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Risk Analysis of the Proposed Keystone XL Pipeline Route

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Notice

This work has been prepared under contract to TransCanada Keystone Pipeline, LP, (Keystone), in response to needs identified by U.S. 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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1. Introduction

Risk assessments are commonly employed to compare impacts that are expected to occur as a result of a proposed action with impacts that may or may not occur because of system failures. The challenge of a risk assessment is to estimate the frequency of possible incidents and their consequences. The first steps are to 1) identify a basis to reasonably estimate the frequency of possible incidents and 2) select a way to measure consequences. The usual industry approach is to utilize information compiled by recognized agencies, such as the Pipeline and Hazardous Materials Safety Administration's (PHMSA) Liquid Incident Database[(1)] (hereafter Database), which covers crude oil pipelines in the United States. Analysis of relevant incident frequency is coupled with the related data on injuries, up to and including fatalities, which could occur to either workers or the general public. Between January 2002 and December 2012, an eleven-year period, two fatalities and five injuries were associated with incidents involving crude oil pipelines. The costs to prevent such injuries can be used as an avoidance cost; however, reliance on the data set would not present a satisfactory picture of pipeline risk because the data points are too sparse to be used as the sole consequence measure, and thus say little about risk to the affected environments. For the Keystone XL Pipeline, the consequence measure used in Appendix P of the Final Environmental Impact Statement (FEIS), and reported in the Draft Supplemental Environmental Impact Statement[(2)] (SEIS) as Appendix Q, was the estimated number of spills per year along the pipeline route. Because spills can vary from a few gallons to thousands of barrels, this measure does not capture the range of impacts from a pipeline spill. In the PHMSA Database, the reported parameters include total damage cost from a spill, as e well as the cost components that make up the total damage cost. As risk is a value-based metric, these cost data provide a better measure of the consequences as compared to metrics like injuries or spill frequency, which are not measures of risk. On that basis, cost data from pipeline spills are used in this analysis as the consequence measure for this risk assessment of the proposed Keystone XL Pipeline as currently routed.

The organization of this document is as follows. Section 2 describes the risk assessment methodology, followed by discussion in Section 3 of the damage costs for the incidents that have occurred between January 2002 and December 2012. Section 3 also summarizes the spill frequency analysis, which is largely taken from Appendix K of the SEIS. Section 4 presents a breakdown of the pipeline into elements for purposes of analysis. The four elements are: Mainline Pipe, Mainline Valves, Tanks at Facilities along the Route, and all Other System Components. Section 5 addresses the risk profiles for these four categories, which include frequency and consequence pairs for three spill sizes, up to 50 barrels, from 50 to 999 barrels and 1000 or more barrels spilled. Section 6 addresses risk reduction factors and other aspects unique to the proposed Keystone XL Pipeline. Section 7 provides a summary of the key findings of this risk assessment, and Section 8 presents the list of references cited.

2. Risk Assessment Methodology

This section describes the methodology that was developed to evaluate the total spill risk for the northern portion of the Keystone XL Pipeline. The basic risk equation is:

$$Risk = \sum_{i=1}^{n} f_i C_i$$

where f_i is the frequency of event i and C_i is the consequence of event i.

Pipeline risks comprise a linear component that reflects the length of the pipeline, as well as risks associated with fixed facilities located at discrete sites along the pipeline's route. These are two very different risk components. They may be expressed as follows:

$$Risk = \sum_{f=1}^{F}\sum_{i=1}^{N} N_f f_{f,i} C_{f,i} + \sum_{s=1}^{S}\sum_{j=1}^{J} l_s f_{s,j} C_{s,j}$$

where $f_{f,i,}$ is the frequency of spill event i at facility f and $C_{f,I}$ is the consequence of spill event i at facility f. An additional term has been added, N_f, recognizing that there could be N facilities of type f along a pipeline route. In the second set of sums, l_s is the length of pipeline segment s, $f_{s,j}$ is the frequency of occurrence of spill j in segment s, and $C_{s,j}$ is the consequence of spill j in segment s. To calculate the risk for the pipeline, the risk for all the segments along the pipeline and all the facilities along the pipeline must be summed.

