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Keystone XL Pipeline: Independent Engineering Assessment – Final Report

Energy Systems
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To

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Privileged and Confidential

Disclaimer and Related Preface

This work has been prepared under contract to TransCanada Keystone Pipeline, LP (Keystone), in response to needs identified by US Government Agencies involved in the evaluation leading to a Record of Decision to grant a Presidential Permit for the proposed Keystone XL Pipeline Project. A number of considerations related to that process and its desired timeline impact this Project, being part of the negotiated scope and terms and conditions.

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List of Acronyms and Abbreviations

ACV	automatic control valve
API	American Petroleum Institute
ARO	abrasion resistant overlay (to the coating)
ASME	American Society of Mechanical Engineers
bpd	barrels per day
CAO	corrective action order
CFR	US Code of Federal Regulation
CP	cathodic protection
CPM	computational pipeline modeling/monitoring
CPS	critical pipeline segment
CV	check valve
dilbit	diluted bitumen
DCVG	direct current voltage gradient
DEIS	draft EIS
DoS	Department of State
DoT	Department of Transportation
EC	external corrosion
EIS	environmental impact statement
EPA	Environmental Protection Agency
EFRD	emergency flow restricting device
ERP	emergency response plan
FBE	fusion bonded epoxy (coating)
FEIS	final EIS
FLIR	forward-looking infrared
gpm	(US) gallons per minute
HCA	high-consequence area
HDD	horizontal directional drill
HVP	high vapor pressure
IC	internal corrosion
ILI	in-line inspection
IMP	integrity management plan/process
Keystone	TransCanada Keystone Pipeline, LP
LDS	leak detection system
LoI	letter of intent
MAOP	maximum allowable operating pressure

MFL	magnetic flux leakage
MLV	mainline valve
MOV	manually operated valve
NACE	National Association of Corrosion Engineers
NAPL	non-aqueous phase liquid
NEPA	National Environmental Policy Act
O&M	operations and maintenance
PAH	polycyclic aromatic hydrocarbon
PHAST	Process Hazard Analysis Software Tool
PHMSA	Pipeline and Hazardous Materials Safety Administration
PRCI	Pipeline Research Council International, Inc.
Project	Keystone XL Pipeline Project
psi	pounds per square inch
QC	quality control
RCV	remote controlled valve
RoW	right-of-way
RP	recommended practice
SCADA	supervisory control and data acquisition
SCC	stress corrosion cracking
SEIS	supplemental EIS
SME	subject matter expert
SMYS	specified minimum yield stress
SOP	standard operating procedure/process
SYSPRT	system-part reporting category
TCPL	TransCanada Pipeline
TPD	third-party damage
US	United States
USA	unusually sensitive area
USGS	US Geological Service
WCSB	Western Canadian Sedimentary Basin

Executive Summary

TransCanada Keystone Pipeline, LP (Keystone) proposes to construct and operate a pipeline and related facilities known as Keystone XL Project (the Project). The Project consists of a crude oil pipeline and related facilities to transport Western Canadian Sedimentary Basin (WCSB) crude oil from an oil supply hub near Hardisty, Alberta, Canada, to existing pipeline facilities near Steele City, Nebraska, for delivery to Cushing, Oklahoma, and the Gulf Coast area. Within the US, the proposed Project would consist of approximately 875 miles of new, 36-inch-diameter pipeline across portions of Montana, South Dakota, and Nebraska.

The US Department of State (DoS) released the *Final Environmental Impact Statement for the Keystone XL Project* (FEIS) in August 2011. Following its release, the DoS, working with the US Department of Transportation (DoT) Pipeline and Hazardous Materials Safety Administration (PHMSA) and the US Environmental Protection Agency (EPA) (the agencies), concluded that it would be beneficial to have a third-party review of the preliminary risk assessment (Risk Assessment) prepared by AECOM and Dynamic Risk Assessment Systems, Inc., on behalf of Keystone. Battelle and E^{x}ponent were selected to address a specific set of engineering and environmental issues for the third-party review.

Battelle was charged to evaluate the following engineering components of the proposed pipeline:

1. failure frequency;
2. risk assessment;
3. outflow analysis and placement of valves;
4. fate and transport;
5. detection of leaks;
6. prevention of leaks; and
7. protective and mitigative measures.

E^{x}ponent was charged to evaluate the following risk-related components and aspects of the proposed pipeline:

1. overall Keystone environmental risk assessment methodology;
2. characteristics of the crude oil being transported;
3. transport and fate characteristics of spilled crude oil;
4. environmentally sensitive issue one – shallow groundwater; and
5. environmentally sensitive issue two – small stream crossings less than 100 feet in width and associated ecological concerns.

This third-party review focuses on the Risk Assessment as presented in Appendix P of the FEIS – Pipeline Risk Assessment and Environmental Consequence Analysis, dated July 2009 (Risk Assessment). Battelle submitted its original third-party review of the Risk Assessment in January 2012. Following the DoS issuance of a *Draft Supplemental Environmental Impact Statement for the Keystone XL Project* [SEIS]) in March 2013, Battelle received comments on the initial draft of this document. This revised report updates the initial assessment based on new information provided in the SEIS and responds to the comments on the initial draft report. The major differences between the FEIS and SEIS are as follows:

- The FEIS included the section from the northern border between the US and Canada to its terminus near Houston, Texas; the SEIS considers only the northern part of the pipeline from the US-Canada border in Montana to Steele City, Nebraska.
- The SEIS considers a new route in Nebraska that avoids the Sand Hills region.
- Appendix P of the FEIS became Appendix Q in the SEIS, and a new Appendix K providing a historical analysis of crude oil spills was added.

In a change from Battelle's original January 2012 report, E^{x}ponent's report was originally included as an appendix to the January 2012 report, but it is now a separate document.

The following subsections of the Executive Summary present the key findings, conclusions, and recommendations from the engineering assessment performed by Battelle. The assessment of each task assigned to Battelle is presented from two viewpoints. First, the assessment is based on the historical record of crude oil pipeline performance. The second is forward-looking. It assumes that Keystone will meet all the regulatory requirements and that the PHMSA will effectively oversee the pipeline from the time it comes under their regulatory authority until it is decommissioned. The first viewpoint is based on fact, the second on assumptions. In looking at the 57 Regulatory Conditions imposed by PHMSA, most are forward-looking, directed at ensuring that the pipeline is constructed to high standards and is maintained to those same high standards.

Failure Frequency

In the FEIS, Keystone based their failure frequency analysis presented in Appendix P of the FEIS (Appendix Q of the SEIS) on the Liquid Hydrocarbon Incident Database maintained by PHMSA. They used the incident data beginning in 2002 and ending in August 2008. All the incidents were used except those related to the transport of high-pressure carbon dioxide. The database divided the incident causes into eight cause categories, and Keystone concluded that five of the eight were applicable. These counts were then divided by the pipeline system mile-years operation (171,000 miles times 6.5 years of data) to calculate the failure frequency for each of the five cause

categories. These rates were then adjusted downward to account for the special conditions that are incorporated into the design specifications and planned operating procedures being applied to the Keystone XL Pipeline. National hazard maps, such as the National Flood Map, were then used to further adjust the failure frequency per mile in flood-prone areas along the pipeline. After all the adjustments were made, the new (and in some areas, mile-post-specific) failure frequencies were added to get an estimate of the failure frequency for the entire pipeline and for each state traversed by the pipeline.

Battelle was able to duplicate the analysis performed by Keystone well enough to conclude that there were no major errors, though some formulation errors exist. Keystone applied all the failures to the system, not recognizing the much lower failure frequency of the mainline pipe. Keystone performed no sensitivity analyses, and the effect of using all the incident records, including records with no cause code, was not evaluated. These failure frequency estimates were eventually used to estimate the median and mean spill sizes. The Battelle evaluation shows that since the failure frequency assessment was incorrectly formulated, the median and mean spill sizes were about an order of magnitude too small. The main cause of this underestimate was the failure to separate incidents occurring on the mainline pipe from incidents at the fixed facilities. In Appendix K of the SEIS, the PHMSA database was also the basis for a historical count of the number of crude oil spills. In this new assessment, the distinction was made between pipeline system elements. Four different systems were evaluated: Mainline Pipe, Mainline Valves, Tanks, and Other System Components. The first two were associated with the pipeline right-of-way (RoW), and the last two were associated with system elements at fixed facilities. The PHMSA database was also used for this analysis, capturing data over a longer time period (from 2002 to July 2012). Appendix Q of the SEIS was not updated based on the new results presented in Appendix K. Appendix P of the FEIS was included in the SEIS, without change, as Appendix Q.

Key Findings

1. Had the results from Appendix K been inserted into Appendix Q of the SEIS, a much more reasonable estimate of the failure frequency and the mean and median spill volumes for mainline pipe would have been realized. It is believed that if the results from Appendix K were inserted into the Appendix Q analysis, the result would support the recommendation (made below) that a median spill volume of 100 barrels be used for planning purposes.
2. A basis should be provided for any engineering factors used to adjust the failure frequencies that are expected to be realized by the new required standards and procedures. In a 2013 draft risk analysis report prepared by Battelle for the northern segment of the Keystone XL

Pipeline[1], another approach was used: comparing the US failure rate with that in other countries–specifically, Australia, where most of their pipeline is built to modern standards. Their failure rate is 10 times lower than the US rate. Because of some characteristics of the US system (for example, the use of larger-diameter pipe, with its increased capacity), the full 10-fold reduction in failure rate might not be realized.

3. The analyses performed in Appendix P of the FEIS (Appendix Q of the SEIS) did not use all the cause codes in the PHMSA database and attributed all the failures to pipelines, in general. The former results in an underestimation of the number of failures, but the latter results in a large overestimation of failure rates for mainline pipe, because about 60 percent of the failures occur at facilities such as pumping stations. In addition, the spills at the fixed facilities and at valve sites tend to be smaller. Thus, the spill frequency for mainline pipe, prior to the engineering adjustments, are overestimated, and even after engineering adjustments are applied, the median and mean spill volumes are underestimated by perhaps as much as an order of magnitude. Appendix K improves the original analysis in Appendix P of the FEIS by considering the following factors: (1) only crude oil spills, (2) a spill record for almost 11 years (instead of 6.5), and (3) division of the pipeline into system elements. Unfortunately, the results from Appendix K were not factored into Appendix Q of the SEIS.

Recommendations

The PHMSA Liquid Hydrocarbon Incident Database should continue to be used, but the analysis should be limited to crude oil spills and should consider the very different spill performance data for major systems (i.e., mainline pipe). The results should be presented without the use of engineering adjustment factors. A decade from now, there will be enough modern pipeline performance data to negate the need for adjustment factors. Until then, data from other sources, such as performance data on the more modern Australian pipeline system, should be used to show that the results presented are conservative. A conservative performance range could be presented if an updated spill frequency estimate is needed for the entire pipeline. Appendix K of the SEIS should be used as the starting point for such an updated analysis. Until that re-evaluation is performed, it is recommended that, for planning purposes, a medium spill volume of 100 barrels be used. A larger volume may have to be used in locations where the terrain produces a hydraulic gradient. See “Outflow Analysis and Valve Placement” below for the assessment of spill volumes in these areas.

[1]McSweeney, T.I., Leis, B.N., Mawalker, S., Harley, M.C., Rine, K.R., and Sanzone, D.M. *Risk Analysis of the Proposed Keystone XL Pipeline Route,* Draft. Battelle Memorial Institute. June 2013.

Risk Assessment

Risk assessment is a basis to evaluate the threat posed to the public and the environment by a business venture. Thus, the methodology used must adequately identify and quantify the nature of the threats. It should also provide a framework to identify effective prevention devices and programs (the most important of which are safeguards) and effective mitigative devices and strategies. The risk reduction program that can be built from a good risk assessment should, over time, reduce the likelihood of and/or the damage to the public and the environment in the unlikely event of a release. Thus, the risk assessment is the tie between the spill frequency analyses and the safeguards employed to protect the environment, the public, and workers.

For the Keystone XL Pipeline, the primary threat is release of crude oil and its resulting effect on the public and environment. The objective of this task was to evaluate the approach documented in Appendix P of the FEIS and republished without change as Appendix Q in the SEIS. The key findings and recommendations listed below are the result of a review of the material presented in the EIS documents and an independent risk analysis performed by Battelle. The key findings and recommendations are made with the recognition that the risk assessment results will form the basis for evaluating all subsequent subtasks to be performed in both the engineering evaluation performed by Battelle and the environmental evaluation performed by E^{x}ponent.

Key Findings

1. The Risk Assessment in Appendix P of the FEIS and republished as Appendix Q of the SEIS does not meet one of the key objectives of a risk assessment program: identifying the major sources of risk, and then identifying the components and/or procedures that can mitigate those risks. The historical spill analysis presented in Appendix K of the SEIS and the risk analysis performed by Battelle demonstrates that a meaningful risk assessment can be performed using data on crude oil spills. The two analyses also show the importance of breaking the system down into major system components and calculating the risk for each system. Such a breakdown of the pipeline system into major components provides the proper emphasis on important preventive, protective, and mitigative devices and programs.
2. While the PHMSA database is useful for assessing the overall performance of pipelines, the risk assessment capabilities of this database are limited. This database should not be the sole source of failure causes and their consequences. Standards such as American Society of Mechanical Engineers (ASME) B31.8S and American Petroleum Institute (API) 1160 describe risk assessment programs which are an essential part of an integrity management program (IMP). The data requirements for this risk assessment are much more extensive and need to be identified during the development of the IMP. The data requirements for

this program are not available for the more general assessments performed for environmental impact statements.

Recommendations

Future risk assessments should divide the pipeline system into component parts, assess the risk for each component, and then calculate the system risk from its components. The risk analysis performed by Battelle used Total Incident (Damage) Cost as a measure of the consequences. This consequence measure would be an ideal measure if the contributors to the overall cost (e.g., emergency response costs, environmental recovery costs) were better understood. At this time, only the effectiveness of preventive programs can be measured using the total damage cost consequence measure. Because spills can never be totally prevented, the only way to value protective and mitigative systems and procedures is to have these programs focus on the component systems that control risk. The Battelle risk analysis shows that the subsystems that generate most of the risk are the mainline pipe and the fixed facilities such as the pumping stations. Thus, when developing preventive, protective, and mitigative programs, equal focus should be on the mainline pipe and the fixed facilities.

Outflow Analysis and Valve Placement

Prior tasks have identified the potential threats and quantified their implications in regard to spill frequency and volume. Realizing that significant spills have occurred, it is essential that the pipeline design protect the environment by controlling a spill through valves located to minimize both the potential spill volume and its consequences. Keystone provided the Battelle team with a privileged and client-confidential appendix to Appendix P of the FEIS that described the model and presented a curve showing the cumulative probability distribution of spill volumes versus spill probability. They also provided the analysis results for a section of the pipeline about 170 miles long going through a portion of Oklahoma and Texas before and after complying with PHMSA Special Condition 32. The result was a 70 percent reduction in spill volume. The Battelle team evaluated (1) the model and the process used to quantify outflow, and (2) the effectiveness of valve placement to minimize outflow and thereby protect the public and environment. The Battelle team was also asked to identify possible gaps.

Key Findings

1. The model used to estimate outflow volumes is based on sound mathematical principles, the Bernoulli Equation, and the assumptions made about crude oil available for release are conservative. While it was not possible to confirm the results, the process used to place the valves is correct.

Recommendations

The model and the process that were used to ensure that valves are placed to minimize the total outflow from a breach appear to be correct and should continue to be used. It is recommended that portions of the outflow analysis be redone to reflect the new route and thereby ensure that the results are not significantly different from the results presented at the time the FEIS was published.

Fate and Transport

The fate and transport analysis presented in Appendix P of the FEIS was assessed to determine the behavior and fate of crude oil in the environment after a spill. While E^{x}ponent conducted additional transport and fate analyses to better describe the behavior of potential spills to the affected environment, our review relies on information provided in the Risk Assessment (Appendix P of the FEIS and Appendix Q of the SEIS) to recommend additional steps that could be taken to better understand fate and transport of the product and develop viable prevention and mitigation steps, such as emergency response plans (ERPs).

Key Findings

1. Major factors affecting the behavior and fate of crude oil in the environment are: (1) the nature of product spilled; (2) the volume and rate of the spill; (3) the physical, chemical, and biological characteristics of the receiving environment; (4) the weather conditions at the time of the spill; (5) the amount of time elapsed until detection; and (6) the adequacy and timing of response activities. Of particular importance is the receiving environment (e.g., water and soil attributes, slope, gradient, topography, underlying geology, and weather and climate), which in turn impacts the dispersion, fate, plume size, and transport.
2. Environmental transport and fate of petroleum products is dependent on many factors, and modeling transport and fate is a complex exercise. Gaps were identified in the Keystone fate and transport analysis regarding the transported product's chemical and physical characteristics, and its weathering and transport behavior. To close these gaps, E^{x}ponent was asked to provide a quantitative fate and transport analysis and numerical screening model, which take into account the characteristics of oil, in order to shed light on potential transport and fate of the transported product.
3. E^{x}ponent's analysis of the physical and chemical characteristics of the transported products indicates they are within the bounds of typical medium to heavy crude oils. The analysis also finds that the products are sufficiently similar such that they should not pose an excess risk as compared to typical crude oil in case of a release.

4. E^{x}ponent's results indicate that even small subsurface spills of oil into the soil become detectable at the surface within about one month. Aboveground surveys then detect these smaller leaks.
5. E^{x}ponent's results indicate that surface or subsurface spills of oil on land will tend to remain localized and will migrate slowly into the soil because of the high viscosity of this crude; therefore, potential threats to groundwater depend on water table levels local to the spill.
6. E^{x}ponent applied a numerical screening model to estimate the behavior of a large spill of diluted bitumen (dilbit) in an area with a highly permeable, shallow aquifer as characteristic of the Sand Hills Region of Nebraska. The outcomes showed that (1) a large spill one foot above the water table could begin forming a non-aqueous phase liquid (NAPL) lens at the water table between one and two years after the spill; (2) despite the short distance to the groundwater, the high viscosity of the oil and the presence of natural soil moisture limits the NAPL permeability in the soil, resulting in limited migration; and (3) the time for formation and subsequent transport of the plume is long relative to the response time for spill control and countermeasures.
7. E^{x}ponent notes that spills into surface waters can be transported beyond the 5-mile distance used to identify sensitive environments (e.g., high-consequence areas [HCAs]).
8. E^{x}ponent's transport and fate analysis in groundwater concludes that plumes of dissolved hydrocarbons in groundwater, to the extent they develop, will be on the order of hundreds of feet in length and will move relatively slowly. Further, they note that longer plumes can occur under pumping conditions.
9. E^{x}ponent notes that a set of criteria were proposed to identify potentially sensitive groundwater areas that include distance from the pipeline (vulnerable areas lie within 1,000 feet), water table elevation (within a few feet of pipeline), and the presence of clusters of domestic and irrigation wells.

Recommendations

E^{x}ponent developed and applied criteria to identify potentially sensitive environments downstream of small stream crossings, with a number of such environments identified along the pipeline route. From an engineering perspective, concern for small streams could and should be managed proactively during construction via micro-bore or such techniques. During construction, and continuing into the operational phase, further analysis should be done to assess overland flow (spreading) and transport for specific pipeline sections that intersect identified sensitive habitats, including the four streams identified by E^{x}ponent. This modeling exercise could then be used to inform ERPs. Well depth and depth of release should also be assessed relative to the water table to screen / identify sensitive groundwater resources that may be more vulnerable to exposure to a

hydrocarbon plume in the event of an oil spill. Finally, it is recommended that the presence of polycyclic aromatic hydrocarbons (PAHs) and naphthenic acids be better quantified for the oils that are actually transported in the pipeline for more informed environmental remediation and response planning.

Leak Detection

While subsequent sections will indicate that modern design, construction, operations, and maintenance/integrity management can more effectively control releases, in reality, no matter how effectively pipeline systems are designed and constructed, there will always be a finite chance that a leak will occur. Therefore, leak detection is essential across the range of potential release scenarios. The objective of the leak detection task was to evaluate the scope of practical technologies to (1) quantify what size leak can be detected as a function of time to alarm; (2) identify potentially useful sensors and schemes that can assist in detecting or avoiding leaks subject to the usual threats to pipeline integrity; and (3) comment on the adequacy of and possible gaps in the leak detection system that will be applied to this pipeline. This is the first of the forward-looking tasks that consider future performance during pipeline operation.

Key Findings

1. The leak detection approach proposed for the Project, computational pipeline monitoring (CPM), is the industry standard for crude oil pipelines and should have better than average performance because of Keystone's more frequent use of sensors. While CPM is the standard practice, the detection limit is normally expressed as time to detect a specified percentage of throughput. Thus, the detection time can be large when the throughput is large, as is the case with the Keystone Pipeline. This means that leak detection cannot rely solely on CPM.
2. Keystone will also rely on the non-standard use of an over/short analysis, which calculates a long-term system volume balance. In some studies, it has been shown that the ability to quickly detect small leaks exists, at levels as small as 1.5 to 2 percent of throughput. Since there is a desire to detect leaks that are smaller than the capability of the CPM, reliance should be placed on other methods such as ground-based or aerial surveillance programs. These surveillance activities could be more frequent in sensitive environmental areas or in areas where third-party damage is more likely.

Recommendations

In the risk analysis performed by Battelle, it was shown that facility risks were significant. Therefore, it is recommended that not all the leak detection efforts be placed on the mainline pipeline sections. Note that between the start of 2002 and the end of 2012, the largest spill was a

49,000-barrel spill from a tank at a fixed facility. The largest spill from a mainline pipe rupture, while still large, was smaller – about 31,000 barrels. Indeed, if the leaks at fixed facilities are significant and frequent, leaks detected by the CPM may be attributed to the facility leaks and an actual leak along the pipeline may go undetected for a longer period of time.

As new leak detection technologies emerge and start to be deployed in the field, Keystone should continue to evaluate these technologies and consider them for implementation if they represent a significant increase in leak detection sensitivity. In-line leak detectors should also be deployed as part of the pig trains run under the IMP. Leaks are not expected to be frequent; however, because many of the failures are the result of human activities, it is recommended that aerial surveys and/or ground patrol frequency be increased to once a week.

Leak Prevention

Results presented for prior tasks have assessed risks and quantified threats and spill volume from pipelines with an average age of greater than 40 years. System integrity is fundamental to leak prevention. The objective of this task was to quantify the effectiveness of the current design, construction, and operation practices. Along the mainline pipe, leak prevention focuses on detection of defects in the pipe itself, on the longitudinal welds made during fabrication and the girth welds that connect the line pipe across the RoW. Battelle's evaluation of leak prevention considered the effectiveness of the external coating placed on the pipe and on the girth welds, as well as on the cathodic protection (CP) system.

Key Findings

1. The minimum 0.465-inch-thick wall adopted for the mainline system affords significantly better resistance to both corrosion and mechanical damage as compared to the historic database. Viable quality controls in place for both the steel and the longitudinal seam ensure that the pipe as delivered meets minimal regulatory and code requirements and the requirements of the PHMSA's Special Conditions associated with the line pipe.
2. Considering normal operation at its maximum allowable operating pressure (MAOP) and at the minimum wall thickness for the mainline system, the first IMP repair time response threshold (repair in 180 days) occurs at a defect depth of 40 percent through-wall and corresponds to an anomaly length in excess of 15 inches. The second repair threshold (repair in 60 days) occurs at a defect depth of 60 percent through-wall and has an associated length on the order of 6 inches. Such features are reliably found using usual in-line inspection (ILI) tools that target corrosion.
3. It was determined that under worst-case circumstances, at least three ILI cycles occur prior to reaching the first IMP (scheduled) threshold (repair in 180 days), which, using worst-case corrosion rates, would not occur until after about 12 years of operation.

4. The planned inspections that Keystone has committed to perform prior to the start of operations should detect any defective welds or major defects in the pipe wall and defects caused by placement of the pipe in the ground. These defects should be repaired before operations and therefore prevent leaks.
5. The practices adopted for corrosion protection since the 1990s directed at the use of fusion-bonded epoxy mill-applied coatings with comparable developments for field-applied coatings have brought about a step reduction in incidents due to external corrosion.
6. While the incidence of internal corrosion is increasing as the diameter and number of pipelines transporting crude increase, Keystone plans to operate the pipeline in the turbulent flow regime, which should control the internal corrosion.
7. The practices that involve one-call and related activities mutually supported by the industry and the regulators have significantly reduced the frequency of third-party damage.
8. While the throughput of modern pipelines has increased significantly relative to the sizes of pipelines that populate the PHMSA database, the spill volumes have shown a step decrease since the 1990s, with a five-fold reduction in volumes.
9. There has been a 40 percent reduction in the median spill volume when comparing pipelines installed before 1990 to that installed since 1990. During that same time period, the throughput has more than doubled and the diameter of the pipe has increased. These two factors would be expected to increase the spill volume, and since it has decreased rather than increased, this is an indication of the improved performance of modern pipeline systems.
10. There is clear evidence that transport of crude oil occurs at the lowest incident frequency and smallest spill volume when transported through recently constructed pipelines. If crude oil is to be moved by pipeline, then new or recently constructed systems are clearly the best option.

Recommendations

It is recommended that ILI be performed proactively prior to the start of operations. These inspections are capable of detecting major defects in welds and in the pipe wall, as well as defects caused by placement of the pipe in the ground. Any detected defects can be repaired before the start of operations and thereby reduce the probability that a leak will occur soon after the start of operations. It is understood that Keystone has committed to these ILIs prior to the start of operations.

Protective and Mitigative Measures

Prior tasks considered risk and then evaluated the likelihood and consequences of a spill relative to the PHMSA database, with the above task making clear that changes made in design and

construction since the 1990s have significant benefits in reducing incident frequency, and their consequences. The objective of this task was to identify and evaluate additional actions that could be taken to improve environmental protection and mitigation in the event of a spill.

Key Findings

1. An analysis of the PHMSA data finds that only 40 percent of all spills are due to mainline pipe spills; however, the lineal (mainline pipe) component of the Project will most likely be the primary source of environmental exposure because of its potential to impact HCAs and other resources along the proposed RoW and because of the remote location for some sections of the pipeline. Consequently, the pipeline's design, construction, operation, and maintenance in compliance with the 57 Conditions are the foundation for pipeline integrity.
2. Keystone is taking preventive actions over and above the U.S. Code of Federal Regulations minimum, including the following: (1) the entire pipeline is being designed as if it transits an HCA; (2) greater than the required depth of cover will be provided for usual trenched construction (4 feet in general, locally deeper for select sites); and (3) horizontal directional drills (HDDs) will be used for select crossings.
3. Keystone developed a very workable method of analyzing the effectiveness of isolation and check valves to limit the spill size. The graphs they provided demonstrated the utility of their calculation scheme to prevent larger volumes of crude oil from being spilled using check valves; however, sufficient detail was not available to demonstrate that the valves were spaced to minimize the total spill volume as required in the regulations.
4. The risk assessment results show a decreasing trend in the median spill volume in modern construction in spite of the use of higher flow rates and greater use of larger diameter pipe. If the pipeline did not have better performance, the use of higher flow rates and bigger diameter pipelines would tend to result in a larger median spill volume. Thus the use of pipelines built to modern standards apppear to have clear environmental benefits when compared to the existing system.

Recommendations

The information provided to Battelle was quite limited and did not address any spills in sensitive areas. Additional spreading analyses should be performed in areas where sensitive environmental receptors are found to demonstrate that these areas are being adequately protected and that additional valves would not have a net benefit. Since it is very expensive to move the placement of valves after all the construction details have been developed, the greatest utility of these calculations would be to have preliminary results available early in the process with the formal validation of their placement, demonstrating that the placement does minimize spill volumes.

During the construction phase, response team and equipment needs should be identified based on the scope of transported products and their potential interaction with the ecosystems that the pipeline traverses. Keystone has recently stated concurrence with this action and has indicated that they will (1) target response plans to the ecosystems and resources traversed, with concern also taken to address unique/site-specific aspects, and (2) reduce the response time to two hours in such cases as compared to the minimum 12 hours of 49 CFR 194. Response teams and packages should be selectively located at ecosystems and resources deemed high-value, at a level more refined than the current narrow PHMSA definitions of an HCA or unusually sensitive area (USA).

Since areas along the pipeline where seals and seats are present (e.g., on equipment and pumps) have a higher potential for spills, Keystone should be diligent about the material selection for seals and seats, from both the design and maintenance perspectives, over the life-cycle of the equipment. They should also consider more frequent scheduled maintenance for valves and other equipment, at least initially, and utilize pre-service offsite leak checks and equipment shakedown where plausible.

Depending on need dictated by the nature of the terrain, aspects of the water table, and other factors, Keystone should consider the selective use of concrete coated line pipe (or an equivalent or better approach). For location-specific elements, like facilities, which are currently sited in sensitive ecosystems or resources, Keystone should also consider unique approaches to protect those sites, such as containment of facility leaks through the use of concrete pads and berms.

Although analysis of anomaly response and trending of the incident causes as a function of the diameter clearly show that the lineal portion of the Keystone XL Project is robust from a preventive perspective in regard to axially oriented anomalies, care should be taken to ensure that similar analyses are considered in the context of the girth welds, and that related defect tolerance is assessed and achieved, subject to the PHMSA process.

Finally, all aspects of prevention, protection, and mitigation should be monitored to ensure that plans and commitments remain viable and are implemented as outlined.

1. Introduction

1.1 The Proposed Project

The proposed Keystone XL Project, as described in the US Department of State (DoS) 2013 *Draft Supplemental Environmental Impact Statement* (SEIS)[(1)], consists of a crude oil pipeline and related facilities to transport Western Canadian Sedimentary Basin (WCSB) crude oil from an oil supply hub near Hardisty, Alberta, Canada, to existing pipeline facilities near Steele City, Nebraska, for delivery to Cushing, Oklahoma, and the Gulf Coast area. The proposed Project would also transport domestically produced Bakken crude oil from a terminal near Baker, Montana, to the existing Keystone Pipeline system at Steele City, Nebraska. The Steele City delivery point currently provides access to the existing Keystone Cushing Extension pipeline. That pipeline delivers crude oil to Cushing, Oklahoma, where there is access to other pipeline systems and terminals, including those serving the Gulf Coast area. The proposed Project would consist of approximately 875 miles of new, 36-inch-diameter pipeline across portions of Montana, South Dakota, and Nebraska (Figure 1). An additional 329 miles of pipeline in Canada were evaluated by the Canadian government.

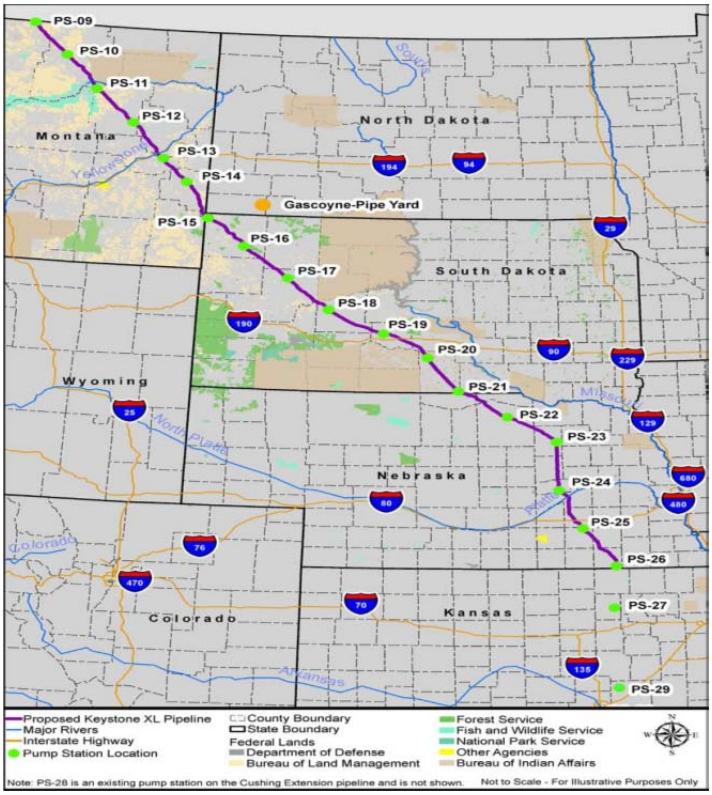


Figure 1. US segment of the proposed Keystone XL Project

Construction of the proposed Project would generally require a 110-foot-wide, temporary right-of-way (RoW) and a variety of aboveground related facilities. When in operation, the proposed Project would maintain a 50-foot, permanent easement over the pipeline. Keystone would have access to property within the easement, but property owners would retain the ability to farm and conduct other activities. The remaining related facilities would include 20 electrically operated pump stations (two of which would be built along existing sections of the Keystone Cushing Extension pipeline in Kansas), 44 mainline valves, and 38 permanent access roads.[1]

[1] Locations for access roads in Nebraska have not yet been determined and are not included in this total.

1.2 The Project Review Team

Battelle, in responding to the above objectives, drew staff from current longer-term assignments whose training and experience matched the anticipated effort. Team leads were chosen and matched to the objectives. Mr. Ted Clark, with more than 30 years of leadership in integrity management for transmission pipeline operators, dealt with the integrity threats aspects. Dr. Tom McSweeney, who has more than 40 years of experience in flow modeling and risk analysis, dealt with failure frequency methodology and outflow analysis. Dr. Diane Sanzone, with 23 years of experience in environmental assessment, most recently with a major integrated Oil and Gas company, dealt with the fate and transport interface between the engineering and environmental aspects. Dr. Bruce Nestleroth, well known in the pipeline community for his work involving monitoring and inspection, dealt with detection and integrated the team's contributions on prevention and mitigation. Finally, Dr. Brian Leis, with 35 years of experience developing criteria for and experience in pipeline risk and integrity management and also experience in flow modeling and failure assessment/root-cause analysis, served as the team and project manager and developed and integrated comments on potential additional protective measures.

