3.13 POTENTIAL RELEASES

3.13.1 Introduction

This section addresses the potential for releases of oil products or crude oil that could occur during construction and operation of the proposed Project. The purpose of this section is to discuss the types of threats to pipeline integrity that could result in such a release and identify the receptors that could be affected by a release. The description of potential releases is based on information provided in the 2011 Final Environmental Impact Statement (Final EIS) as well as new circumstances or information relevant to environmental concerns that have become available since the publication of the Final EIS, including the proposed reroute in Nebraska. The information that is provided here builds on the information provided in the Final EIS and in many instances replicates that information with relatively minor changes and updates. Other information is entirely new or substantially altered from that presented in the Final EIS. Specifically, the following information, data, methods, and/or analyses have been substantially updated in this section from the 2011 document:

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

3.13.2 Crude Oil Characteristics

The physical and chemical properties of the crude oils that would be transported by the proposed pipeline would not be unique to the proposed Project; petroleum quality requirements of crude oil would be specified by National Energy Board and the Federal Energy Regulatory Commission tariffs (18 Code of Federal Regulations [CFR] 341). A comparison of the crude oil that would be transported by the proposed pipeline with other conventional crude oils indicates that the characteristics of the proposed Project's crude oil are generally comparable to those of conventional crude oils (Been and Wolodko 2011). Comparison of incident data from Alberta pipeline systems with data from U.S. pipeline systems (Section 4.13.2.4, Pipeline Incident Information Sources) indicates that Alberta pipelines that have likely shipped diluted bitumen (dilbit), synthetic crude oil (SCO), or Bakken shale oil are not more prone to failure than other pipeline systems carrying conventional crude oils. Further discussion of crude oil characteristics and potential causes and frequencies of pipeline failure is provided below, as well as in Section 4.13, Potential Releases.

Petroleum is a naturally occurring mixture composed primarily of hydrocarbon compounds. Traditionally, petroleum referred only to liquid crude oil; however, current common usage of the term also includes gaseous and solid materials such as natural gas and bitumen. The composition of crude oil varies, depending on the source and processing. Most crude oils are more than

95 percent hydrocarbons, with nitrogen, oxygen, varying amounts of sulfur, and traces of other elements.

Light crude oil is a mixture that can flow through a pipeline without processing or dilution. Heavy crude oil is referred to as *heavy* because its density is higher than that of light crude oil. The American Petroleum Institute (API) has introduced the term *API gravity* to measure how heavy or light a petroleum liquid is compared to water. If an oil's API gravity is greater than 10°, the oil is less dense than water, and thus floats on water; if an oil's API gravity is less than 10°, the oil is more dense than water, and thus sinks in water. In this sense, API gravity is used to compare the relative densities of petroleum liquids. There are different definitions of light and heavy crude oil. Unless otherwise specified, in this section *light oil* is defined as any liquid petroleum with an API gravity greater than 31.1° (corresponding to a density less than 870 kilograms per cubic meter [kg/m^3]); *heavy oil* is defined as any liquid petroleum with an API gravity less than 22.3° (corresponding to a density greater than 920 kg/m^3); and *medium oil* is defined as any liquid petroleum with an API gravity between 22.3° and 31.1°.

In addition, Canadian heavy crude oil is also usually sour (i.e., has a higher sulfur content), with sulfur contents between 2.52 percent and 4.82 percent (mean of 3.27 percent) by weight based on the data from 25 types of heavy crude oils (Enbridge 2011). Typically, crude oil with a sulfur content greater than 2 percent by weight is considered sour.

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

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

3.13.3 General Description of Proposed Pipeline Transported Crude Oils

The crude oil that would be transported by TransCanada Keystone Pipeline, LP (Keystone) as part of the proposed Project would originate from a variety of different sources and locations. The crude oil types for the proposed Project would range from a light crude oil (such as those found in the Bakken formation) to a heavy crude oil (such as those found in the Western Canada Sedimentary Basin (WCSB), which is produced from a material called bitumen). Table 3.13-1 summarizes the general characteristics for the types of crude oil that would be transported by the proposed Project. Table 3.13-2 provides additional information on characteristics of potential Project crude oil types.

