3.13 POTENTIAL RELEASES FROM PROJECT CONSTRUCTION AND OPERATION AND ENVIRONMENTAL CONSEQUENCE ANALYSIS

This section addresses the potential for and consequences of oil products or crude oil releases that could occur during construction and operation of the proposed Project. The analyses presented in the draft EIS were revised based on comments on the draft EIS and updated information or information unavailable at the time the draft EIS was issued. This information includes the most recent PHMSA incident databases for hazardous liquid pipelines.

Safety regulatory requirements and standards, the risk of crude oil and oil product releases, and the environmental consequences of those potential releases are addressed in the following subsections:

- Pipeline Safety Considerations (Section 3.13.1);
- Potential Types of Releases and Volumes from Project Construction and Operation (Section 3.13.2);
- Potential Releases During Project Construction (Section 3.13.3);
- Potential Releases from Project Operations (Section 3.13.4);
- Impacts Related to Oil Spills (Section 3.13.5); and
- Resource-Specific Impacts (Section 3.13.6).

3.13.1 Pipeline Safety Considerations

3.13.1.1 Pipeline Safety Standards and Regulations

U.S. Department of Transportation Regulations

USDOT is mandated to regulate pipeline safety under Title 49, USC Chapter 601. PHMSA is responsible for protecting the American public and the environment by ensuring the safe and secure movement of hazardous materials to industry and consumers by all transportation modes, including the nation’s pipelines. Through PHMSA, the 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. PHMSA is responsible for regulations that require safe operations of hazardous liquid pipelines to protect human health and the environment from unplanned pipeline incidents.

The regulations governing pipeline safety are included in 49 CFR Parts 190 through 199. Parts 190, 194, 195, 198, and 199 are relevant to hazardous liquid (including crude oil) pipelines. Individual states are permitted to adopt additional or more stringent safety regulations for intrastate pipelines. Parts 190, 198, and 199 address issues that are tangential to pipeline system integrity. The regulations at 49 CFR 190 (Pipeline Safety Programs and Rulemaking Procedures) describe the pipeline safety programs and rulemaking procedures used by PHMSA in carrying out its regulatory duties, authorize PHMSA to inspect pipelines, describe the procedures by which PHMSA can enforce the regulations, and describe the legal rights and options of the operating companies in response to PHMSA enforcement actions. The regulations at 49 CFR 198 (Regulations for Grants to Aid State Pipeline Safety Programs) prescribe regulations for grants to aid state pipeline safety compliance programs. The regulations at 49 CFR 199 (Drug and Alcohol Testing) require operators of natural gas, liquefied natural gas, and hazardous liquid pipeline facilities to establish programs for preventing alcohol misuse and to test employees for the presence of alcohol and prohibited drugs.

Regulations that are more directly related to pipeline system integrity and the associated oil spill risk assessment and environmental consequences analyses are addressed in the following paragraphs. The regulations at 49 CFR 194 (Response Plans for Onshore Oil Pipelines) contain requirements for onshore oil spill response plans (the PSRP described in Section 2.4.2.2) that are intended to reduce the environmental impact of oil unintentionally discharged from onshore oil pipelines. Additional information on the requirements of 49 CFR 194 is presented later in this section.

The regulations at 49 CFR 195 (Transportation of Hazardous Liquids by Pipeline) include the design, construction, operation, and maintenance safety standards and reporting requirements for pipelines that transport hazardous liquids, including crude oil. Subparts of 49 CFR 195 include:

- Subpart A: General;
- Subpart B: Annual Accident and Safety-Related Condition Reporting;
- Subpart C: Design Requirements;
- Subpart D: Construction;
- Subpart E: Pressure Testing;
- Subpart F: Operation and Maintenance;
- Subpart G: Qualification of Pipeline Personnel; and
- Subpart H: Corrosion Control.

The regulations at Subpart A, Section 195.6 define unusually sensitive areas (USAs) as public drinking water or ecological resource areas.

The regulations at Subpart C include specifications for determination of the internal pressure acceptable in relationship to other design parameters (Part 195.106).

The regulations at Subpart F include requirements for marking, inspecting, and maintaining pipelines and the regulations at Subpart F, 49 CFR 195.260 (e) require a valve on either side of water crossings that are more than 100 feet across (as measured from high water marks). The regulations at Subpart F, Section 195.452 specify pipeline integrity management requirements in high-consequence areas (HCAs). An HCA is defined as:

- A commercially navigable waterway, which means a waterway where a substantive likelihood of commercial navigation exists;
- A high population area, which means an urbanized area—as defined and delineated by the U.S. Census Bureau—that contains 50,000 or more people and has a population density of at least 1,000 people per square mile;

- Any other populated area, which means a place—as defined and delineated by the U.S. Census Bureau—that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area; or
- An unusually sensitive area (USA) — defined in 49 CFR Part 195.6 as public drinking water or ecological resource areas that are unusually sensitive to environmental effects from hazardous liquid pipeline releases.

Drinking water USAs are a subset of all surface water intakes and groundwater-based drinking water supplies, including public water systems, public water supplies from source water protection areas/wellhead protection areas, and sole-source aquifers. Specifically, drinking water USAs include:

- The surface water intakes for community water systems and non-transient non-community water systems that do not have an adequate alternative drinking water source;
- The source water protection areas for community water systems and non-transient, non-community water systems that obtain their water supply from a Class I or Class IIA aquifer and do not have an adequate alternative drinking water source. If the source water protection area is not available, the wellhead protection areas become the USA; and
- The aquifer recharge area for sole-source aquifers within karst terrains.

For a new hazardous liquid pipeline, the regulations at 49 CFR 195.452 require that HCAs be identified prior to operation and that a written Integrity Management Plan (IMP) be in place within 1 year of the start of operation. The HCA regulation also requires that operators of new hazardous liquid pipelines complete baseline assessments by the start date for pipeline operation. Keystone would conduct a baseline assessment consisting of hydrostatic testing and a caliper/geometry pig inspection prior to the proposed pipeline's operation. Keystone also prepared a pipeline risk assessment that comprises incident frequencies and potential spill volumes and fulfills the risk analysis requirements for HCAs (see Appendix P). The pipeline risk assessment summarizes Keystone's estimate of pipeline miles within various types of HCAs. More detailed analyses would be conducted by Keystone as part of the IMP process that would occur prior to proposed Project operation. PHMSA would review the proposed pipeline's IMP and would conduct periodic inspections of the pipeline during operation. Keystone must implement preventive and mitigating measures to protect each HCA from the consequences of a pipeline failure and release of oil.

Additional actions that may be required include the following:

- Implementing damage prevention Best Management Practices (BMPs);
- Implementing more thorough programs to monitor cathodic protection where corrosion is a concern;
- Establishing shorter inspection intervals;
- Installing emergency flow restriction devices on the pipeline segment;
- Modifying systems that monitor pressure and detect leaks; and
- Providing additional training to personnel on response procedures, conducting drills with local emergency responders, and adopting other management controls.

The regulations at 49 CFR 195 Subpart G include minimum operator qualification requirements for individuals performing tasks required by the regulations, and Subpart H specifies corrosion control requirements.

As described in Section 2.4.2.2, 49 CFR 195.40 requires that an operations manual be developed that addresses abnormal operations for the proposed Project. Keystone developed an ERP for the Keystone Oil Pipeline Project that addresses these requirements (see Appendix C). Keystone has stated that this ERP would serve as the template for an ERP for the proposed Project and Project-specific information would be inserted into that plan as it becomes available (see Section 2.4.2.2).

PHMSA Special Conditions

At the time of publication of the draft EIS, Keystone had applied to PHMSA for consideration of a Special Permit request that if approved, would have allowed Keystone to operate the proposed Project at a slightly higher pressure than would be allowed using the standard design factor (maximum pressure not to exceed 72 percent of the pipe specified minimum yield strength [SMYS]) specified in 49 CFR 195.106. As a part of consideration of the application for a Special Permit, PHMSA initiated development of Special Conditions that, if the permit were granted, would have allowed Keystone to operate the Project at a maximum operating pressure higher than that specified in 49 CFR 195.106. However, on August 5, 2010, Keystone withdrew its application to PHMSA for a Special Permit.

After the application was withdrawn, DOS continued to work with PHMSA and Keystone to develop Special Conditions that could be applied to the proposed Project in response to comments received about pipeline construction, operation, and maintenance. Ultimately, a set of 57 Special Conditions was established (presented in Appendix U) and 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 that is required by 49 CFR 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 57 Special Conditions if the proposed Project is approved. DOS, in consultation with PHMSA, has determined that incorporation of those conditions would result in a Project that would have a degree of safety over any other typically constructed domestic oil pipeline system under current code and a degree of safety along the entire length of the pipeline system similar to that which is required in High Consequence Areas (HCAs) as defined in 49 CFR 195.450.

Standards and Regulations for Affected States

Oversight and inspections of interstate hazardous liquid pipelines are carried out by PHMSA with the assistance of state agencies in the states where PHMSA and the state have a cooperative agreement. In all states that would be crossed by the proposed pipeline, PHMSA regulates, inspects, and enforces interstate liquid pipeline safety requirements. States may adopt regulations with requirements that supplement or exceed federal requirements for intrastate pipelines only.

All states that would be crossed by the proposed Project have adopted state one-call systems to reduce the potential for third-party damage to utilities, including pipelines, during activities that involve excavation or soil boring. During construction and operation, contractors and the operator would be required to use the one-call system in each state to reduce the risk of damage to existing subsurface utilities.

Industry Standards

The proposed Project pipeline design would comply with pertinent industry standards. These industry standards could change if PHMSA adopts updated versions of the standards referenced in 49 CFR 195.3. Standards that would be complied with include the following:

- American Society of Mechanical Engineers (ASME)/American National Standards Institute (ANSI) Code B31.4, "Liquid Transportation Systems for Hydrocarbons, Liquid Petroleum Gas, Anhydrous Ammonia, and Alcohols." This standard addresses requirements for materials of construction welds, inspection, and testing for cross-country hazardous liquid pipelines. ASME B31.4 434.15.2 (a) requires mainline block valves on the upstream side of major river crossings and public water supply reservoirs, and either a block valve or a check valve on the downstream side. 49 CFR Part 195, "Transportation of Hazardous Liquids by Pipelines," has incorporated ASME/ANSI B31.4 code by reference.
- ANSI Standards CSA Z662-03 and Z662.1-03. This standard covers the design, construction, operation, and maintenance of oil and gas industry pipeline systems that convey various fluids, including crude oil.
- American Petroleum Institute (API) 570, "Piping Inspection Code–Inspection, Repair, Alteration, and Re-Rating of In-Service Piping Systems." This code was developed for the petroleum refining and chemical processing industries but may be used for any piping system.
- API RP 1102, "Recommended Practices for Liquid Petroleum Pipelines Crossing Railroads and Highways." This recommended practice is a requirement of ASME/ANSI B31.4.
- API RP 1109, "Recommended Practice for Marking Liquid Petroleum Pipeline Facilities." ASME/ANSI B31.4 advises that this API RP 1109 shall be used as a guide.
- NACE RP 0169, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems." ASME/ANSI B31.4 refers to sections of this recommended practice as a guide for an adequate level of cathodic protection.
- Other documents or portions thereof pertaining to transportation of hazardous liquids and incorporated by reference in 49 CFR 195.3.

Storage tanks associated with the proposed Project or the Bakken Marketlink and Cushing Marketlink connected actions, as well as surge tanks at delivery points in Texas would be designed and constructed in accordance with relevant standards listed in 49 CFR 195. Additionally, Keystone has agreed to incorporate into the proposed Project specifications a set of Project-specific conditions developed by PHMSA (Appendix U). These Special Conditions incorporate the requirements of the following industry standards:

- API Specification 5L, Specification for Line Pipe, 44th Edition. API 5L and other specifications and standards address the steel pipe toughness properties needed to resist crack initiation, crack propagation and to ensure crack arrest during a pipeline failure caused by a fracture;
- ASTM International A578/A578M Level B or equivalent. Standard Specification for Straight-Beam Ultrasonic Examination of Rolled Steel Plates for Special Applications;
- API 1104, *"Welding of Pipelines and Related Facilities."* API 1104 covers the gas and arc welding of butt, fillet, and socket welds in carbon and low-alloy steel piping used in the compression, pumping, and transmission of crude petroleum, petroleum products, fuel gases, carbon dioxide, nitrogen and, where applicable, covers welding on distribution systems. It applies to both new construction and in-service welding. This standard also covers the procedures for radiographic, magnetic particle, liquid penetrant, and ultrasonic testing, as well as the acceptance standards to be applied to production welds tested to destruction or inspected by radiographic, magnetic particle, liquid penetrant, ultrasonic, and visual testing methods;
- API Recommended Practice 1165 *(First Edition), Recommended Practice for Pipeline SCADA Displays;*

- API Recommended Practice 1130, *Computational Pipeline Monitoring for Liquid Pipelines*, (API RP 1130, 1st Edition 2007);
- ASME Standard B31Q, *Pipeline Personnel Qualification Standard* (ASME B31Q), September 2006;
- API Recommended Practice 1162, *Public Awareness Programs for Pipeline Operators*, (API RP 1162 (1st edition, December 2003) or the most recent version incorporated in 195.3);
- Canadian Standards Association, *Oil and Gas Pipeline Systems*, CSA Z662-03, Annex E, Section E.5.2, Leak Detection Manual;
- NACE International RP 0169 (2002 or the latest version incorporated by reference in 195.3) and 0177 (2007 or the latest version referenced through the appropriate NACE standard incorporated by reference in 195.3) (NACE RP 0169 and NACE RP 0177) for interference current levels. NACE RP 0169 was described earlier. NACE RP 0177 addresses mitigation of alternating current and lightning effects on metallic structures and corrosion control systems;
- NACE International RP 0502-2002 (NACE RP 0502-2002) Pipeline External Corrosion Direct Assessment Methodology, or the latest version incorporated by reference in 195.3;
- PHMSA's "Interim Guidelines for Confirming Pipe Strength in Pipe Susceptible to Low Yield Strength for Liquid Pipelines" dated October 6, 2009; and
- The Common Ground Alliance's damage prevention best practices applicable to pipelines.

Summary

As a result of incorporation of the current PHMSA regulations, current industry standards, and the set of 57 Project-specific Special Conditions developed by PHMSA and agreed to by Keystone, the proposed Project 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.

3.13.1.2 U.S. Pipeline Spill Incident History

PHMSA Pipeline Incident Statistics

Incidents that result in unintentional releases from hazardous liquid pipelines, which includes crude oil pipelines, are reported to PHMSA on standard forms in accordance with 49 CFR 195.50. PHMSA maintains a database of pipeline incident reports (available online at: http://primis.phmsa.dot.gov/comm/reports/safety/psi.html). Pipeline incident reports encompass onshore and offshore natural gas and hazardous liquid pipelines. In addition to crude oil pipelines, hazardous liquid pipelines include pipelines that transport oil products, liquefied petroleum gas (LPG), anhydrous ammonia, and other hazardous liquids.

The PHMSA database of hazardous liquid pipeline incidents includes incidents categorized as "significant." Significant hazardous liquid pipeline safety incidents include those that meet one or more of the following criteria:

- Spills releasing 2,100 gallons (50 barrels [bbl])[1] or more;
- Spills of 210 gallons (5 bbl) of highly volatile liquid[2];

[1] 1 bbl equals 42 U.S. gallons. Oil volumes are provided in gallons followed by bbl in this EIS.

- Spills resulting in total costs of $50,000 or more (1984 dollars);
- Spills that result in unintentional fire or explosion; or
- Incidents involving a fatality or an injury requiring in-patient hospitalization.

PHMSA defines a "serious" pipeline incident as one that involves a fatality or an injury requiring in-patient hospitalization. As noted above, significant incidents include all serious incidents.

The PHMSA incident database includes summary tables that provide overviews of serious and significant incidents reported over the last 20 years, ending in 2010. Prior to 2002, PHMSA required reports of hazardous liquid releases of greater than or equal to 2,100 gallons (50 bbl). As of 2002, PHMSA required reports of hazardous liquid releases of greater than or equal to 5 gallons (0.1 bbl). Therefore PHMSA data prior to 2002 likely understate the actual number of incidents and lead to over estimates of average spill volumes.

Table 3.13.1-1 presents the average number of serious incidents in a year for hazardous liquid pipeline operators (combined onshore and offshore pipeline incidents). The summary data indicate a decreasing temporal trend in the annual average number of serious pipeline incidents. These data include 93 serious incidents reported for 20 years, from 1991 to 2010.

TABLE 3.13.1-1
Nationwide Onshore and Offshore Hazardous Liquid Pipeline Systems, Annual Averages for Serious Incidents[a]

Time Period	Annual Average Serious Incidents per Period
5-year average (2006–2010)	3
10-year average (2001–2010)	3
20-year average (1991–2010)	5

[a] Incidents involving a fatality or an injury requiring in-patient hospitalization.
Source: PHMSA 2011.

The average number of significant incidents per year for onshore hazardous liquid pipelines from 1991 through 2010 is presented in Table 3.13.1-2 along with other data related to the reported incidents. These summary data indicate a generally decreasing trend in annual incident frequency and injuries. The average gross spill volume for the 20-year period was higher than that of the other periods, likely reflecting the higher level of integrity for newer pipelines and the effects of increasingly stringent regulatory requirements.

A summary of PHMSA significant pipeline safety incidents by cause for the period from 2008 through 2010 for onshore hazardous liquid pipelines is presented in Table 3.13.1-3.

[2] The statistics include incidents related to highly volatile liquids; however, crude oil is not a highly volatile liquid. Therefore, incident statistics are somewhat overstated when considering incidents involving crude oil pipeline transport.

TABLE 3.13.1-2
Nationwide Onshore Hazardous Liquid Pipeline Systems, Annual Averages for Significant Incidents

Period	Number of Incidents[a]	Fatalities	Injuries	Property Damage[b,c]	Gross Barrels Lost	Barrels Recovered	Net Barrels Lost
3-year average (2008 – 2010)	107	2	3	$244,301,451	108,201	33,279	74,922
5-year average (2006–2010)	106	2	4	$171,257,826	110,921	41,665	69,256
10-year average (2001-2010)	115	2	6	$143,814,380	104,065	38,647	65,418
20-year average (1991-2010)	134	2	9	$111,080,000	125,532	55,695	69,837

[a] Incidents include those that meet one or more of the following criteria: spills releasing 2,100 gallons (50 barrels [bbl]) or more; spills of 210 gallons (5 bbl) of highly volatile liquid; spills resulting in total costs of $50,000 or more (1984 dollars); spills that result in unintentional fire or explosion; or an incident that involves a fatality or an injury requiring in-patient hospitalization.

[b] The costs for incidents prior to 2010 are presented in 2010 dollars. Costs were adjusted using the Bureau of Economic Analysis, Government Printing Office inflation values.

[c] For years 2002 and later, property damage is estimated as the sum of all public and private costs reported in the 30-day incident report. For years prior to 2002, accident report forms did not include a breakdown of public and private costs so property damage for these years is the reported total property damage field in the report.

Note: Totals for the period from 1991 through 2010: 2,672 incidents; 40 fatalities; 178 injuries; $2,221,600,007 property damage; 2,510,639 barrels lost; 1,113,894 barrels recovered, and 1,396,745 net barrels lost.

Source: PHMSA 2011.

TABLE 3.13.1-3
Nationwide Onshore Hazardous Liquid Pipeline Systems, Causes of Significant Incidents (2008-2010)

Cause	Number of Incidents[a]	Percent of Total Incidents (%)	Fatalities	Injuries	Property Damage[b, c]	Percent of Property Damage[c] (%)
All other causes	22	6.7	4	1	$526,062,146	69.6
Corrosion	69	21.0	0	0	$38,672,895	5.1
Excavation damage	42	12.8	1	2	$27,382,678	3.6
Incorrect operation	34	10.3	1	6	$7,352,773	0.9
Material or equipment failure	125	38.1	0	0	$104,184,945	13.8
Natural force damage	20	6.1	0	0	$24,049,849	3.1
Other outside force damage	8	2.4	1	1	$5,199,064	0.6
Total[d]	**320**	**97.5**	**7**	**10**	**$732,904,353**	**97.0**

[a] Incidents include those that meet one or more of the following criteria: spills releasing 2,100 gallons (50 barrels [bbl]) or more; spills of 210 gallons (5 bbl) of highly volatile liquid; spills resulting in total costs of $50,000 or more (1984 dollars); spills that result in unintentional fire or explosion; or an incident that involves a fatality or an injury requiring in-patient hospitalization.

[b] The costs for incidents prior to 2010 are presented in 2010 dollars. Costs were adjusted using the Bureau of Economic Analysis, Government Printing Office inflation values.

[c] Property damage was estimated as the sum of all public and private costs reported in the 30-day incident report, adjusted to 2010 dollars.

[d] Totals presented as reported by PHMSA.

Source: PHMSA 2011.

Outside forces incidents listed in Table 3.13.1-3 include: excavation damage from mechanical equipment, such as bulldozers and backhoes (12.8 percent); natural force damage, including earth movements due to soil settlement, washouts, or geologic hazards and weather effects such as winds, storms, and thermal strains (6.1 percent); and other outside force damage (2.4 percent). Older pipelines have a higher frequency of outside force incidents partly because their location may be less well known and less well marked than it is for newer lines. In addition, the older pipelines contain a disproportionate number of smaller diameter pipes with reduced wall thicknesses, and have a greater rate of incidents related to outside forces. These pipelines are more easily crushed or broken by mechanical equipment or earth movements than larger diameter pipelines such as that of the proposed Project.

Corrosion was the reported cause of 21 percent of all hazardous liquid pipeline incidents from 2008 through 2010 (Table 3.13.1-3). The frequency of incidents is strongly dependent on pipeline age. Older pipelines have a higher frequency of corrosion incidents, because corrosion is a time-dependent process. Also, new pipe generally uses more advanced coatings and cathodic protection to reduce corrosion potential. Significant improvements in corrosion control technology applied to pipelines installed since the 1950s have resulted in reduced corrosion-related incident frequencies. Accordingly, the oldest pipelines (pre-1950) experience a disproportionate frequency of corrosion-related failures (Keifner and Trench 2001). In contrast, the proposed Project would incorporate state-of-the-practice corrosion control methods based on current industry standards, current PHMSA requirements, and the set of Project-specific Special Conditions developed by PHMSA and incorporated into the proposed Project plan (see Sections 2.3 and 3.13.1.1).

It is important to consider pipeline age when assessing risk based on records of incident frequencies. In 2004, the Transportation Research Board (TRB 2004) published a review of pipelines that included "Pipeline Safety Data and Trends" as an appendix. Appendix B of that report summarizes a detailed analysis of API and USDOT hazardous liquid pipeline incident data, and relies heavily on previous work done for API (Keifner and Trench 2001). The API work confirms that hazardous liquid pipeline age is a significant spill risk factor, for various reasons. The study grouped pipelines by decade of construction. The work shows that older pipelines not only experienced a higher frequency of spill incidents in general, but they also experienced a higher frequency of spill incidents due to third-party damage.

Many industry standards and practices, PHMSA regulatory requirements, and the set of Project-specific Special Conditions developed by PHMSA that would be incorporated into the proposed Project would likely reduce the potential for spill incidents associated with the proposed Project as compared to PHMSAs incident data summaries (see Sections 2.3 and 3.13.1, and Appendix U for additional details).

TransCanada and Keystone Operating History

For much of its history, TransCanada's business operations focused on natural gas transportation systems in Canada and the United States. In February 1996, the firm initiated its oil transportation business with a 50/50 joint venture with Alberta Energy Company (now EnCana Corporation) to purchase the Platte pipeline and to construct the Express pipeline later that year. Together, the Express and Platte pipelines constitute a 1,700-mile system between Hardesty, Alberta and Wood River, Illinois. The system became operational in February 1997, with commercial deliveries beginning in April 1997. Alberta Energy Company operated the Express and Platte systems on behalf of the joint venture partnership until October 2000, when TransCanada divested its 50 percent interest to EnCana Corporation.

Keystone Oil Pipeline Project

Keystone, a TransCanada subsidiary, constructed the Keystone Oil Pipeline Project (Keystone Mainline Pipeline and Cushing Extension) and the mainline portion of that system initiated operation in 2010. As a result, TransCanada's limited operating history with crude oil pipelines precludes a direct comparison of accident and oil spill incident rates specific to TransCanada with the industry average rates.

Since the beginning of pre-startup testing and the inception of operations of the Keystone Oil Pipeline Project, there have been 14 unintentional releases of crude oil. None of the releases involved the pipeline itself but rather occurred at pump stations and MLVs. The reported incidents through May 29, 2011, their release volumes, report tracking numbers and incident causes are presented in Table 3.13.1-4. According to Keystone "In each of these incidents, the oil was discovered early, in most cases the leaks were limited to the ground surface, the oil was minimal and was cleaned immediately and no environmental damage was reported. In one case (Ludden Pump Station), low level residual offsite oil spray impacts are being treated in-place in accordance with North Dakota Department of Health in-situ land treatment guidelines." (Keystone 2011). According to PHMSA technical staff (2011), the incidents experienced on the existing Keystone pipeline are not unusual start-up issues that occur on pipelines and are not unique. However, the number of incidents that has occurred prompted PHMSA to take action by issuing a temporary Corrective Action Order that has subsequently been lifted. According to PHMSA technical staff, there is no evidence that any of these incidents resulted from internal corrosion or erosion issues (PHMSA Pers. Comm. 2011).

TABLE 3.13.1-4
Reported Incidents for Existing Keystone Oil Pipeline

Location of Release	Release Volume	Report Tracking Number	Cause of Incident
<u>CARPENTER PUMP STATION – NRC REPORT 05/21/2010</u> 19051 415th Avenue, Carpenter, SD 57322, Clark County Time of incident: 13:45 CST	Spill contained on site: Amount of release reported ~5 gallons *S. Dakota reporting threshold 25 gallons.* *NRC reporting threshold 5 gallons.*	NRC Case number #941193. South Dakota Department of Environment and Natural Resources File #2010.083 closure received 7/9/10.	Failure of a 1½" below ground fitting connected to the mainline isolation valve. Investigation employed identifying isolated event due to defective fitting.
<u>ROSWELL PUMP STATION – NRC REPORT 06/23/2010</u> MP 358.3, South Dakota 42592 236th Street, Howard SD 57349, Miner County Time of incident 12:00PM CST	Spill contained on site: Amount of release reported ~100 gallons *S. Dakota reporting threshold 25 gallons.* *NRC reporting threshold 5 gallons.*	NRC Case number #945213. South Dakota Department of Environment and Natural Resources File #2010.126 closure received 9/8/10.	Leak occurred at PS site during maintenance from a small fitting attached to the sump pump. Investigation identified as isolated event as a result of a failed fitting during on-site maintenance activities.
<u>FREEMAN PUMP STATION – NRC REPORT 08/10/2010</u> MP406.8 South Dakota 282 6th Avenue, Freeman, SD 57029 Hutchinson County Time of incident 11:30CST	Spill contained on site: Amount of release reported ~2 gallons. *Release withdrawal letter sent to PHMSA, leak was determined non-reportable as NRC reporting threshold 5 gallons.*	NRC Case number #950516. South Dakota Department of Environment and Natural Resources File #2010.169 closure received 11/12/10.	Failure of a 1" fitting attached to the pig trap receiver. Investigation identified the fitting to have been improperly installed. Other similar installations were immediately checked for any similar problem, but none were discovered.
<u>HARTINGTON PUMP STATION – NRC REPORT 08/19/2010</u> Cedar County Nebraska MP454.9 55953 883rd Road, Hartington, NE 68739 Time of incident 08:30CST	Spill contained on site: Amount of release reported 10 gallons. *NE Reporting threshold 25 gallons.* *NRC reporting threshold 5 gallons.*	NRC Case number #951480, Nebraska Department of Environmental Quality Report Case Number #081910-JB-1140. 11/1/10 NDEQ correspondence indicated case closed.	Failure of ½" above ground fitting. Investigation determined the source of the spill to be from an improperly installed cap on the ½" fitting. Similar installations were checked and remediated.

TABLE 3.13.1-4
Reported Incidents for Existing Keystone Oil Pipeline

Location of Release	Release Volume	Report Tracking Number	Cause of Incident
FERNEY PUMP STATION – NRC REPORT 01/05/2011 MP263.4 41461 144th Street, Andover, SD 57442, Day County Time of incident: 09:57 CST	Spill contained on site: Amount of release reported <2 gallons *S. Dakota reporting threshold 25 gallons.* *NRC reporting threshold 5 gallons.*	NRC Case number 963799. The NRC report is in the process of being rescinded due to not meeting the reporting threshold, South Dakota Department of Environment and Natural Resources File #2011.004, closure received 3/9/2011.	The leak occurred when a station pump seal bearing started seeping oil. This
SEVERANCE +2_1 VALVE SITE – KDHE REPORT 01/08/2011 Severance +2_1 Valve Site, MP744.3 Doniphan County, Kansas Time of incident: 14:40 CST	Spill contained on site: Amount of release reported <3 gallons. *KS reporting threshold not volumetric based rather "Impacts to soil or water resources." NRC reporting threshold 5 gallons.*	Kansas Department of Health and Environment (KDHE) File #32936, closure received 4/4/2011.	Source of the leak was a seal (packing) on a 6" valve. This is an isolated incident.
TURNEY PUMP STATION – NRC REPORT 01/31/2011 MP 787.1 3490 NE A Hwy., Turney, MO 64493, Clinton County Time of incident: 20:00 CST 1/30/11	Spill contained on site: Amount of release reported <10 gallons. *MO reporting threshold >50 gallons. NRC reporting threshold 5 gallons.*	NRC Case number 966126. Spill cleanup completed 1/31/2011.	Source of the leak was a seal failure on Pump #2.
CUSHING STATION – NRC REPORT 2/3/2011 350953 East 750th Rd., Cushing, OK 74023, Lincoln County Time of incident: 14:10 CST	Spill contained on site: Amount of release reported <15 gallons. *OK reporting threshold 25 gallons. NRC reporting threshold 5 gallons.*	NRC Case number 966497. Oklahoma Department of Environmental Quality File #300-00-00-75078, closure received 2/15/2011.	Source of the release was a temporary vent gas separator.
DAVID CITY PUMP STATION – NDEQ REPORT 2/11/2011 MP 552.9 1016 36th Rd., David City, NE 68632, Butler County Time of incident: 16:37 CST	Spill contained on site: Amount of release reported <100 gallons. *NE reporting threshold 25 gallons. NRC reporting threshold for maintenance related activities 5 barrels.*	Nebraska Department of Environmental Quality (NDEQ) File #021111-NH-1730, closure received 4/21/2011.	Source of release was seal failure during maintenance activity on pump seal.
ROCK PUMP STATION – NRC REPORT 2/23/2011 6347 82nd Rd., Udall, KS 67146, Cowely County Time of incident: 15:10 CST, 2/17/11	Spill contained on site: Amount of release reported 10 gallons. Following cleanup completion, estimated spill volume revised to 30 gallons. *KS reporting threshold not volumetric based rather "Impacts to soil or water resources." NRC reporting threshold 5 gallons.*	NRC Case number 968357. KDHE File #33000, closure report submittal pending.	Source of the leak was a valve seal on a drain line of a pump suction line.
LUDDEN PUMP STATION – NRC REPORT 3/8/2011 10075 119th Ave. SE, Brampton, ND 58017, Sargent County Time of incident: 10:30 CST	Spill contained on site: Amount of release reported <5 gallons. *ND requires reporting any spill, minimum quantities for mandatory reporting have not been established. NRC reporting threshold 5 gallons.*	NRC Case number 969483. NDDoH verbally provided no further action direction after report that spill was contained to pump unit concrete pad and immediately cleaned up.	Source of the leak was a pump unit bearing housing.