The outcomes of their work in meeting the above objectives will be conditioned by the team's insight into the issues as they are identified based on their experience in each of the focus areas sought in the TransCanada Keystone Pipeline, LP (TCPL) letter of intent (LoI). The staff members who make up E^{x}ponent's Project Team are presented in their report, which is included in the draft SEIS[(1)] as a separate document. The E^{x}ponent report is titled *Third-Party Consultant Environmental Review of the TransCanada Keystone XL Pipeline Risk Assessment*[(2)].

1.3 Scope of the Independent Assessment

The DoS released the *Final Environmental Impact Statement for the Keystone XL Project* (FEIS) in August 2011[(3)]. Following its release, the DoS, working with the US Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) and the US Environmental Protection Agency (EPA) (the agencies), concluded that it would be beneficial to have a third-party review of the preliminary risk assessment (Risk Assessment) prepared by AECOM and Dynamic Risk Assessment Systems, Inc., on behalf of TransCanada Keystone Pipeline, LP (Keystone). Battelle and Exponent were selected to address a specific set of engineering and environmental issues for the third-party review. The original third-party review that Battelle produced was submitted in January 2012 and was based on the original Keystone XL pipeline routing. This document has been revised to address comments received by the agencies and to incorporate the new Keystone XL routing plan.

Battelle was charged to evaluate the following engineering components of the proposed pipeline:

1. failure frequency;
2. risk assessment regarding integrity threats;
3. outflow analysis and placement of valves;
4. fate and transport;
5. detection of leaks;
6. prevention of leaks; and
7. protective and mitigative measures.

E^{x}ponent was charged to evaluate the following risk-related components and aspects of the proposed pipeline:

1. overall Keystone environmental risk assessment methodology;
2. characteristics of the crude oil being transported;
3. transport and fate characteristics of spilled crude oil;
4. environmentally sensitive issue one – shallow groundwater; and
5. environmentally sensitive issue two – small stream crossings less than 100 feet in width and associated ecological concerns.

This review focuses on the Risk Assessment as presented in Appendix P of the FEIS – Pipeline Risk Assessment and Environmental Consequence Analysis, dated July 2009 (also Appendix Q of the SEIS).

1.3.1 Failure Frequency

The basis for the failure frequency analysis was the PHMSA Liquid Hydrocarbon Incident Database. The analysis considered the same time period used in the FEIS, from 2002 to August 2008. With the recent publishing of the SEIS, Battelle reviewed the new Appendix K, Historical Pipeline Incident Analyses, and while none of the graphs in Section 2 were updated to the longer time period from 2002 to July 2012, the longer time period was considered and is reflected in some of the conclusions, recommendations, and key findings listed in the Executive Summary and in Sections 3 and 4 of this document. The draft analyses of this report, published in January 2011, identified the importance of separating the mainline pipeline part of the system from the remaining system components if a meaningful failure frequency for the mainline pipe section was to be estimated. Appendix K of the SEIS also recognizes the importance of separating the components, so the SEIS simply supported what was done in the earlier draft and provided added evidence for the separation of system elements.

1.3.2 Risk Assessment

The risk assessment integrates the results of the failure frequency with an analysis of spill volumes. This section also uses the PHMSA database to determine the importance of many of the variables that must be considered when analyzing the threats identified in Section 2.1. Additional analyses also quantify spill volumes by various system components and study the effect of pipe diameter, pipe wall thickness, and pipe installation date. The goal of these engineering assessments is to determine the important variables that can be used to maximize the possible performance of the Keystone XL Pipeline before it has been built.

1.3.3 Outfall Analysis and Placement of Valves

For this task, Battelle evaluates the outfall analysis and valve placement on the proposed pipeline. The source of information for this assessment was Appendix P of the FEIS (Appendix Q of the SEIS). Keystone explained the model they used and the resultant data. In this Engineering Assessment, Battelle evaluates the reasonableness of the model and confirms that the model and the process that were used to ensure that valves are placed to minimize the total outflow from a breach appear to be correct. In the limited time available to perform the review, it was not possible to evaluate whether Keystone's modeling results were correct or whether the valves were properly placed to minimize spill volumes.

1.3.4 Fate and Transport

For this task, Battelle evaluates the modeling of a spill and its eventual fate in the environment. Most of these evaluations were performed by E^{x}ponent, which was given a parallel fate and transport task. The Battelle evaluation focuses on the engineering aspects. The Battelle evaluation was carried out after E^{x}ponent completed their fate and transport analysis.

1.3.5 Detection of Leaks

Battelle was tasked with evaluating the capability of control systems such as supervisory control and data acquisitions (SCADA) to detect leaks. Battelle also identifies and evaluates other technologies, both available and emerging, that might detect smaller leaks than is currently possible with the SCADA system. Other systems, including surveillance systems, were also considered as part of this engineering assessment.

1.3.6 Prevention of Leaks

Battelle was tasked with evaluating inspection and monitoring methods that could be used to identify defects that threaten the integrity of the pipe's pressure boundary. The capability of inspection tools to monitor the growth of defects in the pipe wall and welds over time or to identify damage occurring during construction or from human activities near the pipeline was evaluated.

Battelle was asked to consider tools that are commonly employed as well as emerging technologies. The defect detection capability that can be realized in the Keystone XL pipeline is discussed.

1.3.7 Protective and Mitigative Measures

For this task, Battelle evaluates the protective and mitigative actions that could be used to minimize the impact of a leak. The focus of the Battelle effort is on the engineering aspects of these actions. The role of spill management plans and the placement of equipment and personnel for effective recovery should a spill occur were evaluated.

2. Engineering Assessment

This section presents the results of the detailed engineering assessment of the proposed Keystone XL Pipeline. The organization of the section parallels the task assignment provided to Battelle. The sections that follow are (1) failure frequency, (2) risk assessment, (3) outflow analysis and placement of valves, (4) fate and transport, (5) detection of leaks, (6) prevention of leaks, and (7) protective and mitigative measures in the event of a spill. The purpose of this third-party independent review is to assess the methodology used in regard to failure frequency – along with the pipeline integrity threats considered, the outflow analysis, the fate and transport analysis – and then address prevention, detection, and mitigation (protective) measures. The discussion and recommendations that follow are based on the following: (1) our review of the Risk Assessment commissioned by Keystone (Appendix P of the FEIS and Appendix Q of the SEIS); (2) analysis of the historical record of crude oil pipeline performance from the PHMSA database; (3) the regulatory requirements currently in place and overseen by PHMSA; (4) implementation of the 57 Regulatory Conditions imposed by PHMSA; and (5) our best engineering and risk assessment judgment.

2.1 Failure Frequency

2.1.1 Methodology for and Trending of Threats, Spills, and Leak Response

While the Risk Assessment for the Project[4,5] has evaluated the PHMSA database to quantify threats, spills, outflow, and leak response, there are alternative schemes to pool and trend this database. The practices and methods used are typical of risk assessments for pipelines as part of an integrity management plan/program (IMP) developed for the PHMSA as the pipeline enters service. Such risk assessments are logically organized around likelihood and consequences in a framework that is specific to applicable threats. As such, it is usual procedure to first identify relevant threats, and then quantify threats and consequences. Because historic data provide a sound basis to assess risk from a historic perspective, it is customary to do such analysis based on the historic record. As stated in the Keystone Risk Assessment[4,5], the Project is being weighed relative to the US portion of the system; therefore, their assessment focused exclusively on the US database, which is maintained by the PHMSA. Usual trending practices were applied to the aggregate database specific to onshore pipelines. This is appropriate given the differences between onshore and offshore systems, from routing, through design and construction, and on into the life-cycle considering operations and maintenance. As has been noted by Keystone, all data available were used with the exception of information involving terminals and tanks, with a rationale noted for that decision. As needed, gaps were bridged or adjustments were made in the context of

judgment, which has been a usual practice since risk analysis emerged in the early 1990s as a viable assessment under the auspices of a joint industry-government task force.

Much of what has been done is usual and consistent with industry practices as part of the procedure for obtaining PHMSA approval to commission a pipeline. However, the Risk Assessment presented does go beyond the process typically followed for the National Environmental Policy Act (NEPA) stage of the Federal process. From that perspective, one could view this work as a step forward. However, because the NEPA process is open to stakeholder comment, others might argue whether the work is a step forward.

On the other hand, approaches that differ from that adopted are limited. Quantitative risk analysis is a plausible alternative to using the historic database, but as this type of analysis requires synthesized inputs, it is always open to question. Other alternatives based on historic data exist, wherein the data are parsed to better quantify the drivers for risk, as a path to a broader view of the relevant integrity threats, outflow, and fate and transport, and to identify what and where to best focus prevention, detection, protection and mitigation. One such alternative scheme is evaluated shortly. While other schemes and related assumptions are plausible, a scheme that parses the historic data suffices for this review of the methodology, because it provides a useful and relevant contrast to the outcomes of the aggregated scheme adopted by Keystone.

While the particular scheme adopted leads to quantitative outcomes that differ substantially from those determined using the aggregated database, the emphasis at this point of this review is not that absolute differences emerge. Rather, the emphasis is to:

1. establish response trends for a slightly broader database than that considered in the Project Risk Assessment specific to the elements that comprise a pipeline system, notably: (a) the lineal elements, including the mainline valves (MLVs), which traverse the RoW between discrete sites where (b) facilities, such as tank farms and pumping stations, are located, along with (c) system components and supporting equipment;
2. assess data-pooling and other assumptions made in the Keystone Risk Assessment; and
3. provide perspective in considering/developing protective measures specific to the Project.

The following subsections, “The PHMSA Database” and “Pooling, Culling, and Parsing Data,” discuss the quantitative disparity between the outcomes of this alternative scheme and the aggregated scheme adopted by Keystone, where the details are reviewed and select checks subsequently are made to confirm those outcomes. The PHMSA database[(6)] used by Keystone and herein is openly published, with its fields well documented; therefore, it has been assumed that those not familiar with the PHMSA database can become acquainted with it.

The PHMSA Database. Fundamental to any database or statistical analysis are the quality and consistency of the data. A check of the PHMSA website[6] determines that the database is packaged over intervals of time during which the reporting requirements remained constant. As time passed, however, the concern for the consequences of an incident increased. The criteria to report an incident became more stringent, with a focus on spill volume, and the data required in filing the report expanded. Changes in this context are apparent on the website circa 1971 (year-one), 1986, 2002, and 2009. Independent of the inconsistencies that led to shifts in scope due to these changes, a quick scan of the database reveals issues in data quality. These are obvious, for example, in regard to values of specified minimum yield stress (SMYS) where 52 is listed, but 52,000 is consistent with the majority of the related reporting. Other errors are equally obvious – for example, in regard to wall thickness. Some quality/consistency cross-checks are possible where parameters can be coupled to independently quantify another parameter reported, or where ratios of parameters can be determined for comparison to Code of Federal Regulations (CFR) requirements or common industry patterns. For example, diameter, wall thickness, and grade can be used to infer a maximum allowable operating stress or pressure, which can be compared against the reported value. In addition, the pressure relative to that based on SMYS can be calculated and compared to the CFR requirements and/or typical design levels. The diameter-to-thickness ratio can also be calculated and compared to typical levels. What is less clear is the viability of data where the errors are less obvious and cross-checks are not viable. Unit differences are also an embedded concern. Such errors become evident where the wall thickness approaches or exceeds the diameter or where the thickness (in inches) is listed as 312 when 0.312 is appropriate. These types of errors can be offset by developing an internally consistent set of units.

Little beyond these quality control (QC) checks can be done to resolve the data quality concerns. In contrast, issues related to limited sample size can be offset by pooling data in a conservative framework. Data suited to the present purposes can be found on the PHMSA website, with data captured over the interval from 2002 through 2009 providing the best insight to trending in view of this report's work scope. This interval includes an internally consistent dataset that combines environmental consequences and the pipeline-related causes and other metrics, with a scope sufficient to support assessing frequency of occurrence to quantify likelihood. That database has been analyzed for present purposes much like it has for other Battelle clients, with trending done to meet the objectives of this project.

Pooling, Culling, and Parsing Data. Essential for any statistical analysis is a sufficiently large sample size that is largely free of nulls (blank cells) to establish viable trends. Given that little could be done to identify problem data with certainty, even though outliers were apparent, the database was used as-is, with a few exceptions made for cases where localized QC had clear value

and anomalies/outliers could be identified and resolved with high certainty. Where QC was done, its use is noted, along with the process adopted.

Spill volumes trended for small spills of light crude versus highly viscous heavy crude can be expected to differ relative to each other, as well as relative to white/refined products, all else being equal. This is because the flow through a tight breach depends on at least the fluid's flow characteristics and equation of state, which for the hazardous liquids/products can differ greatly. Differences can be anticipated for the recovery of spilled product, as this process and the recoverable product fraction differ for fluids that flash to vapor as they leak to ambient temperature and pressure, in contrast to heavy crude. Light product fluids also may disperse/migrate more readily from a spill site. Recovery and response parameters for such fluids are logically different than for light crude versus heavy crude versus dilbit. Given such differences, the transported product is reported in the database, which could facilitate sorting on transported product and then trending the outcomes. Such sorting helps to uncouple what are otherwise interdependent parameters, but the downside is a reduction in the volume of related data. This downside is exacerbated by the historic shifts in the definition of an incident and in the scope of the reporting form and required parameters.

Because sorting on crude versus other transported products reduces the database, the decision to assess the pooled-product dataset was taken in light of two considerations. First, the definition of crude used in reporting an incident likely reflects a range of American Petroleum Institute (API) viscosity number, with this aspect limiting the direct utility of such trends in regard to the heavy crude and dilbit to be transported by the Project. Second, pooling results for white/refined products and most high-vapor-pressure (HVP) liquids with those for heavy crude and dilbit likely overestimates the leak and spill response for the typical product to be transported by the Project. But care must be taken when assessing parameters like net spill volume. Because of the presence of volatiles and differences in viscosity, this parameter is not comparable across the range of transported products, from heavy crude and dilbit versus white/refined products and/or most HVP liquids.

Because onshore and offshore pipeline systems differ significantly, it is logical to sort and eliminate offshore pipelines. It is desirable to sort and eliminate smaller-diameter pipelines for several reasons, one noteworthy reason being that such lines are often among the oldest, and in general involve steels and pipe-making processes that are different compared to larger-diameter pipelines. Even so, this sort was not done, because: (1) the cutoff diameter is arbitrary, (2) the amount of data is reduced, particularly if diameters 10 inches and less are excised, and (3) for the older, smaller-diameter pipelines, the steels involved and their construction reflect a worst-case scenario versus modern pipelines, such that their presence leads to conservative trends. Furthermore, sample size preserved on this basis could be easily applied to other parameters that

warranted conservative sorting for present purposes. Most notable in this context was the desire to uncouple the pipeline system into its rudimentary elements: discrete facilities (stations, tanks, etc.), discrete non-mainline equipment and components, and lineal elements (pipeline and MLVs).

2.1.1.1 Trends Characterizing Spills and Outflow

Spills and outflow can be quantified from several perspectives; for example, the Risk Assessment and Environmental Consequence Analysis done for Keystone examines such perspectives[(4)]. This work was developed under contract to Keystone and has since been updated[(5)], with these documents and related documentation provided to the DoS for use in the various stages of the environmental impact statement (EIS) process, from draft through supplemental. Various forms of this content appear on the DoS website for this Project[(7)]. They are typically referenced as appendices, but they are also provided in summary form and in preliminary states prior to incorporation by the DoS.

Risk has been assessed in regard to spills and outflow relative to the pooled PHMSA database, and presented as averages over the system (for example, in terms of frequency of occurrence per mile-year of pipeline system). This is not an unusual practice when examining spills from pipelines[(e.g., see 8)]. However, it can be instructive to parse the data to account for incident location and to cover stations and tanks, versus system components (and "other"), versus pipeline (defined as body, seam, girth-weld, and MLVs). This breakdown adds value to the analysis because the body, seam, and girth-weld, along with the MLVs, represent the lineal portion of the pipeline system. It is specifically these aspects of the lineal element (the pipeline) that comprise the "miles" component of the mile-year metric used to quantify frequency. The other facilities, sites, and components occur at discrete locations, which would better be quantified by a discrete-year metric rather than a lineal-year metric. Given that pumping stations are typically spaced about 20 miles apart (more or less, depending on terrain, etc.), the unit used to determine incident frequency for such discrete sites is at least an order of magnitude less than that applicable to the lineal component of the pipeline system. This tends to diminish the significance of leak frequency for the discrete sites relative to that for the lineal pipeline element.

2.1.1.1.1 Incident Mix and Likelihood – Discrete versus Lineal System Elements

While one can quibble about how to define the lineal versus discrete elements, or how to group or subdivide the discrete sites and component/systems, the overall trends are comparable to those shown in Figure 2.

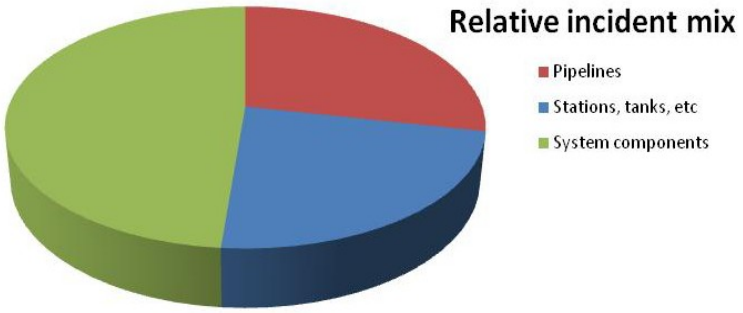


Figure 2. Relative incident likelihood for the lineal and discrete system elements

Figure 2 shows that pipelines comprise slightly less than 30 percent of the incidents, with the discrete system components involving slightly less than 50 percent of the incidents, and the difference involving facilities. Because the discrete elements occur along the system at a rate at least one-tenth that of the lineal element, one can conclude that inadequate attention is given to the threats local to the discrete element, such as "equipment," which could be broadened to include "incorrect operations" if procedures for valve maintenance were inadequate. Likewise, by pooling all incidents into a mile-year metric, the benefits of many of the actions taken to reduce or manage the threats involving the lineal element – such as improvements available in pipe steels and production practices, or in mill and field coatings, or in construction practices – are lost or at least masked.

It follows that care must be taken to appropriately define spill-related metrics. This has significant implications in assessing the methodology used to assess risk for Keystone. Figure 2's relative incident mix implies that the per-mile-year-average incident frequency would decrease significantly in regard to the lineal element (the pipeline), but increase greatly relative to the discrete sites, such as stations, tanks, and valves.

2.1.1.1.2 Leak Volume – Discrete versus Lineal System Elements

From a risk perspective, the consequences of a leak are as significant as the likelihood (frequency) of a leak. Therefore, before one can draw broad conclusions in regard to the trends of Figure 2, consequences must also be considered. Clearly, the potential for a major spill to occur is driven, at least in part, by the possible diameter of the breach. For a pipeline, this is the full diameter of the pipeline, as a full-bore rupture remains a possibility in a worst-case scenario. While concern is often given to the worst case, as for example in some public commentary[9], the process of compounding the worst-case scenario is not always instructive in a NEPA setting[e.g., 10]. It is thus appropriate to consider what is reasonable in regard to a pipeline. It must be recognized that the consequences of a full-bore rupture cannot be anticipated absent extreme acts of nature.

Furthermore, analysis considering axial defects done as part of this work and detailed later determines that the lineal element of the Project, as designed, is resistant to third-party damage and, if constructed and maintained consistent with the requirements of the PHMSA, is not prone to spills. That said, one could assert that the size of a spill from the lineal element of the Project is not worse than the size of spills anticipated from its discrete elements. A viable metric for this assertion is the available spill-volume history in the PHMSA database.

Figure 3 presents the spill volume history for the US liquid pipeline system from 2002 to 2009. The y-axis shows cumulative frequency, which runs from zero to unity, and the x-axis shows spill volume, which runs from zero up to 50,000 barrels. By using a logarithmic scale on the x-axis, increased discrimination at the smaller-volume spills has been achieved. Thus, for each interval along the x-axis, the spill volume increases 10-fold.

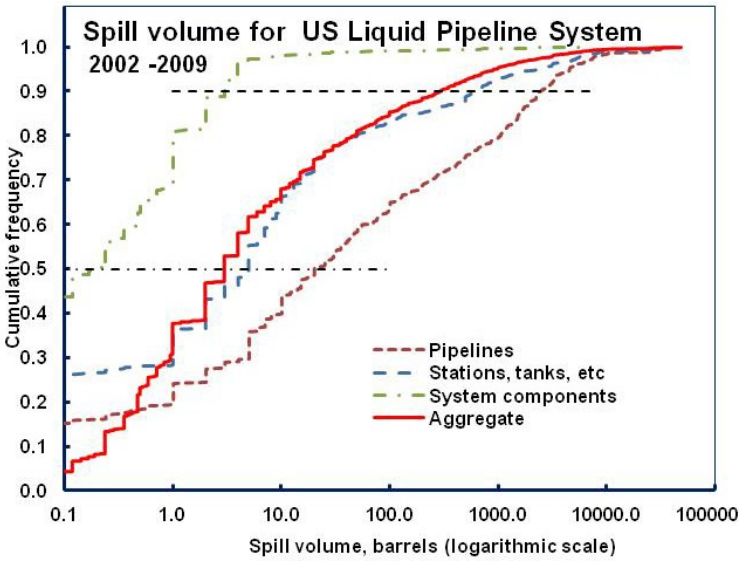


Figure 3. Consequences in terms of spill volume for the lineal and discrete elements

Values on the y-axis in Figure 3 range from zero to unity (one), because the cumulative frequency is normalized. In this format, a value of unity corresponds to 100 percent of the sample, whereas the y-axis value at 0.9 corresponds to 90 percent, or the 90th percentile, and so on down the scale to zero, which corresponds to zero spills. The dashed line at a y-axis value of 0.5 denotes the median (or 50th percentile) for the sample, which tends to be a better measure of central tendency than the mean (equally the average), which tends to be influenced by the extremes in the sample. This is apparent in the median spill volume found at three barrels, for which half of the sample involved larger or smaller volumes, whereas the average, being strongly influenced by a few large spills, was found at about 290 barrels. Figure 3 shows that pipelines typically experience larger spills, with the upper limit on volume along the x-axis being selected to accommodate the largest spill. While

pipeline spills are typically larger than those at discrete sites, the largest spill for this time interval occurred in a station/tank setting and involved about 49,000 barrels. A pipeline had the next largest spill at about 33,000 barrels, while the maximum spill for system components was a little less than 10,000 barrels.

While on a linear rather than logarithmic x-axis it appears that the trends for the lineal and discrete components do not differ appreciably, it is apparent from Figure 3 that at a comparable normalized frequency, the spill-size in pipelines is larger than that in system components by a factor of more than 100 up through the 90th percentile. Because trending over a broader time period, or within any given year-long interval, leads to shifts in these trends, not too much should be made of the absolute differences. For the present, it is sufficient to note that the actual trends are consistent with the engineering assessment of the previous paragraph.

2.1.1.1.3 Spill Volume: Potential Consequences of Using Aggregate Measures

Figure 3 makes clear that the consequences (as inferred from spill volume) differ significantly between the discrete versus lineal elements, as well as between the two elements making up the incidents at discrete sites (facilities versus system components). For this reason, the differences in their likelihood evident in Figure 2 should be coupled with consequences to quantify risk for the Project. In light of Figures 2 and 3, it is apparent that an aggregate measure of consequences and/or likelihood is a poor metric for either, and so likewise is a poor metric for risk. It follows that the implications noted in discussing Figure 2 relative to likelihood will carry over to risk, such that the per-mile-year-average incident risk would decrease significantly in regard to the pipeline, but increase greatly relative to the discrete sites such as stations, tanks, and valves. That observation, coupled with the trends in Figure 3, casts uncertainty on the use of aggregated metrics for risk and/or the use of aggregated "professional engineering judgment"[3] because the aggregation tends to mask the trends, including potentially opposed outcomes.

While the above discussion does cast uncertainty on the practice used in the Keystone analysis, the net effect of the judgment factors applied was relatively small, leading to an increase in incident frequency averaged over the length of the proposed project by a few years. As such, while the aggregation methodology and related assumptions are subject to question, the net impact on the outcomes as they are presented appears to be small, due largely to the magnitude of the factors used.

The trends in Figures 2 and 3 are consistent in regard to the leaks experienced on the existing Keystone Pipeline, as summarized in Table 3.13.1-4 of the FEIS. This tabulation outlines the 13 incidents that have been reported for that project, all of which occurred during commissioning

[3] See for example page A-8 of Appendix H – Risk Assessment – DoS website.

or early in operation at sites inside the fence-line of a pump station. Such results underscore the historic record, which makes clear the need to uncouple at least the lineal mainline from occurrences within the fence-line of a pump station. This distinction is even more essential from a control perspective, because a station's design and construction provide for containment and quick response coupled with early detection. By contrast, the lineal mainline is much harder to protect or mitigate in the event of a spill. Many of the leaks in this tabulation were quite small, on the order of a few gallons, and were associated primarily with bearing and seal issues. However, where a fitting failed, the spill was much larger, releasing about 500 barrels through a ¾-inch nipple in a station. This spill has clear utility in validating models that quantify leak volume and has quantitative implications for the volume that might be released prior to alarm from a small defect at some remote site.

2.1.1.2 Trends Characterizing Leak Detection and Response

When the PHMSA database is parsed to uncouple discrete and lineal components as noted above, some interesting trends emerge that also bear on the methodology that underlies the Keystone Risk Assessment. Several metrics can be evaluated in this context, including net-spill volume, the duration of the spill, and the size of the initial spill.

2.1.1.2.1 Spill Recovery for Discrete versus Lineal Elements

Figure 4 trends the recovery of spilled product in terms of the relative fraction of the product recovered as a function of the lineal and discrete system components. Because some hazardous liquids disperse differently than heavy crude or dilbit, care must be taken to ensure that no bias develops in the trends due to such differences. From analysis of the database, it is evident that the trends shown in Figure 4 are rather insensitive to this concern, apparently because that influence is more or less equal for each of the discrete and lineal components.

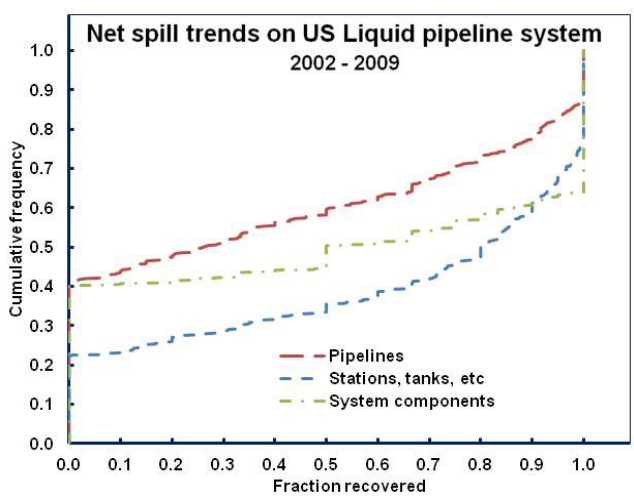


Figure 4. Recovered spill fraction for the lineal and discrete elements

Figure 4 shows that spills within the vicinity of the fence-line of a pumping station or tank farm are recovered more effectively than when they are remote to such facilities. This can be anticipated in view of the design and construction of such facilities and from the observation that timely detection is more likely within or near such facilities. Such differences corroborate the need for and value of uncoupling these system components, in contrast to the aggregation used in the Keystone methodology. Considering that the volume spilled is typically quite small for the system components (see Figure 3), it can also be inferred that smaller spills in and around the stations and tanks are not dealt with as effectively as the larger spills.

Figure 4 shows that, in general, a major fraction of spilled product is captured, but a significant component of the spill remains unrecovered. This could trace to the inclusion of all transported fluids, rather than just crude or heavier products, as the basis for this analysis. This is clearly a potential downside of parsing the database; however, when the details of the database are scrutinized, it becomes clear that the largest spills and the largest unrecovered fractions apparent in Figure 4 trace to a crude release.

Differences in spill recovery can also be viewed relative to the net volume lost versus the initially released volume, which is shown for the period from 2002 through 2009 in Figure 5. This figure presents the initial spill volume on the x-axis, while the net-spill volume is shown on the y-axis. Again, to provide clarity in regard to small releases, a logarithmic format is used, with each interval on either axis representing a 10-fold increment. Values on the x-axis and y-axis that appear as "0" reflect the truncation of decimal values in creating the plot.

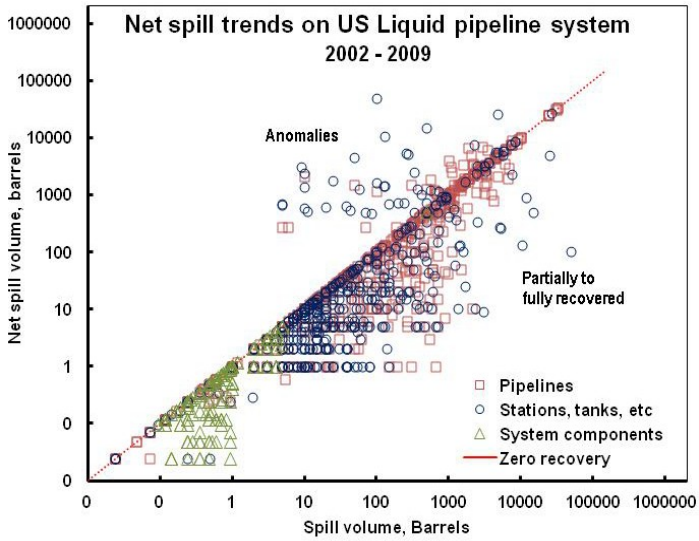


Figure 5. Net volume lost versus release volume for the lineal and discrete elements

In Figure 5, results that lie along a one-to-one trend, shown as the dashed red line, indicate either that recovery was not attempted or that an attempt had marginal utility relative to value. In this context, recovery and cleanup are not comparable terms or processes, with cleanup being broadly mandated as set forth in 49 CFR 195. Data points that lie below the one-to-one line reflect the effects of some recovery, which, if the product were fully recoverable, would lead to points that lie toward or on the y-axis. Realizing that Figure 5 includes incidents for all fluids transported in the hazardous liquid transportation pipeline system, evidence of fractional recovery is anticipated because some products are volatile, while others are less viscous than heavy crude or dilbit.

In contrast, points that lie above the one-to-one line imply potentially anomalous data reporting, as these indicate that the spill grew appreciably in some cases, in spite of the leaking facility component or pipe section being shut-in. Note that such points involve both facilities (stations, tanks, etc.) and pipelines (including MLVs). Because drain-down can continue after a leak is detected and the leak source is shut-in, a continuing release due to outflow or drain-down could rationalize the points above but still close to the one-to-one trend. However, in many cases the disparity is far too large to explain in that manner, which raises the possibility that the data entries were reversed or otherwise in error.

Because a logarithmic scale is used in Figure 5, only vanishingly small numbers can be plotted. Thus, data that reflect zero in regard to net spill volume cannot be shown, such that there are no points evident along the x-axis that quantify full product recovery. Instead of being able to plot such outcomes, another approach − trending the database − yields the following results: about 12 percent of the pipeline spills were fully recovered, while about 23 percent of the facilities spills and about 19 percent of the systems component spills were fully recovered. These full-recovery fractions reflect a database wherein about 16 percent of the records represent products that are gaseous at ambient conditions (unrecoverable), with another about 40 percent being refined products that can involve volatile compounds, for which full recovery is not plausible. This means that about 44 percent of the database is amenable to full recovery, such that the just-noted fully recovered outcomes represent a small fraction of what is possible. That said, the extent of recovery reflects economic and other factors and is not indicative of cleanup or ecosystem recovery, which is a mandated expectation for larger spills.

Figure 5 shows that the smallest spills in relative terms involve what have been labeled as system components, such as valves and equipment, whereas the pipelines and facilities both lead to some significant spills. As might be anticipated, the least effective recovery occurs along the RoW, although there is one quite large spill associated with the station/tank group that remains largely unrecovered. As above, such differences bear out the need for and value of uncoupling the discrete elements (facilities and system components) from the lineal (mainline) elements, in contrast to the aggregation used in the Keystone methodology.

2.1.1.2.2 Spill Duration (Post-Detection) for Lineal and Discrete Elements

The trends quantified in regard to the net volume lost in Figure 5 are shown relative to the initial spill volume as a function of spill duration in Figure 6. The x-axis in this figure is spill duration after detection, while the y-axis is the corresponding volume of the spill.

