Appendix P

Pipeline Risk Assessment and Environmental Consequence Analysis

Keystone XL Project
Pipeline Risk Assessment and Environmental Consequence Analysis

PRIVILEGED AND CONFIDENTIAL MATERIAL

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1.0 Project Overview

TransCanada Keystone Pipeline, LP (Keystone) proposes to construct and operate a crude oil pipeline and related facilities from Hardisty, Alberta, Canada to the Port Arthur and east Houston areas of Texas in the United States (US). The project, known as the Keystone XL Project (Project), will have a nominal capacity to deliver up to 900,000 barrels per day (bpd) of crude oil from an oil supply hub near Hardisty to existing terminals in Nederland near Port Arthur and Moore Junction in Houston, Texas. The Steele City Segment extends from Hardisty, Alberta, southeast to Steele City, Nebraska. The Gulf Coast Segment extends from Cushing, Oklahoma, south to Nederland, Texas. The Houston Lateral extends from the Gulf Coast Segment, Liberty County, Texas, southwest to Moore Junction, Harris County, Texas. See the proposed Project route in **Figure 1-1**.

Figure 1-1 Overview of the Project

In total, the Project will construct approximately 1,707 miles of new, 36-inch-diameter pipeline, consisting of about 327 miles in Canada and 1,375 miles within the US. It will interconnect with the northern and southern termini of the previously approved 298-mile-long, 36-inch-diameter Keystone Cushing Extension segment of the Keystone Pipeline Project (Keystone Cushing Extension). The Project proposes to transport up to 900,000 barrels of crude oil per day. This proposed volume would be 309,000 barrels greater than the rate of

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591,000 barrels per day that was analyzed for the Keystone Cushing Extension in the previous Keystone Pipeline permitting process, completed in 2008. Spill risk and potential environmental consequences described in this Risk Assessment are based on transportation of up to 900,000 barrels per day through all Project pipeline segments within the U.S. Because of this increase in throughput volume, the Keystone Cushing Extension is included as part of the overall Keystone XL Project for spill risk analysis purposes.

1.1 Federal Permitting Process

The Project will require the issuance of a Presidential Permit by the US Department of State (DOS) to cross the US/Canada border. The proposed route also crosses federal lands managed by the Bureau of Land Management (BLM) that will require the issuance of a right-of-way (ROW) grant. The issuance of the Presidential Permit and a ROW grant across federal lands are considered federal actions and, therefore, the Project is subject to environmental review pursuant to the National Environmental Policy Act (NEPA) (42 United States Code § 4321 et seq.). The DOS is the lead federal agency for NEPA compliance, with the BLM participating as a cooperating agency.

In September 2008, Keystone submitted a Presidential Permit application to the DOS, accompanied by a preliminary Environmental Report. In November 2008, Keystone submitted a comprehensive Environmental Report to the DOS. Contemporaneous with this Pipeline Risk Assessment and Environmental Consequence Analysis (Risk Assessment), Keystone is submitting a Supplemental Environmental Report to the DOS. The Environmental Report, as supplemented, includes an objective disclosure of beneficial and adverse environmental impacts resulting from the Project, as well as a set of reasonable alternatives. This Risk Assessment supplements the information in the Environmental Report, as supplemented, disclosing potential environmental consequences that might occur in the unlikely event of a crude oil release from the Project.

2.0 Introduction

This Risk Assessment presents the results of a pipeline incident frequency and spill volume analysis based on the Project's design and operations criteria and applies the resulting risk probabilities to an environmental consequence analysis that incorporates project-specific environmental data. Specifically, this Risk Assessment evaluates the risk of crude oil spills during pipeline operations, including contribution of natural hazards to spill risk and the subsequent potential effects on humans and other sensitive resources, particularly in areas of high environmental sensitivity, including federally designated high consequence areas (HCAs) (e.g., certain populated areas, designated zones around public drinking water intakes, and/or ecologically sensitive areas). Additional effects on public health and safety that could occur during Project construction are discussed under other resource sections (e.g., air quality, water resources, transportation, land use, and aesthetics) within the Environmental Report, as supplemented.

The purpose of this Risk Assessment is threefold. First, it provides a conservative range of anticipated effects from the operation of the Project that is sufficient for the purposes of NEPA. Second, the Risk Assessment provides a preliminary evaluation of potential risk during the pipeline's design phase, facilitating the early selection of possible valve locations. Third, this Risk Assessment provides Keystone with an initial basis for the development of emergency response planning and eventual incorporation of the Project into TransCanada's Integrity Management Program. Given these objectives, the analysis summarized within this Risk Assessment is intentionally conservative (i.e., overestimates risk). Keystone's expectation is that the spill frequencies and volumes presented in this analysis are not likely to occur, but are provided as a conservative framework to ensure agency decisions are based on knowledge of the potential range of effects, as well as allowing Keystone to prepare for the worst-case scenarios in its emergency response preparations as required by applicable federal regulations.

3.0 Incident Frequency-Spill Volume Study

A project-specific incident[1] frequency and spill volume analysis was conducted for the Project (**Appendix A**). This study assessed the US portion of the Project and estimated the frequency and volume of releases for five distinct and independent threats. The study is a quantitative assessment of spill potential for the entire pipeline utilizing publicly available historical incident data collected from Pipeline and Hazardous Materials Safety Administration (PHMSA) incident reports as adjusted to reflect Keystone project design and operational criteria, as well as adjustments to certain risk factors that are responsive to improvements in pipeline design, operation, and safety.

3.1 Incident Frequency

Keystone conducted a threat assessment, which identified five primary threats that could result in a release:

- Corrosion (external, internal, and stress corrosion cracking);
- Materials and construction (e.g., pipe steel flaws, defective welds);
- Accidental damage from third-party excavation;
- Incorrect pipeline operations; and
- Facility damage from natural hazards (e.g., landslides, floods).

These threats have been carefully analyzed taking into account Keystone's proprietary pipeline design and operation requirements. Major elements of Keystone's design and operational standards, which greatly reduce the threat of crude oil releases, include the following:

- Pipe specifications that meet or exceed applicable regulations;
- Use of the highest quality external pipe coatings (fusion bond epoxy or FBE) to prevent corrosion;
- Four feet of soil cover will be provided over the buried pipeline in most locations which exceeds federal standards;
- A variety of pipeline system inspection and testing programs will be implemented 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; and hydrostatic testing of the pipeline at 125 percent of the Maximum Operating Pressure (MOP).
- 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 measurement data are immediately analyzed to determine potential product releases anywhere on the pipeline system.
- Periodic pipeline integrity inspection programs using internal inspection tools to detect pipeline diameter anomalies indicating excavation damage, and loss of wall thickness from corrosion.

[1] An "incident" refers to a variety of abnormal pipeline events that are reportable to the Pipeline and Hazardous Materials Safety Administration (PHMSA), including the release of oil greater than 5 gallons, and accident resulting in human injuries, fatalities, or property damage in excess of $50,000.

- Aboveground aerial and ground surveillance inspections. The aerial inspections will 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 pipeline.

- Mainline valves and intermediate mainline valves and check valves installed along the pipeline route to reduce or avoid spill effects to PHMSA-defined HCAs.

The implementation of all these measures will ensure that the likelihood of spills to occur will be very small, and that the volume released, in the unlikely event of a spill, would be very small.

While future events cannot be known with absolute certainty, historic incident frequencies can be used to estimate the number of events that might occur over a period of time. Based on available PHMSA data, the spill frequency analysis produced a conservative incident frequency of 0.000135 incident per mile per year, equivalent to no more than 2.2 spills in 10 years for the 1,672 miles of the Project, including the Keystone Cushing Extension. For any 1-mile segment, this probability is equivalent to 1 spill every 7,400 years. **Table 3-1** shows the number of spills that might occur along the entire Project during 10 years of service.

Table 3-1 Spill Occurrence Interval Associated with the Project over 10 Years

	Conservative Number of Spills per 10 years
Steele City Segment (850 miles)	1.1
Keystone Cushing Extension (298 miles)	0.4
Gulf Coast Segment and Houston Lateral (525 miles)	0.6
Total (1,672 miles)	2.2

[1] Although the Keystone Cushing Extension has been previously permitted, it is included in this analysis since its nominal throughput has increased from 591,000 to 900,000 bpd.

PHMSA data show that the number of spills on crude oil pipelines has substantially declined in recent years with the implementation of US Department of Transportation's (USDOT) Integrity Management Rule. For the reasons listed above, Keystone expects that the actual number of incidents will be substantially lower than those estimated in this analysis.

3.2 Spill Volume

For this analysis, maximum spill volumes were determined for three spill scenarios (a complete rupture, a large leak, and a small leak) of the Keystone XL pipeline, accounting for maximum throughput, time to isolate the leak (detection and system shutdown), and subsequent draindown from the affected pipeline segment (**Appendix A**). While this analysis utilizes maximum spill volumes, actual incident data from the *Hazardous Liquid Pipeline Risk Assessment* (California State Fire Marshal 1993) indicate that spill volumes are significantly less than the maximum potential draindown volume. For example, in 50 percent of the cases, the actual spill volume represented less than 0.75 percent of the maximum potential draindown volume. In 75 percent of the cases, the actual spill volume represented less than 4.6 percent of the maximum draindown volume. Spill volumes are primarily controlled by mainline and intermediate mainline valves and check valve locations, the sensitivity of the Project leak detection and notification system, and the valve closure rates in the event of an incident. These pipeline detection and control systems are incorporated into the Project design, and represent the primary defenses for reducing spill volumes. Other procedures to reduce spill volume, by reducing draindown and depressurizing, are not estimated or included in the analysis. If these procedures were included, they most likely would significantly reduce the predicted maximum spill volumes estimated for the Project, if a spill were to occur.

PHMSA's incident database (2008) confirms that, maximum spill volumes estimated in this Risk Assessment are highly conservative (i.e., overstate risk). Examination of the current PHMSA dataset (2002 to present) indicates that the majority of actual pipeline spills are relatively small. Fifty percent of the spills consist of 3.0 barrels or less. In 85 percent of the cases, the spill volume was 100 barrels or less. In over 95 percent of the incidents, spill volumes were less than 1000 barrels. Oil spills of 10,000 barrels or larger occurred in 0.5 percent of cases. These data demonstrate that most pipeline spills are small and larger releases of 10,000 barrels or more are extremely uncommon. **Table 3-2** illustrates the frequencies that oil spills of different volumes are predicted to occur over a 10 year interval.

Table 3-2 Spill Occurrence Interval Associated with the Project over 10 Years Breakdown by Volume

	Conservative Number of Spills per 10 years
Spill volume 3 barrels or less	1.1
Spill volume between 3 barrels and 100 barrels	0.8
Spill volume between 100 barrels and 1,000 barrels	0.2
Spill volume between 1,000 barrels and 10,000 barrels	0.1
Spill volume between greater than 10,000 barrels	0.01
Total Spills	2.2

4.0 Consequences of a Spill

4.1 Human Consequences

The risk associated with the operation of the Project can be compared with the general risks encountered in everyday life. The National Center for Health Statistics (Center for Disease Control 2003) overall average annual death rate for the general population in the US is approximately 830 per 100,000. The USDOT reports the historical average risk to the general population per year associated with all hazardous liquids transmission pipelines is 0.004 in 100,000 (USDOT 2002). Therefore, the predicted risk of fatality to the public from incidents associated with the Project over and above the normal US death rate is very small.

4.2 Environmental Consequences

The environmental risk posed by a crude oil pipeline is a function of: 1) the probability of an accidental release; 2) the probability of a release reaching an environmental receptor (e.g., waterbody, fish); 3) the concentration of the contamination once it reaches the receptor; and 4) the hazard posed by that concentration of crude oil to the receptor. Based on spill probabilities and estimated spill volumes, this environmental assessment determines the probability of exposure to environmental receptors and the probable impacts based on a range of potential concentrations.

4.2.1 Crude Oil Composition

The composition of crude oil varies widely, depending on the source and processing. Crude oils are complex mixtures of hundreds of organic (and a few inorganic) compounds. These compounds differ in their solubility, toxicity, persistence, and other properties that profoundly affect their impact on the environment. The effects of a specific crude oil cannot be thoroughly understood without taking its composition into account.

The majority of the crude oil to be transported by the Project is expected to be derived from the Alberta oil sands region in Canada. The oil extracted from the oil sands is called bitumen, which is highly viscous. In order for the bitumen to be transported by pipeline, it is either mixed with a diluent and transported as diluted bitumen or upgraded to synthetic crude oil. The precise composition of diluted bitumen and synthetic crude oil will determined by shippers and is considered proprietary information. Diluted bitumen is similar to other crude oils derived from various locations throughout the world, such as portions of California, Venezuela, Nigeria, and Russia. For the purposes of this analysis, transportation of two crude oil types will be assumed: synthetic crude oil and diluted bitumen. This analysis assumes that the pipeline will contain segregated batches of these two products.

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., polycyclic aromatic hydrocarbons [PAHs], asphaltines). Straight-chained alkanes are more easily degraded in the environment than branched alkanes. Cycloalkanes are extremely resistant to biodegradation. Aromatics (i.e., benzene, toluene, ethylbenzene, xylenes compounds) pose the most potential for environmental concern. Because of their lower molecular weight they are more soluble in water than alkanes and cycloalkanes.

4.2.2 Environmental Fate and Transport

Overall, the environmental fate of crude oil is controlled by many factors and persistence is difficult to predict with great accuracy. The speed and efficiency of emergency response containment and cleanup largely dictates the fate and extent of transport within the environment. This section, however, discusses environmental fate and transport of crude oil, without accounting for the benefits of emergency response. Major factors affecting the environmental fate include spill volume, type of crude oil, dispersal rate of the crude oil, terrain, receiving media, and weather. Once released, the physical environment largely dictates the environmental persistence of the spilled material. Fate and transport of released crude oil are discussed by medium, and the primary degradation processes associated with each medium.

Soils

Overview. If released in soil at pipeline depth, the released oil can volatilize, sorb to soil particles, constituents can dissolve into the groundwater, or remain in residual form (Spence et al. 2001). The movement of crude oil, and the physical and chemical transformations of its constituents are influenced by a variety of factors and processes discussed below.

- Physical factors. The movement of crude oil across the soil surface is governed by slope, soil permeability, and, to a lesser extent, ambient temperature. Spreading across environmental surfaces reduces the bulk quantity of crude oil present in the immediate vicinity of the spill but increases the spatial area within which adverse effects may occur. Spreading and thinning of spilled crude oil in soils or water also increases the surface area of the slick, thus enhancing surface dependent fate processes such as evaporation, degradation, and dissolution.

- Evaporation. The majority of the volatile hydrocarbon fractions will evaporate quickly from pooled oil on the soil surface. Crude oil that has dispersed downward in the soil profile will evaporate more slowly because of less oil surface area exposed to the air, and the presence of other binding forces (see sorption below). The rates of evaporation are primarily controlled by soil porosity, and soil temperature.

- Sorption. Crude oil dispersed in soil will bind (adhere) to soil particles. Crude oil will usually bind most strongly with soil particles in organic soils; crude oil will usually bind less strongly with soil particles in sandy soils.

- Photodegradation. Photodegradation (breakdown of hydrocarbon molecules under exposure to sunlight) is an important process for soils directly exposed to sunlight at the soil surface. Crude oil that has penetrated deeper into the soil profile is not affected by this process.

- Biodegradation. With time, soil microorganisms capable of consuming crude oil generally increase in number and the biodegradation process naturally remediates the previously contaminated soil. The biodegradation process is enhanced as the surface area of spilled oil increases (e.g., by dispersion or spreading). Biodegradation has been shown to be an effective method of remediating soils and sediments contaminated by crude oil.

Water

Overview. If released into water, crude oil will float to the water's surface. If crude oil is left on the water's surface over an extended period of time, some constituents within the oil will evaporate, other fractions will dissolve, and, eventually, some material may descend to the bottom as sedimentation. The following is a summary of the major processes that occur during crude oil dispersion and degradation.

- Physical factors. Crude oil mobility in water increases with wind, stream velocity, and increasing temperature. Most crude oils move across surface waters at a rate of 100 to 300 meters per hour. Surface ice will greatly reduce the spreading rate of oil across a waterbody. Crude oil in flowing, as opposed to contained, waterbodies may cause transitory impacts. Although reduced in intensity, a crude oil spill into flowing waters tend to move over a much larger area.

- Dissolution. Dissolution of crude oil in water is not a significant process controlling the crude oil's fate in the environment, since most components of oils are relatively insoluble (Neff and Anderson 1981). Moreover, evaporation tends to dominate the reduction of crude oil, with dissolution slowly occurring with time. Overall solubility of crude oils tend to be less than their constituents since solubility is limited to the partitioning between oil and water interface and individual compounds are often more soluble in oil than in water, thus they tend to remain in the oil. Nevertheless, dissolution is one of the primary processes affecting the toxic effects of a spill, especially in confined waterbodies. Dissolution increases with decreasing molecular weight, increasing temperature, decreasing salinity, and increasing concentrations of dissolved organic matter. Greater photodegradation also tends to enhance the solubility of crude oil in water.

- Sorption. In water, heavy molecular weight hydrocarbons will 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 sorbing 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. Sedimented oil tends to be highly persistent and can cause shoreline impacts.