TABLE 3.13.1-4 Reported Incidents for Existing Keystone Oil Pipeline			
Location of Release	**Release Volume**	**Report Tracking Number**	**Cause of Incident**
SENECA PUMP STATION – NRC REPORT 3/16/2011 2189 State Hwy. 63, Seneca, KS 66538, Nemaha County Time of incident: 10:00 CST	Spill contained on site: Amount of release reported 3 barrels. Following cleanup completion, estimated spill volume revised to 12 barrels. *KS reporting threshold not volumetric based rather "Impacts to soil or water resources." NRC reporting threshold 5 gallons.*	NRC Case number 970232. KDHE File #33038, closure report submittal pending.	Source of the leak was a pump seal failure.
LUDDEN PUMP STATION – NRC REPORT 5/7/2011 10075 119th Ave. SE, Brampton, ND 58017, Sargent County Time of incident: 06:26 CST	Amount of release reported 100 barrels. Subsequently revised to 450-500 barrels. Earthen berming around the perimeter of the facility contained most of the released oil within the facility. An estimated 5 barrels of oil sprayed offsite impacting neighboring properties to the south. Approximately 385 barrels of free phase oil has been collected and will be transported offsite for recycling. Approximately 800 yd^3 of oil coated site surface gravel and offsite surface soil have been excavated and stockpiled onsite pending offsite disposal. Low level residual offsite oil spray impacts are being treated in-place in accordance with NDDoH in-situ land treatment guidelines. *ND Requires reporting any spill, minimum quantities for mandatory reporting have not been established. NRC reporting threshold 5 gallons.*	NRC Case number 975573.	Source of the leak was a ¾" diameter pipe nipple failure.

TABLE 3.13.1-4 Reported Incidents for Existing Keystone Oil Pipeline			
Location of Release	**Release Volume**	**Report Tracking Number**	**Cause of Incident**
SEVERANCE PUMP STATION – NRC REPORT 05/29/2011 Time of incident: 00:20 CST	Oil was contained on site (with the exception of a slight trace of oil vapor droplets observed on blades of grass in an area immediately adjacent to the site). Amount of release reported 40 bbl. Later revised to <10 bbl. Approximately 5 barrels of free phase oil has recovered and approximately 395 yd3 of oil coated site surface gravel have been excavated and stockpiled onsite pending offsite disposal. Offsite vegetation impacted by residual oil spray were mowed and containerized for disposal. *KS Reporting threshold not volumetric based rather "Impacts to soil or water resources."* *NRC reporting threshold 5 gallons.*	NRC Case number 977695. KDHE File # 33211.	Source of the leak was a 1/2" nipple located on a pressure transmitter

Source: Keystone 2011.

TransCanada Gas Transmission Pipelines

To evaluate TransCanada's experience in operating gas transmission pipelines, a review of PHMSA enforcement actions was conducted on all of the natural gas pipelines it operated in the U.S. The pipelines reviewed, with dates TransCanada assumed control of the assets, are listed below:

- Gas Transmission Northwest Corp. – Operator ID # 15014 – November 2, 2004;
- ANR Pipeline Co. – Operator ID # 405 – February 22, 2007;
- Great Lakes Gas Transmission Co. – Operator ID # 6660 – February 22, 2007;
- Northern Border Pipeline Company – Operator ID # 13769 – April 1, 2007;
- Tuscarora Gas Transmission Co. – Operator ID # 30838 – December 19, 2006;
- Portland Natural Gas Transmission – Operator ID # 31145 – August 3, 2004; and
- North Baja Pipeline – Operator ID # 31891 – November 2, 2004.

For these pipelines, PHMSA identified two 49 CFR Part 192 compliance issues (natural gas) from time of pipeline ownership to December 31, 2009. There were no civil penalties imposed, and all past compliance issues have been resolved with TransCanada and closed by PHMSA.

In addition, TransCanada's Bison Pipeline (natural gas) experienced a rupture and explosion on July 20, 2011 in Campbell County, Wyoming. An official determination of the cause of the incident was not available at the time the EIS was prepared. There were no reported injuries or private party property damages associated with this event.

3.13.2 Spill Volume Categories and Potential Types of Releases

3.13.2.1 Spill Volume Categories

To address potential spills from the proposed Project in this EIS, the following categories of spill volumes were used:

- Very small spills: less than 210 gallons (less than 5 bbl);
- Small spills: 210 to 2,100 gallons (5 to 49.9 bbl);
- Substantive spills: 2,100 to 21,000 gallons (50 to 499.9 bbl);
- Large spills: 21,000 to 210,000 gallons (500 to 5,000 bbl); and
- Very large spills: greater than 210,000 gallons (5,000 bbl).

This size classification is generally similar to the unofficial categories used by PHMSA for spill reporting. The very small spill and very large spill categories were added to facilitate discussion of the majority of spills (less than 210 gallons [5 bbl]) and very rare spills (greater than 210,000 gallons [5,000 bbl]). A range of spill scenarios was assessed to facilitate the impact assessment. Spill scenarios were based on these spill volume categories. Over the past 20 years (from 1990 through 2010), the average spill size in the PHMSA significant incident database for onshore hazardous liquid pipelines was less than 42,000 gallons (1,000 bbl).

Very Small and Small Spills

The most common scenarios are the very small (less than 210 gallons [5 bbl]) and small (210 to 2,100 gallons [5 to 49.9 bbl]) spills of material—usually diesel, hydraulic fluid, transmission oil, or antifreeze—on work pads, roads, and facility parking or work areas. Some of these small spills may result from slow and small (pin hole) leaks of crude oil from the proposed pipeline, or spills during maintenance activities on the pipeline and its facilities (e.g., pump station valves).

Substantive and Large Spills

Substantive (2,100 to 21,000 gallons [50 to 499.9 bbl]) and large (21,000 to 210,000 gallons [500 to 5,000 bbl]) spills would be much less likely to occur than smaller sized spills (see Sections 3.13.2, 3.13.3, and 3.13.4). Large spills would more likely be crude oil releases from the proposed pipeline and would likely occur in the ROW. Both Substantive and large spills could result from tanker truck accidents (during construction), major failure of the fuel storage tanks at construction sites, outside forces such as excavators and major earth movement, or corrosion of the pipe.

Very Large Spills

A very large spill (greater than 210,000 gallons [5,000 bbl]) could occur during operation and could result from either (1) a major rupture or a complete break in the proposed pipeline, or (2) from a failure of one or more of the three, 350,000-bbl crude oil storage tanks at the Cushing tank farm and the concurrent failure of the containment berms surrounding the tanks. As discussed in Section 3.13.4.2, a very large spill from the pipeline would likely require the occurrence of an event that would shear the pipeline such as major earth movement resulting from slides, major earth movement resulting from an earthquake, major flood flows eroding river banks at non-HDD crossings, mechanical damage from third-party excavation or drilling work, or vandalism, sabotage, or terrorist actions.

3.13.2.2 Potential Types of Releases

The following sub sections provide summary information on the types of materials that may be released from the proposed Project during construction and operation. More detailed information, particularly on crude oil, is presented in Section 3.13.5.1.

Refined Oil Products

Release volumes of refined oil products (e.g., gasoline, diesel, and lubricating and hydraulic fluids) during proposed Project construction or operations would typically be very small to small, although larger release volumes are possible. The small to very small releases would typically be associated with equipment fueling and hydraulic fluid line ruptures. These spills would most likely occur at the construction or operation/maintenance sites, at fueling stations, on the roadways, within the ROW, and at similar managed locations where they would be readily contained and remediated. Refined product releases could also result from accidents (e.g., tank truck rollover); excess fuel or lubricants during vehicle, equipment, and machinery maintenance; failure of fuel storage tanks and the surrounding containment berms; and incorrect operation of equipment or fueling procedures.

Hazardous Materials

The volume of hazardous materials that would be used during proposed Project construction and operations would be small and therefore any spills would likely be very small to small with little likelihood of a Substantive spill. Any hazardous material spills would most likely occur at the construction or operation/maintenance sites where materials would be stored in containers that define maximum spill quantities. Implementation of the ERP, SPCC plans, and hazardous materials location restrictions (see the CMR Plan in Appendix B) would reduce the risk that a hazardous material release could affect surface waters.

Crude Oil

Crude oil releases could occur during proposed Project operation and maintenance activities, as discussed in Section 3.13.4. Estimates of potential crude oil spill volumes are presented in those sections and in Appendix P. The characteristics of the crude oil that would be transported by the proposed Project are discussed in Sections 3.13.5.1 and 3.13.5.3.

3.13.3 Potential Releases during Project Construction

Most construction-related spills would likely release minor quantities of refined products (e.g., gasoline, diesel, and lubricating and hydraulic fluids). These releases would be subject to the reporting requirements of 40 CFR Part 110, and would typically result from vehicle and construction equipment fueling and maintenance. Contractor construction staging and pipe storage areas would typically include skid-mounted, aboveground gasoline storage tanks (9,500-gallon [226-bbl] capacity) and diesel storage tanks (10,000-gallon [238-bbl] storage capacity). These fuel tanks would be installed within impermeable containment areas to prevent spilled material from reaching adjacent natural habitats. According to the Pipeline Risk Assessment (Appendix P) and consistent with one of the requirements of 40 CFR Part 112 for each staging area, oil storage tanks would have secondary means of containment (berms) for 110 percent of the capacity of the largest tank. In addition, portable oil storage containers would have berms that hold 110 percent of the total capacity of the containers inside the berm. Lubricating oil may also be stored in tanks in these areas. Construction would also involve fuel delivery by tanker trucks to operating equipment along the construction ROW. The potential maximum spill volume from the failure of the maximum size fuel tank truck would be about 9,000 gallons (214 bbl) for diesel or gasoline. Lubricating or hydraulic fluid would be stored in 55-gallon (1.3-bbl) drums, with up to six drums on a pallet. Thus, the potential maximum spill volume of lubricating oil or hydraulic fluid would be equal to the volume of six drums, or approximately 330 gallons (7.9 bbl). Hydrostatic testing of the pipeline prior to operation would not result in release of oil to the environment as the water used in the testing does not contain oil. Also, the discharged water would be required to meet NPDES discharge permit conditions (see Section 2.3.2.6).

Potential spills from construction activities would be addressed by specific preventive and mitigating measures included in the SPCC Plan described in more detail in section 2.3 and Appendix C.

3.13.4 Potential Spills from Project Operations (Including Maintenance)

3.13.4.1 Operational Spills

Operational spills from the proposed Project could originate from the pipeline, pump stations, MLVs, delivery points, or the Cushing tank farm. Additionally, spills similar to those described for construction could occur as a result of ongoing maintenance activities. As described in Appendix P, releases from the proposed Project could result from the effects of corrosion (external or internal), excavation or other subsurface equipment disturbance damage, defects in materials or defects related to proposed Project construction, hydraulic over-pressuring related to incorrect operating procedures, or geologic hazards (e.g., ground movement, washouts, and flooding). Although leak detection systems (see Section 3.13.5.5 and Appendix P) would be in place, some leaks might not be detected by the system for an extended period of time. A pinhole leak could be undetected for days or a few weeks if the release volume rate were small and in a remote area. However, although the total volume of a release from a pin hole leak could be relatively large (e.g., up to a substantive spill), in most cases the oil would likely remain within or near the pipeline trench where it could be contained and cleaned up after discovery. Detection would likely occur through visual or olfactory identification, either during regular pipeline aerial inspections, ground patrols, or landowner or citizen observation, in most cases before the release of a substantive volume of oil to surface habitats and environment.

Larger spills would most likely be associated with leak sources other than pinhole leaks (e.g., excavation damage and geologic hazards). In larger spills, some of the released oil could be contained in the immediate vicinity of the release point, although the released oil would likely migrate from the release source. However, experience gained from previous large pipeline oil releases suggests that the distance the oil would likely migrate is limited (see Section 3.13.6.4). Prior to PHMSA granting permission to operate the proposed Project, Keystone would be required to prepare and implement an ERP that would guide response actions in the event of an oil release to facilitate rapid response. Nonetheless, actual response with containment equipment and cleanup crews could be delayed due to one or more of the following factors:

- If the leak is at a remote location, visual leak detection could be difficult and reporting could be delayed;
- Locating the leak could require time searching the release area to determine where the leak originates;
- Snow, darkness, or other natural factors could hinder visual detection;
- Weather conditions, natural disasters (e.g., floods, landslides, excessive snow fall, or drifting) could delay access to the spill location, especially for larger equipment and supply vehicles; and

- Depending on spill volume, proximity, and season, the oil could reach wetlands, freshwater ponds and lakes, streams, or larger rivers thus necessitating additional time to mobilize response (see Section 3.13.5.1).

3.13.4.2 Operational Spills Risk Assessments

To assess the likelihood of operational releases from the proposed Project, spill risk assessments were conducted. These risk assessments addressed both the potential frequency of operational pipeline releases and the potential volumes of crude oil associated with the releases. The risk analyses for the proposed Project used data derived from the PHMSA database for hazardous liquid pipelines and crude oil pipelines, and the National Response Center (NRC) database for releases and spills of hazardous substances and oil, as described below.

Oil Spill Frequency

Three separate approaches were used to estimate oil spill frequency and potential spill volume:

- DOS utilized the PHMSA spill databases for both significant spill incidents (for conservatism, DOS assumed that all significant spill events were greater than 50 bbl) and all reported incidents for onshore hazardous liquid pipelines to determine the 10-year average spill frequencies and average spill volumes both nationally and within the specific states (for significant incidents only) that would be traversed by the proposed Project (PHMSA 2011).
- DOS also utilized the NRC database to assess the frequency of transmission pipeline spills of both hazardous liquids and crude oil of any size and of spills less than or equal to 50 bbl to determine the national average spill frequencies in the time period 2002 to 2010.
- DOS also estimated the incident frequency of crude oil spills of any size by combining relevant information from the PHMSA and NRC databases.
- As part of its Presidential Permit application, Keystone submitted a risk analysis performed by Keystone and its consultants (Appendix P). The Keystone risk analysis contained an estimate of spill frequency. Keystone related the spill incident frequency to historic pipeline releases attributed to specific causative mechanisms, and adjusted the frequency for Project-specific design, construction, and operational procedures as well as specific terrain conditions that would be crossed by the proposed Project, excluding the pre-existing Cushing Extension (Appendix P). Baseline incident frequencies were adjusted to account for improved technologies, specific pipeline design considerations, and standard PHMSA regulatory requirements for the proposed Project.

DOS Significant Incident Frequency Projections

A significant incident is defined by PHMSA as any incident reported by a pipeline operator where one or more of the following specifically defined consequences occur:

- Fatality or injury requiring in-patient hospitalization;
- $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; and
- Liquid releases resulting in an unintentional fire or explosion.

For conservatism in this analysis, DOS assumed that any incident recorded as significant by PHMSA involved a release of 50 bbl or more. As of July 2011, PHMSA reported that there were approximately 171,000 miles of onshore hazardous liquid pipelines in the U.S. That pipeline mileage was divided into the 10-year average (2001 to 2010) of 115 significant incidents per year for onshore hazardous liquid pipelines (PHMSA 2011; see Table 3.13.1-2) to calculate the significant incident frequency factor of 0.0007 incidents per pipeline mile per year for nationwide pipelines.

PHMSA's state-by-state hazardous liquid pipeline incident database was used to generate a Project-specific state-by-state subset of the data. The state-by-state PHMSA data summaries (dated June 6, 2011) provide the total miles of hazardous liquid pipelines within each state and the number of significant incidents that occurred therein for onshore hazardous liquid pipelines during the 10-year period from 2001 through 2010. Analysis of these data also resulted in a frequency of 0.0007 incidents per mile per year for the six states evaluated in spite of the fact that there were relatively small numbers of incidents reported in most of the states that would be crossed by the proposed pipeline.

There are approximately 55,000 miles of crude oil transmission lines in the U.S. (Tribal Energy and Environmental Clearing House 2011, Pipeline 101 2011). The detailed PHMSA incident report database was used to obtain the number of incidents of crude oil spills from onshore hazardous liquid pipelines during the reporting period from 1997 through 2008. There were approximately 600 reported incidents during that 10-year period, which equates to a frequency of 0.00109 crude oil incidents per mile per year.

The results of these three analyses were used to project the number of significant incidents per year for each segment of the proposed Project. The calculated numbers of significant incidents by proposed segment and for the entire proposed pipeline are provided in Table 3.13.4-1.

TABLE 3.13.4-1
Projected Significant Spill Incidents (>50 bbl) per Year for the Proposed Project Pipeline

Characteristic	PHMSA Hazardous Liquids Dataset [a]	PHMSA Data for States Crossed by the Proposed Pipeline [b]	PHMSA Data–Crude Oil [c]
Incidents per mile per year	0.0007	0.0007	0.00109
Proposed Project Segment		**Spill Incidents Per Year**	
Steele City Segment (852 miles)	0.60	0.60	0.93
Cushing Extension (298 miles)	0.21	0.21	0.32
Gulf Coast Segment and Houston Lateral (532 miles)	0.37	0.37	0.58
Project Total Incidents per Year (1,682 miles) [d]	**1.18**	**1.18**	**1.83**

[a] Includes all onshore hazardous liquid pipelines in the U.S.
[b] Includes data only for onshore hazardous liquid pipelines in the states that would be crossed by the proposed pipeline.
[c] "Crude oil" includes data just for onshore crude oil pipeline incidents, all states.
[d] Includes existing Cushing Extension.
Source: PHMSA 2010.

DOS Incident Frequency Based on National Response Center (NRC) Database

The above analysis of spill frequency addresses significant spills (i.e., those assumed to be greater than 50 bbl) in the PHMSA database. In its comments on the draft and supplemental EISs, EPA requested that the spill frequency analysis address hazardous liquid and crude oil spills, including those less than 50 bbl, using information from the NRC database. The NRC is the federal government's national communication center for reporting releases involving hazardous substances and oil spills. As a result, DOS conducted the spill frequency analysis described below.

The NRC database listed 1,067 spill incidents from hazardous liquid transmission pipeline from 2002 to 2010. Of that total, 546 incidents involved spills of up to 50 bbl in volume and approximately 407 incidents involved crude oil, of which 200 incidents were up to 50 bbl (see Table 3.13.4-2).

As of 2009, PHMSA reported that there were approximately 171,000 miles of onshore hazardous liquid pipelines in the U.S. The total U.S. hazardous liquid pipeline mileage was divided into the 9-year average of 119 incidents per year involving hazardous liquid spills, including crude oil spills, from hazardous liquid transmission pipelines to calculate the incident frequency factor of 0.0007 incidents per pipeline mile per year for nationwide pipelines. That equates to an estimated spill frequency of 1.16 incidents per year for the entire proposed Project corridor. For hazardous liquid spills up to 50 bbl, the estimated incident frequency factor was 0.0004 incidents per pipeline mile per year, resulting in an estimated frequency of 0.6 incidents along the proposed Project corridor per year.

There are approximately 55,000 miles of crude oil transmission lines in the U.S. (Tribal Energy and Environmental Clearing House 2011, Pipeline 101 2011). Approximately 407 crude oil incidents were reported during the 9-year period, which equates to a frequency of 0.0008 crude oil incidents per mile per year. That equates to an estimated spill frequency of 1.38 incidents per year for the entire proposed Project corridor. For those crude oil transmission pipeline incidents less than or equal to 50 bbl, the incident frequency factor was 0.0004, resulting in an estimated frequency of 0.68 crude oil spills along the proposed Project corridor per year.

TABLE 3.13.4-2
NRC Reported Hazardous Liquid and Crude Oil Transmission Pipeline Spill Incidents per Year from 2002 to 2010

Characteristic	Hazardous Liquids Dataset[a]	Hazardous Liquids Dataset Less than or Equal to 50 Barrels[a]	Crude Oil Dataset[b]	Crude Oil Dataset Less than or Equal to 50 Barrels[b]
Total Number of Spill Incidents	1,067	546	407	200
Average Number of Incidents per Year	119	61	45	22
Incidents per mile per Year	0.0007	0.0004	0.0008	0.0004
Project Total Incidents per Year (1,682 miles)[c]	**1.16**	**0.60**	**1.38**	**0.68**

[a] Includes all onshore hazardous liquid transmission pipeline incidents in the U.S. from 2002 to 2010.
[b] "Crude oil" includes onshore crude oil transmission pipeline incidents in the U.S. from 2002 to 2010.
[c] Includes existing Cushing Extension.
Source: NRC 2011.

DOS Estimated Incident Frequency for Hazardous Liquid and Crude Oil Spills of Any Size

An estimate of incident frequency for hazardous liquid and crude oil spills of any size along the proposed 1,682 mile pipeline corridor can be derived by adding the significant incident frequency from the PHMSA dataset (spills greater than or equal to 50 bbl – see Table 3.13.4-1) to the NRC dataset (restricted to spills less than or equal to 50 bbl – see Table 3.13.4-2). This approach results in an estimated frequency of 1.78 hazardous liquid spills and 2.51 crude oil spills of any size from the proposed Project per year.

Keystone Incident Frequency Analysis

Keystone conducted a threat assessment that identified primary threats that could result in an accidental release of crude oil. These identified threats are materials and construction (e.g., pipe steel flaws, defective welds), corrosion (external, internal and stress corrosion cracking), incorrect pipeline operations (hydraulic surge), accidental damage from third party excavation, and natural hazards (ground movement resulting from seismic and landslide events, flooding and washout). Keystone converted incident frequencies determined using the PHMSA database (2008) to estimated occurrence intervals for the six categories of incident causes specific to the proposed Project (Table 3.13.4-3).

TABLE 3.13.4-3
Corridor Spill Frequency Estimated by Keystone

Threat	Occurrence Interval of One Spill Per Mile	Number of Spills per Mile per Year	Spill per Corridor per Year
Materials and construction	3,300 years	1/3300 = 0.0003	1682 x 0.0003 = 0.50
Corrosion	3,400 years	1/3400 = 0.0003	1682 x 0.0003 = 0.50
Hydraulic surge	6,800 years	1/6800 = 0.0001	1682 x 0.0001 = 0.17
Excavation damage	8,200 years	1/8200 = 0.0001	1682 x 0.0001 = 0.17
Ground movement	81,500 years	1/81500 = 0.00001	1682 x 0.00001= 0.02
Flooding and washout	87,800 years	1/87800 = 0.00001	1682 x 0.00001 = 0.02
Total Estimated Spill Frequency per Year from all Threats for Corridor			**1.38**

It should be noted that the Keystone estimate focused on reported spill incidents from pipelines and pump station facilities in the PHMSA database (2008) for which a cause was reported and only on those causes attributable to the threats included in Table 3.13.4-3.

Keystone modified the above baseline failure frequencies determined from the PHMSA historic database associated with each of the identified threats to reflect reductions in projected failure frequencies for the proposed Project that would result from factors included within the proposed Project design and operations and within the regulatory requirements applicable to the proposed Project, including:

- Standard PHMSA regulatory requirements in 2008, the time the analysis was conducted;
- Pipeline industry best practices incorporated into the proposed Project design;
- The 51 conditions in PHMSA Special Permit #2006-26617 that were known to apply to the existing Keystone Oil Pipeline Project;
- Specific terrain conditions along the proposed Project corridor;
- Specific fault hazard conditions along the proposed Project corridor;
- Specific flood and hurricane threats along the proposed Project corridor;
- Strike and puncture probabilities for the proposed Project resulting from third-party excavation impacts considering pipeline strength, wall thickness, and depth of cover; and
- Technological advances incorporated by Keystone into the proposed Project design, construction, operations, and maintenance plan.

As a result of these threat specific spill frequency reductions, Keystone calculated a Project-specific overall spill frequency of 0.22 spills per year along the entire pipeline corridor. The adjusted Keystone spill frequencies by pipeline segment are shown in Table 3.13.4-4. The adjusted Project-specific spill frequency of 0.22 spills per year includes several layers of conservatism. While the threat analysis is confined to threats to the mainline pipe, the PHMSA (2008) database from which the baseline spill frequency was calculated included all reported spills, not only spills resulting from a mainline pipeline breach. Additionally, the threat analysis did not consider additional safety requirements included within the 57 Project-specific Special Conditions developed by PHMSA and incorporated into the proposed Project that were more restrictive than those applied to the existing Keystone Oil Pipeline Project. For security reasons, the detailed threat specific spill frequency analysis is considered proprietary and confidential. A summary of the threat analysis is provided in Appendix P. A commenter prepared a report (Stansbury 2011) critical of this Keystone spill frequency analysis. Consideration was given to the report in the environmental analysis, and a response to issues raised in the report can be found in Appendix V.

TABLE 3.13.4-4
Projected Spill Occurrence for the Proposed Project over a 10-Year Interval

Proposed Pipeline Segment	Spills per Segment (rounded)
Steele City Segment (852 miles)	1.1
Keystone Cushing Extension (298 miles)	0.4
Gulf Coast Segment and Houston Lateral (532 miles)	0.6
Project Total (1,682 miles)	**2.2**

Source: Keystone 2009a.

Summary of Spill Frequency Projections

Relevant DOS estimates of spill frequency based on the PHMSA database for significant spills range from 1.18 incidents per year for hazardous liquid spills to 1.83 incidents per year for crude oil spills greater than 50 bbl (Table 3.13.4-1). Using the NRC database, DOS estimates of hazardous liquid spill frequencies range from 1.16 incidents per year for spills of any size to 0.6 incidents per year for spills up to 50 bbl. In addition, for crude oil spills, the NRC database estimates range from 1.38 incidents per year to 0.68 incidents per year for spills up to 50 bbl (Table 3.13.4-2). The estimate of incident frequencies for hazardous liquid and crude oil spills of any size using both the PHMSA significant spill database for spills greater than 50 bbl and the NRC database for spills up to 50 bbl ranged from 1.78 hazardous liquid spills to 2.51 crude oil spills of any size.

Keystone initially calculated a baseline spill frequency using the PHMSA (2008) database of 1.38. In addition, Keystone separately estimated a proposed-Project-specific spill frequency for the entire pipeline of 0.22 spills per year (Table 3.13.4-4). That estimate was derived from reductions to spill frequencies by threat category resulting from specific terrain and environmental conditions along the proposed Project corridor, required regulatory controls, depth of cover, strength of materials, and technological advances.

Several commenters have expressed concern with the spill frequency analysis results based on the spill history of the existing Keystone Oil Pipeline Project (See Table 3.13.1-4). While the number of spills to date on the existing Keystone Oil Pipeline Project is higher than the annual estimates of spill frequency for the lifetime of the proposed Project, according to PHMSA (PHMSA pers. comm. 2011), the type and number of spills that have occurred during the start up and initial operations of the Keystone Oil Pipeline Project (see Section 3.13.1.2) are typical of this phase of pipeline operations. While the number of incidents was a concern and prompted PHMSA to take action by issuing a Corrective Action Order, the number of incidents in the start up phase is not indicative of the likely number of spills over time. Therefore, the use of the PHMSA and NRC databases is appropriate to develop estimates of spill frequency throughout the lifetime of the proposed Project. Additionally, the intent of the 57 Project-specific Special Conditions developed by PHMSA and incorporated into the design, construction, operations, and maintenance plans for the proposed Project is to reduce the likelihood of certain types of spills that have occurred in older pipeline systems built and maintained under less stringent requirements.

Oil Spill Volume

Historical Spill Volumes

PHMSA Significant Incident Spill Volumes

The 10-year average of PHMSA onshore hazardous liquid pipeline significant incident data (PHMSA 2011) indicates that the average reported gross volume of fluid lost per year from 2001 through 2010 was 4,376,652 gallons (104,206 bbl) per year. Given an onshore hazardous liquid pipeline mileage of approximately 171,000 miles, this equates to an average fluid loss per pipeline mile per year of approximately 25.6 gallons (0.6 bbl). Using data for onshore hazardous liquid pipelines for each state that would be crossed by the proposed pipeline, the average loss would be 24.8 gallons (0.6 bbl) per mile per year for the full length of the proposed pipeline. Using the PHMSA database for crude oil spills, the loss rate would be approximately 43.7 gallons (1.04 bbl) per mile per year. The average volume for crude oil spills is likely higher than that for all hazardous liquid pipelines due to the fact that larger crude oil volumes are typically transported by pipeline than volumes of other materials. Using these historical spill volume values applied to the pipeline mileage of the proposed Project, the estimates of spill volumes obtained are:

- 42,050 gallons (1,002 bbl) based on the PHMSA significant incident database for onshore hazardous liquid pipelines;
- 41,738 gallons (994 bbl) based on the state-by-state PHMSA significant incident database for onshore hazardous liquid pipelines; and
- 73,503 gallons (1,750 bbl) based on the PHMSA database specific to onshore crude oil pipelines.

PHMSA data for incidents from 2002 through 2010 indicate that 50 percent of the releases over that time period were 126 gallons (3 bbl) or less and that less than 0.3 percent of those releases were 420,000 gallons (10,000 bbl) or greater (PHMSA 2011). However, PHMSA data also indicate that large to very large pipeline spills do occur.

PHMSA All Reported Incidents Spill Volumes (Onshore Hazardous Liquid Pipelines)

The 10-year national average of PHMSA all reported incidents (an average of 344 incidents per year) for onshore hazardous liquid pipelines (PHMSA 2011) indicates that the average reported gross volume of fluid lost per year from 2001 through 2010 was 4,419,836 gallons (105,234 bbl) per year. This equates to a national average fluid loss per pipeline mile per year of approximately 25.8 gallons (0.6 bbl). PHMSA does not provide summary incident reports for all reported incidents by state.

Maximum Spill Volumes

In response to a data request from PHMSA, Keystone conducted a maximum potential pipeline spill volume assessment. A very large (greater than 210,000 gallons [5,000 bbl]) spill would be a very unlikely event (see Appendix P) and would likely result from a major rupture or a complete break in the proposed Project pipeline that releases crude oil somewhere along the ROW. The actual volumes spilled would vary depending on a number of factors, including:

- MLV locations, activation methods, and activation delay times;
- Operating pressure within the pipeline;
- Location of the structural failure;
- Extent to which the proposed pipeline follows topographic contours, and the location of low spots in the pipeline relative to the structural failure; and
- Nature of the structural failure.

A complete structural failure of a high strength 36-inch outer diameter pipeline with the wall thicknesses of the proposed Project pipeline (see Section 2.3.1, Table 2.3.1-1) would be a highly unlikely event. To cause such a failure, the proposed pipeline would likely need to experience a direct shear event. Such events could be caused by:

- A strike-slip fault movement across the proposed pipeline – however, the proposed pipeline corridor does not cross any known active faults;
- An anchor drag event or a collision event within a navigable river that experiences large to very large ship or barge traffic – however, all such river crossings along the proposed corridor would be crossed using HDD and the pipeline would therefore be installed well below the maximum anchor depth and outside any potential collision hazard;
- A major construction-related accidental equipment interaction with the buried pipeline – however, the proposed pipeline would be buried under a minimum of 4 feet of cover, would be clearly marked, would include warning tape (ribbons) as required by the Project-specific Special Conditions developed by PHMSA, would be predominantly routed through rural areas where such large equipment construction impacts would be rare, and Keystone would implement public awareness and damage prevention programs in accordance with 49 CFR 195.440 and API RP 1162. Additionally, the probability of puncture of the X-70 strength steel pipe of the proposed Project would be very low as its puncture resistance is in excess of 65 tons and approximately 98 percent of all excavators in North America have a maximum digging force of less than 35 tons and no excavator has a digging force greater than 40 tons;
- An intentional act of sabotage, vandalism, or terrorism – however, the pipeline would be buried with a minimum of 4 feet of cover and all aboveground facilities would include security fencing, thus reducing facility accessibility to these potential threats;
- A major flood event with the potential to cause deep scour and debris impact to the proposed pipeline – however, at major river crossings, the proposed pipeline would be installed using HDD and would therefore be below the maximum scour depth, and at all stream crossings, the proposed pipeline would be installed below the calculated scour depth;
- A major slide event could be possible in steep slope areas along the proposed pipeline corridor – however, Keystone has considered landslide potential in the routing of the proposed pipeline and has selected crossings of steeper slope areas where the landslide potential is considered minimal, and the potential for landslide activity would be monitored during operations through regular aerial and intermittent ground patrols and through landowner awareness programs; or
- A combination of a high level of corrosion with some external force on the proposed pipeline – however, the proposed pipeline would be designed, constructed and operated consistent with the

requirements of 49 CFR 195 and the Project-specific Special Conditions developed by PHMSA (see Appendix U), many of which address requirements to reduce and monitor corrosion throughout the lifetime of the proposed Project. As described in Section 2.3.1.2, to protect against corrosion, an external coating (fusion-bonded epoxy, or FBE) would be applied to the pipeline and all buried facilities, and cathodic protection (CP) would be applied to the pipeline by impressed current. These measures would be provided in compliance with 49 CFR Part 195, Subpart H (Corrosion Control) and the requirements of 14 of the PHMSA 57 Special Conditions (see Appendix U). The primary impressed current CP systems would be rectifiers coupled to semi-deep vertical anode beds at each pump station, as well as rectifiers coupled to deep-well anode beds at selected intermediate mainline valve sites. The rectifiers would be variable output transformers which would convert incoming AC power to DC voltage and current to provide the necessary current density to the CP design structures. The rectifiers would have a negative cable connection to the design structure and a positive cable connection to the anode beds. The anode beds would consist of high silicon cast iron anodes backfilled with a highly conductive coke powder to allow for an expected anode minimum life of 20 years. During operation, the CP system would be monitored and remediation performed to prolong the anode bed and systems. The semi-deep anode beds would be 12-inch-diameter vertical holes spaced 15 feet apart with a bottom hole depth of approximately 45 feet. The deep-well anode bed would be a single 12-inch-diameter vertical hole with a bottom hole depth of approximately 300 feet.

