of the proposed Project, in accordance with requirements of 49 CFR Part 194. These plans rely on final permitting requirements and detailed design and construction information. A proposed Project-specific, worst-case spill scenario including location, available resources, and response actions would be addressed in the FRP/ERP once the final permitting, detailed design, and construction information were available. A general discussion of worst-case discharges is provided in Appendix P, Risk Assessment. Under current regulations, Keystone would be required to submit the FRP/ERP for review 6 months prior to operation of the proposed Project. PHMSA would provide the FRP/ERP to the USEPA for their review.

Human health can be affected due to short-term and long-term exposure to crude oil and the hazardous chemicals that make up crude oils. Exposure to crude oil can occur through ingestion, inhalation of vapors, and dermal (contact with skin) and ocular exposure (contact with surface of the eye). Human health risks from short-term and long-term exposure to crude oil and the hazardous chemicals that make up crude oils are discussed further in Section 3.13.4.1, High Consequence Areas.

Connected actions of the proposed Project include the Bakken Marketlink Project, the Big Bend to Witten 230-kilovolt (kV) Transmission Line, and electrical distribution lines and substations. These connected actions would be constructed in areas similar to the proposed Project route; the Bakken Marketlink Project could result in a spill to nearby resources and could present similar threats, but because of the short pipeline length, the worst-case spill size would be expected to be less than that of the proposed Project.

3.13.2 Crude Oil Characteristics

The physical and chemical properties of the crude oils that would be transported by the proposed pipeline would not be unique to the proposed Project; petroleum quality requirements of crude oil would be specified by the National Energy Board and the Federal Energy Regulatory Commission tariffs (18 CFR 341). A comparison of the crude oil that would be transported by the proposed pipeline with other conventional crude oils indicates that the characteristics of the proposed Project's crude oil would be generally comparable to those of conventional crude oils (Been and Wolodko 2011, Penspen Integrity 2013). Naphthenic acid, organic sulfur, and chloride salt concentrations in dilbit crude oils are comparable to conventional Alberta heavy crudes (Zhou and Been 2012). These compounds are stable and not considered to be corrosive at pipeline operating temperatures. Additionally, dilbit density and viscosity ranges are comparable to those of heavy crudes. This supports the expectation that shipments of dilbit at Keystone's stated operating temperatures would be typical of crude oil with similar density and viscosity levels (NAS 2013). A comparison of incident data from Alberta pipeline systems with data from U.S. pipeline systems (see Section 4.13.2.4, Pipeline Incident Information Sources) indicates that some Alberta pipelines that have likely shipped dilbit, SCO, or Bakken shale oil (due to their proximity to the oil sands) are not more prone to failure than other pipeline systems carrying conventional crude oils. Further discussion of crude oil characteristics and potential causes and frequencies of pipeline failure is provided below, as well as in Section 4.13, Potential Releases.

Liquid crude oil is traditionally referred to as petroleum and is composed primarily of hydrocarbon compounds. Traditionally, the term *petroleum* has referred only to liquid crude oil; however, current common usage of the term also includes gaseous and solid materials such as natural gas and bitumen. The composition of crude oil varies depending on the source and processing. Most crude oils are more than 95 percent hydrocarbons, with nitrogen, oxygen, varying amounts of sulfur, and traces of other elements.

Light crude oil is a mixture that has a low density and flows freely at ambient temperatures. Heavy crude oil is referred to as *heavy* because its density is higher than that of light crude oil. The American Petroleum Institute (API) has introduced the term *API gravity* to measure how heavy or light a petroleum liquid is compared to water. If an oil's API gravity is greater than 10°, the oil is less dense than water and thus floats on water; if an oil's API gravity is less than 10°, the oil is denser than water and thus sinks in water. In this sense, API gravity is used to compare the relative densities of petroleum liquids. There are different definitions of light and heavy crude oil. Unless otherwise specified, in this section, *light oil* is defined as any liquid petroleum with an API gravity greater than 31.1° (corresponding to a density less than 870 kilograms per cubic meter [kg/m^3]), *heavy oil* is defined as any liquid petroleum with an API gravity less than 22.3° (corresponding to a density greater than 920 kg/m^3), and *medium oil* is defined as any liquid petroleum with an API gravity between 22.3° and 31.1°.

In addition, Canadian heavy crude oil is also usually sour (i.e., has a higher sulfur content), with sulfur contents between 2.52 percent and 4.82 percent (mean of 3.27 percent) by weight based on the data from 25 types of heavy crude oils (Enbridge 2011). Typically, crude oil with a sulfur content greater than 2 percent by weight is considered sour. While the sulfur in dilbit is at the high end of the range for crude oils, it is bound with hydrocarbons and is not a source of corrosive hydrogen sulfide (NAS 2013).

Crude oils may differ in their solubility, toxicity, persistence, and other properties that affect their impact on the environment. The following characteristics are of particular importance with respect to environmental effects from a spill:

- Specific gravity—determines whether the oil would sink or float upon release to a waterbody. In the discussions of crude oil in this section of the Final Supplemental EIS, API gravity is used to describe this characteristic rather than specific gravity. If a crude oil has an API gravity greater than 10°, it is less dense than water and would float on water.[3] If a crude oil has an API gravity less than 10°, it would sink in water.
- Viscosity—a measure of how easily the oil would flow. Typically, viscosity increases (meaning it does not flow as easily) as temperature decreases. This is an important consideration, as air temperatures along the length of the proposed pipeline corridor may range from well below freezing in winter to in excess of 100 degrees Fahrenheit (˚F) (38 degrees Celsius [˚C]) in summer.
- Pour point—the lowest temperature at which the oil changes from a free-flowing liquid to a material that does not flow freely.
- Proportions of volatile and semivolatile fractions—an indicator of 1) the portion of oil that would more readily evaporate, 2) the portion of oil that would more likely physically persist in the environment as it weathers, and 3) the portion of oil that could dissolve or disperse into an aquatic environment and cause potential toxicological effects on animals and plants.
- Proportion of polycyclic aromatic hydrocarbons (such as naphthalene), many of which are considered key toxic components of crude oils.
- Proportions of other elements and compounds, including sulfur and metals.

3.13.3 General Description of Proposed Pipeline Transported Crude Oils

The crude oil that would be transported by Keystone as part of the proposed Project would originate from a variety of different sources and locations. The crude oil types for the proposed Project would range from a light crude oil (such as SCO or shale oil found in the Bakken formation) to a heavy crude oil (such as those found in the Western Canada Sedimentary Basin [WCSB], which is produced from bitumen).

Bitumen is a form of petroleum that occurs naturally in a solid or semi-solid state. Bitumen includes a wide variety of reddish-brown to black materials that are semi-solid and viscous to brittle in character. Canadian oil sand bitumen is composed primarily of high-molecular-weight hydrocarbons, commonly referred to as asphaltines. Canadian oil sands are a mixture of roughly 90 percent clay, sand, and water, and 10 percent bitumen. The dark, sticky sands look similar to topsoil, but can flow when warmed. Colder temperatures reduce the ability of the bitumen to flow and can cause the bitumen to have the appearance of a semi-solid. Raw bitumen is semi-solid to solid, depending on ambient temperatures and, therefore, must be altered into a form that can be transported via pipeline. There are two basic methods used to render bitumen transportable by pipeline: 1) bitumen is processed into SCO, or 2) bitumen is mixed with a suitable diluent, as described below, creating what is known as dilbit. Either of these products

[3] Dilbit sinking is further discussed in Section 4.13.5.2, Safety and Spill Response.

may be transported by the proposed Project. Based on current production projections and the commercial demand at Gulf Coast refineries for WCSB heavy crude from the oil sands, the majority of crude oil that would likely be transported by the proposed Project is expected to be in the form of dilbit (EnSys Energy 2010). Given the concentration of upgrading units in the Gulf Coast region and the economic incentives to run heavy crudes given light-heavy oil price differentials, this region is seen likely to remain a key source of heavy crude demand (Section 1.4, Market Analysis). Additional information regarding chemical characteristics and physical properties of SCO and dilbit are included in Section 3.2 of E^{x}ponent's Environmental Review (E^{x}ponent 2013).

Transportation Research Board (TRB) Special Report 311: *Effects of Diluted Bitumen on Crude Oil Transmission Pipelines* (NAS 2013) discusses in greater detail the sources of bitumen, types of diluents, and the resulting dilbit, as well as SCO properties of Canadian crude oil imported into the U.S. *In situ* recovery[4] accounts for an increasing percentage of Canadian bitumen production compared to mined bitumen. The bitumen recovered during *in situ* recovery is processed into SCO in Canada to be better suited for long-distance transportation by pipeline. The resulting crude oil has lower water and sediment content than mined bitumen. Although the diluents consist of low-molecular-weight hydrocarbons, shipments by pipeline of dilbit do not contain a higher percentage of these light hydrocarbons than do other crude oil pipeline shipments (NAS 2013).

3.13.3.1 Synthetic Crude Oil

SCO is produced from bitumen through a refinery conversion process that turns heavy hydrocarbons into lighter hydrocarbons. The conversion process typically includes the removal of sulfur, resulting in a *light sweet* SCO. The precise composition of SCO varies. Because some composition information may be considered proprietary information by the shipper, generic properties of SCO are listed in Table 3.13-1. The properties of one example of SCO, Suncor Synthetic A Crude Oil, are presented in Table 3.13-2. As shown in Table 3.13-2, the characteristics of WCSB SCO and dilbit are similar to those of conventional crude oils.[5]

3.13.3.2 Dilbit

Dilbit is bitumen mixed with a diluent so it can be transported by pipeline. The composition of the dilbit is only provided here generically because the particular type of bitumen and diluents blend produced is variable and is typically a trade secret. A common condensate stream (liquids derived from natural gas) is currently the primary type of diluent used for Canadian heavy crude. Diluent consists of condensates, ultra-light sweet crudes, and refinery and upgrader naphtha streams from several supply sources. Typically, dilbit uses approximately 25 percent of condensate, where companies use either their own supply sources of light hydrocarbons or purchase the above condensate stream. According to the Saskatchewan Condensate Monthly Report dated September 1, 2012 (Crudemonitor 2012b), the composition of gas condensate is

[4] *In situ* recovery refers to the use of thermal technologies such as steam injection to separate deep underground bitumen from oil sand and thin the bitumen so that it can be pumped to the surface using a well, rather than using mining methods.

[5] The website crudemonitor.ca provides a library of current and historical crude oil stream characteristics and was a key source of the characteristic values used in the assessment of impacts that would result from a potential release.

mainly light hydrocarbons such as iso-butene, n-butane, iso-pentane, n-pentane, and hexanes. Material Safety Data Sheets (MSDSs) (for informational/planning purposes only) for two types of diluents, naphtha and natural gas condensate, assuming a maximum diluent mix, are provided in Appendix Q. It is important to note that the chemical make-up of the diluents can vary greatly from source to source. The bitumen-diluent mixture with bitumen from the oil sands is generally similar to heavy sour crude, which is discussed in more detail. SCO may also be used as a diluent for bitumen, in which case the commodity is known as synbit (bitumen diluted with SCO). Properties of generic dilbit are shown in Table 3.13-1.

Table 3.13-1 Summary of General Characteristics for Types of Crude Oil Similar to Those That Would Be Transported by the Proposed Project

Characteristic	Synthetic Crude Oil[a]	Diluted Bitumen[b]	Bakken Shale Oil[c]
Density	na	na	827 kg/m^3
API gravity[d]	31°-38°	20°-22°	38°-40°
Viscosity	na	52 to 96 centistokes at 38°C	na
Flammability	na	Class B, Division 2: Flammable Liquids	Class B, Division 2: Flammable Liquids
Composition	Gas oils (petroleum), hydrodesulfurized 60% Naphtha (petroleum), hydrotreated heavy 10-30% Naphtha (petroleum), hydrotreated light, 3-7% Butane 1-5% Hydrogen sulfide (H_2S) 0.001-0.01% BTEX 1-1.5%	Bitumen 40-70% Diluent (mixture of Light naphtha and/or Natural gas condensate) 30-60% BTEX 1-1.5%	Light hydrocarbons <40% Pentanes 3-4% Hexanes 4-6% Heptanes 6-8% Octanes 6-8% Nonanes 4-6% Decanes 1-3% BTEX 1-3%
Flash point[e]	-31˚F (<-35°C)	-31˚F (-<-35°C)	-31˚F (-<-35°C)
Toxicity[f]	na	Class D, Division 2, Subdivision A: Very Toxic Material	na
Solubility in water[f]	Insoluble in cold water[e]	Insoluble[g]	Insoluble
Pour point	-5.8˚F (-21˚C)	-22˚F (-30˚C)	-25˚F(-32˚C)
Sulfur	0.25%	3.6%	0.17-0.20%
Other properties	Oxides of carbon, and nitrogen, aldehydes form upon combustion. Hazardous sulfur dioxide and related oxides of sulfur may be generated upon combustion.		

[a] Husky Energy 2011
[b] Imperial Oil 2002
[c] Crudemonitor 2012a; 5-year average was used for numbers.
[d] Crudemonitor 2012b
[e] Tasprailis 2013 (for fresh oil using ASTM D 92 methodology)
[f] USEPA 2000
[g] Insoluble, but volatile organic compound and semivolatile organic compound constituents are soluble (e.g., benzene, toluene, polycyclic aromatic hydrocarbons).
Notes: na = not available; kg/m^3 = kilogram(s) per cubic meter; BTEX = benzene, toluene, ethylbenzene, and xylenes

3.13.3.3 Bakken Shale Oil

Shale oil is found in sedimentary rock formations that are characterized by very low permeability. In these formations, the flow of oil from the rock to an extraction well is limited by the low-permeability, fine-grained nature of the rock, which is the basis for the common term *tight oil*. Recovery of oil trapped in these low-permeability rocks requires well stimulation techniques (i.e., physical or chemical actions performed on a well to improve the flow of oil or gas from the formation rock to the well bore).

The Bakken shale oil from Montana is light and sweet (containing less than 0.42 percent sulfur). The main properties of Bakken shale oil are shown in Table 3.13-1. An MSDS (for informational/planning purposes only) for Bakken sweet crude, assuming a maximum volatile hydrocarbon composition, is provided in Appendix Q, Crude Oil MSDS.

3.13.3.4 Summary of SCO, Dilbit, and Bakken Shale Oil Characteristics

Table 3.13-1 summarizes the general characteristics of an SCO, dilbit, and Bakken shale oil. These crude types are similar to the types of crude oil that would be transported by the proposed Project. Table 3.13-2 provides additional information on characteristics of potential proposed Project crude oil types.

3.13.3.5 Dilbit vs. Crude Oil

As discussed previously, dilbit is formed when a diluent is added to bitumen, a form of petroleum that exists naturally in a solid state and is comprised primarily of asphaltenes. Asphaltenes are comprised primarily of heavy hydrocarbons, nitrogen, oxygen, sulfur, and traces of heavy metals like nickel and vanadium. The diluent component of Canadian dilbit is typically a combination of condensate stream, ultra-light sweet crudes, and naphtha streams. As an example, Condensate Blend, commonly referred to as CRW, is an aggregate of several light sweet streams blended and used as a diluent (Crudemonitor 2013). A summary of the composition of CRW, based on 5-year averages, is presented in Table 3.13-3 below.

Table 3.13-3 Composition of CRW

Parameter (vol%)	CRW (5-Year Average)
iso-Butane	0.51
n-Butane	2.84
iso-Pentane	14.41
n-Pentane	15.13
Hexanes	16.55
C7-C12	40.95
C13-C30+	9.40

Source: Crudemonitor 2013

Bitumen is mostly composed of heavy hydrocarbons, while diluent is composed of light compounds that will typically volatilize when exposed to air. When diluent is added to bitumen to form dilbit, the combined product is a flowable liquid petroleum with a viscosity similar to that of heavy crude oil. Other forms of crude oil tend to consist mostly of a variety of mid-range compounds (i.e., those compounds that are lighter than water, but too heavy to volatilize into the atmosphere). Dilbit, on the other hand, is composed mostly of compounds from both ends of the spectrum (i.e., diluent, which is light and composed of volatiles, and bitumen, which is heavy and occurs naturally in a semi-solid state) (Song 2012).

When combined to form dilbit, bitumen and diluent generally flow together as a uniform liquid. Exposed to air, the diluent component of dilbit will volatilize over time, gradually separating itself from the bitumen component. However, since the exposed surface area of flowing liquid within the pipeline is negligible, significant changes in the composition of dilbit due to volatilization do not occur during transportation. The ratio of diluent to bitumen in dilbit is such that it will still flow at the lowest pipeline operating temperature (42°F (6°C)). Like other crude oils, the viscosity of dilbit decreases rapidly as operating temperatures increase during transportation. Changes in dilbit viscosity with temperature closely follow those of heavy conventional crude oil (Tsaprailis 2013).

A notable difference between dilbit and other forms of crude is its capacity to precipitate out in water. After a period of several days in water, the diluent in dilbit will eventually volatilize into air or dissolve into water, leaving the heavy bitumen behind to sink or become suspended. This could occur with dilbit more so than with other forms of crude due to the higher percentage of heavy compounds present (Tsaprailis 2013).[6] As an example, heavy components, as shown in Table 3.13-1, comprise approximately 10 to 30 percent of SCO in comparison with dilbit, which consists of approximately 40 to 70 percent heavy bitumen.

Natural attenuation of residual oil is often considered a remedial option for the removal of crude oils. Significant components of conventional crude oils include straight hydrocarbon chains and light compounds, both of which biodegrade relatively easily. Dilbit, on the other hand, is largely comprised of branched hydrocarbon chains and heavy hydrocarbons, which are less readily biodegradable. A biodegradation study conducted by the USEPA in response to the 2010 Enbridge dilbit spill in the Kalamazoo River in Michigan concluded that only 25 percent of the residual hydrocarbons impacting the river could be reasonably removed by natural attenuation (USEPA 2013).

Due to the capacity for dilbit to precipitate out in water and its resistance to biodegradation, in the event of a release to a waterbody, more difficult cleanup scenarios (e.g., dredging) for dilbit may be expected than with other types of crude oil. In the event of a land release, however, the opposite is expected to be true. Vertical and horizontal dispersion of dilbit in sandy soil, loamy soil, and topsoil occurs at a slower rate than other crude oils, including heavy crudes with similar viscosities (Tsaprailis 2013). In addition, following a land release, the lighter components of dilbit will gradually volatilize, thereby increasing the viscosity and further impeding dispersion.

[6] Other factors, including salinity and the presence of floating sediments, may also influence the capacity for crude oils to sink or become suspended in water.

Table 3.13-2 Comparison of Global Crude Oil Characteristics

Parameter	Unit	Bakken Crude (North Dakota)[b, d]	Mixed Sweet Blend (Canada)[a]	Ekofisk (Norway)[c]	Qua Iboe (Nigeria)[b]	Azeri Light (Azerbaijan)[c]	Suncor Synthetic A (Canada)[a, d]	Iranian Heavy[b]	Arabian Heavy (Saudi Arabia)[b]	Lloyd Blend (Canada)[a]	Western Canadian Select[a, d]	Western Canadian Blend[a]	Fosterton (Canada)[a]	Maya (Mexico)[b]	Hondo Monterey (California)[b]	Boscan (Venezuela)[b]
Gravity	API	42.1	39.5	38.42	35.8	34.8	33.1	30.0-31.0	27	20.8	20.6	20.6	20.5	20.2	18.3	10.9
Density	g/ml		0.83	0.832		0.85	0.86	0.89	0.89	0.93	0.93	0.93	0.93	0.93	0.94	1
Sulfur	wt%		0.44	0.22	0.12	0.15	0.19	1.20-1.65		3.52	3.49	3.17	3.24		4.7	4.6
MCR	wt%		1.94				ND			9.57	9.61	8.59	9.66			
Sediment	ppmv									333	360	299	207			
TAN	mg KOH/g			0.13		0.26			0.1	0.81	0.93	0.73	0.2			
Benzene	vol%	0.28	0.29	0.12		0.1	0.05	0.083	0.36	0.2	0.16	0.1	0.02	0.075	0.093	0.012
Toluene	vol%	0.92	0.85	0.64		0.33	0.24	0.25	1.89	0.35	0.29	0.18	0.11	0.278	0.21	0.018
Ethyl Benzene	vol%	0.33	0.25				0.14	0.13	1.11	0.06	0.06	0.06	0.17	0.11	0.075	0.012
Xylenes	vol%	1.4	1.1				0.51	0.51	3.46	0.32	0.29	0.25	0.3	0.374	0.2323	0.03
Salt	ptb									56.8	49.1	74.3	13			
Nickel	mg/L		4.3	2.3	3.3	3	ND	22.6		58.5	57.4	45.5	47.8	45.5		117
Vanadium	mg/L		8.3	2.1	0.3	0.7	ND	81		130.7	137.7	98.6	109	257		1320
Butanes	vol%	7.5	3.66				1.7			1.83	2.08	0.63	1.02			
Pentanes	vol%	6.4	3.47				2.96			4.48	4.21	3.69	0.89			
Hexanes	vol%	2.4	5.84				4.01			4.15	3.78	3.08	1.8			
Heptanes	vol%	10	7.19				3.51			2.97	2.74	2.51	2.13			
Octanes	vol%	8.9	7.24				4.47			2.12	2.13	2.16	3.05			
Nonanes	vol%	3.7	5.58				3.8			1.48	1.52	1.85	3			
Decanes	vol%		2.49				2.02			0.7	0.71	0.85	1.42			

Source: exp Energy Services Inc. 2012

Note: Green columns illustrate representative characteristics of crude oil types similar to those that would be transported by the proposed Project.
[a] 5-year averages from CrudeMonitor.ca
[b] Data from Environment Canada's Crude Oil Properties Database
[c] Data from Statoil Crude Oil Assay
[d] Western Canadian Select[7], Suncor Synthetic A and Bakken crude oils are representative types that would be transported by the proposed Project.
Notes: ND indicates measurement below instrument threshold; MCR = micro carbon residue; TAN = total acid number; g/ml = grams per milliliter; wt% = weight percent; ppmw = parts per million weight; mg KOH/g = milligrams of potassium hydroxide per gram; vol% = percent volume; ptb = pounds per thousand barrels; mg/L = milligrams per liter

[7] Diluted bitumen (dilbit)

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Crude oil from the Bakken region is a light crude oil which contains up to 40 percent volatile fraction and, compared to dilbit, has a more evenly distributed range of hydrocarbon densities including intermediate hydrocarbons. Initially, a release to the ground surface of Bakken crude would generally be expected to flow overland in similar fashion to dilbit. As the lighter hydrocarbons volatilize, the viscosity of both crudes would increase, thereby slowing the overland movement of the release. However, since more intermediate hydrocarbons are present in Bakken crude, the viscosity of Bakken crude could theoretically not increase as much as that of dilbit. Therefore, assuming spill conditions were equal, the extent of overland flow of Bakken could be slightly more than that of dilbit; however, the increased extent would likely not be discernible. In a water environment, a release of Bakken crude could initially be expected to float on or near the water’s surface. As the lighter hydrocarbons volatilize, the density would increase, like dilbit, and the heavier hydrocarbons could subsequently sink and be suspended in the water column or drop to the sediment base. Since heavy hydrocarbons comprise 40 to 70 percent of dilbit, compared to only 15 to 40 percent of Bakken crude, a larger volume of sunken material would be expected to result from a release of dilbit than Bakken. However, since there is more combined volatile and intermediate hydrocarbons fraction present in Bakken crude, a release of Bakken crude could result in dissolution of more constituents to water than that of dilbit. Additional discussions pertaining to the effects and propagation of crude oil releases to the environment are presented in Section 4.13.3.

3.13.3.6 Flammability and Explosion Potential

By federal definition, crude oil is considered to be flammable when it has a flash point lower than 100°F (37.8°C) (16 CFR 1500.3, 2011). Most fresh oils are initially considered flammable by this flash point definition. The flash point is determined by the lowest boiling point components (volatiles). The flash point of fresh dilbit is initially lower than that found in other oil types and comparable to that of a diluent. However, medium, heavy, and dilbit crude oils move into the non-flammable classification after a short weathering period due to the loss of much of the volatile components. Consequently, the flash point of dilbit, which is governed by the 20 to 30 percent volume diluent component, will increase as the diluent is evaporated due to weathering (Tsaprailis 2013). Studies indicate that flash point temperatures increase significantly after weathering due to the evaporation of volatiles within both conventional crude oils and dilbit, and dilbit was found to behave similarly to conventional heavy crude oil after weathering, with similar flash points and weight losses. Under study, all weathered flash point values were above 100°F (37.8°C), with weathered dilbit having a flash point of 190°F (88°C). This suggests that the flammability and explosion potential of a dilbit release would be reduced as the dilbit undergoes weathering (Tsaprailis 2013).

Crude oils are flammable petroleum products; however, for an ignition to occur, the following conditions must be met:

- Vapors produced from the oil must be above the lower flammability limit of the vapor;
- Sufficient oxygen must be available; and
- An ignition source must be present.

If crude oil were released outside the pipeline and an ignition source were present, it could potentially ignite under certain conditions. During a release event, crude oils, including dilbit, are initially flammable; however, as the crude oil undergoes weathering, the degree of flammability is reduced. The extent of the reduction is dependent on several factors, including the type of oil. Fires and explosions are discussed further in Section 4.13.3.4, Types of Spill Impact.

Within a closed pipeline, there is insufficient oxygen and an ignition source is not present; therefore, an explosion within a closed pipeline is unlikely.

3.13.3.7 Acidity and Corrosivity Potential

Naphthenic acids are natural compounds in many petroleum sources, including bitumen from oil sands. (Naphthenic acids are not present in SCO.) Under extreme temperatures found at refineries, naphthenic acids can create what is referred to as naphthenic acid corrosion. Research indicates that naphthenic acids are not corrosive at pipeline temperatures and may protect pipelines from corrosion (Messer et al. 2004, Been and Wolodko 2011, Penspen Integrity 2013). The petroleum industry uses a measurement known as the total acid number (TAN) to qualitatively measure the potential for an oil to produce corrosion problems. The measurement of TAN is an indicator, although not a direct measurement, of naphthenic acid content in crude oil. TAN values for heavy WCSB and dilbit are similar to TAN values measured in other heavy crude oil from around the world (Aske et al. 2001, Table 4). This is consistent with information in presentations organized by NAS in July 2012 (NAS 2012), which reported that the TAN of dilbit is comparable with that of conventional crude. With a TAN greater than 1.0, dilbit is considered to be an acidic crude; heavy crude is moderately acidic (Asia Pacific Energy Consulting 2007). Although dilbit has a higher acid content than many other crude oils, the stable organic acids that raise the acidity levels are not corrosive at pipeline temperatures (NAS 2013).

Corrosion due to naphthenic acid is observed primarily at the very high temperatures found in refinery systems (typically, 644 to 788˚F [340 to 420˚C]). Pipelines may be exposed to naphthenic acid, but metal loss like that found in refinery crude systems is not typically observed because of the much lower operating temperature of pipeline systems.

Some oil sand bitumen crudes have been characterized as corrosive by the classical naphthenic models used in chemistry. However, after decades of cumulative operation, only a very few naphthenic acid corrosion cases have been observed in crude units in U.S. refineries and none have been observed in pipelines. Messer et al. (2004) propose a new theory for the corrosivity of naphthenic acids in oil sand bitumen crudes, in which two types of naphthenic acids are introduced: corrosive acids with low molecular weights, and non-corrosive and inhibitive acids with high molecular weights. According to Messer et al., the hot extraction wash of the raw oil sand mixture in dilbit appears to preferentially remove the higher water-soluble fraction of corrosive acids, leaving the less corrosive and less water-soluble fraction. The naphthenic acid type surviving the dilbit thermal hydro-processing tends to be of the inhibitive, non-corrosive type (Messer et al. 2004).

Dettman 2012 and Friesen et al. 2012 discuss two physicochemical characteristics of dilbit related to its corrosive behavior in pipelines: TAN and sulfur content. As discussed above, a diluent is added to bitumen to create dilbit and, therefore, the original organic acid found in bitumen would also be diluted. Bitumen naphthenic (organic) acid content prior to dilution is on the order of 0.3 percent by weight (TAN = 3 milligrams potassium hydroxide per gram [mg KOH/g]) (Dettman 2012). After dilution, the TAN could be reduced to 1.6 mg KOH/g or less.

The recent 5-year average evaluation of Western Canadian Select (dilbit) shows TAN at less than 1.0 mg KOH/g (Table 3.13-2).

A CanmetENERGY study conducted with crude oil data gathered in 1995 indicated a weak correlation between TAN numbers below 1.0 mg KOH/g and corrosion rates at ambient temperatures (Dettman 2012, Friesen et al. 2012). Various TAN numbers produced unnoticeable changes in metal corrosion rates (Friesen et al. 2012). Dilbit corrosivity rates could remain low even for higher TAN values unless temperature is increased close to the naphthenic acid boiling point (530°F [280°C]) (Dettman 2012). The operating temperature of the proposed Project is expected to be approximately between 42 and 135°F (6 and 57°C).

More important to pipeline corrosion is the hydrogen sulfide (H_2S) concentration (Zhou et al. 2013). Sulfur compounds, like H_2S, tend to form iron sulfides and, therefore, could threaten the steel walls of the pipeline. Although much of these are removed during the bitumen extraction/treatment process, some remain in the dilbit. Elemental sulfur is chemically bound to crude oil hydrocarbons, which account for the majority of sulfur content in a crude oil (Dettman 2012). The iron sulfides produced by dilbit are insoluble in oil and, as a result, the H_2S concentration in dilbit is generally lower than in conventional crude oils (Zhou et al. 2013). Under controlled hydraulic conditions in the pipeline (low shear flow), a protective film of iron sulfide could form on the pipeline walls to reduce the internal corrosion effect (Dettman 2012). The remaining sulfur compounds in dilbit would not be in free form, which means they would be strongly attached to hydrocarbons and not a source of corrosive hydrogen sulfide at pipeline temperatures (NAS 2013).

3.13.3.8 Pipeline and Component Integrity Threats

For the discussion on pipeline component integrity threats, the terms *release*, *leak*, and *spill* are used as follows:

- A release is a loss of integrity (failure to contain oil as designed) from a pipeline;
- A leak is a release over time; and
- A spill is the liquid volume of a leak that escapes a containment system (if present) and enters the environment.

There are a number of threats to pipeline component integrity that could cause a release. The term *threat* is used to describe a mechanism that could lead to a pipeline failure. The term *cause* means an action or lack of action that directly leads to or results in a pipeline spill. In this sense, threats have the potential to create the conditions for loss of integrity, and causes have created a release.

ASME B31.8S *Managing System Integrity of Gas Pipelines* (ASME 2010) and API 1160 *Managing System Integrity for Hazardous Liquid Pipelines* (API 2001) were used to identify potential pipeline and component integrity threats. The following threats could apply to the proposed Project during construction and operations, and are described in more detail below:

- External corrosion (e.g., the metal of the pipeline reacts with the environment, causing the pipeline to rust on the outside of the pipe, similar to rust on a car);
- Internal corrosion (e.g., the metal reacts with the contents inside the pipeline);

- Stress corrosion cracking (SCC) (e.g., pressure and temperature changes causes the pipeline to expand and contract, which compromises the pipeline coating and renders the pipeline susceptible to corrosion, subsequently resulting in the development and progression of cracks in the pipeline);
- Manufacturing (e.g., defects in the original characteristics of the pipe (e.g., low-strength material or substandard threading), which result in compromised integrity of the pipe);
- Construction (e.g., a defect in the welding of the pipe);
- Equipment (e.g., unusual wear and tear of pipeline components, such as valves);
- Third-party damage (e.g., a backhoe digging nearby strikes the pipe);
- Incorrect operations (e.g., human error made by pipeline operators); and
- Weather-related and other natural forces (e.g., flooding contributes to stream bank erosion that exposes the pipe or a landslide ruptures the pipe).

These threats are categorized into three time-related groups, according to ASME B31.8S (ASME 2010):

- Time-dependent—primary threats that could be addressed by ongoing and periodic assessments; these include external corrosion, internal corrosion, and SCC.
- Stable—threats that exist but do not materialize unless activated by a change in operations or the surrounding environment; these include manufacturing defects, construction defects, and equipment defects.
- Time-independent—threats that do not fall under the preceding categories; these include third-party damage, incorrect operations, and weather-related and other natural forces.

Alberta, Canada pipeline performance data from 1990 to 2005 show that overall incident frequency for crude oil pipelines is similar to the incident frequency based on U.S. performance data. Alberta pipelines are relevant because the proposed Project could transport crude oil of similar physical and chemical characteristics to that transported by Alberta pipelines. Figure 28 of the report provides estimates of incident frequencies from crude oil pipelines in Alberta (Alberta Energy and Utilities Board 2007). The 1990 to 2005 average is 1.9 incidents per 1,000 kilometer-years, which is approximately 3.0 incidents per 1,000 mile-years. This is very similar to the PHMSA crude oil incident rate of 3.1 incidents per 1,000 mile-years for pipelines and reported elements from 2002 to July 2012, as shown in Appendix K, Historical Pipeline Incident Analysis, Table 4. In addition, corrosion is the main cause of spills in Alberta crude oil pipelines, accounting for 37.7 percent of the incidents. This compares to the U.S. data for pipeline systems (34.4 percent in the PHMSA dataset from Figure 2 of Appendix K, Historical Pipeline Incident Analysis).[8]

[8] See also Energy and Utilities Board—Pipeline Performance in Alberta, 1990-2005 in Section 4.13.2.5, PHMSA Historical Data, of this Final Supplemental EIS.

3.13.3.9 Time-Dependent Threats

Time-dependent threats include corrosion and SCC. Corrosion is defined as the deterioration of a material, usually a metal, by chemical reaction with its environment. The rate at which a metal will corrode is primarily governed by the environment. Corrosion is a process where the metal of the pipe oxidizes because an electric current flows through and induces the pipeline metal to combine with oxygen, creating a non-metallic byproduct (known as rust). In order for corrosion to develop, an oxidizing agent (most commonly water) needs to be present to oxidize the steel used for pipelines. For a pipeline, water can be present inside the pipe, originating from the fluid being transported, or it can be present outside, such as from soil moisture (API 2001). The characteristics of the water present (e.g., acidity due to the corresponding presence of other chemicals/contaminants in the transported material) can also significantly affect the nature of the resulting corrosion. The following methods are typically used to control or mitigate corrosion on pipelines:

- Proper material selection;
- Controlling water and sediment content/accumulation in the pipeline;
- Exterior protective paints and coatings;
- Corrosion treatment chemicals;
- High-resolution in-line inspection tools;
- Dielectric insulation; and
- Cathodic protection.

Three corrosion threats commonly associated with pipelines (external corrosion, internal corrosion, and SCC) are discussed below.

External Corrosion

External corrosion occurs when pipeline walls or seam welds weaken from contact with moist soil or water. External corrosion can be accelerated by microbial activity (ASME 2010). A pinhole is a term used to describe a very small hole (i.e., roughly the size of a pinhead) that could form in a pipe. This hole size is common in corrosion cases, and is typically associated with low leak-rate, long-duration spills. The following factors could cause external corrosion or affect the rate at which external corrosion occurs:

- Exposure time—external corrosion thins the pipeline wall and weakens the pipe material strength. If the pipeline wall were exposed to the corrosive conditions over a sufficient time, weakening of pipe strength and a loss of pipeline integrity could result in a breach of the pipeline wall or failure of a pipeline weld under normal operating conditions. This could then result in a leak or spill.
- Coating—industry standards require that all new steel pipelines, such as the pipeline that would be used for the proposed Project, be coated with fusion-bonded epoxy (FBE) to create a physical barrier between the pipe and the surrounding soil, significantly reducing or eliminating the mechanism for developing rust. Over time, this coating could incur damage, exposing the pipe to moisture, which could result in corrosion. The corrosion generally

occurs evenly over a large portion of the pipeline surface. This type of external corrosion is referred to as general or uniform corrosion (NACE International 2012c).

- Cathodic protection—this counters the effect of corrosion by supplying electrical current to a pipe in order to prevent corrosion at defects or holes that form in the coating where the external environment could come into contact with the steel surface. The proposed pipeline would employ cathodic protection.
- Pitting—pitting is a type of external corrosion where there is a surface defect in the metal of the pipeline, a scratch in the coating, or an area where the coating has broken down. These small areas can then be exposed to moisture in the area surrounding the pipeline, causing the pipe to corrode (NACE International 2012a). The water or moisture connects the metal in the pipeline to the surrounding soil. From there, electric currents can flow naturally between the soil and the pipeline, inducing the pipeline metal to combine with oxygen, resulting in rust. The effects can be increased with pitting, as the current discharges tend to be localized at defects, scratches, or holes in the pipeline coating (Beavers and Thompson 2006). As a result of pitting, pinholes can form.
- Stray currents—man-made underground facilities (e.g., electric lines and piping) can also influence external corrosion rates as they distribute stray electric current fields. In the absence of mitigation measures, once corrosion is initiated, the presence of stray electric currents can result in a high rate of external corrosion and can result in rapid perforation of the pipeline wall (Beavers and Thompson 2006).
- Seasonal variability—local soil conditions (and corrosiveness) can vary from season to season.
- Long-line corrosion cells—pipelines passing through different types of soil may experience differential rates of corrosion due to differences in electrical conductivity in different soil types (American National Standards Institute/NACE International 2008). For example, a pipeline passing from clay soils to sandy loam soils may experience natural pipeline currents leading to loss of metal by anodic dissolution, which would result in the removal of metal from the surface of the pipe to the corresponding electrolyte (in this case, the soil).
- Microbial activity—bacteria are commonly found in soil and water and can contribute to pipeline corrosion. The two basic categories of bacteria are aerobic (oxygen-using) and anaerobic (non-oxygen-using). Both types can be present in the same environment depending on temperature, moisture, nutrient supply, and other factors. Aerobic bacteria are more abundant where oxygen is plentiful, and anaerobic bacteria are more abundant in oxygen-deficient environments. Both types of bacteria can contribute to conditions that could cause external and internal corrosion of pipelines (API 2001). Anaerobic bacteria are found in stagnant bodies of water, heavy clay soils, swamps, bogs, and in most areas that have moisture, organic materials, low oxygen, and some form of sulfates. Some anaerobic bacteria do not directly attack the steel but can create changes in soil chemistry that could increase corrosion activity. Anaerobic bacteria are also found in salt water-bearing formations. Aerobic bacteria can also contribute to corrosion of buried steel structures. If sufficient organic matter or other biodegradable material resides on pipe coating scratches, crevices of pipe repairs, or other pipe surface deformities, bacteria may use these materials and produce

carboxylic acids that could lead to corrosion. These bacterial processes may result in a pipe corrosion mechanism.

Internal Corrosion

Internal corrosion occurs when pipe walls or seam welds deteriorate due to contact with water, bacteria, or chemical contaminants contained in the material transported in the pipeline. Common contaminants, which include oxygen, H_2S, carbon dioxide, or chlorides, can form types of acids. The nature and extent of the corrosion that may occur are a function of the concentration and combination of these various corrosive constituents within the pipe, as well as the operating conditions of the pipeline. Internal corrosion can cause thinning of the pipe wall and weakening of the pipeline's mechanical strength. A sufficient loss of mechanical strength can result in a breach of the pipeline wall or failure of a pipeline weld from loss of structural integrity.

The mechanisms for internal corrosion are similar to those of external corrosion, except that the source of internal corrosion is the product flowing through the pipeline rather than the pipeline's surrounding environment. Internal corrosion can occur at locations where sediment and water (basic sediment) can separate. Underneath deposited sediment, a corrosive water film can form on the pipe wall. It is this localized water that can foster corrosion. Typical dilbit diluents exhibit hydroscopic properties (i.e., they absorb water). The proposed pipeline design indicates that the flow of dilbit would be at pressures greater than 1,100 pounds per square inch when leaving a pump station and drop to 50 pounds per square inch at the inlet of the next pump station approximately 50 miles downstream. According to Been (2012), the nominal velocity of flow in the pipeline would be approximately 5.6 miles per hour. The continuous pumping and pressure gradient would create the conditions necessary for water to be carried with the flowing crude oil (entrainment), which would tend to reduce or eliminate the corrosion threat.

Constituents that potentially contribute to corrosion inside a pipeline include sediment and water that can enter the pipeline with the oil being transported (Ironside 2012). Internal corrosion can occur if these constituents settle on the pipe bottom and establish a corrosion point. Higher density/viscosity crudes have a greater propensity to carry sediment. However, dilbit and SCO, typically carry approximately 25 percent less sediment than conventional heavy oils (Ironside 2012). To manage sediment and water, and consistent with Special Condition 34, Internal Corrosion, Keystone would limit basic sediment and water (BS&W) to 0.5 percent by volume and report BS&W testing results to PHMSA in the annual report. Keystone would also report upset conditions causing BS&W levels above the limit.

Erosion-corrosion is a corrosion action arising from the combined action of electrochemical reaction and mechanical abrasion. Metal alloy pipes are susceptible to wear as a consequence of fluid motion. Increasing fluid motion increases the rate of erosion-corrosion, in particular with solutions when bubbles and particles are present (Callister 1999). Turbulent flow inside the pipeline also increases the corrosion rate. Mitigation to reduce erosion-corrosion effects includes system design to eliminate drastic pipe diameter reductions, elbows, and other areas of flow impingement. Minimization of particles and bubbles in pipeline contents also reduces the effects of this type of corrosion. The potential for this type of corrosion is not unique to dilbit and is also observed in pipelines transporting conventional crude, as documented in the PHMSA database.

Several sources suggest that this corrosion potential for dilbit is similar to the potential for other crude oils transported in U.S. pipelines (Penspen Integrity 2013, Been and Dupuis 2012, Zhou et. al. 2013, Been and Wolodko 2011). According to the NAS TRB Special Report 311 (NAS 2013), dilbit does not have unique or extreme properties that make it more likely than other crude oils to cause internal degradation to transmission pipelines from corrosion or erosion. Dilbit has density and viscosity ranges that are comparable with those of other crude oils. It is moved through pipelines in a manner similar to other crude oils with respect to flow rate, pressure, and operating temperature (NAS 2013).

Some of the available data regarding corrosion for dilbit-carrying and conventional-crude-carrying pipelines are listed below:

- Although the TAN in dilbit is generally higher than conventional crude oil, based on averages of approximately 5 years, the acids are too stable to be corrosive under transmission pipeline temperatures (Been and Wolodko 2011, NAS 2013).
- Dilbit sulfur content is comparable to the sulfur content in other crude oils, and the production of H_2S, which could increase the occurrence of corrosion, is not expected at the pipeline operating temperatures (NAS 2013).
- No evidence of increased sediment erosion in dilbit pipelines, compared to other crude oil pipelines, has been observed in Alberta. Sediment content is managed to be below the limit set by regulatory agencies and industry (Been and Wolodko 2011).
- Dilbit viscosity is comparable to those of conventional heavy crude oils, and there is no evidence of increased corrosion or other potential pipeline threat due to viscosity (Been and Wolodko 2011, NAS 2013).
- Higher pipeline operating temperatures in dilbit pipelines do not correlate to increased corrosion rates (NAS 2013).
- Temperatures above 140°F (60°C) have indicated a higher rate and extent of coating failure, but it has also been shown that, in the presence of cathodic protection, the pipe would remain protected, and blistering and coating failure does not present an integrity threat to a pipeline (Been et al 2005). No stress corrosion cracking failures have been reported for FBE coatings in over 40 years of experience (Been and Wolodko 2011).[9]
- Transmission pipeline failure rates in Alberta are comparable to those in the United States (Been 2011).

Stress Corrosion Cracking

SCC is the cracking of a material produced by the combined action of corrosion and applied stress (Beavers and Thompson 2006, NACE International 2012b). SCC results when microscopic cracks form and coalesce under stress, forming a macroscopic crack (API 2001). The crack eventually expands to produce a failure that results in a breach of the pipeline integrity and subsequent release of pipeline contents. A characteristic of SCC is the development of groups of

[9] The Keystone XL pipeline would be coated with FBE, which is considered permeable to the cathodic protection current.

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longitudinal surface cracks in the pipe that link up to form long, shallow flaws (Beavers and Thompson 2006).

Pipelines expand and contract slightly in response to temperature changes and normal operational cycling of the pipeline internal pressure. This expansion and contraction can cause stress cracks to develop in the pipeline if the temperature variation or pressure cycling is outside the design range. External forces acting on the system may also apply stress, which could create metal fatigue. Examples are vibration sources (e.g., from an active railway crossing) and frost heaving (depending on the soil and seasonal characteristics of the area).

SCC may progress in four stages. In Stage 1, the conditions for the initiation of SCC develop at the pipe surface. The pipe coating detaches, corrosion or rust develops, and the pipe surface may become pitted or uneven. Cracks begin to form in Stage 2, and continued initiation, growth, and crack coalescence occur in Stage 3. In Stage 4, large cracks coalesce and pipeline failure occurs, resulting in a leak.

The effect of SCC is a weakening of the pipeline's mechanical strength. A sufficient loss of mechanical strength through growth and interlinking of the stress-corrosion cracks can result in a breach of the pipeline wall from loss of structural integrity under normal pipeline operating conditions. SCC is controlled by pipeline stress management during pipeline installation and operation in conjunction with external and internal corrosion controls. If stress-corrosion cracks develop, pipeline inspections could reduce the likelihood of a pipeline release by identifying areas that need repair or replacement, or by causing a modification in the pipeline operating conditions.

According to the NAS TRB Special Report 311 (NAS 2013), dilbit and other heavy crude oils have similar densities and viscosities and flow through pipelines at the same rate and within comparable temperatures and pressures ranges. For these reasons, the likelihood of external damage from the operating parameters of a dilbit pipeline does not have a higher propensity for cracking transmission pipelines with comparable density and viscosity (NAS 2013).

3.13.3.10 Stable Threats

Stable threats are those that exist constantly over time and do not manifest unless activated by a change in operations or the surrounding environment.

Manufacturing

Manufacturing threats are defects in the mainline pipe or pipe seams created during manufacturing of the pipeline components. Pipe mill-related anomalies fall into this category (ASME 2010). Examples are lower steel grade, inclusions or imperfections in the steel, deformed joints, and substandard threading. The most common long-term scenarios for material-related pipeline leaks are those in which inadequate materials lead to corrosion. Manufacturing defects also may result in a weakening of the mechanical strength of the pipe body or weakening of the pipe welds over time. A sufficient loss of mechanical strength can result in a breach of the pipeline wall or failure of a pipeline weld under normal pipeline operating conditions. Manufacturing defects are controlled by pre-commissioning inspections and surveys after the pipeline is put into operation.

PHMSA (2009) has identified a manufacturing integrity issue with respect to high-grade mainline pipe. Tests that have been conducted on installed mainline pipe have shown that some of the pipe material has yield strengths, tensile strengths, and/or chemical compositions that do not meet the requirements of the API, Specification for Line Pipe—5L (API 5L), for PSL 2, and the specified pipe grade. Yield strengths below the specified minimum yield strength have been reported and yield strengths up to 15 percent lower than the strength values on the pipe manufacture-produced mill test report have also been reported. In some cases, the affected pipe may successfully pass strength-testing methods contained in current specifications, but may lead to a future pipeline integrity issue. The presence of low-yield-strength mainline pipe installed in a pipeline system may result in increased susceptibility to excessive pipe expansion or rupture during the pre-in-service field hydrostatic strength test.

Special conditions related to pipe design and construction (Appendix B, Potential Releases and Pipeline Safety) have been specified to address the above, in addition, the revised Permit Application specifies that the mainline pipe for the proposed Project would be constructed of API 5L PSL 2 X-70M high-strength steel (a grade of steel that has a yield and tensile strength that exceeds the needs of the planned operating condition of the pipeline). This specification accounts for the 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 allowed for pipeline operation.

Construction

Construction threats are incidents that occur in the field during construction and up to the time of commissioning that may affect a pipeline's structural integrity. Construction threats can include: 1) a defective weld around the circumference of the pipe (girth weld); 2) a defective fabrication weld; 3) a pipe wrinkle, bend, or buckle; and 4) stripped threads, broken pipe, and coupling failure (ASME 2010). Dents occurring during construction that may affect welds or pipe body integrity are also included in this category.

Residual stress present in the pipe body due to pipe bending, buckling, or incorrect pipe-laying is a threat that may lead to a release event provided it is sufficient to locally weaken the pipeline integrity. Mechanical removal of metal during construction is considered a threat (e.g., gouges, cavities, or grooves) since corrosion tends to develop quickly in pipe areas with defects. The pipe-welding process and the pipe-laying process in general are factors that can affect pipe integrity.

The PHMSA Special Conditions related to pre-commissioning quality inspection and detection of construction defects are intended to help ensure high-quality construction standards to minimize the potential for defects. Testing and inspection that take place during pre-commissioning reduce, but do not eliminate, the chance of a leak due to construction threats.

Equipment

An equipment threat is the potential for equipment, including the pipe body itself, to not accomplish its intended design, operational, or functional purpose. A malfunction may include repairable and irreparable failures of pipeline (both linear and discrete) elements. A linear element is related to pipe body or weld seams that connect the pipe. A discrete element is equipment such as pumps, tanks, and non-pipe controls and valves. The equipment also comprises non-metal parts such as seals and rings, plus all the Supervisory Control and Data Acquisition (SCADA) components that assist in monitoring and controlling the pipeline system. The root causes of equipment malfunction could relate to failures in design, operation, or manufacturing if they are not clearly traceable to the construction phase. The following are some examples of potential equipment malfunctions:

- A pressure sensor may stop working and allow for abnormal pressures to develop without triggering alarms;
- Since the pipeline system is expected to be remotely operated, a SCADA malfunction, such as a level sensor that is not properly reading the content level, may also have the potential to result in a loss of containment by overfilling a tank to which the pipeline is connected; and
- Field power blackouts, software glitches, false alarms, and other factors may trigger an automated or human response that might lead to the accidental release of pipeline inventory.

A number of equipment malfunction scenarios could result in a pipeline leak. Wear and tear of valve seals or rings could result in immediate leaks, while the failure of SCADA controls at a critical time may result in an escalation scenario of varying consequences. For all these reasons, leaks from linear and discrete equipment may range from small (less than 50 bbl) to large volumes (greater than 1,000 bbl).

3.13.3.11 Time-Independent Threats

Time-independent threats include third-party damage, incorrect operations, and weather-related and other natural forces. These are discussed below.

Third-Party Damage

A third-party damage threat consists of potential actions of the pipeline operator and/or other parties that could create conditions affecting the pipeline system integrity. Three primary sub-threats comprise potential third-party damage threats: 1) unintentional damage inflicted by the pipeline operator, contractors, or third parties (instantaneous or immediate failure post-construction); 2) intentional damage or vandalism (post-construction); and 3) previously damaged pipe (such as dents or gouges created during manufacturing or construction) (ASME 2010). These threats may directly damage the pipeline system to the point of producing a leak. Excavation is a common action in which the pipeline is subject to an external mechanical force that could result in a pipe failure. Other less common actions include impact by a motor vehicle on aboveground facilities, detonation of an explosive substance, or earth movement related to nearby excavations or heavy traffic over a buried pipeline.

According to the NAS TRB Special Report 311 (NAS 2013), none of the properties or operating parameters of dilbit transportation in transmission pipelines is different from those of other crude oils. Pipelines would be no more vulnerable to impact damage due to the characteristics of dilbit. Additionally, dents, gouges, and scratches to exposed pipe; loss of pipeline support; change in pipeline alignment; and loss of cover due to third-party activities are related third-party threats (API 2001).

Engineering of the proposed Project would help address intentional damage, such as sabotage and terrorism, by considering Transportation Security Administration (TSA) Pipeline Security Guidelines. In April 2011, the TSA Pipeline Security Branch updated the TSA Pipeline Security Guidelines, which provide recommendations for pipeline industry security practices. These updated guidelines also incorporate changes to the Department of Homeland Security threat advisory system. The TSA has also developed a National Terrorism Advisory System Threat

Level Protective Measures Supplement to the TSA Pipeline Security Guidelines. These guidelines contain a series of progressive security measures to reduce vulnerabilities to pipeline systems and facilities during periods of heightened threat conditions. Keystone's confidential Corporate Security Policy and Information Security Policy provide direction and oversight for its Security Management Program. Keystone has stated these policies reference a number of operating procedures, plans, processes, and internal procedures, which together make up the Security Management Program. Accountability for the Security Management Program is held at the Executive Vice President level, with the responsibility for implementation held by the Director, Corporate Compliance and Corporate Security, and the Director, Information Services Governance and Security. Keystone asserts that the TSA Pipeline Security Guidelines are a very significant part of their existing Security Management Program and are specifically covered in their Physical Security Operating Procedure and Critical Facility Procedures. Their Corporate Security Program was reviewed by members of the TSA Pipeline Security group through their Corporate Security Review process. Keystone also employs the above-noted procedures, processes, and security vulnerability assessments to identify potential risks, implement the appropriate physical or cyber security measures, and address the TSA Pipeline Security Guidelines with respect to physical and cyber security.

Incorrect Operations

Although many pipeline operations are automated, personnel still serve a primary role in those operations. Human errors made by a pipeline operator's involvement can lead to the incorrect operation of the system, which in turn may cause a release. One example of an operating error is personnel operating a line valve that will over-pressurize other discrete equipment, resulting in a failure. In addition, extensive delays or prolonged lack of adequate maintenance can lead to a leak. Incorrect SCADA readings may induce a controller to mistakenly divert inventory and overfill storage tanks. If a field inspection routine is bypassed or simply fails to identify a worn seal, a leak could occur. Transient pipeline hydraulic events (temporary change of pressure, volume, or temperature) are also included in this category if they are due to human error. These events may lead to large pressure forces and fluid acceleration into the system. The disturbances may result in pump and other equipment failures, component fatigue, and even pipe rupture.

Weather-Related and Other Natural Forces

Weather-related and other natural force threats include natural hazards whose magnitudes or characteristics might cause damage to the pipeline system.[10] This threat comprises four primary sub-threats: 1) natural earth movement and/or avalanche; 2) heavy rains, floods, or extreme inclement weather; 3) extreme ambient conditions, including ice-loading on exposed structures and fire; and 4) lightning.

Some natural hazards such as earthquakes, floods, and tornadoes have the capacity to directly damage the pipeline and cause a leak. For example, an earthquake could affect the stability of the buried pipe. Tornadoes could damage or temporarily interrupt communications with the monitoring systems or directly damage aboveground elements such as tanks, pumps, sensors, small pipes, and support equipment. Flooding could damage pumps, short out electrical systems and components, or even create corrosive conditions. Heavy rains, snowfall, and high winds may

[10] Please refer to the Section 4.14, Greenhouse Gases and Climate Change.

produce conditions that would affect the system integrity over time. Long-term exposure of aboveground facilities to these weather events could increase wear and tear or weathering, and potentially cause corrosion. Mud slides or soil washout may affect the foundation of exposed pipeline segments, and the undistributed pipe weight may create stress that would cause linear elements to leak. Lightning and wild fires are unlikely to damage the system integrity directly, but could cause the loss of SCADA, crude oil overheating, or damage to the coating of exposed pipe at aboveground facilities.

3.13.3.12 Potential Spill Sources

For the purpose of this section, the following spill sizes are defined for spills related to construction activities, maintenance activities, and operation of the proposed pipeline:

- Small spill (less than 50 bbl);
- Medium spill (50 to1,000 bbl); and
- Large spill (greater than 1,000 bbl).

Construction

The proposed Project, as with most construction projects, has the potential for a release of hazardous fluids during material handling (e.g., delivery or dispensing of fuels, lubricating oil, hydraulic fluid). The possibility exists that during construction, a full gasoline or diesel tank truck could be involved in an accident (e.g., collision or roll-over) and release all or part of its cargo to the environment. Delivery vehicles carrying drums of lubricating or hydraulic fluids could also release hazardous fluids to the environment due to accidents. The areal extent of these types of spills would likely be limited unless they occurred near to or at an open waterbody.

The potential for small spills from construction machinery and operating equipment (e.g., small, intermittent leaks and drips of lubricating oil, hydraulic or transmission fluids, fuels, or similar products) would be almost certain to occur and are typical of most large construction projects. These types of spills—usually occurring in construction areas, equipment storage yards, construction camps, and pipe yards along the route—generally would be identified and managed by equipment operators and/or contractor personnel on site.

Operation

According to the NAS TRB Special Report 311 (NAS 2013), pipeline operations are the same for shipments of dilbit as for shipments of other crude oils. Operational practices are designed to accommodate the range of crude oils in transportation. The study did not find evidence indicating that pipeline operators change or would be expected to change their operational practices in transporting dilbit. Operational spills from the proposed Project could originate from the pipeline, pump stations, mainline valves, delivery points, or at any location along the pipeline. As noted above, most small spills are related to pinhole-type corrosion leaks along the body of the pipe or by leaks from valves, flanges, pumps, or other equipment. However, crude oil exiting a pinhole may create a medium to large spill due to the difficulties for SCADA or aerial surveillance to detect such a leak. Many of these components would be located in pump stations or delivery points along the proposed pipeline route. A pinhole-sized leak caused by defects in materials or faulty construction/fabrication of the pipeline and resulting in drips could occur along any segment of the pipeline. As the majority of the pipeline would be buried, these small, continuous-type releases may go unnoticed for an extended period until the spill is expressed on the surface. This volume of spill generally would remain within the pipeline right-of-way unless the oil was released adjacent to a channel or surface waterbody that could facilitate spreading.

Based on PHMSA data, medium spills (50 to 1,000 bbl) generally occur in association with physical damage to the pipeline (e.g., crack/tear, excavation damage, weld failure). The effects of corrosion or erosion (external or internal) on the proposed pipeline could cause a structural weakness to a section of pipe or pipe joint, which may lead to a pipeline failure along the route. Unauthorized excavation, construction, or drilling in the vicinity of the proposed pipeline could cause direct damage to the pipeline or other pipeline components at any location along the route; however, these types of activities are generally associated with urban or suburban areas. Soil erosion along the topographic highs and lows or near river or stream crossings along the route are also potential locations where spills may occur.

Large spills (greater than 1,000 bbl) are generally associated with severe damage to or complete failure of a major pipeline component. While many of the causes listed above for medium spills could apply to large spills, it is the degree of damage and the location of the spill that generally differentiates medium spills from large spills. For the proposed Project, roughly every 800 feet of mainline pipe could contain 1,000 bbl of oil.

Maintenance

According to the NAS TRB Special Report 311 (NAS 2013), pipeline maintenance practices are the same for shipments of dilbit as for shipments of other crude oils. Maintenance practices are designed to accommodate the range of crude oils in transportation. The study did not find evidence indicating that pipeline operators change or would be expected to change their maintenance practices in transporting dilbit. Small spills may occur during maintenance activities (e.g., valve replacement, pump service, inspection [pigging], or cleanouts) and generally would be expected to occur in or near pump stations, metering facilities, or other aboveground infrastructure locations. Many of these releases are typically attributed to the spilling of residual product during the removal of a pipeline component or bleeding of pressure or product from lines prior to line-breaking type activities. Most small releases associated with maintenance activities are generally identified and managed in a timely fashion.

The Historical Pipeline Incident Analysis (see Appendix K) shows that the majority of medium and large spills are generally not associated with maintenance activities. There are few sources for large (1,000 to 31,000 bbl) spills at maintenance facilities, and once a leak is identified during maintenance activities, spill response is typically rapid and limits the volume of the spill.

A technician or mechanic performing maintenance on the pipeline is usually trained or supervised by person/persons familiar with the reporting or appropriate response actions needed to prevent medium or large releases from occurring.

3.13.4 Potential Spill Receptors

The magnitude of an oil spill impact would be influenced by the type of receptors that might be exposed to the oil. Below are the descriptions of identified spill receptors broken into two main categories: HCAs and other resources. Definitions for HCAs are from the USDOT Federal Register, Title 49 of the CFR Part 195. Other resources are defined in this Final Supplemental

EIS and described below. Figure 3.13.4-1 illustrates the organization of HCAs by the USDOT and how other resources are organized in this Final Supplemental EIS to evaluate potential spill impacts.

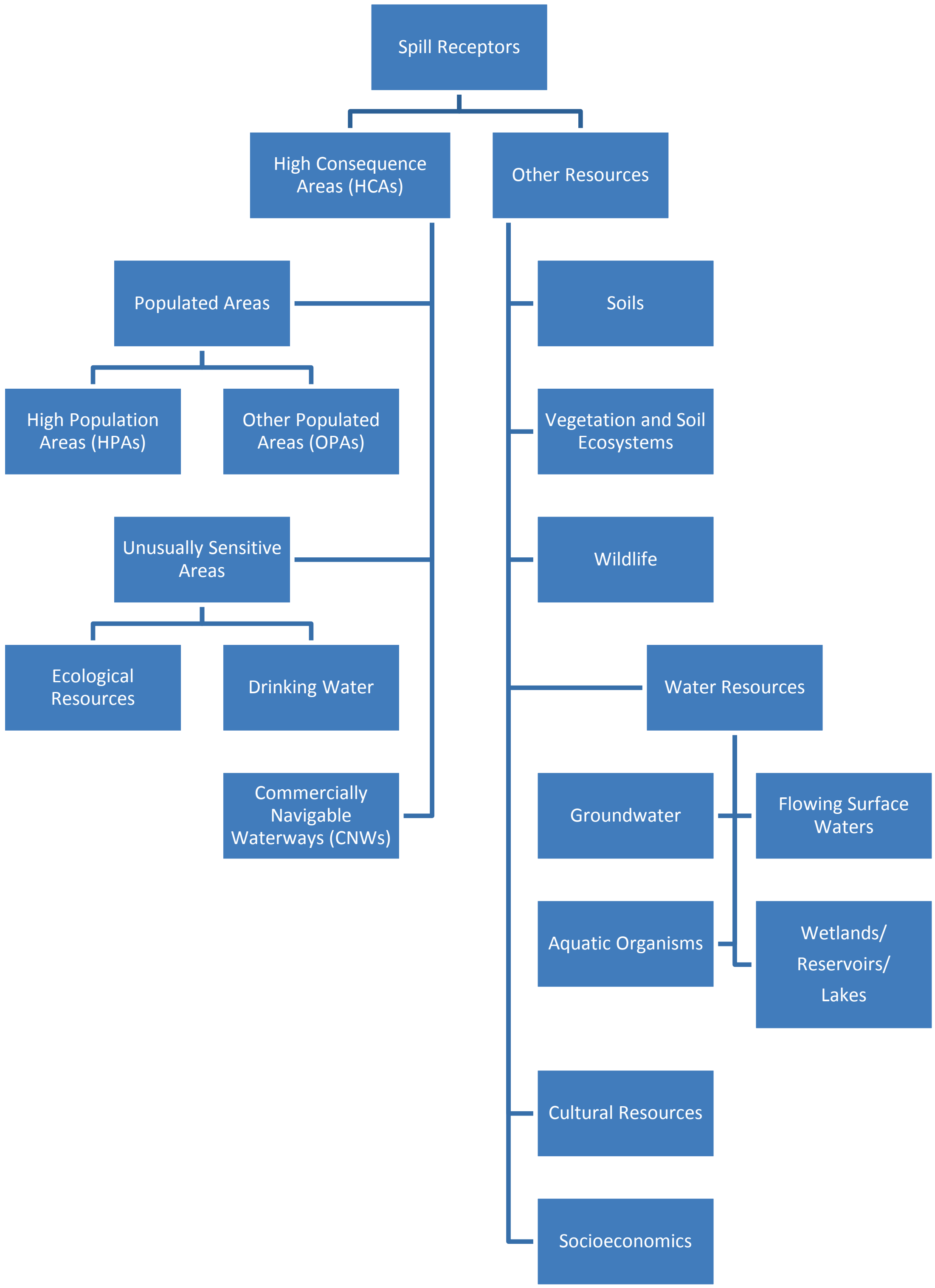

Figure 3.13.4-1 Identified Potential Spill Receptors

3.13.4.1 High Consequence Areas

HCAs are defined in 49 CFR 195 (Transportation of Hazardous Liquids by Pipeline) Subpart F for pipeline integrity management. An HCA is defined as an HPA, OPA, CNW, or Unusually Sensitive Area, including a sole-source drinking water supply.

The *Pipeline Risk Assessment and Environmental Consequence Analysis*, Table 4-12, (see Appendix P, Risk Assessment) identifies the types and lengths of HCAs crossed by the proposed Project route. These HCA data are compiled from a variety of data sources, including federal (e.g., USEPA) and state agencies (e.g., fish and game, environmental quality, hydrology, etc.). Keystone has conducted a preliminary evaluation of HCAs crossed or located downstream of the proposed pipeline route. Portions of the proposed pipeline route in which a release could potentially affect HCAs would be subject to higher levels of inspection and repair criteria (per 49 CFR 195). In addition, at least 6 months prior to beginning pipeline construction, Keystone would review—with the appropriate PHMSA Regional Directors—how HCAs that could be affected were identified and how the design of the pipeline associated with these segments is protective (see Section 4.13.5.1, PHMSA Special Conditions). As a result of a preliminary HCA evaluation, some proposed valve locations were moved and additional valves were added to protect HCAs from potential impact.

Populated Areas

In the event of a spill, the effects on populated areas would depend on the size of the spill and the size of the population in the impacted area. For this reason, populated areas are divided into two categories by the USDOT: HPAs and OPAs. HPAs contain 50,000 or more people and have a population density of at least 1,000 people per square mile. These areas are defined and delineated by the Census Bureau as urbanized areas. OPAs contain concentrations of people and include incorporated or unincorporated cities, towns, villages, or other designated residential or commercial areas, with population densities less than 1,000 people per square mile. The population data used in this report have been updated to include the results of the 2010 Census.

This population division is used to improve the risk analysis, as urban areas may be more susceptible to the impacts of an oil spill. Possible effects of a spill on populated areas include interruptions in daily activities such as access to safe drinking water, decreased air quality, socioeconomic effects, or temporary relocation of population in impacted areas during spill containment and cleanup procedures.

Based on current production projections and the commercial demand at Gulf Coast refineries for WCSB heavy crude from the oil sands, the majority of crude oil that would likely be transported by the proposed Project would be dilbit (EnSys 2010). However, SCO would also be transported by the pipeline.

As stated in the API 2003 report to the USEPA, the following was asserted in comparing SCO with conventional crude oil:

> Synthetic crude oil, from upgraded tar sands, is compositionally similar to high quality conventional crude oil (>33º API). The conventional technologies such as delayed and fluid coking, hydrotreating, and hydrocracking, used to upgrade heavy crude oils and bitumens, are used to convert tar sands into a crude, consisting of blends of hydrotreated naphthas, diesel and gas oil without residual heavier oils . . . This information was supplied to USEPA . . . to support the position that tar sands-derived synthetic crude oil is

comparable to conventional crude oils for health effects and environmental testing, a position with which EPA concurred.

A study on the human exposure symptoms related to the Kalamazoo, Michigan dilbit spill concluded that exposure symptoms were comparable to crude oil (Stanbury et al. 2010). Similarly, the Robust Summary of Information to the USEPA identified that SCO meets the definition of crude oil by the standardized Chemical Abstract Service registry of chemical information and provided a detailed characterization of physio-chemical and toxicological results (API 2003, API 2011). Human health can be affected due to exposure to crude oil and the hazardous chemicals that make up crude oils. Exposure to crude oil can occur through ingestion, inhalation of vapors, dermal exposure (contact with skin), and ocular exposure (contact with surface of the eye). Vapors from spilled oil could lead to human health effects depending on the intensity and duration of exposure. According to the Centers for Disease Control and Prevention (CDC) (2010a and 2010b) and the National Library of Medicine (2012), the short-term exposure effects[11] due to each of these pathways may include the following:

- Mild stomach disturbances, transient nausea, gastrointestinal tract disturbances, and self-limiting diarrhea due to ingestion of a small amount of crude oil (less than 8 ounces). The main risk of the ingestion of crude oil is aspiration of hydrocarbons into the lungs caused by vomiting, which could result in significant lung injury and possibly chemical pneumonitis.
- Irritation of the respiratory system due to inhalation of fresh crude oil. This can cause dizziness, rapid heart rate, headaches, confusion, aplastic anemia, nausea, and/or vomiting. Inhalation hazards of weathered crude oil are less of a concern because the concentrations of the toxic volatile hydrocarbons are greatly reduced following the weathering process.
- Irritation of the respiratory system due to inhalation of burning crude oil. This may harm the passages of the nose, airways, and lung by causing shortness of breath, difficulty breathing, coughing, itching, and black mucous.
- Mild to moderate irritation of the skin depending on the amount and duration of exposure. This can include reddening of the skin, edema (swelling), and burning. Dermal effects can worsen with exposure to sunlight because trace compounds, such as polycyclic aromatic hydrocarbons (PAHs), in the oil are more toxic when exposed to light. Also, depending on the skin sensitivity of the individual, skin effect may be more pronounced after smaller or shorter exposure periods.
- Defatting of the skin due to prolonged skin exposure to crude oil. This also increases the possibility of dermatitis from secondary skin infections.
- Slight stinging, temporary redness, and watery eyes due to ocular exposure.

According to the Michigan Department of Community Health, after the Enbridge 6B pipeline dilbit oil release in 2010, people in the immediate vicinity of the spill experienced some of these short-term effects including headaches, nausea, coughing, and watery/burning eyes. These symptoms are consistent with potential health effects associated with acute exposure to crude oil (Stanbury et al. 2010). Coming into contact with the oil that still remains in floodplains, on

[11] Includes residents, sensitive receptors, sensitive individuals, and spill response workers exposed to the spilled crude.

riverbanks, in the sediment at the bottom of the Kalamazoo River, and in Morrow Lake could cause skin irritation, which could stop if there was no further exposure.

Long-term exposure effects of crude oil have not been researched as rigorously as the constituents of crude oil. Most research indicates that the long-term effects of exposure to crude oil would be similar to the long-term effects of the chemicals that make up crude oil including, but not limited to, benzene, toluene, ethylbenzene, xylene, H_2S, and PAHs (CDC 2010b). Similar to short-term effects, exposure to these chemicals can occur through ingestion, inhalation of vapors, dermal exposure, and ocular exposure. According to the CDC (CDC 2010b), the long-term exposure effects due to each of the chemicals listed above are as follows:

- Benzene is a known carcinogen and long-term exposure can adversely affect bone marrow and cause anemia, leukemia, and possibly death.
- Long-term exposure to toluene may affect the nervous system or kidneys.
- Long-term exposure to ethylbenzene has been observed in animal studies to cause damage to the kidneys, inner ear, and hearing.
- Long-term exposure to xylene may cause impaired reaction time, impaired concentration and memory, and changes in the liver and kidneys.
- Long-term exposure to H_2S may cause permanent or long-term effects including headaches, impaired attention span, impaired memory, or impaired motor function.
- Symptoms of long-term exposure to PAHs may include chronic bronchitis, chronic cough irritation, bronchogenic cancer, and dermatitis.

Although these constituents represent the more toxic individual components present in crude oil, they are generally present in low percentages by comparison to refined petroleum products such as gasoline. Crude oils generally contain a high percentage of heavier hydrocarbons (e.g., carbon number C35 and higher, such as asphaltenes), which do not exhibit significant toxicity or bioavailability. The primary concerns for these heavier hydrocarbon compounds are often more aesthetic or physical in nature rather than toxicological.

Although there is the potential for long-term exposure by the public, long-term exposure effects would likely only be seen in people who were directly interacting with crude oil for multiple hours a day for an extensive period of time (i.e., spill cleanup professionals). These individuals should be trained in appropriate personal protective equipment for the task, exposure limits, work/rest schedule, and other ways to minimize the risk of crude oil interaction.

A human health risk could result from the inhalation of elevated levels of H_2S emitted into the air in the vicinity of the oil spill. Human health effects of exposure to H_2S, an irritant and an asphyxiant, depend on the concentration of the gas and the length of exposure. Background ambient levels of H_2S in urban areas reportedly range from 0.11 to 0.33 parts per billion (ppb), while in undeveloped areas concentrations can be as low as 0.02 to 0.07 ppb (Skrtic 2006). Olfactory perception of H_2S occurs for most people at concentrations in the air of approximately 0.2 parts per million (ppm) or 200 ppb.

In a risk assessment of first responders (local emergency services, emergency response contractors, spill management team) at crude oil spill sites, Thayer and Tell (1999) modeled atmospheric emissions of H_2S from crude oil spills using three different crude oil H_2S

concentrations (1 ppm, 20 ppm, and 350 ppm), calm wind speeds, and temperatures typical of the southern United States. The results of their analysis indicate that H_2S levels in the immediate aftermath of a crude oil spill at the two higher levels of H_2S concentration (20 ppm and 350 ppm) could pose short-term health risks (shortness of breath) to first responders or others at the spill site. Model results indicate that even under worst-case conditions (no wind), modeled concentrations drop to non-toxic levels in less than 4 minutes after oil leaves the pipeline and is exposed to air, assuming no further release of oil. H_2S exposure is expected to be highest where oil has been spreading for the first 4 minutes immediately after discharge from the pipeline (adjacent to the pipeline and within the right-of-way). The Thayer and Tell (1999) modeling effort suggests that exposure to H_2S concentrations could pose health risks in the immediate area of the release of an ongoing release or source.

In the event of a pipeline spill, Keystone has identified and prepared written procedures to address a response action. These activities are provided in Keystone's Draft ERP (see Appendix I, SPCC and ERP). More information describing spill response, including notification procedures, response actions, response teams, and spill impact considerations is discussed in Section 4.13.5.2, Safety and Spill Response.

Unusually Sensitive Areas

Unusually Sensitive Areas include drinking water or ecological resource areas that are especially sensitive to environmental damage from a hazardous liquid pipeline release. These areas have been defined by the USDOT. Unusually Sensitive Areas are separated from other water resources due to their increased potential of direct impact to human health or particularly sensitive wildlife. Other water or ecological resources, not captured by the USDOT-designated areas, are addressed below in the Other Resources discussion.

Drinking Water Resource

PHMSA identifies certain surface water and groundwater resources as drinking water Unusually Sensitive Areas (49 CFR 195.6 and 195.450). An example of a drinking water Unusually Sensitive Area is the water intake for a Community Water System or a Non-Transient Non-Community Water System that obtains its water supply primarily from a surface water source and does not have an adequate alternative drinking water source. The USEPA defines a Non-Transient Non-Community Water System as a public water system that regularly supplies water (but not year-round) to at least 25 of the same people for at least 6 months per year. A drinking water Unusually Sensitive Area could also include a Source Water Protection Area for a Community Water Source or a Non-Transient Non-Community Water System if the water supply is obtained from a USDOT Class I or Class IIA aquifer and does not have an adequate alternative drinking water source. Where a state has yet to identify a Source Water Protection Area, a Wellhead Protection Area is used.

Some segments of the proposed Project route would cross areas that are considered HCAs due to potential risks to sensitive drinking water resources (see Table 4-12 in the *Pipeline Risk Assessment and Environmental Consequence Analysis* in Appendix P, Risk Assessment).

Ecological Resource

An Ecological Resource Unusually Sensitive Area is an area containing a critically imperiled species or ecological community, a multi-species assemblage area, or a migratory water bird concentration area. An Ecological Resource is an area containing an imperiled species; federal threatened, endangered, proposed and candidate species; Bureau of Land Management sensitive species; state threatened and endangered species; species of conservation concern; depleted marine mammal species; or an imperiled ecological community where the species is considered to be one of the most viable, of the highest-quality, or in the best condition. Ecological Resources and special ecological considerations are further discussed in Section 4.13.4.1, High Consequence Areas, and Section 5.4 of E^{x}ponent's Environmental Review (E^{x}ponent 2013).

Commercially Navigable Waterways

CNWs are waterways where a substantial likelihood of commercial navigation exists (PHMSA Section 195.452). These areas are included as HCAs because these waterways are a major means of commercial transportation and critical to interstate and foreign commerce, supply vital resources to many American communities, and are part of a national defense system.

3.13.4.2 Other Resources

Other resources that could be affected by a pipeline release include:

- Soils and sediments;
- Terrestrial vegetation;
- Wildlife;
- Water resources (including groundwater, flowing surface waters, aquatic organisms, and wetlands/reservoirs/lakes);
- Cultural resources; and
- Socioeconomic resources.

Potential impacts to these resources are described in Section 4.13, Potential Releases.

3.13.5 Spill Magnitudes

For the purpose of assessing potential spill impacts for this Final Supplemental EIS, the spill volumes defined and discussed in the Final EIS were simplified from five to three representative spill volumes: small, medium, and large. The entire range of mainline pipe spills in the PHMSA database is addressed by these three spill sizes. These have been reduced from the original five categories to provide a comparison analysis to earlier work done for the State of Nebraska; simplify the range of reported spill volumes in the database, including data under the revised reporting requirements; and facilitate assessment of the spill impact along the proposed Project route. The historic incident frequencies of these three representative spill volumes are detailed using PHMSA data in Appendix K, Historical Pipeline Incident Analysis.

3.13.5.1 Small Spills

Small spills defined herein are less than 50 bbl (2,100 gallons). This spill category represents approximately 79 percent of 1,692 crude oil spills evaluated. Based on the database, this volume of release is typically the result of a pinhole-sized, underground leak. A small volume surface release may also develop from corrosion leaks around valves, flanges, pumps, or other equipment. Small spills may also occur from residual oil encountered during maintenance of pipeline equipment such as valve replacement, pump service, and cleanouts.

Most small releases associated with maintenance activities are generally identified and managed in a timely fashion. Other small releases or pinhole-type releases could be identified during regular pipeline aerial inspections, ground patrols, or landowner or citizen observation. Small releases and spills can also be identified by investigating the source of petroleum odors reported by ground patrols, landowners, or citizens.

Based on a review of historical incident reports for the existing Keystone Pipeline[12] within the first year of operation, 11 of the 12 reported incidents resulted in small releases less than 15 bbl (PHMSA 2013 and National Response Center 2013). These incidents involved discrete elements of the pipeline system (i.e., pumping stations, mainline valves) and were entirely contained on the operator's property.

3.13.5.2 Medium Spills

Medium spills range from greater than 50 bbl (2,100 gallons) to 1,000 bbl (42,000 gallons). This spill category represents approximately 17 percent of 1,692 crude oil spills evaluated. Medium spills can be characterized as either underground releases or surface releases and generally are associated with physical damage to the pipeline, failure of a pipeline component, or operator error where the leak rate is more continuous than a drip. The effects of corrosion (external or internal) on the pipeline may cause a structural weakness that could lead to pipeline failure. Mechanical damage directly to the pipeline or external forces related to ground movement or flooding could cause direct damage to the pipeline. Incorrect operating procedures such as over-pressuring or mechanical vibration could exacerbate pipe weakness resulting in a release.

Historical incident reports for the existing Keystone Pipeline within the first year of operation indicate that one out of the 12 reported incidents resulted in a medium spill (PHMSA 2013 and National Responses Center 2013). The incident occurred at a pumping station and was reported as an equipment failure resulting in a surface release. An estimated 500 bbl (Final Supplemental EIS medium spill classification) of oil were released. Approximately 99 percent of the spill was contained within the pump station with an estimated 5 bbl reported on adjacent farmland. Roughly 80 percent (400 bbl) of the spill was recovered using vacuum-assisted equipment, with the remainder of the spill (an estimated 100 bbl) addressed through the excavation of approximately 300 cubic yards of soil (Crowl 2011). Cleanup activities were initiated within hours and the majority of the remediation was completed in less than a week.

3.13.5.3 Large Spills

Large spills are defined as greater than 1,000 bbl (42,000 gallons) to 31,000 bbl (1,302,000 gallons). The 31,000 bbl spill is roughly the maximum reported spill volume within the data evaluated. This spill category (greater than 1,000 to 31,000 bbl) represents approximately 4 percent of 1,692 crude oil spills evaluated. Large spills are generally characterized as a surface release. This is because the rate of the volume released usually exceeds the capacity at which soil can absorb the released oil. As a result, oil rises to the ground surface.

[12] The *Keystone Pipeline* refers to the existing operational pipeline that runs from Hardisty, Alberta, Canada to Steele City, Nebraska; Wood River, Illinois; and Pakota, Illinois.

Large spills are generally associated with severe damage to or complete failure of a major pipeline component or monitoring system.

While many of the causes listed in this section and Appendix P, Risk Assessments, apply to large spills, it is the degree of damage and the response to the spill that differentiates medium spills from large spills. Pipeline operators are typically alerted to medium and large spills through the pipeline's electronic monitoring or leak detection system (e.g., SCADA). Medium and large spills are generally the result of mechanical damage such as excavation or construction activities and are typically immediately reported and response actions are rapidly implemented.

A pinhole may create a medium to large spill due to the difficulties for SCADA or aerial surveillance to detect such a leak. The SCADA system, in conjunction with Computational Pipeline Monitoring or model-based leak detection systems, would detect leaks to a level of approximately 1.5 to 2 percent of the pipeline flow rate. Keystone has stated it could detect a leak of this size within 102 minutes. Computer-based, non-real-time, accumulated gain/loss volume-trending would be used to assist in identifying low-rate or seepage releases below the 1.5 to 2 percent by volume detection thresholds. Smaller leaks may also be identified by direct observations by Keystone or the public.

There are no large first-year spills for the existing Keystone Pipeline recorded in the historical incident reports.

3.13.6 Connected Actions[13]

There are three connected actions associated with the proposed Project:

- The Bakken Marketlink Project;
- The Big Bend to Witten 230-kV Transmission Line; and
- Electrical Distribution Lines and Substations.

The resources found along and in the proposed connected action project areas are similar to the resources described above for the proposed pipeline route itself.

Of the three connected actions, the Bakken Marketlink Project could potentially result in a spill that would affect nearby resources because of the presence of crude oil containment systems (i.e., pipeline and storage tanks). The threats of a spill are the same as for the proposed Project, as are the sources of spills during construction, operation, and maintenance. However, because of the relatively short pipeline segment length, the maximum worst-case spill size would be much less than it would be for the proposed Project.

3.13.6.1 The Bakken Marketlink Project

The Bakken Marketlink Project would be used to transport light crude oil, which is a high-quality crude oil generally characterized by a high proportion of naturally occurring light hydrocarbon fraction verses dilbit; this has the light fraction added by the introduction of a diluent. Construction and operation of the Bakken Marketlink Project would consist of a 16-inch

[13] Connected actions are those that 1) automatically trigger other actions which may require environmental impact statements, 2) cannot or will not proceed unless other actions are taken previously or simultaneously, 3) are interdependent parts of a larger action and depend on the larger action for their justification.

pipeline approximately 5 miles in length, additional piping, booster pumps, meter manifolds, and two 250,000-barrel tanks that would be used to store crude from connecting third-party pipelines and terminals. Threats of an oil release are similar to those described above for the proposed Project. The Bakken Marketlink Project facilities would be located within private land currently used as pastureland and hayfields.

3.13.6.2 The Big Bend to Witten 230-kV Transmission Line

The Big Bend to Witten 230-kV Transmission Project is located in Lyman and Tripp counties in south-central South Dakota. The project would consist of replacing the existing Big Bend-Fort Thompson No. 2 230-kV Transmission Line Turning Structure on the south side of the Big Bend Dam on Lake Sharpe; constructing a new double-circuit 230-kV transmission line for approximately 1 mile southwest of the dam; and constructing a new Lower Brule Substation south of the dam. The existing Witten Substation would be expanded immediately to the northeast to accommodate the new 230-kV connection. Potential sources for releases of oil or oil products during construction and/or operational phases of the project include fuel storage tanks, transformers, hydraulic and lubricating oil storage, and construction equipment and vehicles.

3.13.6.3 Electrical Distribution Lines and Substations

Multiple private power companies or cooperatives would construct distribution lines to deliver power to 20 pump stations located along the length of the pipeline in the United States. These distribution lines would range in length from approximately 0.1 mile to 62 miles, with the average being 13 miles long, and are estimated to extend about 377 miles, combined. The distribution lines would range in capacity from 69 kV to 240 kV, but the majority would have a capacity of 115 kV. The lines would be strung on a single pole and/or on H-frame wood poles. Potential sources for releases of oil or oil products during construction and/or operational phases of the project include fuel storage tanks, transformers, hydraulic and lubricating oil storage, and construction equipment and vehicles.

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4.3 WATER RESOURCES

4.3.1 Introduction

This section describes potential impacts to water resources associated with the construction and operation of the proposed Project and connected actions and discusses regulatory mitigation measures that are intended to avoid or minimize the potential impacts. The information, data, methods, and/or analyses used in this discussion are based on information provided in the 2011 Final Environmental Impact Statement (Final EIS) as well as new circumstances or information relevant to environmental concerns that have become available since the Final EIS publication, including the proposed major reroute in Nebraska and numerous minor route adjustments in Montana and South Dakota. The information provided here builds on the information in the Final EIS as well as the 2013 Draft Supplemental EIS and, in many instances, replicates that information with relatively minor changes and updates; other information is entirely new or substantially altered.

Specifically, the following information, data, methods, and/or analyses have been substantially updated from the 2011 document:

- A new section (see Section 4.3.2, Impact Assessment Methodology) was added to explain the assessment methodology used to evaluate potential water resources impacts associated with the proposed Project.
- Additional water resource datasets for both ground and surface water were used in South Dakota and Montana to supplement previous information to allow for a more detailed and accurate assessment of impacts to this resource.
- Ground and surface water literature and databases were reviewed, compiled, and analyzed for the major new proposed routing in Nebraska in order to address water quality, flow, usage, and availability.
- The impacts of releases to groundwater were assessed and include anticipated release assessment, response, and mitigation measures.
- Recommended proposed pipeline inspections and testing steps were developed that would supplement typical TransCanada Keystone Pipeline, LP (Keystone) processes and procedures.
- The activities and impacts associated with acquiring water from ground or surface water sources were assessed.
- The number and type of stream crossings and stream crossing methods have changed due to changes in the proposed Project route as well as updated field survey information provided by Keystone. The stream crossing assessment included a desktop analysis based on National Hydrography Dataset (NHD) information and supplemented by Keystone field survey descriptions.

- Based on the limitations of the data used in the desktop analysis, the intermittent and ephemeral stream categories were combined and both were evaluated as intermittent streams. As a result, potential impacts were assessed consistently for both stream types throughout this section.[1]
- Keystone provided a list of surface waterbodies that may be considered as water sources for potential hydrostatic testing or other proposed Project construction uses along the proposed Project route Proposed watersheds with potential withdrawal permit restrictions and/or conditions that may be present at the time of construction were evaluated.
- Ancillary facilities (e.g., access roads, pump stations, and construction camps) with known locations that intersect state and federally designated or mapped floodplain areas – or, in some instances, effective floodplain areas – in Montana, South Dakota, Nebraska, and Kansas were identified. [2]
- Section 4.3.4, Additional Mitigation, provides a list of additional mitigation measures that, depending on a variety of permitting scenarios, may be required by regulatory review to further reduce impacts to water resources.

The following information, data, methods, and/or analyses have been substantially updated from the 2013 Draft Supplemental EIS:

- An additional sub-analysis was added regarding potential Wild and Scenic River (WSR) spill frequency.
- In response to public and agency comments, text has been revised throughout the section where necessary. Further discussion of impacts and potential mitigation measures related to potential crude oil spills from pipeline operations are provided in Section 4.13, Potential Releases.

Summary

Potential impacts to groundwater resources associated with the proposed Project construction, operation, and connected actions could vary significantly along the proposed route (see Section 4.13.4, Spill Impact Assessment). The impact on groundwater resources would be dependent on many factors including depth to groundwater, soil and hydrogeologic conditions, amount and type of material released, among other factors (see Section 3.13.3, General Description of Proposed Pipeline Transported Crude Oils). The impact of a release would be dependent on the

[1] Ephemeral streams are usually defined as a stream segments that flow briefly from localized precipitation events and whose channel beds are located above the water table year-round. Since flows in ephemeral streams are in rapid response to precipitation, they are typically infrequent and tend to have extreme fluctuations during periods of activity. It is, therefore, difficult to assess normal bankfull flow characteristics, which are often used to establish restoration criteria. Additionally ephemeral streams tend to exhibit less aquatic habitat and may be prone to higher rates of bed and bank adjustment. By combining these streams with intermittent streams, which are more likely to carry water in response to seasonal ground water sources as well as precipitation events and are also more likely to support wetland and aquatic habitats, this Final Supplemental EIS has applied a more rigorous evaluation to ephemeral waterbodies. Intermittent waterbodies can have additional protections under federal and state clean water regulation. These protections are often applied based on individual site conditions, which are evaluated during permitting reviews.

[2] In addition to the planned pipeline, the additional supporting infrastructure for the proposed Project consisting of a pipe yard and a rail siding in North Dakota and two pumps stations in Kansas are not anticipated to impact surface waterbodies; as such, North Dakota and Kanas have no entries in the waterbody summaries or tables.

severity and extent of exposure to humans and the environment. A spill entering the groundwater near a well could be a direct exposure pathway to humans and the environment. A spill to soil 6 feet below the ground that does not impact groundwater would most likely have a reduced impact to humans and the environment. Potential impacts to groundwater resources from construction and operation could be small, medium, or large as defined in Section 4.3.2.1, Groundwater. During construction, groundwater withdrawals could have a short-term impact on localized availability and groundwater table elevation.

The responses to releases to groundwater would be similar from both construction and operation related activities and is dependent on the specific release magnitude and duration. During the proposed Project operation, impacts to groundwater could occur due to potential small (<50 barrels [bbls]), medium (2,100 to 1000 bbls), and large (>1000 bbls) spills of crude. Any refined petroleum releases from construction or crude oil releases from operations could potentially impact groundwater where the overlying soils are permeable and the depth to groundwater is shallow. Other significant factors influencing subsurface migration include groundwater velocities, amount of organic matter in the soil, location of fine grained materials (clay and silt), soil porosity, and the oil's physical and chemical characteristics (e.g. viscosity, solubility). Screening-level overland flow and groundwater flow modeling (see Appendix T, Screening Level Oil Spill Modeling, and E^xponent 2013) indicate the potential impact from large dilbit releases could extend up to 2,246 feet with smaller releases extending hundreds of feet. This is supported by numerous other studies related to tank, pipeline, or other point sources where impacts are typically limited to an area within several hundred feet of the release site. A more detailed discussion of the impacts from potential releases is presented in Section 4.13, Potential Releases.

The proposed pipeline would primarily carry dilbit at an elevated temperature due to pipeline operations, including pipe wall friction and pumping activities. Upon release into the environment, the dilbit temperature would decrease significantly, causing the viscosity to increase and limiting the distance that spills would migrate. Additional details on impacts to groundwater from a release are presented in Section 4.3.3.1, Groundwater, and 4.13.4, Spill Impact Assessment, for both the construction and operation/maintenance scenarios.

In the proposed pipeline area, several regional and local aquifers are present, including the Northern High Plains Aquifer (NHPAQ) and the alluvial aquifers in the Ogallala Formation. These two aquifers represent the most commonly used groundwater sources in the proposed pipeline area. Many private and public wells extract groundwater from these aquifers, including those in several Source Water Protection Areas (SWPAs) in the proposed pipeline area; these aquifers are typically at highest risk of contamination from the proposed Project construction and operation because of the relatively shallow depth of water tables in the alluvial and NHPAQ aquifers (commonly <50 feet) as well as the relatively high permeability of the aquifers and overlying material. The combination of an extensive groundwater-use profile and high sensitivity to releases from the proposed pipeline area make these aquifers particularly sensitive to potential releases.

Potential impacts to groundwater resources during the operational phase of the proposed Project and connected actions include altered groundwater quantity and quality. Measures to avoid and minimize these impacts include pipeline system testing spill and maintenance training, pipeline inspection, periodic system updates and maintenance, and others addressed in Section 4.13, Potential Releases. Federal, state, and local regulatory agency permit requirements would further reduce potential impacts to groundwater resources from construction, maintenance, and operational activities. For instance, Keystone has agreed to incorporate into its operations and maintenance plan a requirement to conduct ground inspections of all intermediate valves and non-staffed pump stations during the first year of operation to ensure that small leaks or potential failures in fittings and seals are identified. Keystone has also agreed to Pipeline and Hazardous Material Safety Administration (PHMSA) Project-specific Special Conditions developed by stakeholders to address pipeline concerns. Those conditions are presented in Appendix B, Potential Releases and Pipeline Safety.

Potential impacts to surface water resources associated with construction of the proposed Project and connected actions would vary depending on the type, location, and seasonal condition of the waterbody at the time of the proposed Project construction. To a large extent, the size of the channel, floodplain, and supporting riparian area would determine both the construction duration and the pipe installation method for each waterbody crossing. The installation method would also depend on waterbody classifications, protected status, or permit requirements that apply to the individual waterbody. The proposed Project would install pipe segments at waterbodies using one of the following methods: non-flowing open cut, flowing open cut, dry flume open cut, dry dam-and-pump, horizontal boring, or horizontal directional drill (HDD). The proposed Project plans to implement the HDD techniques to minimize impacts at 14 of the 1,073 waterbody crossings.

Keystone has developed an HDD contingency plan defining specific responsibilities, procedures, and actions necessary to manage the detection of and response to drilling fluid releases or frac-outs[3] during pipeline installations using HDD techniques. The HDD contractor would be responsible for execution of the HDD operation, including actions for detecting and controlling the inadvertent release of drilling fluid.

Potential impacts to surface water resources from construction would be temporary, short term, long term, or permanent as defined in Section 4.3.2.2, Surface Water. Generally, open-cut crossing impacts would include alteration of the streambed and bank structure, habitat reduction or alteration, increased sediment, riparian vegetation loss, and introduction of non-native vegetation. To mitigate impacts to surface water resources, the Construction, Mitigation, and Reclamation Plan (CMRP) (see Appendix G) would be implemented.

Measures to minimize bed and bank impact include temporary vehicle bridges and minimizing in-stream use of equipment; these and other similar measures would result in proposed Project impacts to surface water resources that would predominately be temporary and short term.

Water withdrawal from surface water resources by the proposed Project would be used for construction processes and would consist of hydrostatic testing, HDD make-up water (drilling mud), dust control, and in the construction camps. The proposed Project may temporarily impact surface water volume in locations designated for proposed Project water withdrawals. During withdrawals, minimal disruption of the normal access to and use of surface water resources would be anticipated in the proposed Project ROW and adjacent areas. The water resources affected by the proposed Project construction, as well as landowner and recreational access, would be restored in accordance with the CMRP following construction.

[3] In some instances, pressurized fluids and drilling lubricants used in the HDD process have the potential to escape the active HDD bore, migrate through the soils, and come to the surface at or near the crossing construction site, an event commonly known as a *frac-out*.

Potential impacts to surface water resources during the operational phase of the proposed Project and connected actions are possible during routine maintenance and ROW inspections. These impacts are anticipated to be infrequent, minimal in nature, and managed in accordance with the proposed Project CMRP. Measures to avoid and minimize these maintenance and repair induced surface-water impacts would include aerial and ground surveillance, maintenance of non-forested vegetation, and restoration and revegetation measures conducted in accordance with the CMRP. Additional potential impacts to surface water resources would include accidental pipeline spills. Section 4.13, Potential Releases, describes the pipeline fluids and safety measures of the proposed Project that could be used to mitigate impacts to surface waterbodies. In addition, an independent risk assessment and engineering analysis were conducted on the proposed Project. These assessments identified mitigation measures applicable to releases that could affect both groundwater and surface waterbodies (Leis et al. 2013, McSweeney et al. 2013).

The permit requirements of federal, state, and local regulatory agencies would further reduce potential impacts to surface water resources from construction, maintenance, and operational activities.

Connected actions include the Bakken Marketlink Project, the Big Bend to Witten 230-kilovolt (kV) Transmission Line, and electrical distribution lines and substations. The potential impacts to groundwater resources associated with the Bakken Marketlink Project facilities are minimal in that no significant large-scale potable aquifers are in the area. The potential impacts to surface water resources include seven intermittent waterbody crossings and one perennial waterbody crossing at Sandstone Creek. The Montana Department of Environmental Quality (MDEQ) has listed Sandstone Creek in the 2012 Integrated Water Quality Report as having designated beneficial uses and impairments to aquatic life. Mitigations and permitting associated with the construction of the Bakken Marketlink Project would likely be similar to those described for the proposed Project route in that area. Additionally, the installation and operation of electrical transmission lines and substations associated with the connected actions and potential impacts to groundwater resources are expected to be limited to small-scale refined petroleum product spills related to vehicle operations and fueling. Potential impacts to surface waterbodies adjacent to these lines, in general, are short-term and/or negligible as these lines typically parallel existing roadways or right-of-ways (ROWs). Transmission line designs would generally avoid impacts to surface water by placing poles away from rivers, streams, and riparian areas and thereby spanning surface waterbodies and sensitive riparian habitats. Pole placements in floodplains would be avoided as much as practicable.

4.3.2 Impact Assessment Methodology

4.3.2.1 Groundwater

The proposed Project could impact groundwater quality as a result of both construction- and operations-related activities. The volume of different crude oil release scenarios is based on the same volumetric divisions included in the spill impact assessment discussion in Section 4.13, Potential Releases. During construction activities, the maximum planned storage capacity of refined petroleum products (motor fuels) in a single container is about 700 bbls. Therefore, potential releases from construction-related activities (most likely from vehicles or bulk storage facilities) would be expected to be no more than about 700 bbls; although, based on historic data,

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most spills are expected to be small (<50 bbls) (PHMSA 2012; PHMSA 2013). Releases from these sources would primarily be motor fuel or lubricating oils and would be related to vehicle refueling and maintenance activities.

While potential releases during operation and maintenance of the proposed Project would include some of these same activities, operation of the pipeline could also result in releases of crude oil ranging from small (<50 barrels) to large (>1000 barrels). Additionally, small spills could occur from routine maintenance and inspection activities.

As discussed in Section 4.13.4.4, Types of Spill Impact, impacts from refined petroleum products (e.g., gasoline, diesel, heating oil) and some lighter constituents of crude oil are similar. Compared to the heavier constituents of crude oil, these lighter constituents typically travel more readily in soils and groundwater due to their lower viscosity and higher soluble fractions. Information from releases of both crude oil (including heavier and lighter constituents) and refined petroleum products are also included in the discussion of groundwater impact assessment in Section 4.3.3, Potential Impacts.

Most crude oils are more than 95 percent carbon and hydrogen, with small amounts of sulfur, nitrogen, oxygen, and traces of other elements. Crude oils contain lightweight straight-chained alkanes (e.g., hexane, heptane); cycloalkanes (e.g., cyclohexane); aromatics (e.g., benzene, toluene); and heavy aromatic hydrocarbons (e.g., polycyclic aromatic hydrocarbons, asphaltines). Straight-chained alkanes are more easily degraded in the environment than branched alkanes. Cycloalkanes are extremely resistant to biodegradation. Aromatics (i.e., benzene, toluene, ethylbenzene, and xylene [BTEX] compounds) pose the most potential for toxic exposure because of their lower molecular weight, making them more soluble in water than alkanes and cycloalkanes. Refined petroleum products typically have variable concentrations of these more soluble compounds, with lighter fuel products such as gasoline containing as much as 35 percent or greater BTEX, and heavier distillates used as lubricating oils having no significant BTEX fraction. In general, the higher the concentration of BTEX in the petroleum material, the greater the risk to groundwater quality and groundwater receptors (e.g., humans, livestock, and the environment) related to a release of the material.

To evaluate the potential impacts to groundwater resources, regional aquifer information and well locations within 1 mile of the proposed Project were superimposed on the proposed pipeline route using Geographic Information System (GIS) software. While not all wells within 1 mile of the pipeline are identified within state databases, those that were identified were used in the evaluation. Results of the evaluation of water resources and water use in the proposed Project area are included in Section 3.3.2, Groundwater. The potential impacts to groundwater resources from both construction and operation impacts from the proposed Project are discussed in Section 4.3.3, Potential Impacts. Medium to large spills as defined in the summary above would typically require greater than 3 years to attenuate or remediate and, therefore, would be considered a long-term impact. Small releases can generally be remediated within 3 years and would typically be considered short-term impacts.

Additional groundwater-related impacts may also be related to increased local extraction of groundwater during construction and pipeline testing activities. Additional proposed Project-related groundwater use, although temporary, would remove water from aquifers and could potentially decrease groundwater levels in extraction wells, depending on aquifer recharge characteristics.

Operator response actions for oil or fuel spills that reach groundwater would be similar for construction or operations activities (as discussed in Section 4.13, Potential Releases) and would be appropriately scaled based on the magnitude, duration, and location of the specific release event. Keystone would have the responsibility for implementing and following the CMRP; Spill Prevention, Control, and Countermeasure; and Facility Response Plan/ Emergency Response Plan, as applicable, for releases associated with the pipeline system (e.g, pipelines, terminals, pump stations, vehicles). Mainline pipe releases could result in a higher level of response actions. In the case of spill impacts to wells, alternate water supplies would be either permanent (e.g., installing a new well[s] or connecting users to a water supply system) or short term (e.g., water delivery by truck or temporary pipeline). The length of time that short-term water supplies would be temporarily delivered would be based on when drinking water standards and aesthetic criteria are met. Federal and state criteria would need to be met before the temporary system would be terminated. Keystone is required to enter into agreements with well owners whose land would be crossed regarding easements, impacts, and mitigation during construction or operation.

4.3.2.2 Surface Water

In addition to petrochemical spills as mentioned in Section 4.3.2.1, Groundwater, and Section 4.13.4, Spill Impact Assessment, the remaining impacts of the proposed Project on surface water resources are predominately from land-disturbing activities and can be separated into two categories: construction impacts and operations impacts. In many cases, potential impacts overlap between construction and operations. This impact assessment categorizes potential impacts to surface water resources by duration (temporary, short-term, long-term, and permanent) and describes mitigation measures to reduce or minimize impacts. Durations are described as follows:

- Temporary impacts would generally occur during construction, with the resources returning to preconstruction conditions almost immediately afterwards.
- Short-term impacts would continue up to approximately 3 years following construction.
- Long-term impacts would continue for more than 3 years before recovery to pre-construction conditions.
- Permanent impacts would occur as a result of activities that modify resources to the extent that they would not be returned to preconstruction conditions during the life of the proposed Project.

In addition, the impact assessment calculated several different metrics and performed additional evaluations for surface waterbodies, including the following:

- Calculated the number of waterbodies and waterbody types crossed by the proposed pipeline route;
- Evaluated water quality classifications and impairments as published by state agencies for the waterbodies crossed by the proposed pipeline route;
- Evaluated surface water intakes, diversions, or Wellhead Protection Areas for municipal water supplies within 1 mile of the proposed pipeline centerline;

- Calculated the number of mapped floodplains and the total width of mapped floodplains crossed by the proposed pipeline route; and
- Evaluated the same types of surface water resources and waterbody attributes (such as water quality classifications and impairments) impacted by proposed ancillary features such as access roads, pads, and work areas.

4.3.3 Potential Impacts

4.3.3.1 Groundwater

The impacts of the proposed Project on groundwater might potentially occur as a result of construction-related activities and operation-related activities. The volume of different crude oil release scenarios is based on the same volumetric divisions included in the spill impact assessment discussion in Section 4.13, Potential Releases. Potential small (<50 bbls) releases of petroleum products that could impact groundwater quality would be related to spills or leaks of refined petroleum products from equipment and vehicles. Small (<50 bbls) to medium (50 bbls to 1000 bbls) refined petroleum product spills may also occur from tanks in equipment staging areas during the construction (at camps and at the construction location) and operation phases. Medium to large (>50 to 1000 bbls) spills of crude oil may occur during the proposed Project operation. Any refined petroleum releases from construction or crude oil releases from operations could potentially impact groundwater where the overlying soils are permeable and the depth to groundwater is shallow. The factors influencing subsurface migration of a crude oil release that reaches groundwater are discussed in the following subsections.

Construction-Related Impacts

During construction, there would be potential for spills and releases from equipment maintenance areas, camps, HDD locations, and pipeline placement areas. The size of those spills and releases would generally be less than 700 bbls of refined petroleum, which is the size of the largest stationary tank. In addition, fuel tankers could contain up to 9,500 (~225 bbls) gallons of refined petroleum. Spills and releases would generally be minimized because staff would be present during all fueling operations from a truck tanker, and bulk storage tanks are required to have secondary containment. The CMRP (see Appendix G) includes actions designed to help prevent spills and releases.

Other construction activities could result in the following potential impacts on groundwater:

- Removal of some wells within or near the ROW. The removal would need to be coordinated with and approved by the owners.
- Dewatering where groundwater is less than the burial depth of the pipe (typically, burial is 4 to 7 feet) during pipe-laying activities. Dewatering the excavation could generate substantial localized amounts of water to be discharged. The withdrawal and discharge would need to be permitted, monitored, and performed in a manner that has the least impact on the environment.
- Pipeline trench potentially acting as a conduit for groundwater migration and/or as a barrier to near-surface flow in areas of shallow groundwater (<7 feet below ground surface [bgs]). While the near-surface geology is generally rather transmissive, excavating and backfilling

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for the pipeline may increase groundwater flow along the buried pipe and associated trench construction. Pipe bedding materials and contact zones between the pipe and bedding or between trench backfill and native soils at the trench margin may allow ground water to flow in the disturbed zone. In addition, the pipe can also act as a barrier for near-surface flow down to the bottom of the pipe. Groundwater would accumulate against the pipe or more likely flow under the pipe, assuming that similar geology exists all around the pipe. Impacts from these processes are believed to be minor. There would also be potential impacts to construction water uses, construction camp potable water, and pipeline testing withdrawals from groundwater.

Each state that would be crossed by the proposed pipeline route has different requirements for water well testing. In Nebraska, Keystone would be required by Nebraska Department of Environmental Quality (NDEQ) to conduct baseline water quality testing for domestic and livestock water wells within 300 feet of the centerline of the approved route upon the request of individual landowners who provide access to perform the testing. These baseline samples would be collected prior to placing the pipeline in service. In the event of a significant release, Keystone would conduct water well testing in the location where the release occurred, as required by NDEQ pursuant to Title 118, Nebraska Administrative Code. Keystone would also provide an alternate water supply for any wells where water quality was found to be compromised by a release or spill. In Montana, pre- and post-construction monitoring would be required. Appendix D (Monitoring Plan) of the MDEQ Major Facility Siting Act Certificate states: "In order to protect groundwater resources, Keystone shall conduct pre- and post-construction monitoring of any wells or springs within 100 feet of the ROW. The survey will be conducted by checking state well records, agency records, and personal communication with landowners and field review. Baseline field surveys of each well or spring will include a visual estimate of flow and water clarity, and field-measured temperature, electrical conductivity, and pH. The results of required surveys will be filed with the agencies before construction commences near these wells and springs." In South Dakota, as a permit Condition in the South Dakota Public Utilities Commission Final Decision and Order document, Condition 46 (in Exhibit A) states "In the event that a person's well is contaminated as a result of construction or pipeline operation, Keystone shall pay all costs associated with finding and providing a permanent water supply that is at least of similar quality and quantity; and any other related damages, including but not limited to any consequences, medical or otherwise, related to water contamination." The South Dakota Public Utilities Commission Order also requires well water testing to be conducted where blasting would occur.

Subsequent subsections present potential impacts to the aquifers beneath the proposed pipeline area resulting from the proposed Project construction and/or operation. Mitigation measures that would be put in place to avoid, minimize, and mitigate releases from pipeline operation are discussed in Section 4.13, Potential Releases.

Factors Affecting Subsurface Petroleum Migration and Groundwater Flow

The potential for, and dynamics of, crude oil or refined oil products migrating into groundwater, and subsequent fate and transport[4] in the groundwater as light non-aqueous phase liquid (LNAPL)[5] or as a dissolved-phase plume,[6] is determined by the several factors, including:

- The volume, duration, and areal extent of the petroleum release;
- The viscosity, density, and solubility of the petroleum release;
- The permeability of unsaturated soils and aquifer characteristics within the area of the petroleum release;
- The depth to first groundwater; and
- Horizontal and vertical groundwater gradient and aquifer hydraulic conductivity, including surface water and groundwater interconnections.

Release Volume and Extent

The volume, duration, and extent of a petroleum release are important factors in determining whether or not the release would affect groundwater quality, and to what degree groundwater quality would be affected. Petroleum released to soils at the ground surface or in the subsurface would be absorbed by soil particles, which would limit the migration of the petroleum material downward to groundwater. In order for LNAPL to reach groundwater, the release must be large enough to overcome the natural absorption capacity of the soil through which it migrates. The measure of the maximum amount of petroleum material that a soil can absorb and immobilize is known as *residual saturation*. Typical petroleum residual saturation rates in clean sands range from approximately 5,833 milligrams of petroleum per kilogram of soil for light petroleum products, such as gasoline, to 20,382 to 42,618 milligrams per kilogram of soil for more viscous petroleum products, such as middle distillates, naptha (a major component of dilbit), mineral oil, and paraffin oil (Brost and DeVaull 2000). Residual saturation rates for petroleum products typically increase as soil grain size decreases and viscosity of the petroleum product increases; higher residual saturation rates result in more contaminant mass immobilized within the soil.

Studies related to petroleum product releases from over 600 underground storage tank (UST) leaks indicate that potential surface and groundwater impacts from these releases are typically limited to the area within several hundred feet of the release site (American Petroleum Institute [API] 1998). While this study focuses on refined product, refined product is more mobile than crude oil, such as dilbit and Bakken light (the main liquids to be transported in the proposed pipeline); therefore, this is a conservative comparison. The median length of groundwater plumes composed of soluble petroleum components (BTEX) from these UST sites was 132 feet, and approximately 75 percent of these plumes were under 200 feet (API 1998). Although the petroleum products and release conditions at a crude oil pipeline are somewhat dissimilar from those at a typical UST, the contaminant distribution conditions in soil and groundwater observed

[4] *Fate and transport*: A term alluding to the manner in which a contaminant moves through an aquifer in groundwater, and how concentrations in groundwater are ultimately reduced over time and/or distance.
[5] Light non –aqueous phase liquid: A liquid that does not contain water (e.g., gasoline), has a lower density than water, and would therefore float on a water surface.
[6] Dissolved-phase plume: The portion of a released material that becomes dissolved in groundwater and moves along the direction of groundwater flow.

at UST sites would generally correlate to conditions expected from small to medium releases related to the proposed Project. Released material from a pipeline carrying crude oil and dilbit mixtures would impact adjacent soil. In both UST and pipeline releases there are many variables effecting released material impacts to groundwater including, but not limited to, the distance between the release and groundwater, release material mobility, soil and rock present, and precipitation.

As detailed in Section 4.13, Potential Releases, releases of different volumetric scales (i.e., small, medium, and large) of crude oil from the proposed Project were modeled to evaluate the expected extent of the dissolved-phase petroleum hydrocarbon plume in groundwater that would be expected to be associated with those releases. The release modeling assumed a sandy aquifer similar to many of the alluvial aquifers and of the Tertiary Northern Great Plains Aquifer System (NGPAS) and NHPAQ groups present along the proposed Project route. The model outputs indicate that releases of crude oil from the proposed Project ranging from small (<50 bbls) to large (>1000 barrels) would result in axial lengths of the dissolved-phase petroleum hydrocarbon plumes ranging up to 2,264 feet (see Figure 4.13.4-1).

To further assess groundwater impacts related to a large-scale crude oil release into a coarse-grained, shallow, unconfined aquifer, studies of a 1979 pipeline release near Bemidji, Minnesota, were reviewed because of the material released, similarity of the geology and hydrology, and volume of material released.[7] Approximately 10,700 bbls of crude oil were released onto a glacial outwash (alluvial) deposit consisting primarily of sand and gravel. The water table in the spill area ranged from near ground surface to approximately 35 feet bgs. As of 1996, the leading edge of the subsurface LNAPL plume had migrated approximately 131 feet downgradient from the spill site, and the leading edge of the dissolved contaminant plume had migrated approximately 650 feet downgradient from the spill site.

These studies of the UST sites and the Bemidji release, as well as the results of the petroleum release modeling completed as part of this study (see Section 4.13, Potential Releases), indicate that the size of the oil release is a primary factor influencing the ultimate oil plume dimensions (including the dissolved-phase plume). While there are differences in the rate of oil movement through different soil types, hydrogeologic factors such as hydraulic conductivity and gradient—although important to understanding contaminant migration within an aquifer—are not as significant in determining ultimate plume length (API 1998). Based on a comparison of the UST site releases, the Bemidji release described above, and the release modeling effort completed as part of this study, the petroleum contaminant plume extent in groundwater is not proportional on a one-to-one basis to the volume of the petroleum product released. That is, an incremental increase in release volume typically produces a smaller incremental increase in the areal extent of the impacted groundwater. For example, under the release model developed as part of this study (see Section 4.13, Potential Releases), a release of 50 bbls of crude oil resulted in a groundwater-dissolved contaminant plume that was a maximum of 640 feet long, while a release of >42,000 to 840,000 gallons (or up to 20,000 bbls, which is 400 times as large) resulted in a

[7] In addition to the Bemidji spill, a large dilbit crude oil spill occurred in July 2010 from a 30-inch diameter pipeline near Marshall, Michigan. Released oil entered an adjacent creek and then the Kalamazoo River. Groundwater in glacial deposits were impacted, but all wells (155) within a roughly 200-foot buffer were included in a sampling program, and it was concluded that there were no impacts to the wells from the spill. Unlike the Bemidji spill, the Kalamazoo River spill had significantly greater impacts to surface water.

maximum plume length of 1,050 feet, or roughly twice as long as the plume related to the smaller release.

Viscosity and Density of Released Dilbit and Baken Crude Oil

The pipeline will carry differing grades of crude oil mixed with dilbit to facilitate the flow of the more viscous crude oil. Dilbit is generally derived through the refining process or as a derivative of natural gas. Dilbit contains lighter more mobile and generally more toxic substances than crude oil (which will have many of the same constituents but that are less mobile).

The dilbit that would typically be transported by the proposed pipeline would have a viscosity within the range of 52 to 96 centistokes[8] at a temperature of 38 degrees Celsius (viscosity range of diluted bitumen, Imperial Oil 2002), a viscosity similar to that of corn syrup at room temperature. If the oil was released to the surrounding soils and groundwater, it would cool and the viscosity would increase significantly, with a resultant increase in resistance to flow. Viscosity would also increase somewhat under conditions where diluent material used to decrease the crude viscosity can volatilize to the atmosphere. The relatively high viscosity of the crude oil would not only retard the petroleum flow velocity within soil, but would also result in a residual saturation condition in which small crude oil releases would essentially be immobilized as the petroleum cools and viscosity increases.

The high fluid viscosity and resultant resistance to flow in a compacted granular medium (soil) also suggests a higher likelihood that pipeline releases would preferentially migrate under pressure upward through the disturbed soils excavated during pipeline installation and discharge onto the ground surface, with relatively less crude oil infiltrating under gravity deeper into soil toward groundwater.

The crude oil transported within the proposed pipeline is anticipated to have a specific gravity less than water and would be considered an LNAPL. The bulk of the released material (the LNAPL) would preferentially float on the groundwater surface as LNAPL. However, some constituents of the crude oil would likely separate from the main mass of the released material and either dissolve in the water column or sink, forming a dense non-aqueous phase liquid DNAPL) plume. This would occur mostly with the dilbit rather than the lighter Bakken crude oil. As the dilbit would age and lighter constituents dissolve, the dilbit could slowly sink to form the DNAPL. The viscosity of the DNAPL would eventually increase as the light constituents were lost, reducing the mobility of the oil. Dissolved constituents would move with the groundwater and would be subject to the same properties as the groundwater moving though sediment. DNAPL would also move vertically until reaching denser or more compacted or finer grained sediment that would inhibit downward migration. Depending on the groundwater and sediment parameters (e.g., transmissivity, gradient, grain size) the DNAPL may migrate horizontally, but because of its higher viscosity it would do so at a much lower velocity than the groundwater.

[8] *Centistokes* is a unit of measurement for kinematic viscosity equal to the unit millimeters squared per second. The centistoke is the ratio of a liquid's absolute viscosity in centipoise to the density. *Centipoise* is a unit of measurement for absolute viscosity where one centipoise is equal to the millipascal second, which is one-thousandth of a pascal second.

Soil and Bedrock Permeability

Permeability of soils and aquifer materials also affects transport of LNAPL and dissolved-phase contaminants from petroleum releases to and within groundwater. Shallow unconfined aquifers are commonly overlain by permeable materials and therefore are at risk if the overlying soils are contaminated.

Many petroleum fractions, including BTEX, are present in bituminous crude oil and associated diluents. These fractions can be transported to groundwater by dissolved-phase[9] transport, either by direct contact of groundwater with LNAPL or by infiltration of precipitation and surface water through petroleum-contaminated soil and into groundwater. Once the dissolved-phase petroleum is in groundwater, the material typically flows within the aquifer at a velocity somewhat less than the groundwater flow, as the dissolved-phase petroleum is subject to absorption into soil particles (in a similar manner as described above regarding migrations through soils above the water table) and degradation by naturally occurring bacteria in the aquifer. The LNAPL typically migrates in the direction of groundwater flow at a rate that varies with product viscosity; more viscous materials (such as heavy crude oil) migrate significantly slower than the groundwater flow.

Downward and, less commonly, horizontal migration of contaminants in unsaturated sediments and within aquifers is commonly attenuated[10] by confining layers or zones of finer-grained, lower permeability sediment. Flow through these units is typically very slow or absent. Confining layers are commonly present between aquifer units, and can also be present within aquifers. For example, the Ogallala Formation of the NHPAQ contains many layers of volcanic ash that are much finer than the aquifer materials above and below them; the ash layers typically function as intra-aquifer confining layers. Additionally, glacial till and silty and clayey layers in alluvial aquifers typically form confining layers in those otherwise coarse-grained units.

Depth to Groundwater

Depth to groundwater would also factor into the travel time of petroleum from the point of release to groundwater. Where groundwater is relatively shallow, contaminants can reach groundwater more quickly than in areas where groundwater is deeper, given similar soil types. Where groundwater is in contact with the proposed pipeline, releases from the pipeline would immediately impact groundwater quality nearest the release. Groundwater depths for the purposes of this Final Supplemental EIS were identified on an area-wide basis from wells on or near the proposed route. Specific depths and subsurface hydrogeologic conditions along the entire proposed route would be determined during final investigations and design.

Once specific information is available, then groundwater impacts along the proposed route can more specifically be determined. Following this Final Supplemental EIS, the proponent would prepare final design and installation documents and plans; one of those plans that would be

[9] Dissolved-phase plume: The portion of a released material that becomes dissolved in groundwater and moves along the direction of groundwater flow.
[10] *Attenuation* is a reduction in velocity, volume, extent, and/or concentration.

required is an Integrity Management Plan[11] that specifically identifies sensitive receptors and, among many other requirements, outlines a plan to mitigate releases.

Aquifer Gradients and Hydraulic Conductivity

Groundwater flow gradient and hydraulic conductivity of the aquifer materials affect the migration rates of LNAPL and dissolved-phase petroleum products in groundwater. Gradient is a function of potentiometric differential (i.e., the tendency of water to flow from areas of higher pressure or elevation to areas of lower pressure or elevation). Hydraulic conductivity is a measure of the ability of the fractured or porous aquifer media to transmit fluid; typically, the smaller the grain size of the aquifer material, the lower the hydraulic conductivity. The groundwater flow velocity in an aquifer is the product of the gradient and the hydraulic conductivity; therefore, the higher the gradient and hydraulic conductivity of an aquifer, the higher the velocity of fluid flow through the aquifer.

As an example, the shallow water-bearing zones in the NHPAQ in eastern Nebraska have an average horizontal flow velocity of about 0.1 feet per day (ft/d) based on an observed gradient of 0.002 (Bleed and Flowerday 1998) and a maximum hydraulic conductivity of 50 ft/d (Gutentag et al. 1984). For the Bemidji release mentioned above, the reported groundwater flow velocity was 0.1 ft/d, and estimates of the aquifer soil hydraulic conductivity ranged from 1.25 to 152 ft/d (Strobel et al. 1998). The average flow velocity in the shallow water-bearing zones of the NHPAQ system is similar to that at Bemidji, and the hydraulic conductivity reported for these zones are also within the range of values reported for Bemidji.

Vertical flow within and between aquifers is also important to consider when evaluating contaminant migration, and is driven by pressure differentials within and between water-bearing units. For example, vertical groundwater flow between the water-bearing units in the NGPAS within the proposed pipeline area is typically upward, while groundwater flow from the Ogallala Formation is downward in areas where the underlying aquitards (e.g., the Pierre Shale) are absent. Vertical flow velocities are typically at least an order of magnitude less than horizontal flow velocities in aquifer systems.

Aquifer-Specific Contamination Risk Evaluation

Based on the release and migration dynamics of refined petroleum products and crude oil in the subsurface as discussed above, the potential risk and likely magnitude of potential impacts to groundwater quality in each of the aquifers and aquifer groups along the proposed pipeline area in Montana, South Dakota, and Nebraska are evaluated in the following subsections. The final subsection provides an overview of the presence of shallow groundwater in the proposed Project vicinity, as well as water wells reported within 1 mile of the proposed Project.

Extreme weather conditions such as heavy precipitation and associated flooding or a long drought can impact the distance from a release point to the water table. In the case of heavy rains, the water table could rise closer to the pipeline thereby decreasing travel time before

[11] The Integrity Management Plan is designed to, at minimum, comply with the Final Rule entitled *Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Hazardous Liquid Operators With 500 or More Miles of Pipeline)*, Title 49, Code of Federal Regulations, Part 195 Section 452 (49 CFR § 195.452), which was promulgated by the U.S. Department of Transportation (DOT), Research and Special Programs Administration (RSPA) and published on December 1, 2000.

groundwater would be impacted. Conversely, severe droughts would have the opposite effect, increasing travel times and thereby potentially lessening impacts from releases but possibly increasing concentrations.

Alluvial Aquifers and Northern High Plains Aquifer

Alluvial aquifers and the NHPAQ represent the most commonly used sources of groundwater in the proposed pipeline area. Many private and public wells extract groundwater from these aquifers, including those in several SWPAs in the proposed pipeline area. Compared to the other aquifers in the region (Great Plains Aquifer [GPA], Western Interior Plains Aquifer [WIPA], and NGPAS), these aquifers also are typically at highest risk of contamination from the proposed Project construction and operation because of the relatively shallow depth of water tables in the alluvial and NHPAQ aquifers (commonly <50 feet) and the relatively high permeability of the aquifers and overlying material. The combination of an extensive groundwater-use profile and high sensitivity to releases from the proposed pipeline area make these aquifers particularly sensitive to potential releases.

No information regarding conditions related to large-scale petroleum releases was readily accessible for the alluvial aquifers or NHPAQ along the proposed pipeline area; however, the crude oil release in Bemidji, Minnesota, previously discussed, occurred in an environment similar to the NHPAQ and alluvial aquifers. At that location, approximately 20 years after the release, the leading edge of the LNAPL oil remaining in the subsurface at the water table had moved approximately 131 feet downgradient from the spill site, and the leading edge of the dissolved contaminant plume had moved about 650 feet downgradient.

Although the subsurface conditions in the NHPAQ or alluvial aquifers as compared to the Bemidji spill site are not identical, the aquifers exhibit similar characteristics that affect groundwater flow and contaminant transport. The Bemidji site provides a reasonable physical model to establish expectations for the behavior of crude oil released in the NHPAQ system and alluvial aquifers. The Bemidji site studies and information from many other petroleum releases (as described in Section 4.13, Potential Releases) in similar conditions suggest that a spill of similar magnitude in the NHPAQ and alluvial aquifer systems would remain localized to a similar extent as the Bemidji plume.

The results of an evaluation of the Bemidji release and other petroleum releases indicate that the dissolved-phase petroleum contaminant plume from a large-scale release that reaches groundwater in the NHPAQ and alluvial aquifers could be expected to affect groundwater quality up to several hundred feet downgradient of the release source. The LNAPL plume, if any, could be expected to affect a significantly smaller distance downgradient of the release. Downward vertical migration may occur, but the lower specific gravity of petroleum material limits the downward migration of contaminants under all but the most robust vertical gradient conditions in aquifers. Even under such conditions in which groundwater flow to deeper aquifers occurs, similar attenuation to contaminant flow would be expected as with the shallower aquifer, and lateral extent of the petroleum contaminants within the deeper aquifer would typically be similar in magnitude to those described for shallow aquifer distribution.

The presence of the high nitrate concentrations common in the shallow groundwater of the NHPAQ and alluvial aquifers in Nebraska may promote degradation of some portion of the crude oil released into groundwater. Nitrate in groundwater typically encourages biologic degradation of dissolved-phase petroleum hydrocarbons in groundwater.

Aquifer conditions in the NHPAQ in the proposed Project area indicate that recharge to shallow groundwater is typically from local precipitation and surface water, and shallow groundwater generally discharges to local surface waterbodies. Recharge of shallow groundwater in this area typically does not come from deeper aquifer units or from horizontal flow across long distances. Therefore, petroleum releases from the proposed Project would not be expected to affect groundwater quality within recharge areas that provide a source of groundwater to large portions of the NHPAQ or associated alluvial aquifers. Likewise, drought conditions would tend to lessen the impacts to groundwater because the pipeline to groundwater distance is increased and the groundwater gradient is lower, slowing the spread of petroleum hydrocarbons (although possibly increasing concentrations).

Great Plains Aquifer

Across most of the proposed pipeline area where the GPA is present, it is very unlikely that any releases from the proposed pipeline would affect groundwater quality in the aquifer because the aquifer is typically deeply buried beneath younger, water-bearing sediments and/or aquitard units.

Near the proposed pipeline area in southern Nebraska, where the aquifer is closer to the surface and contains groundwater with low salinity, the GPA is typically overlain by water-bearing sediments of the NHPAQ and alluvial aquifers. Water quality in the GPA could be affected by releases in this area, but only under conditions of a strong downward gradient in the overlying aquifer units. Although a significant downward, vertical gradient is observed between the GPA and overlying aquifers across much of Nebraska, downward gradients in the proposed pipeline area in southern Nebraska are minimal or absent. Given the expected scale, characteristics, and behavior of potential petroleum releases related to the proposed pipeline, it is very unlikely that the proposed pipeline area could affect water quality in the GPA.

Northern Great Plains Aquifer System

After the NHPAQ and alluvial aquifers, the NGPAS represents the third most commonly used groundwater resource in the proposed pipeline area. Hydrogeologic conditions within the NGPAS are relatively complex, with several different aquifer and confining units present; however, within the proposed pipeline area, usable groundwater is typically limited to the Tertiary and Late Cretaceous formations within the aquifer group. The upward groundwater gradient across the NGPAS indicates that only those aquifer portions near the ground surface would be susceptible to water quality impacts from potential releases from the proposed pipeline area.

If a release impacts NGPAS aquifer system water quality, similar fate and transport of the petroleum products as those described for the NHPAQ and alluvial aquifers would be expected. Based on available information, the downgradient extent of groundwater impacts related to a large-scale release would typically be limited to several hundred feet of the release source, similar in scale to that expected from a large-scale release to the NHPAQ or alluvial aquifers.

Shallow aquifer conditions in the NGPAS in the proposed pipeline area indicate that recharge to shallow groundwater is typically a mixture of local precipitation, surface water, and water moving upward from lower aquifers under an upward gradient; therefore, it is not expected that petroleum releases would affect significant groundwater resources within areas that provide groundwater recharge to large portions of the NGPAS. A release would likely impact very shallow groundwater, but the spread and depth of penetration would be limited because of the upward gradient from lower aquifers.

Western Interior Plains Aquifer

There is extremely low probability that a release from the proposed pipeline area would affect water quality in the WIPA given the relative typical depth of the WIPA of several hundred feet in the proposed Project area.

Shallow Groundwater and Water Wells

Table 3.3-1 provides a summary of those areas where water-bearing zones are within 50 feet of the ground surface in the proposed pipeline area. These areas are typically found within alluvial aquifers along streams and rivers, within the Ogallala Formation in southern South Dakota and Nebraska, and within the overlying NDEQ-identified Sand Hills Unit alluvium in Nebraska. A summary of known and potential groundwater use along the proposed Project for each state is as follows:

- In Montana, 523 known and reported wells are present within 1 mile of the proposed Project (see Figure 3.3.2-2). No public water supply (PWS) wells or SWPA are located within this area. A total of six private water wells are located within approximately 100 feet of the proposed pipeline area within McCone, Dawson, Prairie, and Fallon counties.
- In South Dakota, 105 known and reported wells are present within 1 mile of the proposed Project (see Figure 3.3.2-3). One PWS well (associated with the Colome SWPA) is identified within 1 mile of the proposed pipeline in Tripp County. This PWS well is screened at a relatively shallow depth (reportedly <54 feet bgs) within the Tertiary Ogallala Formation. The proposed pipeline area would pass through the Colome SWPA in Tripp County. No private water wells are located within approximately 100 feet of the proposed pipeline area in South Dakota.
- In Nebraska, 2,398 known and reported wells are present within 1 mile of the proposed Project pipeline (see Figure 3.3.2-4). A total of 38 known PWS wells are present within 1 mile of the proposed pipeline in Boyd, Boone, York, Fillmore, Saline, and Jefferson counties. The nine SWPAs within 1 mile of the proposed pipeline area include those for the towns of St. Edward, Bradshaw, York, McCool Junction, Exeter, Western, Jansen, and Steele City, and the Rock Creek State Park. The only SWPA traversed by the proposed pipeline area in Nebraska is in Steele City, Jefferson County. A total of 14 private water wells are located within approximately 100 feet of the proposed pipeline area within Antelope, Polk, York, Fillmore, and Jefferson counties.

If a release from the proposed pipeline impacted groundwater wells, Keystone would be required to contact the applicable regulatory authorities and determine agency requirements for the most appropriate course of action (see Section 4.3.3.1, Groundwater, above for Nebraska, Montana, and South Dakota requirements). Those actions might include well abandonment, providing alternate water supplies, and site remediation. Nebraska has specifically required this notification as well as water supply replacement planning and commitment in the NDEQ Supplemental

Environmental Report. South Dakota and Montana have similar requirements. These actions would be detailed in the Keystone spill response plan. Further, if during construction or operation activities an unregistered well is found, Keystone would provide the landowner with technical assistance to register the pre-existing, unregistered well at the landowner's request.

Groundwater Extraction Effects

Construction of the proposed Project would require use of water for activities such as dust control, directional drilling, and hydrostatic testing of the pipeline. It is likely that at least some of the water used for construction would be come from existing groundwater resources in the vicinity of the proposed Project. Since the proposed Project construction effort would be of relatively short duration, it is unlikely that groundwater extraction related to the Project would affect long-term water levels in any aquifer units along the route.

Effects Related to Proposed Pump Stations

Potential groundwater impacts related to the proposed pump stations include releases of refined petroleum products during construction and operation of the pump stations and/or releases of crude oil from the proposed Project during pipeline operation. The extent of groundwater impacts would be dependent on many factors, such as the volume and duration of releases, constituent properties, depth to groundwater, soil characteristics, location of operating water supply wells that would influence hydraulic gradients, aquifer characteristics (e.g., hydraulic conductivity, transmissivity, storativity), and whether the releases reach surface water because groundwater is typically interconnected with surface waterbodies.

Effects Related to Pipe Yard Development

Potential groundwater impacts related to construction and operation of the proposed pipe yard and rail siding in Bowman County, North Dakota would be related to releases of refined petroleum products used as vehicle fuels and lubricants. These releases would typically be relatively small in volume, and downward migration of the petroleum compounds through the soil to groundwater would be minimal based on the depth to groundwater and the fine-grained shale and coal intervals of the Fort Union Group, which would tend to slow and/or prevent downward migration. There is a low potential for groundwater impacts depending on the volume and extent of the release. The extent of groundwater impacts for any releases that reach groundwater at the North Dakota proposed pipe yard and rail siding would be influenced by the same characteristics and parameters discussed above

4.3.3.2 Surface Water

Impacts to surface waters from the proposed Project may occur as a result of a crude oil spill during pipeline testing and operations. A distance of 10 miles downstream has been selected for impact evaluation. This distance was selected as the area within which overall potential affects to resources may occur beyond the modeled distance of oil spreading. Generally, spill plumes would possibly migrate up to 10 miles with residual crude oil materials traveling further. More information regarding impacts resulting from a pipeline spill is provided in Section 4.13, Potential Releases.

The Missouri River in Montana and South Dakota is a source for two rural/tribal water systems: the Fort Peck Assiniboine & Sioux Rural Water Supply System (ASRWSS) and the Mni Wiconi Rural Water Supply System (MWRWSS).

ASRWSS operates a surface water withdrawal from the Missouri River near Poplar, Montana. The diversion is approximately 77 river miles downstream of the proposed Project crossing. The proposed pipeline ROW does not cross any ASRWSS-related infrastructure.

MWRWSS operates a surface water withdrawal from the Missouri River near Pierre, South Dakota. The proposed pipeline ROW would cross MWRWSS water distribution infrastructure at various locations. The U.S. Bureau of Reclamation (BOR) has supplied Keystone with specific requirements and conditions for the construction of pipeline crossings of MWRWSS infrastructure. The BOR, in conjunction with its American Indian tribal partners, may have additional recommendations or comments during subsequent permit and design reviews. The proposed project would follow BOR crossing design and construction requirements as supplied or subsequent requirements as determined necessary by BOR to protect BOR infrastructure.

Impacts to both of these systems would predominantly be operational and stem from potential spills of transported fluids. Impacts to the intake systems and water treatment facilities include additional treatment, increased maintenance, and possibly the temporary loss of supply during spill response and cleanup. Impacts to these water system intakes are anticipated to be infrequent and the result of residual spill material migrating downstream. The possibility of a spill reaching either the ASRWSS intake near Poplar, Montana, or the MWRWSS intake in Pierre, South Dakota, is exceptionally remote due to the following factors: Based on the risk assessment in Appendix P of the FEIS and the consequence analysis by E^{x}ponent 2013, a distance of at least 10 miles downstream from the proposed pipeline was recommended for the identification of sensitive resources that could be affected by a release from the proposed pipeline. A buffer distance of 10 miles downstream has been selected for impact evaluation in the FEIS and Final Supplemental EIS process. Residual crude oil spill materials such as tar balls could travel farther than 10 miles but would not have a widespread effect on surface water resources. The distance from the pipeline crossing to the ASRWSS intake is over 70 miles, and the MWRWSS intake is over 100 miles, both of which are significantly beyond the proposed Project impact assessment buffer. Additionally, depending upon the width of the individual stream crossing and including an additional 500-foot buffer distance from each stream bank, a release event probability is estimated to be one in 18,000 years to one in 47,500 years.

Conditions specific to the MWRWSS are:

- The Lake Oahe reservoir and dam are upstream of the intake and provide a significant barrier to a spill plume or residual material reaching the MWRWSS intake.
- The distance from the pipeline crossing to the Bad River confluence with the Missouri River is 44 miles. The MWRWSS intake is on the Missouri River and more than 3 miles upstream from the confluence with the Bad River.

Section 4.13, Potential Releases, addresses the nature of and response to pipeline crude oil spills. Impacts such as loss of service for portions of the MWRWSS infrastructure would be possible during construction or repair activities associated with the proposed Project. These impacts would be similar in nature to those associated with typical proposed Project crossings of a water supply or other infrastructure. Industry standard care and precautions would be necessary to prevent damage to water supply infrastructure by excavation equipment or related activities.

Spills of crude oil are possible from damage to the proposed Project infrastructure by maintenance and repair work conducted on MWRWSS infrastructure. MWRWSS contractors would take extra precautions to locate and notify the proposed Project operator in the event of MWRWSS infrastructure maintenance or repairs that may be required near Keystone infrastructure.

The proposed Project would potentially affect waterbodies through construction activities and maintenance activities across the states of Montana, South Dakota, and Nebraska. Potential impacts to water features classified as either open water or riverine are addressed in Section 4.4, Wetlands. A pipe yard and rail siding in North Dakota and pump stations in Kansas would be constructed to support the operation of the proposed Project; due to the lack of significant surface water features at either location, these ancillary facilities would be unlikely to affect surface water quality. It is possible that some minor intermittent drainage swales could be impacted, to the extent such are present in the disturbed areas.

The proposed Project route has been selected and modified to minimize the potential for impacts to surface water resources, as well as other sensitive environments, by avoiding them whenever possible and shifting the route to limit the area affected. Table 4.3-1 presents a summary of potential impacts to mapped surface water resources by state based on the proposed Project route. The final pipeline route may be adjusted based on site conditions, at the request of landowners, or additional regulatory review. These adjustments may reduce impacts and eliminate crossings. For example, where the proposed Project parallels a stream reach and crosses several meanders, the pipeline may be offset during regulatory review and, as a result, not have any crossings in that stream reach.

Table 4.3-1 Summary of Impacts to Surface Water Resources by State[a]

	Montana	South Dakota	Nebraska
Total Waterbodies Crossed	459	333	281
Perennial Waterbodies Crossed	9	16	31
Intermittent Waterbodies[b] Crossed	424	313	237
Other Waterbodies Crossed	26	4	13
Waterbodies with State Use Classifications	15	10	40
Waterbodies with Impairments	9	5	10
Mapped Floodplains	12	4	74
Total Width of Mapped Floodplains (miles)	6.2	1.7	16.2

Source: MDEQ, South Dakota Department of Environment and Natural Resources 2012 and NDEQ 2012a and 2012b; Please also refer to data tables in Section 3.3, Water Resources

[a] The summary numbers in this table are for waterbodies and surface water resources that the proposed pipeline would cross.
[b] For the purposes of the Final Supplemental Environmental Impact Statement (Final Supplemental EIS) and based on limitations of the desktop level of investigation, intermittent and ephemeral waterbodies are assessed as a single category of stream.

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Construction-Related Impacts

Construction activities could result in the following potential impacts on surface water:

- Temporary increases in total suspended solids concentrations and increased sedimentation during stream crossings or at upland locations with soil erosion and transport to streams.
- Temporary to long-term changes in channel morphology and stability caused by channel and bank modifications.
- Temporary to long-term decrease in bank stability and resultant increase in total suspended solids concentrations from bank erosion as vegetation removed from banks during construction is re-establishing.
- Temporary reductions in stream flow and potential other adverse effects during hydrostatic testing activities and stream crossing construction.
- Impacts to surface water resources associated with hazardous liquids spills and leaks. See Section 4.13, Potential Releases. Construction water uses, construction camp potable water, and pipeline testing withdrawals from surface waterbodies.

Stream Crossings and In-Stream Construction Activities

Depending on the type of stream being crossed, one of six construction methods would be used: non-flowing open cut, flowing open cut, dry flume, dry dam-and-pump, HDD, or horizontal bores.

Open-cut methods would be used at most crossings unless deemed infeasible due to site conditions during construction or where other methods better protect sensitive waterbodies, as determined by the appropriate regulatory authority.

The HDD method would be used to cross 14 major or sensitive waterbodies (see Section 3.3, Water Resources, for a listing of specific crossings).[12] The river crossing procedures and measures to reduce impacts included in the CMRP would be implemented. For waterbody crossings where HDD would be used, disturbance to the channel bed and banks would be minimized, although temporary impacts could occur as a result of accessing the waterbody to withdraw water for hydrostatic testing and for HDD make-up water. Make-up water used for the drilling fluids could, if allowed, be extracted from local surface waterbodies, imported from more distant sources, or extracted from groundwater wells near the HDD crossing. This would be a temporary and limited use of these water resources.

In some instances, pressurized fluids and drilling lubricants used in the HDD process have the potential to escape the active HDD bore, migrate through the soils, and come to the surface at or near the crossing construction site, an event commonly known as a frac-out. Measures identified in a required HDD contingency plan would be implemented, including monitoring of the directional drill bore, monitoring downstream for evidence of drilling fluids, and mitigation measures to address a frac-out should one occur.

[12] In addition to these 14 waterbody crossings, Keystone has designated the Ash Creek Bluff location where an HDD installation would be used in order to mitigate construction impacts to a steep hillside slope. This HDD installation would not cross under Ash Creek.