Appendix K of the SEIS, Historical Pipeline Incident Analysis, uses the PHMSA Liquid Spill Database as a basis for the analysis. The Database identifies the system element that failed. In Appendix K, the system elements were broken first into spills that occurred along the mainline pipe and at the fixed facilities along the pipeline. The major components considered along the mainline pipe were the line-pipe and the welds associated with the joints of line-pipe and their construction into a pipeline (the linear component) and the valves (a fixed facility component). While many system elements are listed in the Project Description at the pumping and metering stations along the Keystone XL pipeline, Appendix K considers two: tanks and other discrete elements (pumps and fittings, etc.). While this distinction was made in Appendix K for frequency reasons, the same breakout also makes sense from a consequence standpoint. A storage tank, for example, has the potential for a spill that is as large as a pipeline spill. Similarly, failure of many of the ancillary components at the pumping stations would be expected to occur at a higher frequency because there are so many of them, while at the same time, the quantities spilled are expected to be smaller.

For the pipeline, solving for:

$$L = \sum_{s=1}^{S} l_s$$

L, the total length of the pipeline, must equal the sum of the segment lengths l_s. The number of segments considered and the lengths of the individual segments are dependent on the characteristics of the route. For each segment l_s, the frequency of failure and the consequences of the spill should be the same. The number of segments considered will depend on the ability to parse the data based on the differences in failure rate per mile or differences in consequences based on the presence of a specific feature along the pipeline. The existence of a protective feature on one portion of the pipeline and not in other areas might be another reason for breaking the pipeline into additional segments.

The above risk equation is general; hence if every component had its own risk profile, the data requirements would be enormous. The goal of presenting the general equation is to calculate comprehensive risk, and then attempt to simplify it based on the data. For example, it may or may not be possible to identify differences in risk between releases from valves that occur inside high-consequence areas (HCAs) versus those outside HCAs. Just because the data do not suffice to separate the two data groups, that does not mean that there are no differences. Between 2002 and 2012, there were only 25 mainline valve-related failures from an estimated 26,865 valve-years of exposure (Appendix K, Table 8). It is highly unlikely that the failure data would support subdividing of the mainline valve failure data (e.g., different risk profiles for mainline valves in HCAs and non-HCA areas).

In Appendix K of the SEIS, there are two system elements at pumping stations: storage tanks and ancillary equipment. The PHMSA data supported tabulating spill rates for each of these system elements. The analysis also grouped the spills into three sizes: 0 to 50 barrels, 50 to 1,000 barrels, and greater than 1,000 barrels. Spill rates per pipeline-mile-year or component-year were then obtained as the final result of Appendix K. In the Final EIS (FEIS) for the original Keystone XL Pipeline routing, the spill rate for the segments, adjusted for protective/mitigative features, was summed up for the length of the pipeline and termed the spill risk. The PHMSA Database contains an important consequence measure of value to this analysis, the total cost of each spill. This number includes the cost of emergency response, damage to private property, environmental remediation, the value of lost product, and any other cost incurred as a result of the spill. Three cost ranges are considered in this analysis: high, medium, and low. These costs are estimated for each of the system elements at the pumping stations and for the elements of the mainline pipe, the pipe itself, and the valve stations.

The high, medium, and low values for the spills are based on PHMSA data. The frequency is based on the characteristics of the pipeline. For some system elements, Appendix K provides an estimate of the number of spills per system-element-year; for the pipeline, the spill frequency is estimated by multiplying the high, medium, and low volume spill rates per system-element-year by the number of system elements present along the proposed pipeline and summed to get the risk for that system element.

The final step is to consider the effect of preventers and mitigators on the individual system element failure rates. Normally the preventative and mitigative features would consider if they would affect incident cost. However, since spill volumes are so poorly correlated with incident costs, such effects may be impossible to identify. Each adjustment factor is discussed, as is the basis for its potential impact on risk.

Clearly, the development of the risk profile for the individual system elements is the key to the whole risk assessment. An attempt is made to select reasonably conservative values for the incident costs that make up the risk profile for these individual system elements. Once the final numbers are presented, a brief sensitivity assessment presents the range of possible values given the uncertainty in the numbers. The range of values is useful when attempting to estimate the significance of the risk numbers for the proposed pipeline route. The following sections present historical risk, and develop the risk profile for each of the pipeline system elements.

3. Historical Risk

PHMSA has required operators of liquid hazardous material pipelines to file incident reports since the early 1970s. The information that had to be reported in the earlier years was quite limited; as time passed, more information was required. Since 2002, PHMSA has required a much more comprehensive list of information about a release and has used similar failure modes and damage cost criteria. Thus, even though the data were reported using two different formats (one for 2002–2009, and another from 2010–2012), it is possible to use the two databases (both of which are components of the PHMSA Database) as a source of risk information. The data contained in these two databases are highly variable.