Some commenters have expressed concern that the experience of backfill settling on TransCanada's Bison natural gas pipeline may indicate that 4 feet of cover would not occur in all locations along the proposed Project corridor. DOS issued a data request to Keystone asking that Keystone provide information on the Bison backfill settlement event. The following information is taken from Keystone's response:

"Abnormal trench settlement was experienced on the Bison pipeline during the spring of 2011. Correspondence from PHMSA with respect to this issue is attached. Keystone's response to PHMSA will follow.

There appears to be a strong correlation between ditch subsidence on the Bison Pipeline right-of-way and locations that were backfilled during severe winter conditions. Review of air photos and inspection reports and field review by geotechnical specialists and environmental inspectors suggests that the following causative factors were in play:

Initial ditch subsidence may have been caused by one or several factors. If the backfill contained a relatively high volume of snow, the melting snow would have left voids in the backfill. Similarly, if spoil was frozen at the time of backfill, larger voids between frozen angular peds would have been created. Consequently, what appeared to be well-compacted backfill may have actually further consolidated upon thawing. Another contributing factor may have been the high shrink-swell potential in some of the more clay-rich soil types.

In some areas, ditch subsidence appears to be occurring in conjunction with water migration within the relatively loose backfill. This loss of material can create further surface subsidence. Initial drainage pathways enlarge and increase as voids within the backfill are exploited and expanded by further drainage. If either surface runoff or subsurface water intersected a segment of trench with relatively loose backfill or significant voids, it would have exploited this pathway in which to flow on or beneath the trench surface, creating erosion and/or subsidence. Once subsidence begins, surface runoff seeking the topographic low further contributes to saturation of trench backfill and in some locations creates associated surface erosion.

The Keystone XL project is not proposed to work under frozen soil conditions. However, if unseasonal or early winter conditions appear prematurely TransCanada would employ the following measures:

- Substantial amounts of snow would be removed from the ditch and backfill material to manage excessive moisture thus increasing risks of excessive settling.
- Frozen subsoils placed within the trench would require pronounced "roaching" (pile subsoil material over trench and suspend topsoil replacement until the following summer. Deferring this activity until the following summer would ensure all frozen subsoils are thawed and settled and would be followed up with "re-working" or evening out the subsoil horizon within the trench, ensuring a compacted and evenly distributed subsoil horizon. Following this, topsoil replacement would be conducted over the entire pipeline right-of-way in the affected area.
- Breaking up/ pulverizing subsoils into smaller clods may be necessary if subsoil materials are too large to obtain reasonable subsoil backfilling.

Surface diversion berms would be placed along the right-of-way in specific locations to redirect spring run-off to avoid excessive erosion or scouring of the un-compacted trenchline. Additional bentonite ditch plugs or foam breakers may also need to be installed within the pipeline ditch depending on slope, soil types and active subsurface springs and/or seeps."

Additionally, PHMSA Special Condition 19 requires that Keystone maintain the depth of cover at a minimum of 4 feet, so should any settlement of the backfill occur along the proposed Project for any reason, PHMSA would require Keystone to repair the situation.

To ascertain what the maximum volume release could be at any location along the proposed pipeline corridor as requested by PHMSA, an analysis was conducted by Keystone that assessed maximum leak volume from a complete pipeline structural failure using a spill model that is populated with elevation data points occurring at every point of inflection (PI) in the pipeline or every 100 feet, whatever distance is smaller (in most cases it is the PI). The model evaluated over 100,000 data points detailing the profile of the pipeline. The elevation points were acquired through physical survey of the land (accuracy: 2-3 inches) and supplemented with LiDAR (Light Distancing and Ranging system with a vertical accuracy of approximately 6 inches). The model generated spill volume results at each of these data points. This analysis used the following response times:

- Stop pumping units at all pump station locations: approximately 9 minutes.
- Close remotely operated isolation valves: approximately 3 minutes.
- Total time: approximately 12 minutes.

The analysis also assumed a complete pipeline shear and draindown, a highly unlikely event for the reasons stated above. The analysis considered the configuration of the pipeline and the location of MLVs and pump stations from the Canadian border to delivery terminals. Based on this analysis, the approximate maximum spill volume was estimated to be approximately 2.8 million gallons (66,500 bbl), and it was determined that this size release was only theoretically possible along less than 0.1 percent of the proposed pipeline route (less than 1.7 miles). It is important to note that this approximate maximum spill volume could not occur at all locations along the proposed pipeline corridor. It represents the release that would occur under a structural failure scenario where the distance between MLVs and the terrain gradient in the vicinity of the failure, in combination with other factors, would lead to a maximum draindown condition. At all other locations along the pipeline corridor, the maximum draindown volume would be lower. For approximately 50 percent of the proposed pipeline corridor (approximately 842 miles), the modeled maximum spill volume would be less than 672,000 gallons (16,000 bbl) due to a complete structural failure of the pipeline. For the rest of the pipeline, the maximum release would be less due to topography and MLV placement. Areas where maximum spill volumes would be much lower include river crossings and pump stations where MLVs occur on each side of the river or the pump station.

In summary, the estimates of maximum spill volume were based on an analysis that included the following assumptions:

- Complete structural failure of the pipeline;
- Maximum assumed time between the failure incident and the time of detection;
- Maximum time for shutdown to be initiated and completed;
- Maximum flow rate; and
- Largest potential line drainage volume between the closest MLV on each side of the structural failure given site conditions at each 3-foot segment.

To put the size of these maximum spill estimates into perspective, they can be compared to the size of major historical pipeline oil spills. The largest major historical pipeline spills in the U.S. from 1979 through 2010 ranged from about 300,000 to 1.3 million gallons (7,143 to 30,950 bbl). In this time period, there were less than 10 spills within this range of magnitudes. These spills were all lower in volume than the potential largest spill from the proposed pipeline and they appear to confirm the conservatism in the maximum spill estimates, given that they occurred in pipeline systems much older and designed to less stringent requirements than the proposed Project, although none of the pipelines involved with these spills were of the same pipeline diameter and operating pressure as those of the proposed Project.

A very large spill could occur at the proposed Cushing tank farm. However, each of the three 350,000-bbl tanks would be surrounded by a secondary containment berm (Section 2.2.6) that would hold 110 percent of the contents of the tank plus freeboard for precipitation. Therefore, a very large release to the environment could only occur in the unlikely event of a major failure of a tank and a concurrent failure of the secondary containment berm. All other releases from tank failure would be contained within the bermed areas.

A commenter prepared a report (Stansbury 2011) critical of the Keystone maximum spill analysis. Consideration was given to the report in the environmental analysis, and a response to issues raised in the report can be found in Appendix V.

3.13.5 Impacts Related to Oil Spills

Crude oil released from the proposed pipeline during operations or refined oil released during construction or operations into the environment may affect natural resources, protected areas, human uses and services, and aesthetics to varying degrees, depending on the cause, size, type, volume, location, season, environmental conditions, and depending on the timing and degree of response actions. Small oil spills (e.g., minor intermittent leaks and drips from construction machinery and operating equipment) would be almost certain to occur during construction and operation of the proposed Project, although in aggregate these spills could be of sufficient magnitude to substantively affect natural resources and human uses of the environment.

Most oil spills are only broadly predictable in cause, location, time of occurrence, size, and duration (J.L. Mach et al., Hart Associates, Inc. 2000). For example, it is more likely that:

- A pipeline spill would occur in a populated area where excavation is a frequent activity than in a remote wilderness area;
- A pipeline washout would occur in a major river bed than in a small creek;
- A fueling spill would occur on a fueling station pad than on the ROW; or
- A tanker truck would overturn on a winding mountain road than on the prairie.

When an oil spill occurs, the resulting environmental impact depends on a number of factors, including:

- Amount and duration of oil release, and location with respect to topography, infrastructure, and sensitive receptors;
- Fate and behavior of the spilled oil (i.e., the potential for a spill reaching an environmental receptor and its persistence in the environment);
- Chemical composition and physical characteristics of the oil; and
- Toxicity and other adverse effects of the oil to the receptors.

The oil spill literature is diverse, extensive, and often presents conflicting results and conclusions regarding acute and chronic impacts from oil spills. Much of the literature is not published in the peer-reviewed literature but consists of technical reports prepared by the potentially responsible parties (PRPs), natural resource trustees (e.g., state, federal, and tribal managers for the natural resources), consultants and academics retained by the PRPs and/or Trustees, and other interested parties including NGOs. Nevertheless, the body of literature and information taken together provides a basis for evaluating the potential range of impacts that may result from an oil spill from the construction, operation, maintenance and demobilization of the proposed pipeline. Some of the sources of the information utilized for this analysis include the following:

- NOAA DARP website where the Damage Assessment and Restoration Plans provide a description of oil spill impacts as well as planned restoration actions (www.darrp.noaa.gov);
- USFWS website where impact assessment and restoration plans are provided for a limited number of sites (www.fws.gov/contaminants/restorationplans/plans.cfm);
- Oil and Nature Bulletin by USFWS (www.fws.gov/contaminants/Documents/OilAndNature.pdf);
- Resources on Oil Spills, Response, and Restoration: A Selected Bibliography by Anna Fiolek, Linda Pikula, and Brian Voss. June 2010. National Oceanic and Atmospheric Administration, Library and Information Services Division. (http://docs.lib.noaa.gov/noaa_documents/NESDIS/NODC/LISD/Central_Library/current_references/current_references_2010-2.pdf);
- Damage Assessment and Restoration Plan/Environmental Assessment (DARP/EA) listing by California for several Natural Resource Damage Assessments (NRDAs) (www.dfg.ca.gov/ospr/NRDA);
- Oil spill response in freshwater: Assessment of the impact of cleanup as a management tool by John H. Vandermeulen and Cal W. Ross in Journal of Environmental Management 44(4):297-308, 1995;

- Environment Canada's website (www.ec.gc.ca/scitech/) that provides access to 34 years of publications on oil spill impacts and response (mostly in temperate to cold environments) that have been presented at the annual AMOP Technical Seminar on Environmental Contamination and Response;
- Archived Proceedings of the International Oil Spill Conference (www.iosc.org/papers/search.asp) wherein many papers and posters deal with the fate of oil in freshwater systems as well as the impacts to natural resources; and
- Additional papers, technical reports, Natural Resource Damage Assessments (NRDAs) books, and bibliographies related to freshwater oil spill impacts that provide detailed (and sometimes contradictory) assessments of impacts as well as the recovery of natural resources from oil spills, including many catalogued and/or prepared by EPA, USFWS, NOAA, USCG, and many state agencies.

A discussion of oil spill impacts requires a depiction of typical potential spill scenarios and environmental variables that might affect spilled oil fate and behavior. These depictions are necessarily simplified and do not represent the entire spectrum of events that might be realized in actual spills. However, many of these factors and assumptions have been used in previous similar assessments, and all are based on the peer-reviewed literature, technical reports, and empirical experience of oil spill experts worldwide. The following key factors are addressed below:

- Physical, Temporal and Environmental Factors Affecting Hazardous Liquid Spill Impacts (Section 3.13.5.1);
- Keystone Response Time and Actions (Section 3.13.5.2);
- Factors Affecting the Behavior and Fate of Spilled Oil (Section 3.13.5.3);
- Summary of Environmental Factors Affecting Fate of Spilled Oil (Section 3.13.5.4);
- Keystone Actions to Prevent, Detect, and Mitigate Oil Spills (Section 3.13.5.5); and
- Types of spill impacts (Section 3.13.5.6).

3.13.5.1 Physical, Temporal, and Environmental Factors Affecting Hazardous Liquid Spill Impacts

Impacts related to hazardous liquid spills could be affected by the release location, type and volume of material released, nearby receptors and resource uses, seasonal variations, weather, water levels, and other factors that are described below.

Location of Spill

Most spills would occur and be contained within or in close association with the proposed pipeline ROW or associated infrastructure, including construction yards, pump stations, and maintenance yards. These spills would typically be very small (less than 42 gallons [1 bbl]) and would likely be promptly cleaned up as required by federal, state, and local regulations. During construction, some refined product spills may occur from tank truck accidents along roads leading to the construction sites. Some of these spills may result in much or all of a load being spilled to the land, wetlands, ponds and lakes, or flowing waterbodies adjacent to the road or pad. The maximum volume of gasoline or diesel from a tank trunk would be about 9,000 gallons (214 bbl) for diesel or gasoline and approximately 330 gallons (7.9 bbl) for lubricating or hydraulic fluid (i.e., six 55-gallon drums on a pallet). These spills would likely have limited areal extent unless they occurred at or very near an open water body.

Spills during operation and maintenance of the proposed pipeline would for the most part involve crude oil. Based on experience, spills resulting from excavation damage would likely occur in urban/suburban areas and some agricultural areas where water-conveying canal excavation activities below four feet of depth are common. The locations of greatest concern for potential oil spills would be those that are up-gradient of HCAs, especially water intakes for public drinking water or commercial/industrial users and USAs, especially wetlands, flowing streams and rivers, and similar critical habitats.

Crude Oil Composition

The following section of the EIS addresses the composition of WCSB oil sands derived crude oils relative to other crude oils because of the potential for large-to very large volume releases of crude oil from the proposed Project and because the crude oil transported would ultimately be refined in PADD III.

General Description of WCSB Oil Sands Derived Crude Oils

Crude oil transported by the proposed Project would, for the most part, originate within the Alberta oil sands. The material extracted from the oil sands is typically a very viscous material called bitumen. Bitumen and the types of crude oils produced through either processing or diluting the bitumen are defined as follows:

- *Raw bitumen* – Raw bitumen is solid under ambient conditions and therefore must be diluted or converted prior to transport via pipeline.
- *Upgraded bitumen (SCO or syncrude)* – SCO (synthetic crude oil) is produced from bitumen through a refinery conversion that turns heavy hydrocarbons into lighter hydrocarbons. While SCO can be sour, it is usually a light, sweet crude without heavy fractions.
- *Diluted bitumen (dilbit)* – Dilbit is bitumen mixed with a diluent, usually a natural gas liquid such as gas condensate. This is done to make the mixed product “lighter,” reducing its viscosity so that the dilbit can be transported in a pipeline.
- *Synthetic bitumen (synbit)* – Synbit is usually a combination of bitumen and SCO. The properties of synbit blends vary greatly, but blending lighter SCO with heavier bitumen results in a product more similar to conventional crude oil than either SCO or dilbit.
- *Diluted synthetic bitumen (dilsynbit)* – Dilsynbit is a combination of bitumen and heavy conventional crude oils blended with condensate and SCO, producing a product more similar to conventional crude oil than either SCO or dilbit (IHS CERA 2010).

The types of WCSB crude oil that would be transported by the proposed Project would primarily consist of SCO and dilbit. The upgrading process for SCO and the addition of diluent in dilbit would occur before the oil would be delivered to the proposed pipeline at Hardisty, Alberta. The precise composition of SCO and dilbit would vary by shipper and is considered by the shippers to be proprietary information. In general, these crude oils would be similar to Western Canada Select (WCS - a heavy crude oil) and Suncor Synthetic A (a lighter crude oil). The physical and chemical characteristics of these two types of crude oil, as well as most of the other crude oils derived from the oil sands, are available at http://www.crudemonitor.ca/assays.html and are further described below. The diluents mixed with bitumen are generally similar to kerosene, natural gas condensate or synthetic crude oil. The diluents are composed of hydrocarbon molecules that generally have five carbon atoms (pentanes) or more but they can also contain molecules with four carbon atoms (butane) and may contain trace amounts of molecules with one to three carbon atoms (methane, ethane, and propane, respectively).

Crude oils may differ in their solubility, toxicity, persistence, and other properties that affect their impact on the environment. The effects of a specific crude oil are a function of its composition and physical properties. Of particular importance are:

- Specific gravity, which determines whether the unweathered oil would sink or float upon release to an aquatic environment. A specific gravity of less than 1.0 means the unweathered oil will float on fresh water. In the discussions of crude oil within this section of the EIS, API gravity is used rather than specific gravity. If a crude oil has an API gravity greater than 10, it is lighter and would float on water. If a crude oil has an API gravity less than 10, it would sink in water;
- Viscosity, which determines how readily the oil would flow when released. Typically, viscosity increases as temperature decreases. This may be 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˚F in summer;
- Pour point, an indicator of the temperature at which the oil changes from liquid to a “solid” material that does not flow;
- Proportion of volatile and semi-volatile fractions, an indicator of (1) the amount of oil that would evaporate or volatilize; (2) the amount of oil that would likely physically persist in the environment as it weathers; and (3) the amount of potentially toxic material that could dissolve or disperse into an aquatic environment and cause toxicological impacts;
- Proportion and amount of polycyclic aromatic hydrocarbons (PAHs), many of which are considered key toxic components of crude oils; and
- Proportion of other elements and compounds including sulfur and metals.

Information on example crude oils expected to be transported by the proposed Project (see Tables 3.13.5-1 and 3.13.5-2) indicates that the transported crude oil would likely have the following general characteristics:

- Average specific gravity of approximately 0.846 for Suncor Synthetic A oil and approximately 0.924 for WCS crude oil which means that both types of crude oil would float on fresh water;
- Pour point for heavy crude oil less than approximately -30˚C (-22˚F);
- Pour point for synthetic crude oil less than approximately -21˚C (-5.8˚F);
- PAH concentrations which are considered proprietary by the shippers and unknown to Keystone at this time;
- Benzene, toluene, ethyl benzene, and xylene (BTEX) concentrations are approximately 1 percent by volume of the crude oil volume;
- Sulfur concentrations less than 0.25 percent and 3.6 percent by weight for synthetic and diluted bitumen respectively;
- Nickel concentrations less than 2.5 and 66 parts per million (ppm) for synthetic oil and diluted bitumen respectively, and vanadium concentrations less than 160 and 4 ppm respectively; and
- Average mercury concentrations lower than comparable values for Mexican Maya and Venezuelan heavy sour crude oils (see Table 3.13.5-7).

TABLE 3.13.5-1 Constituents and Properties of Western Canadian Select Crude Oil			
Characteristic	**Observed**	**Past Average**	**Standard Deviations** [a]
Basic Properties			
Relative Density	0.924	0.931	0.005
API Density	21.6	20.6	0.8
Absolute Density (kg/m^3)	923.6	929.6	4.8
Total Sulphur (wt %)	3.37	3.33	0.17
MCR (mass %)	8.93	9.38	0.39
SW (vol %)	- [b]	-	-
Sediment (ppmw)	301	374	97
TAN	1.03	0.86	0.11
Salt in Crude (ptb)	-	40.3	12.6
Iron (mg/L)	-	-	-
Nickel (mg/L)	53.6	53.7	6.1
Vanadium (mg/L)	129.9	130.1	13.2
Molybdenum (mg/L)	-	-	-
Constituent			
Methane	-	-	-
Ethane	-	0.03	0.00
Propane	0.07	0.07	0.02
isoButane	0.57	0.59	0.13
nButane	1.54	1.45	0.26
Total Butanes	2.11	2.04	0.38
Total C4 minus	2.18	2.14	0.40
isoPentane	2.14	1.93	0.29
n-Pentane	2.22	2.01	0.30
Hexanes	4.04	3.58	0.54
C7 Paraffins	0.73	0.64	0.10
C7 Naphthenes	1.16	1.10	0.13
C7 Aromatics	0.40	0.34	0.05
nHeptane	0.62	0.56	0.07
Total Heptanes	2.90	2.65	0.30
C8 Paraffins	0.76	0.74	0.09
C8 Naphthenes	0.61	0.63	0.09
C8 Aromatics	0.48	0.44	0.07
nOctane	0.39	0.38	0.05
Total Octanes	2.25	2.79	0.27
C9 Paraffins	0.35	0.36	0.06
C9 Naphthenes	0.38	0.39	0.06
C9 Aromatics	0.68	0.66	0.10
nNonane	0.26	0.23	0.04
Total Nonanes	1.33	1.64	0.23
C10 Paraffins	0.53	0.49	0.07
C10 Naphthenes	0.05	0.06	0.03
C10 Aromatics	-	-	-
nDecane	0.26	0.24	0.05
Total Decanes	0.84	0.78	0.13

TABLE 3.13.5-1 Constituents and Properties of Western Canadian Select Crude Oil			
Characteristic	**Observed**	**Past Average**	**Standard Deviations**[a]
Distillation Information (°C), % Off			
IBP	-	34.1	1.2
1%	-	35.0	1.7
5%	-	77.2	24.2
10%	-	157.6	35.5
15%	-	222.4	29.2
20%	-	267.5	21.7
25%	-	302.7	18.9
30%	-	333.8	18.3
35%	-	363.9	19.2
40%	-	394.1	20.7
45%	-	423.2	21.5
50%	-	452.3	23.8
55%	-	483.6	26.9
60%	-	518.1	31.1
65%	-	555.7	35.4
70%	-	594.6	37.4
75%	-	633.0	37.8
80%	-	665.7	35.1
85%	-	682.9	28.9
90%	-	698.2	22.1
95%	-	706.6	10.2
98%	-	-	-
99%	-	-	-
100%	-	-	-
FBP	-	716.8	2.5
Residue (%)	-	13.72	4.93
Yield on Crude (Vol %)			
C4 and lighter (mass %)	2.2	2.1	0.4
Naphtha (C5; 190°C)	-	9.1	2.8
Kerosene (190°C – 227°C)	-	10.9	1.2
Distillate (277°C – 343°C)	-	9.7	1.2
Gas Oil (343°C – 565°C)	-	34.7	2.7
Residue (565°C +)	-	33.4	4.8
BTEX (Vol %)			
Benzene	0.18	0.15	0.02
Toluene	0.32	0.27	0.04
EthylBenzene	0.06	0.06	0.01
Xylenes	0.33	0.30	0.05

[a] Past Average and Standard Deviations include 156 records.
[b] - (dash) indicates a tested value below the instrument threshold.
kg/m^3 = kilogram per square meter; wt = weight; vol = volume; mg/L = milligram per liter
Source: Crude Quality Inc. 2010.

TABLE 3.13.5-2 Constituents and Properties of Suncor Synthetic A Crude Oil			
Characteristic	**Observed**	**Past Average**	**Standard Deviations** [a]
Basic Analysis Information			
Relative Density	0.846	0.860	0.006
API Density	35.8	33.1	1.2
Absolute Density (kg/m^3)	844.9	858.7	6.0
Total Sulphur (wt %)	0.19	0.19	0.03
MCR (mass %)	- [b]	0.02	0.06
SW (Vol %)	-	-	-
Sediment (ppmw)	-	-	-
TAN	-	-	-
Salt in Crude (ptb)	-	-	-
Iron (mg/L)	-	-	-
Nickel (mg/L)	-	0.6	1.0
Vanadium (mg/L)	-	1.5	1.4
Molybdenum (mg/L)	-	-	-
Light Ends (Vol %)			
Methane	-	-	-
Ethane	-	-	-
Propane	0.03	0.02	0.01
isoButane	0.37	0.28	0.11
nButane	1.81	1.51	0.32
Total Butanes	2.18	1.80	0.43
Total C4 minus	2.21	1.82	0.45
isoPentane	1.73	1.10	0.19
n-Pentane	2.49	1.88	0.31
Hexanes	5.09	3.96	0.65
C7 Paraffins	1.28	1.01	0.23
C7 Naphthenes	1.29	1.09	0.17
C7 Aromatics	0.38	0.29	0.06
nHeptane	1.48	1.23	0.19
Total Heptanes	4.43	3.62	0.52
C8 Paraffins	1.63	1.56	0.21
C8 Naphthenes	1.35	1.35	0.18
C8 Aromatics	0.89	0.82	0.12
nOctane	0.93	0.91	0.13
Total Octanes	4.80	4.64	0.60
C9 Paraffins	0.93	0.97	0.13
C9 Naphthenes	0.76	0.79	0.13
C9 Aromatics	1.36	1.47	0.21
nNonane	0.78	0.75	0.10
Total Nonanes	3.83	3.98	0.50
C10 Paraffins	1.35	1.25	0.19
C10 Naphthenes	0.07	0.13	0.11
C10 Aromatics	-	0.00	-
nDecane	0.75	0.77	0.13
Total Decanes	0.17	2.17	0.32

TABLE 3.13.5-2 Constituents and Properties of Suncor Synthetic A Crude Oil			
Characteristic	**Observed**	**Past Average**	**Standard Deviations [a]**
Distillation Information (°C) % Off			
IBP	-	34.5	1.6
1%	-	37.5	3.3
5%	-	92.2	14.3
10%	-	132.9	12.4
15%	-	167.0	12.2
20%	-	196.1	12.4
25%	-	223.5	12.3
30%	-	247.7	11.5
35%	-	267.9	10.4
40%	-	285.6	9.7
45%	-	300.9	8.6
50%	-	314.6	8.0
55%	-	327.8	7.7
Distillation Information (°C) % Off (Cont.)			
60%	-	341.0	7.4
65%	-	354.1	7.2
70%	-	367.3	7.1
75%	-	381.3	7.1
80%	-	396.9	7.1
85%	-	414.3	6.8
90%	-	434.3	7.2
95%	-	464.8	8.4
98%	-	502.2	13.8
99%	-	533.5	21.9
100%	-	-	-
FBP	-	572.5	31.3
Residue (%)	-	0.0	-
Yield on Crude (Vol %)			
C4 and lighter (mass %)	2.2	1.8	0.4
Naphtha (C5; 190°C)	-	16.3	2.2
Kerosene (190°C – 277°C)		20.2	1.9
Distillate (277°C – 343°C)	-	22.1	1.0
Gas Oil (343°C – 565°C)	-	23.2	10.9
Residue (565°C +)	-	-	-
BTEX (Vol %)			
Benzene	0.09	0.05	0.03
Toluene	0.30	0.23	0.05
EthylBenzene	0.15	0.15	0.03
Xylenes	0.57	0.52	0.08

[a] Past Average and Standard Deviations include 100 records.

[b] - (dash) indicates a tested value below the instrument threshold.

kg/m^3 = kilogram per square meter; wt = weight; vol = volume; mg/L = milligram per liter

Source: Crude Quality Inc. 2010.

Additional characteristics of these crude oils are reported in copyrighted assays by Crude Quality, Inc. (http://www.crudemonitor.ca/current.html). The crude oils reported in this website represent approximately 85 percent of the current crude oil production in the WCSB (Bill Lywood Pers. Comm. 2011). Some crude oil characteristics is not included in the assay data for the reference crude oils described in the EIS, including viscosity profiles, proportion of volatile and semi-volatiles compounds, the amount or proportion of PAHs, and toxicity to aquatic organisms based on bioassays. Information on these characteristics is therefore drawn from the available literature in the public record.

Several commenters on the draft EIS expressed concerns relating to the chemical composition of the WCSB crude oil, in particular the dilbit crude oil, that would be transported through the proposed Project in relationship to other crude oils. Many commenters on the draft and supplemental draft EIS also expressed concern relative to the potential that WCSB crude oil delivered to PADD III through the proposed Project would create new air quality concerns resulting from refining due to the composition of the WCSB crude oil relative to crude oils currently refined in PADD III. In response to these and other concerns relative to the composition of crude oils that would be transported through the proposed Project, DOS has compared the chemical composition of WCSB oil sands derived crude oils with conventional (i.e., non-oil sands derived) WCSB crude oils that have been transported through pipelines into the U.S. in large quantities for several decades. DOS has also compared the composition of WCSB heavy crude oils likely to be transported through the proposed Project to other heavy crude oils currently refined in PADD III.

Characteristics of WCSB Oil Sands Derived Crude Oils (Dilbits) Compared to Conventional WCSB Heavy Crude Oils

This section of the EIS focuses on comparisons of crude oil characteristics of dilbits relative to reference conventional crude oils that have been imported from Canada for several decades. The categories of crude oils examined and the specific characteristics of these crude oils were obtained primarily from information provided on the website www.crudemonitor.ca. These categories are:

- Light crude oils (both sweet and sour), which generally have an API gravity equal to or greater than 35;
- Medium sour crude oils, which generally have an API gravity between 24 and 35 and sulfur content greater than 0.5 percent;
- Heavy conventional crude oils, which generally have an API gravity equal to or less than 24; and
- Dilbits, which generally have an API gravity less than 24.

As presented in Table 3.13.5-3, since at least 1986 Canadian heavy crude oils (which are all sour) and medium sour crude oils have generally comprised 60 to70 percent of total Canadian imports to the U.S. The import statistics do not distinguish between conventional heavy crude oils and dilbits, but comparing the import statistics with historic production figures provided by CAPP (CAPP 2006), it is reasonable to infer that before 2000 the majority of Canadian heavy crude oil imports were likely from conventional production, and further to infer that since 2000 dilbits have comprised an increasingly large percentage of these heavy crude oil imports. Dilbits are not the only example of crude oils produced by mixing a heavy crude oil (or bitumen) with a lighter hydrocarbon diluent to facilitate transport through pipelines. For example, the heavy crude oil produced for decades in the Lloydminster area of Canada exhibits an API gravity ranging between 10 and 25 at the wellhead (Wong and Ogrodnick 1998). This Lloydminster heavy crude oil is mixed with diluents to create the former benchmark WCSB Lloyd Blend that comprises 80 percent crude oil and 20 percent diluent.

TABLE 3.13.5-3 Historic U.S. Imports of Canadian Crude Oil by Category (thousands of barrels of oil per day)					
Year	**Heavy[a]**	**Medium Sweet[b]**	**Medium Sour[c]**	**Light Sweet and Sour[d]**	**Total**
1986	181	14	205	169	570
1990	242	43	104	254	643
1995	237	53	436	295	1039
2000	433	154	512	252	1351
2005	705	257	500	173	1635
2010	1039	314	344	267	1964

[a] =<24 API
[b] Between 24 and 35 API <.5%
[c] Between 24 and 35 API >.5% sulfur
[d] >=35 sulfur
Source: EIA 2011.

Commenters on the draft EIS and supplemental draft EIS expressed concerns that the characteristics of oil sands derived crude oils, particularly dilbit, make them more corrosive to steel pipelines as compared to conventional crude oils. These corrosivity concerns are discussed in a report (NRDC 2010) produced by several non-profit organizations. Public concern has lead to the possibility that Congress could direct PHMSA to conduct a specific study of dilbit corrosivity in comparison to other crude oils. Additional comments on the supplemental draft EIS regarding WCSB crude oil composition and characteristic were received from the Canadian Association of Petroleum Producers (CAPP), including a report from Crude Quality, Inc. (2011).

To address commenter concerns relative to WCSB crude oil, the following discussion has been clarified, updated, supplemented and reorganized into two subsections addressing crude oil corrosivity/erosivity and volatility/instability, respectively. In preparation of this discussion, DOS reviewed the relevant comments and stakeholder submittals, technical publications referenced in this section, and input from technical experts including corrosion engineers, petroleum engineers, pipeline engineers, chemists, environmental and natural resource scientists, PHMSA personnel, private industry, and academia.

Corrosivity/Erosivity

Some commenters expressed concern that WCSB crude oil pipeline statistics from Canada suggest that corrosion rates for WCSB crude oil pipelines are higher than for other crude oil pipelines. In consultation with ERCB, PHMSA made adjustments to the data ERCB regarding internal corrosion incidents on oil pipelines, to ensure that similar types of pipelines were being compared. When the comparison is made between similar pipelines carrying processed crude oils, the Albertan and U.S. pipeline statistics indicate similar rates of internal corrosion.

Other reports (NRDC 2011) that have suggested a substantially higher percentage of internal corrosion incidents in Albertan crude oil pipelines included statistics not only from crude oil pipelines, but also oil effluent, or multiphase, pipelines. DOS consulted with ERCB regarding the Albertan system for classifying pipelines. According to ERCB, the oil effluent category pipelines are delivering the production of individual oil wells to nearby satellites or batteries. This production is a blend of gases, oil, condensates, and water, in varying compositions (Dave Grzyb, Pers. Comm. 2011). These types of pipelines in the U. S. are not regulated by PHMSA and not included in the PHMSAS statistics. Therefore, it is appropriate to eliminate them from a comparison between PHMSA and Albertan incident statistics.