Permitting requirements would vary based on crossing method, designated waterbody use, and regulatory jurisdiction. Where the HDD method is used for major waterbody crossings or for waterbody crossings where important fisheries resources could be impacted, a site-specific plan addressing proposed additional construction and impact reduction procedures would be developed (see Appendix G, CMRP). Prior to commencing any construction activities at regulated stream-crossings, permits would be required under Section 404 of the Clean Water Act (CWA) through the U.S. Army Corps of Engineers (USACE) and Section 401 Water Quality Certification, per state regulations. Some crossings may require additional permitting under Section 10 of the Rivers and Harbors Act. The agencies responsible for this review could require additional measures to further limit potential project impacts. In addition, water resources projects on designated segments that are determined to have a direct and adverse effect on the free-flowing condition, water quality, or the values for which the rivers were established are prohibited unless impacts can be avoided or eliminated.

Permits required under Sections 401, 402 and 404 of the CWA could include additional site-specific conditions as determined by USACE and appropriate state regulatory authorities. The CWA is U.S. federal law adopted to govern water pollution and maintain regulatory standards to insure surface water resources are fit for human uses and recreation by establishing designated uses and water quality criteria. Section 404 authorizes activities affecting U.S. waters by permit. The USACE is authorized to issue general and individual permits. General permits include Nationwide Permits and are intended to cover a variety of common activities. Individual Permits address more complex activities that are not covered by conditions regulated by general permits and generally more in-depth analysis than general permits. States also have a role in Section 404 decisions through State program general permits, water quality certification, or program assumption.[13] The section 401 certification program allows states to provide 404 permitted projects certification, conditional certification, denials, or waivers. This process allows states to independently incorporate conditions to maintain water quality based on state specific priorities. These conditions enable states to identity issues and the appropriate mitigations and protective measures they require during construction of projects such as the proposed Project, which are permitted under the nationwide portions of the CWA. Keystone has agreed upon many conditions and developed construction plans that would address these potential state concerns. Additional requirements and conditions may be applied during the final permitting review and approval process. More detailed descriptions of each of the crossing method and measures to reduce impacts associated with each method are provided in Appendix G, CMRP, and in Chapter 2.0, Description of the Proposed Project and Alternatives.

Additional review under Section 10 of the Rivers and Harbors Act could be required for some waterbodies. For navigable water crossings regulated under Section 10 (such as the Yellowstone and Missouri rivers), scour depth calculations would be required to show the maximum expected depth of scour at those locations. This evaluation would include the expected scour depth of the riverbed for a range of flows, including very high flows such as the 100-year and 500-year flows.

[13] http://water.epa.gov/lawsregs/guidance/cwa/dredgdis Water: Discharge of Dredged or Fill Materials (404) - Section 404 Permitting

Temporary crossings would be designed and located to minimize damage to stream banks and adjacent lands. The use of temporary crossings could reduce the impacts to the waterbodies by providing access for equipment to specific locations. These crossings would be designed and constructed to provide unimpeded fish and aquatic organism passage during the period the crossing is in place.

Following completion of waterbody crossings, waterbody banks would preferably be restored to preconstruction contours or to a stable slope. Stream banks would be seeded for stabilization and mulched or covered with erosion control fabric in accordance with the CMRP and applicable state and federal permit conditions. Additional erosion control measures would be installed as specified in any permit requirements. Appropriate care in design and installation would be used with erosion control measures, as these have the potential to cause unintended adverse environmental impacts. For example, placement of rock along the bank at a crossing could induce bank failure further downstream.

Many of the rivers in the proposed Project ROW are unstable and have high sediment supply systems with dynamic active channel(s), depositional bars, and active bank margins. Some of the larger rivers crossed by the proposed Project, such as segements of the Yellowstone and Missouri Rivers in Montana, the Cheyenne River in South Dakota or the Platte River, Loup River, and Prairie Creek in Nebraska are all drainage systems capable of substantial lateral channel migration, bank retreat, and subsequent re-activation of historic floodplains and channels during the life of the proposed Project. All states affected by the proposed Project are prone to ice jams on their major rivers, which often cause substantial backwatering and lateral scour. Channel migration zones (CMZs) are defined by the corridor that each river is expected to occupy over a given timeframe and are based on physical geomorphic parameters and local geologic control. As an example, CMZs for the Yellowstone River in Montana have been mapped (Yellowstone River Conservation District Council 2009) as part of an effort by state and federal agencies to provide additional information for minimizing impacts to major surface water and natural resources, including avoidance of poor development decisions and subsequent damage or loss of infrastructure and property. The proposed Project would incorporate CMZ evaluations in the final design of waterbody crossings.

The minimum pipeline cover at crossings of waterbodies, ditches, drainages, and other similar features would be 5 feet (see Table 2.1-15). The proposed Project has stated this minimum cover depth in the project CMRP (see Appendix G) and has further committed to this minimum cover depth in PHMSA Special Condition 19. Minimum cover depths would be measured to the top of pipe or any coatings and concrete weights applied to the pipe. The pipeline would be installed at the minimum water crossing depth for a distance of at least 15 feet beyond each side of the waterbody.

Where major waterbodies are crossed using the HDD method, the depth from the streambed to the top of the pipe would depend on a number of factors for each crossing design including the width of the crossing and potential scour depth of the waterbody being crossed. The proposed Project supplied HDD installation drawings for the FEIS evaluation (FEIS Volume 5, Appendix D, Site Specific Waterbody Crossing Plans). These plans indicate a typical minimum depth of 30 feet from lowest channel elevation to the top of pipe or coating. The plan supplied for the Niobrara river in Nebraska indicates a depth of over 60 feet from the lowest point in the channel to the top of pipe.

The implementation of appropriate measures to protect pipeline crossings from channel incision and channel migration can reduce the likelihood of washout-related emergencies, reduce maintenance frequency, and limit adverse environmental impacts. The design of the crossings also would include the specification of appropriate stabilization and restoration measures.

Wild and Scenic Rivers

The Wild and Scenic Rivers Act (WSRA) was enacted to preserve the free-flowing condition of rivers with outstanding natural and recreational values. The WSRA designates WSR segments, establishes procedures for adding additional river segments to the list, and provides guidance on how those river segments should be managed. A Wild and Scenic designation protects a river's outstandingly remarkable values and free-flowing character; protects existing uses of the river; prohibits federally-licensed dams and imposes restrictions on other federal and federally-assisted projects that would negatively impact the river's outstanding values; establishes a quarter-mile protected corridor on both sides of the designated river segment; and requires the creation of a cooperative river management plan that addresses, among other things, resource protection, development of lands and facilities, and user capacities. A Wild and Scenic designation does not prohibit development, does not affect water rights, and does not affect existing uses. Uses compatible with the management goals of a particular river are allowed.

The WSRA does not specify any buffer zone spacing or specific criteria by which water resources projects are reviewed. Impacts to designated segments determined to have a direct and adverse impact on the Wild and Scenic qualities of the rivers are prohibited unless impacts can be avoided or eliminated. Additionally, water resources projects upstream, downstream, or on tributaries that would affect the area or unreasonably diminish the scenic, recreational, or fish and wildlife values of the rivers would also require review.

The proposed Project crosses the Niobrara River in Nebraska between two WSRA-designated segments on the Niobrara and Missouri Rivers. The Niobrara National Scenic River segment is approximately 12 miles upstream of the proposed Project MP 626.0, and the Missouri National Recreational River is approximately 46 miles downstream of the proposed Project. The proposed Project does not cross either of these WSR segments. There are several areas along the Niobrara and Missouri Rivers under study for Wild and Scenic designation, and these areas are avoided by the proposed project as well. The National Park Service (NPS) has regulatory authority for the U.S. Department of the Interior (DOI) on Wild and Scenic segments in accordance with Section 7(a) of the WSRA (16 United States Code § 1278). As required under WSRA, USACE would contact the DOI/NPS to determine the need for Section 7(a) evaluations for any Section 404 and 401 permit application initiated under the CWA at all pipeline river crossings, including those upstream, downstream, and on tributaries to the WSRA-designated segments of the Niobrara and Missouri Rivers..

As part of the surface water impact evaluation, a sub-analysis was conducted at the request of the NPS to assess the potential impact of a release from the proposed Project to protected water bodies (National Scenic River, WSR, and National Recreational River) of the Niobrara and Missouri River. This analysis calculated the probability of a spill occurring from the proposed pipeline focusing on the tributary streams that could convey a spill to the specially designated water body. Stream crossings, stream widths, and spill travel distances were identified using GIS and the NHD. Spill incident frequencies were calculated using two different sets of historical pipeline spill data from PHMSA: first, a broader data set including crude oil pipelines greater than 16 inches in diameter; second, a more focused data set narrowed to pipeline spills that impacted surface water. (See Section 4.13.3.5, PHMSA Historical Data, and Appendix K, Historical Pipeline Incident Analysis, for additional information.) The analysis identified that there are 39 stream crossings within 40 miles upstream of the specially designated water bodies that could connect a spill from the proposed Project to the waterbody. Seven of these streams flow perennially, and the remaining streams either flow intermittently or are undefined. Most stream crossings are not large; the average width of the stream crossings is 9 feet, and the largest crossing is 110 feet.

Spill frequencies for stream crossings were calculated based on the total combined distance of all stream widths, including an additional 500-foot buffer distance from each stream bank. The probability of any spill occurring within 500 feet of a stream crossing that could convey a spill to a protected waterbody is one spill every 542 years, based on all historical spills from pipelines greater than 16 inches in diameter. Using data for historical spills that impacted surface water, the probability of any spill occurring within 500 feet of a stream crossing that could convey a spill to a protected waterbody is one spill every 1,202 years. The shortest distance a spill would have to travel to impact a protected waterbody is approximately 29 miles.

Based on the above spill probability, it is unlikely that a spill event would occur during the operational life of the pipeline at one of the identified stream crossings. Additionally, the distance from the proposed pipeline to the specially designated river segments further reduces the probability of a spill reaching the protected waterbodies. Nonetheless, in the event of a large spill or undetected release of sufficient duration, some oil could reach a specially designated river segment if flowing water was present within the stream at the time of a release.

In addition to the NPS requested sub-analysis, the DOI has specific requirements, recommendations, and comments related to HDD and open-cut crossing construction activities that are proposed for use upstream of National WSR segments or tributary rivers as well as streams of WSRA-designated rivers, including the associated floodplain areas (DOI 2012). The open-cut wet crossings pipeline installation method has a high potential to impact water resources during construction activities. This method would typically involve excavation of the channel bed and banks of a flowing stream. Construction equipment and excavated soils would be in direct contact with surface water flow. The degree of impact from construction activities would depend on flow conditions, stream channel conditions, and sediment characteristics.

For the types of crossings listed below, the following measures would be implemented on a site-specific basis:

- Contaminated or Impaired Waters – If required, specific crossing and sediment handling procedures would be developed with the appropriate regulatory agencies, and agency consultation and recommendations would be documented and implemented.
- Sensitive/Protected Waterbodies – If required, specific construction and crossing methods would be developed in conjunction with USACE and U.S. Fish and Wildlife Service (USFWS) consultation or other agencies as applicable. The appropriate method of crossing these waterbodies would be determined by the appropriate agency as applicable.
- HDD Crossings – A frac-out contingency plan would be developed in consultation with the regulatory agencies to address appropriate response and crossing implementation in the event of a frac-out during HDD crossings. Implementation of measures as described in the

proposed Project CMRP (see Appendix G) and additional conditions from permitting agencies would reduce adverse impacts that would result from open-cut wet crossings. All contractors would be required to follow the identified procedures to limit erosion and other land disturbances. The CMRP describes the use of buffer strips, drainage diversion structures, sediment barrier installations, and clearing limits, as well as procedures for waterbody restoration at crossings. (See Chapter 2.0, Description of the Proposed Project and Alternatives, and Appendix G, CMRP, for a discussion of the proposed waterbody crossing methods.)

State Permitting

State-level permitting would also be required for pipeline crossings of state-regulated surface waters. Each state with waterbodies crossed by the proposed Project would have authority under CWA section 401 to protect water quality in waters of the state. This process will depend in part on the federal permitting process and what level of permitting is applied to the proposed Project. The CWA defines a state's role in the 401 Water Quality Certification process. Each state's acceptance or denial of the federal Nationwide Permit program dictates whether additional state level review and possible conditions may be required for a particular Nationwide Permit.

In Montana, the MDEQ may issue state-wide permits for crossings. Some crossings may require location-specific permitting and conditions. This permitting process may also require that where open-cut methods are used, any flowing surface water would be diverted, pumped, or flumed around the trench at pipeline crossings. This would be required where water is present or where significant storm runoff may occur during the construction period. As a result, the non-flowing open-cut and flowing open-cut crossing methods may not be applicable for some regulated crossings under the Section 401 authority of the MDEQ. For CWA Permits, a separate Section 401 review by the MDEQ may be required.

In South Dakota, the Department of Environment and Natural Resources is responsible for CWA permit certification and would review proposed stream and river crossings where necessary and may issue project-specific conditions. During project review, South Dakota my impose similar stipulations to conditions outlined for Montana.

In Nebraska, the Department of Environmental Quality has issued a 401 certification or a significant number of Nationwide Permits; however, it has supplied general additions and modifications under its CWA 401 authority. Additionally the state has denied in part or added specific conditions to other Nationwide Permits. The state of Nebraska is likely to have additional regulatory conditions and permitting to that of Montana and South Dakota.

Stream crossings would need to be protected from erosion and sedimentation. Keystone has submitted plans for erosion control and revegetation, which are provided in Appendix G, CMRP. Additional erosion control and revegetation documentation could be required under supplemental state or federal regulations. For example, MDEQ would require compliance with MEPA, under which Keystone would provide a Storm Water Pollution Prevention Plan. The South Dakota Public Commission Order includes specific measures for protecting stream crossings, such as restricting excavated soil placement, maintaining protective buffers around streams, and revegetating riparian areas with native plant species. In Nebraska, trenches through waterbodies that are dry or contain non-moving water at the time of crossing would not be left open for more than 24 hours to reduce sediment discharge from a sudden storm event resulting in runoff. This commitment would not apply where excavation of rock by blasting or mechanical means may be required in the waterbody.

Pump Stations

In addition to pipeline crossings, the locations of pump stations were evaluated for potential impacts to surface waters. The NHD (U.S. Geological Survey 2012) indicates that three proposed pump station boundaries (PS-9 in Phillips County, Montana; PS-10 in Valley County, Montana; and PS-20 in Tripp County, South Dakota) are currently located in areas that contain unnamed intermittent streams. Aerial imagery indicates these areas are tilled fields or fenced range locations crossed by grassy swales. Field surveys also indicated that PS-9 is located in tilled crop land and is not in an intermittent stream. Field surveys in the spring of 2009 and 2010 of PS-10 indicated a rill/drainage feature without water present. For PS-20, field surveys did not identify any intermittent streams at this location.

The initial location and design supplied for PS-24 in Nebraska near the Loup River, while not placed in a mapped floodplain, indicates that PS-24 may have limited or no access during periods of flood. It is possible for one or more access routes to be impassable during high water events. As the location and design for PS-24 is finalized, Keystone has indicated that the proposed Project would develop an access plan for this pump station that takes into account access issues during flood conditions. Any other pump stations located near known flood areas would also be evaluated for access during flood conditions.

Hydrostatic Testing and Water Withdrawals

Water hydrostatic testing is performed to expose defective materials or welds that have missed prior detection, expose possible leaks, and serve as a final validation of the integrity of the constructed system. A hydrostatic test is conducted on individual segments of pipeline prior to completion. Buried high-pressure oil pipelines are tested for strength by pressurizing them to pressures above the maximum pressure that would be used during pipeline operations along their length with water drawn from local water sources. As allowable, water used for hydrostatic testing would be obtained from nearby surface water resources, groundwater, or municipal sources. These sources include streams, rivers, privately owned reservoirs, and private or public wells.

Table 4.3-2 lists the surface waterbodies that may be considered for potential hydrostatic test water sources along the proposed Project route as provided by Keystone. The proposed Project CMRP Section 8 (see Appendix G) specifies the applicant’s committed actions for securing pipeline hydrostatic test water. The Federal Energy Regulatory Commission (FERC) has developed criteria for the minimum separation distance for hydrostatic test manifolds from wetlands and riparian areas appropriate for natural-gas-pipeline construction. Although the proposed Project is not subject to FERC authority, hydrostatic test manifolds would be located more than 100 feet away from wetlands and riparian areas to the maximum extent possible, consistent with FERC criteria.

Table 4.3-2 Potential Hydrostatic Test Water Sources along the Proposed Project Route[a, b, c, d]

County	Approximate Milepost	Waterbody Name	Maximum Water Withdrawal (million gallons)
Montana			
Phillips	25	Frenchman Creek	32
Valley	83	Milk River	32
Valley/McCone	89	Missouri River	55
Dawson	196	Yellowstone River	55
South Dakota			
Harding	295	Little Missouri River	27
Harding	315	Gardner Lake	67
Perkins	361	North Fork Moreau River	36
Meade	430	Cheyenne River	35
Haakon	486	Bad River	22
Tripp	541	White River	39
Nebraska[e]			
Boyd	618	Keya Paha River	37
Holt	626	Niobrara River	37
Antelope	713	Elk Horn River	37
Nance	762	Loup River	37
Polk	775	Platte River	47

[a] These volumes are estimated at this time. Final volumes would be included in appropriate water use permits for each state. At that time, the state permitting agency would determine which rivers can be used, whether it approves the volume, and any permitting conditions associated with the withdrawals. Water would be used for hydrostatic test water, drilling mud for HDD operations, and dust control.
[b] Additional water sources would be needed for dust control. These additional sources would require lower volumes (up to 6 million gallons on average). Dust control water sources would be permitted in accordance with state permit requirements and could include existing irrigation wells.
[c] Groundwater sources (irrigation wells) may be used for water sources instead of the rivers listed. These water sources and the volumes to be used would be purchased from landowners and would be permitted in accordance with state requirements.
[d] These water volumes would be required for the duration of construction.
[e] Additional water would be withdrawn from irrigation wells in several counties crossed by the proposed Project for dust control, hydrostatic testing, and HDD operations.

In an effort to avoid or minimize impacts to sensitive waterbodies, Keystone would take into account environmental conditions when developing plans and obtaining required permitting for water withdrawal from surface waterbodies such as stream crossings in already depleted and drought-prone watersheds.

During droughts, surface water withdrawal permits from larger rivers with existing water rights would be regulated by state regulatory agencies to preserve existing water rights and environmental requirements. If adequate water is not available from rivers, Keystone would use alternative water sources nearby such as local private wells or municipal sources for HDD operations, hydrostatic testing of the mainline, and dust control during these dry conditions. Keystone has indicated that in the event surface water is unavailable, groundwater would be used for HDD operations, hydrostatic testing, and dust control. Water would be purchased from nearby willing sellers with available water rights.

Additionally, the proposed Project would cross the central Platte River using the HDD method at approximate Milepost 775. Activities associated with the proposed Project in that area include temporary water withdrawals for drilling fluids and hydrostatic testing. Lower Platte River Basin water depletions in Nebraska could affect resources by reducing the amount of water available in the Basin. The state of Nebraska in cooperation with the USFWS has developed plans to manage water depletions in conjunction with Section 7 Endangered Species Act consultations (USFWS 2009a). For the proposed Project, temporary water withdrawals during hydrostatic testing in the lower Platte River Basin would avoid impacts to resources since the volume of water needed would be returned to its source within a 30-day period. Temporary water withdrawals are considered to have no effect, as described by the USFWS Platte River species *de minimus* depletions threshold, which states “temporary withdrawals of water (e.g., for hydrostatic pipeline testing) that return all the water to the same drainage basin within 30 days' time are considered to have no effect, and do not require consultation” (USFWS 2009b). Sections 3.8 and 4.8 discuss potential impacts to threatened and endangered species and species of conservation concern.

Withdrawals from impaired or contaminated waterbodies would be avoided and only used if approved as a water source. All surface water resources used for hydrostatic testing would be approved by the appropriate permitting agencies prior to initiation of any hydrostatic testing activities. Planned withdrawal rates for each water resource would be evaluated and approved by these agencies prior to use. No resource would be used for hydrostatic testing without receipt of applicable permits. As stated in Section 8.2 of the proposed Project CMRP (see Appendix G), required water analyses would be obtained prior to obtaining any water for filling or any discharging operations associated with hydrostatic testing.

The water withdrawal methods described in the proposed Project CMRP would be implemented and followed. These procedures include screening of intake hoses to prevent the entrainment of fish or debris, keeping the hose at least 1 foot from the bottom or bed of the water resource, prohibiting the addition of chemicals into the hydrostatic test water, and avoiding discharging any hydrostatic test water that contains visible oil or sheen (from pipe or equipment) following hydrostatic testing activities. Any contaminated water would be disposed of in accordance with local, state, and federal regulations.

As a standard procedure and as part of its water withdrawal and discharge permits, Keystone would identify water rights, as per state requirements, that could be affected by temporary interruptions of water flow. Keystone would also abide by mitigation measures outlined in applicable water withdrawal and discharge permits to protect sensitive receptors, such as fisheries.

Hydrostatic test water would be discharged at an approved location along the waterway/wetland or to an upland area within the same drainage as the source water where it may evaporate or infiltrate. Discharged water would be tested for water quality prior to release in the environment to ensure it meets applicable water quality standards imposed by the discharge permits for the permitted discharge locations. Hydrostatic test water would be tested for water quality during storage or during transfer to storage prior to discharge. If needed, hydrostatic test water can be stored in the pipe following testing or in portable storage vessels or containment. Where hydrostatic test water does not meet standards for discharge proper, treatment or disposal is required. The proposed Project CMRP incorporates additional measures designed to minimize the impact of hydrostatic test water discharge, including regulation of discharge rate, the use of energy dissipation devices, channel lining, and installation of sediment barriers as necessary.

4.3.3.3 Operational-Related Impacts

Surface water impacts associated with potential crude oil spills from pipeline operation are addressed in Section 4.13, Potential Releases.

Channel migration or streambed degradation could expose the pipeline, resulting in temporary, short-term, or long-term adverse impacts to water resources; however, protective activities such as reburial or bank armoring would be implemented to reduce these impacts. As described in the proposed Project CMRP (see Appendix G), a minimum depth of cover of 5 feet below the bottom of all waterbodies would be maintained for a distance of at least 15 feet to either side of the edge of the waterbody. General channel incision or localized headcutting could threaten to expose the pipeline during operations. In addition, channel incision could sufficiently increase bank heights to destabilize the slope, ultimately widening the stream. Sedimentation within a channel could also trigger lateral bank erosion, such as the expansion of a channel meander opposite a point bar. Bank erosion rates could exceed several feet per year. Not maintaining an adequate burial depth for pipelines in a zone that extends at least 15 feet beyond either side of the active stream channel could necessitate bank protection measures that would increase both maintenance costs and environmental impacts. Potential bank protection measures could include installing rock, wood, or other materials keyed into the bank to provide protection from further erosion or re-grading the banks to reduce the bank slope. Disturbance associated with these maintenance activities has the potential to create additional water quality impacts.

The proposed Project would use reasonable care and employ generally accepted engineering practices in the design phases of the proposed Project to insure the proper evaluation of the potential for channel aggradation/degradation and lateral channel migration. The level of assessment for each crossing would vary based on the best judgment of the design personnel. The proposed pipeline would be installed as determined to be necessary to address any hazards identified by the assessment. The pipeline would be installed at the design crossing depth, which may exceed the minimum cover depth of 5 feet over the top the pipe for waterbody crossings, and extend for at least 15 feet beyond each side of the waterbody being crossed. The design of the crossings would also include the specification of appropriate stabilization and restoration measures.

The measures to protect water resources during operations are specified in the CMRP (see Appendix G). In South Dakota, the water protection conditions that were developed by the South Dakota Public Utility Commission as part of its Amended Final Decision and Order (Notice of Entry HP09-001) would be implemented.

4.3.3.4 Floodplains

The proposed pipeline would cross mapped and unmapped floodplains in Montana, South Dakota, and Nebraska. The proposed pipeline would be constructed under many river channels with potential for vertical and lateral scour. In floodplain areas adjacent to waterbodies, the contours would be restored to as close to previously existing contours as practical, and the disturbed area would be revegetated following construction in accordance with the CMRP (see Appendix G). Therefore, after construction, the proposed pipeline would not obstruct flows over designated floodplains, resulting in only minor changes to topography, and thus would not affect local flood dynamics or flood elevations.

Ancillary features such as pump stations, mainline valves, and access roads in mapped and unmapped floodplain areas would be assessed prior to permitting and designed to minimize impacts to floodplains. These facilities would be constructed after consultation with the appropriate county agencies to ensure that the design meets county requirements and to obtain the necessary permits associated with construction in the 100-year floodplain zones. Table 4.3-3 shows the infrastructure in mapped floodplains.

Table 4.3-3 Ancillary Facilities Crossing Designated Floodplain Areas for the Proposed Pipeline Route

State	County	Approximate Project ROW Milepost[a]	Waterbody Associated with Floodplain[b]	Facility Type[c]	Ancillary Facility Identifier
MT	Valley	60	Spring Creek	Access Roads	CAR-084, CAR-225
MT	Valley	62	Morgan Creek	Transmission Line	PS-10
MT	Valley	66	Cherry Creek	Transmission Line	PS-10
MT	Valley	72	East Fork Cherry Creek	Transmission Line	PS-10
MT	Valley	83 - 86	Milk River	Access Roads Transmission Line	CAR-120, CAR-122, CAR-123 PS-10
MT	Valley & McCone	89 - 91	Missouri River	Access Roads HDD portals	CAR-124, CAR-125 2
MT	McCone	148 - 149	Redwater River	Transmission Line	PS-12
MT	Dawson	197 - 198	Yellowstone River	Access Roads HDD portal Valve Other	CAR-127, CAR-292 1 MLV-10 PY-07 SITE 4
SD	Harding	295	Little Missouri River	HDD portal Transmission Line	1 PS-15
SD	Haakon	486	Bad River	Transmission Line	PS-19
SD	Lyman & Tripp	541 - 542	White River	Access Roads HDD portal	CAR-080, CAR-237 1
NE	Boyd	618	Meglin Cr	Access Road	CAR-306
NE	Boyd	618	Unnamed Tributary to Keya Paha River	Access Road	CAR-306
NE	Boyd	618	Keya Paha River	Access Road HDD portal	CAR-307 1
NE	Boyd	626	Niobrara	HDD portal	1
NE	Antelope	713 - 714	Elkhorn River	Access Roads HDD portal	CAR-253, CAR-286 1
NE	Nance	761 - 762	Loup River	Access Roads HDD portals	CAR-264, CAR-268 2
NE	Polk	775 - 776	Platte River	HDD portal	1
NE	York	801 - 802	Unnamed Tributary to Beaver Creek	Access Road	CAR-274, CAR-218

State	County	Approximate Project ROW Milepost[a]	Waterbody Associated with Floodplain[b]	Facility Type[c]	Ancillary Facility Identifier
NE	Saline	838 - 838	Unnamed Tributary to North Fork Swan Creek	Access Road	CAR-280

[a] Ancillary facilities floodplain crossings are listed by the proposed Project milepost numbers and are not necessarily adjacent to the proposed Project ROW at that milepost.
[b] Ancillary facilities may cross unmapped floodplain areas.
[c] Additional ancillary facility floodplain crossings may be incurred when final route adjustments are made.

4.3.4 Additional Mitigation

The following mitigation measures are included in addition to those proposed or planned by Keystone:

- USEPA and other previous commenters have recommended consideration of ground-level inspections as an additional method to detect leaks. The PHMSA report (2007) on leak detection presented to Congress noted that there are limitations to visual leak detection, whether the visual inspection is done aerially or at ground-level. A limitation of ground-level visual inspections as a method of leak detection is that pipeline leaks may not come to the surface on the ROW and patrolling at ground level may not provide an adequate view of the surrounding terrain. A leak detection study prepared for the Pipeline Safety Trust noted: "A prudent monitor of a pipeline ROW would look for secondary signs of [spills] such as vegetation discoloration or oil sheens on nearby land and waterways on and off the ROW" (Accufacts 2007). PHMSA technical staff concurred with this general statement and noted that aerial inspections can provide a more complete view of the surrounding area that may actually enhance detection capabilities. Also, Keystone responded to a data request from the U.S. Department of State (the Department) concerning additional ground-level inspections and expressed concerns that frequent ground-level inspection may not be acceptable to landowners because of the potential disruption of normal land use activities (e.g., farming, animal grazing). Although widespread use of ground-level inspections may not be warranted, in the start-up year it is not uncommon for pipelines to experience a higher frequency of spills from valves, fittings, and seals. Such incidences are often related to improper installation or defects in materials.
- Dust suppression chemical runoff could adversely impact sensitive areas and areas of high water quality present in the proposed Project area. Many of these chemicals are salts of various formulations. Overuse could cause potential localized degradation of groundwater quality where groundwater is near the surface. Part 2.14 of the Revised CMRP mentions the use of calcium chloride as an element of the proposed Project's dust control program with its application limited to roads only. Water-only dust suppression applications near sensitive surface and ground water resources would provide additional protection for these sensitive resources and eliminate the need for salt-based compounds in these areas. Additional protective measures may be required by the appropriate regulating agencies.
- This proposed Project could require authorization under the NDEQ National Pollutant Discharge Elimination System Construction Storm Water General Permit. Conditions of this permit may require modifications to the stabilization of disturbed ground procedure(s) as

discussed within the CMRP. Namely, the Construction Storm Water General Permit requires that ground inactive for 14 days be stabilized (either permanent or temporary stabilization) where National Pollutant Discharge Elimination System permit conditions would supersede any state-level regulation that is less stringent.

- Keystone has supplied a completed HDD design for the Yellowstone River crossing, which accommodates the 100-year CMZ and locates the entry and exit points outside that identified CMZ. Public sources for 100-year CMZ mapping is not readily available for the remaining rivers crossed by the proposed Project. For the stream crossings, designs where 100-year CMZ data does not exist, Keystone referenced available sources including 100-year flood data, conducted additional scour analysis, performed a lateral migration analysis, and reviewed historic aerial imagery to evaluate scour and lateral migration based on the design life of the pipeline (50 years).
- Permitting agencies may require access structures such as culverts and bridges necessary for the proposed Project's long-term operation over regulated waterbodies to meet design and construction conditions that ensure unimpeded fish and aquatic organism passage during the lifetime of the structure. Many recent and reliable engineering manuals provide methods for designing and constructing fish-friendly, road-stream crossings. These methods could be used when road-stream crossings on fish-bearing streams require permitted design.
- For construction camps built along the proposed pipeline route, construction activities and pipeline testing would use water from surface waterbodies, imported water, or groundwater from a local well. Water would be used for drinking, dust suppression, vehicle washing, and other purposes. Water withdrawal from surface waterbodies or wells would need to be permitted and approved by various agencies and water rights owners. There are currently plans for four construction camps in Montana, three in South Dakota, and one camp in Nebraska. Waterbodies with habitats and species sensitive to or potentially impacted by flow reductions would be thoroughly analyzed to prevent adverse effects.

4.3.5 Connected Actions[14]

4.3.5.1 Bakken Marketlink Project

Groundwater

No significant large-scale potable water aquifers underlie the Bakken Marketlink Project area, although alluvium is likely present that contains potable groundwater. The Upper Cretaceous Hells Creek/Fox Hills Aquifer of the NGPAS underlies the area, but water quality in this area of the aquifer is relatively saline. Larger potable water aquifers within recent alluvium are present within several miles to the east and west of the Bakken Marketlink Project area, and Lower Tertiary rocks of the NGPAS containing potable water are present within a few miles west of the western terminus of the Bakken Marketlink Project area (Whitehead 1996, LaRocque 1966). Well depths are also typically greater than 50 feet. Because of the limited amount of potable water that would be directly beneath the Bakken Marketlink Project area and the significant

[14] Connected actions are those that 1) automatically trigger other actions which may require environmental impact statements, 2) cannot or will not proceed unless other actions are taken previously or simultaneously, 3) are interdependent parts of a larger action and depend on the larger action for their justification.

depth to groundwater in this area, it is not likely that releases would significantly impact groundwater resources in the area (see Sections 3.3.2, Groundwater, and 4.3.3.1, Groundwater, for additional discussion of the NGPAS).

Surface Water

Construction and operation of the Bakken Marketlink Project would include metering systems and three new storage tanks near Baker, Montana. Based on a GIS analysis of the planned route and intersections with waterbodies identified in the 2012 NHD, the preliminary Bakken Marketlink Project route would cross seven intermittent waterbodies as well as one perennial waterbody, Sandstone Creek, which has beneficial uses listed in the MDEQ Final Water Quality Integrated Report (MDEQ 2012).

The property proposed for the Bakken Marketlink Project facilities near the proposed Project PS-14 is currently used as pastureland and hayfields. A site inspection of the property indicated that there were no waterbodies or wetlands on the property. The potential impacts associated with expansion of the pump station site, to include the Bakken Marketlink Project facilities, would likely be similar in scope and duration to the proposed Project. The Bakken Marketlink Project pipeline construction and operations would also likely be similar in scope and duration to those of the proposed Project.

4.3.5.2 Big Bend to Witten 230-kV Transmission Line

Groundwater

Groundwater along the alignment of the Big Bend to Witten 230-kV Transmission Line is present primarily in recent alluvium of the White and Missouri Rivers and in Quaternary glacial deposits near the Missouri River. Groundwater is typically present at depths of less than 50 feet bgs in these unconsolidated deposits. The deposits overlie the Cretaceous Pierre Shale, which is a regional aquitard. Water-bearing units of the GPA and WIPA beneath the Pierre Shale are typically saline and not used for drinking water or irrigation purposes.

Potential impacts to groundwater resources related to the installation and operation of the Big Bend to Witten 230-kV Transmission Line are expected to be limited to small-scale refined petroleum product releases related to vehicle operations and fueling. Hydrogeologic conditions and fate and transport of releases would be similar to conditions described for alluvial aquifers in the proposed pipeline area.

Surface Water

The Big Bend to Witten 230-kV electrical transmission line would cross three perennial streams along the preferred route (see Appendix J, Basin Electric Big Bend to Witten 230-kV Transmission Project Routing Report). Potential impacts to crossings of surface water resources would be minimized by spanning them entirely. Transmission project construction would use a typical span length ranging from 650 to 950 feet. The largest perennial waterbody crossed is the White River, which has a maximum waterbody width of 570 feet.

In addition, the transmission line would run parallel to and within 100 feet of perennial and intermittent streams for a cumulative distance of 28,000 feet. As determined by permitting agencies, an adequate buffer between the transmission line corridor and adjacent surface waters would be needed to minimize continued impacts to surface water features during initial construction and long-term operation and maintenance activities.

4.3.5.3 Electrical Distribution Lines and Substations

Groundwater

Potential impacts to groundwater resources related to the installation and operation of electrical transmission lines associated with the proposed pipeline area are expected to be limited to small-scale refined petroleum product releases related to vehicle operations and fueling during operations and maintenance. Hydrogeologic conditions and fate and transport of releases would be similar to conditions described for the proposed pipeline area adjacent to the planned transmission lines.

Surface Water

The proposed Project would require electrical service from local power providers for pump stations and other aboveground facilities in Montana, South Dakota, Nebraska, and Kansas.

Based on a GIS analysis of the planned locations for electrical lines, substations, and intersections with waterbodies identified in the 2012 NHD, there would be a total of 217 waterbodies crossed in Montana; of that total, Duck Creek is the only waterbody classified as perennial: 192 waterbodies are intermittent, 13 are canals/ditches, and 12 are unidentified waterbodies. Using the same GIS comparison, there would be a total of 250 waterbodies crossed in South Dakota. Of the total, 16 are perennial, 218 are intermittent, and 16 are unidentified waterbodies. In Nebraska, there would be an approximate total of 281 waterbodies crossed. These include 31 perennial, 237 intermittent, and 13 unidentified waterbodies. The existing Keystone pump station facilities in Kansas would need new electrical transmission distribution lines installed. Westar has supplied a route design for the transmission line between Osage Road and Redwood Road for the Keystone PS-27 (Riley pump station) in Clay County Kansas. This segment crosses one perennial and one intermittent waterbody. The design indicates appropriate avoidance of surface water impacts associated with pole locations and access ways.

There is no information provided regarding the locations of poles or other on-the-ground features associated with the remaining Kansas pump station transmission routes that could impact the waterbodies identified above; however, effects on surface waters are expected to be limited based on permitting requirements and generally accepted practices used during the construction of distribution lines. These lines typically span surface waterbodies; equipment crossings are likely to use existing access or temporary crossings; and standard construction erosion controls are employed to limit sedimentation, similar to methods that would be used for the proposed pipeline.

Poles placed in effective and designated floodplain areas have the potential to snag and collect debris being conveyed by flood water. Poles in these locations would be inspected to remove any accumulated debris as necessary following flood subsidence. Obstructions in the floodplain have the potential to induce scour and sedimentation; however, based on typical sizing and spacing of poles, the affects to the environment are considered negligible.

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4.13 POTENTIAL RELEASES

4.13.1 Introduction

This section describes potential releases associated with the construction and operation of the proposed Project and connected actions and discusses mitigation measures that would avoid or minimize the frequency of releases and the severity of the potential impacts. The information, data, methods, and/or analyses used in this discussion are based on information provided in the 2011 Final Environmental Impact Statement (Final EIS), as well as new circumstances or information relevant to environmental concerns that have become available since the publication of the Final EIS, including the proposed reroute in Nebraska. The information that is provided here builds on the information provided in the Final EIS, as well as the 2013 Draft Supplemental EIS and, in many instances, replicates that information with relatively minor changes and updates; other information is entirely new or substantially altered.

Specifically, the following information, data, methods, and/or analyses have been substantially updated from the 2011 Final EIS:

- Updated Pipeline Hazardous Material Safety Administration (PHMSA) data up to July 2012 were reviewed.
- Incident[1] rate estimates from PHMSA were expanded in detail to include linear and discrete pipeline elements.
- Spill volume distributions for both linear and discrete pipeline elements were expanded, and spill volume trends were summarized as derived from PHMSA incident data.
- The spill occurrence interval for stream crossings was revised.
- Spill transport modeling was completed for various spill volumes based on spill size distribution categories derived from PHMSA data to identify potential plume sizes, including surface plumes and groundwater impact.
- Sensitivity analysis on spill transport modeling results was completed.
- Potential spill impacts to various resources were estimated such as soils, vegetation, wildlife, wetlands, water wells, and cultural resources.
- Lessons learned from recent pipeline spills, such as the spill impacting the Kalamazoo River in Michigan, were added.
- Section 4.13.6, Additional Mitigation, provides a list of additional mitigation measures to further reduce impacts from potential releases.

The following information, data, methods, and/or analyses have been substantially updated from the 2013 Draft Supplemental EIS:

- PHMSA data were compared to other pipeline incident datasets to identify the variability in incidents related to transporting dilbit and heavy crude oil.

[1] The terms *incident* and *accident* can be used interchangeably or with specified definitions in various agency reports and databases. For the purposes of this report, the term *incident* has been selected for document consistency.

- Added new information on diluted bitumen corrosivity from the National Academy of Sciences.
- Further explanation was provided on how the PHMSA Special Conditions would work to reduce the threat of a release and the benefits that would be created when the conditions are implemented.
- Pipeline leak detection standards publications were identified.
- Updated PHMSA incident data from July 2012 to July 2013 were reviewed.
- Sensitivity analysis was conducted to evaluate assumptions used to calculate incident frequencies for mainline pipe and pump stations.
- Incident rate for reported pipeline injury, fatality, fire, and explosion incidents was added.
- Incident analysis for pipelines 10 years old or less was added.
- Potential incident occurrence (year/incident) for pipeline specifications similar to the proposed Project was conducted and added.
- An incident rate analysis from PHMSA data for first year pipeline releases has been added.
- Additional text on the characteristics of sinking oil was added.
- Remediation detail of sinking oil and the inclusion Kalamazoo dredging was expanded.
- Independent engineering and environmental consequences reports were included.
- An independent risk assessment report was included.
- First-year incident spill response events for the Keystone pipeline were added.
- Lessons learned were updated based on recent pipeline incidents, bulletins, and reports.
- In response to public and agency comments, text has been revised throughout the section where necessary.
- The list of additional mitigation measures included in Section 4.13.6 was revised.

Summary

As discussed in Section 3.13, Potential Releases, several threats could lead to a potential release of pipeline contents during construction and operation of the proposed Project. An analysis of historic incidents, based on the PHMSA database, shows the following:

- Spill volumes from larger-diameter pipelines tend to be larger than those from smaller-diameter pipelines.
- The primary release causes for pipeline components are equipment failure (valves, etc.) and incorrect operations (tanks).
- The primary release causes for the pipeline, not including components, are outside forces and corrosion.

- For all crude oil pipelines, the majority of spills (96 percent) are in the small (up to 50 barrels [bbl]) to medium (50 to 1,000 bbl) size.
- A general spill frequency can statistically be estimated for the mainline pipe.

An independent analysis conducted by Battelle on the effect of applying the PHMSA Special Conditions indicates they could result in a sizable reduction in spill frequency (Leis et al. 2013).

There is potential for product spills during normal operations to affect natural resources, protected areas, human uses, and services. Although leak detection depends on a number of factors, modern pipeline systems are designed to automatically detect leaks. The amount and type of environmental resources that a spill could affect vary depending on the following:

- Cause
- Size
- Type
- Location
- Season
- Geomorphology (the changing terrain)
- Timing and degree of response actions

Spill size is also affected by the following:

- Size of the hole;
- Pipeline pressure;
- Time it takes to detect the leak;
- Time it takes to shut down the pipeline and isolate the leak after detection;
- Pipeline diameter;
- Pipeline elevation change between the valves and the leak location;
- Distance between isolation valves; and
- Effectiveness of the isolation.

The historical pipeline incident analysis (see Appendix K) shows that the majority of spills would likely be in the small to medium range and would occur on construction sites or at operations and maintenance facilities. Once identified, spill response would typically be rapid. For medium (50 to 1,000 bbl) to large (greater than 1,000 bbl) spills, spill size and impact are more sensitive to response time.

Spill modeling (see Appendix T, Screening Level Oil Spill Modeling) indicated that a spill could reach groundwater and move downgradient (essentially, *downhill* underground and on land) for a spill of any size. If a spill were to occur along the buried pipeline, contents could leak into nearby soil and move both vertically and horizontally. If it were to reach groundwater, it could potentially pool and create a dissolved area of chemicals in the groundwater. If an operating well were close enough to use the source of the affected groundwater, humans or animals could be exposed to dissolved chemicals. If the leak were to reach the surface and move horizontally along the ground, it could affect local vegetation, animal life, and surface water such as streams and rivers. Once oil were released into the environment, however, natural processes—including evaporation, degradation (i.e., where bacteria consume the oil), and dilution (the product mixes with water)—would begin to break it down immediately.

If a spill were to occur, the degree of impact to water, people, livestock, soil, and other natural resources would depend on the distance from the spill source. This could be affected by the local environmental conditions present in the area surrounding the leak (e.g., if a leak were to occur at the top of a hill it could flow over a greater distance and affect more resources). Maximum buffer zones (i.e., the estimated maximum distance that oil from a spill would be expected to travel) were calculated for surface waterbodies (10 miles), stream crossings (500 feet [ft]), and surface water drinking water resources (5 miles) (see Appendix P, Risk Assessment). As mentioned in Section 4.13.4.2, Spill Propagation, there are many factors that would generally limit the spreading of most spills over much smaller distances. In addition, maximum distances were calculated using the three different spill sizes (i.e., small, medium, and large) with the finding that oil could spread radially on a flat surface between 112 and 1,214 ft from the pipeline, and that if oil were to reach groundwater, it could spread radially between 640 and 1,050 ft away from the spill point (see Appendix T, Screening Level Oil Spill Modeling). These distances were calculated using a screening model and were based on a spill volume that pooled and spread radially away from the center. The distances were also supported by independent work done by E^xponent (E^xponent 2013).

Other potential spill propagation scenarios (e.g., ground surface to surface water, channeling, etc.) are discussed in Section 4.13.4.2, Spill Propagation. Small spills have the potential to affect groundwater encountered at depths up to 50 ft below ground surface (bgs). It is possible that, under some spill conditions, a small spill could reach groundwater encountered at depths below 50 ft, but it is unlikely. Medium and large size spills could reach groundwater encountered at depths below 50 ft.

The PHMSA Special Conditions were developed to design the pipeline above current minimum safety requirements. Applying the Special Conditions could have a sizable reduction in spill frequency (Leis et al. 2013), as well as the extent of impact if a spill were to occur. If a spill were to occur during construction activities, Keystone has prepared written procedures (i.e., Construction, Management, and Reclamation Plan; Spill Prevention, Control, and Countermeasure [SPCC] Plan) to address a response action. In summary, the response plans include notification procedures, response actions, response teams, and spill impact considerations. Keystone would work with federal, state, and local agencies to clean up any spill that occurred.

Connected actions include the Bakken Marketlink Project, the Big Bend to Witten 230-kilovolt (kV) Transmission Line, and electrical distribution lines and substations. A spill from the Bakken Marketlink Project could potentially impact similar receptors as with the proposed Project.

The scope of this assessment as it relates to pipeline risk and the potential for releases from proposed Project construction and operation within areas that would be crossed by the proposed pipeline route and connected actions is described below.

4.13.2 Proposed Project Background

The proposed Project would include processes, procedures, and systems to prevent, detect, and mitigate potential oil spills that could occur during operation of the pipeline. These are summarized in the subsections below. An Emergency Response Plan (ERP) would contain further detail on response procedures and would be completed and reviewed by PHMSA prior to granting permission to operate the proposed pipeline. PHMSA would also provide the ERP to the U.S. Environmental Protection Agency (USEPA) for their review.

To assess the likelihood of operational releases from the proposed Project, spill risk assessments were conducted as described below. These risk assessments address both the potential frequency of operational pipeline releases and the potential volumes of crude oil associated with the releases. The magnitude of a potential oil spill impact is primarily a function of spill size, oil type, and sensitivity of the receptors affected (American Petroleum Institute [API] 1992, 1997; National Research Council 1985, 2003a, 2003b). Variations in spill size and receptor type are key variables for estimating the magnitude of potential environmental impacts of oil spills from the proposed Project.

Spills ranging in magnitude from small (less than 50 bbl) to large (greater than 1,000 bbl) could occur anywhere along the pipeline system, including construction sites, operations and maintenance facilities, and within the pipeline right-of-way (ROW). Rapid containment and cleanup would be expected to reduce surface oil spreading and its potential infiltration into the ground. For all spills, especially those that reached water resources, the response time between initiation of the spill event and arrival of the response contractors would influence the potential magnitude of impacts to environmental resources. Once the responders were at the spill scene, the efficiency, effectiveness, and environmental sensitivity of the response actions (e.g., containment and cleanup of oil, protection of resources from further oiling[2]) would substantively influence the type and magnitude of potential additional environmental impacts.

The combined implementation of industry integrity management standards and practices aid in reducing the potential for spill incidents associated with the proposed Project; these include those developed by the National Association of Corrosion Engineers International and American Society of Mechanical Engineers, PHMSA regulatory requirements as defined in Title 49 of the Code of Federal Regulations (CFR) Part 195, and the set of proposed Project-specific Special Conditions developed by PHMSA and agreed to by TransCanada Keystone Pipeline, LP (Keystone). As stated in the Final EIS, the U.S. Department of State (the Department), in consultation with PHMSA, has determined that incorporation of those conditions (the below referenced industry standards and practices, combined with PHMSA regulatory requirements and the set of proposed Project-specific Special Conditions developed by PHMSA) would result in a Project that would have a degree of safety over any other typically constructed domestic oil pipeline system under current code and a degree of safety along the entire length of the pipeline system similar to that required in High Consequence Areas (HCAs), as defined in 49 CFR 195.450. Appendix B, Potential Releases and Pipeline Safety, and Section 4.13.6.1, PHMSA Special Conditions, describe each of the Special Conditions.

[2] Covering with oil.

The Keystone XL pipeline has a lower probability of experiencing a spill due to the combined application of the design standards and the addition of the Special Conditions, which add a greater degree of safety over the pipeline systems with reported spill events in the PHMSA incident database. Keystone is taking preventive actions over and above the current regulatory requirements by designing the entire pipeline to a level of protection similar to that required for an HCA (Leis et al. 2013). Federal, state, and local agencies would participate in response activities consistent with their authorities and duties under applicable regulations and in accordance with the requirements of the ERP. Additional mitigation measures have been suggested by these regulatory agencies and are described in Section 4.13.6, Additional Mitigation.

For the discussion on spills[3], the terms *release*, *leak*, and *spill* are used as follows:

- A *release* is a loss of integrity (failure to contain oil as designed) of a pipeline or its components;
- A *leak* is a release over time; and
- A *spill* is the liquid that escapes a designed containment system, if present, and enters the environment.

The total volume of a spill is a combination of the following:

- Size of breach;
- Pipeline pressure;
- Time to detect leak;
- Time to shut down pipeline and isolate the leak after detection;
- Pipeline diameter;
- Elevation profile;
- Distance between isolation valves; and
- Effectiveness of the isolation.

The hole size and pipeline pressure are the primary factors that determine the leak rate from the breach until the leak is detected and isolated. After the leak has been detected and isolated, the volume of liquid in the pipeline between the isolation valves (i.e., valves that stop the flow of pipeline contents) could continue to leak from the pipeline until the hole is repaired. The total volume released is dependent on a number of factors such as hole size, pipeline pressure, pipeline elevation, and the distance between isolation valves.

Keystone would commence shutdown in the following instances:

- On indication of multiple hydraulic or leak triggers including leak alarm, pressure indication, hydraulic signature of flow and pressure, and pump station trip;
- On notification from a third party or employee call-in identifying a release;

[3] It applies to the entire pipeline system.

- On confirmation that a single Supervisory Control and Data Acquisition (SCADA) indication or leak alarm has indicated an actual release; or
- No later than 10 minutes after the initial annunciation to the controller if a single SCADA indication or leak alarm cannot be explained.

No investigation is required before a controller initiates a shutdown of the pipeline of any kind. If the pipeline is shut down for a suspected release, Keystone's procedure requires a technician investigate and, if found to be a false alarm, to have field and Oil Control Center management approval prior to restart of the pipeline. Leak detection depends on a number of factors. In modern pipeline systems, SCADA sensors are designed to automatically detect leaks large enough to produce noticeable changes in pipeline pressure and flow rates. The sensors have a monitoring threshold because pipeline operating variables normally fluctuate within a working range. The SCADA system, in conjunction with Computational Pipeline Monitoring or model-based leak detection systems, would detect leaks to a level of approximately 1.5 to 2 percent of the pipeline flow rate. This range is consistent with the current technical standard range of 1 to 2 percent. Computer-based, non-real time, accumulated gain/loss volume trending would be used to assist in identifying low rate or seepage releases below the 1.5 percent to 2 percent by volume detection thresholds. Smaller leaks may also be identified by direct observations by Keystone or the public. Keystone has stated it could detect a leak above the 1.5 to 2 percent volume threshold within 102 minutes. If pressure, flow, and temperature sensors, in combination with software, detected a deviation exceeding a threshold, an alarm would sound and the control room would enter a 10-minute evaluation window. If the evaluation is indeterminate at the end of the window or a potential leak is confirmed, the control room would shut down the pipeline. During this detection, investigation, and subsequent shutdown time, oil could leak from the pipeline and create a spill. Oil could also spill during a smaller leak that is under the SCADA detection threshold. Keystone has indicated that it will begin validating and utilizing in-line inspection leak detection devices in its hazardous liquid pipelines in 2014 that have the potential to detect leaks below the 1.5 to 2 percent threshold.

Once the leak is detected and confirmed, the operator shuts down operating pumping units, which eliminates the force that would maintain pressure on the pipeline. Isolation valves are also closed as part of shutdown. If a valve malfunctions and does not close properly, outflow could continue after shutdown, either at a reduced or unabated rate. The volume that escapes through ineffective valves would add to the spill. The volume contained in the mainline pipe between the isolation valves may also contribute to the spill. The proportion of the volume that actually leaks into the surrounding environment would vary depending on characteristics such as the topographic location of the spill along that route.

Recognizing the importance of leak detection, PHMSA has included leak detection provisions and considerations in several sections of 49 CFR Parts 192 and 195. In addition to regulations, PHMSA also issues Advisory Bulletins to advise and remind hazardous liquid pipeline operators of the importance of prompt and effective leak detection. In December 2012, PHMSA issued their Leak Detection Study (PHMSA 2012c) that describes the current understanding of pipeline leak detection in the United States. The report does not provide any conclusions or recommendations, only data.

Currently, various standards exist that address the issue of leak detection in liquids pipelines. Some of these standards include:

- API 1130 (*Computational Pipeline Monitoring for Liquids*);
- API 1149 (*Pipeline Variable Uncertainties and Their Effects on Leak Detectability*);
- API 1161 (*Guidance Document for the Qualification of Liquid Pipeline Personnel*);
- API 1164 (*Pipeline SCADA Security*);
- API 1165 (*Recommended Practice for Pipeline SCADA Displays*);
- CSA Z662 Annex E (*Recommended practice for liquid hydrocarbon pipeline system leak detection*) (Canada); and
- TRFL (*Technical Rule for Pipeline Systems*).

Monitoring wells have been used to assist with leak detection at petroleum industry facilities such as tanks, and could be a consideration for the proposed pipeline. Locations for such wells take into account the probability of successful detection and the sensitive resource being protected. Keystone has committed to additional analysis as part of its risk assessment to determine if any specific area along the pipeline would benefit from the placement of monitoring wells, and would install them if appropriate. This analysis would include assessing the efficacy of monitoring wells compared to other methods of leak detection that could detect leaks below the threshold (1-2 percent) of the current leak detection method. Keystone has indicated that it will begin validating and utilizing in-line inspection leak detection devices in its hazardous liquid pipelines in 2014 that have the potential to detect leaks below the 1.5 to 2 percent threshold.

4.13.3 Historical Pipeline Incidents Analysis

Analysis of historical pipeline incident data was conducted to understand what has occurred with respect to pipelines in the United States and Canada, and to provide input for spill impact analysis in this Final Supplemental EIS. Details in the PHMSA incident and mileage reports were analyzed to determine the distribution of historical spill volumes, as well as incident causes and frequencies of crude oil pipeline incidents contained in the PHMSA database. Although the results were not a direct indicator of the nature of possible incidents that could occur in association with the proposed Project, they could be used to provide insight into what could potentially occur with respect to spill volume, incident cause, and incident frequency.

4.13.3.1 Background

PHMSA collects data on hazardous liquid pipeline systems operating in the United States. These data could be used to provide insight into spill volume, incident cause, and incident frequency. Although other information sources were reviewed (see Section 4.13.3.4, Pipeline Incident Information Sources), PHMSA information was the most relevant for this Final Supplemental EIS and the only database that contained raw data.[4]

PHMSA collects information that is available to the general public on reportable pipeline incidents. Information collected for each incident includes the following:

[4] Raw data are data that have not been processed; they must be analyzed and/or manipulated for any meaningful information or conclusions to be drawn from them.

- The date of each reportable incident;
- The type of hazardous liquid associated with the pipeline involved in the incident;
- The volume of hazardous liquid spilled in the incident;
- The part of the pipeline system from which the spill originated;
- The diameter of the hazardous liquid pipeline involved in the incident; and
- The cause of the incident.

The total mileage of pipelines in operation in the United States is collected for each of the following:

- The type of hazardous liquid transported; and
- The diameter of the pipeline.

In addition, for each individual pipeline system in operation in the United States, the number of breakout tanks[5] in use is also collected. As defined for this discussion, linear elements refer to mainline pipe and girth welds, and discrete elements are pipeline components such as pumping stations, mainline valves, and breakout tanks.

4.13.3.2 Objectives

The objective of this pipeline incident analysis was to use PHMSA hazardous liquid pipeline incident data and hazardous liquid pipeline annual (mileage) data to determine the historical spill volumes, incident causes, and incident frequencies of crude oil pipeline spills in the United States. Additionally, this analysis provides separate determinations for mainline pipe and pipeline system discrete components.

4.13.3.3 Method

The method used for this analysis was to filter the PHMSA hazardous liquid incident database covering a fixed period of time by commodity type to obtain a subset of data specific to crude oil pipeline systems. Subsequent filtering of pipeline system component, pipeline diameter, and incident cause resulted in separate subsets of incident counts and associated reported spill volumes for pipeline mainline pipe, mainline valves, pipeline system tanks, and other discrete pipeline components. The historical spill size distributions and incident cause distributions could then be summarized for the time period covered.

By filtering the pipeline mileage data by type and pipeline diameter, an estimate of the total mileage of pipeline in service over the same fixed time period was made. Dividing the number of incidents by the number of mile-years of pipeline in service provides the frequency of historical incidents per mile-year of pipeline (incidents per mile-year is a standard measure for pipeline incidents; it represents the number of incidents for every 1,000 miles of pipeline over a duration of 1 year). Dividing the pipeline tank incidents by the number of tanks in service over the time period provides the frequency of historical tank incidents per tank-year (i.e., per tank per year).

[5] Breakout tanks are those used to a) relieve pressure surges in a hazardous liquid pipeline system or b) temporarily receive and store hazardous liquid transported by a pipeline for continued transportation by pipeline.

Finally, by estimating the average spacing of mainline valves and pumping stations on pipeline systems in service, the number of mainline valves and pumping stations in service could be approximated. Dividing the number of mainline valve incidents with the approximate number of mainline valves in service results in an approximate frequency of incidents per valve-year. Similarly, dividing the number of pipeline discrete incidents by the approximate number of pumping stations in service results in an approximate frequency of incidents per pumping station-year.

The number of incidents resulting from each filtering set is documented to provide a reference for error checking while performing the analysis.

4.13.3.4 Pipeline Incident Information Sources

Incidents that result in unintentional releases from hazardous liquid pipelines are reported by federal and some state and regional agencies.

National Data Sources

Pipeline and Hazardous Material Safety Administration

PHMSA is part of the U.S. Department of Transportation (USDOT). PHMSA is responsible for protecting the American public and the environment by ensuring safe and secure movement of hazardous materials to industry and consumers by all transportation modes, including the nation's pipelines. It is responsible for regulations that require safe operations of hazardous liquid pipelines to protect human health and the environment from unplanned pipeline incidents. Through PHMSA, USDOT develops and enforces regulations for the safe, reliable, and environmentally sound operation of the nation's 2.3-million-mile pipeline transportation system and the nearly 1 million daily shipments of hazardous materials by land, sea, and air. PHMSA administers the national regulatory program to ensure the safe transportation of hazardous liquids, including crude oil, by pipeline. PHMSA develops regulations that address safety in the design, construction, testing, operation, maintenance, and emergency response for hazardous liquid pipelines and related facilities. Many of the regulations are written as performance standards that set the level of safety to be attained and allow the pipeline operators to use various technologies to achieve the required level of safety.

Among its functions, PHMSA prepares incident and mileage reports. PHMSA incident report files and their originating data are available to the general public. The incident data used to create the pipeline incidents and mileage reports are available online (PHMSA 2012a). Reported incidents are available at the PHMSA Freedom of Information Act online library, which spans more than two decades. For the historical data review and historical frequency analysis sections of this report, significant incidents as described below in the PHMSA dataset were studied.

PHMSA distinguishes a serious incident as one that involves a fatality or injury requiring in-patient hospitalization. PHMSA designates significant incidents to include serious incidents as well as any one of the following:

- $50,000 or more in total costs, measured in 1984 dollars;
- Highly volatile liquid releases of 5 bbl or more or other liquid releases of 50 bbl or more; or
- Liquid releases resulting from an unintentional fire or explosion.

The pipeline incident data have been recorded with different reporting criteria in the past decades since the 1980s. Therefore, previous databases had different structures at different times. For this report, two PHMSA databases were used: one with data spanning from January 2002 to December 2009, and the other with data spanning from January 2010 to July 2012 (PHMSA 2012a). Basic database fields are present in both regarding incident information, such as incident number, incident date, commodity type, part of system involved, reported spill volume, reported incident cause, and others incident information.

Mileage reports, termed *Liquid Annuals Data*, summarize pertinent information on a yearly basis, including commodity type, pipeline diameter, year of installation or fabrication, mileage, and other pipeline features. These reports summarize the total population of pipelines in which the relevant incidents occurred.

The information requirements for incident reporting to PHMSA have increased over the years. The January 2010 to July 2012 dataset contains more fields with regard to loss estimation and root causes, which results in a more detailed characterization of spills compared to the 2002 to 2010 dataset. Not all 2002 to 2012 incident records are complete. Several important fields—such as incident cause, system part, item involved, and pipeline diameter—are often blank or null, ambiguous (indicated as *unknown* or *miscellaneous*), or incorrectly attributed, leaving the characterization of certain incidents undetermined or open to subjective interpretation. These null or ambiguous entries are more common in the older (pre-2010) datasets, given they contain 8 years of less detailed data versus 2 years of more detailed data in the 2010 to 2012 dataset, and thus bias the data toward less detail.

The reporting requirements also mean that a number of small spill incidents (less than 50 bbl for crude oil) are not represented. This could bias the historical data to result in lower spill frequency and larger spill sizes than what actually has occurred. The combined PHMSA incident data and mileage data do not contain sufficient information on the type of crude oil involved. The incidents are recorded as *crude oil* only. Thus, historic frequencies specific to dilbit or heavy crude oil cannot be determined using the PHMSA data alone.

Finally, the protective measures used in each pipeline are not detailed in the mileage data. This means that the effects of individual protective measures can also not be determined using the PHMSA data alone.

National Response Center

The National Response Center (NRC) is the primary point of contact in the federal government for reporting oil and chemical spills in the United States. A person may report a spill by contacting the NRC via a toll-free number or by filling out a reporting form at the NRC website (NRC 2012). The NRC operates 24 hours a day, 7 days a week, 365 days a year.

The NRC maintains a database of spill incident responses where basic information of a significant spill provided by the pipeline operator's response team is logged. The report usually contains a brief incident description, location, information about released material, early estimations of released amounts, damages, and details of notifications to government agencies. NRC procedures call for notifying the USDOT regarding incidents related to facilities and operations under its jurisdiction. The NRC communicates with the USDOT at a rate of over 2,500 notifications per year.

Statistics maintained by NRC in cases of pipeline spill incidents are available to the public on an annual basis. Once USDOT is informed about a pipeline incident, PHMSA is the agency in charge of collecting the pertinent data after the spill. The NRC database is focused on emergency response details, and has more flexibility in record keeping than PHMSA. For instance, the material in crude oil spills may be logged as *oil crude, crude oil, crude water mixture, crude mixed with water*, or several other terms to represent the same spilled substance. In addition, emergency spill drills conducted during a year are also logged as *incidents* in the database. Information is recorded to clarify the virtual nature of the record, but it is apparent only after analyzing the data records individually. In brief, NRC incident data may not be comparable with PHMSA data without manipulation. Drawing estimates from combined database records at face value may grossly misrepresent statistics about pipeline system incidents.

National Transportation Safety Board

The National Transportation Safety Board (NTSB) is an independent agency of the U.S. government. It is responsible for incident investigations in civil transportation (NTSB 2012b). In this role, NTSB investigates and reports on aviation incidents, major highway crashes, ship and marine incidents, pipeline release incidents, and railroad incidents (NTSB 2012b). The NTSB is also in charge of investigating cases of hazardous materials releases that occur during transportation.

The following NTSB reports on two more recent large spills were reviewed (NTSB 2012c):

- NTSB/Pipeline Accident Report-12/01: Enbridge Incorporated Hazardous Liquid Pipeline Rupture and Release, Marshall, MI. July 25, 2010 (NTSB 2012a)
- NTSB/Pipeline Accident Report-04/01: Rupture of Enbridge Pipeline and Release of Crude Oil near Cohasset, MN. July 4, 2002 (NTSB 2004)

The purpose of reviewing the incident reports was to gain a better understanding of these two spills. A familiarization with Enbridge pipeline integrity management was considered beneficial because their system carries diluted bitumen (dilbit) and synthetic crude oil (SCO) (see Section 3.13, Potential Releases, for further definitions) in the United States.

California State Fire Marshal

Outside of the national agencies, some U.S. states collect their own internal data. In California, the Office of the State Fire Marshal (SFM) acts as an agent of the PHMSA (formerly the federal Office of Pipeline Safety) for the state (California Department of Forestry and Fire Protection 2012). California data were evaluated in this Final Supplemental EIS because oil in these pipeline systems is typically heavy crude and has characteristics similar to those of dilbit and SCO.

The California SFM exercises safety regulatory jurisdiction over interstate and intrastate pipelines used for the transportation of hazardous or highly volatile liquid substances within California. In 1983, the Pipeline Safety and Enforcement Program was created to administer this effort (California Department of Forestry and Fire Protection 2012).

In 1987, SFM acquired the regulatory responsibility for interstate lines in California when an agreement was executed with the USDOT. In doing so, SFM became an agent of the USDOT responsible for ensuring that California interstate pipeline operators meet federal pipeline safety standards. Interstate pipelines under this agreement are subject to the federal *Pipeline Safety Act* (Title 49 of the U.S. Code Chapter 601) and federal pipeline regulations. SFM's responsibility for intrastate lines is covered in the *Elder California Pipeline Safety Act* of 1981 (Chapter 5.5, California Government Code, Section 51010-51019.1).

The agency's responsibilities are twofold:

- To enforce federal minimum pipeline safety standards over regulated interstate hazardous liquid pipelines within California; and
- To enforce pipeline safety federal standards as well as the *Elder California Pipeline Safety Act* of 1981 on regulated hazardous liquid intrastate pipelines.

SFM conducts studies and gathers incident data for the California pipeline system. For this report, the data of a study conducted over a period of 10 years were analyzed (EDM Services Inc. 1993). The dataset used for the study was the only one with incident/temperature information, although limited to California 1981 to 1990 dataset.

International Data Sources

In Canada where the proposed pipeline originates, there are multiple agencies responsible for regulating pipelines, including the National Energy Board (NEB), Transportation Safety Board (TSB), and the Alberta Energy and Utilities Board (EUB).

National Energy Board

The NEB is an independent federal agency established in 1959 by the Parliament of Canada. The NEB regulates international and interprovincial pipelines, federal energy development, and federal energy trade. The NEB also regulates some aspects of the international electric utility industry. Under this mandate, the NEB carries out the organization's regulatory responsibilities in the Canadian public interest. The NEB reports to Parliament through the Minister of Natural Resources. The Board is made up of several Board members who come from the private or public sector and have various backgrounds and knowledge.

The NEB has identified four goals it hopes to achieve:

- NEB-regulated facilities and activities are safe and secure;
- The environment is protected throughout the lifecycle of NEB-regulated facilities and activities;
- Canadians benefit from efficient energy infrastructure and markets; and
- The rights and interests of those affected by NEB-regulated facilities and activities are respected.

Canadian Transportation Safety Board

The Canadian TSB is an independent agency created by an act of the Canadian Parliament (the *Canadian Transportation Accident Investigation and Safety Board Act* that came into force on 29 March 1990) (Canadian TSB 2012a). The act granted the mandate to TSB to advance transportation safety in the marine, pipeline, rail, and air modes of transportation through the following:

- Conducting independent investigations, including public inquiries when necessary, into selected transportation occurrences (incidents) in order to make findings as to their causes and contributing factors;
- Identifying safety deficiencies, as evidenced by transportation occurrences;
- Making recommendations designed to eliminate or reduce any such safety deficiencies; and
- Reporting publicly on investigations and on their findings.

As part of its ongoing investigations, the TSB also reviews developments in transportation safety and identifies safety risks that it believes government and the transportation industry should address to reduce injury and loss. Since its creation, TSB has conducted periodic reports on the national Canadian pipeline system and, for that purpose, maintained a comprehensive database with incident statistics (Canadian TSB 2012b). Monthly and annual reports are available from the TSB website. Raw incident data are not available. Public reports summarize estimates that are created on data that are aggregated according to different criteria and not solely according to the characterization of specific crude oil types. In addition, the field reporting basis for Canadian incidents was incompatible with PHMSA requirements before 2010. Data between these two datasets, pre- and post-2010, are not directly comparable. However, annual report data and statistical summaries related to incidents from 2002 to 2011 were reviewed and referenced as applicable in this Final Supplemental EIS.

Alberta Energy Resources Conservation Board

In Canada, the province of Alberta accounts for the overwhelming majority (more than 96 percent) of Canada's oil reserves (Alberta Energy 2012b). The Alberta EUB regulates the energy resource development, pipelines, transmission lines, and investor-owned electric, water, and natural gas utilities, as well as certain municipality-owned utilities in the province. The Alberta EUB reports to the Executive Council through the Ministry of Energy.

On January 1, 2008, the EUB was realigned into two separate regulatory bodies (Alberta Energy 2012a):

- The Energy Resources Conservation Board (ERCB), which regulates the oil and gas industry; and
- The Alberta Utilities Commission, which regulates the utilities industry.

The ERCB leads teams of engineers, geologists, technicians, economists, and other professionals at 14 locations in Alberta. The ERCB objectives include the following (ECRB 2012):

- Achieve high standards through effective and efficient regulation of public safety, environmental protections, and energy resource conservation;
- Be proactive in identifying and addressing emerging issues that face the industries the ERCB regulates and stakeholders affected by these issues;
- Provide its customers with easily accessible, relevant, and high-quality data, information, knowledge, and advice related to the energy sectors;

- Institute decision-making processes that are fair, efficient, and adaptable to the circumstances and that achieve a respected public interest balance; and
- Protect Albertans from exposure to long-term industry abandonment and decommissioning liabilities.

One of the reports, *Pipeline Performance in Alberta, 1990-2005* (Alberta EUB 2007), which was prepared by the Alberta EUB, was studied in detail for this Final Supplemental EIS. The purpose of reviewing that report was to compare PHMSA datasets and gain a better understanding of pipeline systems where dilbit, SCO, Bakken crude oil, and heavy crude oils are normally transported.

Other Data Sources

For some larger spills, other publicly available studies and reports were reviewed. These reports contained information regarding the effects to the environment as a result of a spill. The following spills were reviewed:

- Crude Oil Spill at Bemidji, Minnesota, August 29, 1979: Hult 1984 and U.S Geological Survey (USGS) 1998.
- Dilbit spill into Kalamazoo River, Michigan, July 26, 2010: Stratus Consulting Inc. 2005a and 2005b. Stage I Assessment Report, Volumes 1 and 2.
- Crude Oil Spill into Yellowstone River near Laurel, Montana, July 7, 2011: PHMSA 2011; USEPA 2012 and 2011; Center for Toxicology and Environmental Health 2011; Montana Department of Environmental Quality 2012.

The purpose of reviewing the studies and reports was to gain a better understanding of these spills and the results of these spills.

4.13.3.5 PHMSA Historical Data

PHMSA hazardous liquid pipeline incident reports include information on the type of hazardous material spilled, the estimated volume spilled, the part of the pipeline system that was the source of the release, and the probable cause of the incident. The PHMSA liquid incident dataset, which includes incidents from hazardous liquid pipelines, could be filtered to include only crude oil pipeline incidents. The PHMSA hazardous liquid pipeline incident data do not detail the type of crude oil involved with each incident; therefore, the historical incident summaries could not be specific to dilbit, SCO, or Bakken crude oil, but rather could only be specific to crude oil in general.

The historical incident data could be divided into discrete components (e.g., breakout tanks, pumping stations, and valves) and linear components (e.g., mainline pipe). This allows historical spill volumes and incident causes from the mainline pipe to be assessed separately from discrete elements such as pumping stations, breakout tanks, valves, and other associated equipment.

The incident and mileage databases were analyzed to show the distribution of historical spill volumes and incident causes as well as frequencies of crude oil pipeline incidents contained in the PHMSA database. This analysis was done to understand what has occurred historically with respect to pipelines in the United States and to provide input for spill impact analysis in this Final Supplemental EIS.

The analysis of incident data was used to provide insight into the basic parameters of what could potentially occur with respect to spill volume, incident cause, and incident frequency, and is not intended to predict or indicate that spill incidents would be the same or in a similar range for the proposed Project. Once a final route is determined, Keystone would conduct a detailed spill risk assessment for the proposed Project. Appendix K, Historical Pipeline Incident Analysis, summarizes the objectives and results of the PHMSA data analysis.

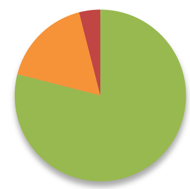
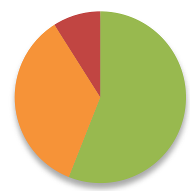
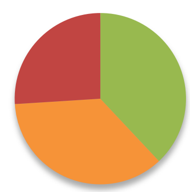
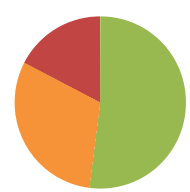
The reported data in the publicly-available PHMSA dataset include statistical data related to age and diameter of pipelines. The age and diameter data are not integrated and are included separately in the incident database, but not in the mileage database. As a result, the direct relationship between pipeline age and incidents is not readily identifiable. For the period 2002 through July 2012, it is possible to determine that the average age of crude oil pipelines in the PHMSA incident dataset is about 47 years, and the average diameter is about 20 inches.

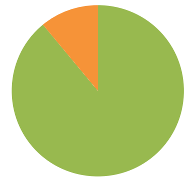
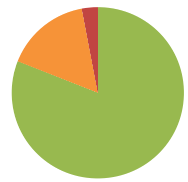
Spill Size Distribution

As discussed in Section 4.13.4, Spill Impact Assessment, spill impacts were analyzed for spill volumes of 0 to 50 bbl, 50 to 1,000 bbl, and greater than 1,000 bbl. Table 4.13-1 shows a summary of the spill size distribution, representative mileage, and frequencies for crude oil incidents in the PHMSA incident database. The estimates of pipeline mile-years shown in Table 4.13-1, along with the estimates of pipeline associated equipment-years, allow differentiating the incident rate between linear elements (mainline pipe and welds around the pipe's circumference) and discrete elements (such as pumping stations and breakout tanks). The incident frequencies contained in the table are the number of incidents divided by the associated mile-years or equipment-years. The summaries show that:

- Spill volumes from the mainline pipeline tend to be larger than spills from discrete elements, other than tanks.
- Spill volumes from larger diameter pipelines tend to be larger than spills from smaller diameter pipelines.
- Spill volumes from pipeline tanks tend to be larger than mainline pipe spills when considering all pipeline diameters.
- Spill volumes from pipeline tanks tend to be similar to mainline pipe spills for 16-inch and larger-diameter pipelines.
- The dominant causes for a release for the mainline pipeline (linear) element are corrosion and outside force.
- Equipment failure is the primary cause for discrete equipment elements.
- Incorrect operations are recorded as the cause of a large proportion of reported incidents for tanks.

Table 4.13-1 Spill Volume[a] Distribution by Pipeline Component

Pipeline Component (number of reported incidents)	0–50 bbl	>50–1,000 bbl	>1,000 bbl	Volume Distribution[b]	Pipeline Mileage[c] or Equipment Exposure[d]	Incident Rate per Mile-Year[c] or Equipment-Year[d]
Pipeline, All Elements (1,692)	79%	17%	4%		537,295 mile-years	0.00313
Mainline Pipe (321)	56%	35%	9%		537,295 mile-years	0.00059
Mainline Pipe, 16-inch Diameter and Greater (71)	38%	36%	26%		287,665 mile-years	0.00025
Pipeline System, Tanks[e] Tanks[d] (93)	51%	30%	19%		537,295 mile-years 18,937 tank-years	0.00017 0.0049

Pipeline Component (number of reported incidents)	0–50 bbl	>50–1,000 bbl	>1,000 bbl	Volume Distribution[b]	Pipeline Mileage[c] or Equipment Exposure[d]	Incident Rate per Mile-Year[c] or Equipment-Year[d]
Pipeline System, Mainline Valves (25)	89%	11%	0%		537,295 mile-years 26,865 valve-years	0.00005 0.00093
Pipeline System, Other Discrete Elements (909)[e]	84%	14%	2%		537,295 mile-years 11,647 pumping station-years	0.00168 0.055

Source: PHMSA 2012a

[a] The volume reported is the estimated amount lost in an incident and is not based on the same definition of a spill as used in this Final Supplemental EIS.
[b] Green: 0 to 50 bbl, orange: 50 to1,000 bbl, red: >1,000 bbl spill.
[c] For linear elements.
[d] For discrete element.
[e] Variability and completeness of incident reports in the PHMSA database suggests that some of these incidents could be allocated to an alternate pipeline component. If so, the frequency of the other components could increase.

When comparing the frequencies in Table 4.13-1 to those frequencies developed in the Final EIS (see Appendix P, Risk Assessment), it is difficult to make a one-to-one comparison. The Final EIS Risk Assessment limited the review to 2008 and referenced summary tables and charts on the PHMSA website that have since been updated. Appendix K, Historical Pipeline Incident Analysis, uses PHMSA incident data from January 2002 through July 2012. In 2010, PHMSA substantially revised the reporting format. As a result, this Final Supplemental EIS utilizes two different databases to conduct the incident analysis. The frequency values in Appendix P, Risk Assessment, and Appendix K, Historical Pipeline Incident Analysis, can vary because there are different numbers of incidents between the two reporting periods, the types of incidents in the post 2010 dataset are different than historical trends, and the more recent causes and spill volumes can be different from historical trends.

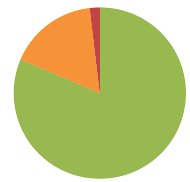
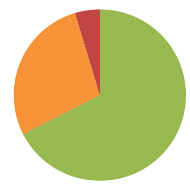
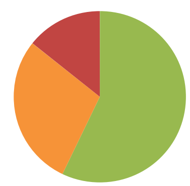
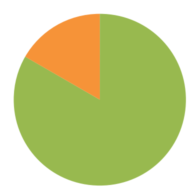
Since the completion of the Final EIS, data through August 2013 have been made available in the PHMSA database. As such, additional analysis after the July 2013 evaluation shown in Table 4.13-1 was completed to reflect the additional 1.1 years of data. This additional analysis includes the April, 2013 Mayflower, Arkansas pipeline spill, however, does not include the October 2013 Tioga, North Dakota pipeline spill that occurred after the August 2013 dataset became available. As shown in Appendix K, Historical Pipeline Incident Analysis, and summarized in Table 4.13-2 below, the additional year of data is consistent with and has nearly the same results as the initial analysis.

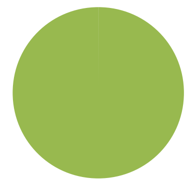
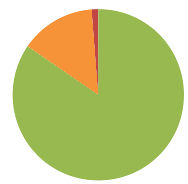
Sensitivity Analysis

A high-level sensitivity evaluation was conducted to help validate the assumptions used in calculating the frequency values for mainline valves and pump stations in service, as discussed above and in Appendix K, Historical Pipeline Incident Analysis. Based on the sensitivity evaluation, the assumptions used are valid and pump stations have the highest incident frequency, followed by mainline pipe, then tanks, and then mainline valves with the lowest incident frequency. (This priority ranking is used to focus mitigation measures.)

Based on this evaluation, to affect the calculated incident frequency for mainline valves or pump stations that would change the priority ranking for the key pipeline elements (i.e., mainline pipe, tanks, mainline valves, pump stations), unreasonable and unlikely spacing assumptions are needed. For example, to shift the priority ranking of the key pipeline elements, there would need to be one pump station every 6 miles, or fewer than 600 mainline valves for the entire U.S. pipeline system. Therefore, any reasonable changes to the spacing assumptions could change the incident frequency, but would have no material effect on the priority ranking for these elements. The assumed spacing used for mainline valves and pump stations in the incident frequency analysis is reasonable. Tables 4.13-3 and 4.13-4 show the variation on spill incident frequencies based on changing spacing assumptions. The *lower* and *upper* estimates are the points of inflection whereby the priority ranking for the mainline valves either changes from third to second (85-mile spacing) or third to fourth (3-mile spacing).

Table 4.13-2 Spill Volume[a] Distribution by Pipeline Component, July 2012–August 2013

Pipeline Component (number of reported incidents)	0–50 bbl	>50–1,000 bbl	>1,000 bbl	Volume Distribution[b]	Pipeline Mileage[c] or Equipment Exposure[d]	Incident Rate per Mile-Year[c] or Equipment-Year[d]
Pipeline, All Elements (215)	81%	17%	2%		62,661 mile-years	0.003431
Mainline Pipe (43)	67%	28%	5%		62,661 mile-years	0.000686
Mainline Pipe, 16-inch Diameter and Greater (41)	57%	29%	14%		31,263 mile-years	0.000448
Pipeline System, Tanks[e] Tanks[d] (6)	83%	17%	0%		62,661 mile-years 2,327 tank-years	0.000096 0.002578

Pipeline Component (number of reported incidents)	0–50 bbl	>50–1,000 bbl	>1,000 bbl	Volume Distribution[b]	Pipeline Mileage[c] or Equipment Exposure[d]	Incident Rate per Mile-Year[c] or Equipment-Year[d]
Pipeline System, Mainline Valves (4)	100%	0%	0%		62,661 mile-years 3,133 valve-years	0.000064 0.001277
Pipeline System, Other Discrete Elements (162)[e]	85%	14%	1%		62,661 mile-years 1,362 pump station-years	0.002585 0.118925

Source: PHMSA 2013

[a] The volume reported is the estimated amount lost in an incident and is not based on the same definition of a spill as used in this Final Supplemental EIS.
[b] Green: 0 to 50 bbl, orange: 50 to1,000 bbl, red: >1,000 bbl spill
[c] For linear elements.
[d] For discrete element.
[e] Variability and completeness of incident reports in the PHMSA database suggests that some of these incidents could be allocated to an alternate pipeline component. If so, the frequency of the other components could increase.

Table 4.13-3 Effect on Spill Incident Frequencies—Mainline Valves

	Base Case: 20-mile Spacing		Lower Estimate: 3-mile Spacing		Upper estimate: 85-mile Spacing	
	Incidents/ Year	**Years Between Incidents**	**Incidents/ Year**	**Years Between Incidents**	**Incidents/ Year**	**Years Between Incidents**
0-50 bbl	0.0450	22.2	0.0068	148.0	0.1914	5.2
50-1,000 bbl	0.0061	162.8	0.0009	1,085.4	0.0261	38.3
1,000+ bbl	0.0000	NA	0.0000	NA	0.0000	NA
Total	**0.0512**	**19.5**	**0.0077**	**130.3**	**0.2175**	**4.6**

NA = Not applicable

Table 4.13-4 Effect on Spill Incident Frequencies—Pump Stations

	Base Case: 46-mile Spacing		Lower[a] Estimate: 6 miles	
	Incidents/Year	**Years Between Incidents**	**Incidents/Year**	**Years Between Incidents**
0-50 bbl	1.3013	0.8	0.1697	5.9
50-1,000 bbl	0.2192	4.6	0.0286	35.0
1,000+ bbl	0.0360	27.8	0.0047	213.2
Total	**1.5565**	**0.6**	**0.2030**	**4.9**

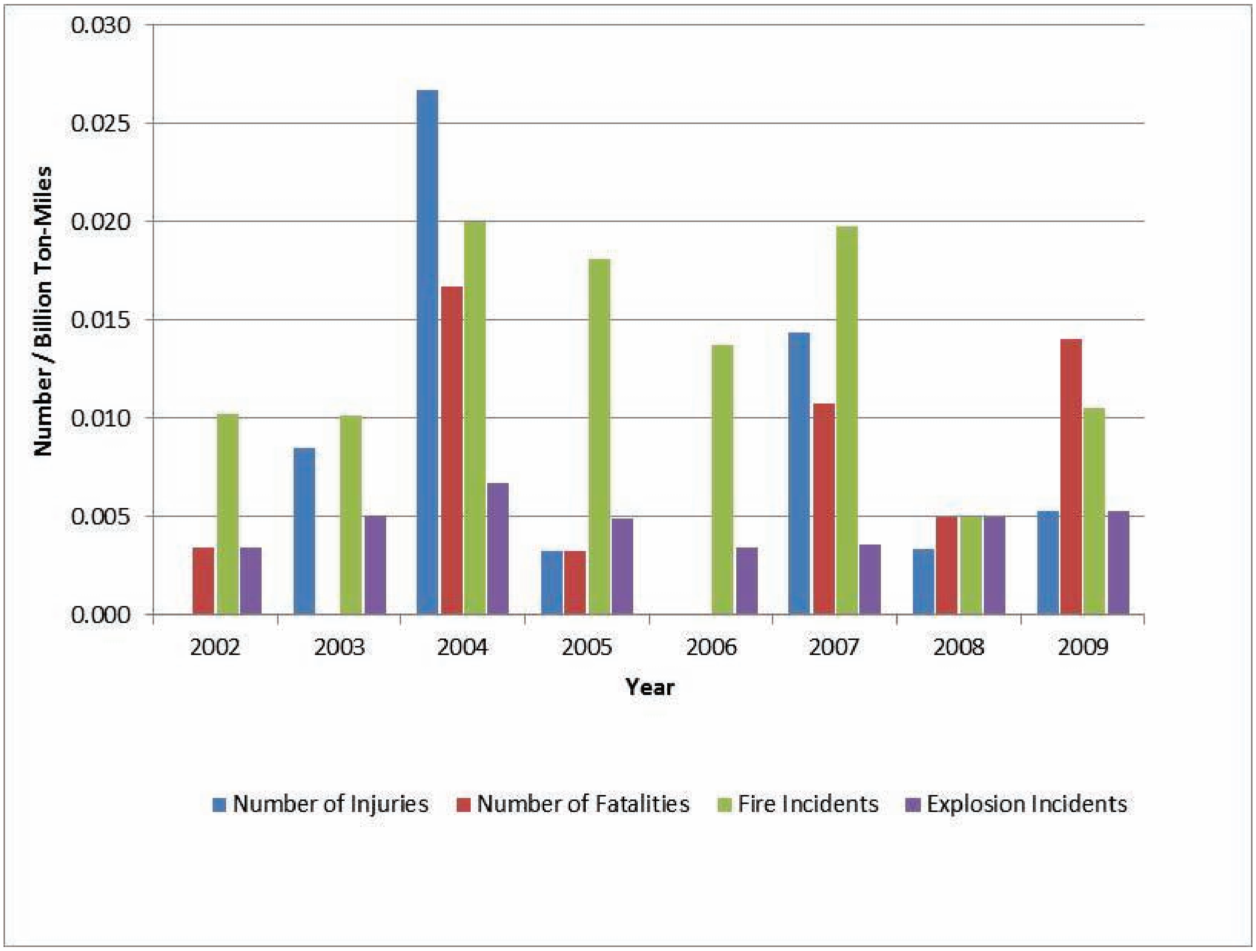
[a] Based on historic data, the priority for pump stations is ranked one (highest); therefore, there is only a lower limit whereby the priority ranking changes from first to second (6-mile spacing).

Although the frequency does vary based on the spacing assumptions, the chosen assumptions remain reasonable based on information about the proposed Project. As such, the mitigation focus based on the priority ranking is the same and any reasonable changes in the spacing would not change the focus.

Historic Pipeline Injury, Fatality, Fire, and Explosion Incidents

In addition to recording incident data on spill volume and cause, PHMSA identifies both serious and significant incidents. A *serious incident* is one that involves a fatality or injury. A *significant incident* includes serious incidents and unintentional fires or explosions, as well as those items discussed in Section 4.13.3.4, Pipeline Incident Information Sources.

A summary of PHMSA historic incidents resulting in an injury, fatality, fire, or explosion, as reported, is shown in Figure 4.13.3-1.



Sources: Incidents from PHMSA Pipeline Incident Data (PHMSA 2012a); Pipeline Ton-Mileage from Association of Oil Pipelines (AOPL 2012)

Notes: Incidents and mileage reflect petroleum and petroleum products only.

Figure 4.13.3-1 Number of Pipeline Injury, Fatality, Fire, and Explosion Incidents per Billion Ton-Miles Transported, Crude Oil and Petroleum Products, 2002 to 2009

Comparison of Different Historical Data

As discussed, there are other sources for data on pipeline incidents. However, unlike PHMSA, the majority of these do not have publicly available raw data that could be analyzed in a similar manner. To aid in identifying the consistency in spill incidences from different sources and the reproducibility of those statistics, the PHMSA data were compared to the summary tables and figures in the Alberta EUB and SFM summary reports. In addition, these other data sources supplemented the PHMSA database because they reflect a heavy crude oil type similar to that which would be transported in the proposed Project.

While, under appropriate circumstances, it may be desirable to further analyze data from pipelines installed in the past decade (i.e., since 2002), there are data gaps that would preclude deriving useful information from a subset analysis. For example, analysis of the data shows that for all incidents, 9 percent of the PHMSA records have an installation date in the last decade and 60 percent of all incidents do not have an identified installation date in the PHMSA database. For onshore crude oil incidents, the percent breakdown is roughly the same. Therefore, conducting a detailed analysis such as the number of pipeline releases based on age would have a greater degree of uncertainty because age data have such a small representation within the entire dataset.

EUB—Pipeline Performance in Alberta, 1990 to 2005

The Alberta EUB report, *Pipeline Performance in Alberta, 1990 to 2005*, analyzed pipeline incident data in Alberta from January 1990 to December 2005.[6] The report contains 411 incidents related to crude oil pipeline systems in the province, which represents approximately 27 incidents per year. Figure 12a in that report (Alberta EUB 2007) shows[7]:

- Corrosion is the main cause of spills in Alberta crude oil pipelines, accounting for 37.7 percent of the incidents. This compares to the U.S. data for pipeline systems (34.4 percent in the PHMSA dataset from Figure 2 of Appendix K, Historical Pipeline Incident Analysis).
- Third-party damage is the second highest cause of spills at 21.6 percent. This is greater than the U.S. data (6.5 percent for outside force in the PHMSA dataset).
- The *other* cause category in the Alberta dataset includes operator error, equipment malfunction, weather, and natural forces (but not earth movement). The total of *other* is 11.9 percent in the Alberta dataset (14.8 percent including earth movement). This is smaller compared to the U.S. data (45.5 percent for equipment malfunction, incorrect operations, weather, or natural forces in the PHMSA dataset).
- The Alberta EUB has several different scenarios for equipment-related incidents, including joint failure[8] and valve/fitting,[9] and only parts of *other* (*other* includes compressor, pump, and meter station, which are equipment-related, as well as operator error, weather, and natural forces [but not earth movement], which are not equipment related). Grouping these categories, including all *other*, gives a total contribution of 22.6 percent in the Alberta dataset. This is smaller than the contribution in the U.S. data (31.9 percent for equipment malfunction in the PHMSA dataset).
- Figure 28 of the report provides estimates of incident frequencies from crude oil pipelines in Alberta. The 1990–2005 average is 1.9 incidents per 1,000 km-years, which is approximately three incidents per 1,000 mile-years. This is very similar to the PHMSA crude oil incident rate of 3.1 incidents per 1,000 mile-years for pipelines and reported elements from 2002–July 2012, as shown in Appendix K, Historical Pipeline Incident Analysis, Table 4.

[6] This is the most recent data available that had been processed and analyzed to provide meaningful information from which to compare.
[7] Values in the bullet points are not a complete summary of all categories of spill causes from the EUB report. Instead, comparisons between U.S. and Canadian data are brought forward to highlight the similarities and differences between the way the U.S. and Canadian data are reported. Therefore, the total for all percentages reported does not equal 100 percent.
[8] Mechanical joint failure (e.g., gasket failure, o-ring failure) or miscellaneous joint failure (e.g., butt fusion, interference joints)
[9] Valve failure or installation failure

California SFM—Hazardous Liquid Pipeline Risk Assessment

The dataset contained in the report is considerably older than the PHMSA dataset. The California data, from which the report draws its conclusions, span from 1981 to 1990[10] (EDM 1993). Because the California pipeline system generally manages heavy crude oil, which is similar in character to dilbit, the California study and the conclusions drawn are useful to assess the potential effects of heavy oil on pipeline corrosion and potential effects on the pipe of the proposed Project. The California report states several conclusions for the analyzed incidents, as follows:

- Smaller-diameter, older pipelines had a significantly higher external corrosion leak incident rate than larger-diameter, newer pipelines.
- Elevated pipeline operating temperatures significantly increased the frequency of leaks caused by external corrosion for all pipelines; however, the 16- to 20-inch diameter range had a relatively low leak rate despite having the highest mean operating temperature range.
- The external corrosion leak incident rate was less for pipelines greater than 16 inches in diameter than it was for smaller lines.
- Although a small number, pipelines without cathodic protection systems had a substantially higher frequency of external corrosion-caused leaks than protected lines.
- In some cases, the pipe specification and type of external corrosion coating affected external corrosion leak incident rates.

The California report states that pipelines operating at higher temperatures are also the oldest. The oldest pipelines in the dataset (50+ years old at the time of the study) tended to leak up to 20 times more frequently than the youngest pipelines (less than 10 years old at the time of the study).

The California report contained an analysis using a dataset that included all pipe diameters to determine whether or not pipe age masked pipe operating temperature effects. The analysis found that, while holding various factors constant, operating temperature correlated with the probability of a leak occurring from external corrosion.[11] However, when analyzing specific pipeline diameter ranges, the California report describes that a good deal of variance exists between pipe diameter range with leak incident rates, and points out that pipelines in the 16- to 20-inch-diameter range had a relatively low leak rate despite having the highest mean operating temperature range. In addition, the 20-inch or greater range has an order of magnitude lower leak rate than the 8- to 10-inch pipe despite a similar mean operating temperature. This means that a correlation with operating temperature and leak incident rate may not hold for large diameter pipelines.

Although temperature could increase the rate of a chemical reaction, such as corrosion for both steel pipe buried in the ground and unburied pipe exposed to the weather, the results of the California study must be evaluated with caution. The pipelines in the California study were installed with different design criteria than the proposed Project would be. Pipeline systems installed more than 20 years ago have different cathodic protection specifications, different

[10] This is the most recent dataset for which information was available.
[11] The specific factors are not detailed in the California report.

external protective coatings, if any, different SCADA systems, and different pipe specifications. Pipeline systems fabricated and installed prior to 1970 could have even less protection than 20-year-old systems, not to mention those that would be installed today. Pipe specification, coating, and cathodic protection are some factors that affect corrosion rates. Therefore, a conclusion that higher leak rates would occur at higher temperatures cannot be drawn based on the California study alone.

Temperature data are not available in the PHMSA dataset; therefore, it is not possible to directly determine if there is a relationship between operating temperature and incident frequency using this dataset.

Several PHMSA Special Conditions are to be in place for the proposed Project to mitigate potential issues associated with pipeline degradation (see Section 4.13.6.1, PHMSA Special Conditions). The ultimate rate of corrosion may not be assessed at this time with the available data. However, as noted in Section 3.13.3.7, Acidity and Corrosivity Potential, a study on the corrosivity of dilbit has been completed by the National Academy of Sciences.

Applied Incident Frequency

While any estimate based on the above historical data would be indicative and not predictive, using the above historical incident data and applying it to an 875-mile pipeline with 55 mainline valves, two tanks, and 20 pump stations—similar to the proposed Project—the number of years of operation per pipeline incident can be estimated:

- Table 4.13-5 shows the resulting years per release from mainline pipe using the historic incident frequency.
- Table 4.13-6 shows the resulting years per release from mainline pipe based on cause for spills greater than 1,000 bbl using the historic incident frequency.
- Table 4.13-7 shows the resulting years per release from a two-tank system, the same number of tanks planned for the proposed Project.
- Table 4.13-8 shows the resulting years per release from a two-tank system based on cause for spills greater than 1,000 bbl using the historic incident frequency.
- Table 4.13-9 shows the resulting years per release from an 875-mile pipeline containing 55 mainline valves. The values reflect only valve incidents and do not include mainline pipe incidents. There are no reported large spill incidents from valves in the reported period (January 2002 through July 2012).
- Table 4.13-10 shows the resulting years per release after applying historic incident frequency from an 875-mile pipeline containing 20 pumping stations, the same number of pumping stations planned for the proposed Project.
- Table 4.13-11 shows the resulting years per release from an 875-mile pipeline containing 20 pumping stations based on cause for spills greater than 1,000 bbl using the historic incident frequency.

Table 4.13-5 Historic Incident Summary, Onshore Mainline Pipe 16-inch-diameter and Larger

Spill Volume	Historic Incident Frequency[a]	875-mile Mainline Pipe, 16-inch-diameter and Greater[b] Incidents/Year	875-mile Mainline Pipe, 16-inch-diameter and Greater[b] Years/Incident
Small (0 to 50 bbl)	1 per 10,654 mile-years	0.082	12
Medium (50 to 1000 bbl)	1 per 11,507 mile-years	0.078	13
Large (>1000 bbl)	1 per 15,140 mile-years	0.056	18

[a] PHMSA 16-inch and larger mainline crude oil pipe (January 2002–July 2012).
[b] Historic 16-inch and larger mainline crude oil pipe incident frequency applied to 875 miles of mainline pipeline.

Table 4.13-6 Historic Incident Summary, Onshore Mainline Pipe 16-inch-diameter and Larger, Spill Size Greater than 1,000 Barrels

Spill Cause	Historic Incident Frequency[a]	875-mile Mainline Pipe, 16-inch Diameter and Greater[b] Incidents/Year	875-mile Mainline Pipe, 16-inch Diameter and Greater[b] Years/Incident
Outside Force/Excavation	1 per 41,095 mile-years	0.021	47
Manufacturing/Construction/ Materials-Related	1 per 71,916 mile-years	0.012	82
Weather/Natural Force	1 per 95,888 mile-years	0.009	110
Corrosion (Internal, External, Unspecified)	1 per 95,888 mile-years	0.009	110
Other	1 per 143,833 mile-years	0.006	164
Incorrect Operations/Equipment Malfunction	No incidents reported[c]	--[d]	--[d]

[a] PHMSA 16-inch and larger mainline crude oil pipe (January 2002 to July 2012).
[b] Historic 16-inch and larger mainline crude oil pipe incident frequency applied to 875 miles of mainline pipeline.
[c] No historic incidents reported in PHMSA 2002 to 2012.
[d] Because there were no historic incidents during the time period analyzed, no value has been calculated.

Table 4.13-7 Historic Incident Summary, Onshore Crude Oil Pipeline System, Tanks

Spill Volume	Historic Incident Frequency[a]	2 Tanks[b] Incidents/Year	2 Tanks[b] Years/Incident
Small (0 to 50 bbl)	1 per 403 tank-years	0.0050	201
Medium (50 to 1000 bbl)	1 per 676 tank-years	0.0030	338
Large (>1000 bbl)	1 per 1052 tank-years	0.0019	526

[a] PHMSA pipeline crude oil tanks (January 2002 to July 2012).
[b] Historic pipeline crude oil tank incident frequency applied to two tanks.

Table 4.13-8 Historic Incident Summary, Onshore Crude Oil Pipeline System, Tanks, Spill Size Greater than 1,000 Barrels

Spill Cause	Historic Incident Frequency[a]	2 Tanks[b] Incidents/Year	2 Tanks[b] Years/Incident
Outside Force/Excavation	No incidents reported[c]	--[d]	--[d]
Manufacturing/Construction/ Materials-Related	1 per 18,937 tank-years	0.0001	9,469
Weather/Natural Force	1 per 6,312 tank-years	0.0003	3,156
Corrosion (Internal, External, Unspecified)	1 per 9,469 tank-years	0.0002	4,734
Other	1 per 4,734 tank-years	0.0004	2,367
Incorrect Operations/Equipment Malfunction	1 per 2,367 tank-years	0.0008	1,184

[a] PHMSA pipeline crude oil tanks (January 2002 to July 2012).
[b] Historic pipeline crude oil tank incident frequency applied to two tanks.
[c] No historic incidents reported in PHMSA 2002 to 2012.
[d] Because there were no historic incidents during the time period analyzed, no value has been calculated.

Table 4.13-9 Historic Incident Summary, Onshore Crude Oil Pipeline System, Mainline Valves

Spill Volume	Historic Incident Frequency[a]	55 Mainline Valves[b] Incidents/Year	55 Mainline Valves[b] Years/Incident
Small (0 to 50 bbl)	1 per 1,221 valve-years	0.05	22
Medium (50 to 1000 bbl)	1 per 8,955 valve-years	0.01	163
Large (>1000 bbl)	No incidents reported[c]	--[d]	--[d]

[a] PHMSA crude oil pipeline mainline valves (January 2002 to July 2012).
[b] Historic crude oil pipeline mainline valves incident frequency applied to 55 mainline valves.
[c] No historic incidents reported in PHMSA 2002 to 2012.
[d] Because there were no historic incidents during the time period analyzed, no value has been calculated.

Table 4.13-10 Historic Incident Summary, Onshore Crude Oil Pipeline System, Pumping Stations

Spill Volume	Historic Incident Frequency[a]	20 Pumping Stations[b] Incidents/Year	20 Pumping Stations[b] Years/Incident
Small (0 to 50 bbl)	1 per 15 pumping station-years	1.31	1
Medium (50 to 1000 bbl)	1 per 91 pumping station-years	0.22	5
Large (>1000 bbl)	1 per 555 pumping station-years	0.04	28

[a] PHMSA other crude oil pipeline discrete elements (January 2002 to July 2012).
[b] Historic other crude oil pipeline discrete elements incident frequency applied to 20 pumping stations.

Table 4.13-11 Historic Incident Summary, Onshore Crude Oil Pipeline System, Pumping Stations, Spill Size Greater than 1,000 Barrels

Spill Volume	Historic Incident Frequency[a]	20 Pumping Stations[b] Incidents/Year	20 Pumping Stations[b] Years/Incident
Outside Force/Excavation	1 per 5,824 pumping station-years	0.0034	291
Manufacturing/ Construction/Materials-Related	1 per 1,456 pumping station-years	0.0137	73
Weather/Natural Force	1 per 5,824 pumping station-years	0.0034	291
Corrosion (Internal, External, Unspecified)	1 per 2,912 pumping station-years	0.0069	146
Other	No incidents reported[c]	--[d]	--[d]
Incorrect Operations/ Equipment Malfunction	1 per 2,329 pumping station-years	0.0086	116

[a] PHMSA other crude oil pipeline discrete elements (January 2002 to July 2012).
[b] Historic other crude oil pipeline discrete elements incident frequency applied to 20 pumping stations.
[c] No historic incidents reported in PHMSA 2002 to 2012.
[d] Because there were no historic incidents during the time period analyzed, no value has been calculated.

4.13.3.6 Applicability of Crude Oil Data

Ideally, incident data from pipelines transporting dilbit, SCO, and Bakken crude oil would be available for the historical data analysis conducted in this report. However, given how incident data are reported, it is not possible to distinguish dilbit, SCO, and Bakken oil spills from the general population of crude oil spills, nor is it possible to distinguish pipelines carrying dilbit, SCO, or Bakken oil from other crude oil pipelines. However, insights could be made by comparing the proposed Project conditions with the historical data:

- The oil that would be transported by the proposed Project would include dilbit, SCO, and Bakken crude oil;
- As discussed in Section 3.13, Potential Releases, dilbit, SCO, and Bakken oil total acid number values are generally consistent with those of 18 international crudes, indicating that corrosivities would be similar;
- Alberta is a source of dilbit[12] and SCO[13]; incident statistics from Alberta show that incident frequencies and corrosion-based incidents are similar for pipelines in the United States and Alberta;
- The anticipated positive effects of the PHMSA Special Conditions are not reflected in the historical data, as there has not been a pipeline designed to these more rigorous set of specifications to date; and

[12] Bitumen is generally produced from deposits in Alberta, Canada, and the Orinco tar sands in Venezuela. The source for the proposed Project is Alberta.
[13] Almost all of Alberta's proven oil reserves are found in Alberta's oil sands. Of Alberta's total oil reserves, 169.3 billion barrels (or about 99 percent) come from the oil sands; the remaining 1.5 billion barrels come from conventional crude oil (Alberta Energy 2012b).

- The integrity threats identified in Section 3.13, Potential Releases, from the dilbit, SCO, and light crude oil that would be transported by the proposed Project are the same as those for a crude oil pipeline.

Section 4.13.6.1, PHMSA Special Conditions, presents more detail on the Special Conditions and how they would be expected to affect the risk of a spill. The Battelle risk analysis reports that Australian pipelines, which reflect smaller pipelines and are built to modern standards, have a 10-fold lower spill rate. It is reasonable to conclude that modern and larger-diameter pipelines would experience a lower spill rate than older pipelines. Modern pipelines have built-in measures to reduce the likelihood of a spill (e.g., modern protective coatings, SCADA monitoring). Using the Australian data to suggest that the Keystone XL pipeline would experience a similarly lower spill rate is not possible. However, with the application of the Special Conditions and various studies that indicate more modern pipelines are less likely to leak, it is reasonable to expect a sizable reduction in spills when compared to the historic spill record.

4.13.3.7 Keystone Pipeline First-Year Release Historical Data

In response to numerous comments received, historical incident data within the PHMSA and NRC incident databases were analyzed to show the distribution of historic spill volumes and incident causes of crude oil pipelines within the first year of operation. This analysis was done to understand what has occurred with respect to crude oil pipelines in general and the existing Keystone pipeline system more specifically. The existing Keystone pipeline system referred to in this analysis includes the Keystone pipeline extending from Hardisty, Alberta, to Patoka, Illinois, and the Cushing Extension extending from Steele City, Nebraska, to Cushing Oklahoma. Results are intended to provide insight into what could potentially occur with respect to spill size and incident cause within the first year of pipeline operation and are not a direct indicator of possible incidents that could occur in association with the proposed Project.

First-Year Historical Incident Data

The PHMSA hazardous liquid pipeline dataset was filtered to include only onshore crude oil pipeline incidents occurring between 2002 and May 2013. In addition to information on the estimated volume spilled, the part of the pipeline system involved in the release, and the probable cause of the incident, the PHMSA database often provides the year of installation. Incidents having the same pipeline operator and year of installation were assumed to be related to the same pipeline system. The year of pipeline installation was not reported for all incidents in the PHMSA database; therefore, this analysis is based only on incidents occurring between January 2002 and May 2013 where year of installation was provided. Pipelines were assumed to begin operations shortly following installation. In addition, releases less than 5 bbl are not required to be reported to PHMSA unless any of the following occurred: an explosion or fire not intentionally set by the operator; death of any person; personal injury necessitating hospitalization; or estimated property damage, including cost of cleanup and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding $50,000.

The NRC spill incident response database was reviewed for consideration in this analysis. Incident reports typically include a brief incident description, location, information about released material, early estimations of released amounts, damages, and details of notifications to government agencies. The database is focused on emergency response details and has more flexibility in record keeping than PHMSA. Materials involved in the incident are logged using different terminology for the same spilled substance, and pipeline operators are identified using slightly different names for the same operating company. In addition, installation years for the pipelines involved are not provided in the NRC incident reports. Information regarding the cause and involved part of the pipeline system is apparent only after analyzing the data records individually. In brief, NRC incident reports do not provide information regarding installation year and may not be comparable with PHMSA without manipulation.

Based on a review of historical incident reports, 79 incidents (not including the existing Keystone pipeline system) were identified to occur within the first year of pipeline operation for crude oil pipelines installed between 2002 and May 2013 (PHMSA 2013). Of the reported incidents, 49 occurred at pump/meter stations and terminal tank farms with the majority of these incidents caused by a pump related malfunctions. Mainline pipelines, including valve sites, accounted for 14 of the 79 reported incidents, only one of which was caused by a failure related to the body of the pipeline. Of the remaining reported first-year incidents, 11 occurred at aboveground storage tanks or breakout tanks and one was related to equipment and piping associated with belowground storage. The occurrence location for four incidents was not specified (PHMSA 2013). The majority of incidents occurring within the first year of operation were related to discrete elements of the pipeline system.

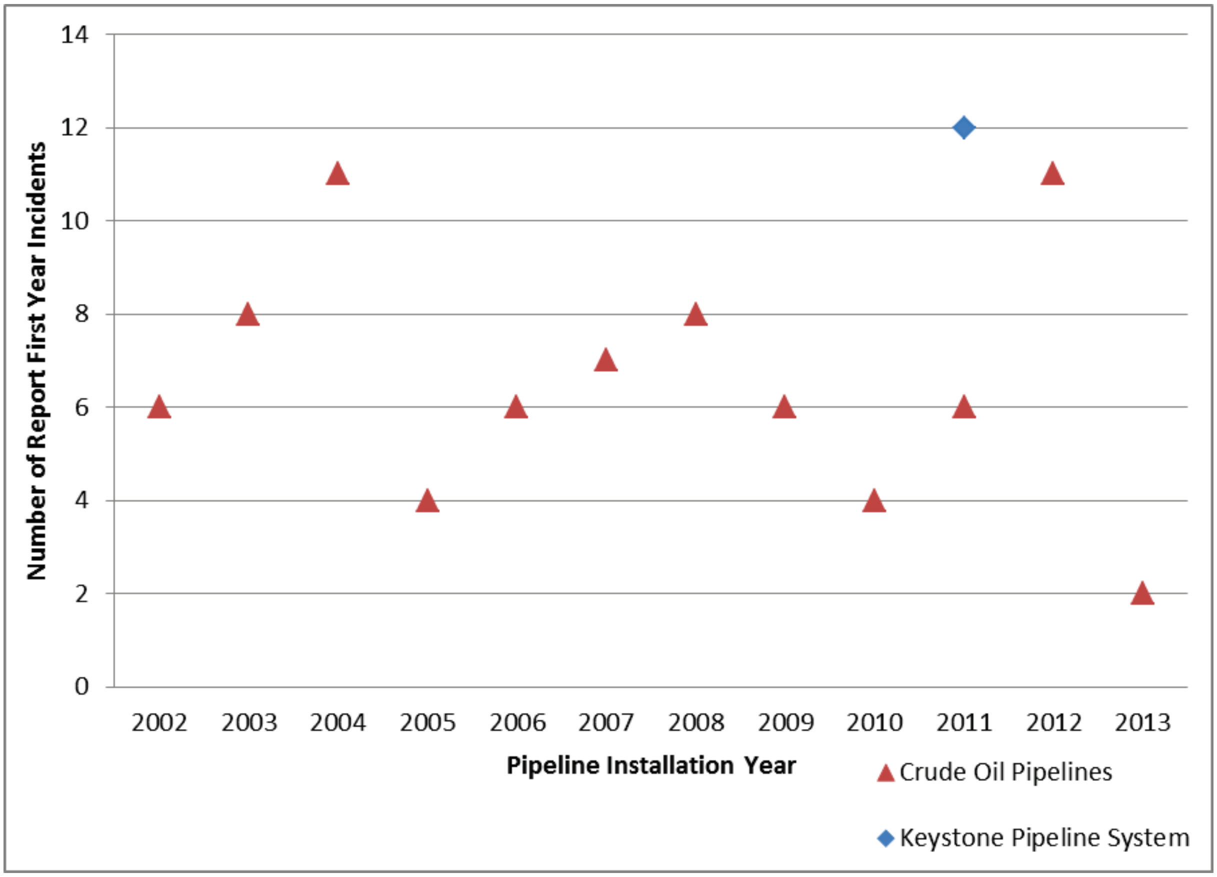
A separate review of historical PHMSA and NRC incident reports was conducted for the existing Keystone pipeline system for comparison to other crude oil pipelines. A total of 12 incidents were identified to have occurred in 2010 and 2011 (PHMSA and NRC 2013). Based on this review, 11 of the 12 reported incidents resulted in a small spill, eight of which were less than 1 bbl. These 11 incidents were contained entirely on the operator's property and remediated. Only one of the reported incidents resulted in a medium spill (50 to 1,000 bbl) and was reported to be caused by an equipment malfunction leading to a surface release that affected an off-site property. The cleanup activities for the one medium-sized spill were initiated within hours and the remediation of the spill was completed in nine days. All reported first-year incidents for the existing Keystone pipeline system involved discrete elements of the pipeline system (i.e., pumping stations, mainline valves); none involved mainline pipe or tanks.

A summary of historic first year of pipeline operation incident data for the existing Keystone pipeline system and other crude oil pipelines installed between 2002 and May 2013 is included in Table 4.13-12 below. As discussed above, there are data gaps related to installation date reporting which can affect a detailed analysis. Figure 4.13.3-2 below shows the first year of pipeline operation reported incident distribution by pipeline installation year (where available) for both crude oil pipelines and the existing Keystone pipeline system.

Table 4.13-12 First-Year Historic Incident Summary, Onshore Crude Oil Pipeline, and Reported Elements[a,b,c]

Item	Other Crude Oil Pipelines[d]	Keystone Pipeline[d,e]	Unit
Data Range	11.42	4.42	Years of data
Range of Total Incidents per Pipeline	1-4	12	Reported first-year incidents
Total Number of Pipeline	66	1	Pipelines with reported first-year incidents
Average Incidents per Pipeline	1.2	12	Reported first-year incidents
Maximum Incident Volume Reported	5,000	400	Barrels
Median Incident Volume Reported	20	0.24	Barrels
Average Incident Volume Reported	187	35.6	Barrels
0 to 50 bbl	71%	92%	Percentage of incidents
50 to 1,000 bbl	25%	8%	Percentage of incidents
Greater than 1,000 bbl	4%	0%	Percentage of incidents

[a] Keystone Pipeline includes the Keystone pipeline from Hardisty, Alberta, to Patoka, Illinois, and the Cushing Extension.
[b] Year of installation was not available for every spill in the PHMSA database. Numbers are based only on incidents where year of installation was provided.
[c] Average Incidents per Pipeline is based only on pipeline with an incident within the first year of installation.
[d] PHMSA Incident Database 2002 – May 2013.
[e] NRC Incident Database 2009 – May 2013.



Notes: Crude oil pipeline incidents reported in PHMSA database 2002 to May 2013. Keystone Pipeline system incidents reported in PHMSA and NRC databases.

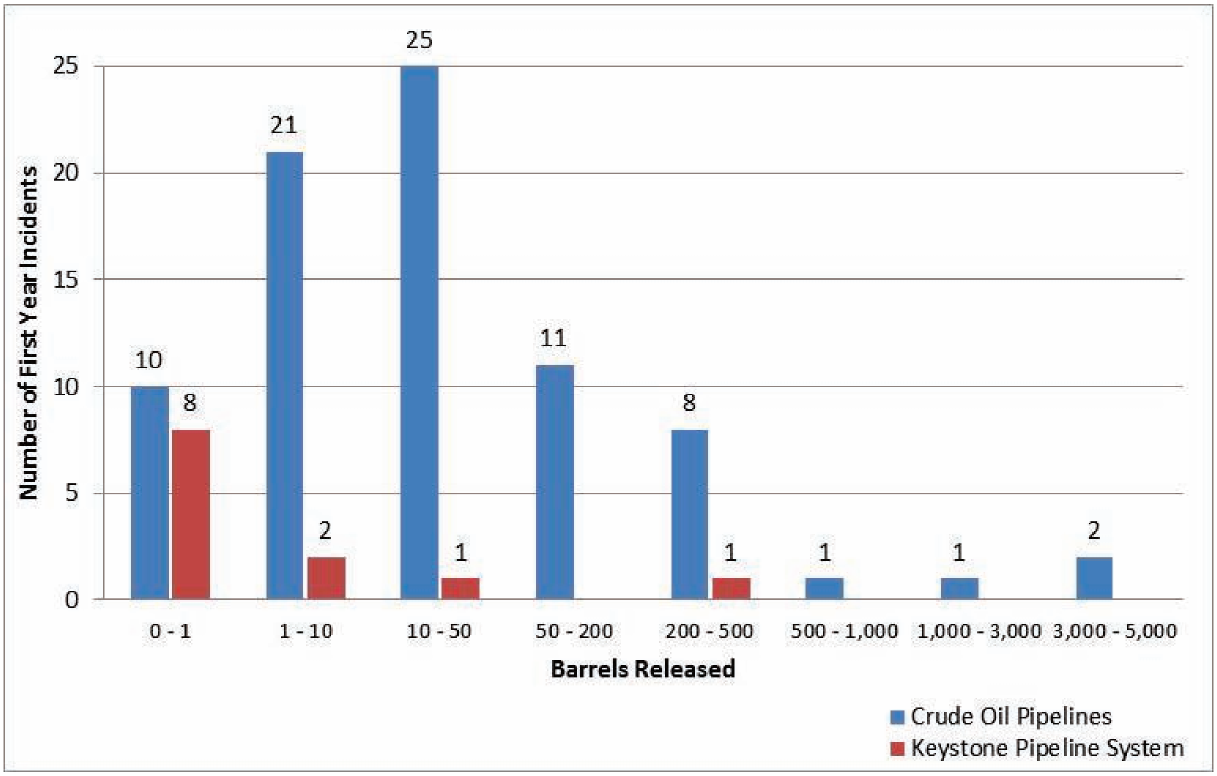
Figure 4.13.3-2 Reported Number of First-Year Incidents by Installation Year, the Keystone Pipeline System and Other Crude Oil Pipelines

First-Year Spill Size Distribution

Spill impacts were analyzed for spill volumes of 0 to 50 bbl, 50 to 1,000 bbl, and greater than 1,000 bbl for spills occurring within the first year of pipeline operation. As shown above in Table 4.13-12, small spills (0 to 50 bbl) accounted for 71 percent of crude oil pipeline first-year incidents and 92 percent of existing Keystone pipeline system first-year incidents with the majority of these incidents occurring at pump/meter stations and terminal tank farms. A total of 56 small spills were reported for crude oil pipeline within the first year of operation, 10 small spills reported were less than 1 bbl, 21 spills were less than 10 bbl, and 25 spills were less than 50 bbl. Medium spills (50 to 1,000 bbl) accounted for 25 percent of crude oil first-year spills with the majority also occurring at pump/meter stations and terminal tank farms. Of the three reported large spills (greater than 1,000 bbl), two were caused by tank malfunctions, and the largest spill of 5,000 bbl was caused by a mainline pipeline malfunction related to a bolted fitting. Based on a review of spill size distribution and associated pipeline system, discrete elements typically result in smaller spill volumes than mainline pipeline and tanks.

For the existing Keystone pipeline system within the first year of operation, eight reported incidents resulted in spill less than 1 bbl, three resulted in a spill less than 15 bbl, and one resulted in a spill of 400 bbl. Within the first year of operation, only one small spill of 0.11 bbl occurred underground and was detected by Keystone pumping station operations staff. The remaining 11 spills occurred above ground.

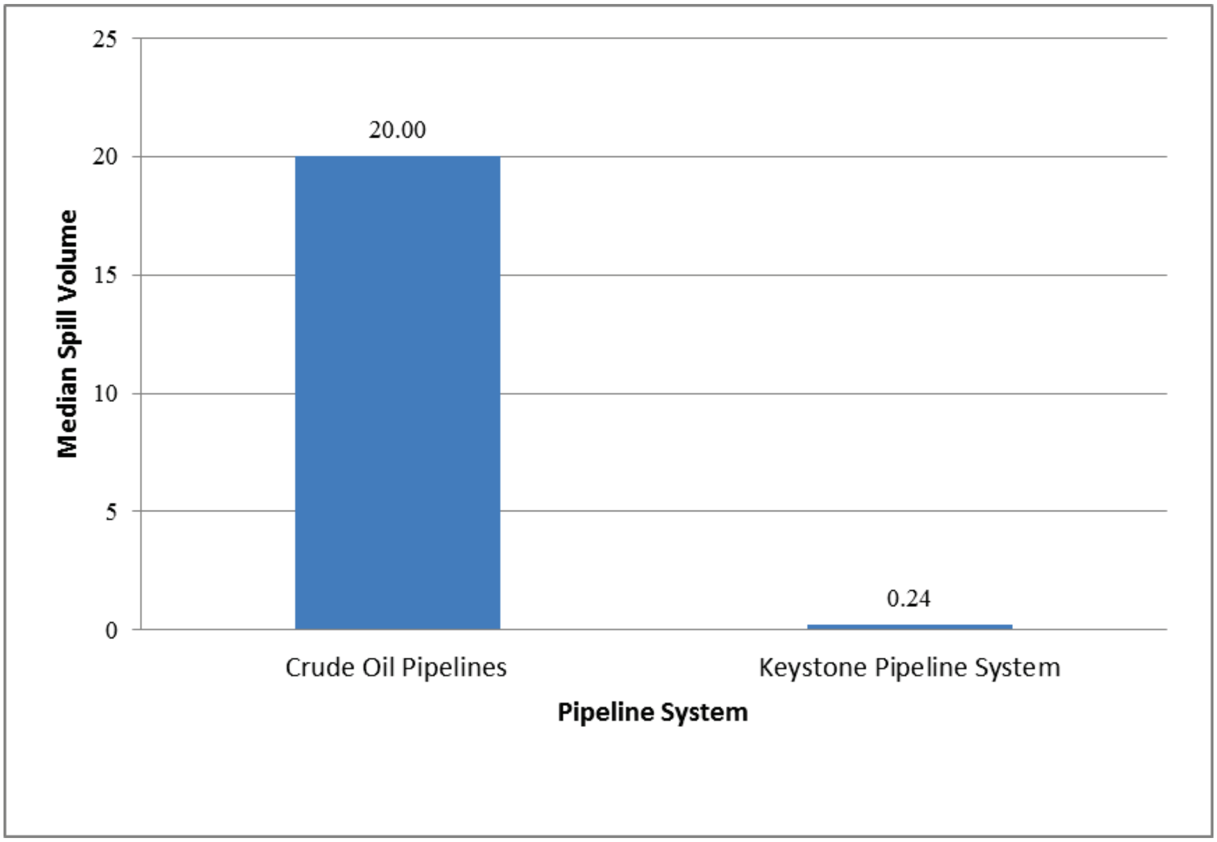
Figure 4.13.3-3 shows a summary of the spill size distribution for crude oil incidents in the PHMSA incident database in comparison to historic incidents for the existing Keystone pipeline system in the PHMSA and NRC incident database.



Notes: Seventy-nine reported crude oil pipeline incidents within the first year of operation 2002- May 2013 (PHMSA). Twelve reported Keystone pipeline system incident within the first year of operation (PHMSA, NRC). Pipeline operation was assumed to begin shortly following installation.

Figure 4.13.3-3 Volume Distribution of Spills within First Year of Pipeline Operation, the Keystone Pipeline System and Other Crude Oil Pipelines

Although the Keystone pipeline system had more reported first-year incidents than other crude oil pipelines, all except one of these incidents resulted in a small spill (less than 50 bbl). Compared to other crude oil pipelines, Keystone had a higher percentage of spills less than 1 bbl (67 percent compared to 13 percent) within the first year of operation. Equipment failure was the primary failure cause for both the Keystone pipeline system and other first-year crude oil pipelines. All reported equipment failure incidents for other crude oil pipelines within the first year of operation resulted in small spills. A comparison of the median spill volumes within the first year of installation for crude oil pipelines and the Keystone pipeline system is shown in Figure 4.13.3-4 below.



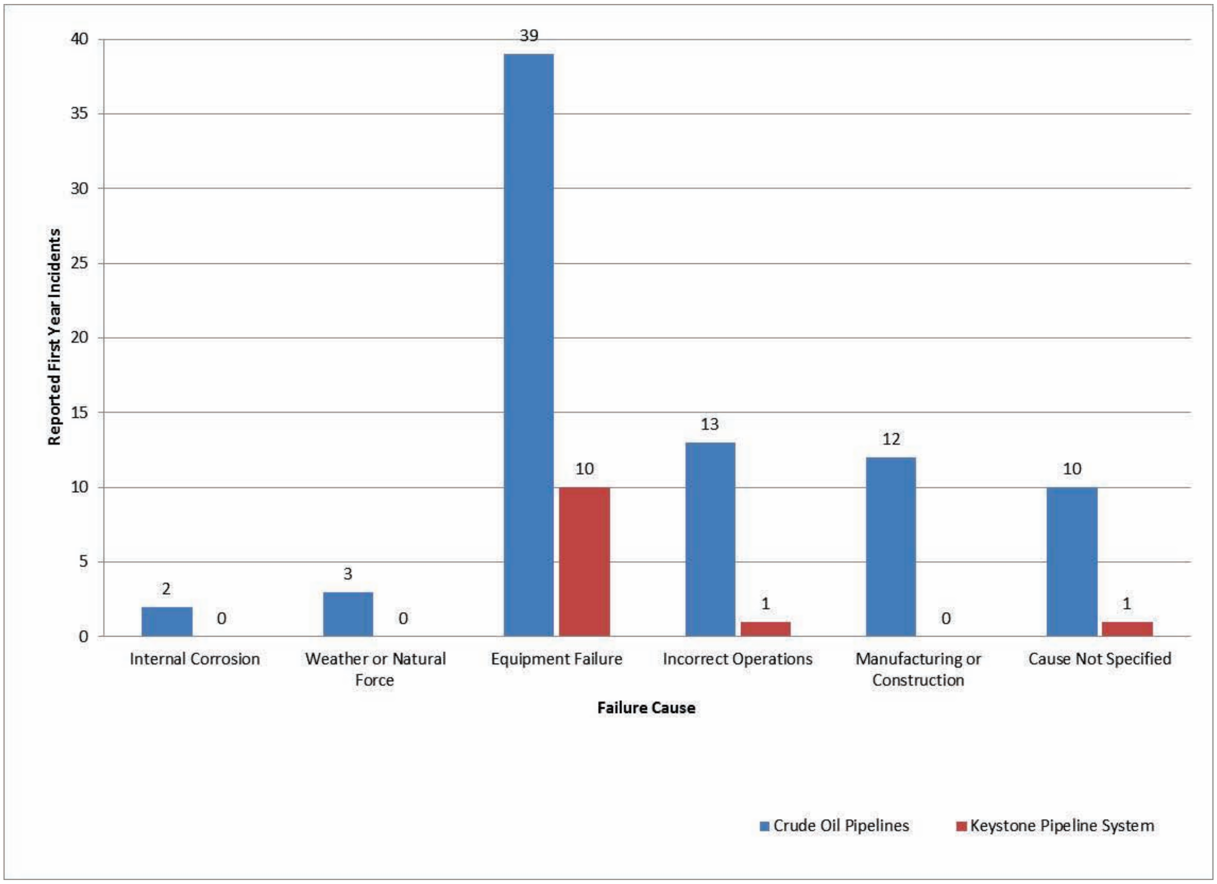
Notes: Crude oil pipeline incidents reported in PHMSA database 2002-May 2013. Keystone pipeline system incidents reported in PHMSA and NRC databases.

Figure 4.13.3-4 Median Spill Volumes Reported in the First Year of Operation, the Keystone Pipeline System and Other Crude Oil Pipelines

First-Year Failure Cause Distribution

Equipment failure was the primary cause involving discrete equipment elements within the first year of pipeline operation. Reported equipment failure causes are mainly related to ruptured or leaking seal/pump packing, or a malfunction of control/relief equipment. All reported first-year incidents caused by an equipment failure resulted in small spill volumes (less than 50 bbl). The dominant causes for a release from mainline pipeline elements and tanks within the first year of operation were incorrect operation and equipment failure. Incidents caused by internal corrosion resulted in small spills of less than 25 bbl and were related to terminal tank farm and mainline pipeline elements. Reported medium spills (50 to 1,000 bbl) were dominantly caused by incorrect operation and manufacturing/construction failures. The largest reported first-year spill (not related to Keystone) was caused by incorrect operation of a mainline pipeline system. Failure causes for other first-year pipelines (not related to the Keystone pipeline system) were not specified for ten reported incidents, two of which were large spills associated with tank malfunctions. The cause of one Keystone pipeline system first-year incidents was reported as unknown. The failure cause distribution for reported spills occurring within the first year of pipeline operation for both Keystone and other crude oil pipelines is shown in Figure 4.13.3-5 below.

For the existing Keystone pipeline system, equipment failure was the primary cause for first year of operation incidents. Reported equipment failure causes include threaded and non-threaded connection failures, pump or pump-related equipment malfunctions, and malfunction of control or relief equipment. The maximum reported spill (400 bbl) was caused by a threaded connection failure from excessive vibration. One incident was caused by incorrect operation and resulted in a spill from sump/separator component. The cause of one incident was reported as unknown.

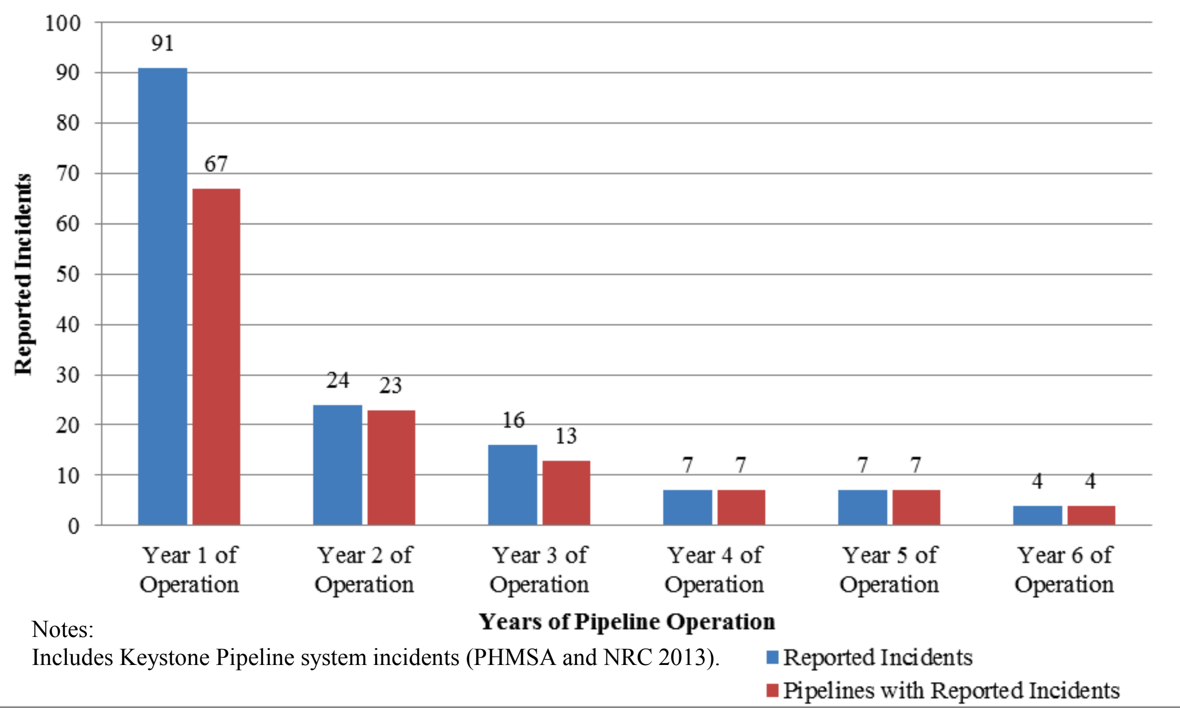


Notes: Seventy-nine other reported crude oil pipeline incidents within the first year of operation 2002-May 2013 (PHMSA). Twelve reported Keystone pipeline system incidents within the first year of operation (PHMSA, NRC). Pipeline operation was assumed to begin shortly following installation.

Figure 4.13.3-5 Failure Cause Distribution of Spills within First Year of Pipeline Operation

An additional analysis was conducted to compare the number of reported incidents for the first year of pipeline operation to subsequent years of pipeline operation. Figure 4.13.3-6 below shows the number of incidents by years of pipeline operation and the number of pipelines with reported incidents for that year of operation. Information on the total number of pipelines in service per year was not available for use in this analysis. As indicated in Figure 4.13.3-6 below, 67 pipelines, including the Keystone pipeline system, reported 91 incidents during their first year of operation, indicating that some pipelines had more than one incident during their first year

(PHMSA 2013). Of the 91 first-year incidents reported, 12 incidents related to the existing Keystone pipeline system (PHMSA and NRC 2013). In subsequent years of pipeline operation, the number of incidents compared to the number of pipelines with incidents decreases significantly from the first year of operation, as well as the number of pipelines with incidents. Since the first year of operation, only one additional incident has occurred related to the existing Keystone pipeline system (PHMSA 2013). This incident was caused by an equipment malfunction and resulted in a release less than 1 bbl that was entirely contained on the operator's property. The incident was discovered during a routine inspection of a pump station.



Notes:
Includes Keystone Pipeline system incidents (PHMSA and NRC 2013).

Figure 4.13.3-6 Reported Number of Incidents and Pipelines by Years of Operation

4.13.4 Spill Impact Assessment

4.13.4.1 Spill Volumes and Potential Impact

Potential crude or refined oil released into the environment from the proposed Project during operations may affect natural resources, protected areas, human uses, and services. Although reported information on dilbit releases is scarce in the literature, once diluents and bitumen are mixed together to form dilbit, they behave as a conventional crude oil. Therefore, this assessment focused on the impact of crude oil in general but, when applicable, evaluated the specific characteristics (i.e., viscosity) of dilbit. The degree of impact could vary depending on the cause, size, type, volume, location, season, environmental conditions, and the timing and degree of response actions. The discussion in this section presents the potential impact of three categories of spills: small, medium, and large,[14] which are defined below:

- Small spills: less than 50 bbl (2,100 gallons);
- Medium spills: greater than 50 bbl (greater than 2,100 gallons) up to 1,000 bbl (42,000 gallons); and
- Large spills: greater than 1,000 bbl (greater than 42,000 gallons) up to 20,000 bbl (840,000 gallons).

These categories were selected to be representative of the earlier Final EIS work, which used five categories; this Final Supplemental EIS reduced the categories to three to simplify the range of spill volumes provided in the PHMSA database. This simplification helps to facilitate assessing the spill-size propagation/migration along the proposed Project route.

According to PHMSA data, most small spills are related to pinhole-type corrosion leaks along the body of the pipe or by leaks from valves, flanges, pumps at pump stations, delivery type facilities, or other equipment. Medium spills are generally caused by damage from corrosion or by excavation/construction equipment damaging the body of the pipe.

The PHMSA data indicate that large spills are associated with severe damage to or complete failure of a major pipeline component (e.g., rupture in the pipe material, complete weld failures that cause pipe separation along seams or joints, third party strike).

These categories represent approximately 79 percent, 17 percent, and 4 percent, respectively, of the 1,692 crude oil spills reported[15] and capture the range of spill volumes provided in the PHMSA database, as shown in Table 4.13-1[16] and Appendix K, Historical Pipeline Incident Analysis. In addition to the volume of product spilled, the consequence of any of the above spill sizes would also be affected by response time and the response efforts. For all spills, the response time, the efficiency and effectiveness of the response actions, and the environmental sensitivity of the receptors would substantively influence the type and magnitude of impacts to environmental resources. Rapid containment and cleanup is expected to reduce surface oil spreading and potential infiltration into the ground. This Final Supplemental EIS is intended to evaluate the potential impact of the small, medium, and large spill sizes, regardless of response time and response efforts.

Potential Impact of Small Volume Spills

Small drips of oil or fluids from equipment or small, intermittent leaks of oil from flanges or gaskets to soil would typically have little effect on nearby natural resources. These types of releases would generally be detected by maintenance or operations personnel and addressed through the repair of the leak. The area impacted by this type of spill would be remediated (e.g., excavation of impacted soil, cleaning of stained concrete or containment areas, etc.) and the waste disposed, thus reducing the potential for environmental impact. Small spills of oil from a

[14] The spill sizes of *small*, *medium*, and *large* are descriptors to facilitate an analysis of spill impact. These descriptors are not intended to be a measure of potential environmental impact should a spill of these sizes occur.
[15] For crude oil spills from a pipeline 16-inch-diameter and larger, the same spill categories represented 38 percent, 36 percent, and 26 percent of the 71 reported incidents.
[16] Table 4.13-1 provides various subsets of the data with percentages based on the three spill volume sizes.

subsurface pipeline would disperse to the surrounding soil, and the oil would generally remain in the immediate vicinity of the spill site or within the pipeline ROW. A slow subsurface release, characterized as a slow drip (i.e., gallons per year as opposed to gallons per minute), would infiltrate down into soil, and could potentially reach a groundwater resource. If the rate of the spill is faster than the amount that could percolate downward through the soil, the oil may surface and potentially flow away from the release site across the ground surface, potentially affecting nearby vegetation or other resources.

While impacts to groundwater from small spills would be unlikely, a subsurface release could go undetected by both SCADA and surface inspections, resulting in impacts to permeable, sandy soils and could reach unconfined shallow groundwater resources. Chemicals in the oil could dissolve into groundwater and then migrate away from the release site. The response action to small spills or releases is generally conducted relatively rapidly once the spill/release is detected, resulting in only short-term (i.e., days to weeks) disruptions to the environment. However, small spills released directly or indirectly (e.g., via runoff from stormwater or overland flow) to lakes, rivers, reservoirs, or other potential drinking water sources as well as wetlands or natural areas could potentially impact human health and/or the environment through the contamination of drinking water supplies or oiling of vegetation or wildlife (i.e., a longer-term disruption).

Potential Impacts of Medium Volume Spills

With medium spills, a release could occur as a subsurface or surface event depending upon the cause. A slow subsurface release could infiltrate down into soil and could potentially reach a groundwater resource. Similar to a small spill, if the rate of the spill is faster than the spill could percolate through the soil, the oil could also seep to the ground surface. Once the oil reached the ground surface it would behave similarly to that of a surface release and potentially flow away from the site, affecting nearby vegetation or other resources. Once the migrating oil leaves the release site, impacts to soil, vegetation, and surface water along the flow path would occur. Some of this volume of material would tend to pool in low areas and potentially infiltrate back into the soil and to groundwater depending on the depth to groundwater. Potential behavior in shallow groundwater would be the same as for small spills that reach groundwater; a plume of chemicals could form and migrate away from the release site. Because of the increased volume of oil released from the pipeline when compared to a small release, it is also possible that oil could pool on the groundwater surface.

If the release enters flowing water or other surface water features, the extent of the release could become more widespread. Depending on the river's flow and the time to respond to the spill, the spill could potentially affect miles of river and shoreline. The same impacts to the shoreline of lakes or ponds could occur if tributaries or wind-driven currents spread the spilled material. Many of these surface water features could serve as potable water sources, and spilled material could threaten water supplies for the local population. Oiling could occur on vegetation and soil along the banks or shore of surface waterbodies. Additionally, over time, oil would degrade as well as mix with particulates in water resulting in the oil sinking below the water surface. In flowing water systems, sinking oil could be transported downstream without the obvious surface oiling of stream banks.

Wetlands and other natural areas along with their inhabitants (e.g., amphibians, reptiles, fish, and aquatic plants) could be impacted if a medium volume spill entered these ecological systems. However, compared to channelized flowing surface water systems, an oil plume within a wetlands-like environment typically would migrate slowly, oiling surface vegetation and wildlife. Additionally, impacts would not only occur from oiling of environmental features, but also from surface disturbance associated with response actions and remediation following a medium spill. Releases resulting in medium-sized spills typically would be detected by the SCADA system as well as by routine visual inspections.

Potential Impacts of Large Volume Spills

In a large land-based spill, the amount of oil contained in the immediate vicinity of the release point is dependent upon the relative size of the spill, terrain, location, soil type, weather, soil cover, and the response of operators to the release. If the spill is directly in a water source, very little of the oil released (relative to the size of the spill) would likely be contained in the immediate vicinity of the release point. The majority of the volume would migrate away from the release site, and the distribution of the oil would be influenced by the same factors as described above.

The potential impacts from a large spill would be similar to the impacts from the medium-sized spill, but on a much greater scale. More oil would seep into the soil over a larger area and could infiltrate deeper into the soil. More oil could enter surface water features and wetlands, if present in the release zone, and could also potentially affect drinking water resources to a greater extent. SCADA systems are designed to detect large volume oil releases, which are often detected by visual means, as well.

4.13.4.2 Spill Propagation

The size or extent of a spill could be affected by the terrain or topography of the release site, release setting (urban/suburban or remote), soil type and soil cover, land-based versus water-based spill, weather, and the timing and effort of the response. Understanding the effects of these factors on the oil could aid in understanding the extent of coverage and the potential impacts to humans and the environment.

Overland Flow with Infiltration to Groundwater

In the event of an undetected leak along a section of buried pipeline, the oil could saturate nearby soil and initially expand both vertically and horizontally along the pipeline. Downward movement could occur until the material reaches groundwater. At the water table, the material potentially could pool and a plume of dissolved chemicals could form. The pool of oil on the groundwater surface could continuously supply the dissolved-constituent plume, which could be carried downward away from the release site by natural flow conditions. In a scenario where a nearby operating water well is using the same groundwater resource, the dissolved chemicals could potentially be drawn to the well, exacerbating migration and potentially exposing humans, animals, and crops to the oil. Oil that moves upward to the ground surface would be noticeable. However, should the release go unchecked for an extended period of time, the oil could flow outside the proposed pipeline ROW and impact local vegetation and surface waterbodies. The oil would continue to spread until it has reached the physical limits of the volume spilled or is contained.