- Evaporation. Over time, evaporation is the primary mechanism of loss of low molecular weight constituents and light oil products. As lighter components evaporate, remaining crude oil becomes denser and more viscous. Evaporation tends to reduce crude oil toxicity but enhances crude oil persistence. In field trials, bulk evaporation of Alberta crude oil accounted for an almost 50 percent reduction in volume over a 12-day period, while the remaining oil was still sufficiently buoyant to float on the water’s surface (Shiu et al. 1988). Evaporation increases with increased spreading of a slick, increased temperature, and increased wind and wave action.

- Photodegradation. Photodegradation of crude oil in aquatic systems increases with greater solar intensity. It can be a significant factor controlling the reduction of a slick, especially of lighter oil constituents, but it will be less important during cloudy days and winter months. Photodegraded crude oil constituents can be more soluble and more toxic than parent compounds. Extensive photodegradation, like dissolution, may thus increase the biological impacts of a spill event.

- Biodegradation. In the immediate aftermath of a crude oil spill, natural biodegradation of crude oil will not tend to be a significant process controlling the fate of spilled crude oil in environments previously unexposed to oil. Microbial populations must become established before biodegradation can proceed at any appreciable rate. Also, prior to weathering (i.e., evaporation and dissolution of light-end constituents), oils may be toxic to the very organisms responsible for biodegradation and high molecular weight constituents tend to be resistant to biodegradation. Biodegradation is nutrient and oxygen demanding and may be precluded in nutrient-poor aquatic systems. It also may deplete oxygen reserves in closed waterbodies, causing adverse secondary effects to aquatic organisms.

4.2.3 Environmental Impacts

An evaluation of the potential impacts resulting from the accidental release of crude oil into the environment is discussed by environmental resource below.

4.2.3.1 Soils

Because pipelines are buried, soil absorption of spilled crude oil could occur, thus impacting the soils. Subsurface releases to soil tend to disperse slowly and are generally located within a contiguous and discrete area, often limited to the less consolidated soils (lower soil bulk density) within the pipeline trench. Effects to soils can be quite slow to develop, allowing time for emergency response and cleanup actions to mitigate effects to potential receptors.

In the event of a spill, a portion of the released materials would enter the surrounding soil and disperse both vertically and horizontally in the soil. The extent of dispersal would depend on a number of factors, including speed and success of emergency containment and cleanup, size and rate of release, topography of the release site, vegetative cover, soil moisture, bulk density, and soil porosity. High rates of release from the buried pipeline would result in a greater likelihood that released materials would escape the trench and reach the ground surface.

If a release were to occur in sandy soils encountered along the Project route, it is likely that the horizontal and vertical extent of the contamination would be greater than in areas containing more organic soils. Crude oil released into sandy soils would likely become visible to aerial surveillance due to product on the soils surface or discoloration of nearby vegetation, which will facilitate emergency response and soil remediation efforts. If present, soil moisture and moisture from precipitation would increase the dispersion and migration of crude oil.

The majority of the Project alignment is located in relatively flat or moderately rolling terrain. In these areas, the oil would generally begin dispersing horizontally within the pipeline trench, and with sufficient spill volume or flow, then the oil could move out of the trench onto the soils surface, generally moving toward low lying areas. If the spill were to occur on a steep slope where trench breakers had been installed during construction, then crude oil would pool primarily within the trench behind any trench breakers. If sufficient volume existed, the crude oil would breach the soil's surface as it extended over the top of the trench breaker. In either case, once on the soil's surface, the release would be more apparent to leak surveillance patrols, facilitating emergency response and remediation.

Both on the surface and in the subsurface, rapid attenuation of light, volatile constituents (due to evaporation) would quickly reduce the total volume of crude oil, while heavier constituents would be more persistent. Except in rare cases of high rate and high total volume releases with environmental settings characterized by steep topography or karst terrain, soil impacts would be confined to a relatively small, contiguous, and easily defined area, facilitating cleanup and remediation. Within a relatively short time, lateral migration would generally stabilize. Downward vertical migration would begin at the onset of a spill, with rates governed by soil permeability. For example, in soils with moderately high permeability, water may penetrate 2.5 inches per hour, while penetration rates for soils of low permeability may occur at 0.05 inch per hour. Crude oil is more viscous than water, therefore, permeability of crude oil would be slower.

In accordance with federal and state regulations, Keystone would be responsible for cleanup of contaminated soils and would be required to meet applicable cleanup levels. Soil cleanup levels for benzene from petroleum hydrocarbon releases vary by state (Montana: 0.04 part per million [ppm]; South Dakota: 17 ppm; Nebraska: 3.63 ppm; Kansas: 9.8 ppm; Oklahoma: no value; Texas: 38 ppm). While Oklahoma has no benzene soil cleanup standard, other risk-based screening values exist for petroleum hydrocarbons and, consequently, soils would still be remediated to ensure human health and environmental quality. Once remedial cleanup levels were achieved in the soils, no adverse or long-term impacts would be expected.

It is difficult to estimate the volume of soil that might be contaminated in the event of a spill. Site-specific environmental conditions (e.g., soil type, weather conditions) and release dynamics (e.g., leak rate, leak duration) would result in substantially different surface spreading and infiltration rates, which in turn, affect the final volume of affected soil to be remediated. Based on historical data (PHMSA 2008), soil remediation involved 100 cubic yards of soil or less at the majority of spill sites where soil contamination occurred, and only 3 percent of the spill sites required remediation of 10,000 cubic yards or more (PHMSA 2008).

4.2.3.2 Vegetation and Soil Ecosystems

Crude oil released to the soil's surface could potentially produce localized effects on plant populations. Terrestrial plants are much less sensitive to crude oil than aquatic species. The lowest toxicity threshold for terrestrial plants found in the US Environmental Protection Agency (USEPA) ECOTOX database (USEPA 2001) is 18.2 ppm for benzene, which is substantially higher than the 7.4 ppm threshold for aquatic species and the 0.005 ppm threshold for human drinking water. Similarly, available data from the USEPA database indicate that earthworms also are less sensitive than aquatic species (toxicity threshold was greater than 1,000 ppm). If concentrations were sufficiently high, however, crude oil in the root zone could harm respiration and nutrient uptake by individual plants and organisms.

While a release of crude oil could result in the contamination of soils (see Section 4.2.2.1, Soils), Keystone will be responsible for cleanup of contaminated soils. Once remedial cleanup levels were achieved in the soils, no adverse or long-term impacts to vegetation would be expected.

4.2.3.3 Wildlife

Spilled crude oil can affect organisms directly and indirectly. Direct effects include physical processes, such as oiling of feathers and fur, and toxicological effects, which can cause sickness or mortality. Indirect effects are less conspicuous and include habitat impacts, nutrient cycling disruptions, and alterations in ecosystem relationships. The magnitude of effects varies with multiple factors, the most significant of which include the amount of material released, the size of the spill dispersal area, the type of crude oil spilled, the species assemblage present, climate, and the spill response tactics employed.

Wildlife, especially birds and shoreline mammals, are typically among the most visibly affected organisms in any crude oil spill. Effects of crude oil can be differentiated into physical (mechanical) and toxicological (chemical) effects. Physical effects result from the actual coating of animals with crude oil, causing reductions in thermal insulative capacity and buoyancy of plumage (feathers) and pelage (fur).

Crude oil released to the environment may cause adverse biological effects on birds and mammals via inhalation or ingestion exposure. Ingestion of crude oil may occur when animals consume oil-contaminated food, drink oil-contaminated water, or orally consume crude oil during preening and grooming behaviors.

Potential adverse effects could result from direct acute exposure. Acute toxic effects include drying of the skin, irritation of mucous membranes, diarrhea, narcotic effects, and possible mortality. While releases of crude oil may have an immediate and direct effect on wildlife populations, the potential for physical and toxicological effects attenuates with time as the volume of material diminishes, leaving behind more persistent, less volatile, and less water-soluble compounds. Although many of these remaining compounds are toxic and potentially carcinogenic, they do not readily disperse in the environment and their bioavailability is low and, therefore, the potential for impacts is low.

Unlike aquatic organisms that frequently cannot avoid spills in their habitats, the behavioral responses of terrestrial wildlife may help reduce potential adverse effects. Many birds and mammals are mobile and generally will avoid oil-impacted areas and contaminated food (Sharp 1990; Stubblefield et al. 1995). In a few cases, such as cave-dwelling species, organisms that are obligate users of contaminated habitat may be exposed. However, most terrestrial species have alternative, unimpacted habitat available, as will often be the case with localized spills (in contrast to large-scale oil spills in marine systems), therefore, mortality of these species would be limited (Stubblefield et al. 1995).

Indirect environmental effects of spills can include reduction of suitable habitat or food supply. Primary producers (e.g., algae and plants) may experience an initial decrease in primary productivity due to physical effects and acute toxicity of the spill. However, these effects tend to be short-lived and a decreased food supply is not considered to be a major chronic stressor to herbivorous organisms after a spill. If mortality occurs to local invertebrate and wildlife populations, the ability of the population to recover will depend upon the size of the impact area and the ability of surrounding populations to repopulate the area.

4.2.3.4 Water Resources

Crude oil could be released to water resources if the pipeline is breached or leaks occur. As part of project planning and in recognition of the environmental sensitivity of waterbodies, the Project routing process attempted to minimize the number waterbodies crossed, including groundwater aquifers. Furthermore, valves have been strategically located along the Project route to help reduce the amount of crude oil that could potentially spill into waterbodies, if such an event were to occur. The location of valves, spill containment measures, and implementing actions in the Project Emergency Response Plan would mitigate adverse effects to both surface water and groundwater.

Groundwater

Multiple groundwater aquifers underlie the proposed Project. Vulnerability of these aquifers is a function of the depth to groundwater and the permeability of the overlying soils. While routine operation of the Project would not affect groundwater, there is the possibility that a release could migrate through the overlying surface materials and enter a groundwater system.

In general, the potential for groundwater contamination following a spill would be more probable in locations where a release into or on the surface of soils has occurred:

- Where a relatively shallow water table is present (as opposed to locations where a deeper, confined aquifer system is present);
- Where soils with high permeability are present throughout the unsaturated zone; and
- Where, in cooperation with federal and state agencies, the PHMSA (in cooperation with the US Geological Service [USGS] and other federal and state agencies) has identified specific groundwater resources that are particularly vulnerable to contamination. These resources are designated by PHMSA as HCAs (Section 4.3.2).

Depending on soil properties, the depth to groundwater, and the amount of crude oil in the unsaturated zone, localized groundwater contamination can result from the presence of free crude oil and the migration of its dissolved constituents. Crude oil is less dense than water and would tend to form a floating pool after reaching the groundwater surface. Movement of crude oil is generally quite limited due to adherence with soil particles, groundwater flow rates, and natural attenuation (i.e., microbial degradation) (Freeze and Cherry 1979; Fetter 1993). Those compounds in the crude oil that are soluble in water will form a larger, dissolved “plume.” This plume would tend to migrate laterally in the direction of groundwater flow. Movement of dissolved constituent typically extends for greater distances than movement of pure crude oil in the subsurface, but is still relatively limited. The flow velocity of dissolved constituents would be a function of the groundwater flow rate and natural attenuation, with the dissolved constituents migrating more slowly than groundwater.

Unlike chemicals with high environmental persistence (e.g., trichloroethylene, pesticides), the aerial extent of the dissolved constituents will stabilize over time due to natural attenuation processes. Natural biodegradation through metabolism by naturally occurring microorganisms is often an effective mechanism for reducing the volume of crude oil and its constituents. Natural attenuation will reduce most toxic compounds into non-toxic metabolic byproducts, typically carbon dioxide and water (Minnesota Pollution Control Agency 2005). Field investigations of more than 600 historical petroleum hydrocarbon release sites indicate the migration of dissolved constituents typically stabilize within several hundred feet of the crude oil source area (Newell and Conner 1998; USGS 1998). Over a longer period, the area of the contaminant plume may begin to reduce due to natural biodegradation. Removal of crude oil contamination will eliminate the source of dissolved constituents impacting the groundwater.

Most crude oil constituents are not water soluble. For those constituents that are water soluble (e.g., benzene) the dissolved concentration is not controlled by the amount of oil in contact with the water, but by the concentration of the specific constituent in the oil (Charbeneau et al. 2000; Charbeneau 2003; Freeze and Cherry 1979). Studies of 69 crude oils found that benzene was the only aromatic or PAH compound tested that is capable of exceeding groundwater protection values for drinking water (i.e., maximum contaminant levels [MCLs] or Water Health Based Limits) (Kerr et al. 1999 as cited in O'Reilly et al. 2001).

If exposure to humans or other important resources would be possible from a release into groundwater, then regulatory standards, such as drinking water criteria (MCL) would mandate the scope of remedial actions, timeframe for remediation activities, and cleanup levels. For human health protection, the national MCL is an enforceable standard established by the USEPA and is designed to protect long-term human health. The promulgated drinking water standards for humans vary by several orders of magnitude for crude oil constituents. Of the various crude oil constituents, benzene has the lowest national MCL at 0.005 ppm[2] and, therefore, it was used to evaluate impacts on drinking water supplies, whether from surface water or groundwater.

However, emergency response and remediation efforts have the potential for appreciable adverse environmental effects from construction/cleanup equipment. If no active remediation activities were undertaken, natural biodegradation and attenuation would ultimately allow a return to preexisting conditions in both soil and groundwater. Depending on the amount of crude oil reaching the groundwater and natural attenuation rates, this would likely require up to tens of years. Keystone will utilize the most appropriate cleanup procedure as determined in cooperation with the applicable federal and state agencies.

<u>Flowing Surface Waters</u>

This report evaluated impacts to downstream drinking water sources by comparing projected surface water benzene concentrations with the national MCL for benzene. Like other pipelines already in existence, the Project will cross hundreds of perennial, intermittent, and ephemeral streams. Rather than evaluate the risk to each waterbody crossed by the Project, this risk assessment evaluated categories of streams, based on the magnitude of streamflow and stream width. **Table 4-1** summarizes the stream categories used for the assessment and identifies several representative streams within these categories.

Table 4-1 Stream Categories

	Streamflow (cubic feet per second [cfs])	Top of Bank Stream Width (feet)	Representative Streams
Low Flow Stream	10 – 100	<50	Many unnamed intermittent tributaries in all states crossed, Bear Creek (MT), South Branch Timber Creek (NE)
Lower Moderate Flow Stream	100 – 1,000	50 – 500	Upper Sevenmile Creek (MT), Lone Tree Creek (MT), Little Blue River (NE)
Upper Moderate Flow Stream	1,000 – 10,000	500 – 1,000	Yellowstone River (MT), White River (SD), Niobrara River (NE)
High Flow Stream	>10,000	1,000 – 2,500	Missouri River (MT), Loup River (NE), Platte River (NE), Canadian River (OK), Red River (TX)

[2] All affected states along the Project route use the national MCL value of 0.005 ppm.

The following extremely conservative assumptions were developed to over-estimate potential spill effects for planning purposes.

- The entire volume of a spill was released directly into a waterbody;
- Complete, instantaneous mixing occurred;
- The entire benzene content was solubilized into the water column.

Under the actual conditions of a crude oil release, the spill and mixing events outlined by these assumptions are not expected to occur at the very high levels described.

A 1-hour release period for the entire spill volume was assumed in order to maximize the product concentration in water. The estimated benzene concentrations were then compared with the human health drinking water MCL for benzene (**Tables 4-2** and **4-3**). Based on these ultra-conservative assumptions, results suggest that most spills that enter a waterbody could result in exceedence of the national MCL for benzene. Although the assumptions used are highly conservative and, thus, overestimate potential benzene water concentrations, the analysis indicates the need for rapid notification of managers of municipal water intakes downstream of a spill so that any potentially affected drinking water intakes could be closed to bypass river water containing crude oil.

In addition to evaluating a general-case spill to flowing water, the potential for impacts to any specific waterbody also were evaluated. To do this, the occurrence interval for a spill at any one representative stream within one of the four stream categories reflected in **Table 4-1** was calculated based on spill probabilities generated from the PHMSA database. To be conservative, a 500-foot buffer on either side of the river was added to the crossing widths identified in **Table 4-1**. The occurrence intervals shown on **Tables 4-2** and **4-3** indicate the chance of a spill occurring at any specific waterbody is very low. Conservative occurrence intervals for a spill at any representative stream within any of the stream categories ranged from about 22,000 years for a large waterbody to over 830,000 years for a small waterbody (less likely to occur in any single small waterbody than any single large waterbody). If any release did occur, it is likely that the total release volume of a spill likely would be 3 barrels or less based on PHMSA data for historical spill volumes.

In summary, while a release of crude oil directly into any given waterbody would likely cause an exceedence of drinking water standards under the conservative assumptions used in this analysis, the frequency of such an event would be very low. Nevertheless, streams and rivers with downstream drinking water intakes represent sensitive environmental resources and could be temporarily impacted by a crude oil release. Keystone's Emergency Response Plan contains provisions for protecting and mitigating potential impacts to drinking water.