According to the ERCB, the higher rate of internal corrosion incidents in oil effluent pipelines is likely attributable to the elevated water and content of the oil effluent resulting from the age and production capability of conventional Alberta oil fields. These older oil fields carry high amounts of water and dissolved gases that are very corrosive to steel. The ERCB statement is consistent with the literature regarding causes of internal corrosion in crude oil pipelines, which identifies water and certain gases such as carbon dioxide and hydrogen sulfide as indicators of internal corrosion potential (Baker 2008). It is also consistent with a California study that concluded that crude oil gathering lines carry a higher percentage of water and other impurities which tend to increase the internal corrosion rate (CSFM 1997).

Direct comparisons between spill frequencies in the Canadian NEB/ERCB incident database and the PHMSA spill frequency database are complicated by differences in spill reporting requirements in the two jurisdictions. In Canada, spills of any size are reported. In the U.S., spills of 5 gallons or more are reported at this time. PHMSA reports that in the U.S. from 2002 to 2009, internal corrosion accounted for approximately 26.5 percent of spill incidents (PHMSA 2011). The NEB/ERCB reported that in Alberta from 1990 to 2005, internal corrosion accounted for approximately 24.8 percent of spill incidents (Alberta Energy and Utilities Board 2007). In a briefing to the U.S. Senate on June 8, 2011, PHMSA presented statistics comparing total failures, internal corrosion related failures, and external corrosion related failures in the U.S. crude oil pipeline transmission system from 2002 to 2010 with similar failures in the Alberta crude oil pipeline transmission system over the same time period (see Table 3.13.5-4). The quantity of oil sands derived crude oil in the Alberta system over this time period was likely much higher on a percentage basis than the quantity of oil sands derived crude oil in the entire U.S. system. Nonetheless, the internal corrosion related failures in the Alberta system over this time period (per 1,000 pipeline miles per year) were approximately 24 percent lower than in the U.S. system. The combined internal and external corrosion related failures in the Alberta system over this time period (per 1,000 pipeline miles per year) were approximately 13 percent lower than in the U.S. system. Therefore, there is no evidence that the transportation of oil sands derived crude oil in Alberta has resulted in a higher corrosion related failure rate than occurs in the transportation of the variable-sourced crude oils in the U.S. system.

TABLE 3.13.5-4
Crude Oil Pipeline Failures U.S. and Alberta (2002-2010)

Incident/Failure Case	Failures/Year	Failures per 1,000 Pipeline Miles per Year
U.S. Crude Oil Pipeline Incident History[a]		
Corrosion - External	9.8	0.19
Corrosion - Internal	22.1	0.42
All Failures	89.3	1.70
Alberta Crude Oil Pipeline Incident History[b]		
Corrosion - External	2.3	0.21
Corrosion - Internal	3.6	0.32
All Failures	22.0	1.97

[a] PHMSA includes spill incidents greater than 5 gallons. U.S. has 52,475 miles of crude oil pipelines in 2008.
[b] Alberta Energy and Utility Board Report, includes spills less than 5 bbls. Alberta has 11,187 miles of crude oil pipelines in 2006.
Source: PHMSA 2011.

Several commenters have expressed concern that dilbits could be more corrosive to pipeline steel because of their total acid numbers (TAN), sulfur content, chloride salts content, and the entrained sediment composition. As explained below, these characteristics are generally either not indicative of the corrosivity of a crude oil to pipeline steel, and/or the available information does not indicate that dilbits are substantially different than conventional crude oils produced in the WCSB, particularly the conventional heavy and the medium sour crude oils that have comprised the majority of Canadian imports into the U.S. since at least 1986.

The TAN of a crude oil does not indicate the corrosion potential of the crude oil to steel piping at temperatures below approximately 450 degrees Fahrenheit (PHMSA 2011). This is because the primary acids being measured by TAN are naphthenic acids which are not active below those elevated temperatures (Norman Kittrell Merichem Company 2006). The maximum operating temperature of the proposed Project pipeline would not exceed 150 degrees Fahrenheit. In light of the above, it appears that a relatively higher TAN number is not indicative of increased corrosion potential in a crude oil transmission pipeline. In addition, while the TAN for WCSB dilbits is higher than for most conventional Canadian crude oils, the dilbit TANs are generally in the midrange of heavy crude oils that are transported to and refined in PADD III, as presented in Table 3.13.5-7. Also, several California crude oils are noted for TANs that are more than double the TANs of the majority of the WCSB dilbits (Sheridan 2006). These California crude oils have been produced and transported by pipeline throughout California for several decades.

The dilbits have a sulfur content that is at the higher end of the range for crude oils produced in the WCSB. The two largest production dilbits, WCS and Cold Lake Blend (CLB), have similar sulfur contents to some of the heavy conventional Canadian crude oils, but other dilbits have a higher sulfur content. The sulfur content of a crude oil, however, is not itself indicative of potential increased risk of corrosion. This is because the sulfur may exist in the crude oil either as elemental sulfur or in a variety of compounds (e.g., hydrogen sulfide) that may or may not be corrosive. A report prepared for PHMSA addressing corrosion issues states that “For internal corrosion, the environment [potentially causing corrosion] would be water containing sodium chloride (salt), hydrogen sulfide, and or carbon dioxide.” (Michael Baker Jr., Inc. 2008).

The hydrogen sulfide content of different crude oils is not typically reported in publicly available information. Hydrogen sulfide is present in some amount in most crude oils, particularly in sour crude oils, but can also be present in sweet crude oils in very small amounts. Total sulfur content of a crude oil, however, does not necessarily correlate with hydrogen sulfide content of that crude oil. For example, Mexican Maya is a heavy crude oil that typically has a total sulfur content of approximately 3.4 percent but reportedly has a hydrogen sulfide content of 100 parts per million (ppm); whereas Mexican Olmeca crude oil is a light crude oil that typically has a sulfur content of approximately 0.9 percent but has a hydrogen sulfide content higher than Mexican Maya crude oil at 116 ppm. Also, the Strategic Petroleum Reserve has four sour crude oil streams that have total sulfur contents of 1.41 to 1.46 percent, but hydrogen sulfide contents ranging from 17 to 82 ppm. Based on the available information, it does not appear that dilbits have elevated hydrogen sulfide levels compared to other crude oils, nor that a higher total sulfur content for a crude oil directly correlates to higher hydrogen sulfide content in the crude oil.

Some commenters have expressed concerns that WCSB oil sands derived crude oils would lead to a higher incidence of stress corrosion cracking (SCC). However, the composition of the crude oil is not a major factor in determining the potential for SCC. According to a report prepared for PHMSA (Michael Baker Jr., Inc. 2005),

> “…the single most important recommendation in the prevention of SCC is an emphasis on coatings that remain bonded to the pipeline, but allow the passage of cathodic protection current in the event of disbondment. Emphasis should also be placed on the quality assurance/quality control of the surface preparation and field application. These considerations would apply to both new pipeline installations as well as to coating replacement projects. Apart from this

consideration, there are limited practical recommendations for pipeline operation processes that can prevent SCC initiation. However, the emphasis must be such that procedures, especially the collection and integration of data specific to SCC development from in-line inspection and direct examinations, are identified and implemented to refine and update this model over time, which will help operators gain a better understanding of the SCC susceptibility. Therefore, it is recommended that operator plans reflect this need for continued data and knowledge development and sharing."

These findings and recommendations are consistent with the approaches included within the 57 Project-specific Special Conditions. Further, it is PHMSA's opinion that relative to SCC, key influencing factors include temperature, pipe coating, and external environment (particularly moisture). According to PHMSA, the coating system for the proposed Project is not conducive to SCC, and the limits on operating temperature included in Special Condition 15 would further reduce the risk of SCC. Therefore, PHMSA does not consider SCC to be a significant potential risk for the proposed KXL pipeline (PHMSA Pers. Comm. 2011).

One type of stress corrosion cracking is chloride stress corrosion cracking. Concern has been expressed that the dilbits have higher salt contents than many conventional crudes, and that this elevated salt content could lead to increased risk of chloride stress corrosion cracking. However, chloride stress corrosion cracking is not a mechanism of corrosion that affects carbon steel pipelines (A. I. [Sandy] Williamson Pers. Comm. 2011). Nonetheless, high salt/chloride content in a crude oil can contribute to internal corrosion, because the chloride ions may increase the conductivity of any water present in the crude (Michael Baker Jr., Inc. 2008). The WCS heavy crude oil salt content (40 pounds per thousand barrels [ptb]), is higher than that of other heavy crude oils shown in Table 3.13.5-7, but data available at the Crude Monitor website (www.crudemonitor.ca) indicates that salt content of the dilbits is in a similar range to the medium sour and heavy crude oils imported from Canada over the past 25 years. The five-year average salt content for the medium sour crude oils ranged from 15 to 65 ptb, for the heavy conventional crude oils ranged from 11.5-68 ptb, and for the dilbits ranged from 6.9 to 46.3 ptb (www.crudemonitor.ca).

Some commenters have expressed concerns that the sediment content of dilbits, particularly portions of the sediment that may be comprised of relatively harder quartz particles, could present increased risk of internal erosion of the proposed Project pipeline.

Relative to the basic sediment and water (BS&W) content of oil sands derived crude oil, bitumen produced by the original naphtha solvent-based process (dilution centrifuge as practiced by Suncor and Syncrude) has approximately 0.3 to 0.5 percent solids and 1 to 2 percent water. This makes it unsuitable for pipelining and direct sale to traditional refineries. However, a paraffinic solvent process commercialized in the Shell-led Albian Sands project has provided the means to produce bitumens that are lower in asphaltenes, substantively lower in BS&W, and more easily blended with other refinery feed stocks (Oil Sands Technology Roadmap: Unlocking the Potential Mining Based Bitumen Extraction). This product meets the necessary 0.5 percent BS&W limit for pipeline transport.

A substantive amount of water and inorganic particulate material is entrained in heavy crude oil during extraction and production. However, as indicated in Table 3.13.5-5, the WCSB medium conventional crude oils, WCSB heavy conventional crude oils, and WCSB dilbits have similar ranges of total sediment content.

TABLE 3.13.5-5 API Gravity and Total Sediment Content for Both Medium to Heavy WCSB Conventional (non-oil sands derived) and WCSB Oil Sands Derived Crude Oils		
Crude Name (Origin)	**API Gravity**	**Total Sediment (ppmw)[a]**
WCSB Conventional		
Midale (MSM)	30.3 ± 0.6	380 ± 185
Mixed Sour Blend (SO)	31.3 ± 2.2	335 ± 71
SHE (SHE)	35.2 ± 2.2	285 ± 191
Bow River North (BRN)	21.5 ± 1.2	360 ± 136
Bow River South (BRS)	23.3 ± 0.6	219 ± 73
Fosterton (F)	20.4 ± 0.6	224 ± 53
Lloyd Blend (LLB)	20.9 ± 0.8	364 ± 95
Lloyd Kerrobert (LLK)	20.6 ± 0.8	324 ± 84
Western Canadian Blend (WCB)	20.7 ± 0.8	288 ± 104
WCSB Dilbit, Synbit, Dilsynbit, Heavy Synthetic		
Access Western Blend (AWB)	21.9 ± 0.9	231 ± 211
Cold Lake (CL)	20.8 ± 0.8	176 ± 103
Peace River Heavy (PH)	20.7 ± 0.7	179 ± 101
Seal Heavy (SH)	20.6 ± 0.8	215 ± 118
Smiley-Coleville (SC)	20.0 ± 0.7	238 ± 69
Wabasca Heavy (WH)	20.3 ± 0.7	183 ± 110
Western Canadian Select (WCS)	20.6 ± 0.8	392 ± 95
Long Lake Heavy (PSH)	20.7 ± 1.1	217 ± 248
Surmont Heavy Blend (SHB)	19.6 ± 0.6	187 ± 166
Suncor Synthetic H (OSH)	19.8 ± 0.3	187 ± 133
Albian Heavy Synthetic (AHS)	19.2 ± 0.3	714 ± 274

[a] ppmw = parts per million by weight.
Source: Crude Quality Inc. 2010.

It is noted that these sediment data do not include the specific composition of the type of sediment in the crude oils. Commenters have expressed concern that the level of internal erosion resulting from dilbit transportation could be related to the sediment composition and specific sediment characteristics, including particle hardness and size distribution. There are anecdotal industry reports suggesting that the sediment in oil sands crude oils may contain from 7 to 25 percent of harder sediments, such as silicates (quartz/sand) and iron sulfide (pyrite). However, based on the production method used for the majority of WCSB conventional heavy crude oils (Cold Heavy Oil Production with Sand, or CHOPS) (Government of Alberta. n.d.) it appears likely that those crude oils also contain quartz sand. The CHOPS method of production uses large amounts of sand to open up channels in the oil reservoir to enhance crude oil production. The amount of sand produced when employing CHOPS can range from 5 percent to as high as 40 percent in initial production stages at the wellhead. In 2000, it was estimated that 460,000 barrels of conventional heavy crude oil were produced using CHOPS and, historically, approximately 60-70 percent of the conventional heavy crude oil produced in the WCSB has been diluted and shipped to the U. S.

To mitigate against any pipeline wall thinning resulting from either corrosion or erosion, Special Condition 33 of the 57 Project-specific Special Conditions developed in consultation with PHMSA and accepted by Keystone includes a requirement that Keystone build the Project to allow internal inline inspection (pigging) throughout and that it prepares and implements a corrosion mitigation and integrity management plan for segments that for any reason do not allow the passage of the inline inspection device. Special Condition 34 requires Keystone to limit basic sediment and water to 0.5 percent by volume and to annually report testing results to PHMSA. Additional measures include requirements to conduct cleaning runs twice in the first year of operation, and at least annually thereafter, and to test the liquids collected during those cleaning runs, including basic sediment and water. Special Condition 34 also requires that Keystone develop internal corrosion mitigation plans based on the results of those tests. This means that if the crude oil transported through the pipeline (whether produced conventionally or from the oil sands) did contain higher amounts of relatively hard sediments that might pose additional internal corrosion risk, Keystone would be required to develop a corrosion mitigation plan specifically to address that risk.

Special Condition 34 is more stringent than the existing regulatory requirements, and more stringent than the tariff specifications that would be in place for the proposed Project. The tariff that would need to be approved by U.S. Federal Energy Regulatory Commission (FERC) specifies that crude oils that exceed a combined bottom (or basic) sediment and water (BS&W) content of 0.5 percent by volume can be rejected. Specifically, Article 4 (Quality) of the FERC tariff would set forth the following specifications to govern the quality of the crude oil that shippers may tender for transportation in the proposed pipeline:

> "4.1 Permitted Petroleum.
>
> Only that Petroleum having properties that conform to the specifications of Petroleum described in Sections 4.2, 4.3 and 4.4 following will be permitted in the Pipeline System. Shipper will not Tender to Carrier (Keystone XL), and Carrier will have no obligation to accept, transport or deliver Petroleum which does not meet said specifications.
>
> 4.2 Specifications of Petroleum.
>
> For the purposes of Section 4.1, the specifications of the Petroleum shall be as follows: (i) Reid Vapor Pressure shall not exceed one hundred and three kilopascals (103kPa); (ii) sediment and water shall not exceed one-half of one percent (0.5%) of volume, as determined by the centrifuge method in accordance with ASTM D4007 standards (most current version) or by any other test that is generally accepted in the petroleum industry as may be implemented from time to time; (iii) the temperature at the Receipt Point shall not exceed thirty-eight degrees Celsius (38°C); (iv) the density at the Receipt Point shall not exceed nine hundred and forty kilograms per Cubic Meter (940 kg/m3); (v) the kinematic viscosity shall not exceed three hundred and fifty (350) square millimeters per second (mm2/s) determined at the Carrier's reference line temperature as posted on Carrier's electronic bulletin board; and (vi) shall have no physical or chemical characteristics that may render such Petroleum not readily transportable by Carrier or that may materially affect the quality of other Petroleum transported by Carrier or that may otherwise cause disadvantage or harm to Carrier or the Pipeline System, or otherwise impair Carrier's ability to provide service on the Pipeline System.
>
> 4.3 Modifications to Specifications.
>
> Notwithstanding Sections 4.1 and 4.2, or any other provision in these Rules and Regulations to the contrary, Carrier shall have the right to make any reasonable changes to the specifications under Section 4.2 from time to time to ensure measurement accuracy and to protect Carrier, the Pipeline System or Carrier's personnel, provided that Carrier shall give Shipper reasonable notice of such changes prior to filing.

4.4 Freedom from Objectionable Matter.

Petroleum shall not contain sand, dust, dirt, gums, impurities or other objectionable substances in quantities that may be injurious to Carrier, the Pipeline System or downstream facilities, or which may otherwise interfere with the transportation of Petroleum in the Pipeline System."

Some commenters have expressed concern about corrosion inhibiting agents that could be added to the crude oil prior to acceptance into the proposed pipeline. Corrosion inhibitors may be added to the crude oil stream with concentrations determined based on crude oil composition, supplier recommendations, and laboratory testing. Any heavy metals associated with corrosion inhibiting agents would be assessed and monitored as required by restrictions imposed through tariff specifications on pipeline transportation and other applicable regulations and requirements related to deleterious crude oil stream constituents.

In summary, while a focused, peer-reviewed study of the potential corrosivity/erosivity of WCSB oil sands derived crude oils relative to other crude oils has not yet been conducted, the existing information and analyses reviewed by DOS in consultation with relevant experts indicate that oil sands derived crude oils do not have unique characteristics that would suggest the potential for higher corrosion rates during pipeline transport of these crude oils.

Volatility/Instability

Concerns have been expressed about the potential volatility and/or instability of dilbits. The concerns are related to the possibility that dilbits are more volatile or unstable when being transported in a pipeline than crude oils currently transported in the U.S. pipeline system, including the possibility that dilbits would undergo flash volatilization when released into the environment through a breach in the pressurized pipeline.

One measure of the volatility of crude oil and petroleum products is the Reid Vapor Pressure (RVP). RVP is the vapor pressure at equilibrium of a hydrocarbon liquid at 100 degrees Fahrenheit in a closed system. A higher RVP indicates a higher level of crude oil volatility. As indicated in Figure 3.13.5-1, the RVP range for dilbits is comparable to the range for conventional heavy crude oils, and lower than the ranges for medium conventional crude oils, light conventional crude oils, and natural gas condensates. It should be noted that the RVP range for dilbits is lower than the range for condensates, indicating that once a diluent is homogeneously mixed with bitumen to create a dilbit, it exhibits the characteristics of that mixture rather than the characteristics of its individual components.

The RVP values confirm that light crude oils and medium crude oils have more "light ends" in that they have a higher concentration of lighter hydrocarbon molecules with lower boiling points that more readily evaporate. Based on information provided at www.crudemonitor.ca, dilbits have light end concentrations in the range of approximately 16 to 25 percent. The light conventional crude oils have light end concentrations in the range of approximately 29 to 42 percent, the medium conventional crude oils have light end concentrations in the range of approximately 27 to 36 percent, and the heavy crude oils have light end concentrations in the range of approximately 13 to 18 percent. These data are consistent with the conclusion that dilbit volatility is comparable to the volatility of conventional crude oils.

Additionally, crude oil is considered a largely homogeneous mixture of a variety of specific hydrocarbon molecules ranging from methane (one carbon) to asphaltines (hundreds of cross-linked carbons). The diluents used in mixture with bitumen to create dilbits are themselves a homogeneous solution of specific hydrocarbon molecules. When blended together with bitumen the resulting crude oil exhibits properties of the mixture – not the individual component parts that were used to produce the blend – and these properties fall within the range of the properties of other crude oils. Blending bitumen with condensate simply puts back components that evaporated from the rock containing the bitumen over millions of years of exposure. However, the gas condensate used as diluent is stabilized (i.e., contains no hydrocarbon gases in solution under high pressure). The assertion that the rapid depressurization of a pipeline as a result of a pipeline breach would result in flash volatilization of gases contained in the diluents is therefore unfounded. The dilbit at rest prior to the development of pumping pressure is stable and at equilibrium between its component parts.

To illustrate this point, the publicly available American Petroleum Institute E&P Tank Program (API 4697) was utilized to assess working and standing losses of volatile compounds resulting from natural crude oil evaporation into air. While this program was designed to model emissions from tanks, it can be employed to provide a rough estimate of working and standing losses from a pipeline crude oil spill. It is recognized that there are limitations in the model's ability to simulate actual conditions involved in a specific pipeline oil spill at a specific location. For modeling purposes, a dilbit with an API gravity of 18 was compared to gas condensate (a typical diluent, API gravity 55.5), West Texas Intermediate (WTI) crude oil (API gravity 41.0), and Alaska North Slope (ANS) crude oil (API gravity 27.5) using the API model. It should be noted that actual WTI and ANS hazardous air pollutant (HAP) and volatile organic carbon (VOC) concentrations may vary since the actual mix of a specific WTI or ANS crude oil would depend on the composition of the blend. For the dilbit, a full component chromatograph assay of a proprietary unstabilized condensate was available which was modified to match the initial boiling point and heavy ends with bitumen as represented in a published dilbit boiling curve (TIAX 2009). The modeling indicates that the dilbit would produce evaporation (i.e., standing and working) total emissions of VOC and HAP about half the emissions of Alaska North Slope crude oil, and 5 to 20 percent of West Texas Intermediate, respectively. This is because the WTI and ANS crude oils are pipelined straight out of the ground and field stock tank, where the gases under pressure in the deep underground reservoir (i.e. methane, ethane, carbon dioxide) have flashed off but the whole crudes stored at atmospheric pressure are not stabilized by further removing residual light hydrocarbon gases such as propane and butane. In comparison with straight condensate, the bitumen in the dilbit blend acts to reduce the partial pressure of light hydrocarbons in the condensate, slowing evaporation. These results clearly show that the behavior of the dilbit is substantially different than the behavior of the unmixed diluent and bitumen taken separately.

Commenters have also expressed concern about the potential for gas pocket formation within the pipeline due to dilbit volatility. According to PHMSA, the potential for gas pocket formations exists during the transport of any crude oil and there are no technical studies that suggest that the potential for gas pocket formation would be any different for crude oils likely to be transported by the proposed Project compared to conventional crude oils. However, regarding the volatility of crude oils, the above comparisons of RVP and light ends content indicate that dilbits are generally less volatile than WCSB light and medium crude oils.

As with any petroleum pipeline, gas pocket formation could occur during a slack-line condition. A slack-line condition can occur in any crude oil pipeline when line flow is insufficient to keep the entire pipe volume filled with liquid, leading to sporadic non-liquid volume pockets. Gas pocket formation is related to local topography and crude oil flow rates. Real time transient modeling addresses this concern, although leak detection sensitivity can be affected. Special Conditions 25 through 32 of the 57 Project-specific Special Conditions developed in consultation with PHMSA and incorporated into the proposed Project design, construction, and maintenance plan by Keystone specifically address the requirements of the SCADA system and its ability to detect leaks within the limitations of current technology. These conditions also address the requirement for SCADA operator training, including training to address transient flow conditions, and the need for the SCADA system to assess flow characteristics upstream and downstream of valve locations. Further, in response to a data request from DOS concerning design approach to address slack flow conditions, Keystone provided the following:

> "Slack flow is defined as a condition where the pressure of the crude oil inside the pipeline is reduced such that the pipeline pressure is less than the vapor pressure of the crude oil itself. The Keystone XL pipeline, under design operating conditions, will not operate in slack flow. Keystone has ensured the operating regime allows for adequate pressure on the crude oil such that a slack flow condition will not arise. The pipeline's controls philosophy (inclusive of valve controls) accomplishes this by regulation of the suction and discharge pressures at the pump stations so they don't drop below the vapor pressure of the crude oil. Further, the pressure in the pipeline is continuously monitored by the Operations Control Center where pressure readings from transmitters placed no more than 20 miles apart along the pipeline are reported back through the SCADA system. Additionally, as Keystone has avoided extreme elevation changes along the route, natural causes for slack flow are eliminated."

Similar concerns relative to gas pocket formation during transport were raised as a result of an interpretation (NRDC 2011) of studies conducted at the University of Alberta on the complex phase behavior of heavy crude oils and bitumen in reservoirs. DOS contacted the author of the original studies to address this concern and determined that it would not be valid to infer from this research that dilbits are any more or less stable than other crude oils, or that they are more likely to cause pressure spikes during transport in pipelines or otherwise pose an increased risk to pipeline safety (John Shaw Pers. Comm. 2011).

Some commenters have expressed concern that air emissions in the event of a dilbit release from the pipeline would be very high and further that the emissions would contain unusually high levels of the volatile aromatic BTEX compounds. However, the total BTEX content of WCSB conventional medium to heavy crude oils is similar to and in a few cases substantially higher than the BTEX content of oil sands derived dilbit crude oils that would be transported by the proposed Project and less than the BTEX content of oil sands derived synthetic crude oils (see Table 3.13.5-6).

TABLE 3.13.5-6
API Gravity and Total BTEX Content for Both Medium to Heavy WCSB Conventional (non-oil sands derived) and WCSB Oil Sands Derived Crude Oils

Crude Name (Origin)	API Gravity	Total BTEX[a] (ppm)
Western Canadian Select (DilSynBit)	21.3	7,700 – 9,100
Midale (Conventional)	30.3	26,700
Mixed Sour Blend (Conventional)	31.2	10,300
Sour High Edmonton	35.0	29,100
Suncor Synthetic A	35.8	11,100
Cold Lake Blend (DilBit)	21.6	9,800
SynCrude Synthetic (Canada)	31.7	13,100
CNRL Light Sweet Synthetic (Canada)	35	9,500
Bow River South (BRS) – Conventional	23.3	9,300
Lloyd Blend (LLB) – Conventional	20.9	9,700
Western Canadian Blend (WCB) – Conventional	20.7	5,800

[a] BTEX = benzene, toluene, ethylbenzene, xylenes.
Source: Crude Quality Inc. 2010.

Characteristics of WCSB Heavy Crude Oils Compared to Other Heavy Crude Oils Currently Refined in PADD III

Several commenters have expressed concern that the composition of WCSB crude oils that would be transported to refineries in PADD III by the proposed Project would be substantially different from crude oils currently refined in PADD III. To address this concern, DOS has assessed the chemical composition of WCSB oil sands derived crude oils and compared them to other heavy crude oils, in particular those currently refined in PADD III.

Mexican Maya, Venezuelan Bachaquero, and Venezuelan Petrozuata crude oils are examples of heavy crude oils currently refined in PADD III. Maya is the "marker" heavy crude oil in the U.S. Gulf Coast with an API gravity ranging from approximately 22 to 25, with a sulfur content of approximately 3 to 3.7 percent by weight. Maya has greater than 35 percent vacuum residue by weight that is approximately 5 percent sulfur by weight, and high in vanadium and nickel with a combined concentration greater than 300 ppm. The two Venezuelan heavy crude oils have a sulfur content ranging from 2.4 to 2.7 percent by weight and a combined nickel and vanadium content of approximately 400 ppm. The vacuum residue for these two crude oils is approximately 59 percent by weight, and some Venezuelan crude oils (such as those from the Orinoco region) have a vacuum distillation residue of 60 percent by weight with a combined vanadium and nickel content in the range of 500 to 600 ppm.

A summary of the range of properties for heavy crude oils currently refined in the PADD III area is provided in Table 3.14.3-7. For comparison purposes, the table also includes properties for two heavy sour crude oils from the Middle East (Dubai Fateh and Arabian Safaniya) and a Canadian dilbit (Cold Lake Blend, a mixture consisting of approximately 70 percent bitumen and 30 percent gas condensate) that may or may not be transported by the proposed Project based on current Project planning. As discussed in more detail below, the WCSB crude oils that would be transported by the proposed Project have characteristics that make them of similar quality to heavy crude oils currently refined in PADD III.

The chemical characteristics of a selection of crude oils are presented in Table 3.13.5-7. These selected crude oils include:

- Western Canadian Select and Suncor Synthetic crudes, representative of WCSB crude oils that would be transported by the proposed Project. (The typical chemical composition of the WCSB crude oil that would be transported by the proposed Project was provided in the May 1, 2009 Response to DOS Data Request #1 and updated with additional details in the July 15, 2010 Response to DOS Data Request #4);
- Crude oils that are currently refined in PADD III and that would be partially or wholly replaced by crude oils that would be transported by the proposed project;
- Two reference heavy crude oils from the Middle East; and
- Another representative WCSB crude oil, the Canadian Cold Lake Blend.

It is apparent from the data provided in Table 3.13.5-7 that the heavy crude oils that would be transported by the proposed Project are comparable to the existing heavy crude oils refined in PADD III. The sulfur content is similar to Mexican Maya, but slightly higher than the other heavy crude oils such as Venezuelan Bachaquero. The nickel and vanadium content would be higher than the Middle Eastern crude oils, but lower than Mexican Maya and the Venezuelan crude oils. Overall, the nickel and vanadium content of the WCSB crude oils is within the expected range for crude oils with an API gravity less than 28 (API 2011). Additionally, mercury content, although not typically reported in crude oil assays, would likely be lower, since Canadian crude oils, and WCSB crude oils in particular, have lower concentrations of total mercury than oils from foreign sources such as Mexico and South America (Hollebone and Yang 2007). Heavy crude oil from Mexico has not been frequently tested for mercury but estimates suggest that those levels may be two to nearly 10 times the average for WCSB crude oils and from 1.5 to 6 times higher than synthetic crude oils produced from the Alberta oil sands. The average mercury level across all grades of Venezuelan crude oils is three times the average in WCSB crude oils and two times the average for synthetic crude oils from the Alberta oil sands. Finally, the total BTEX content of the WCSB crude oils is higher than the Mexican Maya and Venezuelan crude oils, but considerably lower than Arabian Heavy crude oil. Also, the BTEX content of heavy crude oils is generally lower than lighter crude oils (e.g., West Texas Sour and Brent Blend), many of which have twice the BTEX content of the heavy crude oils (Environment Canada 2011).

Additionally, the quality of Maya crude oil imported to PADD III has recently declined. In early 2010, the Maya crude oil had a higher than normal salt and metals content, which led to increased downtime at Mexican refineries (Reuters, June 8, 2010 "Poor Maya crude quality hampers Mexico refineries"). Reportedly, the viscosity of Maya crude oil processed in Mexico has also risen sharply in recent years due to a greater proportion of extra-heavy crude oil from the Ku Maloob Zaap field being added to the domestic Maya blend leading to increased viscosity and the likelihood that the potential corrosivity of the Maya crude oil has also been adversely affected. It should be noted, however, that Maya crude oil has been received for many years at the Louisiana offshore oil port (LOOP) at three offshore single-point moorings and transported to shore through a 56-inch external diameter submarine pipeline.

In summary, the DOS analysis of these crude oils indicates that the WCSB heavy crude oils that would be transported by the proposed Project are not substantially different than the heavy crude oils currently refined in PADD III.