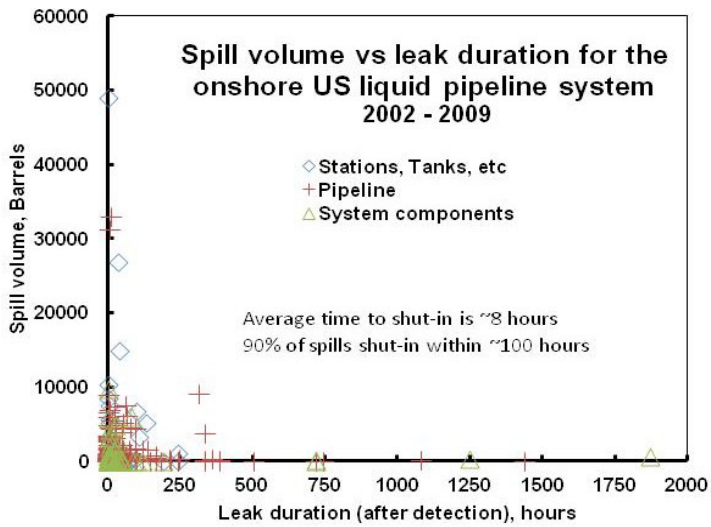


Figure 6. Spill duration (post-detection) for the lineal and discrete elements

It is apparent from this figure that initially, large spills tend to be controlled much faster than smaller spills. This is evident in the observation that the largest spills measured relative to the magnitude of the y-axis fall at smaller values of the x-axis. It also appears from Figure 6 that large spills are shut-in very quickly, whereas smaller leaks could be viewed as allowed to persist. For each of the discrete and lineal elements plotted in this figure, the upper-bound trend to these results could in each case be quite reasonably fitted to an inverse function. Thus, from a mathematical perspective, these results support the assertion that smaller spills tend to be ignored or tolerated. In addition to this mathematics-based observation, it is apparent that the longest period prior to response was almost 1,900 hours (close to three months), which involved one of the smaller leaks. While the nature of the scales for Figure 5 somewhat masks the amount of data presented, these details are more evident in Figure 6, where it is clear that the largest spill for the incident interval considered involves a facility, while the second largest involves a pipeline. It is also clear that several additional larger leaks occur for facilities and pipelines before the spill of somewhat less than 10,000 barrels from a systems component becomes evident. As such, while more frequent, spills involving system components tend to be much smaller.

The trends in Figure 6 can be used to infer the extent to which leak duration might be influenced by concern for the spill size, which could be taken to indicate other underlying factors, such as concern for business losses and/or related cleanup expenses. In light of the environmental concerns

on the public record for the Project, emergency response plans (ERPs) will likely have to deal with the potential for small leaks somewhat differently than the historic database suggests has been past practice.

Figure 7 continues this trending of leak duration in regard to historic industry response to leaks. This figure presents the normalized cumulative distribution for post-detection response time for spills, with a logarithmic scale again used to expand the trends at shorter times. Response time in this context includes the control phase plus the outflow phase of a spill, which reflects the leak detection capability coupled with the response system and protections afforded by the placement and number of valves. Protection in regard to valves can be provided via one or more of four types of commercially available emergency flow restriction devices (EFRDs): remote controlled valves (RCVs), check valves (CVs), automatic control valves (ACVs), and manually operated valves (MOVs). Battelle's review indicates that all but ACVs are used for the Keystone XL Project and that MOVs are used selectively (placed downstream in conjunction with CVs).

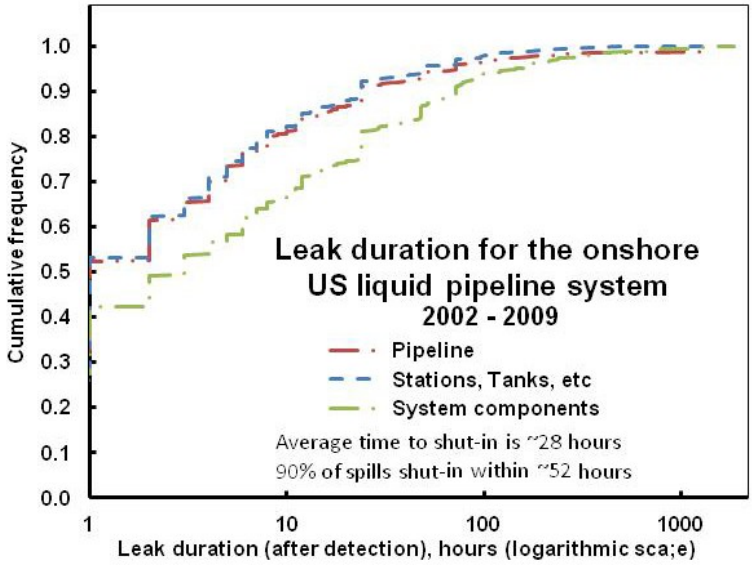


Figure 7. Trends characterizing leak duration

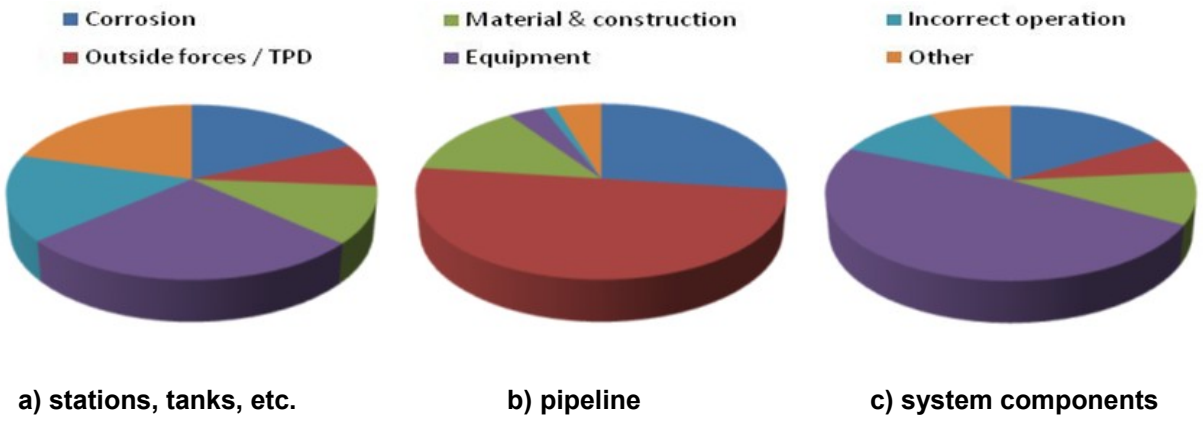
Through use of sensors, a logic-driven feedback loop, and servo-drives, an ACV can respond automatically to pipeline flow conditions, such as a viable leak indication. However, their use in systems transporting largely incompressible fluids, such as crude or dilbit, poses a chance for anomalous response. Even though they are commercially available, and despite the observation that an ACV is conceptually a simple leak detection system (LDS) and an EFRD all in one package, their utility is limited in applications like the Keystone XL Project because uncontrolled closure of any EFRD can cause surge and overpressure concerns. However, as the technology

matures, and programmed closure in response to reliable leak detection can be achieved with certainty, consideration might be given to such technology.

It is apparent from Figure 7 that after detection, most leaks have a relatively short duration. This figure indicates that the easily detected and corrected station leaks have the most rapid response time. This rapid response is comparable to that for pipelines, which motivate rapid response because they have the potential for larger releases due to drain-down. In contrast, the smaller system component leaks and the often remote pipeline leaks have the longest times. The longest time for the interval from 2002 to 2009 is 78 days, which (as shown in Figure 6) involved a small leak from a system component.

2.1.1.2.3 Relative Threat Mix

Threats to the integrity of the Project have been evaluated on the parsed database to determine whether alternative insights might become evident when the Project is examined in light of its discrete and lineal components. The results of this evaluation are shown in Figure 8. Figure 8a (stations, tanks, etc.) and Figure 8c (system components) share the same set of threats, although in differing proportions, while Figure 8b (the pipeline) does not involve the equipment category because equipment is not a major part of this lineal feature. Again, aggregating the data leads to an inaccurate perception of threats. Clearly, in view of the periodic spacing of a pipeline's discrete aspects, such trends suggest that risk should be managed specific to the various components of the pipeline system. This is not a revelation, as pipeline companies have been evolving practices and procedures for operations and maintenance in this context since well before pipeline regulations were considered and incident data were gathered. Nevertheless, it does underscore the benefits of alternate approaches for risk assessment.



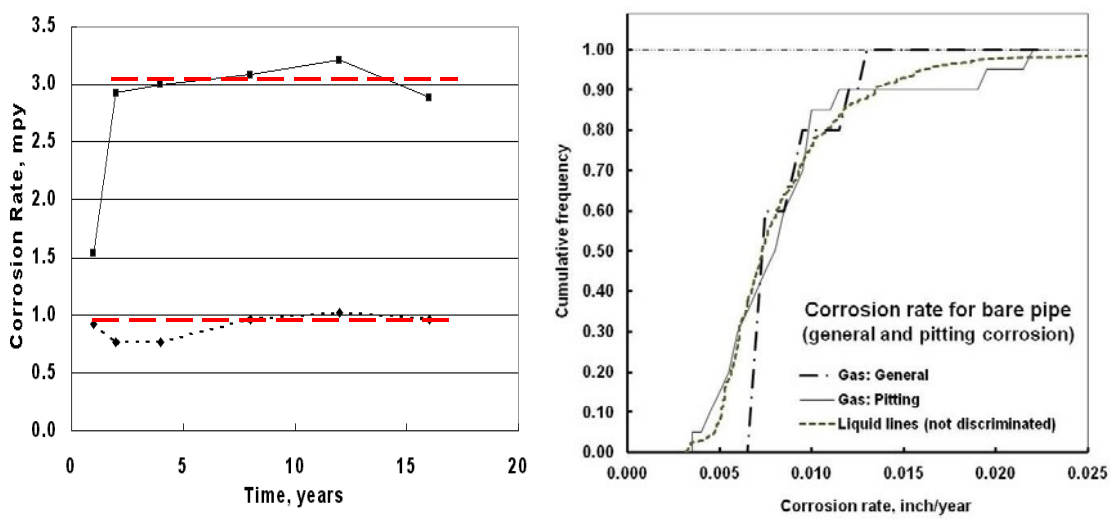
a) stations, tanks, etc. **b) pipeline** **c) system components**

Figure 8. Threats evaluated for the lineal and discrete system components

2.1.1.2.4 Trends for Corrosion Rate and Mechanical Damage

While use of a worst-case corrosion rate is not mandated in the context of a NEPA assessment, aspects dealt with later benefit from knowledge of typical corrosion rates. Such trending began for the purposes of standards development in the era of the "Pipes Act"[11] circa 2002. Work done then led to data trending[12], which considered literature insight from soil-buried undisturbed coupons and bare-protected-pipe incident data compiled in the PHMSA database for natural gas transmission pipelines. Data used in that trending were limited to natural gas pipelines because that work was done as a precursor to American Society of Mechanical Engineers (ASME) B31.8S and related development of external corrosion direct assessment practices, since standardized by the National Association of Corrosion Engineers (NACE) (Recommended Practice [RP] 0502). Virtually no differences in external corrosion are anticipated for hazardous liquid versus natural gas pipelines because the current work deals with hazardous liquid pipelines; however, comparable results have been developed for these systems based on data compiled in the PHMSA database for the interval up through 1986.

Figure 9a reproduces soil-buried undisturbed coupon data[(details per Reference 12)], while Figure 9b presents the combined data for the two bare-protected-pipe datasets. Figure 9a shows results and trends for field tests done with bare, unprotected coupons, with a view to simulate corrosion rates for buried steel structures[13]. The light dashed trends in this figure bracket the results developed in that work, with the trends reinforced by use of heavier dashed lines. Corrosion "rate" for such applications has been calculated by dividing corrosion weight loss averaged over a time interval on the order of a few days.



a) coupon data **b) bare protected pipe**

Figure 9. Trends in corrosion rates relevant to buried pipelines

Figure 9a shows that the lower-bound rate is about 0.001 inch per year, while the upper-bound rate is stable at about 0.003 inch per year. For the higher-rate data, the results imply that the corrosion process was initially much more reactive, as opposed to the stable behavior, which developed after a few days. The bounds shown in Figure 9a represent general corrosion, and differ in rate by a factor of about three. This scatter in rate is indicative of the variability in the general corrosion process, even though these data reflect the same steel, in the same soil, with the same moisture conditions, under controlled testing conditions. While a factor of three due to scatter may seem large, in comparison to fatigue crack initiation for which a factor of 10 can be viewed as low scatter, the variability due to the corrosion process is rather limited.

For present purposes, data such as that in Figure 9a are credible only if they reflect the actual behavior of in-service pipelines. To this end, times to failure were determined for bare but protected pipelines from data in the PHMSA database, with the following exceptions: for the natural gas transmission pipelines, all pipe with diameters of less than 12 inches and any cases involving stress corrosion cracking (SCC) were culled from the database for the reasons discussed in Reference 12. Because data for bare pipelines have been considered, no adjustment has been made to account for coating failure. Corrosion rate has been calculated by dividing the wall lost from the nominal wall thickness by the pipeline's time in service.

Using corrosion kinetics derived from an incident database[4] means the calculated rate reflects worst-case field corrosion conditions as compared to circumstances elsewhere in the pipeline system, where degradation must be occurring at a slower rate over the pipeline's life. A worst-case rate in this context reflects the fastest corrosion rate leading to incidents involving bare, protected pipe. A more reasonable upper-bound rate is that corresponding to the 90th percentile for this incident sample. Finally, a median rate could be identified, or equally a mean (average) rate could be derived for this incident sample; the relevant values are found in Figure 9.

Figure 10 presents trends in incident frequency as a function of pipe wall thickness for incidents associated with damage-related or forces-related incident causes, as well as all causes for the hazardous liquid pipeline database. It also includes the trend for what was termed "outside forces" for the period up through 2002, which as expected is comparable. The y-axis in this figure is the normalized cumulative frequency of incident occurrences, with wall thickness indicated on the x-axis. Figure 10 is interpreted in the same manner as Figure 3 and the other similar plots. Ascending the y-axis is associated with an increasing number of incidents, from zero up through a value of one, which reflects 100 percent of the occurrences.

[4] This database covers lines put into service over more than a 60-year interval, which were operated and maintained differently than today. Because it represents primarily first-to-occur incidents, it reflects corrosion "hot-spots" along those pipelines and provides a reasonable worst-case estimate of corrosion rate.

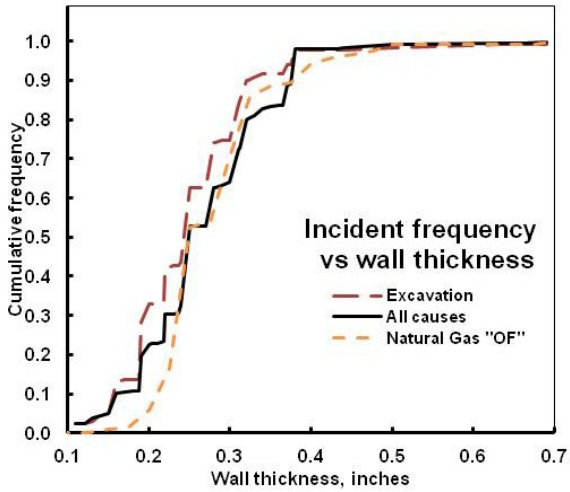


Figure 10. Damage and forces-related incident frequency versus wall thickness

Figure 10 shows that incidents tend to be associated with thinner-wall pipe, with the distribution rising sharply with wall thickness. This is logical because, all else being equal, it is more difficult to penetrate or otherwise damage heavier-wall pipe. This is not to say that incidents cannot occur on pipe with a heavier wall. Rather, it means that the frequency of incidents diminishes significantly as the wall thickness increases beyond some threshold level[14].

The implications of the trends in Figure 10 for the Project are also discussed in Section 2.1.2, which considers threat assessment in detail. Meanwhile, it is appropriate here to note that such trends also would arise if the mileage-fraction of heavier-wall pipe was marginal relative to that for thinner-wall pipe. This possibility is evaluated through subsequent analysis and not found responsible for this trend.

2.1.1.3 Summary and Conclusions

The analyses in this section provide perspective for risk assessment that differs from that of the aggregated methodology adopted by Keystone. Aggregate schemes are the norm, but because stakeholders are engaged by the NEPA process and share different concerns compared to historic values, alternative risk assessment methodologies help to broaden the understanding of risk drivers and to better focus resources if this Project (or other similar projects) move beyond the NEPA phase in the Federal process.

For the specific parsing considered in terms of discrete and lineal elements, the lineal component involving the line-pipe and the MLVs in the RoW lead to slightly less than 30 percent of the incidents, with the discrete system components leading to slightly less than 50 percent of the incidents and the rest of the incidents associated with the discrete facilities. Because the discrete elements occur locally along the system at a rate of about one-tenth that of the lineal element, the data indicate that inadequate attention is given to the threats local to these discrete elements. In

parallel, pooling all incidents into a mile-year metric tends to mask the benefits of many actions taken to reduce or manage the threats involving the lineal component, such as improvements available in pipe steels and production practices, in mill and field coatings, or in construction practices.

Both the likelihood (incident frequency) and the consequences were found to vary significantly between the discrete and lineal elements, with large differences also evident between the system components and the facilities that comprise the discrete elements. Such results cast uncertainty on the use of aggregated metrics for risk, and equally cast uncertainty on the use of aggregated "professional engineering judgment," because the aggregation tends to mask potentially opposed trends. Accordingly, risk should be assessed at the level of these three elements, and a rate other than a per-mile-year-average rate should be used for the discrete elements. If that were done, incident risk would decrease significantly in regard to the pipeline, but increase greatly relative to the discrete sites such as stations, tanks, and related components.

Care must also be taken to appropriately define spill-related metrics. This has potentially significant implications in assessing risk in contrast to the methodology used by Keystone.

It is apparent that the smallest spills (in relative terms) involve what have been labeled system components, such as smaller valves, whereas the pipelines/MLVs and the facilities both lead to some significant spills. The least effective recovery in terms of frequency and volume was found to occur along the RoW, although one quite large spill associated with the station/tank group remains largely unrecovered. Once again, these trends corroborate the need for and value of uncoupling these system components, in contrast to the aggregation used in the Keystone methodology.

The trends show that the response time for remote sites and smaller leaks is about a factor of eight greater than it is for the facilities. Realizing that such spills also pose the greatest environmental consequences, it is clear that a different emergency response will be needed to deal with the lineal portion of the Project. Care must be taken to ensure that the actions proposed by Keystone deal adequately with control and response. Given the environmental sensitivities for the Project, the PHMSA process must ensure that small leaks are dealt with differently than the historic database suggests has been done in past.

2.1.2 Threat Assessment and Implications

2.1.2.1 Introduction

Keystone describes a set of integrity threats considered to be applicable to the pipeline and their associated incident frequencies[4,5]. Estimated spill volumes also were determined, which are

considered in Section 2.2.4. The spill and incident frequencies were then incorporated into a risk assessment scheme, which can provide guidance in regard to pipeline design and presumably will be incorporated in some form into the IMP to be implemented during pipeline operation.

Consistent with pipeline industry practice, Keystone has used the threat guidance available in both ASME B31.8S and API 1160 to determine the specific threats deemed applicable to this pipeline. Their threat matrix is generally similar to the ASME B31.8S format, which assigns 21 threats to nine categories, and further divides them into three time-related groups: time-dependent, stable, and time-independent. Table 1 summarizes the threat descriptions proposed by Keystone. Because the Keystone threat descriptions were not always the same as those in ASME B31.8S, the equivalent descriptions have been included in parentheses.

Table 1. Threat matrix for the Keystone XL Project

Time Dependent	Stable	Time Independent
External Corrosion (EC)	Materials Related (Manufacturing)	Excavation (Third Party/Mechanical Damage)
Internal Corrosion (IC)	Construction Related (Welding and Fabrication)	Hydraulic Event (Incorrect Operations)
Stress Corrosion Cracking (SCC)	Equipment	Natural Hazards (Heavy Rains / Floods, Earth Movement)

Incident frequency, assessed in terms of incidents per mile-year, was determined for most of the nine threat descriptions shown in Table 1. These rates were determined from a subset of the PHMSA database for the interval from 2001 through August 2008 that focused on onshore liquids pipelines. Keystone further eliminated records associated with pump stations and tanks, which, based on the methodology discussion (Section 2.1.1), is appropriate if the concern for the pipeline for purposes of an EIS is simply the lineal element that connects the discrete facilities, where prime-movers and other equipment reside. But it should be clear from the review of the methodology that the facilities that house the pump stations, equipment, tanks, etc., do pose a significant concern from a consequences perspective. Therefore, this consideration of threats does not continue the narrow focus adopted by Keystone, but rather considers the pipeline system and all related threats.

Keystone has stated that a majority of the pipelines covered by their analyses represent the "pre-modern era" (before 1970) and that the incident frequencies would not reflect current pipeline practices, the relevant editions of applicable codes/standards, and the 57 Conditions[7a] that will apply to this project. As such, the incident frequencies derived from the PHMSA database were considered to overestimate the incident frequencies. To generate frequencies considered to be

more consistent with current practices, adjustment factors ranging from 0.1 to 1.0 were assigned to each threat description, with multiple adjustment factors used for a single threat description in some cases. Because the magnitude of these subjective adjustments was primarily based on "professional engineering judgment," their magnitudes are open to discussion. That said, the factors all were within an order of magnitude, which means the swings they lead to in the incident rate is small in absolute as well as relative terms. This practice is comparable to using subject matter experts (SMEs), a common practice in the pipeline industry as part of developing risk assessment models; therefore, this approach is not unusual.

2.1.2.2 Objective and Scope

The objective of this section and the related analyses is to comment on the methods used and the assumptions made by Keystone to quantify incident rates. This section complements the commentary on the methodology and implications that arise from aggregating the PHMSA database. This includes the threats identified by Keystone, with recommendations to consider threats excluded from their analysis.

2.1.2.3 Approach and Database

Each threat considered by Keystone[4,5] has been assessed considering Keystone's desire to develop conservative incident frequencies that could be viable over the long term. The methods described for weighting the PHMSA incident frequencies were considered, as was determining whether or not the process described was consistent with the intent of 49 CFR 452, Appendix X[7b], and the 57 Conditions[7a]. This task also compared Keystone's approach for developing risk models to common industry practices, and possibly relevant threats not included are identified and discussed. Specific input data describing Keystone's methods were contained in their Risk Assessment[4,5] and related filings in support of the EIS[7c]. Other sources included Appendix U (57 Conditions), ASME B31.4-2010, and prior experience gained from threat evaluations and risk model development.

2.1.2.4 Analyses and Outcomes

Table 2 is a list of the threats outlined in Table 1 that were considered relevant by Keystone. It also indicates an assigned level of significance for each threat, as primary or secondary. In two cases, individual threats in Table 1 were combined and represented by a single incident frequency, with threats involving internal corrosion (IC) and external corrosion (EC) being paired, and the materials and construction threats being paired.

Table 2. Threats considered and significance factors assigned by Keystone

Keystone Threat Descriptions	Threat Level
Corrosion (EC and IC)	Both Primary
Excavation Damage	Primary
Materials and Construction	Both Secondary
Hydraulic Event	Secondary
Ground Movement	Secondary
Washout and Flooding	Secondary

Incident frequency adjustment (correction) factors that were assigned to each threat also have been assessed. These correction factors were used to modify the calculated incident frequencies based mainly on data from older pipelines, with a view to account for the more comprehensive liquid pipeline regulations in 49 CFR Part 195, ASME B31.4-2010, and the 57 Conditions that apply to this project.

Under the Time-Dependent group shown in Table 1, both EC and IC have been considered primary threats, which Battelle concurs is consistent with current industry practice. However, these threats are independently reported in the PHMSA database, and statistical analysis demonstrates that they have differing trends. Thus, pooling their occurrence is questionable, as is representing their effects by a combined incident frequency or adjustment factor. A coupled incident frequency adjustment factor was assigned at 0.3[(4)], whereas the basis for this in regard to "safeguards" cites, for example, fusion-bonded epoxy (FBE) coating or CP, both of which deal specifically with EC. Realizing that aspects of such safeguards are not unique to Keystone, the use of a 70 percent reduction might be considered too large. More details that justify the selection are needed, particularly given that it lumps together what are statistically differing causes. A second adjustment factor equal to 0.2 is introduced[(4)], but here the focus is IC. It is clear that the indicated mitigation is cause-specific and that there is no statistical support to justify pooling such causes; therefore, lumping their mitigative effects into a single adjustment factor lacks technical justification.

Keystone included SCC in the Time-Dependent group (Table 1), but this threat was subsequently dismissed based on the usual test of relevance that involves like-similar analysis and/or past history. This action was supported by two citations[(15,16)] that indicate SCC has not been an issue on FBE-coated pipelines, which includes the view of the PHMSA, and with which Battelle concurs.

With respect to the Stable threat group (Table 1), Keystone has, appropriately, incorporated most of the relevant threats listed in B31.8S and API 1160. In this context, construction-induced buckles might be included, but they would be detected by the pre-service in-line inspection (ILI) for deformations mandated by the PHMSA according to the 57 Conditions; therefore, this form of geometric instability is excluded. In-service buckles induced by ground movement represent a

different threat category associated with ground movement; this scenario is addressed by that category, which is already covered (see Table 2) as a secondary threat. Battelle concurs with this secondary assignment and notes that this, too, is a focus of the PHMSA's 57 Conditions.

The Stable threat group of Table 1 notes Materials and Construction as the combination of two of the nine threat categories listed in the Codes. This combination involves pipe manufacturing threats as well as those due to field construction. Based on historical trends, this coupling is not unreasonable. In this context, 10 factors are listed by Keystone that describe actions considered by Keystone to be beyond the norm, whose purpose is to increase the quality and thereby the safety of a "modern" pipeline constructed today. Many of these factors involve requirements that represent incremental value in pipeline safety and integrity; others could apply to any current large-diameter, high-pressure pipeline project, as these reflect company best practices or industry leading practices. One factor noted is inspection of pipe as-delivered (presumably to the job site) in regard to concern for weld-seam transportation-induced fatigue cracks; that factor has not been broadly considered for most pipeline construction as far as we know. Yet, transport to avoid such concerns is addressed by an existing API-recommended practice.

Based on Keystone's analysis of the PHMSA database, an incident frequency of 3.00×10^{-4} incidents per mile-year was established. Adjustment factors were then applied to this incident frequency based on the benefits derived from the 10 factors listed, with a factor of 0.5 applied to account for the beneficial role of Federal regulations, and an additional multiplier of 0.2 applied to account for the beneficial material-related requirements of the PHMSA's 57 Conditions. However, in reality, these two adjustments reflect quite different drivers.

In regard to the PHMSA's 57 Conditions, the outcome can depend on how each condition is implemented. For example, consider the conditions that apply to the line pipe and its construction into the mainline system. Depending on the steel and pipe manufacturer(s) selected for the project, and the field construction contractors and their methods used to build it, one could anticipate quite different incident rates. This is because different steel and pipe suppliers and different construction contractors can take different routes to satisfy the Project's specifications, with outcomes that are not always equal or satisfactory. This is demonstrated in the experience that underlies some of the Special Conditions imposed, which reflect evidence of critical quality shortfalls even though all deliveries to the spreads satisfied the applicable CFR requirements and the company's specifications. On the basis of such concerns, one can take issue with the factors used. On the other hand, the net result of the many adjustment factors involved is quite small, which casts uncertainty on the merits of focusing on this detail when seeking a high-level metric of long-term pipeline integrity. If such details are considered significant, Battelle recommends that the risk analysis uncouple the currently coupled aspects as the process moves forward toward the IMP developed later in the process.

The Stable threat group (Table 1) also contains an Equipment category that mainly includes pipeline operating equipment that would primarily be located in pump stations. Various incidents such as gasket/O-ring failures, seal/pump packing related leaks, etc., are covered by this threat category. Although included in Table 1, it was stated that due to rigorous construction methods, inspection, etc., any equipment-related leak would be too small to require additional consideration, so this threat was eliminated. This decision is not consistent with the 13 pump-station leaks[7c,17] that occurred during commissioning or in early operations for the Keystone pipeline; for these incidents, it is apparent that all causes involved the Fabrication or Equipment categories as defined by Code.

It is evident from discussions with Keystone that many of the failures noted on the existing Keystone Pipeline occurred during the equipment's "break-in" stage. Given that, a decreasing failure rate can be anticipated for that system and any similar one such as the Keystone XL Pipeline, where the rate typically levels off to a much lower/near-zero incident frequency. On the other hand, at least one of the 13 incidents involved a small fitting that could have been a defective fitting integrated into a more complex component. In this context, the earlier assessment of the methodology points to a much higher incident frequency in regard to the Equipment threat category, which raises the question whether this is a secondary cause, as assigned by Keystone (see Table 2). This is a particularly relevant question in light of the large number of fittings and components that typically are built into a pipeline system and its operations and control facilities. This cause category merits further consideration as part of the preventive actions possible for the Project.

The Time-Independent threat group indicated by Keystone includes "Excavation" as a primary threat. This category corresponds to the Third Party/Mechanical Damage (TPD) category of the ASME B31.8S Code. From the Keystone threat description, mechanical damage that results in both immediate and delayed incidents contributes to this category. Battelle concurs that TPD is an important aspect of a pipeline threat assessment and that it should be considered a primary threat.

The excavation damage discussion in the Risk Assessment[4,5] states that pipelines can leak from third-party damage as an immediate failure or a delayed failure due to a gouge. It was further stated that gouges can be detected by "routine" ILI inspection, whereas experience gained through pull-rig testing and with field ILI do not support this view for current single-technology ILI tools. Regarding Keystone's intent in the language regarding "routine" ILI inspection, further inquiries determined that the intent was to refer to ILI frequency rather than the inspection practice. In that context, Keystone clarified that they would utilize state-of-the-art, multiple-technology, high-resolution (third-generation) tools coupled with advanced algorithms and interpretation practices. Thus, while Battelle would take issue with capabilities of "routine ILI" to detect and size dents and gouges, it is clear that specialized ILI tools and algorithms have the ability to discriminate such

features. That said, technology continues to evolve, so there is merit in tracking such developments with a focus on this aspect as this process transitions to the PHMSA.

Six factors have been listed that contribute to reducing the chance of excavation-related damage. This included widely implemented current standard practice, such as line-of-sight markers and the one-call system. Other factors included a 4-foot depth-of-cover, application of the Common Ground Alliance practices, line pipe with higher inherent puncture resistance due presumably to wall thickness, and possibly increased grade and toughness, which are noted to reduce the chance of a puncture. Battelle concurs that such factors can diminish the effect on the extent/severity of mechanical damage, particularly where fatigue failure is possible.

Rather than apply a correction factor to the incident frequency for excavation damage, as was done for the other threats considered, a comparison was made in reference to incident frequency based on a mechanical damage model[18]. This model is indicated to account for the pipe-related factors, maximum excavation equipment sizes, etc.[18] Pipe penetration resistance also was evaluated and was determined to be greater than the force exerted by 98 percent of the excavating equipment operating today in North America. Coupling the PHMSA database incident frequency of 1.22×10^{-4} incidents per mile-year and the model outcomes led to a calculated frequency of 8.58×10^{-7} incidents per mile-year for the rural/agricultural segments of the routing. It was then stated that the difference between these two incident frequencies is equivalent to using the combined effects of three adjustment factors, which were variously rationalized. In turn, this led to use of an incident frequency considerably lower than that based on the PHMSA incident frequency. While this is a credible process that utilizes state-of-the-art technology to temper historical data in a process comparable to that used at Battelle, a key to the practical use of all models is the extent to which they have proven full-scale validation.

To the extent the incident frequency specific to TPD is considered significant, Battelle suggests that such validation be added to the record to support the extent of the modification to the PHMSA-based rate. The model cited in the Keystone Risk Assessment had its roots in industry surveys and empirical historic data. On this basis, one can anticipate that the model used by Keystone would return an outcome that is consistent with past experience, which one further anticipates would not be greatly different from the outcome by trending the PHMSA database. In contrast, the rates cited in the Keystone Risk Assessment led to a reduction in the incident rate of an order of magnitude of more than two. This seems large relative to the role of depth of cover, given that both approaches share a basis in historic information, some of which reflects lines buried deeper than required by Code.

Vandalism is a threat that can contribute to the TPD category, but it was not considered in that context by Keystone. While this might seem justified since history indicates that vandalism seldom

occurs, closely aligned threats include concerns like terrorism and sabotage, which are becoming increasingly relevant in today's changing world. Given the critical nature of the Project, some recognition of this threat seems relevant over the long term, perhaps at a secondary level.

A hydraulic event is the only time-independent threat considered by Keystone. This threat is termed "incorrect operations" in B31.8S (see Table 1), while it has been relegated to secondary status by Keystone (see Table 2). In reference to the incident frequency determined from the PHMSA database as 1.47×10^{-4} incidents per mile-year, Keystone assigned an adjustment factor of 0.5 to account for the reduced likelihood of such incidents. Four mitigating factors affected the determination of this adjustment factor: use of a system model and simulator as part of their supervisory control; use of a system model and simulator as part of their data acquisitions system; increased operator training; and overpressure protection. In many ways, each of these factors can be considered typical of industry norms, some of which are mandatory, with others in play for decades, which casts uncertainty on the use and magnitude of this adjustment.