Aquatic Organisms

The concentration of crude oil constituents in an actual spill would vary both temporally and spatially in surface water; however, localized toxicity could occur from virtually any size of crude oil spill. **Table 4-4** summarizes the acute toxicity values (USEPA 2000) of various crude oil hydrocarbons to a broad range of freshwater species. Acute toxicity refers to the death or complete immobility of an organism within a short period of exposure. The LC_{50} is the concentration of a compound necessary to cause 50 percent mortality in laboratory test organisms. For aquatic biota, most acute LC_{50} for monoaromatics range between 10 and 100 ppm. LC_{50} for the polyaromatic naphthalene were generally between 1 and 10 ppm, while LC_{50} values for anthracene were generally less than 1 ppm.

Table 4-2 Comparison of Estimated Benzene Concentrations with the Benzene MCL Resulting from a Diluted Bitumen Spill

Streamflow	Benzene MCL (ppm)	Stream Flow Rate (cfs)	Product Released							
			Very Small Spill: 3 barrels		Small Spill: 50 barrels		Moderate Spill: 1,000 barrels		Large Spill: 10,000 barrels	
			Benzene Conc. (ppm)	Occurrence Interval (years)	Benzene Conc. (ppm)	Occurrence Interval (years)	Benzene Conc. (ppm)	Occurrence Interval (years)	Benzene Conc. (ppm)	Occurrence Interval (years)
Low Flow Stream	0.005	10	**0.7**	**74,681**	**10.9**	**124,469**	**218**	**248,938**	**2175**	**829,792**
Lower Moderate Flow Stream	0.005	100	**0.07**	**52,277**	**1.1**	**87,128**	**21.8**	**174,256**	**218**	**580,854**
Upper Moderate Flow Stream	0.005	1,000	**0.007**	**39,208**	**0.1**	**65,346**	**2.2**	**130,692**	**21.8**	**435,641**
High Flow Stream	0.005	10,000	0.0007	22,404	**0.01**	**37,341**	**0.2**	**74,681**	**2.2**	**248,938**

Notes:

- Historical data indicate that the most probable spill volume would be 3 barrels or less. However, this entire analysis is based on conservative incident frequencies and volumes calculated from worst-case spill volumes (**Appendix A**), which overestimates the proportion of larger spills. Consequently, the assessment is conservative in its evaluation on the magnitude of environmental consequences.
- Estimated concentration is based on release of benzene into water over a 1-hour period with uniform mixing conditions.
- Concentrations are based on a 0.15 percent by weight benzene content of the transported material.
- Shading indicates estimated benzene concentrations that could exceed the benzene MCL of 0.005 ppm.
- Occurrence intervals are based on an overall predicted incident frequency of 0.000135 incident/mile*year (**Appendix A**), projected frequencies of each spill volume, and estimated stream widths. Widths of higher flow streams are greater than widths of lower flow streams, with more distance where an incident might occur. This results in a greater predicted frequency for high flow streams and a corresponding lower occurrence interval.

Table 4-3 Comparison of Estimated Benzene Concentrations with the Benzene MCL Resulting from a Synthetic Crude Spill

Streamflow	Benzene MCL (ppm)	Stream Flow Rate (cfs)	Product Released							
			Small spill: 3 barrels		Moderate spill: 50 barrels		Large spill: 1,000 barrels		Very Large spill: 10,000 barrels	
			Benzene Conc. (ppm)	Occurrence Interval (years)	Benzene Conc. (ppm)	Occurrence Interval (years)	Benzene Conc. (ppm)	Occurrence Interval (years)	Benzene Conc. (ppm)	Occurrence Interval (years)
Low Flow Stream	0.005	10	**0.2**	**74,681**	**3.6**	**124,469**	**72**	**248,938**	**725**	**829,792**
Lower Moderate Flow Stream	0.005	100	**0.02**	**52,277**	**0.4**	**87,128**	**7.2**	**174,256**	**72.5**	**580,854**
Upper Moderate Flow Stream	0.005	1,000	0.002	39,208	**0.04**	**65,346**	**0.7**	**130,692**	**7.2**	**435,641**
High Flow Stream	0.005	10,000	0.0002	22,404	0.004	37,341	**0.07**	**74,681**	**0.7**	**248,938**

Notes:

- Historical data indicate that the most probable spill volume would be 3 barrels or less. However, this entire analysis is based on conservative incident frequencies and volumes calculated from worst-case spill volumes (**Appendix A**), which overestimates the proportion of larger spills. Consequently, the assessment is conservative in its evaluation on the magnitude of environmental consequences.
- Estimated concentration is based on release of benzene into water over a 1-hour period with uniform mixing conditions.
- Concentrations are based on a 0.05 percent by weight benzene content of the transported material.
- Shading indicates estimated benzene concentrations that could exceed the MCL of 0.005 ppm.
- Occurrence intervals are based on an overall predicted incident frequency of 0.000135 incident/mile*year (**Appendix A**), projected frequencies of each spill volume, and estimated stream widths. Widths of higher flow streams are greater than widths of lower flow streams, with more distance where an incident might occur. This results in a greater predicted frequency for high flow streams and a corresponding lower occurrence interval.

Table 4-4 shows fish are among the most sensitive aquatic biota, while aquatic invertebrates generally have intermediate sensitivities, and algae and bacteria tend to be the least sensitive. Nevertheless, even when major fish kills have occurred as a result of oil spills, population recovery has been observed and long-term changes in fish abundance have not been reported. Benthic (bottom-dwelling) aquatic invertebrates tend to be more sensitive than algae, but are equally or less sensitive than fish. Planktonic (floating) species tend to be more sensitive than most benthic insects, crustaceans, and molluscs.

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 of the toxicity of its constituents. As an example, **Table 4-5** 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.

While lightweight aromatics such as benzene tend to be water soluble and relatively toxic, they also are highly volatile. Thus, most or all of the lightweight hydrocarbons accidentally released into the environment evaporate, and the environmental persistence of this crude oil fraction tends to be low. High molecular weight aromatic compounds, including PAHs, are not very water-soluble and have a high affinity for organic material. Consequently, these compounds, if present, have limited bioavailability, which render them substantially less toxic than more water-soluble compounds (Neff 1979). Additionally, these compounds generally do not accumulate to any great extent because these compounds are rapidly metabolized (Lawrence and Weber 1984; West et al.1984). There are some indications, however, that prolonged exposure to elevated concentrations of these compounds may result in a higher incidence of growth abnormalities and hyperplastic diseases in aquatic organisms (Couch and Harshbarger 1985).

Significantly, some constituents in crude oil may have greater environmental persistence than lightweight compounds (e.g., benzene), but their limited bioavailability renders them substantially less toxic than other more soluble compounds. 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.

Table 4-6 summarizes chronic toxicity values (most frequently measured as reduced reproduction, growth, or weight) of benzene to freshwater biota. 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.

The potential impacts to aquatic organisms of various-sized spills to waterbodies were modeled assuming the benzene content within each type of crude oil completely dissolved in the water. The benzene concentration was predicted based on amount of crude oil spilled and streamflow. The estimated benzene concentrations were compared to conservative acute and chronic toxicity values for protection of aquatic organisms. For aquatic biota, the lowest acute and chronic toxicity thresholds for benzene are 7.4 ppm and 1.4 ppm, respectively, based on standardized trout toxicity tests (USEPA 2000). These toxicity threshold values are considered protective of acute and chronic effects to aquatic biota. Although trout are not found in many of the habitats crossed by the project, trout are among the most sensitive aquatic species and reliable acute and chronic trout toxicity data are available. Using trout toxicity thresholds, therefore, provides a conservative benchmark to screen for the potential for toxicity.

Table 4-4 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*)	---[1]	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	---

[1] Indicates no value was available in the database.

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 4-5 Acute Toxicity of Crude Oil Hydrocarbons to *Daphnia magna*

Compound	48-hr LC_{50} (ppm)	Optimum Solubility (ppm)	Relative Toxicity
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

Note: 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).

Relative toxicity = optimum solubility/LC_{50}.

Table 4-6 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.

Tables 4-7 through **4-10** summarize a screening-level assessment of acute and chronic toxicity to aquatic resources. Broadly, acute toxicity could potentially occur if substantial amounts of crude oil were to enter rivers and streams. If such an event were to occur within a small stream, aquatic species in the immediate vicinity and downstream of the rupture could be killed or injured. Chronic toxicity also could potentially occur in small and moderate sized streams and rivers. However, emergency response, containment, and cleanup efforts would help reduce the concentrations and minimize the potential for chronic toxicity. In comparison, relatively small spills (less than 50 barrels) into moderate and large rivers would not pose a major toxicological threat. In small to moderate sized streams and rivers, some toxicity might occur in localized areas, such as backwaters where concentrations would likely be higher than in the mainstream of the river.

The likelihood of a release into any single waterbody is low, with an occurrence interval of no more than once every 22,000 to 830,000 years (**Tables 4-7** through **4-10**). If any release did occur, it is likely that the total release volume of a spill likely would be 3 barrels or less based on historical spill volumes.

While a release of crude oil into any given waterbody might cause immediate localized toxicity to aquatic biota, particularly in smaller streams and rivers, the frequency of such an event would be very low. Nevertheless, streams and rivers with aquatic biota represent the sensitive environmental resources that could be temporarily impacted by a crude oil release.

<u>Wetlands/ Reservoirs/ Lakes</u>

Although planning and routing efforts have reduced the overall number of wetlands and static waterbody environments crossed by the Project, wetlands and waterbodies with persistently saturated soils are present along and adjacent to the Project route. The effects of crude oil released into a wetland environment will depend not only upon the quantity of oil released, but also on the physical conditions of the wetland at the time of the release. Wetlands include a wide range of environmental conditions. Wetlands can consist of many acres of standing water dissected with ponds and channels, or they may simply be areas of saturated soil with no open water. A single wetland can even vary between these two extremes as seasonal precipitation varies. Wetland surfaces are generally low gradient with very slow unidirectional flow or no discernable flow. The presence of vegetation or narrow spits of dry land protruding into wetlands also may isolate parts of the wetland. Given these conditions, spilled materials may remain in restricted areas for longer periods than in river environments.

Table 4-7 Comparison of Estimated Benzene Concentrations Following a Diluted Bitumen Spill to the Acute Toxicity Thresholds for Aquatic Life (7.4 ppm) for Streams Crossed by the Project

Throughput 435,000 bpd	Stream Flow Rate (cfs)	Acute Toxicity Threshold (ppm)	Product Released							
			Very Small Spill: 3 barrels		Small Spill: 50 barrels		Moderate Spill: 1,000 barrels		Large Spill: 10,000 barrels	
			Benzene Conc. (ppm)	Occurrence Interval (years)	Benzene Conc. (ppm)	Occurrence Interval (years)	Benzene Conc. (ppm)	Occurrence Interval (years)	Benzene Conc. (ppm)	Occurrence Interval (years)
Low Flow Stream	10	7.4	0.7	74,681	10.9	124,469	217.5	248,938	2,175	829,792
Lower Moderate Flow Stream	100	7.4	0.07	52,277	1.1	87,128	21.7	174,256	218	580,854
Upper Moderate Flow Stream	1,000	7.4	0.007	39,208	0.1	65,346	2.2	130,692	21.8	435,641
High Flow Stream	10,000	7.4	0.0007	22,404	0.01	37,341	0.2	74,681	2.2	248,938

Notes:

- Historical data indicate that the most probable spill volume would be 3 barrels or less. However, this entire analysis is based on conservative incident frequencies and volumes calculated from worst-case spill volumes (**Appendix A**), which overestimates the proportion of larger spills. Consequently, the assessment is conservative in its evaluation on the magnitude of environmental consequences.
- Estimated proportion of benzene in the transported material is 0.15 percent, and is assumed to be entirely water solubilized in the event of a spill. The resulting concentration was calculated by multiplying 0.15 percent of the total amount of material released divided by 1 hour of stream flow volume. The model assumes uniform mixing conditions.
- Benzene concentrations are compared against the acute toxicity threshold for benzene.
- Shading indicates concentrations that could potentially cause acute toxicity to aquatic species. The darkest shading represents high probability of acute toxicity (>10 times the toxicity threshold); lighter shading represents moderate probability of acute toxicity (1 to 10 times the toxicity threshold); and unshaded areas represent low probability of acute toxicity (<toxicity threshold).
- Occurrence intervals are based on an overall predicted incident frequency of 0.000135 incident/mile*year (**Appendix A**), projected frequencies of each spill volume, and estimated stream widths. Widths of higher flow streams are greater than widths of lower flow streams, with more distance where an incident might occur. This results in a greater predicted frequency for high flow streams and a corresponding lower occurrence interval.

Table 4-8 Comparison of Estimated Benzene Concentrations Following a Synthetic Crude Spill to the Acute Toxicity Thresholds for Aquatic Life (7.4 ppm) for Streams Crossed by the Project

Throughput 435,000 bpd	Stream Flow Rate (cfs)	Acute Toxicity Threshold (ppm)	Product Released							
			Very Small Spill: 3 barrels		Small Spill: 50 barrels		Moderate Spill: 1,000 barrels		Large Spill: 10,000 barrels	
			Benzene Conc. (ppm)	Occurrence Interval (years)	Benzene Conc. (ppm)	Occurrence Interval (years)	Benzene Conc. (ppm)	Occurrence Interval (years)	Benzene Conc. (ppm)	Occurrence Interval (years)
Low Flow Stream	10	7.4	0.2	74,681	3.6	124,469	72	248,938	725	829,792
Lower Moderate Flow Stream	100	7.4	0.02	52,277	0.4	87,128	7.2	174,256	72.5	580,854
Upper Moderate Flow Stream	1,000	7.4	0.002	39,208	0.04	65,346	0.7	130,692	7.2	435,641
High Flow Stream	10,000	7.4	0.0002	22,404	0.004	37,341	0.07	74,681	0.7	248,938

Notes:

- Historical data indicate that the most probable spill volume would be 3 barrels or less. However, this entire analysis is based on conservative incident frequencies and volumes calculated from worst-case spill volumes (**Appendix A**), which overestimates the proportion of larger spills. Consequently, the assessment is conservative in its evaluation on the magnitude of environmental consequences.
- Estimated proportion of benzene in the transported material is 0.05 percent, and is assumed to be entirely water solubilized in the event of a spill. The resulting concentration was calculated by multiplying 0.05 percent of the total amount of material released divided by 1 hour of stream flow volume. The model assumes uniform mixing conditions.
- Benzene concentrations are compared against the acute toxicity threshold for benzene.
- Shading indicates concentrations that could potentially cause acute toxicity to aquatic species. The darkest shading represents high probability of acute toxicity (>10 times the toxicity threshold); lighter shading represents moderate probability of acute toxicity (1 to 10 times the toxicity threshold); and unshaded areas represent low probability of acute toxicity (<toxicity threshold).
- Occurrence intervals are based on an overall predicted incident frequency of 0.000135 incident/mile*year (**Appendix A**), projected frequencies of each spill volume, and estimated stream widths. Widths of higher flow streams are greater than widths of lower flow streams, with more distance where an incident might occur. This results in a greater predicted frequency for high flow streams and a corresponding lower occurrence interval.

Table 4-9 Comparison of Estimated Diluted Bitumen Concentrations Following a Spill to the Chronic Toxicity Thresholds for Aquatic Life for Streams Crossed by the Project

Throughput 435,000 bpd	Stream Flow Rate (cfs)	Chronic Toxicity Threshold (ppm)	Product Released							
			Very Small Spill: 3 barrels		Small Spill: 50 barrels		Moderate Spill: 1,000 barrels		Large Spill: 10,000 barrels	
			Benzene Conc. (ppm)	Occurrence Interval (years)	Benzene Conc. (ppm)	Occurrence Interval (years)	Benzene Conc. (ppm)	Occurrence Interval (years)	Benzene Conc. (ppm)	Occurrence Interval (years)
Low Flow Stream	10	1.4	0.004	74,681	0.06	124,469	1.3	248,938	12.9	829,792
Lower Moderate Flow Stream	100	1.4	0.0004	52,277	0.006	87,128	0.13	174,256	1.3	580,854
Upper Moderate Flow Stream	1,000	1.4	0.00004	39,208	0.0006	65,346	0.013	130,692	0.13	435,641
High Flow Stream	10,000	1.4	0.000004	22,404	0.00006	37,341	0.0013	74,681	0.013	248,938

Notes:

- Historical data indicate that the most probable spill volume would be 3 barrels or less. However, this entire analysis is based on conservative incident frequencies and volumes calculated from worst-case spill volumes (**Appendix A**), which overestimates the proportion of larger spills. Consequently, the assessment is conservative in its evaluation on the magnitude of environmental consequences.
- Estimated proportion of benzene in the transported material is 0.15 percent, and is assumed to be entirely water solubilized in the event of a spill. The resulting concentration was calculated by multiplying 0.15 percent of the total amount of material released divided by 7 days of stream flow volume. The model assumes uniform mixing conditions.
- The chronic toxicity value for benzene is based on a 7-day toxicity value of 1.4 ppm for trout.
- Exposure concentrations were estimated over a 7-day period since the chronic toxicity value was based on a 7-day exposure.
- Shading indicates concentrations that could potentially cause chronic toxicity to aquatic species. The darkest shading represents high probability of chronic toxicity (>10 times the toxicity threshold); lighter shading represents moderate probability of chronic toxicity (1 to 10 times the toxicity threshold); and unshaded areas represent low probability of chronic toxicity (<toxicity threshold).
- Occurrence intervals are based on an overall predicted incident frequency of 0.000135 incident/mile*year (**Appendix A**), projected frequencies of each spill volume, and estimated stream widths. Widths of higher flow streams are greater than widths of lower flow streams, with more distance where an incident might occur. This results in a greater predicted frequency for high flow streams and a corresponding lower occurrence interval.