TABLE 3.13.5-7
Comparison of Heavy Crude Properties

Basic Analysis	Western Canadian[a] Select Five Year Average (Heavy Sour DilBit)	Suncor Synthetic A[a] (OSA) Five Year Average (Sweet Synthetic)	Mexican Maya[b]	Venezuelan Heavy Sours (Bachaquero and Petrozuata)[c]	Cold Lake Blend[d] (Dilbit; Hardisty)	Dubai Heavy[b] (Fateh)	Arabian Heavy[e, b] (Safaniya)
Density (kg/m^3)	929.4 ± 4.8	858.6 ± 6.6	935.9 @15°C	967.9 @15°C	928.4 ± 5 @15.5°C	873.5 @15°C	0.889
Gravity (°API)	20.6 ± 0.8	33.2 ± 1.3	1.3 - 25.1	16.8 / 19.5	19.7 – 21.2	30.4 - 31.1	27 – 28
Vacuum Residue (wt%)	32[f]	0.3[f]	35 -- 45	59[g]	45 -- 50	20 – 22	19
Sulphur (wt%)	3.40 ± 0.14	0.19 ± 0.03	3.0 – 3.7	2.40 / 2.69	3.66 – 3.95	2 – 2.13	2.9 – 3
Hydrogen Sulphide or Mercaptan Sulphur (wt%)	Alberta Canadian L&M Crudes [h] 0.0020% - 0.0058%	0.0100%	0.0100%	--	0.0034%	< 0.0001% [i]	
MCR (wt%)	9.46 ± 0.40	ND	--	17.3	10.48 ± 0.36	--	--
Bottom Sediment & Water (out) (%v)	0.38% ± 0.095%v	<<0.5%	0.7%-1.5%[j,k]	--	--	--	0.29%[j,k]
TAN (mgKOH/g)	0.88 ± 0.11	--	0.40	1.20	0.94 ± 0.1	0.05	0.4[d]
Salt (ptb)	40.0 ± 13.6		--	6[l]	--	11.9 ± 3.2	--
Mercury (mg/Kg)	1.4 ± 0.3 ; 2.2 ± 0.4[m]	3.5; 13.5[n]	4.2[o,n]	--	--	--	
Nickel (mg/L)	55.9 ± 3.4	ND	45.8 ± 7 (n=3)	55 – 84	65.2 ± 3.6	14 – 19	22 – 25
Vanadium (mg/L)	134.1 ± 10.3	0.1 ± 3.8	267 ± 23 (n=4)	324 – 303	169 ± 11.2	42 – 58	70
Olefins (wt%)	ND	ND	--	--	--	--	--
Naphtha (wt%)	8.9	--	15	2 – 8	16	11.5 – 16	14.7
S:A:R:A (wt%)	11% S: --: --: 33% A	--: --: --: --	23 : 35 : 15 : 27	4 : 4 : 59 : 33	--: --: --: --	--: --: --: 2% A	--: --: --: 9.6% A 5%S: --: --: 11% A
Benzene	0.14	0.15 ± 0.02	0.05 ± 0.03	0.05	0.24 ± 0.03	0.65	0.99

TABLE 3.13.5-7
Comparison of Heavy Crude Properties

Basic Analysis	Western Canadian[a] Select Five Year Average (Heavy Sour DilBit)	Suncor Synthetic A[a] (OSA) Five Year Average (Sweet Synthetic)	Mexican Maya[b]	Venezuelan Heavy Sours (Bachaquero and Petrozuata)[c]	Cold Lake Blend[d] (Dilbit; Hardisty)	Dubai Heavy[b] (Fateh)	Arabian Heavy[e, b] (Safaniya)
Toluene	0.25	0.27 ± 0.04	0.24 ± 0.05	0.13	0.37 ± 0.05	--	3.98
Ethyl Benzene	0.05	0.06 ± 0.01	0.15 ± 0.02	0.07	0.05 ± 0.01	--	2.18

Notes:

"—" No Information obtained as of the date of this report.
ND = Not Detected
S:A:R:A Percent Saturates : Aromatics : Resins : Asphaltenes in whole oil

%BS&W Out: Percent Bottom Sediment and Water after a dehydration process. For example, Maya crude has ~15% BS&W In; pre-dehydration; and 0.7-1.5% BS&W Out; post dehydration (Warren 2002)

[a] Western Canadian Select and Suncor Synthetic A crude data generally from the Canadian crudemonotor: http://www.crudemonitor.ca/crude.php?acr=WCS and http://www.crudemonitor.ca/crude.php?acr=OSH, respectively.

[b] Maya and Dubai (Fateh) data from:

http://www.etc-cte.ec.gc.ca/databases/Oilproperties/; Jacobs Consultancy and Life Cycle Associates. 2009. Life Cycle Assessment Comparison of North American and Imported Crudes. File No. AERI 1747. Prepared for Alberta Energy Research Institute. July 2009

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[c] Bachaquero http://www.etc-cte.ec.gc.ca/databases/Oilproperties/;and Petrozuata.

[d] Cold Lake Blend from:

www.exxonmobil.com/apps/crude_oil/crudes/mn_cold.html; http://www.crudemonitor.ca/report.php?acr=CL
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Al Darouich, T. F. Béhar, C. Largeau, and H. Budzinski. 2005. Separation and Characterisation of the C15- Aromatic Fraction of Safaniya Crude Oil. *Oil & Gas Sci. Technol.Rev. IFP. 60*:681-695;

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http://www.etc-cte.ec.gc.ca/databases/Oilproperties/pdf/WEB_Arabian_Heavy.pdf

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[g] Ancheyta, J. and J.G. Speight. 2007. Hydroprocessing of heavy oils and residua. CRC Press. 345 pp.

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http://books.google.com/books?id=YmLik9YY4uUC&pg=PA240&dq=canadian+crude+h2s&hl=en&ei=fcJoTc36HYSusAO1qJT9Cw&sa=X&oi=book_result&ct=result&resnum=2&ved=0CEUQ6AEwAQ#v=onepage&q=canadian%20crude%20h2s&f=false (last accessed 26 Feb 2011)

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[m] Average for WCSB crude oils per Hollebone, B.P. and C.X. Yang, 2007, including the higher average of 2.2 mg/kg volume-weighted concentration in synthetic crude oils produced from Alberta oil sands. Mercury in Crude Oil Refined in Canada, *Environment Canada*, Ottawa, ON. 82 pp.

[n] Two estimates for mercury in Maya crude by Acosta y Asociados (2001) and EPA (1997) as cited by Acosta y Asociados (2001). Acosta y Asociados Preliminary atmospheric emissions inventory of mercury in Mexico. Project CEC-01. Prepared for Commission for Environmental Cooperation (No. 3.2.1.04). May 30, 2001. P. 18-19.

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Habitat, Natural Resources, and Human Use Receptors

The impact of an oil spill would be heavily influenced by the types of receptors (i.e., habitats, natural resources, and human uses) that might be exposed to the oil. For this EIS, these receptors are generally categorized and described in the following bulleted list, in increasing order of likely environmental impacts and concern to the spectrum of potential stakeholders:[3]

- Terrestrial–agricultural land. Includes grazing, field and row crops, fallow fields, and similar land uses.
- Terrestrial–natural habitat. Includes native and second-growth forests, naturally restoring grasslands, and similar areas that are not being used directly by people for commercial purposes.
- Groundwater. Emphasis is on areas where a public drinking groundwater aquifer is close to the ground surface and/or is overlain by soils permeable to oil or by karst formations.
- Aquatic–wetland habitat. Includes all areas that meet the definition of wetlands.
- Aquatic–lake/pond habitat. Includes agricultural stock ponds, irrigation and drainage ditches, small and large lakes, reservoirs, and similar non-flowing waterbodies.
- Aquatic–stream/small river habitat. Includes smaller flowing waterbodies as well as those that are intermittent or ephemeral. These generally do not support commercial boat traffic and are not restricted with dams or major reservoirs. Some may support important recreational resources and activities or may be limited in beneficial uses.
- Aquatic–large river habitat. Includes large flowing waterbodies (e.g., Yellowstone River, White River, Niobrara River, Platte River, Missouri River, Loup River, Red River, and Canadian River**)** that are perennial, may support commercial traffic, and/or may be restricted by dams and major reservoirs.
- Threatened and endangered species and their critical habitat. Most are USAs and are a special case of resources that may be found in any of the habitats but are limited in population size or spatial distribution.
- Human use–residential. Areas where the proposed pipeline ROW is near rural, suburban, or urban populations. Towns and cities generally have population densities that qualify the area as an HCA. Areas of special concern include any concentrations of low-income or minority populations that could represent environmental justice issues.
- Human use–recreational. Areas, especially lakes, small and large rivers, and reservoirs and associated parks used by people for various recreational activities.
- Human use–commercial. Areas that may be closed to normal use during a spill response action and result in substantive economic impacts.
- Human use–surface water intakes. Many public water intakes are located in reservoirs, and large rivers. Human uses include drinking water, industrial cooling water, and/or agricultural water.

[3] The directly impacted stakeholders (e.g., ranchers, farmers, homeowners) would likely consider the impacts to their resources as very high concern regardless of the overall impact in an ecosystem context. Also, USAs and HCAs would be considered sensitive receptors due to their designation and their ecological or human use significance.

Season

The season in which a spill occurs could dramatically influence spill behavior, fate, impacts, and cleanup response actions. Seasonal variations in potential spill behavior are addressed in this section.

Spring-Fall

The length and timing of the spring-fall season depends on location along the proposed pipeline route and the ambient weather regime. For this EIS, this time period is generally defined as the period when the ground is mostly free of snow and access to the proposed pipeline ROW is not restricted by snow and ice. Most of the rivers and creeks are flowing; ponds, lakes, and reservoirs exhibit open water; land is mostly snow-free; and biological use of land and waterbodies is high. Currents, winds, and passive spreading forces would disperse spills that reach the waterbodies. Spills to land would directly affect the vegetation, although dispersal of the spilled material is likely to be impeded by the vegetation. Spills to wetlands may float on the water or be dispersed over a larger area than would spills to dry land or to ice and/or snow-covered land and waterbodies associated with the wetlands.

Winter

Winter is the period when waterbodies may be covered with ice and possibly snow, and the land surface may be partially to completely covered with snow. Dispersal of oil spilled to the land generally would be slowed, although not necessarily stopped, by the snow cover. Depending on the depth of snow cover as well as the temperature and volume of spilled material, the spill may reach the underlying dormant vegetation or wetlands, ponds, and lakes. Similarly, spills to flowing rivers and creeks generally would be restricted in area by the snow and ice covering the waterbody, compared to seasons with little or no snow and ice cover. Spills under the ice to creeks, rivers, and ponds/lakes might disperse slowly as the currents are generally slow to non-existent in winter. However, because of snow and ice, winter spills may be harder to detect and, when found, more difficult to contain and clean up.

Freeze-up and Breakup in Aquatic Environments

Freeze-up is the transition time in the fall when the lakes and rivers begin to freeze over in the northern regions of the pipeline route. Breakup or spring melt is the short transition period between winter and spring when thawing begins, ice thins and/or breaks up, and river flows increase substantively and quickly, often to flood stages. Major floods may cause bank erosion and ultimately pipeline failure, with the oil entering the river and likely being widely dispersed and difficult to contain or clean up.

An oil spill that results in oil reaching waterbodies during either freeze-up or breakup may be difficult to contain, remove and cleanup. The ice may not be strong enough to support people or equipment. In rivers, the oil may be transported several miles under the ice or in broken ice before it can be contained. Once the ice is strong enough to support people and equipment, it may be more difficult to detect the oil under the ice and to implement measures to affect rapid containment/cleanup at and near the spill site.

Weather and Water Levels

Weather, especially rapid warming periods and heavy rainfall, may cause rapid ice melt in rivers, snowmelt and runoff. These could result in major flood flows that breach levees along larger rivers, erode river banks, alter channels, and expose the proposed pipeline to forces that may break or rupture it. This scenario, although a very low-likelihood event especially at HDD crossings, could occur at large or small stream or river crossings not spanned by HDD[4]. If spilled oil is released to the flooded area, especially to flowing waters, oil could be distributed to adjacent terrestrial, wetland, and aquatic habitats that normally would not be exposed. These habitats and natural resources, as well as human uses of the habitats and resources, may be exposed to the spilled material.

Concern was expressed in comments on the draft EIS relative to potential spray zones associated with operational leaks from the proposed pipeline. Winds, especially high-velocity sustained winds, could spread material released under pressure from hole(s) in the top hemisphere of an exposed portion of the pipeline to create a "spray zone." To generate a spray zone a potential leak would need to occur on the upper hemisphere of the proposed pipeline. If corrosion related leaks occurred, they would typically occur on the lower hemisphere of the pipeline and would likely be associated with entrained water. The implementation of the Project-specific Special Conditions developed in consultation with PHMSA would make such leaks highly unlikely. Potential leaks on the upper hemisphere of the proposed pipeline would likely be associated with accidental equipment impact. However, the likelihood of such events is significantly reduced by the 4-foot minimum cover requirement in most areas and the implementation of public awareness and damage prevention programs. However, if such a release were to occur, ejected material could form a cloud of mist and fine particles, and could be carried downwind. The extent of distribution would depend on wind velocity, direction of the released spray (e.g., downward into the ground, horizontal, or skyward), and characteristics of the release (e.g., pressure in the pipeline, type of oil, size of hole). Under most scenarios, the pressure in the pipeline would drop quickly, the release would be highly visible, and immediate pipeline spill control and shutdown actions would be taken[5] by the CMP and SCADA as well as the onsite personnel. If a leak would occur on the upper hemisphere of the pipeline, Keystone has estimated that the maximum spray zone for an exposed portion of the pipeline would be in the range of 75 to 400 feet (i.e., the areal extent of the release to land would be limited to a few acres or less in the immediate area of the release point and downwind of the release point).

Major flooding or adverse weather conditions (e.g., high winds, tornados, blizzards, and extreme cold) could limit Keystone's ability to detect small releases and/or hinder the spill response contractors from implementing timely and effective oil spill containment and cleanup operations. Response actions appropriate for these conditions would be addressed in the ERP and the PSRP (see Section 2.4.2.2).

3.13.5.2 Keystone Response Time and Actions

For spills ranging in magnitude from very small to substantive, response time and actions by responders would most likely prevent the oil from reaching sensitive receptors or would contain and clean up the spills before significant environmental impacts occurred. Most spills in this category are likely to occur on construction sites or at operations and maintenance facilities, and would not be released to the environment outside of these Project-related areas.

For large spills, very large spills and potentially some substantive spills, especially those that reach aquatic habitats, the response time between initiation of the spill event[6] and arrival of the response contractors would influence the magnitude of impacts to the environmental resources and human uses. This would be particularly true if the oil reaches flowing waters in major rivers. Once the responders are

[4] These type of events account for less than 4 percent of spills (see Table 3.13.1-3) and Keystone has a proactive, preventative plan to shut down the pipeline if severe weather or any other natural event poses a threat to the pipeline integrity.
[5] The SCADA system would shut down the pipeline within 12 minutes of detection of the release (Sections2.4.2.1 and 3.13.5.5).
[6] "Initiation of the event" means when the oil began to leak or spill to the environment, not when it is detected by either the SCADA or other means. There may be a substantive delay between initiation and detection, particularly for slow or pinhole leaks under snow or below ground.

at the spill scene, the efficiency, effectiveness, and environmental sensitivity of the response actions (e.g., containment and clean up of oil, and protection of resources and human uses from further oiling) would substantively influence the type and magnitude of additional environmental impacts.

In response to a DOS data request, Keystone presented its approach to spill response under two hypothetical spill scenarios defined by DOS. The two spill scenarios presented to Keystone and its response to these scenarios provide an opportunity to review the level of preparedness and foresight that would be in place relative to potential spills from the proposed Project.

The first hypothetical spill occurs in the summer in an area with deep groundwater, relatively flat terrain, at least 2 miles from any navigable stream, no wetlands within 1 mile, and with no nearby private water wells or public water intakes. The second hypothetical spill occurs in the winter in an area of relatively shallow groundwater (25 feet bgs), sloping terrain, nearby wetlands, and a navigable stream within 1,000 feet, including private water wells within 100 feet of the release site and a public water intake 2 miles downstream.

For each of these scenarios, Keystone describes the following:

- Response procedures including pipeline shutdown, commencement of field response, spill assessment, and development of incident command post;
- The potential horizontal and vertical spread of crude oil into the environment;
- Response tactics employed for source control;
- Cleanup approaches for spills on land including containment methods and removal methods;
- Cleanup approaches for spills to groundwater including options for short- and long-term remediation;
- Cleanup approaches for spills on calm or slow moving water (lake or pond) and to flowing water (stream or river);
- Cleanup approaches for spills that occur on ice or under ice; and
- Cleanup approaches for spills in wetland areas.

DOS and PHMSA have reviewed these hypothetical spill response scenarios prepared by Keystone and would also review a final ERP to be prepared by Keystone prior to startup of the proposed pipeline (see Section 2.4.2.2 for additional information on the Keystone ERP). Based on its review of the hypothetical spill response scenarios, DOS considers Keystone's response planning appropriate and consistent with accepted industry practice.

3.13.5.3 Factors Affecting the Behavior and Fate of Spilled Oil

The primary and shorter-term processes that affect the fate of spilled oil are spreading, evaporation, dispersion, dissolution, and emulsification (Payne et al. 1987, Boehm 1987, Boehm et al. 1987, Overstreet and Galt 1995). These processes are called weathering. Weathering dominates during the first few days to weeks of a spill. A number of longer term processes also occur, including photo-degradation and biodegradation, auto-oxidation, and sedimentation. These longer-term processes are more important in the later stages of weathering and usually determine the ultimate fate of the spilled oil that is not recovered by the cleanup program.

The chemical and physical composition of oil changes with weathering. Some oils weather rapidly and undergo extensive changes in character, whereas others remain relatively unchanged over long periods. Because of evaporation, the effects of weathering are generally rapid (one to a few days) for hydrocarbons with lower molecular weights (e.g., gasoline, aviation gas, and diesel). Degradation of the higher weight fractions (e.g., crude oil, transmission and lube oil, and hydraulic fluid) is slower and occurs primarily through microbial degradation and chemical oxidation. The weathering or fate of spilled oil depends on the oil properties and on environmental conditions, both of which can change over time.

Spreading

Spreading reduces the bulk quantity of oil present in the vicinity of the spill but increases the spatial area over which adverse effects could occur. Thus, oil in flowing systems (e.g., rivers and creeks) rather than contained systems (e.g., wetlands, ponds, and lakes) would be less concentrated in any given location but could cause impacts, albeit reduced in intensity, over a larger area. Spreading and thinning of spilled oil also increases the surface area of the slick; enhancing surface-dependent fate processes such as evaporation, biodegradation and photo-degradation (see below), and dissolution. However, experience on previous oil spills suggests that the degree of spreading of an oil spill from the spill source is constrained by natural conditions in the vicinity of the release site. For example, in a crude oil release from a pipeline system on August 20, 1979 near Bemidji, Minnesota, approximately 10,700 barrels of crude oil was released onto a glacial outwash deposit consisting primarily of sand and gravel. As of 1996 the leading edge of the oil remaining in the subsurface at the water table had moved approximately 131 feet down gradient from the spill site and the leading edge of the dissolved contaminant plume had moved about 650 feet down gradient. Spreading in subsurface water is discussed further in 3.13.6.3.

Adsorption

Crude or refined oil dispersed in soil would adsorb or adhere to soil particles. Crude oil would usually bind most strongly with soil particles in organic soils and less strongly with soil particles in sandy soils. In water, heavy molecular weight hydrocarbons may bind to suspended particulates, and this process can be significant in highly turbid or eutrophic waters. Organic particles (e.g., biogenic material) in soils or suspended in water tend to be more effective at adsorbing oils 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. However, these processes also render hydrocarbons less susceptible to degradation. Oil in sediment tends to be highly persistent and can cause chronic impacts.

Evaporation

Evaporation is the primary mechanism for loss of low-molecular-weight constituents and light oil products. However, recent studies related to the MC-252 oil spill in the Gulf of Mexico (Deepwater Horizon incident) indicate that higher molecular weight constituents from spilled oil also volatilize over time and distance from the spill source (De Gouw 2011). As lighter components evaporate, remaining petroleum hydrocarbons become denser and more viscous. Evaporation tends to reduce oil toxicity but enhance persistence. Hydrocarbons that volatilize into the atmosphere are broken down by sunlight into smaller compounds. This process, referred to as “photo-degradation,” occurs rapidly in air; the rate of photo-degradation decreases as molecular weight increases.

Dispersion

Dispersion of oil is the spreading of oil in water and dispersion increases when water surface turbulence increases. Wind, gravity, tidal currents, or broken ice movement could cause the turbulence. Dispersion of oil into water increases the surface area of oil susceptible to dissolution and degradation processes, and thereby limits the potential for physical impacts. However, some of the oil could become dispersed in the water column or on the bottom as it adheres to particulate matter suspended in the water column. The presence of particulates, including organic matter, silt and clay, and larger sediment particles, is likely to be greatest during spring ice breakup, flood flows, and wind storms.

Dissolution

Dissolution of oil involves soluble oil components dissolving in a water column. Dissolution in water is not the primary process controlling the fate of the oil in the environment (i.e., oil generally floats on rather than dissolves into water). Despite the characterization of crude oil that would be transported by the proposed Project as heavy crude oil, it would still be lighter than water based on its characteristic specific gravity. Some crude oil components are water-soluble and to the extent that dissolution does occur, it is one of the primary processes affecting the toxic effects of a spill, especially in confined waterbodies. Dissolution increases with decreasing hydrocarbon molecular weight, increasing water temperature, decreasing water hardness or "salinity," and increasing concentration of dissolved organic matter. Under the same environmental conditions, lighter weight petroleum hydrocarbons (e.g., BTEX) would dissolve more readily than the heavier fractions such as PAHs.

Emulsification

Emulsification is the incorporation of oil in water in a colloidal suspension. During emulsification, small drops of water become surrounded by oil. External energy from wave or strong current action is needed to naturally emulsify oil. In general, heavier oils emulsify more readily than lighter oils. The oil could remain in a slick, which could contain as much as 70 percent water by weight and could have a viscosity of a hundred to a thousand times greater than the original oil. Water-in-oil emulsions often are referred to as "mousse." Emulsifications are more common in large water bodies (e.g., large lakes, major rivers, and the ocean) where waves and/or currents mix the surface waters than in smaller water bodies where this mixing energy is usually much less.

Some commenters on the draft EIS were concerned that the bitumen component of WCSB crude oil that would be transported by the proposed Project (specifically dilbits), if released to a waterbody, would be expected to sink and accumulate on the underlying bed of the waterbody leading to difficult cleanup during spill response. This concern is apparently based on the characteristics of a bitumen-based product called Orimulsion. This product is a combination of bitumen (about 70 percent), water (about 30 percent), and surfactants (less than 1 percent) and forms an emulsion (colloidal suspension) that is materially different from the crude oils that would be transported by the proposed Project. Since the ingredients of Orimulsion do not form a solution when combined, they separate into bitumen particles, water, and surfactant when released into water. Additionally, since the specific gravity of the bitumen is either equal to or greater than the specific gravity of water, it can sink after de-emulsification. This does not occur in dilbits, such as the Western Canadian Select crude oil, because the bitumen blended with diluents forms a solution with a specific gravity less than water that would not separate when released and that would initially tend to form a lenticular mass that would float on the water column. However, given sufficient time for volatilization and biodegradation, any crude oil residuum can become more dense than water and sink.

Photo-degradation

Photo-degradation of oil increases with greater solar intensity. It can be a significant factor controlling the disappearance of a slick, especially of lighter constituents, but it would be less important during cloudy days and in winter months. Photo-degraded petroleum constituents tend to be more soluble and more toxic than parent compounds. Extensive photo-degradation leading to increased dissolution could increase the biological impacts of a spill event.

Biodegradation

Biodegradation is the breakdown of compounds by native or introduced microorganisms. Biodegradation of oil by native microorganisms, in the immediate aftermath of a spill, would likely not be a significant process controlling the fate of oil in waterbodies previously unexposed to oil. Although oil-degrading microbial populations are ubiquitous at low densities, a sufficiently large population must become established before biodegradation can proceed at any appreciable rate. Biodegradation is typically a long-term (weeks to years) process that reduces both the toxicity and volume of spilled oil.

3.13.5.4 Summary of Environmental Factors Affecting the Fate of Spilled Oil

The environmental fate of released oil and oil products is controlled by many factors. Major factors affecting environmental fate include the spill volume, spill rate, oil temperature, terrain, receiving environment, time of year, and weather. Crude oil would weather differently than diesel or refined products in that both diesel and refined products would evaporate faster and dissolve to a greater degree into water than crude oil.

The characteristics of the receiving environment, such as the type of land cover, soil porosity, land surface topography and gradient, type of freshwater body, presence of ice and/or snow cover on water or land, and flowing water current velocity, would affect how the spill behaves. In ice-covered waters, many of the same weathering processes occur as in open water. However, ice changes the rates and relative importance of these processes (Payne et al. 1991).

The time of year when a spill occurs has a major effect on the fate of crude oil. The time of year controls climatic factors such as temperature of the air, water, or soil; depth of snow cover; presence of ice; and the depth of the active (soil frost) layer. During winter, colder air temperatures can modify the viscosity of oil so that it would spread less and potentially solidify. Temperature also affects the rate of evaporation of the volatile fraction of hydrocarbons. Frozen ground would limit the depth of penetration of any spill. Weather could also affect the ability to detect, contain, or clean up a spill.

3.13.5.5 Actions to Prevent, Detect, and Mitigate Oil Spills

The proposed Project would include processes, procedures, and systems to prevent, detect, and mitigate potential oil spills that could occur during operation of the proposed pipeline. These are summarized below. The final 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.

Oil Spill Prevention

Immediate control, containment, and cleanup of released oil are important factors in limiting the spatial and temporal effects of a spill. Keystone conducted a pipeline threat analysis using the pipeline industry-published list of threats under ASME B31.8S to determine the applicable threats to the proposed pipeline (see Appendix P). Safeguards were then developed to protect against these potential threats, which have been identified as follows:

- Incorrect pipeline operations (e.g., overpressure of the pipeline);
- Materials and construction damage (e.g., flaws such as defective welds, dents, cracks, nicks in the coating that are a result of transport or construction, and flaws in the seam of the pipeline created during the manufacturing process);
- Corrosion (e.g., internal, external, and stress-corrosion cracking) including defects that develop over time during operation;
- Accidental damage such as external contact with the pipeline (e.g., third-party backhoes, excavators, and drills); and
- Facility damage from natural hazards (e.g., landslides, floods, and earthquakes).

Some commenters expressed concern regarding the threat of terrorism. In the aftermath of the terrorist attacks that occurred on September 11, 2001, terrorism has become a very real issue for infrastructure throughout the country. Since that date, there has been an increase in security awareness throughout the pipeline industry and the nation. The Office of Homeland Security was established with the mission of coordinating the efforts of all executive departments and agencies to detect, prepare for, prevent, and protect against, respond to, and recover from terrorist attacks within the U.S.

There are currently about 500,000 miles of interstate oil and gas transmissions lines, and hundreds of thousands of miles of oil and gas gathering lines and distribution lines throughout the country. Although safety and security are important considerations for those facilities, the number, lengths, and locations of the pipelines precludes having guards, cameras, and other types of continuous surveillance and protection measures. However, to reduce the vulnerability of the proposed Project to terrorism, the pipeline would be buried to a minimum depth of 4 feet, and mainline valves, pump stations, and the Cushing tank farm would be surrounded by locked security fencing. The pipeline route would be routinely inspected by air and ground patrols as required by PHMSA, and the aboveground facilities would routinely be visited by maintenance and monitoring crews.

The likelihood of future attacks of terrorism or sabotage occurring along the proposed Project route, or at any of the many crude oil pipelines, refined product pipelines, natural gas pipelines, or other energy facilities throughout the U.S. is unpredictable given the disparate motives and abilities of terrorist groups. Despite the ongoing potential for terrorist acts along any of the nation's crude oil, product, and natural gas pipelines, the continuing need for the construction of these facilities is not eliminated.

Safeguards were included in the proposed Project's design and would be implemented during construction and operations. These include:

- Pipe specifications that meet or exceed applicable regulations;
- Use of the highest quality external pipe coatings (fusion bond epoxy or FBE) to prevent corrosion;
- Providing 4 feet of soil cover over the buried pipeline in most locations, which exceeds federal standards;
- Public awareness and damage prevention programs in accordance with 49 CFR 195.440 and RP 1162;
- Implementing a variety of pipeline system inspection and testing programs prior to operation, to prevent leaks. Examples of these programs include: an extensive pipeline quality assurance program for pipe manufacturing and coating; non-destructive testing of 100 percent of girth welds; hydrostatic testing in conformance with Special Conditions 8 and 22, that require the pipe

to be subjected to a mill hydrostatic test pressure of 95 percent SMYS or greater for 10 seconds and the pre-in service hydrostatic test must be to a pressure producing a hoop stress of a minimum 100 percent SMYS for mainline pipe and 1.39 times MOP for pump stations for 8 continuous hours;

- An operational pipeline monitoring system (Supervisory Control and Data Acquisition [SCADA]) that remotely measures changes in pressure and volume every 5 seconds on a constant basis. These data would be immediately analyzed to determine potential product releases anywhere on the pipeline system;
- Periodic pipeline integrity inspection and cleaning programs using internal inspection tools (pigs) to detect pipeline anomalies indicating excavation damage, and loss of wall thickness from corrosion;
- Aboveground aerial and ground surveillance inspections (ground-level patrols would be undertaken in the event of a suspected leak but would not be routinely undertaken). The aerial inspections would be conducted 26 times per year (not to exceed 3 weeks apart) to detect leaks and spills as early as possible, and to identify potential third-party activities that could damage the proposed pipeline; and
- Installing MLVs along the proposed pipeline route in accordance with PHMSA regulatory requirements and PHMSA Special Condition 32 (see Appendix U) to reduce or avoid spill effects to PHMSA-defined HCAs.

In addition to the regulatory requirements and industry standards to be incorporated into the design, PHMSA developed a set of Project-specific Special Conditions (see Appendix U) that have been agreed to by Keystone and would be incorporated into the proposed Project. Incorporation of those conditions would result in a Project that would have a degree of safety over any other typically constructed domestic oil pipeline system under current code and a degree of safety along the entire length of the pipeline system similar to that which is required in HCAs as defined in 49 CFR 195.450.

Oil Spill Detection

In addition to the integrity systems and measures that would be implemented as described in Section 2.4.2.1 to maintain pipeline integrity and minimize spills, the proposed Project would utilize a SCADA system that would alert the Operations Control Center (OCC) operator of an abnormal operating condition, indicating a possible spill or leak. SCADA would be installed in accordance with the requirements of 49 CFR 195.446 and the Project-specific Special Conditions (see Appendix U).

SCADA facilities would be used to remotely monitor and control the pipeline system. This would include a redundant fully functional backup system available and ready for service at all times. Automatic features would be installed as integral components within the SCADA system to ensure operation within prescribed pressure limits. Additional automatic features would be installed at the local pump station level and would provide pipeline pressure protection in the event communications with the SCADA host are interrupted.

Software associated with the SCADA monitoring system and volumetric balancing would be utilized to assist in leak detection during pipeline operations. If pressure indications change, the pipeline controller would immediately evaluate the situation. If a leak is suspected, the ERP would be initiated, as described in Section 2.4.2.2. In the event of a pipeline segment shutdown due to a suspected leak, operation of the affected segment would not be resumed until the cause of the alarm (e.g., false alarm by instrumentation, or leak) is identified and repaired. In the case of a reportable leak, USDOT approval would be required to resume operation of the affected segment.

A number of complementary leak detection methods and systems would be available within the OCC and would be linked to the SCADA system. Remote monitoring would consist primarily of monitoring pressure and flow data received from pump stations and valve sites that would be fed back to the OCC by the SCADA system. Software based volume balance systems would monitor receipt and delivery volumes and would detect leaks down to approximately 5 percent of pipeline flow rate. Computational Pipeline Monitoring or model based leak detection systems would monitor small pipeline segments on a mass balance basis. These systems would detect leaks down to approximately 1.5 to 2 percent of pipeline flow rate. Computer based, non-real-time, accumulated gain/loss volume trending would assist in identifying seepage releases below the 1.5 to 2 percent by volume detection thresholds. If any of the software-based leak detection methods indicate that a predetermined loss threshold has been exceeded, an alarm would be sent through SCADA and the Controller would take corrective action. The SCADA system would continuously poll all data on the proposed pipeline at an interval of approximately 5 seconds.

In the event of a leak, the operator would shut down operating pumping units and close the isolation valves. It would take approximately 9 minutes to complete the emergency shut-down procedure (shut down operating pumping units) and an additional 3 minutes to close the isolation valves. Some commenters have expressed concern that the Ludden spill on the existing Keystone Oil Pipeline Project (see Table 3.13.1-4) took longer than 12 minutes to shut down. In the case of the May 7, 2011 Ludden spill, the time from 3:51 to 4:26 pm MST was used to verify flow imbalance trends detected by the SCADA system. At 4:26 pm the Keystone Oil Control Center (OCC) received visual verification of a leak from a local farmer, thus confirming that a leak had occurred and system shutdown was immediately initiated. Shutdown was completed by 4:35 pm MST. The elapsed time from leak confirmation through visual verification to complete system shutdown was 9 minutes. The incident emphasizes the importance and difficulty of leak verification in some instances. The incident confirms that the uncertainty in time to shut down for any leak is primarily a function of the time required to verify that a leak has occurred.

In addition to the SCADA and complimentary leak detection systems, direct observation methods including aerial patrols, intermittent maintenance patrols, and public and landowner awareness programs would be implemented to encourage and facilitate the reporting of suspected leaks and events that could suggest a threat to the integrity of the pipeline.