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

Characteristic	Synthetic Crude Oil[a]	Diluted Bitumen[b]	Bakken Shale Oil[c]
Density	na	na	827 kg/m^3
Specific gravity	0.84–0.86[g]	0.9–1.2	0.82–0.83
Viscosity	na	52 to 96 centistokes at 38°C	na
Flammability	na	Class B, Division 2: Flammable Liquids	Class B, Division 2: Flammable Liquids
Composition	Gas oils (petroleum), hydrodesulfurized 60% Naphtha (petroleum), hydrotreated heavy 10-30% Naphtha (petroleum), hydrotreated light, 3-7% Butane 1-5% Hydrogen sulfide (H_2S) 0.001-0.01% BTEX 1-1.5%	Bitumen 40-70% Light naphtha 15-40% Natural gas condensate 15-40% BTEX 1-1.5%	Light hydrocarbons <30% Pentanes 3-4% Hexanes 4-6% Heptanes 6-8% Octanes 6-8% Nonanes 4-6% Decanes 1-3% BTEX 1-3%
Flash point	68˚F (20°C)	-0.4˚F (-18°C)	na
Toxicity[d]	na	Class D, Division 2, Subdivision A: Very Toxic Material	na
Solubility in water[e]	Insoluble in cold water[f]	Insoluble[f]	Insoluble
Pour point	-5.8˚F (-21˚C)	-22˚F (-30˚C)	-25˚F(-32˚C)
Sulfur	0.25%	3.6%	0.17-0.20%
Other properties	Oxides of carbon, and nitrogen, aldehydes form upon combustion. Hazardous sulfur dioxide and related oxides of sulfur may be generated upon combustion.		

[a] Husky Energy 2011.
[b] Imperial Oil 2002.
[c] Crudemonitor 2012a. Five-year average was used for numbers.
[d] Table 3.13.5-12, Final Environmental Impact Statement (Final EIS).
[e] Table 3.13.5-12, Final EIS.
[f] Insoluble, but volatile organic compound and semivolatile organic compound constituents are soluble, (e.g., benzene, toluene, polycyclic aromatic hydrocarbons).
[g] Specific gravity for water = 1.0.
Notes: na = not available; kg/m^3 = kilograms per cubic meter; BTEX = benzene, toluene, ethylbenzene, and xylenes.

Bitumen is a form of petroleum that occurs naturally in a solid or semi-solid state. Bitumen includes a wide variety of reddish brown to black materials that are semi-solid and viscous to brittle in character. Canadian oil sand bitumen is a high boiling point substance with little material boiling below 350˚C (660˚F). Canadian oil sands are a mixture of roughly 90 percent clay, sand, and water, and 10 percent bitumen. The dark, sticky sands look similar to topsoil, but can flow when warmed. Colder temperatures reduce the ability of the bitumen to flow and can cause the bitumen to have the appearance of a semi-solid. Raw bitumen is solid under ambient conditions and therefore must be altered into a form that can be transported via pipeline. There are two basic methods used to render bitumen transportable by pipeline: 1) Bitumen is processed into SCO; and 2) Bitumen is mixed with a suitable diluent, as described below, creating what is known as dilbit. Either of these products may be transported by the proposed Project. 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 is expected to be in the form of dilbit (EnSys Energy [EnSys] 2010).

3.13.3.1 Synthetic Crude Oil

SCO is produced from bitumen through a refinery conversion process that turns heavy hydrocarbons into lighter hydrocarbons. The conversion process typically includes the removal of sulfur, resulting in a *light sweet* SCO. The precise composition of SCO varies. Some composition information may be considered proprietary information by the shipper. Generic properties of SCO are listed in Table 3.13-1. The properties of one example of SCO, Suncor Synthetic A Crude Oil, are presented in Table 3.13-2. Representative Material Safety Data Sheets (Appendix P, Crude Oil Fact Sheets) were obtained from the 2012 TransCanada Nebraska Supplemental Environmental Report (exp Energy Services Inc. 2012). As shown in Table 3.13-2, the characteristics of WCSB SCO and dilbit are similar to those of conventional crude oils.[1]

3.13.3.2 Dilbit

Dilbit is bitumen mixed with a diluent so it can be transported by pipeline. The diluent is usually a natural gas liquid such as gas condensate. According to the Saskatchewan Condensate Monthly Report dated 1 September 2012 (Crudemonitor 2012b), the composition of gas condensate is mainly light hydrocarbons such as iso-butene, n-butane, iso-pentane, n-pentane, and hexanes. The exact composition of the dilbit is not publicly available because the particular type of bitumen and diluents blend produced is variable and is typically a trade secret. The bitumen-diluent mixture with bitumen from the oil sands is generally similar to heavy sour crude, which is discussed in more detail below. SCO may also be used as a diluent for bitumen, in which case the commodity is known as synbit (bitumen diluted with SCO). Properties of generic dilbit are shown in Table 3.13-1.

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

Table 3.13-2 Comparison of Global Crude Oil Characteristics

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

Source: exp Energy Services Inc. 2012.

Note: Green columns illustrate representative characteristics of crude oil types similar to those that would be transported by the proposed Project.
[a] Five-year averages from CrudeMonitor.ca.
[b] Data from Environment Canada's Crude Oil Properties Database.
[c] Data from Statoil Crude Oil Assay.
[d] Western Canadian Select[2], Suncor Synthetic A and Bakken crude oils are representative types that would be transported by the proposed Project.
Notes: ND indicates measurement below instrument threshold; MCR = micro carbon residue; TAN = total acid number; g/ml = grams per milliliter; wt% = weight percent; ppmw = parts per million weight; mgKOH/g = milligrams potassium hydroxide per gram; vol% = percent volume; ptb = pounds per thousand barrels; mg/L = milligrams per liter.