Overland Flow to Surface Water

The scenario discussed above has the potential to affect surface waterbodies such as streams and rivers. Once the spill reaches the surface, the oil would flow following topography or manmade structures (e.g., roads with side curbing in urban areas) and then pool in low-lying areas (i.e., topographic lows). Topographic lows could be features such as gullies, roadside drainage ditches, culverts, or storm sewers. These drainage features could eventually connect to larger ditches and possibly streams, rivers, lakes, or reservoirs. If the release enters flowing water or other surface water features, the areal extent of the release could become large. Depending on the surface water feature's flow and the spill response time, the spill could potentially affect miles of the surface waterbody and shoreline. The same impacts to the shoreline of lakes or ponds could occur if tributaries or wind-driven currents spread the spilled material. Oiling could occur on vegetation and soil along the banks or shore of surface waterbodies. It is currently understood that if oil remains on the water surface, the oil could degrade as well as mix with particulates in water, resulting in the potential for oil to sink below the water surface. In the USEPA's 1999 document entitled *Understanding Oil Spills And Oil Spill Response*, the USEPA wrote, "heavier oils, vegetable oils, and animal fats may sink and form tar balls or may interact with rocks or sediments on the bottom of the water body," and "evaporation occurs when the lighter or more volatile substances within the oil mixture become vapors and leave the surface of the water. This process leaves behind the heavier components of the oil, which may undergo further weathering or may sink" (USEPA 1999). In flowing water systems, sinking oil could be transported downstream as observed in the Kalamazoo, Michigan, spill. Sinking oil could be deposited in river or stream bottoms and could become a continual source of oil as changing water flows release the deposited oil (see Section 4.13.6.2, Safety and Spill Response, subsection Spill Response Considerations).

Degradation of Crude Oil in the Environment

Once oil is released to the environment, natural processes immediately begin to break down the oil. Many natural processes such as evaporation, biodegradation, dispersion, and dilution act upon the oil and its constituents to different degrees in soil or water. A release to subsurface soils from a buried pipeline would move throughout the nearby soil both laterally and vertically. Downward movement of oil could eventually impact groundwater resources. Crude oil that moves upward could be seen on the surface of the ground or water.

In surface soils, the constituents of the oil could be affected by evaporation, biological degradation (biodegradation), and photodegradation (i.e., degradation by ultraviolet light/sun light). The spreading and thinning of the oil increases the surface area exposed to these processes and could accelerate the degradation of the oil. Evaporation and photodegradation would generally affect the lighter hydrocarbons in the oil.

The remaining heavier, more complex hydrocarbons are typically referred to as weathered oil. This weathered oil would slowly degrade over time from biological processes. The effect these biological processes would have on the released oil would depend on the soil chemistry and the presence of suitable microbial populations.

Should oil reach groundwater or surface water, the more soluble components of oil (e.g., benzene, toluene, xylenes, among others) could dissolve in the water and form plumes that could flow away from the spill site. These dissolved plumes could continue to lengthen and spread until the all of the oil's more soluble components dissolve into the surrounding water. In groundwater, natural processes such as dispersion, dilution, and in time, biodegradation, would begin degrading the plumes. In surface waters, the oil would be diluted as it spreads across the surface in a thin sheen. Currents and wind would affect the movement of the oil. Many of the constituents of the oil sheen would evaporate due to their volatility. As these components evaporate, the oil could become heavier and sink to the bottom sediments where the oil could further degrade.

Topography of the Release Site

The topography or terrain near the spill would affect the potential impacts. Hills, valleys, low areas, and other land features could affect how a release is contained or migrates over the ground surface. A release in an area with a steep slope could accelerate the rate of oil migration and cause the spill to cover a greater area. Releases near low areas or confined valleys could pool and contain the oil and reduce aerial coverage of the release. A spill that flows into a drainage ditch or channel might flow greater distances from the release site due to the funneling of the oil in the channel as well as the slope of the channel. A spill released to level, flat ground would generally not migrate as far from the release site. Smaller drainage channels could eventually connect to larger channels, which potentially could empty to a surface water feature, thus increasing the impacts of the spill.

Effect of Location on a Spill Event

Location is a key component of the consequence of a spill. Topography has an effect, as described in the previous section, as do geomorphology and soil type for spill spreading. The location of the release relative to areas of human activity could affect the overall extent of a spill. Generally, most spills would occur and be contained within or in close proximity to the pipeline ROW or ancillary facilities (e.g., access roads, pump stations, and construction camps). Because of the larger population, urban and suburban surface spills could be noticed earlier than those in a rural setting, thus shortening the response time and mitigating the size of the impact. A spill in an urban setting generally may have different effects on human health and the environment than a rural setting.

However, excavation or construction activities occur more frequently in urban or suburban settings, increasing the chances of pipeline damage and a release. Generally, prompt reporting of the damage by the contractor would decrease the duration and size of the release in an urban or suburban setting, although the potential impact of the release could be greater depending upon the population associated with the urban/suburban area.

In remote areas, small spills may not be discovered immediately, and a small, slow release may not be detected immediately by leak monitoring systems; this could potentially allow a spill to continue for an extended period of time. In remote areas, it is possible that potential impacts from a larger spill could be less than those from a smaller, urban-type spill due to a reduced number of receptors.

The locations of greatest concern for potential oil spills are urban settings, HCAs, and other receptors within the reach of the spill. Water intakes for public drinking water or commercial/industrial users, Unusually Sensitive Areas, wetlands, flowing streams and rivers, and similar critical habitats are particularly important.

Battelle and E[x]ponent discuss in their respective reports (Leis et al. 2013, McSweeney et al. 2013, and E[x]ponent 2013) specific sections of the proposed Project referred to as contributory pipeline segments (CPSs) where, if a spill were to occur, crude oil has the potential to reach HCAs (i.e., *could affect* segments). The researchers applied a process ranking to identify the segments of the pipeline that could potentially affect HCAs, and categorize identified CPSs; the ranking process identified approximately 64 miles of the pipeline (consisting of nine CPSs) with the higher risk ranking. These segments were associated with major river crossings. Pipeline segments potentially affecting HCAs and the risk ranking process used to determine a degree of the potential risk for specific pipeline segments are discussed in more detail in E[x]ponent's Environmental Review, Section 2.5 (E[x]ponent 2013).

4.13.4.3 Effect of Soil Type, Soil Cover, and Temperature on Flow

Ground conditions and temperature could affect the size of the area affected. Ground conditions reduce spill extent by friction, which slows the movement of the oil. Two key types of ground conditions are addressed here, soil type and soil cover. Temperature also affects spill propagation by reducing spreading in colder temperatures or increasing the potential for spreading in warmer temperatures.

Soil Type

The type of soil at the site of the release affects the spread of the spill. Sands and gravels have larger spaces between the particles of soil (pore size), which could increase the upward or downward movement of the oil. Clays and silts have much smaller pore sizes and do not allow the oil to move as much. A spill of equal volume on sandy soils would tend to penetrate deeper because clays and silts allow much less downward movement. In some areas along the route, a spill may potentially penetrate through the sandy soils and impact groundwater resources. The extent of spills of equal volume would be affected by the type of soil on which the release occurred. Because spills tend to move downward in sandy soil, there are generally fewer impacts on the surface, depending on the size of the spill. The reverse is true with clay soils. In areas with a rocky surface, spills would tend to cover the rocks (known as oiling) and pool between the individual rocks.

The moisture content of the soil would influence the spill. In wet or saturated soil, the pores between the soil particles are partially or completely filled by water, leaving little or no room for the less dense oil to move downward. The lack of downward movement in this case generally would lead to a spill covering a larger surface area.

Soil Cover

The surface over which the oil spreads could affect the extent of the spill. Soil covers could include grasses, saturated ground (e.g., wetlands and related vegetation), forests, and hardscape (e.g., concrete, asphalt). Different soil covers retain different amounts of oil. As a spill spreads over land, the oil adheres to dry surfaces. Because saturated soils are less susceptible to downward movement of the oil, they tend to allow the oil to flow over the ground surface. As the oil flows over the ground surface, it would coat vegetation (oiling). The surface area of the impacted plants and the amount of oil retained would affect the overall extent of the spill. Where the oil flows into forested areas, shallow root zones may act as conduits and allow the oil to penetrate deeper into the soil. The oiling of hardscapes (e.g., concrete, asphalt) would tend to be surficial, except where expansion joint seams, cracks, or other deformities in the cover's surface exist. Cracks and joints in roadways could allow the oil to reach the potentially more permeable underlying soils and increase the depth of the impact.

Temperature

The temperature at the time of a spill could influence the extent of the spill. Temperature of dilbit is comparable to a heavy, sour crude oil. Due to friction created by the pumping action of the pipeline system, product would be transported through the pipeline at temperatures between 120°F (50 degrees Celsius [°C]) and 150°F (65°C). Ambient temperatures less than 120°F (50°C) would influence the spill by making the oil less apt to flow. In cold weather, dilbit would be far less mobile in the environment and may behave more like a solid (tar- or putty-like) than a liquid, potentially limiting the impacts and extent of a release to the environment.

Typically the areas traversed by the proposed pipeline experience very cold winters, which would limit the extent of a release during the colder months. The lower outside temperature would cool the product and increase its viscosity. This could inhibit the oil's ability to flow and limit the extent of coverage. Should a release occur in extremely cold conditions, the potential impacts would be further limited as the product would cool very quickly and behave more like a tar- or putty-type material and would not be able to flow. Conversely, the potential impacts of a release during the summer could increase due to the higher summer temperatures. The higher outside temperature would allow the oil to stay fluid longer. Generally, the cooling process is expected to take longer in the summer and could allow the oil to flow more readily. In the summer, surface temperatures (particularly on roadways and other surface covers where temperatures could approach the oil's transport temperature) could allow the oil to continue to flow over land until the source is interrupted. Average maximum summer temperatures in the states traversed by the proposed pipeline range from 75°F (24°C) in Montana to over 90°F (32°C) in Nebraska (NOAA 2013).

4.13.4.4 Types of Spill Impact

There are three types of spill impacts that could affect the spill receptors: physical impacts, chemical and toxicity impacts, and biological (ecological) impacts.

Physical Impacts

Physical impacts of spills of crude oil or petroleum products to natural resources and human uses typically result from physical oiling of soils, sediments, plants, animals, or areas used by people or from fire or explosion.

Oiling

Oiling could affect both wildlife and the physical environment in which they live. The following are common oiling effects:

- Smothering living plants and animals so they cannot feed or obtain oxygen;
- Coating feathers or fur on animals, which reduces insulating efficiency and results in hypothermia;
- Adding weight to the plant or animal so that it cannot move naturally or maintain balance;

- Coating sediments and soils, which reduces water and gas (e.g., oxygen and carbon dioxide) exchange and affects subterranean organisms (e.g., insects);
- Oiling sediment and soils such that they could become a chronic source of oil and its dissolved constituents;
- Oiling livestock, crops, clothes, water-based recreational equipment, pets, and hands/feet; and
- Oiling beaches, water surfaces, wetlands, and other resources used by people, which may result in nuisance odors and visual impacts.

In aquatic areas with high energy (e.g., turbulent river flows, and/or high sediment deposition), the oil may become buried under or mixed beneath stream sediment and soil along stream banks, where it may be trapped and remain for extended periods of time. This buried oil may later be slowly released from the sediment or soil to the environment to re-oil downstream habitats and resources. In some cases, the buried oil could be in an environment without oxygen (anaerobic) and would resist weathering by physical or biological processes, providing a source of nuisance discharges to the environment over several years.

Fire or Explosion

The PHMSA database for significant onshore hazardous liquid incidents indicates that since 2002, six of 3,916 (0.15 percent) reported incidents were attributed to fire. These six incidents were related to the release of flammable hydrocarbons, such as gasoline or liquid propane. Two of the incidences involved a subsequent release of crude oil (one less than 1 gallon and the other less than 10 gallons).

Crude oil is a flammable product; however, the appropriate concentrations of flammable vapors from the oil and oxygen would need to be available in the presence of an ignition source for a fire to occur. Oil spills released to confined areas (e.g., storm sewers and possibly some below ground spills) could potentially generate a sufficient concentration of flammable vapors and ignite. However, the flammable vapors released from a spill in an open environment would likely be dispersed throughout the surrounding area or diluted by the wind and not reach the concentration necessary to cause a fire or explosion. Very low oxygen levels and the lack of an ignition source inside a closed pipeline make it very unlikely for an explosion or fire to occur.

The pump stations for the proposed Project would be powered by electricity, although emergency generators would have integrated fuel tanks. As a result, there would not be natural gas or large quantities of other flammable fuel at the facilities. A crude oil spill at a pump station would likely result in the emission of some hydrocarbon vapors. In such cases, the vapors would typically emit into open atmosphere and be diluted to below explosive limits. Explosions at a pump station could potentially occur due to a fire unrelated to the pipeline such as at generator fuel tanks or local storage tanks.

Chemical and Toxicological Impacts

Toxicological impacts resulting from petroleum releases are a function of the chemical composition of the oil, the solubility of each class of compounds, and the sensitivity of the receptor. The chemical and toxicological characteristics of dilbit, SCO, and diluent are within the range for crude oils. Most crude oils are more than 95 percent carbon and hydrogen, with small amounts of sulfur, nitrogen, oxygen, and traces of other elements. Crude oils contain lightweight straight-chained alkanes (e.g., hexane, heptane); cycloalkanes (e.g., cyclohexane); aromatics (e.g., benzene, toluene); and heavy aromatic hydrocarbons (e.g., polycyclic aromatic hydrocarbons [PAHs], asphaltines). Straight-chained alkanes are more easily degraded in the environment than branched alkanes. Cycloalkanes are extremely resistant to biodegradation. Aromatics (i.e., benzene, toluene, ethylbenzene, and xylene compounds) pose the most potential for toxic impacts because of their lower molecular weight, making them more soluble in water than alkanes and cycloalkanes.

<u>Toxicity to Environment</u>

Toxicological impacts are the result of chemical and biochemical actions of petroleum-based compounds on the biological processes of individual organisms (API 1997, Muller 1987, Neff 1979, Neff and Anderson 1981, Neff 1991, Stubblefield et al 1995, Sharp 1990, Taylor and Stubblefield 1997). Impacts may include: various toxic effects to animals and birds as they try to remove the oil from their fur or feathers; direct and acute mortality; sub-acute interference with feeding or reproductive capacity; disorientation/confusion; reduced resistance to disease; tumors; reduction or loss of various sensory perceptions; interference with metabolic, biochemical, and genetic processes; and many other acute or chronic effects. A description of toxicological effects of petroleum to both human and natural environment receptors is presented in Section 4.0 of the *Pipeline Risk Assessment and Environmental Consequence Analysis* (see Appendix P, Risk Assessment).

While lightweight aromatics such as benzene are highly volatile, they tend to be water soluble and relatively toxic. Most or all of the lightweight hydrocarbons accidentally released into the environment evaporate, and the environmental persistence tends to be low. Monitoring for benzene is typically performed after a large spill. High-molecular-weight aromatic compounds, including PAHs, are not very water soluble, could be retained in soil, and persist in the environment longer than the lightweight aromatics such as benzene. Consequently, these compounds, if present, are substantively less mobile and toxic than more water-soluble compounds (Neff 1979). The concentration of any crude oil constituent in a spill would vary both over time and distance in surface water; however, localized toxicity could occur from virtually any size of crude oil spill.

In addition, these compounds generally do not accumulate in vegetation to any great extent because they are rapidly metabolized by plants (Lawrence and Weber 1984; West et al.1984). There are some indications, however, that prolonged exposure to elevated concentrations of these compounds may result in a higher incidence of growth abnormalities in aquatic organisms (Couch and Harshbarger 1985).

Significantly, some constituents in crude oil, such as PAHs, may remain in the environment longer than lightweight compounds (e.g. benzene). These constituents are generally less mobile through soil and less toxic than other more soluble compounds. Based on the combination of toxicity, solubility, and bioavailability, benzene was determined to dominate toxicity associated with potential crude oil spills.

The toxicity of crude oil is dependent on the toxicity of its constituents. Acute toxicity refers to the death or complete immobility of an organism within a short period of exposure. Most investigators have concluded that the acute toxicity of crude oil is related to the concentrations of relatively lightweight aromatic constituents, particularly benzene. Because the diluted bitumen crude oils have a significant amount of lighter hydrocarbons added, they tend to have higher benzene concentrations than many other heavy oils (such as Mexican Maya and Venezuelan Bachaquero), but lower than many light crude oils (such as Brent Blend or Alaska North Slope) (Environment Canada 2011). Benzene concentrations of SCO and dilbit are discussed further in Section 3.3 of E^{x}ponent's Environmental Review (E^{x}ponent 2013).

Chronic toxicity values on freshwater plant and animal species most frequently represent levels at which concentrations result in reduced reproduction, growth, or weight due to benzene. Chronic toxicity from other oil constituents may occur if sufficient quantities of crude oil are continually released into the water to maintain elevated concentrations. Additional biological and ecological impacts may manifest in local populations, communities, or entire ecosystems depending on the location, size, type, season, duration, and persistence of the spill, as well as the type of habitats and biological resources exposed to spilled oil.

Birds typically are among the most affected wildlife if exposed to the chemical and toxicological effects of an oil spill, whether it is on land or on water (Holmes 1985, Sharp 1990, White et al. 1995). In addition to the potential for external oiling of the feathers and hypothermia or drowning due to loss of flotation, birds may suffer both acute and chronic toxicological effects. Birds are likely to ingest oil as they preen their feathers in an attempt to remove the oil. The ingested oil may cause acute liver, gastrointestinal, and other systemic impacts resulting in mortality, reduced reproductive capacity, loss of weight, inability to feed, and similar effects. Oiled birds that are nesting or incubating eggs may, in turn, coat the eggs or young with oil. Oiled birds may be scavenged by other birds as well as mammals.

Fish and aquatic invertebrates could also experience toxic impacts of spilled oil, and the potential impacts would generally be greater in standing water habitats (e.g., wetlands, lakes, and ponds) than in flowing rivers and creeks. Also, in general, the potential impacts would be lower in larger rivers and lakes and much lower under flood conditions since the toxic hydrocarbon concentrations would likely be diluted by the water relatively rapidly.

Crude oil released into an aquatic environment could sink to the bottom of the water column and coat the benthic substrate and sediments (see Section 4.13.5, Potential Impacts). Crude oil intermixed with sediment, trapped in the river bed or on an oiled shoreline would result in a persistent source of oil due to the slow rate of degradation of crude oil in these environments. While the sinking characteristic is true for all crude oil types it is more prevalent in heavy crude oil. Dissolved components of the crude oil such as benzene, PAHs, and heavy metals could be slowly released back to the water column for many years after the release. The dissolved components (e.g., benzene, PAHs, heavy metals) could allow for long term chronic toxicological impacts to many organisms (e.g., macro-invertebrates) in both the benthic and pelagic portions of the aquatic environment.

In aquatic environments, toxicity is a function of the concentration of a compound necessary to cause toxic effects combined with the compound’s water solubility. For example, a compound may be highly toxic, but if it is not very soluble in water, its toxicity to aquatic biota is relatively low.

The physical and chemical impact processes described previously are manifested at the organism level. Additional biological and ecological impacts may manifest in local populations, communities, or entire ecosystems depending on the location, size, type, season, duration, and persistence of the spill, as well as the type of habitats and biological resources exposed to spilled oil. Except for some endangered, threatened, or protected species and their habitat, loss of a few individuals of a larger population of organisms would result in a minimal impact at a community or ecosystem level. On the other hand, reproductive impairment caused by toxicity could reduce an entire population or biological community, resulting in a significant environmental impact. The potential impact is likely to be greater if the species affected have long recovery times (e.g., low reproductive rates, adverse genetic mutations); limited geographic distribution in the affected area; are key species in the ecosystem; are key habitat formers (those animals that substantially contribute to the formation of an environment); or are otherwise a critical component of the local biological community or ecosystem. Furthermore, if the species or community is a key recreational or commercial resource (e.g., tourist draw, hunted resource), biological impacts manifested at the population or community level may constitute a significant impact to human uses of the resource.

Human health could be affected due to exposure to crude oil and the hazardous chemicals that make up crude oils. Exposure to crude oil could occur through ingestion, inhalation of vapors, dermal (contact with skin), and ocular exposure (contact with surface of the eye). Short-term exposure effects due to each of these pathways are discussed in Section 3.13.5.1, and could include mild stomach and gastrointestinal tract disturbances, transient nausea, diarrhea, irritation of the respiratory system, eye irritation, and mild to moderate skin irritation depending on the amount and duration of exposure. Long-term exposure effects of crude oil are currently not wholly understood; however, most research indicates that effects would be similar to the long-term effects of the chemicals that make up crude oil including, but not limited to, benzene, toluene, ethylbenzene, xylene, hydrogen sulfide, and polycyclic aromatic hydrocarbons. Long-term exposure effects of these chemicals are discussed in Section 3.13.5.1, and could be seen in people who were directly interacting with crude oil for extensive periods of time (i.e., spill cleanup professionals). Human health effects from exposure to elevated level of hydrogen sulfide (H_2S) depend on the concentration of the gas and the length of exposure. In an assessment of risk to first responders at crude oil spill sites, Thayer and Tell (1999) modeled atmospheric emissions of H_2S from crude oil spills. Model results indicate that even under worst-case conditions (no wind), modeled concentrations drop to non-toxic levels in less than 4 minutes after oil leaves the pipeline and is exposed to air, assuming no further release of oil. H_2S exposure is expected to be highest where oil has been spreading for the first 4 minutes immediately after discharge from the pipeline (adjacent to the pipeline and within the ROW). The Thayer and Tell modeling effort suggests that exposure to H_2S concentrations could pose health risks in the immediate area of an ongoing release or source.

Identification of Potentially Affected Spill Receptors

Spill impact was evaluated by developing distance buffers from the proposed Project route. A distance buffer is the zone where potential exposure from a spill could occur, considering a safety factor built-in such that the buffer distance is much greater than would reasonably be expected for an actual spill. This methodology assists in screening potential receptors at a general level. Site-specific impacts cannot be addressed at this stage because specific pipeline design elements are not available. Buffers are based upon data provided in the Final EIS, technical comments by third parties, and the screening model work described below. This screening model work was performed to supplement the information in the Final EIS because of the significant public interest in the issue. A summary of the Final EIS buffers and the buffers developed as part of this work is shown below in Table 4.13-13.

Table 4.13-13 Spill Impact Buffers

Buffer Type	Impact Buffer Size	Basis for Buffer Size
Surface Waterbody (downstream distance)	10 miles	Final EIS, Third-Party Comment
Stream Crossing (width)	500 feet	Final EIS
Surface Water Drinking Water Resources	5 miles	Final EIS
Well Head Protection Area	State-specific	Final EIS, Third-Party Comment
Overland Spill (50 bbl)	112 feet	Screening Model
Overland Spill (1,000 bbl)	367 feet	Screening Model
Overland Spill (20,000 bbl)	1,214 feet	Screening Model
Dissolved-phase Flow (50 bbl)	640 feet	Screening Model
Dissolved-phase Flow (1,000 bbl)	820 feet	Screening Model
Dissolved-phase Flow (20,000 bbl)	1,050 feet	Screening Model

The screening modeling estimates that oil could spread on flat ground between 112 and 1,214 ft from the pipeline, depending on the volume spilled. If oil reached groundwater, screening modeling indicates that the components in the oil, such as benzene, could spread in groundwater between 640 to 1,050 ft downgradient of the spill point. Similarly, if oil accumulated on groundwater, then these dissolved phase components of oil could spread an additional 640 to 1,050 ft from the edge of the oil (i.e., farther from the release point, potentially as far as 2,264 ft based on modeling) and because of the limited extent would not affect an entire aquifer such as the Ogallala Aquifer (see Figure 4.13.4-1). Screening modeling also indicates that the three spill volumes could reach groundwater at a depth of 50 ft (15 meters). Larger volumes could be expected to reach groundwater deeper than 50 ft bgs. This approach assists in identifying potentially affected receptors by identifying those receptors that are within the buffer limits. For an irrigation well, as an example, if a well is within 820 ft of a pipeline ROW it could potentially be affected by a 1,000 bbl spill that impacted groundwater. Similarly, the pipeline could affect a stream if a 50 bbl spill occurred within 612 ft of a river bank (500-ft buffer for the creek plus 112 ft for an overland spill).

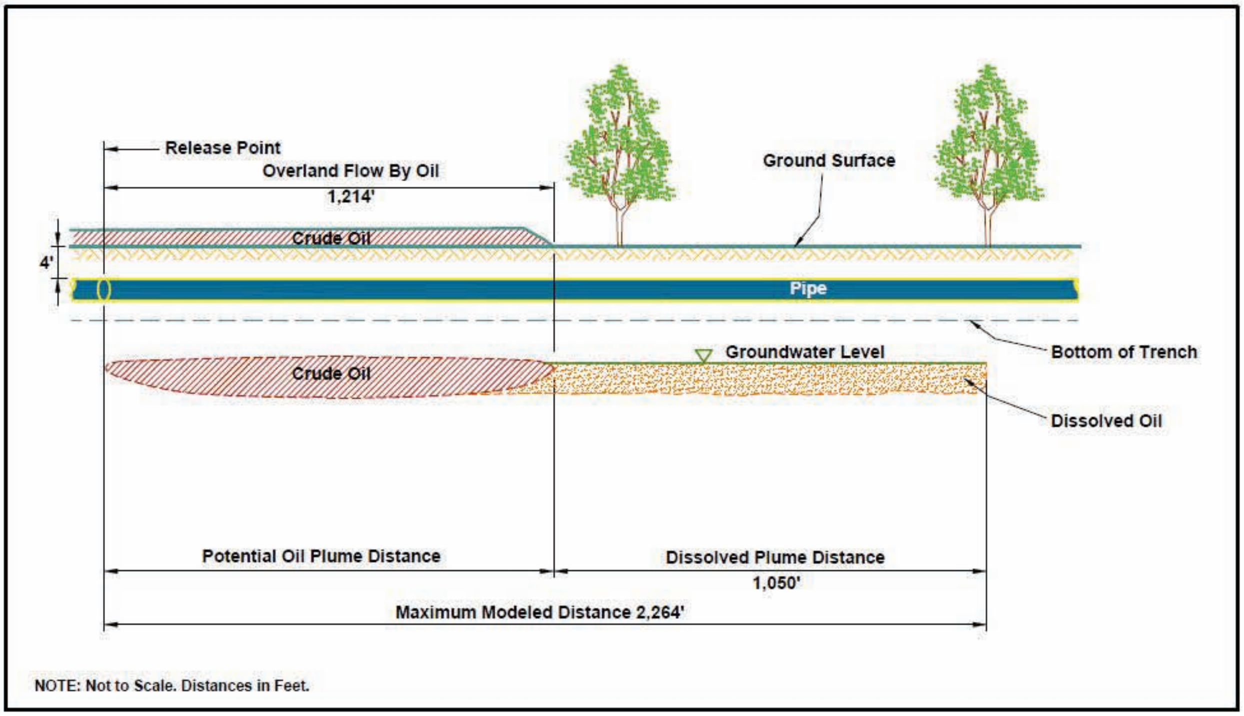


Figure 4.13.4-1 Modeled Maximum Plume Distances

The assumptions used for the screening model were conservative to build in an additional factor of safety. Model results show that the spill impact distances used in the Final EIS exceed those that resulted from the modeling herein; accordingly, the Final EIS concluded a degree of impact to the environment and to sensitive receptors that would likely be higher than expected under actual conditions.

Independent spill modeling was conducted by E^{x}ponent to determine quantitative estimates of the potential transport of oil to groundwater as well as transport over land. E^{x}ponent's modeling results are consistent with the screening model discussed above and are included in Section 4.0 of E^{x}ponent's Environmental Review (E^{x}ponent 2013).

Development of Spill Buffers

Section 4.3 of E^{x}ponent's Environmental Review (E^{x}ponent 2013) used PHMSA-defined HCAs within specified distances of the pipeline to assess potential impact. Several types of HCAs were considered such as populated areas and unusually sensitive ecological areas, which include drinking water protection areas. In addition to the HCAs, the Final EIS identified buffers for surface waterbodies, stream crossings, and surface water drinking water resources. These buffers are designated by each state's source water protection program or their wellhead protection program, and the buffer sizes vary from state to state. An additional 500 ft on either side of a stream crossing was added for stream crossing buffers based on the Final EIS Risk Assessment (see Appendix P, Risk Assessment). Doing so overestimates the calculated risk of the stream crossing to better highlight the potential threat to a waterbody. Additionally, to assess downstream effects from a release at a stream crossing, a 10-mile buffer was used to aid in identifying the presence of sensitive receptors or HCAs along that stream reach.

PHMSA identifies certain surface water and groundwater resources as drinking water Unusually Sensitive Areas (49 CFR Parts 195.6 and 195.450). Surface water Unusually Sensitive Areas include intakes for community water systems that do not have an adequate alternative drinking water source. Groundwater Unusually Sensitive Areas include the source water protection area for community water systems that obtain their water supply from a potable Class I or Class IIA aquifer and do not have an adequate alternative drinking water source. A Class I Aquifer is shallow, permeable, and highly vulnerable to contamination. A Class IIA Aquifer is a high-yield bedrock aquifer that is consolidated and moderately vulnerable to contamination. If the source water protection area has not been established by the state, the wellhead protection area becomes the Unusually Sensitive Area. Surface water Unusually Sensitive Areas identified for their potential as a drinking water resource have a 5-mile buffer placed around their intake location. The groundwater Unusually Sensitive Areas have buffers that vary in size due to site-specific characteristics that could include hydrogeology, annual pumping rates, and local standards. Overland Flow and Groundwater Dispersion

The screening-level approach used in this Final Supplemental EIS evaluates potential receptors along the proposed Project route that could be affected by a spill. Establishing discrete site-specific scenarios or site-specific conditions for the entire length of the pipeline is beyond the scope of this evaluation. By identifying reasonable distances that spill volumes could travel overland or that dissolved-phase plumes could migrate in groundwater, the potential for impact to a receptor could be assessed. Spill volumes were assessed for overland spreading, impact to groundwater, and the resulting dispersion in groundwater of the dissolved-phase constituent benzene. This evaluation uses spill volumes of 50 bbl, 1,000 bbl, and 20,000 bbl and is consistent with spill sizes as described in Section 3.13.6, Spill Magnitudes, and shown in Appendix K, Historical Pipeline Incident Analysis. This evaluation is intended as a screening approach and is not intended to predict the actual spill fate and transport for every condition along the pipeline route. The approach used for screening is described below and the methodology is described in Appendix T, Screening Level Oil Spill Modeling.

Overland Flow

Overland spreading was evaluated by calculating the area of potential impact for each of the identified spill volumes (50 bbl, 1,000 bbl, and 20,000 bbl) using a formula proposed by Grimaz et al. (2007). The model proposed by Grimaz et al. was developed as a simplified technique for predicting the maximum potential oil seepage depth into soil immediately after a release. As part of this model, Grimaz et al. proposed a simplified predictive formula derived from gravity current theory to predict the extent of surface spreading after a release. This part of the model was used for the overland flow calculation. The overland flow estimation using Grimaz et al. was based on a heavy crude oil (see Appendix T, Screening Level Oil Spill Modeling). Based on the approach by Grimaz et al., a light oil would result in a larger overland flow distance than would a heavier oil. This formula calculates the area of an instantaneous release of oil onto a surface. The calculated areas were used to derive the radial distance a spill would travel on a smooth, flat surface. These distances were added perpendicular to the centerline of the proposed Project route to assess possible impacts to receptors.

Groundwater Dispersion

The USEPA's Hydrocarbon Spill Screening Model (HSSM) was used to calculate the extent of the dissolved phase plume. HSSM is a practical approximation tool to estimate contamination levels for uses related to emergency response, initial phases of site investigation, facilities siting, and underground storage tank programs (Weaver et al. 1994). HSSM is not suitable for application to heterogeneous geological formations and is intended to provide order-of-magnitude estimates of contamination levels only. The model was developed for light nonaqueous-phase liquid and is not suitable for denser-than-water nonaqueous-phase liquids (dense nonaqueous-phase liquids) as the light nonaqueous-phase liquids are assumed to *float* on the water table for modeling purposes. In addition, the model is not designed to address dynamic conditions such as fluctuating groundwater, changing gradient, or specific design conditions such as pipeline trench systems or pressurized leaks from a pipeline.

HSSM simulates the flow of a light nonaqueous-phase liquid (e.g., oil) and the transport of a chemical constituent of the oil (in this case benzene) from the surface to groundwater. Should the simulation lead to an impact to groundwater, HSSM simulates the oil spreading at the water table and the dispersion of a dissolved benzene plume in groundwater. To evaluate potential impact to a shallow aquifer, groundwater was assumed to be 0.3 meter (1 foot) below the base of a spill. Hydrologic parameters used in the model for permeable sands were based on Carsel and Parrish (1988). In an additional model simulation, input parameters for the model were modified (e.g., aquifer hydraulic conductivity and porosity, benzene concentration, and crude oil viscosity) for a high-level sensitivity evaluation to simulate the likely lower/upper limits for dissolved plume length that might occur for a 50 bbl and a 20,000 bbl spill. The range of dissolved-phase spill plume lengths under these conditions was between 180 ft (55 m) and 1,608 ft (490 m); however, to achieve these distances, parameters unrepresentative of the soil type along the length of the pipeline were needed. This sensitivity evaluation assisted in assessing those parameters that drive plume length in the model, identifying the magnitude of a dissolved plume, and obtaining reasonable and likely parameters that can maximize dissolved plume length. Reasonable and likely maximum spill impact buffers, based on parameters representative of soil types along the pipeline, are shown in Table 4.13-13, with dissolved-phase plume length ranging from 640 ft (195 m) to 1,050 ft (320 m). Parameters along with their sources that were used to develop these reasonable and likely maximum spill impact buffers are presented in Table 4.13-14 below.

Table 4.13-14 Summary of Key Input Values Used in HSSM Simulation[a]

Parameter	Input Value[b]	Source
Hydrologic Properties		
Depth to Groundwater (m)	0.3	
Horizontal Hydraulic Conductivity (m/d)	15	Gutentag et al. 1984; Stanton 2010
Vertical Hydraulic Conductivity (m/d)[c]	1.5	
Porosity (vol%)	15	Stanton 2010
Hydrocarbon Phase Properties[d]		
Viscosity—Dilbit (cP)[e]	325	Leis et al. 2012
Density—Heavy Crude Oil (g/cm^3)	0.93	exp Energy Services, Inc.2012; Attanasi and Meyer 2007; Enbridge 2011a
Benzene Concentration—Light Crude Oil (vol%)[f]	0.28	exp Energy Services, Inc.2012; Section 3.13, Potential Releases

[a] Input values used were representative values for the geology along the proposed Project route, except for depth to groundwater, which was selected to address immediate impact.
[b] % = percent; cP = centipoises; ft/d = feet per day; g/cm^3 = grams per cubic centimeter; m = meter or meters; m/d = meter per day
[c] Assumed 1/10th of Horizontal Hydraulic Conductivity
[d] These hydrocarbon phase properties represent the range of possible products being transported through the pipeline and are selected to increase the dissolved benzene plume length.
[e] The high-end viscosity of dilbit was used to provide a larger plume size.
[f] Light crude oil was used since it has a higher benzene content than heavy crude oil or dilbit.

Degradation of oil could occur through weathering, which chemically and physically causes the spilled oil to break down and potentially become heavier than water. In open water, the oil could then sink into the water column. When oil mixes with water and oxygen, water-soluble compounds from the oil spread into the water. As the oil loses the water-soluble compounds, the oil becomes dense, sticky tar balls. Also, as oil moves with water, particles in the water such as sand, clay, and plant matter stick to the oil, increasing the oil's density. Examples of oil sinking are found for open water (e.g., lakes) and in rivers and streams. At present, there are no readily available studies indicating that degradation of oil in soil would convert into a dense liquid, reach groundwater, and sink through an aquifer. However, if the oil did degrade below the ground surface, as it degraded the oil would become sticky (increased interfacial tension), reducing the mobility of the oil.

The results of the HSSM simulations were used to identify reasonable benzene concentrations at the source from infiltrating oil, and the distances the dissolved-phase benzene plume would migrate toward potential receptors. The model results show a spill could reach groundwater in all spill volume scenarios (e.g., 50 bbl, 1,000 bbl and 20,000 bbl) and migrate toward downgradient receptors. The configuration for the model is addressed further in Appendix T, Screening Level Oil Spill Modeling. The model was configured to assume groundwater was 1 foot (0.3 meter) below the spill source. It was also assumed that a small and medium plume would continue undetected for 6 weeks (detection by second flyover) and large leaks would be detected immediately by the SCADA. The area of infiltration was based on one-half of the overland flow distance calculated using Grimaz et al (2007). Table 4.13-15 below summarizes the axial length of surface and dissolved-phase benzene plumes developed for each of the spill volumes assessed. These were the buffer distances perpendicular to the pipeline used to identify potential impact to receptors.

Additionally, a high-level sensitivity analysis was conducted using the same parameters above. This analysis determined that the three spill volumes assessed could affect groundwater encountered at a depth of at least 50 ft (15 meters) bgs. The results in Table 4.13-15 are consistent with the results from E^{x}ponent 2013.

Table 4.13-15 Length of Potential Plumes

	50 bbl	1,000 bbl	20,000 bbl
Surface Plume Length in feet (meters)[a]	112 (34)	367 (112)	1,214 (370)
Dissolved-phase Benzene Plume Length in feet (meters)	640 (195)	820 (250)	1,050 (320)

[a] Calculated from the formula proposed by Grimaz et al. 2007

The dissolved-phase plume length of crude oil constituents, such as benzene, stabilizes in groundwater due to a balance of several natural attenuation processes that degrade and dilute the crude oil dissolved components. These processes include biodegradation, evaporation, rate of dissolved components mixing with water, the affinity of the dissolved components to bind with the soil matrix, and the rate of fresh water entering the plume area.

Contaminants Not Found in Crude Oil

Crude oil constituents can be compared against other constituents not found in crude oil, such as chlorinated hydrocarbons, which can sometimes spread over large distances due to the persistent nature of the dissolved components. These persistent plumes often are confused with the non-persistent plumes such as benzene found in crude oil. The following are two examples of persistent plumes:

- Former Nebraska Ordinance Plant Mead, Saunders County, Nebraska; and
- Former Cornhusker Army Ammunition Plant (CHAAP), Hall County, Nebraska.

From 1959 to 1960, reported information suggests that trichloroethylene (TCE, a synthetic, degreasing solvent) was released as ground spills and/or discharged into surface drainage features during the construction of the Atlas Missile facility at the Former Nebraska Ordinance Plant Mead, Saunders County, Nebraska. Other reported historical site information suggests that parts were cleaned with TCE in a laboratory and the used TCE was discharged into a sewer. In 1992, over 30 years after disposal, the U.S. Army Corps of Engineers began a groundwater investigation and discovered a TCE-contaminated groundwater plume extending over 27,000 ft (5 miles) downgradient of the facility. Other groundwater contaminants detected included explosives and metals.

The former CHAAP, which was owned by the U.S. Army, was built in 1942 to produce munitions and provide support functions during World War II. As a consequence of common disposal practices during wartime, groundwater was impacted by explosives. Groundwater containing explosive residue migrated from cesspools and leach pits located in the center of the plant approximately 2 miles beyond the CHAAP boundary into the Grand Island City limits. In 1994 (over 50 years since plant construction), the groundwater plume was 6 miles long and 0.5-mile wide. Other chemical materials used to support munitions production at CHAAP included Freon, paints, grease, oil, and solvents. Solvents reportedly used at CHAAP included acetone, TCE, and 1,1,1-trichloroethane.

4.13.5 Potential Impacts

4.13.5.1 Consequence on Receptors

The magnitude of oil spill impact is primarily a function of size of the spill, type of oil, and sensitivity of the receptors affected (API 1992; API 1997; National Research Council 1985, 2003a, 2003b). Variations in spill size and receptor type are key variables for estimating the consequence of oil spills from the proposed Project. The risk analysis conducted by Battelle Memorial Institute, which uses incident damage cost in dollars as a measure of consequence for a risk assessment of the proposed Project, found that consequence and spill volume are correlated (Battelle 2013. Spill damage costs used as a measure of consequence on receptors are affected by many factors, including spill volume.

The crude oil that would be transported by the proposed Project would primarily consist of dilbit and SCO. Information on the chemical characteristics of these crude oils is provided in Section 3.13.3, General Description of Proposed Pipeline Transported Crude Oils, Table 3.13-1. Spill volume categories used in this impact assessment are presented in Section 4.13.4.1, Spill Volumes and Potential Impacts.

Receptor sensitivity is subjective and the perception of sensitivity can be influenced by the perspectives and biases of evaluators, as well as the actual sensitivity of the receptors to the oil. For example, a farmer whose grain field is oiled could consider impacts to a crop more significant than spill-related impacts on a wetland that supports threatened and endangered species, recreational hunting, and other recreational opportunities. Conversely, a national wildlife refuge manager could evaluate relative impacts very differently. In addition, different receptors could have different sensitivities to a specific compound such as benzene. Fish could be more sensitive to low levels of benzene, whereas crops or mammals could be more tolerant of high concentrations of the same compound. In many oil spills, there are differences in the way that stakeholders (e.g., general public, non-governmental organizations, natural resource management agencies, regulatory agencies, enforcement agencies, private businesses, municipal agencies, and others) value spill-related impacts on natural resources and habitats compared to spill-related impacts on human uses.

The severity of an impact to a receptor from a spill could be described as a function of spill size and receptor sensitivity. Severity generally increases as spill size increases and as receptor sensitivity increases. Table 4.13-16 presents, for each of three representative types of receptors and for each of the three spill sizes, various descriptions of impacts to the receptor, and the qualitative severity levels (low, medium, high) that correspond to these descriptions. The severity levels are based on a subjective evaluation using experience from previous oil spills. This presentation allows for a general assessment of the risk to certain environmental receptors should a spill occur.

Table 4.13-16 Potential Impact to Three Representative Resources[a]

	Resource	Potential Frequency			Resource	Potential Frequency			Resource	Potential Frequency		
	Wildlife and Terrestrial Habitat	**Small Spill**	**Medium Spill**	**Large Spill**	**Water, Wetlands, Aquatic Habitat/ Organisms**	**Small Spill**	**Medium Spill**	**Large Spill**	**Land use**	**Small Spill**	**Medium Spill**	**Large Spill**
Increasing Resource Severity →	Complete loss of habitat (acreage or quality) and/or animal population; habitat restoration measured in terms of years.	low	low	low	Supplemental drinking water supply required. Complete loss of wetland and/or aquatic habitat and/or aquatic organisms	low	low	low	Permanent loss of land use.	low	low	low
	Substantial, clearly measureable change in habitat (acreage or quality) or animal population; occurs throughout key animal life stages (e.g. nesting, breeding)	low	low	medium	Substantial, clearly measureable change in ground water, surface water, wetland and aquatic habitat, or aquatic organism population; occurs throughout key life stages (e.g., spawning)	low	low	medium	Temporary loss of land use due to chemical effects of spill.	low	medium	medium
	Evident, measureable change in habitat (acreage or quality) or animal population; occurs for short period during key animal life stages (e.g. nesting, breeding)	low	medium	medium	Evident, measureable change in groundwater, surface water, wetland and aquatic habitat, or aquatic organism population; occurs for short period during key life stages (e.g., spawning)	medium	medium	medium	Disruption to land use for duration of recovery actions and remediation actions.	medium	medium	high
	Perceptible, but minor change in habitat (acreage or quality) or animal population; occurs only minimally during key animal life stages (e.g. nesting, breeding)	medium	medium	high	Perceptible, but minor change groundwater, surface water, in wetland and aquatic habitat, or aquatic organism population; occurs only minimally during key life stages (e.g., spawning)	medium	high	high	Disruption to land use for duration of recovery actions.	medium	high	high
	No perceptible change in habitat (acreage or quality) or animal population; does not occur during key animal life stages (e.g. nesting, breeding)	high	high	high	No perceptible change in groundwater, surface water, wetland and aquatic habitat or aquatic organism population; does not occur during key animal life stages (e.g., spawning)	high	high	high	Insignificant disruption to land use.	high	high	high

Notes: Land use = soils, vegetation, ecosystem, agricultural, recreational; Green = low potential for impact to be realized for the given spill; Yellow = medium potential for impact to be realized for the given spill; Orange = high potential for impact to be realized for the given spill; Small = <50 bbl (2,100 gallons); Medium = 50 to 1,000 bbl (2,100 to 42,000 gallons); Large - >1,000 to 20,000 bbl (42,000 to 840,000 gallons).

4.13.5.2 High Consequence Areas

As identified in Section 3.13.5, Potential Spill Receptors, HCA categories are identified and defined individually to analyze potential spill impact on each. Based on the risk profile developed by Battelle (McSweeney et al. 2013 and Battelle 2013):

- The consequence in average damage costs to the operator of large spills occurring from mainline pipe in HCA areas is larger than the consequence of large spills on non-HCA areas ($5,484,000 vs. $1,288,000 respectively);
- The consequence in average damage costs to the operator of large spills occurring from system tanks in HCA areas is also larger than the consequence of spills in non-HCA areas ($605,000 vs. $225,000); and
- The consequence in average damage costs to the operator of large spills occurring from other system components (the thousands of parts that are typically part of a pumping station) in HCA areas is significantly higher than large spills in non-HCA areas ($11,561,000 vs. $1,603,000, respectively).

Additional information regarding risk to the human population and HCAs are discussed further in Section 4.2 of E^{x}ponent's Environmental Review (E^{x}ponent 2013).

Populated Areas

In the event of a spill, the effects on populated areas would depend on the size of the spill and the size of the population in the impacted area. For this reason, populated areas are divided into two categories by the USDOT: High Population Areas and Other Populated Areas. This division is done to improve the accuracy of risk analysis of a direct impact by an oil spill. Spill impact buffers for the proposed pipeline route do not cross any populated area HCAs. However, for completeness, the potential impacts of a spill to this type of HCA are discussed below.

Potential effects of a spill on populated areas could include interruptions in daily activities such as access to safe drinking water (discussed in more detail in Drinking Water section below), decreased air quality, and socioeconomic effects (discussed in more detail in Socioeconomics section below), or temporary relocation of population in impacted areas during spill containment and remediation procedures.

A 2003 report to USEPA prepared by the API compared the health effects of SCO with those of conventional crude oil and included the following statement (API 2003, page 9):

> Synthetic crude oil, from upgraded tar sands, is compositionally similar to high quality conventional crude oil (>33° API). The conventional technologies such as delayed and fluid coking, hydrotreating, and hydrocracking, used to upgrade heavy crude oils and bitumens, are used to convert tar sands into an essentially bottomless crude, consisting of blends of hydrotreated naphthas, diesel and gas oil without residual heavier oils . . . This information was supplied to USEPA . . . to support the position that tar sands-derived synthetic crude oil is comparable to conventional crude oils for health effects and environmental testing, a position with which USEPA concurred.

If an identified oil spill occurred that resulted in the contamination of drinking water sources (surface water or groundwater), use of these sources would be prohibited and monitored under state regulatory processes until the levels return to safe drinking water levels and the appropriate agencies authorize resumption of use of these water supplies. Water-related activities would be restricted in any area where there are contaminants present at levels deemed to be unsafe.

Reported background ambient levels of hydrogen sulfide in urban areas range from 0.11 to 0.33 parts per billion (ppb), while in undeveloped areas concentrations could be as low as 0.02 to 0.07 ppb (Skrtic 2006). A rotten egg odor characterizes hydrogen sulfide at low concentrations, and olfactory perception of hydrogen sulfide occurs for most people at concentrations in the air of approximately 0.2 parts per million (ppm). Some people could detect the gas by its odor at concentrations as low as 0.5 ppb (Skrtic 2006). In an assessment of risk to first responders at crude oil spill sites, Thayer and Tell (1999) modeled atmospheric emissions of hydrogen sulfide from crude oil spills using three different crude oil hydrogen sulfide concentrations (1 ppm, 20 ppm, and 350 ppm). The results of their analysis indicate that hydrogen sulfide levels in the immediate aftermath of a crude oil spill at the two higher levels of hydrogen sulfide concentration (20 ppm and 350 ppm) could pose short-term health risks (respiratory paralysis) to first responders at the spill site. The Thayer and Tell modeling effort also suggests that exposure to H_2S concentrations could pose health risks in the immediate area of an ongoing release or source. However, initial responders do not typically arrive at spill sites immediately and model results indicate that even under worst-case conditions (no wind), modeled exposures drop to non-toxic levels in less than four minutes after the oil stops entering the atmosphere for the first time. Hydrogen sulfide exposures would hence not be expected to create substantive health hazards except in the immediate area of the spill source, and until four minutes after the flow has stopped.

The rapid atmospheric dissipation of hydrogen sulfide levels indicated by these model results also suggests that risks to the general public in the event of an oil spill would be similarly confined to the immediate area of the spill source until four minutes after the flow has stopped. Additionally, some commenters have expressed concern that in the event of a fire or explosion involving crude oil that would be transported by the proposed Project, hydrogen sulfide could be released. However, hydrogen sulfide is also flammable and would burn in an explosion or fire, combining with oxygen to form sulfur dioxide and water and greatly reducing the risk due to inhalation of the gas.

Unusually Sensitive Areas

An Unusually Sensitive Area includes a drinking water or ecological resource area that is particularly susceptible to environmental damage from a hazardous liquid pipeline release. These have been defined by the USDOT. Unusually Sensitive Areas are separated from other water resources due to their association with increased potential of direct impact to human health or particularly sensitive wildlife. Other water or ecological resources identified but not captured by the USDOT designated areas are addressed in the other resources discussion below.

Drinking Water

PHMSA identifies certain surface water and groundwater resources as drinking water Unusually Sensitive Areas (49 CFR Parts 195.6 and 195.450). An Unusually Sensitive Area drinking water resource includes a water intake for a Community Water System or a Non-Transient Non-Community Water System that obtains its water supply primarily from a surface water source and does not have an adequate alternative drinking water source. An Unusually Sensitive Area drinking water resource also includes a Source Water Protection Area (SWPA) for a Community Water System or a Non-Transient Non-Community Water System if the water supply is obtained from a USDOT Class I or Class IIA aquifer and does not have an adequate alternative drinking water source. Where a state has yet to identify a SWPA, a Wellhead Protection Area is used. In Nebraska, the Steele City Wellhead Protection Area is the only drinking water Unusually Sensitive Area that a spill buffer overlaps with the Wellhead Protection Area and could be affected by a release from the pipeline. The existing Keystone pipeline system runs through Steele City, which would be the southern terminus of the proposed pipeline.

The route as proposed by Keystone is modified from the Final EIS route to avoid the Nebraska Department of Environmental Quality (NDEQ)-identified Sand Hills Region. The previous pipeline route in Nebraska as presented in the Final EIS trended northwest to southeast beginning at the South Dakota and Nebraska border in Keya Paha County, Nebraska, and ending at Steele City, Nebraska. NDEQ identified the region that it considers to be Nebraska Sand Hills largely based on a 2001 map published by the USEPA title *Ecoregions of Nebraska and Kansas* (NDEQ 2011). The route as proposed by Keystone avoids the NDEQ-identified Sand Hills Region as well as additional areas in Keya Paha County identified by the NDEQ that have soil and topographic characteristics similar to the Sand Hills Region. In response to concerns expressed by NDEQ and other stakeholders, the proposed Project's route is located further away from and downgradient of the wellhead protection area in the Village of Clarks, Nebraska, and avoids the wellhead protection area in the city of Western, Nebraska.

As discussed above, for the purpose of the analysis described herein, surface water Unusually Sensitive Areas identified for their potential as a drinking water resource have a 5-mile buffer placed around their intake location. Groundwater Unusually Sensitive Areas have buffers that vary in size. These buffers are designated by the state's source water protection program or their wellhead protection program and the buffer sizes vary from state to state.

Certain segments of the proposed Project route cross areas that are considered HCAs by PHMSA due to potential risks to sensitive drinking water resources. Oil spilled onto surface water or into groundwater supplies that serve as human drinking water sources would interrupt drinking water supply for the impacted area. The impacted sources would be monitored under state regulatory processes until the levels return to safe drinking water levels and the appropriate agencies authorize resumption of use of these water supplies. Water-related activities would be restricted in any area where there is oil present at levels that the health agencies consider unsafe for human exposure. Private landowners could choose to undertake water-related activities (e.g., installing additional groundwater pumping wells closer to the pipeline) that would increase exposure at their own risk.

Economic effects related to potential impacts to drinking water supplies could occur in the event of a large oil spill. However, the proposed Project route was selected to avoid water supply intakes and nearby potable groundwater well heads to the extent practicable. Nonetheless, numerous water wells exist within a mile on either side of the proposed pipeline centerline. Wells within the extent of groundwater impact as a result of a release could be affected. A large municipal supply well or intake could potentially draw affected water to the well or intake since it would draw from a larger area of groundwater. In the event of oil spill impacts to water supplies for residential, agricultural (e.g., farming, ranching, and livestock grazing on wild land), commercial, or public uses, Keystone would provide alternate sources of water for essential uses such as drinking water, irrigation and livestock watering, industrial cooling water, and water for firefighting and similar public safety services.

Ecological Resource Unusually Sensitive Areas

Impacts to ecologically sensitive areas would be similar to those impacts discussed in the Water Resources, Vegetation and Soil Ecosystems, and Wildlife sections of this Final Supplemental EIS. However, loss or reproductive impairment of any portion of a population of federal threatened, endangered, proposed, and candidate species; Bureau of Land Management (BLM) sensitive species; state threatened and endangered species; and species of conservation concern could result in a significant impact at an ecosystem level. The impact is likely to be even greater if the species affected have long recovery times (i.e., low reproductive rates); limited geographic distribution in the affected area; are key species in the ecosystem; are key habitat formers; or are otherwise a critical component of the local biological ecosystem. Furthermore, if the species were a key recreational or commercial resource, biological impacts manifested to the population may constitute a significant impact to human uses of the resource.

Federal threatened, endangered, proposed and candidate species, BLM sensitive species, state threatened and endangered, and species of conservation concern are discussed in Sections 3.8 and 4.8, Threatened and Endangered Species and Species of Conservation Concern, and are further discussed in Section 5.6 of E^{x}ponent's Environmental Review (E^{x}ponent 2013). Federally protected threatened or endangered species and federal candidate species with the potential to occur in the proposed Project area include two mammals, six birds, two fish, one invertebrate, and two plants. Potential impact analysis and preliminary findings are summarized in Table 1.3-1 of the Keystone XL Project Biological Assessment Final (see Appendix H, 2012 Biological Assessment, 2013 USFWS Biological Opinion, and Associated Documents).

Pipeline stream crossings near areas of special ecological consideration were identified as posing higher risk to ecological resources unless they utilized HDD crossings. E^{x}ponent's Report identifies areas of special ecological consideration (i.e., fisheries, wildlife habitat, wetlands, major waterbodies, or special waterbodies) where the pipeline crosses small streams. Ecological Resource Unusually Sensitive Areas and special ecological considerations are further discussed in Section 5.4 of E^{x}ponent's Environmental Review (E^{x}ponent 2013).

Commercially Navigable Waterways[17]

Commercially Navigable Waterways (CNWs) are waterways where a substantial likelihood of commercial navigation exists. CNWs are included in HCAs because these waterways are a major means of commercial transportation and are critical to interstate and foreign commerce, supply vital resources to many American communities, and are part of a national defense system. Areas defined as CNWs were provided by PHMSA. No CNW HCAs are located within a spill impact buffer as defined above.

[17] Commercially navigable waterways are included because of their importance as a supply route of vital resources to many American communities as well as their role in the national defense system (49 CFR Part 195, Federal Register / Vol. 65, No. 232 / Friday, December 1, 2000 / Rules and Regulations, pg. 75392).

The impact of an oil spill on CNWs is related to surface oil and the potential temporary closure of the CNWs to vessel traffic so that oil dispersion is not increased and response teams could contain oil safely without traffic hindering recovery operations. Temporary closure could be a few hours to a few days depending on the size of the spill.

4.13.5.3 Other Resources

Other resources include environmental resources that are not included in the USDOT definition of HCAs but that are present along the proposed Project route and therefore have been included for evaluation. A more detailed discussion of these receptors is included in Section 3.13, Potential Releases, and in Appendix P, Risk Assessment. Several categories of other resources are discussed below.

Soils

Soil includes the top layer of earth consisting of rock and mineral particles mixed with organic matter, containing living matter, and capable of supporting vegetation. For definition purposes, its upper limit is considered to be air or shallow water, and its lower limit is considered to be hard rock or earthen materials virtually devoid of biological activity. Soil ranges in depth from just a few inches to tens of meters along the proposed Project route. When discussing impacts to soil, this Final Supplemental EIS defines a release, leak, and spill as described in Section 4.13.4, Spill Impact Assessment.

Because the proposed Project pipeline is a buried structure, crude oil released from the pipeline would initially flow into the soil pore spaces. The impact of oil spills on soil would vary greatly depending on the type of soil, porosity, permeability, and water saturation of the soil at the time of the spill. Generally, subsurface releases to soil tend to disperse slowly and often preferentially flow into areas of less consolidated or higher porosity, permeability soils (such as sand layers). Most soils along the proposed route have low to moderate permeability, providing increased time to respond to the spill prior to extensive subsurface movement of the spilled material through soils.

Specific soil characteristics that were identified to be of particular interest were evaluated along the proposed Project route. They included highly erodible; prime farmland; saturated; compaction-prone; stony/rocky; shallow-bedrock; and drought-prone soils. Some of these characteristics are conducive to a greater disturbance than others if impacted (detailed descriptions of each characteristic are provided in Section 3.2.2, Soils, Environmental Setting.). As part of the evaluation, the approximate lengths in miles of the proposed route that would cross the different soils were identified by state. Of the identified total miles that would cross the key soil types (Table 3.2-1), approximately 70 and 270 miles cross the more sensitive highly erodible by wind and highly erodible by water soil types, respectively. The proposed Project route also could cross approximately 350 miles of prime farmland. Based on these mileage and potential oil overland spreading distances of the three different spill volumes used in this Final Supplemental EIS shown in 4.14-2, an estimated total area of potential spill-sensitive soils is shown in Table 4.13-17.

Table 4.13-17 Total Estimated Erodible and Prime Farmland Soils in Potential Spill Areas (acres)[a]

	Small (0 to 50 bbl)			Medium (50 to 1,000 bbl)			Large (1,000 to 20,000 bbl)		
State[b]	Wind Erodible	Water Erodible	Prime Farmland	Wind Erodible	Water Erodible	Prime Farmland	Wind Erodible	Water Erodible	Prime Farmland
MT	76.8	1,651.7	932.2	253.1	5,440.9	3,070.9	836.0	17,974.5	10,144.8
SD	246.7	1,548.3	1,628.1	812.7	5,100.3	5,363.1	2,684.9	16,849.1	17,717.2
NE	715.1	851.0	2,598.7	2,355.5	2,803.2	8,560.4	7,781.4	9,260.6	28,280.1

[a] Values assume flat, level ground, with plume volumes resting at an equilibrium thickness based on the surface tension of heavy sour crude. No potentially affected erodible or prime farmland soils identified in Kansas or North Dakota.
[b] MT=Montana, SD=South Dakota, NE=Nebraska.
Note: 1 acre = 43,560 ft.

It is difficult to estimate the volume of soil that might be contaminated in the event of a spill. Site-specific environmental conditions (e.g., soil type, weather conditions) and release dynamics (e.g., leak rate, leak duration) would result in substantially different surface spreading and infiltration rates which, in turn, would affect the final volume of affected soil. Based on historical data (PHMSA 2012a), soil remediation involved 100 cubic yards of soil or less at the majority of spill sites where soil contamination occurred, and only 3 percent of the spill sites required remediation of 10,000 cubic yards or more (PHMSA 2012a). These statistics suggest that the actual affected soils area would likely be significantly lower than the calculated areas shown in Table 4.13-17.

Spills could also affect soils indirectly by coating the vegetation, which in turn might not survive and expose the soil to water and wind erosion or solar heating. Spill cleanup could affect the soils (e.g., erodible soils) more than the presence of the spilled material itself, unless the cleanup is well controlled and heavy traffic and digging are minimized. Oil that adheres to or is retained between soil grains may weather slowly over a period of years.

Soil productivity could be negatively impacted by oil contamination particularly in the event of large spills. If long-term remediation is required, beneficial uses of the soil could be restricted for the length of the remediation period or longer.

In accordance with federal and state regulations, Keystone would be responsible for cleanup of contaminated soils and would be required to meet applicable cleanup levels (listed below). The residential soil cleanup levels for benzene from petroleum hydrocarbon releases (where applicable) are based on the inhalation of vapors, ingestion of contaminated soil, and dermal contact exposure pathways and vary by state (Montana: 0.04 ppm; South Dakota: 17 ppm; Nebraska: 3.63 ppm; North Dakota and Kansas: no levels established).

Paleontological resources exposed to a spill could also be affected. Remediation activities could also damage paleontological resources. However, in the event of a spill, a paleontological mitigation plan could be prepared to protect significant fossil resources.

Sediments

Sediments (defined here as submerged soils in wetlands and aquatic habitats) are typically fine grained and saturated with water. Crude or refined oils typically do not penetrate beyond the surface layer in sediments unless: 1) there is a substantive amount of turbulence that mixes the oil and sediments, followed by deposition of the mixture in low turbulence areas; 2) the air pockets between grains are large enough (e.g., in gravel and coarse sand) to allow for penetration

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of the oil as it sinks; or 3) physical activities associated with spill response actions mix the surface-deposited oil-sediment mixture into deeper subsurface levels of the sediment profile. Refined products typically would not penetrate sediments because the high water content would cause the oil to remain afloat, but it may penetrate or be mixed further into the sediments under the same turbulent conditions or cleanup actions as for crude oil.

The oil deposited on and remaining in the top sediment layer, especially in aerobic environments, may be subject to biodegradation by microbes, which would reduce or eliminate long-term impacts. Oil that is incorporated into sediments, especially in the anaerobic subsurface levels, may weather very slowly. Sediments of exposed shores could retain oil for extended periods of time, even in higher energy areas (Short et al. 2007).

For large spills that are not immediately or successfully remediated, crude oil constituents could remain in soil, aquatic sediments, or on plant tissues for several years. To the extent that residual oil leads to further contact or ingestion by mammals, effects to individual mammals could also continue.

Vegetation and Soil Ecosystems

An oil spill could result in impacts to vegetation in several ways, especially as it moves through multiple habitats. A surface release could produce localized effects on plant populations such as oil permeating through the soil affecting the root systems and indirectly affecting plant respiration and nutrient uptake. Also, without complete remediation of contaminated soil in a vegetation zone, long-term effects on vegetation could be expected. Tables 4.13-18, 4.13-19, and 4.13-20 summarize the estimated vegetation community acreage along the proposed Project route that could be affected by a surface spill. The acreage is based on spill distances shown in Table 4.13-13.

Crude oil released to the soil's surface could potentially produce localized effects on plant populations. Terrestrial plants are much less sensitive to crude oil than aquatic species. The lowest toxicity threshold for terrestrial plants found in the USEPA ECOTOX database (USEPA 2001) is 18.2 ppm in soil for benzene, higher than the 7.4 ppm threshold for aquatic species. Similarly, subterranean organisms such as earthworms could also be adversely affected by an oil spill. Spilled oil permeating through the soil could lead to sediments and soils being coated with oil, which reduces water and gas (e.g., oxygen and carbon dioxide) exchange and affects subterranean organisms. These organisms could also be coated, reducing their ability to function naturally or gain access to nutrients necessary for survival organisms.

Table 4.13-18 Total Estimated Vegetation Community Acreage in Potential Small Spill Areas

State[a]	Cultivated Crops	Grassland/Pasture	Upland Forest	Open Water	Forested Wetlands	Emergent Herbaceous Wetlands	Shrub-scrub Wetlands	Developed Land
MT	1654.97	5067.67	16.23	8.11	40.56	10.82	841.01	97.35
SD	1333.17	6936.27	13.52	8.11	40.56	35.15	81.13	100.06
NE	4881.08	2157.95	54.08	18.93	51.38	16.23	0.00	229.86

[a] MT=Montana, SD=South Dakota, NE=Nebraska.

Table 4.13-19 Total Estimated Vegetation Community Acreage in Potential Medium Spill Areas

State[a]	Cultivated Crops	Grassland/Pasture	Upland Forest	Open Water	Forested Wetlands	Emergent Herbaceous Wetlands	Shrub-scrub Wetlands	Developed Land
MT	5451.67	16693.51	53.45	26.72	133.62	35.63	2770.37	320.69
SD	4391.62	22848.91	44.54	26.72	133.62	115.80	267.24	329.59
NE	16078.86	7108.55	178.16	62.36	169.25	53.45	0.00	757.18

[a] MT=Montana, SD=South Dakota, NE=Nebraska.

Table 4.13-20 Total Estimated Vegetation Community Acreage in Potential Large Spill Areas

State[a]	Cultivated Crops	Grassland/Pasture	Upland Forest	Open Water	Forested Wetlands	Emergent Herbaceous Wetlands	Shrub-scrub Wetlands	Developed Land
MT	18009.98	55148.20	176.57	88.28	441.42	117.71	9152.13	1059.41
SD	14508.04	75482.99	147.14	88.28	441.42	382.56	882.84	1088.84
NE	53117.66	23483.60	588.56	206.00	559.13	176.57	0.00	2501.39

[a] MT=Montana, SD=South Dakota, NE=Nebraska

Overall, most past spills on terrestrial habitats have caused minor ecological damage, and ecosystems have shown a good potential for recovery, with wetter areas recovering more quickly (Jorgenson and Martin 1997, McKendrick 2000). The length of time that the spilled material remains in contact with the environment depends on several factors, including oil and soil temperature, availability of oleophilic (oil-loving) microorganisms, soil moisture, and the concentration of the product spilled. For the most part, effects of land oil spills would be localized and are not expected to impact vegetation and associated habitat outside the immediate spill area (assuming runoff is controlled to the extent necessary). Spills that occur within or near streams, rivers, and lakes could directly and indirectly affect riparian vegetation and habitat along these waterbodies. Effects on vegetation from subsurface spills that reach the root zones of surface vegetation could assist in leak detection as a result of visible patches of affected vegetation (often indicated by dying vegetation) along the proposed pipeline ROW resulting from oil interference with water and nutrient uptake by plant root systems.

Smaller spills during construction could occur within contractor yards, along access roads, at aboveground facilities and along the proposed pipeline construction ROW, and the spilled fuel or oil would generally remain localized near the release site. These spills would typically produce minor impacts on crops, native vegetation, and associated wildlife.

Large spills during operation would likely result in greater impacts to crops, native vegetation, and associated wildlife due to the larger area covered with oil.

Winter snow cover may occasionally be sufficient to slow and limit the surficial flow of spilled oil, thus limiting the extent of damage to vegetation and habitat. In other seasons, the spilled oil may flow farther on the land surface. Spill response activities could cause impacts on vegetation and habitat if activities are not implemented carefully and with regard for minimal disturbance of the surface soils and vegetation.

A large spill could spread over larger areas and coat vegetation, including row crops, wild lands, seasonal wetlands, and range lands, especially downslope from the spill site. The vegetation within the spill zone might not survive or be damaged or coated with oil, although population level vegetation effects are unlikely. Affected vegetation may not be suitable for grazing animals and any affected commercial row or field crops would likely not be marketable.

Wildlife

Spilled crude oil could affect wildlife directly and indirectly. Direct effects include physical processes, such as oiling of feathers and fur, and toxicological effects, which could cause sickness or mortality. Indirect effects are less conspicuous and include habitat impacts, nutrient cycling disruptions, and alterations in ecosystem relationships. The magnitude of effects varies with multiple factors, the most significant of which include the amount of material released, the size of the spill dispersal area, the type of crude oil spilled, the species assemblage present, climate, and the spill response tactics employed.

The 2010 Enbridge Line 6B spill in Michigan was a 20,082 bbl (PHMSA 2012a) subsurface composite crude oil spill that emerged onto the ground surface and affected forested, scrub/shrub, wetlands, Talmadge Creek, and Kalamazoo River. By examining the effects from the 2010 Enbridge spill, the potential impacts to wildlife from a spill of similar size/magnitude could be evaluated. The Enbridge-specific impacts are detailed in the Enbridge 2011 Conceptual Site Model, where wildlife studies conducted during the response of that spill have shown that more than 90 percent of the animals (including reptiles, crustaceans, amphibians, birds, mammals, and fish) that were collected and rescued during response efforts, were subsequently released during active recovery efforts (Enbridge 2011b).

Table 4.13-21 provides an estimated potential acreage of habitat identified along the proposed Project route that could be affected by a surface release.

Table 4.13-21 Total Estimated Acreage of Habitat in Potential Surface Spill Areas

State[a]	Small (0 to 50 bbl)	Medium (50 to 1,000 bbl)	Large (1,000 to 20,000 bbl)
MT	1814.52	5977.24	19746.23
SD	584.11	1924.12	6356.46
NE	3088.20	10172.88	33606.85

[a] MT=Montana, SD=South Dakota, NE=Nebraska.

Wildlife, especially birds and shoreline mammals, are typically among the most visibly affected organisms in any crude oil spill. Effects of crude oil could be differentiated into physical (mechanical) and toxicological (chemical) effects. Physical effects result from the actual coating of animals with crude oil, causing reductions in thermal insulative capacity and buoyancy of plumage (feathers) and pelage (fur). Toxicological effects on birds and mammals could occur via inhalation or ingestion exposure. Ingestion of crude oil may occur when animals consume oil-contaminated food, drink oil-contaminated water, or orally consume crude oil during preening and grooming behaviors. Unlike aquatic organisms that frequently cannot avoid spills in their habitats, the behavioral responses of terrestrial wildlife may help reduce potential adverse effects as indicated in the Enbridge study. Many birds and mammals are mobile and generally could avoid oil-impacted areas and contaminated food (Sharp 1990; Stubblefield et al. 1995). Many terrestrial species have alternative, unimpacted habitat available, as would often be the case with localized spills (in contrast to large-scale oil spills in marine systems); therefore, mortality of these species would be limited (Stubblefield et al. 1995).

Birds

Birds typically are among the most affected wildlife if exposed to the chemical and toxicological effects of an oil spill, as described in sections above, whether on land or on water (Holmes 1985, Sharp 1990, White et al. 1995). In addition to the potential for external oiling of the feathers and hypothermia or drowning due to loss of flotation, birds may suffer both acute and chronic toxicological effects. Birds are likely to ingest oil as they preen their feathers in an attempt to remove the oil. The ingested oil may cause acute liver damage, gastrointestinal and other systemic impacts resulting in mortality, reduced reproductive capacity, loss of weight, inability to feed, and similar effects. Oiled birds that are nesting or incubating eggs may coat the eggs or young with oil and injure or kill them. Dead oiled birds may be scavenged by other birds as well as mammals.

Potential adverse effects could result from direct acute exposure. Acute toxic effects include drying of the skin, irritation of mucous membranes, diarrhea, narcotic effects, and possible mortality. While releases of crude oil may have an immediate and direct effect on wildlife populations, the potential for physical and toxicological effects reduces with time as the volume of material diminishes, leaving behind more persistent, less volatile, and less water-soluble compounds. Although many of these remaining compounds are toxic and potentially carcinogenic, they do not readily disperse in the environment, do not bioaccumulate, and, therefore, the potential for impacts is low.

Small spills on or near the roads, construction yards, or pump stations would not generally affect birds in large numbers, although a few individual shorebirds, waterfowl, raptors, and songbirds could be exposed to the spilled oil. Exposed individuals could be exposed to hypothermia or from the toxic effects of ingesting the oil during preening, or from ingestion of oiled food and water. Potential impacts would likely be limited to a few individual birds, especially waterfowl and shorebirds that use small ponds and creeks affected by very small to small spills. If a very small to small-size spill occurred during migration periods, greater numbers of birds could be affected. There could also be an associated impact to a few individual scavenging birds and mammals if they feed on oiled carcasses. Small spills would not be expected to cause population-level impacts.

A medium to large spill in terrestrial habitats could cause mortality of birds that spend time foraging or nesting on the ground, such as shorebirds, grassland nesting songbirds (passerines), and upland game birds, where they would come into direct contact with oil and oiled prey or forage. If the spilled material entered wetlands or waters, water-dependent birds such as waders, seabirds, shorebirds, and waterfowl could be exposed. The numbers of individuals oiled would depend primarily on wind conditions, volume of spill, and the numbers of birds within and proximate to the area affected by the spill. Impacts may be detectable at the local population level, especially for resident species with limited geographic distribution if the spill affected important breeding habitat for migratory birds, or if the spill occurred within migration staging habitats during active migration periods. The North Valley Grasslands, crossed by the proposed pipeline in Valley County, Montana (Montana Audubon 2008), is a designated globally significant Important Bird Area supporting resident and migrant grassland nesting birds. Although not designated as an Important Bird Area along the route of the proposed pipeline, the Platte River and associated wetlands in central Nebraska are used for migration staging from mid-February to early April by more than 500,000 sandhill cranes during their northward migration (National Audubon Society 2012).

If raptors, eagles, owls, ravens, crows, magpies, vultures, and other predatory or scavenging birds were present in the spill vicinity, they could become secondarily oiled by eating oiled prey. Mortality of breeding raptors likely would represent a minor loss for local populations but would not likely affect regional populations. Mortality of migrant or winter roosting aggregations of bald eagles attracted to waterfowl aggregations at migration staging and winter open water locations could result in more significant losses for regional bald eagle populations from exposure to oiled prey.

If a large spill moved into wetlands, adjacent riparian habitats, or open water habitats of major rivers along the ROW, waterfowl species that breed, stage, or congregate in these areas during migration could be at risk. A spill entering a major river in spring, especially at flood stage, could significantly affect waterfowl in the short term by contaminating overflow areas or open water where spring migrants of waterfowl and shorebird species concentrate before occupying nesting areas or continuing their migration.

Lethal effects would be expected to result from moderate to heavy oiling of birds. Light to moderate exposure could reduce future reproductive success because of pathological effects on liver or endocrine systems (Holmes 1985) caused by oil ingested by adults during preening or feeding that interfere with the reproductive process. Oiled individuals could lose the water repellency and insulative capacity of feathers and subsequently drown or experience hypothermia. Stress from ingested oil could be additive to ordinary environmental stresses, such as low temperatures and metabolic costs of migration. Oiled females could transfer oil to their eggs, which at this stage could cause mortality, reduced hatching success, or possibly deformities in young. Oil could adversely affect food resources, causing indirect, sub-lethal effects that decrease survival, future reproduction, and growth of the affected individuals.

In addition to the expected mortality due to direct oiling of adult and fledged birds, potential effects include mortality of eggs due to secondary exposure by oiled brooding adults; loss of ducklings, goslings, and other non-fledged birds due to direct exposure; and lethal or sub-lethal effects due to direct ingestion of oil or ingestion of contaminated foods (e.g., insect larvae, mollusks, other invertebrates, or fish). Taken together, the effects of a large spill may be significant for individual waterfowl and their post-spill brood. Population depression at the local or regional scale would be greater than for smaller spills. However, the effects of even a large spill would be attenuated with time as habitats are naturally or artificially remediated and populations recover to again use them. In general, losses from medium to very large spills would likely result in limited impacts to regional bird population levels, but may result in significant impacts to local population levels.

The Biological Assessment (BA) prepared for the proposed Project identifies federally listed and candidate species that were identified by the Department, the U.S. Fish and Wildlife Service and state wildlife agencies as potentially occurring in the proposed Project area (see Appendix H, 2012 Biological Assessment). Table 1.3-1 in the BA summarizes these species and the preliminary impact determinations based on: 1) correspondence with the U.S. Fish and Wildlife Service, the BLM, and state wildlife agencies; 2) habitat requirements and the known distribution of these species within the proposed Project area; and 3) habitat analyses and field surveys that were conducted for these species from 2008 through 2012. The BA includes two mammal species, six bird species, two fish species, one invertebrate species, and two species of plants in the analysis and findings.

Mammals

Most oil spills, including medium to large spills (1,000 to 20,000 bbl), would result in a limited impact on most of the terrestrial mammals using the area affected by the spill. The extent of impacts would depend on the type and amount of oil spilled (see Table 4.13-16); the location and terrain of the spill; the type of habitat affected; mammal distribution, abundance, and activity at the time of the spill; and the effectiveness of the spill response. Typically, the proportion of habitat affected would be very small relative to the area of habitat available for most mammals.

A large spill could affect terrestrial mammals directly or indirectly through impacts to their habitat, prey, or food. For example, a large spill likely would affect vegetation, the principal food of the larger herbivorous mammals, both wild (e.g., deer, elk, and antelope) and domestic (e.g., cattle, sheep, horses). Some of these animals probably would not ingest oiled vegetation, because they tend to be selective grazers and are particular about the plants they consume. Many predators and scavengers could experience toxic effects through feeding on birds, other mammals, reptiles, and fish killed or injured by the oil spill. However, these effects would not generally be life threatening or long term (White et al. 1995). Spill response activities would typically frighten most large mammals away from the spill. As noted previously, vegetation could be affected by the spilled oil, thus temporarily reducing local forage availability, although it is unlikely that the overall abundance of food for large herbivorous mammals would be substantially reduced.

Small mammals and furbearers could be affected directly by spills due to oiling. Furbearers, especially river otters, mink, muskrat, raccoons, and beavers that depend on or frequently use aquatic habitats would likely be exposed to oil if spills reached aquatic habitats within their range. Oiled furbearers would be susceptible to hypothermia and oil toxicity from ingestion during grooming. Impacts to small mammals and furbearers would likely be localized around the spill area and would not cause population-level impacts.

Except for some endangered, threatened, or protected species, loss of a small fraction of a population of organisms would likely result in a minimal impact at an ecosystem level. Loss or reproductive impairment of a significant portion of a population or biological community from an oil spill could result in a significant environmental impact. The impact is likely to be greater if the species affected have long recovery times (i.e., low reproductive rates); limited geographic distribution in the affected area; are key species in the ecosystem; are key habitat formers; or are otherwise a critical component of the local biological community or ecosystem. Furthermore, if the species or community is a key recreational or commercial resource, biological impacts manifested at the population or community level may constitute a significant impact to human uses of the resource. Recreational species that may occur in the proposed Project area due to habitat presence are further discussed in Section 3.6, Wildlife.

Cultural Resources

Most spills would be confined to a construction yard, access roadway, pipeline ROW, or to an adjacent area, with the primary exception being a large spill from the pipeline that affects areas beyond the ROW. Large spills could impact cultural resources identified within the Area of Potential Effect or cultural resources located outside the Area of Potential Effect. Table 4.13-22 identifies the number of previously identified cultural resource sites that are within each of the spill size buffers.

Table 4.13-22 Number of Previously Identified Cultural Resource Sites in Potential Spill Buffers[a]

State[b]	Small (0 to 50 bbl)	Medium (50 to 1,000 bbl)	Large (1,000 to 20,000 bbl)
MT	87	112	120
SD	49	61	65
NE	92	106	112

[a] Due to the size of potential spill buffers and availability of cultural resources locational information, the numbers above may not match those presented in Section 3.11, Cultural Resources.
[b] MT=Montana, SD=South Dakota, NE=Nebraska.

Cultural resources affected by a crude oil release potentially might not be returned to their original state. However, the impacts would be mitigated through documentation and/or data recovery excavations consistent with the requirements of the Programmatic Agreement (see Section 4.11.3, National Register of Historic Places Eligibility, Effects, and Mitigation).

Water Resources

Water resources are defined in Section 3.13, Potential Releases, as sources of water that are potentially useful to humans and wildlife. This includes groundwater and surface water and the ecosystem that relies on these resources. For the purposes of the potential release analysis, groundwater is defined as the first water-bearing zone below the ground surface. Surface water includes open waterbodies such as rivers, lakes, and ponds, as well as wetlands where water is at or near ground level. This section also describes potentially impacted water resources adjacent to the proposed pipeline route, including major aquifers, wells, streams, and rivers that would be crossed, as well as reservoirs and large lakes downstream of these crossings.

Previous sections have discussed the potential for overland flow, the resultant vertical and horizontal migration of the released oil, and impacts of a spill on wetlands. Impacts largely depend on the spill volume and the type of waterbody that the oil contacts. Surface waters with low energy (i.e., static waters, ponds, and small lakes) could result in high localized toxicity levels. Low energy surface waterbodies with more water volume for oil constituents would be more likely to experience higher aquatic toxicity than creeks and rivers with turbulent flow, where there could be an increase in mixing and an increase in evaporation of constituents such as benzene. In aquatic areas with high energy (e.g., waves, turbulent river flows, and/or high sediment deposition), the oil may become buried under or mixed in the sediment.

If released to water, crude oil typically floats on the water's surface. If crude oil were left on the water's surface over an extended period of time, some constituents within the oil would evaporate, other fractions would dissolve, and eventually some material might descend to the bottom. Oil could sink in the water column as it degrades and mixes with particulates in water. The following is a summary of the major processes that occur during crude oil dispersion and degradation; these factors are considered when predicting impacts to receptors and resources:

- **Physical Factors**—Crude oil mobility in water increases with wind, stream velocity, and increasing temperature. Most crude oils move across standing surface waters at a rate of 100 to 300 meters per hour, excluding environmental influences (i.e., wind). Surface ice would greatly reduce the spreading rate of oil across a waterbody. Crude oil in flowing as opposed to contained waterbodies may cause more widespread impacts. Although reduced in intensity (as a result of dilution), a crude oil spill into flowing waters tends to move over a much larger area.
- **Dissolution**—Dissolution of crude oil in water is a process in controlling the crude oil's fate in the environment because most components of oils are relatively insoluble (Neff and Anderson 1981). Moreover, evaporation tends to dominate the reduction of crude oil, with dissolution slowly occurring with time. Overall solubility of crude oils tends to be less than that of their constituents, and individual compounds are often more soluble in oil than in water, thus they tend to remain in the oil. Diluents and bitumen when mixed together to form dilbit behave as a conventional crude oil, with the more soluble compound tending to remain in oil. However, some compounds could dissolve in water (i.e., dissolution). Dissolution is one of the primary processes affecting the toxic effects of a spill, especially in confined waterbodies. Dissolution increases with decreasing molecular weight, increasing temperature, decreasing salinity, and increasing concentrations of dissolved organic matter. Greater photodegradation also tends to enhance the solubility of crude oil in water.

- **Sorption**—In water, heavy molecular weight hydrocarbons would bind or adhere (i.e., sorption) to suspended particulates, and this process could be significant in water with a high particulate concentration (i.e., suspended clay or plant matter). Organic particles (e.g., biogenic material) in soils or suspended in water tend to be more effective at binding to soils than inorganic particles (e.g., clays). Sorption processes and sedimentation reduce the quantity of heavy hydrocarbons present in the water column and available to aquatic organisms. These processes, however, also render hydrocarbons less susceptible to degradation. Sediment covered with oil could be highly persistent and could cause shoreline impacts.
- **Evaporation**—Over time, evaporation is the primary mechanism of loss of low molecular weight constituents and light oil products. As lighter components evaporate, the remaining crude oil becomes denser and more viscous. Evaporation tends to reduce crude oil toxicity, but enhances crude oil persistence. In field trials, bulk evaporation of Alberta crude oil accounted for an almost 50 percent reduction in volume over a 12-day period, while the remaining oil was still sufficiently buoyant to float on the water's surface (Shiu et al. 1988). Evaporation increases with increased spreading of a spill, increased temperature, and increased wind and wave action.
- **Photodegradation**—Photodegradation of crude oil in aquatic systems increases with greater solar intensity. It could be a significant factor controlling the reduction of a slick, especially of lighter oil constituents, but it would be less important during cloudy days and winter months. Photodegraded crude oil constituents could be more soluble and more toxic than parent compounds. Extensive photodegradation, like dissolution, may thus increase the biological impacts of a spill event.
- **Biodegradation**—Soon after a crude oil spill, natural biodegradation of crude oil would not tend to be a significant process controlling the fate of spilled crude oil in environments previously unexposed to oil. Microbial populations must become established before biodegradation could proceed at any appreciable rate. Also, prior to weathering (i.e., evaporation and dissolution of light-end constituents), oils may be toxic to the very organisms responsible for biodegradation and high molecular weight constituents tend to be resistant to biodegradation. Biodegradation is nutrient and oxygen demanding and may be constrained in nutrient-poor aquatic systems. It also may deplete oxygen reserves in closed waterbodies, causing adverse secondary effects to aquatic organisms.

Groundwater

Groundwater is defined here as the first water-bearing zone below the ground surface. Groundwater aquifers are underground geological formations able to store and yield water. A groundwater aquifer is predominantly characterized as a formation with its pore spaces filled with water. Groundwater resources are primary sources of irrigation and potable water in the vicinity of the proposed pipeline route and several primary aquifers and aquifer groups are located within the proposed Project area in Montana, South Dakota, Nebraska, North Dakota, and Kansas (see Section 3.3.2, Groundwater), including the following alluvial aquifers: Northern

High Plains[18] Aquifer, Great Plains Aquifer, Western Interior Plains Aquifer, and the Northern Great Plains Aquifer System. Using the overland flow and groundwater spill impact buffers defined above in Table 4.13-13, the number of wells in the potential reach of a spill is shown below in Tables 4.13-23 through 4.13-25.

Table 4.13-23 Total Number of Wells in Potential Overland Flow Spill Impact Areas[a]

State[b]	Small (0 to 50 bbl)	Medium (50 to 1,000 bbl)	Large (1,000 to 20,000 bbl)
MT	4	17	70
SD	0	6	31
NE	14	126	553

[a] Data obtained from respective State registered well databases.
[b] MT=Montana, SD=South Dakota, NE=Nebraska.

Table 4.13-24 Total Number of Wells in Potential Groundwater Spill Impact Areas[a]

State[b]	Small (0 to 50 bbl)	Medium (50 to 1,000 bbl)	Large (1,000 to 20,000 bbl)
MT	30	46	62
SD	16	20	25
NE	248	317	463

[a] Data obtained from respective State registered well databases.
[b] MT=Montana, SD=South Dakota, NE=Nebraska

Table 4.13-25 Total Number of Wells in Potential Combined[a] Overland/Groundwater Spill Impact Areas[b]

State[c]	Small (0 to 50 bbl)	Medium (50 to 1,000 bbl)	Large (1,000 to 20,000 bbl)
MT	36	68	174
SD	18	27	49
NE	292	542	1009

[a] Combined is distance of oil spreading on groundwater, then dissolved-phase components of oil would spread an additional distance from the oil's edge.
[b] Data obtained from respective State registered well databases.
[c] MT=Montana, SD=South Dakota, NE=Nebraska.

In general, the potential for groundwater contamination following a spill would be more probable:

- Where a relatively shallow water table is present (as opposed to locations where a deeper, confined aquifer system is present);
- Where soils with high permeability are present above groundwater; and
- Where the PHMSA (in cooperation with the USGS and other federal and state agencies) has identified specific groundwater resources that are particularly vulnerable to contamination. These resources are designated by PHMSA as HCAs.

[18] Thousands of miles of pipeline carrying crude and refined products traverse throughout the region where the Ogallala Aquifer, part of the High Plains Aquifer System, is present. Pipelines installed within the last 10 to 15 years are all generally constructed and operated under similar regulatory and engineering procedures and design as would be required of the proposed Project.

The potential for crude oil migration into groundwater is influenced by several factors. These factors include the lateral extent of the oil spill, the viscosity and density of the material, the characteristics of the environment into which the material is released (particularly the characteristics of the underlying soils), and the depth to first groundwater. Groundwater in the alluvial aquifers along the ROW is characteristically shallow (typically less than 50 ft bgs) and often unconfined (meaning that groundwater could be recharged from water seeping from the ground surface). These aquifers are used as a primary source of groundwater for irrigation, domestic, and/or commercial/industrial use along much of the proposed Project route in Montana, South Dakota, and Nebraska. Table 3.3-1 in Section 3.3.2.2, Proposed Pipeline Hydrogeologic Conditions, identifies water-bearing zones shallower than 50 ft.

Generally, the crude oil being transported in the proposed pipeline would become increasingly viscous when released into the environment. As viscosity increases, the vertical migration rate decreases. In most cases, given that vertical migration is controlled by the infiltration rate of the oil into the underlying soil, the extent of vertical migration could be mitigated by rapid emergency response measures that include rapid source control (containment and collection of the oil released) (see Appendix I, SPCC and ERP). Heavy crude oils likely to be transported by the proposed Project are less dense than water and generally would initially float on the surface of waterbodies. If the crude oil infiltrates into soil formations, it would most likely form a floating lens above and slightly below the water table when groundwater is present. The crude oil plume would generally move in the direction of groundwater flow, until it reaches a steady state based on the groundwater flow rate, crude oil characteristics and soil characteristics. Plume expansion could also be affected by the rate of water being pumped out of an aquifer.

Studies related to oil and oil product releases from over 600 underground storage tank leaks indicate that potential surface and groundwater impacts from these releases are typically limited to several hundred ft or less from the release site (Newell and Conner 1998, USGS 1998) and are useful in assessing potential plume migration distances from pipelines. These studies indicate that the size of the oil release is the key factor influencing the ultimate oil plume dimensions (including the dissolved phase plume). While there are differences in the rate of oil movement through different soil types, hydrogeologic factors such as hydraulic conductivity (the rate that water moves through soil) and gradient are not as significant as the size of the release in determining ultimate plume length (Newell and Conner 1998, USGS 1998). However, on a localized basis, it is acknowledged that water withdrawals through extensive pumping could influence the gradient.

An example of a crude oil release from a pipeline system into an environment similar to the proposed Project's aquifers occurred on August 20, 1979, near Bemidji, Minnesota. In this large spill, approximately 449,400 gallons (10,700 bbl) of crude oil were released onto a glacial outwash deposit consisting primarily of sand and gravel. The water table in the spill area ranged from near the surface to about 35 ft bgs. As of 1996, the leading edge of the oil remaining in the subsurface at the water table had moved approximately 131 ft downgradient from the spill site, and the leading edge of the dissolved contaminant plume had moved about 650 ft downgradient.

The hydraulic conductivity of a soil is a property that describes the ease with which water could move through the spaces or pores between soil particles. Several hydraulic conductivity estimates for the soils in which the Bemidji spill occurred are provided below (converted from meters per second to feet per day [ft/d]); these indicate how hydraulic conductivity values could vary based on the measurement methodology:

- 1.59 ft/d estimated from particle-size distributions (Dillard et al. 1997);
- 19.85 ft/d based on a calibrated estimate (Essaid et al. 2003);
- 20.70 ft/d based on aquifer (slug) tests (Strobel et al. 1998); and
- 99.23 ft/d based on permeameter tests (Bilir 1992).

Along the proposed Project route, estimated aquifer hydraulic conductivities range from about 1 ft/d to over 200 ft/d. As an example of this variability, the High Plains Aquifer system exhibits hydraulic conductivities estimated to range from 25 to 100 ft/d in 68 percent of the aquifer, with an average hydraulic conductivity estimated at 60 ft/d (Weeks et al. 1988). In general, groundwater velocity (which takes into account porosity, hydraulic gradient [slope of the water table], and hydraulic conductivity [how easily groundwater moves through soil]) in the High Plains Aquifer system is 1 ft/d and groundwater generally flows in a direction from west to east (Luckey et al. 1986).

Other shallow groundwater resources along the proposed pipeline route may occur within soil profiles somewhat dissimilar from the previously mentioned Bemidji site. In many areas, shallow unconfined aquifers occur within alluvium in flood plains near streams and rivers. Shallow aquifers could also occur under confined conditions. Under confined conditions, the confining layer (i.e., silt or clay) would impede or prevent vertical migration of the crude oil into the aquifer. Unconfined alluvial soils comprised a range of soil constituents, including gravels, sands, silts, and clays in various percentages. As a result, these alluvial soils exhibit a range of hydraulic conductivities, but it is expected that in general vertical and lateral oil migration would follow similar patterns.

Concern was expressed relative to risks of contamination in aquifer recharge areas. Aquifer recharge occurs when overlying permeable materials connect to an aquifer unit. Shallow unconfined aquifers are overlain by such permeable materials and therefore are at risk if contamination of the overlying soils occurs. In areas where parts of deeper bedrock aquifers are exposed at the surface, they could also be at risk if they lie within an oil spill zone. Research by the USGS at the Bemidji site suggests that infiltration of nutrients to an oil spill in unconfined shallow aquifer recharge areas may actually increase the rate of natural biodegradation by microbes (Bekins et al. 2005) in the event of an oil spill.

Specific groundwater data for each shallow aquifer are presented in Section 3.3.2, Groundwater, of the Final Supplemental EIS. A review of publicly available water well data within 1 mile of the proposed Project centerline shows the following results:

- **Montana**—No public water supply wells or SWPAs are located within 1 mile of the proposed pipeline centerline; and six known private water wells are located within approximately 100 ft of the proposed pipeline centerline within McCone, Dawson, Prairie, and Fallon counties.
- **South Dakota**—One public water supply well (associated with the Colome SWPA) is located within 1 mile of the proposed pipeline centerline in Tripp County (within the Tertiary Ogallala aquifer); the proposed pipeline passes through the Colome SWPA in Tripp County; and no known private water wells are located within approximately 100 ft of the proposed pipeline centerline in South Dakota.

- **Nebraska**—Thirty-eight known public water supply wells are located within 1 mile of the proposed pipeline centerline in Boone, York, Fillmore, Saline, and Jefferson counties; there are nine SWPAs within 1 mile of the proposed pipeline centerline and the only SWPA traversed by the pipeline route in Nebraska is in Steele City in Jefferson County; there are a total of 14 known private water wells located within approximately 100 ft of the proposed pipeline centerline within Antelope, Polk, York, Fillmore, and Jefferson counties.

An independent environmental review conducted by E^{x}ponent (E^{x}ponent 2013) considered potential factors that could be used to identify non-HCA shallow groundwater areas that could be at risk in the event of a spill. E^{x}ponent's analysis determined wells located within 1,000 ft from the project centerline could be affected by a spill from the proposed Project and that this distance was reasonable to evaluate spill risk. The E^{x}ponent spill model distance is similar to the Department's modeled distance discussed in Section 4.13.4.2, Spill Propagation, and in Appendix T, Screening Level Oil Spill Modeling. Even though spill modeling suggests that a shorter spill distance can be protective, this Final Supplemental EIS used a distance of 1 mile (5,280 ft) for potential impact from a spill to provide a more protective analysis.

Flowing Surface Waters

Flowing surface water includes open waterbodies such as rivers and streams. There are several streams and bodies of water crossed by the proposed route. Table 4.13-26 summarizes the number of water crossings by state. Table 4.13-27 shows the estimated total miles of proposed pipeline from which a spill could affect waterbodies, based on the spill impact buffers listed in Table 4.13-13; note that the mileage is based on oil spreading on flat ground and effects of topography on spill flow were not addressed.

Table 4.13-26 Waterbody Crossings by the Proposed Project

State[a]	Number of Crossings
MT	459
SD	333
NE	281

[a] MT=Montana, SD=South Dakota, NE=Nebraska.

Table 4.13-27 Estimated Total Pipeline Mileage that Could Affect Identified Waterbodies[a]

State[b]	Small (0 to 50 bbl)	Medium (50 to 1,000 bbl)	Large (1,000 to 20,000 bbl)
MT	109.88	154.22	301.48
SD	79.72	111.88	218.72
NE	67.27	94.41	184.57

[a] Based on number of streams the buffer distance shown in Table 4.13-13.
[b] MT=Montana, SD=South Dakota, NE=Nebraska. There are no waterbodies crossed in North Dakota and Kansas.

Water resource projects on designated segments that are determined to have a direct and adverse effect on the free-flowing condition, water quality, or the values for which the rivers were established are prohibited unless impacts can be avoided or eliminated.

As part of the surface water impact evaluation, a sub-analysis was conducted at the request of the National Park Service, to assess the potential impact of a release from the proposed Project to protected waterbodies (NSR, WSR, and NRR) of the Niobrara and Missouri River. This analysis calculated the probability of a spill occurring from the proposed pipeline, focusing on the tributary streams that could convey a spill to the specially designated waterbody. Stream crossings, stream widths, and spill travel distances were identified using GIS and the National Hydrology Dataset. Spill incident frequencies were calculated using two different sets of historical pipeline spill data from PHMSA: first, a broader dataset including crude oil pipelines greater than 16 inches in diameter and second, a more focused dataset narrowed to pipeline spills that impacted surface water (See Section 4.13.3.5 and Appendix K, Historical Pipeline Incident Analysis, for additional information.)

The analysis identified that there are 39 stream crossings within 40 miles upstream of the specially designated waterbodies that could connect a spill from the proposed Project to the waterbody. Seven of these streams flow perennially and the remaining streams either flow intermittently or are undefined. Most stream crossings are not large; the average width of the stream crossings is 9 feet and the largest crossing is 110 feet.

Spill frequencies for stream crossings were calculated based on the total combined distance of all stream widths including an additional 500-ft buffer distance from each stream bank. The probability of any spill occurring within 500 ft of a stream crossing that could convey a spill to a protected waterbody is one spill every 542 years, based on all historical spills from pipelines greater than 16 inches in diameter. Using data for historical spills that impacted surface water, the probability of any spill occurring within 500 ft of a stream crossing that could convey a spill to a protected waterbody is one spill every 1,202 years. The shortest distance a spill would have to travel to impact a protected waterbody is approximately 28.5 miles.

Based on the above spill probability, it is unlikely that a spill event would occur during the operational life of the pipeline at one of the identified stream crossings. Additionally, the distance from the proposed pipeline to the specially designated river segments further reduces the probability of a spill reaching the protected waterbodies. Nonetheless, in the event of a large spill or undetected release of sufficient duration, some oil could reach a specially designated river segment if flowing water was present within the stream at the time of a release.

The Final EIS Risk Assessment applied the following criteria which overestimated the potential spill impacts:

- The entire volume of a spill was released directly into a waterbody;
- Complete, instantaneous mixing occurred; and
- The entire benzene content was dissolved into the water column.

The Risk Assessment evaluated impacts to downstream drinking water sources by comparing projected surface water benzene concentrations with the national maximum contaminant level (MCL) for benzene (0.005 ppm). Similar to existing pipelines, the proposed Project would cross hundreds of perennial, intermittent, and ephemeral streams. The Risk Assessment evaluated categories of streams based on the magnitude of streamflow and stream width. These categories included Low Flow Stream, Lower Moderate Flow Stream, Upper Moderate Flow Stream, and High Flow Stream. A 1-hour release period for the entire spill volume was assumed to maximize the product concentration in water. The estimated benzene concentrations were then compared with the human health drinking water MCL for benzene. E[x]ponent concluded in their review of the Risk Assessment that the assessment is useful for comparing worst-case benzene concentrations that could affect human and ecological receptors. Transport and fate of a spill to surface waters and the potential risk drivers to human health and ecological receptors are discussed further in Section 4.4 and Section 3.3, respectively, of E[x]ponent's Environmental Review (E[x]ponent 2013).

This report updates the Risk Assessment from the Final EIS to include the revised spill volume categories (small, medium, and large) discussed above and to use the new calculated occurrence interval of 0.00025 incident/mile-year (see Appendix K, Historical Pipeline Incident Analysis, Table 6). The incident frequency is based on historical data for mainline pipe and the revised streamflow results are presented in Tables 4.13-28 and 4.13-29.

Based on these conservative assumptions, results suggest that most spills that enter a waterbody could exceed the national MCL for benzene. Although the assumptions used are highly conservative and, thus, potentially overestimate potential benzene water concentrations, the analysis indicates the need for rapid notification of managers of municipal water intakes downstream of a spill so that potentially affected drinking water intakes from affected surface waterbodies could be closed. Section 2.2, External Notifications, of Keystone's ERP (see Appendix I, SPCC and ERP) contains notification procedures to ensure that these water managers are rapidly notified. Under anaerobic conditions (little to no dissolved oxygen), benzene typically degrades at a slower rate and could be more persistent in groundwater and travel longer distances than benzene in aerobic (normal or abundant dissolved oxygen) conditions. However, the distance of the migration is not unlimited and would be restricted by attenuating processes. In surface water, the mixing of benzene with fresh water, evaporation of benzene, and biodegradation would reduce the concentration of benzene in surface water quickly. Benzene, as a single component, would be reduced to non-detectable levels in a shorter distance in a flow surface water system than in a flowing groundwater system.

Although toxicity threshold values could be exceeded based upon the conservative assumptions, the potential for a release is low based on the risk evaluation above (and described in Appendix K, Historical Pipeline Incident Analysis). Spill occurrence intervals for a diluted bitumen or synthetic crude spill are shown in Tables 4.13-28 and 4.13-29, respectively. For a representative stream size and spill size category, a potential spill occurrence was calculated from data obtained from the PHMSA database. To be conservative, a 500-foot buffer on either side of the river was added to the crossing widths. Conservative occurrence intervals for a diluted bitumen ranged from approximately one spill event in 8,638 years for a high-flow stream to one spill event in 502,857 years for a small low-flow stream. If a release did occur, it is likely that the total release volume of a spill would be 50 bbl or less based on PHMSA data for historical spill volumes (see Appendix K, Historical Pipeline Incident Analysis, Figure 1).

Table 4.13-28 Estimated Surface Water Benzene Concentrations Resulting from a Diluted Bitumen Spill[a]

			Product Released					
			Small Spill		Medium Spill		Large Spill	
Streamflow	Benzene MCL (ppm)	Stream Flow Rate (cfs)[b]	Benzene Concentration (ppm)	Occurrence Interval (years)[c]	Benzene Concentration (ppm)	Occurrence Interval (years)[c]	Benzene Concentration (ppm)	Occurrence Interval (years)[c]
Low Flow Stream	0.005	10	10.9	25,461	218	118,319	2175.0	502,857
Lower Moderate Flow Stream	0.005	100	1.1	17,823	21.8	82,824	218.0	352,000
Upper Moderate Flow Stream	0.005	1,000	0.1	13,367	2.2	62,118	21.8	264,000
High Flow Stream	0.005	10,000	0.01	7,638	0.2	35,496	2.2	150,857

[a] Historical data indicate that the most probable spill volume would be 3 bbl or less. However, this analysis is based on conservative incident frequencies and volumes defined for this Final Supplemental EIS, which overestimates the proportion of larger spills. Consequently, the assessment is conservative in its evaluation of the magnitude of environmental consequences. Estimated concentration is based on release of benzene into water over a 1-hour period, with uniform mixing conditions. Concentrations are based on a 0.15 percent by weight benzene content of the transported material. Occurrence intervals are based on a historical incident frequency of 0.00025 incidents/mile-year (see Appendix K, Historical Pipeline Incident Analysis, Table 6), projected frequencies of each spill volume, and estimated stream widths. Widths of higher flow streams are greater than widths of lower flow streams, with more distance where an incident might occur. This results in a greater predicted frequency for high flow streams and a corresponding lower occurrence interval.
[b] cfs = cubic feet per second.
[c] Occurrence Interval (years) = the number of years that could pass before a spill incident would occur on a stream with this streamflow.

Table 4.13-29 Estimated Surface Water Benzene Concentrations Resulting from a Synthetic Crude Spill[a]

			Product Released					
			Small Spill		Medium Spill		Large Spill	
Streamflow	Benzene MCL (ppm)	Stream Flow Rate (cfs)	Benzene Concentration (ppm)	Occurrence Interval (years)[b]	Benzene Concentration (ppm)	Occurrence Interval (years)[b]	Benzene Concentration (ppm)	Occurrence Interval (years)[b]
Low Flow Stream	0.005	10	0.2	25,461	3.6	118,319	725.0	502,857
Lower Moderate Flow Stream	0.005	100	0.02	17,823	0.4	82,824	72.5	352,000
Upper Moderate Flow Stream	0.005	1,000	0.002	13,367	0.04	62,118	7.2	264,000
High Flow Stream	0.005	10,000	0.0002	7,638	0.004	35,496	0.7	150,857

[a] Historical data indicate that the most probable spill volume would be 3 bbl or less. However, this analysis is based on conservative incident frequencies and volumes defined for this Final Supplemental EIS, which overestimates the proportion of larger spills. Estimated concentration is based on release of benzene into water over a 1-hour period with uniform mixing conditions. Concentrations are based on a 0.15 percent by weight benzene content of the transported material. Occurrence intervals are based on a historical incident frequency of 0.00025 incidents/mile-year (see Appendix K, Historical Pipeline Incident Analysis, Table 6), projected frequencies of each spill volume, and estimated stream widths. Widths of higher flow streams are greater than widths of lower flow streams, with more distance where an incident might occur. This results in a greater predicted frequency for high flow streams and a corresponding lower occurrence interval.
b Occurrence Interval (years) = the number of years that could pass before a spill incident would occur on a stream with this streamflow.

In general, the impacts would be lower in flowing waters than in static water since constituent concentrations would be more rapidly diluted in flowing waters, although spills into rivers and creeks might result in some toxicity within the water column itself. Under certain conditions, oil may sink in the water column as previously described. In large rivers, the impact to the water column would be reduced. In small streams, an oil spill could create direct aquatic toxicity in the water column because of the lower relative volume and rate of water flow. This would lead to a higher likelihood of direct contact between aquatic organisms and the dispersed oil. Some toxicity might persist in these streams for a few weeks to months, until toxic compounds trapped in the sediment were washed out or until impacted sediment was covered by cleaner sediment.

Spills could affect surface water quality if spilled material reaches waterbodies directly or from flowing over the land. However, the vast majority of spills would likely be confined to construction yards, areas in or adjacent to the proposed pipeline ROW, or along access roads. As shown on Table 4.13-1 and in Appendix K, Historical Pipeline Incident Analysis, the volumes of most spills would likely be small. In addition, for some portion of the winter months each year, spill responders could remove much of the spilled material from frozen ground or ice-covered waterbodies prior to snowmelt. During the rest of the year, spills could reach and affect wetlands, ponds, and lakes, as well as creeks and rivers before spill response is initiated or completed.

An oil spill that reaches a surface waterbody not only could cause oiling and constituent toxicity levels, but could also reduce dissolved oxygen (DO) concentrations, particularly from dissolved phase hydrocarbons (e.g., benzene, toluene, ethylbenzene, and xylene). A reduced DO concentration results in a lower sustainable capacity for the plant and aquatic life, thus reducing the overall waterbody population. Because oil slicks are less permeable to oxygen than water, spilled material that reaches wetlands, ponds, or small lakes could lower DO concentrations due to a decreased influx of atmospheric oxygen and the relatively high rate of natural sediment respiration in many shallow waterbodies. In small, shallow waterbodies with limited water movement and presence (e.g., small lakes, farm reservoirs, and stock ponds), the presence of oil could increase biodegradation activity, further reducing oxygen levels.

In winter, however, a small spill may contribute less to an oxygen deficit in still waters than in other seasons, because biological abundance and activity are lower than during other times of the year and the need for oxygen is reduced. Furthermore, sediment respiration has less relative effect in lakes that are too deep to freeze to the bottom. Such lakes tend to be supersaturated with DO in winter (BLM and Minerals Management Service 1998). An exception to such conditions could occur if spilled material were introduced to a waterbody beneath the ice cover, in very restricted waters with depleted oxygen levels and a concentrated population of overwintering fish. During open water periods in most waterbodies, especially larger lakes, rivers, and streams, spilled materials would likely result in little detectable decrease in DO levels. The high water volume (relative to the volume of oil) or the high rate of water flow would disperse oil before it affected DO concentrations.

Long-term aquatic toxicity is considered less likely to occur in larger lakes and rivers because oil would be diluted or dispersed within the sediment over large areas by currents and wind and wave action. Spills into larger rivers and creeks, especially during open water periods, might result in some toxicity within the water column itself. However, in larger rivers, because of the large and rapid dilution of the oil relative to the flow volumes, these impacts would likely be limited to back eddies, calm water regions, and reservoir pools down current of where the spill enters the river. In smaller flowing streams, an oil spill could create direct aquatic toxicity in the water column because of the lower relative volume and rate of water flow, and thus there would be a higher likelihood of direct contact between the biota and the dispersed oil. Some toxicity might persist in these streams for a few weeks or longer, until toxic compounds trapped in the sediment were washed out or until oiled sediment was covered by cleaner sediment.

Since the majority of oil spills are small in volume, these smaller spills, if reaching larger lakes, would result in minimal effects on overall water quality, assuming the lake volume is substantially larger than the volume of spilled oil. Decreases in DO levels would be negligible in most cases but may be greater in large to very large spills that cover much of the water surface for a day or more. Direct toxicity would be short term because of the high dilution volume in these lakes and the rapid evaporation of most of the potentially toxic lighter hydrocarbons. Spreading of a spill over a lake surface may have a minor to major effect on water aesthetics and recreational use. This effect could exist for days to a few weeks until the oil was removed. Removal could include both physical removal by response teams and natural attenuation. Natural attenuation could include biodegradation, evaporation, components dissolving in water and degrading naturally, and dispersion and dilution.

Minor temporary to short-term surface water quality degradation is possible from smaller maintenance equipment and vehicle spills or leaks. Longer-term water quality degradation could be associated with large to very large spills. A larger spill could also affect potable surface water sources and irrigation water supplies. As mentioned previously, the crude oils transported by the proposed Project would tend to float on the surface water column. However, as with any crude oil, over time key components of oil would evaporate and biodegrade resulting in a weathered oil that could potentially sink.

Aquatic Organisms

As defined in Section 3.13, Potential Releases, aquatic organisms include plants, animals, and microorganisms for which life is completely sustained within an aquatic habitat. There are three fish species listed with special status that were identified during field surveys, including Blacknose shiner, Finescale dace, and the Northern redbelly dace. Table 4.13-30 shows that fish are among the most sensitive aquatic organisms, while aquatic clams, snails, etc., generally have intermediate sensitivities, and algae and bacteria tend to be the least sensitive. Nevertheless, even when major fish kills have occurred as a result of oil spills, population recovery has been observed and long-term changes in fish abundance have not been reported. Benthic (bottom-dwelling) aquatic invertebrates tend to be more sensitive than algae, but are equally as or less sensitive than fish. Planktonic (floating) species tend to be more sensitive than most benthic insects, crustaceans, and mollusks.

Table 4.13-30 Acute Toxicity of Aromatic Hydrocarbons to Freshwater Organisms[a]

	Toxicity Values (ppm)				
Taxa/Species	**Benzene**	**Toluene**	**Xylenes**	**Naphthalene**	**Anthracene**
Amphipod/ (*Gammarus lacustris*)	NA[b]	NA	0.35	NA	NA
Amphipod/ (*Gammarus minus*)	NA	NA	NA	3.9	NA
Fish/Carp (*Cyprinus carpio*)	40.4	NA	780	NA	NA
Fish/Channel catfish (*Ictalurus sp.*)	NA[a]	240	NA	NA	NA
Fish/Clarias catfish (*Clarias* sp.)	425	26	NA	NA	NA
Fish/Coho salmon (*Oncorhyncus kisutch*)	100	NA	NA	2.6	NA
Fish/Fathead minnow (*Pimephales sp.*)	NA	36	25	4.9	25
Fish/Goldfish (*Carassius auratus*)	34.4	23	24	NA	NA
Fish/Guppy (*Poecilia reticulate*)	56.8	41	NA	NA	NA
Fish/Largemouth bass (*Micropterus sp.*)	NA	NA	NA	0.59	NA
Fish/Medaka (Oryzias sp.)	82.3	54	NA	NA	NA
Fish/Mosquito fish (*Gambusia affinis*)	NA	1,200	NA	150	NA
Fish/Rainbow trout (*Oncorhyncus mykis*)	7.4	8.9	8.2	3.4	NA
Fish/Zebra fish (*Therapon iarbua*)	NA	25	20	NA	NA
Insect/ *Chlorella vulgaris*	NA	230	NA	25	NA
Insect/ *Microcystis aeruginosa*	NA	NA	NA	0.85	NA
Insect/ *Nitzschia palea*	NA	NA	NA	2.8	NA
Insect/ *Scenedesmus subspicatus*	NA	130	NA	NA	NA
Insect/ *Selenastrum capricornutum*	70	25	72	7.5	NA
Insect/ (*Somatochloa cingulata*)	NA	NA	NA	1.0	NA
Midge/ (*Chironomus attenuatus*)	NA	NA	NA	15	NA
Midge/ (*Chironomus tentans*)	NA	NA	NA	2.8	NA
Rotifer/ (*Brachionus calyciflorus*)	>1,000	110	250	NA	NA
Snail/(P*hysa gyrina*)	NA	NA	NA	5.0	NA
Zooplankton/ (*Daphnia magna*)	30	41	NA	6.3	0.43

Taxa/Species	Toxicity Values (ppm) Benzene	Toluene	Xylenes	Naphthalene	Anthracene
Zooplankton/ (*Daphnia pulex*)	111	NA	NA	9.2	NA
Zooplankton/ (*Diaptomus forbesi*)	NA	450	100	68	NA

Source: Appendix P, Risk Assessment, Table 4-4

[a] Data summarize conventional acute toxicity endpoints from USEPA's ECOTOX database. When several results were available for a given species, the geometric mean of the reported LC50 values was calculated. The LC50 is the concentration of a compound necessary to cause 50 percent mortality in laboratory test organisms within a predetermined time period (e.g., 48 hours) (USEPA 1994).
[b] NA = not available. Indicates no value was available in the database.

The toxicity of crude oil is dependent on the toxicity of its constituents. Table 4.13-31 summarizes the toxicity of various crude oil hydrocarbons to the water flea, *Daphnia magna*. This species of water flea is used as a standard test organism to determine acute and chronic responses to toxicants. Most investigators have concluded that the acute toxicity of crude oil is related to the concentrations of relatively lightweight aromatic constituents, particularly benzene.

Table 4.13-31 Acute Toxicity of Crude Oil Hydrocarbons to *Daphnia magna*

Compound	48-hr LC50[a] (ppm)	Optimum Solubility (ppm)	Relative Toxicity[b]
Anthracene	3	5.9	2
Benzene	9.2	1,800	195.6
Biphenyl	3.1	21	6.8
Cumene	0.6	50	83.3
Cyclohexane	3.8	55	14.5
Decane	0.028	0.052	1.9
Ethylbenzene	2.1	152	72.4
Hexane	3.9	9.5	2.4
9-methylanthracene	0.44	0.88	2
Methyl cyclohexane	1.5	14	9.3
Octane	0.37	0.66	1.8
1-methylnaphthalene	1.4	28	20
2-methylnaphthalene	1.8	32	17.8
Phenanthrene	1.2	6.6	5.5
Pyrene	1.8	2.8	1.6
Toluene	11.5	515	44.8
1,2,4,5-tetramethylbenzene	0.47	3.5	7.4
1,2,4-trimethylbenzene	3.6	57	15.8
1,3,5-trimethylbenzene	6	97	16.2
p-xylene	8.5	185	21.8
m-xylene	9.6	162	16.9
o-xylene	3.2	175	54.7

Source: Appendix P, Risk Assessment, Table 4-4

[a] The LC50 is the concentration of a compound necessary to cause 50 percent mortality in laboratory test organisms within a predetermined time period (e.g., 48 hours) (USEPA 1994).
[b] Relative toxicity = optimum solubility/LC50

While lightweight aromatics such as benzene tend to be water soluble and relatively toxic, they also are highly volatile. Thus, most or all of the lightweight hydrocarbons accidentally released into the environment evaporate, and the environmental persistence of this crude oil fraction tends to be low. High molecular weight aromatic compounds, including PAHs, are not very water-soluble and have a high affinity for organic material. Consequently, these compounds, if present, have limited bioavailability, which renders them substantially less toxic than more water-soluble compounds (Neff 1979). Additionally, these compounds generally do not accumulate to any great extent because these compounds are rapidly metabolized (Lawrence and Weber 1984; West et al. 1984). There are some indications, however, that prolonged exposure to elevated concentrations of these compounds may result in a higher incidence of growth abnormalities and hyperplastic diseases in aquatic organisms (Couch and Harshbarger 1985).

A summary of chronic toxicity values (most frequently measured as reduced reproduction, growth, or weight) of benzene to freshwater biota is provided in Table 4.13-32. Chronic toxicity from other oil constituents may occur if sufficient quantities of crude oil are continually released into the water to maintain elevated concentrations.

Table 4.13-32 Chronic Toxicity of Benzene to Freshwater Biota[a]

Taxa	Test Species		Chronic Value (ppm)
Algae	Green algae	(*Selenastrum capricornutum*)	4.8*
Amphibian	Leopard frog	*(Rana pipens*)	3.7
Fish	Fathead minnow	(*Pimephales promelas*)	17.2*
	Guppy	(*Poecilia reticulata*)	63.0
	Coho salmon	(*Oncorhynchus kitsutch*)	1.4
Invertebrate	Zooplankton	(*Daphnia* spp.)	>98.0

Source: Appendix P, Risk Assessment, Table 4-4

[a] Test endpoint was mortality unless denoted with an asterisk (*). The test endpoint for these studies was growth.

Significantly, some constituents in crude oil may have greater environmental persistence than lightweight compounds (e.g., benzene), but their limited bioavailability renders them substantially less toxic than other more soluble compounds. Based on the combination of toxicity, solubility, and bioavailability, benzene was determined to dominate toxicity associated with potential crude oil spills. E^x^ponent investigated the possibility that other crude oil constituents may pose a greater toxicological risk to aquatic organisms than benzene. Of the crude oil constituents evaluated, only nickel and vanadium were likely to exceed water quality thresholds based on chronic exposure level and these constituents were only likely to exceed for large (10,000 barrels) or medium (1,000 barrels) spills. Because these findings show less risk than predicted for benzene, E^x^ponent concluded that the evaluation of toxicity resulting from spills to surface water appears to be sufficient for judging the potential for toxic effects on aquatic organisms (E^x^ponent 2013).

The potential impact to aquatic organisms of various-sized spills to waterbodies was modeled assuming the benzene content within each type of crude oil completely dissolved in the water. The benzene concentration was predicted based on amount of crude oil spilled and streamflow. The estimated benzene concentrations were compared to conservative acute and chronic toxicity values for protection of aquatic organisms. For aquatic biota, the lowest acute and chronic toxicity thresholds for benzene are 7.4 and 1.4 ppm, respectively, based on standardized trout and Coho salmon toxicity tests (USEPA 1994). These toxicity threshold values are considered protective of acute and chronic effects to aquatic biota. Although trout or Coho salmon are not found in many of the habitats crossed by the proposed Project route, these two species are among the most sensitive aquatic species and reliable acute and chronic toxicity data are available. Using these toxicity thresholds, therefore, provides a conservative benchmark to screen for the potential for toxicity.

Tables 4.13-33 through 4.13-35 summarize a screening-level assessment of acute and chronic toxicity to aquatic resources.

Broadly, acute toxicity could potentially occur if substantial amounts of crude oil were to enter rivers and streams. If such an event were to occur within a small stream, aquatic species in the immediate vicinity and downstream of the rupture could be killed or injured. Chronic toxicity also could potentially occur in small and moderate-sized streams and rivers. However, emergency response, containment, and cleanup efforts would help reduce the concentrations and minimize the potential for chronic toxicity. In comparison, small spills (less than 50 bbl) into moderate and large rivers would not pose a major toxicological threat. In small to moderate sized-streams and rivers, some toxicity might occur in localized areas, such as backwaters where concentrations would likely be higher than in the mainstream of the river. While a release of crude oil into any given waterbody might cause immediate localized toxicity to aquatic biota, particularly in smaller streams and rivers, the frequency of such an event would be very low. Nevertheless, streams and rivers with aquatic biota represent the sensitive environmental resources that could be temporarily impacted by a crude oil release. Environmentally, much information has been acquired and lessons continue to be learned from the Marshall Michigan dilbit spill. The release of dilbit to a river or other aquatic environment introduces the potential for additional impacts and additional recovery challenges for responders of such an event to the environment.

The Department examined existing studies and information to evaluate the impacts of other components of dilbit (e.g., PAHs, heavy metals, etc.), which are similar to heavy crude. These impacts would generally be similar to those discussed in Section 4.13.4.3, Effect of Soil Type, Soil Cover, and Temperature Flow. Allowing for the specific chemical properties and toxicological effects of the other components of heavy crude, anecdotal comparisons could be made regarding the impacts of these components from a submerged dilbit release on the environment and the organisms that inhabit the water column and the underlying sediments and soils.

Table 4.13-33 Comparison of Estimated Benzene Stream Concentrations Following a Diluted Bitumen Spill to the Chronic Toxicity Threshold for Aquatic Life (1.4 ppm)[a]

Throughput 435,000 bpd	Stream Flow Rate (cfs)	Acute Toxicity Threshold (ppm)	Product Released: Small Spill: Benzene Concentration (ppm)	Small Spill: Occurrence Interval (years)[b]	Medium Spill: Benzene Concentration (ppm)	Medium Spill: Occurrence Interval (years)[b]	Large Spill: Benzene Concentration (ppm)	Large Spill: Occurrence Interval (years)[b]
Low Flow Stream	10	1.4	0.06	25,461	1.3	118,319	12.9	502,857
Lower Moderate Flow Stream	100	1.4	0.006	17,823	0.13	82,824	1.3	352,000
Upper Moderate Flow Stream	1,000	1.4	0.0006	13,367	0.013	62,118	0.13	264,000
High Flow Stream	10,000	1.4	0.00006	7,638	0.0013	35,496	0.013	150,857

[a] Historical data indicate that the most probable spill volume would be 3 bbl or less. However, this analysis is based on conservative incident frequencies and volumes defined for this Final Supplemental EIS, which overestimates the proportion of larger spills. Estimated proportion of benzene in the transported material is 0.15 percent, and is assumed to be entirely water solubilized in the event of a spill. The resulting concentration was calculated by multiplying 0.15 percent of the total amount of material released divided by 7 days of stream flow volume. The model assumes uniform mixing conditions. The chronic toxicity value for benzene is based on a 7-day toxicity value of 1.4 ppm for Coho salmon. Exposure concentrations were estimated over a 7-day period since the chronic toxicity value was based on a 7-day exposure. Shading indicates concentrations that could potentially cause chronic toxicity to aquatic species. The darkest shading represents high probability of chronic toxicity (>10 times the toxicity threshold); lighter shading represents moderate probability of chronic toxicity (1 to 10 times the toxicity threshold); and unshaded areas represent low probability of chronic toxicity (<toxicity threshold). Occurrence intervals are based on a historical incident frequency of 0.00025 incidents/mile-year (see Appendix K, Historical Pipeline Incident Analysis, Table 6), projected frequencies of each spill volume, and estimated stream widths. Widths of higher flow streams are greater than widths of lower flow streams, with more distance where an incident might occur. This results in a greater predicted frequency for high flow streams and a corresponding lower occurrence interval.
[b] Occurrence Interval (years) = the number of years that could pass before a spill incident would occur on a stream with this streamflow.

Table 4.13-34 Comparison of Estimated Benzene Stream Concentrations Following a Synthetic Crude Spill to the Acute Toxicity Threshold for Aquatic Life (1.4 ppm) [a]

Throughput 435,000 bpd	Stream Flow Rate (cfs)	Acute Toxicity Threshold (ppm)	Product Released: Small Spill – Benzene Concentration (ppm)	Small Spill – Occurrence Interval (years)[b]	Medium Spill – Benzene Concentration (ppm)	Medium Spill – Occurrence Interval (years)[b]	Large Spill – Benzene Concentration (ppm)	Large Spill – Occurrence Interval (years)[b]
Low Flow Stream	10	7.4	3.6	25,461	72	118,319	725	502,857
Lower Moderate Flow Stream	100	7.4	0.4	17,823	7.2	82,824	72.5	352,000
Upper Moderate Flow Stream	1,000	7.4	0.04	13,367	0.7	62,118	7.2	264,000
High Flow Stream	10,000	7.4	0.004	7,638	0.07	35,496	0.7	150,857

[a] Historical data indicate that the most probable spill volume would be 3 bbl or less. However, this analysis is based on conservative incident frequencies and volumes defined for this Final Supplemental EIS, which overestimates the proportion of larger spills. Estimated proportion of benzene in the transported material is 0.15 percent, and is assumed to be entirely water solubilized in the event of a spill. The resulting concentration was calculated by multiplying 0.15 percent of the total amount of material released divided by 7 days of stream flow volume. The model assumes uniform mixing conditions. The acute toxicity value for benzene is based on a 7-day toxicity value of 7.4 ppm for trout. Exposure concentrations were estimated over a 7-day period since the chronic toxicity value was based on a 7-day exposure. - Shading indicates concentrations that could potentially cause chronic toxicity to aquatic species. The darkest shading represents high probability of chronic toxicity (>10 times the toxicity threshold); lighter shading represents moderate probability of chronic toxicity (1 to 10 times the toxicity threshold); and unshaded areas represent low probability of chronic toxicity (<toxicity threshold). Occurrence intervals are based on an historical incident frequency of 0.00025 incidents/mile-year (see Appendix K, Historical Pipeline Incident Analysis, Table 6), projected frequencies of each spill volume, and estimated stream widths. Widths of higher flow streams are greater than widths of lower flow streams, with more distance where an incident might occur. This results in a greater predicted frequency for high flow streams and a corresponding lower occurrence interval.

[b] Occurrence Interval (years) = the number of years that could pass before a spill incident would occur on a stream with this streamflow.

Table 4.13-35 Comparison of Estimated Benzene Stream Concentrations Following a Diluted Bitumen Spill to the Acute Toxicity Threshold for Aquatic Life (7.4 ppm)[a]

Throughput 435,000 bpd	Stream Flow Rate (cfs)	Acute Toxicity Threshold (ppm)	Product Released					
			Small Spill		Medium Spill		Large Spill	
			Benzene Concentration (ppm)	Occurrence Interval (years)[b]	Benzene Concentration (ppm)	Occurrence Interval (years)[b]	Benzene Concentration (ppm)	Occurrence Interval (years)[b]
Low Flow Stream	10	7.4	0.06	25,461	1.3	118,319	12.9	502,857
Lower Moderate Flow Stream	100	7.4	0.006	17,823	0.13	82,824	1.3	352,000
Upper Moderate Flow Stream	1,000	7.4	0.0006	13,367	0.013	62,118	0.13	264,000
High Flow Stream	10,000	7.4	0.00006	7,638	0.0013	35,496	0.013	150,857

[a] Historical data indicate that the most probable spill volume would be 3 bbl or less. However, this analysis is based on conservative incident frequencies and volumes defined for this Final Supplemental EIS, which overestimates the proportion of larger spills.
Estimated proportion of benzene in the transported material is 0.15 percent, and is assumed to be entirely water solubilized in the event of a spill. The resulting concentration was calculated by multiplying 0.15 percent of the total amount of material released divided by 7 days of stream flow volume. The model assumes uniform mixing conditions.
The acute toxicity value for benzene is based on a 7-day toxicity value of 7.4 ppm for trout.
Exposure concentrations were estimated over a 7-day period since the chronic toxicity value was based on a 7-day exposure.
Shading indicates concentrations that could potentially cause chronic toxicity to aquatic species. The darkest shading represents high probability of chronic toxicity (>10 times the toxicity threshold); lighter shading represents moderate probability of chronic toxicity (1 to 10 times the toxicity threshold); and unshaded areas represent low probability of chronic toxicity (<toxicity threshold).
Occurrence intervals are based on an historic incident frequency of 0.00025 incidents/mile-year (see Appendix K, Historical Pipeline Incident Analysis, Table 6), projected frequencies of each spill volume, and estimated stream widths. Widths of higher flow streams are greater than widths of lower flow streams, with more distance where an incident might occur. This results in a greater predicted frequency for high flow streams and a corresponding lower occurrence interval.
[b] Occurrence Interval (years) = the number of years that could pass before a spill incident would occur on a stream with this streamflow.

As with some other types of oil, dilbit would not float on water indefinitely. The dilbit-specific characteristics, water temperature, and particulate load in the water could result in oil being submerged in the water column. Submerged oil could be suspended in the water column, suspended just above the river bed, or intermixed with sediment and trapped in the river bed and shoreline. In flowing waters, the spreading of the oil in three dimensions creates many challenges for responders to minimize the impacts of the release. Consideration of submerged oil in a flowing water environment would require to a certain extent different response action planning and response equipment to contain and recover the submerged oil. Dilbit intermixed with sediment and trapped in the river bed and shoreline results in a persistent source of oil and has the potential to present additional response and recovery challenges. The understanding and adaptation of response and recovery techniques to dilbit spills in flowing water scenarios continues along the Kalamazoo River in response to the 2010 Enbridge release near Marshall, Michigan. As the response to the Marshall Michigan dilbit spill continues to mature and evolve, the lessons learned from the response and recovery efforts are included in Section 4.13.5.2, and Keystone has stated that these lessons learned would be considered to facilitate the implementation of proper response planning and response strategies to improve the overall response to dilbit spills.

Wetlands/Reservoirs/Lakes

Wetlands are considered in this analysis as lands where saturation with water determines the type of soil, wildlife, and vegetation found in the area. Wetlands include swamps and marshes. Reservoirs are natural or artificial lakes used as a source of water. Lakes are a large body of water surrounded by land. Wetlands, reservoirs, and lakes are grouped together as semi-static waterbodies.

Although planning and routing efforts have attempted to minimize the overall number of wetlands and static waterbody environments crossed by the proposed Project route, wetlands and waterbodies with persistently saturated soils are present along and adjacent to the proposed route. The effects of crude oil released into a wetland environment would depend not only upon the quantity of oil released, but also on the physical conditions of the wetland at the time of the release. Table 4.13-36 identifies the total estimated potential wetland acreage along the proposed route that could be affected by a surface release, based on buffer distance assumptions.

Table 4.13-36 Total Estimated Wetlands Acreage in Potential Surface Spill Areas

State[a]	Small (0 to 50 bbl)	Medium (50 to 1,000 bbl)	Large (1,000 to 20,000 bbl)
MT	81.67	269.02	888.73
SD	197.14	649.39	2145.31
NE	108.98	358.99	1185.95

[a] MT=Montana, SD=South Dakota, NE=Nebraska

An oil spill that reaches these types of waterbodies could result in reduction of oxygen levels within the water. In winter, however, a small spill would not have as much of an impact on oxygen levels as in other seasons, due to the already lowered biological activity that is a part of the natural cycle of freezing waterbodies. If a spill were to occur underneath ice of a frozen lake, oil could accumulate under the ice, the temperature could increase the viscosity, light components could dissolve in water, and recovery efforts could be slowed because of the location and characteristics of the oil. Spills in these conditions are addressed by the Keystone

ERP, which would be updated for the proposed Project. For spills occurring during the rest of the year, most of the product would float on the water or wet soil surface, although some of the light components of the oil (e.g., benzene) could dissolve or disperse in water.

Since most oil spills are statistically small in size, there would be minimal effects in water quality in large lakes, assuming the lake volume is substantially larger than the volume of spilled oil. Decreases in oxygen levels would be negligible in most cases but may be greater in large to very large spills that cover much of the water surface for a day or more. Direct toxicity would be short-term because of the high dilution volume in these lakes and the rapid evaporation of most of the potentially toxic lighter hydrocarbons. Spreading of a spill over a lake surface may have a minor to major effect on water aesthetics and recreational use. This effect could exist for days to a few weeks until the oil was removed.

Impacts of crude oil spills or refined product spills on wetlands are influenced by the type of oil or oil product, the amount and proportion of water surface area covered, the type of vegetation present in the wetland, and cleanup response actions. Refined products tend to be more toxic than crude oil, while crude oil tends to cause more physical impacts (e.g., smothering). Most spilled oil would remain on the water surface where vegetation and wildlife may become coated as the oil disperses.

As the purposed pipeline would carry only crude oil, spills of refined product (e.g., diesel, gasoline) would be more likely to occur during construction. The majority of these spills would be small spills from construction pads or access roads. If the spills occur in winter, the wetland may be covered in ice and spilled product may be contained by snow or remain on top of the ice. In either case, the spilled oil likely would be recovered before it directly affected wetland habitat and associated organisms. Although gasoline spills evaporate quickly, there may be short-term acute effects on wetland wildlife and vegetation. Diesel spills tend to be more persistent, and diesel may infiltrate sediments as well as adhere to emergent vegetation.

Crude oil spills that occur during operation of the proposed Project could affect wetlands either where the proposed pipeline would cross wetlands or waterbodies (e.g., ponds, lakes, reservoirs, streams, rivers, or adjacent riparian habitats) or where the spill site is on land but upgradient of the wetland. Due to the viscosity of heavy crude oils, spills would likely be restricted in areal extent, particularly in colder months. Snow could serve as a medium to hold and further restrict the spill migration. Larger spills in open water seasons could flow into wetlands, cover the water surface, coat wetland wildlife and vegetation, and restrict oxygen exchange between air and water. Some spilled crude oil could sink through the water into underlying sediments and remain there for years, depending on the amount of biodegradation and chemical or physical weathering that takes place.

Smaller refined product or crude oil spills would generally produce minor impacts on wetlands unless the wetland is small and isolated from other waterbodies. In these cases, impacts could be substantive if the majority of the wetland is exposed to the oil. Large to very large crude oil spills could result in substantive impacts on wetlands due to the size of the spill and the proportion of the wetlands that would be affected. Impacts could include a substantial reduction in wildlife population and ecological damage where the wetlands are heavily used by migratory waterfowl and the spill occurred during the spring or fall migration.

Crude oil released from a subsurface pipe within a wetland could reach the surface. If the water table is at the surface, the release would manifest as floating crude oil. The general lack of surface flow within a wetland would restrict crude oil movement. Where surface water is present within a wetland, the spill would spread laterally across the water's surface and be readily visible during routine ROW surveillance. The depth of soil impacts likely would be limited to the depth to groundwater. Conversely, due to shallow groundwater, impacts within the wetland are likely to be confined to the near-surface, enhancing the potential for biodegradation.

Spills to any environment that result in regulatory notification would likely trigger regulator involvement and assessment to implement remedial action. However, response and remediation efforts in a wetland have the potential for appreciable adverse effects from construction/cleanup equipment. Aggressive cleanup methods could mix oil and water, which may result in longer lasting impacts to sensitive wetland habitat. Physical disruption of wetland resources below the water line during spill response could be reduced in some cases through ignition of the oil floating on the water surface. Passive cleanup methods (including natural attenuation) are less likely to impact wetland resources. If no active remediation activities were undertaken, with concurrence of the regulatory body (e.g., state Department of Environmental Quality), natural biodegradation and attenuation would ultimately allow a return to preexisting conditions in both soil and groundwater. This would likely require a timeframe on the order of tens of years. In the unlikely event of a spill in wetlands, Keystone would use the most appropriate cleanup procedures as determined in coordination with the applicable federal and state agencies. At the request of regulators, Keystone would perform the Net Environmental Benefit Analysis, described in further detail below in *Spill Response Considerations*.

Socioeconomics

The Final EIS discussed impacts of oil spills to components of the socioeconomic environment, including populated areas; agricultural activities, water intakes and water supplies, other commercial activities, and single-family home sales and property value. The Final EIS noted, and as stated above, that in the event of oil spill impacts to water supplies for residential, agricultural, commercial, or public uses, Keystone would provide alternate sources of water for essential uses such as drinking water, irrigation, industrial cooling water, and water for firefighting and similar public safety services.

Economic impacts related to short-term disruption in local agricultural production could result from a spill that enters agricultural lands or wild lands used by grazing livestock. The extent and duration (i.e., short term or long term) of the economic impacts would depend on the number of productive acres affected, the response time, the remedial method selected and implemented by the response team, and the length of time required to return land services to conditions similar to those prior to the spill.

If a spill affected recreational lands and/or waterways, businesses relying on hunting, fishing, sightseeing, and other recreational activities could experience a short-term negative economic impact. During response and restoration actions, access to oil-impacted areas would generally be limited or prohibited to anyone except the cleanup and monitoring crews, thus limiting recreational access. Adverse publicity about the impacts of large to very large spills could reduce use by recreationists from the local and regional areas, or even from other areas in the United States for an extended period of time. For small to very small spills, there would likely be negligible economic impacts to businesses relying on recreational uses. In some cases, response to oil spills could generate positive local economic activity for the limited duration of the spill response activities as a result of the need for lodging, meals, equipment, and other facilities, materials, and logistic support for the cleanup crews and the incident command team.

The Final EIS also reviewed the findings of two studies (Simons et al. 2001; Hansen et all 2006) of economic impacts to land and residence values in areas affected by oil spills and concluded that the data suggest that the economic consequences of an oil spill could include a temporary reduction in housing prices that would likely decrease over time. In light of high profile pipeline oil spills on the Kalamazoo River in Calhoun County, Michigan, in 2010, and in Mayflower, Faulkner County, Arkansas, in 2013, other academic studies and anecdotal information were reviewed for this Final Supplemental EIS. The findings of this additional research are consistent with the other literature in that the oil spills appear to have had an immediate to short-term negative effect on house desirability and prices in local real estate markets. The literature on long-term impacts to house values from noxious or incompatible land uses or facilities (such as oil refineries, natural gas wells, or landfills) suggests that a negative effect on residential property occurs so long as the noxious effect of the use or facility exists. Assuming noxious effects lead to negative impacts to property values for as long as they exist, the long term effect of oil spills would likely depend on the resolution of these incidents in terms of remediation, compensation, and management of future risk (Hite et al. 2000), with the stigma effect to property values of a noxious facility existing after a successful resolution only for those homes or properties that are located "in very close proximity" to the site (McCluskey and Rausser 1999).

Environmental Justice Considerations

Information on minority and low-income populations within the proposed Project socioeconomics analysis area including locations that are designated as Health Professional Shortage Areas and Medically Underserved Areas/Populations are presented in Section 4.10, Socioeconomics. Depending on the location and volume of an accidental crude oil release from the proposed Project, it is possible that minority or low-income populations could be affected by the release. Minority and low-income populations could be more vulnerable to health impacts associated with the crude oil release, particularly if access to health care is less available in the release area.

Exposure pathways could include direct contact with the crude oil, inhalation of airborne emissions from the crude oil, or consumption of food or water contaminated by either the crude oil or components of the crude oil. Keystone would be liable for all costs associated with cleanup and restoration as well as other compensations for any release that could affect surface water. Therefore potential impact to minority or low-income populations would be mitigated by the operator's liability for the release. Additionally, Keystone has committed to provide an alternative water supply if an accidental release from the proposed Project contaminates groundwater or surface water used as a source of potable water or for irrigation or industrial purposes, which includes water uses by minority and low-income populations.

Given the potential vulnerability of these populations to health impacts, it is essential that spill response planning considers appropriate communications directed to these populations in the unlikely event of an accidental crude oil release. As a measure to avoid or minimize impacts to minority or low-income populations, response planning would include outreach to Local Emergency Planning Committees (see Sections 3.10.2.5, Public Services, Tax Revenues, and

Property Values, and 4.13.6.2, Spill and Safety Response) to ensure due consideration of the potential issues involved in emergency response in areas where minority and low-income populations have been identified along the proposed Project corridor. Specific consideration for environmental justice communities would involve ensuring that adequate communication—in the form of public awareness materials regarding the construction schedule and construction activities—is provided. Materials would be in appropriate languages and would contain information on how to seek needed services in the event of a health or other social service disruption related to construction activities. Additionally, the Keystone ERP discusses how calls to 911 concerning petroleum spills could alert Local Emergency Planning Committees.

4.13.6 Additional Mitigation

This section addresses the additional measures that have the potential to increase safety and reduce the severity and likelihood of a spill. Increased levels of protection are addressed by implementing the PHMSA Special Conditions discussed below. These measures provide for an additional safety factor on the proposed Project that exceeds those typically applied to a domestic oil pipeline projects. If a spill occurred, pre-defined and systematic plan response actions could take effect to rapidly mitigate the impact.