EPA expressed concern that relying solely on pressure drops and aerial surveys to detect leaks may result in smaller leaks going undetected for some time, resulting in potentially large spill volumes. In light of those concerns, EPA requested consideration of additional measures to reduce the risks of undetected leaks. A PHMSA report (2007) addressed the state of leak detection technology and its applicability to pipeline leak detection. External leak detection technology addressed included liquid sensing cables, fiber optic cables, vapor sensing, and acoustic emissions. In that report PHMSA concludes that while external leak detection systems have proven results for underground storage tank systems there are limitations to their applicability to pipeline systems and they are better suited to shorter pipeline segments. Their performance even in limited application is affected by soil conditions, depth to water table, sensor spacing, and leak rate. While it is acknowledged that some external detection methods are more sensitive to small leaks than the SCADA computational approach, the costs are extremely high and the stability and robustness of the systems are highly variable. Therefore, long-term reliability is not assured and the efficacy of these systems for a 1,384-mile long pipeline is questionable.

Relative to additional ground patrols, Keystone responded to a data request from DOS concerning the feasibility of more ground-level inspections. Keystone responded that based on land owner concerns, additional ground-level inspections are not feasible due to potential disruption of normal land use activities (e.g., farming, animal grazing). However, it should be noted that in the normal course of maintenance Keystone would have crews at various places along the proposed Project corridor (e.g., maintenance inspections of cathodic protection system rectifiers, MLVs, and pump stations). These crews would be trained and experienced in the identification of crude oil releases.

Oil Spill Response Procedures

Prior to the proposed Project construction, an SPCC plan consistent with EPA requirements is required to guide Keystone response in the event of unintended releases of petroleum products and hazardous materials during construction. SPCC requirements are addressed in Section 2.3 and in the CMR Plan in Appendix B; a draft SPCC plan is presented in Appendix C.

Prior to initiation of operation of the proposed Project, an ERP approved by PHMSA is required. The ERP is applicable to the pipeline operations and maintenance activities. The ERP would not be finalized until final definition of proposed Project elements included in all applicable permits. As noted in Section 2.4.2.2, an ERP was previously developed by Keystone for the existing Keystone Mainline and Cushing Extension project and approved by PHMSA. 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 Project route and the differing environmental and public health vulnerabilities along the pipeline corridor. The publically available portion of the Keystone Oil Pipeline System ERP is included as Appendix C (some of the ERP is considered confidential by PHMSA and the U.S. Department of Homeland Security). The Keystone ERP would be used as a template for the ERP for the proposed Project and would include Project-specific information as it becomes available. In addition, as required by 49 CFR 194.107, the response plan submitted to PHMSA would include "procedures and a list of resources for responding, to the maximum extent practicable, to a worst case discharge, and to a substantive threat of such a discharge." Once the Project route is finalized, field work would commence in collecting relevant information to be incorporated into the Project ERP which would then be submitted to PHMSA for review and approval.

Spill response procedures incorporated in the ERP would be followed in the event of a spill. Procedures that are likely to be included in the final, approved, ERP are summarized in this section. Additionally, in response to a DOS data request, Keystone provided its response procedures for two hypothetical release scenarios in areas overlying aquifers. These release scenarios are included in Appendix C and further discussed in Section 3.13.6.4.

The ERP standard operating and response procedures would be utilized by the OCC operator in responding to abnormal pipeline conditions, including leak alarms. The OCC operator would have the full and complete authority to execute a pipeline shutdown. Keystone's OCC operator would follow prescribed procedures in responding to possible spills that may be reported from sources such as:

- Abnormal pipeline condition observed by the OCC operator;
- Leak detection system alarm;
- Employee reported abnormal conditions; and
- Third party reported abnormal conditions.

Upon receipt of an abnormal condition report, leak report, or leak alarm, the OCC operator would implement the following procedures:

- Follow prescribed OCC operating and response procedures for specific directions on abnormal pipeline condition or alarm response;
- Dispatch First Responders;

- Shut down the proposed pipeline within a predetermined time threshold if abnormal conditions or leak alarm cannot be positively ruled out as a leak;
- Complete internal notifications; and
- Report identified spill to federal (including National Response Center [NRC]), state and local responders as required by all applicable reporting regulations.

All Keystone employees are authorized to communicate directly with the OCC should they observe conditions that may signify a possible spill.

Commenters have expressed concern that special procedures would be required to clean up the type of oil that would be transported by the proposed Project in the event of a spill. The proposed Project would transport heavy crude oil similar to heavy crude oils currently transported by pipeline in the U.S. as well as lighter crude oils. As noted in Section 3.13.5.1, the composition of dilbits is not different from other heavy crude oils, including the WCSB conventional heavy crude oils that have been imported into the U.S. for over two decades. As a result, response to a spill from the proposed pipeline would not require unique clean up procedures. As noted by the EPA Office of Emergency and Remedial Response (EPA 1999):

> "Lighter oils tend to evaporate and degrade (break down) very quickly; therefore, they do not tend to be deposited in large quantities on banks and shorelines. Heavier oils, however, tend to form a thick oil-and-water mixture called *mousse*, which clings to rocks and sand. Heavier oils exposed to sunlight and wave action also tend to form dense, sticky substances known as *tar balls* and *asphalt* that are very difficult to remove from rocks and sediments. Therefore, deposits from heavy oils generally require more aggressive cleanup than those from lighter ones."

Therefore, although the cleanup of heavy crude oils that would be transported by the proposed Project would be a difficult task, the spill response procedures currently used by EPA, the U.S. Coast Guard, and cleanup contractors could be effectively used for a spill of heavy crude oil from the proposed Project.

Response Time

In the event of a potential pipeline leak or spill, the estimated time to complete an emergency pipeline shutdown and close remotely operated isolation valves is as follows:

- Stop pumping units at all pump station locations: approximately 9 minutes.
- Close remotely operated isolation valves: approximately 3 minutes.
- Total time: approximately 12 minutes.

Consistent with industry practice and in accordance with regulations, Keystone's response time to transfer the necessary resources to a potential leak site would follow an escalating or tier system as required by 49 CFR 194.115 (Table 3.13.5.8). Dependent 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 3.13.5-8 Response Time Requirements of 49 CFR 194.115 along the Proposed Pipeline			
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.

Spill Response Equipment

In general, Tier 1 emergency response equipment would be pre-positioned for access by Keystone including: 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 H2S, O2, Lower Explosive Level, and benzene concentrations.

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 in order to protect the public and USAs, including ecological, historical, and archeological resources and drinking water locations. The Emergency Site Manager (also known as the Qualified Individual or "QI") 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 USAs downcurrent or down gradient from the spill site; and
- Concentration of wildlife and breeding areas.

The QI 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 product. Site cleanup and restoration activities would then follow, all of which would be conducted in accordance with the ERP and in conjunction with authorities having jurisdiction.

Spill Response Personnel and Training

The number of emergency responders comprising specific response teams would be determined upon completion of the proposed Project ERP. Emergency responders would meet or exceed the requirements of 49 CFR Part 194.115, and would typically be comprised of Hazardous Waste Operations and Emergency Response ("HAZWOPER") trained personnel. The response organization would follow the industry-accepted Incident Command System (ICS) and would typically consist of personnel both onsite and within an established remote or Regional Emergency Operations Center (EOC).

Locations of Spill Responders

Emergency responders would be based consistent with industry practice and consistent with applicable regulations, including 49 CFR 194 and 49 CFR 195. Consequently, emergency responders would be based in close proximity to the following areas:

- Commercially navigable waterways and other water crossings;
- Populated and urbanized areas; and
- USAs, including ecological, historical, and archeological resources and drinking water locations.

The specific locations of other emergency responders would be determined upon conclusion of the detailed location and design of the proposed pipeline, and completion of the ERP.

Spill Training Exercises and Drills

The spill training exercise and drill program would be designed to meet the requirements of the National Preparedness for Response Exercise Program Guidelines developed by the USCG and required by the Oil Pollution Act of 1990 (OPA 90). The primary elements of the exercise program are notification exercises, tabletop exercises, equipment deployment exercises, contractor exercises, unannounced exercises by government agencies, and area-wide exercises up to and including actual field drills conducted by industry and government agencies.

Operating personnel would participate in exercises or responses on an annual basis in order to ensure that they remain trained and qualified to operate the equipment in the operating environment and to ensure that the ERP is effective. However, personnel and equipment that are assigned to multiple Response Zones would participate in only one deployment exercise per year.

Local Emergency Planning Committees (LEPC)

As discussed in Section 3.10.2, LEPCs were established pursuant to the Emergency Planning and Community Right-to-Know Act (EPCRA) of (1986). Keystone has committed to a communication program that would reach out to LEPCs along the proposed pipeline corridor during development of the PSRP and the Emergency Response Plan included within the proposed Project Operations and Maintenance Plan. The LEPCs would participate in emergency response consistent with their authority under EPCRA, their local emergency response plan, and the proposed Project specific response plans addressed previously.

At the suggestion of EPA, DOS reached out to LEPCs along the proposed pipeline corridor to determine the following information:

- LEPC contact information (phone, fax, email, website);
- Counties/cities included in the LEPC plan;
- Date of last LEPC plan update;
- Regularity of LEPC meetings;
- LEPC funding status;
- Last LEPC emergency response training exercise; and
- Components of emergency plan, including potential pipeline releases, railroad or truck transport releases, and potential dangers and/or responses specifically affecting low-income or minority populations in LEPC area.

The information gained from the DOS LEPC survey is presented in Table 3.13.5-9. This information would be used in the development of required emergency and response plans should the proposed Project be implemented.

TABLE 3.13.5-9
LEPC Telephone Survey[a]

Contact Person	Address	Phone/Fax	E-Mail	Counties/ Cities included in the Emergency Plan	Date Emergency Plan was Last Updated	LEPC Meetings (no; or mthly, qrtly, twice yr, yearly, other)	LEPC Funded[b] (no/yes; $ amt)	Date of Last Emergency Exercise	Emergency Plan Website Link[c]	Emergency Plan Addresses Pipelines (yes/no)	Emergency Plan Addresses Railroads/ Trucks (yes/no)	Emergency Plan Addresses Low-income/ Minorities (yes/no)
Greg Spears	P.O. Box 360, Malta, MT 59538	(406) 263-7437	des@phillipscounty.mt.gov	Phillips County	20-May-08	Quarterly	No	1-Jun-11	no	Yes	yes	Yes
Richard Seiler	501 Court Square #10, Glasgow, MT 59230	(406) 228-6224 No answer	rseiler@co.valley.mt.us	Valley County	20-May-08							
Alan Stempel and Ryan Grigg	493 Stoney Rd, Circle, MT 59215	(406) 485-2347 Left a message for Ryan Grigg	mcondes@midrivers.com	McCone County	20-May-08							
George Lane Tim Mort: County Fire Chief; 406.989.1015.	300 S Merrill Ave, Glendive, MT 59330	(406) 377-2361	laneg@midrivers.com	Dawson County	20-May-08	Monthly	No	11-Feb-11	no	Yes. Currently updating plan and planning pipeline spill	Yes	Not sure
John Pisk	P.O. Box 126, Terry, MT 59349	(406) 635-5738	jpisk@co.prairie.mt.us	Prairie County	20-May-08	Quarterly	No	23-Jun-11	no	Yes	Yes	No (there is a general basic needs plan that applies to everyone)
Sam Thielen	P.O. Box 846, Baker, MT 59313	(406) 778-3223 No answer	fcdes@midrivers.com	Fallon County	20-May-08							
Candy Loehding	P.O. Box 42, Ekalaka, MT 59324	(406) 975-6416	cloehding@midrivers.com	Carter County	20-May-08	as needed	No	1-May-11	no	no	yes	yes
Don Thompson	P.O. Box 26, Buffalo, SD 57720	(605) 256-7611	kathy.glines@state.sd.us	Harding County	20-May-08	Quarterly (more as needed)	all volunteer- small grant from EPS	July, 2011	no	yes	yes	yes (everyone gets the same information)
Robert Fines	3200 E Highway 34 Ste 17, Pierre, SD 57501	(605) 723-0900 Left a message	rob.fines@co.hughes.sd.us	Butte County	20-May-08							
Kelly Serr	P.O. Box 234, Bison, SD 57620	(605) 244-5243	perkinscoso@sdplains.com	Perkins County	17-May-08	Quarterly	Yes; no idea	10-Jun-01	no	not sure	yes	yes
Kathie Grant	1400 Main St, Sturgis, SD 57785	(605) 347-4222	emgmgmt@meadecounty.org	Meade County	17-May-08	not active, as needed	No	6/2010, 9/26/11 is planned	no	yes	yes	no for minorities but yes for special needs individuals.
Donald Opie (Part time, retired and a volunteer)	P.O. Box 411, Mobridge, SD 57601	(605) 845-2800 Left a message	warhawk@westriv.com	Ziebach County, SD	17-May-08							
Anthony Carbajal	315 Saint Joe St B-31, Rapid City, SD 57701	(605) 394-2185	pamb@co.pennington.sd.us	Pennington County	20-May-08	Quarterly	Yes, $8500/yr	11-Jun-11	no	not yet, updating now	yes	no
Lola Roseth	20115 Manilla Rd, Midland, SD 57552	(605) 567-3515	lolaroseth@gwtc.net	Haakon County	20-May-08	no	No	28-Jun-11	no	no	yes	no
John Brunskill	P.O. Box 302, Murdo, SD 57559	(605) 669-7100	jamoore29@hotmail.com	Jones County	1-Jul-10	no	No	1-Apr-09	no	no	yes	yes
Steve Manger	P.O. Box 97, Kennebec, SD 57544	(605) 869-2200 Left a message	deputy.manger@lymancoso.org	Lyman County	17-May-08							

TABLE 3.13.5-9 LEPC Telephone Survey[a]													
Contact Person	**Address**	**Phone/Fax**	**E-Mail**	**Counties/ Cities included in the Emergency Plan**	**Date Emergency Plan was Last Updated**	**LEPC Meetings (no; or mthly, qrtly, twice yr, yearly, other)**	**LEPC Funded[b] (no/yes; $ amt)**	**Date of Last Emergency Exercise**	**Emergency Plan Website Link[c]**	**Emergency Plan Addresses Pipelines (yes/no)**	**Emergency Plan Addresses Railroads/ Trucks (yes/no)**	**Emergency Plan Addresses Low-income/ Minorities (yes/no)**
Shawn Pettit	200 E 3rd St, Winner, SD 57580	605-842-1890	ritatrco@gwtc.net	Tripp County	17-May-08	Quarterly, more if needed)	Funded through the state, around $1,000/yr	October 2010	No	No	Yes	Partial component, for evacuation
Damon Wolf	P.O. Box 431, Burke, SD 57523	(605) 775-2626	gregorycoso@gwtc.net	Gregory County	17-May-08	Annually	No	1-Aug-10	no	no	yes	yes
Douglas Fox	365 N Main, Valentine, NE 69201	(402) 684-2424	ccema@inebraska.com	Kay-Paha County	20-May-08 (waiting to see what other counties are developing before making any new additions)	In the process setting one up, not now	No	1-Jul-11	www.nema.ne.gov/leops/nebraskamap.htm	no	yes	yes
Douglas Fox	P.O. Box 178, Bassett, NE 68714	(402) 376-2420	region24@huntel.net	Rock County	20-May-08	In the process setting one up, not now	No	2-Jul-11	www.nema.ne.gov/leops/nebraskamap.htm	no	yes	yes
No Contact provided	P.O. Box 544, O'Neill, NE 68763	(402)340-5664 Left a message	holtcountyema@telebeep.com	Holt County	20-May-08				www.nema.ne.gov/leops/nebraskamap.htm			
Alma Beland	404 4th St, Taylor, NE 68879	(308) 942-3461	region26@cornhusker.net	Garfield County	20-May-08	no	No	1-Apr-10	www.nema.ne.gov/leops/nebraskamap.htm	no	no	no
Alma Beland	405 4th St, Taylor, NE 68879	(308) 942-3461	region26@cornhusker.net	Wheeler County	20-May-08	no	No	2009	www.nema.ne.gov/leops/nebraskamap.htm	no	no	no
Alma Beland	406 4th St, Taylor, NE 68879	(308) 942-3461	region26@cornhusker.net	Greeley County	20-May-08	no	No	2009	www.nema.ne.gov/leops/nebraskamap.htm	no	no	no
Dave Speigel	222 S 4th, Albion, NE 68620	(402) 395-2144 Left a message	bcbcarey@frontiernet.net	Boone County	20-May-08				www.nema.ne.gov/leops/nebraskamap.htm			
Davis Moore	Rt 1 Box 133, Genoa, NE 68640	(308) 536-2452	nancecivildefence@hamilton.net	Nance County	20-May-08	no	No	1-May-11	no	no	no	no (a list of emergency resources is available, but without specific details on what low income/ minorities should do)
Kevin Campbell	1821 16th Ave, Central City, NE 68826	(308) 946-2345 Left a message	merikso@cconline.net	Merrick County	20-May-08				www.nema.ne.gov/leops/nebraskamap.htm			

TABLE 3.13.5-9
LEPC Telephone Survey[a]

Contact Person	Address	Phone/Fax	E-Mail	Counties/ Cities included in the Emergency Plan	Date Emergency Plan was Last Updated	LEPC Meetings (no; or mthly, qrtly, twice yr, yearly, other)	LEPC Funded[b] (no/yes; $ amt)	Date of Last Emergency Exercise	Emergency Plan Website Link[c]	Emergency Plan Addresses Pipelines (yes/no)	Emergency Plan Addresses Railroads/ Trucks (yes/no)	Emergency Plan Addresses Low-income/ Minorities (yes/no)
Kirt Smith	916 13th St, Aurora, NE 68818	(402) 694-5126 Left a message	hcems@hamilton.net	Merrick County	20-May-08				www.nema.ne.gov/leops/nebraskamap.htm			
Rick Schnedier	451 5th St, David City, NE 68632	(402) 367-7400 Left a message	bcema@neb.rr.com	Polk County	20-May-08				www.nema.ne.gov/leops/nebraskamap.htm			
Gary Petersen	16 Eastridge Dr N, York, NE 68467	(402) 362-7744 Cell: 402-643-5761	hlheiden@alltel.net	York County (and Seward Co)	20-May-08	Quarterly	Yes $500/year	March, 2011	www.nema.ne.gov/leops/nebraskamap.htm	No	No	No, working on an "Access and developmental needs" registry. Will be voluntary for citizens.
Donna Mainwaring	P.O. Box 266, Geneva, NE 68361	(402) 759-4914	emergencymanagement@fillmorecounty.org	Fillmore County	20-May-08	Quarterly, in the process of setting up regular meetings	No	May, 2011	www.nema.ne.gov/leops/nebraskamap.htm	No	No	In the evacuation portion of EMP
B.J. Fictum	P.O. Box 865, Wilber, NE 68465. (Under public health annex)	(402) 821-3010	scema@diodecom.net	Saline County	17-May-08	Quarterly	Yes, each county puts in about $500/yr	18-Jun-11	www.nema.ne.gov/leops/nebraskamap.htm	Yes	yes	Yes
John McKee	803 4th St, Fairbury, NE 68352	(402) 729-3602	don@kbsi.us	Jefferson County	20-May-08	Quarterly	Funded through County budget; around $2,000/yr	June 1, 2011	www.nema.ne.gov/leops/nebraskamap.htm	Generally, not specifically	Yes	Special needs registry for evacuations; (GIS database). No mention of minorities
Pam Kemp	603 4th St, Clay Center, KS 67432	(785) 632-5802	kemp@kansas.net	Clay County	26-Jan-11	Monthly	No	2-Jul-11	no	no	no	no
Pam Dunham	2100 N Ohio Ste B, Augusta, KS 67010	(316) 733-9796	pdunham@bucoks.com	Butler County	26-Jan-11	Quarterly	No	10-Jun-11	www.butlercoema.org	no	no	no
Charlie Lawson (started recently)	315 W 6th, Ste 203, Stillwater, OK 74074	(405) 533-6875	ghessier@paynecounty.org	Payne County	20-May-08	Quarterly	Yes, grants for training	not sure	no	yes	yes	not sure
Don Sweger	1008 E Tejon, Bristow, OK 74010	(918) 367-2252 Left a message	bristowcd27@sbcglobal.net	Creek County	20-May-08							
Joey Whitefield	811 Manvel # 4, Chandler, OK 74834	(405) 258-4100 Out through July	lincoln.county@oem.ok.gov	Lincoln County	20-May-08							
Bill Elliot	P.O. Box 26, Okemah, OK 74859	(918) 623-6766	okfuskeeem@onalot.com	Okfuskee County	20-May-08	Quarterly	No	1-Jun-11	no	yes	yes	no

TABLE 3.13.5-9
LEPC Telephone Survey[a]

Contact Person	Address	Phone/Fax	E-Mail	Counties/ Cities included in the Emergency Plan	Date Emergency Plan was Last Updated	LEPC Meetings (no; or mthly, qrtly, twice yr, yearly, other)	LEPC Funded[b] (no/yes; $ amt)	Date of Last Emergency Exercise	Emergency Plan Website Link[c]	Emergency Plan Addresses Pipelines (yes/no)	Emergency Plan Addresses Railroads/ Trucks (yes/no)	Emergency Plan Addresses Low-income/ Minorities (yes/no)
Ernie Willis (no active county manager)	820 Jefferson St, Seminole, OK 74818	(405) 382-3702	semem@armmediapro.com	Seminole County	20-May-08	Monthly	Limited funding	4-May-11	no, thinking about updating	yes	yes	not sure
Robert Nolan	7892 Highway 9 Building B, Wetumka, OK 74883	(405) 379-2203 Busy signal	pnutfarm@netscape.net	Hughes County	20-May-08							
Gene Linton	231 S Townsend, Ada, OK 74820	(580) 436-8015 Left a message	pontotocem@adaok.com	Pontotoc County	20-May-08							
Aaron Blue	9 North Jerome St, Coalgate, OK 74538	(580) 927-0107	burns308@yahoo.com	Coal County	20-May-08	Quarterly	State grants $2K-$4K annually, no actual budget	1-Apr-11	no, will be up by the end of the year	yes	yes	no
Mike Aidaire	P.O. Box 1243, Atoka, OK 74525	(580) 889-4038 Left a message	eddycooke@totalnet.us	Atoka County	20-May-08							
James Dalton	224 W Evergreen Ste 100, Durant, OK 74701	(580) 924-3661	jdalton@durant.org	Bryan County, OK	20-May-08. The next training is July 23 2011, updating now	Monthly	No	1-Apr-11	no	yes	yes	no
Pat Collins* just started July 1	403 E Highland, Hugo, OK 74743	(580) 326-2000	athelta@aol.com	Choctaw County	20-May-03* being updated now	No	No, but applying for grants	July 2010	No	No	Yes	Yes
Darrel Brewer	210 S Main, Bonham, TX 75418	(903) 640-8484	fcmcem@cableone.net	Fannin County	17-May-08	Annually	No	1-Sep-10	no	yes	yes	no
Heath Thomas Heath just started June 1, 2011	125 Brown Ave, Paris, TX 75460	(903) 739-0824	countyjudge_lamar_tx@yahoo.com	Lamar County	17-May-08	not active, as needed	No	1-Sep-10	no	no	yes	not yet, but being constructed now
Joe Matilla	200 W Bonham St, Cooper, TX 75432	(903) 243-1247	N/A	Delta County	20-May-08	Twice a year	Grant driven	1-Apr-11	no	yes	yes	yes
Carl Nix	P.O. Box 288, Sulphur Springs, TX 75483	(903) 439-6217 Left a message	fireadmin@hopkinscountytx.org	Hopkins County	17-May-08							
Gary Allen	P.O. Box 718, Mt. Vernon, TX 75457	(903) 537-2342 Left a message	fcdm@mt-vernon.com	Franklin County	17-May-08	Quarterly	No	June 2011	No	Yes	Yes	No
Randy Sellman	261 Drifting Cloud, Holly Lake, TX 75755	(903) 569-7327 (cell)	mclanton@co.wood.tx.us	Wood County	17-May-08	Annually	No	4-May-11	no, but a hazard plan available on line, but not full EMP.	yes	yes	no
Gary Roberts	P.O. Box 790, Gilmer, TX 75644	(903) 843-2541 Left a message	dean.fowler@countyofupshur.com	Upshur County	17-May-08							
Jim Seaton	11325 Spur 248, Tyler, TX 75707	(903) 590-2653	jseaton@smith-county.com	Smith County	2-Apr-10	No	No	9-Jun-10	no	yes	yes	no
Patty Sullivan	115 N Main # 500-A,	(903) 657-0326	patricia.sullivan@co.rusk.tx.us	Rusk County	17-May-08	Quarterly	No	March 2011	No	No	No	No

TABLE 3.13.5-9
LEPC Telephone Survey[a]

Contact Person	Address	Phone/Fax	E-Mail	Counties/ Cities included in the Emergency Plan	Date Emergency Plan was Last Updated	LEPC Meetings (no; or mthly, qrtly, twice yr, yearly, other)	LEPC Funded[b] (no/yes; $ amt)	Date of Last Emergency Exercise	Emergency Plan Website Link[c]	Emergency Plan Addresses Pipelines (yes/no)	Emergency Plan Addresses Railroads/ Trucks (yes/no)	Emergency Plan Addresses Low-income/ Minorities (yes/no)
	Henderson, TX 75652	Left a message										
Sidney Riley	135 S Main, Rusk, TX 75785	(903) 683-5947 Busy signal	emc@cocherokee.org	Cherokee County	9-Mar-10	Quarterly	No	May 4, 2011	No	Yes	Yes	No
Joe English	101 W Main # 130, Nacogdoches, TX 75961	(409) 560-7793 Wrong number	jenglish@co.nacogdoches.tx.us	Nacogdoches County	17-May-08							
Ricky Connor	P.O. Box 908, Lufkin, TX 75901	(936) 671-4054 Left a message	acem@lcc.net	Angelina County	17-May-08							
Judge Page	P.O. Box 457, Groveton, TX 75845	(936) 642-1746	tcjudge@consolidated.net	Trinity County	17-May-08	working on schedule, new judge	Not sure	Jul-11	www.co.trinity.tx.us	yes	yes	no
Kenneth Hambrick	602 E Church # 400, Livingston, TX 77351	(936) 327-6810 Left a message	emcpolk@livingston.net	Polk County	17-May-08							
Fritz Faulkner	1 State Highway 150 # 5, Cold Spring, TX 77331	(936) 653-4367 Wrong number	fritz.faulkner@co.san-jacinto.tx.us	San Jacinto County	17-May-08							
Debbie Scott	2103 Cos St, Liberty, TX 77575	(936) 334-3219	ken.defoor@co.liberty.tx.us	Liberty County	17-May-08	Quarterly (but not recently)	No	1-Jun-11	no	yes	yes	no
Dennis Gifford	300 Monroe St, Kountze, TX 77625	(409) 755-6031 Left a message	dgifford@lumbertonfirerescue.org	Hardin County	17-May-08		All volunteer					
Greg Fountain	7933 Viterbo Rd Ste 6, Beaumont, TX 77705	(409) 835-8757	corey.cricchio@christushealth.org	Jefferson County	17-May-08	Bi-monthly	Funded by industry, member-ship based so budget fluctuates	1-May-11		yes	yes	no
Lori Ordwin	2520 South Highway 87, Orange, TX 77630	(409) 883-2612 Left a message	nellaij@cpchem.com	Orange County	17-May-08							
Ryan Holzaepfel	P.O. Box 957, Anahuac, TX 77514	(409) 267-2445	rholzaepfel@co.chambers.tx.us	Chambers County	17-May-08	Monthly	No	November, 2009	no	yes	yes	yes
Larry Mousseau	P.O. Box 1847, Channelview, TX 77530	(713) 881-3100	jcchief@pdq.net	Harris County/ Channelview	17-May-08	Daily	Yes, but no idea how much money	July, 2011	hcoem.org	yes	yes	yes[d]
Larry Mousseau	P.O. Box 10817, Houston, TX 77262	(713) 884-3786	nicholas.guillen@cityofhouston.net	Harris County/ City of Houston	17-May-08	Larry handles all of Harris Co, Houston and Channelview						yes[d]

[a] Note: this telephone survey occurred in June and July, 2011. At least four attempts were made to connect with the listed contact persons during this time period.
[b] Note: most grant funding reported in this table is for training purposes only, not for salaries.
[c] Note: some LEPC contact personnel reported that the department of Homeland Security recommends against posting their emergency management plan on a public website.
[d] Specific transportation evacuation options are provided for low income residents who do not have access to transportation. An entire section of government (Harris Co Homeland Security) deals with this.

Mitigation and Liability

Mitigation

Federal, state, and local agencies would participate in response activities and soil, surface water, and groundwater cleanup consistent with their authorities and duties under applicable regulations and consistent with the requirements of the ERP. A list of applicable regulations relative to remediation of crude oil spill contamination at the federal and state level is provided in Table 3.13.5-10. 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 NRDA under either OPA 90 or the Comprehensive Environmental Restoration Compensation and Liability Act (CERCLA), depending on the types of materials spilled, to assess the magnitude of the impacts and the type/amount of suitable restoration actions to offset the loss of natural resource services resulting from the spill.

TABLE 3.13.5.10
Potentially Applicable Federal and State Soil, Surface Water, and Groundwater Cleanup Regulations

Statute/Regulation	Description
Resource Conservation and Recovery Act, 42 U.S.C. § 6973.	EPA 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 RCRA, 42 USC 6973(a), authorizes EPA "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 EPA to require action even if the spill "may present an imminent and substantial endangerment."
Safe Drinking Water Act, 42 U.S.C. §§ 300f, et seq.	EPA 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 EPA deems necessary to protect health. 42 U.S.C. § 300i (a). Civil penalties are available for failure to comply with such an order. Section 1431(a) of SDWA, 42 USC 300i(a), authorizes EPA "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.

TABLE 3.13.5.10 **Potentially Applicable Federal and State Soil, Surface Water, and Groundwater Cleanup Regulations**	
Statute/Regulation	**Description**
Pipeline Safety Act, 49 U.S.C. §§ 60101, et. seq.	PSA 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). <u>Penalties</u> Violations of PHMSA requirements are subject to civil judicial enforcement actions, with varying penalty amounts depending on the nature of the violation (generally, $100,000 for each violation, with a maximum of $1,000,000 for a related series of violations). <u>Written Procedures</u> Regulations require that a pipeline operator prepare and implement a manual for operations, maintenance and emergencies. 49 C.F.R. § 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 C.F.R. § 195.402(e). <u>Notification</u> Regulations require that a pipeline operator make an accident 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 C.F.R. §§ 195.50-195.54.
Comprehensive Environmental Response, Compensation and Liability Act, 42 U.S.C. §§ 9601, et. seq.	Similar to the Oil Pollution Act, 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, as well as contribution rights. Also provides EPA 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: MCA 75-10-705 et seq., Montana's "Comprehensive Environmental Cleanup and Responsibility Act" ("CECRA" - 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 MFSA. Keystone XL falls under MFSA. The regulations that relate to the statutes and may apply are: ARM 17.55.101 et seq. dealing with CECRA ARM 17.53.101 et seq. dealing with hazardous waste ARM 17.30.101 et seq. dealing with water quality

TABLE 3.13.5.10 Potentially Applicable Federal and State Soil, Surface Water, and Groundwater Cleanup Regulations	
Statute/Regulation	**Description**
	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.
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 will be held responsible for a pipeline leak that occurs as a result of his/her normal farming practices over the top of or near the pipeline." 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 wilful misconduct of the landowner or its agents." Second, statutes contained in 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. Clean up 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 (NAC) Title 126, Chapter 18, provide for liability in the event a pipeline spills oil or a hazardous substance in

TABLE 3.13.5.10 Potentially Applicable Federal and State Soil, Surface Water, and Groundwater Cleanup Regulations	
Statute/Regulation	**Description**
	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. NAC Title 126, Chapter 18-038. 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.
Oklahoma	For releases on Oklahoma jurisdictional lands, the Oklahoma Corporation Commission (OCC) is the regulatory agency that has jurisdiction over pollution resulting from pipeline releases. Under OCC's rules (OAC 165:10-7-5), releases to soil, surface waters or groundwater must be reported to the OCC [OAC 165:10-7-5(c)(1)(A)]. These rules also require remediation/cleanup and provide a framework for enforcement albeit the potential penalties levied are typically nominal sums. [OAC 165:10-7-5(c)(1)(B) and OAC 165:10-7-5(c)(2)]. Supplementing the regulatory requirements noted above are common law based landowner/water user rights. These actions are commonplace and are filed by those individuals whose property or health is impacted by the release. These actions are based on theories including but not limited to nuisance, trespass and negligence. Remedies for these claims can include orders to abate the nuisance along with monetary damages awarded by the court. Releases occurring on or threatening Indian tribal land (trust land or otherwise), presents a more complex analysis. Oklahoma has numerous recognized Indian tribes with lands (trust or otherwise) held throughout the state. Federal laws typically apply to these releases, including but not limited to the CWA and OPA and possibly RCRA. In addition, several Indian tribes have passed their own environmental statutes that can address these releases therefore a detailed analysis depends on the exact location of the release and identification of the tribes involved.
Texas	Crude oil spills on land and in groundwater in Texas are regulated by the Texas Railroad Commission. The pertinent regulations are as follows: Spills that contaminate groundwater: Pollution of groundwater is prohibited by Rule 3.8 of the Texas Administrative Code. Rule 3.8 imposes reporting

TABLE 3.13.5.10 Potentially Applicable Federal and State Soil, Surface Water, and Groundwater Cleanup Regulations	
Statute/Regulation	**Description**
	requirements and immediate corrective action when pollution occurs. The Rule makes an operator responsible for immediately removing oil or other pollution materials from the water where it is found, and imposes liability for the cleanup expense on the operator. Additionally, Rule 3.8 subjects violators to the penalties and remedies specified in the Texas Natural Resources Code, Title 3, which include penalties of up to $10,000 per day for each violation, and any other statutes administered by the Commission. Spills that contaminate soil: Rule 3.91 of the Texas Administrative Code establishes guidelines for the cleanup of soil contaminated by a crude oil spill. Under these guidelines, operators must remediate the soil to a final cleanup level of 1.0% by weight total petroleum hydrocarbons, and must comply with notification and reporting requirements regarding the scope of the spill and the progress of the cleanup. In addition to these standard guidelines, Rule 3.91 specifies that cleanup requirements for crude oil spills in sensitive areas will be determined on a case-by-case basis. "Sensitive areas" are defined by the presence of factors, whether one or more, that make an area vulnerable to pollution from crude oil spills. The Railroad Commission is authorized to assess civil penalties for violations that pertain to the prevention or control of pollution, including penalties of up to $10,000 a day for each violation. Additional reporting requirements: Texas law requires pipeline owners who observe or detect any petroleum-based contamination of soil or water in proximity to the pipeline to report the contamination to the Railroad Commission and the owner of the land on which the pipeline is located no later than 24 hours after observing or detecting the contamination. Texas Natural Resource Code § 81.056.