Keystone has provided extensive documentation regarding operator training and related aspects; however, the fact remains that human factors underlie or contribute to continuing failures in pipeline systems. More critically, human factors is a continuing issue for other industries (e.g., aviation/aerospace, the nuclear industry, and the offshore exploration and production industry) that are known for or claim that their training and update/refresher courses are top-end. Given that recurring failures happen in spite of extensive training/retraining, Battelle suggests the need for ongoing improvements in operator training and in fault-response simulation, with particular consideration of upset or other unanticipated events. Battelle concurs that incorrect operations could trigger a hydraulic event, but asserts that safety-related issues due to human error or failure to follow standard operating procedures (SOPs) remains a significant concern. Thus, it is suggested that the broadest perspective be taken in defining hydraulic events, and that the SOPs be refined to minimize the minor releases that are evident in liquid operations and maintenance (O&M) once the lineal and discrete elements of the pipeline system are uncoupled. In discussions on this topic, Keystone notes that periodic review of SOPs is already in place, which is usual in the industry.

The Natural Hazard threat description adopted by Keystone (see Table 1) includes earth movement, landslides, seismic events, and flooding/washout, which are in the Weather Related and Outside Force category in ASME B31.8S. Each of these threats has been considered separately. Because these threats cannot be mitigated completely nor planned for in regard to time or magnitude, but are localized in their occurrence, the incident frequency adjustment factors have been based on the fraction of the pipeline segments exposed to each specific threat. This is considered a good decision, in contrast to applying engineering judgment and distributing the threat over the aggregated system. By way of example, three Project-wide levels were noted (high, medium, and

low) in regard to seismic risk, with corresponding adjustment factors applied along with the applicable pipeline length. Landslides and floods were dealt with likewise.

Discussion concerning ground movement, including landslides and seismic events, outlined the methods and construction practices selected to mitigate these threats, which were considered usual in the industry. Based on the PHMSA database, a frequency for ground movement events was determined to be 1.23×10^{-5} incidents per mile-year. The pipeline RoW was then compared to US Geological Service (USGS) maps to locate where these threats may present a problem. Weighted average adjustment factors for landslide and seismic incident adjustment factors were then determined to develop a Project-wide factor of 0.43. This process of using multiple adjustment factors along with the USGS maps is considered a reasonable basis for locating and weighting the landslide and seismic event incident frequencies.

Also included in Keystone's Natural Hazards threat description were Flooding and Washout, which encompassed hurricane storm surges and heavy rain. The most common event was identified as stream scour resulting from high-velocity water flow during seasonal flooding, which occurs in association with other effects (e.g., pipe impacts by flowing debris). Such events, either alone or acting in combination, can result in pipe damage or rupture if the pipeline becomes exposed. Similar to the landslide and seismic analyses, three levels of flood risk incident rate adjustment factors (high, medium, and low) were coupled with USGS data along the pipeline RoW. The resulting washout and flooding incident rate was 1.14×10^{-5} incidents per mile-year. A hurricane incident rate risk was noted in regard to two levels (high or low). Because hurricane risk would be mainly confined to the southern end of the Project, this hierarchy was considered appropriate. A Project-wide weighted average adjustment factor for a flooding and hurricane incident rate of 0.67 was determined from these analyses. As for the landslide and seismic event incident frequencies, these analyses provided a reasonable basis for locating and quantifying flood- and hurricane-related incident rates.

In addition to the Natural Hazard threats considered above, the Weather Related and Outside Force threat category in B31.8S includes lightning strikes and cold weather. Lightning strikes have interfered with pipeline operation, construction, and maintenance, with pump stations and other aboveground equipment being particularly susceptible. Because the Project RoW traverses cold-weather areas, where frost can penetrate to maximum burial depths, such conditions could adversely affect aboveground and buried segments and facilities. Accordingly, routine functions such as valve operation could be impacted, potentially delaying closure in the event of a release, or other adverse effects could occur during otherwise normal operations. It is Battelle's view that both lightning and cold weather could affect the Project. Therefore, based on related work associated with field failures, Battelle recommends that such events either be clearly addressed in

design or be considered in the threat analyses. Discussion with Keystone in regard to these concerns indicates that they have been covered by design, such that they are IMP concerns dealt with later in this process.

The result of the Keystone Risk Assessment was a Project-wide, averaged incident frequency equal to 1.35×10^{-4} incidents per mile-year. This was determined from a weighted average of state-specific incident frequencies for each threat considered. The multiple adjustment factors for the Natural Hazard threats were applied in this context as a weighted average. The incident frequency for each state is a summation of the individual threat frequencies, presumably including the appropriate weighting factor (although this was not entirely clear from the equation shown). When included in a risk calculation, the incident frequency then is the basis for a metric indicating the incident likelihood.

While it is usual industry practice to quantify frequency on an averaged basis, normalized by distance, such practice is logical only in the context of the Time-Dependent threats. For those threats, it can be viable if the threats are considered to occur without bias to location (relative to the causative factors) along a pipeline system, and the population supports quantifying average in a statistical sense. Likewise, frequency determined on an averaged basis, normalized by distance, can be viable for the anomalies that underlie the Stable category if they are similarly distributed without bias to location along a pipeline system and the population supports quantifying average in a statistical sense. In contrast, events that occur over short segments due to geographic and/or other causes (such as weather patterns), or events that occur infrequently (such as those that underlie the random threat category), are poorly characterized by an average of any form. While it is easy to be critical in this context, it is equally difficult to be constructive, as simple alternatives to the averaging practice are not broadly supported by any database. For that reason, the approach adopted remains in broad use.

It follows that, as the pipeline begins service, it is likely that considerable lengths could be properly evaluated using averaged incident frequencies. Over time, it would be expected that threats and conditions affecting pipeline risk would change to reflect localized factors. At that point, this system-wide metric would likely become selectively inappropriate over some shorter segments. As a result, state- or Project-wide incident frequencies are less relevant. Any weight factors applied should be specific for each pipeline segment[19]. State- or Project-wide incident frequency estimates would tend to reduce the capability of any risk model to effectively discriminate between high- and low-risk pipeline segments. This could have long-range IMP-related impacts.

Although Appendix H[7d] of the EIS is titled "Pipeline Risk Assessment and Environmental Consequence Analysis," risk was not quantified as it is usually defined in reference to the product of consequences and likelihood (see, for example, ASME B31.4-2010, Section 2.2, and/or API

1160-2001, Section 8.2). Consequences, although discussed, have not been coupled with likelihood, nor has a suitable metric been located in the Keystone support documents to define the consequence term in a risk equation, even though the just-noted documents are cited in Appendix H and elsewhere in the Keystone support documents.

Finally, while much has been said in regard to the environmental consequences, consideration should be given as well to societal impacts. Such impacts might occur due to distress caused by contamination of drinking water or upsets in farming due to impacts on the agricultural water resource.

2.1.2.5 Summary and Conclusions

Incident frequencies calculated for the six threat categories considered by Keystone to represent adverse impacts on pipeline safety and integrity were reviewed. It was found that the potential severity was determined for most of the threat categories using trending of the PHMSA database for liquid pipeline incidents, consistent with usual practices. Because these data tend to be representative of older pipelines, adjustment factors were applied to the calculated incident rates to make that outcome more characteristic of a modern pipeline constructed under current regulations, codes/standards, and the applicable 57 Conditions, which add still more stringent requirements. Most of the adjustment factors were developed using "professional engineering judgment" (i.e., the opinions of SMEs); this is a common industry practice. The Natural Hazards threat also incorporated USGS data to supplement the analyses. This approach to risk assessment is a common, accepted methodology broadly used by the pipeline industry to analyze potential threats and develop risk models.

One objective of Keystone's analysis process was to provide conservative incident frequencies for estimating the Project's environmental risk considering the conditions associated with a new pipeline. They also stated that the incident frequencies developed would remain conservative over the Project life since incident rates are declining and pipeline methods and practices would improve over time. Time-Dependent threats will change with time, affecting the validity of the incident frequencies proposed. Also, other threats such as Natural Hazards could create conditions resulting in future maintenance issues that remain in play for many years. While the goal of the Keystone Risk Assessment was continuing conservatism in incident frequency, such cannot be verified. But even if it were, conservative averaged rates do not preclude an incident. Therefore, care must be taken to design, construct, and manage the system over its life-cycle to prevent leaks, protect against their severity, and provide for their mitigation if a leak occurs.

The weighted average of the state-specific incident frequencies has been used to produce a Project-wide incident frequency. These state-specific frequencies are considered to be "macro" incident frequency evaluations that do not facilitate drilling down to identify potential "hot spots" within

specific pipeline segments in any state. During initial operation, long pipeline lengths may be correctly represented by such an incident frequency, but Battelle does not consider that this represents the best long-term approach. Also, a risk model that includes such wide-ranging frequencies tends to have less power to discriminate between higher- and lower-risk areas over short pipeline lengths.

In their Excavation Damage discussion, Keystone stated that "routine magnetic flux leakage (MFL)" ILI operations would be sufficient to detect gouges in the pipeline. Based on Keystone's subsequent clarification that "routine" applies to ILI frequency rather than the technology, Battelle concurs, noting (as Keystone did) that multiple-technology specialized ILI tools exist and are evolving, as are practices to integrate the results of tools or the outcomes of multiple runs of single-technology tools runs, so the certainty of the outcomes is increasing.

Section 2.1.2.4 identified several threats that have not been considered by Keystone but which Battelle considers relevant until further analysis proves otherwise. These should be addressed after PHMSA has approved construction. In addition, it is suggested that the coupled-threat incident frequencies be uncoupled unless there are statistical reasons to pool such data.

The following conclusions derive from this review:

- Equipment-related concerns represent a viable threat, which should either be addressed or demonstrated, through analysis or trending, that they can be ignored.
- The currently coupled threats involving IC and EC should be uncoupled, as should those involving material versus construction threats, unless statistically valid reasons are established to pool these data.
- Incorrect operations should be included as a threat unless it can be demonstrated it is not relevant. Concern exists in this context regarding human error, failure to follow SOPs, and/or the existence of outdated SOPs.
- A rationale should be provided on the record for the exclusion of other threats included in ASME B31.8S.

In closing, the adage "it is easy to be critical, but difficult to be constructive or provide viable alternatives" clearly applies to many facets of risk assessment involving pipelines. This situation traces to the absence of critical data in the PHMSA database or website to facilitate normalizing the drivers for likelihood and consequences. This aspect could benefit from agency action (in conjunction with the industry), working to identify and bridge the gaps in such databases.

2.2 Risk Assessment

2.2.1 Background

The Risk Assessment for the proposed Project was presented in Section 3.13 of the FEIS[7c]. This section extensively referenced the information in Appendix P of the FEIS[7e]. Both sections were reviewed, but because most of the information in Section 3.13 was developed from Appendix P, the appendix was the major focus of the analysis. Both sections rely on historical spill data contained in the PHMSA Hazardous Liquid Pipeline Incident Database, specifically for the interval from January 2002 until August 24, 2008[6a]. The evaluation of spill risk that follows is broken into three major topics: threats, spill frequency, and spill volumes, with the last two sections considering fate and transport and the possible consequences of spills.

2.2.2 Data Available from the PHMSA Database and the Implications of Nulls

The threat data used by Keystone were obtained from the PHMSA database listed under the General Cause (GEN_CAUSE_TXT parameter field). It is apparent that these fields match those common to other well-known structured hazard checklists (for example, The Hammer listing[20]). Table 3 provides a cross-listing of Hammer hazard categories with PHMSA General Cause categories.

Table 3. Hammer hazard categories mapped onto the PHMSA General Cause categories

Hammer Hazard	PHMSA Cause Category Mapped onto Hammer
Acceleration	Natural Forces and Material and/or Weld Failure
Contamination	Considered as a possible cause of Internal Corrosion
Chemical Reaction	Corrosion is the primary chemical reaction
Corrosion	Corrosion
Electrical	Incorrect Operations during a Upset/Transient Event
Explosion	Fire/Explosion under Other Outside Force Damage
Fire	Fire/Explosion under Other Outside Force Damage
Heat and Temperature	Temperature under Natural Forces
Impact and Shock	Incorrect Operations and Material and/or Weld Failure
Leakage	Outcome not an input for this assessment
Moisture	Considered under Corrosion
Power Source Failure	Not specifically listed, would fall under Incorrect Operations
Pressure (high, low or change)	Considered under Incorrect Operations
Radiation (all forms)	Buried Pipeline, not an applicable hazard
Structural Damage or Failure	Material and/or Weld Failure and Excavation Damage
Toxicity	Outcome not an input for this assessment
Vibration and Noise	Not listed, but falls under Material and/or Weld Failure
Weather and Environment	Natural Forces

The PHMSA database is the basis to identify threats relative to causes of prior incidents; therefore, it is appropriate to comment briefly on its structure and evolution relative to the purposes of this review. The focus here is likelihood, because the consequences aspects are considered subsequently in sections dealing with fate and transport of the spilled product relative to the Project.

It is apparent in comparing causes that the corrosion field GEN_CAUSE_TXT is anticipated to encompass incidents due to corrosion, regardless of whether it is IC or EC, and regardless of what part(s) of the pipe failed. When the database is trended on GEN_CAUSE_TXT versus the subcategories fields under CAUSE_TXT, inconsistencies are evident and many nulls (blank fields) are found. Given that the target is a per-mile-year metric of likelihood, nulls cannot be dismissed without somehow accounting for the mileage and the period they represent. Without that accounting, the mile-year metric determined from the database is in error. Review of the scope of the database indicates that the information compiled does not support this accounting process. However, even if the necessary information could be identified, the approach used to account for the nulls would always be a source of criticism.

The significance and implications of the nulls can be assessed by trending the database on GEN_CAUSE_TXT versus the subcategories fields under CAUSE_TXT, for example, in regard to corrosion. In so doing, more than 1,900 GEN_CAUSE_TXT records are identified, yet there about 2,500 data records (i.e., lines of data entry). It is evident in this context that a per-mile-year metric derived by trending the database underestimates the actual medial incident frequency by about 20 percent. If the database is then evaluated in regard to the subcategories fields under CAUSE_TXT, nulls again cause a further nonconservative reduction in the incident rate. This analysis shows that, after summing the records for corrosion-related fields under CAUSE_TXT, about 340 records are found, in contrast to about 550 corrosion records under the GEN_CAUSE_TXT field. It follows that tracking more than two significant digits in regard to any incident frequency could be questioned, as could the use of adjustment factors that further diminish the rates. Similar issues arise in regard to likelihood metrics associated with spill frequency, with parallel concerns arising in regard to spill volume and the consequences of that spill. On this basis, the ensuing discussion tends to utilize only two significant digits.

Against this background, the GEN_CAUSE_TXT and the CAUSE_TXT fields in the PHMSA database are used to quantify the system or component part leading to the incident as the basis to identify threats, with the fields that quantify the traits of incident consequences then evaluated in regard to spill frequency and volume. These are then examined further in terms of quantitative consideration of causes and the threats they infer.

2.2.3 Causes, Inferred Threats, and Incident Occurrence

2.2.3.1 Introduction

This section quantifies the threats to the integrity of the pipeline based on the PHMSA database, which has been compiled in various formats since the early 1970s. Keystone used the GEN_CAUSE fields developed by PHMSA as the basis for their threat matrix.

2.2.3.2 Objective and Scope

The objective is to re-evaluate the threats posed to the pipeline, and in that light quantitatively assess the adequacy of the specific pipeline threats considered by Keystone. While this scope could be considered narrow because the review is limited to the PHMSA database, Table 3 shows that the database is comprehensive in its coverage of threats.

2.2.3.3 Approach

The approach relies on trending and statistical analysis to compare the present results to the outcomes developed by Keystone[4,5,7c…], with reference to (1) how the threats in the CAUSE_TXT field listed in Table 4 were grouped, and (2) how the nulls in the database were dealt with. Note that the 25 CAUSE_TXT categories are subcategories of the eight GEN_CAUSE_TXT categories considered in regard to Table 3.

2.2.3.4 Analysis, Results, and Discussion

Parsing the database field GEN_CAUSE_TXT led to the outcomes summarized in Table 4. The records under the GEN_CAUSE_TXT field or the 25 CAUSE_TXT categories can be grouped in many ways relative to the elements of a pipeline system. For example, the database system-part field (denoted SYSPRT) divides an onshore system into five elements, which pair a number designation and a text designation. These pairs are: (1) aboveground storage tanks, (2) cavern / belowground storage, (3) pump / meter / terminal / tank / farm-related, (4) other, and (5) pipeline (including MLVs). Battelle has added another pair to this as (6)−nulls−to provide for analysis of the nulls. This consideration reflects the observation that over 50 percent of the roughly 2,500 SYSPRT records are null. This means that the median incident frequency would be underestimated roughly by a factor of two in the event that the baseline incident frequency in the Keystone Risk Assessment covered all elements of the pipeline system.

While the exact scope of incidents represented by the baseline rates was not obvious from the Keystone reporting, Keystone noted in a subsequent discussion that they excluded “terminal and tank data.” That said, analysis of the incident rates for the remnant system elements did not lead to rates that match identically the baseline values reported, nor did the outcomes for various other combinations of SYSPRT. Of the combinations considered, the rates for SYSPRT 5 (i.e., the

pipeline and MLVs) were closest. This is reasonable if the intent was to determine the incident frequency relevant to the portion of the system traversing the RoW that was earlier identified as the primary driver for environmental and public consequences. On this basis, this review hereafter addresses likelihood in regard to SYSPRT = 5. Note that the distribution of the nulls between the causes that comprise the GEN_CAUSE_TXT field reasonably matches the distribution that develops for records that include a SYSPRT descriptor. This implies that the median incident frequency would be underestimated roughly by a factor of two for each of the causes that comprise the CAUSE_TXT field, such that estimates of rate for any one cause embed significant uncertainty. This casts uncertainty on the exclusion of any cause category as a threat without cause-by-cause analysis to support such exclusion.

Table 4 presents the outcomes of the Keystone Risk Assessment assigned relative to subcategory causes found under the CAUSE_TXT field relative to that for the pipeline and MLVs (SYSPRT = 5). The first column notes the incident cause using a mix of descriptors chosen between the eight GEN_CAUSE_TXT fields and the 25 CAUSE_TXT fields. This approach assumes that causes of prior failures are considered adequate to represent the scope of future threats. The middle pair of columns presents the total number of incident occurrences by cause category and that associated with SYSPRT 5. The final column restates the middle two as the percentage of pipeline incidents for each cause category. The cause categories considered by Keystone are shown above the line-split across the table, while those below the split were not considered.

Table 4. Threats listed under the General Causes category

Cause/Threat	Incident Occurrences		Pipeline %
	Total	Pipeline	
Corrosion	552	211	38
Material and/or Weld Failures	302	105	35
Excavation	155	129	83
Hydraulic Event (Incorrect	240	10	4
Earth Movement	13	8	62
Heavy Rains and Floods	13	3	23
Total of Above Threats	1,275	466	37
General Cause Categories Not Considered by Keystone			
Natural Forces not considered	82	7	9
Equipment	837	28	3
Other	58	31	53
Other Outside Forces Damage	222	36	16
Total of Threats not considered	1,199	102	9
Total of all Threats	2,474	568	23

Table 4 shows that three threats dominate the list for all causes: Corrosion, Equipment, and Material and/or Weld Failures. Also shown in Table 4 is a column titled "Pipeline" that considers the incidents involved with the SYSPRT = 5. In addition to the focus on onshore, this restricts the spill events to those occurring along the pipeline ROW, including the MLVs. The final column in Table 4 shows the fraction of the incidents that are specific to the pipeline. The data show that Excavation is mainly an event that occurs along the RoW, whereas hydraulic events occur mainly at the facilities. This is expected because that is where the pumps are located, and they would be the primary cause of a hydraulic event. For the remaining threats, the contribution along the RoW is between 20 percent and 40 percent. The last line in Table 4 clearly shows that the majority of the threats are realized at facilities, at a rate of about three out of four.

If Keystone focused on the pipeline rather than the facilities (based on matching incident rates as noted above), then the data in Table 4 indicate that roughly one-half of the incidents and their causes were excluded by the Keystone analysis. This follows from the observation that almost half the threats – specifically 1,199 out of 2,474 – would be ignored in this context. Some justification for this might lie in the more rigorous expectations that the PHMSA 57 Special Conditions[(7a)] will bring about improved SCADA etc.; therefore, on that same basis, one could consider their beneficial impacts on the line pipe quality, and so on, and thereby exclude all causes as indicators of relevant threats. Given the apparent focus on the RoW, it is not surprising that, because the causes that were excluded were common within facilities, only 9 percent of those causes are anticipated to occur along the Keystone RoW.

The results summarized in Table 4 indicate that identifying threat categories can be a complex process. The data, presented in Annex D of Battelle's original third-party review (January 2012), show that under each threat category, there are numerous entries in the database where the cause is left blank; in fact, there are more than 1,000 of them. These blank (null) entries are apparent throughout the tabulations in the PHMSA database. The data in the PHMSA database also show that, if only incidents along the pipeline RoW are considered, null entries are found for both the pipeline RoW and the facilities. While Keystone's outcomes might be questioned in this context, Table 4 shows that only 9 percent of the incidents that are not addressed by Keystone occurred in the RoW. Thus, if completeness is assessed relative to the fraction of the incidents, then the causes excluded from the Keystone Risk Assessment have only a small relative effect. Nevertheless, those excluded include important concerns, such as Outside Force Damage.

The review of the Keystone methodology in Section 2.1.1 of this report noted that their analysis excluded facilities-related causes, as one means to identify threats relevant to the environmental exposure along the RoW. However, all pipeline systems involve facilities and their O&M-related threats. In this context, Table 4 indicates that of the more than 1,270 incidents that occurred for the threats above the horizontal split (i.e., causes considered a threat by Keystone), only 466, or

37 percent, involved the pipeline. Moreover, the scope of the incidents considered by excluding facilities only represents about one-half of the total, such that potentially important causes could be missed. Overlaid on this is the influence of the nulls – and of uncertainty due to causes that are identified in the database as "other" (comprising two subcategories termed "miscellaneous" and "unknown," which cannot be offset in an exact way. While inexact, their potentially significant impact could be assessed by distributing these across the quantified subcategories in the same relative proportion. This would offset errors that arise in the frequency of occurrence and might provide a more rational basis to judge the significance of a cause in the process of identifying threats. Unfortunately, from the details as reported, one cannot determine if this or other similar approaches were considered, but given that the Risk Assessment does not discuss nulls, it appears that Keystone has not corrected for their presence in the database.

Other aspects were evaluated quantitatively as well. These additional evaluations were motivated by the concerns noted in the earlier discussion of Threats, which considered causes and threat identification qualitatively. In regard to the coupling of IC and EC (see Table 2), quantitative analysis and trending clearly support the need to consider IC and EC as independent threats. As noted earlier, some discussion in the Risk Assessment lumps these causes, whereas other discussion regarding mitigation considers them independently. Likewise, the quantitative analysis and trending clearly supports the need to identify materials and construction as independent threats, (they were lumped in Table 2). Such quantitative outcomes are supported as well in practice, because different sources of nominally the same steel and pipe have historically led to different failure causes, and so should be recognized as independent threats.

2.2.3.5 Summary, Conclusions, and Recommendations

The Keystone assessment considered five causes selected from the general and specific cause text categories listed in the PHMSA database and identified them as threats. The outcomes of this process are strongly impacted by the significant frequency of nulls in the database, which, depending on how they were managed, can lead to an underestimate of incident frequency by up to a factor of two. The presence of the nulls promotes uncertainty for all threats identified by Keystone and creates the possibility that causes not considered to be a threat could actually be important.

While the review of the Keystone Risk Assessment methodology in Section 2.1.1 indicates that a decision to exclude facilities-related causes is a rational approach to identify threats when the focus is environmental exposure along the RoW, all pipeline systems include facilities and are exposed to O&M issues. Table 4 indicates that of the more than 1,270 incidents that occurred for the threats above the horizontal split in the table, only 466, or 37 percent, involved the pipeline. Moreover,

the scope of the incidents considered by excluding facilities makes up only half of the total, such that potentially important causes could be masked.

Given the significant fraction of incidents ignored due to such a focus, Battelle notes the need for a more balanced approach to threat identification. In this approach, all causes pursued earlier in considering the methodology are at least considered. It follows that the outcomes summarized in Table 4 quantify the need for a balanced approach and establish to need to implement the recommendations made in Section 2.2.3.4, which considered causes and threat identification from a pipeline perspective rather than a quantitative perspective.

The Keystone analysis does not describe how the causes under the "other," "other outside force damage," and "equipment" cause categories were factored into the analysis and threat identification process. When the likelihood analysis more broadly expands to consider such incidents, as well as those at facilities, the nulls should be addressed. This should be considered in any update of the pipeline risk assessment after PHMSA has given approval for construction. Finally, the recommendations noted in the qualitative threats review done from a pipeline perspective are supported quantitatively. Accordingly, those recommendations should be implemented after PHMSA approval.

2.2.4 Incident and Spill Frequency

2.2.4.1 Introduction

The incident frequency and related spill volume analysis are key aspects of Keystone's Risk Assessment. The median spill volume is stated many times to be very small (three barrels). The consequence section of Appendix P builds on this small median spill volume when assessing spill consequences.

Because not every incident leads to a spill, one could choose to distinguish between these, resulting in a spill frequency that differs from the incident frequency. Reference to the SPILLED field in the PHMSA database indicates that slightly more than 1 percent of the incidents did not lead to a spill; therefore, spill frequency does not differ from incident frequency in a significant way. Accordingly, the analyses and results discussed in Section 2.2.3.4, Table 4, provide the foundation for the assessment of spill frequency. All that is required is consideration of the period and mileage that underlie the incident occurrences in Table 4, with outcomes compared to those reported by Keystone.

Keystone's process first determined a baseline spill frequency per mile of pipeline relative to the incident occurrences for each threat category they considered, with these frequencies summed to determine an overall spill frequency. Then the adjustment factors used were noted as the basis to

reduce the frequencies by threat category. Because some threats are local to a short segment of the pipeline (for example, threats due to nature), those segments were considered to have a higher risk and were assigned a higher spill frequency over the mileage exposed to such threats. Segment spill frequencies were then summed to get an estimate of the spill frequency by state and for the entire 1,375 miles of the Keystone Pipeline operating within the US. Including the effects of the adjustments, an estimate of 2.2 spills per 10 years of operation was determined for the Project's planned mileage within the US.

2.2.4.2 Objective and Scope

The objective is to quantitatively evaluate the spill frequencies estimated by Keystone and determine their applicability to the pipeline, particularly along the RoW between pumping stations versus discrete sites, while also accounting for uncertainty due to nulls and their impact on spill frequency. This evaluation targets spill rate per mile-year, while considering that some segments along the pipeline system might have locally higher spill frequencies. This evaluation differs from the Keystone analysis, which led to differences in the annual spill rate per mile in each state or along the pipeline, based on the observation that if the overall estimate per mile-year is uncertain or prone to quantitative disparities, then estimates determined at the more refined scale used by Keystone are equally problematic.

2.2.4.3 Approach

The approach involved queries of the PHMSA database for the interval from 2002 to 24 August 2008 (as used in the Keystone risk assessment) that were for each of their threat categories, leading to estimates of spill frequency relative to the corresponding pipeline mileage. Various queries initially sought to reconstruct or approximate the spill frequencies listed in Table A-2 of the Keystone Risk Assessment (Appendix A of Appendix P, Keystone XL FEIS)[7e]. Thereafter, queries on other combinations of database fields were used to assess spill frequency for pipeline threats and for facilities and other system threats. The nature and scope of the queries were motivated by the alternate parsing scheme discussed in Section 2.1.1, wherein spills at facilities were noted as easier to detect and remediate, and generally smaller compared to those at remote sites along the RoW. More critically, it was motivated by the observation that the pipeline along the RoW is a static system, in contrast to dynamic systems that operate within the facilities. Concern in regard to dynamic versus static systems derives from the threats and failure experience across many industries, where it is clear that moving components, along with seals and seats on equipment and pumps, lead to much higher potential for spills and also to human error. Finally, this scope was motivated by discussion with Project personnel indicating that, once operational, there will be more than 1 million active components on the pipeline, almost all of which will be located at facilities.

2.2.4.4 Analysis, Results, and Discussion

Table 5 presents the basis for discussion of the analysis and results, with reference also made to the results in Table 4. Thereafter, the outcomes of parsing to separate the pipeline and facilities are discussed in light of the incident occurrences presented in Table 4. This is followed by brief commentary regarding the viability of the adjustment factors applied to the baseline incident frequencies relative to the PHMSA's 57 Special Conditions[7a] and the factors adopted by Keystone. Finally, segments that have higher spill frequencies due to increased potential for intrusion, landslides, or other location-specific threats are discussed.

Table 5. Keystone spill frequency compared to estimates from two queries

GEN_CAUSE_TXT or CAUSE_TXT	Failure Frequency per Mile-Year		
	Keystone Appendix P	This Review	
		All Spills	Pipeline/MLV
Corrosion	2.9E-04	3.0E-04	1.9E-04
Excavation damage	1.2E-04	1.2E-04	1.2E-04
Hydraulic event (incorrect operation)	1.5E-04	9.7E-05	9.0E-06
Material and/or weld failures	3.0E-04	2.8E-04	1.0E-04
Natural forces/earth movement	1.2E-05	1.3E-05	8.0E-06
Natural forces/heavy rains – floods	1.1E-05	1.2E-05	3.0E-06
Total threat frequency	8.8E-04	8.2E-04	4.2E-04
Occurrences per year in the US	1.2	1.1	0.5

The first column in Table 5 lists the causes identified as threats by Keystone. As Table 4 and the discussion in Section 2.2.3.4 have noted, other potential threats might be relevant, but because this is the scope that was addressed by Keystone, the present discussion focuses on this listing. The remaining columns in Table 5 present failure frequency, with the first being the baseline listed in Appendix A of Appendix P (Keystone XL FEIS)[7e]. The next two columns present the corresponding outcomes based on reanalysis of the PHMSA database via queries directed either at all spills or at spills in SYSPRT = 5, as outlined in the discussion of Table 4.

In comparing the entries row by row, it is apparent that the results of the queries do not match exactly those found by Keystone, with the same outcome for each of the queries run. In some cases, the outcomes match those for Keystone for one or the other query, but in no case were all matched consistently. It is conceivable that differences in how nulls were addressed could underlie the disparities, because it was not clear from the Keystone reporting that this was considered and, if so, what was done; the results developed for this review did not consider this possibility for the many nulls in the GEN_CAUSE and CAUSE fields. It is also possible that more careful analysis of the other fields could identify additional incidents that could be included in other threat categories. It is equally possible that incidents associated with "other outside force damage" or

other cause subcategories were embedded in the Keystone analysis, but neither of these possibilities was addressed in Keystone's reporting; therefore, they were not explored.

Regardless of the cause for the differences, as noted earlier in regard to Table 4, the net effect of including nulls is to decrease the incident/spill frequency by as much as a factor of two. But once a spill has occurred, consideration of its likelihood is a moot point. As such, whether the number of occurrences per year in the US as listed in the bottom row of Table 5 is 1.2, 1.1, or 0.58 (or twice that number due to nulls) becomes irrelevant. It follows that spill prevention must be the first line of defense, with viable protection and mitigation in place in the event that a spill occurs.

Keystone used adjustment factors to reduce failure frequency, motivated by differences in vintage versus modern pipelines. They cited such aspects as construction, line-pipe steel and pipe making, and the protection afforded by coatings and CP. The use of SME-determined factors in this context is a common practice, and the process was considered subjective by the consultants supporting Keystone's analysis. But while subjective, use of SME-derived adjustment factors reflects the observation that the PHMSA database used to quantify spill frequencies represents historic practices, and only recently is being populated by incidents that better reflect the clear benefits that accrue to the PHMSA's 57 Special Conditions[7a] and other recent changes. Thus, engineering judgment is appropriate to better understand and estimate rates for time-dependent or infrequent events for the Project.

Section 2.1.2, Threat Assessment and Implications, evaluates the approach used from a pipeline perspective and discusses ways to modify incident rates from a phenomenological perspective. That discussion notes the need to uncouple specific threats and other aspects and makes clear that an averaged incident frequency is inappropriate in applications to localized drivers for failure. That view is tempered by the observation that site-specific concerns can be evaluated provided that the localized threats are adequately characterized. The quantitative approach of this section is tantamount to what Keystone has done – namely, estimate the likelihood of localized failures, such as landslides, and apply those outcomes over the interval threatened, which can be presented as a localized average rate per mile. That said, it is inappropriate to represent the integrated effects of such rates normalized over the length of the pipeline. As such, Battelle does not concur with statements expressing an averaged spill frequency, such as 2.2 spills over 10 years for the entire pipeline. That practice does not help focus preventive, protective, or mitigative actions at the specific locations along the pipeline. Therefore, an alternative risk assessment approach should be adopted if Project construction is approved by PHMSA. At that time, Keystone should utilize a common risk assessment technique wherein incident likelihood is assessed considering the benefits of alternative, preventive, protective, and mitigative features in place.

2.2.4.5 Summary, Conclusions, and Recommendations

The incident frequencies for the major threats to the pipeline considered by Keystone were assessed. It is noted here (as was pointed out in regard to Table 4 and Section 2.1.2) that a quantitative rationale should be presented for causes that have not been recognized as threats. This should be done with the realization that a pipeline system is much more than the lineal portion traversing the RoW. In addition, Keystone should detail their data screening process and the method(s) to deal with nulls, so that a simple query could replicate the baseline frequencies on a threat-specific basis. As described by Keystone, and validated in part by this review, it appears that Keystone employed a query process using the CAUSE and GEN_CAUSE fields to obtain their cause/threat results. Further, it appears that their outcomes exclude the facilities that are an essential element of any pipeline system. Therefore, Battelle suggests that if PHMSA approves this Project, the Risk Assessment should be recast in a more generic setting, as noted in Sections 2.1.1 and 2.1.2. While currently restricted to use by government agencies and selectively by operators, a better approach would capitalize on the PHMSA National Pipeline Mapping System website to geo-locate the historic spill records as the means to better quantify localized threats.