4.13.6.1 PHMSA Special Conditions

PHMSA in consultation with the Department developed a set of Special Conditions that increases public safety above current minimum requirements. Keystone agreed that if the Presidential Permit is granted, it would incorporate those conditions into the proposed Project and in its manual for operations, maintenance, and emergencies required by 49 CFR Part 195.402. PHMSA has the legal authority to inspect and enforce any items contained in a pipeline operator's operations, maintenance, and emergencies manual, and would therefore have the legal authority to inspect and enforce the Special Conditions if the proposed Project is approved. Pipeline operation is also regulated by PHMSA in cooperation with other agencies such as the Occupational Safety and Health Administration (OSHA), the U.S. Army Corps of Engineers, various state public service or public utility commissions, and other state agencies. Jurisdiction of some of the agencies over the proposed Projected is detailed in Section 1.5, Agency Participation. Additionally, environmental inspectors could review the proposed Project construction activities for compliance with state, federal and local regulatory requirements and could have the authority to stop specific tasks as described in Section 2.1.10.2, Environmental Inspection.

Appendix B, Potential Releases and Pipeline Safety, and Section 4.13.6.1, PHMSA Special Conditions, describe each of the Special Conditions. As stated in the Final EIS, the Department, in consultation with PHMSA, has determined that incorporation of those conditions (referenced industry standards and practices, combined with PHMSA regulatory requirements and the set of proposed Project-specific Special Conditions developed by PHMSA) would result in a Project that would have a degree of safety over any other typically constructed domestic oil pipeline system under current code and a degree of safety along the entire length of the pipeline system similar to that which is required in HCAs, as defined in 49 CFR 195.450.

Similarly, Battelle concluded that the "…Special Conditions imposed by the PHMSA make for a safer pipeline with less operational risk." For example, Battelle points out that "the use of tough steel acts to limit the size of a breach in the wall, and facilitates detection of anomalies within the mandated periodic re-inspection of the pipeline." (Leis et al. 2013.)

The majority of the Special Conditions relate to reduction in the likelihood of a release occurring; in addition, some provide mitigation that reduces the consequences and impact of a spill, discussed earlier in this section, should such an event occur. To understand how each one acts, they were considered for their role as preventive controls for the loss of pipeline contents (barriers that could stop a possible threat) and controls in the event of a spill (controls used to mitigate the consequences of a spill). The basis for a barrier/control was if the Special Condition by itself or in conjunction with another (constituting a single barrier) reduces the likelihood of the pipeline threat from causing a release or acts to reduce the consequences of a spill once a release occurs. The following are criteria for identifying a condition as a barrier or control once implemented:

- **Independence**—For the Special Condition to be a barrier or control, its functionality should be independent of other barriers and controls. It is independent if it accomplishes its function without assistance from other barriers/controls, tasks not implied in the conditions, or external equipment.
- **Functionality**—A barrier or control should be able to prevent the threat from developing or progressing further and be capable of serving the purpose for which it was designed or implemented. In other words, the barrier could reduce or prevent a potential threat from becoming a release, and the control would reduce the severity of a release.

A Special Condition might be a barrier for more than one threat, meaning it could prevent a release from occurring or, in certain situations, it could also minimize the impact (i.e., consequence) once a release occurs. In other words, it could help prevent a release from occurring, minimize the effects of the release, or both.

Table 4.13-37 shows that the Special Conditions provide 24 independent barriers, with one to five independent barriers to prevent a release from occurring for each threat. The Special Conditions that are considered threat barriers, and also consequence barriers, include Numbers 24, 25, 26, 30, and 53. Table 4.13-38 describes the 24 barriers that develop by applying one or a combination of the Special Conditions; a brief description is provided of how the Special Condition could prevent threats from causing a release. A detailed description of the PHMSA Special Conditions is provided in Appendix B, Potential Releases and Pipeline Safety.

Table 4.13-37 Special Conditions as Barriers to Threats[a]

Threat	Threat Category	Independent Barrier 1	Independent Barrier 2	Independent Barrier 3	Independent Barrier 4	Independent Barrier 5
Internal corrosion	Time-dependent	SC[b] 33 and 47	SC 34			
External corrosion		SC 9, 15 and 39	SC 10 and 11	SC 35, 36, 21, 37 and 38		
Stress corrosion cracking (SCC)		SC 3	SC 45, 44 and 46			
Materials-related	Stable	SC 1	SC 2 and 8	SC 4 and 12	SC 5	SC 6
Construction-related		SC 14	SC 17 and 18	SC 22 and 23	SC 42 and 43	SC 49 and 51
Equipment malfunction		SC 24-30, 50 and 53	SC 15, 16, 25-26 and 31			
Weather conditions	Time-independent	SC 24-30, 50 and 53				
Excavation/ third-party damage		SC 7, 19 and 53	SC 40-41, 48 and 54			
Operational error		SC 13, 20 and 53	SC 24-30, 50 and 53			

[a] Because not all Special Conditions are designed as a barrier, not all Special Conditions are listed
[b] SC = Special Condition number

Table 4.13-38 Barrier Assessment of Special Condition Threat Mitigations

Threat	Independent Barrier	Brief Barrier Description	Special Condition Reference
Internal corrosion	1	The design of the pipeline, which would allow for 100% internal inspection by smart tools combined with periodic pigging to assess pipe thickness changes would facilitate the early detection of internal corrosion signs as implicit in the provisions of the referenced Special Conditions.	SCs[a] 33 and 47
	2	The following actions stated in the Special Condition are considered capable of decreasing the pipe corrosion rate: 1) limiting sediment and water content to 0.5% by volume; 2) running cleaning tools periodically; and 3) implementing a crude oil monitoring and sampling program that ensures transported products meet pipeline specifications.	SC 34
External corrosion	1	The application of corrosion resistant coating on pipes, and compliance to Canadian Standards Association, National Association of Corrosion Engineers, and International Organization for Standardization standards, plus controls for operating temperature and periodic coating surveys are considered the basis for a good external corrosion program as detailed in the referenced Special Conditions.	SCs 9, 15, and 39

Threat	Independent Barrier	Brief Barrier Description	Special Condition Reference
	2	The use of abrasion resistant coating for trenchless installations and a field joint coating quality control program for holiday detection (a gap or hole in the coating) are considered complementary preventive measures for decreasing external corrosion rates.	SCs 10 and 11
	3	The installation of cathodic protection with periodic performance studies and stray current studies comprise a preventive control against pipe corrosion. Additional measures detailed in the referenced Special Conditions complement a cathodic protection program as a barrier against external corrosion.	SCs 35, 36, 21, 37, and 38
SCC	1	The implementation of fracture control and integrity verification plans addressing the steel pipe properties necessary to resist crack initiation and crack propagation would likely become a preventive control against the SCC threat as detailed in the referenced Special Condition.	SC 3
	2	Complete annual fatigue analysis and flaw growth assessment and periodic in-line inspections consistent with 49 CFR Part 195.452(j)(3), are considered preventive measures against SCC as explicitly stated in the referenced Special Conditions.	SCs 45, 44, and 46
Materials related	1	Steel must be of high quality with specific materials structure and composition, which are fundamental for meeting design specifications, and future pipe performance. This constitutes a barrier to manufacturing threat as implicit in the Special Condition provisions, and to some extent for future corrosion issues.	SC 1
	2	Manufacturer's adherence to API 5L Product Specification Level 2, supplementary requirements for maximum operating pressures and minimum operating temperatures, and quality assurance/ quality control are considered complementary measures against manufacturing threat as outlined in the referenced Special Conditions.	SCs 2 and 8
	3	Steel plate/coil quality control, pipe mill quality assurance/quality control plan, and the implementation of procedures for high quality welding of components as explained in the referenced Special Conditions constitute a barrier against materials related issues.	SCs 4 and 12
	4	Specific pipe seam quality control requirements for pipe manufacturers are considered a barrier against seam welding issues.	SC 5
	5	Special monitoring for seam fatigue from transportation, traceability of tests, and manufacturing records would create a barrier against manufacturing defects as explicitly stated in the referenced Special Condition.	SC 6

Threat	Independent Barrier	Brief Barrier Description	Special Condition Reference
Construction related	1	The post-construction survey to identify changes that would impact design, once implemented, would likely constitute a barrier against many construction related issues as implicit in the referenced Special Condition.	SC 14
	2	Submittal of construction plans and schedules to PHMSA, welding procedures, stress analysis, lowering-in procedures, and engineering critical assessments, are considered best industry practices that would reduce the risks of construction related defects as outlined in the referenced Special Conditions.	SCs 17 and 18
	3	Pipeline hydro-test to 100% specified minimum yield strength and conducting a failure analysis should a test failure occur are considered complementary measures that would assist in correcting construction related issues.	SCs 22 and 23
	4	Performing a baseline geometry tool run after completion of the hydrostatic strength test and backfill of the pipeline with a high-resolution magnetic flux leakage tool would assist in detecting construction flaws and serve for future reference of the system integrity baseline as detailed in in the referenced Special Conditions.	SCs 42 and 43
	5	Complete immediate dig-ups to investigate and/or repair as necessary based on anomalies reported by smart inspection, removal of dents exceeding 2%, and reporting on compliance to the conditions within 180 days of in-service are considered measures that would reduce the risk of construction related issues.	SCs 49 and 51
Equipment malfunction	1	The installation of a sophisticated computerized SCADA system to provide remote control and monitoring of the entire pipeline system, the activities necessary to maintain it in optimum condition, and additional measures detailed in the referenced Special Conditions are measures against the threat of equipment malfunction.	SCs 24-30, 50, and 53
	2	Overpressure control requirements, pressure and temperature controls, enhanced SCADA scan rate to detect small leaks, alarm management policy, and trained personnel in leak detection per Canadian Standards Association guidelines are considered complimentary measures against the threat of equipment malfunction.	SCs 15, 16, 25-26, and 31
Weather conditions	1	The installation of a sophisticated SCADA system to provide remote control and monitoring of the entire pipeline system plus the activities necessary to maintain it in an optimum condition are measures to reduce the risk of a release due to natural forces as implicit in the referenced Special Conditions.	SC 24-30, 50, and 53

Threat	Independent Barrier	Brief Barrier Description	Special Condition Reference
Excavation/ third-party damage	1	Specific requirements for steel pipe to be puncture-resistant to excavators, deeper pipeline cover depths, and the use of a threat matrix are considered measures to prevent loss of containment due to third parties as outlined in the referenced Special Conditions.	SC 7, 19, and 53
	2	Pipeline markers in addition to frequent ROW patrols constitute a proven barrier to prevent inadvertent third party damage as explicitly stated in the referenced Special Conditions.	SC 40-41, 48 and 54
Operational error	1	Traceability of components to the correct intended operating pressure, requirements for operator's qualifications, and the use of a threat matrix for the pipeline system are considered measures against inadvertent operational errors as detailed in the referenced Special Conditions.	SC 13, 20, and 53
	2	The installation of a sophisticated SCADA system to provide remote control and monitoring of the entire pipeline system plus the activities necessary to maintain it in an optimum condition would likely assist in detecting operational errors promptly. Additional measures detailed in the referenced Special Conditions would also assist in executing recovery procedures before the spill occurs.	SC 24-30, 50, and 53

[a] SC = Special Condition

Subsequent to agreeing with the PHMSA Special Conditions, Keystone agreed to incorporate the following additional conditions into the written design, construction, and operating and maintenance plans and procedures:

- Keystone would develop and implement a Quality Management System that would apply to the construction of the entire Keystone XL project in the United States to ensure that this pipeline is, from the beginning, built to the highest standards by both Keystone personnel and its many contractors; and
- Keystone would hire an independent third-party inspection company (TPIC) to monitor the construction of the Keystone XL project. PHMSA must approve the TPIC from among companies Keystone proposes. Keystone and PHMSA would work together to develop a scope of work to help ensure that all regulatory and technical EIS conditions are satisfied during the construction and commissioning of the pipeline project. The TPIC would oversee the execution and implementation of the DOS-specified conditions and the applicable pipeline safety regulations and would provide monitoring summaries to PHMSA and Keystone concurrently. Keystone would address deficiencies or risks identified in the TPIC's assessments.

4.13.6.2 Safety and Spill Response

The United States (through PHMSA) collaborates with several other countries to provide guidelines on emergency response. The publication entitled *Emergency Response Guidebook - A Guidebook for First Responders during the Initial Phase of a Dangerous Goods/Hazardous Materials Transportation Incident* (PHMSA, 2012b) is available at http://phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Files/Hazmat/ERG2012.pdf and describes safety precautions related to hazardous material identification and emergency contact information.

The Keystone Oil Pipeline System ERP was previously developed for the existing Keystone Mainline and Cushing Extension project and approved by PHMSA. The Keystone ERP would be used as a template for the ERP for the proposed Project and would include the necessary proposed Project-specific information. A review of the Keystone ERP (not the Keystone XL-specific plan) provided in Appendix I, SPCC and ERP, shows that response personnel, whether Keystone employees or contractors, must complete the appropriate Keystone and OSHA training in line with their responsibilities in order to implement a safe and effective response action to oil spills. All Keystone and contractor personnel are expected to follow the facility-specific safety plan for addressing a spill. Several of the aspects of responder training are provided below as listed in the ERP in Appendix I:

- Any concern regarding health or safety issues should be immediately addressed.
- The First Responder must consider the spill site as dangerous and the local atmosphere explosive until air monitoring procedures prove that the area is safe.
- The First Responder must exit the area against or across the wind, if possible, and must also evacuate others who are working in the area.
- All injuries, no matter how minor, must be reported to the Incident Commander in a timely manner.
- Prior to entering a spill area, a qualified person must perform an initial safety and health evaluation of the site.

In the event of a spill during construction and reclamation activities, Keystone has identified and prepared written procedures to address a response action. These response activities are provided in Keystone's Draft SPCC Plan (see Appendix I, SPCC and ERP). This draft SPCC document has been submitted as a template for the proposed Project's SPCC Plan. The SPCC's primary purpose is minimizing the potential for releases of hazardous materials, fuels, and lubricants during the construction phase of the proposed Project.

A Facility Response Plan (FRP), which would include the project-specific ERP, would be prepared and submitted to PHMSA prior to initiating operation of the proposed Project in accordance with requirements of 49 CFR Part 194. PMHSA would also provide it to the USEPA for review. A project-specific, worst-case spill scenario including location, available resources, and response actions is addressed in the FRP/ERP. A general discussion of worst-case discharges is provided in Appendix P, Risk Assessment. The project-specific ERP, which is not available at the time of this report, would address the procedures to implement in the event of a release and the location of response teams and resources. These plans rely on final permitting requirements and detailed design and construction information. While not available at the time of this report, consistent with standard practice and current regulations, the applicant would be required to submit the FRP/ERP for review 6 months prior to the operation of the proposed Project.

The draft plans provided in the Final Supplemental EIS would be subject to change pending final permitting requirements as well as design and construction details. As such, a formal plan is not included in this Final Supplemental EIS although the initial response actions for a variety of emergency conditions are provided in the Keystone ERP in Appendix I, SPCC and ERP. There are four key measures addressed in the Keystone ERP that would likely be similar to the ERP for the proposed Project:

- Notification procedures;
- Response actions;
- Response teams; and
- Spill impact considerations.

Notification Procedures

According to the Keystone ERP, for the purpose of this notification procedure, immediate reporting means reporting as soon as a person (Keystone personnel, public, industry partners, or emergency response agencies) has knowledge of an actual or suspected leak, uncontrolled release of product, any unplanned spill, or other pipeline system failure (see Appendix I, SPCC and ERP, Section 2.2). The internal and external notification procedures in the ERP are separated to provide clarity with no implied order of preference. All notifications are of extreme importance and must be completed in a timely manner (see Appendix I, SPCC and ERP, Section 2.0).

Upon discovery of a leak or if a leak is suspected, reporting procedures call for contacting Keystone's Oil Control Center initially, followed by local emergency services (e.g., fire department, police or sheriff, emergency medical technicians, as needed). The Keystone Oil Control Center is contacted first to ensure the pipeline is shut down and then to activate a response by both internal and external responders. In addition, the NRC, appropriate federal agencies, county emergency management, state environmental management, and utilities services are contacted. The internal response units establish the command structure, engage the appropriate internal support teams, contact emergency spill response contractors, and fulfill federal and state notification obligations. The ERP lists contact phone numbers for the Local Emergency Planning Committees in each county through which the proposed Project runs. All entities along the pipeline that could be affected by oil migration would be included in the ERP. These entities include local municipalities, American Indian and First Nations, Local Emergency Planning Committees, Sheriff's Offices, and Fire Departments. These entities along with contracted Oil Spill Removal Organizations would evaluate, prioritize, and respond to impacts on city infrastructure and stormwater systems, and coordinate evacuations as necessary.

Keystone would reach out to first responders at least annually via a public awareness program which includes, as a baseline, contact information, pipeline location, and how to respond. Additionally, Keystone would conduct multiple exercises and training sessions annually, which first responders would be invited to attend and participate. Training and exercises include Incident Command System (ICS), table top, deployment, and full scale exercises. Exercise planners would invite first responders to full scale exercises, which include the development of an incident management team and the simultaneous deployment of equipment resources to approximate a real event. These exercises would be conducted in various locations along the pipeline system. Keystone has stated that they would commit in their ERP to spill drills and exercises that address both floating and submerged oil.

On November 20, 2012, Keystone conducted an emergency response drill at their regional office in Omaha, Nebraska. The objective of the drill was to identify and distribute appropriate Material Data Safety Sheets (MSDS) to first responders at the scene of the spill based upon the time and location of the incident. The drill scenario was based on a third party severing a buried portion of a pipeline while excavating. The location of the strike was selected at random by an observer at the drill that was not a Keystone employee. The drill commenced with a simulated call from the equipment operator who severed the pipeline. The equipment operator called the number posted on the pipeline ROW signs who in turn contacted Keystone. Once this information was received by Keystone, a local first responder was called and sent to the site to confirm the leak and gather specific location information (the actual site inspection was not done for this simulation). The Keystone Oil Control Center was notified of confirmation of the release and the spill response process was initiated, which included simulated shut down of the pipeline and multi-level notifications by phone by local/regional representatives to local responders (law enforcement, local emergency responders, and officials). Simultaneously, while local contacts were being informed, notifications are being made by corporate team members to Nebraska Emergency Management Agency, NRC, PHMSA, state Department of Environmental Quality, and the USEPA. The randomly selected location of the pipeline strike resulted in a scenario where the potential for two different types of oil could be present in the pipeline at the spill scene. The batches were identified by the Oil Control Center and the MSDSs for both products were distributed electronically to the first responders at the scene. Receipt of the MSDSs was confirmed by phone. The objective of the drill was achieved in roughly 17 minutes. Keystone has stated that they could provide specific MSDS to emergency responders within 1 hour of a release. The MSDS would contain the product specifications related to the released oil.

Emergency Communication

Detailed emergency communication procedures and contact information for internal and external notifications are provided in the ERP. In the event of a release, the specific MSDSs and exact composition of the product shipped (and released) would be provided to emergency responders (including any state, local, or federal agencies involved in spill response actions) within 1 hour of the release. Keystone would maintain a point of contact (and procedure to contact this point of contact with this hour timeframe) for requests for MSDSs and the identification of the exact composition of the product (both crude and diluents) shipped in the pipeline (when a release occurs) who would be authorized to release the MSDS and chemical composition information (as described above) to first responders.

In the event of a release or other emergency incident pertaining to the pipeline, Keystone would notify local First Responders (i.e., fire, police, and rescue departments), Keystone's emergency response contractors, and appropriate entities such as the U.S. National Response Center, which in turn would disseminate telephonic and electronic reports to the USEPA or Coast Guard, as appropriate, and other agencies. Keystone would also contact the appropriate federal agencies, the leading provincial/state environmental agency, State Emergency Response Center, the county emergency management department, Local Emergency Planning Committee, and service utilities, as appropriate. In the event that the incident met the criteria of a crisis (e.g., emergency-level interagency coordination were required to protect human health and the environment), the NRC would activate the National Response Team if required and Keystone would notify TransCanada's Crisis Management Team.

As required by the incident-specific circumstances, and as soon as practical following the incident, a written report would be submitted to such entities as PHMSA, USEPA, and the leading provincial/state environmental agency, as appropriate. Other entities, such as the state/local health department, county commission, and state parks and wildlife department, may also be subsequently notified by Keystone.

Response Actions

The ERP provides guidance on how first responders are to classify a spill to the environment or a complaint made within the community. These classifications—minor, serious, major, or critical—are based on the potential for impacts to public safety and the environment. Provided in the ERP is the checklist of actions to be taken to minimize the potential impact of a release as shown below:

- Take appropriate personal protective measures;
- Secure the site;
- Call for medical assistance if an injury has occurred;
- Notify the Oil Control Center and area management of the incident;
- Eliminate possible sources of ignition in the near vicinity of the spill;
- Take necessary fire response actions by trained staff and responding fire departments;
- Advise personnel or public in the area of any potential threat and/or initiate evacuation procedure;
- Identify/isolate the source and minimize the loss of product;
- Restrict access to the spill site and adjacent area as the situation demands;
- Take additional steps necessary to minimize any threat to health and safety; and
- Verify the type of product and quantity released (Material Safety Data Sheet(s) are available).

There are 11 potential emergencies that could be presented in the ERP (listed below) that have been identified and response guidance is provided on each:

- Initial response for public safety measures
- Fire
- Line break or leak
- Release to groundwater
- Severe thunderstorm/flash flooding/landslide
- Winter storm

- Tornadoes
- Earthquake
- Volcanic eruptions
- Bomb threat/terrorist activity
- Abnormal operations

Guidance is also provided to document initial response actions, oil containment, recovery and waste minimization, and management procedures. Emergency medical treatment and safety awareness are also addressed (e.g., first aid, site safety plan, air monitoring, decontamination procedures, personal protective equipment).

Prior to PHMSA granting permission to operate the proposed Project, Keystone would be required to prepare the proposed Project-specific ERP to facilitate rapid response in the event of an oil release. However, there are many factors that could affect a response action and the extent of the release. Some of these include:

- Geographic location and site access;
- Position of the leak (surface or subsurface leak);
- Time to expose a leak (subsurface location);
- Time of day (night versus day);
- Terrain, topography, or geomorphology;
- Weather; and
- Natural disaster-related causes (e.g., flooding, landslides, excessive snow fall, earthquake).

Based on the response time to a release site, level of effort needed for containment measures, characteristics of the spill location and containment location, and the volume of spilled material, the areal extent and receptors affected could be significantly different for every potential spill.

Response Teams

The initial response to a release would be provided by the local Keystone personnel, whose tasks include initiating the notification process and providing pertinent release information to the Operations Control Center. The Operations Control Center would engage response team members to provide the appropriate level of support, personnel and contractors, emergency services, and resources needed to address the release. As part of Keystone's implementation of the ICS, the first company employee onsite would become the Incident Commander and the duties of the Incident Commander are transferred to more senior company personnel as they arrive on site. The ICS is a nationally recognized response framework for responding to various emergencies, allowing communication between responders and a scaled response. The effective execution of the ICS would generally lead to safer, more organized, and more focused response action. With an authoritative command structure established and support roles defined, this focused effort would have the potential to reduce response time and potential impact and increase the confidence and support from local, federal, state, and public sector emergency response personnel.

The ERP for the proposed Project would have the same general approach as presented in the Keystone ERP but would have many specific differences, such as the names and contact information for responders along the proposed Project route and the differing environmental and public health vulnerabilities along the pipeline corridor. Once the proposed Project route is finalized, fieldwork would commence to collect relevant information to be incorporated into the ERP for the proposed Project, which would then be submitted to PHMSA for review and approval. The USEPA would also be provided with the ERP for their review. Keystone has committed to consult and communicate with the Local Emergency Response Planning Committees and other emergency service agencies during ERP development to ensure ERPs are aligned. During an emergency, Keystone would form a Unified Command with local first responders and liaise with all impacted community stakeholders, including the Local Emergency Response Planning Committees.

A spill response is initiated by the reporting of a suspected or confirmed release (e.g., direct observation, SCADA detection, community report, or other notification). As stated in the Keystone ERP, "For the purpose of this procedure, immediate reporting means reporting the instant a person has knowledge of an actual or suspected leak, uncontrolled release of product, any unplanned spill or other pipeline system failure. Information that causes any employee to reasonably suspect a leak or uncontrolled release of product must be immediately reported, even when the actual existence or location of a leak or release cannot yet be confirmed."

As discussed above, many factors influence the response to a release. The time between the actual occurrence of the release and the reporting of the release is critical to the response effort and the potential impact from the spill to human health and the environment. In general, the sooner an effective, efficient response action begins, the sooner the impacts from a release could be addressed, reduced, or eliminated. Keystone's response times to transfer the necessary resources to a potential release site as required by 49 CFR Part 194.115 are shown in Table 4.13-39 below. Depending on the nature of site-specific conditions and resource requirements, Keystone would meet or exceed the requirements along the entire length of the proposed pipeline system.

Table 4.13-39 Response Time Requirements of 49 CFR Part 194.115

Area	Tier 1 Resources	Tier 2 Resources	Tier 3 Resources
High-volume area[a]	6 hours	30 hours	54 hours
All other areas	12 hours	36 hours	60 hours

[a] High-volume area indicates an area where an oil pipeline with a nominal outside diameter of 20 inches or more crosses a major river or other navigable waters; because of the velocity of the river flow and vessel traffic on the river, this area would require a more rapid response in the case of a worst-case discharge or the substantive threat of such a discharge.

As stated above, as soon as an effective, efficient response action begins, the sooner the impacts from a release could be addressed, reduced, or eliminated. For releases to streams or rivers, these response times affect the distance which oil could be transported downstream before an effective containment system is encountered. For overland flow, these response times affect where nearby streams or rivers could be affected or if spreading is contained before a sensitive receptor is impacted. Once the flow is controlled and containment of the spill is achieved, reclamation, remediation, and restoration of the release site and affected areas could begin.

In general, Tier 1 emergency response equipment would be pre-positioned for access by Keystone along the proposed route. Equipment could include pick-up and vacuum trucks; containment boom, skimmers, pumps, hoses, fittings, and valves; communications equipment including cell phones, two-way radios, and satellite phones; containment tanks and rubber bladders; expendable supplies including absorbent boom and pads; assorted hand and power tools including shovels, manure forks, sledge hammers, rakes, hand saws, wire cutters, cable cutters, bolt cutters, pliers, and chain saws; personnel protective equipment including rubber gloves, chest and hip waders; and air monitoring equipment to detect hydrogen sulfide, oxygen, lower explosive level, and benzene.

Additional equipment, including helicopters, fixed-wing aircraft, all-terrain vehicles, snowmobiles, backhoes, dump trucks, watercraft, bull dozers, and front-end loaders also may be accessed depending on site-specific circumstances. Other types, numbers, and locations of equipment would be determined upon concluding the detailed design of the proposed pipeline and completing Keystone's final ERP. This plan would be completed and submitted to PHMSA for review prior to commencing operations as described above.

The primary task of the Tier 1 response team is to reduce the spread of the spill on the ground surface or water to protect the public and Unusually Sensitive Areas, including ecological, historic, and archeological resources and drinking water locations. The Incident Commander would perform an initial assessment of the site for specific conditions, including the following:

- The nature and amount of the spilled material;
- The source, status, and release rate of the spill;
- Direction(s) of spill migration;
- Known or apparent impact of subsurface geophysical features that may be affected;
- Overhead and buried utility lines and pipelines;
- Nearby population, property, or environmental features and land or water use that may be affected;
- Location of HCAs including Unusually Sensitive Areas downstream or downgradient from the spill site; and
- Concentration of wildlife and breeding areas.

The Incident Commander would request additional resources in terms of personnel, equipment, and materials from the Tier 2 and if necessary, the Tier 3 response teams. Once containment activities have been successfully concluded, efforts would then be directed toward the recovery and transfer of free oil. Site cleanup and restoration activities would then follow, all of which would be conducted in accordance with the ERP and in conjunction with regulatory agencies having jurisdiction. Keystone is required to prepare to respond to a worst-case discharge (WCD) by regulations in 49 CFR Part 194. This consists of calculating and identifying where the WCD may potentially occur, plans to ensure that adequate personnel and equipment resources are available to respond, and scenario development. By developing such plans for a WCD, Keystone could be better prepared to respond to a large-scale incident such as the 20,000 bbl spill on the Kalamazoo River in Marshall, Michigan, in 2010. Keystone would ensure internal personnel are trained to respond to oil spills through annual exercises and training sessions including full scale field exercises held in various locations in various operating environments and weather.

When developing the ERP, Kalamazoo River Spill lessons learned would be considered, including ensuring consultants are contracted as appropriate to facilitate a large-scale and prompt response; developing source containment plans including strategies and tactics; minimizing response times with appropriate equipment; identifying equipment resources required to respond to sunken and submerged oil, and ensuring personnel are appropriately trained.

Spill Response Considerations

The ERP would address spill impact response requirements including oil containment and removal for land or surface spills, spills occurring in waterbodies, on or under ice, urban areas, and wetlands. The ERP would also address socioeconomic sensitivities by providing guidance and procedures to reduce or mitigate impacts to heritage resources, archeological sites, fisheries, and wildlife in the event of a spill or when conducting reclamation or remediation activities (see Appendix I, SPCC and ERP Sections).

As identified above, oil spill response actions and remediation could affect receptors or the environment. If requested by regulators, Keystone would perform a Net Environmental Benefit Analysis, which is a tool used to compare the interactions between oil spill prevention, planning, and response actions and the effects they could have on potential receptors in a given situation. The process tries to balance the advantages and disadvantages of oil spill prevention techniques and efficient response actions against the potential these countermeasures may have to ecological, social, economic, environmental, and the other receptors discussed in Section 4.13.5, Potential Impacts. This approach considers the potential impact to affected resources and receptors, assesses the degree of protection that could be provided to each under the existing spill conditions and the available response resources present, and seeks to implement a response that provides the best overall outcome to a spill. The process could also be used to identify existing data gaps and often reveals the differences in the stakeholders' concerns related to the various resources.

The Net Environmental Benefit Analysis process described above would weigh the potential impact to the various resources and receptors that could be affected by ensuring that response actions limit the impact to the surrounding areas and result in net environmental benefit. For example, proper use of mats or other materials when moving or operating heavy equipment could minimize potential impact to soils by reducing ruts and damage to soil cover. Similar means could be used for drill rigs installing monitor or recovery wells and treatment systems to reduce the potential impact to the area surrounding a spill response action. In waterbodies, the use of flat-bottom, shallow draft boats, which reduce the potential for damage to shorelines, aquatic plants and animals, would be considered.

The methods for remediating spills in both construction and operation phases of the proposed Project would generally vary only in the magnitude of the effort. As discussed in the Construction, Mitigation and Reclamation Plan (see Appendix G), many of the spills that occur during construction would be generally small in volume and could be addressed by containment, excavation, and other remedial processes. Many of these same processes are also discussed in the ERP (see Appendix I, SPCC and ERP) as related to potentially larger spill volumes. Recovery, reuse, and recycling are the best choices for remediation of a spill. The more effort applied to recovery of spilled product generally means shorter-lived remediation efforts and less impact to the environment.

The use of skimmers, vacuums, sorbent materials, and other means of recovery of spilled products would be managed during remediation efforts to help to prevent further impacts to the local environment or receptors. The reuse of hydrocarbon-affected soils as road base or in asphalt mixtures (as approved by the appropriate agencies) is another way to remediate affected soil at a spill site. Recovered product from skimming or vacuum operations could be recycled by removing water and debris and re-blending. Incineration or burning of oiled media for energy recovery may be other options to consider. However, there could be limitations on incineration and local air quality authorities would need to be contacted for approval. Disposal of oiled soil and debris at a solid or hazardous waste landfill is the least environmentally sound method of disposal and would be considered only as the last option. Once the spill recovery effort is no longer effective or efficient, more passive remediation methods could be implemented to further the remediation and restoration of affected soil, groundwater, and surface water.

There are many ways to remediate hydrocarbon-affected soil, groundwater, and surface water. Action would include: soil excavation, bioremediation of oil, groundwater recovery with pumps and water treatment, oil recovery from surface water as well as groundwater, degradation of oil compounds using other chemical compounds, and natural degradation.

Many of the technologies and methods used to address the detection, containment, and recovery of spilled crude oil listed below are well-established and have been employed in the field over the past several decades. Technological refinements and advances in addressing oil spills continue to improve and advance the state-of-the-art oil spill response.

Oil that is heavier than water would likely become submerged in the water column or sink to the bottom. Oil that sinks may act much like oil on dry land, collecting in low lying areas and thus resting on the bottom. Sinking or submerged oil is oil that has not reached the bottom yet or has been disturbed and is currently suspended in the water column by tide or current. In water with a current of less than 0.7 knots, oil that is heavier than water would tend to sink to the bottom. Any current above 0.7 knots has the potential to remove oil from its resting place on the bottom and carry the oil downstream. Types of equipment used to contain oil that is sunken or submerged include net booms, bottom hugging weighted booms and watergate dams, silt curtains, and gabion baskets lined with impermeable membranes. Filter fences such as Turner Valley Gates can also be lined with impermeable membranes, and booms with deep skirts to help resurface submerged oil.

Natural attenuation of residual oil is a potential remedial option for the removal of crude oils. Significant components of conventional crude oils include straight hydrocarbon chains and light compounds, both of which biodegrade relatively easily. Dilbit, on the other hand, is largely comprised of branched hydrocarbon chains and heavy hydrocarbons, which are less readily biodegradable. A biodegradation study conducted by the USEPA in response to the 2010 Enbridge dilbit spill in the Kalamazoo River in Michigan concluded that only 25 percent of the residual hydrocarbons impacting the river could be reasonably removed by natural attenuation (USEPA 2013). Due to the capacity for dilbit to precipitate out in water and its very slow biodegradation rate, more difficult cleanup scenarios (e.g., dredging) for dilbit may be expected in the event of a release to a waterbody than with other types of crude oil.

Methods to detect submerged oil include the use of Sonar, which has been used to locate submerged oil in calm water such as lakes, ponds, and bays with some success. Remote and diver operated underwater video detection systems are useful, but success is dependent on visibility and the water's current. Visual observation can be used in shallow water, although expert analysis is essential for this technique as aquatic biota (vegetation) in the water may be mistaken for oil. Currently, the best method for sampling for submerged oil is to drop weighted sorbent materials such as *pom-pom* snare boom or sorbent chain drags into low areas for short distances and then visually inspect them for oil to map oil distribution. This provides a bottom sample indicating whether or not oil is present. Gabion baskets filled with sorbent materials are also used for detection of sunken and mobile oil. These sorbent filters allow water to flow through them, thus capturing any suspended or sunken oil. By examining the filter, it can be determined if submerged or sunken oil is present. Collection of core samples can also be a method to detect sunken oil. The sampling area of the core may be too small to be effective, but historically cores have been used for subsurface contamination assessments.

A cost effective method to recover oil is the use of a vacuum system to collect concentrations of submerged oil. Another common method is to dredge the bottom and remove the oil. Where appropriate, dredging is used to remediate contaminated sites but may generate a large amount of waste material that must be properly managed and disposed. Both vacuum systems and dredging only work for completely sunken oil. To capture suspended oil, an underwater filter can be constructed. This filter can be created using multiple types of porous containers such as gabion baskets, prawn or crab traps, silt fences, and chicken wire. The container is filled with sorbent material such as oil snares, weighted down and submerged into the water column. The sorbent materials are monitored and replaced as needed for oil recovery.

In shallow water where oil can be seen from the surface, dip nets or pool nets have been successfully used as an effective way to collect oil. This method is useful if the oil has emulsified or is thick enough to scoop up with the nets.

In considering the treatment methods listed above, it would be necessary to weigh the effectiveness of the remediation technique used against the intrusiveness of the remedial effort on the environment and potential receptors. These methods would be implemented following approval of the appropriate agencies and managed by qualified persons knowledgeable in the application of the technology.

After safety, the highest priority for a spill response is to prevent product from reaching water and then to mitigate oil migration out of the source area. To accomplish this, there are many different ways to contain or deflect oil. Oil can be trapped in ditches and gullies by earth dams. Where excavating machinery is available, dams can be created to contain the oil. Dams could be effectively employed to protect priority areas such as inlets to drains, sewers, ducts and watercourses. Dams can be constructed of earth, sandbags, absorbents, planks, pillow (inflatable with air/water) dams, or any other effective method. The terrain would dictate the placement of the dams. If the spill is minor, natural dams or earth absorption could stop the oil before it advances a significant distance. Whenever possible, potential routes of migration should be closed off by the use of sandbags, planks, earth, or other dams. This is used as a preventative measure in case precipitation begins and the oil starts to migrate.

In urban locations such as city streets or concrete drainage ditches, a combination of sorbent booms in front with a layer of sandbags behind holding the boom in place can be used as an effective means to create containment along with some collection. Instead of building dikes and dams, another method of containment is to dig collection pits. This creates a new low point for the oil to run off into, providing a recovery point for removal. Approaches to remove oil from urban infrastructure include:

- Removal with suction equipment to tank truck if concentrated in volumes large enough to be collected. Channels can be formed to drain pools of oil into storage pits. The suction equipment can then be used.
- Small areas can be cleaned by hand. Use of sorbent pads to soak up the oil is the preferred method.
- Storage of contaminated soil, if not immediately shipped off site for appropriate disposal, should be done using plastic lined containers. This would prevent loss of oil and run-off.
- For ground contaminated with oil that cannot be removed, such as paved roads, concrete curbing, or concrete drainage ditches, an effective cleaning method is heated pressure washing. The collection of produced wastes, including the water used for cleaning, is important; therefore, a vacuum truck or some other type of collection must be available.
- Cleaning agents (surfactants) may also be used to lift the oil off hard surfaces such as concrete for collection and recovery.

Facility Response Plan

The Facility Response Plan (which includes the ERP) would be prepared and submitted to PHMSA prior to initiating operation of the proposed Project, in accordance with requirements of 49 CFR Part 194. The FRP/ERP would detail Keystone's spill response plan and describe the location and volume of a worst case scenario discharge, as well as the procedures and resources in place to manage the discharge. The FRP/ERP requires PHMSA review and approval; however, there is a 2-year grace period under which operation of the pipeline could proceed while PHMSA reviews and approves the FRP/ERP. This period would allow PHMSA to review the proposed Project in its final, as-built state.

While the draft FRP/ERP for the proposed Project is not yet available, Keystone prepared similar plans for the existing Keystone pipeline and the Gulf Coast Project. These plans for the proposed Project would have the same general approach as those plans but would have differences specific to the proposed Project, such as the contact information for the local fire, law enforcement, and emergency service departments; local government officials; and response team members along the proposed Project route.

Keystone First-Year Spill Response

Between May 21, 2010 and May 29, 2011 (the first year of operation), 12 spills occurred along the Keystone pipeline. Of the 12 spills, 11 were small in size (less than 50 bbl), and of these, nine were less than 3 bbl, or 126 gallons. None of these spills were related to the failure of the mainline pipe, but rather were related to fittings, pump seals, and valves generally located within pump station facilities. The spills were generally contained on site. Once identified, the spills were contained and remediated, and the cases were closed by the respective state environmental departments, generally within 90 days of the incident.

One of the 12 spills was medium-sized (500 bbl or 21,000 gallons). This spill occurred near Brampton, North Dakota, where roughly 500 bbl (21,000 gallons) were spilled at the Ludden Pump Station and onto a small area of adjacent farmland. The spill was due to the failure of a small pipe nipple on discharge piping. The cleanup activities (both on site and off site) were initiated within hours, and the collection of all free-phase oil, excavation of contaminated soil, and the decontamination of equipment and fencing was completed in nine days.

A more detailed assessment of first-year spill data is provided in Section 4.13.3.7, Keystone Pipeline First-Year Release Historical Data.

Keystone Southern Segment Pipe Replacement

Keystone is constructing the Gulf Coast Project in compliance with the Special Conditions developed by the Department of State and PHMSA during the review of the proposed Keystone XL Pipeline project. In accordance with Special Condition 43 and the interim guidelines referenced in that condition, Keystone is required to perform inline inspection (ILI) of the entire pipeline using specific tools capable of high resolution detection of deformation in the pipe wall in the form of dents or expansion. This inline inspection must be performed subsequent to hydro-testing the pipeline. Further, Keystone's specification requires examination for ovality (the overall deformation) of the pipe as a means to ensure the pipe can allow passage of ILI tools in the future that are used to monitor both corrosion integrity and third-party damage.

The ILI tool is run through continuous segments of pipeline (approximately 30-mile sections), and the data are analyzed in accordance with the analysis methodology, conforming to Special Conditions 43 and 49. All dents, expansion, and ovality reported by the ILI tool greater than the limits predefined by Special Conditions 43 and 49 and TransCanada's specifications are investigated by excavating the pipeline. Subsequent to excavation and removal of overburden that may be causing the deformation, physical field measurements are conducted to confirm permanent deformation equal or greater than the predefined criteria; if confirmed, a segment of affected pipe is removed. Further, any pipe segments with dents that occur directly on a field weld or factory weld are removed in accordance with 49 CFR 195.452. The pipe predominantly used on the Gulf Coast Project has a helical factory weld seam, which leads to more pipe seam exposure. As of mid-June 2013, 5 percent of the anomalies investigated required replacement in accordance with the pre-defined conditions. Expanded pipe occurs when a pipe diameter expands greater than 0.60 percent of the nominal or actual rolled pipe diameter following pressure testing. None of the pipeline segments investigated has confirmed expanded pipe issues (e.g., bulges, swelling, outward deformities) in excess of the applicable standards. Expanded pipe is generally a result of low-strength steel, which is not intended to be used for the proposed Project.

Removed pipe segments are replaced with previously hydro-tested pipe. The field welds of the new pipe segments are subjected to non-destructive testing using two methods: gamma radiation with high resolution film and, after a 24-hour period, retesting using a form of automated ultrasonic examination. The welds are then recoated with field applied epoxy coating, and the coating of the entire exposed segment of pipe is retested to ensure integrity.

Denting and ovality of the pipeline occur subsequent to burying the pipeline and are caused by conditions not detected by rigorous visual inspection during installation and backfilling the pipe in the trench. Dents generally occur at locations of smooth but hard trench bottom (hard pan) rock that is shallow buried on the trench bottom and rock that is not detected in backfill. Ovality can occur in areas of hard pan and where additional backfill compaction is required along the sides of the pipeline. Expanded pipe has not been detected on the Gulf Coast Project. Figure 4.13.6-1 illustrates these anomalies.

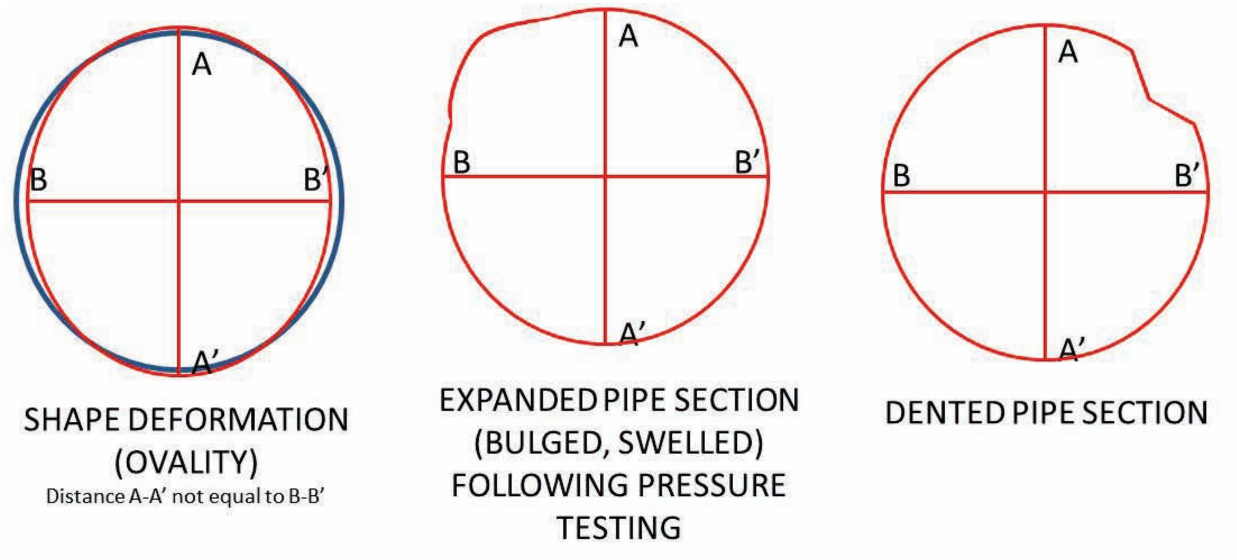

Figure 4.13.6-1 Types of Pipe Wall Deformations

TransCanada's specifications are designed to minimize the occurrence of these conditions and include requirements such as trench bottom sand padding, backfill operations that screen out rock size that could be damaging to the pipe, use of rock shielding materials in soils with abundant small rock, use of foam pads to prevent the bottom of pipe from contacting a hard or rocky trench bottom, and other measures.

Keystone has employed industry best construction and inspection practices whereby all construction and inspection staff are trained and verified to perform activities in accordance with Special Condition 20. The final inspection of the pipeline via hydrostatic testing, high resolution deformation ILI, and physical verification of reported ILI results help ensure the pipeline's reliability and integrity prior to crude oil service.

The conditions described herein are typical to the construction of large diameter pipelines. The PHMSA Special Conditions and TransCanada's specifications demand that rigorous testing for integrity of the pipeline be conducted, that all anomalies meeting pre-defined criteria be investigated and evaluated, and that following physical verification of such anomalies, corrective action be implemented as described above.

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Lessons Learned

The pipeline involved in the Marshall, Michigan, incident was constructed in the 1950s. Pipeline standards have evolved, and new technologies have resulted in improvements in pipeline safety performance. Pipelines are now constructed with higher quality steel that is stronger, has better fracture resistant properties, and helps reduce the impacts of external forces such as flooding and excavation damage. Improvements in external pipeline coatings, the use of cathodic protection, and mandatory ILI tools have resulted in significant reductions in corrosion-related incidents. Keystone has not experienced a corrosion-related failure on any of its pipelines that utilize modern fusion-bonded epoxy coatings. Federal pipeline regulations have evolved over time, and pipeline operators are now required to actively manage their pipelines to reduce the possibility of incidents. Operating procedures and leak detection capabilities have improved to more rapidly detect leaks, thereby reducing the amount of crude oil released and subsequent impacts.

Commenters have raised concerns about the possibility of a spill on the proposed Project comparable to the Kalamazoo spill in Marshall, Michigan. Based on the lessons learned from the Kalamazoo spill, Keystone has indicated that it recognizes the additional potential challenges that could result from a release of dilbit to a water environment. In the event of such a release, Keystone intends to allocate additional manpower and resources towards the timely response, containment, and cleanup of releases to a waterbody. Pre-positioned equipment and materials would be stationed for timely access, and local response teams would be utilized to minimize response times. Additionally, Keystone intends to minimize the potential challenges discussed above by placing a strong focus on spill prevention and early detection of releases.

Environmentally, the lessons learned from the Marshall, Michigan, dilbit spill and related response implications include the following:

- The total volume of dilbit released to a river would not float on water indefinitely, and dilbit characteristics, water temperature, and particulate load in the water could result in much of the oil being submerged in the water column (USEPA 2013). Keystone has asserted that, in the event of a release to a body of water, Keystone would focus initially on timely containment and recovery efforts to remove floating material. However, Keystone response teams would be prepared to lend additional efforts for timely detection, containment, and recovery of submerged oil, as well, particularly in colder-temperature waterbodies with significant suspended sediment loads. Response personnel and contractors would be trained for the proper deployment and use of a number of submerged oil containment options (e.g., net booms, silt curtains, bottom-hugging weighted booms and watergate dams) and recovery alternatives (e.g., weighted sorbent, vacuum systems, dredging.)
- Submerged oil could be suspended in the water column, suspended just above the river bed, or intermixed with sediment and trapped in the river bed and shoreline (USEPA 2013). Keystone has asserted that their response teams and contractors would be trained and prepared to employ multiple remedial alternatives for effective removal of floating, submerged, and suspended oil. To contain and recover suspended oil, multiple types of underwater filters are available and may be replaced as needed for continued recovery.
- Submerged oil in a flowing water environment introduces additional recovery challenges for responders. In the event of a release to a flowing water environment, Keystone has stated that initial efforts would include prevention of the downstream migration of released material and that subsequent efforts for cleanup of submerged oil would extend to downstream areas.

Depending upon the characteristics of the flowing water environment, a number of methods for detecting submerged oil would be available and may include remote and diver-operated underwater video systems, visual observations, and/or sampling to delineate the lateral and vertical extent of submerged oil impacts.

- Response action planning and response equipment to contain and recover submerged oil should be considered. As such, the ERP and FRP would directly address submerged oil in a surface water release scenario. Response equipment and materials designated for containment and recovery of submerged oil would be pre-positioned in order to ensure timely response. These aspects are discussed further in the Spill Response Considerations subsection.
- Dilbit intermixed with sediment and trapped in the river bed and shoreline may result in a persistent source of oil and dissolved components such as benzene, polycyclic aromatic hydrocarbons, and heavy metals that could be slowly released back to the water column and transported down current. Various sampling techniques may be employed in order to delineate the extent of impacts to water from leaching contaminants, and long-term implementation of containment and recovery alternatives may be required to reduce the downstream migration of contaminants.
- Dilbit intermixed with sediment could persist for years. A biodegradation study conducted by the USEPA in response to the 2010 Enbridge dilbit spill in the Kalamazoo River in Michigan concluded that only 25 percent of the residual hydrocarbons impacting the river could be reasonably removed by natural attenuation (USEPA 2013). As such, in the event of a release to a water environment, Keystone is prepared to implement a number of other remedial alternatives, such as vacuum excavation, dredging, and/or treatment.

The NTSB 2012c Marshall, Michigan, Accident Report identified conditions that led to operational failures on the pipeline and resulted in the spill. Keystone would include mitigations learned from this event, including the following:

- According to Keystone, timeliness of a tactical response to an oil spill into water is imperative. While Keystone has stated that it already uses this philosophy, the Kalamazoo spill reinforced this need to respond with as many resources as possible, as rapidly as possible. To that end, Keystone would strategically store specialized spill equipment and employ personnel and contractors along the length of the pipeline. Keystone asserts that it is their objective and intent to respond as rapidly and as safely as possible for all operating areas, regardless of High Volume Area status. As per 49 CFR 194, responders must be on site within 6 hours in a High Volume Area and within 12 hours in non-High Volume Areas; however, Keystone asserts that it is their goal to respond sooner in all situations if it is safe to do so.
- Pre-qualify a large contractor network: Contractors would be used to supplement any response Keystone would make to an oil spill. By ensuring that a large pool of trained/skilled contractors along the length of the pipeline have been pre-qualified and contracted with Keystone, the response time would be minimized and the resources (equipment and personnel) available would be maximized.
- Emergency response planning details need to include source containment: source containment plans including strategies and tactics would be included in the overarching ERP.

- Equipment resources required for sunken and submerged oil: Keystone would further identify equipment resources required to respond to sunken and submerged oil and ensure personnel are appropriately trained. A primary strategy for oil spill response would still be required to contain and recover as much oil as possible, as rapidly as possible, to prevent oil from weathering and therefore potentially becoming submerged and sinking. In addition, Keystone already owns and practices the use of containment devices that would prevent downstream migration of submerged and sunken oil such as dams. This type of equipment would be further identified and procured for the proposed Project.

Keystone would use relevant PHMSA advisory bulletins, relevant NTSB incident reports, and applicable major Standards and Association recommended practices, as appropriate, within the applicable phase of the project. Specifically, lessons learned that are documented in these industry publications would be obtained from:

- PHMSA Advisory Bulletins: These items could be incorporated in the applicable phase (i.e., design, construction, or operations) through modification of specific design requirements, construction scope of work, or incorporation into an Integrity Management Plan or Operations Manual.
- NTSB Incident Reports: The draft and final reports can be reviewed for pertinent findings and incorporated into design basis or procedures, if applicable.
- Industry Publications: These serve as representation on major Standards and Association Committees and incorporate appropriate feedback into specification revisions for pipeline assets through company engineering standards.
- PHMSA Special Conditions 25c and 43: These are examples of where NTSB incident reports and PHMSA advisory bulletins are incorporated into the proposed Project.

Spill Liability and Responsibility

In addition to Keystone staff and resources and consistent with the requirements of the proposed Project's ERP, federal, state, and local agencies would engage in response activities where soil, surface water, and groundwater cleanup are needed. Participation would be within agencies' authorities and duties under applicable regulations. Required mitigation for crude oil or oil products spill impacts would be determined by these agencies. In addition, the state, tribal, and federal natural resource trustee agencies could require a Natural Resource Damage Assessment under either the Oil Pollution Act (OPA 90) or the Comprehensive Environmental Restoration Compensation and Liability Act, depending on the types of materials spilled and the assessment of the magnitude of the impacts and the type/amount of suitable restoration actions to offset the loss of natural resource services resulting from a spill. The Nebraska Environmental Protection Act, Nebraska RRS S 81-1501, et seq. and the Nebraska Administrative Code Title 126, Chapter 18, provide for operator liability in the event a pipeline spills oil or a hazardous substance in or on land or waters of the state. Table 4.13-40 summarizes potentially applicable federal and state soil, surface water, and groundwater cleanup regulations.

Table 4.13-40 Potentially Applicable Federal and State Soil, Surface Water, and Groundwater Cleanup Regulations

Statute/Regulation	Description
Resource Conservation and Recovery Act, 42 U.S. Code (USC) § 6973.	USEPA may issue an order or bring a suit in district court against any person who has contributed or who is contributing to the handling, treatment, storage, transportation, or disposal of solid or hazardous waste which may present an imminent and substantial endangerment to health or the environment. Persons who violate an order are subject to civil penalties of up to $7,500 per day. Section 7003(a) of Resource Conservation and Recovery Act, 42 USC 6973(a), authorizes USEPA upon receipt of evidence that the past or present handling, storage, treatment, transportation or disposal of any solid waste or hazardous waste may present an imminent and substantial endangerment to health or the environment, to bring suit in district court or to issue an administrative order to any person who contributed or is contributing to that handling, storage, treatment, transportation to restrain or take any other action in response. Oil released from a pipeline would constitute solid or hazardous waste, and the authority allows USEPA to require action even if the spill may present an imminent and substantial endangerment.
Safe Drinking Water Act (SDWA), 42 USC §§ 300f, et seq.	USEPA may issue orders to any person in circumstances where contaminant is present in or is likely to enter a public water system or an underground source of drinking water (defined broadly to include virtually almost all groundwater) which may present an imminent and substantial endangerment to the heal of persons and states (to whom primary responsibility is granted under the SDWA) are not acting. The orders may require that person to take such actions as USEPA deems necessary to protect health. 42 USC § 300i (a). Civil penalties are available for failure to comply with such an order. Section 1431(a) of SDWA, 42 USC 300i(a), authorizes USEPA upon receipt of information that a contaminant which is present in or is likely to enter a public water system or an underground source of drinking water which may present an imminent and substantial endangerment to the health of persons, to take such actions as [it] deems necessary, including issuance of orders and civil judicial actions. Again, this authority is quite broad. An underground source of drinking water is virtually any underground water that has the potential to be used for drinking water, and a contaminant is any biological, chemical, or physical substance in water.
Pipeline Safety Act, 49 USC §§ 60101, et. seq.	The Pipeline Safety Act, as amended in 2011, provides authority for PHMSA to establish minimum safety standards for interstate hazardous liquid pipelines, including petroleum pipelines. The standards may apply to the design, installation, inspection, emergency plans and procedures, testing, construction, extension, operation, replacement and maintenance of pipeline facilities. § 60102(a)(2). Penalties Violations of PHMSA requirements are subject to civil judicial enforcement actions, with varying penalty amounts depending on the nature of the violation (generally $200,000 for each violation, with a maximum of $2,000,000 for a related series of violations).

Statute/Regulation	Description
	Written Procedures Regulations require that a pipeline operator prepare and implement a manual for operations, maintenance and emergencies. 49 CFR Part 195.402. For emergencies, the manual must include procedures for (a) receiving, identifying and classifying notices of events which need immediate response and (b) responding promptly to the emergency, including fire or explosion near or involving a pipeline, accidental release of materials from a pipeline, operational failures and natural disasters. 49 CFR Part 195.402(e). Notification Regulations require that a pipeline operator make an incident report, including telephonic report, for pipeline failures which result in (a) explosion or fire, (b) release of 5 gallons or more of petroleum (with certain exceptions), (c) death, (d) personal injury necessitating hospitalization, or (e) property damage (including cleanup) in excess of $50,000. 49 CFR Parts 195.50-195.54.
Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), 42 USC §§ 9601, et. seq.	Similar to the OPA 90, but addresses releases of hazardous substances and specifically excludes oil and petroleum. Provides for liability for response costs and natural resource damages against owners or operators of a vessel or facility and persons who arranged for disposal of hazardous substances. The act contains similar defenses as for the OPA 90, as well as contribution rights. Also provides USEPA authority to issue administrative orders requiring response actions.
Montana	There is no single statutory scheme under Montana law governing liability for pipeline spills on land and in groundwater, but one or more of the following provisions could apply depending on the circumstances: Montana Code Annotated (MCA) 75-10-705 et seq., Montana‘s ―Comprehensive Environmental Cleanup and Responsibility Act (Montana‘s version of CERCLA) MCA 75-10-401 et seq., the ―Montana Hazardous Waste Act – while crude oil is not specifically listed in the definition of hazardous waste‘ the definition may be broad enough to apply to a crude oil spill MCA 75-5-101 et seq., Montana‘s water quality statutes – applicable to both surface water and groundwater MCA 75-20-101 et seq., the ―Montana Major Facility Siting Act – applicable to ―facilities, including pipelines, that fall under the MFSA. Keystone XL falls under MFSA. The regulations that relate to the statutes and may apply are: Administrative Rules Montana (ARM) 17.55.101 et seq. dealing with Comprehensive Environmental Cleanup and Responsibility Act ARM 17.53.101 et seq. dealing with hazardous waste ARM 17.30.101 et seq. dealing with water quality ARM 17.20.101 et seq. dealing with MFSA There are also various common law grounds under Montana law for asserting liability for pipeline spills, and Montana also has clean and healthful environment constitutional provisions that could be used to assert liability.

Statute/Regulation	Description
South Dakota	First, South Dakota Public Utilities Commission permit HP09-001 authorizing the project in the state, issued in final form June 29, 2010, provides at Condition 48: No person would be held responsible for a pipeline leak that occurs as a result of his/her normal farming practices over the top of or near the pipeline. The permit provides further at Condition 49: Keystone shall pay commercially reasonable costs and indemnify and hold the landowner harmless for any loss, damage, claim or action resulting from Keystone's use of the easement, including any resulting from any release of regulated substances . . . except to the extent such loss, damage claim or action results from the gross negligence or willful misconduct of the landowner or its agents. Second, statutes contained in South Dakota Codified Law (SDCL) Chapter § 34A-12, which create the regulated substance response fund, provide for corrective action in case of a spill or leak from a tank. The definition of tank includes pipeline facilities which transport and store regulated substances. SDCL § 34A-12-1(12). A regulated substance is defined to include crude oil. SDCL § 34A-12-1(8). Under the chapter, the Department of Environment and Natural Resources is directed to take corrective action to clean up any unauthorized discharge of a regulated substance, but only after first ordering the responsible person to take corrective action. A responsible person is as a person who has caused a discharge of a regulated substance, or a person who is an owner or operator of a tank at any time during or after a discharge. SDCL § 34A-12-1(10). If the responsible person fails to act, then the department may seek injunctive relief to compel corrective action. SDCL § 34A-12-10. If a responsible person cannot be identified or refuses to undertake corrective action, or if emergency action is needed to prevent an imminent threat to public health or safety, then the department may undertake correction action with funds from the response fund. SDCL § 34A-12-4(2), (3). The department may recover corrective action costs from either the responsible person, SDCL § 34A-12-6, or from any person who has caused a discharge of a regulated substance. SDCL § 34A-12-12. That statute also provides that the person causing a discharge is strictly liable for the corrective action costs expended by the department. Third, SDCL Chapter § 34A-2 addresses the discharge of petroleum substances into state waters. SDCL § 34A-2-96 imposes liability on the owner or operator of a facility that stores or transports petroleum substances for the costs of containment and recovery of discharges into the waters of the state. SDCL § 34A-2-96. This section also provides that —any person causing the discharge shall be strictly liable to the owner or operator for all costs and proximate damages resulting from the discharge. A violation of an order issued pursuant to the statute is a class 1 misdemeanor. SDCL §§ 34A-2-96, 34A-2-75. Finally, landowners who experience a discharge have civil court remedies for damage to their property, including loss of use and loss of future productivity. Cleanup costs incurred by the landowner are a recoverable element of damage.
Nebraska	The Nebraska Environmental Protection Act, Nebraska RRS § 81-1501, et seq. (Act) and the Nebraska Administrative Code Title 126, Chapter 18, provide for liability in the event a pipeline spills oil or a hazardous substance in or on land or waters of the State. Waters of the State include both surface waters and groundwater. In the event of a release, the person responsible for the release has various responsibilities. Responsible person means any person producing, handling, storing, transporting, refining, disposing of an oil or hazardous substance when a release occurs, either by accident or otherwise. This includes carriers or any other person in control of an oil or hazardous substance when a release occurs, whether they own the oil or hazardous substances or are operating under a lease, contract, or other agreement with the legal owner thereof. Nebraska Administrative Code Title 126, Chapter 18-038.

Statute/Regulation	Description
	The responsible person must: (1) notify the Nebraska Department of Environmental Quality (NDEQ) if the release exceeds threshold quantities, or, regardless of quantity, if the release occurs beneath the surface of the land or impacts or threatens waters of the State or threatens the public health and welfare, (2) must take all necessary steps to stop the release and contain all released material, and take action to preclude continued or future releases, (3) investigate the release, to determine its impact, and the investigation must be reported to NDEQ, (4) take remedial action, which remedial action is subject to the review and approval of NDEQ, (5) properly dispose of any waste generated from the cleanup. Compliance with these requirements does not relieve the responsible person from liabilities, damages, or penalties resulting from the release, cleanup and disposal. The Act also has civil and criminal penalties that may be assessed in the event of a release. The Act further provides for reimbursement to the State for any loss of fish or wildlife as a result of a release.

Keystone is committed to ensuring the safe operation of its pipeline system and to prevent any incidents from occurring. Should a release occur from the Keystone XL pipeline, Keystone is committed to clean up any releases that may occur. Keystone is also legally required to clean up spills under Title 118 and OPA 90. Keystone has stated that they would commit in their ERP to the implementation of a long-term groundwater sampling/monitoring program after a spill in the event that Keystone determines, in consultation with relevant agencies, that post cleanup and restoration and site conditions suggest an ongoing potential risk to water and/or the potential for residual contamination. In addition to all of the above, and in response to public concern, Keystone would commit to file annually with the Nebraska DEQ by May 1 of each year:

(a) A certificate of insurance as evidence that it is carrying a minimum of $200 million in third-party liability insurance as adjusted by calculating the gross domestic product implicit price deflator from the date a Presidential permit is issued for the Project and adjusting the amount of the third-party liability insurance policy by this percentage. The third-party liability insurance shall cover sudden and accidental pollution incidents from Keystone XL Pipeline in Nebraska.

(b) A copy of Keystone's Securities and Exchange Commission Form 10-K and Annual Report. Keystone's Major Facilities Siting Act (MFSA) Certificate contains a similar requirement.

Keystone is willing to adopt a similar requirement in South Dakota.

Section 1001(32)(B) of the OPA 90 states that in the case of an onshore facility, any person owning or operating the facility is the responsible party. Additionally, under Section 1002 of OPA 90, Keystone would be liable for discharge of oil (or threat of discharge) to navigable waters of the United States and their adjoining shorelines. The term "navigable waters" is defined in OPA 90 as the waters of the United States, including the territorial sea. Groundwater is not within the scope of the OPA 90 unless a direct connection to surface waters could be affirmed.

If there is an accidental release that could affect surface water, no matter what the reason, Keystone would be liable for all costs associated with cleanup and restoration, including damages to natural resources; to real or personal property for the loss of subsistence use of natural resources; for the net loss of taxes, royalties, rents, fees, or net profit shares from injuries to real or personal property or natural resources; for loss of profits or impairment of earning capacity by any claimant; or for net cost of providing increased or additional public services, up to a maximum of $350,000,000 per OPA 90 (U.S. Department of Homeland Security 2012). However, this statutory liability limit does not apply where the incident was proximately caused by 1) gross negligence or willful misconduct, or 2) the violation of an applicable federal safety construction or operating regulation by Keystone or a person acting pursuant to a contractual relationship with Keystone. Additionally, under the Clean Water Act, Keystone would be liable for up to $50 million for U.S. removal costs for harmful quantities of oil discharged from a Keystone-owned or operated facility unless the discharge was caused solely by an act of God, an act of war, negligence by the United States, or the act or omission of a third party. Liability for the full cost of oil removal applies if the discharge resulted from Keystone‘s willful negligence or willful misconduct.

The limits of liability under OPA 90 are also expanded in Section 1018, which allows for additional liabilities to be imposed by the state (or political sub-division thereof) in which the incident occurred. Keystone would also be subject to penalty provisions of the Rivers and Harbors Act and the Pipeline Safety Act. In addition to the provisions described above, in the event that a release of crude oil contaminates groundwater, Keystone has agreed that it would be responsible for cleanup and restoration, and for providing an appropriate alternative water supply for groundwater that was used as a source of potable water, or for irrigation or industrial purposes.

Per 26 CFR, Chapter 38, Section 4611, *Environmental Taxes*, the Oil Spill Liability Trust Fund financing rate is 8 cents a barrel in the case of crude oil received or petroleum products entered before January 1, 2017 and increases to 9 cents a barrel for crude oil received or petroleum products entered after December 31, 2016. The liability for this tax is as follows:

- If the crude oil is received into the United States at a refinery, the tax imposed shall be paid by the operator of the refinery.
- If the crude oil is imported into the United States, the tax imposed shall be paid by the person/operator entering or importing the crude oil for consumption, use, or warehousing into the United States.

In May 2011, the Internal Revenue Service concluded that imported oil sands, which includes diluted bitumen, were excluded from the excise tax based on the definitions of *crude oil* and *petroleum products* obtained from a 1980 House Committee Report on the 1980 CERCLA, which states "…The term crude oil does not include synthetic petroleum, e.g., shale oil, liquids from coal, *tar sands* [emphasis added], or biomass or refined oil." Keystone has asserted that it reads the IRS conclusion to mean that *certain products* are therefore exempt "from excise tax because the IRS conclusion does not rest on any stated findings regarding the physical or chemical properties of the exempted products". The Department does not take a view on the accuracy of Keystone's assertion, and for purposes of this Final Supplemental EIS uses the term *crude oil* throughout this document to refer to the physical and chemical properties of the material transported by the proposed pipeline.

Regardless of the origin of an oil, should an oil spill require federal intervention, funds from the Oil Spill Liability Trust Fund may be utilized by federal on-scene coordinators and trustees to ensure rapid and effective response to oil spills. The Oil Spill Liability Trust Fund was authorized with the passage of OPA 90 and is used to cover expenses associated with mitigating the threat of a spill, spill containment, countermeasures, cleanup, and waste disposal. The National Pollution Funds Center administers the payments from the fund to cover response action costs incurred by the U.S. Coast Guard or the USEPA, state response activities, payments for natural resource damage assessments and restoration, payment of claims for uncompensated costs or damages, research and development, and other allocations. The Oil Spill Liability Trust Fund is currently funded in part from cost recoveries from responsible parties that are liable for costs and damages, and the fines or civil penalties incurred by responsible parties liable for incidents.

However, if a release is caused by negligent or willful acts of others, Keystone may ultimately recover costs from those committing the acts since individuals are not automatically protected from liability associated with negligent acts or willful misconduct leading to property destruction and environmental damage. Specific liability warrants and indemnifications are included within individual easement agreements. The Department has no regulatory authority to intervene in the negotiation of those agreements. In addition, consideration of liability is beyond the scope of National Environmental Policy Act environmental reviews and is therefore not addressed in this Final Supplemental EIS.

In summary, Keystone has committed to a number of mitigation measures beyond the spill cleanup measures required by federal and state regulations. This commitment would be formalized in a legally binding agreement, as appropriate, as a condition of the proposed Project proceeding, should it be approved. These measures include:

- Consulting and communicating with the Local Emergency Response Planning Committees and other emergency service agencies during ERP development to ensure ERPs are aligned.
- Cleaning up any releases that may occur.
- Preparing a paleontological mitigation plan to protect significant fossil resources in the event that a spill affects a paleontological resource.
- In the event that a spill contaminates groundwater, being responsible for cleanup and restoration and for providing an appropriate alternative water supply for groundwater that was used as a source of potable water, or for irrigation or industrial purposes. If the permit were approved, Keystone would memorialize that agreement through an appropriate written agreement with the Environmental Protection Agency.
- Filing annually with the Nebraska DEQ by May 1 of each year:
  - A certificate of insurance as evidence that it is carrying a minimum of $200 million in third-party liability insurance as adjusted by calculating the gross domestic product implicit price deflator from the date a Presidential permit is issued for the Project and adjusting the amount of the third-party liability insurance policy by this percentage. The third-party liability insurance shall cover sudden and accidental pollution incidents from Keystone XL Pipeline in Nebraska.
  - A copy of Keystone's Securities and Exchange Commission Form 10-K and Annual Report. Keystone's MFSA Certificate contains a similar requirement.
- On request, filing the documents listed above with other appropriate state agencies.

Additional Mitigation

In addition to the mitigation measures that Keystone would implement as discussed above, additional mitigation measures may be identified and required by agencies during other permitting processes (e.g., USACE, State DEQs, other state agencies, local authorities). For example, some of those mitigations identified by agencies, which were learned from the Kalamazoo River spill, include:

- Spill response would be coordinated with statutory authorities of other agencies with responsibility for conducting response to and/or response oversight for an oil discharge. The development of an ERP could be incomplete without this coordination and potentially limit its effectiveness and efficiency of implementation. It is likely that interaction, coordination and communication with governmental regulators and/or response authorities (i.e., USEPA, USDOT, and U.S. Coast Guard) for a potentially integrated response would be necessary. For example, under the Federal Emergency Management Agency's (FEMA), ICS, a response to a spill of sufficient scope/magnitude would most likely involve unified command.

- The ERP and FRP would address submerged oil as well as floating oil in a surface water release scenario. The USDOT Pipeline Response Plan would be reviewed in coordination with USEPA and include contingency plans to address a submerged oil response and cold weather response. Section 4.13.6.2, Safety and Spill Response, focuses on a traditional oil spill response and not a strategy to address submerged oil or cold weather.
- Pre-positioned response assets would include equipment that could address submerged oil. Response strategies, such as pre-positioning of equipment to address submerged oil, would be considered and may be fine-tuned with USEPA consultation.

Mitigation measures related to potential releases and pipeline safety are included in Appendix B, Potential Releases and Pipeline Safety. Keystone has committed to implement the measures in Appendix B.

4.13.7 Connected Actions[19]

4.13.7.1 Bakken Marketlink Project

A spill from the Bakken Marketlink Project would potentially impact similar receptors as the proposed Project. Groundwater, surface water, and soil impact would be the key affected media with consequence on resident receptors (e.g., birds, fish, and snails) dependent upon spill size.

Spills from the pipeline could result in surface spreading or infiltration to groundwater. Surface spreading could potentially reach nearby creeks. Groundwater of the Upper Cretaceous Hells Creek/Fox Hills Aquifer shallower than 50 ft potentially could be affected by a small spill volume (less than 50 bbl). Spills at water crossings could affect larger downstream surface waterbodies. These spill migration pathways are the same as those of the proposed Project.

Leaks or spills from storage tanks would likely be contained within regulatory required berm or containment system. Therefore, overland spreading would be restricted. The threat of infiltration to groundwater and soil impact would still remain.

High-quality groundwater is not present in the area, and therefore, drinking water users are limited.

4.13.7.2 Big Bend to Witten 230-kV Transmission Line

A spill along the Big Bend to Witten 230-kV Transmission Line would be related to construction and maintenance activities. If a spill occurred, groundwater might be affected; however, because construction and maintenance activities are managing hundreds of gallons of fuel or less, related to vehicles, temporary localized refueling tanks, fuel powered equipment, etc., the impact from a release by one of these sources would be much less than from proposed pipeline construction and operation activities. In addition, spill response would generally be immediate because of the presence of staff during these activities.

[19] Connected actions are those that 1) automatically trigger other actions which may require environmental impact statements, 2) cannot or will not proceed unless other actions are taken previously or simultaneously, 3) are interdependent parts of a larger action and depend on the larger action for their justification.

4.13.7.3 Electrical Distribution Lines and Substations

Potential spill impacts for electrical distribution lines and substations would be similar to those associated with construction and maintenance activities as described above for the Big Bend to Witten 230-kV Transmission Line.

4.13.8 References

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APPENDIX I

Spill Prevention Control and Countermeasure Plan and

Emergency Response Plan

This Appendix includes the following documents:

- Spill Prevention Control and Countermeasure Plan
- Emergency Response Plan Redaction Summary
- Emergency Response Plan (ERP)

Note: The Emergency Response Plan has been made available for review by the general public. Accordingly, security sensitive, business confidential, personal, and otherwise confidential information has been removed. A summary of the redacted information is included.

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Keystone XL Pipeline Project

Spill Prevention, Control and Countermeasure Plan

DRAFT

Subject to Change

Note: This document is a template for the Project's Spill Prevention, Control and Countermeasure Plans and will be finalized by each contractor based on all required site-specific information.

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Attachment J Contractor’s Material Safety Data Sheets (MSDS)
Attachment K Typical Layouts; Fuel Transfer Stations
Attachment L Spill Report Form
Attachment M Certification of the Applicability of the Substantial Harm Criteria

1 Introduction

The purpose of this Spill Prevention, Control and Countermeasure (SPCC) Plan is to establish procedures to prevent the discharge of hazardous or regulated materials during construction of the Keystone XL Pipeline Project (Project), particularly into or upon Waters of the U.S. The SPCC Plan is designed to reduce the likelihood of a spill, provide for prompt identification and proper removal of contaminated materials if a spill does occur, comply with applicable state and federal laws (e.g., Title 40 Code of Federal Regulations [CFR] Parts 112 and 122) and Project permits, and to protect human health and the environment. The SPCC Plan is designed to complement existing laws, regulations, rules, standards, policies and procedures pertaining to safety standards and pollution rules, in order to minimize the potential for unauthorized releases of hazardous materials, fuels and lubricants.

TransCanada Keystone Pipeline, L.P. (Keystone) anticipates that the Project Pipeline construction contactor (Contractor) will store or handle more than the threshold quantities of oil products and will therefore be subject to federal SPCC preparation requirements. In conformance with federal regulations, a cross-reference table is provided in **Attachment A** that lists the relevant sections in Title 40 CFR 112.7 and the equivalent sections in this SPCC Plan.

Amendments to the SPCC Plan will be made as necessary during construction to account for increases in the volumes of materials stored or other changes associated with the handling or storage of hazardous materials.

1.1 Scope

This SPCC Plan applies to all construction and reclamation activities on the Project, but does not cover pipeline or pump station operations or maintenance. The Keystone XL Project Emergency Response Plan will contain the SPCC requirements for operation and maintenance of the pipeline and pump stations.

This plan outlines the procedures for prevention, containment, and control of potential spills during Project construction and reclamation. The SPCC Plan applies to the use of hazardous materials on the right-of-way and all ancillary facilities. This includes the refueling or servicing of all equipment with diesel fuel, gasoline, lubricating oils, grease, hydraulic and other fluids during normal upland work and for special applications located within 100 feet of streams and wetlands. In addition, site-specific information to be provided by the Contractor is identified and will be attached to the document.

This document is not a complete summary of all requirements. The Contractor is responsible for thoroughly researching, understanding, and complying with all applicable federal, state, and local requirements related to all aspects of work on the Project, including polluting, toxic, and hazardous materials handling, storage, transportation, spill prevention, clean-up and disposal, documentation, notification, hazardous waste, and training.

2 Contractor Supplied Site-Specific Information

This document is a template for the Project's SPCC Plans and will be finalized by each contractor based on all required site-specific information.

The following information must be supplied by the Contractor for review and approval by Keystone at least 30 days prior to construction activities.

- Contractor yard or fueling station facility diagram (**Attachment B**) showing at a minimum the following:
    - storage tanks, including content and capacity;

- mobile portable containers that store 55 gallons or more (including contents and capacity);
- oil-filled equipment, electrical transformers, circuit breakers, etc. that store 55 gallons or more;
- any other oil-filled equipment (including content and capacity);
- oil/fuel transfer area;
- secondary containment structures;
- storm drain inlets and surface waters that could be affected by a discharge;
- direction of flow in the event of a discharge (topography) and potential receiving waters;
- legend that indicates scale and identifies symbols used in the diagram;
- location of response kits and firefighting equipment;
- location of valves or drainage system control that could be used in the event of a discharge to contain materials on the site; and
- compass direction.

- A complete inventory of all hazardous materials that will be used or stored on site, including reportable quantities in compliance with state and federal law (**Attachment C**);
- Contractor's training program for fuel truck drivers and mechanics (See **Attachment D** and Section 3,1 Training section below for details);
- Designation of the Contractor's Spill Response Coordinator (to be included in **Attachment E** Emergency Response Contacts);
- Emergency response procedures (**Attachment F**), as described in the Construction Mitigation and Reclamation Plan. In addition, the Contractor will include a prediction of the direction, rate of flow, and total quantity of oil/fuel which has the reasonable potential to be discharged, based on experience. A form has been provided in **Attachment F**;
- Contractor's Commitment to providing the necessary emergency response support for the Project (**Attachment G**);
- Certification by a registered Professional Engineer (**Attachment H**);
- A complete discussion of applicable state-specific requirements regarding oil product and hazardous materials handling that are stricter than the federal requirements (to be included in **Attachment I** State Requirements), if any. If none, then the Contractor will clearly state that in the discussion;
- Material Safety Data Sheets (MSDS) as supplied by the Contractor (**Attachment J**); and
- Any mutual aid agreements between the Contractor and other emergency response personnel.

The Contractor is encouraged to use the Environmental Protection Agency's (EPA) guidance document for preparing facility diagrams provided at the following website: www.**epa.gov**/oilspill/pdfs/guidance/6_FacilityDiagrams.pdf.

Amendments to the Contractor-Supplied SPCC Plan will be made as necessary during construction to account for increases in the volumes of materials stored or other changes associated with the handling or storage of hazardous materials.

3 Prevention

Keystone's goal is to prevent spills or exposure to hazardous or dangerous substances during construction of the Project. The Contractor is required to follow the prevention measures outlined below and implement other measures as necessary and required to promote spill prevention.

3.1 Training

Personnel accountable for carrying out the procedures specified in this plan will be designated before construction and informed of their specific duties and responsibilities with respect to environmental compliance and hazardous materials. The Contractor will be required to provide additional spill prevention, response and hazardous materials handling training to all of their staff who handle hazardous materials, fuels and lubricants on a regular basis. The Contractor will provide the details of this training to Keystone prior to the start of work (**Attachment D**). At a minimum, training will include:

- A review of this SPCC Plan;
- An overview of all regulatory requirements;
- Waste minimization practices;
- Proper storage and handling methods for hazardous materials, fuels, lubricants, gases, etc.;
- Spill prevention, clean-up, and reporting requirements;
- Proper disposal techniques for hazardous materials, fuels, lubricants, etc.;
- Proper procedures for transferring fuels and containing fluids while doing maintenance on vehicles;
- Special requirements for refueling within 100 feet of wetlands and waterbodies;
- The location of the MSDSs and the SPCC Plan;
- The proper use of personal protective equipment;
- Emergency and spill response material locations, proper use, and maintenance;
- Emergency contact information and notification procedures; and
- Procedures for documenting spills and standard spill information to be provided to Keystone for agency notification.

All personnel working on the Project, including all Contractor personnel, are required to attend a Project-sponsored training session prior to starting work. Keystone will conduct training to ensure all responsible Contractor employees know of and comply with all project-specific environmental and TransCanada environmental policy requirements. The environmental training program will address refueling restrictions, hazardous materials handling, spill prevention and cleanup requirements, as well as other Project environmental and safety topics.

3.2 Site Security

The Contractor's site-specific plan and documentation for the construction yard will address site security procedures. Bulk fuel storage areas (including valves and switches), fuel trucks, lubricants and hazardous materials will be secured to minimize tampering and accidental releases by unauthorized personnel. Site security will include the following, in compliance with 40 CFR 112.7(g):

- The oil/fuel storage site will be fully fenced with a locked or guarded entrance gate when facility is unattended;
- Container master flow and drain valves will be secured so that they will remain in the closed position when not in use;
- Fuel pump starter controls will be locked in the "off" position where only authorized personnel can access them when not in use; and
- Facility lighting at night that will assist leak detection and vandalism prevention.

If the above procedures will not be followed, the Contractor will provide a detailed explanation of why the site cannot be secured as described above and the equivalent method the Contractor will use to secure the site.

All storage containers will be closed when not in use and the storage areas will be secured (gated, locked and/or guarded) at night and/or during non-construction periods.

3.3 Equipment Inspection and Maintenance

The Contractor will ensure that all equipment is free of leaks prior to use on the Project, and prior to entering or working in or near waterbodies or wetlands. Throughout construction, the

Contractor will conduct regular maintenance and inspections of the equipment to reduce the potential for spills or leaks.

Contractor mechanics will assess the general condition of equipment valves, lines and hoses and all deteriorated parts will be promptly repaired or replaced. Vehicles and equipment that develop leaks during construction activities will cease work, move to a location at least 100 feet from streams or wetlands, and buckets or absorbent materials will be placed under the equipment until the leak can be repaired. Soils contaminated by the leaking material will be collected and removed from the right-of-way for proper disposal. Equipment that requires extensive repairs will be removed from the right-of-way until the repairs are completed or a protection plan will be developed by the Keystone Environmental Inspector if the equipment can not be moved.

All equipment maintenance and repairs will be performed in upland locations at least 100 feet from waterbodies and wetlands. Mechanics will take precautionary measures when performing equipment maintenance or repair activities by placing absorbent pads (or equivalent materials) on the ground beneath the equipment when changing crankcase oil, repairing hydraulic lines, or adding coolant to construction equipment and when appropriate for other repair activities.

All equipment parked overnight shall be at least 100 feet from a watercourse or wetland, if possible. Equipment shall not be washed in streams or wetlands.

3.4 Materials Storage and Handling

The Contractor shall ensure that all oil products, fuels, gases, hazardous and potentially hazardous materials are transported, stored and handled in accordance with all applicable legislation.

Staging areas (including contractor yards and pipe yards) will be set up for each construction spread. Contractors conducting work in each of these areas will establish bulk fuel storage tanks within the staging area, or they will fill their fuel trucks at existing bulk fuel dealerships. In addition, a variety of lubricants and materials will be stockpiled at the staging area for use during construction of the Project. Bulk fuel storage tanks, fuel trucks and stockpiles of lubricants or hazardous materials will be stored only in the designated staging areas and equipment storage yards, and at least 100 feet from all streams and wetlands. No hazardous materials will be stored in areas subject to flooding or inundation.

Spent oils, lubricants, filters, etc. shall be collected and disposed of or recycled at an approved location in accordance with state and federal regulations.

Keystone contractors will not keep on site or operate the following:

- Completely or partially buried storage tanks
- Buried piping
- Internal steam heat coils
- Large, field-erected storage tanks

The following sections detail Project requirements associated with storage of bulk fuels and lubricants, as well as temporary storage of hazardous materials at staging areas.

3.4.1 Tanks

Keystone contractors will maintain commonly used fuels such as gasoline and diesel in bulk storage tanks in the pipeline contractor yards. All storage tanks or trailers, rigid steel piping, valves and fittings and fuel transfer or dispensing pumps will be contained within a secondary containment structure providing 110 percent containment volume of the largest storage tank or trailer within the containment structure. This containment structure will consist of sandbag or earth berms lined with a chemical resistant membrane liner or a concrete structure. The

Contractor will remove any collected precipitation from the containment structure to maintain 110 percent capacity. The Contractor will inspect accumulated precipitation first for evidence of oil or contamination and then collect the material for proper disposal off-site.

The attached drawings are typical layouts for diesel and gasoline fuel transfer stations. Self-supporting tanks will be constructed of carbon steel or other materials compatible with contents of each tank, and all tanks will be elevated above grade and inspected weekly and when the tank is refilled. To prevent overfill, all tanks will have visual level gauges and actual tank levels will be checked against the gauge reading during inspections. Inspection records shall be maintained by the Contractor.

For receiving and offloading fuels from a fuel distributor into the bulk storage tanks, the distributor will connect a petroleum rated hose from the delivery tanker to the fuel transfer stations fill line at the fill truck connection. The fill truck connection and fill line will consist of a cam-loc connection followed by a block valve, rigid steel piping, tank block valve(s) and check valve(s) just upstream of the connection to the tank. Off-loading of fuel is normally accomplished by a transfer pump powered by the delivery vehicle's power take off. Proper grounding of equipment shall be undertaken during fuel transfer operations. Fuel trucks from fuel distributors will be inspected closely prior to leaving the contractor yard to ensure that all valves are tightly closed and no leaks occur during transit.

For transfer of fuels from the bulk storage tanks in the contractor yards to fuel distribution trucks, the truck will connect a petroleum rated hose between the truck's tank and the bulk storage tank's withdrawal connection. The withdrawal truck connection and withdrawal line will consist of rigid steel piping from the tank, through a block valve(s) to an electric explosion-proof fuel transfer pump. Downstream of the fuel transfer pump will be a cam-loc connection. The fuel transfer pump will be equipped with an emergency shut-off at the pump and a secondary emergency shut-off at least 100 feet away. Proper grounding of equipment shall be undertaken during fuel transfer operations. Fuel truck drivers will inspect the truck after each re-filling from the bulk fuel tanks in the contractor yard to ensure that all valves are tightly closed and no leaks occur during transport.

For dispensing gasoline and on-road diesel to equipment or vehicles, the transfer pump will be a dispensing pump with petroleum rated hoses with automatic shut-off nozzles. Refueling operations will be attended closely at all times by personnel familiar with the operation of the refueling equipment. Warning signs requiring drivers to set brakes and chock wheels shall be displayed at all fixed refueling points. Proper grounding of equipment shall be undertaken during fuel transfer operations.

3.4.2 Containers

All containers 55 gallons or greater shall be stored on pallets within a secondary temporary containment structure. Secondary containment structures may consist of temporary earthen berms with a chemical resistant liner or a portable containment system constructed of steel, PVC, or other suitable material. The secondary containment structure will be capable of containing 110 percent of the volume of material stored in these areas. The Contractor will inspect all container storage areas for leaks and deterioration at least weekly, and leaking or deteriorated containers will be replaced as soon as the condition is first detected. In the event of a leak or deterioration of the container or liner, cleanup measures would be implemented to remediate all contamination.

No incompatible materials will be stored in the same containment area and the containers must be suitable and compatible with the wastes or materials in them. If a container leaks or sustains damage, its contents must be transferred to a container in good condition. Waste and hazardous materials will be kept in separate containers for proper disposal.

Containers holding hazardous substances will be closed during transport and storage, except as necessary to add or remove the substance.

3.4.2.1 Container Labeling Requirements

The Contractor will comply with labeling requirements for any on-site containers, including tanks that store fuels, lubricants, accumulated hazardous wastes and other materials. Hazardous waste containers will be labeled, as required in Title 40 CFR Part 262, and will display at least the following:

- Chemical name (e.g., oil, diesel, etc.);
- When the container reaches 55 gallons in volume, the accumulation start date and/or the start date of the 90-day storage period; and
- The words “Hazardous Waste” and warning words specifying the relevant hazards, such as “flammable”, “corrosive”, or “reactive”.

3.4.3 Concrete Coating

Concrete coating and any washout necessary will be conducted at least 100 feet from wetlands or waterbodies boundaries whenever possible. In some circumstances, it may not be possible to maintain this buffer due to topography or the extent of the resource. If it is necessary to apply concrete coating less than 100 feet from a wetland or waterbody boundary, then sufficient containment (such as plastic sheeting and berms, etc.) will be provided by the Contractor to prevent any uncured concrete or concrete washout from reaching the ground. Excess concrete shall not be disposed of in wetlands or waterbodies. Concrete washout shall be contained within the work area and will not be allowed to enter wetlands, waterbodies, or storm drains.

3.4.4 Disposal of Solid and Hazardous Wastes

The Contractor will be responsible for ensuring that the regular collection and disposal of all solid and hazardous wastes generated during its operations is in compliance with all applicable laws. If state laws pertaining to waste disposal are more stringent than federal laws, state laws will take precedence. The Contractor will determine the details on the proper handling and disposal of hazardous waste, and will assign responsibility to specific individuals before construction.

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

Hazardous wastes will typically include contaminated soils, spent batteries, and other items. The Contractor will make every effort to minimize hazardous waste production during the Project, including, but not limited to:

- Minimizing the amount of hazardous materials needed for the Project;
- Using alternative non-hazardous substances when available; and
- Recycling usable materials, such as batteries, to the extent possible.

3.4.5 Equipment Refueling and Servicing

All equipment refueling will be performed in upland areas at least 100 feet from all wetlands and waterbodies, and at least 150 feet from private and public water wells, respectively. If site-specific constraints require refueling/servicing the equipment closer than 100 feet from the wetland or waterbody, special precautions may be implemented with the Environmental Inspector’s approval – as described below.

At all refueling locations along the right-of-way, the Contractor will ensure that absorbent materials are on hand at all times. Each refueling vehicle shall have a sufficient number of shovels, brooms, 10-mil polyethylene sheeting, and fire protection equipment to contain a moderate spill.

During refueling, the Contractor will take appropriate measures to reduce the risk of a spill, including not overfilling fuel tanks and placing an absorbent pad under the fuel nozzle while fueling equipment. Contractor personnel will observe and control refueling at all times to prevent overfilling. Drivers of tank trucks are responsible for safety and spill prevention. Procedures for loading and unloading tank trucks shall meet the minimum requirements established by the Department of Transportation.

3.4.6 Spill Response Equipment

The Contractor will be required to have emergency response equipment available at all areas where hazardous materials are handled or stored. This equipment shall be readily available to respond to a hazardous material emergency. The Contractor is required to have the appropriate spill response materials on site to address spills of materials stored or handled at the location. Such equipment shall include, but not be limited to, the following:

- First aid kits and supplies, sized to meet the needs of the numbers of personnel anticipated;
- Telephone or communications radio;
- Personal protective equipment (Tyvek® or equivalent suits, gloves, goggles, hard hat, and other personal protective equipment appropriate to the materials to be handled);
- Fire extinguishers;
- Absorbent materials;
- Storage containers;
- Non-sparking bung wrench; and
- Shovels.

Hazardous material emergency containment and clean-up materials and equipment shall be carried in all fuel trucks, mechanic and supervisor (foremen) vehicles. This equipment shall include, at a minimum:

- 2 shovels;
- First aid kit and supplies;
- Telephone or communications radio;
- Phone numbers for emergency contacts;
- 2 sets of protective clothing (Tyvek® or equivalent suit, gloves, goggles, boots);
- 6 heavy duty plastic garbage bags (30 gallon);
- 5 absorbent socks;
- 10 spill pads;
- 20 lb. fire extinguisher;
- Barrier tape;
- 2 orange reflector cones; and
- 200 square feet 10-mil plastic sheeting.

Fuel and service trucks shall also carry a minimum of 20 pounds of suitable commercial sorbent material and a catch-pan for fluids.

Each construction crew, including clean-up crews shall have on hand sufficient tools and materials to stop leaks and supplies of absorbent and barrier materials to allow rapid containment and recovery of spilled materials.

The Contractor shall inspect emergency equipment weekly, and service and maintain equipment regularly, replenishing supplies as necessary. Records shall be kept of all inspections and service.

3.4.7 Activities in Environmentally Sensitive Areas

The Contractor will obtain approval from the Keystone Environmental Inspector prior to refueling or performing equipment repair (involving lubricants, fuels, oil products, or hazardous materials) within 100 feet of a wetland or waterbody boundary. The Contractor shall monitor the refueling and equipment operation at all times. The Contractor will take precautions to prevent spillage by not overfilling fuel tanks, placing an absorbent pad under the fuel nozzle while fueling, and wiping the nozzle when fueling is complete.

Stationary equipment will be placed within a secondary containment if it will be operated or require refueling within 100 feet of a wetland or waterbody boundary.

In order to respond quickly to a potential spill in a major waterbody, the Contractor shall have on hand during all river crossings at least 400 feet of sorbent boom/sock and provide in **Attachment F** a method for deployment and collection.

4 Spill Control and Countermeasures

It is Keystone's goal to promptly stop spills, however the safety and health of Project personnel and the public is the foremost priority. Personnel should only respond to a spill if they have adequate training to do so safely.

All spills and leaks of hazardous materials and petroleum products will be cleaned up. Upon discovery of a spill, the Contractor will immediately:

1. Assess the area for safety: identify the material spilled, the cause, and any potential hazards. If it is an emergency threatening human health, dial 911. If telephone service is not available or 911 does not work in the area, immediately contact the spread office so emergency responders can be notified. Implement appropriate safety procedures, based on the nature of the hazard.
2. Extinguish or remove ignition sources, if the spilled material is flammable.
3. Shut off leaking equipment, if safe to do so.
4. Stop leaks, if possible.
5. Contain the spill using spill response materials and by creating a berm or dike, if necessary. Block culverts, storm sewers, and other points, if necessary to limit spill travel.
6. Notify supervisor of the spill, including material, quantity, time, and location. Supervisors are responsible for notifying Keystone of spills (see section below).

Personnel entry and travel on contaminated soils shall be minimized. The Contractor will commence spill clean-up immediately, if it is safe to do so. The Contractor is responsible for removing and disposing of contaminated material in accordance with applicable federal, state, and local laws. It is anticipated that most spills will be small and easily removed with a shovel, with contaminated soil deposited in plastic bags or similar containers for transport to the Contractor's yard. Larger spills may require the use of equipment or special services.

All efforts will be made to prevent a release to water resources; however, if the spilled material reaches water, sorbent booms, socks, and/or pads will be deployed to contain and remove the spilled material.

5 Documentation and Reporting

The Contractor shall notify Keystone immediately of any spill of a potentially hazardous substance that meets government reporting criteria as well as any existing soil contamination discovered during construction. If pre-existing contamination is suspected, the Contractor shall stop work in the area and not resume work until authorized to do so by Keystone.

In the event of a spill that meets government reporting criteria, the Contractor shall notify the Keystone representative immediately, who, in turn, shall notify the appropriate regulatory agencies. Any material released into water that creates a sheen must be reported immediately to Keystone. The Contractor is required to notify Keystone immediately if there is any spill of oil, oil products, or hazardous materials that reaches a wetland or waterbody. Incidents on public highways shall be reported to Keystone and the appropriate agencies. A sample spill report form is provided in **Attachment L**.

The Contractor is responsible for documenting spills as required by federal, state, and local regulations.

As described on the EPA's website, facilities that spill more than 1,000 gallons of oil into navigable waters or onto adjoining shorelines in a single incident, or have two reportable oil spills of more than 42 gallons within any 12-month period, must submit a report to the appropriate EPA Regional Administrator within 60 days from the time the spill occurs. More details can be found at the EPA website. EPA will review the report and may require the facility owner or operator to amend the SPCC Plan if it does not meet the regulations or if an amendment is necessary to prevent and contain oil spills from the facility.

6 Inspection and Record Keeping

The Contractor will regularly inspect all storage facilities (not less than weekly) and record the condition of the facility in a weekly log. In addition to inspection items discussed in previous sections, inspections will include the outside of all containers for signs of deterioration, discharges, or accumulation of oil inside containment structures or dikes. Inspections will also include all aboveground valves, piping appurtenances and the general condition of items such as flange joints, expansion joints, valve glands and bodies, pipe supports, and metal surfaces.

In addition to the weekly log, the Contractor will maintain records for hazardous materials and hazardous wastes, as required by all applicable federal, state, and local regulations and permit conditions. Record-keeping requirements include, at a minimum:

- Hazardous materials/Waste inspection log,
- Transportation documents,
- Bills of lading,
- Manifests,
- Shipping papers,
- Training records,
- Release report forms, and
- Spill history and documentation of clean-up/handling.

The Environmental Inspector will monitor, inspect, document and report on the Contractor's compliance with hazardous materials and hazardous waste management practices. Inspection records will be kept with the SPCC Plan for at least three years.

7 Applicable State Requirements

The Contractor is required to include in submittals to Keystone a complete discussion of applicable state-specific requirements regarding oil product and hazardous materials handling that are stricter than the federal requirements, if any, to be included in **Attachment I**. If none, then the Contractor will clearly state that in the discussion.

8 Certification of Non-Substantial Harm

Keystone does not anticipate that this Project will satisfy the “substantial harm” criteria set forth in 40 CFR 112.20(e). The EPA requires that facilities that do not meet the criteria maintain a certification form to that affect with the SPCC Plan. This certification form is included in **Attachment M**.

Attachment A

SPCC Cross Reference Table

SPCC Rule	Description of Section	Page/Section
§ 112.7	General requirements for SPCC Plans for all facilities and all oil types.	1/1
§ 112.7(a)(1)	General requirements; discussion of facility's conformance with rule requirements.	1/1; throughout SPCC Plan
§ 112.7(a)(2)	Deviations from Plan requirements.	3/3.2; 4 & 5/ 3.4.1
§ 112.7(a)(3)	Facility characteristics that must be described in the Plan and the Facility Diagram.	1 & 2/2
§ 112.7(a)(3)(i)	Types of oil and container storage capacity.	Attachment C
§ 112.7(a)(3)(ii)	Discharge prevention measures.	2 through 8/3
§ 112.7(a)(3)(iii)	Discharge or drainage controls.	3 through 7/3.2; 3.3; 3.4
§ 112.7(a)(3)(iv)	Countermeasures for discharge, discovery, response, and cleanup	8/4
§ 112.7(a)(3)(v)	Methods of disposal of recovered or waste materials	4 through 6/3.3; 3.4; 3.4.3; 3.4.4
§ 112.7(a)(3)(vi)	Contact list and phone numbers.	Attachment E
§ 112.7(a)(4)	Spill reporting information in the Plan.	8/5; Attachment I
§ 112.7(a)(5)	Emergency procedures.	2/2; 9/4; Attachment F
§ 112.7(b)	Fault analysis. Equipment failure information.	2/2; Attachment F
§ 112.7(c)	Secondary containment.	4/3.4.1; 5/3.4.2; 7/3.4.7
§ 112.7(d)	Contingency planning, alternative means, integrity testing.	4/3.4.1; 5/3.4.2; 8/4; Attachment F
§ 112.7(e)	Inspections, tests, and records.	4/3.4.1; 5/3.4.2; 9/6
§ 112.7(f)	Employee training and discharge prevention procedures.	2 & 3/3.1
§ 112.7(g)(1)	Security (excluding oil production facilities).	3/3.2
§ 112.7(g)(2)	Flow valves secured.	3/3.2
§ 112.7(g)(3)	Oil pumps controls locked.	3/3.2
§ 112.7(g)(4)	Secure loading/unloading connections on oil piping.	Not Applicable
§ 112.7(g)(5)	Provide facility lighting.	3/3.2
§ 112.7(h)(1)	Loading/unloading (excluding offshore facilities): provide containment system for loading and unloading area.	Not Applicable
§ 112.7(h)(2)	Loading/unloading: systems to prevent vehicles from departing before complete disconnection.	5/3.4.1
§ 112.7(h)(3)	Loading/unloading: inspect vehicle to prevent liquid discharge while in transit.	4/3.4.1
§ 112.7(i)	Brittle fracture evaluation requirements.	Not applicable
§ 112.7(j)	Discuss conformance with more stringent State rule, regulations, and guidelines.	7/9
§ 112.8 / § 112.12	Requirements for onshore facilities (excluding production facilities).	-
§ 112.8(a) / § 112.12(a)	General and specific requirements	See above and below
§ 112.8(b) / § 112.12(b)	Facility drainage.	4/3.4.1
§ 112.8(c) / § 112.12(c)	Bulk storage containers.	4/3.4.1; 5/3.4.2
§ 112.8(d) / § 112.12(d)	Facility transfer operations, pumping, and facility process.	4/3.4.1; 5/3.4.2
§ 112.9 / § 112.13	Requirements for onshore production facilities	Not applicable

SPCC Rule	Description of Section	Page/Section
§ 112.9(a) / § 112.13(a)	General and specific requirements	Not applicable
§ 112.9(c) / § 112.13(c)	Oil production facility bulk storage containers.	Not applicable
§ 112.9(d) / § 112.13(d)	Facility transfer operations, oil production facility.	Not applicable
§ 112.10 / § 112.14	Requirements for onshore oil drilling and workover facilities.	Not applicable
§ 112.10(a) / § 112.14(a)	General and specific requirements.	Not applicable
§ 112.10(b) / § 112.14(b)	Mobile facilities.	Not applicable
§ 112.10(c) / § 112.14(c)	Secondary containment - catchment basins or diversion structures.	Not applicable
§ 112.10(d) / § 112.14(d)	Blowout prevention.	Not applicable
§ 112.11 / § 112.15	Requirements for offshore oil drilling, production, or workover facilities.	Not applicable
§ 112.11(a) / § 112.15(a)	General and specific requirements.	Not applicable
§ 112.11(b) / § 112.15(b)	Facility drainage.	Not applicable
§ 112.11(c) / § 112.15(c)	Sump systems.	Not applicable
§ 112.11(d) / § 112.15(d)	Discharge prevention systems for separators and treaters.	Not applicable
§ 112.11(e) / § 112.15(e)	Atmospheric storage or surge containers; alarms.	Not applicable
§ 112.11(f) / § 112.15(f)	Pressure containers; alarm systems.	Not applicable
§ 112.11(g) / § 112.15(g)	Corrosion protection.	Not applicable
§ 112.11(h) / § 112.15(h)	Pollution prevention system procedures.	Not applicable
§ 112.11(i) / § 112.15(i)	Pollution prevention systems; testing and inspection.	Not applicable
§ 112.11(j) / § 112.15(j)	Surface and subsurface well shut-in valves and devices.	Not applicable

Attachment B

Contractor Yard or Fueling Station Facility Diagram

Attachment C

Hazardous Materials Inventory and Reportable Quantities

DRAFT

Attachment D

Contractor's Training Program

Attachment E

Emergency Response Contacts

Emergency Response Contacts

DIAL 911 IN CASE OF EMERGENCY

The Contractor is to fill out the applicable information required below. Contractor will attach additional sheets as necessary.

Contractor: ______________________ Spread/Station: ________________________

Contractor Spill Response Coordinator: ____
NAME TELEPHONE NUMBER

Keystone Representative: ____
NAME TELEPHONE NUMBER

Sheriffs' Telephone Numbers, by County

County	Telephone Number	County	Telephone Number

Highway Patrol: _________________________ _________________________

U.S. Poison Control Center: 800-222-1222

Hospitals Near Work Areas

Name	Address	Telephone Number	County

Spill Response and Cleanup Contractor: ____
NAME TELEPHONE NUMBER

Spill Response and Cleanup Contractor: ____
NAME TELEPHONE NUMBER

Spill Response and Cleanup Contractor: ____
NAME TELEPHONE NUMBER

Keystone is the designated contact for all agency notifications.

Agency	Telephone Number	Home Page Website	Online Spill Report Form Webpage
Federal			
National Response Center	800-424-8802	http://www.nrc.uscg.mil/nrchp.html	http://www.nrc.uscg.mil/report.html
Montana			
Montana Department of Environmental Quality	800-424-8802	http://www.deq.mt.gov/enf/spillpol.asp	http://www.deq.mt.gov/enf/spill.asp
South Dakota			
South Dakota Department of Environment & Natural Resources	605-773-3296 and 605-773-3231 after hours	http://www.state.sd.us/denr/DES/ground/Spills/SpillReporting.htm	http://www.state.sd.us/denr/DES/ground/Spills/SpillsFollowUp.asp
Nebraska			
Department of Environmental Quality	402-471-2186 or 877-253-2603 and Nebraska State Patrol at 402-471-4545 after hours	http://www.deq.state.ne.us/	Not applicable
Kansas			
Kansas Emergency Management	800-275-0297 or 785-296-8013	http://www.kansas.gov/kdem/hazards/hmenrg.shtml	http://www.kansas.gov/kdem/pdf/hazards/082102_formA.pdf
Oklahoma			
Oklahoma Corporation Commission	918-367-3396 and 405-521-2240 after hours	http://www.occ.state.ok.us/Divisions/OG/spill(c).htm	Not applicable
Texas			
Texas Commission on Environmental Quality (TCEQ)	800-832-8224	http://www.tceq.state.tx.us/response/spills.html	Not applicable

Attachment F

Contractor's Emergency Response Procedures

Equipment Failure and Potential Spill Source Prediction[1]

Source	Type of Failure	Total Quantity (gallons)	Rate of Flow (gpm)[2]	Direction of Flow	Containment

[1] Title 40 CFR 112 states: "where experience indicates a reasonable potential for equipment failure (such as loading or unloading equipment, tank overflow, rupture, or leakage, or any other equipment known to be a source of a discharge), include in your Plan a prediction of the direction, rate of flow, and total quantity of oil which could be discharged from the facility as a result of each type of major equipment failure."

[2] GPM = gallons per minute

Attachment G

Contractor's Commitments

Contractor's Commitments

I hereby certify that I am at a level of management within ______________________________, with the authority to, and do hereby commit the necessary manpower, equipment, and materials to implement this SPCC Plan (40 CFR Part 112) in accordance with the provisions set forth therein.

Name: ____________________________

Name: ____________________________ (Signature)

Title/Company: ____________________________________

Date: _____________________________

Attachment H

Professional Engineer's Certification

Registered Professional Engineer Certification

By means of this certification, I attest that:

- **I have reviewed this Spill Prevention, Control and Countermeasure Plan (SPCC);**
- **I am familiar with the requirements of Title 40 Code of Federal Regulations (CFR) Part 112;**
- **I or my agent has visited and examined the facility;**
- **This SPCC Plan has been prepared in accordance with good engineering practice, including consideration of applicable industry standards, and with the requirements of Title 40 CFR Part 112;**
- **Procedures for required inspections and testing have been established; and**
- **This SPCC Plan is adequate for the facility.**

____
Signature of Registered Professional Engineer

______________________________ ______________________________
Name (Printed) **Date**

Attachment I

State Requirements

Attachment J

Contractor's Material Safety Data Sheets (MSDS)

Attachment K

Typical Layouts; Fuel Transfer Stations

Attachment L

Spill Report Form

SPILL REPORT FORM

LOCATION AND DATE DETAILS **Facilit y Telephone Number:**

Form Completed by: ________________________ Date: ______________

Date of spill: ________________________ Time of spill: ______________

Date of spill discovery: ____________________ Time of spill recovery: __________

Location: __________________________ County: ________________

Short legal description: T_______R________S_________ Weather Conditions: _________

Directions from nearest community: ________________________________

____

Name and Title of Discoverer: ______________________________
NAME TITLE

SPILL AND MATERIAL DETAILS

Type of material spilled and product name: ____________________________

Manufacturer's name: ____________________________________

Estimated volume spilled: ______________ Estimated volume recovered: _________

Topography and surface condition of spill site: _________________________

Spill medium: ❑ Pavement ❑ Soil ❑ Water ❑ Other: ______________ (Check all that apply)

Responsible party (Name, Phone Number): ____________________________
NAME TELEPHONE NUMBER

Describe the causes and circumstances resulting in the spill: ____________________

____

____

____

WATER RESOURCES AFFECTED

Did the spill reach a waterbody? ❑ Yes ❑ No If "Yes", was a sheen present? ❑ Yes ❑ No

Proximity of spill to surface waters or wetlands: ______________Feet

Estimated quantity of material that entered surface waters or wetland: ______________

Direction and time of travel (if in stream): ____________________________

____

SPILL REPORT FORM CONTINUED

DESCRIPTION OF SPILL/ HARMFUL EFFECTS

Describe extent of observed contamination, both horizontal and vertical: ____________________
____
____

Resources and installations that may be affected: ________________________________
____

Describe any injuries or potential impact on human health caused by the spill: ______________
____
____

COURSE OF ACTION

Describe immediate spill control and/or cleanup methods used and implementation schedule: ___
____
____

Evacuation necessary? ❑ Yes ❑ No Describe: ________________________________
____

Current status of cleanup actions: ________________________________
____

Future follow-up required, if any: ________________________________
____

NAME/COMPANY/TELEPHONE NUMBER FOR THE FOLLOWING

Contractor Superintendent: ________________________________
NAME COMPANY TELEPHONE NUMBER

Contractor's Environmental Coordinator: ________________________________
NAME COMPANY TELEPHONE NUMBER

Lead Environmental Inspector: ________________________________
NAME COMPANY TELEPHONE NUMBER

Other: ________________________________
NAME COMPANY TELEPHONE NUMBER

Contractor must complete this form for any spill that meets state or federal reportable quantities, and for petroleum spills that enter waterbodies or wetlands, affect human health, or exceed 42 gallons, and submit the form to the Lead Environmental Inspector immediately.

Attachment M

Certification of the Applicability of the Substantial Harm Criteria

DRAFT

Certification of the Applicability of the Substantial Harm Criteria

Facility Name: ***Keystone Pipeline Project***
Facility Address: ***Various locations along the pipeline route in Montana, South Dakota, Nebraska, Kansas, Oklahoma, and Texas. Mailing address:***

Keystone XL Pipeline Project
7509 Tiffany Springs Parkway
Northpointe Circle II, Suite 200
Kansas City, Missouri 64153

1. Does the facility transfer oil over water to or from vessels and does the facility have a total oil storage capacity greater than or equal to 42,000 gallons?

Yes _____ No __X__

2. Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and does the facility lack secondary containment that is sufficiently large to contain the capacity of the largest aboveground oil storage tank plus sufficient freeboard to allow for precipitation within any aboveground oil storage tank area?

Yes _____ No __X__

3. Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and is the facility located at a distance (as calculated using the appropriate formula in Attachment C–III to this appendix or a comparable formula[3]) such that a discharge from the facility could cause injury to fish and wildlife and sensitive environments? For further description of fish and wildlife and sensitive environments, see Appendices I, II, and III to DOC/NOAA's "Guidance for Facility and Vessel Response Plans: Fish and Wildlife and Sensitive Environments" (see Appendix E to this part, section 13, for availability) and the applicable Area Contingency Plan.

Yes _____ No __X__

4. Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and is the facility located at a distance (as calculated using the appropriate formula in Attachment C-III to this appendix or a comparable formula[1]) such that a discharge from the facility would shut down a public drinking water intake[4] ?

Yes _____ No __X__

5. Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and has the facility experienced a reportable oil discharge in an amount greater than or equal to 10,000 gallons within the last 5 years?

Yes _____ No __X__

Certification
I certify under penalty of law that I have personally examined and am familiar with the information submitted in this document, and that based on my inquiry of those individuals responsible for obtaining this information, I believe that the submitted information is true, accurate, and complete.

____
Signature

____
Name (please type or print)

______________________________ ______________________________
Title

[3] If a comparable formula is used, documentation of the reliability and analytical soundness of the comparable formula must be attached to this form.

[4] For the purposes of 40 CFR part 112, public drinking water intakes are analogous to public water systems as described at 40 CFR 143.2(c).

APPENDIX I, continued

Emergency Response Plan Redaction Summary

Emergency Response Plan

Notice of Redaction of Confidential Information

The Emergency Response Plan has been made available for review by the general public. Accordingly, security sensitive, business confidential, personal, and otherwise confidential information has been removed. A summary of redacted information is presented on the following pages.

-This page intentionally left blank-

KEYSTONE PIPELINE EMERGENCY RESPONSE PLAN – TABLE OF REDACTED INFORMATION

PAGE NO.	REDACTED MATERIAL	REASON FOR REDACTION	NOTES
6	Location of oil control center and backup oil control center	Security concerns	1
14	Discharge scenario barrels and planning volume barrels	Security concerns	2
21-23	Personnel names and telephone numbers	Security concerns / Privacy	3
69-71	Bomb threat info	Security concerns	4
72	Environmental sensitive areas	Security concerns	5
154	Environmental sensitive areas	Security concerns	5
155-173	High Consequence Area (HCA) / Other Environmentally sensitive areas and associated maps	HCA confidentiality / Security concerns / Canada	6
174	Drain tiles	Security and land owner privacy concerns	7
190-220	Agreements/Contracts	Commercial / Safety / Canada	8
223	Worst Case Discharge Volumes and Calculations	Security concerns / Canada	2
226	Worst Case Discharge Volumes and Calculations	Security concerns / Canada	2
227	Worst Case Discharge Volumes and Calculations	Security concerns / Canada	2
230	Worst Case Discharge Volumes and Calculations	Security concerns / Canada	2
231	Worst Case Discharge Volumes and Calculations	Security concerns	2
234	Worst Case Discharge Volumes and Calculations	Security concerns	2
235	Worst Case Discharge Volumes and Calculations	Security concerns	2
238	Worst Case Discharge Volumes and Calculations	Security concerns	2
239	Worst Case Discharge Volumes and Calculations	Security concerns	2
242	Worst Case Discharge Volumes and Calculations	Security concerns	2

REDACTION MATERIAL FOR TRANSCANADA (Cont'd)

PAGE NO.	REDACTED MATERIAL	REASON FOR REDACTION	NOTES
286-287	Keystone Commodities	Shipper confidentiality / Commercial	9
289-293	MSDS	Shipper confidentiality / Commercial	9
295-302	MSDS	Shipper confidentiality / Commercial	9
304-310	MSDS	Shipper confidentiality / Commercial	9
312-318	MSDS	Shipper confidentiality / Commercial	9
320-325	MSDS	Shipper confidentiality / Commercial	9
327-338	MSDS	Shipper confidentiality / Commercial	9
340-350	MSDS	Shipper confidentiality / Commercial	9
352-362	MSDS	Shipper confidentiality / Commercial	9
364-373	MSDS	Shipper confidentiality / Commercial	9
375-385	MSDS	Shipper confidentiality / Commercial	9
387-388	MSDS	Shipper confidentiality / Commercial	9
390-391	MSDS	Shipper confidentiality / Commercial	9
393-394	MSDS	Shipper confidentiality / Commercial	9
396-405	MSDS	Shipper confidentiality / Commercial	9
407-412	MSDS	Shipper confidentiality / Commercial	9
414-415	MSDS	Shipper confidentiality / Commercial	9
417-426	MSDS	Shipper confidentiality / Commercial	9
428-436	MSDS	Shipper confidentiality / Commercial	9
438-439	MSDS	Shipper confidentiality / Commercial	9
441-447	MSDS	Shipper confidentiality / Commercial	9
449-456	MSDS	Shipper confidentiality / Commercial	9
458-469	MSDS	Shipper confidentiality / Commercial	9
471-474	MSDS	Shipper confidentiality / Commercial	9
476-481	MSDS	Shipper confidentiality / Commercial	9
483-489	MSDS	Shipper confidentiality / Commercial	9
491-498	MSDS	Shipper confidentiality / Commercial	9

REDACTION MATERIAL FOR TRANSCANADA (Cont'd)

PAGE NO.	REDACTED MATERIAL	REASON FOR REDACTION	NOTES
500-507	MSDS	Shipper confidentiality / Commercial	9
509-517	MSDS	Shipper confidentiality / Commercial	9
519-525	MSDS	Shipper confidentiality / Commercial	9
527-534	MSDS	Shipper confidentiality / Commercial	9
536-543	MSDS	Shipper confidentiality / Commercial	9
545-551	MSDS	Shipper confidentiality / Commercial	9
553-562	MSDS	Shipper confidentiality / Commercial	9
564-568	MSDS	Shipper confidentiality / Commercial	9
624-625	Personnel	Privacy concern / Canada	3
629-632	Personnel	Privacy concerns	3
635-636	Personnel	Privacy concern/ Canada	3
648-649	Personnel	Privacy concerns	3
664-665	Personnel	Privacy concerns	3
679-680	Personnel	Privacy concerns	3

Notes

1 The Oil Control Center and Backup Oil Control Center are both critical components when initiating an oil spill emergency response and, therefore, are included on the Emergency Response Plan's distribution list. However, the address of each location has been redacted to protect the safety of the employees that work there and the security of the critical facility.

2 In preparing the ERP, TransCanada performed calculations to determine the worst potential discharges from each of the line sections along the pipeline system in addition to the location of the calculated discharges. These volumes and locations were identified for purposes of establishing emergency response scenarios and for emergency response planning. These volumes and locations are redacted for homeland security purposes, as disclosure would make public potential target locations for terrorist attacks or other threats. Further, as indicated, some of these locations are in Canada and would have no impact on the United States.

3 TransCanada considers safety of our employees and their families to be a concern of utmost importance. Therefore, the names and contact information of company employees are being withheld for their safety and privacy. This information is not material to understanding the ERP.

4 In addition to addressing oil spills, the ERP contains emergency response actions that should be taken for other emergencies including bomb threats. Making public the details of our response procedures in the event of a bomb threat could compromise our efforts in reacting to such an event. Accordingly, this information is redacted.

5 While preparing the ERP, TransCanada researched and identified environmentally sensitive areas along the pipeline system to help develop appropriate planning considerations that are critical for responding to an oil spill in those areas. These pre-identified sensitive areas are being redacted to avoid disclosing locations for potential terrorist attacks or other threats.

6 High Consequence Areas (HCAs), as identified by PHMSA, include highly populated areas, drinking water sources, and unusually sensitive ecological areas. The specific locations of these HCAs are only available to pipeline operators due to the sensitive nature of their content. TransCanada obtains this information under a confidentiality commitment. Moreover, these locations are being redacted to avoid disclosing locations for potential terrorist attacks or other threats.

7 While preparing the ERP, TransCanada research field drain tiles as they can provide a conduit for spilled oil to reach environmentally sensitive areas. Therefore, the locations of these tiles are being redacted to avoid disclosing locations for potential terrorist attacks or other threats.

8 TransCanada has contracted with a nationally recognized Oil Spill Removal Organization (OSRO) to ensure that resources and personnel are available to TransCanada during an oil spill. The commercial terms of our contracts and key individuals for each party are redacted for proprietary reasons. In addition, names and contact information of individuals mobilizing response resources are redacted for their safety.

9 TransCanada is prohibited under contract to disclose proprietary information provided by its shippers regarding the commodities transported through the pipeline. This specifically includes Material Safety Data Sheets (MSDSs). In lieu of the MSDSs, TransCanada is providing a document that summarizes the range of information and considerations reflected on the MSDSs for the products expected to be shipped on the pipeline.

EMERGENCY RESPONSE PLAN

Keystone Pipeline System

Prepared for:

TransCanada
450 - 1st Street
Calgary, AlbertaT2P 5H1
(403)920-2033

Prepared by:

O'Brien's Response Management Inc.
818 Town & Country Blvd., Suite 200
Houston, TX 77024-4564
Phone: (281) 320-9796 I Fax: (281) 320-9700
www.obriensrm.com

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Executive Summary

The Keystone Pipeline is a 3,460-kilometre pipeline that transports crude oil from Hardisty, Alberta to markets in the American Midwest at Wood River and Patoka in Illinois, and at Cushing, Oklahoma. The Canadian portion of the pipeline runs from Hardisty, Alberta east into Manitoba where it turns south and crosses the border into North Dakota. From North Dakota, the pipeline runs south through South Dakota and Nebraska. At Steele City, Nebraska, one arm of the pipeline runs east through Missouri for deliveries into Wood River and Patoka, Illinois; another arm runs south through Oklahoma for deliveries into Cushing, Oklahoma.

Deliveries to Wood River and Patoka began in the summer of 2010, and deliveries to Cushing began in February of 2011. The pipeline system currently has the capacity to deliver up to 590,000 bpd of Canadian crude oil into these important North American refining markets.

A critical aspect of operating the Keystone Pipeline system is to have a comprehensive Emergency Management System. A key component of the system includes having an Emergency Response Plan. The Keystone emergency response plan was prepared to achieve a number of goals: ensure regulatory compliance, appropriate for all key stakeholders including field operations, include all emergencies and response measures, timely internal and external notification procedures, and training requirements. In addition, the plan contains information related to worst case discharge, company owned equipment, environmental sensitivities, contract resources, and public officials, and tactical control plans.

The plan is distributed to key internal and external stakeholders and delivered to TransCanada personnel through a secure internet portal hosted by one of TransCanada's emergency response providers and co-preparer of the plan. The plan has been submitted to the National Energy Board in Canada and the United States Department of Transportation's Pipeline and Hazardous Material safety Administration office. The plan will be updated annually and when substantial changes are made or when deemed necessary by either of the agencies.

The Keystone Emergency Response Plan is combined with a rigorous training program,, retention of and access to the industry's most known response experts, and a state of the art pipeline integrity and maintenance program making emergency response for the Keystone pipeline system a priority fully endorsed at all levels within TransCanada.

ACKNOWLEDGMENT AND PLAN APPROVAL

The information and procedures in this Plan must be treated as guidelines only. The user should determine to what extent it is practical and advisable to follow them. This decision may involve considerations not discussed in this Plan.

The information and procedures contained herein are considered to be accurate as of this date and are consistent with the National Contingency Plan (NCP) and applicable Area Contingency Plans (ACP) as detailed in Section 1.5.

CERTIFICATION OF QUALIFIED INDIVIDUAL AND ALTERNATE QUALIFIED INDIVIDUAL

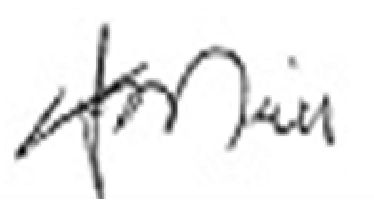
TransCanada hereby certifies that the individuals identified as Qualified Individual and Alternate Qualified Individual in this Plan have the full authority in accordance with the applicable United States Federal and State regulations and as detailed in this Plan to:

1. Activate and engage in contracting with oil spill removal organizations.

2. Act as a liaison with the pre-designated Federal On-Scene Coordinate (OSC), and

3. Obligate funds required to carry out response activities.

Plan Approved:



VP of Pipeline Operations in the U.S.

Signature	Title
Vern Meier	12/06/2012
Name (please type or print)	Date

NOTE: O'Brien's Response Management Inc. provided consulting and plan development services in the preparation of this Plan utilizing data provided by the owner/operator. O'Brien's assumes no liability for injury, loss, or damage of any kind resulting directly or indirectly from the use of the regulatory interpretation, response planning, or information contained in this plan.

OPERATOR'S STATEMENT - SIGNIFICANT AND SUBSTANTIAL HARM AND CERTIFICATION OF RESPONSE RESOURCES

FACILITY NAME: Keystone Pipeline System

CORPORATE ADDRESS: 450 - 1st Street
Calgary, Alberta T2P 5H1

1.	Is the pipeline greater than 6 and 5/8 inches (168 mm) in outside nominal diameter, greater than 10 miles (16.1 km) in length? and	Yes ✓ No
2.	Has any line section experienced a release greater than 1,000 barrels (159 cubic meters) within the previous five years? or	Yes No ✓
3.	Has any line section experienced two or more reportable releases, as defined in 49 CFR 195.50, within the previous five years? or	Yes ✓ No
4.	Does any line section contain any electric resistance welded pipe, manufactured prior to 1970 and operates at a maximum operating pressure established under 49 CFR 195.406 that corresponds to a stress level greater than 50 percent of the specified minimum yield strength of the pipe? or	Yes No ✓
5.	Is any line located within a 5-mile (8 km) radius of potentially affected public drinking water intakes and could reasonably be expected to reach public drinking water intakes? or	Yes ✓ No
6.	Is any line located within a 1-mile (1.6 km) radius of potentially affected environmentally sensitive areas and could reasonably be expected to reach these areas?	Yes ✓ No

Based on the U.S. DOT PHMSA criteria above, the Keystone Pipeline System is considered "Significant and Substantial Harm".

TransCanada hereby certifies to the Pipeline and Hazardous Materials Safety Administration of the U.S. Department of Transportation that we have identified and ensured, by contract or by other means, the availability of personnel and equipment to respond, to the maximum extent practicable, to a worst case discharge.

VP of Pipeline Operations in the U.S.

Signature | Title

Vern Meier | 12/06/2012

Name (please type or print) | Date

NOTE: It is the responsibility of the holder of this Plan to ensure that all changes and updates are made. The Plan Holder must:

- Remove and discard obsolete pages.
- Replace obsolete pages with the updated pages.

REVISION RECORD		
CHANGE DATE	**AFFECTED PAGE NUMBER(S)**	**DESCRIPTION OF CHANGE(S)**
May 2011	Section 2	Update Notification
December 2009	Appendix F	Updated Air Operations Checklist
March 2010	Appendix A	Added Location description to A.1
April 2010	FWD	Distribution List updated TSB contact
June 2011		Shared Contact has been updated.
October 2011	Section 6	Added Drain Tile
December 2011	Entire Plan	Qualified Individual Updated, Drain Tile Information Added, Air Monitoring Guideleins Updated, OSRO Updated, Activation Flowchart Updated, Emergency Response Contractors Updated, MSDS Updated,Misc. Forms Updated
February 2012		Contact Association has been updated.
February 2012		Contact Association has been updated.
February 2012		Shared Contact has been updated.
March 2012		Pipeline has been updated.
March 2012	Section 3	Added Range of Reported thicknesses table to Section 3
April 2012	Section 2, Glossary and Acronyms	Updated External Notifications and Glossary
July 2012		Shared Contact has been updated.
December 2012	Foreword, Sections 1 - 4, Section 6, Apps. C & D, App. G, App. I, Glossary, and Response Zones	Updated Approver, QI(s), other contacts & Distrib. List, Revised Notification Procedures and Response Actions, Revised and added new MSDS, Updated Environmental/Socio Economic Sensitivities, Updated Media Information, Updated Glossary, Updated 24-Hour Emergency Contact Number in all Response Zones, minor typo changes, Uploaded Guidelines for Creating and Maintaining Privilege US and Canada documents and the Oil Properties Composition List into "Other Documents" section

DISTRIBUTION LIST	
COPY NUMBER	**PLAN HOLDER[1]**
1	TransCanada Dean Cowling - VP of Community Safety & Envir. 450 1st Street SW Calgary, Alberta T2P 5H1
2	TransCanada Senior Emergency Management Specialist 450 1st Street SW Calgary, Alberta T2P 5H1
3	TransCanada Corporate Emergency Operations Center 450 1st Street SW Calgary, Alberta T2P 5H1
4	TransCanada Alternate Corporate EOC 450 1st Street SW Calgary, Alberta T2P 5H1
5	TransCanada Emergency Response Analyst 450-1st Str. SW Calgary, T2P 5H1
6	TransCanada Central Region Emergency Prepar Coordinator 104 Terracon Place Winnipeg, Manitoba R2J 4G7
7	TransCanada Central Region Emergency Operations Center 104 Terracon Place Winnipeg, Manitoba R2J 4G7
8, 9, 10	National Energy Board Secretary 444 Seventh Avenue SW Calgary, Alberta T2P 0X8
11, 12 (electronic)	Office of Pipeline Safety - PHMSA Melanie Barber U.S. Department of Transportation 1200 New Jersey Avenue, SE-E-22-321 Washington, District Of Columbia 20590
13	O'Brien's Response Management ePlanPro Manager 818 Town & Country Blvd., Suite 200 Houston, Texas 77024
14	TransCanada Great Plains Emergency Operations Center 13710 FNB Parkway; Suite 300 Omaha, Nebraska 68154
15	TransCanada Incident Management Specialist

	13710 FNB Parkway; Suite 300 Omaha, Nebraska 68154
16	TransCanada Oil Control Center [redacted]
17	TransCanada Alternate Oil Control Center [redacted]
18	Transportation Safety Board Larry Gales Transportation Safety Board of Canada Place du Center 4th Floor - Suite 481 200 Promenade du Portag Gatineau (Hull), Quebec K1A 1K8
19	TransCanada Director of Operations Central Region 104 Terracon Place Winnipeg, Manitoba R2J 4G7
20	TransCanada Director of Operations Great Plains Region 13710 FNB Parkway; Suite 300 Omaha, Nebraska 68154
21	TransCanada Incident Management Specialist 104 Terracon Place Winnipeg, Manitoba R2J 4G7
22	TransCanada Vern Meier - VP of US Pipeline Operations 717 Texas Street Houston, Texas 77002-2761
23	TransCanada Garnet Scaman - VP of Cdn Pipeline Operations 450 1st Street SW Calgary, Alberta T2P 5H1

NOTE[1]**:** The Distribution of this Plan is controlled by the Copy Number located on the front cover or CD label. The Plan Distribution Procedures provided in Section 1.3 and the Plan Review and Update Procedures provided in Section 1.4 should be followed when making any and all changes.

1.0 INTRODUCTION AND PLAN CONTENT

1.1 **Plan Purpose/Objectives**
1.2 **Scope of Plan**
1.3 **Controlled Plan Distribution Procedures**
1.4 **Plan Review and Update Procedures**

1.5 **Regulatory Compliance**

Figure 1.1 **Facility Information**

Figure 1.2 **Piping System Overview**

1.1 PLAN PURPOSE/OBJECTIVES

The purpose of this Emergency Response Plan (ERP) is to assist TransCanada personnel in preparing for and responding quickly and safely to emergencies originating from the pipelines and associated facilities. The Plan provides techniques and guidelines for achieving an efficient, coordinated, and effective response to emergencies which may occur along the pipeline.

The specific objectives of the Plan are to:

- Establish Response Teams, assign individuals to fill the positions on the teams, and define the roles and responsibilities of team members.
- Define notification, activation, and mobilization procedures to be followed when a discharge occurs.
- Define organizational lines of responsibility to be adhered to during a response operation.
- Document equipment, manpower, and other resources available to assist with the response.
- Ensure compliance with National Energy Board (NEB) Onshore Pipeline Regulations 1999 and the U.S. National Oil and Hazardous Substances Pollution Contingency Plan and associated Area Contingency Plan(s) for the area of operation.

1.2 SCOPE OF PLAN

This Plan has been developed in accordance with the regulation published in SOR/99-294, S. 32-354 – Emergency Procedures Manual and 49 CFR Part 194 - Response Plans for Onshore Oil Pipelines.

This Plan contains prioritized procedures for Company personnel to prevent or mitigate emergencies resulting from the operation of the pipeline. A description of the Pipeline's details is presented in Figure 1.1 with additional information provided in the sections, appendices and annexes.

1.3 CONTROLLED PLAN DISTRIBUTION PROCEDURES

Senior Emergency Response Analyst is responsible for maintenance and distribution of the Plan. Distribution will be handled in the following manner:

- Distribution of controlled Plans is determined by the copy number assigned to agency and designated corporate Plan Holders. A distribution list is included in the Foreword.
- Company personnel who may be called upon to provide assistance during discharge response activities will have access to a copy of the Plan for their use and training.
- Any person holding a controlled copy of the Plan shall ensure that the copy is transferred to their replacement in the event of reassignment or change in responsibility.
- Various regulatory agencies will also be distributed a controlled copy of the Plan. The list of agencies is detailed in the Distribution List located in the Foreword.

1.4 PLAN REVIEW AND UPDATE PROCEDURES

Review/Update

The Plan resides as a web-based document, which permits authorized Corporate and field staff access to make:

- Appropriate revisions as required by operational or organizational changes.
- Appropriate revisions as required by changes in the names and phone numbers detailed in Section 2.0.
- Appropriate revisions as required by improved procedures or deficiencies identified during response team tabletop exercises or actual emergency responses.

Incorporation of Plan Revisions

Email notification allows Authorized Plan Holders to update hard copy Plans as changes occur.

The Individual Plan Holder shall:

- Review and insert the revised pages into the Plan.
- Discard or archive the obsolete pages.

Agency Revision Requirements

Company shall revise and resubmit changes to the Canadian National Energy Board (CA NEB) and the U.S. DOT/PHMSA Pipeline Response Plans Officer within 30 days of each change that would substantially affect the implementation of the Response Plan. Additionally, the South Dakota Department of Environment and Natural Resources shall be notified within 30 days of any change. Examples of changes in operating conditions that would cause a significant change to the Plan include:

Requiring Changes

- An extension of the existing pipeline or construction of a new pipeline in a response zone not covered by the previously approved Plan.
- Relocation or replacement of portions of the pipeline, which in any way substantially affect the information included in this Plan, such as a change in the Worst Case Discharge volume.
- A change in the type of oil handled, stored, or transferred that materially alters the required response resources.
- A change in the name of the Oil Spill Removal Organization (OSRO).
- A material change in capabilities of the OSRO that provides equipment and personnel.
- A change in emergency response procedures.
- A change in the Qualified Individual.
- A change in the NCP or an ACP that has significant impact on the equipment appropriate for response activities.

- Any other changes that materially affect the implementation of the Plan.
- As a result of post incident or drill evaluations.

1.5 Regulatory Compliance

CA NEB and U.S. DOT/PHMSA must be provided such revisions. The Company must submit the U.S. DOT/PHMSA issued Facility Control Number with the changes (the PHMSA Control Number is listed in Figure 1.1). In addition to the required changes listed above,TransCanada will resubmit the Emergency Response Plan to U.S. DOT/PHMSA annually from the last approval date of the Plan.

Except as provided above, amendments to the following do not require approval by U.S. DOT/PHMSA:

- Personnel and telephone number lists included in the Plan.
- OSRO(s) change which does not result in a material change in support capabilities.

The development, maintenance, and use of this Plan implements Company policy and addresses the following regulatory requirements and guidelines:

The response zones have been reviewed for consistency with the following plans:

- Canada - United States Joint Inland Pollution Contingency Plan - Annex II CANUSCENT
- CA National Environmental Emergencies Contingency Plan
- Greater St. Louis Sub-Area Plan
- U.S. EPA Region 5 Oil and Hazardous Substances Integrated Contingency Plan
- U.S. EPA Region 6, Regional Integrated Contingency Plan
- U.S. EPA Region 7 Regional Contingency Plan
- U.S. EPA Region 8 Regional Contingency Plan
- U.S. National Oil and Hazardous Substances Pollution Contingency Plan (NCP)

FIGURE 1.1

FACILITY INFORMATION

GENERAL INFORMATION		
Facility Name:	Keystone Pipeline System	
U.S. DOT/PHMSA Control:	TC59	
Owner Name:	(Canada)TransCanada (U.S.)	
Address:	***Physical Address*** 450 - 1st Street Calgary, Alberta T2P 5H1	***Operators Address*** 450 - 1st Street S.W. Calgary, Alberta T2P 5H1
Mainline Number:	(800) 447-8066 (24 Hours)	
Contact Person:	Niki Affleck Senior Emergency Management Specialist	
Primary NAICS Code:	486910	
Determination of Significant and Substantial Harm (U.S. DOT PHMSA):	All Response Zones meet the criteria for "Significant and Substantial Harm."	
Operator Statement of (U.S.DOT PHMSA) "Significant and Substantial Harm":	It is the Company's goal to respond as quickly as possible to all uncontrolled releases of crude oil, regardless of the source point location along the system. Based upon this goal, and the overbreadth of the definitions provided in 49 CFR 194.103 (c)(4) & (5), the Company is compelled to consider all the active line sections listed below in the Response Zone Annexes as capable of a release potentially causing "significant and substantial harm".	

PIPELINE LOCATION	
Provinces/States/Counties:	The System covers 5 specific Response Zones covering 3 Provinces, 7 States and 56 Counties specifically detailed in this Figure 1.1.
Provinces Traversed:	Alberta, Saskatchewan, Manitoba
States Traversed:	North Dakota, South Dakota, Nebraska, Kansas, Missouri, Illinois, Oklahoma
Pipeline System Overview Diagram:	**See Figure 1.2**

PYSICAL DESCRIPTION - PIPELINE

Response Zone(s):

- The Keystone Pipeline transports crude oil from Hardisty, Alberta to U.S. Midwest markets at Wood River, Patoka, Illinois and Cushing, Oklahoma. The Canadian portion includes 232 miles (373 km) of pipeline, pump stations and terminal facilities at Hardisty, Alberta. The U.S. portion includes approximately 1,352 miles (2,846 km) of pipeline and pump stations.
- The Keystone Pipeline System is divided into 5 specific Pipeline Response Zones. The Response Zones are as follows (Specific information to Response Zones are provided later in the Response Zone Appendices):
  - Hardisty Pump Station/ Regina Pump Station
  - Regina Pump Station / Haskett Pump Station
  - North Dakota, South Dakota, Nebraska
  - Kansas, Missouri, Illinois
  - Cushing Extension

General:

- The Keystone Pipeline System includes pipeline sections of 30, 34 or 36-inch diameter as well as pump stations.

- This Plan is written in English and understood by personnel responsible for carrying out the Plan.

Pipeline Specifications:

- ***Products Type:***

  Crude Oil

- ***Pipe Detail:***The pipeline system consists of several pipeline sections with the following diameters.

  30" - 0 km Point (KP) - 274.2 KP and 1148.3 KP to 1239.4 KP (CANADA, New Construction AB, SK, MB)
  34" - 274 KP - 1148 KP (CANADA, Line 1 Conversion, SK& MB, New Construction, MB)
  30" - 1239.4 KP - 2983.9 KP (USA, ND, SD, NE, KS, MO, IL)
  36" - 0 KP - 479.5 KP (initiates at 2268.5 KP, USA KS, OK)

RESPONSE ZONE INFORMATION

Response Resources:

Facility spill mitigation procedures and response guidelines are provided in Section 3.0 for discharges that could result from any of the following scenarios:

- Pipeline rupture/leak
- Explosion and/or fire
- Failure of facility piping
- Equipment failure (e.g. pumping system failure, relief valve failure, etc.)

Response Zone	Discharge Scenario (Bbls.)	Provinces / Counties Traversed	Planning Volume (Bbls.)
Hardisty Pump Station/ Regina Pump Station	[redacted]	Alberta, Saskatchewan,Eastern Alberta, Western Saskatchewan, Eastern Saskatchewan	[redacted]
Regina Pump Station / Haskett Pump Station	[redacted]	Saskatchewan, Manitoba,Eastern Saskatchewan, Southwestern Manitoba, Western Saskatchewan	[redacted]
North Dakota, South Dakota, Nebraska	[redacted]	Barnes, Beadle, Butler, Cavalier, Cedar, Clark, Colfax, Day, Gage, Hanson, Hutchinson, Jefferson, Kingsbury, Marshall, McCook, Miner, Nelson, Pembina, Platte, Ransom, Saline, Sargent, Seward, Stanton, Steele, Walsh, Wayne, Yankton, Lincoln	[redacted]
Kansas, Missouri, Illinois	[redacted]	Audrain, Bond, Brown, Buchanan, Caldwell, Carroll, Chariton, Clinton, Doniphan, Fayette, Lincoln, Madison, Marion, Marshall, Montgomery, Nemaha, Randolph, St. Charles, Washington, Clay, Dickinson, Butler, Cowley	[redacted]
Cushing Extension	[redacted]	Butler, Clay, Cowley, Dickinson, Jefferson, Kay, Lincoln, Marion, Noble, Payne, Washington, Marshall, Nemaha, Brown, Doniphan, Cedar, Wayne, Stanton, Platte, Colfax, Seward, Saline, Gage	[redacted]

FIGURE 1.2
PIPING SYSTEM OVERVIEW


Figure 1.2 System Overview Map
Map Prepared By
O'Brien's Response Management
Shared Services, GIS Group
O'BRIEN'S
RESPONSE MANAGEMENT
Lloydminster (Part)
Prince Albert
North Battleford
Saskatoon
Alberta
Saskatchewan
Manitoba
Ontario
Yorkton
Medicine Hat
Swift Current
Moose Jaw
Regina
Portage la Prairie
Brandon
Winnipeg
Hanover
Kenora
Estevan
Thunder Bay
Grand Forks
North Dakota
Montana
Bismarck
Fargo, Moorhead
Duluth
Michigan
Minnesota
Billings
St. Cloud
Wausau
Minneapolis, St. Paul
Eau Claire
Green Bay
Wisconsin
Appleton, Neenah
Oshkosh
South Dakota
Rapid City
Rochester
La Crosse
Sioux Falls
Milwaukee
Madison
Wyoming
Casper
Waterloo, Cedar Falls
Dubuque
Beloit
Rockford
Sioux City
Iowa
Cedar Rapids
Aurora
Des Moines
Davenport, Rock Island, Moline
Nebraska
Cheyenne
Omaha
Peoria
Lincoln
Fort Collins
Greeley
Illinois
Boulder
Utah
Denver
Decatur
Columbia
St. Louis
Kansas City
Lawrence
TransCanada
In business to deliver
Keystone
Pipeline Project
Map Key
Pump Stations
Pipeline
Miles
Kilometers
Kansas
Missouri
Wichita
Springfield
Joplin
Kentucky
Arkansas
Oklahoma
Tulsa
Fayetteville, Springdale
Texas
Tennessee
Oklahoma City
Fort Smith, AR--OK
Memphis

2.0 NOTIFICATION PROCEDURES

2.1 Internal Notifications

2.2 External Notifications

Figure 2.1 Emergency Activation Flowchart

Figure 2.2 Internal Notification References

Figure 2.3 Notification Data Sheet

Figure 2.4 External Notification Flowchart

Figure 2.5 External Notification References

Figure 2.6 Possible Command Post Locations

This Section is a guide for notification procedures that should be implemented immediately after discovering a discharge incident and, if possible, securing the source. Internal and external notifications are described separately for clarification purposes only. All notifications are of extreme importance and must be completed in a timely manner.