Liability

Many commenters requested information regarding what Keystone's liability would be in the event of an accidental release of crude oil from the Project. 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 any discharge of oil (or threat of discharge) to the 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" (OPA 90). In Rice v. Harken Exploration Co. (2001) the Fifth Circuit confirmed a lower court ruling that groundwater is not within the scope of the OPA unless a direct connection to surface waters can be affirmed. Otherwise it is likely that any spill with the potential to contaminate surface waters of the United States would fall within the purview of OPA 90.

Therefore, 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 as well as other compensations, up to a maximum of $350,000,000. However this statutory liability limit does not apply where the incident was proximately caused by (1) gross negligence or willful misconduct of, 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 CWA, Keystone would be liable for up to $50,000,000 for United States 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. The limit does not apply if the discharge resulted from Keystone's willful negligence or willful misconduct. Keystone would also be liable for 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. There are no limits to these liabilities. Keystone would also be subject to the civil and criminal penalty provisions of the CWA. 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 clean-up 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.

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. DOS has no regulatory authority to intervene in the negotiation of those agreements. In addition, consideration of liability is beyond the scope of NEPA environmental reviews and is therefore not addressed in this EIS.

In addition to the various provisions described above, Keystone has agreed that it would be responsible for providing appropriate alternative water supply, and for clean-up and restoration in the event of a release of crude oil into groundwater.

3.13.5.6 Types of Oil Spill Impacts

This section summarizes the types and magnitudes of physical, chemical and biological impacts that may occur to a variety of resources and activities due to spills that occur during either construction or operation of the proposed Project. However, due to the potentially greater magnitude of spill size from an accidental release from the pipeline during operation, this section focuses primarily on crude oil spills from the pipeline. The descriptions are necessarily somewhat general because of the large number of independent spill-related variables listed below, most of which have a wide range of values in magnitude, duration, and range of effects depending upon the exposed resource, and many of which are unpredictable in spatial and temporal distribution as well as frequency of occurrence. In addition, there is a wide range of values and variability of values for those variables, for the numerous human and natural resources encountered along the proposed pipeline route.

Physical Impacts

Physical impacts of spills of crude oil or petroleum products to natural resources and human uses typically result from physical coating of soils, sediments, plants, animals, or areas used by people. Physical impacts include, but are not limited to:

- Smothering living organisms so they cannot feed or obtain oxygen;
- Coating feathers or fur, which reduces their insulating efficiency and results in hypothermia;
- Adding weight to the organism 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; and
- Coating beaches, water surfaces, wetlands, and other resources used by people which may result in offensive odors, visual impacts, as well as soiled livestock, crops, clothes, recreational equipment, pets, and hands/feet.

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 into the substratum where it may remain for extended periods of time and may be slowly released to the environment to re-oil downstream habitats and resources. In some cases, the buried oil would be in an anoxic environment and would resist weathering by physical or biological processes. Upon release to the environment, this "unweathered" oil may result in additional but delayed impacts.

Potential for Explosion and Fire

Several commenters on the draft EIS expressed concern about the potential for explosion and fire associated with the operation of the proposed Project. Crude oil releases are very unlikely to result in an explosion because crude oil contains a relatively small proportion of volatile hydrocarbons and most spills do not occur in confined spaces which allow the buildup of vapors to potentially explosive levels. Almost all "petroleum or hydrocarbon pipeline explosions" occur in pipelines that are transporting highly flammable, highly volatile hydrocarbons such as natural gas, LPG, propane, LNG, gasoline, naphtha, and similar products. The released material from these product and natural gas pipelines could rapidly form a flammable vapor cloud that could explode if exposed to an ignition source in a confined area at an explosive concentration. A release of diesel, gas condensate, kerosene, or similar refined liquid hydrocarbon will ignite and burn rapidly and seem to "explode" if the vapors are exposed to a fire or similar high temperature heat source, usually a fire caused by some other accident.

The PHMSA database for significant onshore hazardous liquid incidents (PHMSA 2010) indicates that only 6 of 2,706 (0.2 percent) reported incidents were attributed to "fire/explosion as a primary cause." Those 6 incidents were related to the release of flammable hydrocarbons, such as gasoline or liquid propane, and did not involve releases of crude oil.

The pump stations for the proposed Project would be powered by electricity. As a result, there would not be natural gas or other flammable fuel at the facilities that could ignite explosively. A crude oil spill at a pump station would likely result in the emission of some hydrocarbon vapors, but the vapors would not be emitted into confined spaces and therefore an explosion would be unlikely.

Other commenters have expressed concern that diluents would flash volatilize from the homogenous mixture dilbits in the event of a pressurized pipeline breach and subsequent crude oil release leading to a severe fire and explosion risk. As discussed previously in this section, dilbits would not experience flash volatilization in the event of a pipeline rupture. Additional concerns related to a hypothetical flash volatilization event included the potential release of hydrogen sulfide. Not only is flash volatilization from crude oil that would be transported by the proposed Project physically not possible, the hydrogen sulfide concentration of crude oils that could be transported on the proposed Project is very low and in the very unlikely event of a fire from any cause, any small concentration of hydrogen sulfide released would combust with oxygen to produce sulfur dioxide and water.

Chemical and Toxicological Impacts

Toxicological impacts are a function of the chemical composition of the oil, the solubility of each class of compounds, and the sensitivity of the receptor. The primary classes of compounds found in crude oil are alkanes (hydrocarbon chains), cycloalkanes (hydrocarbons containing saturated carbon rings), and aromatics (hydrocarbons with unsaturated carbon rings). 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., cyclyohexane); aromatics (e.g., benzene, toluene); cycloalkanes; and heavy aromatic hydrocarbons (e.g., 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, xylenes compounds) pose the most potential for toxic impacts because of their lower molecular weight making them more soluble in water than alkanes and cycloalkanes.

Toxicological impacts are the result of chemical and biochemical actions of petrogenic compounds on biological processes of individual organisms (e.g., 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; narcosis; reduced resistance to disease; tumors; reduction or loss of various sensory perceptions; interference with metabolic, biochemical, and genetic processes; and a host of other acute or chronic effects. A description of toxicological effects of petroleum to both human and natural environment receptors is presented in Appendix P.

For most construction spills, the volume and areal extent of the oil spill would be limited and generally confined to the construction ROW, construction yards, and roadways. Livestock would typically be restricted from these areas until construction activities are completed. Wild animals, especially birds and mammals, also would tend to avoid these areas during construction. If a spill does occur and impacts a substantive amount of habitat, the response personnel would encourage and assist farmers and ranchers to move livestock if necessary.

Oil spills are not likely to have toxic effects on the general public because of the numerous restrictions that local, state and federal agencies would impose to restrict environmental exposure. A 2003 report to EPA prepared by the American Petroleum Institute (API) compared the health effects of synthetic crude oil 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 (>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 an essentially 'bottomless' crude, consisting of blends of hydrotreated naphthas, diesel and gas oil without residual heavier oils . . . This information was supplied to EPA . . . 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."

However, it should be noted that based on current production projections and the market demand at Gulf Coast refineries, the majority of crude oil that would likely be transported by the proposed Project would be dilbit crude oils (EnSys 2010).

Fumes from spilled oil could lead to human health effects depending on the intensity and duration of exposure. The reported range of hydrogen sulfide or mercaptan sulfur in WCSB crude oils typical of those that would be transported on the proposed Project is from 20 to 100 ppm (Table 3.13.5-7). In the event of an oil release, the potential human exposure risk would relate to the inhalation of any hydrogen sulfide emitted into the air column in the vicinity of the oil spill. The hydrogen sulfide volatilized into the air column would be at concentrations much lower than the concentration in the crude oil. Olfactory perception of hydrogen sulfide occurs for most people at concentrations in the air of approximately 0.2 ppm. Human health effects of exposure to hydrogen sulfide, an irritant and an asphyxiant, depend on the concentration of the gas and the length of exposure. Background ambient levels of hydrogen sulfide 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). A rotten egg odor characterizes hydrogen sulfide at low concentrations, and some people can 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. However, since 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 4 minutes, hydrogen sulfide exposures would not be expected to create substantive health hazards. The rapid atmospheric dissipation of hydrogen sulfide levels indicated by these model results also suggests that risks to the general public would be very small to negligible in the event of an oil spill. 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 would not be a likely by-product in the unlikely event of an explosion or fire involving the proposed Project because hydrogen sulfide itself is highly flammable and any hydrogen sulfide involved in an explosion or fire would rapidly combine with oxygen to form sulfur dioxide and water.

Oil spilled into surface or groundwater supplies that serve as human drinking water sources would be detected and monitored 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 and the Incident Commander consider unsafe for human exposure. Private landowners could choose to undertake activities that would increase exposure at their own risk.

Birds typically are the most affected wildlife if exposed to the chemical and toxicological effects of an oil spill, whether it is on land or on water (e.g., 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 hepatic, 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.

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 impacts would be lower in larger rivers and lakes and much lower under flood conditions since the toxic hydrocarbon concentrations would likely be relatively rapidly diluted.

The concentration of crude oil constituents in a spill would vary both temporally and spatially in surface water; however, localized toxicity could occur from virtually any size of crude oil spill. Acute toxicity values of various crude oil hydrocarbons to a broad range of freshwater species are presented in Table 3.13.5-11. Acute toxicity refers to the death or complete immobility of an organism within a short period of exposure. The LC50 is the concentration of a compound necessary to cause 50 percent mortality in laboratory test organisms. For aquatic biota, most acute LC50 for monoaromatics range between 10 and

100 ppm. LC50 for polyaromatic naphthalene was generally between 1 and 10 ppm, while LC50 values for anthracene were generally less than 1 ppm.

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 then its toxicity to aquatic biota is relatively low. The toxicity of crude oil is dependent on the toxicity of its constituents. As an example, Table 3.13.5-12 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. The relative toxicity of decane is much lower than for benzene or ethylbenzene because of the comparatively low solubility of decane. 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).

While lightweight aromatics such as benzene tend to be water soluble and relatively toxic, they are also 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 render them substantively 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).

Significantly, some constituents in crude oil may have greater environmental persistence than lightweight compounds (e.g., benzene), but their limited bioavailability renders them substantively less toxic than other more soluble compounds. For example, aromatics with four or more rings are not acutely toxic at their limits of solubility (Muller 1987). Based on the combination of toxicity, solubility, and bioavailability, benzene was determined to dominate toxicity associated with potential crude oil spills.

Chronic toxicity values (most frequently measured as reduced reproduction, growth, or weight) of benzene to freshwater biota are summarized in Table 3.13.5-13. Chronic toxicity from other oil constituents may occur, however, if sufficient quantities of crude oil are continually released into the water to maintain elevated concentrations. However, that condition would not result from an accidental release from the proposed Project since the release would be a one-time occurrence and would not be continuous, and the release would be followed by the required response and repair activities.

TABLE 3.13.5-11
Acute Toxicity of Aromatic Hydrocarbons to Freshwater Organisms

Species	Toxicity Values (ppm)				
	Benzene	**Toluene**	**Xylenes**	**Naphthalene**	**Anthracene**
Carp (*Cyprinus carpio*)	40.4	---	780	---	---
Channel catfish (*Kctalurus*)	--[a]	240	---	---	---
Clarias catfish (*Clarias* sp.)	425	26	---	---	---
Coho salmon (*Oncorhyncus kisutch*)	100	---	---	2.6	---
Fathead minnow *(Pimephales*)	---	36	25	4.9	25
Goldfish (*Carassius auratus*)	34.4	23	24	---	---
Guppy (*Poecilia reticulate*)	56.8	41	---	---	---
Largemouth bass (*Micropterus*)	--	--	--	0.59	---
Medaka (*Oryzias* sp.)	82.3	54	---	---	---
Mosquito fish (*Gambusia affinis*)	---	1,200	---	150	---
Rainbow trout (*Oncorhyncus mykis)*	7.4	8.9	8.2	3.4	---
Zebra fish (*Therapon iarbua*)	--	25	20	--	---
Rotifer *(Brachionus calyciflorus)*	>1,000	110	250	---	---
Midge *(Chironomus attenuatus)*	--	--	--	15	--
Midge *(Chironomus tentans)*	--	--	--	2.8	--
Zooplankton *(Daphnia magna)*	30	41	---	6.3	0.43
Zooplankton *(Daphnia pulex)*	111	---	---	9.2	---
Zooplankton *(Diaptomus forbesi)*	---	450	100	68	---
Amphipod *(Gammarus lacustris)*	--	--	0.35	--	---
Amphipod *(Gammarus minus)*	--	--	--	3.9	--
Snail *(Physa gyrina)*	--	--	--	5.0	--
Insect *(Somatochloa cingulata)*	--	--	--	1.0	---
Chlorella vulgaris	---	230	---	25	---
Microcystis aeruginosa	--	--	--	0.85	---
Nitzschia palea	--	--	--	2.8	---
Scenedesmus subspicatus	---	130	---	---	---
Selenastrum capricornutum	70	25	72	7.5	---

[a] -- Indicates no value was available in the database; ppm = parts per million.

Note: 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 LC_{50} values was calculated.

TABLE 3.13.5-12 Acute Toxicity of Crude Oil Hydrocarbons to *Daphnia magna*			
Compound	**48-hr LC_{50} (ppm)[a]**	**Optimum Solubility (ppm)**	**Relative Toxicity[b]**
Hexane	3.9	9.5	2.4
Octane	0.37	0.66	1.8
Decane	0.028	0.052	1.9
Cyclohexane	3.8	55	14.5
methyl cyclohexane	1.5	14	9.3
Benzene	9.2	1,800	195.6
Toluene	11.5	515	44.8
Ethylbenzene	2.1	152	72.4
p-xylene	8.5	185	21.8
m-xylene	9.6	162	16.9
o-xylene	3.2	175	54.7
1,2,4-trimethylbenzene	3.6	57	15.8
1,3,5-trimethylbenzene	6	97	16.2
Cumene	0.6	50	83.3
1,2,4,5-tetramethylbenzene	0.47	3.5	7.4
1-methylnaphthalene	1.4	28	20.0
2-methylnaphthalene	1.8	32	17.8
Biphenyl	3.1	21	6.8
Phenanthrene	1.2	6.6	5.5
Anthracene	3	5.9	2.0
9-methylanthracene	0.44	0.88	2.0
Pyrene	1.8	2.8	1.6

[a] The LC_{50} 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 2000).
[b] Relative toxicity = optimum solubility/LC_{50}
ppm = parts per million.
Source: USEPA 2000.

TABLE 3.13.5-13 Chronic Toxicity of Benzene to Freshwater Biota		
Taxa	**Test Species**	**Chronic Value (ppm)**
Fish	Fathead minnow (*Pimephales promelas*)	17.2 *
	Guppy (*Poecilia reticulata*)	63
	Coho salmon (*Oncorhynchus kitsutch*)	1.4
Amphibian	Leopard frog (*Rana pipens*)	3.7
Invertebrate	Zooplankton (*Daphnia* spp.)	>98
Algae	Green algae (*Selenastrum capricornutum*)	4.8 *

Note: Test endpoint was mortality unless denoted with an asterisk (*). The test endpoint for these studies was growth.

Biological (Ecological) Impacts

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, loss of a small fraction of a population of organisms would result in a minimal impact at a community to 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 (e.g., 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.

Assessment of Impact Magnitude

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). The crude oil that would be transported by the proposed Project would primarily consist of diluted bitumen (dilbit) and syncrude. Information on the chemical characteristics of these crude oils is provided in Section 3.13.5.1. Variations in spill size and receptor type are key variables for estimating the magnitude of environmental impacts of oil spills from the proposed Project. Spill volume categories used in this impact assessment are presented in Section 3.13.2.1. Receptor sensitivity is subjective and is influenced by the perspectives and biases of evaluators and 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. The relative sensitivities of receptors are presented in Table 3.13.5-11, based on historical spill sensitivity assessments and input from a typical range of stakeholders.

The magnitude of environmental impacts generally increases within a receptor type as spill size increases (i.e., from left to right in Table 3.13.5-11). Within a spill size, the magnitude of impact increases with increasing sensitivity of the receptors (i.e., from top to bottom in the table). Combining size and sensitivity, the magnitude of impacts generally increases from top left to bottom right in the table. In many oil spills, there are clear 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. Table 3.13.5-11 reflects a ranking of these values, recognizing that the concept of “impact assessment and magnitude” is anthropogenic and not a component of ecosystem function.

For this EIS, five levels of environmental impact were considered and entered into the table to indicate the generally expected magnitude of impacts from oil spills. The magnitude of impact may vary from these general trends depending on a number of site-specific variables described previously.

TABLE 3.13.5-11
Typical Ranges of Potential Crude Oil Spill Environmental Impacts[a,b]

Type of Receptor[c]	Very Small (<210 gal [5 bbl])	Small (210 – 2,100 gal [5-49.9 bbl])	Substantive (2,100 – 21,000 gal [50-499.9 bbl])	Large (21,000 – 210,000 gal [500-5,000 bbl])	Very Large (>210,000 gal [5,000 bbl])
Terrestrial–agricultural land	Negligible	Negligible to minor	Minor to substantive	Minor to substantive	Substantive
Terrestrial–natural habitat	Negligible	Minor	Minor to substantive	Substantive	Substantive
Groundwater	Negligible	Negligible	Negligible to minor	Minor to substantive	Substantive
Aquatic–wetlands	Negligible	Minor	Minor to substantive	Substantive	Major to catastrophic
Aquatic–lakes and ponds	Negligible	Negligible to minor	Minor to substantive	Substantive	Major
Aquatic–streams and small rivers	Negligible	Negligible to minor	Substantive	Major	Major to catastrophic
Aquatic–large rivers	Negligible	Negligible	Minor	Substantive to major	Major to catastrophic
Threatened and endangered species and habitat	Negligible to minor	Minor to substantive	Substantive	Substantive to major	Major to catastrophic
Human use–commercial	Negligible	Negligible to minor	Minor	Minor to substantive	Substantive to major
Human use–residential	Negligible	Negligible to minor	Minor	Minor to substantive	Substantive to major
Human use–recreational	Negligible	Negligible to minor	Minor to substantive	Substantive to major	Major to catastrophic

[a] Magnitude of impact is defined as follows:

[b] Spill size categories are described in Section 3.13.2.1.

[c] Receptor sensitivity subjective and based on experience from previous oil spill responses and analyses.

Negligible Impact – Little to no detectable impact on most resources; may be some visible presence of oil on land, vegetation, or water. Zero to few organisms apparently killed or injured. Impacts are temporary (measured in days) and spatial distribution localized to spill site. There are no detectable effects on HCAs including USAs.

Minor Impact – Measurable presence of oil and limited impacts on local habitats and organisms. Impacts are temporary (measured in days to weeks) and local (measured in acres). Some organisms, likely birds, fish, and aquatic macroinvertebrates, may be killed or injured in the immediate area. There may be limited effects on HCAs including USAs.

Substantive Impact – Patchy to continuous presence of oil on terrestrial and aquatic habitats near the spill site. Impacts may be present for weeks to a few months and affect tens of acres or a few miles of stream/river habitat. There may be impacts to the local biological community and population-level effects on organisms and human uses of the area. There may be detectable effects on HCAs including USAs.

Major Impact – Patchy to continuous and heavy presence of oil on terrestrial and aquatic habitats near the spill site and for substantive distances down gradient from the spill site. Impacts may be present for weeks to months and potentially for a year or more. The impacted area may include many acres to sections of land or wetlands, and several miles of riverine habitat. There may be effects on the local biological community and population-level impacts on organisms and habitats, as well as disruption of human uses in local oiled areas. There may be substantive effects on HCAs including USAs.

Catastrophic Impact – Mostly continuous or nearly continuous presence of oil on all habitats near and/or for substantive distances down gradient of the spill site. Impacts may be present for months to years. The impacted area may include many acres to sections of land or wetlands, and several to numerous miles of river or other aquatic habitat. There may be both local and regional disruption of human uses. There may be both local and regional impacts to biological populations and communities. There may be significant to catastrophic effects on HCAs including USAs.

3.13.6 Resource-Specific Impacts

This section addresses potential impacts related to the resources described in Sections 3.1 through 3.12 that may result from very small spills to very large spills. Additional or corroborative information on the potential impacts of oil spills is presented in Appendix P.

3.13.6.1 Geology

Potential impacts from oil spills would not involve geological features that have received state or federal protection, nor would they involve any geological features of known tribal significance along the proposed route, although concerns related to paleontological resources have been identified. Potential impacts to geologic resources due to a spill from either construction or operation of the proposed Project are addressed in the following sections.

Paleontological Resources

Most spills would be confined to a construction yard, access roadway, or pipeline ROW, or to an adjacent area. The primary exceptions would be large to very large spills from pipelines that affect areas beyond the ROW. Paleontological resources exposed to a spill could be affected. Cleanup activities could also damage paleontological resources. However, a Paleontological Mitigation Plan would be developed in South Dakota and a Memorandum of Understanding (MOU) in Montana to protect significant fossil resources that may be encountered during construction or damaged as the result of an oil spill. Locations with the potential for significant paleontological fossils occur infrequently in limited areas along the proposed route.

Mineral and Fossil Fuel Resources

For surface and near-surface resources such as sand, gravel, clay and stone, small to substantive spills may result in localized reduction in resource availability and value depending on actions involved in the incident response and subsequent remedial activities. For large and very large spills, the impacts may be proportionally greater. However, the distribution of these mineral resources and their relatively undeveloped state along the ROW indicate that the overall potential for impacts to the resources and their associated industries would be small.

The proposed route would cross deposits of sand, gravel, clay, and stone, but the acreage of deposits covered by the proposed ROW is insignificant compared to the total acreage of deposits present in each state. The proposed route would not cross any currently active aggregate mining operations. Thus, impacts from spills in the vicinity of these resources would be negligible for small or even substantive spills that are rapidly contained. Even large spills would result in minor impact because of the wide spatial distribution of these resources and their current state of development.

The proposed Project route would not cross the well pads of any active or proposed oil or gas wells, although active oil and gas wells are located near the proposed ROW along some portions of the proposed route. Spills of any size would not likely result in more than minor impacts to these oil and gas resources due to the proposed pipeline’s location and the depth and containment afforded by the extraction equipment, operations, and sites.

3.13.6.2 Soils and Sediments

Soils

The impact of oil spills on soil is a function of several variables, including the type of material spilled. Once oil reaches the soil surface, the depth of penetration into the soil would depend on the porosity of the soil and the extent to which it is frozen or water saturated. The area affected would be limited to that area immediately adjacent to and covered by the spill. Porous soils (e.g., sand, gravel, and moraines) are more permeable than clays and silts. Karst areas, especially where the karst formations are close to the surface and the overlying soils are porous, may be especially vulnerable to impacts from a spill, if the oil reaches and moves through the karst. Most soils along the route have low to moderate permeability providing sufficient time to control and cleanup the oil prior to extensive movement through soils.

Spills could affect soils indirectly by affecting the vegetation, which in turn could die and expose the soil to water and wind erosion or solar heating, even if the soil itself was not directly affected by the spilled material. Spill cleanup is more likely to affect the soils than the presence of the spilled material itself, unless the cleanup is well controlled and heavy traffic and digging are minimized (especially for summer spills). Oil that adsorbs to or is retained between soil grains may weather only slowly over one to several years.

Soil productivity could be negatively impacted by oil contamination particularly in the event of large to very 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.

Sediments

Sediments (defined here as submerged soils in wetlands and aquatic habitats) are typically fine grained and saturated with water. They may be covered by or integrated with a substantive amount of organic material, primarily from riparian and aquatic vegetation. The sediment may be more coarse-grained in fast-flowing streams and rivers, and in areas where glacial moraines dominate the parent soil materials. 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 energy areas; (2) the interstitial spaces are large enough (e.g., in gravel and coarse sand) to allow for penetration 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 also typically would not penetrate sediments because of the water content but 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 can retain oil for extended periods of time, even in higher energy areas (Short et al. 2007).

3.13.6.3 Water Resources

Surface Water

Spills could affect surface freshwater 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. The volumes of most spills would likely be very small to small (see spill size categories in Section 3.13.2.1). In addition, for some portion of the winter months each year, in the northernmost portions of the route, 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.

Released oil that reaches a water body directly or indirectly would float in a lenticular layer on the water surface. In some cases, oil could be physically mixed into upper portions of the water column or incorporated into bottom sediments in high energy aquatic environments.

An oil spill that reaches a freshwater body could cause reduced dissolved oxygen (DO) concentrations and increased toxicity to aquatic organisms, particularly from dissolved phase hydrocarbons (e.g., BTEX). 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 high organic loading (e.g., small lakes, farm reservoirs, and stock ponds), increased biodegradation resulting from the addition of oil to the water column may further reduce oxygen levels.

In winter, however, a small spill would not likely contribute substantively to an oxygen deficit in most waters because biological abundance and activity are depressed and water column respiration rates at that time would be low to negligible. 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 MMS 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 would be 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 the first few 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 to months, 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.

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 volatilization of the aromatic fraction and biodegradation could lead to an oil residuum that would sink.

Groundwater

During construction and operation of the proposed Project, potential minor, short- to longer-term groundwater quality degradation is possible from equipment and vehicle spills or leaks. Substantive spills of refined products, especially diesel or gasoline, and substantive to very large spills of crude oil may reach groundwater where the overlying soils are porous and the upper boundary of the water table is relatively near the surface. Areas near major wetlands and meandering streams or rivers as well as the Sand Hills topographic region of Nebraska are key examples of locations where the water table may be close to the surface. In some of these areas, it may be difficult to distinguish between groundwater and surface water. A summary of locations where shallow aquifers are present and a description of the NHPAQ system in Nebraska are provided in Section 3.3.1.

Subsurface Crude Oil Migration and Groundwater Flow

The potential for crude oil or oil products migration into subsurface groundwater is determined by several factors. These factors include the areal 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. 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 can be mitigated by quick emergency response measures that include rapid source control (containment and collection of the oil released) (see Appendix C). An evaluation of these factors is presented below.

The crude oil that would primarily be transported by the proposed Project is classified as heavy crude oil. All heavy crude oils are more viscous than lighter crude oils. Most of the crude oil transported by the proposed Project would originate from bitumen, and would either be pre-processed into a heavy synthetic crude oil or pre-processed and blended with petroleum diluents (typically a light aromatic hydrocarbon) to produce an acceptable viscosity for pipeline transport (see Section 3.13.5). These types of crude oil would become more viscous when released into the environment as the lighter aromatic fraction volatilizes. Increasing viscosity tends to reduce vertical crude oil migration rates in soil profiles. Crude oil vertical migration would be further restricted by the cooling of the crude oil after its release (a decrease in temperature will increase the viscosity of oil), particularly in the cooler months of the year.

Heavy crude oils likely to be transported by the proposed Project are less dense than water and would form a lenticular layer that floats on surface waterbodies. If crude oil infiltrates into soil formations, it would tend to form a distended lens above and slightly below the water table when groundwater is encountered, largely based on the amount of the spill and the associated vertical hydraulic head pressure. The crude oil plume would then spread horizontally, in an ellipsoid in the down-gradient direction, until it reaches a steady state based on the crude oil head pressure, groundwater flow rate, and soil characteristics. Plume expansion can also be affected by the rate of water being pumped out of an aquifer.

Studies related to oil and oil products releases from over 600 underground storage tank leaks indicate that potential surface and groundwater impacts from these releases are typically limited to several hundred feet or less from the release site (API 1998). The median length of groundwater plumes comprised of these soluble components (BTEX) was 132 feet and approximately 75 percent of these plumes were under 200 feet (API 1998). 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 and gradient are not as significant in determining ultimate plume length (API, 1998). However, on a localized basis, it is acknowledged that water withdrawals through extensive pumping can influence the hydraulic gradient.

An example of a crude oil release from a pipeline system into an environment similar to the NHPAQ system and Sand Hills topographic region occurred on August 20, 1979 near Bemidji, Minnesota. 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 feet below ground surface. As of 1996 the leading edge of the oil remaining in the subsurface at the water table had moved approximately 131 feet down gradient from the spill site, and the leading edge of the dissolved contaminant plume had moved about 650 feet down gradient.

Estimates of the hydraulic conductivity (the rate that water moves through soil) of soils at the Bemidji site ranged from 1.59 feet per day (ft/d) to 99.23 ft/d. These hydraulic conductivity estimates were provided in an oral communication with a USGS scientist with extensive experience evaluating impacts from the Bemidji spill (Delin, pers. comm. 2011). The following specific hydraulic conductivity estimates were provided (converted from meters per second to ft/d):

- 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).

As described in Section 3.3, the High Plains Aquifer system (which includes the NHPAQ 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 also takes into account the porosity and the hydraulic gradient [slope of the water table]) in the High Plains Aquifer system is 1 ft/d and flows from west to east (Luckey et al. 1986).

Estimates of the hydraulic conductivity of the Sand Hills Unit of the NHPAQ system are variable, with a high end estimate of 50 ft/d (Gutentag et al. 1984) and a lower range estimate of 13 to 40 ft/d (Lappala 1978). Hydraulic conductivity values for surficial dune sands (8 inches in depth) in the Sand Hills Unit range from 16.4 to 23.0 ft/d (Wang et al. 2006). At intermediate depths within the root zone, hydraulic conductivity values range from 26.3 to 32.8 ft/d in lowland areas and from 32.8 to 49.2 ft/d in higher elevation areas. In the lower boundary of the root zone, at approximately 6.5 feet bgs, hydraulic conductivities ranged from 42.7 to 49.2 ft/d (Wang et al. 2006). These values were based on direct in-situ measurements by a constant head permeameter.