A related observation is that sensitivity analysis apparently was not used to understand underlying drivers for incidents by Keystone when estimating spill frequencies. Such analysis could help to identify localized threats. Further, although Keystone might have relied on SMEs to help quantify infrequent events like flash floods, general flooding, landslides, and so on, the scope and results of such activity are not clearly evident.

Finally, in regard to expressions of average risk, care should be taken when stating a US threat rate or a state-level incident rate because this downplays the absolute importance of potentially large localized and/or periodic events. This practice does not help focus preventive, protective, or mitigative actions at specific locations along the pipeline, so an alternative risk assessment approach should be adopted if the PHMSA approves construction. At that time, Keystone should assess incident likelihood considering the benefits of alternative, preventive, protective, and mitigative features in place. Recognizing that Appendix C of 49 CFR 195 requires assessment of both the need for and the effectiveness of preventive and mitigative safety features, changes to deal with any shortfall at that time could be very expensive. Thus, although not typically considered nor required by the regulations at this time, prudence suggests that sufficient detail be considered if and when the Project moves forward.

2.2.5 Total Spill Volume

2.2.5.1 Introduction

The spill volume is an essential input to fate and transport and environmental consequence modeling because larger spills are more likely to affect sensitive areas and cause grater environmental damage. Thus, an accurate understanding of spill volume and its likelihood as a function of the threats is an important consideration. Because the Keystone assessment apparently focused on spills along the RoW, this subsection retains that focus. Keystone quantified spill volume in regard to the PHMSA database. They also quantified spill volume using a numerical model that simulated the pipeline, including the valves and the effects of elevation over the length of the pipeline segment considered. This subsection addresses outcomes in regard to the PHMSA database.

Keystone considered many performance metrics in assessing incident (and equally spill) frequency, with care needed to ensure that the correct metric is used for the application at hand. One metric considered was spill frequency per mile of pipeline, which was quantified in statistical terms as the median of the sample, as well as the maximum for the database. Such statistical parameters can be calculated relative to each of the metrics considered. Other performance metrics included spills per-year per-state and spill volume per pipeline mile-year, which has been multiplied by the mileage of pipe for the US part of the Project to give an average volume lost per year for the proposed Project.

2.2.5.2 Objective and Scope

For spill frequency, the first objective was to replicate the outcomes of Keystone's spill volume analysis, and the second objective was to expand the quantitative analysis of spill frequency by separating the spills along the pipeline RoW from those within the facilities. These results serve as inputs to the fate and transport and consequence portions aspects of risk.

2.2.5.3 Approach

The approach relied on queries of the PHMSA database for the interval from 2002 to 24 August 2008 (as used in the Keystone Risk Assessment) for each of their threat categories, leading to estimates of spill frequency relative to the corresponding pipeline mileage. Initially, various queries sought to reconstruct the spill volumes associated with the frequencies in Table A-2 of the Keystone Risk Assessment (Appendix A of Appendix P, Keystone XL FEIS)[7e]. Later queries were used to determine the spill volume due to pipeline threats for comparison with the spill volume associated with facilities and other system threats. This query scope was motivated by the review in Section 2.1.1, where spills at facilities were noted as easier to detect and remediate and

were generally smaller than those at remote sites along the RoW, and the other reasons cited in regard to spill frequency.

Before the queries were run, the data in the PHMSA database were aggregated for onshore transmission with the data binned into spill volume categories, and the units were harmonized in terms of barrels. Queries then determined spill volume by threat category, in reference to all spills, spills for facilities and system components, and for the pipeline in the manner detailed in Table 4. This was done to better understand the complete pipeline system.

2.2.5.4 Analysis, Results, and Discussion

The PHMSA database provides fields for entries that cover the spill unit (as barrels or gallons US), the spill volume, and the recovered volume, for the interval from 2002 to 24 August 2008. This interval was used because it was current to the period that Keystone did their risk assessment. In regard to incident occurrences and spill frequency, exactly how Keystone queried this database is unclear. However, it is reasonable to assume that early in their process, they considered using all spill data, which amounts to slightly fewer than 2,500 records. Regardless of their starting point, they binned their data to quantify the frequency distribution of spill volumes and determined that the median spill size is three barrels. In addition, they estimated that the probability of a spill being less than 1,000 barrels is 95 percent, and that the probability of a spill being less than 10,000 barrels is 99.5 percent (see Section 5.5 of Appendix P[7e]). Finally, based on the PHMSA database, they state that the historical maximum spill size is 49,000 barrels.

Table 6 summarizes the results of queries run to quantify the distribution of barrels lost for each scenario. Because the spill volumes range from smaller numbers at lower likelihoods up through nearly 50,000 barrels at the maximum, the choice was made to report sufficient detail to discriminate the losses over this range.

The second column in Table 6 presents the outcomes of an assessment comparable to that just noted, where the query was run on all spills. Aside from round-off differences, the tabulated percentages are comparable to Keystone's at 1,000 and 10,000 barrels lost. The remaining columns in Table 6 consider queries run on other criteria that could be used to estimate the spill frequency distribution. The third column considers spills in regard to SYPPRT = 5, which is Onshore Pipeline Including Valve Sites. Compared to all spills, the results show a much lower percentage lost at 1,000 barrels, whereas it is actually higher at 10,000 barrels. This indicates that there are more spills in the 1,000-to-10,000-barrel range for mainline pipelines, which can have important implications when considering additional preventive and mitigative measures.

Table 6. Cumulative probability of fewer barrels being lost in a spill

Barrels Lost	Percentage Barrels Lost					
	All Spills	Pipeline and MLVs	Pipeline Corrosion	Pipeline Outside Force	Pipeline Material / Weld	Incorrect Operations
1	28.9%	8.4%	8.4%	3.6%	15.7%	4.0%
5	57.0%	16.3%	15.8%	6.4%	28.4%	5.9%
10	64.6%	25.1%	24.8%	10.0%	38.2%	7.9%
20	72.0%	35.2%	37.6%	15.7%	48.0%	9.9%
50	79.6%	47.8%	56.4%	24.3%	52.9%	15.8%
100	84.2%	56.7%	66.3%	32.9%	62.7%	22.8%
300	89.8%	70.2%	79.2%	54.3%	71.6%	40.6%
1,000	95.1%	85.3%	92.6%	75.7%	85.3%	68.3%
3,000	97.7%	93.7%	98.0%	90.7%	90.2%	86.1%
7,500	99.4%	98.6%	99.5%	100.0%	97.1%	86.1%
10,000	99.5%	99.1%	99.5%		99.0%	99.0%
30,000	99.9%	99.6%	99.5%		100.0%	
33,000	100.0%	100.0%	100.0%			
49,000	100.0%					

The data for the Pipeline Corrosion query are similar to that for the All Spills case, but for the group of threats consisting of Outside Forces (Human Disturbance and Natural Forces), a much larger percentage of the spills fall between 1,000 and 3,000 barrels, with the maximum recorded at 7,500 barrels. Such maximum values are not absolute, but simply the largest spill to occur over the 7-year period covered by the database.

In regard to the All Spills and Incorrect Operations columns, all the probabilities shown in Table 6 are for spills involving the pipeline and MLVs. Results for Incorrect Operations are tabulated for All Spills rather than for just the Pipeline/MLV dataset because parsing on just Pipeline/MLV reduced the sample size to 13 records, which is too small a sample to be considered meaningful.

The Keystone analysis often mentions that the median spill size is three barrels and builds on that volume when discussing the probability of the environmental impacts associated with this small spill. Table 7 presents the results for the median, mean, and maximum spill sizes, which confirm that the All Spills case does have a small median spill size on the order of three barrels with the 29 “no-spill” records included but the nulls excluded. Where small differences exist in the values presented by Keystone and those in Table 5, they likely reflect accounting for the nulls (unreported spill volumes). Table 7 shows that, with the exception of facilities in regard to pumping stations, the other parsing of the spill data results in much higher median spill volumes. Likewise, with the exception of facilities in regard to pumping stations, the mean values are larger, although the difference relative to All Spills is less than a factor of 3.

Table 7. Median, mean, and maximum spill sizes for various spill categories

Metric	Barrels						
	All Spills	Pipeline and MLVs	Facility	Pipeline Corrosion	Pipeline Outside Force/TPD	Pipeline Material/ Weld	Incorrect Operation
Median	3	50	2	30	258	21	20
Mean	293	738	160	412	859	1,394	398
Maximum	49,000	33,010	49,000	33,010	7,500	31,322	10,380

Figure 11 plots the cumulative frequency trends for each of the circumstances quantified in Table 7. The x-axis in this figure is the spill volume, which is plotted using a log scale to better discriminate the various cases considered. The y-axis is cumulative frequency, running from zero up through 100 percent, which in this figure represents the percentage of cases with fewer barrels spilled.

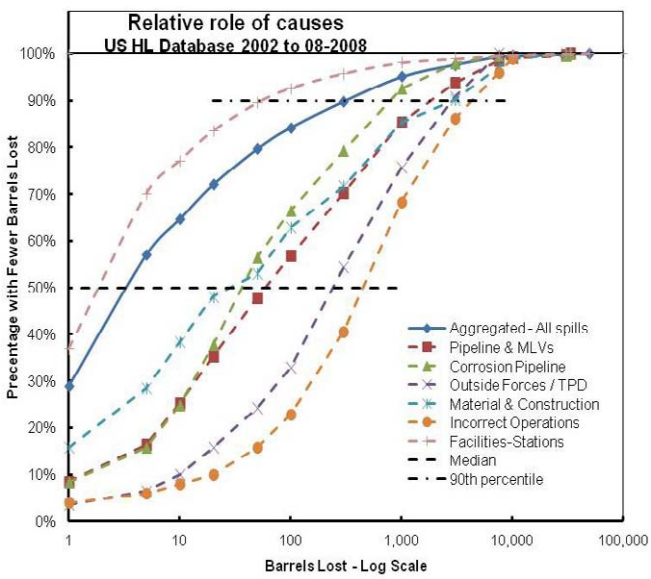


Figure 11. Plot of barrels lost for various threat groupings

The All Spills case used as the benchmark by Keystone to characterize spill volume underestimates the cumulative loss probabilities. Figure 11 shows that all trends except that for the pumping stations lie to the right of the All Spills trend. Inspection of this figure indicates that parsing on the Incorrect Operations, Natural Forces/TPD, and Pipeline/MLV General Cause categories leads to larger values for the median and at the 90th percentile. Accordingly, there is the potential for much larger spills than has been considered in regard to the All Spills benchmark case.

Figure 12 is comparable to Figure 11 except that the number of trends is reduced to contrast the All Spills benchmark to parsing of the Pipeline/MLV and the Facilities-Station General Cause datasets. Also shown above the x-axis are the interpolated median and 90th percentile spill volumes for these General Cause categories. As usual for such comparisons, the most significant differences are in the median spill volumes. Rounding the smaller volumes leads to median spill volumes for the station at two barrels, for all spills at three barrels, and for the pipeline at 50 barrels, with the difference being significant for the Pipeline/MLV portion of the pipeline system, which characterizes the environmental exposure along the RoW.

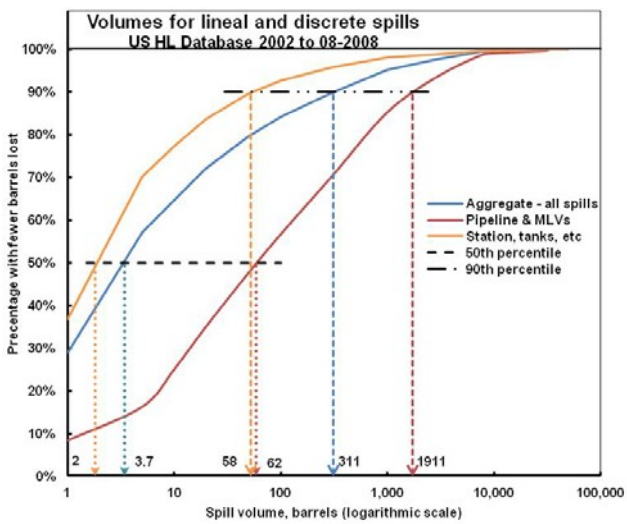


Figure 12. All Spills contrasted to Pipeline/MLV and Station spill distributions

2.2.5.5 Summary, Conclusions, and Recommendations

Adopting the All Spills outcomes relative to those for other choices based on the General Cause categories in the PHMSA database (as done by Keystone) significantly underestimates the median spill volume relative to the environmental exposure along the pipeline RoW. Trending of the cumulative distributions of spill volumes shows that the Keystone benchmark under-predicts the likelihood of larger spills except at the higher percentiles, where all trends converge. The results indicate that parsing on the Incorrect Operations, Natural Forces/TPD, and Pipeline/MLV General Cause categories leads to larger values for the median spill and at the 90th percentile. Accordingly, there is the potential for much larger spills than has been considered relative to the All Spills benchmark case. Because such trends represent a system-level analysis of historic incidents that typically involve much smaller-diameter line pipe as compared to the Project, there is the potential for still larger spills where unique site-specific threats exist along the RoW. Thus, if Project construction is approved by PHMSA, consideration should be given to a broader assessment of the environmental consequences relative to the probability of occurrence and spill volume, including the potential implications of pipe diameter.

2.2.6 Conclusions and Recommendations

Adopting the All Spills outcomes relative to those for other choices based on the General Cause categories in the PHMSA database, as was done by Keystone, significantly underestimates the median spill volume relative to the environmental exposure along the pipeline RoW. Trending of the cumulative distributions of spill volumes shows that the Keystone benchmark under-predicts the likelihood of larger spills except at the higher percentiles, where these trends converge. The results indicate that parsing on the Incorrect Operations, Natural Forces/TPD, and Pipeline/MLV General Cause categories leads to order-of-magnitude or larger values for the median spill, and a factor of 5 or larger values at the 90th percentile. Likewise, it appears that Keystone has ignored the nulls, which indicates a higher spill frequency than has been estimated. If the historical data are relevant to the Project, there is the potential for more frequent spills as well as for larger spills than was considered in regard to the All Spills benchmark. In addition, because such trends represent a system-level analysis of historic incidents that typically involve much smaller-diameter line pipe compared to the Project, there is the potential for still larger spills where unique site-specific threats exist along the RoW.

If PHMSA approves Project construction, consideration should be given to a broader assessment of the environmental consequences relative to the probability of occurrence and spill volume, with consideration of the potential implications of pipe diameter. Spill analysis should focus on the threats associated with the major General Cause categories such as facilities, the pipeline, and its system components, which should present a clearer picture of the spill potential for the Project. In turn, this should facilitate focusing the spill prevention, protection, and mitigation where it is most relevant.

2.3 Outflow Analysis and Placement of Valves

Consideration has been given to quantitative analyses or trending to perform an assessment in regard to the viability of protective or mitigative aspects, with too little detail initially available to support quantitative review. Subsequently, in response to inquiries from Battelle, Keystone provided analysis outcomes and discussed their valve placement process in sufficient detail to assess its viability. The simulation data that Keystone provided quantified the effectiveness of the protection achieved by placing valves at critical locations along the RoW, and its 20-mile spacing in between. Effectiveness can be assessed in this context by contrasting the cumulative distribution of spill volume for the initial placement plan (circa July 2009) with that after additional valves were deployed, and the locations modified, in response to PHMSA Special Condition 32 circa 2011. Figure 13 trends these distributions.

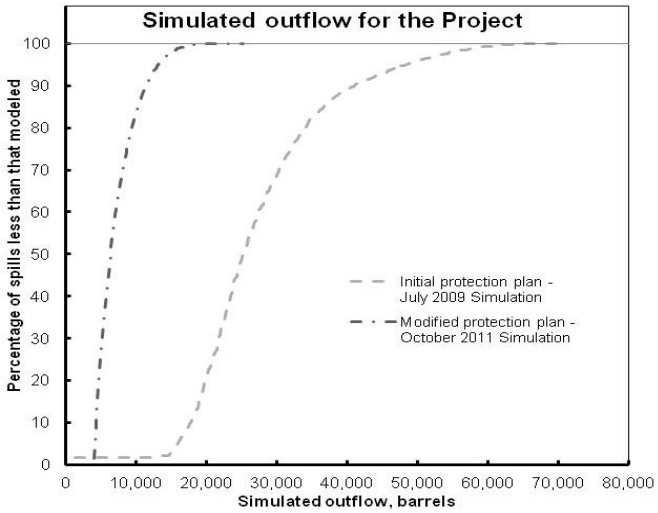


Figure 13. Protection afforded by values for the final versus initial valve placement

The results in Figure 13 represent the cumulative distribution of spill volume with the relative frequency (or number of occurrences) shown on the y-axis as a function of the total spill volume (detect, control, outflow) shown on the x-axis. In this format, a y-axis value of zero can be viewed in a practical context as no spills over the range of the volumes plotted, whereas a y-axis value at one means that all spills had a volume less than that found on the x-axis as the trend reaches unity on the y-axis. Two trends are shown. The trend on the right is for the initial placement plan; the trend on the left is the spill trend for the revised plan, representing what Keystone terms an optimized plan that involved additional valves and modified locations.

It is apparent from Figure 13 that the simulated releases for the updated plan achieve about a four-fold reduction in spill volume, with the upper bound on the worst-case spill being about 15,000 barrels in contrast to about 60,000 barrels for the initial plan. It is also apparent that the distribution for the new plan rises sharply as compared to the original plan, which means that the outflow has been broadly reduced for the cases simulated.

While Figure 13 indicates that the changes made in the number and placement of valves have been effective, the question remains: Would additional values or changing valve sites lead to still greater reduction? The total volume of a spill shown in Figure 13 is the sum of the outflow after closure that can be limited by valves, the volume lost in the time interval prior to confirmed detection, and the volume lost during shutdown and the valve closure sequence. For the Project, the time interval is 12 minutes at a minimum, which at full flow corresponds to about 90 barrels. This is a small component of the total spill volume for the worst case evident in Figure 13, which is equally so for most any other spill. This means that valves and their placement are central to spill control. Accordingly, this review focuses on the number of valves and on optimizing their placement, balanced with the risks of minor spills due to valve maintenance and the concern for major spills

due to possible valve malfunction. Specifically, the process used to place values – aside from the practical issues such as power and access – was evaluated relative to minimizing total spill volume relative to critical/high-value resources.

Evaluation of the process used to place values indicates that the algorithm used by Keystone targets the minimum total spill volume and considers issues such as upslope location to minimize local outflow to critical ecosystems and resources. As such, their process is viable, and its outcome meets the expectations of 49 CFR 195 while affording effective control and protection for the environment.

The model used to estimate outflow volumes is based on sound mathematical principles, the Bernoulli Equation, and the assumptions made about crude oil available for release are conservative. While it was not possible to confirm the results, the process used to place the valves is correct. The model and the process that were used to ensure that valves are placed to minimize the total outflow from a breach appear to be correct and should continue to be used.

It is noteworthy in this context that the adage "a little is good, so a lot is better" is not applicable in regard to valves. A liquid pipeline is a "hard" system due to the largely incompressible nature of fluids in their liquid phase. For this reason, inadvertent malfunction of a valve can cause significant pressure pulses, leading to an overpressure state if the flow is not managed. The more valves, the greater the chance for such upset states, which means valves are placed in liquid pipelines to minimize the outflow in the event of an incident. It is precisely this reasoning that underlies the language in 49 CFR 195 dealing with valves. Aside from concerns for malfunction, the more valves, the greater the chance for seals, seats, and packing to incur problems, even when subject to regular maintenance. Battelle has reviewed the practices and algorithms used by Keystone to minimize outflow and finds them consistent with the state of the art or better. On this basis, and in light of the effectiveness of the outcome achieved in Figure 13, Battelle considers the existing plans appropriate.

In the event that this Project moves forward to PHMSA oversight, valve placement as directed within their 57 Conditions is again subject to review and acceptance by the PHMSA. Based on that observation and the present review, Battelle determines that the current plan is viable in regard to the expectations of a Presidential Permit. It is recommended that portions of the outflow analysis be redone to reflect the new route and thereby ensure that the results are not significantly different from the results presented at the time the FEIS was published.

Aspects of the mitigation plan also were reviewed, although such analyses are in practical terms less quantitative. Keystone has committed in writing to locate response teams local to critical ecosystems and resources and to reduce the response time to two hours in such cases (as compared to the minimum 12 hours of 49 CFR 194). In contrast to similar recent permits, it follows that

these response plans are viable regarding the unique issues faced by this Project and the expectations of a Presidential Permit. Key in this context is the follow-up on these plans in the event the Project moves on to PHMSA oversight.

2.4 Fate and Transport

2.4.1 Introduction

The previous sections established criteria to assess the Keystone Risk Assessment and evaluated the methodology used and the threats, spill frequencies, and spill volumes. The next logical step is to consider the fate and transport of crude oil from an engineering perspective in the event of a release. The analysis and discussion regarding fate and transport develops in reference to the related assessment done for the Project[7e].

Because environmental transport and fate of petroleum products depend on many factors, modeling transport and fate is a complex exercise. In addition to work presented in the Risk Assessment, evidence of the complexity involved with fate and transport specific to the Project can be found in E^{x}ponent's report[2] and in Annex F of Battelle's original third-party review (January 2012). Major factors affecting the behavior and fate of crude oil in the environment are: (1) the nature of product spilled; (2) the volume and rate of the spill; (3) the physical, chemical, and biological characteristics of the receiving environment; (4) the weather conditions at the time of the spill; (5) the amount of time elapsed until detection; and (6) the adequacy and timing of response activities. Once a spill occurs, the focus turns to consequences and mitigation, with consequences being dictated by the amount spilled, the timing and extent of the spilled product (transport and fate), and the adequacy of the response capabilities. Of particular importance is the receiving environment (e.g., water and soil attributes, slope, gradient, topography, underlying, geology, and weather and climate), which in turn impacts the dispersion, fate, plume size, and transport. Fate and transport in this context can be viewed as the bridge between the prior spill frequency and volume discussion and the consequences as impacted by environmental transport and fate of the spilled product.

This section considers the adequacy of the qualitative description of (1) the physical and chemical processes that act upon the spilled product in the environment, and (2) the theoretical distances the product could travel based on E^{x}ponent's reporting, which provides quantitative estimates via screening-level modeling of transport and fate, and potential consequences of that transport to the environment. E^{x}ponent's report details the underlying quantitative estimates of the potential transport of spilled product to groundwater for a large volume spill (rupture) and a small leak. The report also briefly discusses the potential transport of oil in a river, along with recommendations going forward as the requirements of 49 CFR 195 are implemented.

2.4.2 Objective

The objective is to determine whether environmental transport and fate is sufficiently addressed by the Keystone Risk Assessment and to determine if the analysis of transport and fate was sufficient to identify and categorize the risk of a potential spill to the surrounding environment in order to "determine the need for additional mitigation measures" (FEIS, 3.13, p. 102-103). Where gaps are identified, the results of E^{x}ponent's report are considered as a means to bridge those gaps.

2.4.3 Approach

This section makes use of the consequences information in the PHMSA database to provide engineering perspective for fate and transport considerations. Thereafter, criteria to assess fate and transport are evaluated relative to the benchmarks established early in this report. Finally, aspects of the fate and transport analysis included in the Keystone Risk Assessment are evaluated in balance with these criteria.

2.4.4 Implications of the Historical Data

Understanding past trends in regard to spill consequences and the related trends in environmental impacts is instructive when evaluating the fate and transport of spilled product into its surrounding environment; when assessing the need for preventive and protective actions; and when planning mitigative actions. While the likelihood of a spill can be minimized by preventive actions, it is unreasonable to assume a spill will not occur.

Consistency with the timeframe considered in the Keystone analysis leads to a focus on reported spills in the PHMSA database over the interval from 2002 to August 2008, the results of which can be found in Annex F of Battelle's original third-party review (January 2012). A focus on the environmental exposure along the pipeline RoW leads to consideration of 568 spills. The database tabulates impacts to high-consequence areas (HCAs), groundwater, flowing waters, and soils in reference to liquid petroleum products, crude oil, liquefied natural gas, other liquefied gases, and unknown products. Because the liquefied gas categories are by definition gaseous at ambient conditions (they are called out as CO_2/N_2/Other non-flammable nontoxic fluids and Highly volatile liquids/Other flammable or toxic fluids, which are a gas at ambient conditions), these can be expected to disperse to the atmosphere and so have nominally little impact in the present context.

The database indicates that the highest number of HCAs impacted by spills occurs for crude oil, followed by other liquid petroleum products. The number of spills that required remediation for surface waters was largest for crude oil, while the number of spills that required remediation for groundwater was largest for other liquid petroleum products. Remediation of soils and vegetation were most often necessary after crude oil spills. Of the 568 spills in the database, soils are most frequently impacted for all spills, but almost always in the case of crude oil spills (though often

these spills are small in volume). Review of the PHMSA database shows 153 spills to water bodies, 62 of which occurred due to crude oil spills. The volumes of 226 crude oil spills to water in the historical data (2002-2008) range from less than 1 barrel to 6,909 barrels, 27 of which were over 100 barrels and 10 of which were over 1,000 barrels.

Figure 14 presents the distribution of RoW spills by the media contaminated and by spill volume. The number of spills considered was 557, which is less than the total records available because spill volumes of zero were excluded. It is evident that the more than half of the spills are less than 100 barrels and that the distribution of spill volumes does not appear sensitive to the type of media contaminated, which is logical if the cause for the release is random along the RoW.

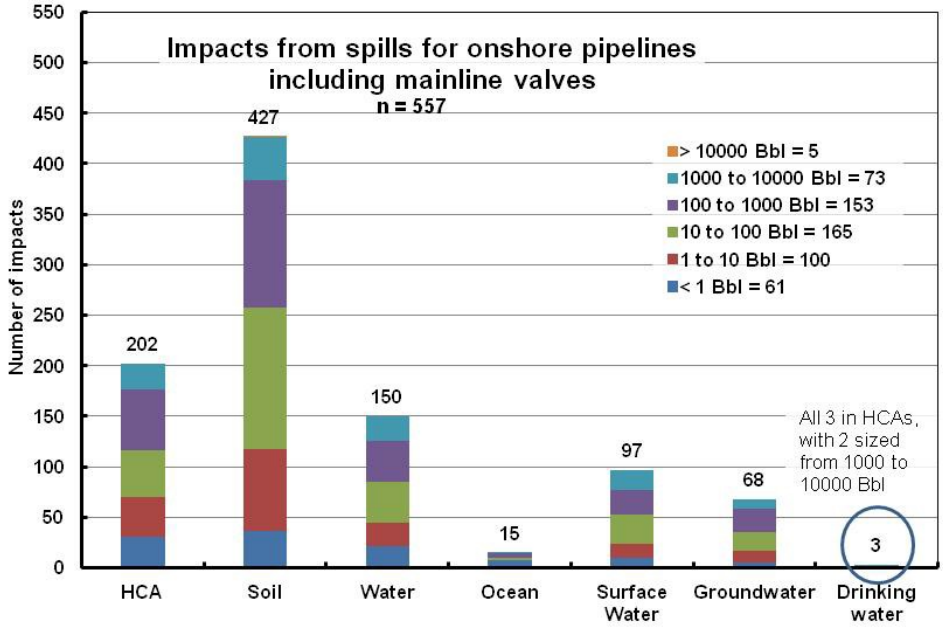


Figure 14. Number of impacts to HCAs, soils, and water

Annex F of Battelle's original third-party review (January 2012) considers the relationship between number of barrels lost and cubic yards of soil impacted for all liquid hydrocarbon spills in HCAs, and number of barrels lost and cubic yards of soil impacted for all crude oil spills in HCAs. Though almost one-third of the spills are in areas defined as HCAs, there is no relationship evident between spill volume and number of barrels lost in HCAs, which suggests such a relationship, if any, could be complex. This reinforces the need to understand environmental factors that influence the transport and fate of released materials through the environment.

2.4.5 Review Criteria

Criteria that serve as a basis to assess the scope and adequacy of the fate and transport aspects considered in the Keystone Risk Assessment include consistency with prior Presidential Permits

and with other EISs filed in the context of pipelines. However, there is scant mention of risk assessment, with fate and transport getting little attention in recent Presidential Permits. For example, the more than 500 pages documenting the environmental analysis of one recently granted Permit[21] used the term "fate" just once, and did so in introducing the impact of spills on the environment. Specifically, the text there stated that

> *…when an oil spill occurs, the resulting environmental impact depends on a number of factors, including fate and behavior of the spilled oil (i.e., potential for a spill reaching an environmental receptor)…*

The ensuing coverage simply noted other potential factors for the impact of a spill. The environmental analysis section of that FEIS also cited work reported in 2003 by the National Research Council that involved fate in regard to oil in the sea. However, that citation was made in context of assessing impact magnitude, not fate. In contrast to fate, the term "transport" is widely used in the just noted section on environmental analysis[21]. But that usage spoke to the transported product within the pipeline, referring to the function of an intact pipeline, not the movement of the product in the pipeline's surroundings due to a leak.

It follows that, in general terms, prior environmental analyses tend to focus on an assessment of the environmental threats and the identification of the impacts by location and ecosystem and/or resource impacted. Thus, if consistency with prior Presidential Permits is adopted as the template to assess the fate and transport aspects as considered in the Keystone Risk Assessment, it could be judged equal to or better than that of the past.

Other criteria also were noted in parallel to consistency, including Federal agency expectations. A comment letter from the EPA to the DoS concerning the SEIS for the proposed Keystone XL Project focuses specifically on fate and transport. That commentary states[22b]:

> *Predicting the fate and transport of spilled oil is also important to establish potential impacts and develop response strategies. While the SDEIS provides additional information about the different classes of crude oils that may be transported, we recommend the Final EIS evaluate each class of crude that will be transported, how it will behave in the environment, and qualitatively discuss the potential issues associated with responding to a spill given different types of crude oils and diluents used.*

Finally, in general, the "Environmental Consequences" section of any EIS in regard to NEPA should provide a technical/scientific basis to identify significant impacts and ensure that the statement informs decision-makers and the public concerning the severity of the potential consequences of the proposed project.

The EPA commentary identifies the need to: (1) evaluate each class of crude to be transported, and (2) assess how it will behave in the environment, with qualitative consideration of the potential issues associated when responding to a spill given the different types of crude oils and diluents used. While the objectives of Battelle's work targeted fate and transport from an engineering perspective, work targeting the EPA's recommendations was done by E^{x}ponent in parallel with Battelle's work. That work has been documented in E^{x}ponent's report.

2.4.6 Analysis and Outcomes

Understanding risks and impacts from a potential release requires a quantitative characterization of transport and fate. A key finding of this review is that the Risk Assessment in the FEIS provides only brief qualitative descriptions of the transport and fate of oil in the various receiving environments along the pipeline route. Additional quantitative data and analyses are necessary to characterize the risks and impacts of a potential spill to the surrounding environment. E^{x}ponent's report provides an assessment of spill behavior, which was not provided in the Risk Assessment (e.g., assessment of whether the spill remains near the surface or sinks deeper into an aquifer).

The physical, chemical and biological processes related to transport and fate are described in some detail in the Risk Assessment and FEIS. However, there is limited information and quantitative data specific to heavy crude for estimating the size of potential spills to the surrounding environment, either in general along the RoW or for specific critical pipeline segments (CPSs). As the Risk Assessment correctly points out, transport and fate are dependent on spill volume and type of crude, as well as leak rate and the characteristics of the receiving environment. Consequently, it would be a difficult task to model transport and fate for the entire length of the pipeline in general terms. E^{x}ponent's report provides example analyses using empirical data and screening models. The focus of Exponent's assessment is to evaluate whether spilled oil may travel further than the 5 miles used in the Risk Assessment to judge potential for exposures of HCAs or of areas not yet designated as HCAs that might be considered sensitive areas. The results of E^{x}ponent's evaluation are subsequently used in their report to evaluate sensitive areas at and downstream of small stream crossings (less than 100 feet wide at the high water line).

Because the Risk Assessment did not quantify spill impacts to sensitive environmental receptors, additional consideration should be given to expanding the analysis that E^{x}ponent has performed as the proposed Project continues toward agency oversight by the PHMSA. In this regard, data, analysis, and modeling results from the segments of the Keystone pipeline currently in operation could prove beneficial. Such work should be considered as needed to evaluate the extent of significant environmental risks, including the area of impact and the communities, habitats, and resources within that area, and to inform recommendations on response and preparedness.

The original Risk Assessment[4], also Appendix P of the FEIS[7e], was updated in October 2011[5] based on comments received concerning the draft EIS (DEIS). In support of their analysis, Keystone developed a model designed to estimate the spill volume should a release occur over any 100-foot interval along the pipeline (now Appendix Q of the SEIS). In addition to presenting historical data from the PHMSA database, the updated Risk Assessment[5] also modeled worst-case discharge volumes over 100-foot intervals along the pipeline. For reasons related to security concerns, such details were not publicly available, but the process used by Keystone did consider these results in relation to available elevation profiles to assess the best positioning of the valves. Similarly, profile and geology should be considered in order to assess the potential horizontal and vertical spread of crude oil into surrounding ecosystems, which would occur if/when the Project moves to agency oversight by the PHMSA.