Table 1 shows the high variability of the incident data. Over the 11-year period from 2002 to 2012, the maximum loss in a year ranged from a low of about 2,880 barrels to a high of 49,000 barrels, a factor of 17. The average spill size in a year ranged from a low of 82 barrels to a high of over 600 barrels, a factor of 7.5. The average damage cost in a year, escalated to 2013 dollars, ranged from a low of just over $100,000 to a high of about $6.5 million, or about a factor of 65. Given this variation, any risk assessment performed will present an average expectation in any given year. In an average year, the average release is expected to be about 260 barrels, and the average damage cost from the release is expected to be about $1 million (Table 1).

Table 1. Annual crude oil reporting statistics.*

Incident Year	Maximum Loss (Barrels)	Average Release (Barrels)	Average Damage Cost
2002	6000	113	$158,183
2003	9762	161	$108,318
2004	3148	137	$168,159
2005	25435	622	$1,353,176
2006	49000	537	$86,436
2007	4800	99	$106,911
2008	31322	387	$179,329
2009	3416	128	$174,684
2010	20082	347	$6,516,106
2011	12229	245	$1,215,369
2012	2880	82	$246,655
Average		**260**	**$937,575**

* Records restricted to net positive loss of oil (barrels) and $ damage costs.

The results in Table 1 do not consider records with a null entry for the System Part that failed – for example, *Mainline Pipe Including Valves*. In all, 800 crude oil incidents were identified and analyzed in the two databases over the 11-year period. For crude oil incidents an additional 617 records do not list a system part as failed. All instances of no system part listed were recorded in the 2002– 2009 database. The volume of crude oil lost from those spills totaled less than 1,500 barrels and the costs associated with those spills totaled $5.5 million, compared to a total cost of $1.767 billion for all spills (just 0.2% of the total dollar value). Table 1 shows an average damage cost of $937,575, so the 617 records lacking information about the system part that failed have a value equal to less than six average incidents. If the 617 could have been allocated to the various system elements, the average damage cost could have been cut almost in half. It will have to be assumed that these incidents, which have a average loss rate of about 2.5 barrels, were not considered by the reporting pipeline operator to be major spills and thus not worthy of full and comprehensive reporting. This problem does not carry over into the current reporting Database.

Continuing the analysis without regard to component parts, Figure 1 shows the distribution of total volume of crude oil lost (450,000 barrels) across seven categories of cause over the 11-year period. The entries listed for each slice in this pie chart denote the lost volume in barrels. It is apparent from the chart that the releases are dominated by three causes, each contributing about a quarter of the total loss: corrosion, material and/or weld failures, and natural forces. The numbers show that over 200,000 barrels have been spilled as a result of corrosion and material and/or weld failure combined, which on average is roughly 18,000 total barrels per year. The natural forces category is next in size, with about 74,000 barrels, which on average amounts to roughly 6,700 barrels per year. Referring to Table 1, there is much variability from year to year.