[2] Diluted bitumen, or dilbit.

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3.13.3.3 Bakken Shale Oil

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

The Bakken shale oil from Montana is light and sweet (containing less than 0.42 percent sulfur). The main properties of Bakken shale oil are shown in Table 3.13-1.

3.13.3.4 Flammability and Explosion Potential

Diluents used in dilbit are thoroughly mixed with the bitumen and, when mixed, no longer exhibit the same flammability as they would by themselves. Dilbit is capable of igniting at low temperatures (-0.4˚F [-18˚C]) (Imperial Oil 2002, exp Energy Services, Inc. 2012) and ceasing to flow at temperatures of -22˚F (-30˚C). SCO can produce flammable or explosive vapors when above its 68˚F (20˚C) flashpoint (Husky Energy 2011). Both dilbit and SCO are flammable petroleum products; however, for an ignition to occur, produced vapors from the oil must be above the lower flammability limit of the vapor and sufficient oxygen and an ignition source must be present. Given the liquid nature of dilbit, friction alone would not be an ignition source. Within a pipeline, oxygen conditions are typically too low and an ignition source is not present, so an explosion within a closed pipeline is unlikely. If crude oil is released outside the pipeline, and an ignition source is present, it could potentially ignite under specific conditions.

3.13.3.5 Acidity and Corrosivity Potential

Naphthenic acids are natural constituents in many petroleum sources, including bitumen from oil sands. (Naphthenic acids are not present in SCO.) Naphthenic acids can create corrosion problems. This type of corrosion is referred to as naphthenic acid corrosion (NAC). Because of the lack of available naphthenic acid concentration data for crude oil, the petroleum industry uses a measurement known as the total acid number (TAN) to qualitatively measure the potential for an oil to produce such corrosion problems. The measurement of TAN is an indicator, although not a direct measurement, of naphthenic acid content in crude oil. TAN values for heavy WCSB and dilbit are similar to TAN values measured in other crude oil from around the world (Aske et al. 2001, Table 4). This is consistent with information in presentations at the meeting organized by the National Academy of Sciences (NAS) in July 2012 (NAS 2012)[3], which reported that the TAN of dilbit overlaps with that of conventional crude. With a TAN greater than 1.0, dilbit is considered to be an acidic crude; heavy crude is moderately acidic (APEC 2005). Due to an extraction washing process used to separate bitumen from oil sands, it is expected that acids remaining in dilbit would not be higher than in conventional crude.

[3] Pursuant to the Pipeline Safety, Regulatory Certainty, and Jobs Creation Act of 2012, PHMSA contracted with NAS to study whether transportation of dilbit by transmission pipeline has an increased likelihood of release compared with pipeline transportation of other crude oils. NAS expects to complete this study in 2013. If NAS concludes that an increased likelihood of release it would make recommendations for changes to PHMSA regulations to address the increased risk. The references to the NAS 2012 presentations in this Supplemental EIS are done to present the most updated information on this topic; however, these presentations are preliminary and should not be interpreted to prejudge any conclusions NAS may reach.

Corrosion due to naphthenic acid is observed primarily at the very high temperatures found in refinery systems (typically, 644-700˚F [340-372˚C] for crude units, 716-788 ˚F [380-420 ˚C] for vacuum units). Pipelines may be exposed to NAC, but metal loss like that found in refinery crude systems is not typically observed because of the much lower operating temperature of pipeline systems.

Some oil sand bitumen crudes have been characterized as corrosive by the classical naphthenic models used in chemistry. However, after decades of cumulative operation, only a very few NAC cases have been observed in crude units in U.S. refineries. It has been proposed a new theory for the corrosivity of naphthenic acids in oil sand bitumen crudes in which two types of naphthenic acids are introduced: corrosive acids with low molecular weights, and non-corrosive and inhibitive acids with high molecular weights. The hot extraction wash of the raw oil sand mixture in dilbit appears to preferentially remove the higher water-soluble fraction of corrosive acids. The more benign fraction is left, being less corrosive and less water-soluble. The naphthenic acid type surviving the dilbit thermal hydro-processing tends to be of the inhibitive, non-corrosive type (Messer et al. 2004).

Dettman, 2012, and Friesen, et al. 2012, discuss two physicochemical characteristics of dilbit related to its corrosive behavior in pipelines: TAN and sulfur content. As discussed above, a diluent is added to bitumen to create dilbit and, therefore, the original organic acid found in bitumen would also be diluted. Bitumen naphthenic (organic) acid content prior to dilution is on the order of 3% by weight (TAN = 3 mg KOH/g) (Dettman, 2012). After dilution, the TAN could be reduced to 1.6 mg KOH/mg or less. The recent 5-year average assay of Western Canadian Select (dilbit) shows TAN at less than 1.0 mg KOH/g (Table 3-13-2).