2.1 INTERNAL NOTIFICATION

The following internal notifications should be made for each emergency incident to the extent that the incident demands (telephone reference is provided in Figure 2.2). In no event shall notification be delayed because the immediate supervisor is inaccessible. Authorization is given to bypass management levels if necessary to provide timely notification to appropriate management. The typical internal notification responsibilities for each person potentially involved in the initial response are as follows:

Employee Discovering Discharge

- Immediately notify the Keystone Oil Control Center (OCC) (contact information is listed in Figure 2.2).
- Notify the local fire department, police department, and rescue, as needed.
- Notify the Spill Response Contractor, Quantam Murray at (877) 378-7745 (Canada only).
- Notify the Spill Response Contractor, National Response Corporation at (800) 337-7455 (US only).
- Notify the contracted Spill Management Team, the O'Brien's Group at (985) 781-0804 if required (Canada & US).
- Notify Area Manager or Regional On-Call Manager.

Keystone Oil Control Center (OCC)

- Verify emergency.
- Immediately notify the Keystone Console Manager and Regional On-Call Manager.
- Notify the emergency response contractor if the employee that discovered the discharge has not already made the notification.
- Notify: U.S. National Response Center, the CA Transportation Safety Board National Response Center, CA National Energy Board, appropriate Federal agencies, County Emergency Management, Province/State Environmental Agency, and the Utilities One-Call, as needed (notification requirements and contact information are listed in Figure 2.5).

Calgary Emergency Operations Center (EOC) Manager

- Once the emergency has been verified by the Oil Control Center (OCC), request contact information for Regional On Call Manager.
- Contact the Regional On Call Manager to confirm activation of Regional EOC and inform that activation of the Corporate EOC will be completed.
- Notify the Corporate Emergency Response Team (CERT) and activate the Corporate Emergency Operations Center (EOC).
- Dial into Regional EOC conference line to establish communications with Regional EOC and Incident Management Team on site.
- Once Corporate EOC is activated, determine with Corporate Security whether emergency seems to meet "crisis" criteria.
- If yes, ensure Corporate Security activates TransCanada's Crisis Management Team.
- Continue to provide support to both Regional EOC and Incident Management Team throughout the emergency response phase.

Corporate Security

- Engage in Corporate Emergency Operations Center (EOC)
- Confirm emergency meets "crisis" criteria.
- Notify the Executive VP of Operations and Engineering.

Regional Emergency Operations Center

- Activate Regional Emergency Operations Center (EOC).
- Set up Regional conference line to establish communications with Incident Management Team and Corporate Emergency Operations Center (EOC).
- Immediately provide support to Incident Management Team.
- Complete all local notifications.
- Facilitate ongoing communication between Incident Management Team and the Corporate EOC.
- Transmit appropriated MSDS to Incident Commander, local officials, and State Environmental Agencies.

Corporate Emergency Response Team (CERT)

- Attend Corporate Emergency Operations Center (EOC).
- Immediately notify senior management to inform about the emergency event.
- Fulfill profile of service and functional plan as required based on the type of emergency event.
- Continue to provide support to Incident Management Team and Regional EOC.

O'Brien's Response Management Command Center

- Email is received at the O'Brien's Command Center as well as by key Response Services personnel.
    - Primary - response@obriensrm.com
    - Secondary - ccenter@obriensrm.com

FIGURE 2.1

EMERGENCY ACTIVATION FLOWCHART

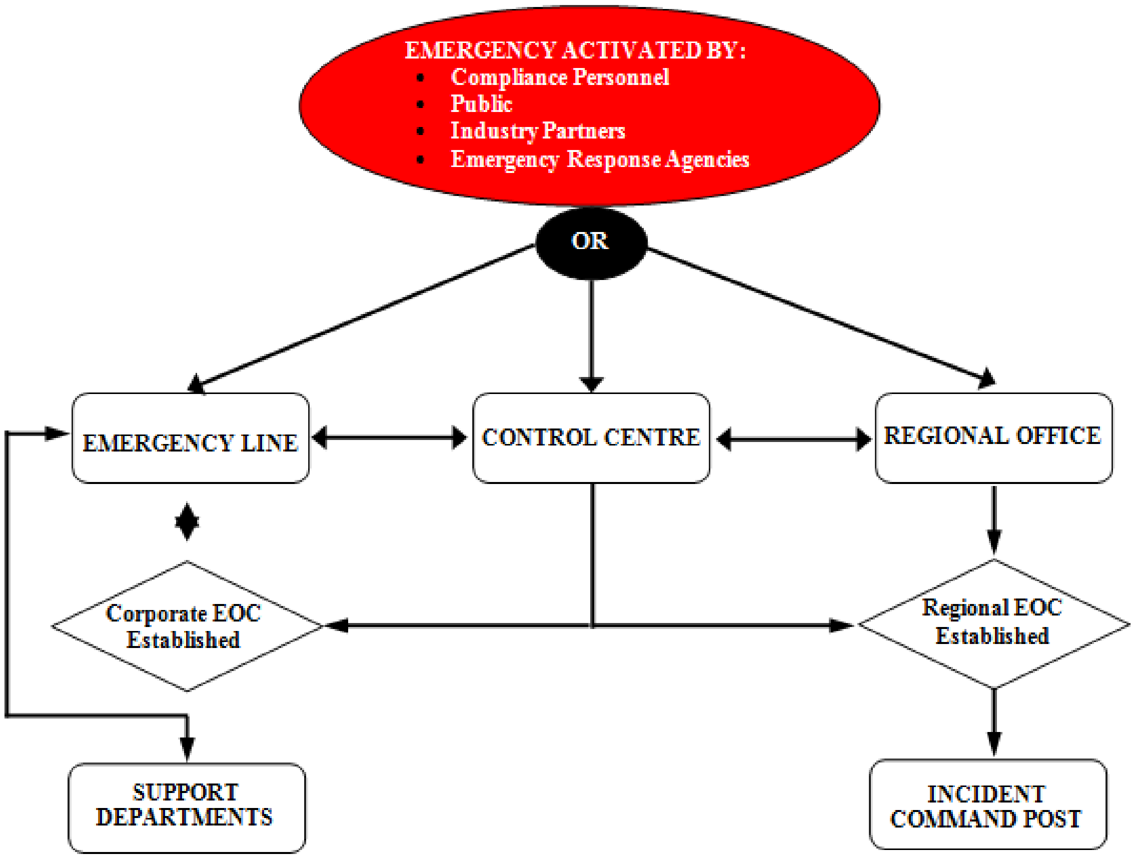


FIGURE 2.2

INTERNAL NOTIFICATION REFERENCES

CORPORATE RESPONSE PERSONNEL / OTHER COMPANY CONTACTS INTERNAL NOTIFICATIONS					
POSITION/TITLE	NAME	OFFICE	HOME	CELL	PAGER

Hardisty Pump Station/ Regina Pump Station					
POSITION/TITLE	NAME	OFFICE	HOME	CELL	PAGER

Regina Pump Station / Haskett Pump Station					
POSITION/TITLE	NAME	OFFICE	HOME	CELL	PAGER

North Dakota, South Dakota, Nebraska					
POSITION/TITLE	NAME	OFFICE	HOME	CELL	PAGER

Kansas, Missouri, Illinois

POSITION/TITLE	NAME	OFFICE	HOME	CELL	PAGER

Cushing Extension

POSITION/TITLE	NAME	OFFICE	HOME	CELL	PAGER

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2.2 EXTERNAL NOTIFICATIONS

External notifications are those made to entities outside of the Company including Federal, Province/State and local regulatory agencies, as well as railroad and utility companies. These notifications include both verbal and written requirements.

Verbal Notification Requirements

Immediate internal notification is to be made in accordance with the Internal Notification Procedures found in Section 2.1 when a system operational failure or other type of incident occurs. This will allow immediate evaluation and classification of incidents and prompt immediate telephonic notification as detailed in Figure 2.4 and 2.5 to the Transportation Safety Board, National Response Center (NRC), Province/State agencies, local agencies, and other Federal agencies as required. The information found on the Notification Data Sheet, Figure 2.3, should be used to disseminate incident information to the appropriate agencies.

For the purpose of this procedure, immediate reporting means reporting the instant a person has knowledge of an actual or suspected leak, uncontrolled release of product, any unplanned spill or other pipeline system failure. Information that causes any employee to reasonably suspect a leak or uncontrolled release of product must be immediately reported, even when the actual existence or location of a leak or release cannot yet be confirmed.

Written Notification Requirements

In the United States, a written report is to be filed as soon as practical, but not later than 30 days after discovery of the incident to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, US Department of Transportation. Information concerning the event shall be reported on Pipeline and Hazardous Materials Safety Administration Form 7000-1 on-line on the Pipeline and Hazardous Materials Safety Administration website via log-in. Paper reports are not required. This report is to be filed for all incidents reported telephonically and other incidents required to be reported in accordance with the criteria listed below.

The information required for completing the 30-day written report will be furnished by the Area Offices to the Department of Transportation Regulatory Compliance Department for submission to the Department of Transportation. Any subsequent or additional information that was not reported on the initial written report must be reported to the Department of Transportation Regulatory Compliance Department by the Area Office. This information will be utilized in filing a supplemental written report to the Department of Transportation as soon as possible, but no later than 30 days after its discovery.

In Canada, a detailed written incident report is required as soon as practicable.

Transportation Safety Board (TSB)

The TSB's role is to advance transportation safety through the investigation of transportation occurrences in the marine, pipeline, rail and aviation modes.

<u>TSB Classification System</u>

The primary criterion for determining if an occurrence in any mode will be investigated is whether or not such analysis is likely to lead to a reduction of risk to persons, property, or the environment.

Class 1 Occurrences (Public Inquiry)

- the potential for reducing the risk to persons, property, or the environment;
- whether an inquiry would uncover facts that might not otherwise be made known;
- whether an inquiry would result in quicker remedial action;
- the actual or potential extent of injuries and/or loss of life;

- the degree of public interest in and concern about public safety; or
- the possible involvement of an arm of government.

Class 2 Occurrence (Individual Occurrence Investigation)

- there is a high probability of advancing Canadian transportation safety in that there is significant potential for reducing the risk to persons, property, or the environment; or
- the Governor in Council so requests (pursuant to Section 14(1) of the CTAISB Act).

Class 3 Occurrences (Individual Occurrence Investigation)

- there is significant public expectation that the TSB should independently make findings as to cause(s) and contributing factors; or
- there is potential for better understanding the latent unsafe conditions contributing to a significant safety issue; or
- a government representative so requests (pursuant to Section 14(2) of the CTAISB Act); or
- the Board must do so to meet its obligations or commitments.

Class 4 Occurrences (Safety Issue Investigation)
Multiple occurrences, which the Board deems to be indicative of significant unsafe situations or conditions, will be subject to a safety issue investigation when:

- there is a high probability of advancing Canadian transportation safety by reducing the risk to persons, property, or the environment; or
- in the Board's opinion, there is widespread public expectation that the TSB should independently analyze a particular safety issue.

Class 5 Occurrences (Data Collection)

Data pertaining to occurrences that do not meet the criteria of classes 1 through 4 will be recorded in suitable scope and detail for possible safety analysis, statistical reporting, or archival purposes.

National Energy Board (NEB)

The NEB's role and responsibilities generally includes:

- The NEB's top priority in any emergency is to make sure that people are safe and secure, and that property and the environment are protected. Any time there is a serious incident, the NEB Inspectors may attend the site to oversee a company's immediate response. The NEB will require that all reasonable actions are taken to protect employees, the public and the environment. Further, the NEB will verify that the regulated company conducts adequate and appropriate clean-up and remediation of any environmental effects caused by the incident.

  And/or

As lead regulatory agency, the NEB:

- Monitors, observes and assesses the overall effectiveness of the company's emergency response in terms of:
  - Emergency Management
  - Safety
  - Security
  - Environment
  - Integrity of operations and facilities; and
  - Energy Supply.

- Investigates the event, either in cooperation with the Transportation Safety Board of Canada, under the Canada Labour Code, or as per the National Energy Board Act or Canada Oil & Gas Operations Act (whichever is applicable)
- Inspects the pipeline or facility
- Examines the integrity of the pipeline or facility
- Requires appropriate repair methods are being used
- Requires appropriate environmental remediation of contaminated areas is conducted
- Coordinates stakeholder and Aboriginal community feedback regarding environmental clean-up and remediation
- Confirms that a company is following its Emergency Procedures Manual(s) commitments, plans, procedures, and NEB regulations and identifies non-compliances
- Initiates enforcement actions as required
- Approves the restart of the pipeline.

Transportation Safety Board of Canada Pipeline Occurrence Reporting	
Citation	**Description**
Extracts from Transportation Safety Board Regulations Sections 5(1) and 5 (5)	When a reportable pipeline accident or incident takes place, the operator and any employee of the operator having direct knowledge of the accident or incident shall report to the Board as soon as possible and by the quickest means available. Where any person mentioned above makes a report, no other person referred to is required to make such a report.
Transportation Safety Board Regulations Section 2(1)	A "reportable pipeline accident" is an accident resulting directly from the operation of a pipeline, where (a) a person sustains a serious injury or is killed as a result of being exposed to i. a fire, ignition or explosion, or ii. a commonly released from the pipeline, or (b) the pipeline i. sustains damage affecting the safe operation of the pipeline as a result of being contacted by another object or as a result of a disturbance of its supporting environment, ii. causes or sustains an explosion, or a fire or ignition that is not associated with normal operating circumstances, or iii. sustains damage resulting in the release of any commodity.
Transportation Safety Board Regulations Section 2(1)	A "reportable pipeline incident" means an incident resulting directly from the operation of a pipeline where (a) an uncontained and uncontrolled release of a commodity occurs, (b) the pipeline is operated beyond design limits, (c) the pipeline causes an obstruction to a ship or to a surface vehicle owing to a disturbance of its supporting environment, (d) any abnormality reduces the structural integrity of the pipeline below design limits, (e) any activity in the immediate vicinity of the pipeline poses a threat to the structural integrity of the pipeline, or (f) the pipeline, or a portion thereof, sustains a precautionary or emergency shut-down for reasons that relate to or create a hazard to the safe transportation of a commodity.

NOTE: Refer to Figure 2.5 for any additional Province/State written reporting requirements.

FIGURE 2.3

NOTIFICATION DATA SHEET

Date: ________ ***Time:*** ________

INCIDENT DESCRIPTION

Reporter's Full Name: ________ ***Position:*** ________
Day Phone Number: ________ ***Evening Phone Number:*** ________
Company: ________ ***Organization Type:*** ________
Facility Address: ________ ***Owner's Address:*** ________
Facility Latitude: ________ ***Facility Longitude:*** ________
Spill Location: ________
(if not at Facility) ________
Responsible Party's Name: ________ ***Phone Number:*** ________
Responsible Party's Address: ________
Source and/or cause of discharge: ________
Nearest City: ________
County: ________ ***State:*** ________ ***Zip Code:*** ________
Section: ________ ***Township:*** ________ ***Range:*** ________
Distance from City: ________ ***Direction from City:*** ________
Container Type: ________ ***Container Storage Capacity:*** ________
Facility Oil Storage Capacity: ________
Material: ________

Total Quantity Released	**Water Impact (*YES or NO*)**	**Quantity into Water**

RESPONSE ACTION(S)

Action(s) taken to Correct, Control, or Mitigate Incident: ________
Number of Injuries: ________ ***Number of Deaths:*** ________
Evacuation(s): ________ ***Number Evacuated:*** ________
Damage Estimate: ________
More information about impacted medium: ________
Possible hazards to human health or the environment outside of the Facility: ________

CALLER NOTIFICATIONS

National Response Center (NRC): 1-800-424-8802 ***Transportation Safety Board:*** 819-997-7887
Additional Notifications (Circle all applicable): ***USCG*** ***NEP*** ***EPA*** ***Province*** ***State*** ***Other***
National Response Center Incident Assigned No. ________

ADDITIONAL INFORMATION

Any information about the incident not recorded elsewhere in this report including estimated quantity and disposition of recovered material: ________

NOTE: DO NOT DELAY NOTIFICATION PENDING COLLECTION OF ALL INFORMATION.

FIGURE 2.4

EXTERNAL NOTIFICATION FLOWCHART

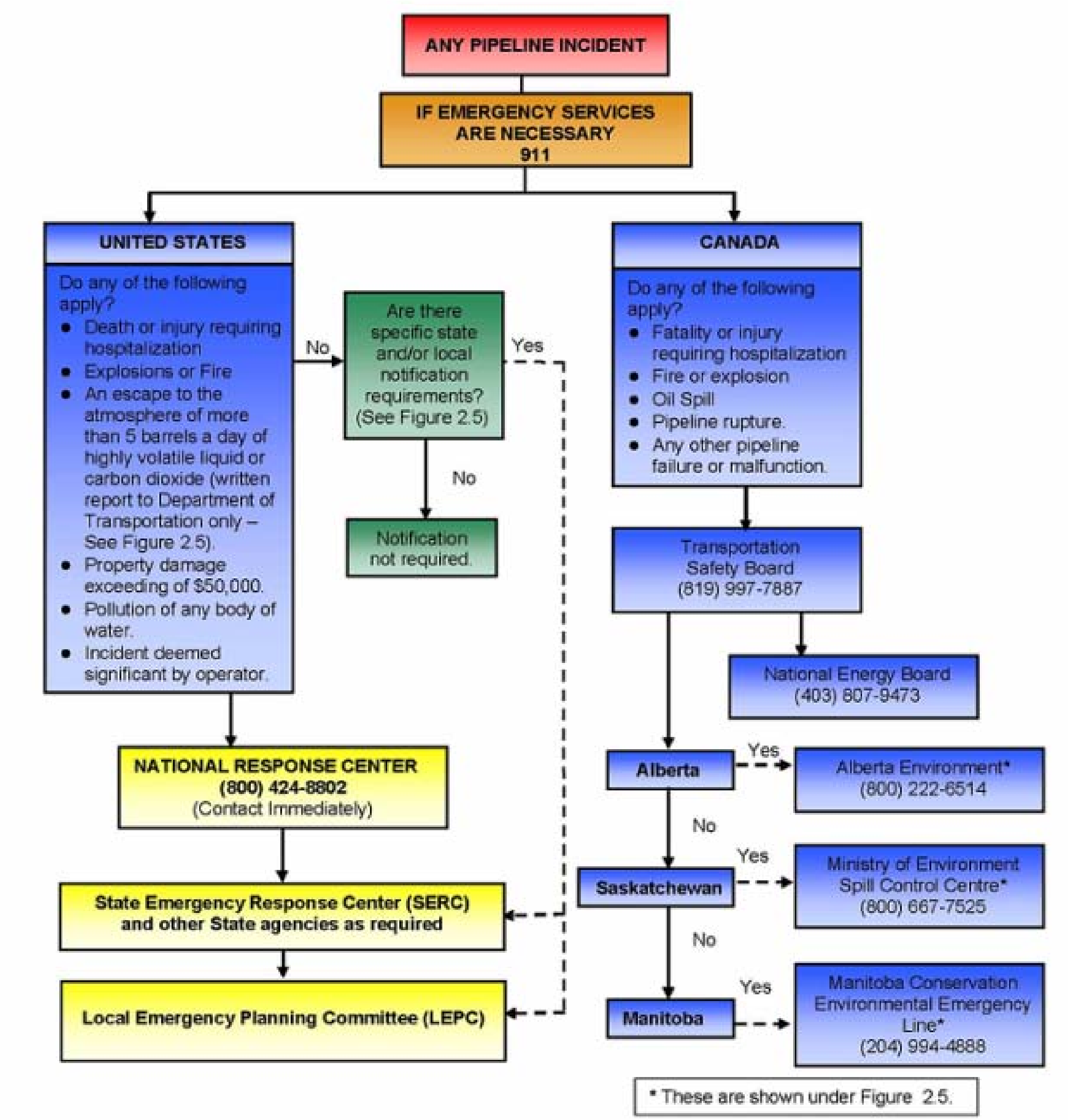

FIGURE 2.5

EXTERNAL NOTIFICATION REFERENCES

REQUIRED NOTIFICATIONS	
National Response Center (NRC) c/o United States Coast Guard (CG-5335) - Stop 7581, 2100 2nd Street, SW Washington, District Of Columbia 20593-0001	(800) 424-8802 (202) 267-2675
REPORTING REQUIREMENTS TYPE: Any discharge or sighting of oil on navigable waters. VERBAL: Immediate notification required (within 2 hours). WRITTEN: If an RQ limit is reached, refer to state requirements for written report requirements. NOTE: A call to the NRC must also be made for spills or releases of hazardous substances that meet or exceed their RQ.	
Office of Pipeline Safety and Hazardous Materials U.S. Department of Transportation 1200 New Jersey Avenue SE-E-22-321 Washington, District Of Columbia 20590	(202) 366-4000
REPORTING REQUIREMENTS TYPE: In addition to the reporting of accidents to the NRC as noted below, a written accident report PHMSA Form 7000-1. VERBAL: Call to the NRC meets the required verbal notification under DOT reporting requirement. WRITTEN: Reported on PHMSA Form 7000-1 no later than 30 days, submit a report resulting from explosion/ fire/ hospitalization, death, property damage greater than $50,000, or above reportable quantity. NOTE:	
Saskatchewan Environment and Resource Management Box 3003, 800 Central Avenue. Prince Albert, Saskatchewan S5V 6G1	(800) 667-7525
REPORTING REQUIREMENTS TYPE: Any oil spill to water or oil spill greater than or equal to 50 L. to land. VERBAL: Immediately WRITTEN: Within 7 days. NOTE:	
Transportation Safety Board (TSB) of Canada 200 Promenade du Portage, Place du Centre, 4th Floor Gatineau, Quebec 1K8	(819) 997-7887 (800) 387-3557
REPORTING REQUIREMENTS TYPE: All pipeline accidents with fatality or serious injury, fire or explosion, oil spill, pipeline rupture or any other pipeline failure or malfunction. VERBAL: Immediately. WRITTEN: Within 30 days. NOTE:	

Alberta Environment 9915 -108 Street 10th Floor, Petroleum Plaza South Tower Edmonton, Alberta T5K 2G8	(800) 222-6514
REPORTING REQUIREMENTS TYPE: All spills to water or exceeds a reportable quantity or emission level. VERBAL: Immediately. WRITTEN: Within 7 days. NOTE:	
Canadian National Energy Board (CA NEB) 444 Seventh Avenue SW Calgary, Alberta T2P OX8	(403) 807-9473 (800) 899-1265
REPORTING REQUIREMENTS TYPE: All pipeline incidents with fatality or serious injury, fire or explosion, oil spill or hyrocarbon release, or any operation beyond the design limits of the pipeline. VERBAL: Immediately. WRITTEN: As requested by the Agency. NOTE: For further definition of Incident see Glossary.	
Manitoba Water Stewardship Manitoba Water Stewardship Box 11 200 Saulteaux Crescent Winnipeg, Manitoba R3J 3W3	1-866-626-4862 1-204-945-6398
REPORTING REQUIREMENTS TYPE: VERBAL: WRITTEN: NOTE:	
Manitoba Conservation Environmental Emergency Line Winnipeg, Manitoba	(204) 994-4888
REPORTING REQUIREMENTS TYPE: All spills or discharges. VERBAL: Immediately. WRITTEN: As requested by the Agency. NOTE:	
South Dakota Department of Environment and Natural PMB 2020 Joe Foss Building, 523 East Capitol Pierre, South Dakota 57501-3182	(605) 773-3296 (605) 773-3231
REPORTING REQUIREMENTS TYPE: All spills or discharges VERBAL: Immediately. WRITTEN: As requested by the Agency. NOTE:	

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U.S. Environmental Protection Agency, Region 8 999 18th Street Suite 500 Denver, Colorado 80202-246	(303) 312-6312
REPORTING REQUIREMENTS TYPE: Immediately for spills that impact or threaten navigable water or adjoining shoreline. VERBAL: Notification to the EPA is typically accomplished by the call to the NRC. WRITTEN: In accordance with the applicable SPCC regulations, within 60 days for a spill in excess of 1,000 gallons (24 Bbls) in a single event or two spill events within a twelve month period into or upon nav NOTE: In accordance with the applicable SPCC regulations, within 60 days for a spill in excess of 1,000 gallons (24 Bbls) in a single event or two spill events within a twelve month period into or upon nav	
Department of Environmental Quality 1200 N Street Suite 400 / PO Box 98922 Lincoln, Nebraska 68509-8922	(402) 471-2186 (402) 471-4545
REPORTING REQUIREMENTS TYPE: Any Discharge that leaves the Facility or threatens to impact navigable waters. VERBAL: Immediately, but not longer than 30 minutes. WRITTEN: As Requested by the Agency NOTE:	
Department of Natural Resources Nebraska	(308) 697-3730
REPORTING REQUIREMENTS TYPE: VERBAL: Courtesy Reporting WRITTEN: NOTE:	
Environmental Health Sect, Div. of Water Quality North Dakota	(701) 328-5210
REPORTING REQUIREMENTS TYPE: VERBAL: Courtesy Reporting WRITTEN: NOTE:	
Game & Fish, Conservation and Communication Div North Dakota	(701) 328-6612 (701) 328-6300
REPORTING REQUIREMENTS TYPE: VERBAL: Courtesy Reporting WRITTEN: NOTE:	

Game, Fish and Parks South Dakota	(605) 223-7660
REPORTING REQUIREMENTS TYPE: VERBAL: Courtesy Reporting WRITTEN: NOTE:	
Nebraska Emergency Management Agency Lincoln, Nebraska	(402) 499-1219
REPORTING REQUIREMENTS TYPE: VERBAL: Courtesy Reporting WRITTEN: NOTE:	
North Dakota Dept. of Health-Environmental Health 918 East Divide Avenue Bismarck, North Dakota 58501-1947	(701) 328-5150 (701) 328-5210
REPORTING REQUIREMENTS TYPE: VERBAL: Courtesy Reporting WRITTEN: NOTE:	
Nebraska Game & Parks Commission Lincoln, Nebraska	(402) 471-5423 (402) 471-0641 (402) 271-5440
REPORTING REQUIREMENTS TYPE: VERBAL: Courtesy Reporting WRITTEN: NOTE:	
City of South Sioux Nebraska	(402) 494-7517 (402) 494-7500
REPORTING REQUIREMENTS TYPE: VERBAL: Courtesy Reporting WRITTEN: NOTE:	
North Dakota Division of Emergency Management PO Box 5511 Bismarck, North Dakota 58506-5511	(701) 328-8100
REPORTING REQUIREMENTS	

TYPE: Any spill or discharge above RQ.
VERBAL: Immediately.
WRITTEN: Within 30 days.
NOTE:

North Dakota Industrial Commission State Capitol, 14th Floor, 600 E. Boulevard Ave., Dept 405 Bismarck, North Dakota 58505-0840	(701) 328-8020

REPORTING REQUIREMENTS
TYPE:
VERBAL: Courtesy Reporting
WRITTEN:
NOTE:

City of Fargo Fargo, North Dakota	(701) 241-1310

REPORTING REQUIREMENTS
TYPE:
VERBAL: Courtesy Reporting
WRITTEN:
NOTE:

Public Service Commission, Public Utilities Divisi North Dakota	(701) 328-4077

REPORTING REQUIREMENTS
TYPE:
VERBAL: Courtesy Reporting
WRITTEN:
NOTE:

South Dakota DENR, Div of Environmental Services 523 East Capitol Ave. Pierre, South Dakota 57501-3182	(605) 773-3296 (605) 773-3231

REPORTING REQUIREMENTS
TYPE: Any Spill or discharge greater than reportable quantity.
VERBAL: Immediately.
WRITTEN: Within 30 days.
NOTE:

South Dakota DENR, Division of Oil and Gas South Dakota	(605) 394-2229

REPORTING REQUIREMENTS
TYPE:
VERBAL: Courtesy Reporting
WRITTEN:
NOTE:

South Dakota Department of Environment and Natural South Dakota	(605) 773-6035

REPORTING REQUIREMENTS
TYPE:
VERBAL: Courtesy Reporting
WRITTEN:
NOTE:

South Dakota Department of Transportation, RR	(605) 773-3046 (605) 773-3921

REPORTING REQUIREMENTS
TYPE:
VERBAL: Courtesy Reporting
WRITTEN:
NOTE:

South Dakota Department of Transportation, ROW South Dakota	(605) 773-3710 (605) 773-4249

REPORTING REQUIREMENTS
TYPE:
VERBAL: Courtesy Reporting
WRITTEN:
NOTE:

South Dakota Office of Emergency Management South Dakota	(605) 773-3231

REPORTING REQUIREMENTS
TYPE:
VERBAL: Courtesy Reporting
WRITTEN:
NOTE:

South Dakota Public Utilities Commission South Dakota	(605) 773-3201

REPORTING REQUIREMENTS
TYPE:
VERBAL: Courtesy Reporting
WRITTEN:
NOTE:

Tri-County Water District North Dakota	(701) 345-8240

REPORTING REQUIREMENTS

TYPE:
VERBAL: Courtesy Reporting
WRITTEN:
NOTE:

Environmental Protection Agency - IL Office Illinois	(217) 524-3908 (217) 785-9250

REPORTING REQUIREMENTS
TYPE:
VERBAL: Courtesy Reporting
WRITTEN:
NOTE:

U.S. Environmental Protection Agency, Region 5 77 W. Jackson Blvd., 5th Floor Chicago, Illinois 60604	(312) 353-2318 (312) 353-2000

REPORTING REQUIREMENTS
TYPE: Any oil discharge that has impacted or threatens to impact navigable waters or release of hazardous substances in an amount equal or greater than the reportable quantity.
VERBAL: Notification to the EPA is typically accomplished by the call to the NRC.
WRITTEN: For oil discharge within 60 days, in accordance with applicable SPCC RQ.
NOTE:

City of Troy Troy, Missouri	(636) 528-4712 x.227 (636) 528-7562

REPORTING REQUIREMENTS
TYPE:
VERBAL: Courtesy Reporting
WRITTEN:
NOTE:

DeKalb County PWSD No 1 Missouri	(816) 393-5311

REPORTING REQUIREMENTS
TYPE:
VERBAL: Courtesy Reporting
WRITTEN:
NOTE:

Douglas County Commission Missouri	(417) 683-4714

REPORTING REQUIREMENTS
TYPE:
VERBAL: Courtesy Reporting
WRITTEN:
NOTE:

Hickory County Commission Missouri	(417) 745-6450

REPORTING REQUIREMENTS
TYPE:
VERBAL: Courtesy Reporting
WRITTEN:
NOTE:

Illinois Department of Natural Resources (IDNR) 1 Natural Resources Way Springfield, Illinois 62702	(618) 462-1181 (Region 4) (217) 782-6302 (State of IL)

REPORTING REQUIREMENTS
TYPE: Wildlife Protection / Rehabilitation
VERBAL: Courtesy Reporting
WRITTEN: As the agency may request depending on circumstances.
NOTE:

Illinois Department of Transportation (IDOT) 2300 S. Dirksen Parkway Springfield, Illinois 62764	(217) 782-7820 (217) 782-2937

REPORTING REQUIREMENTS
TYPE: All spills or discharges.
VERBAL: Immediately.
WRITTEN: As requested by the Agency.
NOTE: As requested by the Agency.

Illinois Emergency Management Agency (SERC) 2200 South Dirksen Parkway Springfield, Illinois 62703	(800) 782-7860 (217) 782-7860

REPORTING REQUIREMENTS
TYPE: Any Discharge or sighting of oil, or hazardous substances exceeding a reportable quantity in Cook County, IL.
VERBAL: Immediately.
WRITTEN: As soon as practicable after the release.
NOTE:

Kansas Department of Health & Environment Curtis State Office Building 1000 SW Jackson Topeka, Kansas 66612	(785) 296-1679

REPORTING REQUIREMENTS
TYPE: All Spills that impact soil, surface water or groundwater.
VERBAL: Immediately, within one hour.
WRITTEN: As requested by Agency.
NOTE:

Kansas Dept. of Transportation Dwight D. Eisenhower State Office Building, 700 S.W. Harrison Street Topeka, Kansas 66603-3754	(785) 296-3566
REPORTING REQUIREMENTS TYPE: All spills or discharges. VERBAL: Immediately. WRITTEN: As requested by the Agency. NOTE:	
Kansas Dept. of Wildlife and Parks Kansas	(620) 672-5911 (620) 672-0795
REPORTING REQUIREMENTS TYPE: VERBAL: Courtesy Reporting WRITTEN: NOTE:	
McDonald County Commission Missouri	(417) 223-4717
REPORTING REQUIREMENTS TYPE: VERBAL: Courtesy Reporting WRITTEN: NOTE:	
Missouri DNR, Environmental Improvement and Energy PO Box 176 Jefferson City, Missouri 65102	(573) 751-4919
REPORTING REQUIREMENTS TYPE: Any Spill or discharge that meets or exceeds the Federal reportable quantity. VERBAL: Immediately, within 30 minutes WRITTEN: As requested by Agency. NOTE:	
Missouri U.S. Fish and Wildlife Service Columbia, Missouri	(573) 234-2132
REPORTING REQUIREMENTS TYPE: VERBAL: Courtesy Reporting WRITTEN: NOTE:	
New Madrid County Commission New Madrid, Missouri	(573) 748-2524

REPORTING REQUIREMENTS
TYPE:
VERBAL: Courtesy Reporting
WRITTEN:
NOTE:

Nodaway County Commission Maryville, Missouri	(660) 582-2251

REPORTING REQUIREMENTS
TYPE:
VERBAL: Courtesy Reporting
WRITTEN:
NOTE:

Pike County Commission Missouri	(573) 324-2412

REPORTING REQUIREMENTS
TYPE:
VERBAL: Courtesy Reporting
WRITTEN:
NOTE:

Polk County Commission Missouri	(417) 326-4031

REPORTING REQUIREMENTS
TYPE:
VERBAL: Courtesy Reporting
WRITTEN:
NOTE:

Taney County Missouri	(417) 546-7200

REPORTING REQUIREMENTS
TYPE:
VERBAL: Courtesy Reporting
WRITTEN:
NOTE:

U.S. Army Corps of Engineers, Missouri Office Missouri	(573) 634-5667

REPORTING REQUIREMENTS
TYPE:
VERBAL: Courtesy Reporting
WRITTEN:
NOTE:

U.S. Corps of Engineers - Illinois Illinois	(309) 794-5351
REPORTING REQUIREMENTS TYPE: VERBAL: Courtesy Reporting WRITTEN: NOTE:	
Vernon County Commission Missouri	(417) 448-2500
REPORTING REQUIREMENTS TYPE: VERBAL: Courtesy Reporting WRITTEN: NOTE:	
Oklahoma Department of Environmental Quality 707 N Robinson Oklahoma City, Oklahoma 73102	(405) 702-1000
REPORTING REQUIREMENTS TYPE: VERBAL: Courtesy Reporting WRITTEN: NOTE:	
U.S. Environmental Protection Agency, Region 6 1445 Ross Avenue, Suite 1200 Dallas, Texas 75202	(214) 665-6595 (866) 372-7745
REPORTING REQUIREMENTS TYPE: Immediately for all spills that impact or threaten navigable water or adjoining shoreline. VERBAL: Notification to the EPA is typically accomplished by the call to the NRC. WRITTEN: As the agency may request depending on circumstances. NOTE: N/A	

ADDITIONAL RESPONSE RESOURCES		
Planning and Incident Support		
COMPANY	**LOCATION**	**TELEPHONE**
National Response Corporation	3500 Sunrise Hwy Ste. T103 Great River, New York 11739	(800) 899-4672
O'Brien's Response Management Inc.	Slidell, Louisiana	(985) 781-0804
ENSR	Fort Collins, Colorado	(800) 722-2440
Western Canadian Spill Services	Calgary, Alberta	(403) 250-9606
Saskatchewan Co-op Area 1 Chairman	Saskatchewan	(780) 573-7350
Saskatchewan Co-op Area 1 Alt. Chairman	Saskatchewan	(306) 387-6449
Saskatchewan Co-op Area 2 Chairman	Box 1132 Kindersley, Saskatchewan S0L 1S0	(306) 968-2503
Saskatchewan Co-op Area 2 Co-Chairman	Box 5 Coleville, Saskatchewan S0L 0K0	(306) 965-2731
Saskatchewan Co-op Area 2 Custodian	Saskatchewan	(306) 834-7898
Saskatchewan Co-op Area 3 Chairperson	Saskatchewan	(306) 773-0234
Saskatchewan Co-op Area 3 Secretary	Saskatchewan	(306) 773-9381
Saskatchewan Co-op Area 3 Custodian	Saskatchewan	(306) 672-3723
Saskatchewan Co-op Area 4&5 Chair	Saskatchewan	(306) 842-1818
Saskatchewan Co-op Area 4&5 Vice-Chair	Saskatchewan	(306) 842-3088
Saskatchewan Co-op Area 6 Call-out	Saskatchewan	(306) 791-5058
Aberdeen Flying Service	Aberdeen, South Dakota	(605) 225-1384
Advantage Flight Solutions	Reno, Nevada	(775) 852-3512
Aero Air, LLC	Hillsboro, Oregon	(503) 640-3711
Air Services Inc	Traverse City, Michigan	(888) 922-0406
Airwest Helicopters,	Glendale, Arizona	(623) 516-2790
American Jet Charter	Oklahoma City, Oklahoma	(405) 495-5453
Aviation Charter Inc	Duluth, Michigan	(800) 486-5387
Bemidji Aviation	Bimidji, Minnesota	(218) 751-1880
Blatti Aviation, Elwood, IL	Elwood, Illinois	(815) 423-5659
Brainerd Helicopter Service	Brainard, Minnesota	(218) 829-5484
Charter First	Marshall, Minnesota	(866) 776-6261
Concrod Helicopter Charters	Concord, New Hampshire	(800) 615-1655
Crow Executive Air	Millbury, Ohio	(800) 972-2769
Custom Air Charter	Greenville, Mississippi	(662) 334-6444
Duncan Aviation	Lincoln, Nebraska	(402) 475-2611
Elliott Aviation - Des Moines	Des Moines, Iowa	(800) 447-6711
Elliott Aviation - Moline	Moline, Illinois	(800) 447-6711
Encore FBO, Sioux Falls, SD	Sioux Falls, South Dakota	(800) 888-1646

Executive Air	Bismark, North Dakota	(701) 258-5024
Executive Airaft Charter	Lafayette, Louisiana	(866) 343-9940
Fargo Jet Center	Fargo, North Dakota	(701) 235-3600
Felts Field Aviation	Spokane, Washington	(509) 535-9011
First Wing Executive Air	Indianapolis, Indiana	(317) 293-6935
Frontline Aviation	Green Bay, Wisconsin	(800) 379-3359
Helimotion, LLC	Joliet, Illinois	(815) 725-9300
Hillsboro Aviation	Hillsboro, Oregon	(503) 648-2831
JBI Helicopter Service	Pembroke, New Hampshire	(603) 225-3134
Jet Linx	Omaha, Nebraska	(402) 422-0393
Leading Edge Aviation	Bend, Oregon	(541) 383-8825
MaxAir Inc	Appleton, Wisconsin	(800) 833-1544
Midwest Corporate Aviation	Wichita, Kansas	(316) 636-9738
North Country Aviation	Gaylord, Michigan	(800) 959-1829
North Country Heliflite	North Clarendon, Vermont	(518) 361-1380
PHI Helicopters	Lafayette, Louisiana	(337) 235-2452
Rhinelander Flying Service	Wausau, Wisconsin	(715) 365-3456
Sharkeys Helicopters	West Lebanon, New Hampshire	(603) 298-8728
Silver Hawk Aviation	Lincoln, Nebraska	(800) 479-5851
Tri State Aero	Evansville, Indiana	(800) 473-2904
Tulip City Air Service	Holland, Michigan	(800) 748-0515
Ultra Air, LLC	Omaha, Nebraska	(402) 345-7372
Vermont Helicopter Charters	Burlington, Vermont	(866) 224-8830
Worcester Helicopter Charters	Worcester, Massachusetts	(800) 226-1116
Quantam Murray	100-3600 Viking Way Richmond, B.C., V6V1N6	1-877-378-7745
Alberta Coop Area 2U Custodian	Hardisty, Alberta	(780) 888-3845
Albert Coop Area 1S Regional Custodian	Lethbridge, Alberta	(403) 329-0427
Alberta Coop Area 1S Equip. Custodian	Brooks, Alberta	(403) 362-6551
Quantam Murray	100-3600 Viking Way Richmond, B.C., V6V1N6	1-877-378-7745
Euroway Industrial Svc Co. Ltd	Winnipeg, Manitoba	(204) 661-0500

FIGURE 2.6

POSSIBLE COMMAND POST LOCATIONS

TRANSCANADA COMMAND POSTS			
Pump Station to Pump Station	**Hotel Name**	**Contact Numbers**	**Accommodations**
Hardisty PS/Lakesend PS	R&R Hotel 4744-49th Street Hardisty, Alberta Canada Box 251 Hardisty AB TOB 1VO	(780) 888-0004	Meeting Room Accomodates 40 people
Lakesend PS/Monitor PS	La Biche Inn PO Box 321 Lac La Biche, AB T0A 2C0, Canada	(780) 623-4427	Meeting Room accommodates 30 people
Monitor PS/Oyen PS	Super 8 - Provost 3611 57th Avenue Provost, AB T0B 3S0, Canada	(780) 753-2255	Meeting Room accommodates 55 people
Monitor PS/Oyen PS	Lucky Lake Hotel Main St Lucky Lake, SK S0L 1Z0, Canada	(306) 858-2008	Meeting Room accommodates 40 people
Oyen PS/Bindloss PS	None Available		
Blindloss PS/Cabri PS	Super 8 Motel Junction of Hwy 9 & 41 Oyen, AB T0J 2J0, Canada	(403) 664-3010	Meeting Room accommodates 65 people
Blindloss PS/Cabri PS	Swift Current Travelodge 605 North Service Road, East Swift Current, SK S9H 3T8, Canada	(306) 773-3101	Meeting Room accommodates 20 people
Cabri PS/Herbert PS	Super 8 Motel 405n Service Rd E Swift Current, SK S9H 0A1, Canada	(306) 778-6088	Meeting Room accommodates 20 people
Cabri PS/Herbert PS	Best Western Inn 105 George St W Swift Current, SK S9H 0K4, Canada	(306) 773-4660	Meeting Room accommodates 35 people
Herbert PS/Caron PS	Howard Johnson Inn - Swift Current 1150 South Service Road East Swift Current, SK S9H 3X6, Canada	(306) 773-2033	Meeting Room accommodates 55 people
Herbert PS/Caron PS	Days Inn Hwy 1 E Swift Current, SK S9H 3X6, Canada	(306) 773-4643	Meeting Room accommodates 250 people
	Comfort Inn & Suites		

Caron PS/Regina PS	155 Thatcher Drive W. Moose Jaw, SK S6J 1M1, Canada	(306) 692-2100	Meeting Room accommodates 40 people
Caron PS/Regina PS	Hotel Saskatchewan Radisson Plaza 2125 Victoria Avenue Regina, SK S4P 0S3, Canada	(306) 522-7691	Meeting Room accommodates 100-800 people

TRANSCANADA COMMAND POSTS (Cont'd)			
Pump Station to Pump Station	**Hotel Name**	**Contact Numbers**	**Accommodations**
Regina PS/Kendal PS	Best Western 7 Oaks Inn 777 Albert St Regina, SK S4R 2P6, Canada"	(306) 757-0121	Meeting Room accommodates 150 people
Regina PS/Kendal PS	Holiday Inn Express Hotel & Suites Regina 1907 11th Avenue Regina, SK S4P 0J2, Canada"	(877) 863-4780	Meeting Room accommodates 50 people
Kendal PS/Grenfell PS	The Prince William Suites Hotel Box 1030 21 Mall Road, Melville, SK S0A 2P0, Canada	(306) 728-4546	Meeting Room accommodates 300 people
Kendal PS/Grenfell PS	Holiday Inn Hotel & Suites Regina 1800 Prince Of Wales Drive Regina, SK S4Z 1A4, Canada	(877) 863-4780	Meeting Room accommodates 80 people
Grenfell PS/Moosomin PS	Katepwa Beach Resort Hotel Lebret, SK S0G 2Y0 Canada	(306) 332-4696	Meeting Room accommodates 30 people
Grenfell PS/Moosomin PS	Whitewood Inn Hwy 1 & 9 Whitewood, SK S0G 5C0, Canada	(306) 735-2651	Meeting Room accommodates 250 people
Moosomin PS/Rapid City PS	The Russell Inn Hwy 16 & 83 MB R0J 1W0, Canada	(204) 773-2186	Meeting Room accommodates 150 people
Moosomin PS/Rapid City PS	Royal Oak Inn & Suites Brandon 3130 Victoria Avenue Brandon, MB R7B 0N2, Canada	(204) 728-5775	Meeting Room accommodates 50 people
Rapid PS/Portage La Prairie PS	Canadian Inn 150 5th Street Brandon, MB R7A 3K4, Canada	(204) 727-6404	Meeting Room accommodates 200 people
Rapid PS/Portage La Prairie PS	Super 8 Portage La Prairie MB Saskatchewan Avenue West Portage la Prairie, MB R1N, Canada	(204) 857-8883	Meeting Room accommodates 20 people
Portage La Prairie PS/Carman PS	Days Inn Highway 1 Quill Trail Portage la Prairie, MB R1N 3C3, Canada	(204) 857-9791	Meeting Room accommodates 50 people
Portage La Prairie PS/Carman PS	Days Inn & Suites-Winkler 395 Boundary Trail Winkler, MB R6W 4B1, Canada	(204) 325-8888	Meeting Room accommodates 40 people
Carman PS/Haskett PS	Super 8 Motel 400 Main St S MB R0G 1K0, Canada	(204) 746-6879	Meeting Room accommodates 30 people

TRANSCANADA COMMAND POSTS (Cont'd)			
Pump Station to Pump Station	**Hotel Name**	**Contact Numbers**	**Accommodations**
Carman PS/Haskett PS	Heartland Inn 851 Main St Winkler, MB R6W 2L8, Canada	(204) 325-4381	Meeting Room accommodates 300 people
Haskett PS/Edinburg PS	Holiday Mountain Ski Resort & Golf Course Holiday Mountain La Riviere, MB R0G 1A0, Canada	(204) 242-2172	Meeting Room accommodates 70 people
Haskett PS/Edinburg PS	Cedar Inn Steak House & Motel 502 Division Ave S Cavalier, ND 58220	(701) 265-8341	Meeting Room accommodates 50 people
Edinburg PS/Niagara PS	Forestwood Inn 504 Sunset Ave Walhalla, ND 58282	(701) 549-2651	Meeting Room accommodates 30 people
Niagara PS/Luverne PS	Holiday Inn Express Hotel & Suites Grand Forks 4051 32nd Ave South Grand Forks, ND 58201	(877) 863-4780/ (701) 772-7700	Meeting Room accommodates 30 people
Niagara PS/Luverne PS	Quality Inn & Suites 507 25th St. SW Jamestown, ND 58401	(701) 252-3611	Meeting Room accommodates 325 people
Luverne PS/Fort Ransom PS	Governors Inn & Conference Center 2050 Governors Dr Casselton, ND 58012	(701) 347-4524	Meeting Room accommodates 450 people
Luverne PS/Fort Ransom PS	America Inn 280 Wintershow Rd SW Valley City, ND 58072	(701) 845-5551	Meeting Room accommodates 60 people
Fort Ransom PS/Ludden PS	Holiday Inn Express Jamestown 803 20th St. S.W. Jamestown, ND 58401	(701) 251-2131	Meeting Room accommodates 25 people
Fort Ransom PS/Ludden PS	Ramada Aberdeen 2727 6th Avenue SE Aberdeen, SD 57401	(605) 225-3600	Meeting Room accommodates 25 people
Ludden PS/Ferney PS	Best Western-Ramkota Hotel 1400 8th Ave NW Aberdeen, SD 57401-2602	(605) 229-4040	Meeting Room accommodates 150 people
Ludden PS/Ferney PS	Ramada 2727 6th Ave SE Aberdeen, SD 57401 US	605-225-3600	Meeting Room accommodates 400 people
Ferney PS/Carpenter PS	Holiday Inn Express Hotel & Suites Aberdeen 1330-1399 7th Ave SE Aberdeen, SD 57401	(877) 863-4780/ (605) 725-4000	Meeting Room accommodates 100 people

TRANSCANADA COMMAND POSTS (Cont'd)			
Pump Station to Pump Station	**Hotel Name**	**Contact Numbers**	**Accommodations**
Ferney PS/Carpenter PS	Country Inn Suites Watertown Reviews 100 S Maple Watertown, SD 57201	(605) 886-8900	Meeting Room accommodates 70 people
Carpenter PS/Roswell PS	Best Western Of Huron 2000 Dakota Ave S Huron, SD 57350-4027	(605) 352-2000	Meeting Room accommodates 50 people
Carpenter PS/Roswell PS	Super Deluxe Inn & Suites 288 US Highway 14 W De Smet, SD 57231	(605) 854-9388	Meeting Room accommodates 100 people
Roswell PS/Freeman PS	Days Inn Mitchell 1506 South Burr St. Mitchell, SD 57301	(605) 996-6208	Meeting Room accommodates 50 people
Roswell PS/Freeman PS	Best Western Ramkota Hotel Sioux Falls 3200 West Maple Street Sioux Falls, SD 57107	(605) 336-0650	Meeting Room accommodates 700-1500 people
Freeman PS/Hartington PS	Cameron Inn 131 E Main St Canistota, SD 57012	(605) 296-3555	Meeting Room accommodates 25 people
Freeman PS/Hartington PS	Best Western Kelly Inn 1607 East Highway 50 Route Yankton, SD 57078	(605) 665-2906	Meeting Room accommodates 125 people
Hartington PS/Stanton PS	Holiday Inn Express Hotel & Suites Vermillion 1200 N. Dakota St. Vermillion, SD 57069	(877) 863-4780/ (605) 624-7600	Meeting Room accommodates 100 people
Hartington PS/Stanton PS	Holiday Inn Express Hotel & Suites Norfolk 920 South 20th Street Norfolk, NE 68701	(877) 863-4780/ (402) 379-1524	Meeting Room accommodates 200 people
Stanton PS/David City PS	New World Inn & Conference Center 265 33rd Ave Columbus, NE 68601	(402) 564-1492	Meeting Room accommodates 1000 people
Stanton PS/David City PS	Holiday Inn Express Hotel & Suites Columbus 524 E 23rd St Columbus, NE 68601	(877) 863-4780/ (402) 564-2566	Meeting Room accommodates 200 people
David City PS/Wilber PS	Sleep Inn & Suites 303 23rd St Columbus, NE 68601	(402) 562-5200	Meeting Room accommodates 35 people
David City PS/Wilber PS	Holiday Inn Lincoln-Downtown 141 N. 9th St. Lincoln, NE 68508	(877) 863-4780/ (402) 475-4011	Meeting Room accommodates 500-1000 people

TRANSCANADA COMMAND POSTS (Cont'd)			
Pump Station to Pump Station	**Hotel Name**	**Contact Numbers**	**Accommodations**
Wilbur PS/Steele City PS	Embassy Suites Hotel Lincoln 1040 P Street Lincoln, NE 68508	(402) 474-1111	Meeting Room accommodates 500-1000 people
Wilbur PS/Steele City PS	Hotel Wilber 203 S Wilson St Wilber, NE 68465	(402) 821-2020	Meeting Room accommodates 30 people
Steele City (to State Line)	Travelers Lodge 3500 North 6th Street Beatrice, NE 68310	(402) 223-4074	Meeting Room accommodates 30 people
Steele City (to State Line)	Holiday Inn Express Hotel & Suites Beatrice 4005 N 6th Street Beatrice, NE 68310	(402) 228-7000	Meeting Room accommodates 350 people
State Line to Seneca	Hiawatha Lodge 101 Lodge Rd Hiawatha, KS 66434	(785) 742-7401	Meeting Room accommodates 50 people
State Line to Seneca	Oak Tree Inn 1127 Pony Express Hwy # A Marysville, KS 66508	(785) 562-1234	Meeting Room accommodates 40 people
Seneca PS/Severance PS	Marysville Surf Motel 2105 Center Street Marysville, KS 66508	(785) 562-2354	Meeting Room accommodates 30 people
Seneca PS/Severance PS	Big Lake Resort Big Lake State Park 200 Lake Shore Drive Big Lake, MO 64437-4477	(660) 442-5432	Meeting Room accommodates 35, can use dining hall which adds an additional 100 people
Severance PS/Turney PS	Days Inn - St. Joseph 4312 Frederick Ave. Saint Joseph, MO 64506	(816) 279-1671	Meeting Room accommodates 40 people
Severance PS/Turney PS	Crowne Plaza Hotel Kansas City Downtown 1301 Wyandotte St. Kansas City, MO 64105	(888) 444-0401/ (816) 474-6664	Meeting Room accommodates 200-250 people
Turney PS/Tina PS	Radisson Hotel Kansas City Airport 11828 NW Plaza Cir Kansas City, MO 64153	(816) 464-2423	Meeting Rooms accommodates 200 people
Turney PS/Tina PS	Comfort Inn 1803 Comfort Lane Cameron, MO 64429	(816) 632-5655	Meeting Room accommodates 30 people
Tina PS/Salisbury PS	Comfort Inn Marshall Station 1356 W. College Ave. Marshall, MO 65340	(660) 886-8080	Meeting Room accommodates 25 people

TRANSCANADA COMMAND POSTS (Cont'd)			
Pump Station to Pump Station	**Hotel Name**	**Contact Numbers**	**Accommodations**
Tina PS/Salisbury PS	Holiday Inn Express Hotel & Suites 1801 West Outer Road Moberly, MO 65270	(877) 863-4780/ (660) 269-9700	Meeting Room accommodates 30 people
Salisbury PS/Centralia PS	Country Inns & Suites 817 N Keene St Columbia, MO 65201	(573) 445-8585	Meeting Room accommodates 50 people
Centralia PS/Middletown PS	Holiday Inn - Wentzville 1175 Technology Drive O'Fallon, MO 63368	(636) 300-4844	5 Meeting Rooms accommodates 10-250 people
Centralia PS/Middletown PS	Days Inn Conference Center Columbia 1900 I-70 Drive SW Columbia, MO 65203	573-445-8511	Accommodates 400 people
Middletown PS/Saint Paul PS	Comfort Inn 425 E. Veterans Memorial Pkw Warrenton, MO 63383	(636) 456-6000	Meeting Room accommodates 25 people
Middletown PS/Saint Paul PS	Comfort Inn & Suites - O'Fallon/St Charles 100 Comfort Inn Court O'Fallon, MO 63366	(636) 696-8000	Meeting Room accommodates 35 people
Saint Paul PS/Hartford PS	Holiday Inn Express St. Louis Airport - Riverport 13735 Riverport Drive St. Louis, MO 63043	(314) 298 3400	Meeting 120 Classroom Style
Saint Paul PS/Hartford PS	Best Western Airport Plaza Inn & Conf. Center 4530 N. Lindbergh Blvd. Bridgeton, MO 63044	314-731-3800	Accommodates 300 people
Hartford PS/Pierron PS	Mariners Village Resort 1 Resort Dr Carlyle, IL 62231	618-594-7666	TBD
Hartford PS/Pierron PS	Holiday Inn Express Highland 20 Central Blvd. Highland, IL 62249	(877) 786-9480/ (618) 651-1100	TBD
Pierron PS/Patoka Terminal	Holiday Inn Express Hotel & Suites 21 Mattes Ave Vandalia, IL 62471	618-283-0010	Meeting Room
Pierron PS/Patoka Terminal	Ramada 2707 Veterans Ave. Vandalia, IL, 62471	618-283-1400	Meeting Room accommodates 30 people
Steel City PS/ Hope PS	Herington Inn & Suites 565 Highway 77 Herington, KS 67449	785-258-3300	Meeting Room accommodates 20 people

TRANSCANADA COMMAND POSTS (Cont'd)			
Pump Station to Pump Station	**Hotel Name**	**Contact Numbers**	**Accommodations**
Steel City PS/ Hope PS	Holiday Inn Express Hotel & Suites 110 E. Lafayette Abilene, KS 67410	(877) 863 4780/ (325) 675-9800	Meeting Room accommodates 20 people
Hope PS/ Rock PS	Hampton Inn Derby 1701 Cambridge Street Derby, KS 67037	316-425-7900	Meeting Room accommodates 30 people
Hope PS/ Rock PS	Holiday Inn Express Hotel & Suites Andover East 54 Wichita 600 S Allen St. Andover, KS 67002	(877) 863-4780/ (316) 733-8833	Meeting Room accommodates 40 people
Rock PS/ Ponca City PS	Comfort Inn & Suites 3101 N. 14th Street Ponca City, OK 74604	(580) 765-2322	Meeting Room accommodates 30 people
Rock PS/ Ponca City PS	Holiday Inn Express Hotel & Suites Ponca City 2809 North 14th St. Ponca City, OK 74601	(877) 863-4780/ (580) 762-3700	Meeting Room accommodates 100 people
Noosomin PS/Rapid City PS	Canalta Hotel 405 Mtn. Street Moosomin, SK Canada	(306) 435-3044	Meeting Room Accomodates 40 ppl
Severence PS/Turney PS	Stoney Creek Inn 1201 North Woodbine Road St. Joseph, MO 64506	(816) 901-9600	TBD

3.0 RESPONSE ACTIONS

3.1 Initial Response Actions

Figure 3.1 Spill Classification

Initial Response
Line Break Or Leak
Fire
Severe Thunderstorm/Flash Flooding/Landslide
Tornadoes
Earthquake
Winter Storm
Volcanic Eruptions
Bomb Threat
Release To Groundwater
Abnormal Operations

3.2 Documentation of initial Response Actions

3.3 Oil Containment, Recovery and Disposal/Waste Management

Figure 3.2 Product Specific Response Considerations

3.4 Storage/Disposal

3.5 Sampling and Waste Analysis Procedures

3.6 Safety Awareness

3.7 Emergency Medical Treatment and First Aid

3.1 INITIAL RESPONSE ACTIONS

Initial response actions are those taken by local personnel immediately upon becoming aware of a discharge or emergency incident, before the Initial Response Team (described in Section 4.0) is formed and functioning. Timely implementation of these initial steps is of the utmost importance because they can greatly affect the overall response operation.

The pages that follow discuss initial response actions for a variety of emergencies that have the possibility of occurring. These emergencies are discussed in the order listed below:

- Initial Response
- Line Break or Leak
- Fire
- Severe Thunderstorm/Flash Flooding/Landslide
- Tornadoes
- Earthquake
- Winter Storm
- Volcanic Eruptions
- Bomb Threat
- Release to Groundwater
- Abnormal Operations

It is important to note that **these actions are intended only as guidelines** . The appropriate response to a particular incident may vary depending on the nature and severity of the incident and on other factors that are not readily addressed. Note, that **without exception, employees and public safety is first priority.**

The first Company person on scene will function as the Incident Commander (IC) until relieved by an authorized supervisor who will assume the IC position. Transfer of command will take place as more senior management respond to the incident. The role of IC will typically be assumed and retained by area management.

The person functioning as **Incident Commander** during the initial response period **has the authority to take the steps necessary to control the situation and must not be constrained by these general guidelines.**

INITIAL RESPONSE ACTIONS - SUMMARY PERSONNEL AND PUBLIC SAFETY IS FIRST PRIORITY

RESPONSE TIMES*

US DOT Tier	1	2	3
High Volume Area	6 HR	30 HR	54 HR
All Other Areas	12 HR	36 HR	60 HR

CONTROL

- Eliminate sources of ignition
- Isolate the source of the discharge, minimize further flow

NOTIFY

- Make internal and external notifications
- Activate local Company personnel as necessary
- Activate response contractors and other external resources as necessary

CONTAIN

- Begin spill mitigation and response activities
- Monitor and control the containment and clean-up effort
- Protect the public and environmental sensitive areas

* Response resources and personnel available to respond within time specified after discovery of a worst case discharge per US DOT 49 CFR Part 194.115

In addition to the potential emergency events outlined in this Section, the Company has identified several "abnormal operations" that could be expected in the pipeline facilities. The Company has defined the events and established procedures to identify, eliminate or mitigate the threat of a worst case discharge due to these events. In compliance with 49 CFR 195.402(d), these procedures are defined in the Company's Operations Manual.

Company First Responder / On Scene

- Verify emergency exists.
- Notify the Keystone Oil Control Center of the incident.
- Follow the appropriate steps outlined in the "Specific Incident Response Checklist" (Figure 3.1) and the "Product Specific Response Considerations" (Figure 3.2).
- Notify the Keystone Oil Control Center of the incident.
- Contact / Utilize local emergency services, as necessary (police, fire, medical).
- Follow TransCanada's Working Alone Procedures (EDMS No. 003743627).

Regional Emergency Operation Center

- Ensure local emergency agencies have been contacted (police, fire, medical).
- Assign personnel immediately to the discharge site to assist with emergency response (QI) and spill containment.
- Activate additional company and response contractors to site as situation demands.
- Confirm safety aspects at site, including need for Personal Protective Equipment (PPE), sources of ignition, and potential need for evacuation.
- Evaluate the severity, potential impact, safety concerns and response requirements based on the initial data provided by the First Person On-scene. Refer to the spill response evaluation Flowchart in this section.
- Establish communications with the Corporate Emergency Operations Center
- Perform notifications using Figure 2.1, as appropriate.

Area Management

- Proceed to spill site and coordinate response and clean-up operations.
- Assume the role of Incident Commander.
- Coordinate/perform activation of additional spill response contractors, as the situation demands (telephone reference is provided in Figure 2.5).
- Direct containment, dispersion, and/or clean-up operations in accordance with the "Product Specific Response Considerations" provided in Figure 3.2.
- Complete the "Product Release Report" provided in Appendix F.

Local Company Personnel

- Assigned personnel will immediately respond to a discharge from the Pipeline or Facility, as the situation demands.
- Assist as directed at the spill site.
- Assume Incident Management Team roles as deemed by Incident Commander

Range of Reported Oil Thicknesses Tool

	Barely Discernible	**Silvery Sheen**	**Rainbow Colors**	**Darkening Bands of Color**	**Dull Colors**	**Light Brown**
Reported average threshold, Microns	**0.09**	**0.1**	**0.6**	**0.9**	**2.7**	**8**
Range, microns	**0.04 - .016**	**0.05 - 0.18**	**0.1 - 1.0**	**0.1 - 2.5**	**1.0 - 5.5**	**2.0 - 15.0**

Source ExxonMobil Research and Engineering Company, Oil Spill Response Field Manual. Revised 2008

FIGURE 3.1

[redacted]

Spills/Releases to Environment:

Minor

- A spill/release, onsite, that poses no adverse affect to the environment nor impact neither to a water body nor to groundwater. The spill may or may not be reportable to a regulatory agency.

Serious

- A spill/release, onsite or off-site/off-right-of-way, that poses an adverse affect to the environment but no impact to a water body nor to groundwater.

Major

- A spill/release, onsite or off-site/off ROW, that poses an adverse affect to the environment including an impact to a water body or to groundwater.

Critical

- Emergency response for containment or clean up is required. A spill/release, onsite or off-site/off ROW, that poses an adverse affect to the environment including an impact to a water body or to groundwater.

Complaints - Health & Safety:

Minor

- Unverified community complaint from a Landowner, Police, Fire, Municipality, or a Ministry.
- Verified employee complaint where an investigation is required to obtain resolution.

Serious

- Verified community complaint likely to cause danger/risk to the public, employees or TransCanada facilities.

Major

- Employee work refusal based on belief of unhealthy or unsafe work conditions.

Critical

- Regulatory body notified of employee complaint (by employee) and investigates employee work refusal.

SPECIFIC INCIDENT RESPONSE CHECKLIST

INITIAL RESPONSE

- Take appropriate personal protective measures.
- Conduct vapour monitoring
- Complete hazard assessment
- Secure site.
- Call for medical assistance if an injury has occurred.
- Notify Keystone Oil Control Center and area management of the incident.
- Eliminate possible sources of ignition in the near vicinity of the spill.
- Advise personnel or public in the area of any potential threat and/or initiate evacuation procedures.
- Identify/isolate the source and minimize the loss of product.
- Restrict access to the spill site and adjacent area as the situation demands. Take additional steps necessary to minimize any threat to health and safety.
- Verify the type of product and quantity released. (Material Safety Data Sheet(s) are provided in Appendix G).

All personnel are reminded that outsiders other than emergency services will not be allowed in the area during the time of an emergency and that statements issued to the media or other interested parties should be given by designated Company Management. Be courteous with media representatives and direct them to the designated spokesperson.

LINE BREAK OR LEAK, SPECIFIC RESPONSE (Including Piping Rupture/ Leak Valve Rupture/Leak and Manifold Failure)

Oil Control Center (OCC)

- Shut down pipeline.
- Close upstream and downstream block valves.
- Notify On-call regional designate to attend site as a First Responder.
- Initiate Regional EOC Manager Notification once incident is confirmed by First Responder.
- Initiate Calgary EOC Manager Notification and pass on Regional EOC contact Information.
- Notify Oil Control Center On-call designate.
- Notify Oil Movements Scheduling.
  - During Business /After hours - Callout Database
- Should media inquiries be received directly in the Oil Control Center, inform callers that all media inquiries are to be referred to our Media Relations Representative at the following Phone Numbers:
  - (403) 920-7859
  - (800) 608-7859

FIRES (MINOR, MAJOR, EXPLOSION) SPECIFIC RESPONSE

Oil Control Procedures

Be aware of Fire Weather conditions.

- Watch - Critical fire weather conditions are forecast to occur.
- Red Flag Warning - Critical Fire weather conditions are either occurring or will shortly.

Individual Discovering the Fire - (All Employees)

- Call the Local Emergency Response Agency (911).
- Notify Oil Control Center (this should be the 1st notification completed in the event that it is a remote location with no immediate impacts to life safety).
- Notify Area Management.
- Complete all First Responder responsibilities and initially assume the role of TransCanada's Incident Commander.
- Ensure ongoing communications with Keystone Oil Control Center.
- Follow the instructions outlined in section 3.1 Initial Response and the Responsibilities outlined in TransCanada's First Responder checklist.

Note: Pipeline right-of-ways are used by Firefighters as a fire break (barrier) to isolate fires and prevent them from growing in size. Right-of-ways are commonly used to access to fire areas. Many times Firefighters will need to increase the size of the cleared space over the Pipeline right-of-way to prevent the fire from leaping from tree top to tree top. To do this, heavy equipment may be used to quickly increase the amount of cleared space between the fire area and unignited forest. The following are steps to consider when working with the local authority on creating these fire breaks.

- Use your best judgment to ensure the safety of staff, fire ground workers and the public when determining if this activity is safe to perform;
- Call and confirm with Asset Reliability if this activity is safe and implement any instructions provided by Asset Reliability. Asset Reliability's role is to provide directions to protect the health and safety of those involved as well as pipeline integrity;
- Be physically on site to coordinate the activities related to any pipeline crossings;
- Stake the pipeline to identify the location of the pipe(s) in the right-of-way.
- First preference is to use already existing pipeline crossing areas;
- Gather the appropriate information to complete a formal pipeline crossing agreement. In Canada, send required information to the Land Department in Calgary.
- Notify Keystone Console and area management.
- Shut off pumps.
- Coordinate with the Keystone Oil Control Center to close appropriate valves to isolate in the vicinity of the fire, if necessary.
- Isolate Pump Station from Mainline.
- Evacuate site as safety considerations dictates.
- Notify Keystone Console of evacuation route and final destination.
- Notify Keystone Console of safe arrival.

- Inspect pump station, equipment and controls after the fire is extinguished and safe to return.
- Evaluate pipeline, monitoring or control systems for evidence of heat damage.
- Notify engineering to conduct further investigation if damage is found.
- Make appropriate repairs and return Pipeline to service.

Third Party Call In Confirmation of Fire

This procedure applies to a pipeline facility integrity threat identified received via third party thru TransCanada Emergency Line (PDL 800-447-8066) or direct call to Keystone Oil Control reporting a fire at or adjacent to Keystone Pipeline Facilities or ROW.

If the third party indicates a pipeline facility (Pump Station/QMU Building/ESB Building etc.) is on fire or in jeopardy of catching fire the controller will do the following:

- Should the call come from PDL, confirm receipt of third party call-in contact information. If third party call-in comes direct to console please fill out third party call-in form Third Party Template
- Once confirming all information with the caller and it is clear that the pipeline facilities are at risk, implement the following steps:
- Shutdown and Isolate the affected pump station OR
- Confirm, checking with leak triggers and discussion with third party, that the fire is not due to a pipeline failure.
- Once confirmed that the source is not us, keep the pipeline running.
- Notify On-call regional designate to investigate as a First Responder and provide further guidance.
- Initiate Regional EOC Manager Notification once incident is confirmed by First Responder.
- Initiate Calgary EOC Manager Notification and pass on Regional EOC contact Information.
- Notify Oil Control Center On-call designate.
- Notify Oil Movements Scheduling.
    - During Business /After hours - Callout Database
- Should media inquiries be received directly in the Oil Control Center, inform callers that all media inquiries are to be referred to our Media Relations Representative at the following Phone Numbers:
    - (403) 920-7859
    - (800) 608-7859

Aerial Pipeline Patrol Confirmation of Fire

If the Oil Control Center receives a call from the Aerial Pipeline Patrol indicating a fire on or adjacent to Keystone Pipeline ROW/Facilities, the controller's response will be as follows:

If the pilot/observer indicates a pipeline facility (Pump Station/QMU Building/ESB Building etc.) is on fire or in jeopardy of catching fire the controller will do the following:

- Once confirming all information from the pilot/observer is clear that the pipeline facilities are at risk.
- Shutdown and Isolate the affected pump station.
- Notify On-call regional designate to investigate as a First Responder and provide further guidance.
- Initiate Regional EOC Manager Notification once incident is confirmed by First Responder.
- Initiate Calgary EOC Manager Notification and pass on Regional EOC contact Information.

- Notify Oil Control Center On-call designate.
- Notify Oil Movements Scheduling.
    - During Business /After hours - Callout Database

If the pilot/observer indicates a fire on or adjacent to our Pipeline ROW, the controller will do the following:

- Confirm, checking with leak triggers and discussion with third party, that the fire is not due to a pipeline failure.
- Once confirmed that the source is not us keep the pipeline running.
- Notify On-call regional designate to investigate as a First Responder and provide further guidance.
- Initiate Regional EOC Manager Notification once incident is confirmed by First Responder.
- Initiate Calgary EOC Manager Notification and pass on Regional EOC contact Information.
- Notify Oil Control Center On-call designate.

Company Employee Confirmation of Fire

If the integrity threat is confirmed by a TransCanada Employee that has been dispatched as a First Responder to a third party call-in of a fire, at or adjacent to Keystone Pipeline Facilities or ROW, the controller's response will be as follows:

- Confirm isolation of affected area, including valve positions with Regional personnel and commence further isolation or pipeline shutdown strategy with Regional personnel as required.
- Should the recommendation from the field be to shutdown the pipeline, the controller is to do a controlled shutdown and isolate as per Pipeline Isolation and Segmentation Standards
- Confirm EMS has been initiated and Calgary EOC is active. Continue Monitoring pressure profiles using SCADA/LDS.
- Ensure all receipt and delivery interconnects are notified and updated as required.
- Notify Oil Control Center On-call designate.
- Notify Oil Movements Scheduling.
    - During Business /After hours - Callout Database
- Should media inquiries be received directly in the Oil Control Center, inform callers that all media inquiries are to be referred to our Media Relations Representative at the following Phone Numbers:
    - (403) 920-7859
    - (800) 608-7859

TRANSCANADA GAS PIPELINE RUPTURE/FIRE - KEYSTONE CONVERSION PIPE ROW

This procedure applies to a Keystone Pipeline integrity threat from an adjacent TransCanada Gas Pipeline rupture/fire in the conversion Pipeline ROW. The Conversion Pipeline ROW extends from Burstall Pigging Station to Elm Creek Pigging Station.

In the Event that the controller receives a suspected or a confirmed notification of a TransCanada Gas Pipeline rupture/fire adjacent to Keystone Oil Pipeline, the controller is to do the following:

- Confirm thru SCADA/LDS that pressures and flow rates are steady and that no other leak triggers are present.
- If no other leak triggers are present, the controller is to drive Keystone Pipeline to safe discharge limits and continue running.
- Notify On-call designate/first responder that the Keystone Pipeline is still running and we will await their direction once they arrive on scene.

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- First responder will instruct the controller to shutdown or continue running once on scene and the integrity of Keystone Pipeline has been assessed.
- Notify Oil Control Center On-call designate.
- Confirm EMS has been initiated and Regional/Calgary EOC is active. Continue monitoring pressure profiles using SCADA/LDS.
- Should media inquiries be received directly in the Oil Control Center, inform callers that all media inquiries are to be referred to our Media Relations Representative at the following Phone Numbers:
  - (403) 920-7859
  - (800) 608-7859

If one or more leak triggers exist, the controller is to initiate an Emergency Pipeline Shutdown and isolate as per Pipeline Isolation and Segmentation Standards

- Notify On-call designate/first responder that the Keystone Pipeline has been shutdown and we will await their direction once they arrive on scene.
- Notify Oil Control Center On-call designate.
- Confirm EMS has been initiated and Regional/Calgary EOC is active. Continue monitoring pressure profiles using SCADA/LDS.
- Notify Oil Movements Scheduling.
  - During Business /After hours - Callout Database
- Should media inquiries be received directly in the Oil Control Center, inform callers that all media inquiries are to be referred to our Media Relations Representative at the following Phone Numbers:
  - (403) 920-7859
  - (800) 608-7859

TRANSCANADA GAS PIPELINE RUPTURE/FIRE - KEYSTONE CONVERSION PIPE SHARED PUMP STATION

This procedure applies to a Keystone Pipeline integrity threat from an adjacent TransCanada Gas Pipeline rupture/fire at a shared pump station . The Shared Pump Stations include Cabri, Herbert, Caron, Regina, Kendall, Grenfell, Moosomin, Rapid City and Portage La Prairie.

In the event that the suspected or confirmed TransCanada Gas Pipeline rupture/fire occurs at a shared pump station facility, the controller is to do the following:

- Confirm thru SCADA/LDS that pressures and flow rates are steady and that no other leak triggers are present.
- If no other leak triggers are present, the controller is to isolate the pump station from the mainline and drive Keystone Pipeline to safe discharge limits and continue running.
- Notify On-call designate/first responder that the Keystone Pipeline is still running and we will await their direction once they arrive on scene.
- First responder will instruct Keystone Pipeline Operator to shutdown or continue running once on scene and the integrity of Keystone Pipeline has been assessed.
- Notify Oil Control Center On-call designate.
- Confirm EMS has been initiated and Regional/Calgary EOC is active. Continue monitoring pressure profiles using SCADA/LDS.
- Should media inquiries be received directly in the Oil Control Center, inform callers that all media inquiries are to be referred to our Media Relations Representative at the following Phone Numbers:
  - (403) 920-7859
  - (800) 608-7859

If one or more leak triggers exist, the controller is to initiate an Emergency Pipeline Shutdown and isolate as per Pipeline Isolation and Segmentation Standards

- Notify On-call designate/first responder that the Keystone Pipeline has been shutdown and the pump station has been isolated and we will await their direction once they arrive on scene.
- Notify Oil Control Center On-call designate.
- Confirm EMS has been initiated and Regional/Calgary EOC is active. Continue monitoring pressure profiles using SCADA/LDS.
- Notify Oil Movements Scheduling.
    - During Business /After hours - Callout Database
- Should media inquiries be received directly in the Oil Control Center, inform callers that all media inquiries are to be referred to our Media Relations Representative at the following Phone Numbers:
    - (403) 920-7859
    - (800) 608-7859

SEVERE THUNDERSTORM (Flash Flooding/Landslide) SPECIFIC RESPONSE

Severe Thunderstorm/Flash Flooding/Landslide

Thunderstorms are a year round occurrence with lightning a major threat. The potential of flash flooding is also possible when one area is affected for an extended period.

- Be aware of changing weather conditions.
  - Severe Thunderstorm Watch - Conditions are favorable to the development of thunderstorms.
  - Severe Thunderstorm Warning - A severe thunderstorm has been observed or is imminent.
  - Flash Flood Watch- Flash flooding is possible within 6 hours after heavy rains have ended.
  - Flash Flood Warning - Flash flooding is occurring or imminent.
- Terminate outdoor work when lightning is occurring and move to shelter.
- Avoid areas subject to sudden flooding until the thunderstorm passes.
- Evaluate the situation after weather event.
  - Does standing water prevent visual inspection?
  - Have flood waters damaged the Pipeline?
  - Have flood waters exposed buried piping?
  - Has soil shifted that could lead to a landslide?
- Initiate appropriate pipeline patrol by the most expedient means possible to determine extent of damage.
- Make all necessary repairs.

TORNADO/STRAIGHT LINE WINDS SPECIFIC RESPONSE

Tornadoes

Although many disasters cannot be prevented or predicted, preparation can significantly reduce losses. In the event of a severe weather condition or a natural disaster, the Area Manager or assigned designee will be the Emergency Coordinator.

- **Be Aware of Changing Weather Conditions**
  - Tornado watch - Conditions are right for the formation of a tornado.
  - Tornado warning - A tornado has been sighted but is not in the area at this time.
  - Tornado alert - A tornado has been sighted in the immediate area, take cover immediately.

- **If Severe Weather Conditions Threaten**
  - Carry a battery operated portable radio and monitor conditions.
  - If a tornado is observed and time permits, evacuate the area.
  - If the tornado is approaching a pump station, notify the Keystone Console to remotely isolate the station.
  - In vehicle, drive away from tornado at right angle. Get out of car and seek shelter if tornado cannot be avoided.
  - If outdoors, shelter in ditch, excavation or other low spot and lie flat, face down.
  - Make certain that all personnel are aware of the condition.
  - Stay in shelter until conditions are safe.

- **Immediately After the Storm**
  - Account for all personnel.
  - Survey for damages.
  - Initiate team for any repairs.
  - Refer to this Plan for additional response guidance regarding fires, spills, etc., as needed.

EARTHQUAKE SPECIFIC RESPONSE

Earthquake

The actual movement of the ground in an earthquake is rarely the direct cause of death or injury. Most casualties result from falling objects and debris because the shocks can shake, damage or demolish buildings and other structures.

- **Stay calm. Don't panic.**
- If you are indoors, stay there. Do not run outside.
- If you are in a building, take cover under a heavy furniture or stand in an inside doorway away from windows. (A door frame or the inner core of a building is its strongest point and least likely to collapse.)
- Exit building as situation determines.
- If you are outside, stay there. Move away from buildings to avoid falling debris. Avoid damaged utility lines.
- If you are driving, stop quickly and stay in your car. If possible, do not stop on a bridge, overpass or where buildings can fall on you. Your car can provide protection from falling debris.
- Do not reenter damaged buildings. Walls may collapse after the original shaking has ceased.
- Evaluate the situation and initiate appropriate pipeline patrol by the most expedient means possible to determine extent of damage.
- Make all necessary repairs as resources and conditions allow.

SEVERE WINTER STORM SPECIFIC RESPONSE

Winter Storm

- Be aware of Changing Weather Conditions
    - Winter Storm Watch - Conditions are expected but not imminent.
    - Winter Storm Warning - A significant winter storm is occurring, imminent, or likely.
    - Blizzard Warning - Winds at least 35 mph, blowing snow frequently reducing visibility to 0.25 miles or less, and dangerous wind chills are expected.
- Listen to local radio stations for weather advisory and road condition reports, carry a survival kit, and start the trip with a full tank of gasoline.
- Inspect pump station, equipment, and controls after storm for damage.
- Make any repairs as necessary.

VOLCANIC ERUPTIONS SPECIFIC RESPONSE

Volcanic Eruptions

If a volcanic eruption ejects a large ash plume and the wind carries the ash to the pipeline facilities, this may cause a disruption of operations by making travel difficult or impossible due to reduced visibility.

- Begin gathering information from news media, field personnel, etc. to assess any ash cloud size, location, heading and speed as soon as news of an eruption breaks.
- Consider recalling crews prior to the expected arrival of the ash cloud while it is still clear to travel. If a crew is at a station when an ash fall begins, they should probably stay there for the duration and not travel until it is determined to be safe after the event.
- Advise contract aerial patrol service of the situation if contacted for the beginning of a pipeline patrol or if an aerial patrol is in progress.
- Inspect pump station, equipment and controls after eruption for damage.
- Make any repairs as necessary.

[redacted]

Bomb Threats

The following pages provide guidelines for actions to be taken in the event a bomb threat is received. A bomb threat to the pipeline system or personnel may present itself in any of several ways:

- Phone
- E-mail
- Fax
- Radio
- Mail
- Word-of-mouth
- Increase in the Homeland Defense Status

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RELEASE TO GROUNDWATER SPECIFIC RESPONSE

The following procedure has been prepared in the event of a release of crude oil from the pipeline into a hydraulically sensitive groundwater resource area, but may not be currently identified as a high consequence area by PHMSA. Specific areas of concern have been evaluated for their sensitivity and plans to effect cleanup have been discussed. These specific areas include:

- [redacted]
- [redacted]
- [redacted]

RESPONSE PROCEDURE

- Evaluate the topography and evidence of surface contamination.
- Establish containment, accounting for public safety, spill volume, terrain, and presence of surface water.
- Notify landowner and appropriate public agencies of potential groundwater contamination.
- Immediately retain an independent consultant with expertise in this area to evaluate impacts and remediation options.
- Consult with appropriate agencies regarding remediation, including water and soil cleanup levels, and need for groundwater monitoring.
- Notify and procure additional response equipment and personnel as necessary to address site-specific conditions.
- Dig intercept trench downgradient of release point.
- Line trench and stage vacuum truck to remove contaminated oil/water mixture.
- Excavate surface catchment upgradient of the intercept trench and near leading edge of visible contamination.
- Excavate until contaminated soil is completely removed and clean soil is encountered or conditions prohibit continued digging.
- Line the catchment to limit or prohibit further groundwater contamination.
- Move vacuum truck from intercept trench to catchment to recover oil and/or oily water.
- Line drop down area to stage contaminated soil as excavated.
- Segregate waste streams to minimize later disposal.
- Based on anticipated release, stage temporary storage and additional vacuum trucks to ensure recovery efforts continue without interruption.

  Options for Long term Remediation:

  - Air sparging
  - Vacuum extraction
  - Conventional pump and treat
  - Bioslurping
  - Excavation
  - Enhanced biodegradation/bioremediation
  - Chemical addition/oxidation

  - Natural Attenuation
- Enlist additional experts, as appropriate, for continuing remediation and coordination with appropriate agencies.

ABNORMAL OPERATIONS SPECIFIC RESPONSE

Abnormal Operations Specific Response

- If operating design limits have been exceeded (increase or decrease pressure or flow) and no emergency condition exists, stop operations and immediately investigate the pipeline.
- Verify whether a true safety problem, equipment malfunction, or operator error is present. Note: In all cases, safety to operations, the general public, and property will govern actions taken.
- Make appropriate repairs before continuing operations. Note: Corrective action will only be done by qualified personnel to perform the type of work involved.
- Monitor affected systems until normal operations are resumed.
- Complete follow-up and written reporting, as the situation demands.

Note: It is the responsibility of the pipeline operator to carry out the response procedures for abnormal pipeline operations as outlined in their respective O&M Manual.

3.2 DOCUMENTATION OF INITIAL RESPONSE ACTIONS

It is difficult, particularly during the first few minutes of an initial response operation, to think about the importance of documentation. A log should be maintained which documents the history of the events and communications that occur during the response. When recording this information, it is important to remember that the log may become instrumental in legal proceedings, therefore:

- Record only facts, do not speculate.
- Do not criticize the efforts and/or methods of other people/operations.
- Do not speculate on the cause of the spill.
- Do not skip lines between entries or make erasures. If an error is made, draw a line through it, add the correct entry above or below it, and initial the change.
- Record the recommendations, instructions, and actions taken by government/regulatory officials.
- Document conversations (telephone or in person) with government/regulatory officials.
- **Request that government/regulatory officials document and sign their recommendations or orders (especially if company personnel do not agree with the suggestions, instructions, or actions).**

3.3 OIL CONTAINMENT, RECOVERY AND DISPOSAL/WASTE MANAGEMENT

After initial response has been taken to stop further spillage and notifications made to the required agencies, the Company will begin spill containment, recovery, and disposal operations.

The Incident Commander will assess the size and hazards of the spill (see Figure 3.2). The type of product, the location of the spill, and the predicted movement of the spill will be considered.

Based on this assessment, additional clean-up personnel and equipment will be dispatched to the site and deployed to control and contain the spill. Boom may be deployed in waterways to contain the spill and to protect socio-economic and environmentally sensitive areas. Booms may also be used in waterways to deflect or guide the spill to locations where it can more effectively be cleaned up using skimmers, vacuum trucks, or sorbent material. Clean-up equipment and material will be used in the manner most effective for rapid and complete clean-up of all spilled product.

Response and clean-up will continue until all recoverable product is removed, the environment is returned to its pre-spill state, and the Unified Command of the Company Incident Commander and the Federal and/or State On-Scene Coordinators determine that further response and cleanup is no longer necessary.

FIGURE 3.2

<table>
<tr><td colspan="2">FLAMMABLE LIQUIDS
(Non-Polar/Water-Immiscible)</td></tr>
<tr><td colspan="2">The following information is intended to provide the initial responder(s) with data that may be useful in making quick decisions and executing prompt response actions. The information is intended for guideline purposes only.</td></tr>
<tr><td colspan="2">PRODUCTS: Crude Oil</td></tr>
<tr><td colspan="2">HAZARD IDENTIFICATION / RECOGNITION</td></tr>
<tr><td>GUIDE NO. 128</td><td>DANGERS

1. HIGHLY FLAMMABLE: Will be easily ignited by heat, sparks or flames.
2. Vapors may form explosive mixtures with air.
3. Vapors may travel to source of ignition and flash back.
4. Most vapors are heavier than air. They will spread along ground and collect in low or confined areas (sewers, basements, tanks).
5. Vapor explosion hazard indoors, outdoors or in sewers.
6. Those substances designated with a “P” may polymerize explosively when heated or involved in a fire.
7. Runoff to sewer may create fire or explosion hazard.
8. Containers may explode when heated.
9. Many liquids are lighter than water.
10. Substance may be transported hot.
11. If molten aluminum is involved, refer to Emergency Response Guide No. 169.</td></tr>
<tr><td colspan="2">HEALTH</td></tr>
<tr><td colspan="2">1. Move victim to fresh air. Call 911 or emergency medical service.
2. Apply artificial respiration if victim is not breathing. Administer oxygen if breathing is difficult.
3. Remove and isolate contaminated clothing and shoes.
4. In case of contact with substance, immediately flush skin or eyes with running water for at least 20 minutes.
5. Wash skin with soap and water.
6. Keep victim warm and quiet.
7. Ensure that medical personnel are aware of the material(s) involved, and take precautions.</td></tr>
<tr><td colspan="2">PUBLIC SAFETY</td></tr>
<tr><td colspan="2">1. Isolate spill or leak area immediately for at least 50 meters (150 feet) in all directions.
2. Keep unauthorized personnel away.
3. Stay upwind.
4. Keep out of low areas.
5. Ventilate closed spaces before entering.</td></tr>
<tr><td>EVACUATION</td><td>Large Spill 1. Consider initial downwind evacuation for at least 300 meters (1,000 feet). Fire 1. If tank, rail car or tank truck is involved in a fire, ISOLATE for 800 meters (1/2 mile) in all directions; also, consider initial evacuation for 800 meters (1/2 mile) in all directions.</td></tr>
<tr><td colspan="2">Information provided by the Emergency Response Guidebook 2008.</td></tr>
</table>

3.4 STORAGE/DISPOSAL

Strict rules designed to ensure safe and secure handling of waste materials govern the Company waste disposal activities. To ensure proper disposal of recovered oil and associated debris, the following guidelines should be considered:

- In the event of a product spill, Facilities have limited capacity to store recovered product and water. Separated product is pumped to frac tanks or to trucks to be carried to the Facility for processing.
- Oily debris will be segregated on site and containerized for temporary storage prior to disposal in accordance with hazardous waste regulations.
- Transportation of waste material will be performed in accordance with all applicable Federal and State Regulations.
- Waste associated with the spill will be disposed at sites that have the necessary permits to accept the type of waste to be discharged.

The Company's Community, Safety and Health Administration Dept. will coordinate activities and secure the permits to ensure proper disposal or recycling of recovered product and debris.

3.5 SAMPLING AND WASTE ANALYSIS PROCEDURE

The Company's sampling and waste analysis practices are governed by the regulations for the applicable Province/State and Federal agency. These regulations outline methods and procedures for determining the chemical and physical characteristics of wastes generated by the Facility, including waste associated with spills, so that they may be properly stored, treated, or disposed.

3.6 SAFETY AWARENESS

It is the corporate policy of the Company to provide a safe workplace for all workers. All employees and contractors are responsible for maintaining the safety and health of all workers on the pipeline and the response operations.

Prior to engaging in any spill response activity:

- All employees/contractors must have received orientation from the Company Safety Plan.
- All U.S. contractor response personnel must be in compliance with Occupational Safety and Health Administration training requirements.
- All other personnel will have completed appropriate training for their position as outlined in Section 4.0.
- No employee/contractor shall engage in activities which place them at risk without the appropriate protective equipment and training.

Response Safety

All Company and contractor personnel are expected to comply with the Site Safety Plan for each spill incident.

- Any concern regarding health or safety issues should be immediately addressed.
- The First Responder must consider the spill site as dangerous and the local atmosphere explosive until air monitoring procedures prove that the area is safe.

- The First Responder must exit the area against or across the wind, if possible, and must also evacuate others who are working in the area.
- All injuries, no matter how minor, must be reported to the Incident Commander in a timely manner.
- Prior to entering a spill area, a qualified person must perform an initial safety and health evaluation of the site.

Air Monitoring

A Safety Monitor shall be designated who is trained in the operation of air monitoring equipment. The Incident Commander must ensure that Safety Monitors are trained and that their equipment is maintained and ready for use.

- The air monitoring equipment shall be activated and checked at the location in which it is stored.
- Calibration of instruments should be performed before use.
- Air monitoring measurements which are to be made prior to entry into the spill area include:
  - Oxygen content
  - Lower Explosive Limit (LEL) with a pentane calibrated instrument
  - Benzene level

H2S

- Lower Explosive Limit readings above 10% require immediate evacuation of the area and elimination of ignition sources.
- Oxygen readings below 19.5% require the use of air supplied respiratory protection.
- After assuring that there are no hazards relating to explosion or oxygen depletion, sampling for benzene or total petroleum hydrocarbons shall dictate the appropriate respiratory devices to be used by persons entering the area.
- Benzene levels must be below 0.5 ppm to work without respiratory protection. At a level of greater the 0.5 but less than 5 ppm a half face respirator may be used. When the level is between 5.0 and 25 ppm a full face respirator must be used. Anything readings higher than 25 ppm, a supplied air or SCBA must be used.

If H2S is present in low concentrations respiratory protective equipment may be used following the following criteria based on approved protection factors. Using the approved protection factors of 10 for ½ face respirators and 50 for full face and the most stringent OEL which is 1 ppm (Canadian Federal COHSR) the corresponding maximum use concentrations would be 10 ppm for ½ face and 50 ppm for full face. The use of respirators however should be limited to areas with concentrations less than 10 ppm. If concentrations are higher workers should immediately leave the area.

- Hydrogen Sulfide is an extremely hazardous toxic compound that is present in most crude oils that are transported through the pipeline.
- Air monitoring for Hydrogen Sulfide will be done by all personnel working on or near the pipeline and during any cleanup operation.

- Hydrogen Sulfide is characterized by a rotten egg smell at low level concentrations.
- The gas causes rapid temporary paralysis of the olfactory system leading to the loss of the sense of smell.
- Permissible exposure limits in many countries is 10 ppm. In Canada the occupational exposure level is 1 ppm.

Symptoms of exposure to Hydrogen Sulfide are:

- 0-10 ppm no known health effects for most people
- 10-100 ppm can cause headache, dizziness, nausea (100 ppm is the immediately dangerous to life and health level)
- 100-500 ppm above mentioned effects within a short time and more severe. Loss of breathing and death is possible within minutes.
- 500-700 ppm affects the central nervous system. Symptoms could include a loss of balance and a loss of reasoning. You could become unconscious and stop breathing within seconds
- 700 and greater would result in immediate loss of consciousness and permanent brain damage due to hypoxia or death if not rescued immediately
- The Incident Commander is responsible for arranging industrial hygiene monitoring in the post discovery period.

Decontamination

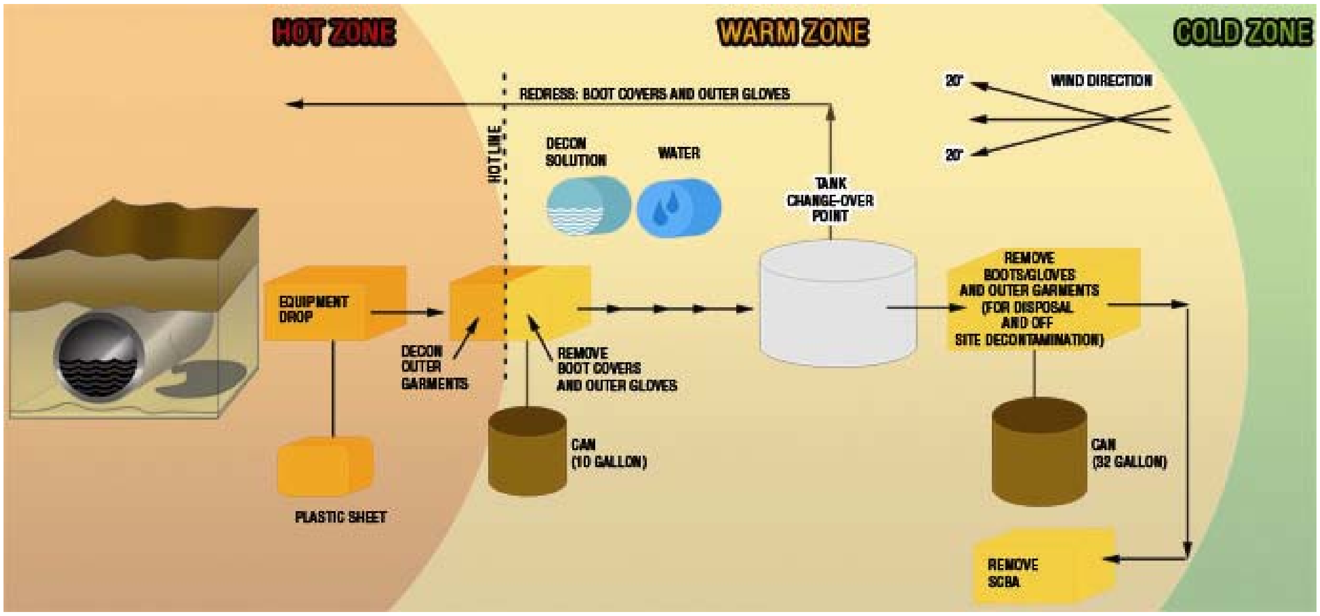
Through training programs, Facility personnel know and understand the importance of the removal of hazardous substances from their person if they are contaminated. Eyewash stations and safety showers provide a means to quickly remove gross contamination of harmful agents, including gasoline. Personnel must immediately shower and remove any clothing which is wet or otherwise contaminated. Showers in the change room are to be used for thorough cleansing. Persons should inspect themselves thoroughly before donning a fresh change of clothing.

Contaminated clothing should be properly disposed. Contaminated personal protective equipment must be washed and sanitized before re-using. The washing of contaminated equipment is performed in a "contained area" to assure that the disposal of the wash water can be handled properly.

Establishing "Exclusion - Hot", "Decontamination - Decon", and "Support - Safe" Zones are required to prevent the removal of contaminants from the contaminated area as well as unauthorized entry into contaminated areas.

- Regardless of the decontamination facilities available, all efforts to minimize personnel exposure should be taken.
- Decontamination facilities should be positioned prior to employee/ contractor entrance to areas where the potential for exposure to contamination exists. The appropriate Material Safety Data Sheets (MSDS) are available to aid health professionals treating the injured parties. Material Safety Data Sheets are located in Appendix G.
- Decontamination facilities should be designed to prevent further contamination of the environment and should have a temporary storage area for items that will be reused in the contaminated area.
- Particular attention should be paid to personal hygiene prior to eating, drinking, or smoking.

MINIMUM DECONTAMINATION LAYOUT
LEVELS A & B PROTECTION



Personal Protective Equipment (PPE)

The following represents OSHA/USEPA designated PPE levels for responding to emergencies, post emergency cleanup sites, and/or Temporary Storage and Disposal (TSD) sites. The responder's PPE should be chosen based on his/her level of training and assigned job duties.

LEVEL A • Self Contained Breathing Apparatus (SCBA) (worn inside suit) • Encapsulated Chemical Protective Suit • Chemical Protective Gloves • Chemical Protective Boots • Hard Hat • Safety Toe Footwear • Safety Glasses	To be selected when the greatest level ok skin, respiratory, and eye protection is required.
LEVEL B • SCBA (worn outside suit) • Chemical Protective Suit w/Hood • Chemical Protective Boots • Chemical Protective Gloves • Hard Hat • Safety Toe Footwear • Safety Glasses	To be selected when the highest level of respiratory protection is necessary but a lesser level ok skin is needed.
LEVEL C • Air Purifying Respirator (APR) • APR a½ Face / Full Face • Hard Hat • Glasses (worn with a½ face APR) • Chemical Protective Boots • Chemical Protective Gloves • Chemical Protective Suit/Tyvek • Safety Toe Footwear • Safety Glasses	To be selected when the concentration and type of airborne substances is known and the criteria for using air purifying respirators are met.
MODIFIED LEVEL C Same as level C except no APR requirements.	To be selected when the concentration and type of airborne substances is known and the criteria for using air purifying respirators are met.
LEVEL D • Hard Hat • Safety Glasses • Work Uniform / Clothes • Leather Gloves • Safety Boots • Nomex (if required by the Company)	The atmosphere contains no known hazard and work functions preclude the potential for unexpected inhalation of or contact with hazardous levels of any chemicals.

3.7 EMERGENCY MEDICAL TREATMENT AND FIRST AID

Call 911 immediately. On-site emergency medical response requires the same rapid assessment of the patient as any other situation, but requires the responders to be aware of other considerations that may affect the way they handle the patient. These considerations include the following:

- The potential for contamination of the patient, responders, and equipment should be addressed. Responders should arrange to treat all patients AFTER the injured party has been decontaminated according to the Site Safety Plan.
- Site personnel should make the initial assessment of the patient and determine the severity of the injury/illness.
- If the treatment needed is critical care or "life saving" treatment, rapid decontamination of the injured/ill party should be started. Refer to the Site Safety Plan for steps to be taken in an "abbreviated" decontamination for medical treatment.
- The need for full decontamination should be carefully weighed against the need for prompt medical treatment.
- The ambulance responding to medical emergencies shall be contacted as soon as possible and instructed exactly where to respond when needed and the nature of the contaminant. Telephone reference is provided in Annexes.
- Material Safety Data Sheet information will be available from the Incident Commander and should be provided to medical personnel to alert them of decontamination requirements.
- Report all injuries, incidents or close calls.
- If emergency medical treatment is needed, the Incident Commander, or his designated representatives, will request assistance from trained medical personnel.

4.0 RESPONSE TEAMS

4.1 **Introduction**

4.2 **Qualified Individual**

4.3 **Initial Response Team (IRT)**

4.4 **Regional Emergency Preparedness Team (REPT)**

4.5 **Incident Command System (ICS)**

4.6 **Unified Command**

Figure 4.1 Incident Command System

4.7 **ICS Roles and Responsibilities**

Figure 4.2 Operational Period Planning Cycle

4.1 INTRODUCTION

This Section describes organizational features and duties of the local responders, the Regional Emergency Preparedness Team (EPT), and the broader Emergency Management Team (EMT) as defined in TransCanada's Incident Management System (IMS). The Incident Management System integrates Incident Management, Emergency Management and Crisis Management and is maintained separately.

The key to an effective emergency response is a rapid, coordinated, tiered response by the affected Facility, the Regional Emergency Operations Center, and the Corporate Emergency Operations Center, consistent with the magnitude of an incident.

First response to an incident at the Facility will be provided by the local responders. The Regional EOC will respond, to the degree necessary, to incidents exceeding local capability.

Our response teams will use the National Incident Management System (NIMS) Incident Command System (ICS) to manage the emergency response activities. Because the Incident Command System is a management tool that is readily adaptable to incidents of varying magnitude, it will typically be used for all emergency incidents. Staffing levels will be adjusted to meet specific response team needs based on incident size, severity, and type of emergency.

An explanation of Incident Command System and the roles and responsibilities for primary members of the response teams are provided in Section 4.7 per CAN/CSA-2731-03. The USCG Incident Management Handbook (IMH) contains an in-depth description of all Incident Command System positions, Incident Command System development, response objectives and strategies, command responsibilities, Incident Command System specific glossary/acronyms, resource typing, the Incident Action Plan process, and meetings. The IMH can be located on the USCG's Homeport Website.

4.2 QUALIFIED INDIVIDUAL

It is the responsibility of the Qualified Individual (QI) or his/her designee to coordinate with the Federal On-Scene Coordinator (FOSC) and State On-Scene Coordinator (SOSC) throughout the response, if applicable.

Vital duties of the Qualified Individual (QI) include:

- Notify all response personnel, as needed.
- Identify the character, exact source, amount, and extent of the release, as well as the other items needed for notification.
- Assess the interaction of the spilled substance with water and/or other substances stored at the Facility and notify response personnel at the scene of that assessment.
- Assess the possible hazards to human health and the environment due to the release. This assessment must consider both the direct and indirect effects of the release (i.e., the effects of any toxic, irritating, or asphyxiating gases that may be generated, or the effects of any hazardous surface water runoffs from water or chemical agents used to control fire and heat-induced explosion).
- Assess and implement prompt removal actions to contain and remove the substance released.
- Coordinate rescue and response actions as previously arranged with all response personnel.
- Activate and engage in contracting with oil spill removal organizations.

- Use authority to immediately access Company funding to initiate cleanup activities.

- Direct cleanup activities until properly relieved of this responsibility.

- Arrangements will be made to ensure that the Qualified Individual (QI) or the Alternate Qualified Individual (AQI) is available on a 24-hour basis and is able to arrive at the Facility in a reasonable time.

- The AQI shall replace the QI in the event of his/her absence and have the same responsibilities and authority.

4.3 INITIAL RESPONSE TEAM (IRT)

The first Company person on scene (First Responder) will function as the Incident Commander and person-in-charge until relieved by an authorized supervisor who will then assume the position of Incident Commander (IC). Transfer of command will take place as more senior management contract support respond to the incident. For response operations within the control of the Initial Response Team, the role of IC will typically be assumed and retained by the Qualified Individual.

The number of positions/personnel required to staff the Incident Management Team will depend on the size and complexity of the incident. The duties of each position may be performed by the IC directly or delegated as the situation demands. The IC is always responsible for directing the response activities and will assume the duties of all the primary positions until the duties can be delegated to other qualified personnel.

A complete functional ICS organization is shown in Figure 4.1. The Incident Commander should try to fill the necessary positions within the Incident Management Team and request additional support from both the Regional and Corporate Emergency Operations Centers to fill/back up all the positions as the incident may dictate. Detailed job descriptions of the primary response team positions are provided in Section 4.7.

4.4 REGIONAL EMERGENCY PREPAREDNESS TEAM (EPT)

The Emergency Preparedness Team (EPT) will activate a Regional Emergency Operations Center (EOC) to support the Initial Response Team/Incident Management Team. The number of positions/personnel required to staff the Regional EOC will depend on the size and complexity of the incident.

The Regional EOC is staffed by personnel from various Regional locations. The Regional EOC provides necessary information to the appropriate Federal, State/Province, and Local authorities with designated response roles, including the National Response Center (NRC), the Canadian National Energy Board (NEB), if necessary, State Emergency Response Commission (SERC) Provincial Ministry, and local response agencies.

4.5 INCIDENT COMMAND SYSTEM (ICS)

The Incident Command System is intended to be used as an emergency management tool to aid in mitigating all types of emergency incidents. This system is readily adaptable to very small emergency incidents as well as more significant or complex emergencies. The Incident Command System utilizes the following criteria as key operational factors:

- Assigns overall authority to one individual

- Provides structured authority, roles and responsibilities during emergencies

- The system is simple and familiar, and is used routinely at a variety of incidents
- Communications are structured
- There is a structured system for response and assignment of resources
- The system provides for expansion, escalation, and transfer/transition of roles and responsibilities
- The system allows for "Unified Command" where agency involvement at the command level is required

Effective establishment and utilization of the Incident Command System during response to all types of emergencies can:

- Provide for increased safety
- Shorten emergency mitigation time by providing more effective and organized mitigation
- Cause increased confidence and support from local, State, Federal, and public sector emergency response personnel
- Provide a solid cornerstone for emergency planning efforts

Section 4.7 provides a comprehensive list of every response team member's duty assignment.

4.6 UNIFIED COMMAND

As a component of an Incident Command System, the Unified Command (UC) is a structure that brings together the Incident Commanders of all major organizations involved in the incident to coordinate an effective response while still meeting their own responsibilities. The Unified Command links the organizations responding to the incident and provides a forum for the Responsible Party and responding agencies to make consensus decisions. Under the Unified Command, the various jurisdictions and/or agencies and responders may blend together throughout the organization to create an integrated response team. The Incident Command System process requires the Unified Command to set clear objectives to guide the on-scene response resources.

Multiple jurisdictions may be involved in a response effort utilizing Unified Command. These jurisdictions could be represented by any combination of:

- Geographic boundaries
- Government levels
- Functional responsibilities
- Statutory responsibilities

The participants of Unified Command for a specific incident will be determined taking into account the specifics of the incident and existing response plans and/or decisions reached during the initial meeting of the Unified Command. The Unified Command may change as an incident progresses, in order to account for changes in the situation.

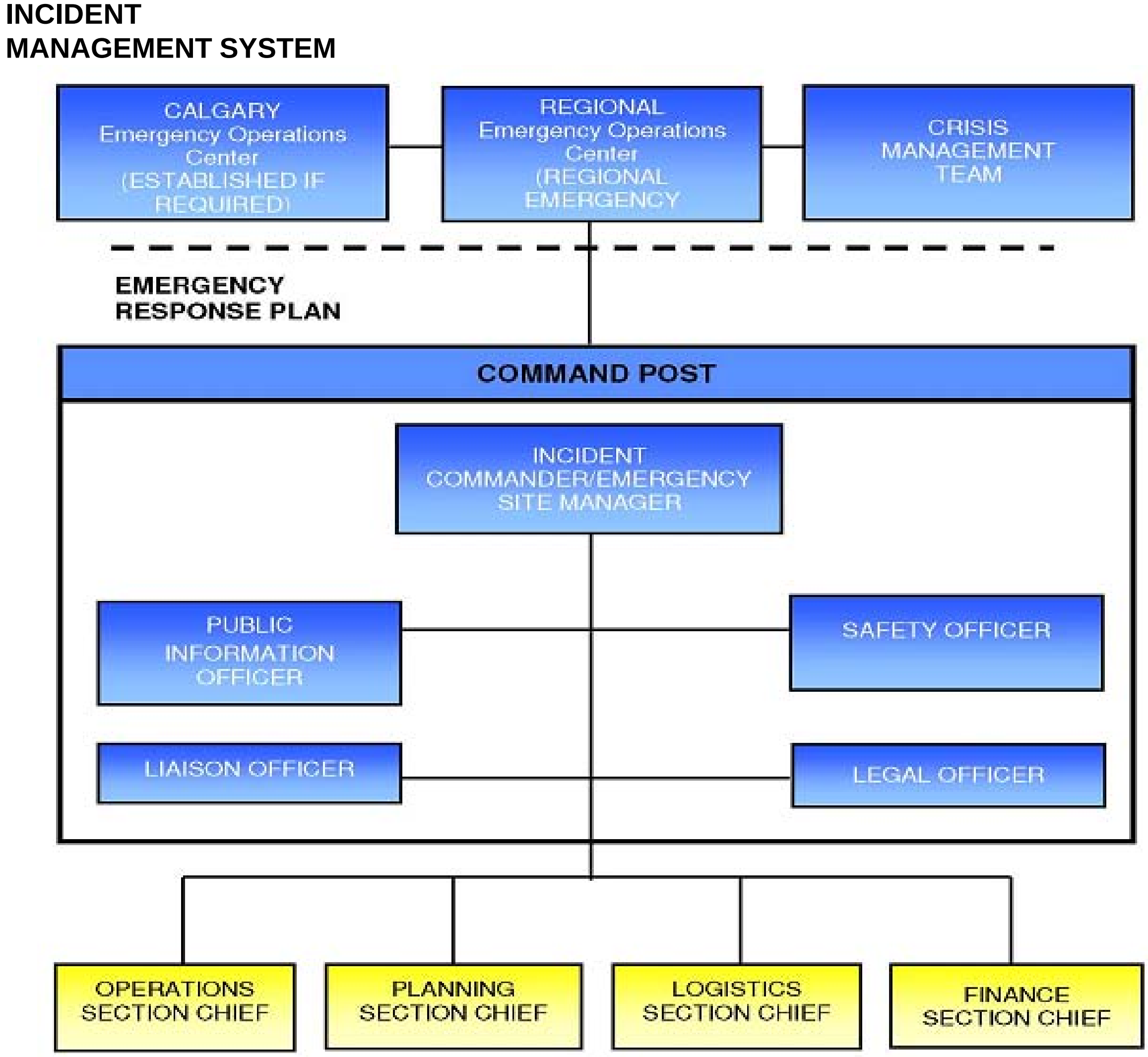
The Unified Command is responsible for overall management of an incident. The Unified Command directs incident activities and approves and releases resources. The Unified Command structure is a vehicle for coordination, cooperation and communication which is essential to an effective response.

Unified Command representatives must be able to:

- Agree on common incident objectives and priorities
- Have the capability to sustain a 24-hour-7-day-per-week commitment to the incident
- Have the authority to commit agency or Company resources to the incident
- Have the authority to spend agency or Company funds
- Agree on an incident response organization
- Agree on the appropriate Command and General Staff assignments
- Commit to speak with "one voice" through the Public Information Officer or Joint Information Center
- Agree on logistical support procedures
- Agree on cost-sharing procedures

FIGURE 4.1

INCIDENT COMMAND SYSTEM



4.7 ICS ROLES AND RESPONSIBILITIES

COMMON RESPONSIBILITIES

The following is a checklist applicable to all personnel in an Incident Command System organization:

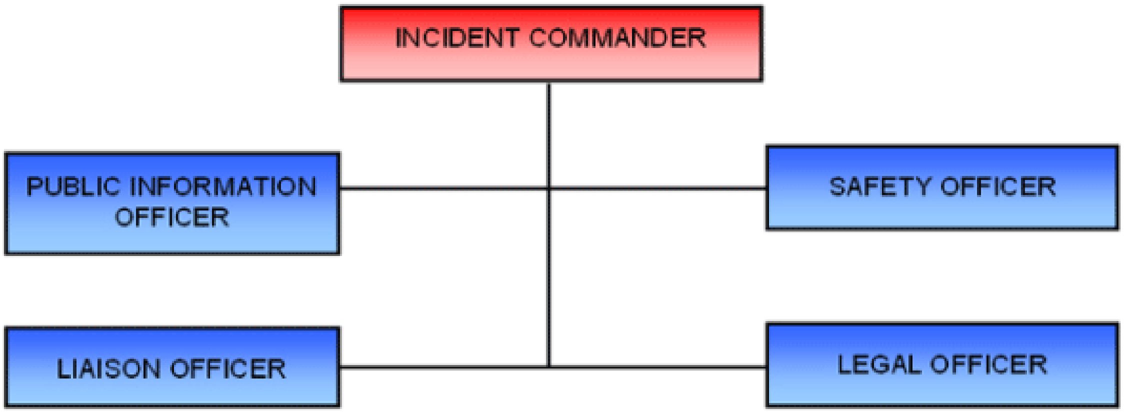
- Receive assignment, including:
    - Job assignment
    - Resource order number and request number
    - Reporting location
    - Reporting time
    - Travel instructions
    - Special communications instructions
- Upon arrival, check-in at designated check-in location.
- Receive briefing from immediate supervisor.
- Acquire work materials.
- Supervisors maintain accountability for assigned personnel.
- Organize and brief subordinates.
- Know your assigned radio frequency(s) and ensure communications equipment is operating properly.
- Use clear text and Incident Command System terminology (no codes) in all communications.
- Complete forms and reports required of the assigned position and send to Documentation Unit.
- Maintain unit records, including Unit Log (ICS Form 214).
- Respond to demobilization orders and brief subordinates regarding demobilization.

UNIT LEADER RESPONSIBILITIES

In Incident Command System, a Unit Leader's responsibilities are common to all units in all parts of the organization. Common responsibilities of Unit Leaders are listed below.

- Review common responsibilities.
- Receive briefing from Incident Commander, Section Chief or Branch Director, as appropriate.
- Participate in incident planning meetings, as required.
- Determine current status of unit activities.
- Order additional unit staff, as appropriate.
- Determine resource needs.
- Confirm dispatch and estimated time of arrival of staff and supplies.
- Assign specific duties to staff; supervise staff.
- Develop and implement accountability, safety and security measures for personnel and resources.
- Supervise demobilization of unit, including storage of supplies.
- Provide Supply Unit Leader with a list of supplies to be replenished.
- Maintain unit records, including Unit Log (ICS Form 214).

COMMAND


INCIDENT COMMANDER
PUBLIC INFORMATION OFFICER
SAFETY OFFICER
LIAISON OFFICER
LEGAL OFFICER

INCIDENT COMMANDER

- Assess the situation and/or obtain a briefing from the prior Incident Commander.
- Determine Incident Objectives and strategy.
- Establish the immediate priorities.
- Establish an Incident Command Post.
- Brief Command Staff and Section Chiefs.
- Review meetings and briefings.
- Establish an appropriate organization.
- Ensure planning meetings are scheduled as required. (Refer to Figure 4.2 "Operational Period Planning Cycle" for assistance).
- Approve and authorize the implementation of an Incident Action Plan.
- Ensure that adequate safety measures are in place.
- Coordinate activity for all Command and General Staff.
- Coordinate with key people and officials.
- Approve requests for additional resources or for the release of resources.
- Keep agency administrator informed of incident status.
- Approve the use of trainees, volunteers, and auxiliary personnel.
- Authorize release of information to the news media.
- Ensure incident Status Summary (ICS Form 209-CG) is completed and forwarded to appropriate higher authority.
- Order the demobilization of the incident when appropriate.
- Assign any of the Incident Commander roles and responsibilities to a Deputy Incident Commander as needed.

Incident Commander's Checklist

PUBLIC INFORMATION OFFICER

- Determine from the Incident Commander if there are any limits on information release.
- Develop material for use in media briefings.
- Obtain Incident Commander approval of media releases.
- Inform media and conduct media briefings.
- Arrange for tours and other interviews or briefings that may be required.
- Obtain media information that may be useful to incident planning.
- Maintain current information summaries and/or displays on the incident and provide information on the status of the incident to assigned personnel.

Public Information Officer's Checklist

LIAISON OFFICER

- Be a contact point for Agency Representatives.
- Maintain a list of assisting and cooperating agencies and Agency Representatives. Monitor check-in sheets daily to ensure that all Agency Representatives are identified.
- Assist in establishing and coordinating interagency contacts.
- Keep agencies supporting the incident aware of incident status.
- Monitor incident operations to identify current or potential inter-organizational problems.
- Participate in planning meetings, providing current resource status, including limitations and capability of assisting agency resources.
- Coordinate response resource needs for Natural Resource Damage Assessment and Restoration (NRDAR) activities with the Operations during oil and HAZMAT responses.
- Coordinate response resource needs for incident investigation activities with the Operations.
- Ensure that all required agency forms, reports and documents are completed prior to demobilization.
- Coordinate activities of visiting dignitaries.

Liaison Officer's Checklist

SAFETY OFFICER

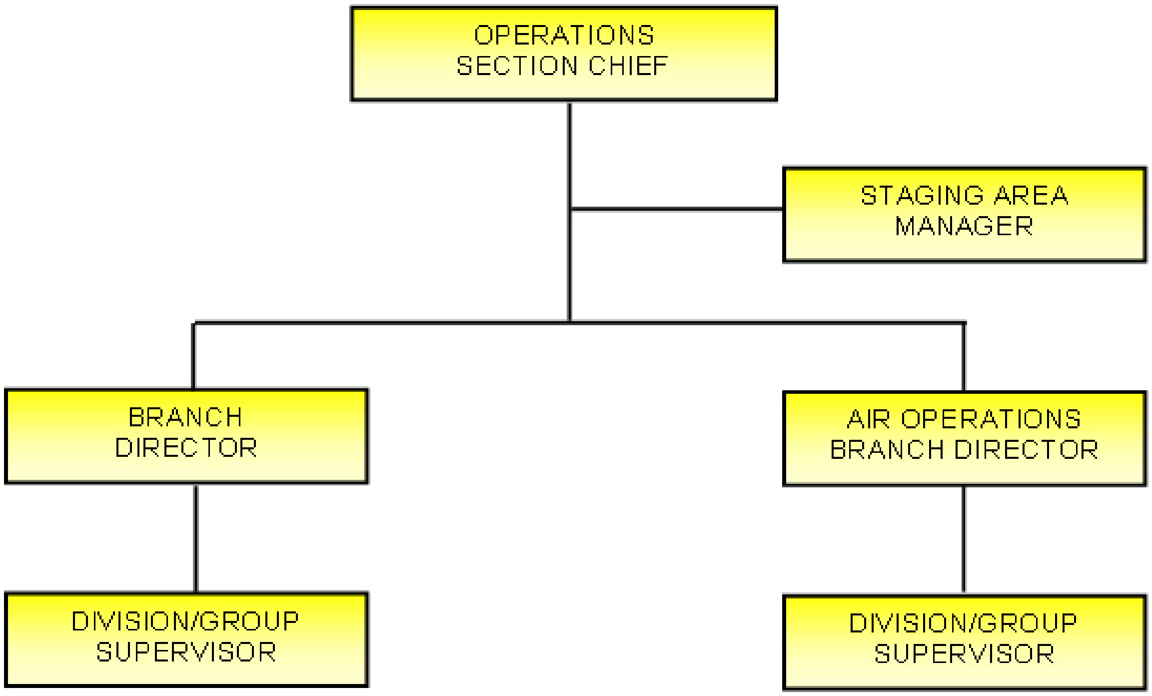
- Participate in planning meetings.
- Identify hazardous situations associated with the incident.
- Review the Incident Action Plan for safety implications.
- Exercise emergency authority to stop and prevent unsafe acts.
- Investigate accidents that have occurred within the incident area.
- Review and approve the medical plan.
- Develop the Site Safety Plan and publish Site Safety Plan summary (ICS Form 208) as required.

Safety Officer's Checklist

LEGAL OFFICER

- Participate in planning meetings, if requested.
- Advise on legal issues relating to in-situ burning, use of dispersants, and other alternative response technologies.
- Advise on legal issues relating to differences between Natural Resource Damage Assessment Restoration (NRDAR) and response activities.
- Advise on legal issues relating to investigations.
- Advise on legal issues relating to finance and claims.
- Advise on legal issues relating to response.

OPERATIONS


OPERATIONS
SECTION CHIEF
STAGING AREA
MANAGER
BRANCH
DIRECTOR
AIR OPERATIONS
BRANCH DIRECTOR
DIVISION/GROUP
SUPERVISOR
DIVISION/GROUP
SUPERVISOR

OPERATIONS SECTION GENERAL FUNCTIONS

- Responsible for managing tactical operations at the incident site directed toward reducing the immediate hazard, saving lives and property, establishing situational control, and restoring normal operations.
- Directs and coordinates all incident tactical operations.
- Executes the Incident Action Plan.

OPERATIONS SECTION CHIEF

- Develop operations portion of Incident Action Plan.
- Brief and assign Operations Section personnel in accordance with the Incident Action Plan.
- Supervise Operations Section.
- Determine need and request additional resources.
- Review suggested list of resources to be released and initiate recommendation for release of resources.
- Assemble and disassemble strike teams assigned to the Operations Section.
- Report information about special activities, events, and occurrences to the Incident Commander.
- Respond to resource requests in support of National Resource Damage Assessment and Restoration activities.

Operations Section Chief's Checklist

BRANCH DIRECTOR

- Develop with subordinates alternatives for Branch control operations.
- Attend planning meetings at the request of the Operations.
- Review Assignment List (ICS Form 204-CG) for Divisions/Groups within the Branch. Modify lists based on effectiveness of current operations.
- Assign specific work tasks to Division/Group Supervisors.
- Supervise Branch operations.
- Resolve logistic problems reported by subordinates.
- Report to Operations when: the Incident Action Plan is to be modified; additional resources are needed; surplus resources are available; or hazardous situations or significant events occur.
- Approve accident and medical reports originating within the Branch.

DIVISION/GROUP SUPERVISOR

- Implement Incident Action Plan for Division/Group.
- Provide the Incident Action Plan to Strike Team Leaders, when available.
- Identify increments assigned to the Division/Group.
- Review Division/Group assignments and incident activities with subordinates and assign tasks.
- Ensure that the Incident Commander and/or Resources Unit is advised of all changes in the status of resources assigned to the Division/Group.
- Coordinate activities with adjacent Division/Group.
- Determine need for assistance on assigned tasks.
- Submit situation and resources status information to the Branch Director or the Operations.
- Report hazardous situations, special occurrences, or significant events (e.g., accidents, sickness, discovery of unanticipated sensitive resources) to the immediate supervisor.
- Ensure that assigned personnel and equipment get to and from assignments in a timely and orderly manner.
- Resolve logistics problems within the Division/Group.
- Participate in the development of Branch plans for the next operational period.

STAGING AREA MANAGER

- Establish Staging Area layout.
- Determine any support needs for equipment, feeding, sanitation and security.
- Establish check-in function as appropriate.
- Post areas for identification and traffic control.
- Request maintenance service for equipment at Staging Area as appropriate.
- Respond to request for resource assignments.
- Obtain and issue receipts for radio equipment and other supplies distributed and received at Staging Area.
- Determine required resource levels from the Operations.
- Advise the Operations when reserve levels reach minimums.
- Maintain and provide status to Resource Unit of all resources in Staging Area.
- Demobilize Staging Area in accordance with the Incident Demobilization Plan.

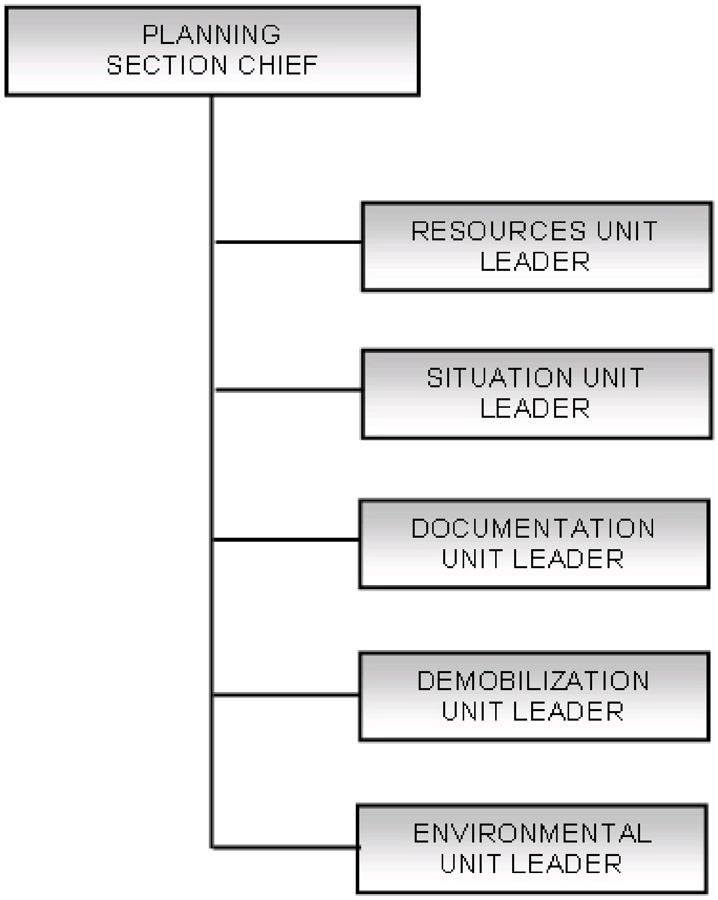
Staging Area Manager's Checklist

AIR OPERATIONS BRANCH DIRECTOR

- Organize preliminary air operations.
- Request declaration (or cancellation) of restricted air space
- Participate in preparation of the Incident Action Plan through the Operations. Insure that the air operations portion of the Incident Action Plan takes into consideration the Air Traffic Control requirements of assigned aircraft.
- Perform operational planning for air operations.
- Prepare and provide Air Operations Summary (ICS Form 220) to the Air Support Group and Fixed-Wing Bases.
- Determine coordination procedures for use by air organization with ground Branches, Divisions, or Groups.
- Coordinate with appropriate Operations Section personnel.
- Supervise all air operations activities associated with the incident.
- Evaluate helibase locations.
- Establish procedures for emergency reassignment of aircraft.
- Schedule approved flights of non-incident aircraft in the restricted air space area.
- Coordinate with the Operations Coordination Center (OCC) through normal channels on incident air operations activities.
- Inform the Air Tactical Group Supervisor of the air traffic situation external to the incident.
- Consider requests for non-tactical use of incident aircraft.
- Resolve conflicts concerning non-incident aircraft.
- Coordinate with Federal Aviation Administration.
- Update air operations plans.
- Report to the Operations on air operations activities.
- Report special incidents/accidents.
- Arrange for an accident investigation team when warranted.

Air Operation Branch Director's Checklist

PLANNING


PLANNING
SECTION CHIEF
RESOURCES UNIT
LEADER
SITUATION UNIT
LEADER
DOCUMENTATION
UNIT LEADER
DEMOBILIZATION
UNIT LEADER
ENVIRONMENTAL
UNIT LEADER

PLANNING SECTION GENERAL FUNCTIONS

- Responsible for gathering, evaluating, and disseminating tactical information and intelligence critical to the incident.
- Maintaining incident documentation and providing documentation services.
- Preparing and documenting Incident Action Plans.
- Conducting long-range and/or contingency planning.
- Developing alternative strategies.
- Tracking resources assigned to the incident.
- Developing plans for waste disposal.
- Developing plans for demobilization.

PLANNING SECTION CHIEF

- Collect and process situation information about the incident.
- Supervise preparation of the Incident Action Plan.
- Provide input to the Incident Commander and the Operations in preparing the Incident Action Plan.
- Chair planning meetings and participate in other meetings as required. (Refer to Figure 4.2 "Operational Period Planning Cycle" for assistance).
- Reassign out-of-service personnel already on-site to Incident Command System organizational positions as appropriate.
- Establish information requirements and reporting schedules for Planning Section Units (e.g., Resources, Situation Units).
- Determine the need for any specialized resources in support of the incident.
- If requested, assemble and disassemble Strike Teams and Task Forces not assigned to Operations.
- Establish special information collection activities as necessary (e.g., weather, environmental, toxics, etc.).
- Assemble information on alternative strategies.
- Provide periodic predictions on incident potential.
- Report any significant changes in incident status.
- Compile and display incident status information.
- Oversee preparation and implementation of the Incident Demobilization Plan.
- Incorporate plans (e.g., Traffic, Medical, Communications, Site Safety) into the Incident Action Plan.

Planning Section Chief's Checklist

RESOURCES UNIT LEADER

- Establish the check-in function at incident locations.
- Prepare Organization Assignment List (ICS Form 203-CG) and Incident Organization (ICS Form 207-CG).
- Prepare appropriate parts of Assignment List (ICS Form 204).
- Prepare and maintain the Incident Command Post display (to include organization chart and resource allocation and deployment).
- Maintain and post the current status and location of all resources.
- Maintain master roster of all resources checked in at the incident.

SITUATION UNIT LEADER

- Begin collection and analysis of incident data as soon as possible.
- Prepare, post, or disseminate resource and situation status information as required, including special requests.
- Prepare periodic predictions or as requested by the Planning Section Chief.
- Prepare the Incident Status Summary (ICS Form 209-CG).
- Provide photographic services and maps if required.

DOCUMENTATION UNIT LEADER

- Set up work area; begin organization of incident files.
- Establish duplication service; respond to requests.
- File all official forms and reports.
- Review records for accuracy and completeness; inform appropriate units of errors or omissions.
- Provide incident documentation as requested.
- Store files for post-incident use.

Documentation Unit Leader's Checklist

DEMOBILIZATION UNIT LEADER

- Participate in planning meetings as required.
- Review incident resource records to determine the likely size and extent of demobilization effort.
- Based on the above analysis, add additional personnel, workspace, and supplies as needed.
- Coordinate demobilization with Agency Representatives.
- Monitor the on-going Operations Section resource needs.
- Identify surplus resources and probable release time.
- Develop incident check-out function for all units.
- Evaluate logistics and transportation capabilities to support demobilization.
- Establish communications with off-incident facilities, as necessary.
- Develop an Incident Demobilization Plan detailing specific responsibilities and release priorities and procedures.
- Prepare appropriate directories (e.g., maps, instructions, etc.) for inclusion in the demobilization plan.
- Distribute demobilization plan (on and off-site).
- Provide status reports to appropriate requestors.
- Ensure that all Sections/Units understand their specific demobilization responsibilities.
- Supervise execution of the Incident Demobilization Plan.
- Brief the Planning Section Chief on demobilization progress.

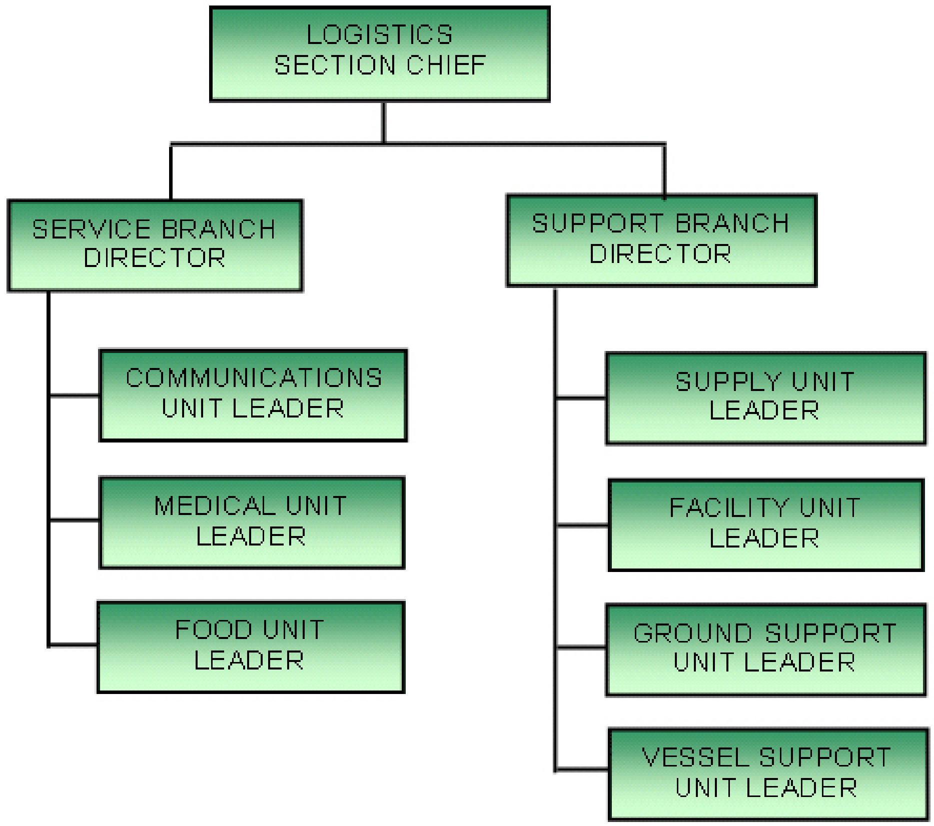
Demobilization Unit Leader's Checklist

ENVIRONMENTAL UNIT LEADER

- Participate in Planning Section meetings.
- Identify sensitive areas and recommend response priorities.
- Following consultation with natural resource trustees, provide input on wildlife protection strategies (e.g., removing oiled carcasses, pre-emptive capture, hazing, and/or capture and treatment).
- Determine the extent, fate and effects of contamination.
- Acquire, distribute and provide analysis of weather forecasts.
- Monitor the environmental consequences of cleanup actions.
- Develop shoreline cleanup and assessment plans. Identify the need for, and prepare any special advisories or orders.
- Identify the need for, and obtain, permits, consultations, and other authorizations including Endangered Species Act (ESA) provisions.
- Following consultation with the Federal OnScene Commander's Historical/Cultural Resources Technical Specialist identify and develop plans for protection of affected historical/cultural resources.
- Evaluate the opportunities to use various response technologies.
- Develop disposal plans.
- Develop a plan for collecting, transporting, and analyzing samples.

Environmental Unit Leader's Checklist

LOGISTICS


LOGISTICS SECTION CHIEF
SERVICE BRANCH DIRECTOR
SUPPORT BRANCH DIRECTOR
COMMUNICATIONS UNIT LEADER
MEDICAL UNIT LEADER
FOOD UNIT LEADER
SUPPLY UNIT LEADER
FACILITY UNIT LEADER
GROUND SUPPORT UNIT LEADER
VESSEL SUPPORT UNIT LEADER

LOGISTICS SECTION GENERAL FUNCTIONS

- Responsible for all support requirements needed to facilitate effective and efficient incident management, including ordering resources from off-incident locations.
- Ordering, obtaining, maintaining, and accounting for essential personnel, equipment, and supplies.
- Providing communication planning and resources.
- Setting up food services.
- Setting up and maintaining incident facilities.
- Providing support transportation.
- Providing medical services to incident personnel.

LOGISTICS SECTION CHIEF

- Plan the organization of the Logistics Section.
- Assign work locations and preliminary work tasks to Section personnel.
- Notify the Resources Unit of the Logistics Section units activated including names and locations of assigned personnel.
- Assemble and brief Branch Directors and Unit Leaders.
- Participate in preparation of the Incident Action Plan.
- Identify service and support requirements for planned and expected operations.
- Provide input to and review the Communications Plan, Medical Plan and Traffic Plan.
- Coordinate and process requests for additional resources.
- Review the Incident Action Plan and estimate Section needs for the next operational period.
- Advise on current service and support capabilities.
- Prepare service and support elements of the Incident Action Plan.
- Estimate future service and support requirements.
- Receive Incident Demobilization Plan from Planning Section.
- Recommend release of Unit resources in conformity with Incident Demobilization Plan.
- Ensure the general welfare and safety of Logistics Section personnel.

Logistics Section Chief's Checklist

SERVICE BRANCH DIRECTOR

- Determine the level of service required to support operations.
- Confirm dispatch of Branch personnel.
- Participate in planning meetings of Logistics Section personnel.
- Review the Incident Action Plan.
- Organize and prepare assignments for Service Branch personnel.
- Coordinate activities of Branch Units.
- Inform the Logistics Section Chief of Branch activities.
- Resolve Service Branch problems.

COMMUNICATIONS UNIT LEADER

- Prepare and implement the Incident Radio Communications Plan (ICS Form 205-CG).
- Ensure the Incident Communications Center and the Message Center is established.
- Establish appropriate communications distribution/maintenance locations within the Base/Camp(s).
- Ensure communications systems are installed and tested.
- Ensure an equipment accountability system is established.
- Ensure personal portable radio equipment from cache is distributed per Incident Radio Communications Plan.
- Provide technical information as required on:
    - Adequacy of communications systems currently in operation.
    - Geographic limitation on communications systems.
    - Equipment capabilities/limitations.
    - Amount and types of equipment available.
    - Anticipated problems in the use of communications equipment.
- Supervise Communications Unit activities.
- Maintain records on all communications equipment as appropriate.
- Ensure equipment is tested and repaired.
- Recover equipment from Units being demobilized.

Communication's Unit Leader's Checklist

MEDICAL UNIT LEADER

- Participate in Logistics Section/Service Branch planning activities.
- Prepare the Medical Plan (ICS Form 206-CG).
- Prepare procedures for major medical emergency.
- Declare major emergency as appropriate.
- Respond to requests for medical aid, medical transportation, and medical supplies.
- Prepare and submit necessary documentation.

Medical Unit Leader's Checklist

FOOD UNIT LEADER

- Determine food and water requirements.
- Determine the method of feeding to best fit each facility or situation.
- Obtain necessary equipment and supplies and establish cooking facilities.
- Ensure that well-balanced menus are provided.
- Order sufficient food and potable water from the Supply Unit.
- Maintain an inventory of food and water.
- Maintain food service areas, ensuring that all appropriate health and safety measures are being followed.
- Supervise caterers, cooks, and other Food Unit personnel as appropriate.

Food Unit Leader's Checklist

SUPPORT BRANCH DIRECTOR

- Determine initial support operations in coordination with the Logistics Section Chief and Service Branch Director.
- Prepare initial organization and assignments for support operations.
- Assemble and brief Support Branch personnel.
- Determine if assigned Branch resources are sufficient.
- Maintain surveillance of assigned units work progress and inform the Logistics Section Chief of their activities.
- Resolve problems associated with requests from the Operations Section.

SUPPLY UNIT LEADER

- Participate in Logistics Section/Support Branch planning activities.
- Determine the type and amount of supplies en route.
- Review the Incident Action Plan for information on operations of the Supply Unit.
- Develop and implement safety and security requirements.
- Order, receive, distribute, and store supplies and equipment.
- Receive and respond to requests for personnel, supplies, and equipment.
- Maintain an inventory of supplies and equipment.
- Service reusable equipment.
- Submit reports to the Support Branch Director.

Supply Unit Leader's Checklist

FACILITY UNIT LEADER

- Review the Incident Action Plan.
- Participate in Logistics Section/Support Branch planning activities.
- Determine requirements for each facility, including the Incident Command Post (See Figure 2.6 for list of hotels).
- Prepare layouts of incident facilities.
- Notify Unit Leaders of facility layout.
- Activate incident facilities.
- Provide Base and Camp Managers and personnel to operate facilities.
- Provide sleeping facilities.
- Provide security services.
- Provide facility maintenance services (e.g., sanitation, lighting, clean up).
- Demobilize Base and Camp facilities.
- Maintain facility records.