Several examples of models used from historical spills that present the transport, fate, and behavior of spilled oil can be found in the literature (see E^{x}ponent's report for an example of such a model). Relating the results from the worst-case discharge scenario to ecosystems along the pipeline route is crucial to understanding the risk and potential consequences of a release to ecosystems along the pipeline route, and should underpin the environmental response plans for the Project.

In the Risk Assessment, transport and fate of crude oil are discussed with respect to two general media types: soil and water. While the Risk Assessment correctly points out that oil tends to remain in discrete patches and disperse more slowly in soils than in water, there is great variability between soils types due to varying hydrology and soil characteristics. In general, the spread of oil is greater in sandy soils than in soils with higher organic content. Because the pipeline crosses large areas where the soil is more permeable and the water table is shallow, and because stakeholder concern is greater due to the potential impacts to drinking water resources in those areas, quantitative transport and spread analyses should be addressed under agency oversight by the PHMSA, to determine the possible fate of crude oil. As pointed out above and in E^{x}ponent's report, overland flow of a large spill will depend on many factors, including topography, ground cover, soil type, product characteristics, meteorological conditions, and other factors that affect infiltration, evaporation, and flow of spilled product.

For the purposes of conducting a screening analysis to evaluate how far oil might flow over land during a large spill, upper-bound values on how far product might spread were calculated using simplifying assumptions by E^{x}ponent. The report also discusses a screening-level analysis that is illustrative for the purposes of groundwater contamination and infiltration (E^{x}ponent report, Figure RB01a[2]). It would be instructive to understand possible overland transport under various conditions because of the large diameter of this pipeline, its high flow rate, and the potentially large volumes that could be released prior to detection and in the interval between spill confirmation and control. Additional local valve placement affords little protection over short segments of the

pipeline, and in fact could increase risk because of the greater chance for seals, seats, and packing to cause a slow small leak in the vicinity of an HCA.

In general, prevention and mitigation must be relied upon when dealing with short CPSs over an HCA or narrow stream. Because the entire pipeline has been designed as if it were an HCA, increased prevention relative to the remainder of the pipeline implies using even heavier wall thickness over such CPSs. The mainline wall thickness is effective in preventing incidents due to the TPD threat, whereas the mandated interval for ILI effectively identifies other key threats before they become an integrity concern. Because risk is not effectively reduced with either prevention or protection, risk must be managed via mitigation local to such sites. It follows that consideration should be given to targeting mitigation at sites where the local receptors lead to significant environmental consequences.

The FEIS states that crude oil released to sandy soils will be visible to aerial surveillance, which is confirmed by E^{x}ponent's model analysis of a small spill. Their analysis shows that the worst case for surface detection of a small spill, compared to that of a large spill, would be detectable at the surface within about a month. E^{x}ponent points out that "because of the duration between the spill and when the lens is expected to impact groundwater, the development of a dissolved plume and subsequent transport is slow." Accordingly, small leaks can go undetected for longer periods of time, with 32 days determined by E^{x}ponent as the period prior to visual detection at the surface. This increases the possibility for transport of oil spilled from the pipe and the development of a plume. E^{x}ponent notes that plumes less than a mile long form over a period of about 10 years, implying that transport is relatively slow on land. Thus, even though detection at the surface takes about a month, the limited transport indicates that impacts to groundwater or soils before a leak is detected or visible by aerial surveillance will be limited in scale, and so more easily contained and mitigated. More frequent patrols would be effective in this setting to minimize and mitigate potential impacts if a RoW spill occurred.

Even though the high viscosity of the oil and its slow migration facilitate containment and cleanup, Keystone has considered additional preventive or mitigative measures beyond the protection afforded by valve placement. Key factors in this context would include: (1) areas where highly permeable soils exist and the groundwater table is at or near the surface; (2) remote areas of the pipeline that are not easily inspected or that will have heavy third-party traffic; (3) areas of steep terrain where larger volumes of oil could be spilled due to a steep incline of the pipe; and (4) the winter season, when snow is present and plants, which might otherwise be easily detected by aircraft, are absent. After considering such concerns, discussions during the course of this review indicate that because the full length of the pipeline is designed as if it transits an HCA, Keystone will focus on mitigation to address local CPSs. Further, Keystone has stated they will target

response teams in critical areas and will reduce the response time to two hours in contrast to the Code-required 12-hour period. Such aspects should remain in focus when the agency oversight shifts to the PHMSA.

Environmental transport and fate of crude oil into flowing surface waters is discussed in the Risk Assessment in the FEIS as it relates to possible impacts to downstream drinking water resources from benzene. Benzene is useful as a conservative metric of environmental toxicity and human health effects; however, by focusing the Risk Assessment on this particular lighter aromatic component of the product, Keystone has not directly addressed transport and fate of dilbit/crude and its various components to flowing water. Because the document focuses on benzene releases, ignoring the heavier components, their analysis is incomplete. Adequately assessing transport and fate of the crude oil remains an issue because, while the Keystone XL routing sought to minimize the number of water bodies crossed, "the Project will cross hundreds of perennial, intermittent, and ephemeral streams" (FEIS p. 4-7[3]), which could be impacted by a spill.

Environmental transport and fate of crude oil will vary depending on various stream characteristics, including velocity, stream-bed morphology, groundwater and tributary inputs, transient storage capacity, temperature, and benthic and pelagic biological communities. One of the major assumptions of Keystone's analysis is that complete and instantaneous mixing occurs in flowing waters. That assumption needs to be clarified with regard to the "general-case spill to flowing water." As pointed out above and by E^{x}ponent[2], analysis of transport and fate should consider crude oil in addition to modeling benzene toxicity. In light of Section 3.1 of E^{x}ponent's review, the crude oil being considered for this pipeline can be bracketed into heavy (diluted bitumen) and medium (synthetic crude oil) crudes, both of which are in the range of typical benzene concentrations for "typical crude oils." While the details remain to be finalized, depending on the implications of screening analyses, a more comprehensive transport model might be needed, with consideration given to physical attributes such as advection (downstream transport), dispersion (e.g., caused by turbulence), transient storage, and the effects of weathering.

While the Keystone discussion of spill likelihoods, occurrence intervals, and toxicity thresholds in relation to stream size is important (see Tables 4-2, 4-3, 4-7, 4-8, 4-9 and 4-10 of the Risk Assessment), other aspects are of concern. These include transport distances and fate of crude oil for various stream types and flow regimes, including pipeline segments that cross riverine habitats. Because model results are available for 100-foot intervals along segments of the pipeline and in relation to available elevation profiles, assessing the horizontal and vertical spread of crude oil to surrounding ecosystems is possible. Enbridge Energy's July 2010 spill from their 6B Pipeline, which is reported to have leaked about 820,000 US gallons of oil sands crude into Talmadge Creek (impacting 25 miles of stream habitat and about 100,000 cubic yards of soil), highlights the need to

understand transport and fate of crude oil to various types of streams to most effectively stage equipment and personnel.

The Risk Assessment correctly points out that the potential impacts to wetlands, lakes, and reservoirs from a crude oil spill depends not only on the quantity of oil released, but also on the specific environmental attributes of the water body it is released to. The Risk Assessment also points out that wetlands can vary greatly between seasons due to precipitation patterns and underlying hydrology. The discussion of standing water focuses on the amount of water necessary to dilute spill volumes below aquatic toxicity and drinking water thresholds. While toxicity is an important metric, it does not address transport distances or environmental fate of crude oil. For example, in the Risk Assessment it is assumed that the crude oil will float and its movement will be restricted; hence, it will be quickly discovered and cleaned up. While spills to environmentally sensitive areas are infrequent, they do occur. Furthermore, cleanup is not necessarily quick and can be influenced by seasonal factors. The spill from the GC2 pipeline oil spill detected 2 March 2006 on Alaska's North Slope illustrates each of these aspects, as follows: (1) an estimated 5,053 barrels of crude oil impacted 1.9 acres of tundra; (2) the leak occurred through a small 0.25-inch hole in a larger (34-inch) diameter pipeline (buried under a caribou crossing); (3) the spill is estimated to have been leaking for at least five days (when it was discovered by an operator due to its odor), although the exact duration is unknown; and (4) the spill occurred when the active layer of the soil was completely frozen, so the transport of the crude oil was limited and impacted only a small acreage. Seasonal and other influences on the transport and fate of crude oil illustrate the need to more broadly understand these aspects and to adequately identify the impact of potential crude oil spills into environmentally sensitive areas.

2.4.7 Summary and Conclusions

Understanding the transport and fate of crude oil in the event of a spill is crucial to understanding what mitigation and response measures are necessary to protect communities, resources, and sensitive areas along the pipeline route. As the Project moves toward PHMSA oversight, consideration should be given to additional quantitative analyses of transport and fate processes similar to the modeling and analysis presented in E^{x}ponent's report. That would help to better determine whether and where additional mitigation measures should be considered. Other sections of this review discuss proactive measures that could help limit the likelihood of a spill to sensitive areas, as well as leak detection systems, which could limit the amount, and hence the spread, of crude oil released. These too should be considered.

In discussions with the review team and the agencies, Keystone has stated that additional quantitative analysis on the transport and fate of the various classes of crude oil to be transported will be completed for all pipeline segments after the exact routing of the pipeline is decided and

within a mandated timeframe as required in 49 CFR 195, Appendix C of the Code of Federal Regulations (guidance for implementation of an IMP) and as regulated by PHMSA (11 and 27 October 2011, Houston). Keystone has also stated that they will implement the requirements of the IMP to the standards written in 49 CFR 195, as if the entire pipeline was routed through an HCA (as defined by PHMSA). As is the case for prior cross-border pipelines, this timeline leads to a situation where the IMP is not available for review. While that detail is not yet available, the results of E^{x}ponent's analyses do offer insight into the nature of the transported product and the potential impact of a spill. Their results indicate that the product did not pose unique concerns in comparison to other crude oil, with its transport being rather slow and so contained / mitigated, even in the event of a small leak that went undetected for some time. This does not offset the initial impact of a leak, but it does indicate that the impacts would be limited and can be mitigated in the same manner as for other crude oil pipelines.

In light of this review and the work of E^{x}ponent, the following major conclusions have been drawn:

- Analysis of the physical and chemical characteristics of the transported products indicates that they are within the bounds of typical medium to heavy crude oil, so fate and transport could be modeled as such.
- Surface spills of oil on land will tend to remain localized and will migrate slowly into the soil because of the high viscosity of this crude. Therefore, potential threats to groundwater will depend on water table levels, the amount of crude spilled, and response times.
- Analysis of transport and fate of liquid hydrocarbons in groundwater concludes that plumes of dissolved hydrocarbons in groundwater, to the extent they develop, will be on the order of hundreds of feet in length and will move relatively slowly. Analysis also shows that longer plumes can potentially occur under pumping conditions.
- For the purpose of identifying potentially sensitive groundwater areas, a set of criteria was proposed that includes distance from the pipeline (within 1,000 feet), water table elevation (within a few feet of pipeline), and the presence of clusters of domestic and irrigation wells.
- Spills into surface waters can be transported beyond the 5-mile distance used to identify sensitive environments (e.g., HCAs) in the original risk assessment. E^{x}ponent developed and applied additional criteria to identify potentially sensitive environments at small stream crossings along the pipeline route. Concern for small streams could be managed through construction via micro-bore or such techniques, with the suggestion that the four streams identified by E^{x}ponent be added to those originally identified by Keystone.

2.5 Leak Detection

2.5.1 Introduction

The proposed approach for leak detection for the Project involves CPM as the primary scheme, coupled with long-term volume balancing, aerial/ground line patrol, third-party reporting, and inspections by company staff as secondary and supporting schemes. CPM is a standard method used in the industry to detect leaks in liquid pipelines. CPM is a term developed by the API that refers to software-based, algorithmic monitoring tools designed to enhance the ability of a Pipeline Controller to recognize hydraulic anomalies on a pipeline. These anomalies may be indicative of a leak or commodity release from the pipeline. The CPM has a sensitivity limit, with smaller leaks detected using a long-term volume balancing scheme to detect loss over time. Alternative methods to detect leaks (often referred to as external methods) that are potentially applicable to the Project have also been evaluated and are discussed.

In addition to measurement-based leak detection systems, there are plans for scheduled patrols of the pipeline RoW, along with use of public and landowner awareness programs. Communities along the pipeline would be given information to facilitate the identification and reporting of suspected leaks and events that could suggest a threat to pipeline safety/integrity.

As important as leak detection is leak avoidance. Two physical systems are involved: the cross-country pipe, and the piping and components at the pumping station. Two threats that continue through the life of a pipeline are corrosion and mechanical damage.

Avoidance requires that plans be in place to prevent these threats from initiating and progressing to leaks. These plans include the following:

- IC control using inhibitors, product sampling, and turbulent flow, along with inside diameter corrosion rate assessment using coupons.
- EC control using mill and field-applied coatings, which will be coupled with (1) temperature monitoring to ensure that the coating remains functional; (2) direct current voltage gradient (DCVG) to detect coating faults; (3) CP; and (4) close interval survey to ensure the current applied is appropriate.
- TPD avoidance enhanced through a burial depth of 4 feet of cover in general (deeper on a segment- or site-specific basis).
- Bi-weekly aerial patrols, one-call, public outreach, and related damage prevention programs.

Periodic inspection using in ILI is planned as a backup to corrosion prevention, with multiple-technology ILI also noted in discussions with Keystone to detect and size other forms of

degradation, such as due to TPD. For leaks in station piping and components, berms will be used for containment. Based on discussions with Keystone, a full concrete pad and related containment structure may be used for one facility located in a highly sensitive eco-site.

2.5.2 Objective and Scope

The objective is to review leak detection as outlined in the Risk Assessment relative to available technology and processes and to comment as appropriate on adequacy and possible gaps. The viability of the approach to detect smaller leaks resulting in potentially significant spill volumes also was considered.

2.5.3 Approach and Database

The proposed approach for leak detection for the Project was evaluated. Data were collected on the operating parameters, leak detection system performance, analyses to calculate leak rates as a function of orifice sizes, and potential spill volumes prior to detection. Given concern regarding usual leak detection schemes, information on alternative schemes with the potential to reduce the risk of undetected leaks was gathered and evaluated. This included external as well as internal schemes, including systems that directly detect leaks (generally termed "external leak detection systems" in the liquid pipeline industry).

Inputs to this process included data provided by Keystone, API-recommended practices, the technical literature, phone queries, and on-line resources detailing emerging technologies. Well-known resources as well as emerging data were considered, starting with the following:

- Pipeline Safety Trust report on "Observations on Practical - Leak Detection for Transmission Pipelines - An Experienced Perspective" [(23)];
- A 2007 Pipeline Research Council International, Inc. (PRCI) report on "Detection of Small Leaks in Liquid Pipelines: Gap Study of Available Methods" [(24)]; and
- The topics presented at the Alaska Department of Environmental Conservation 2011 Pipeline Leak Detection Technology Conference September 2011. Proceeding to be published in December 2011. [(25)]

These resources were supplemented as noted by information from leak detection vendors via electronic and voice query, including discussions on the smart-ball technology[(26)].

2.5.4 Analysis and Outcomes

Pipelines are designed to contain a valuable commodity and, for the most part, rarely leak. When a leak occurs, even a small leak, the detection equipment must alarm quickly but avoid false alarms, because incorrectly shutting down a pipeline could lead to failure and a larger loss of product. This

leads to a difficult design specification for a system that hopefully never has to serve its intended function but must operate flawlessly over decades of service.

Most CPM systems quote leak detection capability as a percentage of the pipeline's throughput. Spill assessment and some leak detection systems typically quote the performance specification as a volume of oil per unit of time. To simplify comparison of the various standards, Table 8 summarizes percentages of throughput and common volumes per unit of time for many of the leak rates described in this text. These calculations were based on 72 percent SMYS operating pressure of 1,308 pounds per square inch (psi), and a throughput of 830,000 barrels per day (bpd) or 24,000 US gallons per minute (gpm).

The CPM system planned for use with the Project is anticipated to have sensitivity between 1.5 percent and 2 percent of pipeline throughput. While not specified, the long-term volume balancing method which reports leaks as a percentage of flow per time is expected to perform better, with some likely percentages cited. Two leak sizes were modeled using PHAST (Process Hazard Analysis Software Tool): one for a ½-inch-diameter hole, and the second for a 1/32-inch-diameter "pinhole." The last value in Table 8 is the leak detection capability for a specific leak detection system.

Table 8. Conversion table to facilitate comparing volume per unit of time

% of Throughput	bpd	gpm	Feet^3/day	Comments
2	16,600	485	93,200	CPM system upper limit
1.50	12,450	364	69,900	CPM system lower limit
1	8,300	242	46,600	Less than 1.5%
0.87	7,190	210	40,380	1/2 inch Hole
0.5	4,150	121	23,300	Less than 1.5%
0.1	830	24	4,660	Less than 1.5%
0.0034	28	0.83	159	1/32 inch Hole
0.0004	3	0.10	19	potential external system

2.5.4.1 Computational Pipeline Monitoring

The API established RP 1130 as the recommended basis to implement CPM. The algorithm of that RP uses many instruments, including mass flow, volume flow, temperature, density, valve position, and pump status, to recognize a change in hydraulic condition over a time interval that indicates a leak may have occurred. Estimating the sensitivity of CPM systems and the time to detect leaks is the subject of API RP 1149. The PRCI sponsored a gap analysis on detection of small leaks in liquid pipelines to assess what liquid pipeline operators need in terms of leak detection versus what detection technologies (primarily CPM) provide, specifically related to small leaks. For PRCI's purpose, small leaks were considered to be releases less than 5 percent of nominal pipeline flow rate, whereas for the Project it is anticipated that the CPM system will have sensitivity between 1.5 percent and 2 percent. Thus, the Project's need is beyond what most CPM systems deliver, with this need being met through use of additional instrumentation (versus that typically used over their minimum 20-mile valve spacing), and SCADA scan-cycle-time of 5 seconds. In response to a Battelle inquiry, Keystone's leak detection system performance was stated (relative to the pipeline flow) as follows:

- A leak of 50 percent will be alarm detected within 2 minutes;
- A leak of 15 percent will be alarm detected within 15 minutes;
- A leak of 5 percent will be alarm detected within 60 minutes; and
- A leak of 2 percent will be alarm detected within 120 minutes.

Table 9 summarizes the performance targets and leak time along with the projected volume of product that leaks before the alarm, while Figure 15 presents aspects of this timeline and the related spill volumes prior to detection.

Table 9. Time to alarm leak and the projected spill size before alarm

Leak Size	Time	Volume of Product Leaked Before Alarm		
% of System	min	Barrels	Gallons	Cubic Feet
50	2	57	24,15	3,20
15	15	1,30	55,60	7,30
5%	60	1,72	72,00	9,70
2%	120	1,38	58,00	7,70

Table 9 shows that the time to alarm detect a leak is greater for smaller leaks, but the total volume of product lost before the alarm is not a strong function of leak size. To illustrate the point, Figure 15 shows a schematic of the total volume lost as a function of time for the current commitment (as provided by Keystone) and a plausible target. These types of schematic representations show that the total volume leaked approaches an upper bound. The reason for using a schematic representation is that pipeline leak detection systems typically perform better than the committed values; however, the values are dependent on the actual pipe parameters and installed instrumentation. To provide a better estimate on leak system performance, tests on the operating segments of the Keystone system are being performed, but the details are not yet public.

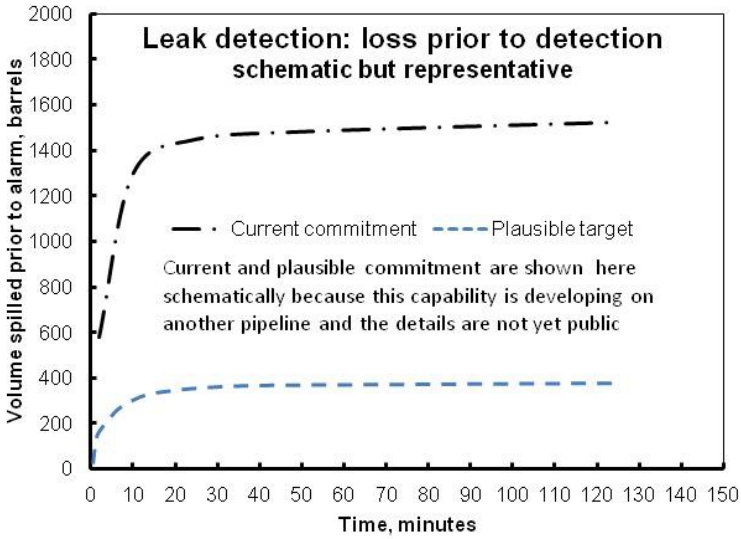


Figure 15. Aspects of the performance of CPM for the Keystone XL Project

The proposed approach also includes a computer-based system that does not rely on the CPM system directly to assist in identifying leaks below the 1.5 to 2 percent detection thresholds. For detection of smaller leaks less than 1.5 percent, Keystone intends to use what is called the over/short report. This tool calculates a long-term volume balance of the system over a period of time (days, weeks, months). This is not a real-time detection system, with smaller leaks taking more time to detect. At this time, based on sensitivity analysis that is proprietary, Keystone can state that the intent is to be able to detect small leaks over a long-term period and that typically,

these types of tools (long-term volume balance) will detect leaks smaller than 1.5 to 2 percent. The algorithms are currently being developed and tested on operating segments of the existing Keystone Pipeline system, with this system also planned for use on the Project.

Regulations require CPM testing to be performed on a periodic basis. It is recommended that the CPM system be tested thoroughly upon the initial operation if the pipeline is approved and built. Based on these results, if the system does not meet the specification, additional leak detection methods should be considered.

2.5.4.2 Potential Additional Methods for Automated Leak Detection

Automated leak detection technologies that directly measure the presence of a leak (rather than measuring the response of the product flowing inside the pipeline) are referred to in the liquid pipeline community as "external leak detection systems." Various approaches include sound (acoustics) generated by a leak, while thermal, remote visual, and chemical methods are also available to detect hydrocarbon once it has left the pipeline. Many of the systems have dedicated analysis packages that indicate a potential leak via the SCADA system. A summary of the attributes and limitations of the potential methods follows.

Acoustic monitoring. A leak from a pipeline produces acoustical energy that can propagate along the pipe. Various sensors such as hydrophones that contact the liquid and accelerometers on the outside of the pipe can be used to detect the sound energy emanating from a leak. The closer a sensor is to the leak, the better the sensitivity. In a typical configuration, an array of sensors is connected to a processing computer. Continuous monitoring is performed that can be tied to the SCADA system, and can be combined with mass balance technologies, to estimate leak rates. The major disadvantage is that the most sensitive sensors, hydrophones, introduce another fitting which has the potential to leak.

Forward-looking infrared (FLIR) technology. Infrared vision systems are starting to be employed to detect leaks on pipelines. For warm pipelines, the thermal changes from leaks are detected. Gaseous hydrocarbons absorb energy in specific near-infrared bands and are easily detectable with this equipment. This equipment is used regularly on the North Slope to look for leaks under insulation on aboveground piping. It is being tested on buried pipelines where the ground disperses the heat quickly from small leaks. This technology could augment patrols, either airborne or ground. The performance of the equipment varies with the seasons.

Laser systems. Laser-based technology has been commercially deployed as a portable gas sensor. First, a large site is screened for hydrocarbons with hand-held, vehicle-mounted or aircraft-mounted systems. Then, areas of elevated gas concentration can be bracketed using shorter path lengths in order to locate leaking valves, flanges, or fittings. Commercially available systems can

detect hydrogen fluoride (HF), hydrogen chloride (HCl), hydrogen sulfide (H_2S), ammonia (NH_3), methane (CH_4), carbon dioxide (CO_2), hydrogen cyanide (HCN), ethylene (C_2H_4) and acetylene (C_2H_2) with no interference from other gases. The lightest component in the dilbit product is propane (C_3) at less than 0.1 percent volume and butane (C_4) on the order of 1.0 percent volume. While an airborne-deployed detection system can find parts per million of methane, and attempts have been made to develop system for propane, the technology is not currently appropriate for detection of the lightest diluents.

Fiber optic systems. Fiber optic systems that are buried in the RoW are being developed for pipelines. The cables detect sudden heat change or sound energy. The more successful implementations detect gas leaks due to Joule Thomson cooling. These systems provide continuous monitoring where a broken cable can be a sign of excavation in the RoW. There is a concern with false calls, and implementation has been limited.

In-line hydrophone technology. While an oxymoron in the liquid pipeline terminology, the in-line hydrophone mounted in a ball, trade-named Smartball™[26], would be characterized as an external leak detection system. It is an inspection tool like a pig, but much simpler in use and data analysis. This technology was developed for and has been proven on water lines. The in- line leak detection equipment is launched and received in existing pig traps. The tool travels nominally with the flow and would require about a day to inspect a typical segment. Once the equipment is out of the line, leaks are identified within about an hour. Pipeline company personnel can be trained to operate this leak detection technology, with the data sent to the inspection vendor to perform leak rate calculation on detected leaks. The major advantage is that very small leaks have been detected on operating crude lines on the order of fractional gallon per minute, more than 100 times more sensitive than CPM systems. It has been used on crude oil pipelines. To save cost, initial screening runs are performed without tracking; if leaks are found, a rerun is performed to pinpoint the leak location. Since the equipment uses existing pig traps, the current Keystone pipeline design is appropriate for this technology; however, the use of this technology will adversely impact pipeline throughput, since pump stations between launch and receive traps, typically two, must be shut down. The use of this technology on a routine basis may be excessive for a pipeline where potential threats such as corrosion or mechanical damage are have not caused damage. This technology could be one that Keystone considers in the future, depending on pipeline condition. To offset the impact of throughput reduction, it could be run as part of an IMP pig-train, with ball launcher/receivers rather than full pig traps considered at intermediate pump stations.

It is recommended that in-line leak detection be considered as part of the pig train that will be run to assess the pipeline for corrosion. This will ensure that very small leaks (if any are present) would be identified, while having only minimal operational impacts because the pipeline throughput will be reduced during this process. It is also recommended that in-line leak detection

be considered in the future for line segments that have experienced significant corrosion or where excavation equipment may have impacted the pipeline. This method could also be used to provide additional data on segments where the CPM and long-term volume balance approaches require additional time to assess the possibility of leaks. On the downside, fitting a pipeline with dedicated leak detection equipment can be expensive, provide minimal benefit if the preventive measures work, and in some cases can cause more leaks; therefore, these are not recommended for installation. However, as time passes and technology evolves, consideration should be given to such developments. Keystone has committed to conduct regular inquiries on this technology.

2.5.4.3 Augmenting Patrols

To reduce the impact of a leak, detection shortly after it occurs is essential. Leaking crude may not appear at the surface quickly, or patrols may not visually detect leaks on the first pass. Sniffer systems for hydrocarbon are available and might be appropriate for patrols to increase the probability of detection, although the limited transport distance (and speed) noted in E^{x}ponent's report[(2)] would limit their utility.

Patrols may also benefit from the use of FLIR technology. If the constituents of the diluents that reach the surface vaporize before the crude, early detection could be enhanced by FLIR technology, because hydrocarbon gases absorb infrared radiation in the 2- to 5-micron wavelength range. If sniffer and FLIR technologies are considered as a possible basis to augment patrols, the fact that these methods must still be tested prior to wide-scale implementation must be factored into that process. In the same context, seasonal issues such as snow cover have been known to confound the performance of these systems, and also the utility of patrols.

2.5.4.4 Corrosion Assessment

Metal loss anomalies caused by corrosion are the most common cause of leaks that can be readily detected in the cross-country pipes that have been in service for many years. Inspection for corrosion is planned for the Project. The initial ILI of the pipeline, noted to come after just three years, is better than the industry standard and provides baseline information for future runs. Thereafter, the plan of conducting a corrosion inspection every five years matches the industry standard.

The designated inspection method is MFL. The class of MFL inspection to be used is designated as high resolution; however, all MFL vendors use this designation or extra-high resolution to describe their ILI pigs. MFL is good for corrosion detection, but the accuracy of sizing the dimension of pits is limited, and nearly through-wall pits can be undersized. If corrosion is detected by MFL tools, leak prevention can be enhanced by the use of better inspection technology, such as ultrasonic tools. The general depth-sizing accuracy of both tools is as follows:

- MFL: ±10 percent of wall thickness or ±0.046 inches (1.2mm) in the nominal 0.465 wall thickness pipe, with an 80 percent certainty (16 of 20 within tolerance). This is the depth at the deepest point.
- Ultrasonic: ±0.0157 (0.4mm), with a 95 percent certainty (19 of 20 within tolerance). This accuracy is not a function of wall thickness and will be the same in the thicker segments. The depth of the corrosion is measured in a grid pattern.

Since the ultrasonic tools can better determine the corrosion depth over the entire anomaly, advanced failure criteria such as RSTRENG can be used, with growth rates calculated based on data from successive runs. Because steps have been taken to reduce the incidence of corrosion and ultrasonic tools are more expensive to use, their use could be restricted to segments where corrosion is becoming problematic; otherwise, the MFL tools could be used. Thus, an inspection plan that starts with MFL is appropriate, but the plan should be flexible such that the most appropriate tool is used subject to the frequency and severity of the corrosion. A risk-based integrity management system is recommended wherein the frequency and accuracy requirements of ILI are based on quantitative risk assessment, subject to the results of each inspection. Inquiries indicate that this is current practice for Keystone, with this practice also planned for the Project.

2.5.4.5 Detecting Mechanical Damage

Mechanical damage anomalies caused by machinery working in the RoW are another significant threat to pipeline integrity. This threat is being mitigated for the Project by specifying that the minimum cover over the pipeline be maintained at 4 feet; 3 feet is commonly used because that is the code requirement. Mandated pipeline marking, RoW patrols, and the one-call system, which have been effective in reducing the number mechanical damage failures, also are specified. Increasing the frequency of patrols could be effective in avoiding damage, in addition to visually detecting leaks. Active encroachment detection using fiber optic cable in the RoW and acoustic methods are being developed under the current DoT PHMSA Research program, but these have not been used over long distances, nor are they fully commercialized.

Most reported mechanical damage failures in the DoT database occur during or shortly after the contact. Anecdotal evidence indicates that only about 1 in 20 mechanical damage failures were delayed failures. This means that detecting mechanical damage with the potential for delayed failures occurs much less frequently than corrosion (with inspection for mechanical damage also less frequent). But, because delayed mechanical damage failures tend to cause ruptures rather than leaks, ILI tools are commercially available to detect such damage in the form of dents and gouges. Such tools have been used to detect gouges and dents introduced during construction. Where gouges form, denting often accompanies the gouge, but such denting is unlikely to be large enough to be detected by caliper tools because of the heavier wall thickness of the mainline line pipe used

for the Project. Damage can be found via ILI tools that utilize circumferential MFL, ultrasonic, and dual-field MFL technologies. It is recommended that such tools be considered for initial inspection and during operation on segments in regions where excavation and farming operations are common. In addition, prior to and during service, it is recommended that a DCVG assessment be made along with the mandated use of the high-resolution ILI caliper assessment, with topside dents and other feature follow-up done as needed.

2.5.5 Summary and Conclusions

Pipelines are designed to contain a valuable commodity and should rarely leak when designed well and properly maintained. If a leak occurs, the detection approach and performance becomes an importance consideration.

Major conclusions and considerations that can be derived from leak detection analyses are as follows:

- CPM, the leak detection approach proposed for the Project, is the industry standard for crude oil pipelines. The CPM system implementation should have better-than-average anticipated performance because, as Keystone's response to information inquiries emphasizes, this Project will make more frequent use of sensors. Such responses also emphasize the non-standard use of an over/short analysis.
- While Keystone notes that more is being done, it can also be said that more should be done given the higher-than-usual throughput of this pipeline, which follows because the "small leak" defined in traditional terms as percentage of flow becomes large in terms of volume released to the surrounding environment.
- Prevention of leaks is a primary goal because any leak could release product into potentially sensitive ecosystems or into critical resources. Flexibility is recommended in the inspection plan and requirements to ensure that prevention is effective over the life-cycle of the Project.
- A risk-based integrity management system should be used whereby the frequency and accuracy requirements of ILI are based on quantitative risk assessment as indicated by conditions found after each inspection.
- If significant corrosion is detected by the lower-cost ILI tools, then "high-resolution" MFL tools, more frequent inspection, or better tools are recommended.
- Inspection for mechanical damage using other technology should also be considered in selected areas where the chance for such damage is locally higher.
- Requirements for additional leak detection technology for small leaks should be tempered by demonstrated need. Most leaks occur at stations at fittings and valves and

can be detected by visual methods. Leaks on cross-country pipelines are rare and occur where prevention methods fail.

- Use of in-line leak detection technology on a selected basis may be appropriate in more environmentally sensitive areas, in areas where third-party damage is more likely, and on segments after significant corrosion is indicated.
- It is recommended that in-line leak detection be considered as part of the pig train that will be run to assess the pipeline for corrosion. This will help ensure that no small leaks have developed and that any leaks missed by other schemes have minimal environmental impact, while also minimizing operational impact (as the pipeline throughput is already reduced).
- In-line leak detection also could be considered in the future for line segments that have experienced significant corrosion or on segments where excavation equipment may have impacted the pipeline.
- The current pipeline design does not preclude the uses of emerging technology for improved inspection and leak detection. For the purposes of a Presidential Permit, weighed against prior schemes, leak prevention and detection is adequate. As the pipeline matures, the PHMSA may consider some of the improved corrosion detection and leak detection approaches discussed in this section, as well as any new technologies that have evolved.