These referenced estimates for hydraulic conductivity in the NHPAQ system and the Sand Hills Unit are within the range of values estimated for the Bemidji spill site. Although the subsurface conditions in the Sand Hills Unit, the NHPAQ system, and at the Bemidji spill site are not identical, the soils exhibit similar hydraulic conductivities and flow characteristics. However, three dimensional transmissivity may differ. For instance, hydraulic conductivity in the Sand Hills topographic region near the top of a dune may be higher than in nearby lowlands or lakes. Other differences between the two sites likely include saturated thickness and potential influence of well pumping on hydraulic gradient. While the two sites are not completely analogous, the Bemidji site provides the best physical model for response to an oil release in the NHPAQ system and studies of the Bemidji site suggest that a spill of similar magnitude in the Sand Hills would remain localized and the dimensions of the liquid plume and associated dissolved plumes would be similar in extent to the plumes at the Bemidji site.

Other shallow groundwater resources along the proposed pipeline corridor may occur within soil profiles somewhat dissimilar from the Bemidji site (see Section 3.3). In many areas, shallow unconfined aquifers occur within alluvium in flood plains near streams and rivers. Shallow aquifers can also occur under confined conditions. Under confined conditions, the confining layer (e.g., silt or clay) would impede or prevent vertical migration of the crude oil into the aquifer. Unconfined alluvial soils are comprised of 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.

EPA expressed concern 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. Where surface expressions of deeper bedrock aquifers outcrop, they could also be at risk if they lie within an oil spill zone. Section 3.3 provides information on the locations of known recharge areas along the proposed Project corridor based on available information. Recharge areas are also addressed in comparisons between the I-90 Corridor Alternatives, the Keystone Corridor Alternatives, and the proposed Project in Section 4.3.3. It should also be noted that research by the USGS at the Bemidji site suggests that downward migration 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.

Response Time, Source Control, Cleanup and Remediation

Relative to reducing potential groundwater impacts, DOS recognizes the importance of rapid response leading to source control, containment, and cleanup in the event of an oil spill in shallow aquifer areas. The ability to respond in a timely and appropriate manner to an unanticipated oil release is of critical importance. In response to a DOS data request, Keystone presented its approach to spill response under two hypothetical spill scenarios defined by DOS. The two scenarios presented to Keystone and its response to these scenarios provide an opportunity to review the level of preparedness and foresight currently in place relative to potential spills in relatively shallow groundwater areas.

The first hypothetical spill occurs in the summer in an area with deeper groundwater, relatively flat terrain, at least 2 miles from any navigable stream, no wetlands within 1 mile, and with no nearby private water wells or public water intakes. The second hypothetical spill occurs in the winter in an area of relatively shallow groundwater (25 feet bgs), sloping terrain, nearby wetlands, and a navigable stream within 1,000 feet, including private water wells within 100 feet of the release site and a public water intake 2 miles downstream.

For each of these scenarios, Keystone described the following in detail:

- Response procedures including pipeline shutdown, commencement of field response, spill assessment, and development of incident command post;
- The potential horizontal and vertical spread of crude oil into the environment;
- Response tactics employed for source control;

- Cleanup approaches for spills on land including containment methods and removal methods;
- Cleanup approaches for spills to groundwater including options for short- and long-term remediation;
- Cleanup approaches for spills on calm or slow moving water (lake or pond) and to flowing water (stream or river);
- Cleanup approaches for spills that occur on ice or under ice; and
- Cleanup approaches for spills in wetland areas.

In the first scenario, a low likelihood of groundwater contamination was determined. For the second scenario, it was determined that emergency response teams would respond prior to the time the subsurface oil plume reaches groundwater. This would allow rapid cleanup of the surface plume to reduce the downward head pressure on the oil plume. However, groundwater would likely be impacted. Impacted groundwater would be remediated by short-term mechanical approaches (excavation and vacuum methods), medium-term chemical methods (chemical oxidation), biological methods (bioremediation), and long-term natural attenuation.

In most real-world spills, a combination of methods would be used to accomplish the highest degree of remediation practicable in the shortest amount of time. However, DOS acknowledges that in areas such as the Sand Hills region, where groundwater may be very shallow (less than 10 feet bgs), some level of groundwater impact would likely occur even with very rapid and efficient spill response. Although cleanup and remediation efforts would be more complicated and potentially of longer duration if groundwater were affected, the extent of aerial contamination would be limited primarily depending on the size of the release.

Wetlands

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). Any refined or crude oil release would tend to remain on the water surface, and would therefore affect oxygen exchange between water and air, potentially affecting the water column DO content. Toxic components of a refined product release may dissolve and disperse over the affected area. In the event of a heavy crude oil release, dense stands of emergent vegetation could act like oil booms and collect oil at the edges of the stands, particularly given the heavy crude oil viscosity. Aggressive and intrusive cleanup methods could mix oil with water and sediments (which are often anoxic below the surface layer) leading to longer lasting impacts. Passive cleanup methods (including natural attenuation) are likely to cause less impact on wetland resources. 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[7].

Spills of refined product (e.g., diesel or gasoline) would be more likely to occur during construction. The majority of these spills would be very small to 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

[7] Burning of oil and oiled emergent vegetation in wetlands with an overlying water layer has been used several times in Texas and Louisiana. The vegetation above the waterline along with the floating oil is burned but the submerged vegetation including the roots is generally unharmed. Regrowth occurs rapidly. This technique reduces the chances of oil exposure to birds and other wildlife, and reduces the physical impact of cleanup crews disrupting the marsh during manual removal methods.

remain on top of the ice. In either case, the spilled oil would likely be recovered before it directly affected wetland habitat and associated organisms. 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 volatile fraction may dissolve or disperse in water. 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 sorbent to 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. Substantive and 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 approach a catastrophic level in areas where the wetlands are heavily used by migratory waterfowl and the spill occurs during the spring or fall migration.

3.13.6.4 Biological Resources

Vegetation

Smaller spills during construction could occur within contractor yards, along access roads, at above-ground 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. However, substantive and large to very large spills during operation would likely result in greater impacts.

Along the Steele City Segment of the proposed pipeline, 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. On other pipeline segments and on the Steele City Segment 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.

The majority of spills would likely be very small to small (see Section 3.13.2.1 for spill volumes within spill categories) and would typically cover less than 1 acre, but large to very large spills could be extensive, with the areal extent partially dependent on topography and the density, rigidity, and structural complexity of grass/forb/shrub vegetation on the surface of the land. 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 a spill persists 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. Spills that occur within or near streams, rivers, and lakes could indirectly affect riparian vegetation and habitat along these waterbodies. Affects on vegetation from subsurface leaks that reach the root zones of surface vegetation could assist in leak detection as a result of visible patches of affected vegetation along the pipeline ROW resulting from oil interference with water and nutrient uptake by plant root systems.

A large to very large spill could spread over larger areas and coat vegetation, including row crops, wild lands, seasonal wetlands, and range lands, especially down slope from the spill site. The vegetation within the spill zone could be injured, killed or coated with oil, although population level vegetation effects are unlikely. Affected vegetation may not be suitable for grazing animals and any commercial row or field crops would not be marketable.

Birds

Very small or small spills on or near the roads, construction yards, pump stations, or MLV sites would not generally affect birds, although a few individual shorebirds, waterfowl, raptors and passerine birds could be exposed to the spilled oil. Exposed individuals could die from 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. Very small to small spills would not be expected to cause population-level impacts.

A substantive to very 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 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 Important Bird Area (IBA) supporting resident and migrant grassland nesting birds. Although not designated as an IBA 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 (Audubon 2010).

If raptors, eagles, owls, ravens, crows, magpies, vultures, and other predatory or scavenging birds are 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 die from drowning or hypothermia. Stress from ingested oil can 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 utilize them. In general, losses from substantive to very large spills would likely result in negligible to minor impacts to regional bird population levels but may result in significant impacts to local population levels.

Mammals

Most oil spills, including large to very large spills, would result in a limited impact on most of the terrestrial mammals utilizing the area affected by the spill. The extent of impacts would depend on the type and amount of oil spilled; the location and terrain of the spill; the type of habitat affected; mammal distribution, abundance, and behavior 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 to very large spill could affect terrestrial mammals directly or indirectly through impacts to their habitat, prey, or forage. For example, a large spill likely would affect vegetation, the principal food of the larger herbivorous mammals, both wild (e.g., ungulates) and domestic (e.g., cattle, sheep, and horses). Some to most 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 (e.g., bears, foxes, and raccoons) 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 for the predator or scavenger (White et al. 1995). Spill response activities would typically frighten most large mammals away from the spill, thus reducing the possibility of mammal ingestion of oiled vegetation. 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 substantively reduced.

For large spills that are not immediately or successfully cleaned up, the potential for contamination would persist for a longer time and the likelihood of animals being exposed to the weathered oil would be greater. Over time, any remaining oil would gradually degrade. Although oiling of animals would not likely remain a threat after cleanup efforts, some toxic products could remain in soil, aquatic sediments, or in or on plant tissues, potentially up to 5 years or longer. To the extent that residual oil leads to further contact or ingestion by mammals, effects to individual mammals would continue.

Small mammals and furbearers could be affected directly by spills due to oiling or indirectly through ingestion of contaminated forage or prey items. Furbearers, especially river otters, mink, muskrat, raccoons, and beavers that are dependent 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.

Fish and Other Aquatic Species

Spills within aquatic habitats could affect fish, macroinvertebrates (e.g., mussels, crustaceans, insects, and worms), algae and other aquatic plants, amphibians, and reptiles; many of which are prey for mammals and birds. Aquatic habitats include wetlands, ponds, lakes, reservoirs, drainage ditches, streams and rivers.

The effects of oil spills on freshwater fish, macroinvertebrates, and other aquatic organisms have been documented and discussed in reports of assessments of many previous spills (Poulton et al. 1997, Taylor and Stubblefield 1997, Vandermulen et al. 1992, API 1992a, 1992b, and 1997). Specific effects would depend on the concentration of spilled crude oil or oil product present, the length of exposure, and the stage of development (larvae and juveniles are generally most sensitive) of affected individuals. If lethal concentrations of spilled material are encountered (or sub-lethal concentrations over a long enough period), mortality of aquatic organisms would likely occur. However, extensive mortality from exposure to oil spills is typically observed in small, enclosed waterbodies and in the laboratory environment. Most acute-toxicity values (96-hour lethal concentration for 50 percent of test organisms [LC50]) for fish are generally from 1 to 10 ppm of toxic hydrocarbons. Concentrations observed within the water column beneath surface oil slicks have usually been less than the acute values for fish, macro invertebrates, and plankton. For example, extensive sampling following the Exxon Valdez oil spill (approximately 11 million gallons [262,000 bbl] in size) revealed that hydrocarbon levels were well below those known to be toxic or to cause sub-lethal effects in fish and plankton (Neff 1991). The low concentration of hydrocarbons in the water column following a large oil spill appears to be the primary reason for the lack of lethal effects on fish and plankton. Should a substantive to very large crude oil spill occur during proposed Project operation, the hydrocarbon concentration in flowing rivers and creeks within the affected area would likely be relatively low based on the observations made following the Exxon Valdez spill.

If an oil spill of sufficient size occurred in a small water body that contained fish or other sensitive aquatic species and that exhibits restricted water exchange (e.g., ponds and small, slow-flowing creeks), lethal and sub-lethal effects could occur for the fish and food resources in that water body. Toxic concentrations of oil in a confined area would result in greater lethal impacts on larval/juvenile fish than adults. Larval/juvenile fish are generally more sensitive than adults (Hose et al. 1996, Heintz et al. 1999). Sub-lethal effects include changes in overwintering and spawning behavior, reduction in food resources, consumption of contaminated prey, and temporary displacement (Morrow 1974, Brannon et al. 1986, Purdy 1989). If a large to very large spill reached a slow-flowing, small to moderate size river in summer, the impacts due to toxic exposures could be greater than in the same river when flows are higher and water temperatures are cooler.

McKim (1977) reviewed results from 56 toxicity tests and found that, in most instances, larval and juvenile stages were more sensitive than adults or eggs. Increased mortality of larval fish would be expected because they are relatively immobile and often found at the water's surface, where contact with oil would be more likely. Adult fish would be able to avoid contact with oiled waters during a spill in the open water season, but survival would be expected to decrease if oil were to reach an isolated pool of ice-covered water.

An example of potential impacts on fish food resources is provided by Barsdate et al. (1980), who studied the limnology of an arctic pond near Barrow, Alaska, with no outlet, after an experimental oil spill. The study concluded that half of the experimental spill was biodegraded or naturally attenuated during the first year. The remaining oil was trapped along the edge of the pond; most of it sank to the bottom by the end of summer. Researchers found no change in pH, alkalinity, or nutrient concentrations. Photosynthesis was briefly reduced and then returned to normal levels after several months. Carex aquatilis, a vascular plant, was affected after the first year due to emerging leaves encountering oil. Certain aquatic insects and invertebrates that lived in these plant beds were reduced in numbers, presumably from entrapment in the oil on plant stems. Some of the insects were still absent six years after the spill. There were no fish in this pond; therefore, the impact of the loss of a prey base to the fish could not be measured. Reducing food resources in a closed lake or pond, as described above, would decrease fitness and potentially reduce reproduction until prey species recovered.

Another potential impact could occur if oil that spilled before or during the spring floods from spring snowmelt or extremely high rainfall dispersed into some of the adjacent wetlands or lakes with continuous or ephemeral connection to rivers and large creeks. This oil could be left stranded when the water recedes and the oil could cause limited toxic or physical smothering effects to riparian, terrestrial and aquatic plants and animals in the flooded area. Lethal effects to fish in streams and some lakes would be unlikely during high-water events such as floods, because toxic concentrations of hydrocarbons would be unlikely. However, toxic levels could be reached in lakes that are normally not connected to the river/creek system except during the high-water periods. If hydrocarbon concentrations in the water column reach toxic levels, these fish could suffer mortality or injury.

Although lethal effects of oil on fish have been established in laboratory studies (Rice et al. 1979, Moles et al. 1979), large kills following oil spills are not well documented, likely because toxic hydrocarbon concentrations in the water column seldom occur. In instances where oil does reach the water, sub-lethal effects are more likely to occur, including changes in growth, feeding, fecundity, survival rates, and temporary displacement. Other possibilities include interference with movements to feeding, overwintering, or spawning areas; localized reduction in food resources; and consumption of contaminated prey.

Most oil spills from the proposed Project would not be expected to measurably affect fish populations in the vicinity of the proposed route. Oil spills occurring in a small body of water containing fish with restricted water exchange would be expected to kill a small number of individual fish but would not be expected to measurably affect fish populations. The same assessment would generally apply to many macroinvertebrates, amphibians, and reptiles because they are motile and generally have a wide geographic distribution. However, sessile freshwater mussels with limited geographic distribution could be affected at a population level in large to very large spills that affect a substantive segment of a stream or river.

Although very unlikely, a large to very large spill under or adjacent to a river could affect water quality, aquatic resources, and other water-associated resources, as well as subsistence and recreational fisheries in downstream areas. In the winter season, an undetected spill, especially under ice, depending on the length of time until spill detection and the volume of released oil, could affect aquatic resources downstream of the spill source. Mortality could result for fish and macroinvertebrates in deeper pools within the spill migration zone. Early-arriving birds could be exposed in any open water pools and cracks in the river ice. Depending on the season of occurrence, however, containment and cleanup of a large or very large oil spill could be difficult.

Sensitive, Threatened and Endangered Species

Most of the potential impacts to the habitats used by threatened, endangered, and protected species are included in the previous discussions of impacts on biological resources. The important additional consideration for these species is that, by definition, they have limited distribution and/or population sizes. Although exposure to oil may adversely affect only a few individuals or a small, localized population of individuals, such a loss could represent a significant portion of the population and its gene pool. Consequently, even a very small or small spill could substantively affect a threatened or endangered species. The likelihood of impacts on threatened, endangered, and protected species would be low because the majority of spills would likely occur at construction yards, on roads, at pump stations, or at MLV sites that have been sited to avoid or minimize any impacts on these habitats and species.

Spilled oil is more likely to affect species that heavily use or completely depend on aquatic and wetland habitats than those in terrestrial habitats. The oil could be transported into flowing streams and rivers, especially with substantive to very large spills, and thus affect a substantive portion of some populations of aquatic species (i.e., freshwater mussels, fish, herptiles, and water birds).

Based on the results of formal consultation between DOS and USFWS, any oil spill in designated habitat for the American Burying Beetle would require initiation of additional consultation to determine appropriate response actions and follow-up. In the event of a spill sufficiently large or coincident with occupied habitat or individuals of any sensitive, threatened or endangered species, Keystone would implement provisions of the ERP to protect potentially affected habitats and species from oiling and would conduct response actions as required by local, state, and federal agencies to return impacted areas to an agreed-upon condition.

3.13.6.5 Land Use, Recreation and Special Interest Areas, and Visual Resources

Agricultural land and rangeland is the predominant land use along the proposed pipeline corridor, comprising about 78 percent of land crossed by the proposed Project. A large to very large spill could affect agricultural activities, including irrigation water supplies.

Most very small to small spills would be confined to construction yards, roads, pump stations, MLVs, or the immediate vicinity of the proposed pipeline ROW. Substantive to very large spills would likely extend beyond the proposed ROW, although the overall extent of terrestrial releases would likely be limited unless the spilled material reaches flowing rivers or streams. Impacts from spills on recreational uses and wilderness-type values of scenic quality, solitude, naturalness, or primitive/unconfined recreation would vary depending on the overall extent of spill migration. Since the majority of releases would likely be small to very small and confined within the proposed Project ROW, their effects on these uses would be negligible to minor.

For some substantive to very large spills, particularly those that reach a stream or river, land use impacts could be substantive. Spilled oil could be visible and result in impacts to agricultural uses and recreational uses for weeks or years depending on the extent and duration of the spill. Agricultural production and crop yields within the spill zone could be reduced until remediation of affected soils and groundwater is accomplished. Rangeland forage in the spill zone could be negatively affected although livestock could likely find sufficient forage in unaffected areas. Fishing, boating, kayaking, tubing, camping, scenic values, and other recreational pursuits could be affected if spilled crude oil reaches lakes and rivers used by recreationists.

3.13.6.6 Cultural Resources

Most known cultural resources which have been previously identified would be avoided by the proposed Project alignment. Any cultural resources that are eligible for listing on the National Register of Historic Places impacted by a crude oil or oil products release would be mitigated through documentation and/or data recovery excavations consistent with the requirements of the Programmatic Agreement (PA). An Unanticipated Discoveries Plan is included within the PA. Proposed Project facilities, including the proposed pipeline, were located to minimize proximity to and potential adverse effects on identified cultural and historical resources.

Large to very large spills could impact cultural resources already identified within the Area of Potential Effect (APE) or cultural resources that are outside of the APE and are currently unidentified. Measures to avoid potential harm to historic properties would be undertaken as part of the spill response efforts. If necessary, identification and mitigation of potentially eligible cultural resources would occur during response efforts consistent with the requirements of the PA.

The proposed pipeline corridor crosses National Historic Trails administered by the NPS. If these areas were impacted by an oil or oil products spill, special care would be required during spill response actions to limit damage to the historic values of the trail systems.

3.13.6.7 Socioeconomics

Oil spills, especially large or very large spills, could affect components of the socioeconomic environment, including:

- Populated areas, especially residential areas, and other HCAs;
- Agricultural activities including farming, ranching, and livestock grazing on wild land;
- Water intakes and water supplies (e.g., drinking water and agricultural irrigation water);
- Other commercial activities; and
- Single-family home sales and property value.

Economic affects related to potential impacts to drinking water supplies could occur in the event of a large to very large oil spill. However, the proposed Project was sited to avoid water supply intakes and nearby potable groundwater well heads. Nonetheless, as discussed in Section 3.3, numerous water wells exist within a mile on either side of the proposed pipeline centerline along its route. Since all of these water wells are over 100 feet from the proposed Project centerline, the impact to these users would likely be minor for small to very small spills and could be substantive if a large to very large spill affects nearby water wells or intakes for a substantive period of time. 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 fire fighting and similar public safety services. Economic affects 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 (e.g., 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.

Some commenters expressed concern about spilled oil reaching surface water supply intakes and affecting fire fighting capability. As stated previously, the proposed pipeline was sited to avoid water supply intakes. Additionally, most surface water supply intakes draw water well below the water surface and would therefore draw water from below the lenticular floating spill mass in the unlikely event it moved over a water intake.

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 U.S. 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.

Economic impacts to land and residence values in areas affected by oil spills could occur. Simons et al. (2001) conducted a study of 2,300 single-family home sales before and after an oil pipeline rupture that spilled 120,000 gallons of mostly number 2 fuel oil into 10 miles of the Patuxent River in Prince George County, Maryland, in the spring of 2000. The study determined that a statistically significant reduction in sales prices of over 10 percent occurred for properties located off of the river (i.e., "interior" properties) for the first sales season after the spill (i.e., about 6 months), and further determined that there was also a reduction in sales volumes during that period.

Hansen et al. (2006) evaluated the impacts to properties in Bellingham, Washington as a result of a June 1999 rupture of a 19-inch-diameter gasoline pipeline that spilled 229,000 gallons of gasoline into Whatcom Creek and led to an explosion and fire. Due to associated fatalities and injuries, this incident received significant national media coverage and led to a temporary halt to pipeline development and the passage of the Pipeline Safety Improvement Act of 2002. The Hansen study evaluated single-family home sales within 1 mile of the affected Olympic Pipeline, and also the Trans Mountain crude oil pipeline located less than 1,500 feet away, for 5.5 years prior to and 5 years after the incident. An analysis of 3,765 sales showed the following statistically significant reductions in the mean sale price (slightly more than $209,000) depending on distance from the pipeline:

- A reduction of $9,613 for property located 50 feet from the pipeline;
- A reduction of $4,863 for property located 100 feet from the pipeline;
- A reduction of $2,446 for property located 200 feet from the pipeline; and
- A reduction of $491 for property located 1,000 feet from the pipeline.

Over time after the spill and explosion, changes in mean sale prices within 100 feet of the pipeline varied as follows:

- A reduction of $5,813 after 6 months;
- A reduction of $4,784 after 12 months;
- A reduction of $4,267 after 24 months; and
- A reduction of $4,008 in price 48 months.

Thus, the impacts of the pipeline incident decreased somewhat over time. These data suggest that the economic consequences of an oil spill could include a temporary reduction in housing prices that would likely decrease over time.

Environmental Justice Considerations

Information on minority and low-income populations within the proposed Project environmental justice analysis area, including locations along the proposed Project corridor that are designated as HPSA and/or MUA/P areas are presented in Section 3.10. 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. However, as discussed previously in Section 3.13.5.5, Keystone would be liable for all costs associated with cleanup and restoration as well as other compensations, up to a maximum of $350,000,000 for any release that could affect surface water, no matter what the reason. Therefore potential impacts 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. Emergency communications should be provided in languages appropriate for identified populations at risk. As a measure to avoid or minimize impacts to minority or low-income populations, response planning should include outreach to Local Emergency Planning Committees (LEPCs) (see Sections 3.10.2 and 3.13.5.5) 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 (see Section 3.10.1).

3.13.6.8 Air Quality

Impacts on air quality from an oil spill would be localized and transient, even for very large spills. Evaporation of the lighter hydrocarbon fractions typically occurs within one to a few days, and the vapors are usually dissipated below risk levels within a short distance of the source. Additional evaporation of the heavier compounds would take place over a longer period of time and could be an important source of organic aerosol pollution (De Gouw 2011). The oil spill response personnel would monitor air for hydrocarbon vapors. Public access to areas exceeding specified risk levels would be restricted and authorized personnel within the restricted areas would be equipped with appropriate personal protective equipment. Nearby farmers and ranchers would be informed of potential hazards to livestock and other farm animals, and assistance would be provided in moving livestock if necessary.

Based on models by Hanna and Drivas (1993), the majority of volatile organic compounds (VOCs) from crude oil spills would likely evaporate almost completely within a few hours after the spill occurred, especially during late spring/early fall when air and soil surface temperatures are higher. Emissions of VOCs, such as BTEX, would peak within the first several hours after the spill and likely drop by two orders of magnitude after approximately 12 hours. The heavier compounds would take longer to evaporate, particularly at the colder temperatures typical of the winter season, and might not peak until more than 24 hours after the spill. In the event of an oil spill on land, the air quality effects would be less severe than those for a spill on water because some of the oil could be absorbed by vegetation or into the ground. However, some effects might last longer on land before the VOC compounds are completely dissipated.

During construction, diesel fuel oil, kerosene and similar hydrocarbons could be spilled during refueling, from a broken diesel refueling line, or from accidents involving vehicles or equipment. A diesel spill would evaporate faster than a crude oil spill. Ambient hydrocarbon concentrations would be higher than for a crude oil spill but would persist for a shorter time.

Gasoline and solvents would typically evaporate and disperse very rapidly. Almost all the released volume would evaporate, except for small amounts that may seep into the upper soil and vegetation layers from which it would be released over 1 day to several days. Gasoline vapors are generally not toxic at the concentrations experienced in spills but they may lead to flammable or explosive vapor concentrations. Public and response personnel access to fire and explosion hazards would be restricted.

In general, impacts on air quality related to oil spills would be localized and short term. The associated VOC air emissions would result in little impact to the biological or physical resources in the vicinity of the spill.

3.13.7 Potential Additional Mitigation Measures

The following potential mitigation measures have been suggested by regulatory agencies:

- As a potential mitigation for concerns relative to environmental justice, the information gathered by phone survey of LEPCs along the proposed Project corridor shown in Table 3.13.5-8 can be used during development of the PSRP and the ERP within the onsite O&M Plan to determine whether additional considerations should be included within these Project-specific plans. Response planning should also consider the potential vulnerability of HPSA and/or MUA/P designated areas when assessing potential response times for any exposed populations. In response to a DOS request, Keystone provided information relative to the level of environmental justice community involvement that it intends to incorporate into proposed Project emergency planning. With regard to emergency response, tribal officials associated with the Integrated Public Awareness (IPA) Program were identified and updated in the Keystone IPA database. A protocol for Keystone's Emergency Management process was developed at an emergency planning scenario on the Fort Peck Reservation in Montana with Keystone personnel, the local municipalities and tribal emergency entities. Should the proposed Project be implemented, Keystone would reach out to LEPCs during and after the development of its Emergency Response Plan (ERP) and public awareness materials with special emphasis on considerations of low income and minority communities in those preparedness efforts. As described in Section 2.4.2.2, Keystone would be required to develop a PSRP for review and approval by PHMSA and an ERP for review by PHMSA for the proposed Project. PHMSA may request EPA and U.S. Coast Guard consultation on the response elements of the PSRP. Keystone would share on its own volition portions of the PSRP with community emergency responders along the proposed pipeline corridor to ensure an appropriate level of collaborative emergency response planning. However, based on a PHMSA advisory bulletin issued on November 3, 2010, Keystone would be required to share the ERP with local emergency responders in relevant jurisdictions along the proposed Project corridor.
- EPA suggested considering the placement of additional intermediate mainline valves, particularly in areas of shallow groundwater and at river crossings of less than 100 feet where sensitive aquatic resources may exist. Project-specific Special Condition 32 developed in consultation with PHMSA that Keystone agreed to incorporate into the proposed Project plan states:

> "Keystone shall locate valves in accordance with 49 CFR § 195.260 and by taking into consideration elevation, population, and environmentally sensitive locations, to minimize the consequences of a release from the pipeline. Mainline valves must be placed based on the analysis above or no more than twenty (20) miles apart, whichever is smaller."

The requirement to take into consideration elevation, population, and environmentally sensitive locations to minimize consequences of a release, and the maximum valve spacing of 20 miles exceed what is currently required in 49 CFR § 195.260. Based on Special Condition 32, the proposed Project was redesigned to increase the number of intermediate mainline valves from 76 to 112 and some previously planned valve locations were moved. As per standard code requirements, there would also be two valves at each of the 30 pump stations. Section 2.2.2 has been updated to include information on the additional intermediate valves and valve locations.

EPA also expressed concern that relying solely on pressure drops and aerial surveys to detect leaks may result in smaller leaks going undetected for some time, resulting in potentially large spill volumes. In light of those concerns, EPA requested consideration of additional measures to reduce the risks of undetected leaks, such as external leak detection systems. A PHMSA report (2007) addressed the state of leak detection technology and its applicability to pipeline leak detection. External leak detection technology assessed in that report included liquid sensing cables, fiber optic cables, vapor sensing, and acoustic emissions. The report concluded that while external leak detection systems have proven results for underground storage tank systems, there are limitations to their applicability to long pipeline systems and they are better suited to shorter pipeline segments. The performance of external leak detection systems even in limited application is affected by soil conditions, depth to water table, sensor spacing, and leak rate. Some external detection methods are more sensitive to small leaks than the SCADA computational approach, but the stability and robustness of the systems are highly variable, particularly over long pipeline segments, and the costs are extremely high. Therefore, long-term reliability is not assured and the efficacy of these systems for a 1,384-mile long pipeline is questionable. It may be possible, however, to incorporate external leak detection methods along discrete segments of pipeline where particularly sensitive resources may exist. For example, in the development of the original Keystone pipeline, specific analysis was commissioned at the request of the North Dakota Public Utilities Commission to examine the possibility of using external leak detection in the area of the Fordville aquifer. That analysis was performed by Accufacts, Inc., a widely recognized expert on pipeline safety that has authored a report for the Pipeline Safety Trust on leak detection technology. The Accufacts, Inc. report (2007) on the Fordville aquifer noted:

> "Such real-time external systems should be considered as complementing CPM [computational pipeline monitoring] leak detection in those few ultra-sensitive areas where the environment can quickly spread low rate releases. These systems may be justified in a few areas that can have high consequences because of the number of sensitive receptors (i.e., people) or the potential to critically impact the environment."

The author of the report defined "ultra-sensitive" areas as those areas where low rate or seepage pipeline release could "reach a sensitive area, have serious consequences, and could not be actively remediated." (Accufacts, Inc. 2007).

DOS in consultation with PHMSA and EPA determined that Keystone should commission an engineering analysis by an independent consultant that would review the proposed Project risk assessment and proposed valve placement. The engineering analysis would, at a minimum, assess the advisability of additional valves and/or the deployment of external leak detection systems in areas of particularly sensitive environmental resources. The scope of the analysis and the selection of the independent consultant would be approved by DOS with concurrence from

PHMSA and EPA. After completion and review of the engineering analysis, DOS with concurrence from PHMSA and EPA would determine the need for any additional mitigation measures.

- EPA and other commenters on the draft and supplemental draft EIS 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 right of way 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 will look for secondary signs of releases 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 DOS 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). PHMSA technical staff indicated that such concerns about landowner acceptance of more frequent ground-level inspections were consistent with their experience with managing pipelines in the region. 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. In light of this fact, DOS in consultation with PHMSA and EPA determined that if the proposed Project were permitted, it would be advisable for the applicant to conduct inspections of all intermediate valves, and unmanned pump stations during the first year of operation to facilitate identification of small leaks or potential failures in fittings and seals. It should be noted however, that the 14 leaks from fittings and seals that have occurred to date on the existing Keystone Oil Pipeline were identified from the SCADA leak detection system and landowner reports.
- EPA requested that language be added to address Keystone's commitment to cleanup and restoration, even in groundwater areas that are not linked to navigable waters of the U.S. In response, Keystone has agreed that it would be responsible for providing appropriate alternative water supply, and for clean-up and restoration in the event of a release of crude oil into groundwater, even in areas that are not linked to navigable waters of the U.S.
- EPA requested the following to be included in the PSRP and/or ERP:
  - Develop a contingency plan before commencement of operation for emergency response and remedial efforts to control contamination from a release in order to avoid and minimize potential impacts through all media (i.e., surface and ground water, soil, and air) to minority, low-income and Tribal populations rather than relying solely on after-the-fact compensation measures. Provide translation of emergency information to linguistically isolated communities. Provide bottled water to Environmental Justice communities in the event the drinking water supply becomes contaminated.
  - Provide notification to individuals affected by soil or groundwater contamination, ensuring the public is knowledgeable and aware of emergency procedures and contingency plans (including posting procedures in high traffic visibility areas), and providing addition monitoring of air emissions and conducting medical monitoring and/or treatment responses where necessary.

- Designate staging and deployment areas for oil spill equipment, and dedicated oil spill-contingency-plan buildings and equipment at each of the pump stations.
- Develop spill scenarios that cover a variety of terrains, oil products, spill volumes, and seasonal conditions.
- Have aerial photographs of the pipeline to aid in spill response planning.

- The risks of spills or leaks could be assessed using 3-dimensional modeling of a spill of a particular magnitude in the Sand Hills. The modeling could assess fate and transport, including routes of exposure to human and ecosystem receptors (Professor Gates and Professor Woldt, UNL).

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