Facility Unit Leader's Checklist

GROUND SUPPORT UNIT LEADER

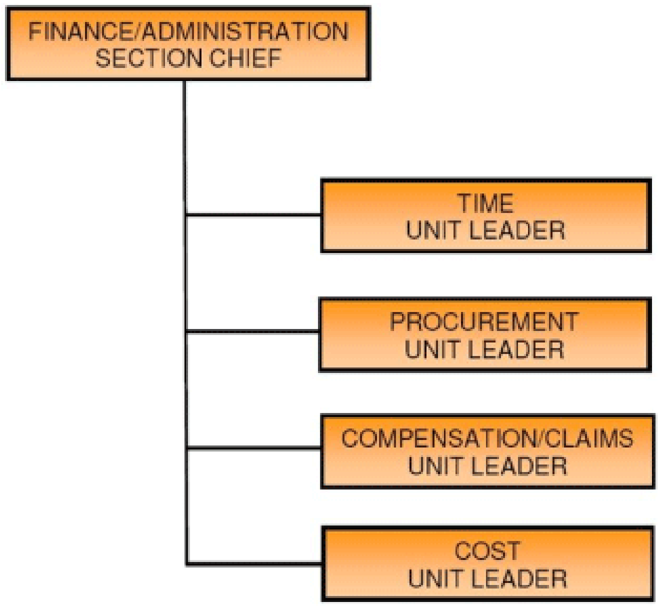
- Participate in Support Branch/Logistics Section planning activities.
- Develop and implement the Traffic Plan.
- Support out-of-service resources.
- Notify the Resources Unit of all status changes on support and transportation vehicles.
- Arrange for and activate fueling, maintenance, and repair of ground resources.
- Maintain Support Vehicle Inventory and transportation vehicles (ICS Form 218).
- Provide transportation services, in accordance with requests from the Logistics Section Chief or Support Branch Director.
- Collect information on rented equipment.
- Requisition maintenance and repair supplies (e.g., fuel, spare parts).
- Maintain incident roads.
- Submit reports to Support Branch Director as directed.

Ground Support Unit Leader's Checklist

VESSEL SUPPORT UNIT LEADER

- Participate in Support Branch/Logistics Section planning activities.
- Coordinate development of the Vessel Routing Plan.
- Coordinate vessel transportation assignments with the Protection and Recovery Branch or other sources of vessel transportation.
- Coordinate water-to-land transportation with the Ground Support Unit, as necessary.
- Maintain a prioritized list of transportation requirements that need to be scheduled with the transportation source.
- Support out-of-service vessel resources, as requested.
- Arrange for fueling, dockage, maintenance and repair of vessel resources, as requested.
- Maintain inventory of support and transportation vessels.

FINANCE/ADMINISTRATION



FINANCE/ADMINISTRATION SECTION GENERAL FUNCTIONS

- Responsible for all financial and cost analysis aspects of an incident. (Note: Not all incidents will require a separate Finance/Administration Section. In cases that require only one specific function (e.g., cost analysis), this service may be provided by a member of the Planning Section.)
- Administering any contract negotiation.
- Providing cost analysis as it pertains to the Incident Action Plan.
- Maintaining cost associated with the incident.
- Tracking personnel and equipment time.
- Addressing compensation for injury or damage to property issues.

FINANCE/ADMINISTRATION SECTION CHIEF

- Attend planning meetings as required.
- Manage all financial aspects of an incident.
- Provide financial and cost analysis information as requested.
- Gather pertinent information from briefings with responsible agencies.
- Develop an operating plan for the Finance/Administration Section; fill supply and support needs.
- Determine the need to set up and operate an incident commissary.
- Meet with assisting and cooperating agency representatives, as needed.
- Maintain daily contact with agency(s) administrative headquarters on Finance/ Administration matters.
- Ensure that all personnel time records are accurately completed and transmitted, according to policy.
- Provide financial input to demobilization planning.
- Ensure that all obligation documents initiated at the incident are properly prepared and completed.
- Brief administrative personnel on all incident-related financial issues needing attention or follow-up prior to leaving incident.

Finance/Administration Section Chief's Checklist

TIME UNIT LEADER

- Determine incident requirements for time recording function.
- Determine resource needs.
- Contact appropriate agency personnel/representatives.
- Ensure that daily personnel time recording documents are prepared and in compliance with policy.
- Establish time unit objectives.
- Maintain separate logs for overtime hours.
- Establish commissary operation on larger or long-term incidents as needed.
- Submit cost estimate data forms to the Cost Unit, as required.
- Maintain records security.
- Ensure that all records are current and complete prior to demobilization.
- Release time reports from assisting agency personnel to the respective Agency Representatives prior to demobilization.
- Brief the Finance/Administration Section Chief on current problems and recommendations, outstanding issues, and follow-up requirements.

PROCUREMENT UNIT LEADER

- Review incident needs and any special procedures with Unit Leaders, as needed.
- Coordinate with local jurisdiction on plans and supply sources.
- Obtain the Incident Procurement Plan.
- Prepare and authorize contracts and land-use agreements.
- Draft memoranda of understanding as necessary.
- Establish contracts and agreements with supply vendors.
- Provide for coordination between the Ordering Manager, agency dispatch, and all other procurement organizations supporting the incident.
- Ensure that a system is in place that meets agency property management requirements. Ensure proper accounting for all new property.
- Interpret contracts and agreements; resolve disputes within delegated authority.
- Coordinate with the Compensation/Claims Unit for processing claims.
- Coordinate use of impress funds, as required.
- Complete final processing of contracts and send documents for payment.
- Coordinate cost data in contracts with the Cost Unit Leader.
- Brief the Finance/Administration Section Chief on current problems and recommendations, outstanding issues, and follow-up requirements.

COMPENSATION/CLAIMS UNIT LEADER

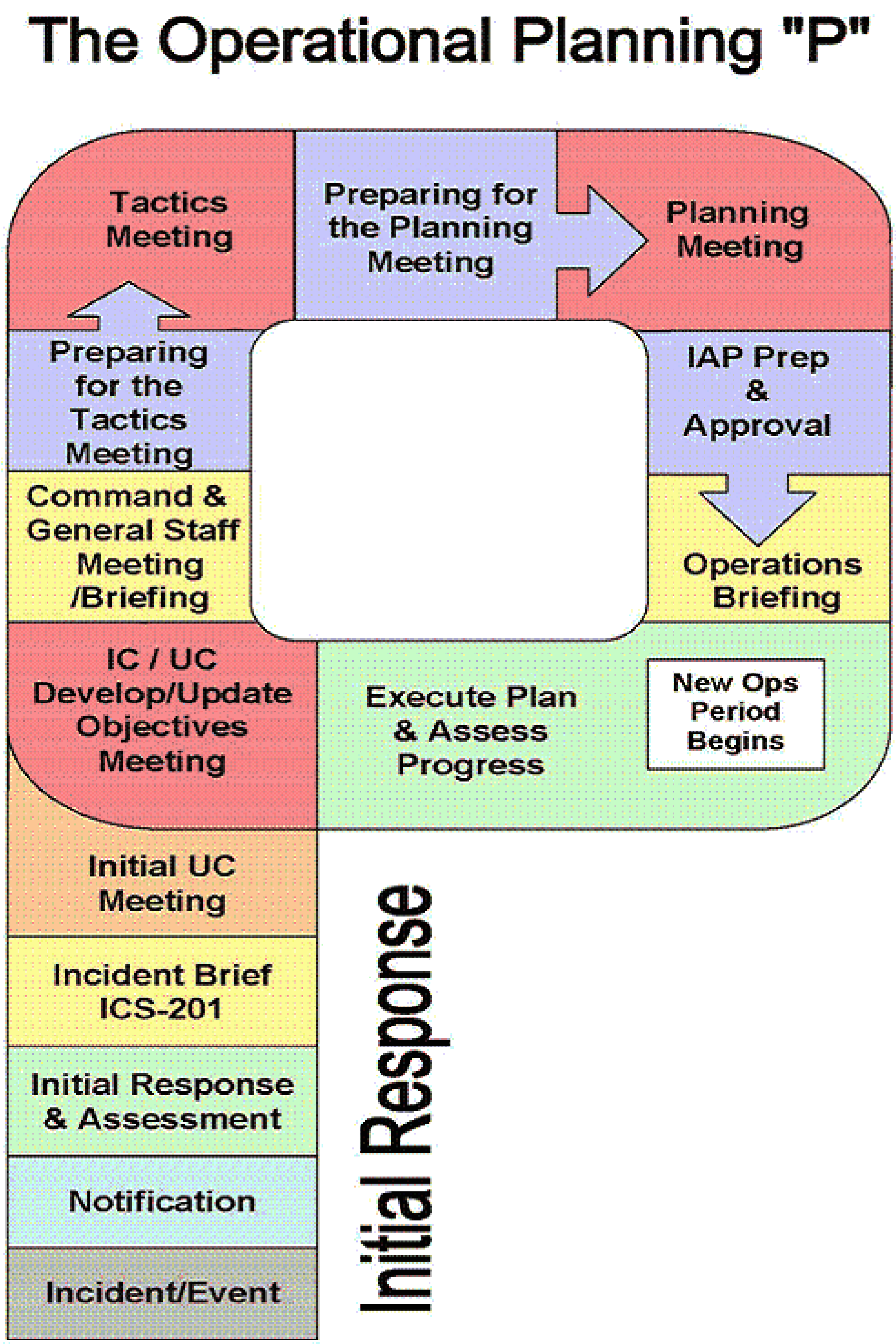
- Establish contact with the incident Security Officer and Liaison Officer (or Agency Representatives if no Liaison Officer is assigned).
- Determine the need for Compensation for Injury and Claims Specialists and order personnel as needed.
- Establish a Compensation for Injury work area within or as close as possible to the Medical Unit.
- Review Medical Plan (ICS Form 206-CG).
- Ensure that Compensation/Claims Specialists have adequate workspace and supplies.
- Review and coordinate procedures for handling claims with the Procurement Unit.
- Brief the Compensation/Claims Specialists on incident activity.
- Periodically review logs and forms produced by the Compensation/Claims Specialists to ensure that they are complete, entries are timely and accurate and that they are in compliance with agency requirements and policies.
- Ensure that all Compensation for Injury and Claims logs and forms are complete and routed appropriately for post-incident processing prior to demobilization.
- Keep the Finance/Administration Section Chief briefed on Unit status and activity.
- Demobilize unit in accordance with the Incident Demobilization Plan.

COST UNIT LEADER

- Coordinate cost reporting procedures.
- Collect and record all cost data.
- Develop incident cost summaries.
- Prepare resources-use cost estimates for the Planning Section.
- Make cost-saving recommendations to the Finance/Administration Section Chief.
- Ensure all cost documents are accurately prepared.
- Maintain cumulative incident cost records.
- Complete all records prior to demobilization.
- Provide reports to the Finance/Administration Section Chief.

FIGURE 4.2

UNITED STATES COAST GUARD
Operations Period Planning



5.0 RESPONSE PLANNING

5.1 Incident Action Plan

5. 2 Site Safety Plan

5.1 INCIDENT ACTION PLAN

Emergency response activities are planned and coordinated through the use of an Incident Action Plan (IAP), which is developed for each Operational Period of a response by the Initial Response Team. For small responses, an ICS 201 may be used as the Incident Action Plan and, for all incidents, the ICS 201 will serve as the initial Incident Action Plan.

For larger or more complex incidents, a more complete Incident Action Plan will be necessary. These Incident Action Plans are generally created through the completion and compilation of several standard Incident Command System forms. These forms include, but are not limited to:

ICS FORM NUMBER	FORM TITLE	PREPARED BY
IAP Cover Sheet	ICS IAP Cover Sheet	**Planning Section** - Situation Unit Leader
201-CG	Incident Briefing	**Command Section** - Initial Response Incident Commander
202-CG	Incident Objectives	**Planning Section** - Planning Section Chief
203-CG	Organization Assignment List	**Planning Section** - Resources Unit Leader
204-CG	Assignment List	**Operations Section** - Chief & Resources Unit Leader
204a-CG	Assignment List Attachment	**Operations Section** - Chief & Resources Unit Leader
205-CG	Incident Radio Communication Plan	**Logistics Section** - Communication Unit Leader
205a-CG	Communications List	**Logistics Section** - Communication Unit Leader
206-CG	Medical Plan	**Logistics Section** - Medical Unit Leader
207-CG	Incident Organization	**Planning Section** - Resources Unit Leader
209-CG	Incident Status Summary	**Command Section** - Incident Commander
211-CG	Check-In List	
213-RR CG	Resource Request Message	
214-CG	Unit Log	**Planning Section** - Situation Unit Leader
215-CG	Operational Planning Worksheet	
215A-CG	Incident Action Plan Safety Analysis	
218	Support Vehicle Inventory	**Logistics Section** - Ground Support Unit Leader
220-CG	Air Operations Summary	**Operations Section** - Air Operations Branch Director
230-CG	Daily Meeting Schedule	
232-CG	Resources at Risk Summary	**Planning Section** - Situation Unit Leader
232a-CG	ACP Site Index	
233-CG	Incident Open Action Tracker	
234-CG	Work Analysis Matrix	
235-CG	Facility Needs Assessment Worksheet	

	Site Safety Plan	**Command Section** - Safety Officer
	Employee Certification Page	
	Media Statement	

Depending on the nature and severity of the emergency, additional documents may be included in the Incident Action Plan. These may include:

- Sensitivity Maps (Provided in Section 6)
- Waste Management and Disposal Plans (Provided in Appendix E)
- Plans for use of Alternative Technologies (Dispersant/In-situ Burning/ Bioremediation)
- Security Plans
- Decontamination Plans
- Traffic Plans

5.2 SITE SAFETY PLAN

Site Safety Plans (SSPs) are required by United States Occupational Safety and Health Administration (29 CFR 1910.120(b)(4)) for all hazardous waste operations. The Site Safety Plan should address all on-site operations and hazardous as well as on-site emergency procedures.

The Site Safety Plan is typically prepared by the Safety Officer and approved by the Incident Commander. All personnel must be familiar with the contents of the Site Safety Plan and the Site Safety Plan must be updated as conditions, operations and hazards associated with the response change.

1. Incident Name	2. Operational Period to be covered by IAP (Date/Time) From: To:	IAP COVER SHEET

3. Approved by:

FOSC ______
SOSC ______
RPIC ______
______ ______
______ ______

INCIDENT ACTION PLAN

The items checked below are included in this Incident Action Plan:

- ☐ ICS 202-OS (Response Objectives)
- ☐ ICS 203-OS (Organization List) – OR – ICS 207-OS (Organization Chart)
- ☐ ICS 204-OSs (Assignment Lists)
  One Copy each of any ICS 204-OS attachments:
  - ☐ Map
  - ☐ Weather forecast
  - ☐ Tides
  - ☐ Shoreline Cleanup Assessment Team Report for location
  - ☐ Previous day's progress, problems for location
- ☐ ICS 205-OS (Communications List)
- ☐ ICS 206-OS (Medical Plan)
- ☐ ______
- ☐ ______
- ☐ ______
- ☐ ______
- ☐ ______
- ☐ ______

4. Prepared by: Date/Time

IAP COVER SHEET June 2000

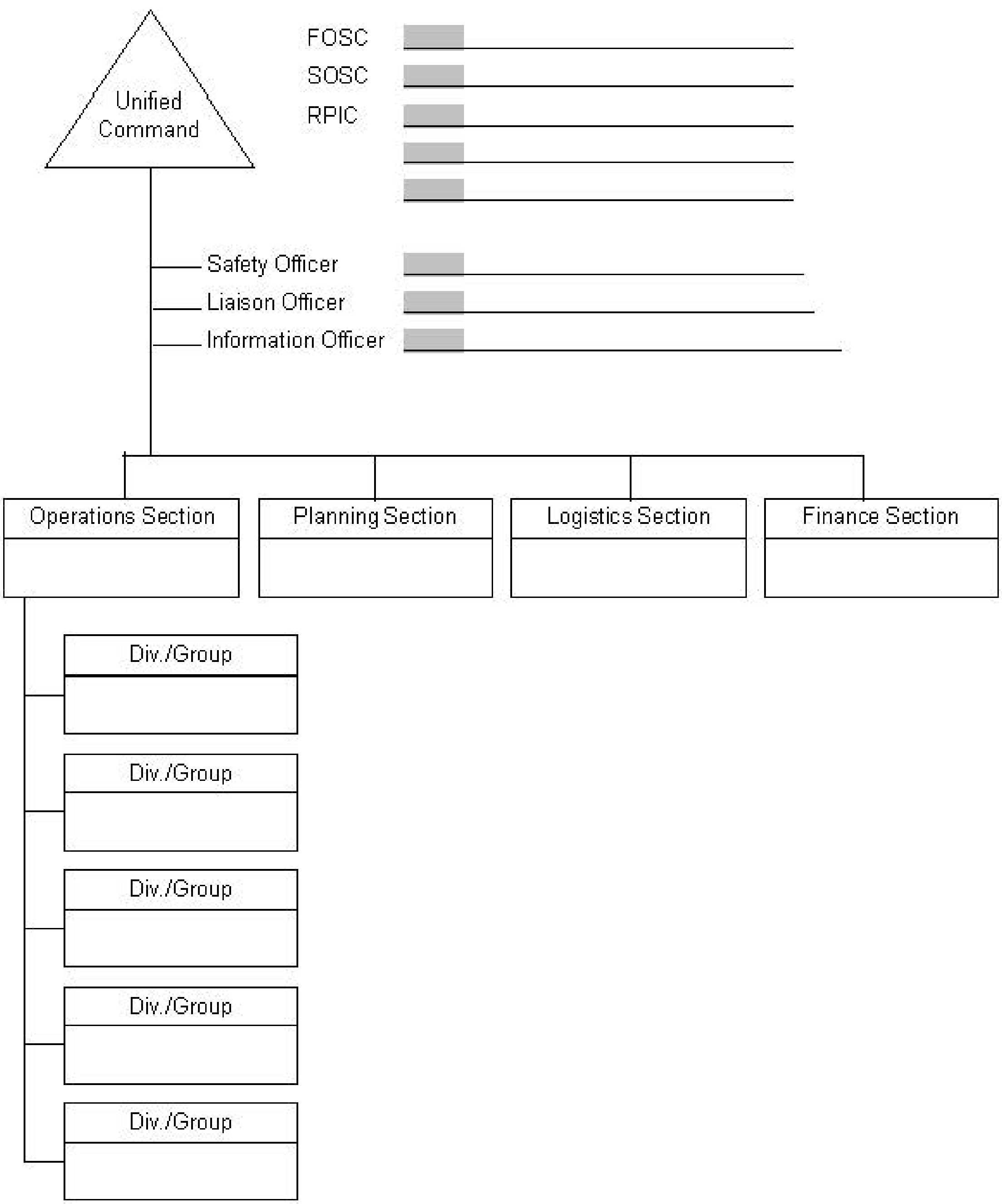
1. Incident Name	2. Prepared by: (name) Date: Time:	INCIDENT BRIEFING ICS 201-CG
3. Map/Sketch (include sketch, showing the total area of operations, the incident site/area, overflight results, trajectories, impacted shorelines, or other graphics depicting situational and response status)		
4. Current Situation:		

1. Incident Name	2. Prepared by: (name) Date: Time:	INCIDENT BRIEFING ICS 201-CG

5. Initial Response Objectives, Current Actions, Planned Actions

1. Incident Name	2. Prepared by: (name) Date: Time:	INCIDENT BRIEFING ICS 201-CG

3. Current Organization



1. Incident Name	2. Prepared by: (name) Date: Time:	INCIDENT BRIEFING ICS 201-CG

7. Resources Summary Resource	Resource Identifier	Date Time Ordered	ETA	On-Scene (X)	NOTES: (Location/Assignment/Status)

1. Incident Name	2. Operational Period (Date/Time) From: To:	INCIDENT OBJECTIVES ICS 202-CG
3. Objective(s)		
4. Operational Period Command Emphasis (Safety Message, Priorities, Key Decisions/Directions)		
Approved Site Safety Plan Located at:		
5. Prepared by: (Planning Section Chief)	Date/Time	

1. Incident Name	2. Operational Period (Date/Time) From: To:	ORGANIZATION ASSIGNMENT LIST ICS 203-CG

3. Incident Commander(s) and Staff		
Agency	IC	Deputy
Safety Officer:		
Information Officer:		
Liaison Officer:		

4. Agency Representatives	
Agency	Name

5. PLANNING/INTEL SECTION	
Chief	
Deputy	
Resources Unit	
Situation Unit	
Environmental Unit	
Documentation Unit	
Demobilization Unit	
Technical Specialists	

6. LOGISTICS SECTION	
Chief	
Deputy	
a. Support Branch	
Director	
Supply Unit	
Facilities Unit	
Vessel Support Unit	
Ground Support Unit	
b. Service Branch	
Director	
Communications Unit	
Medical Unit	
Food Unit	

7. OPERATION SECTION		
Chief		
Deputy		
Deputy		
Staging Area Manager		
Staging Area Manager		
Staging Area Manager		
a. Branch – Division Groups		
Branch Director		
Deputy		
Division Group		
Division Group		
Division Group		
Division/Group		
Division/Group		
b. Branch – Division/Groups		
Branch Director		
Deputy		
Division/Group		
Division/Group		
Division/Group		
Division/Group		
Division/Group		
c. Branch – Division/Groups		
Branch Director		
Deputy		
Division/Group		
Division/Group		
Division/Group		
Division/Group		
Division/Group		
d. Air Operations Branch		
Air Operations Br. Dir		
Helicopter Coordinator		

8. FINANCE/ADMINISTRATION SECTION	
Chief	
Deputy	
Time Unit	
Procurement Unit	
Compensation/Claims Unit	
Cost Unit	

9. Prepared By: (Resources Unit)	Date/Time

NRC Incident No. #________________________________

1. Incident Name	2. Operational Period (Date / Time) From: To:	MEDICAL PLAN ICS 206-CG

3. Medical Aid Stations

Name	Location	Contact #	Paramedics On site (Y/N)

4. Transportation

Ambulance Service	Address	Contact #	Paramedics On board (Y/N)

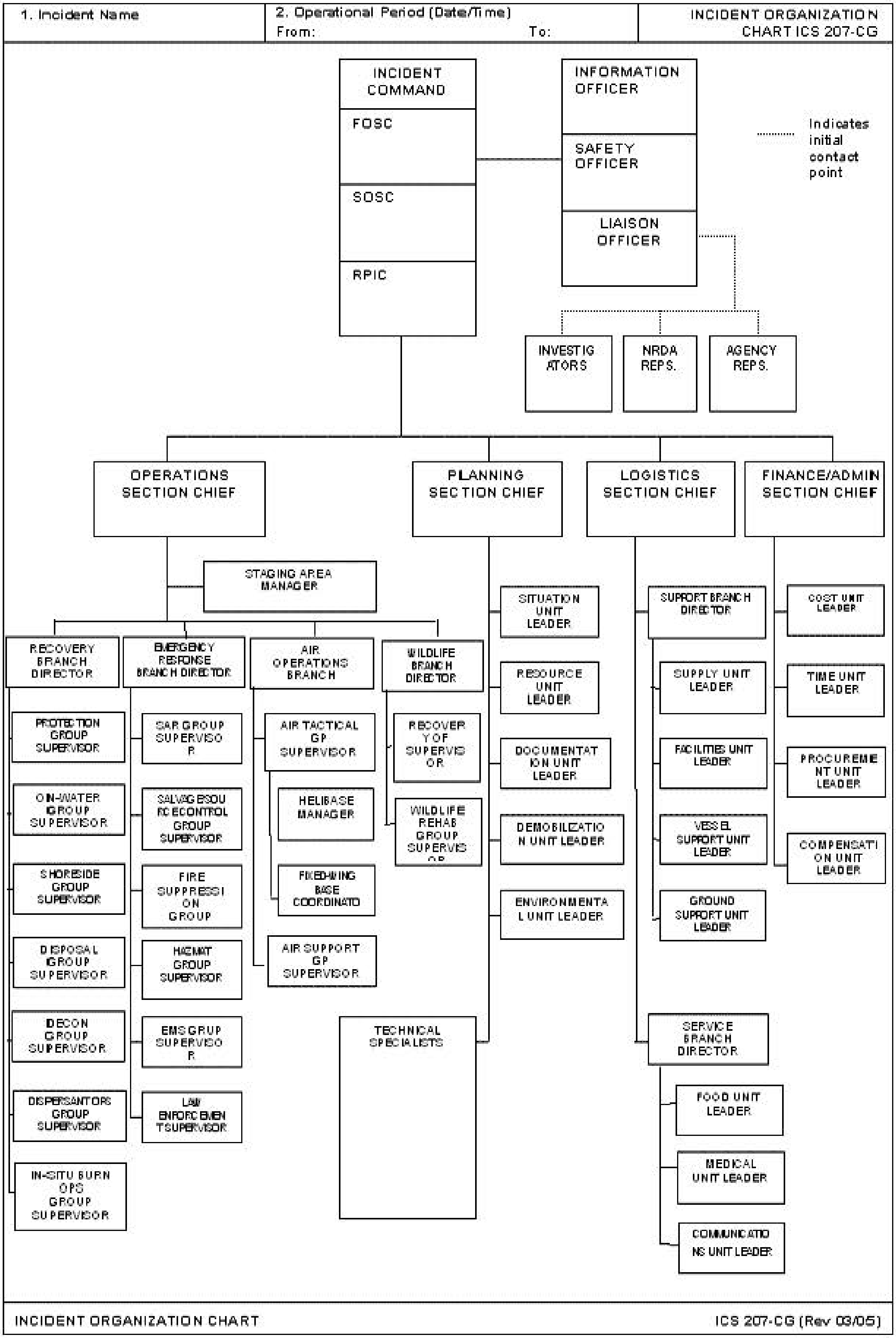
5. Hospitals

Hospital Name	Address	Contact #	Travel Time		Burn Ctr?	Heli-Pad?
			Air	Ground		

6. Special Medical Emergency Procedures

7. Prepared by: (Medical Unit Leader) Date/Time	8. Reviewed by: (Safety Officer) Date/Time

MEDICAL PLAN ICS 206-CG (Rev.07/04)


1. Incident Name
2. Operational Period (Date/Time)
From: To:
INCIDENT ORGANIZATION CHART ICS 207-CG
INCIDENT COMMAND
FOSC
SOSC
RPIC
INFORMATION OFFICER
SAFETY OFFICER
LIAISON OFFICER
Indicates initial contact point
INVESTIG ATORS
NRDA REPS.
AGENCY REPS.
OPERATIONS SECTION CHIEF
PLANNING SECTION CHIEF
LOGISTICS SECTION CHIEF
FINANCE/ADMIN SECTION CHIEF
STAGING AREA MANAGER
RECOVERY BRANCH DIRECTOR
EMERGENCY RESPONSE BRANCH DIRECTOR
AIR OPERATIONS BRANCH
WILDLIFE BRANCH DIRECTOR
PROTECTION GROUP SUPERVISOR
ON-WATER GROUP SUPERVISOR
SHORESIDE GROUP SUPERVISOR
DISPOSAL GROUP SUPERVISOR
DECON GROUP SUPERVISOR
DISPERSANT OPS GROUP SUPERVISOR
IN-SITU BURN OPS GROUP SUPERVISOR
SAR GROUP SUPERVISOR
SALVAGE/SOURCE CONTROL GROUP SUPERVISOR
FIRE SUPPRESSION GROUP
HAZMAT GROUP SUPERVISOR
EMS GRUP SUPERVISOR
LAW ENFORCEMENT SUPERVISOR
AIR TACTICAL GP SUPERVISOR
HELIBASE MANAGER
FIXED-WING BASE COORDINATOR
AIR SUPPORT GP SUPERVISOR
RECOVERY OF SUPERVISOR
WILDLIFE REHAB GROUP SUPERVISOR
SITUATION UNIT LEADER
RESOURCE UNIT LEADER
DOCUMENTATION UNIT LEADER
DEMOBILIZATION UNIT LEADER
ENVIRONMENTAL UNIT LEADER
TECHNICAL SPECIALISTS
SUPPORT BRANCH DIRECTOR
SUPPLY UNIT LEADER
FACILITIES UNIT LEADER
VESSEL SUPPORT UNIT LEADER
GROUND SUPPORT UNIT LEADER
SERVICE BRANCH DIRECTOR
FOOD UNIT LEADER
MEDICAL UNIT LEADER
COMMUNICATIONS UNIT LEADER
COST UNIT LEADER
TIME UNIT LEADER
PROCUREMENT UNIT LEADER
COMPENSATION UNIT LEADER
INCIDENT ORGANIZATION CHART
ICS 207-CG (Rev 03/05)

SITE SAFETY PLAN

I. General

☐ Pump Station ☐ Pipeline Spill ☐ Spill to Water ☐ Excavation ☐ Other: ________

Location: ____ ___

Work to be performed: _________________________________ ___

Issuing Date: _________ Time: _______
Temperature: ____° Wind Direction: ____
Humidity: ________

II. Hazards to be Evaluated

Y	N		Y	N		Y	N	SPECIFIC HAZARDS
☐	☐	Oxygen Deficient/Enriched	☐	☐	Ingestion / Skin Absorption	☐	☐	Crude Oil
☐	☐	Flammable Atmosphere	☐	☐	Frostbite	☐	☐	Other* ( )
		(Explosion Fire)	☐	☐	Chemical/MSDS # ________			
☐	☐	Toxic Atmosphere: ______			(Must be attached)			
☐	☐	Boat Operations	☐	☐	Physical Hazard _________			
☐	☐	Confined Space	☐	☐	Traffic ______________			
			☐	☐	Vapor Cloud			

III. Testing & Monitoring (Check required items)

Tests are to be performed in the order listed.

ACCEPTABLE ENTRY CONDITIONS

Y	N		Continuous		Frequency		SPECIAL WORK PRACTICES OR PPE REQUIRED	EXIT LEAVE AREA WORK EFFORTS SHOULD BE DIRECTED AT REDUCING CONCENTRATIONS
☐	☐	Oxygen Level	☐Y	☐N	______ every ____	19.5 – 23.0% in air	< 19.5% or 23.0% in air	< 16.0 or ≥ 23.5% in air
☐	☐	LEL	☐Y	☐N	______ every ____	< 10% in air	≥ 10.0 but < 20.0% in air	≥ 20.0% in air
☐	☐	Hydrogen Sulfide	☐Y	☐N	______ every ____	< 10 ppm	≥ 10 but < 100 ppm	≥ 100 ppm
☐	☐	Benzene	☐Y	☐N	______ every ____	< .5 ppm	≥ .5 but < 10 ppm	≥ 10 ppm
☐	☐	Total Hydrocarbons	☐Y	☐N	______ every ____	< 300 ppm	≥ 300 but < 750 ppm	≥ 750 ppm
☐	☐	Other: _________	☐Y	☐N	______ every ____			

IV. Required Personal Protective Equipment (Check for required use)

General	Eye Prot.	Respiratory Prot.	Hearing Prot.	Gloves	Footwear	Clothing
☐ Hard Hat	☐ Safety Glasses	☐ SCBA/Air Line w/Escape	☐ Ear Plugs	☐ Leather	☐ Steel-toes	☐ FR Coveralls
☐ Safety Harness	☐ Goggles	☐ Air Line	☐ Ear Muffs	☐ Rubber	☐ Rubber	☐ Tyvek
☐ PFD	☐ Face-shield	☐ Air Purifying (Full Mask)	☐ Combination	☐ Nitrile	☐ Hip-boots	☐ Coated Tyvek
	☐ Tinted Lens	Cartridge Type: ☐ OV	☐ Hepa-OW	☐ PVC	☐ ________	☐ Saranyx
				☐ _____		☐ _________

Any other special PPE: ____

V. Emergency Information and Rescue Services

Emergency Contact Person: ______________________ Contact by: ______________

Fire Department: ______________________________ Contact by: ______________

Ambulance: __________________________________ Contact by: ______________

Hospital: ____________________________________ Contact by: ______________

Rescue Services: ______________________________ Contact by: ______________

(if not provided by above)

VI. Required Safety & Rescue Equipment (on site)

☐Lights	☐Fall Protection	☐First Aid Kit	☐Drinking Water	☐Fire Extinguisher	☐Tripod	☐**Other:**
☐Ladder	☐Retrieval Lines	☐Resuscitator	☐**Communication Method**			

VII. Comments or Special Work Procedures

VIII. Report All Injuries Immediately

IX. Control Measures

• Isolation & Lockout (identify items to be locked out)	• Ventilation ☐ Natural ☐ Mechanical
• Establish Work Zones when completed	Continuous ☐ No ☐ Yes
☐ Hot Zone = Red Ribbon	• Flagman / Watchman ☐
☐ Warm Zone = Yellow Ribbon	• Confined Space – Safety Watch ☐
☐ Cold Zone = Blue Ribbon	(See Exhibit "B" for Permit)
	• Evacuation Routes – (Identify on Map)
	☐ Air Horn – Emergency
	☐ Primary Route
	☐ Secondary Route

X. Monitoring Results	Zone													
Oxygen	Time													
	Level													
	By													
LEL	Time													
	Level													
	By													
Hydrogen Sulfide	Time													
	Level													
	By													
Benzene	Time													
	Level													
	By													
VOC	Time													
	Level													
	By													
	Time													
	Level													
	By													
	Time													
	Level													
	By													
	Time													
	Level													
	By													
	Time													
	Level													
	By													

Equipment: Type:__________ Mfger:__________ Calibration / Expiration: __________
Type: __________ Mfger:__________ Calibration / Expiration: __________

NRC Incident No. #________________________________

1. Incident Name	2. Operational Period (Date/Time) From: To:	**UNIT LOG** **ICS 214-CG**

3. Unit Name/Designators	4. Unit Leader (Name and ICS Position)

5. Personnel Assigned

NAME	ICS POSITION	HOME BASE

6. Activity Log (Continue on Reverse)

TIME	MAJOR EVENTS

7. Prepared by:	Date/Time

UNIT LOG ICS 214-CG (Rev 6/05)

NRC Incident No. #______________________

1. Incident Name	2. Operational Period (Date/Time) From: To:	UNIT LOG (CONT.) ICS 214-CG

6. Activity Log (Continue on Reverse)	
TIME	MAJOR EVENTS
7. Prepared by:	Date/Time:

UNIT LOG ICS 214-CG (Rev 6/05)

6.0 SPILL IMPACT CONSIDERATIONS

6.1 Critical Areas to Protect

6.2 Environmental/Socio-Economic Sensitivities

6.3 Fisheries and Wildlife Protection

6.4 Staging Areas

6.5 Containment and Recovery of Spilled Product

Figure 6.1 On-Water Response Flowchart

6.6 Vulnerability Analysis

6.7 Alternative Response Strategies

Figure 6.2 Environmental Sensitivity Maps

Figure 6.3 Endangered/Threatened Species Listing

Figure 6.4 Aquifers

Figure 6.5 Affected HCA/Environmental

Figure 6.6 Drain Tiles

6.1 CRITICAL AREAS TO PROTECT

The critical areas to protect are classified as high, moderate, and low sensitivity to oil for non-coastal/inland environments. The Federal, Province/State, and Local authorities will further clarify these categories at the time of the response. The categories are defined as follows:

HIGH SENSITIVITY
• Areas which are high in productivity, abundant in many species, extremely sensitive, difficult to rehabilitate, or inhabited by threatened/endangered species. • Areas which consist of forested areas, brush/grassy areas, wooded lake areas, freshwater marshes, wildlife sanctuaries/refuges, and vegetated river/stream banks.

MODERATE SENSITIVITY
• Areas of moderate productivity, somewhat resistant to the effects of oiling. • Areas which consist of degraded marsh habitat, clay/silt banks with vegetated margins, and gravel/cobble beaches.

LOW SENSITIVITY
• Areas of low productivity, man-made structures, and/or high energy. • Areas which consist of gravel, sand, or clay material, barren/rocky riverbanks and lake edges, man-made structures, and concrete/compacted earthen drainage ditches.

6.2 ENVIRONMENTAL/SOCIO-ECONOMIC SENSITIVITIES

Environmental/Socio-economic sensitivities are of extreme importance when planning a response effort.The health and safety of the public and the environment, as well as the protection of the various socio-economic sensitivities, must be promptly addressed in order to mitigate the extent of damage and minimize the cost of the clean-up effort.

It is important to protect archeological sites and heritage resources (e.g. National Parks, National Marine Conservation Areas, and National Historic Sites). Impacted archeological sites or heritage resources of an area need to be identified and the likely impacts that result from the activities should be addressed. Specific consideration should be given to access to, and general use and disturbance of areas. The assessment should consider both direct and indirect impacts, cultural protocols and strategies for minimizing impacts. Consultation with local indigenous communities should occur as part of the planning process.

The Company will explore, where appropriate, equivalent environmental protection systems, methods, devices, or technologies that maintain or may be less damaging to the character of heritage resources or archeological sites. If a release from the pipeline impacts a heritage resource, the Company will respond as outlined in Section 3.0, report to the appropriate authority prescribed by law, cleanup and restore the area as required by regulation, and conduct such sampling, analyses, or associated monitoring during and after restoration.

All environmental/socio-economic sensitivities are worthy of protection, but must be prioritized during a response effort.When making decisions on which areas to designate as collection areas and which to protect, the following sources may be consulted:

- Canadian Wildlife Services, U.S. Fish and Wildlife Service and related province/ state agencies
- Applicable Area Contingency Plans
- Other industry and private experts
- Indigenous groups

The environmental and socio-economic sensitivities in the vicinity of the Pipeline have been broken down into specific categories and identified in this Section. To further clarify the location of the sensitive areas of concern, references to published Area Contingency Plans and Environmental Sensitivity Maps are also provided in this section.

6.3 FISHERIES AND WILDLIFE PROTECTION

The Company will work with Federal, Province/State, and local agency personnel to provide labor and transportation to retrieve, clean, and rehabilitate birds and wildlife affected by an oil spill, as necessary. Oversight of the Company's wildlife preservation activities and coordination with Federal, Province/State, and Local agencies during an oil spill is the responsibility of the Incident Commander.

Protecting fish habitat (e.g. spawning and rearing grounds) is important to both consumers and commercial fisheries. Beyond typical response strategies, other options could include moving floating facilities, temporarily sinking facilities using cages designed for this purpose, temporary suspension of water intakes, or closing sluice gates to isolate the facilities from contamination.

Special consideration should be given to the protection and rehabilitation of endangered species and other wildlife and their habitat in the event of an oil spill and subsequent response. Jurisdictional authorities should be notified and worked with closely on all response/clean-up actions related to wildlife protection and rehabilitation. Laws with significant penalties are in place to ensure appropriate protection of these species.

Wildlife Rescue

The Company will work with Federal, Province/State, and Local agency personnel to provide labor and transportation to retrieve, clean, and rehabilitate wildlife affected by an oil spill, as the situation demands.

The following are items which should be considered for wildlife rescue and rehabilitation during a spill response:

- Bird relocation can be accomplished using a variety of deterrents, encouraging birds to avoid areas of spilled oil. Bird relocation can be accomplished by utilizing deterrent methods including:
  - Use of visual stimuli, such as inflatable bodies, owls, stationary figures, or helium balloons, etc.
  - Use of auditory stimuli, such as propane cannons, recorded sounds, or shell crackers.
  - Use of herding with aircraft, boats, vehicles, or people (as appropriate).Use of capture and relocation.

Search and Rescue - Points to consider

- **The Company's involvement should be limited to offering assistance as needed or requested by the agencies.**
- Prior to initiating any organized search and rescue plan, **authorization must be obtained from the appropriate Federal/State agency.**
- **Initial search and rescue efforts, if needed, should be left up to the appropriate agencies.**

They have the personnel, equipment, and training to immediately begin capturing contaminated wildlife.

- With or without authorization, it must be anticipated that volunteer citizens will aid distressed/contaminated wildlife on their own. It is important to communicate that it may be illegal to handle wildlife without express authority from appropriate agencies. Provisions should be made to support an appropriate rehabilitator; however, **no support should be given to any unauthorized volunteer rescue efforts.**

- The regulatory agencies and response personnel should be provided the name and location of a qualified rehabilitator in the event contaminated wildlife is captured.

- Resources and contacts that can assist with wildlife rescue and rehabilitation are provided in Section 2.0. This list includes:

    - Outside rehabilitation organizations
    - Local regulatory agencies
    - Other resources

6.4 STAGING AREAS

When establishing personnel and equipment staging areas for a response to a Pipeline discharge, the following criteria should be evaluated:

- Access to waterborne equipment launching facilities and/or land equipment.

- Access to open space for staging/deployment of heavy equipment and personnel.

- Access to public services utilities (electricity, potable water, public phone, restroom and washroom facilities, etc.).

- Access to the environmental and socio-economically sensitive areas which are projected for impact.

6.5 CONTAINMENT AND RECOVERY OF SPILLED PRODUCT

General descriptions of various specific response techniques that may be applied during a response effort are discussed below. Company responders are free to use all or any combination of these methods as incident conditions require, provided they meet the appropriate safety standards and other requirements relative to the situation encountered. Data was obtained from reports, manuals and pamphlets prepared by the American Petroleum Institute, Environmental Protection Agency, and the United States Coast Guard. The most effective cleanup of a product spill will result from an integrated combination of clean-up methods. Each operation should complement and assist related operations and not merely transfer spillage problems to areas where they could be more difficult to handle.

The spill should be assessed as soon as possible to determine the source, extent and location of travel. Terrain and other physical conditions downgradient of the spill site will determine the methods of control at a point in advance of the moving product. Often, the bulk of a spill can be contained at a single location or a few key locations in the immediate vicinity of the source point. When possible, the execution of this type of initial containment strategy helps confine a spill to a relatively limited area.

Spill on Land (Soil Surfaces)

- **Containment Methods**

  Product can be trapped in ditches and gullies by earth dams. Where excavating machinery is available, dams can be bulldozed to contain lakes of product. Dams, small and large, should be effectively employed to protect priority areas such as inlets to drains, sewers, ducts and watercourses. These can be constructed of earth, sandbags, absorbents, planks or any other effective method. If time does not permit a large dam, many small ones can be made, each one holding a portion of the spill as it advances. The terrain will dictate the placement of the dams. If the spill is minor, natural dams or earth absorption will usually stop the product before it advances a significant distance. Cleanup is the main concern in such situations.

  In situations where vapors from a spill present a clear and present danger to property or life (possible ignition because of passing automobiles, nearby houses, or work vehicles approaching the area), spraying the surface of the spill with dispersant will greatly reduce the release of additional vapors from the product. This method is especially adapted to gasoline spills on soil surfaces.

- **Removal Methods**

  The recovery and removal of free product from soil surfaces is a difficult job. The best approaches at present seem to be:

  - Removal with suction equipment to tank truck if concentrated in volumes large enough to be picked up. Channels can be formed to drain pools of product into storage pits. The suction equipment can then be used.

  - Small pockets may have to be dipped up by hand.

  - If practicable after removal of the bulk of the spill, controlled burning presents the possibility of a fast, simple, and inexpensive method of destruction of the remainder of the product. If all other options have been executed and the site is still unsafe for further activity because explosive vapors persist, the vapors may need to be intentionally ignited to prevent an accumulation sufficient to become an explosive mixture, provided the other requirements of these guidelines for controlled burning are met.

Intentional ignition to remove released product should be utilized only if all of the following conditions are met:

- Other steps and procedures have been executed and a determination has been made that this is the safest remaining method of control.
- Intentional burning will not unduly damage pipelines, adjacent property, or the environment.
- Controlled burning is permitted by government authorities. Local government authorities to be contacted may include city council, county board of commissioners, city or county fire chiefs, the county forestry commission or fire tower, and the local environmental protection agency. In seeking permission from these authorities, be prepared to convince them that adequate safety precautions have been and will be taken during the operation.
- Controlled burning is conducted with the consent of local land owners.
- Safety must always be a prime consideration when considering controlled burning of product. Sparks and heat radiation from large fires can start secondary fires and strong winds make fire control difficult. There must be no danger of the fire spreading beyond control limits. All persons must be at a safe distance from the edge of the inflammable area. Remember that all burning must be controlled burning.

Spill on Lake or Pond (Calm or Slow-Moving Water)

- **Containment Methods**

A lake or pond offers the best conditions for removal of product from water. Although the removal is no easy task, the lake or pond presents the favorable conditions of low or no current and low or no waves.

The movement of product on a lake or pond is influenced mainly by wind. The product will tend to concentrate on one shore, bank or inlet. Booms should be set up immediately to hold the product in the confined area in the event of a change in wind direction.

If the spill does not concentrate itself on or near a shore (no wind effect), then a sweeping action using boats and floating booms will be necessary.

The essential requirement for this operation is that it be done very slowly. The booms should be moved at not more than 40 feet per minute. Once the slick is moved to a more convenient location (near shore), the normal operations of removal should begin.

If the slick is small and thin (rainbow effect) and not near the shoreline, an absorbent boom instead of a regular boom should be used to sweep the area very slowly and absorb the slick. The product may not have to be moved to the shoreline. See Figure 6.1 for on-water recovery decision tree.

- **Removal Methods**

If the Containment slick is thick enough, regular suction equipment may be used first; however, in most instances, a floating skimmer should be used.

If the floating skimmer starts picking up excess water (slick becomes thin), drawing the boom closer to the bank as product is removed will also keep film of product thicker.

However, when the slick becomes too thin, the skimmer should be stopped and an absorbent applied (with a boat if necessary) to remove the final amounts. The floating skimmer (if speed is a must) or hand skimmers (if water is shallow enough) or both can be used to pick up the product-soaked absorbent. Before pumping the product-soaked absorbent with a floating skimmer, ensure that the absorbent in question can be pumped and will not harm the pump. Several types are nonabrasive to pump internals. If the floating skimmer is used first, the product-soaked absorbent/water mixture should be pumped into a tank truck.

A better method of retrieving the product-soaked absorbent is to draw it in as close to the shore as possible with the booms used to confine the product initially. The absorbent can then be hand skimmed from the water surface and placed in drums, on plastic sheets or in lined roll-off boxes. It should then be disposed of by acceptable means.

The final rainbow on the surface can be removed with additions of more absorbent.

Spill on Small to Medium Size Streams (Fast-Flowing Creeks)

- **Containment Methods**

The techniques used for product containment on fast-flowing shallow streams are quite different from the ones used on lakes, ponds, or other still bodies of water. The containment and removal processes require a calm stretch of water to allow the product to separate onto the surface of the water. If a calm stretch of water does not exist naturally, a deep slow-moving area should be created by damming. The dam can be constructed by using sandbags, planks or earth. If a dam is required, it should be situated at an accessible point where the stream has high enough banks. The dam should be constructed soundly and reinforced to support the product and water pressure.

- Underflow dam - The underflow dam is one method that can be used, especially on small creeks. The water is released at the bottom, of the dam using a pipe or pipes which are laid during construction of the dam. The flow rate through the pipe must be sufficient to keep the dam from overflowing. One method is to lay the pipe at an angle through the dam (while dam is being constructed) so that the height of the downstream end of the pipe will determine the height the water will rise behind the dam.

- Overflow dam - Another method of containment is the overflow type dam. The dam is constructed so that water flows over the dam, but a deep pool is created which slows the surface velocity of the water. Therefore, the condition of a calm stretch of water is met. The overflow dam may be used where larger flow rates (medium size creeks) of water are involved

  With this type dam, a separate barrier (floating or stationary boom) must be placed across the pool created by the dam. The separate barrier arrests the surface layer of product. At the same time, the water is flowing under the barrier and over the top of the dam. The barrier should be placed at an angle of 45 % across the pool to decrease the effective water velocity beneath it. Also, it helps to concentrate the product at the bank and not all along the barrier. A second barrier should be placed approximately 10 to 15 feet downstream of the first one as a secondary back-up.

  The stationary boom type barrier should be made of wood planks or other suitable material. The stationary boom should be soundly constructed and sealed against the bank. The ends of the planks
  can be buried in the banks of the stream and timber stakes driven into the stream bed for support as needed. The necessary length of the boom will be

approximately 1-1/2 times the width of the waterway.

The plank boom should extend six to eight inches deep into the water and about two inches or higher above the water level. If the increase in velocity under the stationary boom is causing release of trapped product, it should be moved upward slightly. At no time should barrier be immersed more than 20% of the depth of the pool at the barrier location; that is, if the pool created by damming is three feet deep, do not exceed an immersion depth of seven inches with the barrier at the position the barrier is installed.

Another method used with the underflow dam is having the pipe or pipes sized to carry only a portion of the flow needed. The pipe would be placed at the bottom of the dam and level with the creek bed. The remaining flow of the creek could be siphoned or preferably pumped around the dam from a point away from the dam and from the deepest portion of the pool. The pumping or siphoning can be controlled to maintain the desired water level at the dam. The key is the removal of water through or around the dam at the lowest point in the basin. This prevents the oil from escaping with the released water.

A floating boom can be used in place of the stationary type if the created pool's size (bank to bank) and depth will permit. Since changing the depth and/or length of a standard floating boom in a small stream is difficult, the use of the stationary type permits adjustments to be made in depth to provide for a better separation of product and water. The advantages of using a floating boom are the speed of deployment and the fact that there is not need for additional support as with the stationary boom.

- Multiple Impoundments - Since emergency built dams (either underflow or overflow) are seldom perfect, a series of dams is usually required. The first one or two will trap the bulk and the ones that are downstream will trap the last traces of product. Precautions should be taken to ensure that the foundations of emergency dams are not washed away by the released water. If earth is used to construct an overflow dam, a layer of earth-filled bags should be placed on top of the dam so erosion will not take place. See Figure 6.1 for on-water recovery decision tree.

- **Removal Methods**

Once the containment dams are constructed, the problem or removal of the product from the water surface should be the prime consideration. The removal must be continuous or else build-up of product behind the dams or booms might lead to product escaping the traps.

The type of removal procedures used depends largely on the amount of product being trapped in a given span of time, if the amount of product moving down the stream is of sufficient quantity, the first dam or fixed boom would quite possibly trap enough for the floating skimmer to work efficiently. The skimmer will pump the product and possibly some water to a tank truck or other holding tank. Separated water may be released from the bottom of the tank truck if it becomes necessary. The absorbents could then be used at downstream dams or booms. It is inadvisable to place an absorbent in the stream prior to or at the first dam in anticipation of the arriving product. Let the product accumulate at the first dam and use the floating skimmer to recover the product.

Disposal of gross amount of product-soaked absorbent would not then be a problem. Follow directions on use of each absorbent. Some are designed to be placed on water before product arrives; others are intended only to be placed on the product after it accumulates on the water. Plastic sheets should be used to place the product- soaked absorbent on as it is hand skimmed from the water. Alternatively, the material may be placed in drums or lined roll-off boxes.

The containment and removal of spilled product on small to medium fast-flowing streams might require a combination of underflow or overflow dams, fixed booms, skimmers, and absorbents, to ensure a complete cleanup.

Spill on Large Streams and Rivers

- **Containment Methods**

The containment techniques differ considerably on large streams and rivers versus small streams. First, the smooth calm area of water necessary for product-water separation must be found along the stream or river rather than making one as with small streams. Floating booms (rather than fixed booms or dams) must be used to trap the surfaced product.

Local conditions of current and wind must be considered when selecting the site for the boom. A point with a low water velocity near the bank, sufficient depth to operate the product removal equipment, and good access are required. The fact that wind may tend to concentrate the product against one bank must be considered. A smooth, undisturbed area of water is required immediately upstream of the boom to ensure that the product has opportunity to separate out onto the surface. The boom should be positioned where the current is at a minimum. It is more effective to boom at a wide, slow position than on a narrow, fast stretch of water.

If the boom are positioned straight across a river or stream, at right angles to the flow, surface water tends to dive beneath the barrier (boom) when current velocities exceed about ½ knot (0.8 ft./sec.). However, if the current of the entire river is ½ knot or less, then a boom can be positioned straight across the river or large stream, but angled slightly in relation of the banks. By placing the boom at an angle to the banks, product on the surface is diverted along the boom to the side of the river.

The current velocity is usually much slower near the river bank than in the center and the product will move along the boom toward the bank for removal. A water-tight seal between the bank and the boom is essential. A secondary boom should be set up immediately downstream of the first one to capture the amounts that escape the upstream boom. A boom can be employed parallel to the river flow at the bank to form the seal with the booms used to trap the product.

Where the current velocity of the chosen site exceeds ½ knot, the boom should be positioned in two smooth curves from a point of maximum velocity (usually the center of the river) to both banks. However, this double-boom required product to be removed from both sides of the river. To determine the appropriate angle of boom placement and support (mooring) needed to hold the booms in position, the current velocity should be measured by timing a floating object which is 80% submerged over a distance of 100 feet. A time of 60 seconds over this distance indicates a water current of approximately 1 knot.

For currents from 1 to 2.5 knots (1.7 to 4.2 ft./sec.), the more the boom will have to be angled acute to the bank. The length of the boom will have to be such to reach the center of the river. For currents between ½ and 1 knot (0.8 and 1.7 ft./sec.), the angle of employment can be enlarged.

The major load on the boom is taken by the terminal moorings, particularly the one in the center of the river. However, intermediate moorings are also required both to maintain the smooth curve of the boom to prevent breaking of the boom and to assist with preventing skirt deflection. The intermediate moorings are preferably positioned every 25 feet and must be adjusted to avoid the formation of indentations in the boom profile. These trap product in pockets, prevent its deflection to the bank, and also encourage diving currents. The moorings' ropes should be five times the water depth.

In certain situations, it might be advantageous to position booms to deflect the approaching spilled product to a slower moving area. Naturally, additional booms would have to be positioned around this slower moving area prior to deflecting the product to the area. This approach has been used along river which has lagoons, etc., with a very low current action. The recovery would take place in the lagoons and not along the river bank. See Figure 6.1 for on-water recovery decision tree.

- **Removal Methods**

The product collected upstream of the floating booms in a large stream or river should be removed from the water surface as it accumulates. Regular suction equipment, a floating skimmer, and/or absorbents (including absorbent booms) should be used to remove the product as appropriate to the quantity being trapped in a given span of time. If the amount moving down the stream is of sufficient quantity, the primary floating boom would possibly trap enough for the floating skimmer to work efficiently. The skimmer will pump the product and some water to a tank truck or other holding tank.

The absorbents would then be used upstream of the secondary boom to absorb the underflow from the primary boom. An absorbent boom can also be placed between the primary and secondary booms to help the other absorbents control the underflow from the primary boom.

It is best to hand skim the saturated absorbents and place on plastic sheets. However, if the absorbent used can be pumped after product absorption and speed of removal is a necessity, the floating skimmer can be used to remove the product-soaked absorbent.

The disadvantage of pumping the product-soaked absorbent to a truck is the volume that will accumulate (skimmer will pump excess water) and the disposal problems associated with the large water/product-soaked absorbent mixture.

Spill on Stream which Flows into Lake or Pond

In certain locations where streams (small and large ones) flow into lakes or ponds at relatively short distances, it is conceivable that a spill could reach the lake before containment and recovery operations are set up. If time permits for containment operations to be set up on the stream in question, it then would be handled as described above depending upon the stream size involved.

However, if product in the stream is near the lake site or if product is flowing into the lake with a significant amount yet to arrive, a different containment should be employed.

- **Containment Methods**

Product on a stream flowing into a lake should be boomed as close to the entrance as possible. The boom should be positioned on the lake at an angle to the residential stream current so as to direct the surface water to a slower moving area. The area where the product is being deflected should be enclosed by booms to contain it. An additional boom for sweeping the product to the bank will be required. This area of containment should not have a current velocity of more than 1/2 knot (0.8 ft./sec.), preferably less. See Figure 6.1 for on-water recovery decision tree.

- **Removal Methods**

  The removal of product from the lake or pond's surface would be handled as described earlier.

  For sizable releases, collected product will usually be pumped into tank trucks and transported to a storage facility. Tank trucks are available at several locations throughout.

Spill in Urban Areas

Oil spills in urban areas can greatly impact recreational use, human health, wildlife habitat(s), and potential beach or park closures. Manmade structures along waterways require unique protection strategies. Manmade structures could include vertical shore protection structures such as seawalls, piers, and bulkheads, as well as riprap revetments and groins, breakwaters, and jetties. Vertical structures can be constructed of concrete, wood, and corrugated metal. They usually extend below the water surface, although seawalls can have beaches or riprap in front of them. These structures are very common along developed shores, particularly in harbors, marinas, and residential areas. The range in degree of exposure to waves and currents varies widely, from very low in dead-end canals, to very high on offshore breakwaters. Boat wakes can generate wave energy in otherwise sheltered areas. Maintaining shipping or other kinds of vessel traffic through navigation channels or waterways during a spill response is a difficult consideration because there is usually economic and political pressure to re-establish normal operations as soon as possible. This consideration extends to vehicular traffic through urban areas. Deploying booms and skimmers or constructing recovery sites can conflict with such traffic for several days. Also, passage of deep-draft vessels through the waterway can suddenly change water level and flow or create wakes, causing booms to fail. For these reasons, recovery efforts must be coordinated through the Unified Command to ensure the cooperation of all parties involved.

- **Containment Methods**

  Containment techniques in an urban area depend greatly on the ability to deploy equipment due to obstacles presented by the urban area. Most booming and containment techniques will work with slight modifications such as direct anchoring instead of the use of booming buoys. Often, debris and other obstacles cause gaps in containment or clog up the flow of oil in diversion booming. Vessel traffic can also cause containment to fail, due to splash over from vessel wakes.

- **Removal Methods**

  Normal recovery techniques work when recovering oil in an urban area. However, recovery can be hampered by several situations. Floating debris clogging skimming equipment is the main cause for low recovery rates. Another problem for recovery in an urban area is lack of storage space. Often traffic problems or lack of access prevent storage equipment such as frac tanks and vacuum trucks from approaching the recovery zone.

Spill Under Ice

- **Containment Methods**

  The traditional strategy for dealing with oil under the ice in a river or lake is to cut a slot to aid in recovery. Ice slots can be cut using chain saws, handsaws, ice augers or some form of trencher. Another effective variation of this technique is the diversionary plywood barrier method which is also discussed below. See Figure 6.1 for on-water decision tree.

- **Removal Methods**

Ice slotting is a very basic technique used to gain access to oil trapped beneath the ice. In ice slotting, a J shaped outline is sketched into the ice at a 30 degree angle to the current. The slight J hook or curve is necessary at the upstream side to provide flow towards the recovery area. In general, the slot width should be 1.5 times the thickness of the ice. Remember, a block of ice is heavy and the width of the slot must be taken into consideration so it can be safely removed or pushed under if the water beneath the ice is sufficiently deep. The length of the slot will be determined by the width of the river and strategy.

This technique is a successful strategy to implement. However, there are a few pit falls to be aware off. First, responders will fatigue rapidly if required to cut the slot or slots by hand using a chain saw or hand held saw. This can present a problem if there are not a sufficient number of Hazmat technicians available. Secondly, when cutting with chain saws, large volumes of water are kicked up by the moving chain onto the responder. This is a safety problem when the responders get wet in extreme cold weather conditions. Wearing rain gear however can reduce this problem.

A second technique is to slot the ice and use plywood to help divert oil beneath the ice to a recovery area. This technique is called the diversionary plywood barrier method. In this technique, a narrow slot is made through the ice and 4' x 8' sheets of plywood or equivalent are dropped into the slot to create a barrier and force the oil to follow along it to the collection area. This is the same principal employed when using floating boom.

The slot can be cut or drilled depending on the equipment available at the time of the response. If drilling is required, a gas powered ice auger can be used. In this scenario a series of 8" or 10" holes are drilled next to each other in the J pattern.

A chain saw can be used to connect the holes if an ice bridge exists between two auger holes. After the ice auguring is complete, plywood can be dropped into the augured slot.

Again, river ice is dirty and chipper blades on the augers may only last long enough to complete a single auger hole. This technique requires a large inventory of chipper blades. Extra auger flights can be used, which reduces down time to change blades. A real plus to slotting the ice with an ice auger is the limited exposure of responders to water. The water is generally restricted to the area around the responder's feet.

If an ice auger is not available, a chain saw can be used to cut a narrow slot. After the slot has been cut and ice removed, plywood can be inserted. When using a chainsaw that makes a 3/8" cut, a 1/8"-1/4" plywood or outdoor siding can be inserted into the slot and effectively be used to create the barrier. Again, the down side when using a large chain saws is fatigue and splash from water being kicked up by the chain. However, this problem is not as bad as cutting large slots as described above. Since only a single slot is made, the number of responders can be reduced and extra personal protective equipment in the form of rain gear can be used to minimize the water splash.

Spill on Ice

When managing an oil spill on ice special consideration must be given to several safety factors. Thickness of the ice and general accessibility of equipment must be considered when planning for on- ice recovery. Ice that is too thin to safely traverse or broken ice may prevent active recovery.

- **Containment Methods**

For ice-covered on-land or on- water spills, snow or earthen berms may be constructed to contain oil around the leak, if terrain permits. Dikes filled with sorbent materials may be used on spills in smaller streams to create a manmade dam to prevent the further migration of the oil.

Oil may become encapsulated due to melting and refreezing of the ice. Oil may then be more difficult to access and remove. See Figure 6.1 for on-water recovery decision tree.

- **Removal Methods**

  Generally, on-ice recovery consists of the manual removal of the product from the spill site. If conditions permit, vacuum trucks or suction pumps may be used to remove pools of oil that may have collected. Often, product removal will be done by hand using brooms, shovels and rakes. Manually moving the oil/snow mixture into piles for collection where it is either vacuum or manually collected into storage containers.

Spill in Wetland Areas

Wetlands, which include upland and inland marshes, swamps and bogs, are highly sensitive to spills because they collect run-off from surrounding environments, and because they are home to many commercially and ecologically important species. Wetlands are very susceptible to damage and are a high priority to protect. Precautions should be taken so that the recovery effort does not cause more damage than that cause by the release.

- **Containment Methods**

  Containment booms can be strategically deployed to contain or divert the product into recovery areas where skimmers and vacuums can be used to remove the product. Berms can also be built to contain or divert the product. Consideration must be given to the damage that can be caused by holding the product in the wetland areas. Often, allowing the product to flow to natural collection areas and possibly assisting the flow by the use of high volume low pressure water pumps may be the best course of action.

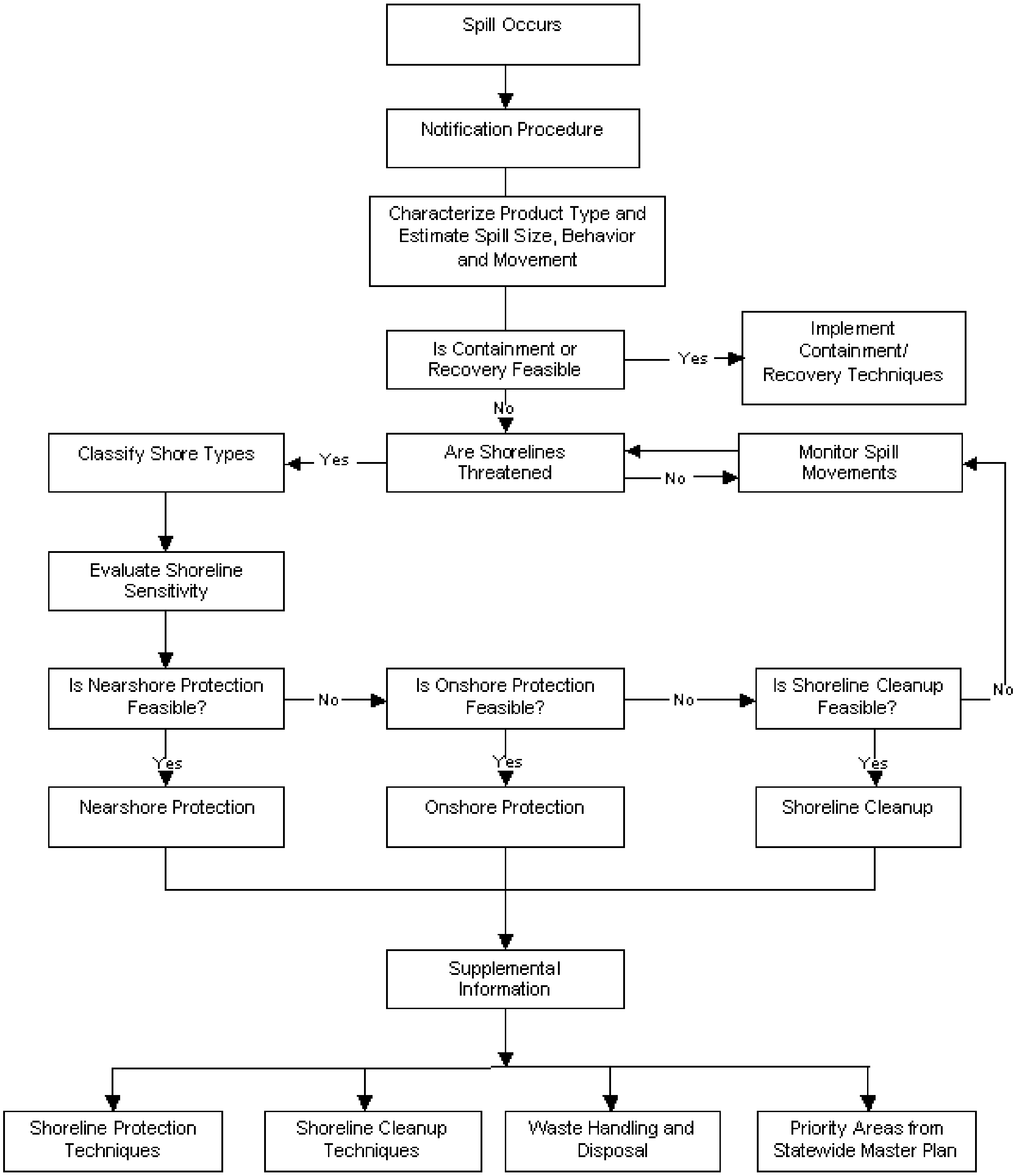
- **Removal Methods**

  Skimmers and vacuums can be deployed to recover contained oil. Other acceptable response techniques might include bioremediation, sorbents and in-situ burning. The use of heavy equipment is often not practical because of the damage it can cause to plant and animal life. During recovery, specially designed flat bottom shallow draft vessels and the use of plywood or boards may be used to reduce the damage caused by recovery personnel. If the water table is high and the oil will not permeate the soil, shallow trenches may be dug to collect oil for removal.

  The Unified Command must balance the need to remove the product with the damage caused by active removal. Considerations for long term passive recovery should be considered.

FIGURE 6.1

ON-WATER RESPONSE FLOWCHART



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6.6 VULNERABILITY ANALYSIS

The thorough examination of published Area Contingency Plans (ACPs) was conducted to identify sensitive areas in all the response zones.

The Environmental Sensitivity Maps located in Figure 6.2 identify sensitive areas along the Pipeline. The appropriate Area Contingency Plan maps are also included to provide more detailed information on sensitivities and possible potential response options.

6.7 ALTERNATIVE RESPONSE STRATEGIES

There are no pre-approved response options for inland spills within the United States. Any plans to use dispersants or in situ burn by the Company will be submitted to the Federal On-Scene Coordinator for Regional Response Team approval prior to such action being taken.

IN SITU BURNING

When considering the use of in situ burning the following considerations should be evaluated. In most cases, an agency application with further considerations will need to be completed before burning will be approved by the agency.

Size, Nature, and Product Spilled

- Flammability of the product. (Will the product burn?)
- Location of spill. (Distance and direction to nearest human use areas.)
- Volume of product released.
- Estimate of the surface area covered by the spill.
- How long has oil been exposed?
- Will burning cause more hazardous by-products?

Weather and Forecast

- Current weather conditions. (Rain / Heat)
- Wind speed and direction.
- 24 hour forecast.
- 48 hour forecast.

Evaluate the Response Operations

- Is there time enough to conduct burning?
- Is safety equipment available?
- Is adequate personnel available for monitoring / emergency response?
- Is mechanical recovery more intrusive than burning?

Habitats Impacted and Resources at Risk

- Have local agency / Officials been contacted.
  - Public Health
  - Land Owner / Manager
  - Local Fire Management (Fire Marshall)
  - Historic Property Specialist
  - Province / State Resource Agency
  - Aboriginal / Native American interests
- What is / will be the impact to surface water intakes and wells.
- Are endangered habitats / endangered species present?
- Is area used by Migratory Animals?
- What wildlife is present?

Burn Plan

- How much of the oil is expected to burn?
- How long will it be expected to burn?
- How will burn be ignited?
- How will burn be extinguished?
- How will burned oil residue be collected?
- What are the monitoring protocols?

DISPERSANT USE

Dispersants are not commonly used on inland spills. Working closely with Federal, Province / State and local agencies will be necessary for gaining approval to use dispersants. Since dispersants do not eliminate the oil, only break up and spread the oil throughout the water column, it is important to look at the total effect the oil will have on the environment while considering the use of dispersants.

FIGURE 6.2

ENVIRONMENTAL SENSITIVITY MAPS

Remember these maps are to be utilized as guidelines only. During a real response effort Federal, Province/State, and local agencies should be contacted to provide further assistance in the proper identification and protection of the various environmental and socio-economic sensitive areas

Canada ESM Map 1
Canada ESM Map 2
Canada ESM Map 3
Canada ESM Map 4
Canada ESM Map 5
Canada ESM Map 6
Canada ESM Map 7
Canada ESM Map 8
Canada ESM Map 9
Canada ESM Map 10
Canada ESM Map 11
Canada ESM Map 12
Canada ESM Map 13
Canada ESM Map 14
Canada ESM Map 15
Canada ESM Map 16
Canada ESM Map 17
Canada ESM Map 18
Canada ESM Map 19
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Canada ESM Map 23
Canada ESM Map 24
Canada ESM Map 25
Canada ESM Map 26
Canada ESM Map 27
Canada ESM Map 28
US ESM Map 1
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US ESM Map 4
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US ESM Map 21
US ESM Map 22

US ESM Map 23
US ESM Map 24
US ESM Map 25
US ESM Map 26
US ESM Map 27
US ESM Map 28
US ESM Map 29
US ESM Map 30
US ESM Map 31
US ESM Map 32
US ESM Map 33
US ESM Map 34
US ESM Map 35
US ESM Map 36
US ESM Map 37
US ESM Map 38
USL Index Map
USL Map 2
USL Map 3
USL Map 3C1
USL Map 3D1
USL Map 3D2
USL Map 3D3
USL Map 3D4
USL Map 5P51
USL Map 5P53
USL Map 5P54
USL Map 5P62
USL Map 6
USL Map 6P61
USL Map 8
USL Map 9
USL Map 10
USL Map 11
USL Map 12
USL Map 12A2
USL Map 12A3
USL Map 12C2
USL Map 12D2
USL Map 13
USL Map 18
USL Map 19
USL Map 24
Cushing Extension ESM 1
Cushing Extension ESM 2
Cushing Extension ESM 3
Cushing Extension ESM 4
Cushing Extension ESM 5
Cushing Extension ESM 6
Cushing Extension ESM 7
Cushing Extension ESM 8
Cushing Extension ESM 9
Cushing Extension ESM 10
Cushing Extension ESM 11

FIGURE 6.3

ENDANGERED/THREATENED SPECIES LISTING

Canada

Common Name	Scientific Name
Animals	
Burrowing Owl	*Athene cunicularia*
Olive-backed Pocket Mouse	*Perognathus fasciatus*
Long-billed Curlew	*Numenius americanus*
Short-eared Owl	*Asio flammeus*
Northern Leopard Frog	*Rana pipiens*
Sprague's Pipit	*Anthus spragueii*
Plants	
Bushy cinquefoil	*Potentilla paradoxa*
Chaffweed	*Anagallis minima*
Common tickseed	*Coreopsis tinctoria*
Dillen's wood sorrel	*Oxalis dillenii*
Endolepis	*Atriplex suckleyi*
Few-flowered aster	*Aster pauciflorus*
Few-flowered salt-meadow grass	*Torreyochloa pallida var pauciflora*
Lance-leaved loosestrife	*Lysimachia hybrida*
Little-seed rice grass	*Oryzopsis micrantha*
Low townsedia	*Townsendia exscapa*
Nevada rush	*Juncus nevadensis*
Pale blue-eyed grass	*Sisyrinchium septentrionale*
Rush-pink	*Stephanomeria runcinata*
Salt-marsh sand spurry	*Spergularia salina*
Short-stalk mouse-ear chickweed	*Cerastium brachypodum*
Shrubby evening-primrose	*Calylophus serrulatus*
American pellitory	*Parietaria pensylvanica*
American lopseed	*Phryma leptostachya*
Fox sedge	*Fox sedge*
Honewort	*Cryptotaenia canadensis*
Rice cutgrass	*Leersia oryzoides*
Yellow water crowfoot	*Ranunculus flabellaris*
Other	
None Listed	*N/A*

Illinois

Common Name	Scientific Name
Animals	
Bald Eagle	*Haliaeetus leucocephalus*
Loggerhead Shrike	*Lanius ludovicianus*
Indiana Bat	*Myotis sodalis*
Black-crowned Night Heron	*Nycticorax nycticorax*
Eastern Massasauga	*Sistrurus catenatus catenatus*

Western Sand Darter	*Ammocrypta clarum*
Kirtland's Snake	*Clonophis kirtlandi*
Least Bittern	*Lxobrychus exilis*
Greater Prairie Chicken	*Tympanuchus cupido*
Barn Owl	*Tyto alba*
Lake Sturgeon	*Acipenser fulvescens*
Timber Rattlesnake	*Crotalus horridus*
Little Blue Heron	*Egretta caerulea*
Butterfly	*Ellipsaria lineolata*
Peregrine Falcon	*Falco peregrinus*
Common Moorhen	*Gallinula chloropus*
Bigeye Shiner	*Notropis boops*
Yellow-crowned Night Heron	*Nyctanassa violacea*
Illinois Chorus Frog	*Pseudacris streckeri*
Pallid Sturgeon	*Scaphirhynchus albus*
Royal Catchfly	*Silene regia*
Lined Snake	*Tropidoclonion lineatum*
Yellow-headed Blackbird	*Xanthocephalus xanthocephalus*
Henslow's SparrowAmmodramus henslowii	*Ammodramus henslowii*
Short-eared Owl	*Asio flammeus*
Upland Sandpiper	*Bartramia longicauda*
Northern Harrier	*Circus cyaneus*
King Rail	*Rallus elegans*
Barn Owl	*Tyto alba*
Plants	
Prairie Rose Gentian	*Sabatia campestris*
Ear-leafed Foxglove	*Tomanthera auriculata*
Sedge	*Carex bromoides*
Fibrous-rooted Sedge	*Carex communis*
Drooping Sedge	*Carex prasina*
Blazing Star	*Liatris scariosa var. nieuwlandii*
Prairie Rose Gentian	*Sabatia campestris*
Grass-leaved Lily	*Stenanthium gramineum*
Ear-leafed Foxglove	*Tomanthera auriculata*
Spring Ladies' Tresses	*Spiranthes vernalis*
Prairie Spiderwort	*Tradescantia bracteata*
Decurrent False Aster	*Boltonia decurrens*
Other	
None Listed	*N/A*

Kansas

Common Name	Scientific Name
Animals	
American Burying Beetle	*Nicrophorus americanus*
Bald Eagle	*Haliaeetus leucocephalus*
Eastern Spotted Skunk	*Spilogale putorius*
Eskimo Curlew	*Numenius borealis*
Least Tern	*Sterna antillarum*
Peregrine Falcon	*Falco peregrinus*

Piping Plover	*Charadrius melodus*
Snowy Plover	*Charadrius alexandrinus*
Western Silvery Minnow	*Hybognathus argyritis*
Chestnut Lamprey	*Ichthyomyzon castaneus*
Flathead Chub	*Platygobio gracilis*
Pallid Sturgeon	*Scaphirhynchus albus*
Sicklefin Chub	*Macrhybopsis meeki*
Silver Chub	*Macrhybopsis storeriana*
Silverband Shiner	*Notropis shumardi*
Smooth Earth Snake	*Virginia valeriae*
Sturgeon Chub	*Macrhybopsis gelida*
Topeka Shiner	*Notropis topeka*
Whooping Crane	*Grus americana*
Sharp Hornsnail	*Pleurocera acuta*
Arkansas Darter	*Etheostoma cragini*
Arkansas River Shiner	*Notropis girardi*
Arkansas River Speckled Chub	*Macrhybopsis tetranema*
Flutedshell Mussel	*Lasmigona costata*
Plants	
None Listed	*N/A*
Other	
None Listed	*N/A*

Missouri

Common Name	Scientific Name
Animals	
Indiana Bat	*Myotis sodalis*
Bald Eagle	*Haliaeetus leucocephalus*
Pallid Sturgeon	*Scaphirhynchus albus*
Interior Least Tern	*Sterna antillarum athalassos*
Eastern Massasauga	*Sistrurus catenatus catenatus*
Spectaclecase	*Cumberlandia monodonta*
Plants	
Running Buffalo Clover	*Trifolium stoloniferum*
Decurrent False Aster	*Boltonia decurrens*
Other	
None Listed	*N/A*

North Dakota

Common Name	Scientific Name
Animals	
Horned Grebe	*Podiceps auritus*
American White Pelican	*Pelecanus erythrorhynchos*
American Bittern	*Botaurus lentiginosus*
Swainson's Hawk	*Buteo swainsoni*
Ferruginous Hawk	*Buteo regalis*

Yellow Rail	*Coturnicops noveboracensis*
Willet	*Catoptrophorus semipalmatus*
Upland Sandpiper	*Bartramia longicauda*
Long-billed Curlew	*Numenius americanus*
Marbled Godwit	*Limosa fedoa*
Wilson's Phalarope	*Phalaropus tricolor*
Franklin's Gull	*Larus pipixcan*
Black Tern	*Chlidonias niger*
Black-billed Cuckoo	*Coccyzus erythropthalmus*
Sprague's Pipit	*Anthus spragueii*
Grasshopper Sparrow	*Ammodramus savannarum*
Baird's Sparrow	*Ammodramus bairdii*
Nelson's Sharp-tailed Sparrow	*Ammodramus nelsonii*
Lark Bunting	*Calamospiza melanocorys*
Chestnut-collared Longspur	*Calcarius ornatus*
Canadian Toad	*Bufo hemiophrys*
Plains Spadefoot	*Spea bombifrons*
Smooth Green Snake	*Liochlorophis vernalis*
Western Hognose Snake	*Heterodon nasicus*
Black-tailed Prairie Dog	*Cynomys ludovicianus*
Sturgeon Chub	*Macrhybopsis gelida*
Sicklefin Chub	*Macrhybopsis meeki*
Pearl Dace	*Margariscus margarita*
Blue Sucker	*Cycleptus elongatus*
Northern Pintail	*Anas acuta*
Canvasback	*Aythya valisineria*
Redhead	*Aythya americana*
Northern Harrier	*Circus cyaneus*
Golden Eagle	*Aquila chrysaetos*
Bald Eagle	*Haliaeetus leucocephalus*
Prairie Falcon	*Falco mexicanus*
Sharp-tailed Grouse	*Tympanuchus phasianellus*
Greater Prairie Chicken	*Tympanuchus cupido*
Greater Sage-grouse	*Centrocercus urophasianus*
Piping Plover	*Charadrius melodus*
American Avocet	*Recurvirostra americana*
Least Tern	*Sterna antillarum*
Short-eared Owl	*Asio flammeus*
Burrowing Owl	*Athene cunicularia*
Red-headed Woodpecker	*Melanerpes erythrocephalus*
Loggerhead Shrike	*Lanius ludovicianus*
Sedge Wren	*Cistothorus platensis*
Dickcissel	*Spiza americana*
Le Conte's Sparrow	*Ammodramus leconteii*
Bobolink	*Dolichonyx oryzivorus*
Common Snapping Turtle	*Chelydra serpentina*
Short-horned Lizard	*Phrynosoma douglassi*
Northern Redbelly Snake	*Storeria occipitomaculata*
Pygmy Shrew	*Sorex hoyi*
Richardson's Ground Squirrel	*Spermophilus richardsonii*
Swift Fox	*Vulpes velox*
River Otter	*Lutra canadensis*

Black-footed Ferret	*Mustela nigripes*
Paddlefish	*Polyodon spathula*
Pallid Sturgeon	*Scaphirhynchus albus*
Silver Chub	*Macrhybopsis storeriana*
Northern Redbelly Dace	*Phoxinus eos*
Flathead Chub	*Platygobio gracilis*
Trout-perch	*Percopsis omiscomaycus*
Threeridge	*Amblema plicata*
Wabash Pigtoe	*Fusconaia flava*
Mapleleaf	*Quadrula quadrula*
Black Sandshell	*Ligumia recta*
Creek Heelsplitter	*Lasmigona compressa*
Pink Heelsplitter	*Potamilus alatus*
Whooping Crane	*Grus americana*
Peregrine Falcon	*Falco peregrinus*
Brewer's Sparrow	*Spizella breweri*
McCown's Longspur	*Calcarius mccownii*
Smooth Softshell Turtle	*Apalone mutica*
False Map Turtle	*Graptemys pseudogeographica*
Northern Prairie Skink	*Eumeces septentrionalis*
Northern Sagebrush Lizard	*Sceloporus graciosus*
Arctic Shrew	*Sorex arcticus*
Western Small-footed Myotis	*Myotis ciliolabrum*
Long-eared Myotis	*Myotis evotis*
Long-legged Myotis	*Myotis volans*
Plains Pocket Mouse	*Perognathus flavescens*
Hispid Pocket Mouse	*Chaetodipus hispidus*
Sagebrush Vole	*Lemmiscus curtatus*
Eastern Spotted Skunk	*Spilogale putoris*
Gray Wolf	*Canis lupis*
Chestnut Lamprey	*Ichthyomyzon castaneus*
Silver Lamprey	*Ichthyomyzon unicuspis*
Central Stoneroller	*Campostoma anomalum*
Hornyhead Chub	*Nocomis biguttatus*
Pugnose Shiner	*Notropis anogenus*
Blacknose Shiner	*Notropis heterolepis*
Rosyface Shiner	*Notropis rubellus*
Finescale Dace	*Phoxinus neogaeus*
Yellow Bullhead	*Ameiurus natalis*
Flathead Catfish	*Pylodictis olivaris*
Logperch	*Percina caprodes*
River Darter	*Percina shumardi*
Pink Papershell	*Potamilus ohiensis*
Plants	
None Listed	*N/A*
Other	
None Listed	*N/A*

Nebraska

Common Name	Scientific Name

Animals	
Eskimo Curlew	*Numenius borealis*
Whooping Crane	*Grus americana*
Interior Least Tern	*Sterna antillarum athalassos*
Bald Eagle	*Haliaeetus leucophalus*
Piping Plover	*Charadrius melodus*
Mountain Plover	*Charadrius montanus*
Black-footed Ferret	*Mustela nigripes*
Swift Fox	*Vulpes velox*
River Otter	*Lutra canadensis*
Southern Flying Squirrel	*Glaucomys volans*
Black-tailed Prairie Dog	*Cynomys ludovicianus*
Pallid Sturgeon	*Scaphirhyncus albus*
Topeka Shiner	*Notropis topeka*
Sturgeon chub	*Macrhybopsis gelida*
Blacknose shiner	*Notropis heteropis*
Lake sturgeon	*Acipenser fulvescens*
Northern Redbelly Dace	*Phoxinus eos*
Finescale Dace	*Phoxinus neogaeus*
American Burying Beetle	*Nicrophorus americanus*
Massasauga	*Sistrurs catenatus*
Scaleshell Mussel	*Leptodea leptodon*
Plants	
Hayden's (blowout) penstemon	*Penstemon haydenii*
Colorado Butterfly Plant	*Gaura neomexicana coloradensis*
Saltwort	*Salicornia rubra*
Western Prairie Fringed Orchid	*Platanthera praeclara*
Ute Lady's Tresses	*Spiranthes diluvialis*
Ginseng	*Panax quinquefolium*
Small White Lady's Slipper	*Cypripedium candidum*
Other	
None Listed	*N/A*

South Dakota

Common Name	Scientific Name
Animals	
American Burying Beetle	*Nicrophorus americanus*
Scaleshell	*Leptodea leptodon*
Higgins Eye	*Lampsilis higginsii*
Dakota Skipper	*Hesperia dacotae*
Banded Killifish	*Fundulus diaphanus*
Blacknose Shiner	*Notropis heterolepis*
Finescale Dace	*Phoxinus neogaeus*
Longnose Sucker	*Catostomus catostomus*
Northern Redbelly Dace	*Phoxinus eos*
Pallid Sturgeon	*Scaphirhynchus albus*
Pearl Dace	*Margariscus margarita*
Sicklefin Chub	*Macrhybopsis meeki*

Sturgeon Chub	*Macrhybopsis gelida*
Topeka Shiner	*Notropis topeka*
Eastern Hognose Snake	*Heterodon platirhinos*
False Map Turtle	*Graptemys pseudogeographica*
Lined Snake	*Tropidoclonion lineatum*
American Dipper	*Cinclus mexicanus*
Bald Eagle	*Haliaeetus leucocephalus*
Eskimo Curlew	*Numenius borealis*
Interior Least Tern	*Sterna antillarum athalassos*
Osprey	*Pandion haliaetus*
Peregrine Falcon	*Falco peregrinus*
Piping Plover	*Charadrius melodus*
Whooping Crane	*Grus americana*
Black-footed Ferret	*Mustela nigripes*
Gray Wolf	*Canis lupus*
River Otter	*Lontra canadensis*
Swift Fox	*Vulpes velox*
Western Prairie Fringed Orchid	*Platanthera praeclara*
Plants	
None Listed	*N/A*
Other	
None Listed	*N/A*

Oklahoma

Common Name	Scientific Name
Animals	
Mississippi Alligator	*Alligator mississippiensis*
Gray Bat	*Myotis grisescens*
Indian Bat	*Myotis sodalis*
Ozark Bat	*Corynorhinus townsendii ingens*
Ozark Cavefish	*Amblyopsis rosae*
Whopping Crane	*Grus americana*
Eskimo Curlew	*Numenius borealis*
Leopards Darter	*Percina pantherina*
Bald Eagle	*Haliaeetus leucocephalus*
Neosho Madtom	*Noturus placidus*
Pipping Plover	*Charadrius melodus*
Ouachita Rock Pocketbook	*Arkansia wheeleri*
Arkansas River Shiner	*Notropis girardi*
Least Tern	*Sterna antillarum*
Black-Capped Vireo	*Vireo atricapillus*
Red-Cockaded Woodpecker	*Picoides borealis*
Plants	
Western Prairie Fringed Orchid	*Platanthera praeclara*
Other	

Note: Country and Province information is maintained separately from the plan for emergency responder use.

FIGURE 6.4

AQUIFERS		
NAME	COUNTY/STATE	PROVINCE
[redacted]	[redacted]	[redacted]

HYDRAULICALLY SENSITIVE AREAS AND OPERATOR DESIGNATED HCAs	
NAME	LOCATION
[redacted]	[redacted]

FIGURE 6.5

US ENVIRINMENTAL SENSITIVE AREAS			
ID	SOURCE	ORGANIZATION	Map Sheet
[redacted]			

	[redacted]	

[redacted]

[redacted]

[redacted]

[redacted]

US HIGH POPULATED AREAS				
HPA ID	NAME	COUNTY NAME	STATE NAME	MapSheet
[redacted]				

US POPULATED AREAS				
ID	NAME	COUNTY NAME	STATE NAME	MapSheet
[redacted]				

US DAMS				
DAM NAME	COUNTY	RIVER	STATE	MapSheet
[redacted]				

US LAKES		
NAME	STATE	MapSheet
[redacted]		

US RIVERS & STREAMS			
FEATURE	NAME	STATE	MapSheet
[redacted]			

[redacted]

ALBERTA, CANADA SENSITIVITY AREAS

OBJECT ID	SITE NAME	MapSheet
	[redacted]	

CANADIAN WILDLIFE		
WOP ID	OBSERVATION	MapSheet
[redacted]		

CANADIAN POPULATED AREAS				
PLACE ID	PROVIDENCE	GEONAME	CONCISE	MapSheet
[redacted]				

CANADIAN MANUFACTURING WATERWELLS					
WELL_ID	WELL_OWNER	AQUIFER	WELL_USE	MapSheet	
[redacted]					

CANADIAN MUNICIPAL WELLS			
WATER USE	WELL USE	Sask_ID	MapSheet
[redacted]			

CANADIAN LAKES		
NAME	Lake_ID	MapSheet
[redacted]		

CANADIAN RIVERS & STREAMS

NAME	MapSheet
[redacted]	[redacted]

[redacted]

FIGURE 6.6

DRAIN TILES

"Consideration needs to be given to the presence of drain tiles and how they could provide a hydraulic conduit for the migration of the product off the right of way."

SPREAD 3B DRAIN TILE LOCATIONS - NORTH OF 197TH STREET								
POINT	STATION	ANGLE	DESCRIPTION	DC FILE	TRACT NO.	MILE POST	LAT	LONG
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
RANDOM LOCATION								
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

APPENDIX A

RESPONSE EQUIPMENT/RESOURCES

A.1 Company Owned Response Equipment

A.2 Other Company Resources

A.3 Contract Resources

A.4 Cooperative/Mutual Aid Resources

A.5 Volunteers

A.6 Communications

Figure A.1 Company Owned Spill Response Equipment

Figure A.2 Response Resources

Figure A.3 USCG OSRO Classifications

Figure A.4 Coop Agreements/OSRO Contracts

RESPONSE EQUIPMENT/RESOURCES

A.1 COMPANY OWNED RESPONSE EQUIPMENT

The Company owns and operates oil spill response equipment contained within response trailers staged throughout the pipeline system. This equipment is maintained according to manufacture's recommendations by Company and/or contracted personnel. An equipment summary detailing locations, type and amount stored in the response trailers is listed in Figure A.1. The Company also has contracts in place with Oil Spill Removal Organizations and other clean-up contractors that are capable of responding to all discharges along the Pipeline. Figure A.2 lists the contracted Oil Spill Removal Organizations.

Equipment trailers are located at the Hardisty Pump Station (Alberta), Regina Pump Station (Saskatchewan), in Valley City (North Dakota) at an external contractor site, in Brookings (South Dakota), Yankton (South Dakota), Cushing (Oklahoma) and St. Joseph (Missouri) at a TransCanada office location.

The Qualified Individual has the authority to activate other private contractors, experts, and consultants as the situation demands.

All Pipeline personnel who might be involved in an oil spill have been informed that detergents or other surfactants are prohibited from being used on an oil spill in the water and that dispersants can only be used with the approval of the Canadian Regional Environmental Emergency Team (REET) or US Regional Response Team, the interagency group composed of Federal and State agency representatives that coordinates oil spill response.

A.2 OTHER COMPANY RESOURCES

Additional Company spill response equipment and manpower resources are not available to supplement the response operation; however, third party contractors will be activated on an as needed basis.

A.3 CONTRACT RESOURCES

The resources will be secured from a Company approved contractor. Management will typically handle notification/implementation of these resources. Figure A.2 provides a quick reference to the Oil Spill Removal Organizations and details their response capability and estimated response times. **Telephone reference is provided in Figure 2.5.** *(Note: The Company will ensure that each OSRO has a comprehensive maintenance program and applicable training / drills programs in place at contract renewal.)*

A.4 COOPERATIVE/MUTUAL AID RESOURCES

The Company is a member of the following Oil Spill Cooperatives or mutual aid groups:

- Western Canadian Spill Services Ltd.
- Alberta - Area U and S Oil Spill Cooperatives
- Saskatchewan - Area 3, 6, and 4 & 5 Oil Spill Cooperatives

A.5 VOLUNTEERS

Volunteers will not be utilized by the Company for the response operations. In the U.S., all volunteers will be referred to the Federal Regional Response Team.

A.6 COMMUNICATIONS

Effective and efficient communications systems are essential for emergency response at every level. The communications system will be utilized to gather information and current status reports as well as to provide coordination and direction to widely separated work groups involved in search, containment/diversion, repair, traffic control, public control or evacuation, and restoration.

The Company's overall Emergency Notification Chart (Figure 2.2) indicates individuals within the Company and governmental agencies who must be contacted in the event of an emergency.

Notification information for the Qualified Individuals, Alternate Qualified Individuals, emergency response contractors, and governmental agencies is located in Section 2.0 and the Response Zone Annexes.

Lines of communication between the Incident Commander, local personnel, and contractors are demonstrated in the organization charts provided in Figures 4.1 and 4.2. Communication of the overall spill response operation between the Company and the responsible government agencies will occur between the Incident Commander and the Federal On-Scene Coordinator.

Central Communications System

Prearranged communication channels are of the utmost importance in dealing with Company emergencies. The notification procedures and telephone contacts documented in Section 2.0 will be reviewed in accordance with the earlier documented updating procedures. The predetermined communications channels include the following:

- A list of emergency telephone numbers for internal management and emergency response personnel (Figures 2.2 and 2.5).
- A list of emergency telephone numbers for various external resources such as the Fire Departments, Public Officials and local agencies is provided in the Annexes.
- A list of emergency telephone numbers for contract response resources (Figure 2.5).

Communications Equipment

Field communications during a spill response will be handled via radios, telephones, cellular phones, fax machines, and computers and will be maintained by Company personnel. In the event of a Worst Case Discharge, field communications will be enhanced with contract resources as the situation demands.

Communications Type

Voice communications may be conducted over the public telephone system or Company provided two-way radio equipment.

Radios **-** Hand-held and vehicle-mounted radio sets are the most effective means of communication for the field response operation. The units are battery operated, multi-channeled, and have a typical range that will cover the area of the response operation. Additional radio sets and battery packs/charges will be necessary in the event of a prolonged response operation.

Telephone (Conventional) **-** Conventional land line telephones are the most effective means of communication for regulatory and advisory notifications during a spill response operation. Additional telephone lines can be installed in the event of a prolonged response operation. All major facilities have access to standard telephone service.

Cellular - Cellular telephones are useful during spill events giving the user the ability to travel while using the communication system.

FAX Machines - FAX machines allow for a rapid transfer of information/documentation such as status reports/updates, written notifications, and purchase orders. All administrative office have facsimile machines.

Computers - Computers are commonly used in networks which allow access to various other locations and company personnel. Computers also speed the consolidation of information and preparation of a written report.

FIGURE A.1

COMPANY OWNED SPILL RESPONSE EQUIPMENT

COMPANY OWNED RESPONSE EQUIPMENT	
5 SPILL RESPONSE TRAILERS (ONE PER RESPONSE ZONE)	
Description	**Quantity**
Response boat 18.5 foot work boat with a 60 HP outboard	1
Jon boat 14 foot Safety boat with a 9.9 hp	1
34 ft Equipment trailer with 6 ft office includes equipment shelving, heat lights, power awning, rear ramp door and 1 side door. Roof rack for storage of the 14' boat and 500ft boom.	1
River Boom 6" x 6'	500 ft
Portable dam 50 ft	1
Diesel /hydraulic Skimming System with diesel power transfer pump and hoses	1
Sorbent pads	5 bales
Sorbent boom	5 bales
500 gallon portable tank	1
2,000 gallon portable tank	1
10,000 gallon portable bladder	1
Winter equipment(e.g. Chain saws, chains, pry bars, ropes,ice,augers)	varies
Bird Hazing Kit	1
20' boom Trailer	1

Supplemental Trailer Equipment List

FIGURE A.2

RESPONSE RESOURCES

Zone : Hardisty Pump Station/ Regina Pump Station

COOPERATIVES
Western Canadian Spill Services Ltd.
Albert - Area U and S Oil Spill Cooperatives
Saskatchewan - Area 3 and 6 Oil Spill Cooperatives
National Response Corporation (OSRO, not a Cooperative)

Zone : Regina Pump Station / Haskett Pump Station

COOPERATIVES
National Response Corporation (OSRO, not a Cooperative)
Western Canadian Spill Services Ltd.
Saskatchewan - Area 6 and 4 & 5 Oil Spill Cooperatives

Zone : North Dakota, South Dakota, Nebraska

Area : North Dakota, South Dakota, Nebraska						
OSRO Name	Contract Number	Environment Type	Facility Classification Level			
			MM	W1	W2	W3
National Response Corporation	TBD	River/Canal	X	X	X	X
		Inland	X	X	X	X
		Open Ocean	X	X	X	X
		OffShore	X	X	X	X
		Near Shore	X	X	X	X
		Great Lakes				

Zone : Kansas, Missouri, Illinois

Area : Kansas, Missouri, Illinois						
OSRO Name	Contract Number	Environment Type	Facility Classification Level			
			MM	W1	W2	W3
National Response Corporation	TBD	River/Canal	X	X	X	X
		Inland	X	X	X	X
		Open Ocean	X	X	X	X
		OffShore	X	X	X	X
		Near Shore	X	X	X	X
		Great Lakes				

Zone : Cushing Extension

Area : Cushing Extension Area						
OSRO Name	Contract Number	Environment Type	Facility Classification Level			
			MM	W1	W2	W3
National Response Corporation	TBD	River/Canal	X	X	X	X
		Inland	X	X	X	X
		Open Ocean	X	X	X	X
		OffShore				
		Near Shore	X	X	X	X
		Great Lakes	X	X	X	X

FIGURE A.3

USCG OSRO CLASSIFICATIONS

The USCG has classified OSROs according to their response capabilities, within each Captain of the Port (COTP) zone, for vessels and for facilities in four types of environments. Response capabilities are rated MM, W1, W2, or W3 as described below

MINIMUM EQUIPMENT REQUIREMENTS FOR OSRO CLASSIFICATION			
Classification	**Resource Quantity Guidelines**	**Maximum Facility Response Times**	**Maximum Vessel Response Times**
		Rivers/Canals	
MM	Protective Boom: 4,000*ft EDRC:; 1,200 bbls TSC: 2,400 bbls	High Volume Ports: 6 hours Other Ports: 12 hours	High Volume Ports: 12 hours Other Ports: 24 hours
W1	Protective Boom: 25,000*ft EDRC:; 1,875 bbls TSC: 3,750 bbls	High Volume Ports: 12 hours Other Ports: 24 hours	High Volume Ports: 12 hours Other Ports: 24 hours
W2	Protective Boom: 25,000*ft EDRC:; 3,750 bbls TSC: 7,500 bbls	High Volume Ports: 30 hours Other Ports: 36 hours	High Volume Ports: 36 hours Other Ports: 48 hours
W3	Protective Boom:25,000*ft EDRC:; 7,500 bbls TSC: 15,000 bbls	High Volume Ports: 54 hours Other Ports: 60 hours	High Volume Ports: 60 hours Other Ports: 72 hours
		Great Lakes	
MM	Protective Boom: 6,000*ft EDRC:; 1,250 bbls TSC: 2,500 bbls	All Ports: 6 hours	All Ports: 12 hours
W1	Protective Boom:30,000*ft EDRC:; 6,250 bbls TSC: 12,500 bbls	High Volume Ports: 12 hours Other Ports: 24 hours	High Volume Ports: 12 hours Other Ports: 24 hours
W2	Protective Boom:30,000*ft EDRC:; 12,500 bbls TSC: 25,000 bbls	All Ports: 36 hours	All Ports: 42 hours
W3	Protective Boom:30,000*ft EDRC:; 25,000 bbls TSC: 50,000 bbls	All Ports: 60 hours	All Ports: 66 hours

MINIMUM EQUIPMENT REQUIREMENTS FOR OSRO CLASSIFICATION			
Classification	**Resource Quantity Guidelines**	**Maximum Facility Response Times**	**Maximum Vessel Response Times**
Inland			
MM	Protective Boom:6,000*ft EDRC:; 1,200 bbls TSC: 2,400 bbls	High Volume Ports: 6 hours Other Ports: 12 hours	High Volume Ports: 12 hours Other Ports: 24 hours
W1	Protective Boom: 30,000*ft EDRC:; 12,500 bbls TSC: 25,500 bbls	High Volume Ports: 12 hours Other Ports: 24 hours	High Volume Ports: 12 hours Other Ports: 24 hours
W2	Protective Boom: 25,000*ft EDRC:; 12,500 bbls TSC: 25,500 bbls	High Volume Ports: 30 hours Other Ports: 36 hours	High Volume Ports: 36 hours Other Ports: 48 hours
W3	Protective Boom: 25,000*ft EDRC:; 50,500 bbls TSC: 100,500 bbls	High Volume Ports: 54 hours Other Ports: 60 hours	High Volume Ports: 60 hours Other Ports: 72 hours
Great Lakes			
MM	Protective Boom: 8,000*ft EDRC:; 1,200 bbls TSC: 2,400 bbls	High Volume Ports: 6 hours Other Location: 24 hours	High Volume Ports: 12 hours Other Ports: 24 hours
W1	Protective Boom: 30,000*ft EDRC:; 12,500 bbls TSC: 25,500 bbls	High Volume Ports: 12 hours Other Ports: 24 hours	High Volume Ports: 12 hours Other Ports: 24 hours
W2	Protective Boom: 30,000*ft EDRC:; 25,500 bbls TSC: 50,500 bbls	High Volume Ports: 30 hours Other Ports: 36 hours	High Volume Ports: 36 hours Other Ports: 48 hours
W3	Protective Boom: 30,000*ft EDRC:; 50,000 bbls TSC: 100,000 bbls	High Volume Ports: 54 hours Other Location: 60 hours (for open ocean, plus travel time from shore)	High Volume Ports: 60 hours Other Location: 72 hours (for open ocean, plus travel time from shore)

MINIMUM EQUIPMENT REQUIREMENTS FOR OSRO CLASSIFICATION			
Classification	**Resource Quantity Guidelines**	**Maximum Facility Response Times**	**Maximum Vessel Response Times**
	Offshore		
MM	Protective Boom:6,000*ft EDRC:; 1,200 bbls TSC: 2,400 bbls	High Volume Ports:6 hours Other Ports: 12 hours	High Volume Ports: 12 hours Other Ports: 24 hours
W1	Protective Boom: 15,000*ft EDRC: 12,500 bbls TSC: 25,500 bbls	High Volume Ports:24hours Other Ports: 48hours	High Volume Ports: 24 hours Other Ports: 48 hours
W2	Protective Boom: 15,000*ft EDRC: 25,000 bbls TSC: 50,000 bbls	High Volume Ports:30hours Other Ports: 36hours	High Volume Ports: 36hours Other Ports: 48hours
W3	Protective Boom: 15,000*ft EDRC: 50,000 bbls TSC: 100,000 bbls	High Volume Ports:54hours Other Ports: 60hours	High Volume Ports: 60hours Other Ports: 72hours
	Open Ocean		
MM	Protective Boom: 0*ft EDRC: 1,200 bbls TSC: 2,400 bbls	High Volume Ports:6hours Other Ports: 12hours	High Volume Ports: 12hours Other Ports: 24hours
W1	Protective Boom: 0*ft EDRC: 12,500 bbls TSC: 25,000 bbls	High Volume Ports:6hours Other Ports: 12hours	High Volume Ports: 12hours Other Ports: 24hours
W2	Protective Boom: 0*ft EDRC: 25,000 bbls TSC: 50,000 bbls	High Volume Ports:30hours Other Ports: 36hours	High Volume Ports: 36hours Other Ports: 48hours
W3	Protective Boom: 0*ft EDRC: 50,000 bbls TSC: 100,000 bbls	High Volume Ports:54hours Other Ports: 60hours	High Volume Ports: 60hours Other Ports: 72hours

1. Rivers/canals include bodies of water, including the Intracoastal Waterway and other bodies artificially created for navigation, confined within an inland area and having a project depth of 12 feet (3.66 meters).
2. EDRC stands for "effective daily recovery capacity," or the calculated recovery capacity of oil recovery devices determined by using a formula that takes into account limiting factors such as daylight, weather, sea state, and emulsified oil in the recovered material.
3. TSC stands for "temporary storage capacity," meaning sufficient storage capacity equal to twice the EDRC of an OSRO. Temporary storage may include inflatable bladders, rubber barges, certified barge capacity, or other temporary storage that can be utilized on scene at a spill response and which is designed and intended for the storage of flammable or combustible liquids. It does not include vessels or barges of opportunity for which no pre-arrangements have been made. Fixed shore-based storage capacity, ensured available by contract or other means, will be acceptable.

* In addition, 1,000 feet of containment boom plus 300 feet per skimming system.

FIGURE A.4

AGREEMENTS/CONTRACTS

Click to view the file - NRC Packet_23_1_2009_14_31_34.pdf

Click to view the file - WCSS Packet_29_11_2008_10_23_9.pdf

Click to view the file - Alberta Area 2U Packet_29_11_2008_10_27_35.pdf

Click to view the file - Alberta Area 1S Packet_29_11_2008_10_28_3.pdf

Click to view the file - Sask Area 3 Packet_29_11_2008_10_28_27.pdf

Click to view the file - Sask Area 6 Packet_29_11_2008_10_29_12.pdf

Click to view the file - Sask Area 4and5 Packet_29_11_2008_10_29_50.pdf

Decision Summary (DS-244)

TransCanada
In business to deliver

To:	[redacted]	**Date:**	October 14, 2008
From:	[redacted]	**Location:**	Calgary, Alberta
Subject:	NRC OSRO Resource Retainer		

Decision Proposed ([redacted] per Annum(U.S. Currency) for 3 years)

Your approval is requested for funds related to emergency response planning and preparedness. As a matter of risk mitigation and regulatory compliance, it is proposed to enter into a contractual retainer to address a number of emergency response functions during operations. This amount falls within the existing capital expenditures for emergency response for 2009.

Background

National Response Corporation (NRC) will provide Keystone with Oil Spill Response Organization (OSRO) resources. Specifically, NRC will be the overall coordinating company that has the ability to safely respond to spill related incidents along the pipeline. NRC ensures spill readiness which included supplier subcontracts, training, workshops and overall spill site coordination. NRC has the proven ability to handle spills of all sizes and is approved by the United States Coastguard.

NRC has its own equipment, spill managers and a network of related industries to ensure Keystone is prepared to respond efficiently and effectively. The retention of a contractor is mandatory for Keystone to meet regulatory requirements. Having a retainer guarantees Keystone the resources when most needed.

The contract should start on January 1, 2009 and will form part of the existing Emergency Response Plan for 2009. This type of contract was not contemplated in the original Emergency Response budget of [redacted], but is part of the overall plan. The first year will be absorbed by the existing budget and for future years, these costs should be part of a field operations budget.

Requested by:

[redacted]	14 October 2008 Date

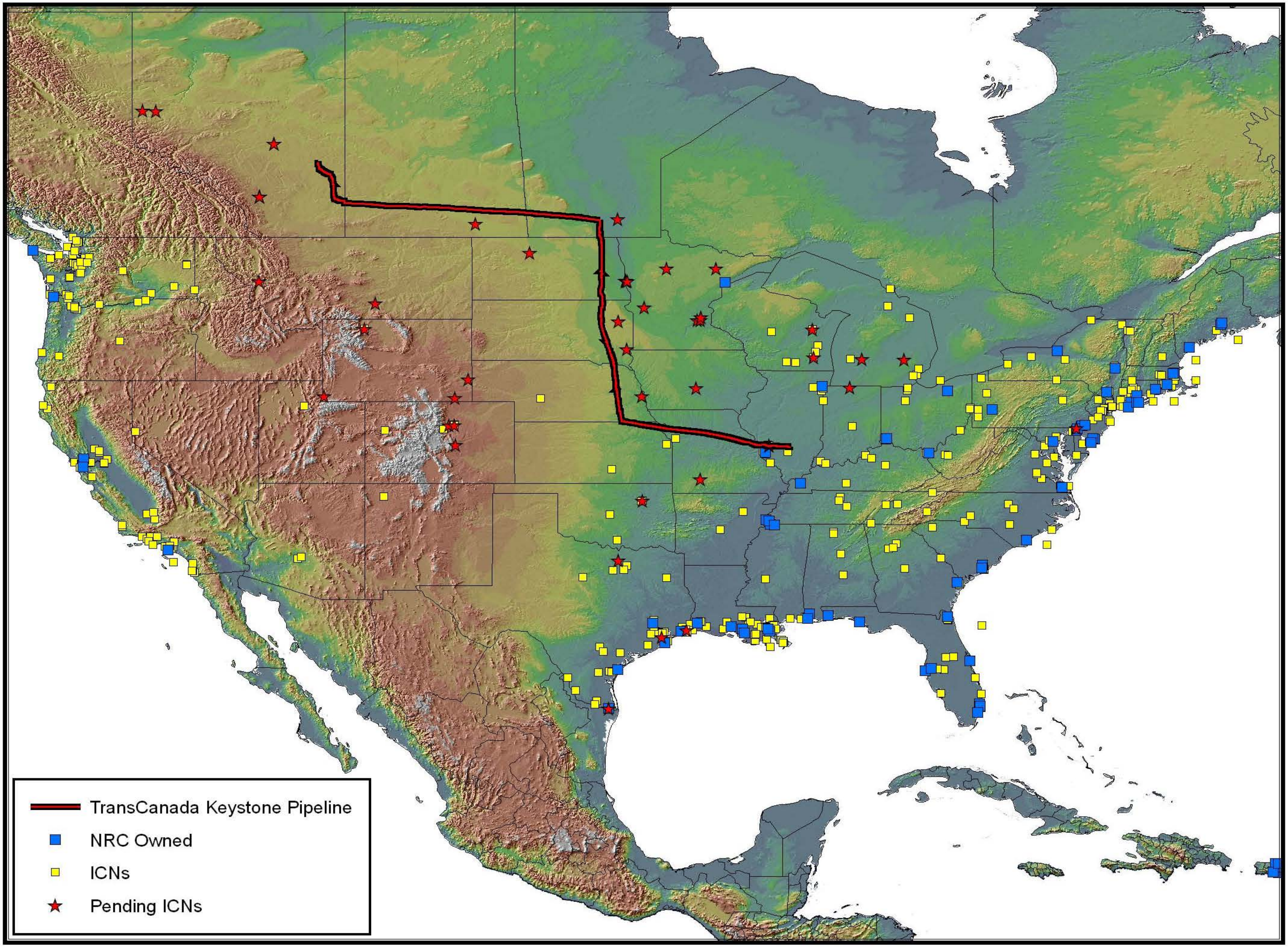
Approved by:

[redacted]	14 October 2008 Date

National Response Corporation, Inc.

National Response Corporation, Inc. is an Oil Spill Response Organization contracted to conduct oil recovery for TransCanada Keystone Limited Partnership and TC Oil Pipeline Operations, Inc. National Response Corporation uses a network of associated cleanup contractors throughout North America and the world. National Response Corporation has been certified by the United States Coast Guard, as described in the Emergency Response Manual, to respond to releases along the length of the Pipeline.

For further information about National Response Corporation and a list of response equipment you can visit their website at http://www.nrcc.com.


TransCanada Keystone Pipeline
NRC Owned
ICNs
Pending ICNs

030374

Oil Spill Cooperative Agreement

TransCanada Keystone Limited Partnership has agreed and intends to join the Oil Spill Cooperative organizations in all areas which its pipeline crosses. Currently, the pipeline is not in operation, therefore the contracts / agreements are not in place. When contracts / agreements are completed they will replace this page of this document and will be made available for inspection.

Western Canadian Spill Services Ltd

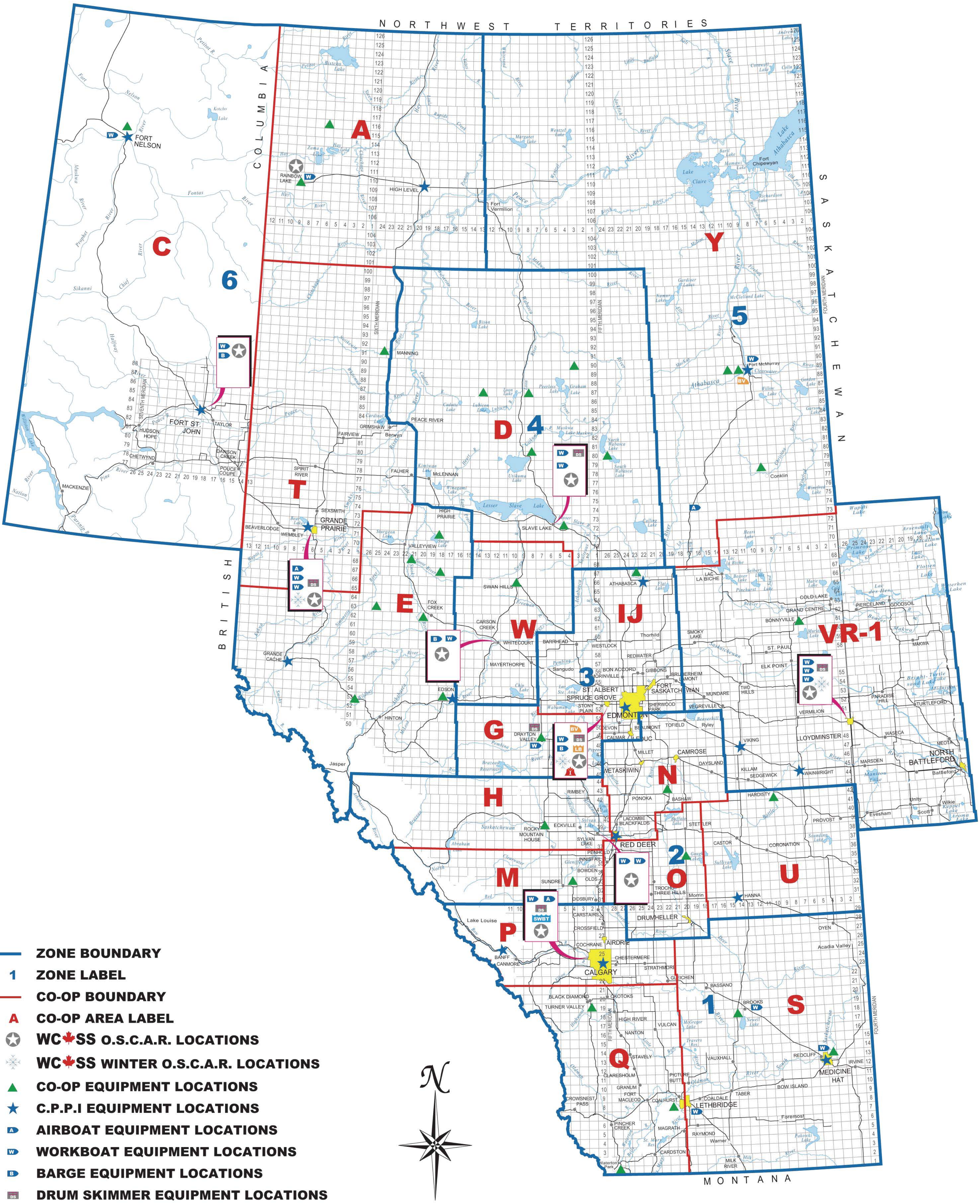
Western Canadian Spill Services Ltd. is the spill preparedness organization of the upstream petroleum industry in North East British Columbia, Alberta and Cooperative VR1 that extends into Saskatchewan. The purpose of Western Canadian Spill Services is to maintain an effective spill response capability for the upstream petroleum industry in Western Canada and to provide information and education on spill issues including spill prevention.

Through an agreement between Western Canadian Spill Services and the Canadian Petroleum Products Institute the members of the Western Canadian Spill Services in good standing can have access to the equipment owned by Canadian Petroleum Products Institute.

In Manitoba, the Western Canadian Spill Services contracts with Euroway Industrial Service Company Ltd, to store and maintain response equipment available for use by members of the Western Canadian Spill Services. Euroway is located in Winnipeg, Manitoba.

For further information about Western Canadian Spill Services and a list of response equipment you can visit their website at http://www.wcss.ab.ca. Information on the Canadian Petroleum Products Institute can be found at their website www.cppi.ca.

WC✱SS OIL SPILL COOPERATIVE BOUNDARIES 2008



ZONE BOUNDARY

1 ZONE LABEL

CO-OP BOUNDARY

A CO-OP AREA LABEL

WC✱SS O.S.C.A.R. LOCATIONS

WC✱SS WINTER O.S.C.A.R. LOCATIONS

CO-OP EQUIPMENT LOCATIONS

C.P.P.I EQUIPMENT LOCATIONS

AIRBOAT EQUIPMENT LOCATIONS

WORKBOAT EQUIPMENT LOCATIONS

BARGE EQUIPMENT LOCATIONS

DRUM SKIMMER EQUIPMENT LOCATIONS

BOOM VANE EQUIPMENT LOCATIONS

SHALLOW WATER BOOM TRAILER LOCATIONS

LAKE BOOM EQUIPMENT LOCATIONS

INCINERATOR EQUIPMENT LOCATIONS

SCALE

0 20 40 60 80 100 200 300 km

0 20 40 60 80 120 160 200 miles

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CPPI/WCSS* Environmental Protection Unit (EPU) Custodian Information

Alberta	CPPI Equip.	Custodian	Contact	Address	Phone	Night Phone	Fax	E-mail
Athabasca	Basic	Volunteer Fire Dept. (Town)	Fire Chief Denis Mathieu	4707-50 Street T9S 3A3	[redacted]			
Banff	Basic	Fire Department	Deputy Jim Watt	201 Beaver Street PO Box 1260 T0L 0C0	[redacted]			
Calgary	Basic	ECL Transportation	Bruce Thomson Gail Sharko	7100 44 St SE T2C 2V7 (Gail) 5366-55 Street SE T2C 3G9 (trailer)	[redacted]			
Edmonton	Basic	ECL Transportation	Randy Johnston Gail Sharko (Calgary)	1810 66 Ave T6P 1M4	[redacted]			
Edson	Basic	Fire Department	Chief Allan Schram	6 Avenue 49 Street Box 6300 T7E 1T7	[redacted]			
Ft. McMurray	CPPI Basic . WCSS Equip. OSCAR, Skid Unit, Work Boat, Boom Vane	Eveready Industrial (TriVax Enterprises)	Brent Bakke	230A MacKay Crescent T9H 5C6	[redacted]			
Grande Prairie	Basic	Fire Department (cheque NOT to City)	Deputy Chief Harvey Pearson Dennis Driver, Stn. Captain	8111 Resources Road T8V 7Y2	[redacted]			
Hanna	Basic	Volunteer Fire Dept.	Chief David Mohl	201 1 Ave East Box 430 T0J 1P0	[redacted]			
High Level	Basic	Fire Department	Chief Rod Schmidt	10201-100 Ave T0H 1Z0 (FD) 9813 102 St T0H 1Z0 (town)	[redacted]			
Lethbridge	WCSS Equip. Muskrat, mini OSCAR, work boat	Mid-West Pump (90) Ltd.	Gerry Colburn Ed Carpenter	311 33 St N T1H 3Z6	[redacted]			
Medicine Hat	Basic	Fire Department	Chief Garry Mauch Deputy Allan Guest Randy Stotz	440 Maple Ave SE T1A 7S3	[redacted]			
Viking	Basic	Fire Department	Chief Ken Ruzicka	4920-53 Avenue T0B 4N0	[redacted]			

* WCSS - Western Canadian Spill Services
(see www.wcss.ab.ca for additional locations of WCSS equipment)

CPPI/WCSS* Environmental Protection Unit (EPU) Custodian Information

BC	CPPI Equip.	Custodian	Contact	Address	Phone	Night Phone	Fax	E-mail
Burns Lake	Basic	Lyle Sande Agencies (Chevron)	Lyle Sande Kristi McCrindle	65 Railway Ave. PO Box 619 V0J 1E0	[redacted]	[redacted]	[redacted]	[redacted]
Campbell River	Basic	K&S Petroleum Ltd. (Chevron)	Kerry Coulson	4700 Orange Point Road PO Box 968 V9W 6Y4	[redacted]	[redacted]	[redacted]	[redacted]
Castlegar	Basic	Fire Department	Chief Gerry Rempel Ast Chief Tony Cooper	2161 6 Ave V1N 3B2	[redacted]	[redacted]	[redacted]	[redacted]
Cranbrook	Basic	Jepson Petroleum Ltd (Petro-Canada)	Mgr. Chris Jepson Dave Schmideder	1814 Theatre Road V1C 7G1	[redacted]	[redacted]	[redacted]	[redacted]
Creston	Basic	R A Glennon Petroleum (Shell)	Robert Smith Randy Glennon Stacey Ostendorf	1411 Northwest Blvd RR 6 V0B 1G6	[redacted]	[redacted]	[redacted]	[redacted]
Ft. Nelson	Basic	Fire Department	Chief Dennis Muise Asst. Chief James Childs	5404 48 Ave Bag 399 V0C 1R0	[redacted]	[redacted]	[redacted]	[redacted]
Ft. St. John	Basic	Fire Department	Dep Chief Fred Burrows Chief Jeff Lambert Doreen Holmes	9407-100 Avenue V1J 6W1 10631-100 Street V1J 3Z5 (Town Office)	[redacted]	[redacted]	[redacted]	[redacted]
Golden	Basic	Fire Department	Chief Shawn Tomash	1107-11 Avenue S. P.O. Box 350 V0A 1H0	[redacted]	[redacted]	[redacted]	[redacted]
Kamloops	Basic	Petro-Canada Terminal	Stephen Demianiuk Rick Geier	2955 Tranquille Rd V2B 7W2	[redacted]	[redacted]	[redacted]	[redacted]
Kelowna	Basic	Fire Department	Eileen Davies	2255 Enterprise Way V1Y 8B8	[redacted]	[redacted]	[redacted]	[redacted]
Nanaimo	Basic	Nanaimo Fire Rescue	Deputy Chief Bob Simpson	**Trailer: Fire Stn #2 2499 Dorman Road V9S 5T3** / 200, 575 Fitzwilliam St V9R 3B2 (BS)	[redacted]	[redacted]	[redacted]	[redacted]
Prince George	Basic	Husky Energy Refinery	Greg Primus Bill Fraser	2542 Pulp Mill Rd PO Box 1390 V2L 4V4	[redacted]	[redacted]	[redacted]	[redacted]
Revelstoke	Basic	Big Eddy Fuel (Shell)	Peter Humphries	733 South Highway 23 Box 1740 V0E 2S0	[redacted]	[redacted]	[redacted]	[redacted]
Surrey (Cloverdale)	Basic	D.W.P. Distributors Limited (Chevron)	Bill Poppy	5504 176 Street Surrey, BC V3S 4C3	[redacted]	[redacted]	[redacted]	[redacted]
Terrace	Basic	Fire Department	Chief Peter Weeber	3, 3215 Eby Street V8G 2X8	[redacted]	[redacted]	[redacted]	[redacted]

* WCSS - Western Canadian Spill Services
(see www.wcss.ab.ca for additional locations of WCSS equipment)

030380

CPPI/WCSS* Environmental Protection Unit (EPU) Custodian Information

BC	CPPI Equip.	Custodian	Contact	Address	Phone	Night Phone	Fax	E-mail
Valemount	Basic	Fire Department	Chief Rick LaLonde, Hugh Miller, Dep. Donovan Gee, Dep.	1380 5 Avenue Box 727 V0E 2Z0	[redacted]			
Williams Lake	Basic	TaGerra Holdings Ltd. (Chevron)	Tammi Caferra Linda Dudoski	101 25 Hodgson Road V2G 3P5				

* WCSS - Western Canadian Spill Services
(see www.wcss.ab.ca for additional locations of WCSS equipment)

CPPI/WCSS* Environmental Protection Unit (EPU) Custodian Information

Manitoba	CPPI Equip.	Custodian	Contact	Address	Phone	Night Phone	Fax	E-mail
Brandon	Basic	Fire Department	A/Lt. Donald Matthews	**Trailer @ Fire Stn #2** 637 Princess Avenue R7A 0P2 (DM)	[redacted]			
Dauphin	Basic	Brendonn Holdings Ltd. (Petro-Canada)	Mike Gawaziuk	Hwy. 5A West PO Box 607 R7N 2V4	[redacted]			
Swan River	Basic	Doak's Fuel Service (Imperial Oil)	Dale Macooh Troy Carter	PO Box 695 523-3 Avenue S R0L 1Z0	[redacted]			
The Pas (Town)	Basic	Fire Department	Deputy Chief Richard Paetzold Chief Ron Bourquin	81 Edwards Ave PO Box 870 R9A 1K8	[redacted]			
Thompson	Basic	Doak's Fuel Service (Imperial Oil)	Rob Bilawka	CN Grounds-Station Rd PO Box 309 R8N 1N1	[redacted]			
Winnipeg	CPPI Basic . WCSS Equip. OSCAR, 2 Jet Boats	Euroway Industrial Service Co. Ltd.	Gary Mittermayr	245 Transport Road Box 4, Group 582, RR 5 R2C 2Z2	[redacted]			

* WCSS - Western Canadian Spill Services
(see www.wcss.ab.ca for additional locations of WCSS equipment)

030382

CPPI/WCSS* Environmental Protection Unit (EPU) Custodian Information

Saskatch.	CPPI Equip.	Custodian	Contact	Address	Phone	Night Phone	Fax	E-mail
La Ronge	Basic	Fire Department	Chief Ron Pratt	1222 Hildebrand Drive PO Box 5680 S0J 1L0	[redacted]			
North Battleford	Basic	Fire Department	Chief Mike Saunders Deputy Bryan Beach	902 104 Street PO Box 460 S9A 2Y6				
Prince Albert	Basic	Marsollier Petroleum Ltd. (Esso)	Kelly Bartel Curtis Parent	1100 6 Ave E S6V 2J9				
Regina	Basic	Envirotec Services Inc.	Lyle Clouatre (Daniel Guskjolen looks after trailer - 99 Andre Ave, Regina S4T 7N1)	804-46 Street East Saskatoon S7K 3V7 **Trailer: 1910 Winnipeg Street N., Regina**				
Saskatoon	Basic	Fire Department	Chief Gary Kobussen (admin office) Jim Wood (AO) (Captain Jerry Unser looks after trailer)	125 Idylwyld Dr S S7M 1L4 (admin offices) **Trailer: Fire Hall 7 3550 Wanuskewin Road Saskatoon**				
Swift Current	Basic	Fire Department	Chief Bob Rindahl Cathie Werbowetsky	236 Chaplin Street E S9H 5B2				
Weyburn	Basic	Fire Department	Chief Denis Pilon & Asst Murray Sabados	55-16 Street NE PO Box 370 S4H 2K6				
Yorkton	Basic	Brendonn Holdings Ltd. (Petro-Canada)	Tony Ripa & R Kuschak	24 Broadway Street W S3N 0L4				

* WCSS - Western Canadian Spill Services
(see www.wcss.ab.ca for additional locations of WCSS equipment)

CPPI/WCSS* Environmental Protection Unit (EPU) Custodian Information

NWT	CPPI Equip.	Custodian	Contact	Address	Phone	Night Phone	Fax	E-mail
Hay River	Basic	Matonabee Petroleum Ltd. (Petro-Canada)	Bill Wright	43064 MacKenzie Highway X0E 0R9	[redacted]	[redacted]	[redacted]	[redacted]
Yellowknife	Basic	Matonabee Petroleum Ltd. (Petro-Canada)	Shawn Delaney Dalyn Chan	117 Kamlake Road Box 2697 X1A 2R1	[redacted]	[redacted]	[redacted]	[redacted]
Yukon	**CPPI Equip.**	**Custodian**	**Contact**	**Address**	**Phone**	**Night Phone**	**Fax**	**E-mail**
Whitehorse	Basic	Dall Contracting Ltd. (Petro-Canada)	Mike Baldwin	110 Galena Rd Y1A 2W6	[redacted]	[redacted]	[redacted]	[redacted]

* WCSS - Western Canadian Spill Services
(see www.wcss.ab.ca for additional locations of WCSS equipment)

030384

Oil Spill Cooperative Agreement

TransCanada Keystone Limited Partnership has agreed and intends to join the Oil Spill Cooperative organizations in all areas which its pipeline crosses. Currently, the pipeline is not in operation, therefore the contracts / agreements are not in place. When contracts / agreements are completed they will replace this page of this document and will be made available for inspection.

Albert Area 2U Oil Spill Cooperative

The Province of Alberta is divided into 6 oil spill cooperative zones. Each zone is then divided into areas. The designation 2U means area U of zone 2. The TransCanada Keystone Pipeline system begins and travels south through this area. The cooperative is run by a managing committee with custodians who are responsible for storage and maintenance of the response equipment.

Through the preceding agreement TransCanada Keystone Pipeline system will have the ability to use the cooperatives equipment, if available, during an incident.

The equipment list, contact information and maps are included in this document.

Zone 2 - Coop Area U

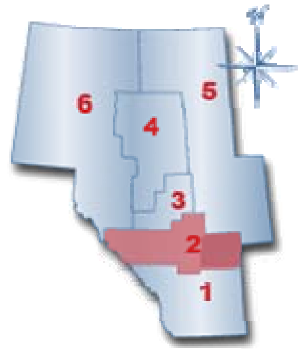
COOP Custodian

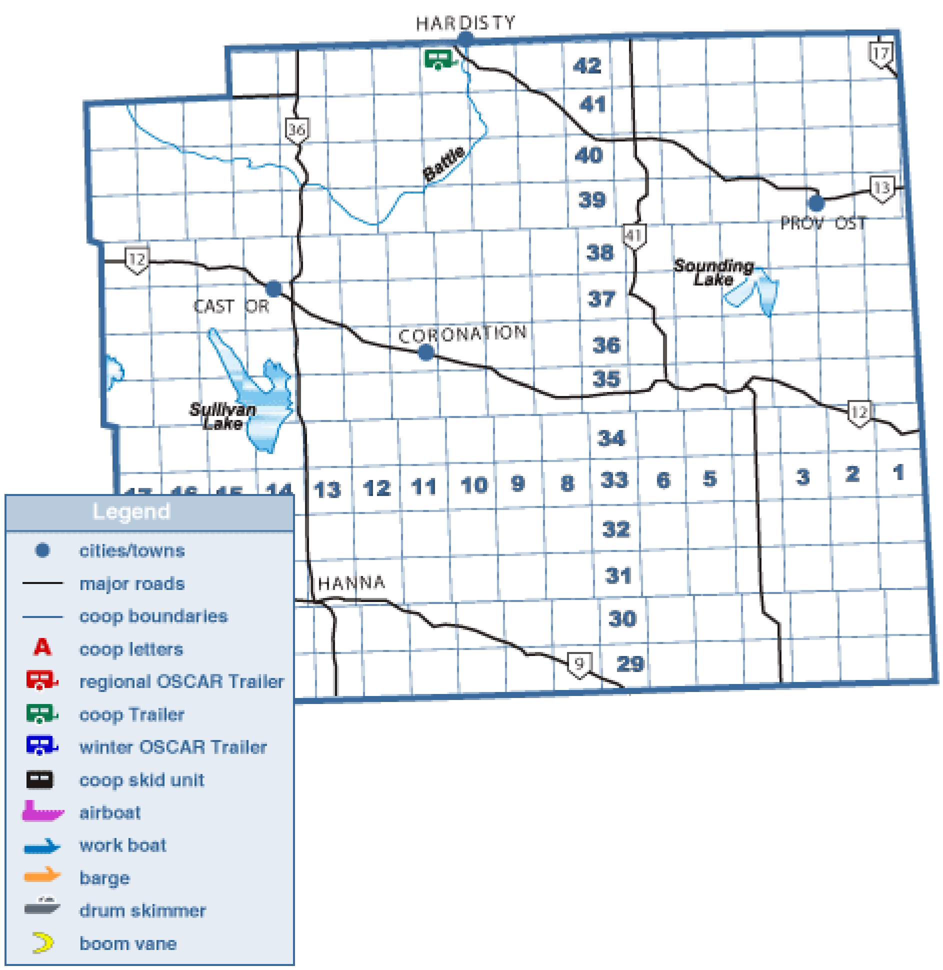
Greg Schmidt/Trevor Bitzer
Greg's Contracting Services Ltd.
Ph : [redacted]
After Hours: Max Devey
[redacted]

Equipment Location
Greg's Contracting Services Ltd. Box 29 4616A 47 Street
Hardisty, AB T0B 1V0

Equipment Summary

- OSCAR Trailer





Oil Spill Cooperative Agreement

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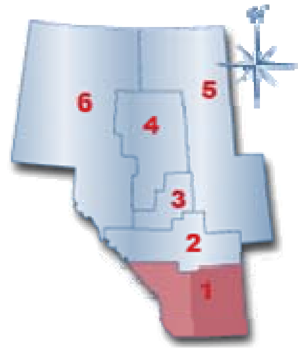
Albert Area 1S Oil Spill Cooperative

The Province of Alberta is divided into 6 oil spill cooperative zones. Each zone is then divided into areas. The designation 1S means area S of zone 1. The TransCanada Keystone Pipeline system traverses the north east corner of this area. The cooperative is run by a managing committee with custodians who are responsible for storage and maintenance of the response equipment.

Through the preceding agreement TransCanada Keystone Pipeline system will have the ability to use the cooperatives equipment, if available, during an incident.

The equipment list, contact information and maps are included in this document.

Zone 1 - Coop Area S



Regional Custodian

Adrian Schuurman
Mid-West Pumps (90) Ltd.
[redacted]
24-HR: [redacted]
Fax: (403) 327-4660

Ed Carpenter

Equipment Location
Lethbridge

Equipment Summary

- Mini-OSCAR
(3/4-ton truck with 2 5/16" ball hitch)
- Muskrat
(1/2-ton truck with 2" ball hitch)
- Marathon Workboat (1/2-tin with 2" ball hitch)

Coop Custodian

Mike Wenner
P&H Oilfield Maintenance
24-HR Ph: [redacted]
Fax: (403) 362-0107
Cell: [redacted]

Equipment Location
NE 34-18-15 W4M Brooks, AB

Equipment Summary

- 45' Trailer (Tractor Truck)
- Muskrat Workboat
(1/2-ton with 2" ball hitch)

Directions
From Brooks, take Castle Road heading west towards Hwy 36 for 5 kms. Yard is located on south side of road, or Junction of Hwy 1 and Hwy 36. Head south of Hwy 36 until you reach Castle Road , yard is located on south side.

Mike Wenner
P&H Oilfield Maintenance
24-HR Ph: [redacted]
Fax: (403) 362-0107
Cell: [redacted]

Equipment Location
15-7-13-5-W4 Enerplus site North of Medicine Hat, AB

Equipment Summary

- C-Can Skid Unit (Bed Truck)


SASKATCHEWAN BORDER
OYEN
BASSANO
BROOKS
McGregor Lake
Newell Lake
Travers Res.
VAUXHALL
REDCLIFF
MEDICINE HAT
IRWIN
PICTURE BUTTE
LETHBRIDGE
TABER
BOW ISLAND
RAYMOND
Pakowki Lake
MILK RIVER
Deer
River
South
Saskatchewan
Oldman
Milk
Legend
cities/towns
major roads
coop boundaries
coop letters
regional OSCAR Trailer
coop Trailer
winter OSCAR Trailer
coop skid unit
airboat
work boat
barge
drum skimmer
boom vane

Oil Spill Cooperative Agreement

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Saskatchewan Area 3 Oil Spill Cooperative

The Province of Saskatchewan is divided into 5 oil spill cooperative areas. The TransCanada Keystone Pipeline travels from west to east through area 3. The cooperative is run by a steering committee with custodians who are responsible for storage and maintenance of the response equipment.

Through the preceding agreement TransCanada Keystone Pipeline system will have the ability to use the cooperatives equipment, if available, during an incident.

The equipment list, contact information and maps are included in this document.

AREA 3 Emercency Response Unit

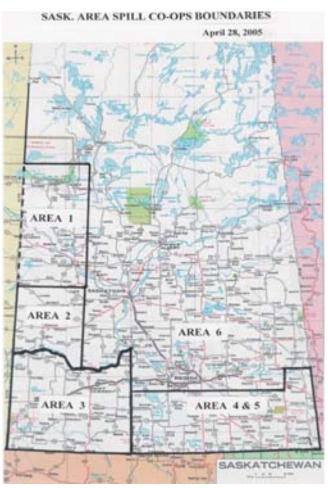
Trailer Location:

06-08-011-18w3 Bench Oil Battery – Husky Energy Inc.

Steering Committee:

Title	Name	Office	Phone
CHAIRMAN:	Gilbert Cadrain	Husky Energy Inc.	[redacted]
SECRETARY:	Gary Hammer	Plains Marketing	[redacted]
TREASURER:	Garry Zinger	Focus Energy	[redacted]
COMMITTEE:	Ron Dolter	S.I.R	[redacted]
	Darcy Thoreson	Equipment Custodian	[redacted]
	Dave Knipfel	Huskey Energy	[redacted]
	Jeff Seffern	Talisman Energy Inc.	[redacted]
	Rob Forester	Crescent Point	[redacted]
	Tim Stevenson	Penn West	[redacted]
	Blake Barsness	Acclaim Energy	

Boundry Map:



AREA III ENVIRONMENTAL RESPONSE TRAILER UNIT

The following equipment is stored in a 8' x 28' tandem axle trailer c/w pintle hitch.

EMERGENCY RESPONSE TELEPHONE NUMBERS

EMERGENCY 911

COMPANY	CONTACT	PHONE
Ambulance (non-emergency)	Swift Current Cabri Gull Lake Shaunavon	[redacted]
Air Ambulance	Saskatoon (Information)	[redacted]
Fire Department (non-emergency)	Swift Current Cabri Shaunavon (Kevin) Gull Lake	[redacted]
Hospitals Cabri Health Centre Gull Lake Health Centre S. C. Union Hospita Shaunavon Union Hospital	Cabri Gull Lake Swift Current Shaunavon	[redacted]
Royal Canadian Mounted Police	Swift Current Gull Lake Shaunavon Cabri	[redacted]
Saskatchewan Pow Corporation Elec. Swift Current	Emergencies 24 Hour	[redacted]
Gas Swift Current Shaunavon Cabri	24 Hour 24 Hour 24 Hour	[redacted]

Website Address for Spill Cooperatives:

www.area3eru.com
http://areatwo.sasktelhosting.net
/
http://www.saskoilspill.com/
http://www.saskoilspill.com/main.htm
http://www.area6sask.com/

INITIAL SPILL REPONSE FLOW CHART

SPILL OBSERVED ? RESPONSE

1. ASSESS THE SPILL OCCURRENCE:
   - ASSESS IMMEDIATE HAZARDS TO:
     - PERSONAL SAFETY
     - PUBLIC SAFETY
     - PROPERTY
     - ENVIRONMENTAL

2. ASSESS THE SPILL OCCURRENCE:
   - ASSESS AND REPORT SOURCE
   - ASSESS AND REPORT SPILL TYPE
     - OIL
     - SALT WATER
     - CHEMICAL
   - ASSESS AND REPORT SPILL SIZE
   - ASSESS SPILL AND REPORT FLOW DIRECTION AND FURTHER CONTAMINATION

3. NOTIFY IMMEDIATE SUPERVISOR:
   - IDENTIFY LOCATION OF SPILL
   - NOTE TIME SPILL DISCOVERED
   - NOTE ADVERSE WEATHER CONDITIONS
     - WEATHER
     - TERRAIN
     - DOWNSTREAM WATER USERS
   - POTENTIAL TO STOP FLOW FROM SOURCE
   - POTENTIAL TO CONTAIN SPILL FLOW
   - COMMUNICATE ON SITE RESPONSE ACTION PLAN

SPILL REPORTED ? IMMEDIATE SUPERVISOR IS NOW THE INTERIM ON-SCENE COMMANDER.