2.6 Protective and Mitigative Measures

As established earlier, the lineal (pipeline) component of the Project is the primary source of environmental exposure because its remoteness in many places, where it traverses HCAs and other resources along the proposed RoW, makes potential mitigation efforts difficult. Consequently, compliance with the 57 Conditions[(7a)] in regard to the pipeline's design, construction, operation, and maintenance is the foundation for pipeline integrity, which in turn protects the environment as well as the public against the effects of unplanned releases.

Aside from the regulatory and Keystone-specific aspects of the 57 Conditions, there are several provisions that are unique in the context of historic hazardous liquid pipelines. These conditions focus primarily on operations aspects, including leak detection. Clearly, leak detection is the key in the event that the pressure (safety) boundary is breached, with small leaks being a major concern. This too is an area of focus for this section, along with actions directed at avoiding a breach in the pressure boundary because integrity of the pressure boundary is central to maintaining the ecosystems that this pipeline traverses. If that boundary remains intact, leaks do not occur.

It follows that the 57 Conditions contribute to the protective measures taken in regard to operating any hazardous liquid pipeline. Such measures involve actions taken to keep the product within the

pipeline system and to control and respond to an inadvertent release from early detection through cleanup. Such measures and actions relative to the Keystone XL Project are discussed below in regard to mitigation (which limits release consequences), prevention (which involves avoiding a release), and what are termed protective measures (which constitute actions that minimize release impacts). It is noteworthy in this context that if protective measures are defined relative to minimizing the impacts of a release, then mitigation and prevention likewise are protective, as they limit or are designed to avoid such impacts.

2.6.1 Mitigative Actions

Mitigative actions in the context of an oil spill are directed at limiting release consequences, and so involve the post-detection response to the spill. Title 49 of the CFR, Parts 194 and 195 and their appendices, establish the minimum requirements for any hazardous liquid pipeline, whose eventual implementation is the responsibility of the PHMSA. Because PHMSA approval for construction comes after the NEPA phase, aspects of the mitigation plan remain high-level. Considering for present purposes that mitigative actions implicit in PHMSA approval are mandatory and so can be viewed as "existing actions," this section focuses on additional actions that merit consideration for the Project. Key potential actions in that context include the following:

1. Provide response teams and equipment that are designed for the scope of transported products, and their potential interaction with the ecosystems that the pipeline traverses.
2. Locate the response teams and equipment selectively at resources deemed critical or high-value, considering a broader view than the current narrow PHMSA definitions of an HCA or unusually sensitive area (USA) (which are currently the subject of potential Federal review).

2.6.2 Preventive Actions

Preventive actions in the context of an oil spill are directed at avoiding a release. They focus on keeping the product within the line-pipe and the system components. As noted above, Parts 194 and 195 (and appendices) of Title 49 of the CFR establish the minimum requirements for any hazardous liquid pipeline. The eventual implementation of these requirements is under the oversight of the PHMSA. Accordingly, details associated with the PHMSA approval that comprise preventive actions are not well defined at this stage of the Federal process.

Considering for present purposes that the preventive actions implicit in PHMSA approval are "existing," this section focuses on additional actions over and above minimum that either are known or otherwise merit consideration for the Project. Key actions include the following:

1. At present, discussions and documentation[(7)] indicate that the following actions are over and above the Code minimum: the entire pipeline is being designed as if it

transits an HCA; greater than the required depth of cover will be provided for usual trenched construction (4 feet in general, locally deeper for select sites); and horizontal directional drills (HDDs) will be used for select crossings.

   a. Evaluation indicates that reasonable judgment underlies the site-selection process used by Keystone.
   b. Because the wall thickness is already that for an HCA/USA, wall thickness relative to that for an HCA/USA cannot be added to locally reduce risk or avoid consequences. More importantly, data show that added wall thickness does not affect risk related to threats such as corrosion[(12)].

2. Consider the selective use of (micro-) bores to better manage threats near sites with critical/high-value resources or sites where history indicates locally higher threat (for example, where the potential for scour or washout is unusually high).
3. Consider alternative practices in regard to seals and seats, from material selection through maintenance.
4. Consider more frequent scheduled maintenance for valves and other equipment, at least initially.
5. Consider the use of pre-service offsite leak checks and equipment shakedown where plausible.
6. Consider more frequent patrols in population-defined HCAs. The nominal two-week interval is less effective than desirable where encroachment is likely.
7. To improve data interpretation, run pre-service ILI for all technologies anticipated for use in the IMP to establish a background against which subsequent interpretation can better distinguish changes in potential threats.
8. To avoid onerous aspects tied to the focused use of smart ball technology, consider running such technology as part of an early pig train, which is part of usual operations to establish the background. Then, consider its periodic use as part of pig trains that are required for the IMP.

2.6.3 Protective Actions – Valves and Outflow Management

Protective actions in the context of an oil spill cover aspects designed to minimize environmental impacts by reducing the exposure in the event of a spill, which can be achieved by early detection of the spill, and by limiting the duration of, and outflow from, a spill. Again, Parts 194 and 195 (and appendices) of Title 49 of the CFR establish the minimum requirements for any hazardous liquid pipeline. Because the eventual implementation is under the oversight of the PHMSA, details associated with PHMSA approval that comprise protective actions tend to be poorly defined at this stage of the Federal process. Considering for present purposes that the protective actions implicit

in PHMSA approval are "existing," this section focuses on additional actions over and above minimum that either are known or otherwise merit consideration for the Keystone XL Project.

1. Analysis by E^{x}ponent indicates that leaks larger that about 20 barrels could be detectable aboveground, visually or by other sensor, within a reasonable timeline. Analysis discussed in Section 2.5 indicates that spills of about 1,400 barrels can be detected within two hours under Keystone's current detection commitment. Reasonable expectations based on unpublished data suggest that this volume could be reduced to several hundred barrels detected within 45 minutes. Though this is encouraging, smaller leaks are still a concern. Given that leaks of less than 20 barrels are not easily detectable aboveground, consideration should be given to the use of technologies noted in Section 2.5. These technologies could complement CPM and the other schemes currently adopted, with the survey frequency matched to the specific technology considered.
2. Given that E^{x}ponent's work indicates that leaks of more than 20 barrels can be recognized within a reasonable timeframe aboveground (detectable visually or by other sensor), the use of detection technologies noted in Section 2.5 should be considered, along with a patrol frequency that is matched to such technologies.
3. Depending on the nature of the terrain, aspects of the water table, and other factors, consideration should be given to the selective use of concrete coated line pipe, or an equivalent or better scheme such as Rock Jacket® that, in contrast to a concrete coating, can be field-bent and facilitates CP.
4. While Keystone has used leading practices in assessing valve location and spacing, there is potential value in refining the existing plan to include the following.
    a. Four types of EFRDs exist: RCVs, CVs, ACVs, and MOVs. There is evidence that all but ACVs are involved in this Project (note that the MOVs are placed in conjunction with and just downstream of the CVs). ACVs respond automatically to pipeline flow conditions, which poses the chance for anomalous response. Yet, an ACV conceptually represents a simple LDS and an EFRD in one package. As technology matures such that these become reliable and can be programmed to close and minimize surge, consideration should be given to such devices.
    b. Valve response times for liquid lines are limited by the potential of fluid hammer and related overpressure surge. The published literature points to issues in regard to times of about 10 minutes, and much more in some cases. Therefore, concern exists in regard to the closure interval, noted currently at 12 minutes. If this process transitions to the PHMSA, care should be taken to validate the underlying dynamic analysis and related plans.

5. As noted in point 1, detection of small leaks is problematic in view of the prior section that considered this topic. We recommend the following in regard to small leaks.
    a. As time passes and technology evolves/matures, Keystone should plan to consider those developments and aggressively move to implement viable technology.
    b. Based on responses to inquiries made over the course of the work that show Keystone investing through ongoing industry activities, such actions would be a part of Keystone's change management practices.
    c. Alternative approaches should be considered to prevent leaks. Such approaches are discussed in the next section and are noted above in the context of prevention.

2.6.4 Keeping the Product in the Pipeline System and Managing Outflow

In view of the current difficulties in detecting small leaks, the basis for design, construction, operations, and maintenance over the life cycle has to be this: "If you cannot quickly detect smaller leaks, then you have to prevent them." In addition, given that even the best-laid plans cannot prevent a leak, care must be taken to establish viable outflow management and ensure that the mitigation plans address expectations.

2.6.4.1 Viability of Leak Prevention

Because much has been done in regard to pipeline design, and because the lineal portion of the pipeline system presents the primary environmental exposure where it is also most difficult to mitigate (or detect) spills, it is prudent to more quantitatively assess the relative role of the lineal portion of the pipeline in regard to prevention. This is done relative to 49 CFR 194 and 195 as the minimum basis for design, construction, operations, and maintenance. The focus here is specific to corrosion and TPD because these are the primary threats in light of the data that underlie Figure 8b and in light of the observations regarding corrosion rate and damage susceptibility in regard to Figures 9 and 10.

Methods to predict the response of anomalies to the forces on pipelines have been validated by full-scale testing, which form the basis for this assessment[27]. Such models have been developed to quantify this response for anomalies that fail by either plastic collapse or by fracture, for features oriented either around or along the axis of the pipeline. Because the worst-case response develops for axially oriented features under usual pipeline loadings, it is customary to consider this orientation.

With this background, the results for predictions for axially oriented features are presented in Figure 16. The bounds shown reflect consideration of sharp crack-like defects, as this reflects the

worst case for corrosion and is relevant to what can develop from TPD. The y-axis in Figure 16 presents the failure pressure normalized relative to SMYS as a function of the length of the anomaly, which is shown on the x-axis. Figure 16 presents trends that show the dependence of the failure pressure as a function of the anomaly's depth, which is normalized in this figure relative to the mainline (and also the minimum) wall thickness for the Project (i.e., 0.465-inch). On this coordinate system, constant pressure is a horizontal line: service at 72 percent of SMYS corresponds to a horizontal line at a y-axis value of 0.72; while service at 50 percent of SMYS corresponds to a horizontal line at a y-axis value of 0.50; and so on. The uppermost horizontal line is associated with failure of anomaly-free pipe by plastic collapse, whereas the dashed bound across the figure at a y-axis value of unity corresponds to nominal yield at SMYS.

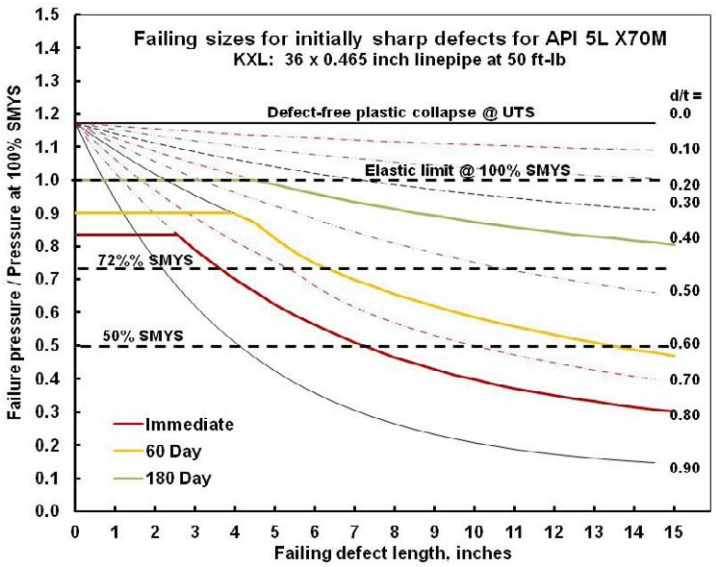


Figure 16. Failure boundaries for sharp defects in the Project line pipe

Three bounds are included in Figure 16, which pertain to anomaly response as part of the formal IMP of the PHMSA. These bounds reflect the anomaly sizes and intervals that require response, along with the timelines for response, and relate to nominal anomaly depths of 40 percent, 60 percent, and 80 percent with corresponding cutoff pressures. These respectively correspond to "scheduled" response within 180 days, versus a response prior to 60 days, versus an "immediate" response (subject to the PHMSA's interpretation of these response timelines). As evident in Figure 16, these bounds are separated by an increment in wall thickness equal to 20 percent of the wall, or for the mainline pipe nominally 0.093 inch.

Figure 16 shows that for operation at 72 percent of SMYS, which corresponds to the maximum allowable operating pressure (MAOP) under normal operating circumstances, the first response threshold is associated with continuous axial cracking over lengths of more than 15 inches. Experience indicates that defects with such continuous lengths oriented along the pipeline are

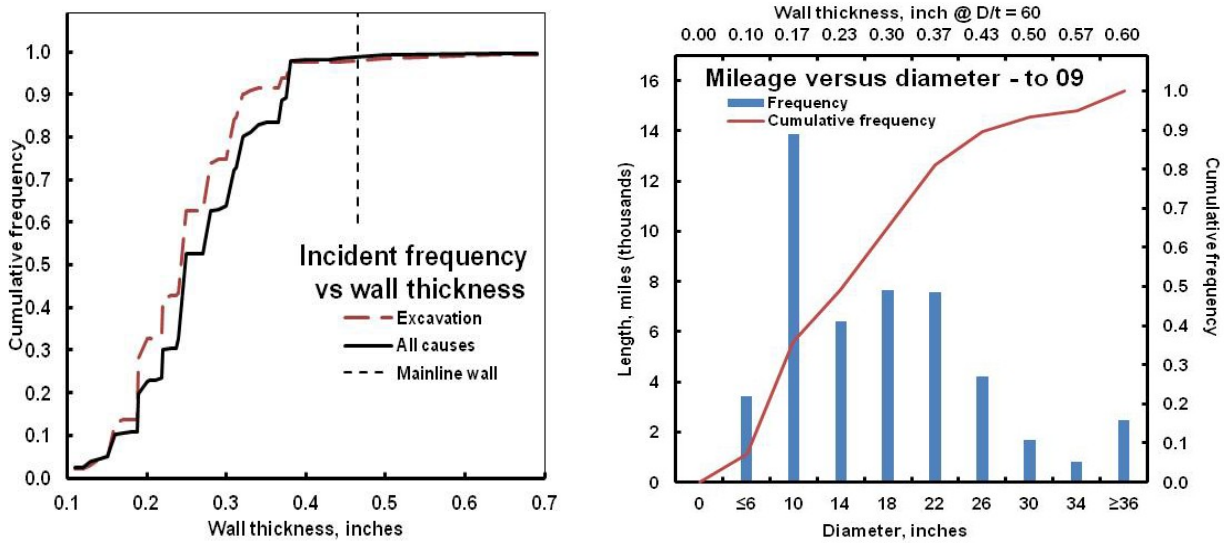
uncommon, even when serious areal corrosion develops. The second threshold at 60 percent wall depth is associated with shorter cracking, on the order of 6 inches overall. The depths associated with both of these response thresholds can be reliably found using ILI that targets corrosion.

Considering that the usual 10 percent allowance for uncertainty in ILI outcomes is offset by the conservatism embedded by representing blunt corrosion by a sharp crack, and using the NACE RP 0502-suggested corrosion growth rate of 0.015 inch per year, it is found that the transition between these response intervals corresponds to a little more than six years. The PHMSA mandates ILI for the hazardous liquid pipeline industry at a maximum interval of five years. It follows that at least one ILI cycle is associated with the transition between these anomaly-response intervals. The threshold for this anomaly-response process is a depth of 40 percent of the wall. If a benchmark ILI run is made pre-service, as suggested above in Preventive Actions, then the nominally defect-free pre-service pipeline system will experience a total of three ILI cycles before reaching the first schedule threshold. According to the worst-case rate, this would occur after a total of 12 years of operation.

Because Figure 9 and related discussion indicate that the NACE rate is close to the upper bound for the historic database; therefore, it follows that the interval prior to first IMP concern for a scheduled anomaly response is typically much longer than just discussed. If a more representative rate based on a mean or upper-percentile is adopted, the above-noted interval of six years to traverse 20 percent of the wall increases by as much as a factor of two. Thus, it also follows that as designed – without any consideration of the benefits of coating or CP – the line pipe for the Project provides a significant margin of preventive protection against corrosion.

Similar analyses done in the context of the girth welds and related defect tolerance are typically considered as part of the PHMSA approval for construction, with the expectation that the welding practices and the related inspection and quality controls will produce equally robust results. Nevertheless, care should be taken to ensure that this is addressed under PHMSA oversight.

Consider next the Project line-pipe in regard to trends between incident cause and the related threat relative to the mainline (Project minimum) wall thickness. Figure 17a presents trending developed from the PHMSA hazardous liquid database by sorting incident cause as a function of wall thickness. In particular, the database was parsed to consider incidents involving onshore pipelines, including valve sites, which in the database is denoted SYSPRT = 5. This leads to about 570 records involving thickness, with numerical records ranging from zero up through 375, excluding nulls (blanks). A data quality check identified many questionable entries, such as those lacking a decimal point as large as 375, which is inferred to be in units of thousandths of an inch. Obvious outliers such as those were rationalized en route to the trending in Figure 17a.



a) database trends on thickness **b) inferred wall-thickness distribution**

Figure 17. Excavation / third-party damage and wall thickness implications

The trend for incidents decreasing as wall thickness increases evident in Figure 17a also could reflect the influence of a population wherein the relative fraction of heavier-wall pipe decreases on a mileage basis. Thus, data to assess and normalize this influence have been sought through use of PHMSA data. It is apparent from the PHMSA website that the mileage data are presented independent of the incident data, with the mileage data binned as intervals of pipe diameter with the associated mileage. To be useful in assessing the trends in Figure 17a, the diameter-mileage distribution must be transformed into a thickness-mileage distribution, in reference to the trend between diameter, D, and thickness, t, based on the PHMSA database. Data for SYSPRT = 5 parsed as noted above were trended in regard to thickness as a function of diameter, to identify the trend in D/t. Known data quality issues, and the extent of the nulls, meant that quality issues had to be resolved to maintain the sample size. Criteria used for this data QC check included wall thickness less than the diameter, consistency of the ratio of the stress at maximum operating pressure to SMYS as compared to code limits, and consistency between the D/t ratio and historic industry practice. Records found inconsistent with those metrics were either rationalized, identified as an obvious data reporting error, or culled. This process led to a value of D/t on the order of 43 for the historic data. For present purposes, a more conservative value of 60 has been adopted.

Trending the mileage by diameter for the hazardous liquid transmission pipeline system indicates that in spite of recent construction trends, the mileage continues to be concentrated in the interval for pipe nominally 8 to 10 inches in diameter, with diameters larger than 22 inches being a declining share of the mileage. But it is also apparent that the historic trend is shifting (due for example to longer transport distances and the need to consolidate lines), with a number of larger-diameter pipelines going into service over the last decade or being planned. While the database

leads to D/t = 43 and is consistent with the few incidents involving heavier-wall pipe, the use of a higher value of D/t is conservative for purposes of this assessment. On that basis, D/t = 60 has been used to trend wall thickness versus mileage, with the outcome shown in Figure 17b.

Figure 17b presents the distribution of mileage on the x-axis as a function of diameter on the primary y-axis, with the wall thickness for D/t = 60 shown on the secondary y-axis. The raw mileage data are shown in histogram format as the blue vertical bars binned by wall thickness relative to mileage (shown on y-axis to the left side). The corresponding cumulative frequency is shown by the line rising from left to right, relative to the y-axis to the right side of the figure. Finally, the desired range of wall thicknesses relative to this distribution is shown across the secondary (upper) x-axis, ranging upward to six-tenths of an inch. Using this surrogate for the actual (as yet unreported) distribution of wall thickness indicates that the trends in Figure 17a are viable, which in turn indicates that relative to the thinnest-wall line-pipe planned for the Keystone XL Project, the pipeline should be resistant to the historic mainline threats for a pipeline system.

Figure 17a shows that virtually all incidents occur in pipe whose wall thickness is less than that for the Keystone XL mainline line-pipe, whether dealing only with excavation damage or with the aggregated database for causes that involve damage and forces-related causes, along with the other six causes noted for the SYSPRT = 5 reporting category. It follows based on the information available that, as designed, the line pipe for the Keystone XL Project provides a significant margin of preventive protection against all apparent historic threats that impact the mainline system, including mechanical damage. This outcome exists even without consideration of the potential risk reduction that could accrue from using a burial depth deeper than that required by code; HDDs; and an abrasion resistant overlay (ARO) coating on specific segments, along with several other protections cited in the Risk Assessment.

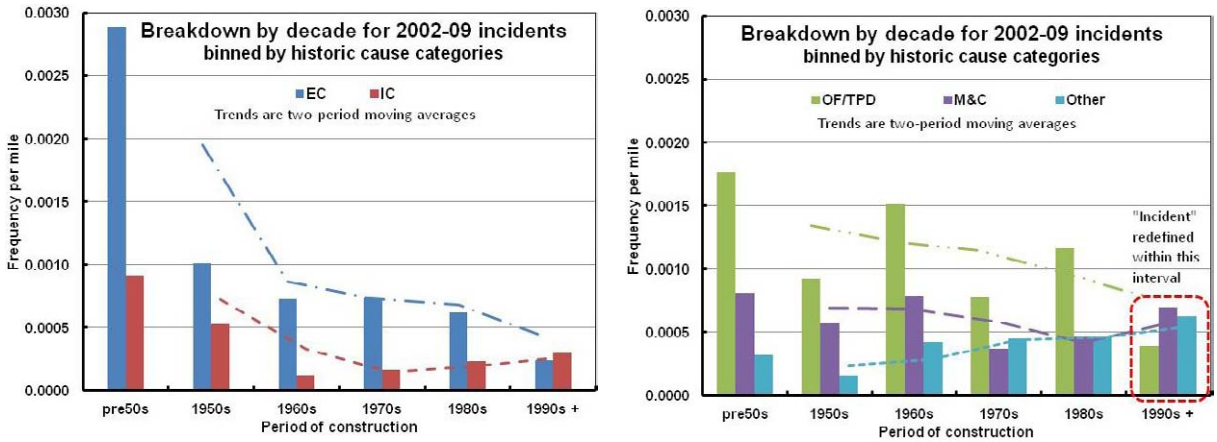
2.6.4.2 Viability of Modern Pipelines – Incident Likelihood

The PHMSA database was analyzed and trended in many ways in this report in reference to spill frequency and volumes, through environmental consequences. It remains to assess this database as it relates to integrity and threats in reference to modern versus historic construction and as it relates to potential latent threats or emerging trends. This can be done at various levels of detail and can trace back into the data prior to the reporting changes made in 2002; however, issues emerge in melding data and in dealing with nulls in the historic data due to the much simpler form used previously. More critically, the database for the period after 2002, which trends the data parsed by year of construction based on the part-year (PRTYR) field, suffices for present purposes. When, as occurred on occasion, the part-year field was null, the manufactured-year (MANYR) field served as a surrogate. Trending intervals for construction year were chosen subject to two considerations: (1) the need to pool enough data to establish viable incident trends normalized on a per-mile basis,

and (2) reporting that assessed the evolution of pipeline design, steel and pipe making, and pipeline construction[e.g., 28,29]. This led to binning the year of construction as prior to 1950, then by decade for the period from the 1950s through the 1980s, with the final interval covering the period from 1990 through 2009. Mileage by decade since the 1930s through 2000 came from Reference 28, with the mileage since then obtained from the PHMSA[6b].

Trends in regard to incident causes were subject to three considerations: (1) the need to pool enough data to establish viable trends for each cause category used; (2) historic practices in reporting incidents; and (3) the relative significance of causes. In regard to the relative significance of causes, trending by the API[30], for example, indicates the clear significance of corrosion, which it partitions as IC or EC, and also of outside forces/mechanical damage. Historic practices, as evident in the reporting forms prior to the change that occurred in 2002, indicates the use of eight categories: corrosion, natural forces, excavation damage, other outside force damage, material and/or weld failures, equipment, incorrect operation, and a catchall category termed "other." Some of these categories are sparsely populated and several can be considered related, the latter being evident in the grouping of the refined bins for the current CAUSE_TXT field for the higher-level GEN_CAUSE_TXT field. On this basis, incidents due to outside forces and mechanical damage have been lumped into a category labeled OF/TPD. Likewise, incidents associated with aspects involving the material and construction have been lumped into a category labeled M&C. Given the historic separation of IC versus EC, this distinction has been retained, as has the category labeled "other." The use of these five categories leads to a simple picture, with adequate data to facilitate trending. More detailed trending could be instructive and is suggested if the Project moves toward the PHMSA's oversight.

Analysis of the database using the above-listed intervals and categories leads to the results shown in Figures 18a and 18b, which respectively present the data for EC and IC and for the other three cause-categories. The y-axis in these bar graphs is the number of incidents in the cause-bin divided (normalized) by the corresponding mileage, while the x-axis presents the binned intervals in terms of the period of construction. Because the intervals on the x-axis cover a period of 10 years or more and represent a significant mileage, the results for any one interval provide a reasonable indicator of the behavior over that period. Consistent with prior trending, the trends shown in these figures represent the raw data. However, some "smoothing" is present through use of an incremental average across adjacent time periods, with this averaged trend shown as the dashed lines in these figures.



a) trends for EC and IC **b) trends for the remaining causes circa 2002**

Figure 18. Incident trends by period of construction

Where there is no clear trend over time, as occurs for OF/TPD, the data across the timeframe evaluated could be random. As evident for the case of OF/TPD, this random tendency remains even when an adjacent-bin time average is used (although this averaging does diminish variability). In the case of OF/TPD, this behavior is anticipated because the occurrence of such incidents does not depend on time or on acts over short segments of pipeline, which means their likelihood will not be well represented on a time- or distance-averaged basis.

Several observations can be made in view of Figure 18.

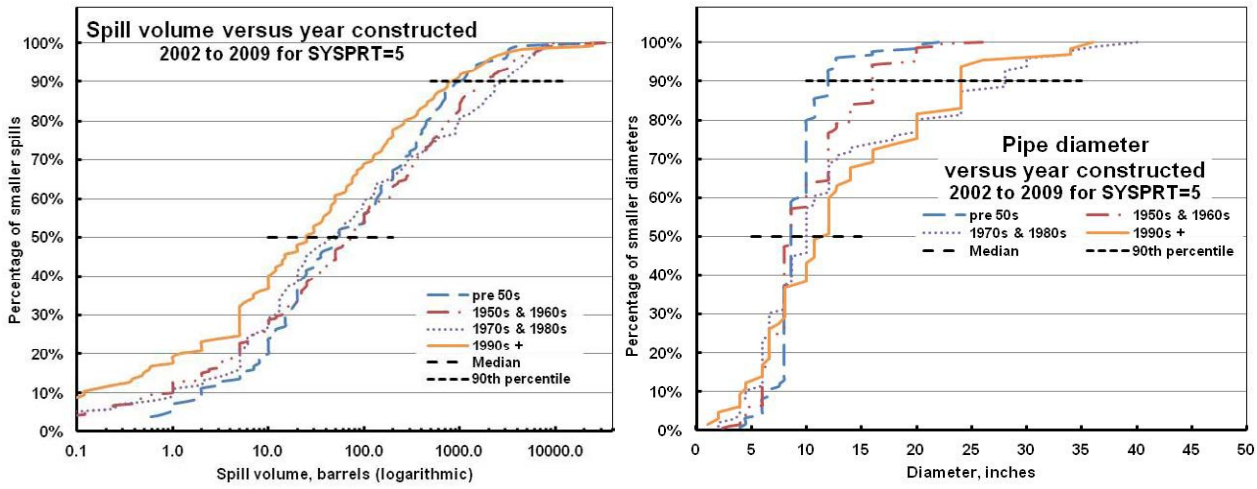
- The data for EC show a clear decreasing trend over time and a marked drop into the period for modern pipelines, which now covers almost two decades. While the use of CP was mandated in 1970, its selective use began for some operators well before that, with the ongoing effort to improve CP incrementally evident over time. Thus, the sharp drop in EC evident now for almost two decades more likely reflects the benefits of good mill-applied coatings and the increasing use of effective field-applied coatings. Such results support the use of adjustment factors and provide a quantitative basis to reduce the frequency of corrosion when determined from historic data.
- There is a gradual decay for IC, followed by a stable period. But there is also a recent upswing in IC incidence, apparently because the mileage and diameter of pipelines in crude service is increasing relative to that for refined products pipelines. While for this Project this concern is minimized by transport under turbulent flow conditions and other actions, the trend in Figure 18 makes clear that this threat warrants focused management for the Keystone system.
- There is no clear long-term trend evident for OF/TPD, whose incidence per mile varies widely by period of construction. Yet, for the modern pipelines with construction occurring from the 1990s and forward, it is apparent that the required one-call response,

working in conjunction with "call before you dig" and the efforts of the Common Ground Alliance and others, has cut the incidence of TPD significantly. But while the incidence of TPD is reduced, other analysis suggests that second-party and first-party incidents appear to continue. While in theory such incidents could approach zero, this category is unlikely to ever reach zero over any extended period of time because it includes random acts of nature.

- For early construction, there were many M&C issues, with lesser concern evident for the "other" catchall category. As time passed and as cause-effect relationships developed the understanding needed to avoid such causes, these categories stabilized until the period beyond the 1960s. Since then, newer, higher-strength grades continued to emerge and pose challenges that continue to affect construction. In addition, as time has passed, the pipeline systems have become more complex, with monitoring and SCADA playing an increased role. With this increased complexity comes concern for small leaks such as those related to MLVs and other fittings or gaskets. This report has stressed the need to for the Project to focus on SCADA-related concerns and to more broadly assess emerging threats, realizing that latent threats are plausible. This is evident in Figure 18 in the continued increase in such incidents for modern pipelines.
- When the trends in Figure 18 are coupled with (1) analyses of the related consequences, and (2) the observation that the primary threats leading to a major spill are external corrosion and OF/TPD, it is clear that new construction is the best means to minimize the risks involved with transporting crude oil, for both the environment and the public. A second clear observation is that while pipeline systems in operation for decades do pose higher risks, monitoring and effective timely maintenance can hold the system at a risk level approaching that of new or recently constructed pipelines. What is not apparent from Figure 18, but is clear from Figure 16, is that the heavier wall construction planned for the Project in conjunction with other planned actions like the 57 Special Conditions (some of which are unique) lead to the conclusion that the proposed Project would very likely be one of the safest pipelines, if not the safest, ever built in the US.

2.6.4.3 Viability of Modern Pipelines – Spill Volume

Figure 18 shows the benefits of transporting crude in modern construction as opposed to pipelines constructed prior to 1990. In light of Figure 15 and Figure 16, this benefit traces respectively to improved defect tolerance (due to better mechanical and fracture properties) and increased wall thickness. Benefits due to increased defect tolerance and heavier wall thickness should also be manifest in decreased spill volume for recent versus historic construction. This expectation is evaluated in Figure 19.



a) spill volume **b) diameter dependence**

Figure 19. Spill volume and pipe diameter as a function of period of construction

Figure 19a presents the cumulative distribution of spill volume on the y-axis as a function of the spill volume on a logarithmic x-axis, with contours shown in the figure for the same construction intervals considered above in Figure 18. Figure 19b presents the cumulative distribution of pipeline diameter on the y-axis as a function of diameter on the x-axis, with contours shown for the construction intervals considered in Figure 18.

Using the data summarized in Figure 19, the mean spill volume before for crude oil pipelines installed before 1990 is 50 barrels and after 1990 the mean spill volume is 30 barrels. During the same time period the total volume of crude oil being transferred has more that doubled. From Figure 19b, it can be seen that this decrease is occurring at the same time as median diameter of the pipeline being installed is increasing in the 1990 and beyond time period. Thus the post 1990 pipeline has better performance despite the increases in both flow rate and diameter of the pipeline, a trend that would not be anticipated if the post 1990 pipeline was not performing better. To more accurately quantify the improved performance would require the analysis to consider the pipeline-mile-years represented by the two sets of data, pre-1990 and 1990 and after. Since the miles of crude oil pipeline operating in the United States was not reported prior to 2002, the miles of crude oil pipeline before 2002 would have to be estimated. The conclusion at this time is that the post 1990 crude oil pipelines are performing better than the pre-1990 installed pipeline in spite of the use of higher flow rates and bigger diameter pipe, both competing factors that would suggest larger median spills.

2.6.5 Summary and Priorities

Priorities at a high level focus on prevention and protection with a view to avoid and/or minimize any inadvertent release, followed by mitigation, which becomes the focal point in the event that the

preventive and protective actions fail to function as planned. Analysis of anomaly response and trending of the incident causes as a function of the diameter clearly show that the lineal portion of the Keystone XL Project is robust from a preventive perspective in regard to axially oriented anomalies. Care should be taken to ensure that similar analyses are considered in the context of the girth welds and that related defect tolerance is assessed and achieved, subject to the PHMSA process. Similar assessments made in regard to the protective or mitigative aspects show that these too are in balance with needs. If this Project moves forward to PHMSA oversight, all aspects of prevention, protection, and mitigation should be monitored to ensure that plans and commitments remain viable and are implemented as outlined to date. Care should also be taken to heed the guidance that is emerging from recent efforts to avoid potential incidents built in during construction[31].

3. Summary and Conclusions

Following discussions among the DoS, PHMSA, EPA, and Keystone, Battelle and E^{x}ponent were contracted by Keystone to provide third-party review. E^{x}ponent was requested to perform an environmental review; and Battelle was requested to perform a general engineering review and evaluate any findings arising from the E^{x}ponent assessment. Battelle and E^{x}ponent were asked to address a list of questions posed by the agencies. This report presents the outcome of Battelle's review in consultation with E^{x}ponent, with a focus on the Project's 2009 Project Risk Assessment and the proposed valve placement incorporated in light of the PHMSA's project-specific Condition 32.