Table 4-10 Comparison of Estimated Synthetic Crude Oil Concentrations Following a Spill to the Chronic Toxicity Thresholds for Aquatic Life for Streams Crossed by the Project

Throughput 435,000 bpd	Stream Flow Rate (cfs)	Chronic Toxicity Threshold (ppm)	Product Released							
			Very Small Spill: 3 barrels		Small Spill: 50 barrels		Moderate Spill: 1,000 barrels		Large Spill: 10,000 barrels	
			Benzene Conc. (ppm)	Occurrence Interval (years)	Benzene Conc. (ppm)	Occurrence Interval (years)	Benzene Conc. (ppm)	Occurrence Interval (years)	Benzene Conc. (ppm)	Occurrence Interval (years)
Low Flow Stream	10	1.4	0.001	74,681	0.02	124,469	0.4	248,938	4.3	829,792
Lower Moderate Flow Stream	100	1.4	0.0001	52,277	0.002	87,128	0.04	174,256	0.4	580,854
Upper Moderate Flow Stream	1,000	1.4	0.00001	39,208	0.0002	65,346	0.004	130,692	0.04	435,641
High Flow Stream	10,000	1.4	0.000001	22,404	0.00002	37,341	0.0004	74,681	0.004	248,938

Notes:

- Historical data indicate that the most probable spill volume would be 3 barrels or less. However, this entire analysis is based on conservative incident frequencies and volumes calculated from worst-case spill volumes (**Appendix A**), which overestimates the proportion of larger spills. Consequently, the assessment is conservative in its evaluation on the magnitude of environmental consequences.
- Estimated proportion of benzene in the transported material is 0.05 percent, and is assumed to be entirely water solubilized in the event of a spill. The resulting concentration was calculated by multiplying 0.05 percent of the total amount of material released divided by 7 days of stream flow volume. The model assumes uniform mixing conditions.
- The chronic toxicity value for benzene is based on a 7-day toxicity value of 1.4 ppm for trout.
- Exposure concentrations were estimated over a 7-day period since the chronic toxicity value was based on a 7-day exposure.
- Shading indicates concentrations that could potentially cause chronic toxicity to aquatic species. The darkest shading represents high probability of chronic toxicity (>10 times the toxicity threshold); lighter shading represents moderate probability of chronic toxicity (1 to 10 times the toxicity threshold); and unshaded areas represent low probability of chronic toxicity (<toxicity threshold).
- Occurrence intervals are based on an overall predicted incident frequency of 0.000135 incident/mile*year (**Appendix A**), projected frequencies of each spill volume, and estimated stream widths. Widths of higher flow streams are greater than widths of lower flow streams, with more distance where an incident might occur. This results in a greater predicted frequency for high flow streams and a corresponding lower occurrence interval.

Crude oil released from a subsurface pipe within a wetland could reach the soil surface. If the water table reaches the surface, the release would manifest as floating crude oil. The general lack of surface flow within a wetland would restrict crude oil movement. Where surface water is present within a wetland, the spill would spread laterally across the water's surface and be readily visible during routine ROW surveillance. The depth of soil impacts likely would be minimal, due to shallow (or emergent) groundwater conditions. Conversely, groundwater impacts within the wetland are likely to be confined to the near-surface, enhancing the potential for biodegradation. If humans or other important resource exposures were to occur in proximity to the wetland, then regulatory drivers would mandate the scope of remedial actions, timeframe for remediation activities, and cleanup levels. However, response and remediation efforts in a wetland have the potential for appreciable adverse effects from construction/cleanup equipment. If no active remediation activities were undertaken, natural biodegradation and attenuation would ultimately allow a return to preexisting conditions in both soil and groundwater. This would likely require a timeframe on the order of tens of years. In the unlikely event of a spill, Keystone will utilize the most appropriate cleanup procedures as determined in coordination with the applicable federal and state agencies.

The chance of a spill occurring at any specific wetland along the pipeline is very low. Based on survey data and aerial interpretation, wetlands comprise 46.0 miles of the entire Project (Table 3.5-7 of the Project Environmental Report November 2008). Of the estimated maximum of 2.2 spills postulated to occur during a 10-year period within the entire pipeline system, about 0.06 spill would be expected to occur within wetland areas (equivalent to no more than one spill every 161 years). If any release did occur, it is likely that the total release volume of a spill likely would be 3 barrels or less based on historical spill volumes (**Appendix A**).

The predicted effects of a spill reaching standing water (e.g., reservoirs, lakes) would depend largely upon the volume of crude oil entering the waterbody and the volume of water within the waterbody.

Table 4-11 summarizes the amount of water necessary to dilute spill volumes below aquatic toxicity and drinking water thresholds. While this preliminary approach does not account for fate and transport mechanisms, mixing zones, environmental factors, and emergency response capabilities, it does provide an initial screening benchmark for identifying areas of potential concern.

Table 4-11 Amount of Water Required to Dilute Crude Oil Spills Below Benchmark Values

Barrels of Crude Oil	Volume of Water Required to Dilute Crude Oil Below Benchmark (acre-feet)[1]		
	Acute Toxicity Threshold (7.4 milligrams per liter [mg/L])	Chronic Toxicity Threshold (1.4 mg/L)	Drinking Water MCL (0.005 mg/L)
Diluted Bitumen			
3	0.3	1.5	413
50	4.6	24.3	6,890
1,000	92.0	486	136,136
10,000	920	4,862	1,361,358
Synthetic Crude			
3	0.09	0.5	138
50	1.6	8.2	2,297
1,000	31	164	45,930
10,000	310	1,640	459,301

[1] Benchmarks based on aquatic toxicity and drinking water thresholds established for benzene. The estimated benzene content of the diluted bitumen is 0.15 percent by weight. The synthetic crude oil is estimated to have a benzene content of 0.05 percent by weight.

Based on a review of publicly available toxicity literature for wetland plant groups (i.e., algae, annual macrophytes, and perennial macrophytes), crude oil is toxic to aquatic plants but at higher concentrations than observed for fish and invertebrates. Therefore, spill concentrations that are less than toxic effect levels for fish and invertebrates (see Aquatic Organisms, above) also would not affect wetland plant species.

In summary, while a release of crude oil into wetland and static waterbodies has the potential to cause temporary environmental impacts, the frequency of such an event would be very low.

4.3 Risk to Populated and High Consequence Areas

Consequences of inadvertent releases from pipelines can vary greatly, depending on where the release occurs. Pipeline safety regulations use the concept of HCAs to identify specific locales and areas where a release could have the most significant adverse consequences. HCAs include populated areas, designated zones around public drinking water intakes, and unusually sensitive ecologically resource areas (USAs) that could be damaged by a hazardous liquid pipeline release. **Table 4-12** identifies the types and lengths of HCAs crossed by the Project. These HCA data are compiled from a variety of data sources, including federal and state agencies (e.g., state drinking water agencies, the USEPA). PHMSA acknowledges that spills within a sensitive area might not actually impact the sensitive resource and encourages operators to conduct detailed analysis, as needed. Keystone has conducted a preliminary evaluation of HCAs crossed or located downstream of the pipeline (**Appendix B**). Portions of the pipeline that could potentially affect HCAs will be subject to higher levels of inspection, as per 49 CFR Part 195. Furthermore, Keystone has subsequently evaluated the location of valves as a measure to reduce potential risk to HCAs. As a result of the preliminary HCA evaluation, some proposed valve locations were moved and additional valves were added to protect HCAs (**Appendix B**).

Table 4-12 Mileage Summary of PHMSA-Defined HCAs Identified Along the Project Route

	Miles of Pipeline				Projected Number of Spills in 10 years (occurrence interval)			
	Populated Areas	Drinking Water	Ecologically Sensitive Area	Total in HCAs[1]	Populated Areas	Drinking Water	Ecologically Sensitive Area	Total HCAs[1]
Montana	0.0	0.0	0.4	0.4	NA	NA	0.0005 (18,600 years)	0.0005
South Dakota	0.0	0.0	14.9	14.9	NA	NA	0.02 (500 years)	0.02
Nebraska	0.0	0.0	3.9	3.9	NA	NA	0.005 (1,900 years)	0.005
Steele City subtotal	**0.0**	0.0	**19.1**	**19.1**	NA	NA	**0.03 (390 years)**	**0.03**
Nebraska	0.0	0.0	0.0	0.0	NA	NA	NA	NA
Kansas	1.7	29.7	36.1	52.9	0.002 (4,400 years)	0.04 (250 years)	0.05 (210 years)	0.07

Table 4-12 Mileage Summary of PHMSA-Defined HCAs Identified Along the Project Route

	Miles of Pipeline				Projected Number of Spills in 10 years (occurrence interval)			
	Populated Areas	Drinking Water	Ecologically Sensitive Area	Total in HCAs[1]	Populated Areas	Drinking Water	Ecologically Sensitive Area	Total HCAs[1]
Oklahoma	0.0	10.0	3.1	11.9	NA	0.01 (740 years)	0.004 (2,400 years)	0.02
Cushing Extension subtotal	***1.7***	***39.7***	***39.2***	***64.8***	***0.002 (4,400 years)***	***0.05 (190 years)***	***0.05 (190 years)***	***0.09***
Oklahoma	3.2	10.5	3.9	12.3	0.004 (2,300 years)	0.01 (700 years)	0.005 (1,900 years)	0.02
Texas	8.9	16.4	1.6	25.6	0.01 (830 years)	0.02 (450 years)	0.002 (4,600 years)	0.03
Gulf Coast Subtotal	***12.1***	***26.9***	***5.6***	***37.9***	***0.02 (600 years)***	***0.04 (280 years)***	***0.008 (1,300 years)***	***0.05***
Texas – Houston Lateral	3.4	17.6	0.0	19.3	0.005 (2,200 years)	0.02 (420 years)	NA	0.03
Project Total	**17.2**	**84.3**	**63.9**	**141.2**	**0.02 (430 years)**	**0.1 (90 years)**	**0.09 (120 years)**	**0.2 (53 years)**

[1] Numbers are not additive because some miles overlap in the different types of HCAs.

Note: NA indicates no PHMSA-defined populated area within the segment.

Projected number of spills in 10 years and occurrence interval were conservatively estimated based on the conservative probability of spills (0.000135 incidents/mile*year). This conservative analysis intentionally overestimates the potential risk, and assumes risk is evenly distributed along the entire Project and includes the Keystone Cushing Extension.

Assuming that 2.2 spills occurred along the Project in a 10-year period, it is estimated that approximately 0.2 of these spills would occur in HCAs. Although the number of predicted spills in HCAs is relatively small, the potential impacts of these individual spills are expected to be greater than in other areas due to the environmental sensitivity within these areas. **Table 4-13** also shows the number of spills and their predicted sizes.

Table 4-13 Release and Spill Volume Occurrence Interval Associated with the Project

	Miles of Pipe[1]	Total Number of Predicted Spills	<3 barrels	3 to 50 barrels	50 to 1,000 barrels	1,000 to 10,000 barrels
Steele City						
Populated Areas	0.0	NA	NA	NA	NA	NA
Drinking Water Areas	0.0	NA	NA	NA	NA	NA
Ecologically Sensitive Areas	19.1	0.003 (390 years)	0.001 (780 years)	0.0008 (1,300 years)	0.0004 (2,600 years)	0.0001 (8,600 years)
Cushing Extension						
Populated Areas[2]	1.7	0.0002 (4,400 years)	0.0001 (8,700 years)	0.00007 (15,600 years)	0.00003 (29,000 years)	0.00001 (97,000 years)
Drinking Water Areas	39.7	0.005 (190 years)	0.003 (370 years)	0.002 (600 years)	0.0008 (1,200 years)	0.0002 (4,200 years)
Ecologically Sensitive Areas	39.2	0.005 (190 years)	0.003 (380 years)	0.002 (630 years)	0.0008 (1,300 years)	0.0002 (4,200 years)
Gulf Coast						
Populated Areas	12.1	0.002 (610 years)	0.0008 (1,200 years)	0.0005 (2,000 years)	0.0002 (4,100 years)	0.00007 (13,600 years)
Drinking Water Areas	26.9	0.004 (280 years)	0.002 (550 years)	0.001 (920 years)	0.0005 (1,800 years)	0.0002 (6,100 years)
Ecologically Sensitive Areas	5.6	0.0007 (1,300 years)	0.0003 (2,700 years)	0.0002 (4,400 years)	0.0001 (8,800 years)	0.00003 (29,000 years)
Houston Lateral						
Populated Areas	3.4	0.0005 (2,200 years)	0.0002 (4,400 years)	0.0001 (7,300 years)	0.00007 (15,000 years)	0.00002 (49,000 years)
Drinking Water Areas	17.6	0.002 (420 years)	0.001 (840 years)	0.0007 (1,400 years)	0.0004 (2,800 years)	0.0001 (9,400 years)
Ecologically Sensitive Areas	0.0	NA	NA	NA	NA	NA

Table 4-13 Release and Spill Volume Occurrence Interval Associated with the Project

	Miles of Pipe[1]	Total Number of Predicted Spills	<3 barrels	3 to 50 barrels	50 to 1,000 barrels	1,000 to 10,000 barrels
Entire Project						
Populated Areas	17.2	0.002 (430 years)	0.001 (860 years)	0.0007 (1,400 years)	0.0003 (2,900 years)	0.0001 (9,600 years)
Drinking Water Areas	84.3	0.01 (90 years)	0.006 (180 years)	0.003 (300 years)	0.002 (590 years)	0.0005 (2,000 years)
Ecologically Sensitive Areas	63.9	0.009 (120 years)	0.004 (230 years)	0.003 (390 years)	0.001 (780 years)	0.0004 (2,600 years)

[1] The amount of pipe located within HCAs was quantified by the Project's geographical information system and was based on the intersection of the pipeline's centerline and PHMSA-defined HCAs. Probability of a spill was based on the conservative incident frequency of 0.000135 incident per mile per year (**Appendix A**).

4.3.1 Populated Areas

PHMSA-defined populated areas occur along 17.2 miles of the Project. These populated areas have been classified as HCAs based on US Census data (**Table 4-12**). Approximately 90 percent (15.5 miles) of these miles are located within the Gulf Coast Segment. Keystone has conducted a more thorough evaluation to identify HCAs associated with populated areas (**Appendix B**).

4.3.2 Drinking Water

PHMSA identifies certain surface water and groundwater resources as drinking water USAs (49 CFR Sections 195.6 and 195.450). Surface water USAs include intakes for community water systems and non-transient non-community water systems that do not have an adequate alternative drinking water source. Groundwater USAs include the source water protection area 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 has not been established by the state, the wellhead protection area becomes the USA.

Surface water USAs identified for their potential as a drinking water resource have a 5-mile buffer placed around their intake location. The groundwater USAs have buffers that vary in size. These buffers are designated by the state's source water protection program or their wellhead protection program and the buffer sizes vary from state to state.

Isolated segments of the Project cross areas that are considered HCAs by the PHMSA due to potential risks to sensitive drinking water resources (**Table 4-12**). These areas occur along the Keystone Cushing Extension and Gulf Coast Segment of the Project; there are no drinking water HCAs crossed by the route within the Steele City Segment. Keystone has conducted a more thorough evaluation to identify HCAs associated with sensitive drinking water resources (**Appendix B**). Segments of the pipeline that could potentially affect HCAs will be subject to higher levels of inspection, as per 49 CFR Part 195. Based on Keystone's assessment, some valve locations have been moved and additional valves have been added to protect drinking water USAs.

4.3.3 Ecologically Sensitive Ares

Certain ecologically sensitive areas are classified as HCAs by PHMSA due to potential risks to unusually sensitive ecological resources. These areas focus on the characteristics of rarity, imperilment, or the potential for loss of large segments of an abundant population during periods of migratory concentration. These include:

- Critically imperiled and imperiled species and/or ecological communities;
- Threatened and endangered species (or multi-species assemblages where three or more different candidate resources co-occur);
- Migratory waterbird concentrations;
- Areas containing candidate species or ecological communities identified as excellent or good quality; and
- Areas containing aquatic or terrestrial candidate species and ecological communities that are limited in range.

Portions of the Project cross ecologically sensitive HCAs (**Table 4-12**). These ecologically sensitive HCAs are frequently associated with major river systems (e.g., Missouri, Platte, and Canadian rivers). As with other HCAs, these locations will be subject to higher levels of inspection, as per 49 CFR Part 195, in order to reduce the chance of pipeline incident.

4.3.4 Management of Risk Within HCAs

To protect particularly sensitive resources, HCAs would be subject to a higher level of inspection per USDOT regulations. Federal regulations require periodic assessment of the pipe condition and timely correction of identified anomalies within HCAs. Keystone will develop management and analysis processes that integrate available integrity-related data and information and assess the risks associated with segments that can affect HCAs.

Keystone will conduct a yearly survey to locate HCA changes along the pipeline system. If portions of he pipeline become population HCAs during the operational pipeline life, Keystone will notify the appropriate representatives at PHMSA.