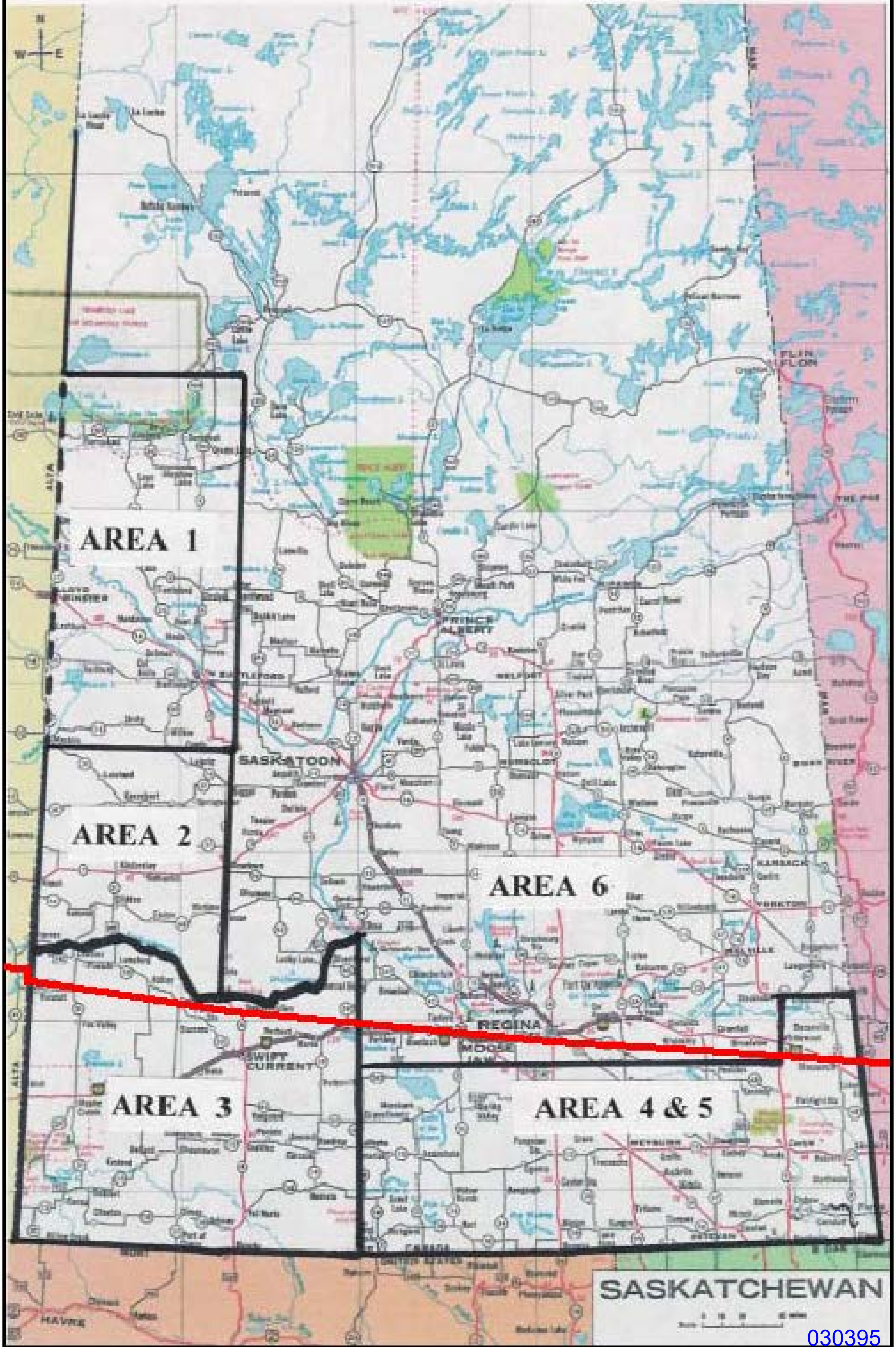
1. ACTIVATE OIL SPILL CONTINGENCY PLAN
   - SET THE RESPONSE UNIT INTO MOTION
   - ESTABLISH THE ON-SCENE COMMANDER

AREA III MOBILIZATION TO SPILL SITE ? ON-SCENE COMMANDER

1. ESTABLISH AND MAINTAIN COMPLETE CONTROL OF THE OPERATION:
   - SET UP A COMMAND POST FOR OPERATIONS
   - DISPATCH FIELD STAFF TO SPILL SITE TO VERIFY THE SPILL LOCATION, THE EXTENT OF THE SPILL AND PROCEED WITH SHUT-IN PROCEDURES
   - MOBILIZE THE AREA III EQUIPMENT ?(COMBINATION #1, 2, 3, 4.)
   - CALL KEY PERSONNEL AND REGULATORY AGENCIES
   - ORGANIZE AND ACTIVATE CONTINGENCY PLAN AS PER AREA III SPILL CONTINGENCY MANUAL FOR CONTAINMENT AND CLEANUP OF SPILL.

SASK. AREA SPILL CO-OPS BOUNDARIES

April 28, 2005



030395

Oil Spill Cooperative Agreement

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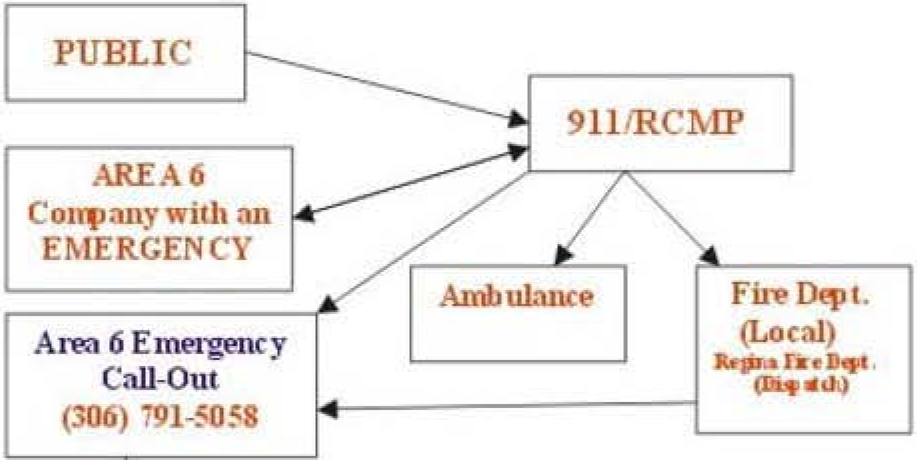
Saskatchewan Area 6 Oil Spill Cooperative

The Province of Saskatchewan is divided into 5 oil spill cooperative areas. The TransCanada Keystone Pipeline travels from west to east through the southernmost part of area 6. The cooperative is comprised of several oil companies in the area who designate their company owned response equipment to be available to other members of the area cooperative for use during an incident.

Through the preceding agreement TransCanada Keystone Pipeline system will have the ability to use the cooperatives equipment, if available, during an incident.

Contact information and Saskatchewan area map are included in this document.

AREA 6 EMERGENCY RESPONSE CO-OP
CALL-OUT CHART & INSTRUCTIONS (May 2008)



Alliance Pipeline
1-800-884 8811
Kinder Morgan (Cochin)
1-800-265 6000
Co-op Refineries
(306) 721 5372
Spectra Energy
1-403-838-3764
Imperial Oil
(24/7) (306) 757 4342

Enbridge Pipelines
1-877-420 8800
Moose Jaw Asphalt
1-306-691 7800 (ext. 0)
Petro Canada
(Saskatoon)
1-306-382 1455 (ext. 0)
Plains Midstream
1-866-875 2554
SaskEnergy/TransGas
(306) 777 9800

MEMBER INSTRUCTIONS

*** THE "FIRST" COMPANY TO RECEIVE A CALL or have a PIPELINE EMERGENCY shall contact the AREA 6 EMERGENCY CALL-OUT and announce the following summary message:

"(your company) is calling on behalf of the Area 6 Emergency Response Co-op.

There is a "pipeline emergency" at the following (location).

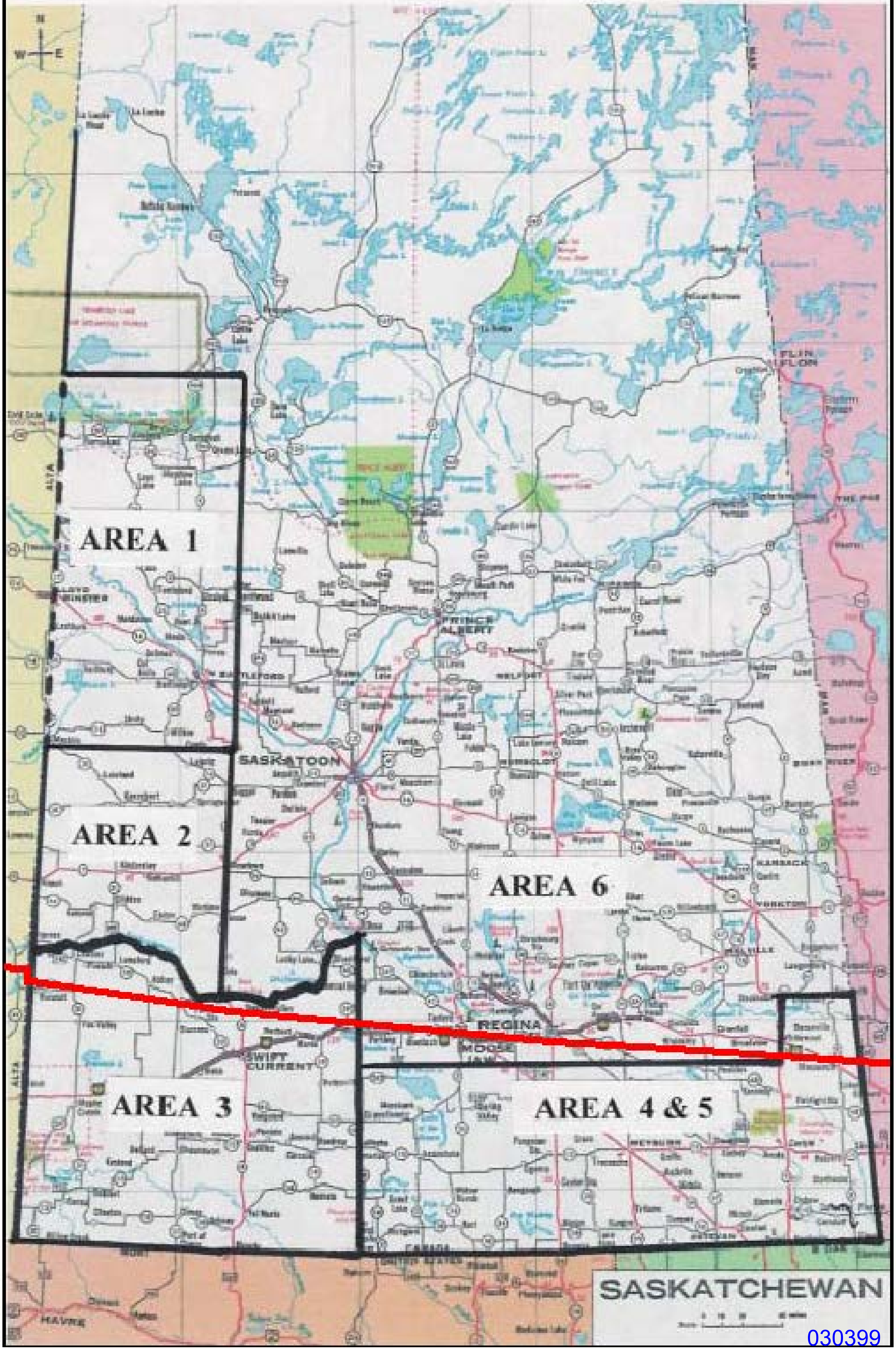
The company involved is (state name if known) or (state unknown).

Please "ACTIVATE" the Area 6 Emergency Response Co-op's "Call-Down Procedure".

SPECIAL INSTRUCTIONS: Please state if you are requesting assistance or this is for notification purposes only. Also if you require equipment, manpower or any special requests or instructions.

SASK. AREA SPILL CO-OPS BOUNDARIES

April 28, 2005



030399

Oil Spill Cooperative Agreement

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Saskatchewan Area 4&5 Oil Spill Cooperative

The Province of Saskatchewan is divided into 5 oil spill cooperative areas. The TransCanada Keystone Pipeline travels from west to east through a small area in the north-east corner of area 4&5. The cooperative is run by a steering committee with custodians who are responsible for storage and maintenance of the response equipment.

Through the preceding agreement TransCanada Keystone Pipeline system will have the ability to use the cooperatives equipment, if available, during an incident.

The equipment location, contact information and Saskatchewan area map are included in this document.

OIL SPILL FIRST RESPONSE

Phone: **(306) 634-6277** to notify the Oil Spill Contingency that you will need the trailer and to make arrangements to pick up the trailer.

EQUIPMENT LOCATION

Oil spill equipment is stored in a 32 foot trailer.

TRAILER LOCATION

Redigo Construction Company Limited
44 Hwy 39 East
Estevan, Saskatchewan

DRIVER QUALIFICATION AND VEHICLE RATING REQUIREMENTS

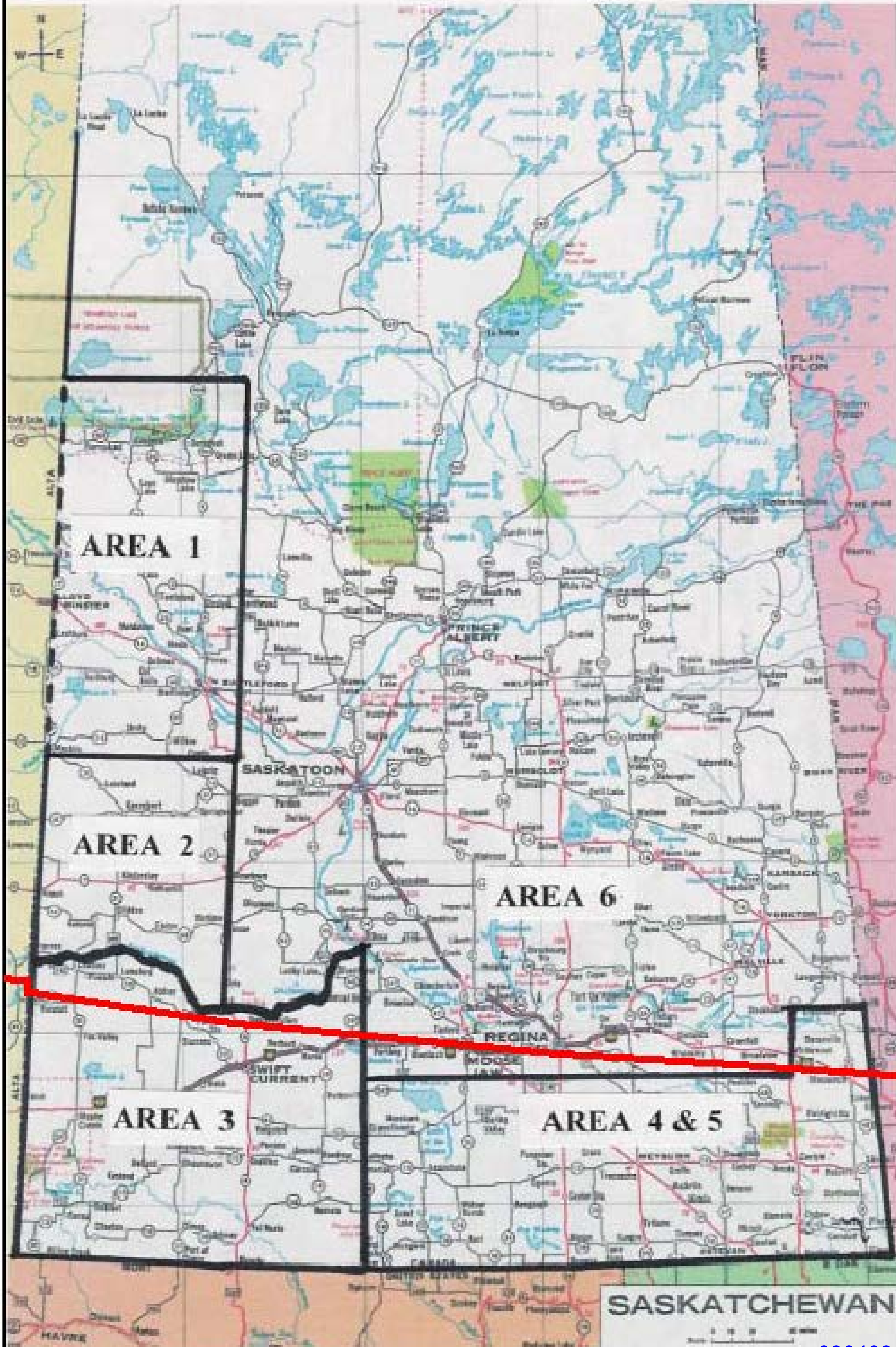
As the trailer is greater than 10,000 lb (actual weight approx. 13,000 lb), drivers must possess a minimum of a Class 1G license, as per SGI requirements. Also, vehicles must be rated accordingly. Below is a list of contractors with qualified drivers and vehicles. Any other contractors with qualified drivers and vehicles may also be used to mobilize and de-mobilize the trailer.

Murray Towing and Boosting Service, Estevan [redacted]
Carson Welding & Maintenance , Lampman - [redacted]
Jerry Mainil Limited, Weyburn- [redacted]

The ball for the hitch is located just inside the side door.

SASK. AREA SPILL CO-OPS BOUNDARIES

April 28, 2005



APPENDIX B

WORST CASE DISCHARGE ANALYSIS AND SCENARIOS

Introduction

Hardisty Pump Station/ Regina Pump Station
- **Worst Case Discharge**
- **Planning Volume Calculations**

Regina Pump Station / Haskett Pump Station
- **Worst Case Discharge**
- **Planning Volume Calculations**

North Dakota, South Dakota, Nebraska
- **Worst Case Discharge**
- **Planning Volume Calculations**

Kansas, Missouri, Illinois
- **Worst Case Discharge**
- **Planning Volume Calculations**

Cushing Extension
- **Worst Case Discharge**
- **Planning Volume Calculations**

INTRODUCTION

This Appendix identifies potential causes for oil discharges and discusses the response efforts that are necessary for successful mitigation. Included in this Appendix are hypothetical scenarios for various types of spills that have the potential to occur along the system. It is anticipated that the Company will respond to spills in a consistent manner regardless of the location. Therefore, the guidelines discussed in this appendix will apply to all spills whenever possible.

United States Department of Transportation/Pipeline and Hazardous Materials Safety Administration Discharge Volume Calculation

- **Worst Case Discharge**

  The largest volume (Bbls) of the following:

  - *Pipeline's maximum release time (hrs), plus the maximum shutdown response time (hrs), multiplied by the maximum flow rate (bph), plus the largest line drainage volume after shutdown of the line section.*

    --***OR***--

  - *Largest foreseeable discharge for the line section is based on the maximum historic discharge, if one exists, adjusted for any subsequent corrective action or preventive action taken.*

    --***OR***--

  - *Capacity of the single largest breakout tank or battery of tanks within a single secondary containment system, adjusted for the capacity or size of the secondary containment system.*

Scenario Types

The occurrence of a Worst Case Discharge (WCD) could be the result of any number of scenarios along the pipeline system including:

- Piping rupture.
- Piping leak, under pressure and not under pressure.
- Explosion or fire.
- Equipment failure (e.g. pumping system failure, relief valve failure, or other general equipment relevant to operational activities associated with internal or external facility transfers).

The response actions to each of these scenarios are outlined in Section 3.1 and Figure 3.1. The response resources are identified in a quick reference format in Figure 2.5. Pipeline response personnel list/telephone numbers and other internal/external resources telephone numbers are detailed in Figures 2.2 and 2.5.

RESPONSE CAPABILITY SCENARIOS

(Canada) **Hardisty Pump Station/ Regina Pump Station**

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

(Canada) **Hardisty Pump Station/ Regina Pump Station**

RESPONSE PLANNING VOLUME CALCULATIONS

Location Data			
[redacted]			[redacted]
[redacted]			[redacted]
[redacted]			[redacted]
[redacted]			[redacted]
[redacted]			[redacted]
Discharge Volumes/Calculations			
[redacted]			[redacted]
Selected Calculation Factors (Based on USCG Tables)			
[redacted]			[redacted]
[redacted]			[redacted]
[redacted]			[redacted]
[redacted]			[redacted]
[redacted]			[redacted]
[redacted]			[redacted]
[redacted]			[redacted]
Response Planning Volume Calculation			
[redacted]			[redacted]
[redacted]			[redacted]
[redacted]			[redacted]
	Tier 1	Tier 2	Tier 3
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

RESPONSE CAPABILITY SCENARIOS

(Canada) **Regina Pump Station / Haskett Pump Station**

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

- [redacted]
- [redacted]

  [redacted]
- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

(Canada) **Regina Pump Station / Haskett Pump Station**

RESPONSE PLANNING VOLUME CALCULATIONS

Location Data			
[redacted]			[redacted]
[redacted]			[redacted]
[redacted]			[redacted]
[redacted]			[redacted]
[redacted]			[redacted]
Discharge Volumes/Calculations			
[redacted]			[redacted]
Selected Calculation Factors (Based on USCG Tables)			
[redacted]			[redacted]
[redacted]			[redacted]
[redacted]			[redacted]
[redacted]			[redacted]
[redacted]			[redacted]
[redacted]			[redacted]
[redacted]			[redacted]
Response Planning Volume Calculation			
[redacted]			[redacted]
[redacted]			[redacted]
[redacted]			[redacted]
	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

RESPONSE CAPABILITY SCENARIOS

North Dakota, South Dakota, Nebraska

Pipeline Worst Case Discharge = [redacted]

Description

The pipeline-based Worst Case Discharge is projected as a scenario [redacted] feet downstream of [redacted]

Volume

Worst Case = (Initial Line Fill Volume - Pumping Rate Volume) x [redacted] = Barrels
= [redacted]

The Worst Case Discharge for this response zone was calculated electronically using elevation data, pipeline statistics, and designed operational levels. The first calculation completed was the volume released prior to the shutdown of the pipeline system. This volume is noted as "Pumping Rate Volume" and is equal to [redacted] barrels. Using the designed operational levels, the pumping rate volume is calculated by taking the pumping rate of [redacted] barrels per day and multiplying by the shutdown time of [redacted] minutes. The [redacted] minutes of shutdown time consists of [redacted] minutes of evaluation time, where the controllers decide that there is a problem and the line needs to be shut down, [redacted] minutes of pump station shutdown, which must be completed in a certain order to prevent damage to the system. To ensure that the volume is not underestimated, the [redacted] minutes of shutdown time is multiplied by the full pumping rate, [redacted] barrels per minute, even though, as pump stations are shut down the rate will decrease throughout the [redacted] minutes of shutdown.

The second calculated number is the amount of drain down. These calculations were done at [redacted] foot increments throughout the length of the pipeline. This drain down volume is calculated using electronic elevation data and assumes a complete break in the pipeline. The computer program used develops elevation profiles of the pipeline and provides the volume of a release at each [redacted] foot point taking into account the large elevation changes in the pipeline. The combination of the pumping rate volume and the drain down volume provides the "Initial Line Fill Volume".

In the Initial Line Fill Volume calculation the program only accounts for large elevation changes. In such, long flat portions that have smaller hills and valleys are calculated as draining fully, when common sense and subject matter studies, such as the California State Fire Marshall report of March 1993, have proven that these smaller elevation changes will prevent much of these areas from draining. Therefore, the worst case discharge has been calculated above reducing the line drainage component to 60% of the computer generated amount.

Response Requirement

The Company has identified sufficient response resources, by contract or other approved means, to respond to a Worst Case Discharge to the maximum extent practicable. These response resources include:

- Resources capable of arriving at the staging area within the applicable response tier requirements for non-high volume areas (Tier 1 = 12 hours; Tier 2 = 36 hours; Tier 3 = 60 hours).
- Resources capable of oil recovery in inclement weather conditions (i.e. heavy rain, snow, ice).

Notes

- Contracted and Company owned equipment and manpower resources are detailed in Figure 2.5 and Appendix A.
- Telephone references are provided in Figures 2.2 and 2.5.

Breakout Tanks
There are no breakout tanks in the Response Zone. ***Volume*** If the Response Zone had breakout tank(s), a worst case discharge scenario involving breakout tankage uses the single largest volume tank in the response zone, adjusted for the size of the secondary containment system.

North Dakota, South Dakota, Nebraska

RESPONSE PLANNING VOLUME CALCULATIONS

Location Data			
Location Type			Inland/Near Shore
Port Type			Non-High Volume
WCD Product Type			Crude Oil
Product Group			3
Pipeline and Hazardous Materials Safety Administration WCD Volume (bbls)			[redacted]
Discharge Volumes/Calculations			
Worst Case Discharge - Based on Pipeline and Hazardous Materials Safety Administration criteria (bbls)			[redacted]
Selected Calculation Factors (Based on USCG Tables)			
Removal Capacity Planning Volume - Percent Natural Dissipation			30%
Removal Capacity Planning Volume - Percent Recovered Floating Oil			50%
Removal Capacity Planning Volume - Percent Oil Onshore			50%
Emulsification Factor			2
Tier 1 - On Water Oil Recovery Resource Mobilization Factor			15%
Tier 2 - On Water Oil Recovery Resource Mobilization Factor			25%
Tier 3 - On Water Oil Recovery Resource Mobilization Factor			40%
Response Planning Volume Calculation			
On-Water Recovery Volume (bbls)			[redacted]
Shoreline Recovery Volume (bbls)			[redacted]
Shoreline Cleanup Volume (bbls)			[redacted]
	Tier 1	Tier 2	Tier 3
On-Water Recovery Cpcty (bbls/day)	[redacted]	[redacted]	[redacted]
Shallow Water Resp Cpblty (bbls/day)	[redacted]	[redacted]	[redacted]
Storage Capacity (bbls/day)	[redacted]	[redacted]	[redacted]
On-Water Response Caps (bbls/day)	12,500	25,000	50,000
Additional Response Req'd (bbls/day)	0	0	0
Response Time (hrs)	12	36	60

RESPONSE CAPABILITY SCENARIOS

Kansas, Missouri, Illinois

Pipeline Worst Case Discharge = [redacted]

Description

The pipeline-based Worst Case Discharge is projected as a scenario [redacted] upstream of [redacted]

Volume

Worst Case = (Initial Line Fill Volume - Pumping Rate Volume) x [redacted] = Barrels
= [redacted]

The Worst Case Discharge for this response zone was calculated electronically using elevation data, pipeline statistics, and designed operational levels. The first calculation completed was the volume released prior to the shutdown of the pipeline system. This volume is noted as "Pumping Rate Volume" and is equal to [redacted] barrels. Using the designed operational levels, the pumping rate volume is calculated by taking the pumping rate of [redacted] barrels per day and multiplying by the shutdown time of [redacted] minutes. The [redacted] minutes of shutdown time consists of [redacted] minutes of evaluation time, where the controllers decide that there is a problem and the line needs to be shut down, [redacted] minutes of pump station shutdown, which must be completed in a certain order to prevent damage to the system. To ensure that the volume is not underestimated, the [redacted] minutes of shutdown time is multiplied by the full pumping rate, [redacted] barrels per minute, even though, as pump stations are shut down the rate will decrease throughout the [redacted] minutes of shutdown.

The second calculated number is the amount of drain down. These calculations were done at [redacted] foot increments throughout the length of the pipeline. This drain down volume is calculated using electronic elevation data and assumes a complete break in the pipeline. The computer program used develops elevation profiles of the pipeline and provides the volume of a release at each [redacted] foot point taking into account the large elevation changes in the pipeline. The combination of the pumping rate volume and the drain down volume provides the "Initial Line Fill Volume".

In the Initial Line Fill Volume calculation the program only accounts for large elevation changes. In such, long flat portions that have smaller hills and valleys are calculated as draining fully, when common sense and subject matter studies, such as the California State Fire Marshall report of March 1993, have proven that these smaller elevation changes will prevent much of these areas from draining. Therefore, the worst case discharge has been calculated above reducing the line drainage component to 60% of the computer generated amount.

Response Requirement

The Company has identified sufficient response resources, by contract or other approved means, to respond to a Worst Case Discharge to the maximum extent practicable. These response resources include:

- Resources capable of arriving at the staging area within the applicable response tier requirements for non-high volume areas (Tier 1 = 12 hours; Tier 2 = 36 hours; Tier 3 = 60 hours).
- Resources capable of oil recovery in inclement weather conditions (i.e. heavy rain, snow, ice).

Notes

- Contracted and Company owned equipment and manpower resources are detailed in Figure 2.5 and Appendix A.
- Telephone references are provided in Figures 2.2 and 2.5.

Breakout Tanks

There are no breakout tanks in the Response Zone.

Volume

If the Response Zone had breakout tank(s), a worst case discharge scenario involving breakout tankage uses the single largest volume tank in the response zone, adjusted for the size of the secondary containment system.

Kansas, Missouri, Illinois

RESPONSE PLANNING VOLUME CALCULATIONS

Location Data			
Location Type			Inland/Near Shore
Port Type			High Volume
WCD Product Type			Crude Oil
Product Group			3
Pipeline and Hazardous Materials Safety Administration WCD Volume (bbls)			[redacted]
Discharge Volumes/Calculations			
Worst Case Discharge - Based on Pipeline and Hazardous Materials Safety Administration criteria (bbls)			[redacted]
Selected Calculation Factors (Based on USCG Tables)			
Removal Capacity Planning Volume - Percent Natural Dissipation			30%
Removal Capacity Planning Volume - Percent Recovered Floating Oil			50%
Removal Capacity Planning Volume - Percent Oil Onshore			50%
Emulsification Factor			2
Tier 1 - On Water Oil Recovery Resource Mobilization Factor			15%
Tier 2 - On Water Oil Recovery Resource Mobilization Factor			25%
Tier 3 - On Water Oil Recovery Resource Mobilization Factor			40%
Response Planning Volume Calculation			
On-Water Recovery Volume (bbls)			[redacted]
Shoreline Recovery Volume (bbls)			[redacted]
Shoreline Cleanup Volume (bbls)			[redacted]
	Tier 1	Tier 2	Tier 3
On-Water Recovery Cpcty (bbls/day)	[redacted]	[redacted]	[redacted]
Shallow Water Resp Cpblty (bbls/day)	[redacted]	[redacted]	[redacted]
Storage Capacity (bbls/day)	[redacted]	[redacted]	[redacted]
On-Water Response Caps (bbls/day)	12,500	25,000	50,000
Additional Response Req'd (bbls/day)	0	0	0
Response Time (hrs)	6	30	54

RESPONSE CAPABILITY SCENARIOS

Cushing Extension

Pipeline Worst Case Discharge = [redacted]

Description

The pipeline-based Worst Case Discharge is projected as a scenario [redacted] downstream of Station Steele City.

Volume

Worst Case = (Initial Line Fill Volume - Pumping Rate Volume) x [redacted] = Barrels
= [redacted]

The Worst Case Discharge for this response zone was calculated electronically using elevation data, pipeline statistics, and designed operational levels. The first calculation completed was the volume released prior to the shutdown of the pipeline system. This volume is noted as "Pumping Rate Volume" and is equal to [redacted] barrels. Using the designed operational levels, the pumping rate volume is calculated by taking the pumping rate of [redacted] barrels per day and multiplying by the shutdown time of [redacted] minutes. The [redacted] minutes of shutdown time consists of [redacted] minutes of evaluation time, where the controllers decide that there is a problem and the line needs to be shut down, [redacted] minutes of pump station shutdown, which must be completed in a certain order to prevent damage to the system. To ensure that the volume is not underestimated, the [redacted] minutes of shutdown time is multiplied by the full pumping rate, [redacted] barrels per minute, even though, as pump stations are shut down the rate will decrease throughout the [redacted] minutes of shutdown.

Response Requirement

The Company has identified sufficient response resources, by contract or other approved means, to respond to a Worst Case Discharge to the maximum extent practicable. These response resources include:

- Resources capable of arriving at the staging area within the applicable response tier requirements for non-high volume areas (Tier 1 = 12 hours; Tier 2 = 36 hours; Tier 3 = 60 hours).
- Resources capable of oil recovery in inclement weather conditions (i.e. heavy rain, snow, ice).

Notes

- Contracted and Company owned equipment and manpower resources are detailed in Figure 2.5 and Appendix A.
- Telephone references are provided in Figures 2.2 and 2.5.

Breakout Tanks
There are no breakout tanks in the Response Zone. ***Volume*** If the Response Zone had breakout tank(s), a worst case discharge scenario involving breakout tankage uses the single largest volume tank in the response zone, adjusted for the size of the secondary containment system.

Cushing Extension

RESPONSE PLANNING VOLUME CALCULATIONS

Location Data			
Location Type			Inland/Near Shore
Port Type			High Volume
WCD Product Type			Crude Oil
Product Group			3
Pipeline and Hazardous Materials Safety Administration WCD Volume (bbls)			[redacted]
Discharge Volumes/Calculations			
Worst Case Discharge - Based on Pipeline and Hazardous Materials Safety Administration criteria (bbls)			[redacted]
Selected Calculation Factors (Based on USCG Tables)			
Removal Capacity Planning Volume - Percent Natural Dissipation			30%
Removal Capacity Planning Volume - Percent Recovered Floating Oil			50%
Removal Capacity Planning Volume - Percent Oil Onshore			50%
Emulsification Factor			2
Tier 1 - On Water Oil Recovery Resource Mobilization Factor			15%
Tier 2 - On Water Oil Recovery Resource Mobilization Factor			25%
Tier 3 - On Water Oil Recovery Resource Mobilization Factor			40%
Response Planning Volume Calculation			
On-Water Recovery Volume (bbls)			[redacted]
Shoreline Recovery Volume (bbls)			[redacted]
Shoreline Cleanup Volume (bbls)			[redacted]
	Tier 1	Tier 2	Tier 3
On-Water Recovery Cpcty (bbls/day)	[redacted]	[redacted]	[redacted]
Shallow Water Resp Cpblty (bbls/day)	[redacted]	[redacted]	[redacted]
Storage Capacity (bbls/day)	[redacted]	[redacted]	[redacted]
On-Water Response Caps (bbls/day)	12,500	25,000	50,000
Additional Response Req'd (bbls/day)	0	0	0
Response Time (hrs)	6	30	54

APPENDIX C

EMERGENCY PRE-PLANNING

C.1 **Release Detection**

C. 2 **Leak Detection Systems**

C. 3 **Discharge Prevention Systems**

EMERGENCY PRE-PLANNING

Leak detection and discharge prevention is accomplished through safe operating procedures and maintenance procedures outlined in the Company Operations and Maintenance (O&M) Manual. The Company Operations and Maintenance Manual is designed to meet the requirements found in Statutory Orders and Regulations /99-294 S27, National Energy Board, Operation and Maintenance Manuals, and Title 49, US Code of Federal Regulations, Part 195, Transportation of Hazardous Liquids by Pipeline.

C.1 RELEASE DETECTION

- The Keystone Console and Company Field Employees are responsible for ensuring the integrity of facilities and detecting releases.

- There are four primary types of indications that a release may be occurring:

  - An unexplained hydraulic upset condition observed in the Pipeline system operating data.
  - A consistent unexplainable Pipeline system shortage occurring over several check time periods.
  - An alarm from a Supervisory Control and Data Acquisition-based leak detection system.
  - A report of a direct observation of a release or released product received from an employee or the public.

- All indications, including supposedly direct observation, are subject to confirmation; however, the Company policy is to shut down if any doubt exists as to the integrity of the Pipeline system. The simultaneous occurrence of two or more of the indicators above greatly increases the probability that the Pipeline system has lost integrity.

- Specific guidance for response to abnormal operating conditions and determining the location of a suspected pipeline release may be found in the Company's Operations and Maintenance Manual, maintained separately.

- A form for recording conversations with an observer who reports an emergency is located in Appendix F of this Plan. Copies of this form should be kept readily accessible at telephones.

- Routine actions to be taken by Company Field Employees to ensure facility integrity and detect releases are listed as follows:

  - Keystone Console Monitors Pressures using Supervisory Control and Data Acquisition
  - Routine Station/ROW Checks Performed
  - Routine Aerial Surveillance
  - 24 Hour Emergency Reporting Phone Number Monitored

C.2 LEAK DETECTION SYSTEMS

Leak detection systems utilized along the Pipeline include:

- System-level indication is accomplished through usage of a Supervisory Control and Data Acquisition (SCADA) system. This system is capable of monitoring flow rates, pressure, metering information (delivery / receipt volumes), temperature, and valve positions. The Supervisory Control and Data Acquisition system is monitored on a 24-hour per day basis by both the centralized Pipeline Control Center and Secondary Control points.

The location of a spill caused by a catastrophic break, which may be indicative of a Worst Case Discharge, can be inferred by Supervisory Control and Data Acquisition personnel down to a Pipeline section between operating pump stations. This inference is based upon rapid and abrupt changes in operating conditions.

C.3 DISCHARGE PREVENTION SYSTEMS

Pipeline pump stations are designed in a manner that maximizes the containment of leaks on-site and deters the migration of leaks off-site. Discharge prevention is accomplished through the following measures:

- Pipelines and related structures have grounding systems to reduce the possibility of accidental ignition due to lightning.

- Discharge prevention is also accomplished through the use of general housekeeping procedures and leak inspection system.

APPENDIX D

TRAINING AND DRILLS

D.1 Response Team Training

Emergency Response Plan Review
Hazardous Waste Operations and Emergency Response (29 CFR 1910.120)
Incident Command System
Training Records Maintenance
Contractor Training
Training Qualifications

D. 2 Response Team Exercises

Quarterly QI Notification Exercise
Annual Equipment Deployment Exercise
Annual Response Team Tabletop Exercise
Government-Initiated Unannounced Exercise
Area Exercises
Exercise Documentation

D. 3 Purpose of Review and Evaluation

Outline of Review
Detection
Notification
Assessment/Evaluation
Mobilization
Response - Strategy
Response - Resources Used
Response - Effectiveness
Command Structure
Measurement
Government Relations
Public Relations

D.1 RESPONSE TEAM TRAINING

The Company provides training related to discharge prevention, testing and response, including measures to repair Pipeline ruptures and mitigate discharges. The training methods address oil discharges from the Pipeline from several perspectives: human health and safety, rupture control and repair operations, pollution control, and overall (crisis) management of the emergency.

The competency of each training program is closely monitored by the Training Section through observation of and/or participation in actual training sessions.

Through the various training methods described below the Company's training program is intended to ensure the following results:

That all personnel know:

- Their responsibilities under the Plan.
- The name, address and procedures for contacting the operator on a 24-hour basis.
- The name of and procedures for contacting the Qualified Individual on a 24-hour basis.

That all reporting personnel know:

- The Pipelines and Response Zone details for the affected area (Response Zones Annexes).
- The telephone number of the Federal Provincial/State and local agencies and other required notifications (Section 2.0).
- The notification process. (Section 2.0).

That all response personnel know:

- The characteristics and hazards of the oil discharged (Section 3.0 and Appendix G - MSDS).
- The conditions that is likely to worsen emergencies, including the consequences of pipeline malfunctions, and the appropriate corrective actions.
- The steps necessary to control any accidental discharge of oil and to minimize the potential for fire, explosion, toxicity or environmental damage (Section 3.0).
- The proper firefighting procedures and use of equipment, fire suits, and breathing apparatus (Section 3.0). Only trained persons will be utilized. Company personnel are only trained on the use of handheld Ansul 30# fire extinguisher units for small incipient fires.

Emergency Response Plan Review

All Response Team Members should review their Emergency Response Plan whenever their job position or responsibilities change under the Plan. A copy of this Plan will be available at all times to Team Members.

HAZARDOUS WASTE OPERATIONS AND EMERGENCY RESPONSE (29 CFR 1910.120)

Federal and State regulations require that Response Team Members maintain up-to-date Hazardous Waste Operations and Emergency Response training necessary to function in their assigned positions. At a minimum, team members will receive "First Responder Awareness Level" training. All personnel responding to an incident must satisfy the applicable Hazardous Waste Operations and Emergency Response training requirements of 29 CFR 1910.120.

OCCUPATIONAL SAFETY AND HEALTH ADMINISTRATION HAZARDOUS WASTE OPERATIONS AND EMERGENCY RESPONSE TRAINING REQUIREMENTS

Responder Classification	Required Training Hours	Refresher
29CFR 1910.120(q) Emergency Response		
First Responder - Awareness Level First Responder - Operations Level Hazardous Materials Technician Hazardous Materials Specialist Incident Commander	2-4 hrs demonstration of competency 8 hrs 24 hrs plus competency 24 hrs plus competency in specialized areas 24 hrs plus competency	same 8 hrs 8 hrs 8 hrs 8 hrs
29CFR 1910.120(e) Clean Up Sites		
General Site Workers	40 hrs / 3 days on the job training	8 hrs
Occasional Workers (Limited Tasks)	24 hrs / 1 day on the job training	8 hrs
General Site Workers (Low Hazard)	24 hrs / 1 day on the job training	8 hrs
Supervisors	8 hrs supervisor training	8 hrs
* Previous work experience and/or training certified as equivalent by employer.		

Incident Command System

Response Team Members will receive Incident Command System training and may also receive supplemental training in other related general topics.

Training Records Maintenance

Emergency response training records are maintained at the Company's office. Training records for response personnel will be maintained for as long as personnel have duties in this Emergency Response Plan.

Contractor Training

The Company also recognizes that contract personnel must also have sufficient training to respond emergency response situations. The Company communicates this training need to its key contractors during contract negotiations and often specifically spells out this requirement in its contracts. The Company also tends to use well-known spill response contractors whose reputation and experience levels help ensure personnel who respond will be trained to appropriate levels.

Training Qualifications

As no formalized method of certifying training instructors has been provided by Occupational Safety and Health Administration, the Company ensures the competency of its instructors and training organizations by selecting trainers and/or organizations with professional reputations and extensive hands-on and classroom experience in their subject matter. The Company personnel with responsibility to coordinate the training program also conduct periodic informal audits of training courses selected for the Company training program to ensure their suitability for the program.

D.2 RESPONSE TEAM EXERCISES

Spill Management Team members, government agencies, contractors, and other resources must participate in response exercises required by Federal, State, or local regulations and as detailed in the "National Preparedness for Response Exercise Program (PREP) Guidelines." The Company (through the Community, Safety and Environment Department) will conduct announced drills to maintain compliance, and each plan-holder must participate in at least one exercise annually. The following table lists the triennial exercise cycle for facilities (see National Preparedness for Response Exercise Program Guidelines for full details).

TRIENNIAL CYCLE		
Total Number	**Frequency**	**Exercise Type/Description**
12	Quarterly	Qualified Individual Notification Exercise
3	Annually	Equipment Deployment Exercise *(Facility-owned equipment)*
3	Annual	Response Team Tabletop Exercise
3	Annual	Equipment Deployment Exercise *(facilities with Oil Spill Removal Organization-owned equipment)*
3	3 per Triennial Cycle	Unannounced Exercise *(not a separate exercise)* Actual response can be considered as an unannounced exercise. Credit can also be given for unannounced equipment deployment and Response Team tabletop exercises.
NOTES: 1) All Emergency Response Plan components must be exercised at least once in the Cycle.		

Quarterly QI Notification Exercise

- **Scope:** Exercise communication between Pipeline personnel and the Qualified Individual(s) and/or designated alternate(s). At least once each year, one of the notification exercises should be conducted during non-business hours.

- **Objective:** Contact must be made with a Qualified Individual or designated alternate, as identified in the Plan.

- **General:** All personnel receiving notification shall respond to the notification and verify their receipt of the notification. Personnel who do not respond should be contacted to determine whether or not they received the notification.

Annual Equipment Deployment Exercise (for operator and/or Oil Spill Removal Organization equipment)

- **Scope:** Demonstrate ability to deploy spill response equipment identified in the Emergency Response Plan.

  May consist entirely of operator owned equipment, or a combination of OSRO and operator equipment.
  The number of equipment deployment exercises conducted should be such that equipment and personnel assigned to each Response Zone are exercised at least one a year. If the same personnel and equipment respond to multiple zones, they need only exercise once per year. If different personnel and equipment response to various Response Zones, each must participate in an annual equipment deployment exercise.

- **Objective:** Demonstrate personnel's ability to deploy and operate response equipment. Ensure that the response equipment is in proper working order.

- **General:** The Facility may take credit for actual equipment deployment to a spill, or for training sessions, as long as the activities are properly documented.

Annual Response Team Tabletop Exercise

- **Scope:** Exercise the response team's organization, communication, and decision- making in managing a spill response. Each team identified within the Plan must conduct an annual Response Team Tabletop Exercise.

- **Objective:** Exercise the response team in a review of the following:

  Knowledge of the Plan.
  Proper notifications.
  Communications system.
  Ability to access an OSRO.
  Coordination of internal spill response personnel.
  Review of the transition from a initial team to a regional team.
  Ability to effectively coordinate response activity with the National Response System (NRS) Infrastructure.
  Ability to access information in the Area Contingency Plan.

- **General:** A minimum of one Response Team Tabletop Exercise in a triennial cycle will involve a Worst Case Discharge scenario.

Government-Initiated Unannounced Exercise

- **Scope:** Demonstrate ability to respond to a Worst Case Discharge spill event.

- **Objectives:** Designated Emergency Response Team Members should demonstrate adequate knowledge of their Emergency Response Plan and the ability to organize, communicate, coordinate, and respond in accordance with that Plan.

- **General:** Annually, the Pipeline and Hazardous Materials Safety Administration may conduct up to 20 unannounced exercises throughout the U.S. for the pipeline industry as a whole. A single owner or operator will not be required to participate in a PHMSA-initiated unannounced exercise if they have already participated in one within the previous 36 months.

Area Exercises

- **<u>Objective:</u>** The purpose of the area exercise is to exercise the entire response community in a particular area. An area is defined as ?that geographic area for which a separate and distinct Area Contingency Plan has been prepared, as described in Oil Pollution Act 90.? The response community includes the Federal, State, and local government and industry. The area exercises are designed to exercise the government and industry interface for spill response.

- **<u>General:</u>** The goal is to ensure that all areas of the country are exercised triennially. All of the area exercises will be developed by an exercise design team. The exercise design team is comprised of representatives from the Federal, State, and local government and industry. A lead plan holder would lead each area exercise. The lead plan holder is the organization (government or industry) that holds the primary plan that is exercised in the area exercise. The lead plan holder would have the final word on designing the scope and scenario of the exercise.

Exercise Documentation

- All exercises should be documented and maintained at the Company office; documentation should specify:

  The type of exercise;
  Date and time of the exercise;
  A description of the exercise;
  The objectives met in the exercise;
  The components of the response plan exercised; and
  Lessons learned.

- Exercise documentation should be kept on file for the required length of time depending on the regulating agency (three (3) years for the U.S. Coast Guard and five (5) years for the Pipeline and Hazardous Materials Safety Administration and the U.S. Environmental Protection Agency).

D.3 PURPOSE OF REVIEW AND EVALUATION

This Section provides procedures and information useful to responders for post incident/exercise review and evaluation. Post incident/exercise reviews should be conducted in a timely manner following an incident/exercise. The Plan should be evaluated to determine its usefulness during the incident/exercise and appropriate revisions should be made. All incident/exercise documentation should be included in the Plan evaluation process.

Outline of Review

Given below are items a team composed of outside people knowledgeable in spill response and key members of the response teams should examine. These questions are intended as guidelines only; many other questions are likely to be appropriate at each stage of a critique.

- ***Detection***

  Was the spill detected promptly?
  How was it detected? By whom?
  Could it have been detected earlier? How?
  Are any instruments or procedures available to consider which might aid in spill detection?

- ***Notification***

  Were proper procedures followed in notifying government agencies? Were notifications prompt?
  Was management notified promptly/response appropriate?
  Was the Pipeline owner/operator notified promptly? If so, why, how, and who? If not, why not?

- ***Assessment/Evaluation***

  Was the magnitude of the problem assessed correctly at the start?
  What means were used for this assessment?
  Are any guides or aids needed to assist spill evaluation?
  What sources of information were available on winds and on water currents?
  Is our information adequate?
  Was this information useful (and used) for spill trajectory forecasts? Were such forecasts realistic?
  Do we have adequate information on product properties?
  Do we need additional information on changes of product properties with time, i.e., as a result of weathering and other processes?

- ***Mobilization***

  What steps were taken to mobilize spill countermeasures?
  What resources were used?
  Was mobilization prompt?
  Could it have been speeded up or should it have been?
  What about mobilization of manpower resources?
  Was the local spill cooperative used appropriately?
  How could this be improved?
  Was it appropriate to mobilize the Pipeline owner/operator resources and was this promptly initiated?
  What other resources are available and have they been identified and used adequately?

- ***Response - Strategy***

  Is there an adequate Spill Response Plan for the location?
  Is it flexible enough to cope with unexpected spill events?
  Does the Plan include clear understanding of local environmental sensitivities?
  What was the initial strategy for response to this spill?
  Is this strategy defined in the Spill Plan?
  How did the strategy evolve and change during this spill and how were these changes implemented?
  What caused such changes?
  Are there improvements needed? More training?

- ***Response - Resources Used***

  What resources were mobilized?
  How were they mobilized?
  How did resource utilization change with time? Why?
  Were resources used effectively?

  - Contractors
  - Government agencies
  - Company resources
  - Cooperatives
  - Volunteers
  - Consultants
  - Other (e.g., bird rescue centers)

  What changes would have been useful?
  Do we have adequate knowledge of resource availability?
  Do we have adequate knowledge of waste disposal capabilities?

- ***Response - Effectiveness***

  Was containment effective and prompt?
  How could it have been improved?
  Should the location or the local cooperative have additional resources for containment?
  Was recovery effective and prompt?
  How could it have been improved?
  Should the location or the local cooperative have additional resources for recovery of spilled product?
  Was contaminated equipment disposed promptly and safely?
  Was there adequate in-house product separation, recovery, and disposal?
  How could it have been improved?
  Was there adequate outside disposal resources available?

- ***Command Structure***

Who was initially in charge of spill response?
What sort of organization was initially set up?
How did this change with time? Why?
What changes would have been useful?
Was there adequate surveillance?
Should there be any changes?
Were communications adequate?
What improvements are needed? Hardware, procedures, etc.
Was support from financial services adequate? Prompt?
Should there be any changes?
Is more planning needed?
Should financial procedures be developed to handle such incidents?

- ***Measurement***

Was there adequate measurement or estimation of the volume of product spilled?
Was there adequate measurement or estimation of the volume of product recovered?
Was there adequate measurement or estimation of the volume of product disposed?
Should better measurement procedures be developed for either phase of operations?
If so, what would be appropriate and acceptable?

- ***Government Relations***

What are the roles and effects of the various government agencies which were involved?
Was there a single focal point among the government agencies for contact?
Should there have been better focus of communications to the agencies?
Were government agencies adequately informed at all stages?
Were too many agencies involved?
Are any changes needed in procedures to manage government relations?
Examples of affected U.S. agencies (there may be others):

- U.S. Coast Guard
- Environmental Protection Agency
- National Oceanic and Atmospheric Administration
- Dept of Fish and Wildlife
- State Parks
- Harbors and Marinas
- States
- Cities
- Counties

Was there adequate agreement with the government agencies on disposal methods?
Was there adequate agreement with the government agencies on criteria for cleanup?
How was this agreement developed?
Were we too agreeable with the agencies in accepting their requests for specific action items (e.g., degree of cleanup)?
Should there be advance planning of criteria for cleanup, aimed at specific local environmentally sensitive areas? (Such criteria should probably also be designed for different types of product.)

- ***Public Relations***

How were relations with the media handled?
What problems were encountered?
Are improvements needed?
How could public outcry have been reduced? Was it serious?
Would it be useful to undertake a public information effort to "educate" reporters about product and effects to it if spilled?
These areas should be investigated shortly after the incident to assure that actions taken are fresh in peoples' minds.

APPENDIX E

DISPOSAL PLAN

E.1 Overview

E. 2 Waste Classification

E. 3 Waste Handling

E. 4 Waste Storage

E. 5 Waste Disposal

Figure E. 1 Temporary Storage Methods

Figure E. 2 Oily Waste Separation and Disposal Methods

E.1 OVERVIEW

A major oil spill response would generate significant quantities of waste materials ranging from oily debris and sorbent materials to sanitation water and used batteries. All these wastes need to be classified and segregated (i.e., oily, liquid, etc.), transported from the site, and treated and/or disposed at approved disposal sites. Each of these activities demands that certain health and safety precautions be taken, which are strictly controlled by Federal and State Laws and Regulations. This Section provides an overview of the applicable State Regulations governing waste disposal, and a discussion of various waste classification, handling, transfer, storage, and disposal techniques. It is the responsibility of the Environmental Unit to manage waste disposal needs during an oil spill cleanup.

E.2 WASTE CLASSIFICATION

Oily- Liquid Wastes

Oily liquid wastes (i.e., oily water and emulsions) that would be handled, stored, and disposed during response operations are very similar to those handled during routine storage and transfer operations. The largest volume of oily liquid wastes would be produced by recovery operations (e.g., through the use of vacuum devices or skimmers). In addition, oily water and emulsions would be generated by vehicle operations (e.g., spent motor oils, lubricants, etc.), and equipment cleaning operations.

Non-Oily - Liquid Wastes

Response operations would also produce considerable quantities of non-oily liquid wastes. Water and other non-oily liquid wastes would be generated by the storage area and stormwater collection systems, equipment cleaning (i.e., water contaminated with cleaning agents), and office and field operations (i.e., sewage, construction activities).

Solid Wastes

A solid waste is defined as any discarded material provided that it is not specifically excluded under the regulations. These exclusions cover materials such as domestic sewage and mixtures of sewage discharged through a sewer system or industrial wastewater point source discharges.

A discarded material is any material which is abandoned (disposed, burned or incinerated) or accumulated, stored or treated prior to being abandoned. A discarded material is also any material recycled or any material considered inherently wastelike. Recycled material is considered solid waste when used in a manner constituting disposal, placed on land or burned for energy recovery.

A solid waste may be considered a hazardous waste. A solid waste, as defined above, may be a hazardous waste if it is not excluded from regulation and is either a listed hazardous waste or exhibits the characteristics of a hazardous waste. A solid waste exhibits the characteristics of a hazardous waste if it exceeds the thresholds established in determining the following:

1. ignitability
2. corrosivity
3. reactivity
4. toxicity

A solid waste may also become a hazardous waste if it is mixed with a listed hazardous waste or, in the case of any other waste (including mixtures), when the waste exhibits any of the characteristics identified above.

Oily - Solid / Semi-Solid Wastes

Oily solid/semi-solid wastes that would be generated by containment and recovery operations include damaged or worn-out booms, disposable/soiled equipment, used sorbent materials, saturated soils, contaminated beach sediments, driftwood, and other debris.

Non-Oily - Solid / Semi-Solid Wastes

Non-oily solid/semi-solid wastes would be generated by emergency construction operations (e.g., scrap, wood, pipe, and wiring) and office and field operations (i.e., refuse). Vessel, vehicle, and aircraft operations also produce solid wastes.

E.3 WASTE HANDLING

A primary concern in the handling of recovered oil and oily debris is contaminating unaffected areas or recontaminating already cleaned areas. Oily wastes generated during the response operations would need to be separated by type and transferred to temporary storage areas and/or transported to incineration or disposal sites. Proper handling of oil and oily wastes is imperative to ensure personnel health and safety.

Safety Considerations

Care shall be taken to avoid or minimize direct contact with oily wastes. All personnel handling or coming into contact with oily wastes shall wear protective clothing. A barrier cream can be applied prior to putting on gloves to further reduce the possibility of oily waste absorption. Safety goggles shall be worn by personnel involved in waste handling activities where splashing might occur. Any portion of the skin exposed to oily waste should be washed with soap and water as soon as possible. Decontamination zones should be set up during response operations to ensure personnel are treated for oil exposure.

Wastes Transfer

During response operations, it may be necessary to transfer recovered oil and oily debris from one point to another several times before the oil and oily debris are ultimately recycled, incinerated or disposed at an appropriate disposal site. Depending on the location of response operations, any or all of the following transfer operations may occur:

- From portable or vessel-mounted skimmers into flexible bladder tanks, storage tanks of the skimming vessel itself, or a barge.
- Directly into the storage tank of a vacuum device.
- From a skimming vessel or flexible bladder to a barge.
- From a vacuum device storage tank to a barge.
- From a barge to a tank truck.
- From a tank truck to a processing system (e.g., oil/water separator).
- From a processing system to a recovery system and/or incinerator.
- Directly into impermeable bags that, in turn, are placed in impermeable containers.
- From containers to trucks.

There are four general classes of transfer systems that may be employed to affect oily waste transfer operations:

- **Pumps:** Rotary pumps, such as centrifugal pumps, may be used when transferring large volumes of oil, but they may not be appropriate for pumping mixtures of oil and water. The extreme shearing action of centrifugal pumps tends to emulsify oil and water, thereby increasing the viscosity of the mixture and causing low, inefficient transfer rates. The resultant emulsion would also be more difficult to separate into oil and water fractions. Lobe or "positive displacement" pumps work well on heavy, viscous oils, and do not emulsify the oil/water mixture. Double-acting piston and double acting diaphragm pumps are reciprocating pumps that may also be used to pump oily wastes.
- **Vacuum Systems:** A vacuum truck may be used to transfer viscous oils but they usually pick up a very high water/oil ratio.
- **Belt/Screw Conveyors:** Conveyors may be used to transfer oily wastes containing a large amount of debris. These systems can transfer weathered debris laden oil either horizontally or vertically for short distances (i.e., 10 feet) but are bulky and difficult to set up and operate.
- **Wheeled Vehicles:** Wheeled vehicles may be used to transfer liquid wastes or oily debris to storage or disposal sites. These vehicles have a limited transfer volume (i.e., 100 barrels) and require good site access.

E.4 WASTE STORAGE

Interim storage of recovered oil, oily and non-oily waste would be considered to be an available means of holding the wastes until a final management method is selected. In addition, the segregation of wastes according to type would facilitate the appropriate method of disposal. The storage method used would depend upon:

- The type and volume of material to be stored.
- The duration of storage.
- Access.

During an oil spill incident, the volume of oil that can be recovered and dealt with effectively depends upon the available storage capacity. Typical short-term storage options are summarized in Figure E-1. The majority of these options can be used either onshore or offshore.

If storage containers such as bags or drums are used, the container must be clearly marked with the proper Canadian Transport Dangerous Goods/United States Department of Transportation marking to indicate the type of material/waste contained and/or the ultimate disposal option.

Fuel barges may be the best option for temporary storage of oil recovered in open waters and frac tanks for inland spills. Depending on size, these vessels may be able to hold up to 6,000 barrels of oil and water and frac tanks may hold up to 500-550 barrels. The barge deck can be used as a platform for operating oil spill clean-up equipment and storing containment boom.

Steel or rubber tanks can be used to store oil recovered near the shoreline. To facilitate offloading, demulsifiers may be used to break emulsions prior to placing the recovered substance into the barges or storage tanks.

Use of any site for storage is dependent on the approval of the local authorities. The following elements affect the choice of a potential storage site:

- Geology.
- Ground water.
- Soil.
- Flooding.
- Surface water.
- Slope.
- Covered material.
- Capacity.
- Climatic factors.
- Land use.
- Toxic air emissions.
- Security.
- Access.
- Public contact.

E.5 WASTE DISPOSAL

Techniques for Disposal of Recovered Oil

Recovery, reuse, and recycling are the best choices for remediation of a spill, thereby reducing the amount of oily debris to be bermed onsite or disposed of at a solid waste landfill. Treatment is the next best alternative, but incineration and burning for energy recovery have more options within the state. There are some limitations and considerations in incinerating for disposal. Environmental quality of incineration varies with the type and age of the facility. Therefore, when incineration becomes an option during an event, local air quality authorities would be contacted for advice about efficiency and emissions of facilities within their authority. Approval of the local air authorities is a requirement for any incineration option. Landfilling is the last option. Final disposal at a solid or dangerous waste landfill is the least environmentally sound method of dealing with a waste problem such as oily debris.

Note: Prior to the disposal of ANY waste products, the Incident Commander or his designee must contact the Keystone / TransCanada Community, Safety and Environmental Department to receive direction and guidence on the proper disposal methods and procedures.

During an oil spill incident, the Company would consult with the proper regulating agency to identify the acceptable disposal methods and sites appropriately authorized to receive such wastes. The Company maintains a list of approved disposal sites that satisfy local, Province/State, and Federal

Regulations and Company requirements. This identification of suitable waste treatment and disposal sites would be prepared by the Environmental Unit in the form of an Incident Disposal Plan which must be authorized by the U.S. Coast Guard and/or the Environmental Protection Agency or National Energy Board.

An Incident Disposal Plan would include predesignated interim storage sites, segregation strategies, methods of treatment and disposal for various types of debris, and the locations/contacts of all treatment and disposal site selections. Onsite treatment/disposal is preferred.

In order to obtain the best overall Incident Disposal Plan, a combination of methods should be used. There is no template or combination of methods that can be used in every spill situation. Each incident should be reviewed carefully to ensure that an appropriate combination of disposal methods is employed.

The different types of wastes generated during response operations would require different disposal methods. To facilitate the disposal of wastes, they should be separated by type for temporary storage, transport and disposal. Figure E-2 lists some of the options that would be available to segregate oily wastes. The figure also depicts methods that may be employed to separate free and/or emulsified water from the oily liquid waste.

The following is a brief discussion of some disposal techniques available for recovered oil and oily debris.

Recycling

This technique entails removing water from the oil and blending the oil with uncontaminated oil. Recovered oil can be shipped to refineries provided that it is exempt from hazardous waste regulations. There it can be treated to remove water and debris, and then blended and sold as a commercial product.

The Company's designated Disposal Specialist is responsible for ensuring that all waste materials be disposed at an internally approved disposal site.

Incineration

This technique entails the complete destruction of the recovered oil by high temperature thermal oxidation reactions. There are licensed incineration facilities as well as portable incinerators that may be brought to a spill site. Incineration may require the approval of the local Air Pollution Control Authority. Factors to consider when selecting an appropriate site for onsite incineration would include:

- Proximity to recovery locations.
- Access to recovery locations.
- Adequate fire control.
- Approval of the local air pollution control authorities.

In Situ Burning / Open Burning

Burning techniques entail igniting oil or oiled debris and allowing it to burn under ambient conditions. These disposal techniques are subject to restrictions and permit requirements established by federal, province/state and local laws. They would not be used to burn Polychlorinated biphenyls, waste oil containing more than 1,000 parts per million of halogenated solvents, or other substances regulated by the Environmental Protection Agency or Environment Canada. Permission for in situ burning may be difficult to obtain when the burn takes place near populated areas.

As a general rule, in situ burning would be appropriate only when atmospheric conditions will allow the smoke to rise several hundred feet and rapidly dissipate. Smoke from burning oil will normally rise until its temperature drops to equal the ambient temperature. Afterwards, it will travel in a horizontal direction under the influence of prevailing winds.

Landfill Disposal

This technique entails burying the recovered oil in an approved landfill in accordance with regulatory procedures. Landfill disposal of free liquids is prohibited by Federal Law in the United States.

With local health department approval, non-burnable debris which consists of oiled plastics, gravel and oiled seaweed, kelp, and other organic material may be transported to a licensed, lined, approved municipal or private landfill and disposed of in accordance with the landfill guidelines and regulations. Landfill designation would be planned only for those wastes that have been found to be unacceptable by each of the other disposal options (e.g., waste reduction, recycling, energy recovery). Wastes would be disposed only at Company-approved disposal facilities. The Disposal Specialist is responsible for ensuring that all waste materials are disposed at a Company internally approved disposal site. Disposal at a non-approved facility would require approval by the Disposal Specialist prior to sending any waste to such a facility.

FIGURE E-1

TEMPORARY STORAGE METHODS

CONTAINER	ONSHORE	OFFSHORE	SOLIDS	LIQUIDS	NOTES
Barrels	x	x	x	x	May require handling devices. Covered and clearly marked.
Tank Trucks	x	x		x	Consider road access. Barge-mounted offshore.
Dump/Flat Bed Trucks- Roll-offs	x		x		May require impermeable liner and cover. Consider flammability of vapors at mufflers.
Barges		x	x	x	Liquids only in tanks. Consider venting of tanks.
Oil Storage Tanks	x	x		x	Consider problems of large volumes of water in oil.
Bladders	x	x		x	May require special hoses or pumps for oil transfer.
Frac Tanks	x			x	Consider road access.

FIGURE E-2

OILY WASTE SEPARATION AND DISPOSAL METHODS

TYPE OF MATERIAL	SEPARATION METHODS	DISPOSAL METHODS
LIQUIDS		
Non-emulsified oils	Gravity separation of free water	Incineration Use of recovered oil as refinery/production facility feedstock
Emulsified oils	Emulsion broken to release water by: • heat treatment • emulsion breaking chemicals • mixing with sand • centrifuge • filter/belt press	Use of recovered oil as refinery/production facility feedstock
SOLIDS		
Oil mixed with sand and soil	Collection of liquid oil leaching from sand during temporary storage Extraction of oil from sand by washing with water or solvent Removal of solid oils by sieving	Incineration Use of recovered oil as refinery/production facility feedstock Direct disposal Stabilization with inorganic material Degradation through land farming or composting
Oil mixed with cobbles or pebbles	Screening Collection of liquid oil leaching from materials during temporary storage Extraction of oil from materials by washing with water or solvent	Incineration Direct Disposal Use of recovered oil as refinery/production facility feedstock
Oil mixed with wood and sorbents	Screening Collection of liquid oil leaching from debris during temporary storage Flushing of oil from debris with water	Incineration Direct disposal Degradation through land farming or composting for oil mixed with seaweed or natural sorbents

APPENDIX F

MISCELLANEOUS FORMS

Forms and Exercise Documentation
File Maintenance Procedures

- Forms and exercise documentation records should be maintained in a separate file in the Facility's office filing system.
- These files must be available for presentation upon request by regulatory agency personnel.

F 7000-1

Click to view the file - PlanFiles/PlanContent/TRANSCANADAPLAN/PHMSA F 7000-1_30_10_2008_9_8_46%2Epdf

Date: ______________________________ **NRC Incident No. #**____________________

PHMSA F 7000-1 Accident Report – Hazardous Liquid Pipeline Systems Form

Date: ________________________ **NRC Incident No. #**__________________

NOTICE: This report is required by 49 CFR Part 195. Failure to report can result in a civil penalty not to exceed $25,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $500,000 as provided in 49 USC 60122 **Form Approved OMB No. 2137-0047**

U.S. Department of Transportation
Pipeline and Hazardous Materials
Safety Administration

ACCIDENT REPORT – HAZARDOUS LIQUID PIPELINE SYSTEMS

Report Date ______________
No. ______________
(DOT Use Only)

INSTRUCTIONS

Important: *Please read the separate instructions for completing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions, you can obtain one from the Office Of Pipeline Safety Web Page at http://ops.dot.gov.*

PART A – GENERAL REPORT INFORMATION

Check: ☐ **Original Report** ☐ **Supplemental Report** ☐ **Final Report**

1. a. Operator's OPS 5-digit Identification Number (if known) /__/__/__/__/__/
   b. If Operator does not own the pipeline, enter Owner's OPS 5-digit Identification Number (if known) /__/__/__/__/__/
   c. Name of Operator ______________
   d. Operator street address ______________
   e. Operator address ______________
   City, County, State and Zip Code

IMPORTANT: IF THE SPILL IS SMALL, THAT IS, THE AMOUNT IS AT LEAST 5 GALLONS BUT IS LESS THAN 5 BARRELS, COMPLETE THIS PAGE ONLY, UNLESS THE SPILL IS TO WATER AS DESCRIBED IN 49 CFR §195.52(A)(4) OR IS OTHERWISE REPORTABLE UNDER §195.50 AS REVISED IN CY 2001.

2. Time and date of the accident

/__/__/__/__/ hr. /__/__/ month /__/__/ day /__/__/ year

3. Location of accident
(If offshore, do not complete a through d. See Part C.1)

a. Latitude: __________ Longitude: __________
(if not available, see instructions for how to provide specific location)

b. ______________
City, and County or Parish

c. ______________
State and Zip Code

d. Mile post/valve station ○ or survey station no. ○
(whichever gives more accurate location)
____

4. Telephone report

/__/__/__/__/__/__/__/ NRC Report Number /__/__/ month /__/__/ day /__/__/ year

5. Losses *(Estimated)*

Public/Community Losses reimbursed by operator:

Public/private property damage $__________
Cost of emergency response phase $__________
Cost of environmental remediation $__________
Other Costs $__________
(describe) ______________

Operator Losses:

Value of product lost $__________
Value of operator property damage $__________
Other Costs $__________
(describe) ______________

Total Costs $__________

6. Commodity Spilled ○Yes ○ No
(If Yes, complete Parts a through c where applicable)

a. Name of commodity spilled ______________

b. Classification of commodity spilled:
○ HVLs /other flammable or toxic fluid which is a gas at ambient conditions
○ CO_2 or other non-flammable, non-toxic fluid which is a gas at ambient conditions
○ Gasoline, diesel, fuel oil or other petroleum product which is a liquid at ambient conditions
○ Crude oil

a. Estimated amount of commodity involved :
○ Barrels
○ Gallons (check only if spill is less than one barrel)

Amounts:
Spilled : __________
Recovered: __________

CAUSES FOR SMALL SPILLS ONLY (5 gallons to under 5 barrels) : ***(For large spills [5 barrels or greater] see Part H)***

○ **Corrosion** ○ **Natural Forces** ○ **Excavation Damage** ○ **Other Outside Force Damage**
○ **Material and/or Weld Failures** ○ **Equipment** ○ **Incorrect Operation** ○ **Other**

PART B – PREPARER AND AUTHORIZED SIGNATURE

____
(type or print) Preparer's Name and Title | Area Code and Telephone Number

____
Preparer's E-mail Address | Area Code and Facsimile Number

____
Authorized Signature | (type or print) Name and Title | Date | Area Code and Telephone Number

030452

Date: ______________________ NRC Incident No. #______________

PART C – ORIGIN OF THE ACCIDENT (Check all that apply)

1. Additional location information
   a. Line segment name or ID ______________
   b. Accident on Federal land other than Outer Continental Shelf O Yes O No
   c. Is pipeline interstate? O Yes O No

Offshore: O Yes O No *(completed if offshore)*

d. Area ______________ Block # ______________

State / / / or Outer Continental Shelf ☐

2. Location of system involved (*check all that apply*)
   - ☐ Operator's Property
   - ☐ Pipeline Right of Way
   - ☐ High Consequence Area (HCA)?
     Describe HCA______________

3. Part of system involved in accident
   - O Above Ground Storage Tank
   - O Cavern or other below ground storage facility
   - O Pump/meter station; terminal/tank farm piping and equipment, including sumps
   - O Other *Specify:* ______________
   - O Onshore **pipeline**, including valve sites
   - O Offshore **pipeline**, including platforms

*If failure occurred on **Pipeline**, complete items a - g:*

4. Failure occurred on
   - O Body of Pipe O Pipe Seam O Scraper Trap
   - O Pump O Sump O Joint
   - O Component O Valve O Metering Facility
   - O Repair Sleeve O Welded Fitting O Bolted Fitting
   - O Girth Weld

Other *(specify)* ______________

Year the component that failed was installed: / / / / /

5. Maximum operating pressure *(MOP)*
   a. Estimated pressure at point and time of accident: ______ *PSIG*
   b. MOP at time of accident: ______ *PSIG*
   c. Did an over pressurization occur relating to the accident? OYes O No

a. Type of leak or rupture
   - OLeak: O Pinhole O Connection Failure *(complete sec. H5)*
     - O Puncture, diameter *(inches)* ______________
   - ORupture: O Circumferential – Separation
     - O Longitudinal – Tear/Crack, length *(inches)* ______
     - Propagation Length, total, both sides *(feet)* ______
   - ON/A
   - OOther ______________

b. Type of block valve used for isolation of immediate section:
   - Upstream: ☐ Manual ☐ Automatic ☐ Remote Control ☐ Check Valve
   - Downstream: ☐ Manual ☐ Automatic ☐ Remote Control ☐ Check Valve

c. Length of segment isolated ______ ft

d. Distance between valves ______ ft

e. Is segment configured for internal inspection tools? OYes O No

f. Had there been an in-line inspection device run at the point of failure? O Yes O No O Don't Know
   O Not Possible due to physical constraints in the system

g. If *Yes*, type of device run (*check all that apply*)
   - ☐ High Resolution Magnetic Flux tool Year run: ______
   - ☐ Low Resolution Magnetic Flux tool Year run: ______
   - ☐ UT tool Year run: ______
   - ☐ Geometry tool Year run: ______
   - ☐ Caliper tool Year run: ______
   - ☐ Crack tool Year run: ______
   - ☐ Hard Spot tool Year run: ______
   - ☐ Other tool Year run: ______

PART D – MATERIAL SPECIFICATION

1. Nominal pipe size *(NPS)* / / / / / / in.
2. Wall thickness / / / / / / in.
3. Specification ______________ SMYS / / / / / / / /
4. Seam type ______________
5. Valve type ______________
6. Manufactured by ______________ in year / / / / / /

PART E – ENVIRONMENT

1. Area of accident
   - O Under pavement
   - O Underground
   - O Inside/under building
   - O In open ditch
   - O Above ground
   - O Under water
   - O Other ______________
2. Depth of cover: ______________ inches

PART F – CONSEQUENCES

1. Consequences *(check and complete all that apply)*

a.

	Fatalities	Injuries
Number of operator employees:		______
Contractor employees working for operator:		______
General public:		______
Totals:		______

b. Was pipeline/segment shutdown due to leak? OYes O No

If Yes, how long? ______ days ______ hours ______ minutes

c. Product ignited OYes O No d. Explosion OYes O No

e. ☐ Evacuation *(general public only)* / / / / / / people

Reason for Evacuation:
- O Precautionary by company
- O Evacuation required or initiated by public official

f. Elapsed time until area was made safe: / / / / hr. / / / / min.

2. Environmental Impact

a. Wildlife Impact:
- Fish/aquatic O Yes O No
- Birds O Yes O No
- Terrestrial O Yes O No

b. Soil Contamination O Yes O No
   If Yes, estimated number of cubic yards: ______

c. Long term impact assessment performed: O Yes O No

d. Anticipated remediation O Yes O No
   If Yes, check all that apply: ☐ Surface water ☐ Groundwater ☐ Soil ☐ Vegetation ☐ Wildlife

e. Water Contamination: O Yes O No (*If Yes, provide the following*)
   - Amount in water ______ barrels
   - Ocean/Seawater O No O Yes
   - Surface O No O Yes
   - Groundwater O No O Yes
   - Drinking water O No O Yes (*If Yes, check below.*)
     - O Private well O Public water intake

030453

Date: ______________________________ **NRC Incident No. #**________________

PART G – LEAK DETECTION INFORMATION

1. Computer based leak detection capability in place? ○ Yes ○ No
2. Was the release initially detected by? (check one):
   - ○ CPM/SCADA-based system with leak detection
   - ○ Static shut-in test or other pressure or leak test
   - ○ Local operating personnel, procedures or equipment
   - ○ Remote operating personnel, including controllers
   - ○ Air patrol or ground surveillance
   - ○ A third party ○ Other (specify) ________________
3. Estimated leak duration days ____ hours ____

PART H – APPARENT CAUSE

Important: *There are 25 numbered causes in this Part H. Check the box corresponding to the primary cause of the accident. Check one circle in each of the supplemental categories corresponding to the cause you indicate. See the instructions for guidance.*

H1 – CORROSION

1. ☐ External Corrosion
2. ☐ Internal Corrosion

(Complete items a – e where applicable.)

a. Pipe Coating
- ○ Bare
- ○ Coated

b. Visual Examination
- ○ Localized Pitting
- ○ General Corrosion
- ○ Other ___________________

c. Cause of Corrosion
- ○ Galvanic ○ Atmospheric
- ○ Stray Current ○ Microbiological
- ○ Cathodic Protection Disrupted
- ○ Stress Corrosion Cracking
- ○ Selective Seam Corrosion
- ○ Other ___________________

d. Was corroded part of pipeline considered to be under cathodic protection prior to discovering accident?
○ No ○ Yes, Year Protection Started: /__/__/__/__/

e. Was pipe previously damaged in the area of corrosion?
○ No ○ Yes ⇒ Estimated time prior to accident: /__/__/ *years* /__/__/ *months* *Unknown* ☐

H2 – NATURAL FORCES

3. ☐ Earth Movement ⇒ ○ Earthquake ○ Subsidence ○ Landslide ○ Other ____________________________
4. ☐ Lightning
5. ☐ Heavy Rains/Floods ⇒ ○ Washouts ○ Flotation ○ Mudslide ○ Scouring ○ Other ________________
6. ☐ Temperature ⇒ ○ Thermal stress ○ Frost heave ○ Frozen components ○ Other ________________
7. ☐ High Winds

H3 – EXCAVATION DAMAGE

8. ☐ Operator Excavation Damage (including their contractors/Not Third Party)
9. ☐ Third Party *(complete a-f)*

a. Excavator group
○ General Public ○ Government ○ Excavator other than Operator/subcontractor

b. Type: ○ Road Work ○ Pipeline ○ Water ○ Electric ○ Sewer ○ Phone/Cable
○ Landowner-not farming related ○ Farming ○ Railroad
○ Other liquid or gas transmission pipeline operator or their contractor
○ Nautical Operations ○ Other ______________________

c. Excavation was: ○Open Trench ○ Sub-strata (boring, directional drilling, etc…)

d. Excavation was an ongoing activity (Month or longer) ○Yes ○ No If Yes, Date of last contact /___/___/___/

e. Did operator get prior notification of excavation activity?
○ Yes; Date received: /__/__/ mo. /__/__/ day /__/__/__/__/ yr. ○ No
Notification received from: ○ One Call System ○ Excavator ○ Contractor ○ Landowner

f. Was pipeline marked as result of location request for excavation? ○ No ○ Yes *(If Yes, check applicable items i - iv)*
- i. Temporary markings: ○ Flags ○ Stakes ○ Paint
- ii. Permanent markings: ○
- iii. Marks were (check one) : ○ Accurate ○ Not Accurate
- iv. Were marks made within required time? ○ Yes ○ No

H4 – OTHER OUTSIDE FORCE DAMAGE

10. ☐ Fire/Explosion as primary cause of failure ⇒ Fire/Explosion cause: ○ Man made ○ Natural
11. ☐ Car, truck or other vehicle not relating to excavation activity damaging pipe
12. ☐ Rupture of Previously Damaged Pipe
13. ☐ Vandalism

Date: ____ NRC Incident No. #____________________

H5 – MATERIAL AND/OR WELD FAILURES

Material

14.☐ Body of Pipe ⇒ O Dent O Gouge O Bend O Arc Burn O Other ______________

15.☐ Component ⇒ O Valve O Fitting O Vessel O Extruded Outlet O Other ______________

16.☐ Joint ⇒ O Gasket O O-Ring O Threads O Other ______________

Weld

17.☐ Butt ⇒ O Pipe O Fabrication O Other ______________

18.☐ Fillet ⇒ O Branch O Hot Tap O Fitting O Repair Sleeve O Other ______________

19.☐ Pipe Seam ⇒ O LF ERW O DSAW O Seamless O Flash Weld
O HF ERW O SAW O Spiral O Other ______________

*Complete a-g if you indicate **any** cause in part H5.*

a. Type of failure:
O Construction Defect ⇒ O Poor Workmanship O Procedure not followed O Poor Construction Procedures
O Material Defect

b. Was failure due to pipe damage sustained in transportation to the construction or fabrication site? O Yes O No

c. Was part which leaked pressure tested before accident occurred? O Yes, *complete d-g* O No

d. Date of test: /___/___/___/___/ yr. /___/___/ mo. /___/___/ day

e. Test medium: O Water O Inert Gas O Other __________________________

f. Time held at test pressure: /___/___/ hr.

g. Estimated test pressure at point of accident: __________________________ *PSIG*

H6 – EQUIPMENT

20. ☐ Malfunction of Control/Relief Equipment ⇒ O Control valve O Instrumentation O SCADA O Communications
O Block valve O Relief valve O Power failure O Other ______________

21. ☐ Threads Stripped, Broken Pipe Coupling ⇒ O Nipples O Valve Threads O Dresser Couplings O Other ______________

22. ☐ Seal Failure ⇒ O Gasket O O-Ring O Seal/Pump Packing O Other ______________

H7 – INCORRECT OPERATION

23. ☐ Incorrect Operation

a. Type: O Inadequate Procedures O Inadequate Safety Practices O Failure to Follow Procedures
O Other ___________________________________

b. Number of employees involved who failed a post-accident test: drug test: /___/___/___/ alcohol test /___/___/___/

H8 – OTHER

24. ☐ Miscellaneous, *describe:* ____

25. ☐ Unknown
O Investigation Complete O Still Under Investigation *(submit a supplemental report when investigation is complete)*

PART I – NARRATIVE DESCRIPTION OF FACTORS CONTRIBUTING TO THE EVENT *(Attach additional sheets as necessary)*

030455

Preliminary Incident Report

Click to view the file - PlanFiles/PlanContent/TRANSCANADAPLAN/Preliminary Incident Report_22_1_2009_13_30_47%2Epdf

date

Transportation Safety Board of Canada
Place du Centre, 4th Floor
200 Promenade du Portage
Hull, Québec
K1A 1K8

Attention: Mr. Larry Gales, P. Eng.

Dear Sir:

Re: Preliminary Incident Report involving event type on the TransCanada PipeLines Limited (“TransCanada”) Canadian Mainline at Station/MLV Location, near Town, Province, on date of occurrence

Further to our verbal report of date to Board Staff Member Mr. x, the following is TransCanada's Preliminary Incident Report in accordance with the requirements of Section 52 of the National Energy Board’s Onshore Pipeline Regulations and Section 5 of the Transportation Safety Board Regulations.

(a) describe the incident, including the events leading up to and following the incident;

(b) list all relevant agencies contacted and persons affected by the incident;

(c) summarize any losses or impacts to people (e.g., injury, fatalities), environment (e.g., terrain, habitats, animals), production (e.g., interruption or reduction in service), and property;

If this were a gas release incident, use the following canned statement:

The environmental impact of this gas release is related to greenhouse gas emissions to atmosphere. This incident resulted in a maximum emission of ________ kt of methane which corresponds to _________ kt of CO_2 equivalents. The gas released from this incident will be included in our annual green house gas emission report to Statistics Canada.

Aside: Following is the formula for calculating kilotonnes of methane and kilotonnes of CO_2:

$$\frac{10^3\ m^3 \times 0.71}{1000} = \text{kt Methane}$$

$$\text{kt Methane} \times 21 = \text{kt } CO_2 \text{ equivalents}$$

(d) identify any unsafe acts or conditions contributing to or causing the incident;

(e) provide details on any emergency response,

(f) state any corrective actions taken or planned to be taken to minimize the effects of the incident.

Yours very truly,
TransCanada PipeLines Ltd.

Original signed

R.P. Lancée, P. Eng.
Senior Regulatory Compliance Specialist

cc: (appropriate Regional Director)
(appropriate Compliance Manager)
(appropriate Area Manager)

J. Baggs	(all reports)
K. Black	(all reports)
D. King	(all reports)
B. McConaghy	(if safety, health or environment related)
G. Scaman	(all reports)
J. Scott	(Legal review)
D. Wishart	(all reports)

Incident & Issue Tracking No. _________

Detailed Incident Report

Click to view the file - PlanFiles/PlanContent/TRANSCANADAPLAN/Detailed Incident Report_22_1_2009_13_31_48%2Epdf

TransCanada
In business to deliver

date

Transportation Safety Board of Canada
Place du Centre, 4th Floor
200 Promenade du Portage
Hull, Québec
K1A 1K8

Attention: Mr. Larry Gales, P. Eng.

Dear Sir:

Re: Detailed Incident Report involving event type on the TransCanada PipeLines Limited ("TransCanada") Canadian Mainline, Station/MLV Location, near Town, Province, on date of occurrence

The following is TransCanada's Detailed Incident Report, in accordance with the requirements of Section 52 of the National Energy Board's Onshore Pipeline Regulations, 1999 and Section 5 of the Transportation Safety Board Regulations.

Board Staff Member Mr. (name) was notified of the event type on date of occurrence. The Preliminary Incident Report was filed with the Board on date.

a) provide any details regarding the failure mechanism and detailed analysis of the failed component (if necessary);

(b) identify the underlying causes of the incident;

(c) update the progress of any corrective actions taken or planned to be taken to minimize the effects of the incident;

(d) state any actions taken or planned to be taken to prevent a similar incident.

Yours very truly,
TransCanada PipeLines Limited

Original signed

R.P. Lancée, P. Eng.
Senior Regulatory Compliance Specialist

cc: (appropriate Regional Director)
(appropriate Compliance Manager)
(appropriate Area Manager)

J. Baggs	(all reports)
K. Black	(all reports)
D. King	(all reports)
B. McConaghy	(if safety, health or environment related)
G. Scaman	(all reports)
J. Scott	(legal review)
D. Wishart	(all reports)

Incident & Issue Tracking No. __________

Unauthorized Activity

Click to view the file - PlanFiles/PlanContent/TRANSCANADAPLAN/Unauthorized Activity_22_1_2009_13_32_24%2Epdf

450 - 1st Street S.W
Calgary, Alberta, Canada T2P 5H1
tel 403.920-7069
fax 403.920-2319
E-mail roel_lancee@transcanada.com

Date

National Energy Board
444 Seventh Avenue S.W.
Calgary, Alberta
T2P 0X8

Attention: Ms. Claudine Dutil-Berry, Secretary

Dear Madame:

Re: Unauthorized event type at TransCanada PipeLines Limited ("TransCanada") Canadian Mainline Station/MLV Location, near Town, Province, on date of occurrence

TransCanada PipeLines Limited ("TransCanada") files this Incident Report to report unauthorized mechanical excavation activities pursuant to the reporting requirements of Section 13 of the National Energy Board's Pipeline Crossing Regulations Part II.

Board Staff Member ______________ was initially notified of the unauthorized_____________ on date of notification.

a.) Date of Occurrence

b.) Location of occurrence (Legal Land Description, MLV, mileage post, etc)

c.) Indicate whether the activity involved mechanical excavation

d.) Location of pipeline markers with respect to the unauthorized activity

e.) Indicate whether a permit was issued by pipeline company (yes or no)

f.) Name of landowner or facility owner, address and contact information (phone, fax, e-mail if applicable) g.) Name of excavator or contractor, address and contact information (phone, fax, e-mail if applicable)

h.) Name of Pipeline company representative dealing with violation and contact information (phone, fax, e-mail if applicable)

i.) Concerns the pipeline company may have regarding the safety of the pipeline as a result of the construction or installation or of the excavation

j.) Any action the company intends to take or has taken

Mr. __________ met with Mr. ________ on date and discussed the requirements of notifying Info-Excavation prior to undertaking any mechanical excavation activities within the province and of having a Company Representative present to locate the pipeline and monitor the excavation when excavating on or within 30-metres of the TQM pipeline Right-of-Way. Mr. __________ provided Mr. _________ with a copy of the Integrated Public Awareness Package to remind him of their discussions.

Yours very truly,
TransCanada PipeLines Limited

R.P. Lancée, P. Eng.
Senior Regulatory Compliance Specialist

cc: (appropriate Regional Director)
(appropriate Compliance Manager)
(appropriate Area Manager
(appropriate Land Representative)
J. Baggs
K. Black
D. King
B. McConaghy
G. Scaman
J. Scott
D. Wishart

cc: S. Berthelet National Energy Board

Incident & Issue Tracking No. _________

South Dakota Supplemental Emergency Response and Equipment Statement

Click to view the file - PlanFiles/PlanContent/TRANSCANADAPLAN/Sup for SD_19_10_2009_15_35_10%2Epdf

1.1 SUPPLEMENTAL EMERGENCY RESPONSE AND EQUIPEMENT STAEMENT

The purpose of this is to fulfill the South Dakota Department of Environment and Natural Resources request for additional information regarding TransCanada – Keystone Pipeline's ability to respond to a spill specifically in South Dakota

- Detail description of company owned assets is found in appropriately marked Appendix A: RESPONSE EQUIPMENT/RESOURCES. Additional information is linked to Appendix F. The trailer for the Keystone Response Zone 3, North Dakota, South Dakota, and Nebraska is appropriately located in Yankton, South Dakota.

- Keystone Pipeline's primary contractor, National Response Corporation, is strategically aligned with Coteau Environmental based in Watertown, SD. Currently, no other National Response Corporation assets or Sub-Contractors reside inside of South Dakota borders.

- Keystone Pipeline fully expects to have the required assets for a spill within the four (4) hour time frame previously stated in the Response Plan.

APPENDIX G

MATERIAL SAFETY DATA SHEET(S)

Keystone Commodities - Legal Names & Codes/Acronyms

Click to view the file - Keystone Commodities - Legal Names Codes_Synonyms_27_11_2012_8_5_48.pdf

Keystone Commodities List: Legal Names & Codes

[redacted]

[redacted]

Alberta Common Synthetic (ACS): Husky Oil Operations Limited

Click to view the file - Alberta Common Synthetic - Husky Oil Operations Ltd_13_2_2012_17_6_49.pdf

Albian Heavy Synthetic Crude (Dec2008) - Shell Canada

Click to view the file - Albian Heavy Synthetic Crude (Jan2012) - Shell Canada Ltd_27_11_2012_7_41_14.pdf

Albian Muskeg River Heavy (AMH) Shell Canada Limited

Click to view the file - Albian Muskeg River Heavy (Feb2011) - Shell Canada_2_2_2012_18_22_22.PDF

Albian Resid Blend Shell Canada Limited

Click to view the file - Albian Resid Blend (Nov2010) - Shell Canada_3_2_2012_9_28_26.PDF

Albian Vacuum Gasoil Blend

Click to view the file - Albian Vacuum Gasoil Blend (Nov2010) - Shell Canada_3_2_2012_9_28_59.PDF

Canadian Heavy Oil - BP Canada Energy Trading Co

Click to view the file - Canadian Heavy Oil - BP Canada Energy Trading Co_26_11_2012_13_8_43.pdf

Crude Oil, Sour: Phillips 66 Company

Click to view the file - Crude Oil Sour (May2012) - Phillips 66 Company_27_11_2012_7_44_28.pdf

Crude Oil Sweet (Canada) Conoco Phillips Canada Limited

Click to view the file - Crude Oil Sweet (May2012) - Phillips 66 Company_27_11_2012_12_16_59.pdf

Dilbit: MEG Energy

Click to view the file - Dilbit (AWB) (Aug2011) - MEG Energy Corp_27_11_2012_7_45_29.pdf

Diluted Bitumen Nexen Canada Inc

Click to view the file - Diluted Bitumen (June2011) - Nexen Canada_3_2_2012_9_29_35.pdf

Heavy Crude Oil/Diluent Mix - Cenovus Energy Inc.

Click to view the file - Heavy Crude Oil_Diluent Mix - Cenovus Energy Inc_12_4_2011_14_28_52.pdf

Heavy Crude Oil_Diluent Mix (Christina Lake_Foster Creek) - Encana Corporation

Click to view the file - Heavy Crude Oil_Diluent Mix (Christina Lake_Foster Creek) - Encana Corporation_11_9_2009_17_27_58.pdf

Horizon Sweet Light Oil Canadian Natural Resources Ltd

Click to view the file - Horizon Sweet Light Oil - Canadian Natural Resources Ltd_3_2_2012_9_30_1.pdf

MacKay River MSDS - CDN 02 08 20

Click to view the file - Suncor MKH (Oct2012) - Suncor Energy Inc_29_11_2012_14_0_12.pdf

MacKay River MSDS - US

Click to view the file - MacKay River MSDS - US_11_9_2009_17_28_31_29_11_2012_13_59_25.pdf

Petroleum Crude Oil (Sour) Gibson Energy ULC

Click to view the file - Petroleum Crude Oil (Sour) - Gibson Energy Limited_2_2_2012_18_18_56.pdf

Petroleum Crude Oil (Sour): Husky Oil

Click to view the file - Petroleum Crude Oil (Sour) - Husky Oil Operations Limited_27_11_2012_7_47_1.pdf

Petroleum Crude Oil Sweet (Feb 2012) - BP Canada Energy Co

Click to view the file - Petroleum Crude Oil Sweet (Feb2012) - BP Canada Energy Co_26_11_2012_13_8_8.pdf

Petroleum Heavy Crude Oil: Canadian Natural Resources Ltd.

Click to view the file - Petroleum Heavy Crude Oil - Canadian Natural Resources Ltd_20_12_2011_17_6_58.pdf

Premium Albian Synthetic Crude Shell Canada Limited

Click to view the file - Premium Albian Synthetic Crude (Nov2010) - Shell Canada_3_2_2012_9_30_28.PDF

Product Gas Oil (OSZ MSDS)

Click to view the file - Product Gas Oil (OSZ MSDS)_11_9_2009_17_28_43.pdf

PSC Nexen Inc.

Click to view the file - PSC (Aug2011) - Nexen Inc_27_11_2012_7_47_48.pdf

Sales Oil: Statoil

Click to view the file - Sales Oil (Nov2010) - Statoil_3_2_2012_9_30_48.PDF

Seal Heavy Crude Oil Shell Canada Limited

Click to view the file - Seal Heavy Crude Oil - Shell Canada_3_2_2012_9_31_10.pdf

Shell Synthetic Blend Shell Canada Limited

Click to view the file - Shell Synthetic Blend (Nov2010) - Shell Canada_3_2_2012_9_31_53.PDF

Sour Produced Gas, Sour Produced Water, Sour Crude Oil Shell Canada Limited

Click to view the file - Sour Produced Gas_Sour Produced Water_Sour Crude Oil - Shell Canada_3_2_2012_13_37_16.pdf

Suncor OSA - Suncor Energy Inc

Click to view the file - Suncor OSA - Suncor Energy Inc_27_11_2012_7_48_38.pdf

Suncor OSB

Click to view the file - Suncor OSB_11_9_2009_17_29_35.pdf

Suncor OSC

Click to view the file - Suncor OSC_11_9_2009_17_29_54.pdf

Suncor OSH

Click to view the file - Suncor OSH_11_9_2009_17_30_8.pdf

Surmont Phase 1 Synbit Sales Oil (Canada) - ConocoPhillips

Click to view the file - Surmont Phase 1 Synbit Sales Oil (Canada) - ConocoPhillips_11_9_2009_17_30_23.pdf

Syncrude Sweet Blend Crude Oil - Syncrude

Click to view the file - Syncrude Sweet Blend Crude Oil - Syncrude_11_9_2009_17_31_14.pdf

Synthetic Crude Oil - Husky Oil Operations Limited

Click to view the file - Synthetic Crude Oil - Husky Oil Operations Ltd_27_11_2012_7_49_27.pdf

Western Canadian Select (WCS) - Husky Energy

Click to view the file - Western Canadian Select (WCS) - Husky Energy_11_9_2009_17_31_55.pdf

APPENDIX H

BASICS OF OIL SPILL RESPONSE

H.1 Dikes, Berms and Dams
Figure H.1 Culvert Blocking

H.2 Deflection Boom
Figure H.2 Deflective Booming Technique(Single Boom method)
Figure H.3 Deflective Booming Technique(Single Boom method)
Figure H.4 Deflective Booming Technique(Cascade method)

H.3 Containment Boom
Figure H.5 Containment Booming (Catenary method)

H.4 Diversion Boom
Figure H.6 Open Chevron Boom Technique
Figure H.7 Closed Chevron Boom Technique

H.5 Shoreline Recovery

H.6 Ice Operations
Figure H.8 Ice Slotting Technique
Figure H.9 Deflective Board Recovery Strategy
Figure H.10 Close up view of Deflective Board

H.1 DIKES, BERMS AND DAMS

Dikes, berms, and dams are land-based tactics, with the objective of containing spilled oil and limiting spreading of oil slicks, thus minimizing impacts to the environment. Dikes, berms and dams are embankment structures built-up from the existing terrain, placed to contain and accumulate oil for recovery. These barriers can serve to:

- Contain and stabilize a contaminated area.
- Contain or divert oil on water or oil that has potential to migrate.
- Create cells for recovery.
- Use natural depressions to act as containment areas for recovery.

The tactic may be deployed in association with a recovery tactic, such as Shoreline Recovery or On-land Recovery. Dikes, berms, and dams are most effective when placed before oil arrives. Dikes, berms, and dams can also be used to exclude oil from a sensitive area, which is covered in the Beach Berms and Exclusion Dams tactic. The tactic can also be used in conjunction with an excavation tactic to enhance containment volumes (see Pits, Trenches, and Slots).
The general strategy is to:

1. Identify the location and trajectory of the spill or potential spill.
2. Plan a deployment configuration that best supports the operating environment and available resources.
3. Mobilize to the location and deploy response resources.
4. Construct the containment structure and ensure it does not leak.
5. Consider the need to remove any water-bottom that may collect beneath the oil inside the structure.
6. Monitor the containment structure on an appropriate basis.
7. If oil collects in the structure, utilize an appropriate recovery system for removal.

Tactic Description
This tactic involves building an embankment perpendicular to the flow of the oil slick or around a contaminated area. Dike, berm, and dam structures can be constructed with a wide variety of materials including: soil, gravel, snow, sand bags, oil boom, timbers and logs. Selection of the construction material depends on the operating environment, location, available materials, and whether the structure is to be temporary or permanent. The containment area should be lined with an impermeable membrane, such as plastic sheeting, to keep oil and oily water from leaking or migrating into the soil. The structure may include a method to regulate flow, such as a weir or spill way. Dikes, berms, and dams can be built by manual labor or with earth-moving equipment depending on the location and available resources.

Deployment Configurations

BERMS

A containment berm can be constructed of available materials such as earth, gravel, or snow. Use earth-moving equipment or manual labor to construct the berm. Form the materials into a horseshoe shape ahead of the flow of oil. Use plastic sheeting to line the walls of a soil berm to prevent oil penetration. Sandbags filled with sand or other heavy material also make excellent containment barriers.

DAMS

An underflow dam can be used when there is too much water flow to allow for a complete blockage of a drainage channel. The dam is built of earth, gravel, or other barriers such as sandbags or plywood sheets. Wherever possible, line the upstream side of the dam with plastic sheeting to prevent erosion and penetration of oil into the dam material.

Underflow dams use inclined culverts or pipes to move water downstream while leaving the spill contained behind the dam. The capacity of the pipe(s) should exceed the stream flow rate. It may be necessary to use pumps to remove water behind a dike. Valves or culvert plugs can also be used to control flow rate.

Pipes must be placed on the upstream side of the dam, with the elevated end on the downstream side. Make sure that the upstream end of the pipe is submerged and below the oil/water interface. The height of the elevated downstream end of the pipe will determine the water level behind the dam.

EXISTING ROADS

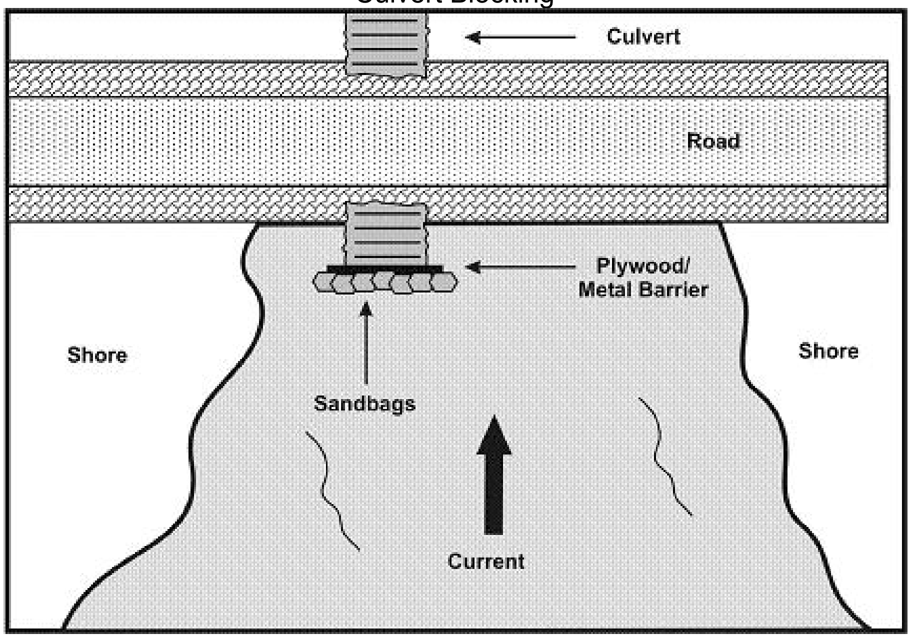
Roadways that are built up above the terrain can be used as dikes. However, road construction usually allows for natural drainage through culverts or bridges. These drainage structures must be controlled to turn the road into a barrier.

CULVERT BLOCKING

A culvert can be blocked using sheet metal, plywood barriers, or inflatable culvert plugs. Use a full block only when the culvert will be blocked for the entire cleanup operation, if the oil floating on the water will not contaminate additional soil or tundra, and if blocking the water flow will not threaten the road. Otherwise, an adjustable weir or culvert plug should be used.

Plywood and/or sandbags can also be used as culvert blocks, but are more labor-intensive and pose a higher potential for injury. A wood block may require a headwall with kickers oriented to support the boards or plywood. Place the blocking materials over the upstream end of the culvert. Plastic sheeting over the outside of the block will prevent oil penetration.

FIGURE H.1
Culvert Blocking



EARTH MOVING EQUIPMENT

A bulldozer, road grader, or front-end loader drives around the spill with its blade angled towards the spill, pushing earth or snow into a berm. Once the perimeter has been covered with an initial berm, shore-up areas as necessary.

SNOW

Because of the absorbent quality of snow, it makes an excellent berm for both containment and recovery. A snow berm can be strengthened by spraying it with a fine water mist that forms an ice layer on top of the snow. A snow berm is built around the areas of heaviest oiling to contain oil or diesel spilled to tundra and/or ice in winter.

MESH FENCE

Plastic mesh fencing may be used to quickly construct an underflow dam system. The mesh fencing is placed across the drainage and held in place with stakes. Absorbent boom, oil boom, plywood, or even dry dead grass can be placed on the upstream side of the fencing. Running water will find its way under the barrier fence, but oil floating on top of the water will be trapped. The advantages of this system are that it is lightweight and mobile.

H.2 DEFLECTION BOOM

Objective & Strategy

The objective is to direct spilled oil away from a location to be protected or simply to change the course of the slick. "Deflection" is used to describe the tactic where oil is redirected away from an area but not recovered.

Tactic Description

The boom is placed at an optimum angle to the oil trajectory, using the movement of the current to carry oil along the boom and then releasing it into the current again with a new trajectory. The angle is chosen to prevent oil from entraining beneath the boom skirt. Boom may be held in place by anchors, vessels, or a boom control device.

Deflection Boom may be used to temporarily avoid impacts to a sensitive area, but there is no recovery associated with the tactic, thus no oil is removed from the environment.

The general strategy is to:

1. Identify the location and trajectory of the spill or potential spill.
2. Identify, prioritize, and select sensitive areas to be protected from impact.
3. Select a deployment configuration that best supports the operating environment and available resources.
4. Mobilize to the location and deploy the tactic.
5. Place boom using secured anchor systems, mooring points, vessels, boom control devices, etc.
6. Monitor and adjust the boom on an appropriate basis.

BOOM ANGLE

Select the appropriate boom angle to keep oil from entraining under the boom. Where currents exceed 3 knots the boom must be almost parallel to the current to prevent entrainment. In currents exceeding 3 knots, a cascade of boom arrays may be used; the first boom array will slow the velocity of the slick allowing subsequent arrays to deflect the oil.

ANCHOR SYSTEMS

Boom is secured in place using standard anchoring systems. Anchor sizes vary depending on the boom type and the operating equipment.

DEPLOYMENT CONFIGURATIONS

Single Boom

Boom is deployed from a site at an optimum angle to the current and anchored to deflect the oil away from a location. Figures H.2 and H.3 illustrate two single boom deflection techniques.

FIGURE H.3
Deflective Booming Technique (Single Boom Method)

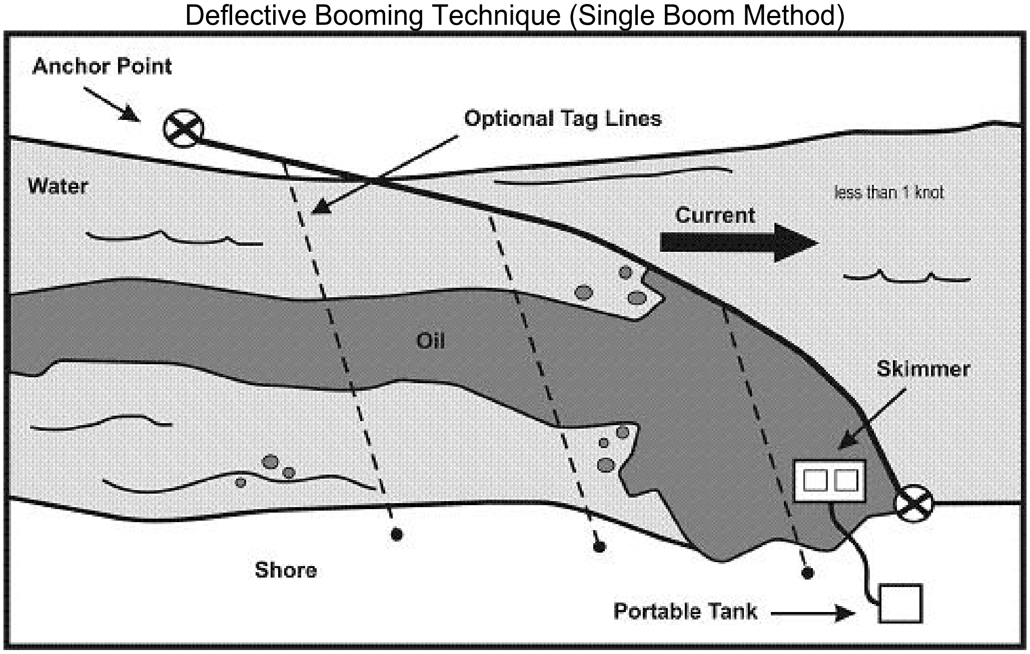
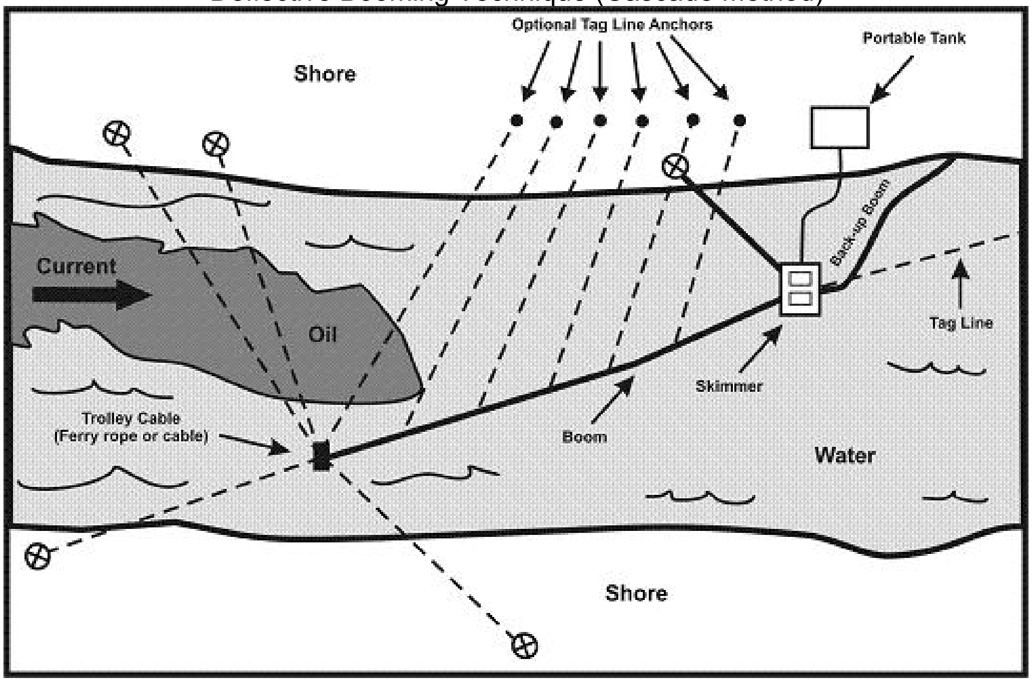


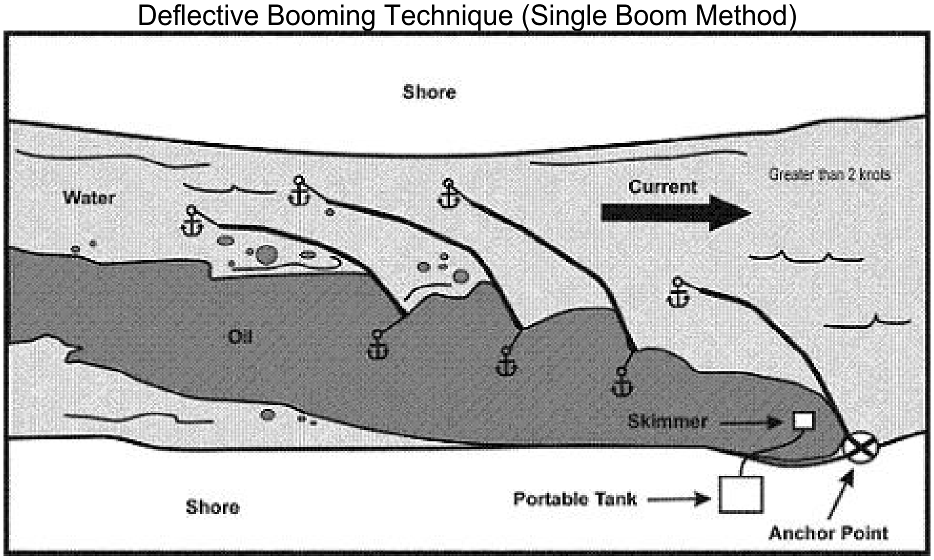
FIGURE H.4
Deflective Booming Technique (Cascade Method)



Cascade

Several booms are deployed in a cascade configuration when a single boom cannot be used because of fast current or because it is necessary to leave openings in the boom for vessel traffic, etc. This configuration can be used in strong currents where it may be impossible to effectively deploy one continuous section of boom. Shorter sections of boom used in a cascade deployment are easier to handle in faster water, thereby increasing efficiency. Additional equipment may be required to set and maintain this system as compared to the single boom configuration.

FIGURE H.2
Deflective Booming Technique (Single Boom Method)



H.3 CONTAINMENT BOOM

Objective & Strategy

Containment booming is a fixed-boom tactic. The objective is to corral spilled oil on the water, usually near the source, thus minimizing spreading and impacts to the environment. It is usually deployed with Shoreline Recovery.

This tactic can be deployed for oil spill migrating downstream or downhill to water or through water.

The general strategy is to:

1. Identify the location and trajectory of the spill or potential spill.
2. Select a deployment configuration that best supports the operating environment and available resources.
3. Mobilize to the location and deploy the tactic.
4. Place boom, using secure anchor system or mooring points.
5. Monitor the boom on an appropriate basis.
6. If oil collects in the boom, utilize an appropriate recovery tactic to remove it.

Tactic Description

Containment boom systems are comprised of the appropriate oil boom for containment and concentration, and anchoring systems to hold the boom in place.

Containment boom systems are not recommended for the fast water environment because of the high probability of fixed-boom failure and the difficulty of anchoring in this environment.

Containment boom systems are not recommended for the broken ice environment, because of the high probability of fixed-boom failure and loss due to ice encounters.

Anchoring systems are often deployed first and then the boom is set from one anchor to the adjacent anchor. Boom can be placed from shoreline to shoreline.

A second layer of containment boom, outside the primary boom, has two advantages:

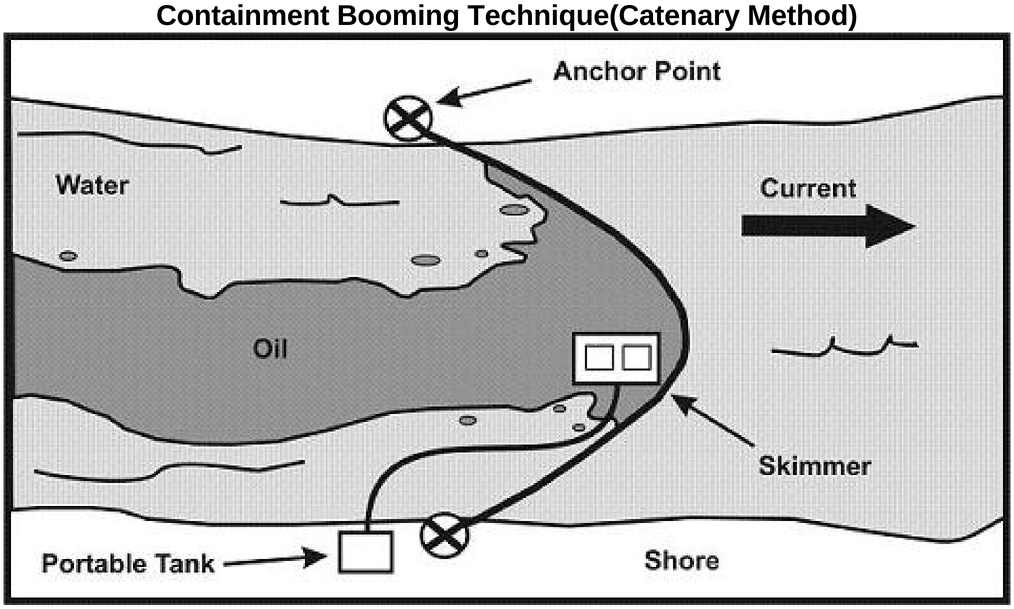
1. It breaks the sea chop and reduces its impact on the primary boom,
2. It may capture oil that has escaped if the primary boom fails.

Figure H.5 illustrates a simple containment booming technique.

Deployment Considerations

- It is often advisable to “line” the containment boom with sorbent materials (passive recovery) to recover the sheen and reduce decontamination costs.
- If the oil slick is moving, due to wind or current, consider containment at the source and ahead of the leading edge.
- If spill is moving in excess of 1 knot consider the Diversion Boom Tactic.
- Anchor systems must be selected based on the maximum stress that might be expected to occur on the boom array, considering stronger currents and winds than when the anchor is set.
- Site conditions will influence deployment configuration options.
- Combinations of Containment Boom and Diversion Boom tactics are often used together to optimize success.

FIGURE H.5
Containment Booming Technique(Catenary Method)



H.4 DIVERSION BOOM

Objective & Strategy

The objective is to redirect the spilled oil from one location or direction of travel to a specific site for recovery. For the purposes of maintaining consistent and clear terms, diversion is always associated with oil recovery, in contrast with the term deflection, which is used to describe the tactic where oil is redirected away from an area but not recovered.

Tactic Description

The Diversion Boom tactic is for water-born spills where there is some current, usually from 0.5 to 3.0 knots. The boom is placed at an optimum angle to the oil trajectory, using the movement of the current to carry oil along the boom to a recovery location. The angle is chosen to prevent oil from entraining beneath the boom skirt. Oil can be diverted to a shoreline or away from a shoreline or shoal waters. This tactic is always associated with a Shoreline Recovery. Figures H.6 and H.7 illustrate two diversionary booming techniques. These techniques are the Open Chevron and the Closed Chevron technique respectively.

FIGURE H.6
Open Chevron Booming Technique

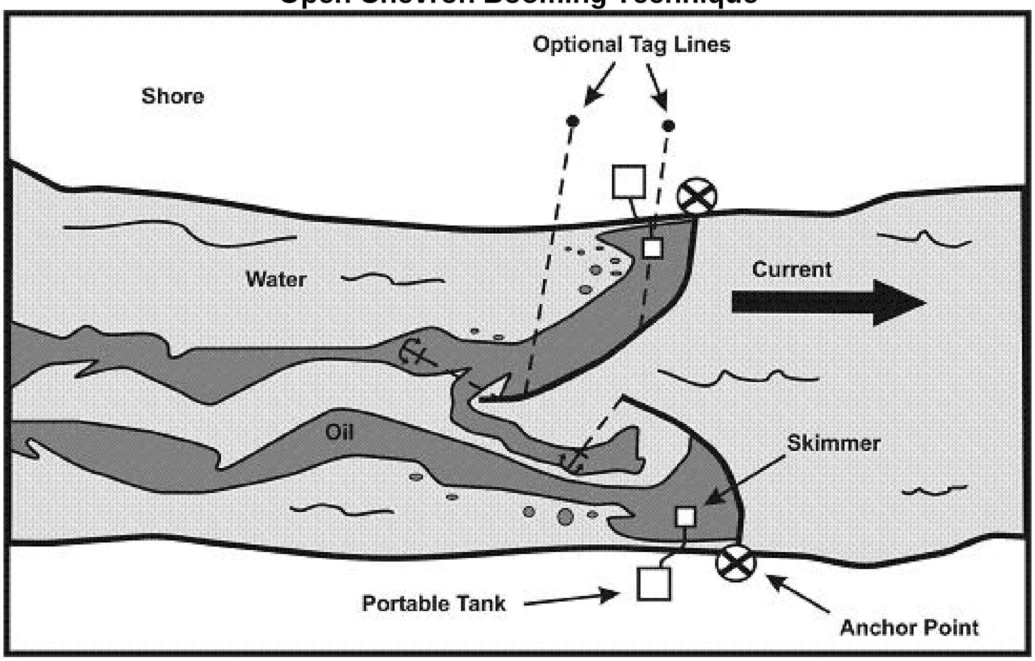
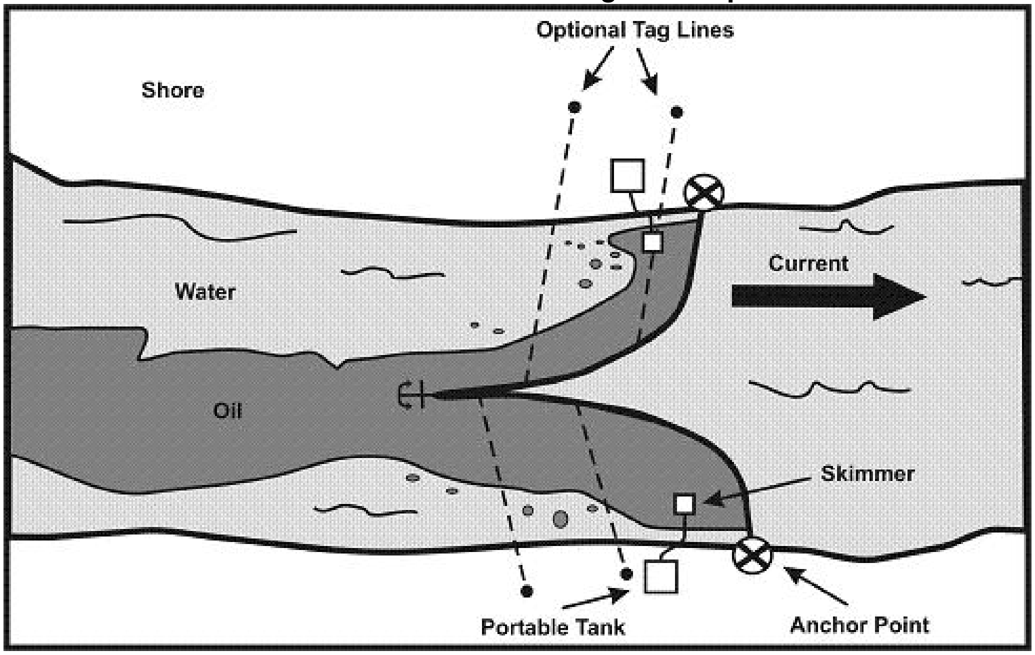


FIGURE H.7
Closed Chevron Booming Technique



ANCHOR SYSTEMS

Boom is secured in place using standard anchoring systems. Anchor sizes vary depending on the boom type and the operating environment.

Boom Angle

Select the appropriate boom angle to keep oil from entraining under the boom. Note that the angle relative to the current decreases rapidly as the current increases. Where currents exceed 3 knots the boom must be almost parallel to the current to prevent entrainment. In currents exceeding 3 knots, a cascade of boom arrays may be used; the first boom array will slow the velocity of the slick allowing subsequent arrays to deflect the oil.

Single Boom

A basic diversion technique is to divert oil from a current to a recovery site along a shoreline. The recovery site is chosen where there is minimal current and a suitable recovery system can be deployed. The boom is then anchored at the site and deployed at an optimum angle to the current and secured/anchored to divert the oil to the shoreline for recovery.

H.5 SHORELINE RECOVERY

Objective & Strategy

The objective is to remove spilled oil that has been diverted to a designated recovery site accessible from the shore.

Shoreline Recovery is usually deployed as part of another tactic, such as Diversion Boom strategy. When deployed in conjunction with another tactic, fewer personnel may be required.

The general strategy is to:

1. Identify the primary recovery site.
2. Assess site conditions and access routes.
3. Determine the appropriate recovery and storage systems based on oil type, access, and deployment restrictions.
4. Mobilize and deploy equipment to recover and temporarily store the oil from the recovery site.
5. Take precautions to minimize contamination of the shoreline at the collection site.
6. Man and monitor the system as appropriate.
7. Store and transfer recovered oil and oily water according to an approved waste management plan.

Tactic Description

Shoreline recovery systems can be deployed from land access routes (beaches, all-terrain vehicles), or water access. Access to the recovery site and the oil type will influence/dictate the options of equipment to be used.

SKIMMING SYSTEMS

Shoreline recovery requires at least one portable skimming system to remove spilled oil. The typical portable skimming system includes:

- Skimmer with pump and power pack
- Hose (suction and discharge with fittings)
- Oil transfer and decanting pump(s)
- Repair kit (tools and extra parts)

There are many models of skimmers to choose from, but they all fall into three types:

- **Weir skimmers** draw liquid from the surface by creating a sump in the water into which oil and water pour. The captured liquid is pumped from the sump to storage. Weir skimmers can recover oil at high rates, but they can also recover more water than oil, especially when the oil is in thin layers on the surface of the water. This creates the need to separate the water from the oil and decant it back into the environment. Otherwise, the recovered water takes available storage volume. Weir skimmers are best employed where oil has been concentrated into thick pools or where there are very large volumes of oil and recovered liquid storage capacity.
- **Oleophilic skimmers** pick up oil that adheres to a collection surface, leaving most of the water behind. The oil is then scraped from the collection surface and pumped to a storage device. Oleophilic skimmers do not recover oil as fast as weir skimmers, but they have the advantage of recovering very little water. Oleophilic skimmers may be used where oil is very thin on the surface. Oleophilic skimmers are a good choice where liquid storage capacity is limited.
- **Suction skimmers** use a vacuum to lift oil from the surface of the water. These skimmers require a vacuum pump or air conveyor system. Like weir skimmers, suction skimmers may also collect large amounts of water if not properly operated. Most suction skimmers are truck mounted and work best at sites with road access.

Primary Oil Storage Devices

Primary oil storage devices for shoreline recovery can be portable tanks, bladders, or truck-mounted tanks on the shoreline. If access is not restricted, larger systems can be used and deployed by heavy lifting equipment. If the site is accessible by road, vacuum trucks may be used for oil recovery, storage, and transport.

Recovery Location

Selection of a shoreline recovery location is critical to the success of this tactic. A recovery site should be in calm water with minimal currents. The site must have enough level ground to set up and operate a power pack and portable tanks. Sites with road access are preferred, but if not available, the site must have some other suitable access. Shelter, food and water for the response crew must also be considered in selecting a site.

H.6 ICE OPERATIONS

Objective & Strategy

Much like that of diversion booming, the objective is to redirect the spilled oil from one location or direction of travel to a specific site for recovery. With a layer of ice preventing the use of booming equipment, other response strategies must be employed.

Tactic Description

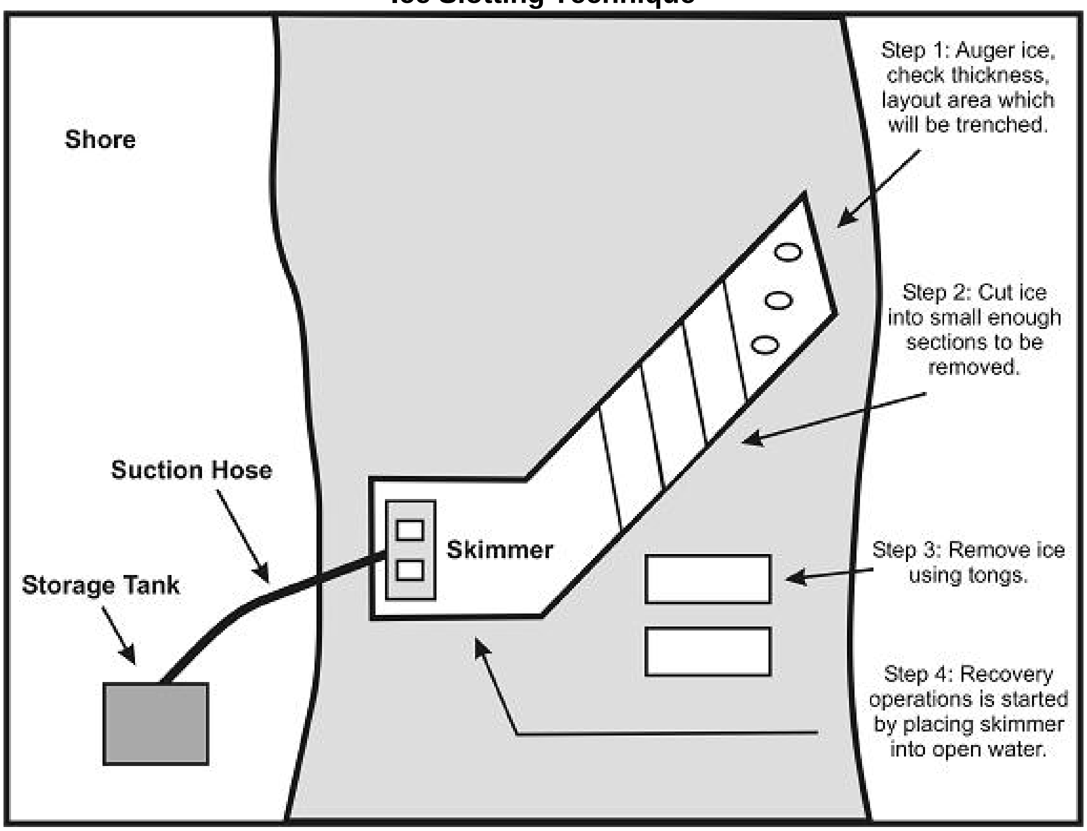
ICE SLOTTING

Ice slotting (Figure H.8) may be used in cases where the ice is thick enough to support the response equipment and personnel. Consideration for the weakening and cracking of the ice must be taken when conducting ice slotting operations.

Slotting Angle

The slot should be angled at approximately 30 degrees to the river's edge. The slotting needs to be wide enough to place a skimming system into the water to recover the oil. The lead end of the slot should have a slight curve which parallels the river current to allow the current to push the oil towards the recovery area.

FIGURE H.8
Ice Slotting Technique



DEFLECTION BOARDS

In place of using booming equipment it may be possible to use flat boards, such as plywood, to divert the oil under the ice into a recovery area, which has been cut out. To use this form of diversion, the depth of the water under the ice and the speed of the current ice must be considered. The angle in which the boards are placed is derived much like that of deflection booming. In any current above 3 knots, a series of cascading boards should be considered. Also, the depth of the water must be considered. The stronger the current the deeper the boards must be placed to prevent entrainment. If the water is not deep enough to place the boards to prevent entrainment, ice slotting methods may be required. Figure H.9 illustrates the overall method of using deflective boards. Figure H.10 illustrates a close up of the deflective board response method.

FIGURE H.9
Deflective Boards Recovery Strategy

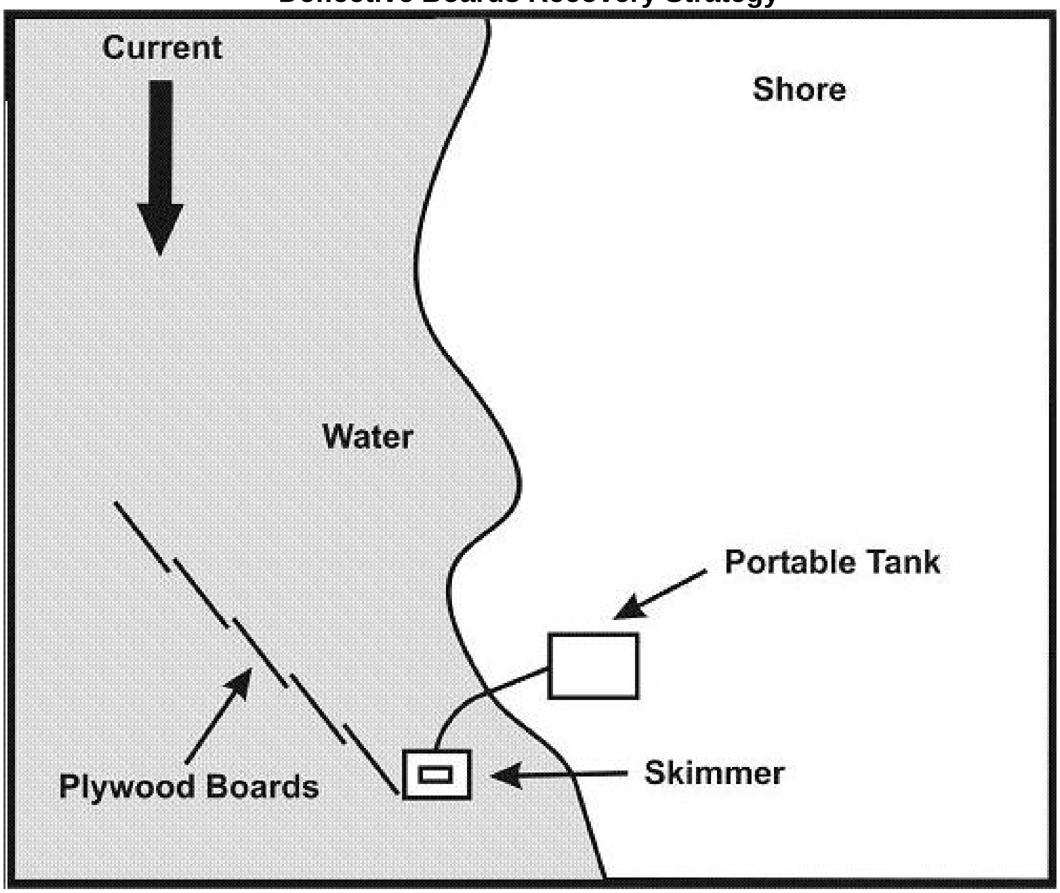
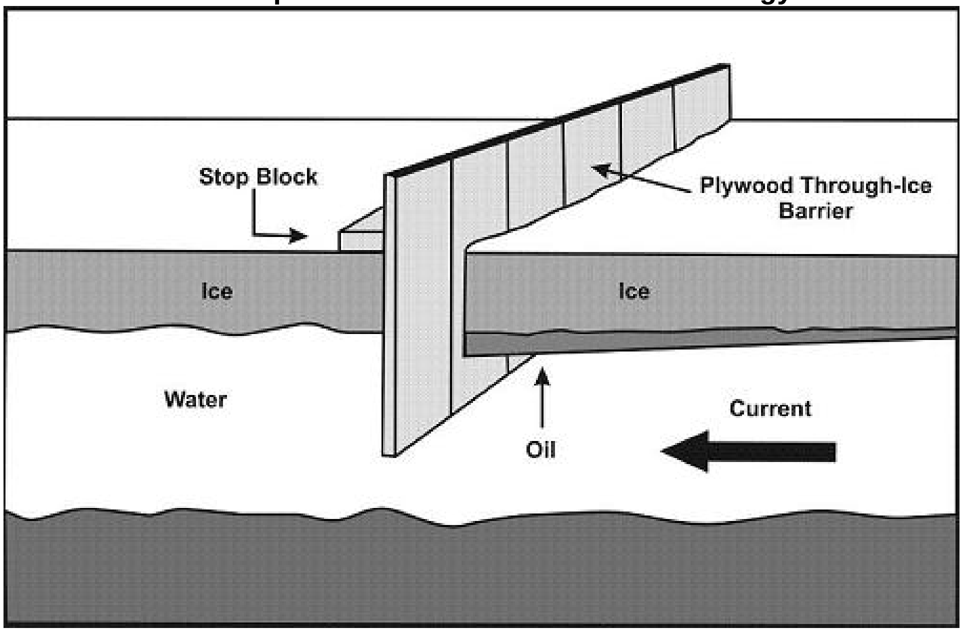


FIGURE H.10
Close up view of the Deflective Board Srategy



APPENDIX I

MEDIA RELATIONS

I.1 Introduction

I.2 Dealing with Agencies, the Media and the Public

I.3 The Public Wants to Know

I.4 Target Audiences

I.5 Media Statements

I.6 Holding Statements

I.7 Media Advisories

I.8 Press Releases

I.9 News Conferences

I.10 Media Center

I.11 Post Incident Public Affairs

Figure I.1 Media Holding Statement

Figure I.2 Procedures and Considerations

Figure I.3 Layout for Press Conference

I.1 INTRODUCTION

Goals:

- Provide a coordinated communications response to ensure appropriate information is disseminated in an accurate and timely manner
- Communicate concisely the nature of the emergency, the steps being taken to address it and the effectiveness of those measures
- Control the communications environment as much as possible in an effort to protect the reputation of the Company

I.2 DEALING WITH AGENCIES, THE MEDIA AND THE PUBLIC

<u>Only official Company spokespersons are authorized to release incident information.</u> Receptionists and others may receive calls or be required to take messages. They should take the following information from each caller and give reporters the media line number: 1-800-608-7859.

- Name
- Media outlet-publication, TV/radio station and market they are serving
- Time of call
- Nature of request
- Phone and fax number(s)
- E-mail address

Deadline

The Company's goal is to prioritize and return media calls as soon as possible knowing that a reporter working on a breaking news story will attempt to fill the information void. The Company will want to be the ones to fill that void. It may not be possible to return all phone calls. Reporters might also be directed to other sources such as our website or instructed to call back at a specific time.

Objectives During Emergencies

- Provide as much relevant information as possible about how the Company is responding to the incident to build and maintain stakeholder and media trust
- Present an accurate, compassionate and up-to-date account of the crisis
- Balance the resolution of the technical emergency while managing human issues

- Maintain an accurate record of what is happening and actions being taken to respond to the crisis
- Present a positive and accurate perception of the Company
- Identify factual and interpretative errors and develop a strategy to respond
- Bring positive developments to the forefront quickly
- Prepare spokespersons to deliver the message
- Communicate the policies, attitudes and actions of the Company to convey that the organization has a plan in place to deal with the crisis
- Maintain credibility in the communication process by ensuring consistency in the message and the information being disseminated

I.3 THE PUBLIC WANTS TO KNOW

- Does the Company care?
- Does the Company have a plan in place?
- Is Company's priority to keep people and the environment safe?
- Is the Company doing everything possible to address the situation?

It is the job of the Public Information Officer or Company spokesperson to convey to the audiences and to assist Executive Management to convey that the answer to all these questions is a resounding **"Absolutely."**

I.4 TARGET AUDIENCES

Each emergency is unique and requires careful judgment to determine which audiences to target and which audiences have priority. Given the media's pervasive and instant capability to relay information and impact public opinion, it is clearly the key audience for Company's communications strategy and actions.

The following list indicates the audiences who should be considered when developing the key messages that will be communicated by the media.

Internal

- Employees and Employees' families
- Affiliated Companies/Businesses

External (Local, Regional, National, and International)

- Media
- Environmental Community
- Impacted Communities/General Public
- Contractors
- Site Investigators
- Industry Associations
- Elected Officials
- Vendors
- Shareholders
- Securities Exchanges
- Analysts
- Neighboring Businesses
- Regulators
- Governmental Entities
- General Public
- Bankers

When responding, always prepare for the worst possible scenario. It is important to recognize that no two incidents will be the same. The Company must remain flexible and adapt a response to meet the unique characteristics of the current situation.

I.5 MEDIA STATEMENTS

Three types of media statements for communicating information can be generated:

1. **Holding Statement**
2. Media Advisory
3. Press Release

I.6 HOLDING STATEMENTS

A holding statement should be prepared **immediately** to reduce media frustration and quickly establish a channel of communication. Immediate action will help to fill the information void with accurate details. The holding statement is the response to any inquiries made to the Company prior to a press release being issued. The holding statement should contain the following:

- Nature of incident
- Time and date of incident
- Location of incident
- Impact of the incident (e.g., any people involved? Injuries? Damage?)
- Report fatalities only if cleared by the Public Information Officer and Legal and only after the family has been notified.

- It is OK to say "no information is available" on any given topic if the information is not yet known
- Status of emergency crews – en route or on the scene
- When to expect an update

Not Release

- Fatalities unless cleared by the Public Information Officer and Legal Officer.
- Names of injured or deceased.
- Nature of injuries.
- Any Company communication or Company record.
- Any opinion as to the cause of the incident.
- Hazardous Materials involved.

Holding Statement Template

DATE:(YY/MM/DD) ____________________ TIME: ____________________☐ AM

☐ PM

MY NAME IS: ________________________ MY JOB TITLE IS: ______________

______

This is the information I can give you so far:

At *(time)* ______________ ☐ AM ☐ PM, on ____________________________

(date). *a(n) (fire, explosion, gas release, spill – specify)* occurred at (Company's name) ____________'s ______________________location, located __________ ______ kilometers *(east/west/north/south)* ____________________ of *(nearest town or city)* ____.

Presently, *(number of personnel)* _____________________ Company employees or Contract personnel, are (O.K., not injured, are being treated for injuries, etc. – specify).

____

______.

Note: The names and condition of the injured can only be released after they have been released by the proper authorities.

The *(plant / pipeline / office, etc. – specify)* ________________________________

______

_____________________________________ has been shut down and isolated.

Company staff have activated the Emergency Response Plan and are directing emergency response procedures to protect the Public, our employees and the environment.

The cause of the (fire, explosion, gas release, spill, etc. – specify) _____is not yet known and no estimate of damage is available. Further information will be released as it becomes available.

I.7 MEDIA ADVISORIES

A media advisory should be issued immediately after the holding statement has been finalized. Essentially, the holding statement is the media advisory; the only difference is that the media advisory is issued externally. The Public Information Officer has overall responsibility for ensuring this advisory is issued externally.

I.8 PRESS RELEASES

Press releases will be prepared and issued by External Communications, working with the Public Information Officer. If deemed appropriate, a release would be issued as soon possible following the distribution of a holding statement and/or a media advisory. Subsequent news releases should be issued as new information becomes available.

They should include the following details:

- Time, date and location of the release
- Spokesperson name and contact number
- Summary of holding statement information
- Current status of the incident
- Status of the investigation
- Concern for public health and safety, safety of responders and environmental impact
- Involvement of authorities and outside responders
- Time of next update or news conference, if warranted
- Refer to media specific web site, if available

Consider using other tools for the media when appropriate:

- Fact Sheets
- Backgrounders
- Visuals (e.g., maps, etc.)

I.9 NEWS CONFERENCES

A number of factors will determine the need for a news conference, including:

- The level of media interest the story has generated;
- The need to make technical experts available to journalists to explain complex details such as nature of a substance released, environmental impact, public health threats, etc.;
- A significant change in the status of the situation; or
- The investigation is complete and the results are ready for release.

Strategy

- If possible, hold press conferences at a location removed from Company property
- Give media some type of guideline for the timing (i.e., there will NOT be a briefing before a given time)
- Determine who will open the news conference and what the ground rules will be (e.g., time limits, etc.)
- Determine who will make statements and whether there will be a question period
- It is appropriate to outline the ground rules for those attending the press conference before the conference formally begins
- Prepare opening statement and review potential questions with key spokesperson. Any new information released during the press conference should be cleared with the Public Information Officer (if PIO is not a member of the External Communications team at this point in the cycle, all information will be reviewed and approved by the External Communications team).

Note: Media should never be left unattended on Company property. If necessary, arrange for media escorts. Also, arrange for any Security personnel or law enforcement as deemed necessary.

News Conference Checklist

- Check with Public Information Officer (and spokesperson) to select the best time for the conference. (Arrange for Technical Advisor to be present.) Keep in mind demands of the news cycle. Late morning and early afternoon are typically best for electronic media. Late afternoon will better serve the print media and might facilitate a "live shot" by electronic media
- Stage the conference at a local hotel or hall. Keep in mind accommodations for cameras, reporters, technical staff, parking for live or satellite trucks and cable

run for television crews

- Distribute media advisory of time and location, including directions and parking information
- Compile list of media who have indicated they will attend. If possible, determine if there is a particular area of interest
- Invite outside officials, as appropriate
- Compile background information that may serve as a resource for reporters

I.10 MEDIA CENTER

The need to establish a media center will be determined by the Public Information Officer (only if the PIO is a member of the External Communications team). The level of media interest in the story will be a key factor in determining if a media center is needed.