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

Sulfur compounds like H_2S tend to form iron sulfides and therefore could threaten the pipeline steel walls. Although much of these are removed during the bitumen extraction/treatment process, some remain present in dilbit. Sulfur is mostly bound to the dilbit hydrocarbons, which could account for up to 3.9% by weight in a pipeline inventory (Dettman, 2012). The recent 5-year average assay of Western Canadian Select (dilbit) shows sulfur at less than 3.5% by weight (Table 3-13-2). However, iron sulfides produced by dilbit are insoluble in oil. Under controlled hydraulic conditions in the pipeline (low shear flow), a protective film could form on the pipeline walls to reduce internal corrosion effect. This is a documented industry practice (Dettman, 2012). The remaining sulfur compounds in dilbit would not be in free form, which means they would be strongly attached to hydrocarbons and not available to react until subjected to refinery-type process conditions.

3.13.4 Pipeline and Component Integrity Threats

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

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

A loss of pipeline integrity can result in an unintentional release of crude oil. There are a number of failures that can result in a release. The failures may range from something very visible, such as an external crack in the pipe, to something subtle, like a sensor malfunctioning and transmitting spurious readouts resulting in improper pipeline operation. The term *threat* is preferred to cause to label a mechanism that could lead to a pipeline failure. The term *cause* is used once a mechanism for a release has been identified. In this sense, threats have the potential to create the conditions for a release (loss of integrity), and causes have created a release.

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

- External corrosion, such as oxidation of the metal surface in contact with humid air;
- Internal corrosion, such as NAC;
- Stress corrosion cracking (SCC), such as cracks caused by repeated expansion and contraction due to temperature changes;
- Manufacturing, such as defects in the pipe;
- Construction, such as welding defects;
- Equipment, such as wear and tear of valve seals;
- Third-party damage, such as from earth movement in nearby excavations;
- Incorrect operations, such as operating errors that lead to the over-pressurization of the pipeline or components; and
- Weather-related and other natural forces, such as earthquakes.

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

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

3.13.4.1 *Time-Dependent Threats*

Time-dependent threats include corrosion and SCC. Corrosion is defined as the deterioration of a material, usually a metal, by reaction with its environment. The rate at which a metal will corrode is primarily governed by the environment. Corrosion is a process where the metal of the pipe oxidizes because a naturally occurring electric current flows through and induces the pipeline metal to combine with oxygen, creating a non-metallic by-product (known as rust). For corrosion to develop, an oxidizing agent (most commonly water) needs to be present to oxidize the steel used for pipelines. For a pipeline, water can be inside the pipe, originating from the fluid being transported, or it can be outside from soil moisture (API 1160). The characteristics of the water present (for example, acidity due to the corresponding presence of other chemicals/contaminants in the transported material) can also significantly affect the nature of the resulting corrosion. The following are typically successful methods of corrosion control and mitigation:

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

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

External Corrosion

External corrosion occurs when pipeline walls or seam welds weaken from contact with moist soil or water. External corrosion can be accelerated by microbial activity (ASME B31.8S-2010). A pinhole is a term used to describe a very small hole (i.e., roughly the size of a pinhead) that could form in a pipe. This hole size is common in corrosion cases, and is typically associated with low leak-rate, long-duration spills. The following factors could affect the rate at which external corrosion occurs:

- Exposure time: external corrosion thins the pipeline wall and weakens the pipe material strength. If the pipeline wall is exposed to the corrosive conditions over a sufficient time, weakening of pipe strength and a loss of pipeline integrity could result in a breach of the pipeline wall or failure of a pipeline weld under normal operating conditions. This could then result in a leak or spill.
- Coating: industry standards require that all new steel pipelines, such as the pipeline that would be used for the proposed Project, are coated with fusion-bonded epoxy (FBE) to create a physical barrier between the pipe and the surrounding soil, significantly reducing or eliminating the mechanism for developing rust. Over time, this coating could incur damage, exposing the pipe to moisture, which could result in corrosion. The corrosion generally occurs evenly over a large portion of the pipeline surface. This type of external corrosion is referred to as general or uniform corrosion (NACE International 2012c).

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

Internal Corrosion

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

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

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

Although a focused, peer-reviewed study of the potential corrosivity/erosivity of oil-sands-derived crude oils relative to other crude oils has not yet been conducted, review of the available data suggests that this potential for dilbit is similar to the potential for other crude oils transported in U.S. pipelines.