Due to Homeland Security reasons, the precise risk for specific locations of HCAs is highly confidential. Keystone is therefore providing a confidential preliminary evaluation of risk to HCAs for federal agencies (**Appendix B**). Per federal regulations (Integrity Management Rule, 49 CFR Part 195), the site-specific evaluation of risk is an ongoing process and is regulated by the PHMSA.

Based on Keystone's preliminary assessment of HCAs (**Appendix B**), some valve locations were moved from their initial locations and additional valves have been added to provide supplemental protection of HCAs, where warranted. In addition, Keystone will develop and implement a risk-based integrity management program (IMP). The IMP will use state-of-practice technologies applied within a comprehensive risk-based methodology to assess and mitigate risk associated with all pipeline segments including HCAs.

5.0 Keystone's Pipeline Safety Program

Pipelines are one of the safest forms of crude oil transportation and provide a cost-effective and safe mode of transportation for oil on land. Overland transportation of oil by truck or rail produces higher risk of injury to the general public than the proposed pipeline (USDOT 2002). The Project will be designed, constructed, and maintained in a manner that meets or exceeds industry standards.

Safeguards have been implemented during design, and will be implemented during construction and operations of the pipeline. Steel suppliers, mills and coating plants are pre-qualified using a formal qualification process consistent with ISO standards. The pipe is engineered with stringent chemistry for such compounds as carbon to ensure weldability during construction. Each batch of pipe is mechanically tested to prove strength, fracture control and fracture propagation properties. The pipe is hydrostatically tested. The pipe seams are visually and manually inspected and also inspected using ultrasonic instruments. Each pipe joint is traceable to the steel supplier and pipe mill shift during production. The coating is inspected in the plant with stringent tolerances on roundness, nominal wall thickness. A formal quality surveillance program is in place at the steel mill and coating plant. During construction, inspection will be performed on various aspects on the pipeline activities. The pipeline field welds will be non-destructively tested and the pipeline will be hydrostatically tested.

Historically, one of the most significant risk associated with operating a crude oil pipeline is the potential for third-party excavation damage. To minimize the risk of third party damage, the pipeline will be built within an approved ROW and markers will be installed at all road, railway, and water crossings. The depth of cover required by federal regulations is 30 inches in most locations. In an effort to reduce excavation damage, Keystone has taken the proactive measure to increase the typical depth of cover to 4 feet (18 inches more cover than federal requirements).

Keystone will have a maintenance, inspection, and repair program that ensures the integrity of the pipeline during operations. Keystone's annual Pipeline Maintenance Program (PMP) will be designed to maintain the safe and reliable operation of the pipeline. The PMP is underpinned by a company-wide goal to ensure facilities are reliable and in service. Data collected in each year of the program will be fed back into the decision-making process for the development of the following year's program.

Keystone will mitigate third-party excavation risk by implementing comprehensive Public Awareness and Damage Prevention programs focused on education and awareness in accordance with 49 CFR Section 195.440 and API RP1162. Further, Keystone's operating staff will complete regular visual inspections (ground or aerial) of the ROW as per 49 CFR Section 195.412 and monitor activity in the area to prevent unauthorized trespass or access.

To mitigate the effects of corrosion on the pipeline, Keystone will use fusion bonded epoxy (FBE), a protective coating that is applied to the external surface of the pipe to prevent corrosion. A cathodic protection system is installed, comprised of engineered metal alloys or anodes, which are connected to the pipeline. A low voltage direct current is applied to the pipeline; the process corrodes the anodes rather than the pipeline. A tariff specification of 0.5 percent sediment and water by volume is contained in Keystone's transportation agreement with its shippers. This specification is lower than the industry standard of 1 percent to minimize the potential for internal corrosion. The pipeline is designed to operate in turbulent flow to minimize water drop out, which is also a potential cause of internal corrosion. During operations, the pipeline is cleaned using in-line inspection tools. The pipeline is inspected with a smart in-line inspection tool, which measures and records internal and external metal loss, thereby allowing Keystone the ability to proactively detect corrosion.

In addition, the pipeline will be monitored 24 hours a day, 365 days a year from the Operations Control Center (OCC) using a sophisticated SCADA system. In an event of a leak or rupture, Keystone would implement multiple leak detection methods and systems that are overlapping in nature and progress through a series of leak detection thresholds. The leak detection methods are as follows:

- Remote monitoring performed by the OCC Operator, which consists of monitoring pressure and flow data received from pump stations and valve sites fed back to the OCC by the Keystone SCADA system. Remote monitoring is typically able to detect leaks down to approximately 25 to 30 percent of the pipeline flow rate.
- Software-based volume balance systems that monitor receipt and delivery volumes. These systems are typically able to detect leaks down to approximately 5 percent of the pipeline flow rate.
- Computational Pipeline Monitoring or model-based leak detection systems that break the pipeline into smaller segments and monitor each of these segments on a mass balance basis. These systems are typically capable of detecting leaks down to a level of approximately 1.5 to 2 percent of pipeline flow rate.
- Computer-based, non-real time accumulated gain/(loss) volume trending to assist in identifying low rate or seepage releases below the 1.5 to 2 percent by volume detection thresholds.
- Direct observation methods, which include aerial patrols, ground patrols, and public and landowner awareness programs that are designed to encourage and facilitate the reporting of suspected leaks and events that may suggest a threat to the integrity of the pipeline.

The leak detection system will be configured in a manner capable of alarming the OCC operators through the SCADA system and also will provide the OCC operators with a comprehensive assortment of display screens for incident analysis and investigation. In addition, there will be a redundant, stand-by OCC to be used in case of emergency.

Lastly, Keystone will have an Emergency Response Program (ERP) in place to respond to incidents. The ERP contains comprehensive manuals, detailed training plans, equipment requirements, resources plans, auditing, change management and continuous improvement processes. The Integrity Management Program (IMP) (49 CFR Part 195) and ERP will ensure Keystone will operate the pipeline in an environmentally responsible manner.

6.0 Conclusion

In summary, this conservative analysis of the proposed Project shows that the predicted frequency of incidents is very low, the probability of a large spill occurring is very low, and, consequently, risk of environmental impacts is minimal. Compliance with regulations, application of Keystone's IMPs and Emergency Response Plan, as well as adherence to safety procedures will help to ensure long-term environmentally responsible and safe operation of the pipeline.

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8.0 Glossary

Accidental Release

An accidental release is an unplanned occurrence that results in a release of oil from a pipeline.

Acute exposure

Exposure to a chemical or situation for a short period of time.

Acute toxicity

The ability of a substance to cause severe biological harm or death soon after a single exposure or dose.

Adverse effect

Any effect that causes harm to the normal functioning of plants or animals due to exposure to a substance (i.e., a chemical contaminant).

Algae

Chiefly aquatic, eukaryotic one-celled or multicellular plants without true stems, roots and leaves that are typically autotrophic, photosynthetic, and contain chlorophyll. They are food for fish and small aquatic animals.

Aquifer

An underground layer of water-bearing permeable rock or unconsolidated materials (gravel, sand, silt, or clay) from which groundwater can be usefully extracted using a water well.

Barrel

A barrel is a standard measure of a volume of oil and is equal to 42 gallons.

Benthic invertebrates

Those animals without backbones that live on or in the sediments of a lake, pond, river, etc.

Bioavailability

How easily a plant or animal can absorb a particular contaminant from the environment.

Biodegradation

Biodegradation is the breakdown of organic contaminants by microbial organisms into smaller compounds. The microbial organisms transform the contaminants through metabolic or enzymatic processes. Biodegradation processes vary greatly, but frequently the final product of the degradation is carbon dioxide or methane.

BPD

Abbreviation for barrels per day.

Cathodic Protection System

A technique to provide corrosion protection to a metal surface by making the surface of the metal object the cathode of an electrochemical cell. In the pipeline industry that is done using impressed current. Impressed current cathodic protection systems use an anode connected to a DC power source (a cathodic protection rectifier).

Chronic toxicity

The capacity of a substance to cause long-term poisonous health effects in humans, animals, fish, or other organisms. Biological tests use sublethal effects, such as abnormal development, growth, and reproduction, rather than mortality, as endpoints.

Contaminant

Any physical, chemical, biological, or radiological substance found in air, water, soil or biological matter that has a harmful effect on plants or animals; harmful or hazardous matter introduced into the environment.

Ecosystem

The sum of all the living plants and animals, their interactions, and the physical components in a particular area.

Emergency Flow Restricting Device

An emergency flow-restricting device is a device used to restrict or limit the amount of oil that can release out of a leak or break in a pipeline. Check valves and remote control valves are types of emergency flow restricting devices.

Exposure

How a biological system (i.e., ecosystem), plant, or animal comes in contact with a chemical.

Event

An event is a significant occurrence or happening. As applicable to pipeline safety, an event could be an accident, abnormal condition, incident, equipment failure, human failure, or release.

Facility

Any structure, underground or above, used to transmit a product.

Geographical Information System

A computer data system for creating and managing spatial data and associated attributes.

Habitat

The place where a population of plants or animals and its surroundings are located, including both living and non-living components.

High Consequence Area (HCA)

A high consequence area is a location that is specially defined in PHMSA pipeline safety regulations as an area where pipeline releases could have greater consequences to health and safety or the environment. For oil pipelines, HCAs include high population areas, other population areas, commercially navigable waterways, and areas unusually sensitive to environmental damage, including certain ecologically sensitive areas and drinking water resources. Regulations require a pipeline operator to take specific steps to ensure the integrity of a pipeline for which a release could affect an HCA and, thereby, provide protection of the HCA.

High Population Area

A high population area is an urbanized area, as defined and delineated by the US Census Bureau, which contains 50,000 or more people and has a population density of at least 1,000 people per square mile. High population areas are considered HCAs.

Incident

As used in pipeline safety regulations, an incident is an event occurring on a pipeline for which the operator must make a report to the Office of Pipeline Safety. There are specific reporting criteria that define an incident that include the volume of the material released, monetary property damage, injuries, and fatalities (Reference 49 CFR Section 191.3, 49 CFR Section 195.50).

Incident Frequency

Incident frequency is the rate at which failures are observed or are predicted to occur, expressed as events per given timeframe.

Incident Probability

Incident probability is the probability that a structure, device, equipment, system, etc. will fail on demand or will fail in a given time interval, expressed as a value from 0 to 1.

Incident Rate

Incident rate is the rate at which failures occur. It is the number of failure events that occur divided by the total elapsed operating time during which those events occur or by the total number of demands, as applicable.

Integrity Management Program (IMP)

An IMP is a documented set of policies, processes, and procedures that are implemented to ensure the integrity of a pipeline. An oil pipeline operator's IMP must comply with the federal regulations (i.e., the Integrity Management Rule, 49 CFR Part 195).

Integrity Management Rule

The Integrity Management Rule specifies regulations to assess, evaluate, repair, and validate the integrity of hazardous liquid pipelines that, in the event of a leak or failure, could affect HCAs.

Invertebrates

Animals without backbones: e.g., insects, spiders, crayfish, worms, snails, mussels, clams, etc.

LC_{50}

A concentration expected to be lethal to 50 percent of a group of test organisms.

Leak

A leak is a small opening, crack, or hole in a pipeline allowing a release of oil.

Likelihood

Likelihood refers to the probability that something possible may occur. The likelihood may be expressed as a frequency (e.g., events per year), a probability of occurrence during a time interval (e.g., annual probability), or a conditional probability (e.g., probability of occurrence, given that a precursor event has occurred).

Maximum Contaminant Level (MCL)

The maximum level of a contaminant allowed in drinking water by federal or state law and is based on the avoidance of health effects and currently available water treatment methods.

National Pipeline Mapping System (NPMS)

The National Pipeline Mapping System is a geographical information system database that contains the locations and selected attributes of natural gas transmission lines, hazardous liquid trunklines, and liquefied natural gas facilities operating in onshore and offshore territories of the US.

One-Call System

A one-call system is a system that allows excavators (individuals, professional contractors, and governmental organizations) to make one telephone call to underground facility operators to provide notification of their intent to dig. The facility operators or, in some cases, the one-call center can then locate the facilities before the excavation begins so that extra care can be taken to avoid damaging the facilities. All 50 states within the US are covered by one-call systems. Most states have laws requiring the use of the one-call system at least 48 hours before beginning an excavation.

Other Populated Areas

An ‘other populated area’ is a census designated place, defined and delineated by the US Census Bureau as settled concentrations of population that are identifiable by name but are not legally incorporated under the laws of the state in which they are located. Other populated areas are considered HCAs by PHMSA.

Operator

An operator is a person who owns or operates pipeline facilities (Reference 49 CFR Section 195.2).

Polycyclic Aromatic Hydrocarbons (PAHs)

Group of organic chemicals.

Pipeline

Used broadly, pipeline includes all parts of those physical facilities through which gas, hazardous liquid, or carbon dioxide moves in transportation. Pipeline includes but is not limited to: line pipe, valves and other appurtenances attached to the pipe, pumping/compressor units and associated fabricated units, metering, regulating, and delivery stations, and holders and fabricated assemblies located therein, and breakout tanks.

Playa Lake

A rain-filled small, round depression in the surface of the ground.

Prairie Pothole

Water-holding depressions of glacial origin in the prairies of northern US and southern Canada. Water is supplied by rainfall, basin runoff and seepage inflow of groundwater.

Receptor

The species, population, community, habitat, etc. that may be exposed to contaminants.

Risk

Risk is a measure of both the likelihood that an adverse event could occur and the magnitude of the expected consequences should it occur.

Sediment

The material of the bottom of a body of water (i.e., pond, river, stream, etc.).

Stressor

Any factor that may harm plants or animals; includes chemical (e.g., metals or organic compounds), physical (e.g., extreme temperatures, fire, storms, flooding, and construction/development) and biological (e.g., disease, parasites, depredation, and competition).

Supervisory Control and Data Acquisition System

A supervisory control and data acquisition system is a pipeline control system designed to gather information such as pipeline pressures and flow rates from remote locations and regularly transmit this information to a central control facility where the data can be monitored and analyzed.

Throughput

The volume of oil through a pipeline during a specified time (e.g., barrels per day).

Toxicity Testing

A type of test that studies the harmful effects of chemicals on particular plants or animals.

Toxicity Threshold

Numerical values that represent concentrations of contaminants in abiotic media (sediments, water, soil) or tissues of plants and animals above which those contaminants are expected to cause harm.

Unusually Sensitive Areas (USAs)

USAs refers to certain drinking water and ecological resource areas that are unusually sensitive to environmental damage from a hazardous liquid pipeline release, as defined in 49 CFR Section 195.6.

Zooplankton

Small, usually microscopic animals (such as protozoans) found in lakes and reservoirs.

Appendix A

Analysis of Incident Frequencies and Spill Volumes for Environmental Consequence Estimation for the Keystone XL Project

July 6, 2009

Analysis of Incident Frequencies and Spill Volumes for Environmental Consequence Estimation for the Keystone XL Project

TransCanada
In business to deliver

TransCanada Keystone Pipeline, LP

July 2009

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1.0 Introduction

TransCanada Keystone Pipeline, LP (Keystone) proposes to construct and operate a new crude oil pipeline and related facilities from Hardisty, Alberta, Canada to the Port Arthur and east Houston areas of Texas in the United States (US). The project, known as the Keystone XL Pipeline Project (Project), will have a nominal capacity to deliver up to 900,000 barrels per day of crude oil from an oil supply hub near Hardisty, Alberta to existing terminals in Nederland near Port Arthur, Texas, and the Moore Junction in Houston, Texas. See the proposed Project route in **Figure A-1**.

Figure A-1 Overview of the Project

In total, the Project will consist of approximately 1,707 miles of new, 36-inch-diameter pipeline, consisting of about 327 miles in Canada and 1,375 miles within the US. It will interconnect with the northern and southern termini of the previously approved 298-mile-long, 36-inch-diameter Keystone Cushing Extension segment of the Keystone Pipeline Project (Keystone Cushing Extension). The Project proposes to transport up to 900,000 barrels of crude oil per day. This proposed volume would be 309,000 barrels greater than the rate of 591,000 barrels per day that was analyzed for the Keystone Cushing Extension in the previous Keystone

Pipeline permitting process, completed in 2008. Spill risk and potential environmental consequences described in this Risk Assessment are based on transportation of 900,000 barrels per day through all Project pipeline segments within the U.S. Because of this increase in throughput volume, the Keystone Cushing Extension is included as part of the overall Keystone XL Project for spill risk analysis purposes. Key design parameters associated with the Project are identified in **Table A-1**.

Table A-1 Project Design Parameters

Parameter	Value
Pipe Specifications	36-inch high-strength steel (X70 or X80).
Coating	Fusion bond epoxy (FBE) coating.
Maximum Pump Station Discharge Pressure	1,440 psig.
Maximum Operating Pressure	1,440 psig, 1,600 psig[1]
Depth of Cover	Generally 4 feet of cover, exceeding federal requirements.
Aboveground versus Belowground Piping	Pipe will be belowground except within pump stations, valve sites, and terminal facilities.
Pipe Wall Thickness	Varies due to engineering and regulatory requirement (0.485 inch to 0.748 inch).
Intermediate Remotely Operated Mainline Valves (includes Cushing Extension)	57 remotely operated intermediate mainline valves.
Intermediate Mainline Check Valves (includes Cushing Extension)	32 intermediate mainline check valves and mainline/check valve sets.
Pump Stations	30 pump stations in the US.
Leak Prevention Program	Multiple overlapping and redundant systems, including: • Quality Assurance program for pipe manufacture and pipe coating; • FBE coating; • cathodic protection; • non-destructive testing of 100 percent of the girth welds; • hydrostatic testing to 125 percent of the maximum operating pressure (MOP); • periodic internal cleaning and high-resolution in-line inspection; • depth of cover exceeding federal standards; • periodic aerial surveillance in accordance with federal requirements; • public awareness program; • Supervisory Control and Data Acquisition (SCADA) system; and • Operations Control Center (with complete redundant backup) providing monitoring of the pipeline every 5 seconds, 24 hours a day, every day of the year.