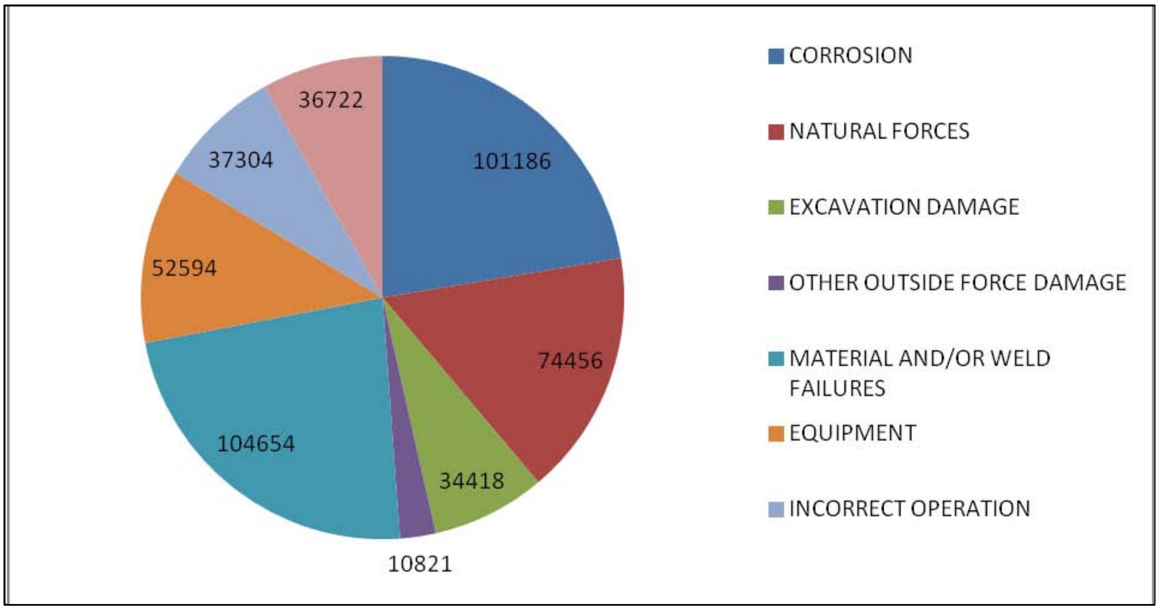


Figure 1. Loss of crude oil (barrels) by cause, 2002-2012 (PHMSA Database).

Figure 2 shows the cost payouts by cause code over the last 11 years, covering small (less than 50 barrels), medium (between 50 and 999 barrels), and large (greater than 1000 barrels) spills. Thus, this pie chart does not discriminate cost by spill size. The cause code with the greatest contribution to damage cost is material and/or weld failures, making up slightly more than one-half of the total cost. The next largest cause code is natural forces, which accounts for about

25 percent of the total damage costs. Taken together all other cause codes combine for a little less than 25% of the total cost.

The sum of the damage costs quantified in 2013 dollars shown in each slice of the pie in Figure 2 total $1.767 billion over the 11-year period. The average cost per incident per year, calculated simply as the total cost of incidents and divided by the number of incidents, is a consequence measure. In reference to Equation 1, risk involves both consequences and frequency. Realizing that the calculation to quantify the consequence metric involved dividing by the total number of incidents, one can also view this consequence metric as a measure of risk. This risk metric is on average approximately $160 million/year, since this average amount is paid out in damages on a yearly basis as a result of crude oil pipeline operations in the U.S.