Based on the experiences obtained from the Enbridge Liquid Pipelines System, which has been transporting crude oil originating from the oil sands since 1968, constituents that potentially contribute to corrosion inside a pipeline include sediment and water that can enter the pipeline with the oil being transported. Internal corrosion can occur if these constituents settle on the pipe bottom and establish a corrosion point. Higher density/viscosity crudes have a greater propensity to carry sediment. However, dilbit and SCO, on average, typically carry approximately 25 percent less sediment than conventional heavy oils (Ironside 2012). Some of the available data regarding corrosion for dilbit-carrying and conventional-crude-carrying pipelines are listed below (Been 2011):

- Although the TAN in dilbit is higher than that of Western Canadian crude oil, based on averages of approximately 5 years, the acids are too stable to be corrosive under transmission pipeline temperatures.
- Dilbit sulfur content is comparable to the sulfur content in other crude oils, and the production of H_2S, which could increase the occurrence of corrosion, is not expected at the pipeline operating temperatures.
- No evidence of increased sediment erosion in dilbit pipelines, compared to other crude oil pipelines, has been observed in Alberta. Although some dilbit blends may contain more sediments than conventional crude oils, it would be well below the limit set by regulatory agencies and industry.
- Dilbit viscosity is comparable to those of conventional heavy crude oils and there is no evidence of increased corrosion or other potential pipeline threat due to viscosity.
- Higher temperatures in dilbit pipelines do not correlate to increased corrosion rates.
- Temperatures up to 60°C have indicated a higher rate and extent of coating failure, but it has also been shown that, in the presence of cathodic protection, the pipe will remain protected, and blistering and coating failure does not present an integrity threat to a pipeline. No stress corrosion cracking failures have been reported for FBE coatings in over 40 years of experience.[4]
- Transmission pipeline failure rates in Alberta are comparable to those in the United States.

Stress Corrosion Cracking

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

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

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

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

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

3.13.4.2 Stable Threats

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

Manufacturing

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

PHMSA (2009) has identified a manufacturing integrity issue with respect to high-grade mainline pipe. Tests that have been conducted on installed mainline pipe have shown that some of the pipe material has yield strengths, tensile strengths, and/or chemical compositions that do not meet the requirements of the API, Specification for Line Pipe—5L (API 5L), for PSL 2, and the specified pipe grade. Yield strengths below the minimum specified yield strength have been reported and yield strengths up to 15 percent lower than the strength values on the pipe manufacture-produced mill test report have also been reported. In some cases, the affected pipe may successfully pass strength testing methods contained in current specifications but may lead to a future pipeline integrity issue. The presence of low-yield-strength mainline pipe installed in a pipeline system may result in increased susceptibility to excessive pipe expansion or rupture during the pre-in-service field hydrostatic strength test. The revised Permit Application identifies that mainline pipe for the proposed Pipeline would be constructed of API 5L PSL2 X-70M high-strength steel. Per the application, the maximum operating pressure for the pipeline would be 72 percent of the minimum specified yield strength.

Construction

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

Residual stress present in the pipe body due to pipe bending, buckling, or incorrect pipe laying is a threat that may lead to a release event provided it is sufficient to locally weaken the pipeline integrity. Mechanical removal of metal during construction is considered a threat (e.g., gouges, cavities, or grooves) since corrosion tends to develop quickly in pipe areas with defects. The pipe-welding process and the pipe-laying process in general are factors that can affect pipe integrity. The PHMSA special conditions related to pre-commissioning quality inspection and detection of construction defects should ensure high-quality construction standards to minimize the potential for defects. Testing and inspection that take place during pre-commissioning reduce, but do not eliminate, the chance of a leak due to construction threats.

Equipment

An equipment threat is the potential for equipment to not accomplish its intended design, operational, or functional purpose. A malfunction may include repairable and unrepairable failures of pipeline (both linear and discrete) elements. Linear element failure includes any loss of containment from pipe body or weld seams that connect the pipe. Discrete element malfunction pertains to equipment above ground such as pumps, tanks, and non-pipe controls and valves. The equipment also comprises non-metal parts such as seals and rings, plus all the supervisory control and data acquisition (SCADA) components that assist in monitoring and controlling the pipeline system. The root causes of equipment malfunction could relate to failures in design, operation, or manufacturing if they are not clearly traceable to the construction phase. The following are some examples of potential equipment malfunctions:

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

A number of equipment malfunction scenarios could result in a pipeline leak. Wear and tear of valve seals or rings could result in immediate leaks, while the failure of SCADA controls at a critical time may result in an escalation scenario of varying consequences. For all these reasons, leaks from linear and discrete equipment may range from small (less than 50 barrels [bbl][5]) to large volumes (greater than 1,000 bbl).

[5] Forty-two U.S. gallons.