Table A-1 Project Design Parameters

Parameter	Value
Leak Detection Systems	• Remote Monitoring with SCADA; • volume balancing systems; • computational pipeline monitoring; • non-real time volume trending analysis; and • direct observation.
Direct Observation Surveillance Frequency	• Aerial surveillance: 26 times per year, not to exceed 3 weeks intervals; and • periodic Close Interval Survey (CIS) integrated with in-line-inspection assessments.

[1] The design of the Project pipeline system is based on a maximum 1,440 pounds per square inch gauge (psig) discharge pressure at each pump station. The result is that the MOP of the pipeline between pump stations is generally 1,440 psig. In liquid pipelines, some sections at lower elevations relative to the pump station discharge may be exposed to slightly higher pressures due to the combined station discharge pressure and hydrostatic head.

This report evaluates the potential incident frequency and worst-case spill volumes for the Project. The results of this analysis will be incorporated into Keystone's initial risk assessment that evaluates spill risk and its potential environmental consequences.

The values within this document overestimate risk associated with the Project to a level much greater than what is actually anticipated to occur. The purpose of overestimating risk is threefold. First, the incident frequency and spill volume estimates provide a highly conservative range of effects anticipated from the operation of the Project, which is appropriate for the purposes of the National Environmental Policy Act. Second, the incident frequency and spill volume analysis provides a preliminary evaluation of risk during the pipeline's design phase, providing early indications of possible valve locations. Third, the preliminary incident frequency and spill volume analysis provides Keystone with an initial basis for the development of emergency response planning and eventual incorporation of the Project into Keystone's Integrity Management Program. Given these objectives, the analysis summarized within this appendix is intentionally conservative (i.e., overestimates risk). Keystone's expectation is that the incident frequencies and spill volumes presented in this analysis are not likely to occur, but are provided as a highly conservative framework to ensure agency decisions are based on knowledge of the potential range of effects, as well as allowing Keystone to identify optimal valve locations and to prepare the worst-case scenarios in its emergency response preparations.

This document discusses the procedures used to estimate incident frequencies and spill volumes for the Project. Chapter 2.0 identifies the primary causes of pipeline incidents.[1] Chapter 3.0 discusses the potential frequency of these primary causes for the Project. Chapter 4.0 combines each of the state-specific incident frequencies into an overall, project-wide incident frequency. Chapter 5.0 discusses maximum spill volumes estimated for the Project and compares these values with historical spill volume data.

[1] The term "incident" can range from a small drip to a complete pipeline rupture. The volume of the most common incident is small, consisting of three barrels or less, as discussed in Chapter 6.0.

2.0 Applicable Threats

In order to establish the particular incident threats that would apply to the Project at service initiation, three key points were considered:

- This is a new construction project, developed with the benefit of TransCanada's more than 50 years of pipeline construction and operating experience;
- The Project will be constructed and operated in accordance with comprehensive regulatory guidelines (49 CFR 195) and pipeline design standards (ASME B31.4), and;
- Keystone has applied for a Special Permit from the Pipeline and Hazardous Materials Administration (PHMSA) that would allow Keystone to design, construct, and operate the Project up to 80 percent of the steel pipe's specified minimum yield strength (SMYS) in all but limited areas, rather than 72 percent SMYS as otherwise required by federal regulations. To ensure that the safety of the pipeline in areas subject to the Special Permit is equal to or greater than the safety under the otherwise applicable regulations, the PHMSA Special Permit will include a multitude of supplemental requirements that exceed industry standards and current regulations.

Taking these factors into consideration, the applicable threats can be determined using American Society of Mechanical Engineers (ASME) B31.8S and American Petroleum Institute (API) 1160 as guidance.

2.1 Time Dependent Threats

2.1.1 Corrosion

2.1.1.1 External Corrosion

External corrosion is a pertinent threat to all steel pipelines. On a newly constructed pipeline, external corrosion is not considered to be a primary integrity threat. Nonetheless, external corrosion must be considered.

2.1.1.2 Internal Corrosion

In a hazardous liquid pipeline, internal corrosion can occur for a number of reasons (product corrosivity, water drop out due to flow conditions, suspended solids). On a new pipeline, internal corrosion is not considered to be a primary threat; however, it must be considered.

2.1.2 Stress Corrosion Cracking

Stress corrosion cracking (SCC) refers to localized pipe damage (cracks) caused by the combined influence of a susceptible pipeline coating, conducive environment (e.g., corrosive soils), operational stresses, and to a limited extent, temperature of the pipe. The coating system to be used on the Project is a high performance FBE. This coating system provides excellent protection against SCC due to the performance of the primer and the durability of the applied epoxy coating. According to Canadian Energy Pipeline Association Recommended Practices 2nd Edition Section 5.1.1.1, Coating Type and Coating Condition, "No SCC has been documented in association with FBE, field applied epoxy or epoxy urethanes, or extruded polyethylene" and according to PHMSA[2], "applying special coatings (fusion bonded epoxy) will protect the pipeline from the occurrence of SCC." Additionally, the cathodic protection system will be monitored to prevent cathodic protection

[2] PHMSA Fact Sheet on Stress Corrosion Cracking 120604 http://primis.phmsa.dot.gov

overcharging, which could promote SCC growth. Consequently, SCC is not considered to be a viable threat for the Project.

2.2 Stable Threats

2.2.1 Materials and Construction

2.2.1.1 Materials (Manufacturing) Related

In addition to the conditions expected to be contained in the PHMSA Special Permit, Keystone's current internal quality management system (which includes mill inspection and ongoing surveillance, as well as material and chemical testing) will ensure the highest quality steel pipe is used. Manufacturing defects, such as the presence of hard spots or long seam defects are extremely unlikely. While not a primary threat, this analysis retained materials-related incidents as a secondary threat.

2.2.1.2 Construction (Welding and Fabrication) Related

In addition to the conditions expected to be contained in the PHMSA Special Permit, the Project's proprietary construction specifications will require Keystone to follow exacting procedures along with rigorous testing and inspection to ensure the highest quality construction practices are used. While not a primary threat, this analysis retained construction-related incidents as a secondary threat.

2.2.2 Equipment

Equipment-related incidents are incidents associated with certain equipment used on pipelines, such as flange gaskets, regulator valves, set point drift on regulators, O-rings, valve seals, and packings. The Project will not have any flanges below grade (only located aboveground within pump stations), as all mainline valves will be manufactured as weld-end valves. As required by 49 Code of Federal Regulations (CFR) Section 195.420, each mainline valve must be inspected twice per year. All sub-assemblies will be hydrostatically tested in the fabrication shop to a minimum of 125 percent of MOP for 4 hours. For such aboveground equipment, a small leak is the typical failure mode if an incident occurs.

Because equipment is so localized and spill volume is minimal, equipment-related incidents are not considered to be a primary or secondary threat for the purposes of this assessment and are not considered further.

2.3 Time Independent Threats

2.3.1 Excavation (Third-party) Damage

Damage due to third-party excavation/mechanical damage is the most prevalent threat to most buried pipelines. This threat is considered to be a primary threat to the Project and will continuously be assessed both during design and operation phases of the Project.

2.3.2 Hydraulic Event (Incorrect Operations)

Incorrect operations or failure to follow standard operating procedures can lead to an overpressure event or hydraulic surge. Although a series of human and mechanical errors would need to occur for a hydraulic event to take place, it is considered a potential secondary threat to the operations of any liquid system and will be addressed in this analysis.

2.3.3 Natural Hazards (Ground Movement/Flooding)

Hydrological and geotechnical concerns are very site-specific issues that are considered in the routing and design of the project. The route selection is done to avoid, inasmuch as practical, potentially geologically unstable slopes, meandering streams, saturated soils, and active seismic hazards. Because the threat cannot be completely eliminated, it is considered a secondary threat.

2.4 Summary of Threats

The following threats to the Project are considered to be viable for this assessment:

1. Corrosion (External/Internal);
2. Excavation Damage;
3. Materials and Construction (Manufacturing, Welding, and Fabrication);
4. Hydraulic Event (Incorrect Operations); and
5. Ground Movement, Washouts, and Flooding.

3.0 PHMSA Baseline Incident Frequencies

Since the Project has not yet been constructed, it does not have an operational history from which to derive incident frequency rates. Consequently, a conservative approach was taken by first determining the baseline incident frequencies from industry data (i.e., PHMSA data) and then utilizing adjustment factors to account for project- and site-specific conditions. These adjustment factors include improved technologies and practices that are used on a newly constructed pipeline and are not currently reflected in the historical PHMSA incident frequencies.

Baseline incident frequencies are derived from historical national pipeline incident data (PHMSA 2008). Since the majority of pipelines in the US were constructed in the "pre-modern" era (i.e., the 1970s or earlier), these baseline frequencies reflect incident rates associated with earlier pipeline design and construction methods that often do not meet the current regulatory requirements or best management practices. Further, these historical data do not account for supplemental protective measures that Keystone will implement, including those expected to be required by the PHMSA Special Permit.

By adjusting baseline incident frequencies to account for improved technologies and practices that will be employed in the pipeline's design, construction and operations, this analysis provides a more reasonable approximation of incident frequency than unmodified PHMSA baseline frequencies. The adjustment factor for each baseline incident frequency threat ranges from a value of 0.1 -1, where the value 1 would equate the calculated Project frequency to the PHMSA baseline frequency. A fractional adjustment factor less than 1 indicates that the Project incident frequency would be less than that predicted by the PHMSA incident frequency data base. Nevertheless, this analysis selected conservative adjustment factors so that the calculated incident frequencies continue to overestimate risk.

The baseline incident frequencies identified in **Table A-2** were generated from the PHMSA incident database (PHMSA 2008) and are expressed as per mile of pipeline per year (i.e., /mile-year).

Table A-2 Baseline Incident Frequencies

Threat Name	Incident Frequency/mile-yr [1]	Occurrence Interval (years)
Corrosion	2.90E-04	3,400
Excavation damage	1.22E-04	8,200
Materials and Construction	3.00E-04	3,300
Hydraulic Event	1.47E-04	6,800
Ground movement	1.23E-05	81,500
Washout and flooding	1.14E-05	87,800

[1] Incident frequencies are expressed in scientific notation. A value of 2.90E-04 incidents/mile-year is equivalent to 0.00029 incident/mile-year, which is approximately equivalent to one incident every 3,400 years.

3.1 Corrosion

Based on PHMSA data (2008), the baseline incident frequency for corrosion-induced leaks is 2.90E-04 incidents/mile-year. For the Project, this baseline frequency was adjusted to account for current industry standard practices and Keystone's supplemental protective measures. Industry standards currently require frequent internal inspections (at least every 5 years per 49 CFR Part 195), govern material selection on new pipe, and require use of active cathodic protection along the entire pipeline. These industry practices have caused significant reductions in the number of incidents in recent years. To account for the current minimum industry standards using professional engineering judgment, Keystone assigned a 0.3 adjustment factor to the baseline frequency for corrosion.

Keystone will have multiple safeguards in place over and above these current, minimum industry standards to further reduce the likelihood of corrosion-related incidents, including:

- Use of high performance FBE external coating;
- Use of abrasion-resistant coatings for trenchless installation;
- Temperature monitoring and management along the pipeline and at pump stations in order to prevent potential coating damage;
- Installation of a cathodic protection (CP) system and an initial CP survey within 6 months of being placed in service. Additionally, a close interval survey will be performed within 1 year of placing the pipeline in-service and these data will be integrated with in-line inspection data;
- Implementation of alternating current and direct current control program when paralleling high voltage power lines; and
- Conducting high-resolution magnetic flux leakage (MFL) in-line inspections (ILI) as a baseline integrity assessment, within 3 years of the in-service date, and on a periodic reassessment schedule that meets or exceeds federal requirements.

In a new pipeline system, such as this Project, the probability of incident due to corrosion prior to the first MFL inspection is very remote. Utilizing conservative assumptions about corrosion growth rate and feature incidence rate and projecting to the time of baseline inspection, the external corrosion incident probability would be nearly zero. Even with conservative assumptions about growth rate (1 millimeter a month, with a standard deviation of 0.25 millimeter), it would be 15 years before the external corrosion incident probability would become appreciable, in the order of 1E-06 incident/mile-year.

Sediment and water are the largest contributors to internal corrosion risk. Keystone will limit sediment and water by tariff specifications to 0.5 percent by volume and will report compliance with these limitations to PHMSA. The pipeline will not transport crude oil with a sour service designation under NACE MR0175 Part 2, Annex C/CSA Z662. Additionally, cleaning pigs will be run through the line twice in the first year of operation and then as necessary, based on monitoring programs. Cleaning pigs will aid in removing sediment and water, though build-up of these materials is expected to be minimal due to designed turbulent flow within the pipeline. With the baseline MFL inspection occurring 3 years from in-service, the internal corrosion incident probability would be negligible as well.

The corrosion baseline frequency derived from PHMSA data was further reduced to reflect the Keystone supplemental protection measures described above. To account for these supplemental protection measures, and based on professional judgment, an adjustment factor of 0.2 was assigned. Notwithstanding this adjustment, the corrosion-related incident frequency is still considered to be a very conservative estimate of incident probability.

3.2 Excavation Damage

Excavation damage leading to pipeline incidents includes damage to the pipe caused by third-parties or pipeline operators. Historically, third-party damage is one of the leading causes of pipeline damage. Operator damage is less frequent because operating safety procedures are required to be followed for all maintenance activities. Consequently, installation of pipelines in sparsely populated areas, adequate depth of cover, use of pipeline markers, and frequent aerial surveillance that looks for excavation activities near or within the pipeline right-of-way, are all factors that minimize the risk of excavation damage and thereby contribute to the overall safety of a pipeline.

Pipelines can leak from third-party damage either due to immediate puncture or through delayed failure from gouging, which is detectable by routine ILI inspections. Since the probability of puncture is dependent on the yield strength and impact toughness of the pipe material, the force required to puncture the pipe can be calculated.

The PHMSA Special Permit requirements are expected to include several key factors designed to reduce the likelihood of impact, which Keystone will implement, including the following:

- Resistance to puncture from an excavator weighing up to 65 tons;
- Depth of cover (4 feet) exceeds regulatory requirements;
- Line-of-sight pipeline markers;
- Common Ground Alliance[3] best practices to be used in damage prevention program;
- One-call system in place; and
- Bi-weekly aerial surveillance.

Using an industry-based reliability model[4], the frequency of a puncture as a result of a pipeline strike can be calculated. The model takes into account the preceding PHMSA conditions and supplemental measures as well as the probability of the pipeline being struck by excavation equipment. In the case of the pipe to be used on the Project, the probability of immediate puncture is very low (less than 5E-06 incidents/ mile-year), as its puncture resistance is in excess of 65 tons and, according to heavy equipment industry surveys, 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 (equivalent to an excavator weighing less than 65 tons[5]). State-specific incident frequencies are identified in **Table A-3**.

Based on PHMSA data (2008), the baseline incident frequency for excavation-induced leaks is 1.22E-04 incidents/ mile-year, which includes incidents on all pipeline sizes and year of construction. In comparison, the incident frequency for the Project based on the industry-based reliability model that accounts for impact frequency and the high degree of puncture resistance ranges from 5.87E-06 incidents/mile-year in urban areas to 8.58E-07 in rural, agricultural areas The reduction in incident frequency is best described as an adjustment factor of 0.5 for the reduction in impact frequency due to the excavation mitigation measures listed above, an adjustment factor of 0.1 owing to the high puncture resistance of the pipe, and an adjustment factor of 0.15 in rural areas due to reduced excavation activity.

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[3] Common Ground Alliance is an association of pipeline companies, underground facilities owners, and excavators to address issues related to damage prevention of underground facilities. The group published a full range of safe practices, including the establishment of “One Call” centers; procedures for excavation, mapping, locating and marking; compliance; planning and design; reporting and evaluation; public education and emerging technologies.

[4] Chen, Q. and M. Nessim. “Reliability-based Prevention of Mechanical Damage to Pipelines,” Pipeline Research Council International, Inc. (PRCI), Catalog No. L51816, 1999.

[5] J. Keifner. Impact of 80 percent SMYS Operation on Resistance to Third Party Mechanical Damage. March 21, 2006.