The Battelle review evaluated the following engineering aspects of the pipeline: (1) failure frequency; (2) risk assessment; (3) outflow analysis and placement of valves; (4) fate and transport analysis; (5) detection of leaks; (6) prevention of leaks; and (7) protective and mitigative measures. Battelle's review was made in consultation with E^{x}ponent. The work by E^{x}ponent[(2)] dealt in part with questions posed by the EPA and considered (1) the Keystone environmental risk assessment methodology; (2) the characteristics of the crude oil being transported; (3) the transport and fate characteristics of spilled crude oil; and (4) two environmentally sensitive issues: shallow groundwater and small stream crossings.

Many conclusions derive from this review and the analyses performed to support it. General conclusions are presented first, followed by those that focus on specific topics.

3.1 General Findings

The PHMSA database is the primary source of data on pipeline incidents. When analyzing and characterizing spill frequency and volumes, it is important to consider the discrete system elements. For example, mainline pipe represents about 40 percent of the total incidents. The graphs in Section 2.2.5 clearly show that the mainline pipe is the primary source of environmental exposure as it traverses remote ecosystems and natural resources. As discussed in Section 2.6, design, construction, and O&M compliance with the 57 Conditions[(7a)] is the foundation for pipeline integrity, which in turn protects the environment as well as the public against the effects of unplanned releases. These conditions focus on ensuring that the pressure boundary remains intact during the operational period of the pipeline, thereby ensuring the protection of the ecosystems it traverses. As discussed in Section 2.6.4.2, the steel and the long-seam weld of the line-pipe, the girth-welding, and the inspection and other practices involved in the construction phase have benefited from continuous improvement, which is a Code requirement. Similarly, the mill coatings, field coatings, and inspection practices have benefited from more stringent Code requirements and have resulted in continuous improvement.

While a great deal of attention has been focused on the use of material and welding practices that result in improved performance of the mainline pipe, similar attention has not been placed on pumping stations and other discrete aspects of the system, as the earlier spills from the existing Keystone Pipeline makes clear.

The potential for a leak posed by pumping stations and other discrete aspects of the system is larger than generally perceived, with benefits potentially accruing in regard to elements such as valve seats, bearings, and other seals or in regard to scheduled actions or enhancements to O&M procedures. Keystone notes that reliability and other analysis developing under a PHMSA corrective action order (CAO) on the existing Keystone Pipeline should bring about improvements, although this clearly depends on the outcomes in response to the CAO.

Several conditions of the Special Permit that are unique to the typical hazardous liquid pipelines focus on operations aspects, including leak detection. However, detection of leaks smaller than the detection threshold for the primary monitoring system, combined with the large flowthrough planned for this pipeline, clearly creates a key environmental concern in the event that the safety boundary is breached.

The mainline line-pipe, construction, coating, and inspection practices for modern pipelines are greatly improved, in contrast to those still dominating the incident records in the PHMSA Liquid Hydrocarbon Incident Database. This suggests that such historic data will overestimate incident likelihoods associated with the mainline, particularly in regard to EC. In addition, one of the PHMSA's 57 Conditions pertaining to internal cleaning should reduce the likelihood of failures due to IC. The minimum wall thickness that applies throughout the mainline (0.465-inch) will greatly reduce susceptibility to mechanical damage, as will a deeper, 4-foot minimum burial depth of the pipeline. While the incorporation of these requirements tends to reduce the mainline system concerns, the requirements are not being imposed to reduce the likelihood of releases from valves, stations/tanks, and related equipment. Equipment-related concerns (discussed in Section 2.1.1.1.3) therefore represent a viable threat. These concerns should be either addressed or demonstrated, through analysis or trending, that they can be disregarded. Keystone notes that reliability and other analysis developing under a PHMSA CAO on the existing Keystone Pipeline should bring about improvements; however, as stated above, this depends on the outcomes in response to the CAO.

3.2 Failure Frequency

The failure frequency analysis began by developing a comprehensive list of threats to the pipeline system. One recommendation from the evaluation was that the currently coupled threats involving IC and EC (discussed in Section.2.2.3.4) should be uncoupled, as should those for materials and construction, unless statistically valid reasons are established to pool these data. Keystone asserts that this coupling of threats is valid. However, the PHMSA database administrators recognize that

they rely on independent drivers who must report independently; these independent reports support the documentation of statistical trends. As discussed in Section 2.2.6, incorrect operations should be included as a threat unless it can be demonstrated that it is not relevant. Similarly, human error, including failure to follow standard operating procedures (SOPs) and/or the existence of outdated SOPs, was identified as a viable threat. Vandalism, in the context of terrorism and sabotage, is considered plausible in today's world. The risk assessments described in ASME B31.8S and API 1160, which will be developed as part of the IMP, will define further data requirements.

The analysis of the threats clearly showed that failure frequencies of the pipeline cannot be accurately determined unless the mainline pipe is analyzed separately from the other pipeline system components. In the review of the current SEIS, Appendix considered four major system components: mainline pipe, mainline valves, tanks, and other system components. This breakout clearly shows that these system components have very different failure frequencies. In the 2013 draft risk analysis report *Risk Analysis of the Proposed Keystone XL Pipeline Route*[32], Battelle developed an alternative to the use of engineering factors to determine failure frequencies; that alternative adjusts the failure frequency downward to account for the additional requirements imposed on the pipeline. The Battelle risk analysis reports that Australian pipelines, which are built to modern standards, have a 10-fold lower spill rate. That factor-of-10 reduction might not be realized in the failure frequency of the Keystone XL pipeline because it is much larger than the Australian pipeline system; however, a sizable reduction can be anticipated.

3.3 Risk Assessment

The fundamental source of spill data is the PHMSA Liquid Hydrocarbon Incident Database. The risk assessments performed for the FEIS and the SEIS were reviewed and the database was also used to provide histograms and cumulative probability distributions for spill volumes as a function of pipe diameter and age. The historical distribution of failure causes was also developed to show the effect of improvements in the material of construction and in welding and coating technologies over the last several decades. The analysis of the data clearly showed that the time to recover from a spill was longer and the amount of material recovered was smaller along the mainline pipe RoW. This indicates the difficulty in recovering from spills in more remote areas, as opposed to fixed facilities such as pumping stations.

The risk assessment results show a decreasing trend in the median spill volume in modern construction in spite of the use of higher flow rates and greater use of larger diameter pipe. If the pipeline did not have better performance, the use of higher flow rates and bigger diameter pipelines would tend to result in a larger median spill volume. Thus the use of pipelines built to modern standards apppear to have clear environmental benefits when compared to the existing system.

Additional results from the queries of the database are as follows:

1. The flow rate and diameter (and so the transported volume) of this pipeline are among the largest for hazardous liquid pipelines in service in the US.
    a. Accordingly, the time over which a spill is controlled (noted as 12 minutes) corresponds to a minimum release close to 90 barrels (for the worst-case full-bore rupture).
    b. This volume excludes outflow through drain-down (the loss that occurs while the leak remains undetected) such that 90 barrels is a lower bound to the worst-case spill volume.
    c. Based on simulations of system response, an estimate of the upper-bound worst-case spill is about 20,000 barrels, with this value reduced significantly by planned valve placement. Based on responses to Battelle's inquiries, valves will cut this level by a factor of two to four, depending on the scenario considered.
2. Because of the pipeline's flow rate and diameter, if a leak develops, the Project has the potential for a very large spill well in excess of those quantified for the existing history tabulated in the PHMSA database (and other databases as well).
    a. Response plans matched to the product, threats, and potential consequences should be developed if this Project is sanctioned. In response to a Battelle suggestion, Keystone notes that the response plans are developing to address manpower, equipment, and ecosystem or resource-specific needs, which by 49 CFR 915 will be subject to review and approval by the PHMSA if the Project moves forward.
    b. As the PHMSA is the responsible agency for this activity, care must be taken to ensure appropriate consideration of response plans.
3. Significant spills do occur, as was evident more than once during 2011.
    a. The projected historic risk rate per mile-year (adjusted for application to this pipeline) points to a spill every several years.
    b. This historic rate is small in contrast to the often-cited spill frequency for the almost new Keystone Pipeline (regardless of the spill's cause or the volume released).
    c. Issues with the recently completed Keystone Pipeline expose the Keystone XL Project to stakeholder criticism and work to undermine regulatory confidence.
4. Spills are occasional events that, while over time might be declining, must be better understood in order to prevent them more effectively.
    a. Analysis of the historic data tabulated by the PHMSA indicates that there is a statistical difference between the susceptibility for pipelines to leak

and the susceptibility for stations/tanks/valves to leak, which suggests that these data should not be pooled.

b. It is noteworthy that the issues experienced early on for the Keystone XL Project all occurred in the vicinity of stations.

5. Small spills are hard to detect and so might not be identified quickly. Where they have occurred, they involve the longest-duration events in the PHMSA database.

Realizing that leak detection technology is neither adequate, nor convenient, nor efficient for the present application, the best alternative is leak prevention through an effective IMP that keeps the product in the pipeline, supported by other related preventive actions.

The engineering evaluation of spill frequency in Section 3.2 states the importance of breaking the system down so that components with very different failure rates are treated separately. The 2013 Battelle risk analysis shows that a breakout of the system elements results in a much better estimate of the median spill volume for mainline pipe and recommends, for planning purposes, a median spill volume of 100 barrels. The figures in Section 2.1.1.2 support this recommendation.

3.4 Outflow Analysis and Placement of Valves

As discussed in Section 2.3, Keystone provided the Battelle team with a privileged and client-confidential appendix to Appendix P of the FEIS that described the model and presented a curve showing the cumulative probability distribution of spill volumes versus spill probability. They also provided the analysis results for a 170-mile-long section of the pipeline traversing a portion of Oklahoma and Texas before and after complying with PHMSA Special Condition 32. The result was a 70 percent reduction in spill volume. The Battelle team evaluated (1) the model and the process used to quantify outflow, and (2) the effectiveness of valve placement to minimize outflow and thereby protect the public and environment. The Battelle team reviewed the outflow model and concluded that it was based on sound mathematical principles and should provide conservative estimates of spill volumes. The information was not sufficient to demonstrate that the valves were placed in a manner that would provide adequate protection to sensitive environmental areas.

Valve placement (location and placement) can be both a benefit and a liability. The CFR language under §195.260 is encompassing, stating that (paraphrased) a valve must be installed at locations along the pipeline system to minimize damage or pollution, as appropriate for the terrain or for population, with other provisions that motivate the use of valves applicable. Analysis of the Keystone responses suggests that these requirements have been met, along with a reduction in the mainline spacing from 20 miles to 10 miles. However, trending the tabulated PHMSA database indicates that equipment and incorrect operations, both of which are relevant to valves, pose significant threats. This suggests that limiting the number of valves might be warranted. It also indicates that valve maintenance is essential for all valves and critical for those that are on the

critical path with respect to pipeline operations and control. It is noteworthy that the PHMSA is currently seeking public comment in regard to valve spacing[33]. Significantly, incorrect operations also have the potential to cause a major release.

3.5 Fate and Transport, and Sensitive Environmental Resources

To reduce the impact of a leak, it is essential to detect such events shortly after they occur. Leaking crude may not present at the surface quickly, and patrols may not visually detect leaks on the first pass. The results of the fate and transport modeling presented in E^{x}ponent's report[2] show the importance of detection on the first pass of a patrol. Leaks just below the threshold of detection of an internal LDS could result in significant loss of product when detection is delayed by one patrol cycle. Sniffer systems for hydrocarbons are available and might be appropriate for patrols to increase the probability of detection. Analysis of the physical and chemical characteristics of the transported products indicates that they are within the bounds of typical medium to heavy crude oil. Therefore, these products should not result in excess risk in case of a release.

Surface spills of oil on land will tend to remain localized and migrate slowly into the soil because of the high viscosity of this crude. This means that potential threats to groundwater depend on water table levels. Spills into surface waters can be transported beyond the 5-mile distance used to identify sensitive environments (e.g., HCAs).

Transport and fate analysis in groundwater concludes that plumes of dissolved hydrocarbons, to the extent they develop, will be on the order of hundreds of feet in length and will move relatively slowly. Longer plumes can occur under pumping conditions.

For the purpose of identifying potentially sensitive groundwater areas, the following criteria were proposed: distance from the pipeline (within 1,000 feet); water table elevation (within a few feet of the pipeline); and the presence of clusters of domestic and irrigation wells.

Because oil spill detection and response times are much faster than the times required for an oil spill to develop hydrocarbon plumes and for those plumes to travel toward receptors, spill countermeasure plans and associated cleanup actions should be effective at protecting groundwater resources. Criteria were developed and applied to identify potentially sensitive environments at small stream crossings; a number of such environments were identified along the pipeline route. Concern for small streams can be managed through construction via micro-bore or similar techniques, with the suggestion that four streams be added beyond those identified by Keystone.

Theoretical modeling exercises of subsurface transport raise the possibility that a low-volume release could go undetected as it migrates up to the surface or as it travels along the bottom of the pipe ditch, which often serves as a conduit for groundwater.

1. Conceptually, this response differs greatly with product viscosity. The possible presence of volatiles that would flash as the product exits the pipeline and the pressure drops to ambient could also be a factor.
2. Conceptually, this migration will vary with soil type, terrain, drainage, and other local factors.
3. Because the time available precludes other than order-of-magnitude analyses of such aspects, care should be taken to explore this range of possibilities in the event the Project proceeds through the NEPA/EIS process.
4. In particular, as part of the PHMSA-related process, consideration should be given to each class of transported product and to how it will respond in the environment.
5. Care should be taken to ensure that a one-size-fits-all response is viable across the range of crude oils and diluents that could reasonably be anticipated.

The analysis identified many factors affecting the behavior and fate of crude oil in the environment: (1) the nature of product spilled; (2) the volume and rate of the spill; (3) the physical, chemical, and biological characteristics of the receiving environment; (4) the weather conditions at the time of the spill; (5) the amount of time elapsed until detection; and (6) the adequacy and timing of response activities. Of particular importance is the receiving environment (e.g., water and soil attributes, slope, gradient, topography, underlying geology, and weather and climate), which in turn impacts the dispersion, fate, plume size, and transport. Gaps were identified in the Keystone fate and transport analysis regarding the transported product's chemical and physical characteristics and its weathering and transport behavior. To close these gaps, E^{x}ponent was asked to provide a quantitative fate and transport analysis and numerical screening model, which take into account the characteristics of oil, in order to shed light on the potential transport and fate of the transported product.

From an engineering perspective, it is important to use proper construction techniques, such as micro-bore, for small stream crossings. During construction, and continuing into the operational phase, additional analyses are needed to assess overland flow (spreading) and transport for specific pipeline sections that intersect identified sensitive habitats, including the four streams identified by E^{x}ponent. Such modeling exercises can be used to inform ERPs. Well depth and depth of release can also be assessed relative to the water table to screen and identify sensitive groundwater resources that may be more vulnerable to exposure to a hydrocarbon plume in the event of an oil spill. Finally, it is important to determine the presence of PAHs and naphthenic acids so their transport can be better quantified, resulting in more informed environmental remediation and response planning.

3.6 Detection of Leaks

Detection technology still falls short of the level needed to effectively detect smaller spills on large-diameter high-flow-rate pipelines, with the metric used to quantify detection as a percentage of flow, causing confusion about the volume that potentially could be detected for pipelines such as the Keystone XL Project. While Keystone is actively addressing the state-of-the-art detection capability for large-diameter, high-flow-rate scenarios and is engaged in testing/evaluating options as they emerge, the reality falls short of quickly detecting small leaks for the Keystone XL Project. Because detection of small leaks remains a concern, Keystone should plan to address those developments and aggressively move to implement the technology as time passes and technology evolves/matures. Based on their responses to inquiries made over the course of the work, Keystone has demonstrated that they are fully engaged in related industry activities. Detection of small leaks should be a part of Keystone's change management practices. The leak detection approach proposed for the Project, CPM, is the industry standard for crude oil pipelines and should have better-than-average performance because of Keystone's more frequent use of sensors. While CPM is the standard practice, the detection limit is normally expressed as time to detect a specified percentage of throughput. Thus, for a specified spill size, the detection time can be longer when the throughput is higher, as is the case with the Keystone Pipeline. This means that leak detection cannot rely solely on CPM.

Keystone will also rely on the non-standard use of an over/short analysis, which calculates a long-term system volume balance. In some studies, it has been shown that the ability to quickly detect small leaks exists at levels as small as 1.5 to 2 percent of throughput. Since there is a desire to detect leaks that are smaller than the capability of the CPM, reliance must be placed on other methods such as ground-based or aerial surveillance programs. These surveillance activities could be more frequent in sensitive environmental areas or in areas where third-party damage is more likely.

The risk analysis performed by Battelle showed that facility risks were significant. While leaks at facilities tend to cause less environmental damage, the Battelle risk analysis (2013) clearly showed that it would be cost-effective to focus more effort on facility leaks. Between the start of 2002 and the end of 2012, the largest spill was a 49,000-barrel spill from a tank at a fixed facility. The largest spill from a mainline pipe rupture, while still large, was smaller − about 31,000 barrels. Indeed, if the leaks at fixed facilities are significant and frequent, leaks detected by the CPM may be attributed to a facility, and an actual leak along the pipeline may go undetected for a longer period of time.

The pipeline industry is always looking at implementing new leak detection technologies as they come available and can be deployed in the field. They could represent a significant increase in leak

detection sensitivity. In-line leak detectors can be deployed as part of pig trains run under the IMP. Leaks are not expected to be frequent; however, because many of the failures are the result of human activities, establishing an effective patrol frequency may detect, and therefore minimize, the consequences of a leak before a CPM system detects the leak.

3.7 Prevention of Leaks

Results presented for prior tasks have assessed risks and quantified threats and spill volume from pipelines with an average age of greater than 40 years. System integrity is fundamental to leak prevention. The objective of this task was to quantify the effectiveness of the current design, construction, and operation practices. Along the mainline pipe, leak prevention focuses on detection of defects in the pipe itself, on the longitudinal welds made during fabrication, and on the girth welds that connect the line pipe across the RoW. Battelle's evaluation of leak prevention considered the effectiveness of the external coating placed on the pipe and on the girth welds, as well as on the CPM system.

Recognizing the need for an effective IMP that keeps the product in the pipeline, usual procedures and company best practices could be refined to enhance certainty involving various integrity metrics. A baseline run for each of the inspection technologies to be used in the IMP has the potential to avoid/minimize uncertainty in the analysis of data obtained once the pipeline is in service and subject to the IMP. For many of the ILI and other inspection technologies, the ILI industry is well into a third generation of tools; however, uncertainty with data interpretation persists. Repeat runs of select technologies could enhance certainty and define the need and utility of such practices, to optimize the IMP.

Prevention is directed at avoiding a release by keeping the product within the line-pipe and the system components. Several actions were identified beyond those associated with satisfying Title 49 of the CFR or the steps already planned by Keystone beyond Code; these actions indicate reasonable underlying judgment. Potential actions include the following:

1. Consider alternative practices in regard to specifying seals and seats, from design and material selection through related implications in maintenance, over the life-cycle of the equipment.
2. Consider more frequent scheduled maintenance for valves and other equipment, at least initially, and utilize pre-service offsite leak checks and equipment shakedown where plausible.
    a. To improve data interpretation, run pre-service ILI for all technologies anticipated for use in IMP to establish a background against which subsequent interpretation can better distinguish changes in potential threats.
    b. To avoid onerous aspects tied to the focused use of in-line leak detection

technology, consider running such technology as part of an early pig train, which is part of usual operations to establish the background. Then, consider its periodic use as part of pig trains that are required for IMP.

Because small leaks remain hard to detect, the only recourse is to prevent them, which requires that the Keystone XL Project have a robust leak detection program. The discussion in Section 2.2.3 shows that the primary environmental exposure was the mainline pipe portion of the Project. Disregarding external forces, the dominant failures are at the line-pipe, the girth welds, and the mainline valves. Because these parts of a pipeline system can be remote (meaning spills at these components are most difficult to mitigate or detect) their adequacy was assessed quantitatively. The analysis results in the following conclusions:

1. Analysis indicated that for normal operation at 72 percent of SMYS (MAOP for the Project), the first IMP response threshold (at a 40 percent deep part-through-wall) is associated with an anomaly length in excess of 15 inches.
    a. This result is uncommon even when serious areal corrosion develops.
    b. The second IMP response threshold (at a 60 percent deep part-through-wall) was associated with lengths of about 6 inches.
    c. Such features can be reliably found with ILI that targets corrosion.
2. It was determined that under worst-case circumstances, at least one ILI cycle would occur with the transition from one anomaly-response threshold to the next, and that if a benchmark ILI run is made pre-service, then a total of three ILI cycles occur before reaching the first IMP (scheduled) threshold.
    a. According to a worst-case corrosion rate, the scheduled threshold would be first experienced after about 12 years of operation.
    b. If a more representative rate is considered, this interval doubles to more than 24 years.
    c. In view of the above, the line pipe for the Keystone XL Project – as designed and without considering the benefits of coating or CP – provides a significant margin of preventive protection against corrosion.
3. A similar engineering critical assessment is done for the girth welds to ensure their defect tolerance as part of the PHMSA's process, which ensures this same outcome in regard to the girth welds and the related inspection and quality control.
4. Incident trending in regard to wall thickness indicates that virtually all incidents in the historical database for excavation damage or for the aggregated causes identified for the SYSPRT = 5 reporting category have occurred in pipe whose wall thickness is less than that for the Project's mainline line-pipe.

   a. As designed, the line-pipe for the Keystone XL Project provides a significant margin of preventive protection against all apparent historic threats that impact the mainline, including mechanical damage.
   b. This outcome holds even without the benefit of the potential risk reduction that could accrue from deeper-than-code-required burial depth, the use of HDDs, and the segment-specific use of an ARO coating.
6. Survey/patrol frequency, even at the nominal two-week interval, is largely ineffective based on some analysis.
   a. Analysis done by Battelle staff over the years indicates that the likelihood of missing an encroachment action at a two-week patrol frequency was quite high.
   b. Work done C-FER[e.g., 14] (Reliability Based Prevention of Mechanical Damage to Pipelines) likewise indicates about a 90 percent chance of nondetection at two-week intervals.

3.8 Protective and Mitigative Measures

Actions can be taken to (1) prevent/avoid a release through design, (2) mitigate by limiting release consequences, through control and response to an inadvertent release from early detection through cleanup, and (3) protect the environment by minimizing release impacts through the use of enhanced LDS or EFRD technology. The term "protective measures," when defined relative to minimizing the impacts of a release, can be considered generic, encompassing mitigation and prevention because they too limit or avoid environmental impacts.

Mitigation targets the post-detection response to a spill, with several actions identified beyond those associated with satisfying Title 49 of the CFR. Potential actions include the following:

1. Provide response teams and packages that are designed for the scope of transported products and their potential interaction with the ecosystems that the pipeline traverses.
2. Locate those response teams and packages selectively at ecosystems and resources deemed critical/high-value, at a level that is broader than the current narrow PHMSA definitions of an HCA or USA (which are currently the subject of Federal review[33]). While such aspects become more definitive post-NEPA (as part of PHMSA's oversight), correspondence prepared by Keystone, which emerged subsequent to identifying this action, makes a commitment in writing to Senator Mike Flood (Nebraska) regarding the design of their response teams and their placement relative to critical ecosystems and resources. Keystone also offers a performance bond to back up that commitment, along with other actions cited under the protective heading.

Protection involves aspects from design through O&M, and related organization, to minimize environmental impacts by reducing the exposure in the event of a spill. This can be achieved by

detecting a spill early and by limiting the duration of and outflow from the spill. Several actions were identified beyond those associated with satisfying Title 49 of the CFR or steps already planned by Keystone beyond Code. Potential actions include the following:

1. Consider broader use of the technologies identified in Section 2.5 and utilize patrols on a frequency matched to such technologies.
2. Depending on the nature of the terrain, aspects of the water table, and other factors, consideration should be given to the selective use of concrete coated line pipe (or an equivalent or better approach).
3. Review indicates that Keystone has used leading practices in assessing valve location and spacing.
    a. The current plan, which utilizes RCVs, CVs, and MOVs, added valves and made other modifications subject to PHMSA Special Condition 32, which could achieve a significant decrease in outflow in the event of a spill.
    b. Because the response times for valves in liquid lines are limited by the potential of fluid hammer and related overpressure surge, the current valve protection plan influences only the cumulative distribution of releases and their potential size if valve closure works as expected. Response times for systems cited in the literature call into question Keystone's stated closure interval (12 minutes), which suggests that if the Project transitions to PHMSA oversight, consideration should be given to confirmatory analysis to validate the underlying assumptions and dynamic modeling, with the related plans reassessed as needed.
4. For location-specific elements like facilities that are currently sited in or threaten sensitive ecosystems or resources, consider unique approaches to protect those sites.
    a. It is recognized that correspondence prepared by Keystone states a commitment in writing to Senator Flood (Nebraska) regarding the use of a facilities design that rests on a concrete pad and related containment, which directly provides such protection. Keystone also offers a performance bond to back up that commitment.

Consideration was given to comparable quantitative analyses for the protective or mitigative aspects. Quantitative outcomes developed for valve placement and spacing demonstrated a significant reduction in the potential outflow when additional valves were installed and when the placement of valves was modified in response to PHMSA Special Condition 32. Proper siting of response teams could achieve a reduced response time, from the maximum of 12 hours mandated by regulations down to two hours, and could better mitigate the effects of a spill on sensitive environmental areas in the event of an unplanned release. Once construction begins, such analyses

will be subject to PHMSA review and comment, which provides the basis for further stakeholder assessment and comment.

If effectively implemented, the 57 Special Conditions for this pipeline could make the Keystone XL Pipeline one of the safest pipeline to operate in the US. Further, the analysis presented makes clear that in spite of increased throughput and the greater use of larger diameter pipe, the trend shows a decrease in the median spill volume with modern construction. The reduced median spill volume indicates that the transport of crude by new construction should result in environmental benefits.

4. High-Level Recommendations

The proposed Keystone XL Project, as described in the DoS 2013 SEIS[1], consists of a crude oil pipeline and related facilities to transport WCSB crude oil from an oil supply hub near Hardisty, Alberta, Canada, to existing pipeline facilities near Steele City, Nebraska, for delivery to Cushing, Oklahoma, and the Gulf Coast area. The US portion of the transboundary Project consists of approximately 875 miles of new, 36-inch-diameter pipeline across portions of Montana, South Dakota, and Nebraska.

The DoS released the FEIS for the Project in August 2011. Following its release, the DoS, PHMSA, and the EPA jointly concluded that it would be beneficial to have a third-party review of the Risk Assessment prepared by AECOM and Dynamic Risk Assessment Systems, Inc., on behalf of TransCanada Keystone Pipeline, LP. As part of this third-party review, Battelle was charged to evaluate the following engineering components of the pipeline and original Risk Assessment: (1) failure frequency (2) risk assessment, (3) outflow analysis and placement of valves; (4) fate and transport; (5) detection of leaks; (6) prevention of leaks, and (7) mitigative and protective measures in the event of a spill.

The recommendations that follow are based on (1) our review of the Risk Assessment commissioned by Keystone (Appendix P of the FEIS and Appendix Q of the SEIS); (2) analysis of the historical record of crude oil pipeline performance from the PHMSA database; (3) the regulatory requirements currently in place and overseen by PHMSA; (4) implementation of the 57 Regulatory Conditions imposed by PHMSA; and (5) our best engineering and risk assessment judgment.

Failure Frequency: The PHMSA Liquid Hydrocarbon Incident Database should continue to be used, but the analysis should be limited to crude oil spills and should consider the very different spill performance data for major systems (i.e., mainline pipe). The results should be presented without the use of engineering adjustment factors. Until there is enough modern pipeline performance data to negate the need for adjustment factors, data from other sources, such as performance data on the more modern Australian pipeline system, should be used to show that the results presented are conservative. Appendix K of the SEIS should be used as the starting point for such an updated analysis. Until that re-evaluation is performed, it is recommended that, for planning purposes, a medium spill volume of 100 barrels be used. A larger volume may have to be used in locations where the terrain produces a hydraulic gradient.

Risk Assessment: Future risk assessments for this pipeline should divide the pipeline system into component parts, assess the risk for each component, and then calculate the system risk from its components. The risk analysis performed by Battelle used Total Incident (Damage) Cost as a measure of the consequences. The risk analysis shows that the subsystems that generate almost all

the risk are the mainline pipe and the fixed facilities such as the pumping stations. Thus, when developing preventive, protective, and mitigative programs, equal focus should be on the mainline pipe and the fixed facilities.

Outflow Analysis and Valve Placement: It is essential that the pipeline design protect the environment by controlling a spill through valves located to minimize both the potential spill volume and its consequences. The model and the process that were used by Keystone to ensure that valves are placed to minimize the total outflow from a breach appear to be correct and should continue to be used. It is recommended that portions of the outflow analysis be redone to reflect the new route and thereby ensure that the results are not significantly different from the results presented at the time the FEIS was published.

Fate and Transport: E^{x}ponent developed and applied criteria to identify potentially sensitive environments downstream of small stream crossings, with a number of such environments identified along the pipeline route. From an engineering perspective, concern for small streams could and should be managed proactively during construction via micro-bore or such techniques. During construction, and continuing into the operational phase, further analysis should be done to assess overland flow (spreading) and transport for specific pipeline sections that intersect identified sensitive habitats, including the four streams identified by E^{x}ponent. This modeling exercise could then be used to inform ERPs. Well depth and depth of release should also be assessed relative to the water table to screen / identify sensitive groundwater resources that may be more vulnerable to exposure to a hydrocarbon plume in the event of an oil spill. Finally, it is recommended that the presence of PAHs and naphthenic acids be better quantified for the products that are actually transported in the pipeline to better inform environmental remediation and response planning.

Leak Detection: No matter how effectively pipeline systems are designed and constructed, there will always be a finite chance that a leak will occur. Therefore, leak detection is essential across the range of potential release components of the pipeline. Because facility risks are significant, it is recommended that leak detection efforts be placed on both the mainline pipe sections and facilities (including tanks). As new leak detection technologies emerge and start to be deployed in the field, Keystone should continue to evaluate these technologies and consider them for implementation if they represent a significant increase in leak detection sensitivity. In-line leak detectors should also be deployed as part of the pig trains run under the integrity management programs. Leaks are not expected to be frequent; however, because many of the failures are the result of human activities, it is recommended that aerial surveys and/or ground patrol frequency be increased to once a week.

Leak Prevention: The objective of this task was to quantify the effectiveness of the current design, construction, and operation practices in preventing leaks. Along the mainline pipe, leak prevention focuses on detection of defects in the pipe itself, on the longitudinal welds made during fabrication,

and on the girth welds that connect the line pipe across the RoW. Battelle's evaluation of leak prevention considered the effectiveness of wall thickness, controls for steel and longitudinal seams, and the external coating placed on the pipe and on the girth welds, as well as on the CP system. It is recommended that ILI be performed proactively prior to the start of operations. These inspections are capable of detecting major defects in welds and in the pipe wall, as well as defects caused by placement of the pipe in the ground. Any detected defects can be repaired before the start of operations and thereby reduce the probability that a leak will occur soon after the start of operations. It is understood that Keystone has committed to these ILIs prior to the start of operations.

Mitigative and Protective Measures: The information provided to Battelle was quite limited and did not address any spills in sensitive areas. Additional spreading analyses should be performed in areas where sensitive environmental receptors are found to demonstrate that these areas are being adequately protected and that additional valves would not have a net benefit. Since it is very expensive to move the placement of valves after all the construction details have been developed, the greatest utility of these calculations would be to have preliminary results available early in the process with the formal validation of their placement, demonstrating that the placement does minimize spill volumes.

During the construction phase, response team and equipment needs should be identified based on the scope of transported products and their potential interaction with the ecosystems that the pipeline traverses. Keystone has recently stated concurrence with this action and has indicated that they will (1) target response plans to the ecosystems and resources traversed, and (2) reduce the response time to two hours in such cases as compared to the minimum 12 hours of 49 CFR 194. Response teams and packages should be selectively located at ecosystems and resources deemed high-value, at a level more refined than the current narrow PHMSA definitions of an HCA or USA.

Since areas along the pipeline where seals and seats are present (e.g., on equipment and pumps) have a higher potential for spills, Keystone should be diligent about the material selection for seals and seats, from both the design and maintenance perspectives, over the life-cycle of the equipment. They should also consider more frequent scheduled maintenance for valves and other equipment, at least initially, and utilize pre-service offsite leak checks and equipment shakedown where plausible.

Depending on need dictated by the nature of the terrain, aspects of the water table, and other factors, Keystone should consider the selective use of concrete coated line pipe (or an equivalent or better approach). For location-specific elements, like facilities, which are currently sited in sensitive ecosystems or resources, Keystone should also consider unique approaches to protect those sites, such as containment of facility leaks through the use of concrete pads and berms.

Although analysis of anomaly response and trending of the incident causes as a function of the diameter clearly show that the lineal portion of the Keystone XL Project is robust from a preventive perspective in regard to axially oriented anomalies, care should be taken to ensure that similar analyses are considered in the context of the girth welds, and that related defect tolerance is assessed and achieved, subject to the PHMSA process.

Finally, all aspects of prevention, protection, and mitigation should be monitored to ensure that plans and commitments remain viable and are implemented as outlined.

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