3.13.4.3 Time-Independent Threats

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

Third-Party Damage

A third-party damage threat consists of potential actions of the pipeline operator and/or other parties that could create conditions affecting the pipeline system integrity. Three primary sub-threats comprise potential third-party damage threats: 1) unintentional damage; 2) intentional damage or vandalism; and 3) previously damaged pipe (such as dents or gouges created during manufacturing, construction, or operation) (ASME 2010). These threats may directly damage the pipeline system to the point of producing a leak. Excavation is a common action in which the pipeline is subject to an external mechanical force that could result in a pipe failure. Other less common actions include impact by a motor vehicle, detonation of an explosive substance, or earth movement related to nearby excavations or heavy traffic over a buried pipeline. Additionally, dents, gouges, and scratches to exposed pipe; loss of pipeline support; change in pipeline alignment; and loss of cover due to third-party activities are related third-party threats (API 2001).

Incorrect Operations

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

Weather-Related and Other Natural Forces

Weather-related and other natural force threats include natural hazards whose magnitudes or characteristics might cause damage to the pipeline system[6]. This threat is comprised of four primary sub-threats: 1) natural earth movement and/or avalanche; 2) heavy rains or floods; 3) extreme ambient conditions, including ice-loading on exposed structures; and 4) lightning.

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

[6] Please refer to the Section 4.14, Climate Change.

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

3.13.4.4 Potential Spill Sources

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

- Small spill (< 50 bbl);
- Medium spill (50-1,000 bbl); and
- Large spill (>1,000 bbl).

Construction

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

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

Operation

Operational spills from the proposed Project could originate from the pipeline, pump stations, mainline valves, delivery points, or at any location along the pipeline. As noted above, most small spills are related to pinhole-type corrosion leaks along the body of the pipe or by leaks from valves, flanges, pumps, or other equipment. However, crude oil exiting a pinhole may create a medium to large spill due to the difficulties for SCADA or aerial surveillance to detect such a leak. Many of these components would be located in pump stations or delivery points along the proposed pipeline route. A pinhole-sized leak resulting in drips from defects in materials or faulty construction/fabrication of the pipeline could occur along any segment of the pipeline. As the majority of the pipeline would be buried, these small, continuous-type releases may go unnoticed for an extended period until the spill volume is expressed on the surface. This volume of spill generally would remain within the pipeline right-of-way unless the oil was released adjacent to a channel or surface water body that could facilitate spreading.

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

Large spills (>1,000 bbl) are generally associated with severe damage to or complete failure of a major pipeline component. While many of the causes listed above for medium spills could apply to large spills, it is the degree of damage and the location of the spill that generally differentiates medium spills from large spills.

For example, a full, 36-inch-diameter pipe contains roughly 6,660 bbl per mile of length. This means that the minimum volume for a large spill (1,000 bbl as defined above) exists in roughly every 800-foot section of 36-inch-diameter pipe, not considering response measures to stop the leak or the presence of design features such as mainline valves to mitigate the volume released.

Maintenance

Small spills may occur during maintenance activities (e.g., valve replacement, pump service, inspection [pigging], or cleanouts) and generally would be expected to occur in or near pump stations, metering facilities, or other aboveground infrastructure locations. Many of these releases are typically attributed to the spilling of residual product during the removal of a pipeline component or bleeding of pressure or product from lines prior to line-breaking type activities. Most small releases associated with maintenance activities are generally identified and managed in a timely fashion.

Medium or large-sized spills are generally not associated with maintenance events. A technician or mechanic performing maintenance on the pipeline is usually trained or supervised by person/persons familiar with the reporting or appropriate response actions needed to prevent medium or large releases from occurring.

3.13.5 Potential Spill Receptors

The magnitude of an oil spill impact would be influenced by the type of receptors that might be exposed to the oil. Below are the descriptions of identified spill receptors broken into two main categories: high consequence areas (HCAs) and other resources. Definitions for HCAs are from the U.S. Department of Transportation (USDOT) Federal Register, Title 49 of the CFR Part 195. Other resources are defined in this Supplemental EIS and described below. Figure 3.13.5-1 illustrates the organization of HCAs by the USDOT and how other resources are organized in this Supplemental EIS to evaluate potential spill impacts.