Table A-3 Excavation Incident Frequencies by State

State	Project Length (miles)	High Population Areas		Other Population Areas		Other Areas (Agricultural)		Resultant Failure Frequency
		Percent	(miles)	Percent	Miles	Percent	Miles	FF/mile-year
Montana	282.3	0.0	0.0	0.0	0.0	100.0	282.3	8.58E-07
South Dakota	312.8	0.0	0.0	0.0	0.0	100.0	312.8	8.58E-07
Nebraska	255.2	0.0	0.0	0.0	0.0	100.0	255.2	8.58E-07
Total Steele City Segment	**850.3**	**0.0**	**0.0**	**0.0**	**0.0**	**100.0**	**850.3**	**8.58E-07**
Nebraska	2.5	0.0	0.0	0.0	0.0	100.0	2.5	8.58E-07
Kansas	211.1	0.0	0.0	0.8	1.7	99.2	209.5	8.67E-07
Oklahoma	82.4	0.0	0.0	0.0	0.0	100.0	82.4	8.58E-07
Total Keystone Cushing Extension	**296.0**	**0.0**	**0.0**	**0.0**	**1.7**	**100.0**	**296.0**	**8.58E-07**
Oklahoma	154.9	0.0	0.0	2.1	3.2	97.9	151.7	8.81E-07
Texas	323.3	0.8	2.7	1.9	6.3	97.2	314.4	8.76E-07
Total Gulf Coast Segment	**478.2**	**0.6**	**2.7**	**2.0**	**9.5**	**97.5**	**466.1**	**8.78E-07**
Houston Lateral	**47.2**	**3.5**	**1.7**	**3.7**	**1.8**	**92.7**	**43.8**	**8.85E-07**

3.3 Materials and Construction

Pipeline incidents associated with materials and construction can be caused by improper selection of materials and lack of quality control and inspection during the manufacturing and construction process. Many of the historical releases contained within PHMSA data set relate to “pre-modern” pipelines where pipeline failures were related to deficiencies in these factors.

Federal regulations currently govern material selection on new pipe and require non-destructive testing (e.g., radiographic or ultrasonic) of 10 percent of the girth welds and hydrostatic testing to 125 percent of MOP. These regulations are designed to detect and remove material defects and construction deficiencies prior to an operational incident. TransCanada has leveraged over 50 years of pipeline operating experience into a complete set of practices for the specification, procurement, transportation, construction, inspection, and quality assurance of any pipeline it constructs. In addition to TransCanada’s proprietary specifications and quality management system , the PHMSA Special Permit is expected to have several conditions related to the manufacture and construction of the pipeline, including:

- Extensive requirements for quality of steel used in manufacture of pipe, over and above the requirements of API 5L Product Specification Level 2 – 44th Edition;
- Comprehensive fracture control plan relating to pipe quality and toughness;
- Extensive inspection of pipe steel and pipe seam;
- Inspection of seam of delivered pipe for signs of seam fatigue from transportation;
- Mill hydrostatic test to 95 percent SMYS;
- Pre-commission hydrostatic test to 100 percent SMYS and 125 percent MOP (in areas at 80 percent SMYS);
- Documentation and quality control of all fittings, flanges and valves;
- Extensive welding quality control requirements, including complete inspection of 100 percent of all girth welds;
- Comprehensive construction quality program; and
- A plan to assess any potential flaw growth after 2 years in service.

Based on PHMSA data (2008), the baseline incident frequency for material defects and construction deficiencies is 3.00E-04 incidents/mile-year. For the Project, this baseline frequency was adjusted to account for current federal regulations and Keystone’s supplemental protective measures. Based on engineering judgment, Keystone assigned a 0.5 adjustment factor to the baseline frequency to account for current federal regulatory requirements, and a further 0.2 adjustment factor to account for Keystone’s supplemental measures, including anticipated Special Permit requirements as listed above, to reduce material defects and construction deficiencies. This is a conservative incident frequency to use, as the effect of complete inspection of 100 percent of all field welded joints and post-construction hydrostatic test to 125 percent MOP would be to remove all near-critical defects, ensuring that an operational incident would be extremely unlikely.

3.4 Hydraulic Surge (Incorrect Operations)

Hydraulic events, such as pressure surges (the “water hammer” effect), are caused by sudden changes in flow and can be caused by operator error, failure of pressure controls, or failure of pressure relief equipment.

As part of the requirements expected in a PHMSA Special Permit, several items relating to SCADA control and operator qualification are directly aimed at reducing the likelihood of a pipeline release. These include:

- Overpressure protection to 110 percent of MOP per 49 CFR 195.406(b);
- Increased training for SCADA alarm management and response;
- Use of SCADA pipeline model and simulator, with use of simulator in training, as well as for controller recognition of abnormal operating conditions; and
- Compliance with the requirements of ASME B31Q Pipeline Personnel Qualification Standard, as part of an enhanced training and qualification plan for all SCADA operating personnel, which includes extensive training requirements, qualification and re-qualification procedures.

Hydraulic events can be mitigated by devices that prevent quick stoppages. In an emergency situation, Keystone's SCADA system would allow the operator to shut down the Project in a controlled sequence, with complete shutdown of pump stations and valves occurring in 12 minutes. Prior to operation, the pipeline would be hydrostatically tested to 125 percent of the MOP per federal regulations, providing a safety factor if a hydraulic event occurred. If a hydraulic event occurred on the pipeline, Keystone would be required to report the event to PHMSA, investigate the cause and assess the pipeline to determine if any adverse effects occurred before restarting normal operations.

Based on PHMSA data (2008), the baseline incident frequency for hydraulic events is 1.47E-04 incidents/ mile-year. For the Project, this baseline frequency was adjusted to account for hydraulic controls such as SCADA system, as well as enhanced operator training and response systems. Keystone has committed to comply with industry recommended practices, such as API RP 1165, RP 1130, RP 1162, and ASME B31Q. Based on engineering judgment, Keystone assigned a 0.5 adjustment factor to the baseline frequency to account for all the factors discussed in this section.

3.5 Natural Hazard Related

The natural hazard category encompasses several different threats, including earth movement due to geotechnical, landslide or seismic hazards, and flooding (heavy rains or storm surges). The threat of damage from these potential threats also is somewhat dependent upon the pipe's ability to withstand these external forces. Historically, "pre-modern" era pipe had more difficulty dealing with these stresses than modern pipe due to the field welding quality, pipelines using mechanical couplings or threaded joints, lower toughness steel with less fracture control properties, and other factors. Field data show that modern pipe is very robust and more capable of withstanding these external forces than older pipe. Since this hazard cannot be completely eliminated, the susceptibility to outside forces is based upon the percentage of the Project exposed to each type of hazard (**Table A-4** and **Table A-5**).

Table A-4 PHMSA Seismic Hazard Categories (Project-wide)

PHMSA Seismic Risk Category	Seismic Risk	Adjustment Factor	# of Miles Exposed
0 – 69	Low	0.1	1,671.7
69 – 84	Moderate	0.8	0.0
84 – 100	High	1.0	0.0

Table A-5 PHMSA Landslide Hazard Categories (Project-wide)

PHMSA Landslide Risk Category	Landslide Risk	Adjustment Factor	# of Miles Exposed
0 – 69	Low	0.1	1,230.2
69 – 84	Moderate	0.8	71.3
84 – 100	High	1.0	370.2

3.5.1 Ground Movement

Ground movements, such as landslides and seismic events, can threaten the integrity of a pipe. Ground movement is a minor cause of pipeline incidents, accounting for only 1.2 percent of all pipeline incidents. Routing can minimize the exposure of the pipeline to such hazards. In active seismic areas, surface breaking faults and low stability soils (which may liquefy due to seismic shaking) are avoided when practical. To mitigate risk from landslides, steep slopes, which exhibit signs of instability, are avoided when practical. However, it is not always possible to avoid the threat in all cases. In areas susceptible to ground movement, pre-construction engineering and design can minimize the potential effects of ground movement on the pipe. During operations, aerial surveillance will look for signs of any ground movement (e.g., slumping, sloughing, surface fissures, leaning trees), which could be used as indications of slope instability. Areas where ground movement is suspected will be investigated. In some cases, geometric ILI tools may be used to investigate potential ground movement.

Based on PHMSA data (2008), the baseline incident frequency for ground movement events is 1.23E-05 incidents/mile-year. For this Project, this baseline frequency was adjusted to account for regional earthquake and landslide risk (**Table A-6** to **Table A-8**). Seismic and landslide hazards have been plotted on a national scale by the US Geological Survey (USGS) and are available through PHMSA. Seismic and landslide hazards are generally low along the pipeline route, though localized areas exist along some portions of the route. The weighted average factors for landslide and seismic risk results in a project-wide adjustment factor is 0.43.

3.5.2 Flooding and Washout

Flooding covers a broad spectrum of potential threats to the line, including storm surges due to hurricanes. PHMSA, in coordination with the USGS, has categorized flooding and hurricane hazard areas and these have been quantified along the Project route (**Table A-9** and **Table A-10**). The most common event is stream scour associated with seasonal flooding. Stream scour occurs when stream velocities are higher than normal, causing erosion of the soil covering the pipeline within the streambed, as well as erosion of the banks of the stream. If the storm scour is severe or the scour area is not remediated, the pipe may eventually become partially or completely exposed. Exposed pipe can be susceptible to a number of hazards, such as fatigue due to vortex shedding (where a long span is exposed), loading due to debris pile up (material transported down the stream), or damage due to impacts from falling debris or passing boats. To reduce these potential hazards, steps are taken at the design phase to determine the scour depth of a stream, as well as its potential for bank erosion, and including factors such as thalweg depth and bankfull conditions in a rare event flood (e.g., a 1-in 100-year flood event).

Keystone will conduct a scour analysis at stream crossings susceptible to scour. Where stream scour may be an issue, the Project will be buried at depths below the anticipated scour depth. Based on PHMSA data (2008), the baseline incident frequency for washout and flooding events is 1.14E-05 incidents/mile-year. For

Table A-6 Seismic Hazard Quantification for the Project (by State)

State	Project Length (miles)	Earthquake Risk Factor – Percent					
		0 – 69		70 – 84		85 – 100	
		Percent	Miles	Percent	Miles	Percent	Miles
Montana	282.3	100.0	282.3	0.0	0.0	0.0	0.0
South Dakota	312.8	100.0	312.8	0.0	0.0	0.0	0.0
Nebraska	255.2	100.0	255.2	0.0	0.0	0.0	0.0
Total Steele City Segment	**850.3**	**100.0**	**850.3**	**0.0**	**0.0**	**0.0**	**0.0**
Nebraska	2.5	100.0	2.5	0.0	0.0	0.0	0.0
Kansas	211.1	100.0	211.1	0.0	0.0	0.0	0.0
Oklahoma	82.4	100.0	82.4	0.0	0.0	0.0	0.0
Total Cushing Extension	**296.0**	**100.0**	**296.0**	**0.0**	**0.0**	**0.0**	**0.0**
Oklahoma	154.9	100.0	154.9	0.0	0.0	0.0	0.0
Texas	323.3	100.0	323.3	0.0	0.0	0.0	0.0
Total Gulf Coast Segment	**478.2**	**100.0**	**478.2**	**0.0**	**0.0**	**0.0**	**0.0**
Houston Lateral	**47.2**	**100.0**	**47.2**	**0.0**	**0.0**	**0.0**	**0.0**

Table A-7 Landslide Hazard Quantification for the Project (by State)

State	Project Length (miles)	Landslide Risk Factor – Percent					
		0 – 69		70 – 84		85 – 100	
		Percent	Miles	Percent	Miles	Percent	Miles
Montana	282.3	62.0	175.1	2.0	5.6	36.0	101.6
South Dakota	312.8	30.9	96.6	4.6	14.3	64.5	201.8
Nebraska	255.2	90.3	230.5	2.0	5.1	7.7	19.6
Total Steele City Segment	**850.3**	**59.1**	**502.2**	**2.9**	**25.0**	**38.0**	**323.0**
Nebraska	2.5	0.0	0.0	0.0	0.0	100.0	2.5
Kansas	211.1	91.7	193.7	5.0	10.6	3.3	6.9
Oklahoma	82.4	100.0	82.4	0.0	0.0	0.0	0.0
Total Cushing Extension	**296.0**	**93.3**	**276.0**	**3.6**	**10.6**	**3.2**	**9.4**
Oklahoma	154.9	91.1	141.1	4.3	6.6	4.6	7.1
Texas	323.3	81.5	263.6	9.0	29.0	9.5	30.6
Total Gulf Coast Segment	**478.2**	**84.6**	**404.7**	**7.5**	**35.7**	**7.9**	**37.8**
Houston Lateral	**47.2**	**100.0**	**47.2**	**0.0**	**0.0**	**0.0**	**0.0**

Table A-8 Ground Movement Incident Frequencies (by State)

State	Length (miles)	Weighted Adjustment Factor (Seismic)	Weighted Adjustment Factor (Landslide)	Relative Incident Frequency /mi-yr (Ground Movement Total)
Montana	282.3	0.10	0.44	6.62E-06
South Dakota	312.8	0.10	0.71	1.00E-05
Nebraska	255.2	0.10	0.18	3.48E-06
Total Steele City Segment	**850.3**	**0.10**	**0.46**	**6.92E-06**
Nebraska	2.5	0.10	1.00	1.35E-05
Kansas	211.1	0.10	0.16	3.25E-06
Oklahoma	82.4	0.10	0.10	2.46E-06
Total Cushing Extension	**296.0**	**0.10**	**0.15**	**3.12E-06**
Oklahoma	154.9	0.10	0.17	3.34E-06
Texas	323.3	0.10	0.25	4.28E-06
Total Gulf Coast Segment	**478.2**	**0.10**	**0.22**	**3.98E-06**
Houston Lateral	**47.2**	**0.10**	**0.10**	**2.46E-06**

Table A-9 PHMSA Flood Risk Categories (Project-wide)

PHMSA Flood Risk Category	Flood Risk	Adjustment Factor	# of Miles Exposed
0 – 69	Low	0.1	975.7
69 – 84	Moderate	0.8	361.4
84 – 100	High	1.0	334.6

Table A-10 PHMSA Hurricane Risk Categories (Project-wide)

PHMSA Hurricane Risk Category	Hurricane Risk	Adjustment Factor	# of Miles Exposed
0 – 84	Low	0.1	1,418.5
84 – 100	High	1.0	253.2

this Project, this baseline frequency was adjusted to account for regional flood risk, depth of cover, and Keystone's preventative measures such as scour analysis to ensure the pipe is buried sufficiently below the streambed (**Table A-11** to **Table A-13**). The weighted average factor for flooding and hurricane risk results in a project-wide adjustment factor of 0.67.

Table A-11 Flooding Hazard Quantification for the Project (by State)

State	Length (miles)	Flood Risk Factor – Percent					
		0 – 69		70 – 84		85 – 100	
		Percent	Miles	Percent	Miles	Percent	Miles
Montana	282.3	73.4	207.3	18.8	53.0	7.8	21.9
South Dakota	312.8	70.1	219.4	22.2	69.4	7.7	24.0
Nebraska	255.2	88.5	225.9	7.0	17.8	4.5	11.5
Total Steele City Segment	**850.3**	**76.8**	**652.6**	**16.5**	**140.2**	**6.8**	**57.5**
Nebraska	2.5	0.0	0.0	0.0	0.0	100.0	2.5
Kansas	211.1	14.3	30.1	36.1	76.3	49.6	104.7
Oklahoma	82.4	20.3	16.7	43.8	36.1	35.9	29.6
Total Cushing Extension	**296.0**	**15.8**	**46.9**	**38.0**	**112.4**	**46.2**	**136.8**
Oklahoma	154.9	43.8	67.8	23.0	35.7	33.2	51.4
Texas	323.3	55.9	180.8	20.2	65.2	23.9	77.4
Total Gulf Coast Segment	**478.2**	**52.0**	**248.6**	**21.1**	**100.8**	**26.9**	**128.8**
Houston Lateral	**47.2**	**58.5**	**27.6**	**16.8**	**7.9**	**24.6**	**11.6**

Table A-12 Hurricane Hazard Quantification for the Project (by State)

State	Length (miles)	Hurricane Risk Factor – Percent			
		0 – 84		85 – 100	
		Percent	Miles	Percent	Miles
Montana	282.3	100.0	282.3	0.0	0.0
South Dakota	312.8	100.0	312.8	0.0	0.0
Nebraska	255.2	100.0	255.2	0.0	0.0
Total Steele City Segment	**850.3**	**100.0**	**850.3**	**0.0**	**0.0**
Nebraska	2.5	100.0	2.5	0.0	0.0
Kansas	211.1	100.0	211.1	0.0	0.0
Oklahoma	82.4	100.0	82.4	0.0	0.0
Total Cushing Extension	**296.0**	**100.0**	**296.0**	**0.0**	**0.0**
Oklahoma	154.9	100.0	154.9	0.0	0.0
Texas	323.3	36.3	117.3	63.7	206.0
Total Gulf Coast Segment	**478.2**	**56.9**	**272.2**	**43.1**	**206.0**
Houston Lateral	**47.2**	**0.0**	**0.0**	**100.0**	**47.2**

Table A-13 Flooding and Hurricane Incident Frequency by State

State	Length (miles)	Weighted Adjustment Factor (Flood)	Weighted Adjustment Factor (Hurricane)	Relative Incident Frequency (Flooding and Hurricane)
Montana	282.3	0.30	0.10	4.58E-06
South Dakota	312.8	0.32	0.10	4.84E-06
Nebraska	255.2	0.19	0.10	3.30E-06
Total Steele City Segment	**850.3**	**0.28**	**0.10**	**4.29E-06**
Nebraska	2.5	1.00	0.10	1.25E-05
Kansas	211.1	0.80	0.10	1.03E-05
Oklahoma	82.4	0.73	0.10	9.46E-06
Total Cushing Extension	**296.0**	**0.78**	**0.10**	**1.01E-05**
Oklahoma	154.9	0.56	0.10	7.52E-06
Texas	323.3	0.46	0.67	1.29E-05
Total Gulf Coast Segment	**478.2**	**0.49**	**0.49**	**1.11E-05**
Houston Lateral	**47.2**	**0.44**	**1.00**	**1.64E-05**

4.0 Conclusion

This study was completed to provide conservative incident frequency values for the purposes of estimating the environmental risks for the Project. The pertinent threats were identified, analyzed, and incident frequencies were calculated.