If a media center is established appropriate news organizations will be notified by way of fax and e-mail distribution. Access to the media center should be confined only to credentialed "working press." Arrange for Security personnel or law enforcement as deemed necessary.

Media Center Checklist

- Work Tables and Chairs
- External telephone lines (might not be possible if center is located in the field)
- Radio
- Television/VCR
- Podium with microphone and audio distribution (mult box)
- Extension cords
- Blank audio and videotapes
- Copier/Fax machine
- Laptop computer and printer
- If the center is in the field, you might need a generator to provide power
- Car battery adapter for PC
- Cell phone car adapter
- Power generator (if remote location)

Supplies

- The Company letterhead
- Pens and pencils
- Background material
- Past press releases
- Fact sheets
- Maps
- Refreshments

I.11 POST INCIDENT PUBLIC AFFAIRS

Once the incident is concluded, the Public Information Officer should prepare one final press release, possibly in the form of a chronology, to describe the incident and the subsequent response. The media may also be looking for any follow-up information as to the cause of the incident, people involved, long term effects on the company, costs associated with the incident, etc. These requests will have to be considered on a case-by-case basis. All releases should be reviewed by the Legal Officer and approved by the Incident Commander (or a higher authority) prior to being released.

FIGURE I.1

MEDIA HOLDING STATEMENT

The following statement is an example of how to address reporters when you need more time to gather facts before speaking to them.

Open:

Hi___________. I'm _______________, and I am the spokesperson for ________ _______.

I am in the process of gathering more facts for you regarding _________________ _______.

I know you want accurate information, so I will need______(how much time) to get these facts confirmed.

Basic Facts: (If confirmed)

I can tell you...Who: (Background -- optional at this point)

When:

Where:

What:

Priority:
"A preliminary investigation into the _______has already begun. That is all the information I have for you at this time.

Holding Statement:

We could meet back here (or via phone) at _______ o'clock.

Meantime, let me get your business card, cell phone, etc...

Questions & Offers: (Optional)

What is your deadline?

I can give you our web address for more information on our Company.

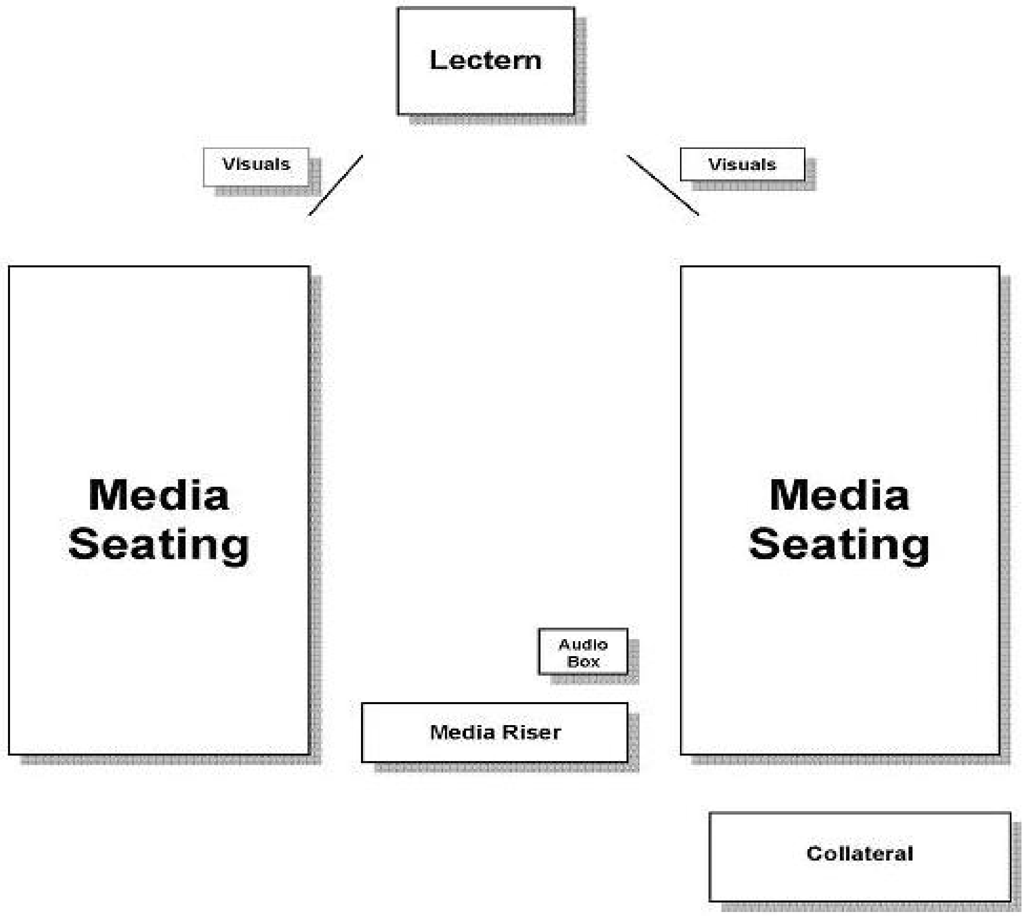
I can provide our public affairs contact and number (or provide your business card):

FIGURE I.2

PROCEDURES AND CONSIDERATIONS	
Identify Your Audience • Employees • Clients • Local Media • National / International Media • Special Interest Groups • Stakeholders • Agencies / Public Officials • Industry Associations • Suppliers • Competitors	Identify Key Message(s) • People / Safety • Environment • Property • Potential Impacts of Incident • Basis for Company's Position / Action(s) • Business Continuity
Prepare Official Company Statement • Facility / Personnel Fact Sheet(s) • Issues Applicable to Identified Audience • No Speculation of Any Kind • Confidentiality Issues • Express Care and Concern • Do Not Accept Liability or Offer Compensation • Include Photos / Video • Must be Reviewed and Approved by Incident Commander and Legal Officer	Identify Communications Methods • Media Advisory • Toll-free Telephone • Web-Site • Press Release • Telephone Interviews • Personal Interviews • Press Briefings (Alone or Jointly?) • Holding Statement
Determine Support Requirements • Personnel • Equipment • Physical Space • Photos, Videos, Charts, Graphs, Maps	Determine Frequency of Communications • Times per Shift • Daily • Corporate IC's Discretion • Maintain Awareness of Audience Deadlines / Schedules • Obtain Corporate IC's Approval
Identify Spokesperson(s) if Applicable • Ensure Understanding of Incident • Ensure Familiarity With Expected Audience • Ensure Understanding of Confidentiality / Privacy Issues • Brief on Anticipated Questions and Answers • Ensure Equal Treatment of All Audience Members • Establish Conference Duration • Do Not Underestimate the Impact of Television Reports • Coordinate Responses if Joint Conference • Be Positive • Be-Supportive of Agencies, Investigators, and Responders	Monitor Audience Reaction to and Perception of Message • Hostile Press • Special Interest Groups • Public Outrage or Increased Demands • Attempts to Place Blame • Distribution of Disinformation
Revise/Update Message • Answer Earlier Questions • Provide Additional Facts • Address Previous and New Concerns • Adjust Position as suitable or Necessary but Do Not Appear to "Flip-Flop" or Waiver • Maintain Awareness of Audience Deadlines / Schedules • Must be Reviewed and Approved by Incident Commander and Legal Officer	

FIGURE I.3

LAYOUT FOR PRESS CONFERENCE



REGULATORY CROSS REFERENCE

DOT/PHMSA 49 CFR Part 194 Cross Reference
ONSHORE PIPELINE REGULATION, 1999 SOR/99-294
Annex A to Can/CSA-Z-731-03

DOT/PHMSA 49 CFR PART 194		
§ 194.105	**BRIEF DESCRIPTION**	**LOCATION in PLAN**
(a)	... determine the worst case discharge ... provide methodology, including calculations, used to arrive at the volume.	App B
(b)	The worst case discharge is the largest volume, in barrels, of the following:	-----
(b)(1)	... maximum release time in hours, plus the maximum shutdown response time in hours, multiplied by the maximum flow rate expressed in barrels per hour, plus the largest line drainage volume after shutdown of the line section (s) ...; or	App B
(b)(2)	The largest foreseeable discharge for the line section(s) within a response zone, expressed in barrels, based on the maximum historic discharge, if one exists, adjusted for any subsequent corrective or preventative action taken; or	App B
(b)(3)	If the response zone contains one or more breakout tanks, the capacity of the single largest tank or battery of tanks within a single secondary containment system, adjusted for the capacity or size of the secondary containment system, expressed in barrels.	App B
(b)(4)	Operators may claim prevention credits for breakout tank secondary containment and other specific spill prevention measures as follows:…	App B
§ 194.107	**BRIEF DESCRIPTION**	**LOCATION in PLAN**
(a)	Each response plan must plan for resources for responding, to the maximum extent practicable, to a worst case discharge, and to a substantial threat of such a discharge.	App A
(b)	An operator must certify in the plan … reviewed NCP and each applicable ACP…	Foreword
(b)(1)	As a minimum to be consistent with the NCP as a facility response plan must:	-----
(b)(1)(i)	Demonstrate an operator's clear understanding of the function of the Federal response structure…	§ 4.0
(b)(1)(ii)	Establish provisions to ensure the protection of safety at the response site; and	§ 4.0 (Command), § 5.0
(b)(1)(iii)	Identify the procedures to obtain any required Federal and State permissions for using alternative response strategies such as in-situ burning and dispersants…	§ 6.7, App. E
(b)(2)	As a minimum, to be consistent with the applicable ACP the plan must:	-----
(b)(2)(i)	Address the removal of a worst case discharge and the mitigation or prevention of a substantial threat of a worst case discharge;	§ 3, App B
(b)(2)(ii)	Identify environmentally and economically sensitive areas;	§ 6.0
(b)(2)(iii)	Describe the responsibilities of the operator and of Federal, State and local agencies in removing a discharge and in mitigating or preventing a substantial threat of a discharge; and	§4.0
(b)(2)(iv)	Establish the procedures for obtaining an expedited decision on use of dispersants or other chemicals.	§ 6.8
(c)	Each response plan must include:	----
(c)(1)	A core plan consisting of …	----
(c)(1)(i)	An information summary as required in § 194.113,	Fig 1.1
(c)(1)(ii)	Immediate notification procedures,	§ 2.0

(c)(1)(iii)	Spill detection and mitigation procedures,	§ 3.0
(c)(1)(iv)	The name, address, and telephone number of the oil spill response organization, if appropriate,	Fig 2.5, App A
(c)(1)(v)	Response activities and response resources,	§ 3.0, App A
(c)(1)(vi)	Names and telephone numbers of Federal, State, and local agencies which the operator expects to have pollution control responsibilities or support,	Fig 2.5
(c)(1)(vii)	Training procedures,	App D
§ 194.107	**BRIEF DESCRIPTION**	**LOCATION in PLAN**
(c)(1)(viii)	Equipment testing,	App D.2
(c)(1)(ix)	Drill program - an operator will satisfy the requirement for a drill program by following the National Preparedness for Response Exercise Program (PREP) guidelines. An operator choosing not to follow PREP guidelines must have a drill program that is equivalent to PREP. The operator must describe the drill program in the response plan and OPS will determine if the program is equivalent to PREP.	App D.2
(c)(1)(x)	Plan review and update procedures;	§ 1.4
(c)(2)	An appendix for each response zone that includes the information required in paragraph (c)(1)(i)-(ix) of this section and the worst case discharge calculations that are specific to that response zone. An operator submitting a response plan for a single response zone does not need to have a core plan and a response zone appendix. The operator of a single response zone onshore pipeline shall have a single summary in the plan that contains the required information in § 194.113.7; and.	Annexes
(c)(3)	A description of the operator's response management system including the functional areas of finance, logistics, operations, planning, and command. The plan must demonstrate that the operator's response management system uses common terminology and has a manageable span of control, a clearly defined chain of command, and sufficient trained personnel to fill each position.	§ 4.0
§ 194.111	**BRIEF DESCRIPTION**	**LOCATION in PLAN**
(a)	Each operator shall maintain relevant portions of its response plan at the operator's headquarters and at other locations from which response activities may be conducted, for example, in field offices, supervisor's vehicles, or spill response trailers.	Foreword Distribution List
(b)	Each operator shall provide a copy of its response plan to each qualified individual	Foreword Distribution List
§ 194.113	**BRIEF DESCRIPTION**	**LOCATION in PLAN**
(a)	The information summary for the core plan, required by § 194.107, must include:	----
(a)(1)	The name and address of the operator.	Fig 1.1
(a)(2)	For each response zone which contains one or more line sections that meet the criteria for determining significant and substantial harm as described in § 194.103, a listing and description of the response zones, including county(s) and state(s).	Fig 1.1, Response Zone Annexes
(b)	The information summary for the response zone appendix, required in § 194.107, must include:	----
(b)(1)	The information summary for the core plan.	Fig 1.1
(b)(2)	The names or titles and 24-hour telephone numbers of the qualified individual (s) and at least one alternate qualified individual(s);	Fig 1.1, Fig 2.2

(b)(3)	The description of the response zone, including county(s) and state(s), for those zones in which a worst case discharge could cause substantial harm to the environment.	Fig 1.1, Response Zone Annexes
(b)(4)	A list of line sections for each pipeline contained in the response zone, identified by milepost or survey station number, or other operator designation.	Fig 1.1
(b)(5)	The basis for the operator's determination of significant and substantial harm.	Foreword
(b)(6)	The type of oil and volume of the worst case discharge.	App B
§ 194.115	**BRIEF DESCRIPTION**	**LOCATION in PLAN**
(a)	Each operator shall identify and ensure, by contract or other approved means, the resources necessary to remove, to the maximum extent practicable, a worst case discharge and to mitigate or prevent a substantial threat of a worst case discharge.	App A
(b)	An operator shall identify in the response plan the response resources which are available to respond within the time specified, after discovery of a worst case discharge, or to mitigate the substantial threat of such a discharge.	App A
§ 194.117	**BRIEF DESCRIPTION**	**LOCATION in PLAN**
(a)	Each operator shall conduct training to ensure that:	-----
(a)(1)	All personnel know --	-----
(a)(1)(I)	Their responsibilities under the response plan	
(a)(1)(ii)	The name and address of, and the procedure for contacting, the operator on a 24-hour basis	§ 4.0
(a)(1)(iii)	The name of, and procedures for contacting, the qualified individual on a 24-hour basis	§ 2.0, Fig 2.2
(a)(2)	Reporting personnel know --	-----
(a)(2)(I)	The content of the information summary of the response plan.	Fig 1.1
(a)(2)(ii)	The toll-free telephone number of the National Response Center	Fig 2.5
(a)(2)(iii)	The notification process	§ 2.0, Fig 2.5
(a)(3)	Personnel engaged in response activities know --	-----
(a)(3)(I)	The characteristics and hazards of the oil discharged	Fig 3.2, App G
a)(3)(ii)	The conditions that are likely to worsen emergencies, including the consequences of facility malfunctions or failures, and the appropriate corrective actions.	§ 3.0
(a)(3)(iii)	The steps necessary to control any accidental discharge of oil and to minimize the potential for fire, explosion, toxicity, or environmental damage	§ 3.0
(a)(3)(iv)	The proper firefighting procedures and use of equipment, fire suits, and breathing apparatus	§ 3.0
(b)	Each operator shall maintain a training record for each individual that has been trained as required by this section. These records must be maintained in the following manner as long as the individual is assigned duties under the response plan	App D.1
(b)(1)	Records for operator personnel must be maintained at the operator's headquarters	App D.1
(b)(2)	Records for personnel engaged in response, other than operator personnel, shall be maintained as determined by the operator.	App D.1
(b)(3)	Nothing in this section relieves an operator from the responsibility to ensure that all response personnel are trained to meet the OSHA standards for emergency response operations in 29 CFR 1910.120 ...	App D.1

§ 194.119	BRIEF DESCRIPTION	LOCATION in PLAN
(a)	Each owner shall submit two copies...	Distribution
(b)	...PHMSA will notify the operator of any alleged deficiencies...	-----
(c)	The operator...may petition PHMSA for reconsideration within 30 days...	-----
(d)	...PHMSA will approve the Response Plan...	-----
(e)	...The operator may submit a certification to PHMSA...that the operator has obtained, through contract or other approved means, the necessary private personnel and equipment to record, to the maximum extent practicable, to a worst case discharge...	Foreword (Operator's Statement)
(f)	...PHMSA may require an operator to provide a copy of the response plan to the OSC...	-----
§ 194.121	**BRIEF DESCRIPTION**	**LOCATION in PLAN**
(a)	Each operator shall update its response plan to address new or different operating conditions or information. In addition, each operator shall review its response plan in full at least every 5 years from the date of the last submission or the last approval as follows:	§ 1.4
(a)(1)	For substantial harm plans, an operator shall resubmit every 5 years from the last approval date.	§ 1.4
(a)(2)	For significant and substantial harm plans, an operator shall resubmit every 5 years form the last approval date.	§ 1.4
(b)	If a new or different operating condition or information would substantially affect the implementation of a response plan, the operator must immediately modify its response plan to address such a change…	§ 1.4
(b)(1)	An extension of the existing pipeline or construction of a new pipeline in a response zone not covered by the previously approved plan;	§ 1.4
(b)(2)	Relocation or replacement of the pipeline in a way that substantially affects the information included in the response plan, such as a change to the worst case discharge volume;	§ 1.4
(b)(3)	The type of oil transported, if the type affects the required response resources, such as a change from crude oil to gasoline;	§ 1.4
(b)(4)	The name of the spill removal organization;	§ 1.4
(b)(5)	Emergency response procedures;	§ 1.4
(b)(6)	The qualified individual;	§ 1.4
(b)(7)	A change in the NCP or an ACP that has significant impact on the equipment appropriate for response activities; and	§ 1.4
(b)(8)	Any other information relating to circumstances that may affect full implementation of the plan.	§ 1.4
(c)	If PHMSA determines that a change to a response plan does not meet the requirements of this part, PHMSA will notify the operator of any alleged deficiencies, and provide operator…opportunity to correct deficiencies.	-----
(d)	An operator who disagrees with a determination that proposed revisions to a plan are deficient may petition PHMSA for reconsideration, within 30 days from the date of receipt of PHMSA's notice…	-----

SOR/99-294		
S 32-34	**BRIEF DESCRIPTION**	**LOCATION in PLAN**
-----	Directions for Use of Manual;	§ 1.0
-----	Emergency Preparedness and Response Policy;	§ 3.0
-----	Description of Initial Responses to Incident Calls;	§ 3.1
-----	Management of Threat Information;	§ 3.1
-----	Definitions and Levels of Emergencies;	§ 3.1
-----	Corporate and Operational Chains of Command;	§ 4.0
-----	Internal and External Contact Lists;	Fig. 2.2, 2.5
-----	External Communication Information (e.g. media outlets);	
-----	Description of General and Site Specific Emergency Response Procedures;	§ 3.0
-----	Roles and Responsibilities (e.g. checklist of duties);	§ 4.0
-----	Site-Specific Emergency Information (e.g. control points);	
-----	Lists of Persons in Emergency Planning Zones (or on separate file);	Fig. 2.2
-----	Environmental or Other Areas Requiring Special Consideration or Protection;	§ 6.0
-----	Detailed Product Information (e.g. MSDS);	App. G
-----	Description and Location of Response Equipment;	App. A
-----	Internal and External Reporting Requirements;	§ 2.0
-----	Area Maps;	Fig. 1.2
-----	Training Requirements;	App. D
-----	Role of Government Departments;	§ 4.6
-----	Manual Updating Procedure and Schedule;	§ 1.4
-----	Forms and Records; and	App. F
-----	Manual Distribution List.	Foreword

ANNEX A TO CAN/CSA-Z731-03	
SAMPLE TABLE OF CONTENTS FOR AN EMERGENCY PREPAREDNESS MANUAL	
REFERENCE	**LOCATION**
1 Administration	-----
1.1 Emergency Preparedness Policy	Sec. 1.1
1.2 Purpose of This Manual	Sec. 1.2
1.3 Distribution of This Manual	Foreword, Sec. 1.3
1.4 Definitions	Glossary of Terms/Acronyms
2 Organization of Emergency Areas	Annexes
3 Roles ad Responsibilities	Sec. 4.0
4 Communications	App. A.6
5 Emergency Response	-----
5.1 Emergencies Caused by Human Activity	Fig. 3.1
5.2 Natural Disasters	Fig. 3.1
6 Emergency Resources	-----
6.1 Contact List	Fig 2.2, 2.5
6.2 Personnel/Equipment	App. A
7 Training	-----
7.1 Employees	App. D.1
7.2 Contractors	App. D.1
7.3 Training Drills	App. D.2
8 Checklists	App. F
8.1 Role Checklists	App. F
8.2 Equipment Checklists	App. F

GLOSSARY OF TERMS AND ACRONYMS

Glossary

Acronyms

GLOSSARY OF TERMS

This glossary contains definitions of terms that will be used frequently during the course of response operations.

Activate: The process of mobilizing personnel and/or equipment within the response organization to engage in response operations.

Activator: An individual in the response organization whose responsibilities include notifying other individuals or groups within the organization to mobilize personnel and/or equipment.

Adverse Weather: The weather conditions that will be considered when identifying response systems and equipment in a response plan for the applicable operating environment. Factors to consider include significant wave height, ice, temperature, weather - related visibility, and currents within the Captain of the Port (COTP) zone in which the systems or equipment are intended to function.

Agency Representative: Individual assigned to an incident from an agency who has been delegated full authority to make decisions on all matters affecting that agency's participation in response operations.

Area Committee: As defined by Sections 311(a)(18) and (j)(4) of CWA, as amended by OPA, means the entity appointed by the President consisting of members from Federal, State, and local agencies with responsibilities that include preparing an Area Contingency Plan for the area designated by the President. The Area Committee may include ex-officio (i.e., non-voting) members (e.g., industry and local interest groups).

Area Contingency Plan: As defined by Sections 311(a)(19) and (j)(4) of CWA, as amended by OPA, means the plan prepared by an Area Committee, that in conjunction with the NCP, shall address the removal of a discharge including a worst-case discharge and the mitigation or prevention of a substantial threat of such a discharge from a vessel, offshore facility, or onshore facility operating in or near an area designated by the President.

Average Most Probable Discharge : A discharge of the lesser of 50 barrels or 1% of the volume of the worst case discharge.

Barrel (bbl): Measure of space occupied by 42 U.S. gallons at 60 degrees Fahrenheit.

Bioremediation Agents: Means microbiological cultures, enzyme additives, or nutrient additives that are deliberately introduced into an oil discharge and that will significantly increase the rate of biodegradation to mitigate the effects of the discharge.

Boom: A piece of equipment or a strategy used to either contain free floating oil to a confined area or protect an uncontaminated area from intrusion by oil.

Booming Strategies: Strategic techniques which identify the location and quantity of boom required to protect certain areas. These techniques are generated by identifying a potential spill source and assuming certain conditions which would affect spill movement on water.

Bulk: Material that is stored or transported in a loose, unpackaged liquid, powder, or granular form capable of being conveyed by a pipe, bucket, chute, or belt system.

Chemical Agents: Means those elements, compounds, or mixtures that coagulate, disperse, dissolve, emulsify, foam, neutralize, precipitate, reduce, solubilize, oxidize, concentrate, congeal, entrap, fix, make the pollutant mass more rigid or viscous, or otherwise facilitate the mitigation of deleterious effects or the removal of the oil pollutant from the water. Chemical agents include biological additives, dispersants, sinking agents, miscellaneous oil spill control agents, and burning agents, but do not include solvents.

Clean-up Contractor: Persons contracted to undertake a response action to clean up a spill.

Cleanup: For the purposes of this document, cleanup refers to the removal and/or treatment of oil, hazardous substances, and/or the waste or contaminated materials generated by the incident. Cleanup includes restoration of the site and its natural resources.

Coastal Waters: For the purpose of classifying the size of discharges, means the waters of the coastal zone except for the Great Lakes and specified ports and harbors on inland rivers.

Coastal Zone: As defined for the purpose of the NCP, means all United States waters subject to the tide, United States waters of the Great Lakes, specified ports and harbors on inland rivers, waters of the contiguous zone, other waters of the high seas subject to the NCP, and the land surface or land substrata, ground waters, and ambient air proximal to those waters. The term coastal zone delineates an area of federal responsibility for response action. Precise boundaries are determined by EPA/USCG agreements and identified in federal regional contingency plans.

Coast Guard District Response Group (DRG): As provided for by CWA sections 311(a)(20) and (j)(3), means the entity established by the Secretary of the department in which the USCG is operating within each USCG district and shall consist of: the combined USCG personnel and equipment, including firefighting equipment, of each port within the district; additional prepositioned response equipment; and a district response advisory team.

Command: The act of controlling manpower and equipment resources by virtue of explicit or delegated authority.

Command Post: A site located at a safe distance from the spill site where response decisions are made, equipment and manpower deployed, and communications handled. The Incident Commander and the On-Scene Coordinators may direct the on-scene response from this location.

Communications Equipment: Equipment that will be utilized during response operations to maintain communication between the Company employees, contractors, Federal/State/Local agencies. (Radio/ telephone equipment and links)

Containment Boom: A flotation/freeboard device, made with a skirt/curtain, longitudinal strength member, and ballast unit/weight designed to entrap and contain the product for recovery.

Contingency Plan: A document used by (1) federal, state, and local agencies to guide their planning and response procedures regarding spills of oil, hazardous substances, or other emergencies; (2) a document used by industry as a response plan to spills of oil, hazardous substances, or other emergencies occurring upon their vessels or at their facilities.

Contract or Other Approved Means: For OPA 90, a written contract with a response contractor; certification by the facility owner or operator that personnel and equipment are owned, operated, or under the direct control of the facility, and available within the stipulated times; active membership in a local or regional oil spill removal organization; and/or the facility's own equipment.

Critical Areas to Monitor: Areas which if impacted by spilled oil may result in threats to public safety or health.

Cultural Resources: Current, historic, prehistoric and archaeological resources which include deposits, structures, ruins, sites, buildings, graves, artifacts, fossils, or other objects of antiquity which provide information pertaining to the historical or prehistorical culture of people in the state as well as to the natural history of the state.

Damage Assessment: The process of determining and measuring damages and injury to the human environment and natural resources, including cultural resources. Damages include differences between the conditions and use of natural resources and the human environment that would have occurred without the incident, and the conditions and use that ensued following the incident. Damage assessment includes planning for restoration and determining the costs of restoration.

Decontamination: The removal of hazardous substances from personnel and their equipment necessary to prevent adverse health effects.

Discharge: Any spilling, leaking, pumping, pouring, emitting, emptying, or dumping.

Dispersants: Means those chemical agents that emulsify, disperse, or solubilize oil into the water column or promote the surface spreading of oil slicks to facilitate dispersal of the oil into the water column.

Diversion Boom: A floatation/freeboard device, made with a skirt/curtain, longitudinal strength member, and ballast unit/weight designed to deflect or divert the product towards a pick up point, or away from certain areas.

Drinking Water Supply: As defined by Section 101(7) of CERCLA, means any raw or finished water source that is or may be used by a public water system (as defined in the Safe Drinking Water Act) or as drinking water by one or more individuals.

EM: Emergency Management. Serves as the focal point for senior management support of an incident.

Economically Sensitive Areas: Those areas of explicit economic importance to the public that due to their proximity to potential spill sources may require special protection and include, but are not limited to: potable and industrial water intakes; locks and dams; and public and private marinas.

Emergency Management: The personnel identified to staff the organizational structure identified in a response plan to manage response plan implementation.

Emergency Service: Those activities provided by state and local government to prepare for and carry out any activity to prevent, minimize, respond to, or recover from an emergency.

Environmentally Sensitive Areas: Streams and water bodies, aquifer recharge zones, springs, wetlands, agricultural areas, bird rookeries, endangered or threatened species (flora and fauna) habitat, wildlife preserves or conservation areas, parks, beaches, dunes, or any other area protected or managed for its natural resource value.

Facility: Either an onshore facility or an offshore facility and includes, but is not limited to structures, equipment, and appurtenances thereto, used or capable of being used to transfer oil to or from a vessel or a public vessel. A facility includes federal, state, municipal, and private facilities.

Facility Operator: The person who owns, operates, or is responsible for the operation of the facility.

Federal Fund: The spill liability trust fund established under OPA.

Federal Regional Response Team: The federal response organization (consisting of representatives from selected federal and state agencies) which acts as a regional body responsible for planning and preparedness before an oil spill occurs and providing advice to the FOSC in the event of a major or substantial spill.

Federal Response Plan (FRP): Means the agreement signed by 25 federal departments and agencies in April 1987 and developed under the authorities of the Earthquake Hazards Reduction Act of 1977 and the Disaster Relief Act of 1974, as amended by the Stafford Disaster Relief Act of 1988.

First Responders, First Response Agency: A public health or safety agency (e.g., fire service or police department) charged with responding to a spill during the emergency phase and alleviating immediate danger to human life, health, safety, or property.

Handle: To transfer, transport, pump, treat, process, store, dispose of, drill for, or produce.

Harmful Quantity Of Oil: The presence of oil from an unauthorized discharge in a quantity sufficient either to create a visible film or sheen upon or discoloration of the surface of the water or a shoreline, tidal flat, beach, or marsh, or to cause a sludge or emulsion to be deposited beneath the surface of the water or on a shoreline, tidal flat, beach, or marsh.

Hazardous Material: Any nonradioactive solid, liquid, or gaseous substance which, when uncontrolled, may be harmful to humans, animals, or the environment. Including but not limited to substances otherwise defined as hazardous wastes, dangerous wastes, extremely hazardous wastes, oil, or pollutants.

Hazardous Substance: Any substance designed as such by the Administrator of the EPA pursuant to the Comprehensive Environmental Response, Compensation, and Liability Act; regulated pursuant to Section 311 of the Federal Water Pollution Control Act, or discharged by the SERC.

Hazardous Waste: Any solid waste identified or listed as a hazardous waste by the Administrator of the EPA pursuant to the federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act (RCRA), 42 U.S.C., Section 6901,et seq as amended. The EPA Administrator has identified the characteristics of hazardous wastes and listed certain wastes as hazardous in Title 40 of the Code of Federal Regulations, Part 261, Subparts C and D respectively.

HAZMAT: Hazardous materials or hazardous substances, exposure to which may result in adverse effects on health or safety of employees.

HAZWOPER: Hazardous Waste Operations and Emergency Response Regulations published by OSHA to cover worker safety and health aspects of response operations.

Heat Stress: Dangerous physical condition caused by over exposure to extremely high temperatures.

Hypothermia: Dangerous physical condition caused by over exposure to freezing temperatures.

Incident: "Incident" means an occurrence that results in:
(a) the death of or serious injury to a person;
(b) a significant adverse effect on the environment;
(c) an unintended fire or explosion;
(d) an unintended or uncontained release of LVP hydrocarbons in excess of 1.5m3;
(e) an unintended or uncontrolled release of gas or HVP hydrocarbons;
(f) the operation of a pipeline beyond its design limits as determined under CSA Z662 or CSA Z276 or any operating limits imposed by the Board [Onshore Pipeline Regulations, 1999 (SOR/99-294), s. 1].

Incident Briefing Meeting: Held to develop a comprehensive, accurate, and up-to-date understanding of the incident, nature of status of control operations, and nature and status of response operations; ensure the adequacy of control and response operations; begin to organize control and response operations; and prepare for interactions with outside world.

Incident Command Post (ICP): That location at which all primary command functions are executed.

Incident Command System (ICS): The combination of facilities, equipment, personnel, procedures, and communications operating within a common organizational structure, with responsibility for the management of assigned resources at an incident.

Incident Commander (IC): The one individual in charge at any given time of an incident. The Incident Commander will be responsible for establishing a unified command with all on-scene coordinators.

Indian Tribe: As defined in OPA section 1001, means any Indian tribe, band, nation, or other organized group or community, but not including any Alaska Native regional or village corporation, which is recognized as eligible for the special programs and services provided by the United States to Indians because of their status as Indians and has governmental authority over lands belonging to or controlled by the Tribe.

Initial Cleanup: Remedial action at a site to eliminate acute hazards associated with a spill. An initial clean-up action is implemented at a site when a spill of material is an actual or potentially imminent threat to public health or the environment, or difficulty of cleanup increases significantly without timely remedial action. All sites must be evaluated to determine whether initial cleanup is total cleanup, however, this will not be possible in all cases due to site conditions (i.e., a site where overland transport or flooding may occur).

Initial Notification: The process of notifying necessary the Company personnel and Federal/ State/Local agencies that a spill has occurred, including all pertinent available information surrounding the incident.

Initial Response Actions: The immediate actions that are to be taken by the spill observer after detection of a spill.

Inland Area: The area shoreward of the boundary lines defined in 46 CFR part 7, except that in the Gulf of Mexico, it means the area shoreward of the lines of demarcation (COLREG lines) as defined in §80.740 through 80.850 of this chapter. The inland area does not include the Great Lakes.

Inland Waters: State waters not considered coastal waters; lakes, rivers, ponds, streams, underground water, et. al.

Inland Zone: Means the environment inland of the coastal zone excluding the Great Lakes, and specified ports and harbors on inland rivers. The term inland zone delineates an area of federal responsibility for response action. Precise boundaries are determined by EPA/USCG agreements and identified in federal regional contingency plans.

Interim Storage Site: A site used to temporarily store recovered oil or oily waste until the recovered oil or oily waste is disposed of at a permanent disposal site. Interim storage sites include trucks, barges, and other vehicles, used to store waste until the transport begins.

Lead Agency: The government agency that assumes the lead for directing response activities.

Lead Federal Agency: The agency which coordinates the federal response to incident on navigable waters. The lead federal agencies are:

- **U.S. Coast Guard:** Oil and chemically hazardous materials incidents on navigable waters.
- **Environmental Protection Agency:** Oil and chemically hazardous materials incidents on inland waters.

Lead State Agency: The agency which coordinates state support to federal and/or local governments or assumes the lead in the absence of federal response.

Loading: Transfer from Facility to vehicle.

Local Emergency Planning Committee (LEPC): A group of local representatives appointed by the State Emergency Response Commission (SERC) to prepare a comprehensive emergency plan for the local emergency planning district, as required by the Emergency Planning and Community Right-to-know Act (EPCRA).

Local Response Team: Designated Facility individuals who will fulfill the roles determined in the oil spill response plan in the event of an oil or hazardous substance spill. They will supervise and control all response and clean-up operations.

Lower Explosive Limit: Air measurement utilized to determine the lowest concentration of vapors that support combustion. This measurement must be made prior to entry into a spill area.

Marinas: Small harbors with docks, services, etc. for pleasure craft.

Medium Discharge: Means a discharge greater than 2,100 gallons (50 Bbls) and less than or equal to 36,000 gallons (85+ Bbls) or 10% of the capacity of the largest tank, whichever is less and not to exceed the WCD.

National Contingency Plan: The plan prepared under the Federal Water Pollution Control Act (33 United State Code §1321 et seq) and the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (42 United State Code § 9601 et seq), as revised from time to time.

National Pollution Funds Center (NPFC): Means the entity established by the Secretary of Transportation whose function is the administration of the Oil Spill Liability Trust Fund (OSLTF). Among the NPFC's duties are: providing appropriate access to the OSLTF for federal agencies and states for removal actions and for federal trustees to initiate the assessment of natural resource damages; providing appropriate access to the OSLTF for claims; and coordinating cost recovery efforts.

National Response System (NRS): Is the mechanism for coordinating response actions by all levels of government in support of the OSC. The NRS is composed of the NRT, RRTs, OSC, Area Committees, and Special Teams and related support entities.

National Strike Force (NSF): Is a special team established by the USCG, including the three USCG Strike Teams, the Public Information Assist Team (PIAT), and the National Strike Force Coordination Center. The NSF is available to assist OSCs in their preparedness and response duties.

National Strike Force Coordination Center (NSFCC): Authorized as the National Response Unit by CWA section 311(a)(23) and (j)(2), means the entity established by the Secretary of the department in which the USCG is operating at Elizabeth City, North Carolina, with responsibilities that include administration of the USCG Strike Teams, maintenance of response equipment inventories and logistic networks, and conducting a national exercise program.

Natural Resource: Land, fish, wildlife, biota, air, water, ground water, drinking water supplies, and other such resources belonging to, managed by, held in trust by, appertaining to or otherwise controlled by the state, federal government, private parties, or a municipality.

Navigable Waters: As defined by 40 CFR 110.1 means the waters of the United States, including the territorial seas. The term includes:

All waters that are currently used, were used in the past, or may be susceptible to use in interstate or foreign commerce, including all waters that are subject to the ebb and flow of the tide;

Interstate waters, including interstate wetlands;

All other waters such as interstate lakes, rivers, streams (including intermittent streams), mudflats, sandflats, and wetlands, the use, degradation, or destruction of which would affect or could affect interstate or foreign commerce including any such waters:

- that are or could be used by interstate or foreign travelers for recreational or other purposes;
- from which fish or shellfish are or could be taken and sold in interstate or foreign commerce; and
- that are used or could be used for industrial purposes by industries in interstate commerce.

All impoundments of waters otherwise defined as navigable waters under this section;

Tributaries of waters identified in paragraphs (a) through (d) of this definition, including adjacent wetlands; and

Wetlands adjacent to waters identified in paragraphs (a) through (e) of this definition: Provided, that waste treatment systems (other than cooling ponds meeting the criteria of this paragraph) are not waters of the United States.

Waters of the United States do not include prior converted cropland. Notwithstanding the determination of an area's status as prior converted cropland by any other federal agency, for the purposes of the Clean Water Act jurisdiction remains with EPA.

Nearshore Area: For OPA 90, the area extending seaward 12 miles from the boundary lines defined in 46 CFR Part 7, except in the Gulf of Mexico. In the Gulf of Mexico, it means the area extending seaward 12 miles from the line of demarcation defined in §80.740 - 80.850 of title 33 of the CFR.

Non-persistent or Group I Oil: A petroleum-based oil that, at the time of shipment, consists of hydrocarbon fractions:

1. At least 50% of which by volume, distill at a temperature of 340 degrees C (645 degrees F);
2. At least 95% of which volume, distill at a temperature of 370 degrees C (700 degrees F).

Ocean: The open ocean, offshore area, and nearshore area as defined in this subpart.

Offshore area: The area up to 38 nautical miles seaward of the outer boundary of the nearshore area.

Oil or Oils: Naturally occurring liquid hydrocarbons at atmospheric temperature and pressure coming from the earth, including condensate and natural gasoline, and any fractionation thereof, including, but not limited to, crude oil, petroleum gasoline, fuel oil, diesel oil, oil sludge, oil refuse, and oil mixed with wastes other than dredged spoil. Oil does not include any substance listed in Table 302.4 of 40 CFR Part 302 adopted August 14, 1989, under Section 101(14) of the federal comprehensive environmental response, compensation, and liability act of 1980, as amended by P. L. 99-499.

Oil Control Centre (OCC): Responsible for 24/7 Remote Monitoring and Control of Oil Pipelines Facilities.

Oil Spill Liability Trust Fund: Means the fund established under section 9509 of the Internal Revenue Code of 1986 (26 U.S.C. 9509).

Oily Waste: Product contaminated waste resulting from a spill or spill response operations.

On-Scene Coordinator (OSC): Means the federal official predesignated by the EPA or the USCG to coordinate and direct response under subpart D.

On-site: Means the areal extent of contamination and all suitable areas in very close proximity to the contamination necessary for implementation of a response action.

Open Ocean: means the area from 38 nautical miles seaward of the outer boundary of the nearshore area, to the seaward boundary of the exclusive economic zone.

Owner or Operator: Any person, individual, partnership, corporation, association, governmental unit, or public or private organization of any character.

Persistent Oil: A petroleum-based oil that does not meet the distillation criteria for a non-persistent oil. For the purposes of this Appendix, persistent oils are further classified based on specific gravity as follows:

1. Group II specific gravity less than .85
2. Group III specific gravity between .85 and less than .95
3. Group IV specific gravity .95 and including 1.0

4. Group V specific gravity greater than 1.0

Plan Holder: The plan holder is the industry transportation related facility for which a response plan is required by federal regulation to be submitted by a vessel or facility's owner or operator.

Primary Response Contractors or Contractors: An individual, company, or cooperative that has contracted directly with the plan holder to provide equipment and/or personnel for the containment or cleanup of spilled oil.

Qualified Individual (QI): That person or entity who has authority to activate a spill cleanup contractors, act as liaison with the "On-Scene Coordinator" and obligate funds required to effectuate response activities.

Recreation Areas: Publicly accessible locations where social/sporting events take place.

Regional Response Team (RRT): The Federal response organization (consisting of representatives from selected Federal and State agencies) which acts as a regional body responsible for overall planning and preparedness for oil and hazardous materials releases and for providing advice to the OSC in the event of a major or substantial spill.

Remove or Removal: As defined by section 311(a)(8) of the CWA, refers to containment and removal of oil or hazardous substances from the water and shorelines or the taking of such other actions as may be necessary to minimize or mitigate damage to the public health or welfare (including, but not limited to, fish, shellfish, wildlife, public and private property, and shorelines and beaches) or to the environment. For the purpose of the NCP, the term also includes monitoring of action to remove discharge.

Reportable Commodity Pipeline Accident: “reportable commodity pipeline accident” means an accident resulting directly from the operation of a commodity pipeline, where:
(a) a person sustains a serious injury or is killed as a result of being exposed to
 (i)a fire, ignition or explosion, or
 (ii)a commodity released from the commodity pipeline, or
(b) the commodity pipeline
 (i)sustains damage affecting the safe operation of the commodity pipeline as a result of being contacted by another object or as a result of a disturbance of its supporting environment,
 (ii)causes or sustains an explosion, or a fire or ignition that is not associated with normal operating circumstances, or
 (iii)sustains damage resulting in the release of any commodity [Transportation Safety Board Regulations (SOR/92-446), s2(1)}.

Reportable Commodity Pipeline Incident: “reportable commodity pipeline incident” means an incident resulting directly from the operation of a commodity pipeline, where:
(a) an uncontained and uncontrolled release of a commodity occurs,
(b) the commodity pipeline is operated beyond design limits,
(c) the commodity pipeline causes an obstruction to a ship or to a surface vehicle owing to a disturbance of its supporting environment,
(d) any abnormality reduces the structural integrity of the commodity pipeline below design limits,
(e) any activity in the immediate vicinity of the commodity pipeline poses a threat to the structural integrity of the commodity pipeline, or
(f) the commodity pipeline, or a portion thereof, sustains a precautionary or emergency shut-down for reasons that relate to or create a hazard to the safe transportation of a commodity [Transportation Safety Board Regulations (SOR/92-446), s. 2(1)}.

Response Activities: The containment and removal of oil from the water and shorelines, the temporary storage and disposal of recovered oil, or the taking of other actions as necessary to minimize or mitigate damage to public health or welfare, or the environment.

Response Contractors: Persons/companies contracted to undertake a response action to contain and/or clean up a spill.

Response Guidelines: Guidelines for initial response that are based on the type of product involved in the spill, these guidelines are utilized to determine clean-up methods and equipment.

Response Plan: A practical manual used by industry for responding to a spill. Its features include: (1) identifying the notifications sequence, responsibilities, response techniques, etc. in an easy to use format; (2) using decision trees, flowcharts, and checklists to insure the proper response for spills with varying characteristics; and (3) segregating information needed during the response from data required by regulatory agencies to prevent confusion during a spill incident.

Response Priorities: Mechanism used to maximize the effective use of manpower and equipment resources based upon their availability during an operational period.

Response Resources: All personnel and major items of equipment available, or potentially available, for assignment to incident tasks on which status is maintained.

Responsible Party: Any person, owner/operator, or facility that has control over an oil or hazardous substance immediately before entry of the oil or hazardous substance into the atmosphere or in or upon the water, surface, or subsurface land of the state.

Restoration: The actions involved in returning a site to its former condition.

Rivers and Canals: A body of water confined within the inland area that has a project depth of 12 feet or less, including the Intracoastal Waterway and other waterways artificially created for navigation.

Securing the Source: Steps that must be taken to stop discharge of oil at the source of the spill.

Serious Injury: "serious injury" includes an injury that results in :
(a) the fracture of a major bone;
(b) the amputation of a body part;
(c) the loss of sight in one or both eyes;
(d) internal hemorrhage;
(e) third degree burns;
(f) unconsciousness; or
(g) the loss of a body part or function of a body part. (blessure grave)

Significant Adverse Effect: “significant adverse effect” is defined under the Canadian Environmental Assessment Act as any effect of any change on:
(i) any change the project may cause on the environment, including any change it may cause to a listed wildlife species, its critical habitat or the residences of individual of that species, as those terms are defined in subsection 2(1) of the Species at Risk Act.
(ii) health and socio-economic conditions;
(iii) physical and cultural heritage;
(iv) the current use of lands and resources for traditional purposes by aboriginal persons;
(v) any structure, site or thing that is of historical, archaeological, paleontological or architectural significance;
(vi) any change to the project that may be caused by the environment.

Sinking Agents: Means those additives applied to oil discharges to sink floating pollutants below the water surface.

Site Characterization: An evaluation of a cleanup site to determine the appropriate safety and health procedures needed to protect employees from identified hazards.

Site Conditions: Details of the area surrounding the facility, including shoreline descriptions, typical weather conditions, socioeconomic breakdowns, etc.

Site Safety and Health Plan: A site specific plan developed at the time of an incident that addresses:

- Safety and health hazard analysis for each operation.
- Personal protective equipment to be used.
- Training requirements for site workers.
- Medical surveillance requirements.
- Air monitoring requirements.
- Site control measures.
- Decontamination procedures.
- Emergency response procedures.
- Confined space entry procedures.

Site Security and Control: Steps that must be taken to provide safeguards needed to protect personnel and property, as well as the general public, to ensure an efficient clean-up operation.

Skimmers: Mechanical devices used to skim the surface of the water and recover floating oil. Skimmers fall into four basic categories (suction heads, floating weirs, oleophilic surface units, and hydrodynamic devices) which vary in efficiency depending on the type of oil and size of spill.

Snare Boom: Oil will adhere to the material of which this boom is made of and thus collect it.

Sorbents: Materials ranging from natural products to synthetic polymeric foams placed in confined areas to soak up small quantities of oil. Sorbents are very effective in protecting walkways, boat decks, working areas, and previously uncontaminated or cleaned areas.

Spill: An unauthorized discharge of oil or hazardous substance into the waters of the state.

Spill Observer: The first Facility individual who discovers a spill. This individual must function as the first responder and person-in-charge until relieved by an authorized supervisor.

Spill of National Significance (SONS): Means a spill which due to its severity, size, location, actual or potential impact on the public health and welfare or the environment, or the necessary response effort, is so complex that it requires extraordinary coordination of federal, state, local, and responsible party resources to contain and cleanup the discharge.

Spill Management Team: The personnel identified to staff the organizational structure identified in a response plan to manage response plan implementation.

Spill Response: All actions taken in responding to spills of oil and hazardous materials, e.g.: receiving and making notifications; information gathering and technical advisory phone calls; preparation for and travel to and from spill sites; direction of clean-up activities; damage assessments; report writing, enforcement investigations and actions; cost recovery; and program development.

Spill Response Personnel: Federal, state, local agency, and industry personnel responsible for participating in or otherwise involved in spill response. All spill response personnel will be pre-approved on a list maintained in each region.

Staging Areas: Designated areas near the spill site accessible for gathering and deploying equipment and/or personnel.

State Emergency Response Commission(SERC): A group of officials appointed by the Governor to implement the provisions of Title III of the Federal Superfund Amendments and Re-authorization Act of 1986 (SARA). The SERC approves the State Oil and Hazardous Substance Discharge Prevention and Contingency Plan and Local Emergency Response Plans.

Surface Collecting Agents: Means those chemical agents that form a surface film to control the layer thickness of oil.

Surface Washing Agent: Is any product that removes oil from solid surfaces, such as beaches and rocks, through a detergency mechanism and does not involve dispersing or solubilizing the oil into the water column.

Tanker: A self-propelled tank vessel constructed or adapted primarily to carry or hazardous material in bulk in the cargo spaces.

Tidal Current Tables: Tables which contain the predicted times and heights of the high and low waters for each day of the year for designated areas.

Trajectory Analysis: Estimates made concerning spill size, location, and movement through aerial surveillance or computer models.

Transfer: Any movement of oil to, from, or within a vessel by means of pumping, gravitation, or displacement.

Trustee: Means an official of a federal natural resources management agency designated in subpart G of the NCP or a designated state official or Indian tribe or, in the case of discharges covered by the OPA, a foreign government official, who may pursue claims for damages under section 1006 of the OPA.

Underwriter: An insurer, a surety company, a guarantor, or any other person, other than an owner or operator of a vessel or facility, that undertakes to pay all or part of the liability of an owner or operator.

Unified Command: The method by which local, state, and federal agencies and the responsible party will work with the Incident Commander to:

- Determine their roles and responsibilities for a given incident.
- Determine their overall objectives for management of an incident.
- Select a strategy to achieve agreed-upon objectives.
- Deploy resources to achieve agreed-upon objectives.

Unified or Coordinated Command Meeting: Held to obtain agreement on strategic objectives and response priorities; review tactical strategies; engage in joint planning, integrate response operations; maximize use of resources; and minimize resolve conflicts.

Volunteers: An individual who donates their services or time without receiving monetary compensation.

Waste: Oil or contaminated soil, debris, and other substances removed from coastal waters and adjacent waters, shorelines, estuaries, tidal flats, beaches, or marshes in response to an unauthorized discharge. Waste means any solid, liquid, or other material intended to be disposed of or discarded and generated as a result of an unauthorized discharge of oil. Waste does not include substances intended to be recycled if they are in fact recycled within 90 days of their generation or if they are brought to a recycling facility within that time.

Waters of the United States: See **Navigable Waters** in this Glossary.

Wetlands: Those areas that are inundated or saturated by surface or groundwater at a frequency or duration sufficient to support, and that under normal circumstances do support, a prevalence of vegetation typically adapted for life in saturated soil conditions. Wetlands generally include playa lakes, swamps, marshes, bogs, and similar areas such as sloughs, prairie potholes, wet meadows, prairie river overflows, mudflats, and natural ponds (40 CFR 112.2(y)).

Wildlife Rescue: Efforts made in conjunction with Federal and State agencies to retrieve, clean, and rehabilitate birds and wildlife affected by an oil spill.

Worst Case Discharge: The largest foreseeable discharge under adverse weather conditions. For facilities located above the high water line of coastal waters, a worst case discharge includes those weather conditions most likely to cause oil discharged from the facility to enter coastal waters.

ACRONYMS

AMIO	-	Alien Migration Interdiction Operation
AQI	-	Alternate Qualified Individual
AM	-	Ante Meridiem
ACP	-	Area Contingency Plan
ACP	-	Area Contingency Plans
Avg.	-	Average
bbl/hr	-	Barrel per Hour
Br	-	Branch
BLM	-	Bureau of Land Management
CANUSCENT	-	Canada - United States Joint Inland Pollution Contingency Plan - Annex II
CA	-	Canada
CA NEB	-	Canadian National Energy Board
COTP	-	Captain of the Port
Ctr.	-	Center
CAS Number	-	Chemical Abstracts Service
CST	-	Civil Support Team
CG	-	Coast Guard
CFR	-	Code of Federal Regulations
Cont'd	-	Continued
CMT	-	Crisis Management Team
DOA	-	Dead on Arrival
Dept.	-	Department
DOD	-	Department of Defense
DENR	-	Department of Environment and Natural Resources
DHS	-	Department of Homeland Security
DOI	-	Department of Interior
DNR	-	Department of Natural Resources
DOT	-	Department of Transportation
D.C.	-	District of Columbia
Div.	-	Division
DOCL	-	Documentation Unit Leader
EMS	-	Emergency Management System
EM	-	Emergency Manager
EOC	-	Emergency Operations Center
ESA	-	Endangered Species Act
EET	-	Environmental Emergency Team
EDRC	-	Estimated Daily Recovery Capability
ETA	-	Estimated Time of Arrival
etc.	-	Et Cetera
exempli gratia e.g.	-	For Example
FAA	-	Federal Aviation Administration
FBI	-	Federal Bureau of Investigation
FOSC	-	Federal On-Scene Coordinator
Ft./Sec.	-	Feet/Second
FIR	-	Field Investigation Report

FR	-	Fire Retardant
FWD	-	Forward
Freq.	-	Frequency
GRP	-	Group
Gru Sups.	-	Group Supervisors
HAZMAT	-	Hazardous Material
HAZWOPER	-	Hazardous Waste Operations and Emergency Response Standard
HVAC	-	Heating, Ventilating, and Air Conditioning
HEPA OVV	-	High Efficiency Particle Air Device
HF ERW	-	High Frequency Electric-Resistance Weld
HLS	-	Homeland Security
Hrs.	-	Hours
ID NO.	-	Identification Number
IL	-	Illinois
IDNR	-	Illinois Department of Natural Resources
IAW	-	In Accordance With
IAP	-	Incident Action Plan
ICS	-	Incident Command System
ICS	-	Incident Command System
IC	-	Incident Commander
IMH	-	Incident Management Handbook
IMS	-	Incident Management System
Info.	-	Information
KS	-	Kansas
KM	-	Kilometer
KP	-	Kilometer Point
LE	-	Law Enforcement
LO	-	Liaison Officer
LPG	-	Liquefied Petroleum Gas
LEPC	-	Local Emergency Planning Committee
LRT	-	Local Response Team
LSC	-	Logistics Section Chief
LF ERW	-	Low Frequency Electric-Resistance Weld
LEL	-	Lower Explosive Limit
MO	-	Missouri
MSDS	-	Material Safety Data Sheets
MEDEVAC'D	-	Medical Evacuation
NCP	-	National Contingency Plan
NE	-	Nebraska
NEECP (CA)	-	National Environmental Emergencies Contingency Plan
NFPA	-	National Fire Protection Association
NIMS	-	National Incident Management System
ND	-	North Dakota
NOAA	-	National Oceanographic Atmospheric Administration
NCP (U.S.)	-	National Oil and Hazardous Substances Contingency Plan
NRC	-	National Response Center
NRC/ES	-	National Response Corporation

NRDAR	-	Natural Resource Damage Assessment and Restoration
N	-	No
NW	-	North West
N/A	-	Not Available
OCC	-	Oil Control Centre
OSHA	-	Occupational Safety & Health Administration
OSRO	-	Oil Spill Removal Organization
OSRP	-	Oil Spill Response Plan
OSRV	-	Oil Spill Response Vessel
OSC	-	On-Scene Coordinate
OSC	-	Operation Section Chief
OP	-	Operational Period
Op.	-	Operations
OPS	-	Operations
O&M	-	Operations and Maintenance
OCC	-	Operations Coordination Center
OV	-	Organic Vapor
PPM	-	Parts Per Million
PFD	-	Personal Floatation Device
PPE	-	Personal Protective Equipment
PHMSA	-	Pipeline and Hazardous Materials Safety Administration
PSC	-	Planning Section Chief
PSC	-	Planning Section Chief
POC	-	Point of Contact
PVC	-	Polyvinyl Chloride
P.M.	-	Post Meridiem
PREP	-	Preparedness for Response Exercise Program
Prot.	-	Protection
PWSD	-	Public Water Supply District
QI	-	Qualified Individual
RPT	-	Regional Preparedness Team
Req.	-	Required
RCRA	-	Resource Conservation and Recovery Act
RESL	-	Resource Leader
RP	-	Responsible Party
RPIC	-	Responsible Party Incident Commander
Rev.	-	Revision
R/W	-	Right-of-Way
RWD	-	Rural Water District
SAR	-	Search and Rescue
SART	-	Search and Rescue Transporter
SD	-	South Dakota
SI	-	Security Incident
SO	-	Security Officer
SCBA	-	Self Contained Breathing Apparatus
SSPs	-	Site Safety Plans
SITL	-	Situation Unit Leader

Spec.	-	Special
SPCC	-	Spill Prevention, Control, and Countermeasure
SORS	-	Spilled oil Recovery System
Sq. Ft.	-	Square Foot
STAM	-	Staging Area Manager
SERC	-	State Emergency Response Center
SERC	-	State Emergency Response Commission
SOSC	-	State On-Scene Coordinator
SOR	-	Statutory Orders and Regulations
SCADA	-	Supervisory Control and Data Acquisition
TOC	-	Table of Contents
TC	-	TC Oil Pipeline Operations Inc.
TSD	-	Temporary Storage and Disposal
TSC	-	Temporary Storage Capacity
TGLO	-	Texas General Land Office
id est, I.E.	-	That is
TBA	-	To be Assigned
TSB	-	Transportation Safety Board
UC	-	Unified Command
UN Number	-	United Nations
US	-	United States
USCG	-	United States Coast Guard
EPA	-	US Environmental Protection Agency
USN	-	US Navy Supervisor Salvage
Vsl.	-	Vessel
VOSS	-	Vessel of Opportunity Skimmer System
VOC	-	Volatile Organic Compound
Vol.	-	Volume
W	-	West
WCD	-	Worst Case Discharge
Y	-	Yes

RESPONSE ZONE INFORMATION

Hardisty Pump Station/ Regina Pump Station

RESPONSE ZONE CONTACT INFORMATION	
Owner Name:	TransCanada
Addresses:	Physical Address 450 - 1st Street Calgary, Alberta T2P 5H1
24 Hour Emergency Contact Phone Numbers:	1-800-447-8066 (24 Hours)
Telephone/Fax:	Telephone references, including 24 hour numbers, for the Facility, Owner, and Qualified Individual/Alternate Qualified Individual are provided in Figure 2.2.
Provinces/States Traversed:	Alberta, Saskatchewan
Areas/Counties Traversed:	Eastern Alberta, Western Saskatchewan

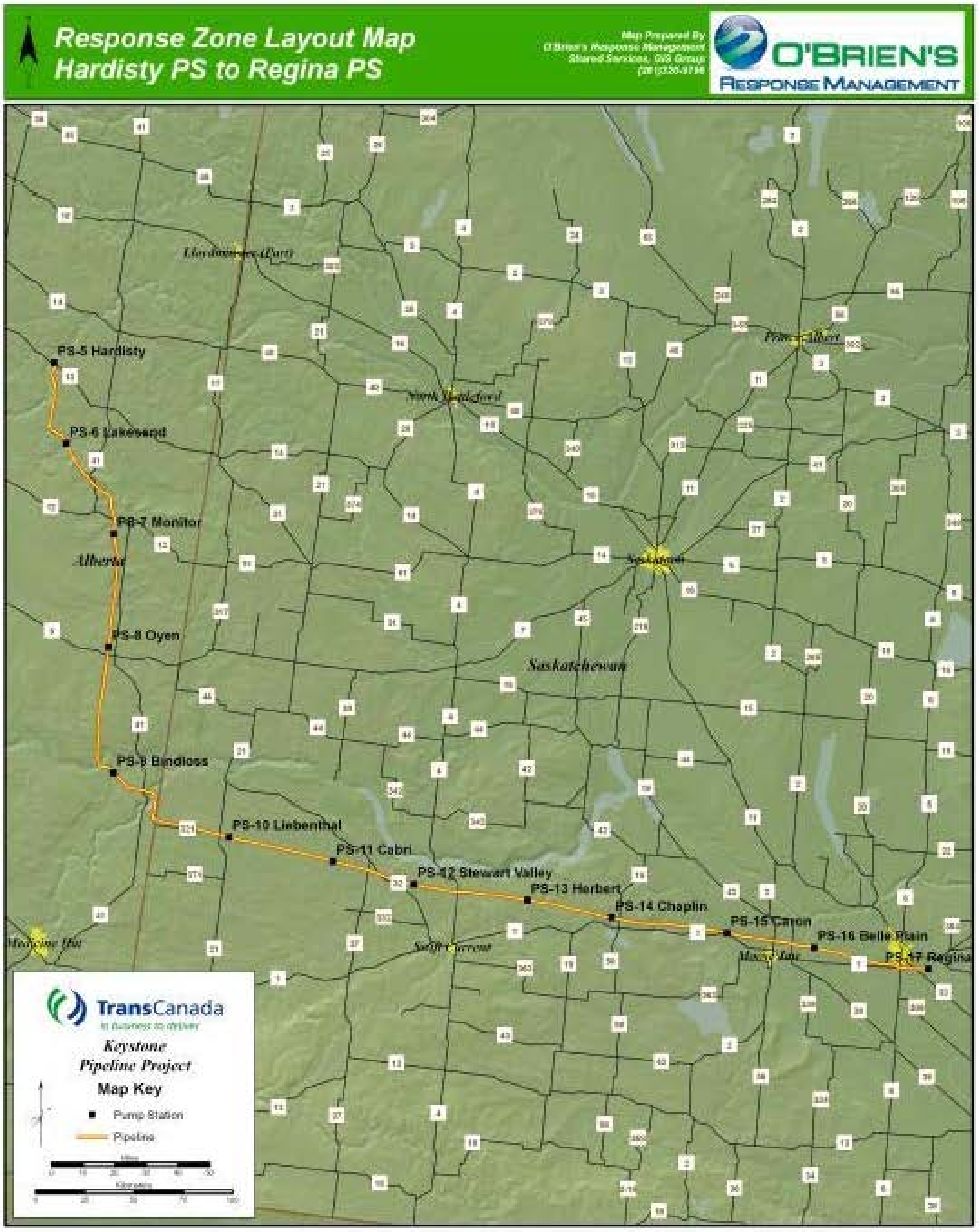
INFORMATION SUMMARY

Determination of Significant and Substantial Harm (United States Department of Transportation/Pipeline and Hazardous Materials Safety Administration):

This Response Zone has been determined to meet the significant and substantial harm classification because at least one (1) line section within the response zone has met at least one of the criteria listed in 49CFR194.103(c)(1).

Worst Case Discharge (Refer to Appendix B for calculations):

- **Potential Oil Group:** 3
- **United States Department of Transportation/Pipeline and Hazardous Materials Safety Administration Planning Volume:** 41,504 Bbls


Response Zone Layout Map
Hardisty PS to Regina PS
O'BRIEN'S
RESPONSE MANAGEMENT
PS-5 Hardisty
PS-6 Lakesend
PS-7 Monitor
Alberta
PS-8 Oyen
PS-9 Bindloss
PS-10 Liebenthal
PS-11 Cabri
PS-12 Stewart Valley
PS-13 Herbert
PS-14 Chaplin
PS-15 Caron
PS-16 Belle Plain
PS-17 Regina
Saskatchewan
TransCanada
Keystone
Pipeline Project
Map Key
Pump Station
Pipeline

RESPONSE ZONE COMPANY CONTACTS				
POSITION/TITLE	NAME	OFFICE	HOME	CELL
[redacted]				

Area: Hardisty Pump Station / Regina Pump Station

Qualified Individuals:

Qualified Individuals			
NAME	OFFICE	HOME	CELL
[redacted]			

Alternate Qualified Individuals:

Alternate Qualified Individuals			
NAME	OFFICE	HOME	CELL

Pipeline Specifications:

The tables below list the pipeline facilities within the East Response Zone Response Zone.

Pipeline Specifications			
Location	Type of Oil	State	County
Caron PS / Regina PS	Crude Oil	Saskatchewan	Western Saskatchewan
Hardisty PS / Lakesend PS	Crude Oil	Alberta	Eastern Alberta
Lakesend PS / Monitor PS	Crude Oil	Alberta	Eastern Alberta

Monitor PS / Oyen PS	Crude Oil	Alberta	Eastern Alberta
Oyen PS / Bindloss PS	Crude Oil	Alberta	Eastern Alberta
Blindloss PS / Cabri PS	Crude Oil	Alberta	Eastern Alberta
Cabri PS / Herbert PS	Crude Oil	Saskatchewan	Western Saskatchewan
Herbert PS / Caron PS	Crude Oil	Saskatchewan	Western Saskatchewan

Company Owned Response Equipment:

Response Equipment		
NAME	**LOCATION**	**DESCRIPTION**
Equipment Response Trailer		See Equipment List - Appendix A

Breakout Tanks:

Breakout Tanks			
FACILITY NAME	TANK NUMBER	CAPACITY (Bbls)	TYPE OF OIL

EXTERNAL NOTIFICATION REFERENCES
Saskatchewan

OTHER POTENTIAL REQUIRED NOTIFICATIONS

DIAL 911 for all Police, Fire and Ambulance Services.

*** Calls to 911 concerning petroleum spills will usually alert LEPC; however, it is advisable to notify them directly for any spill that requires a 911 notification.**

AGENCY	LOCATION	OFFICE / ALTERNATE
Western Saskatchewan		
Abbey Fire Department	Abbey, Alberta	[redacted]
Bindloss Fire Department	Bindloss, Alberta	[redacted]
Bow Island Fire Department	Bow Island, Alberta	[redacted]
Burstall Ambulance Services	Burstall, Saskatchewan	[redacted]
Burstall EMO Services	Burstall, Saskatchewan	[redacted]
Burstall Fire Department	Burstall, Saskatchewan	[redacted]
Cabri Ambulance Services	Cabri, Saskatchewan	[redacted]
Cabri Fire Department	Cabri, Saskatchewan	[redacted]
Cabri RCMP Detachment	Cabri, Saskatchewan	[redacted]
Caronport Fire Department	Caronport, Saskatchewan	[redacted]
Central Butte Ambulance Services	Central Butte, Saskatchewan	[redacted]
Cereal Fire Department	Cereal, Alberta	[redacted]
CFB Suffield Military Police Detachment	Ralston, Alberta	[redacted]
Chaplin Fire Department	Chaplin, Saskatchewan	[redacted]
City of Regina - Emergency Planning	Regina, Saskatchewan	[redacted]
Climax Fire Department	Climax, Saskatchewan	[redacted]
Eastend Fire Department	Eastend, Saskatchewan	[redacted]
Elkwater Fire Department	Elkwater, Alberta	[redacted]
Fox Valley Fire Department	Fox Valley, Saskatchewan	[redacted]
Frontier Ambulance Services	Frontier, Saskatchewan	[redacted]
Frontier Fire Department	Frontier, Saskatchewan	[redacted]

Gull Lake Ambulance Services	Gull Lake, Saskatchewan	[redacted]
Gull Lake EMO Services	Gull Lake, Saskatchewan	[redacted]
Gull Lake Fire Department	Gull Lake, Saskatchewan	[redacted]
Herbert Fire Department	Herbert, Saskatchewan	[redacted]
Kipling Fire Department	Kipling, Saskatchewan	[redacted]
Leader Ambulance Services	Leader, Saskatchewan	[redacted]
Leader EMO Services	Leader, Saskatchewan	[redacted]
Leader Fire Department	Leader, Saskatchewan	[redacted]
Leader RCMP Detachment	Leader, Saskatchewan	[redacted]
Maple Creek Ambulance	Maple Creek, Saskatchewan	[redacted]
Maple Creek EMO Services	Maple Creek, Saskatchewan	[redacted]
Maple Creek RCMP Detachment	Maple Creek, Saskatchewan	[redacted]
Medicine Hat Police Service	Medicine Hat, Alberta	[redacted]
Medicine Hat Fire Department	Medicine Hat, Alberta	[redacted]
Moose Jaw Ambulance Services	Moose Jaw, Saskatchewan	[redacted]
Moose Jaw EMO Services	Moose Jaw, Saskatchewan	[redacted]
Moose Jaw Fire Department	Moose Jaw, Saskatchewan	[redacted]
Moose Jaw RCMP Detachment	Moose Jaw, Saskatchewan	[redacted]
Morse Fire Department	Morse, Saskatchewan	[redacted]
Morse RCMP Detachment	Morse, Saskatchewan	[redacted]
Pense Fire Department	Pense, Saskatchewan	[redacted]
Piapot Fire Department	Piapot, Saskatchewan	[redacted]
RCMP - Gull Lake Community Detachment	Swift Current, Saskatchewan	[redacted]
Regina City Police Department	Regina, Saskatchewan	[redacted]
Regina EMS - Ambulance	Regina, Saskatchewan	[redacted]
Regina Fire Department	Regina, Saskatchewan	[redacted]

Regina RCMP Detachment	Regina, Saskatchewan	[redacted]
Richmound Ambulance Services	Leader, Saskatchewan	[redacted]
RM of Moose Jaw EMO Services	Moose Jaw, Saskatchewan	[redacted]
RM of Wheatland EMO Services	Mortlach, Saskatchewan	[redacted]
Rural Municipality of Riverside No.168 Fire Depart	Pennant, Saskatchewan	[redacted]
Sceptre Fire Department	Sceptre, Saskatchewan	[redacted]
Shaunavon Ambulance Services	Shaunavon, Saskatchewan	[redacted]
Shaunavon EMO Services	Shaunavon, Saskatchewan	[redacted]
Shaunavon Fire Department	Shaunavon, Saskatchewan	[redacted]
Shaunavon RCMP Detachment	Shaunavon, Saskatchewan	[redacted]
Stewart Valley Fire Department	Stewart Valley, Saskatchewan	[redacted]
Swift Current Ambulance Services	Swift Current, Saskatchewan	[redacted]
Swift Current Fire Department	Swift Current, Saskatchewan	[redacted]
Swift Current RCMP Detachment	Swift Current, Saskatchewan	[redacted]
Val Marie Ambulance Services	Val Marie, Saskatchewan	[redacted]
Val Marie Fire Department	Val Marie, Saskatchewan	[redacted]

RESPONSE ZONE INFORMATION

Regina Pump Station / Haskett Pump Station

RESPONSE ZONE CONTACT INFORMATION	
Owner Name:	TransCanada
Addresses:	Physical Address 450 - 1st Street Calgary, Alberta T2P 5H1
24 Hour Emergency Contact Phone Numbers:	1-800-447-8066 (24 Hours)
Telephone/Fax:	Telephone references, including 24 hour numbers, for the Facility, Owner, and Qualified Individual/Alternate Qualified Individual are provided in Figure 2.2.
Provinces/States Traversed:	Saskatchewan, Manitoba
Areas/Counties Traversed:	Eastern Saskatchewan, Southwestern Manitoba

INFORMATION SUMMARY

Determination of Significant and Substantial Harm (United States Department of Transportation/Pipeline and Hazardous Materials Safety Administration):

This Response Zone has been determined to meet the significant and substantial harm classification because at least one (1) line section within the response zone has met at least one of the criteria listed in 49CFR194.103(c)(1).

Worst Case Discharge (Refer to Appendix B for calculations):

- **Potential Oil Group:** 3
- **United States Department of Transportation/Pipeline and Hazardous Materials Safety Administration Planning Volume:** [redacted] Bbls

RESPONSE ZONE INFORMATION

Regina Pump Station / Haskett Pump Station

RESPONSE ZONE CONTACT INFORMATION	
Owner Name:	TransCanada
Addresses:	Physical Address 450 - 1st Street Calgary, Alberta T2P 5H1
24 Hour Emergency Contact Phone Numbers:	1-800-447-8066 (24 Hours)
Telephone/Fax:	Telephone references, including 24 hour numbers, for the Facility, Owner, and Qualified Individual/Alternate Qualified Individual are provided in Figure 2.2.
Provinces/States Traversed:	Saskatchewan, Manitoba
Areas/Counties Traversed:	Eastern Saskatchewan, Southwestern Manitoba

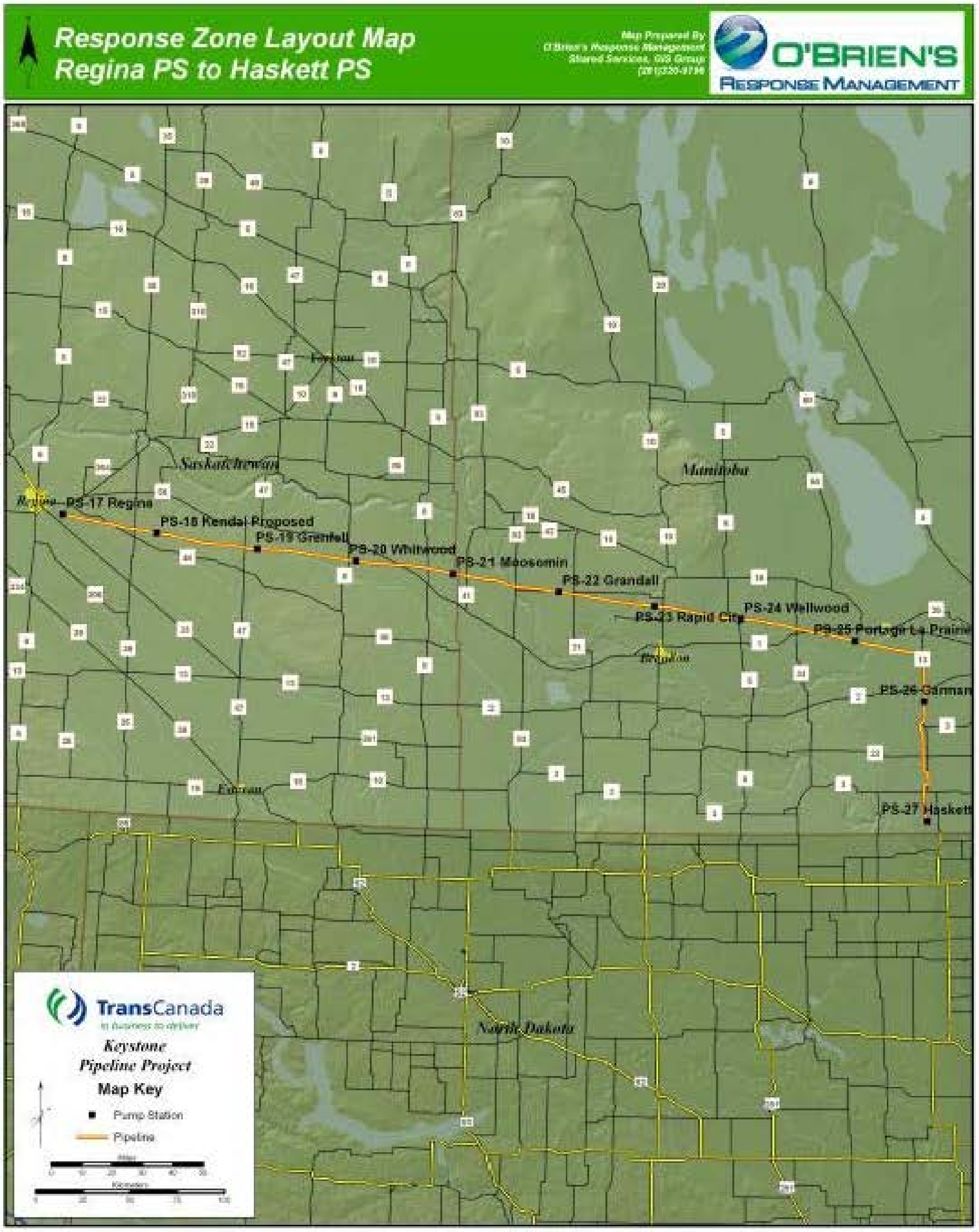
INFORMATION SUMMARY

Determination of Significant and Substantial Harm (United States Department of Transportation/Pipeline and Hazardous Materials Safety Administration):

This Response Zone has been determined to meet the significant and substantial harm classification because at least one (1) line section within the response zone has met at least one of the criteria listed in 49CFR194.103(c)(1).

Worst Case Discharge (Refer to Appendix B for calculations):

- **Potential Oil Group:** 3
- **United States Department of Transportation/Pipeline and Hazardous Materials Safety Administration Planning Volume:** 51,413 Bbls


Response Zone Layout Map
Regina PS to Haskett PS
O'BRIEN'S
RESPONSE MANAGEMENT
Saskatchewan
Manitoba
North Dakota
Regina
PS-17 Regina
PS-18 Kendal Proposed
PS-19 Grenfell
PS-20 Whitwood
PS-21 Moosomin
PS-22 Grandall
PS-23 Rapid City
PS-24 Wellwood
PS-25 Portage La Prairie
PS-26 Carman
PS-27 Haskett
Brandon
TransCanada
Keystone
Pipeline Project
Map Key
Pump Station
Pipeline

030570

RESPONSE ZONE COMPANY CONTACTS				
POSITION/TITLE	NAME	OFFICE	HOME	CELL
[redacted]				

Area: Regina Pump Station / Haskett Pump Station

Qualified Individuals:

Qualified Individuals			
NAME	OFFICE	HOME	CELL

[redacted]

Alternate Qualified Individuals:

Alternate Qualified Individuals			
NAME	OFFICE	HOME	CELL

Pipeline Specifications:

The tables below list the pipeline facilities within the East Response Zone Response Zone.

Pipeline Specifications			
Location	Type of Oil	State	County
Regina PS / Kendal PS	Crude Oil	Saskatchewan	Eastern Saskatchewan
Kendal PS / Grenfell PS	Crude Oil	Saskatchewan	Eastern Saskatchewan
Grenfell PS / Moosomin PS	Crude Oil	Saskatchewan	Eastern Saskatchewan
Moosomin PS / Rapid City PS	Crude Oil	Manitoba	Southwestern Manitoba
Rapid PS / Portage La Prairie PS	Crude Oil	Manitoba	Southwestern Manitoba

Portage La Prairie PS / Carman PS	Crude Oil	Manitoba	Southwestern Manitoba
Carman PS / Haskett PS	Crude Oil	Manitoba	Southwestern Manitoba

Company Owned Response Equipment:

Response Equipment		
NAME	**LOCATION**	**DESCRIPTION**
Equipment Response Trailer		See Equipment List - Appendix A

Breakout Tanks:

Breakout Tanks			
FACILITY NAME	TANK NUMBER	CAPACITY (Bbls)	TYPE OF OIL

EXTERNAL NOTIFICATION REFERENCES
Saskatchewan

OTHER POTENTIAL REQUIRED NOTIFICATIONS

DIAL 911 for all Police, Fire and Ambulance Services.

*** Calls to 911 concerning petroleum spills will usually alert LEPC; however, it is advisable to notify them directly for any spill that requires a 911 notification.**

AGENCY	LOCATION	OFFICE / ALTERNATE
Eastern Saskatchewan		
Balgonie Fire Department	Balgonie, Saskatchewan	(306) 771-2206
Carry The Kettle Fire Department	Sintaluta, Saskatchewan	(306) 727-2135
City of Regina - Emergency Planning	Regina, Saskatchewan	(306) 777-7886
Glenavon Fire Department	Glenavon, Saskatchewan	(306) 429-2220
Grenfell Ambulance Services	Grenfell, Saskatchewan	(306) 697-2707
Grenfell Fire Department	Grenfell, Saskatchewan	(306) 697-2217
Indian Head Fire Department	Indian Head, Saskatchewan	(306) 695-3887
Indian Head RCMP Detachment	Indian Head, Saskatchewan	(306) 695-5200
Kipling Ambulance Service	Kipling, Saskatchewan	(306) 736-2553
Kipling RCMP Detachment	Kipling, Saskatchewan	(306) 736-6400
Montmartre Fire Department	Montmartre, Saskatchewan	(306) 424-2040
Montmartre RCMP Detachment	Montmartre, Saskatchewan	(306) 424-6400
Moosomin Ambulance Services	Moosomin, Saskatchewan	(306) 435-2962
Moosomin Fire Department	Moosomin, Saskatchewan	(306) 435-2105
Moosomin RCMP Detachment	Moosomin, Saskatchewan	(306) 435-3361
Regina City Police Department	Regina, Saskatchewan	(306) 777-6500
Regina EMS - Ambulance	Regina, Saskatchewan	(306) 766-7007
Regina Fire Department	Regina, Saskatchewan	(306) 777-7829 /7830
Regina RCMP Detachment	Regina, Saskatchewan	(306) 780-5560
Val Marie Fire Department	Val Marie, Saskatchewan	(306) 298-2012 /2022
White City Fire Department	White City, Saskatchewan	(306) 781-2303

Whitewood Fire Department	Whitewood, Saskatchewan	(306) 735-2331
Wolseley Fire Department	Wolseley, Saskatchewan	(306) 698-2288

EXTERNAL NOTIFICATION REFERENCES
Manitoba

OTHER POTENTIAL REQUIRED NOTIFICATIONS

DIAL 911 for all Police, Fire and Ambulance Services.

*** Calls to 911 concerning petroleum spills will usually alert LEPC; however, it is advisable to notify them directly for any spill that requires a 911 notification.**

AGENCY	LOCATION	OFFICE / ALTERNATE
Southwestern Manitoba		
Austin Fire Department	Austin, Manitoba	(204) 637-2169
Brandon Ambulance	Brandon, Manitoba	(204) 729-2400 /2406
Brandon Fire Department	Brandon, Manitoba	(204) 729-2400 /2406
Brandon RCMP Detachment	Brandon, Manitoba	(204) 726-7500 /7522
Broadview Fire Department	Broadview, Saskatchewan	(306) 696-2533
Broadview RCMP Detachment	Broadview, Saskatchewan	(306) 696-5200
Carberry - Assiniboine EMS	Carberry, Manitoba	(204) 834-3548
Carberry Ambulance Services	Carberry, Manitoba	(204) 834-3548
Carberry Fire Department	Carberry, Manitoba	(204) 834-2212
Carberry RCMP Detachment	Carberry, Manitoba	(204) 834-2905
Cartier Ambulance	Elie, Manitoba	(204) 353-4161
Cartier Fire Department	Elie, Manitoba	(204) 353-2214 /2424
City of Brandon Emergency Management Services	Brandon, Manitoba	(204) 729-2239
Dominion City Fire Department	Dominion City, Manitoba	(204) 427-2628
Emerson Ambulance Department	Emerson, Manitoba	(204) 373-2002
Emerson Fire Department	Emerson, Manitoba	(204) 373-2335 /2414
Emerson RCMP	Emerson, Manitoba	(204) 373-2505
Falcon / Whiteshell Fire Department	Falcon Lake, Manitoba	(204) 349-8772
Gladstone RCMP Detachment	Gladstone, Manitoba	(204) 385-3035
Hadashville Ambulance Services	Hadashville, Manitoba	(204) 426-5328

Hamiota - Ambulance EMS	Hamiota, Manitoba	(204) 764-4207
Hamiota Fire Department	Hamiota, Manitoba	(204) 764-3050 /3055
Hamiota RCMP Detachment	Hamiota, Manitoba	(204) 759-2704 /2732
Headingley Fire Department	Headingley, Manitoba	(204) 837-5766
Headingley RCMP Detachment	Headingley, Manitoba	(204) 888-0358
Headingley Traffic Services	Winnipeg, Manitoba	(204) 984-6911
Ile des Chenes Ambulance Services	St. Pierre-Jolys, Manitoba	(204) 433-3330
MacDonald Ambulance Services	Oak Bluff, Manitoba	(204) 837-3332
MacGregor Ambulance Services	MacGregor, Manitoba	(204) 685-2161
MacGregor Fire Department	MacGregor, Manitoba	(204) 685-2161
MacGregor RCMP	Portage la Prairie, Manitoba	(204) 857-4445
McAuley Fire Department	McAuley, Manitoba	(204) 722-2211
Miniota Fire Department	Miniota, Manitoba	(204) 567-3683 /3813
Minnedosa Ambulance Services	Minnedosa, Manitoba	(204) 867-5555
Minnedosa EMO Services	Minnedosa, Manitoba	(204) 867-5273
Minnedosa Fire Department	Minnedosa, Manitoba	(204) 867-2727
Minnedosa RCMP Detachment	Minnedosa, Manitoba	(204) 867-2916
Morris RCMP Detachment	Morris, Manitoba	(204) 746-2323
Neepawa Ambulance Services	Neepawa, Manitoba	(204) 476-7840
Neepawa Fire Department	Neepawa, Manitoba	(204) 476-7654
Neepawa RCMP Detachment	Neepawa, Manitoba	(204) 476-7340
North Eastman Health Association Inc	Pinawa, Manitoba	(204) 753-2015
Oak Bank RCMP Detachment	Oak Bank, Manitoba	(204) 444-3847
Oak River Fire Department	Oak River, Manitoba	(204) 566-2126
Portage la Prairie Ambulance Central Region Health	Portage la Prairie, Manitoba	(204) 857-5444
Portage la Prairie Fire Department	Portage la Prairie, Manitoba	(204) 239-5154

Portage la Prairie RCMP Detachment	Portage la Prairie, Manitoba	(204) 857-8767 /4445
Rapid City EMO	Rapid City, Manitoba	(204) 826-2679
Rapid City Fire Department	Rapid City, Manitoba	(204) 826-2652 /2679
Richer Fire Department	Richer, Manitoba	(204) 422-5929
Ritchot Fire Department	Ile Des Chenes, Manitoba	(204) 981-6782
Rivers Ambulance Services	Rivers, Manitoba	(204) 328-6201
Rivers Fire Department	Rivers, Manitoba	(204) 328-7437 /7930
Rivers Police Services	Rivers, Manitoba	(204) 328-7430
RM of Reynolds Fire Department	Hadashville, Manitoba	(204) 426-2265 /2266
RM of Tache Fire Department	Lorette, Manitoba	(204) 878-9977
Sanford Fire Department	Sanford, Manitoba	(204) 736-2255
Shoal Lake RCMP Detachment	Shoal Lake, Manitoba	(204) 759-2390
Souris RCMP Detachment	Souris, Manitoba	(204) 483-2854
South Eastman Health/EMS	Ste. Anne, Manitoba	(204) 935-2730
St. Malo Fire Department	St. Malo, Manitoba	(204) 347-5246 /
St. Pierre-Jolys Ambulance Service	St. Pierre-Jolys, Manitoba	(204) 433-7701
St. Pierre-Jolys Fire Department	St. Pierre-Jolys, Manitoba	(204) 433-7117
St. Pierre-Jolys RCMP Detachment	St. Pierre-Jolys, Manitoba	(204) 433-7908
Ste. Anne Fire Department	Ste. Anne, Manitoba	(204) 422-9110
Ste. Anne Police Service	Ste. Anne, Manitoba	(204) 422-8209
Steinbach Ambulance Services	Steinbach, Manitoba	(204) 346-6411
Steinbach Fire Department	Steinbach, Manitoba	(204) 326-1109 /9877
Steinbach RCMP Detachment	Steinbach, Manitoba	(204) 326-1234 /4452
Virden & Wallace Fire Department	Virden, Manitoba	(204) 748-1304
Virden Ambulance Services	Virden, Manitoba	(204) 748-4332
Virden RCMP Detachment	Virden, Manitoba	(204) 748-2046

Whitemouth Ambulance Services	Whitemouth, Manitoba	(204) 348-7700
Whitemouth Fire Department	Whitemouth, Manitoba	(204) 348-7911
Winnipeg Fire Paramedic Service	Winnipeg, Manitoba	(204) 986-6380
Winnipeg Police Service	Winnipeg, Manitoba	(204) 986-6222
Winnipeg RCMP Detachment	Winnipeg, Manitoba	(204) 983-5420

RESPONSE ZONE INFORMATION

North Dakota, South Dakota, Nebraska

RESPONSE ZONE CONTACT INFORMATION	
Owner Name:	TransCanada
Addresses:	Physical Address 450 - 1st Street Calgary, Alberta T2P 5H1
24 Hour Emergency Contact Phone Numbers:	1-800-447-8066 (24 Hours)
Telephone/Fax:	Telephone references, including 24 hour numbers, for the Facility, Owner, and Qualified Individual/Alternate Qualified Individual are provided in Figure 2.2.
Provinces/States Traversed:	North Dakota, South Dakota, Nebraska
Areas/Counties Traversed:	Barnes, Beadle, Butler, Cavalier, Cedar, Clark, Colfax, Day, Gage, Hanson, Hutchinson, Jefferson, Kingsbury, Marshall, McCook, Miner, Nelson, Pembina, Platte, Ransom, Saline, Sargent, Seward, Stanton, Steele, Walsh, Wayne, Yankton

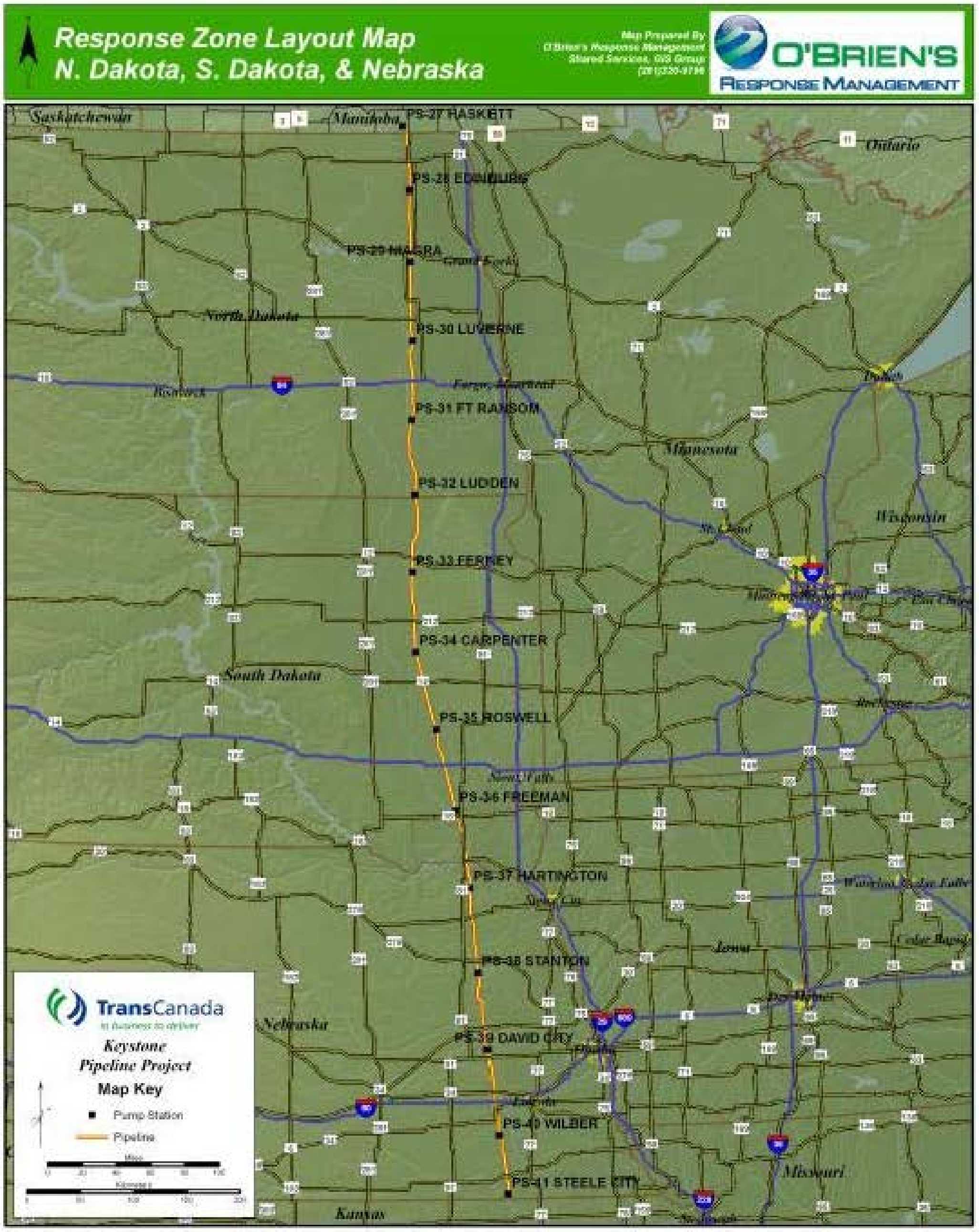
INFORMATION SUMMARY

Determination of Significant and Substantial Harm (United States Department of Transportation/Pipeline and Hazardous Materials Safety Administration):

This Response Zone has been determined to meet the significant and substantial harm classification because at least one (1) line section within the response zone has met at least one of the criteria listed in 49CFR194.103(c)(1).

Worst Case Discharge (Refer to Appendix B for calculations):

- **Potential Oil Group:** 3
- **United States Department of Transportation/Pipeline and Hazardous Materials Safety Administration Planning Volume:** 27,329 Bbls


Response Zone Layout Map
N. Dakota, S. Dakota, & Nebraska
O'BRIEN'S
RESPONSE MANAGEMENT
Saskatchewan
Manitoba
Ontario
North Dakota
Minnesota
Wisconsin
South Dakota
Iowa
Nebraska
Kansas
Missouri
PS-27 HASKETT
PS-28 EDINBURG
PS-29 NIAGRA
PS-30 LUVERNE
PS-31 FT RANSOM
PS-32 LUDDEN
PS-33 FERNEY
PS-34 CARPENTER
PS-35 ROSWELL
PS-36 FREEMAN
PS-37 HARTINGTON
PS-38 STANTON
PS-39 DAVID CITY
PS-40 WILBER
PS-41 STEELE CITY
TransCanada
Keystone
Pipeline Project
Map Key
Pump Station
Pipeline

030583

RESPONSE ZONE COMPANY CONTACTS				
POSITION/TITLE	NAME	OFFICE	HOME	CELL
[redacted]				

Area: North Dakota, South Dakota, Nebraska

Qualified Individuals:

Qualified Individuals			
NAME	OFFICE	HOME	CELL
[redacted]			

Alternate Qualified Individuals:

Alternate Qualified Individuals			
NAME	OFFICE	HOME	CELL

Pipeline Specifications:

The tables below list the pipeline facilities within the East Response Zone Response Zone.

Pipeline Specifications			
Location	Type of Oil	State	County
Ferney PS / Carpenter PS	Crude Oil	South Dakota	Day, Clark
Carpenter PS / Roswell PS	Crude Oil	South Dakota	Clark, Beadle, Kingsbury, Miner
Roswell PS / Freeman PS	Crude Oil	South Dakota	Miner, Hanson, McCook, Hutchinson

Freeman PS / Hartington PS	Crude Oil	Nebraska , South Dakota	Hutchinson, Yankton, Cedar
Hartington PS / Stanton PS	Crude Oil	Nebraska	Cedar, Wayne, Stanton
Stanton PS / David City PS	Crude Oil	Nebraska	Stanton, Platte, Colfax, Butler
David City PS / Wilber PS	Crude Oil	Nebraska	Butler, Seward, Saline
Wilber PS/Steele City PS	Crude Oil	Nebraska	Saline, Jefferson
Steele City / State Line	Crude Oil	Nebraska	Jefferson, Gage
US-CAN Border / Edinburg PS	Crude Oil	North Dakota	Cavalier, Pembina, Walsh
Edinburg PS / Niagara PS	Crude Oil	North Dakota	Walsh, Nelson
Niagara PS / Luverne PS	Crude Oil	North Dakota	Nelson, Steele
Luverne PS / Fort Ransom PS	Crude Oil	North Dakota	Steele, Barnes, Ransom
Fort Ransom PS / Ludden PS	Crude Oil	North Dakota	Ransom, Sargent
Ludden PS / Ferney PS	Crude Oil	North Dakota , South Dakota	Sargent, Marshall, Day

Company Owned Response Equipment:

Response Equipment		
NAME	**LOCATION**	**DESCRIPTION**
Equipment Responses Trailer		See Equipment List - Appendix A

Breakout Tanks:

Breakout Tanks			
FACILITY NAME	TANK NUMBER	CAPACITY (Bbls)	TYPE OF OIL

EXTERNAL NOTIFICATION REFERENCES
Nebraska

OTHER POTENTIAL REQUIRED NOTIFICATIONS		
DIAL 911 for all Police, Fire and Ambulance Services. * Calls to 911 concerning petroleum spills will usually alert LEPC; however, it is advisable to notify them directly for any spill that requires a 911 notification.		
AGENCY	**LOCATION**	**OFFICE / ALTERNATE**
Cedar		
Cedar County	Hartington, Nebraska	(402) 254-7411
Cedar County (LEPC)	Hartington, Nebraska	(402) 254-7411
Cedar County Sheriff & Emergency Mgmt.	Hartington, Nebraska	(402) 254-6884
City of Hartington	Hartington, Nebraska	(402) 254-6353
Wayne		
City of Wayne	Wayne, Nebraska	(402) 375-1733
City of Wayne Electric Distribution Department	Wayne, Nebraska	(402) 375-2896
City of Wayne Fire Department	Wayne, Nebraska	(402) 375-1122
City of Wayne Police Department	Wayne, Nebraska	(402) 375-2626
City of Wayne Public Works Department	Wayne, Nebraska	(402) 375-1300
City of Wayne Water Department	Wayne, Nebraska	(402) 375-5250
Wayne County (LEPC)	Wayne, Nebraska	(402) 833-5190
Stanton		
City of Stanton	Stanton, Nebraska	(402) 439-2119
Stanton County LEPC	Stanton, Nebraska	(402) 439-2631
Stanton County Sheriff	Stanton, Nebraska	(402) 439-2212
Village of Pilger	Stanton, Nebraska	(402) 396-3563
Platte		
City of Columbus	Columbus, Nebraska	(402) 562-4224
Platte County LEPC	Columbus, Nebraska	(402) 564-1206
Platte County Sheriff	Columbus, Nebraska	(402) 564-3229
Colfax		

City of Schuyler Schools	Schuyler, Nebraska	(402) 352-3527
Colfax County	Schuyler, Nebraska	(402) 352-8502
Colfax County LEPC	Schuyler, Nebraska	(402) 352-8522
Colfax County Sheriff	Schuyler, Nebraska	(402) 352-8526
Village of Leigh	Leigh, Nebraska	(402) 487-3303
Village of Richland	Richland, Nebraska	(402) 564-0609
Butler		
Butler County First Responder / Sheriff	David City, Nebraska	(402) 367-7400
Butler County LEPC	David City, Nebraska	(402) 367-3125
David City Electric & Light Department	David City, Nebraska	(402) 367-3197
David City Park & Auditorium Department	David City, Nebraska	(402) 367-3914
David City Police Department	David City, Nebraska	(402) 367-3133
David City Power Plant	David City, Nebraska	(402) 367-3138
David City Water & Sewer Department	David City, Nebraska	(402) 367-3132
Seward		
City of Milford	Milford, Nebraska	(402) 761-3247
City of Seward	Seward, Nebraska	(402) 643-2928
City of Seward Electric Department	Seward, Nebraska	(402) 643-3151
City of Seward Fire Department	Seward, Nebraska	(402) 643-6088
City of Seward Police Department	Seward, Nebraska	(402) 643-2759
City of Seward Sheriff	Seward, Nebraska	(402) 643-2359
City of Seward Water Department	Seward, Nebraska	(402) 643-3433
Seward County	Seward, Nebraska	(402) 643-6262
Seward County LEPC	Seward, Nebraska	(402) 643-4722
Village of Bee	Bee, Nebraska	(402) 643-6247
Village of Goehner	Goehner, Nebraska	(402) 534-4311
Village of Staplehurst	Staplehurst, Nebraska	(402) 535-2507

Jefferson		
City of Fairbury	Fairbury, Nebraska	(402) 729-2476
Jefferson Co. Emergency Management Agency/Planning	Fairbury, Nebraska	(402) 729-3602
Village of Diller	Diller, Nebraska	(402) 793-5991
Village of Plymouth	Plymouth Village, Nebraska	(402) 656-3132
Saline		
City of Wilber	Wilber, Nebraska	(402) 821-2320
City of Wilber Fire Department	Wilber, Nebraska	(402) 821-2647
City of Wilber Police Department	Wilber, Nebraska	(402) 821-2201
Saline County	Wilber, Nebraska	(402) 826-2363
Saline County LEPC	Wilber, Nebraska	(402) 821-3010
Saline County Sheriff	Wilber, Nebraska	(402) 821-2111
Village of Dorchester	Dorchester, Nebraska	(402) 946-3201
Village of Swanton	Swanton, Nebraska	(402) 448-2285
Gage		
Gage County LEPC	Beatrice, Nebraska	(402) 223-1305
Gage County Sheriff / First Responder	Beatrice, Nebraska	(402) 223-1382

EXTERNAL NOTIFICATION REFERENCES
North Dakota

OTHER POTENTIAL REQUIRED NOTIFICATIONS		
DIAL 911 for all Police, Fire and Ambulance Services. * Calls to 911 concerning petroleum spills will usually alert LEPC; however, it is advisable to notify them directly for any spill that requires a 911 notification.		
AGENCY	**LOCATION**	**OFFICE / ALTERNATE**
Cavalier		
Cavalier County	Langdon, North Dakota	(701) 256-2229
Cavalier County Fire Department	Langdon, North Dakota	(701) 256-3911
Cavalier County LEPC	Langdon, North Dakota	(701) 256-3911
Cavalier County Water Resource	Langdon, North Dakota	(701) 256-2220
Fremont Township	Walhalla, North Dakota	(701) 549-2748
Pembina		
City of Cavalier	Cavalier, North Dakota	(701) 265-8800
City of Walhalla	Walhalla, North Dakota	(701) 549-3176
Drayton, North Dakota	Drayton, North Dakota	(701) 265-4231
Pembina County	Cavalier, North Dakota	(701) 265-4231
Pembina County LEPC	Cavalier, North Dakota	(701) 265-4849
Pembina County Water Resource Board	Cavalier, North Dakota	(701) 265-4511
Walsh		
City of Grafton	Grafton, North Dakota	(701) 352-1561
City of Lankin	Lankin, North Dakota	(701) 593-6322
City of Minto	Minto, North Dakota	(701) 248-3480
City of Park River	Park River, North Dakota	(701) 284-6426
Golden Township	Park River, North Dakota	(701) 284-6846
Norton Township	Fordville, North Dakota	(701) 593-6249
Town of Norton	Park River, North Dakota	(701) 331-0810
Vesta Township	Adams, North Dakota	(701) 944-2790

Walsh County LEPC	Grafton, North Dakota	(701) 352-2311
Nelson		
Adler Township, Nelson County	Petersburg, North Dakota	(701) 345-8287
Dodds Township, Nelson County	Lakota, North Dakota	(701) 247-2279
Michigan City	Michigan, North Dakota	(701) 259-2553
Nelson County	Lakota, North Dakota	(701) 247-2463
Nelson County Fire Department	Lakota, North Dakota	(701) 247-2474
Nelson County First Responder	Lakota, North Dakota	(701) 247-2474
Petersburg Township, Nelson County	Petersburg, North Dakota	(701) 345-6134
Steele		
City of Finley	Finley, North Dakota	(701) 352-1651
Steele County	Finley, North Dakota	(701) 945-2572
Steele County LEPC	Finley, North Dakota	(701) 524-2742
Barnes		
Barnes County	Sanborn, North Dakota	(701) 646-6983
Barnes County Emergency Manager (LEPC)	Valley City, North Dakota	(701) 845-8510
Township of Alta	Valley City, North Dakota	(701) 845-2744
Township of Baldwin	Hope, North Dakota	(701) 945-2436
Township of Cuba	Valley City, North Dakota	(701) 845-0533
Township of Grand Prairie	Valley City, North Dakota	(701) 845-2544
Township of Noltimier	Valley City, North Dakota	(701) 845-3835
Township of Norma	Oriska, North Dakota	(701) 924-8629
Valley City	Valley City, North Dakota	(701) 845-1700 ext. 17
Ransom		
City of Lisbon	Lisbon, North Dakota	(701) 683-4472 Rvrsd Bldg Ctr
Ransom County LEPC	Lisbon, North Dakota	(701) 683-5823, x125
Sargent		
City of Forman	Forman, North Dakota	(701) 724-3673

Denver Township	Gwinner, North Dakota	(701) 753-7671
Jackson Township	Forman, North Dakota	(701) 724-3420
Sargent County First Responder	Forman, North Dakota	(701) 724-3302
Sargent County LEPC	Forman, North Dakota	(701) 724-6241, x113
Southwest Township	Forman, North Dakota	(701) 724-3452
Verner Township	Oakes, North Dakota	(701) 742-3711
Verner Township	Gwinner, North Dakota	(701) 753-7161

EXTERNAL NOTIFICATION REFERENCES
South Dakota

OTHER POTENTIAL REQUIRED NOTIFICATIONS

DIAL 911 for all Police, Fire and Ambulance Services.

*** Calls to 911 concerning petroleum spills will usually alert LEPC; however, it is advisable to notify them directly for any spill that requires a 911 notification.**

AGENCY	LOCATION	OFFICE / ALTERNATE
Marshall		
BDM Rural Water System, Inc.	Britton, South Dakota	(605) 448-5417
City of Britton, South Dakota	Britton, South Dakota	(605) 448-5721
Marshall County LEPC	Britton, South Dakota	(605) 448-2401
Marshall County South Dakota	Britton, South Dakota	(605) 448-2116
Mc Cook Co., SD County Emergency Management	Britton, South Dakota	(605) 425-2791
Day		
City of Webster, South Dakota	Webster, South Dakota	(605) 345-3241
Day County, South Dakota LEPC	Webster, South Dakota	(605) 345-9500
Clark		
City of Clark, South Dakota	Clark, South Dakota	(605) 532-3512
Clark County, South Dakota	Clark, South Dakota	(605) 532-5921
Clark County, South Dakota LEPC	Clark, South Dakota	(605) 532-5953
Beadle		
Beadle County, South Dakota	Huron, South Dakota	(605) 352-5010
Beadle County, South Dakota LEPC	Huron, South Dakota	(605) 353-8421
City of Huron, South Dakota	Huron, South Dakota	(605) 353-8500
Kingsbury		
City of De Smet, South Dakota	De Smet, South Dakota	(605) 854-3731
Kingsbury County Fire Department / First Responder	De Smet, South Dakota	(605) 854-3832
Kingsbury County, South Dakota	De Smet, South Dakota	(605) 854-3832
Kingsbury County, South Dakota LEPC	De Smet, South Dakota	(605) 854-3711

Miner		
Miner County Fire Department / First Responder	Howard, South Dakota	(605) 772-4671
Miner County, South Dakota LEPC	Howard, South Dakota	(605) 772-4533
Hanson		
Edgerton Township	Alexandria, South Dakota	(605) 239-4361
Hanson County Fire Department	Alexandria, South Dakota	(605) 239-4717
Hanson County, South Dakota	Alexandria, South Dakota	(605) 239-4717
Hanson County, South Dakota LEPC	Alexandria, South Dakota	(605) 239-4218
Spring Lake Township	Canova, South Dakota	(605) 523-2546
McCook		
McCook Co., SD County Emergency Management	Salem, South Dakota	(605) 425-2791
McCook County, South Dakota LEPC	Salem, South Dakota	(605) 425-2466
Hutchinson		
City of Olivet	Olivet, South Dakota	(605) 387-5596
Grandview Township	Freeman, South Dakota	(605) 925-4142
Hutchinson County, South Dakota	Menno, South Dakota	(605) 387-4217
Hutchinson County, South Dakota LEPC	Menno, South Dakota	(605) 387-5104
Molan Township	Menno, South Dakota	(605) 387-5250
Pleasant Township	Bridgewater, South Dakota	(605) 449-4669
Valley Township	Menno, South Dakota	(605) 387-5480
Yankton		
City of Yankton Fire Department	Yankton, South Dakota	(605) 668-5210
City of Yankton, Department of Public Works	Yankton, South Dakota	(605) 668-5251
City of Yankton, South Dakota	Yankton, South Dakota	(605) 668-5210
Jamesville Township	Jamesville, South Dakota	(605) 387-5756
Mission Hill Township	Mission Hill, South Dakota	(605) 665-7592
Utica Township	Utica, South Dakota	(605) 665-1341

Yankton County Fire Department	Yankton, South Dakota	(605) 668-3567
Yankton County LEPC	Yankton, South Dakota	(605) 668-5289
Yankton County, South Dakota	Yankton, South Dakota	(605) 668-3567

RESPONSE ZONE INFORMATION

Kansas, Missouri, Illinois

RESPONSE ZONE CONTACT INFORMATION

Owner Name:	TransCanada
Addresses:	Physical Address 450 - 1st Street Calgary, Alberta T2P 5H1
24 Hour Emergency Contact Phone Numbers:	1-800-447-8066 (24 Hours)
Telephone/Fax:	Telephone references, including 24 hour numbers, for the Facility, Owner, and Qualified Individual/Alternate Qualified Individual are provided in Figure 2.2.
Provinces/States Traversed:	Kansas, Missouri, Illinois
Areas/Counties Traversed:	Audrain, Bond, Brown, Buchanan, Caldwell, Carroll, Chariton, Clinton, Doniphan, Fayette, Lincoln, Madison, Marion, Marshall, Montgomery, Nemaha, Randolph, St. Charles

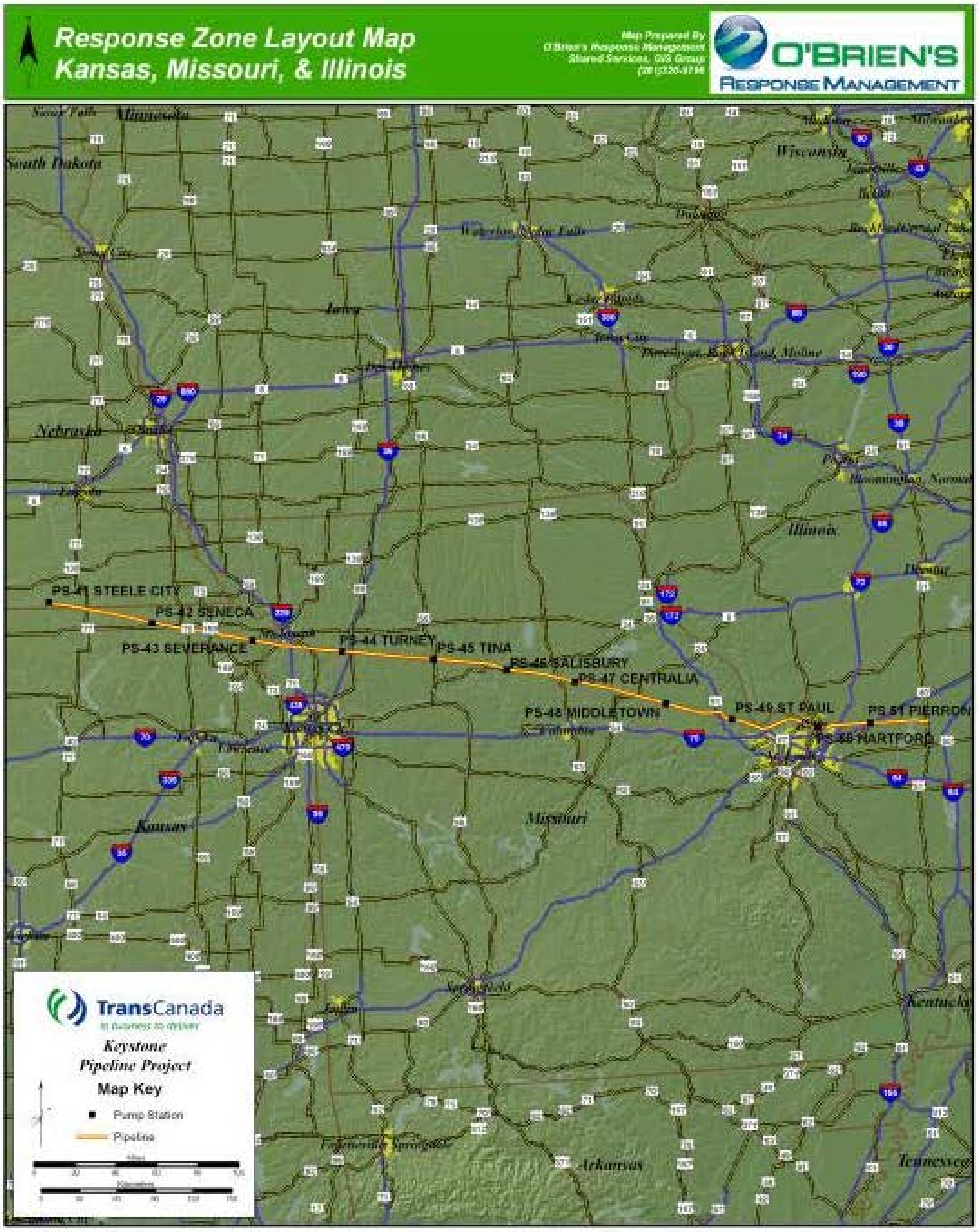
INFORMATION SUMMARY

Determination of Significant and Substantial Harm (United States Department of Transportation/Pipeline and Hazardous Materials Safety Administration):

This Response Zone has been determined to meet the significant and substantial harm classification because at least one (1) line section within the response zone has met at least one of the criteria listed in 49CFR194.103(c)(1).

Worst Case Discharge (Refer to Appendix B for calculations):

- **Potential Oil Group:** 3
- **United States Department of Transportation/Pipeline and Hazardous Materials Safety Administration Planning Volume:** 24,069 Bbls


Response Zone Layout Map
Kansas, Missouri, & Illinois
O'BRIEN'S
RESPONSE MANAGEMENT
PS-41 STEELE CITY
PS-42 SENECA
PS-43 SEVERANCE
PS-44 TURNEY
PS-45 TINA
PS-46 SALISBURY
PS-47 CENTRALIA
PS-48 MIDDLETOWN
PS-49 ST PAUL
PS-50 HARTFORD
PS-51 PIERRON
South Dakota
Nebraska
Kansas
Missouri
Illinois
Wisconsin
Arkansas
Kentucky
Tennessee
TransCanada
Keystone
Pipeline Project
Map Key
Pump Station
Pipeline

RESPONSE ZONE COMPANY CONTACTS				
POSITION/TITLE	NAME	OFFICE	HOME	CELL
[redacted]				

Area: Kansas, Missouri, Illinois

Qualified Individuals:

Qualified Individuals			
NAME	OFFICE	HOME	CELL
[redacted]			

Alternate Qualified Individuals:

Alternate Qualified Individuals			
NAME	OFFICE	HOME	CELL

Pipeline Specifications:

The tables below list the pipeline facilities within the East Response Zone Response Zone.

Pipeline Specifications			
Location	Type of Oil	State	County
State Line / Seneca PS	Crude Oil	Kansas	Marshall, Nemaha
Seneca PS / Severance PS	Crude Oil	Kansas	Nemaha, Brown, Doniphan
Severance PS / Turney PS	Crude Oil	Kansas , Missouri	Doniphan, Buchanan, Clinton
Turney PS / Tina PS	Crude Oil	Missouri	Clinton, Caldwell, Carroll
Tina PS / Salisbury PS	Crude Oil	Missouri	Carroll, Chariton

Salisbury PS / Centralia PS	Crude Oil	Missouri	Chariton, Randolph, Audrain
Centralia PS / Middletown PS	Crude Oil	Missouri	Audrain, Montgomery
Middletown PS / Saint Paul PS	Crude Oil	Missouri	Montgomery, Lincoln
Saint Paul PS / Hartford PS	Crude Oil	Illinois , Missouri	Lincoln, St. Charles, Madison
Hartford PS / Patoka Terminal	Crude Oil	Illinois	Madison, Bond, Fayette, Marion

Company Owned Response Equipment:

Response Equipment		
NAME	**LOCATION**	**DESCRIPTION**
Equipment Response Trailer		See Equipment List - Appendix A

Breakout Tanks:

Breakout Tanks			
FACILITY NAME	TANK NUMBER	CAPACITY (Bbls)	TYPE OF OIL

EXTERNAL NOTIFICATION REFERENCES
Illinois

OTHER POTENTIAL REQUIRED NOTIFICATIONS		
DIAL 911 for all Police, Fire and Ambulance Services. * Calls to 911 concerning petroleum spills will usually alert LEPC; however, it is advisable to notify them directly for any spill that requires a 911 notification.		
AGENCY	**LOCATION**	**OFFICE / ALTERNATE**
Madison		
City of Edwardsville	Edwardsville, Illinois	(618) 692-7520
City of Edwardsville Fire Department	Edwardsville, Illinois	(618) 692-7541
City of Edwardsville, Illinois Public Works	Edwardsville, Illinois	(618) 692-7535
City of Highland Fire Department	Highland, Illinois	(618) 654-5901
City of Wood River Fire Department	Wood River, Illinois	(618) 251-3100
Madison Co. Ambulance (Fire Dept) First Respons	Edwardsville, Illinois	(618) 692-4433
Madison Co. IL Emergency Svcs. and Disaster Agency	Edwardsville, Illinois	(618) 692-0537
Madison County	Edwardsville, Illinois	(618) 692-4482
Madison County (LEPC)	Edwardsville, Illinois	(618) 296-4482
Bond		
Bond Co. IL Emergency Svcs. and Disaster Agency	Greenville, Illinois	(618) 644-1442
Bond County (LEPC)	Greenville, Illinois	(618) 644-1442
Bond County First Responder (Fire Department)	Greenville, Illinois	(618) 664-2151
City of Greenville	Greenville, Illinois	(618) 664-1644
City of Greenville Public Works Department	Greenville, Illinois	(618) 664-1644
Village of Pocahontas	Pocahontas, Illinois	(618) 669-2431
Fayette		
City of Alton Fire Department	Alton, Illinois	(618) 463-3565
City of Vandalia Public Works Department	Vandalia, Illinois	(618) 283-1296

City of Vandalia, Illinois	Vandalia, Illinois	(618) 283-1196
Fayette County	Vandalia, Illinois	(618) 283-5000
Fayette County (LEPC)	Vandalia, Illinois	(618) 283-4292
Fayette County Ambulance / First Responder	Vandalia, Illinois	(618) 283-2141
Marion		
Army Corps of Engineers - St. Louis District	Illinois	(314) 331-8583
City of Patoka	Patoka, Illinois	(618) 432-5855
City of Salem Marion County	Salem, Illinois	(618) 548-2222
Marion Co. Ambulance (Fire Dept) / First Response	Salem, Illinois	(618) 548-2141
Marion County (LEPC)	Salem, Illinois	(618) 548-2600
Marion County Department of Environmental Quality	Salem, Illinois	(618) 692-0537

EXTERNAL NOTIFICATION REFERENCES
Kansas

OTHER POTENTIAL REQUIRED NOTIFICATIONS

DIAL 911 for all Police, Fire and Ambulance Services.

*** Calls to 911 concerning petroleum spills will usually alert LEPC; however, it is advisable to notify them directly for any spill that requires a 911 notification.**

AGENCY	LOCATION	OFFICE / ALTERNATE
Marshall		
City of Axtell	Axtell, Kansas	(785) 736-2834
City of Beattie	Beattie, Kansas	(785) 353-2527
City of Summerfield	Summerfield, Kansas	(785) 244-6531
Marshall County LEPC First Responder	Marysville, Kansas	(785) 562-3141
Marshall County Public Works Department	Marysville, Kansas	(785) 562-5349
Nemaha		
City of Oneida Sewerage Department	Oneida, Kansas	(785) 336-3038
City of Seneca	Seneca, Kansas	(785) 336-2747
Nemaha Co. Emergency Management / First Responder	Seneca, Kansas	(785) 336-2135
Brown		
Brown County Fire Department	Hiawatha, Kansas	(785) 742-7125
Brown County LEPC	Hiawatha, Kansas	(785) 547-3415
City of Fairview	Fairview, Kansas	(785) 467-3521
City of Hamlin	Hamlin, Kansas	(785) 742-2995
City of Hiawatha	Hiawatha, Kansas	(785) 742-2967
City of Robinson	Robinson, Kansas	(785) 544-7766
Irving Township	Hiawatha, Kansas	(785) 544-6691
Mission Township	Hiawatha, Kansas	(785) 474-3564
Morrill Township	Morrill, Kansas	(785) 459-2277
Padonia Township	Hiawatha, Kansas	(785) 742-2777
Powhattan Township	Powhattan, Kansas	(785) 467-3520

Robinson Township	Robinson, Kansas	(785) 544-6831
Walnut Township	Walnut, Kansas	(785) 467-3250
Doniphan		
City of Denton	Denton, Kansas	(785) 359-6952
City of Denton Fire Department	Denton, Kansas	(785) 359-6641
City of Severance	Severance, Kansas	(785) 359-6589
City of Troy	Troy, Kansas	(785) 985-2101
Doniphan Co. Emergency Management / Zoning Dept.	Troy, Kansas	(785) 985-2229
Doniphan County Fire District No. 1	Wathena, Kansas	(785) 989-3265
Doniphan County Fire District No. 2	Highland, Kansas	(785) 359-6699
Doniphan County Fire District No. 3	Denton, Kansas	(785) 359-6715
Doniphan County Fire District No. 4	Elwood, Kansas	(913) 365-8697
Doniphan County Fire District No. 5	Troy, Kansas	(785) 985-2145
Independence Township	Independence, Kansas	(785) 988-4425
Union Township	Denton, Kansas	
Wayne Township	Troy, Kansas	(785) 985-2400
Wold River Township	Severance, Kansas	(785) 442-3775
Marion		
Army Corps of Engineers - St. Louis District	Illinois	(314) 331-8583
City of Patoka	Patoka, Illinois	(618) 432-5855
City of Salem Marion County	Salem, Illinois	(618) 548-2222
Marion Co. Ambulance (Fire Dept) / First Response	Salem, Illinois	(618) 548-2141
Marion County (LEPC)	Salem, Illinois	(618) 548-2600
Marion County Department of Environmental Quality	Salem, Illinois	(618) 692-0537

EXTERNAL NOTIFICATION REFERENCES
Missouri

OTHER POTENTIAL REQUIRED NOTIFICATIONS

DIAL 911 for all Police, Fire and Ambulance Services.

*** Calls to 911 concerning petroleum spills will usually alert LEPC; however, it is advisable to notify them directly for any spill that requires a 911 notification.**

AGENCY	LOCATION	OFFICE / ALTERNATE
Buchanan		
Buchanan County LEPC	St. Joseph, Missouri	(816) 271-1574
City of Gower Clerk	Gower, Missouri	
City of St Joseph Council	St Joseph, Missouri	(816) 271-4640
City of St Joseph LEPC	St Joseph, Missouri	(816) 271-4603
Colony Fire District	St. Joseph, Missouri	(816) 232-5307
Dearborn Fire District, Buchanan County	Dearborn, Missouri	(816) 992-8919
Easton Fire District, Buchanan County	Easton, Missouri	(816) 262-7057
Edgerton Fire District, Buchanan County	Edgerton, Missouri	(816) 790-3362
Maxwell Heights Fire District, Buchanan County	St. Joseph, Missouri	(816) 233-4160
Rushville Fire District, Buchanan County	Rushville, Missouri	(816) 688-7900
San Antonio Fire District, Buchanan County	San Antonio, Missouri	(816) 232-1664
South Buchanan Fire District, Buchanan County	Faucett, Missouri	(816) 253-9018
Sugar Lake Fire District, Buchanan County	Rushville, Missouri	(913) 367-2655
Village of Agency Clerk	Agency, Missouri	(816) 253-9176
Village of Dekalb Clerk	Amity, Missouri	(816) 685-3305
Village of Lewis & Clark Clerk	Lewis & Clark, Missouri	(816) 579-5737
Clinton		
City of Cameron	Cameron, Missouri	(816) 632-2177
City of Cameron Fire Department	Cameron, Missouri	(816) 632-2345
City of Cameron Police Department / First Responde	Cameron, Missouri	(816) 632-6521

City of Cameron Public Works Department	Cameron, Missouri	(816) 632-2177
City of Cameron Water and Electric Department	Cameron, Missouri	(816) 632-2177
City of Lathrop	Lathrop, Missouri	(816) 740-4251
Clinton County PWSD No 1	Plattsburg, Missouri	(816) 370-2528
Clinton County PWSD No 4	Plattsburg, Missouri	(816) 580-7211
Lathrop Fire District	Lathrop, Missouri	(816) 740-3218
Osborne Fire District	Osborne, Missouri	(816) 675-2549
Plattsburg City Hall	Plattsburg, Missouri	(816) 539-2148
Plattsburg Fire District	Plattsburg, Missouri	(816) 539-3017
Stewartsville Fire District	Stewartsville, Missouri	(816) 669-3387
Village of Turney	Turney, Missouri	(816) 664-2009
Caldwell		
Caldwell County	Kingston, Missouri	(816) 586-2571
Cowgill No 1 Water District	Cowgill, Missouri	(660) 255-4421
Grant Township	Livonia, Missouri	(660) 354-2337
Rockford Township	Polo, Missouri	
Carroll		
Carroll County	Carrollton, Missouri	(660) 542-0615
Carroll County Fire Protection District No. 1	Carrollton, Missouri	(660) 542-2178
City of Carrollton	Carrollton, Missouri	(660) 542-1414
Hale Fire Protection District	Hale, Missouri	(660) 565-2212
Norborne Fire Protection District	Norborne, Missouri	(660) 594-3505
North Central Fire Protection District	Bogard, Missouri	(660) 731-5371
Stet Fire Protection District	Norborne, Missouri	(660) 484-3179
Chariton		
Chariton County, Missouri	Keytesville, Missouri	(660) 288-3200
Chariton County, Missouri LEPC/First Responder	Keytesville, Missouri	(660) 288-3277

City of Keytesville, Missouri	Keytesville, Missouri	(660) 288-3745
City of Salisbury, Missouri	Salisbury, Missouri	(660) 388-6197
Randolph		
City of Huntsville, Missouri	Huntsville, Missouri	(660) 277-3110
City of Moberly, Missouri Public Works	Moberly, Missouri	(660) 269-8705
Randolph County County Government	Huntsville, Missouri	(660) 277-4714
Randolph County LEPC	Huntsville, Missouri	(573) 564-2283
Audrain		
Audrain County, Missouri	Mexico, Missouri	(573) 473-5822
Audrain County, Missouri LEPC	Mexico, Missouri	(660) 582-8183
City of Mexico, Missouri	Mexico, Missouri	(573) 581-2100
Montgomery		
City of Montgomery, Missouri	Montgomery City, Missouri	(573) 564-3160
Montgomery County	Montgomery City, Missouri	(573) 564-8084
Montgomery County LEPC	Montgomery City, Missouri	(573) 564-2283
Lincoln		
Lincoln County Fire Protection District	Troy, Missouri	(636) 528-8567
Lincoln County, Missouri	Troy, Missouri	(636) 528-6300
Lincoln County, Missouri LEPC	Troy, Missouri	(636) 528-6182
St. Charles		
Central County Fire & Rescue	St. Peters, Missouri	(636) 970-9700
City of O'Fallon, Missouri	O'Fallon, Missouri	(636) 379-5500
City of St. Charles City/Municipal Government	St. Charles City, Missouri	(636) 949-3260
City of St. Charles Fire Department	St. Charles, Missouri	(636) 949-3250
City of St. Peters, Missouri	St. Peters, Missouri	(636) 477-9920
Dardenne Prairie Township	O'Fallon, Missouri	(636) 300-0014
O'Fallon Fire Protection District	O'Fallon, Missouri	(636) 272-3493

O'Fallon Township	O'Fallon, Missouri	(636) 978-4144
St. Charles County First Responder	St. Charles, Missouri	(636) 949-1818
St. Charles County Government	St. Charles, Missouri	(636) 949-7455
St. Charles County LEPC	St. Charles, Missouri	(636) 949-3023
Wentzville Fire Protection District	Wentzville, Missouri	(636) 327-6239
Wentzville Township	Wentzville, Missouri	(636) 332-5101

RESPONSE ZONE INFORMATION

Cushing Extension

RESPONSE ZONE CONTACT INFORMATION	
Owner Name:	TransCanada
Addresses:	Physical Address 450 - 1st Street Calgary, Alberta T2P 5H1
24 Hour Emergency Contact Phone Numbers:	1-800-447-8066 (24 Hours)
Telephone/Fax:	Telephone references, including 24 hour numbers, for the Facility, Owner, and Qualified Individual/Alternate Qualified Individual are provided in Figure 2.2.
Provinces/States Traversed:	Kansas, Nebraska, Oklahoma
Areas/Counties Traversed:	Butler, Clay, Cowley, Dickinson, Jefferson, Kay, Lincoln, Marion, Noble, Payne, Washington

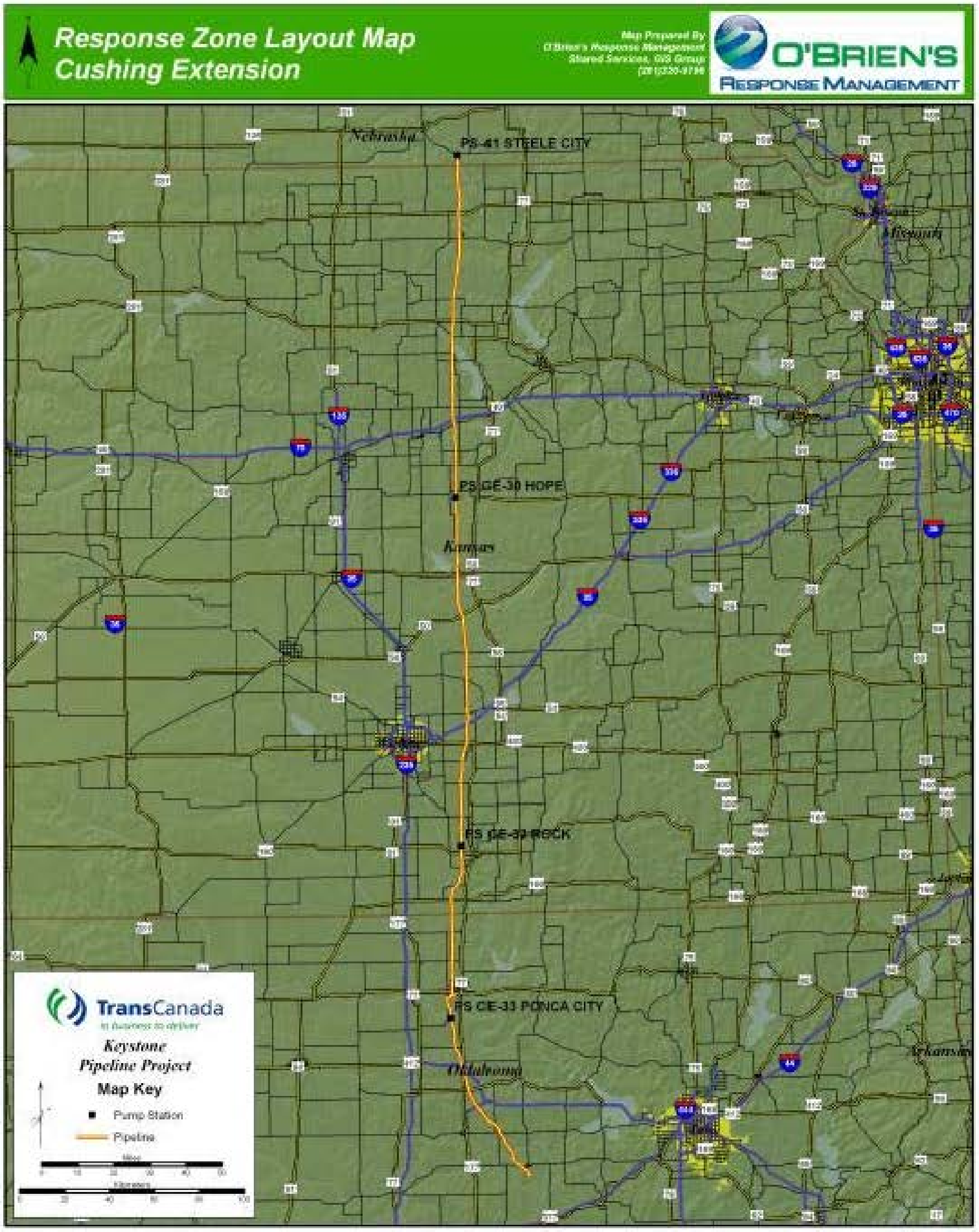
INFORMATION SUMMARY

Determination of Significant and Substantial Harm (United States Department of Transportation/Pipeline and Hazardous Materials Safety Administration):

This Response Zone has been determined to meet the significant and substantial harm classification because at least one (1) line section within the response zone has met at least one of the criteria listed in 49CFR194.103(c)(1).

Worst Case Discharge (Refer to Appendix B for calculations):

- **Potential Oil Group:** 3
- **United States Department of Transportation/Pipeline and Hazardous Materials Safety Administration Planning Volume:** 32,265 Bbls


Response Zone Layout Map
Cushing Extension
Map Prepared By
O'BRIEN'S
RESPONSE MANAGEMENT
Nebraska
PS-41 STEELE CITY
PS GE-30 HOPE
Kansas
PS GE-33 PONCA CITY
Oklahoma
Missouri
TransCanada
Keystone
Pipeline Project
Map Key
Pump Station
Pipeline

RESPONSE ZONE COMPANY CONTACTS				
POSITION/TITLE	NAME	OFFICE	HOME	CELL
[redacted]				

Area: Cushing Extension Area

Qualified Individuals:

Qualified Individuals			
NAME	OFFICE	HOME	CELL
[redacted]			

Alternate Qualified Individuals:

Alternate Qualified Individuals			
NAME	OFFICE	HOME	CELL

Pipeline Specifications:

The tables below list the pipeline facilities within the East Response Zone Response Zone.

Pipeline Specifications			
Location	Type of Oil	State	County
Station Steele City / Hope PS	Crude Oil	Kansas , Nebraska	Jefferson, Washington, Clay, Dickinson
Hope PS / Rock PS	Crude Oil	Kansas	Marion, Dickinson, Butler, Cowley
Rock PS / Ponca City PS	Crude Oil	Kansas , Oklahoma	Cowley, Kay

Ponca City PS / Cushing Extension	Crude Oil	Oklahoma	Kay, Noble, Payne

Company Owned Response Equipment:

Response Equipment		
NAME	**LOCATION**	**DESCRIPTION**
Equipment Response Trailer		See Equipment List - Appendix A

Breakout Tanks:

Breakout Tanks			
FACILITY NAME	TANK NUMBER	CAPACITY (Bbls)	TYPE OF OIL

EXTERNAL NOTIFICATION REFERENCES
Kansas

OTHER POTENTIAL REQUIRED NOTIFICATIONS

DIAL 911 for all Police, Fire and Ambulance Services.

*** Calls to 911 concerning petroleum spills will usually alert LEPC; however, it is advisable to notify them directly for any spill that requires a 911 notification.**

AGENCY	LOCATION	OFFICE / ALTERNATE
Marion		
City of Marion Fire Department	Marion, Kansas	(620) 382-3833
Lost Springs Fire Dept.	Lost Springs, Kansas	(785) 983-4410
Marion County EMS	Marion, Kansas	(620) 382-6271
Marion County Environmental Dept.	Marion, Kansas	(620) 382-2550
Marion County LEPC	Marion, Kansas	(620) 382-2144
Marion County Sheriff	Marion, Kansas	(620) 382-2144
Washington		
City of Linn Fire Department	Linn, Kansas	(785) 348-5373
Hanover Fire Department	Washington, Kansas	(785) 325-2293
Hanover Hospital	Hanover, Kansas	(785) 337-2214
Washington County LEPC	Washington, Kansas	(785) 325-2924
Washington County Sheriff	Washington, Kansas	(785) 325-2293
Washington Hospital	Washington, Kansas	(785) 325-2211
Clay		
Clay Center Fire Dept.	Clay Center, Kansas	(785) 632-5606
Clay County (First Responder)	Kansas	
Clay County Ambulance Service	Clay Center, Kansas	(785) 632-2166
Clay County Health Dept.	Clay Center, Kansas	(785) 632-3193
Clay County LEPC	Clay Center, Kansas	(785) 632-2166
Clay County Sheriff	Clay Center, Kansas	(785) 632-5601
Milford Fire Dept.	Milford, Kansas	(785) 463-5490
Dickinson		

City of Abilene Fire Dept.	Abilene, Kansas	(785) 263-1121
City of Enterprise Fire Dept.	Enterprise, Kansas	(785) 263-8323
Dickinson County Emergency Management	Abilene, Kansas	(785) 263-3608
Dickinson County EMS	Abilene, Kansas	(785) 263-0716
Dickinson County Environmental Services	Abilene, Kansas	(785) 263-4780
Dickinson County LEPC	Abilene, Kansas	(785) 263-1121
Dickinson County Sherriff	Abilene, Kansas	(785) 263-4081
Herrington Fire Dept.	Herrington, Kansas	(785) 258-3020
Butler		
Augusta Fire Dept.	Augusta, Kansas	(316) 775-4500
Butler County (LEPC)	Augusta, Kansas	(316) 733-9796
Butler County Emergency Communications	El Dorado, Kansas	(316) 322-4207
Butler County EMS	El Dorado, Kansas	(316) 321-9264
Butler County Fire District No. 3	Rose Hill, Kansas	(316) 776-0401
Butler County Sherriff	El Dorado, Kansas	(316) 322-4254
El Dorado Fire Department	El Dorado, Kansas	(316) 321-9100
Towanda Fire Department	Towanda, Kansas	(316) 541-2373
Cowley		
Arkansas City Fire Department	Arkansas City, Kansas	(620) 441-4430
Arkansas City Police Dept.	Arkansas City, Kansas	(620) 441-4444
Cowley County (LEPC)	Winfield, Kansas	(620) 221-0470
Winfield Ambulance Service	Winfield, Kansas	(620) 221-2300
Winfield Fire Department	Winfield, Kansas	(620) 221-5560
Winfield Police Dept.	Winfield, Kansas	(620) 221-5555

EXTERNAL NOTIFICATION REFERENCES
Nebraska

OTHER POTENTIAL REQUIRED NOTIFICATIONS		
DIAL 911 **for all Police, Fire and Ambulance Services.** * Calls to 911 concerning petroleum spills will usually alert LEPC; however, it is advisable to notify them directly for any spill that requires a 911 notification.		
AGENCY	**LOCATION**	**OFFICE / ALTERNATE**
Butler		
Augusta Fire Dept.	Augusta, Kansas	(316) 775-4500
Butler County (LEPC)	Augusta, Kansas	(316) 733-9796
Butler County Emergency Communications	El Dorado, Kansas	(316) 322-4207
Butler County EMS	El Dorado, Kansas	(316) 321-9264
Butler County Fire District No. 3	Rose Hill, Kansas	(316) 776-0401
Butler County Sherriff	El Dorado, Kansas	(316) 322-4254
El Dorado Fire Department	El Dorado, Kansas	(316) 321-9100
Towanda Fire Department	Towanda, Kansas	(316) 541-2373
Jefferson		
Fairbury Clinic	Fairbury, Nebraska	(402) 729-3361
Fairbury Fire Department		(402) 729-3761
Jefferson County Ambulance	Fairbury, Nebraska	(402) 729-3304
Jefferson County Emergency Management	Fairbury, Nebraska	(402) 729-3602
Jefferson County LEPC	Beaumont, Texas	
Jefferson County Sheriff	Beaumont, Texas	
Lincoln		

EXTERNAL NOTIFICATION REFERENCES
Oklahoma

OTHER POTENTIAL REQUIRED NOTIFICATIONS

DIAL 911 for all Police, Fire and Ambulance Services.

*** Calls to 911 concerning petroleum spills will usually alert LEPC; however, it is advisable to notify them directly for any spill that requires a 911 notification.**

AGENCY	LOCATION	OFFICE / ALTERNATE
Kay		
Kay County (LEPC)	Ponca City, Oklahoma	(580) 362-2517
Kay County Emergency Management	Newkirk, Oklahoma	(580) 362-3825
Kay County Sheriff's Office	Newkirk, Oklahoma	(580) 362-2517
Newkirk Ambulance Service	Newkirk, Oklahoma	(580) 362-3131
Newkirk Fire Dept.	Newkirk, Oklahoma	(580) 362-3606
Ponca City Fire Dept.	Ponca City, Oklahoma	(580) 767-0368
Noble		
City of Perry Fire Dept.	Perry, Oklahoma	(580) 336-9755
Marland Fire Dept.	Marland, Oklahoma	(580) 268-3468
Morrison Fire Dept.	Morrison, Oklahoma	(580) 724-3535
Noble County (LEPC)	Perry, Oklahoma	(580) 336-3517
Noble County Sherriff	Perry, Oklahoma	(580) 336-2141
Payne		
City of Stillwater Fire Dept.	Stillwater, Oklahoma	(405) 742-8308
Cushing City Ambulance	Cushing, Oklahoma	(918) 225-1790
Cushing Fire Dept.	Cushing, Oklahoma	(918) 225-3361
Payne County (LEPC)	Stillwater, Oklahoma	(405) 372-0497
Payne County Sherriff	Stillwater, Oklahoma	(405) 372-4522

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