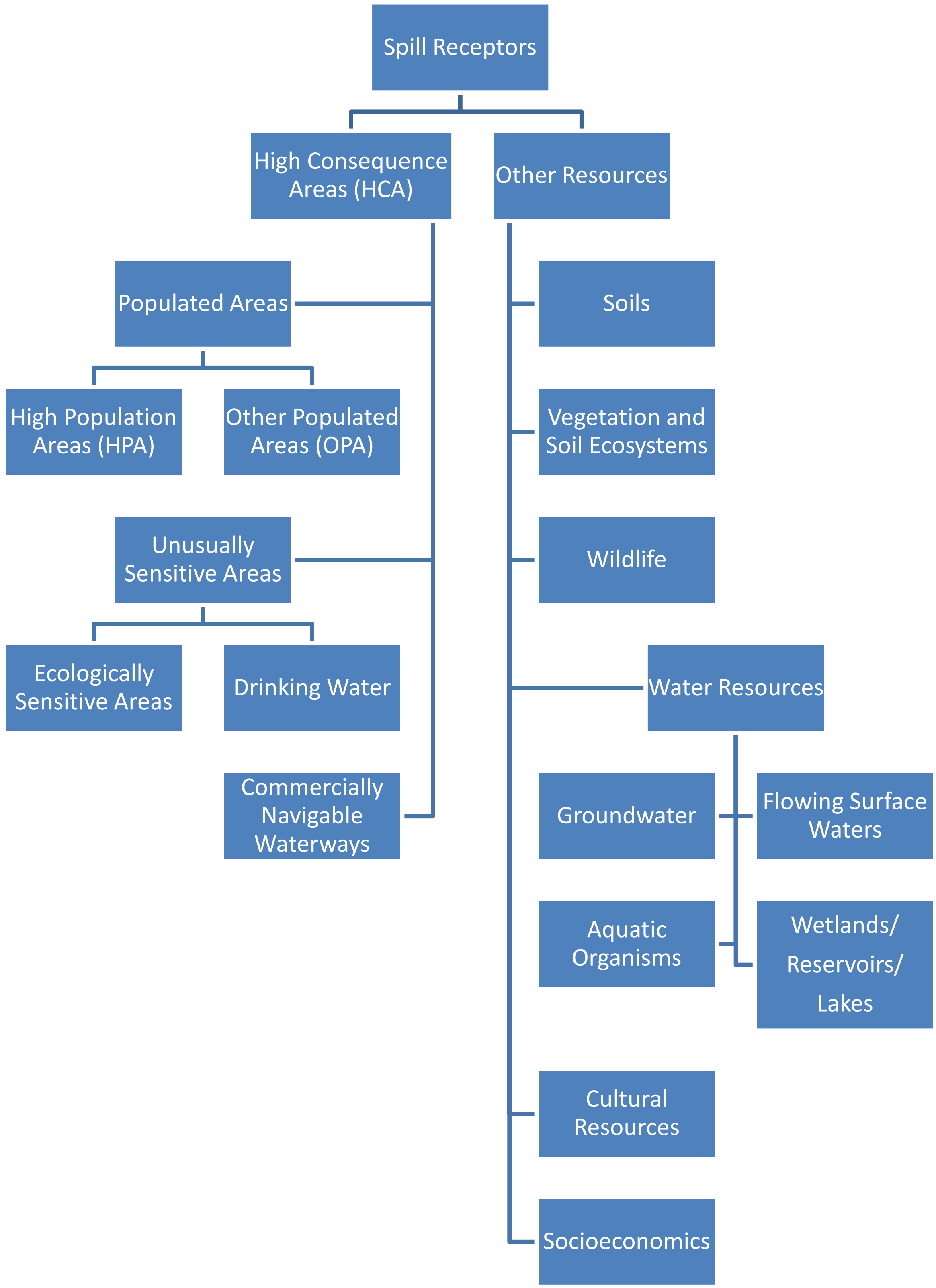

Figure 3.13.5-1 Identified Potential Spill Receptors

3.13.5.1 High Consequence Areas

HCAs are defined in 49 CFR 195 (Transportation of Hazardous Liquids by Pipeline) Subpart F for pipeline integrity management. An HCA is defined as a high-population area, other populated area, commercially navigable waterway, or unusually sensitive environmental area, including a sole-source drinking water supply.

Appendix Q, Pipeline Risk Assessment and Environmental Consequence Analysis, Table 4-12, identifies the types and lengths of HCAs crossed by the proposed Project route (HCA data for the rerouted portion of the proposed Project in Nebraska are currently unavailable and will be included in the Final Supplemental EIS as available). These HCA data are compiled from a variety of data sources, including federal (e.g., U.S. Environmental Protection Agency [USEPA]) and state (e.g., fish and wildlife, environmental quality, hydrology, etc.) agencies. Keystone has conducted a preliminary evaluation of HCAs crossed or located downstream of the proposed pipeline route. Portions of the proposed pipeline route in which a release could potentially affect HCAs would be subject to higher levels of inspection (per 49 CFR 195). As a result of the preliminary HCA evaluation, some proposed valve locations were moved and additional valves were added to protect HCAs from potential impact.

Populated Areas

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

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

According to a 2003 report to USEPA on a comparison of the health effects of SCO with those of conventional crude oil, the following statement was made (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 a crude, consisting of blends of hydrotreated naphthas, diesel and gas oil without residual heavier oils . . . This information was supplied to USEPA . . . to support the position that tar sands-derived synthetic crude oil is comparable to conventional crude oils for health effects and environmental testing, a position with which EPA concurred.

It should also 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 (EnSys 2010).