The estimated incident frequency is based on conditions when the pipeline is placed into service. Although the risk from time-dependent threats may change over time, Keystone believes that the analysis will remain conservative and applicable for the service life of the project and beyond for the following reasons:

- The analysis is based on historical data. Analysis of these data demonstrates a marked decline in pipeline incident rates over the last 10 years, primarily due to a reduction in corrosion-related events. The decline is attributed to the industry's increased use of in-line inspection tools, improved coatings, and use of cathodic protection.
- The analysis is based on a historical database where the majority of pipe is 'pre-modern' construction. Because of improving steel quality and properties, construction practices and inspection requirements, pipelines installed today will have much lower incident frequencies than pre-modern pipes.
- The adjustment factors are conservative and the analysis therefore overestimates actual risk even over a period of decades.
- Industry best management practices and the regulatory environment will continue to evolve, resulting in improved inspection and protection of pipelines. As a consequence, there will be a continued decline in the frequency of pipeline incidents.

For each state, the overall incident frequency was calculated by summing the likelihood of each individual root cause.

$$f_{total} = f_{co} + f_{ex} + f_{md} + f_{hy} + f_{gm} + f_{wo}$$

Where:

f_{total} = total leak frequency

f_{co} = leak frequency from corrosion

f_{ex} = leak frequency from excavation

f_{md} = leak frequency from material defects or construction deficiency

f_{hy} = leak frequency from a hydraulic event

f_{hy} = leak frequency from ground movement

f_{wo} = leak frequency from washout event

The resultant state-specific incident frequencies are summarized in **Table A-14**. Based on a weighted average of the state-specific incident frequencies, the resultant project-wide leak frequency is 1.35E-04 incidents/mile-year, equivalent to one incident in 7,400 years per mile of pipe.

Table A-14 Incident Frequencies by State

State	Length (miles)	Incident Frequency	Occurrence Interval (years)
Montana	282.3	1.33E-04	7,500
South Dakota	312.8	1.37E-04	7,300
Nebraska	255.2	1.29E-04	7,800
Steele City Segment	**850.3**	**1.33E-04**	**7,500**
Nebraska	2.5	1.48E-04	6,800
Kansas	211.1	1.35E-04	7,400
Oklahoma	82.4	1.34E-04	7,500
Cushing Extension	**296.0**	**1.35E-04**	**7,400**
Oklahoma	154.9	1.33E-04	7,500
Texas	323.3	1.39E-04	7,200
Gulf Coast Segment	**478.2**	**1.37E-04**	**7,300**
Houston Lateral	**47.2**	**1.41E-04**	**7,100**
Project-wide (including Keystone Cushing Extension)	**1671.7**	**1.35E-04**	**7,400**

5.0 Spill Volumes

5.1 Methodology

Keystone has evaluated maximum spill volumes that could potentially occur along the Project for the purpose of emergency response planning. This approach is consistent with the requirements of 49 CFR Section 194.105, which requires an operator to determine the worst-case discharge of each of its emergency response zones. The worst-case discharge is defined as the largest volume based on the maximum release time, maximum shut down response time, maximum flow rate and the largest line drainage volume after shut down of the line section within the response zone. This section describes the methodology used to estimate maximum spill volumes for the Project.

5.2 Leak Detection

In an event of a leak or rupture, Keystone would implement multiple leak detection methods and systems that are overlapping in nature and progress through a series of leak detection thresholds. The leak detection methods are as follows:

- Remote monitoring performed by the OCC Operator, which consists of monitoring pressure and flow data received from pump stations and valve sites fed back to the OCC by the Keystone SCADA system. Remote monitoring is typically able to detect leaks down to approximately 25 to 30 percent of the pipeline flow rate.
- Software-based volume balance systems that monitor receipt and delivery volumes. These systems are typically able to detect leaks down to approximately 5 percent of the pipeline flow rate.
- Computational Pipeline Monitoring or model-based leak detection systems that break the pipeline into smaller segments and monitor each of these segments on a mass balance basis. These systems are typically capable of detecting leaks down to a level of approximately 1.5 to 2 percent of pipeline flow rate.
- Computer-based, non-real time accumulated gain/(loss) volume trending to assist in identifying low rate or seepage releases below the 1.5 to 2 percent by volume detection thresholds.
- Direct observation methods, which include aerial patrols, ground patrols, and public and landowner awareness programs that are designed to encourage and facilitate the reporting of suspected leaks and events that may suggest a threat to the integrity of the pipeline.

While large, rapid releases are quickly detected, a pinhole leak with a slow rate of release may not be immediately detected by the first four detection mechanisms above, and patrolling and public awareness may be the first to detect these small leaks. PHMSA data indicate that pipeline spills are usually detected within 1.2 days and 97 percent of spills are detected within 7 days (PHMSA 2008). Even when leaks were not detected within the first 48 hours, PHMSA data indicate that the total spill volumes were not catastrophic, rather the median total spill volume for spills not detected within the first 48 hours was 15 barrels, and the maximum spill volume was 12,000 barrels (detected after 4 days).

5.3 Methodology

The total spill volume is based on three leak duration periods:

- The pre-pump-closure period,
- The pre-valve-closure period and,
- After-valve-closure period.

Prior to the pump shut-down sequence to stop the pipeline in the event of a release, the pressure in the pipeline can be estimated through well-defined friction loss equations in combination with gravity head calculations. The total volume released before pump shut-off is the culmination of a constant leak rate over the duration of a leak.

After pump shutdown, the intermediate mainline valves will require a few minutes to close; where a check valve is installed, this type of valve enables “immediate one-way” closure of the valves after pump shut down to prevent backflow caused by gravity drainage. After pump shutdown, the liquid could drain out of the line under the gravity head difference between the leak and the adjacent elevated pipeline segments. This free draining process is modeled as a multi-loop “U” tube, with the middle open to the atmosphere and the other two ends connected to up and downstream valves. This concept is illustrated in **Figure A-2**.

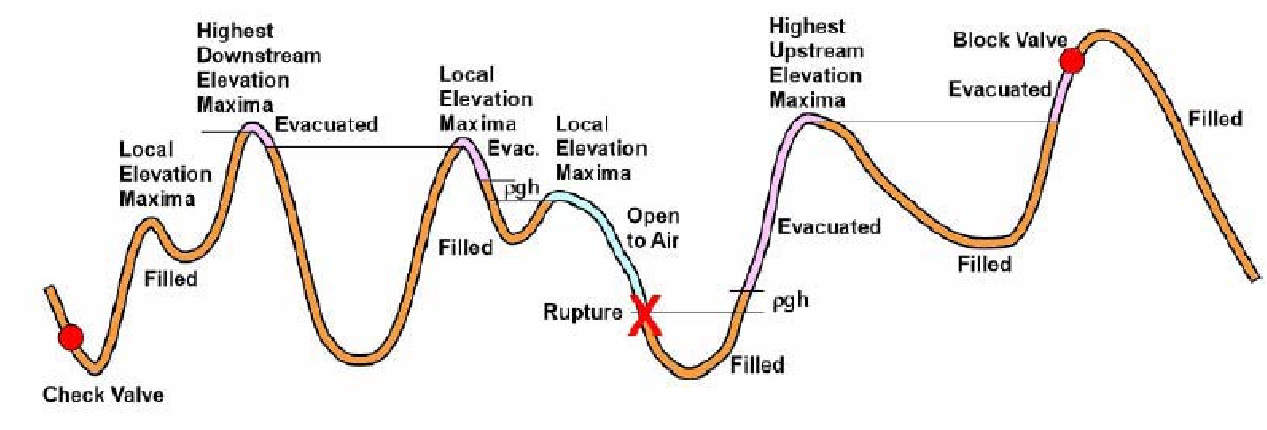

Figure A-2 Schematic of Drained Segments after Valve Closure

There are three ways draindown can occur depending upon the proximity of the segments to the leak location:

1. If a leak is in proximity upstream or downstream from an adjacent segment with a higher elevation than the leak location, the segment will be fully drained. On the other hand, if the adjacent segment elevation is lower than the leak location, the first segment will still be filled with liquid in the line.

2. In situations where vapor pressure can be assumed to be zero there must be a liquid segment of height with equivalent pressure of *pgH*[6] to balance atmospheric pressure. If there isn’t enough elevation above this height, there will be no further drain-down. If there are segments that have more than *ghρ* equivalent pressure, then more segments in the line will be drained. In this case, the second drained segment immediately adjacent to the first drained segment will be at least “H” above the first drained segment. In situations where vapor pressure is considered, a conservative approach is used to assume there is no head (*pgH*) balancing atmospheric pressure.

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[6] See Section 6.4 for equation defining “*pgH.*”

3. In addition, adjacent to the second drained segments, the pressure is only balanced by the vacuum. Therefore, the elevation of the one end of the drained segment will be the same as the other end of the previous drained segment. This scenario will be the same for any further drained segments.

Before pump-closure, the leak volume is the leak rate computed from the Bernoulli equation, where pressure is the result of local gravity and operating pressure. After pump shut-off but before valve closure, drainage is calculated using the whole pipeline including check valves, (which prevent backflow). This period is relatively short compared to the after-valve-closure period. Given that all the segments of the whole pipeline can possibly drain down without valve restrictions, the drainage process needs to be considered as time-dependent. This consideration is especially important for small leak sizes, because within the response time of closing the valves, a limited number of segments are susceptible to drainage based on the Bernoulli equation. The time dependent-manner of this drainage is caused by reduced gravity head along with the draining process. This draining needs to satisfy the following equation:

At any time (*t*):

$$\rho g H = {}^{1}\!/_{2}\, \rho v^2$$

Where:

- *H* = the maximum relative elevation above the leak in the pipeline at instant *t*
- *g* = gravity acceleration
- *ρ* = fluid density

After a short time interval, *H* is reduced and is recomputed based on the leak rate (*v*) for each time interval. This calculation uses the drained volume, which is measured using the cross sectional area of the pipe, the average slope of the draining segments, and the number of U-tube sections being drained: sections with elevations higher than the fluid level at time *t*.

The maximum fluid level above the leak is updated after each time interval to the Bernoulli equation to compute the updated leak velocity. This process is iterated until total time is elapsed when pump shutdown exceeds the valve closure response time and the total drained down volume is computed by this time.

After all the valves are closed, the liquid drainage only occurs between the two nearest block valves. The analysis also can be considered similar to the aforementioned scenario but the volume drainage analysis is confined between two adjacent valves that enclosed the leak location. However, a conservative and simpler approach is to assume that the leak cannot be stopped in time and all oil that should be drained down will be freely drained out of the pipeline. This simplification eliminates the need to do iterative calculations described above.

The release volumes from the above three phases can be combined to produce a total outflow volume for the overland spill model simulations. Repeating these calculations at multiple points along the pipeline can identify areas of greatest concern in accordance with federal requirements and evaluate the effectiveness of valve placement for the protection of HCAs.

5.4 Spill Scenarios

Keystone estimated maximum spill volumes based on three scenarios: worse case discharge, large leak, and a small leak. These maximum spill volumes were calculated using the outflow model described above. Maximum spill volumes estimated for the Project for each scenario described below are presented by state, segment, and project-wide. Based on historical averages, spills of these proportions are rare. Nevertheless, Keystone will be prepared to respond to spills of any size in accordance with Federal requirements.

5.4.1 Worst-Case Discharge Scenario

For this scenario, a worst-case discharge (rupture) was defined as a hole in the pipeline with a diameter equal to the pipeline's diameter. In this case, as the release rate from the rupture will be similar to the operating flow rate, the leak detection system will detect the leak virtually instantaneously due to the pressure drop in the line. Following detection, an emergency shutdown procedure is initiated, with pumps shutting down first (9 minutes for shutdown), followed by approximately 3 minutes for intermediate remotely operated valve closure.

5.4.2 Large Leak Scenario

For this scenario, a large leak is defined as one that results from a hole having a mean diameter of 1.96 inches. The mean diameter for this scenario is based on conservative geometry of an injurious flaw that would cause a leak of this nature. The leak detection system will detect this leak, as it will be a significant fraction of the normal operating flow rate. Following initial detection of a potential leak, the OCC would confirm the leak and begin a controlled system shutdown.

5.4.3 Small Leak Scenario

A small leak is defined as one that results from a hole having a mean diameter of 0.06-inch. As the release rate will be a very small percentage of the flow rate, the computational leak detection systems would not detect the leak immediately The leak in this scenario would be more likely detected by line patrol or reported by a third-party. If the leak remained undetected by direct observation for an extended period of time, the computational leak detection systems could detect such a leak. Following notification and confirmation of a leak, the OCC would begin a controlled system shutdown.

5.4.4 Spill Size Distribution

Figure A-3 provides a view of the spill size distribution. The cumulative distribution of spill volumes is based on simulated spills at approximately 3 foot intervals along the pipeline. Fifty percent of all spills modeled are less than 16,000 bbls and only 0.1 percent of all spills modeled are greater than 66,500 bbls.

5.5 Comparison of Worst-case Spill Volumes with Actual Spill Volumes

Examination of the current PHMSA dataset (2002 to June 2008) indicates that the vast majority of pipeline spills are relatively small, with 50 percent of the spills consisting of 3.0 barrels or less (**Table A-15**). In 85 percent of the cases, the spill volume was 100 barrels or less. In over 95 percent of the cases, spill volume was less than 1,000 barrels. Oil spills of 10,000 barrels or greater only occurred in 0.5 percent of cases. These data demonstrate that most pipeline spills are small and very large releases of 10,000 barrels or more are extremely uncommon.

While the majority of historical pipeline spills have been relatively small, it is critical to evaluate worst-case spill scenarios for the purposes of design refinement (e.g., placement of valves) and emergency pre-planning purposes, allowing for optimal valve placement and pre-positioning of personnel and equipment.

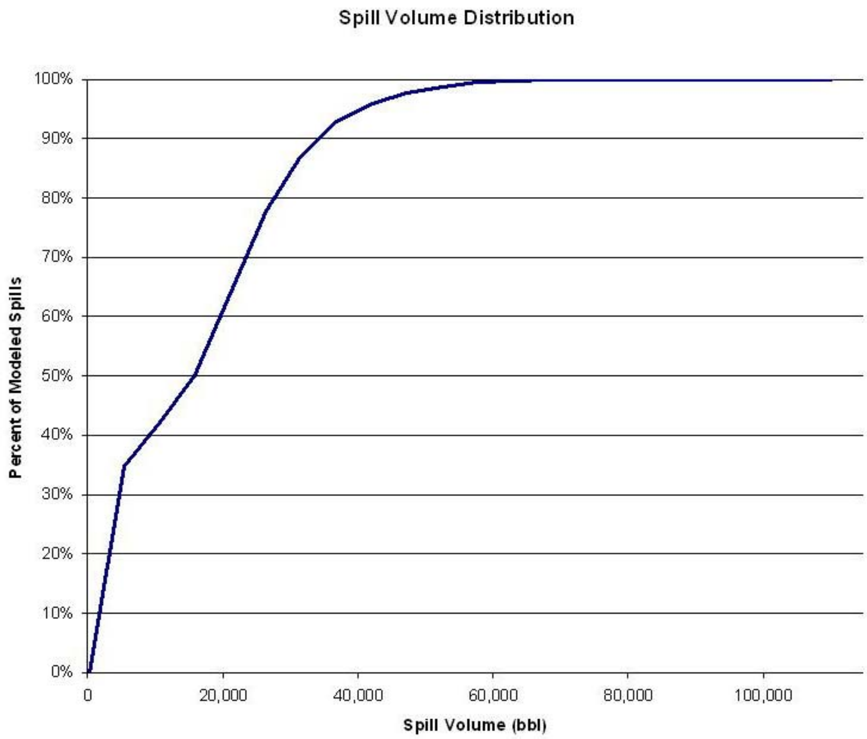

Figure A-3 Spill Volume Distribution

Table A-15 Historical Spill Volumes Based on the PHMSA Database (2002-2009)

	Spill Volume (barrels)
Mean (barrels)	296
Median (barrels)	3.0
Minimum (barrels)	0.0
Maximum (barrels)	49,000

5.6 Conclusion

Spill volume data from actual pipeline incidents reported between 2002 and 2008 shows that the majority of spills consist of only 3 barrels or less (PHMSA 2008). In contrast, Keystone is estimating maximum spill volumes to prepare for the worst-case scenario. These maximum spill volumes will be used for emergency planning purposes, such as the identification of the amount of equipment and resources that could be potentially required to respond to an event. Keystone also will use these data combined with fate and transport analyses to pre-position emergency response personnel and their response equipment. In the unlikely event of a spill, the actual size of a spill is expected to be significantly smaller than the maximum spill volume.

6.0 References

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