Vapors from spilled oil could lead to human health effects depending on the intensity and duration of exposure. In particular, a human health risk could result from the inhalation of any H_2S emitted into the air column in the vicinity of the oil spill. Human health effects of exposure to H_2S, an irritant and an asphyxiant, depend on the concentration of the gas and the length of exposure. Background ambient levels of H_2S in urban areas reportedly range from 0.11 to 0.33 parts per billion, while in undeveloped areas concentrations can be as low as 0.02 to 0.07 parts per billion (Skrtic 2006). Olfactory perception of hydrogen sulfide occurs for most people at concentrations in the air of approximately 0.2 parts per million (ppm).

In an assessment of risk to first responders (local emergency services, emergency response contractors, spill management team) at crude oil spill sites, Thayer and Tell (1999) modeled atmospheric emissions of H_2S from crude oil spills using three different crude oil H_2S concentrations (1 ppm, 20 ppm, and 350 ppm), calm wind speeds, and temperatures typical of the southern United States. The results of their analysis indicate that H_2S levels in the immediate aftermath of a crude oil spill at the two higher levels of H_2S concentration (20 ppm and 350 ppm) could pose short-term health risks (shortness of breath) to first responders 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 after oil leaves the pipeline and is exposed to air, H_2S exposures would not be expected to create substantive health hazards. Therefore, H_2S exposure is expected to be highest where oil has been spreading for the first 4 minutes immediately after discharge from the pipeline (adjacent to the pipeline and within the right-of-way). The rapid atmospheric dissipation of H_2S levels indicated by these model results suggests that risks to the general public would be very small to negligible.

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

Unusually Sensitive Areas

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

Drinking Water

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

Some segments of the proposed Project route would cross areas that are considered HCAs due to potential risks to sensitive drinking water resources (Appendix Q, Pipeline Risk Assessment, Table 4-12). HCA drinking water data are pending and will be included in the Final Supplemental EIS.

Ecologically Sensitive Areas

An ecological unusually sensitive area is an area containing a critically imperiled species or ecological community, a multi-species assemblage area, or a migratory water bird concentration area. An ecologically sensitive area may also be defined as an area containing an imperiled species, threatened or endangered species, depleted marine mammal species, or an imperiled ecological community where the species or community is aquatic, aquatic-dependent, or terrestrial with a limited range. Finally, an ecologically sensitive area is an area containing an imperiled species, threatened or endangered species, depleted marine mammal species, or imperiled ecological community where the species or community occurrence is considered to be one of the most viable, highest quality, or in the best condition. HCA ecological data are pending and will be included in the Final Supplemental EIS.

Commercially Navigable Waterways

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

3.13.5.2 Other Resources

Other resources that could be affected by a pipeline release are listed below; potential impacts to these resources are described in Section 4.13, Potential Releases:

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

3.13.6 Spill Magnitudes

For the purpose of assessing potential spill impact for this Supplemental EIS, the spill volumes defined and discussed in Section 3.13.2.1 of the Final EIS were simplified to three spill volumes—small, medium, and large. The entire range of mainline pipe spills in the PHMSA database are addressed by these three spill sizes but have been reduced from the original five categories to provide a comparison analysis to other current work being done for the State of Nebraska, simplify the range of reported spill volumes in the database including data under the revised reporting requirements, and facilitate assessment of the spill impact along the proposed Project route. The evaluation of small, medium, and large spill-size categories based on PHMSA data is shown in detail in Appendix K, Historical Pipeline Incident Analysis.

3.13.6.1 Small Spills

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

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

3.13.6.2 Medium Spills

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

3.13.6.3 Large Spills

Large spills are defined as greater than 1,000 bbl (42,000 gallons) to 20,000 bbl (840,000 gallons). The 20,000 bbl spill is roughly the maximum reported spill volume within the data evaluated. This spill category (>1,000 bbl–20,000 bbl) represents approximately 4 percent of 1,692 crude oil spills evaluated. Large spills are generally characterized as a surface release. This is because the rate of the volume released usually exceeds the capacity at which soil can absorb the released oil. As a result, oil rises to the ground surface. Large spills are generally associated with severe damage to or complete failure of a major pipeline component or monitoring system.

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

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

3.13.7 Connected Actions

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

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

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

The Bakken Marketlink Project would involve the construction and operation of metering systems, a 5-mile pipeline segment, three new storage tanks near Baker, Montana, and two new storage tanks within the boundaries of the proposed Cushing tank farm. The property proposed for the Bakken Marketlink Project facilities near Pump Station 14 is currently used as pastureland and hayfields; a survey of the property indicated that there were no waterbodies or wetlands on the property. However, the pipeline segment does have stream crossings and these crossings lead to larger surface water bodies. The Big Bend to Witten 230-kV Transmission Line would provide upgrades to the power grid in South Dakota to support power requirements for pump stations in South Dakota. The third connected action is associated with the electrical distribution lines and substations that would be required throughout the length of the proposed Project corridor to support pump stations and other integral Project-related ancillary facilities.

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

Spill volumes are based on reported mainline pipe spills. The PHMSA Database has reported spill volumes greater than 20,000 bbls for tanks.

3.13.8 References

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