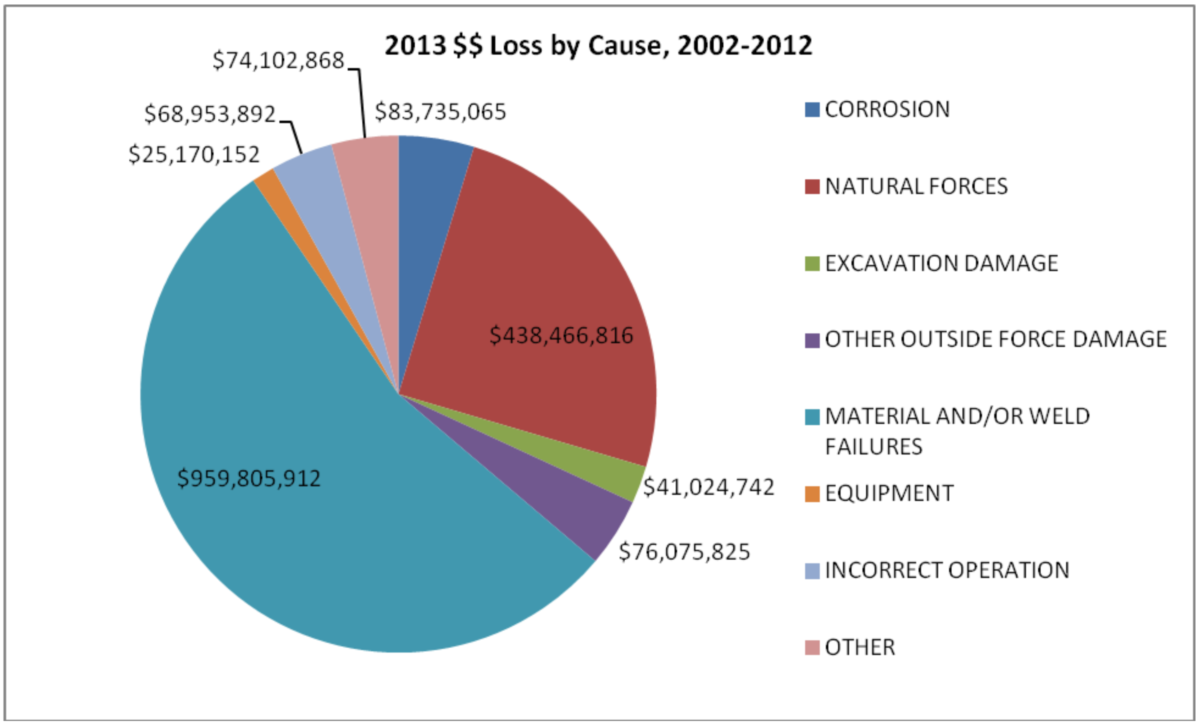


Figure 2. Reported loss by cause in 2013 dollars, 2002–2012 (PHMSA Database).

The data in Figure 2 show that 54 percent of the total damage cost is attributed to material and/or weld failures. A detailed analysis of this result shows that 90 percent of the damage cost is attributed to the 2010 Enbridge spill, whose estimated cost as reported in the PHMSA Database is over $870 million in 2013 dollars. The damage cost from that single incident represents 49 percent of the total damage costs experienced over the 11-year period. This rupture involved a 30-inch diameter pipeline with a 0.250-inch wall thickness that was placed in service in 1969. Based on our best judgment and technical review of the pipeline specifications and 57 Special Conditions, it is our opinion that similar losses are not expected for the Keystone XL Pipeline, as detailed later in Section 6 of this report (Application of Risk Reduction Factors).

4. Consequences Evaluated by System Element

As noted above, the consequences of an incident are quantified in terms of the average incident cost from small, medium, and large spills. Our analysis separates spills into small, medium, and large spills (defined as less than 50 barrels, 50 to 999 barrels and 1000 or more barrels, respectively). The costs will be estimated for these size spills from two PHMSA Databases, the first of which contains data from 2002– 2009 while the second runs from 2010–2012.

Cost data were used from all of 2012, which is a slightly longer timeframe than that used for Appendix K, which ended in July 2012. The rationale was as follows: (1) the data are now available, and (2) because of the scatter in the data, the more data used, the better the average value to be used as a consequence measure. Similar to Appendix K, the consequence measures are developed for four system elements: mainline pipeline sections, mainline valves along the linear sections of the pipeline, tanks, and other ancillary system elements that are at pumping, metering and terminal facilities located along the pipeline. Because there were some early indications that the costs might be different for incidents occurring in HCAs versus non-HCA areas, where the trends show a possible effect, a difference in the average spill cost number is used. Note that because of the scatter in the data, the analysis is looking at trends rather than using any statistical tests. In each of the four sections, a table is presented that shows the average damage cost from the three spill size categories for both HCAs and non-HCA areas. A graph showing the data used to get the averages is also included.

It must also be pointed out that this analysis considered only spills with greater than zero cost and greater than zero spill volume, so the fraction of the spills classified as small, medium, and large are slightly different from those shown in Appendix K of the SEIS(2). In addition, it was not possible to identify as many “other system components” as found in Appendix K, so a lower rate of failure was estimated for that system element.

4.1 Main Pipeline

The first element to be evaluated is the mainline pipe. A total of 331 incident records involving mainline pipe were identified between the start of 2002 and the end of 2012. This element largely traverses either government or leased land. These linear sections have the greatest potential to expose a large land area to contamination. The data also have a huge range of damage costs, ranging from over $800 million to a few dollars. It can be seen from Table 2 that the HCAs have significantly higher damage costs for the large-sized and medium-sized spills, but the difference is negligible for small spills.

The scatter diagram showing the total barrels lost versus damage cost in 2013 dollars is shown in Figure 3. Three conclusions can be drawn from this figure. First, the amount of scatter is very large. Second, the damage cost, on average, is not a strong function of amount of material lost. Third, although the data shown in Table 2 show the average cost of spills occurring in HCAs is different from the average cost for spills outside a HCA, it would be difficult to conclude that from the scatter diagram in Figure 3.

Table 2. Average Damage Costs for Mainline Pipe Sections by Spill Category for HCA and non-HCA.

	Mainline Pipe			
Spill Size	HCA	Non HCA	Combined	Spill Probability
Large (>1000)	$71,892,005	$3,362,679	$34,690,371	11%
Medium (50-999)	$1,570,861	$541,157	$815,191	37%
Small (<50)	$186,078	$182,084	$183,408	52%

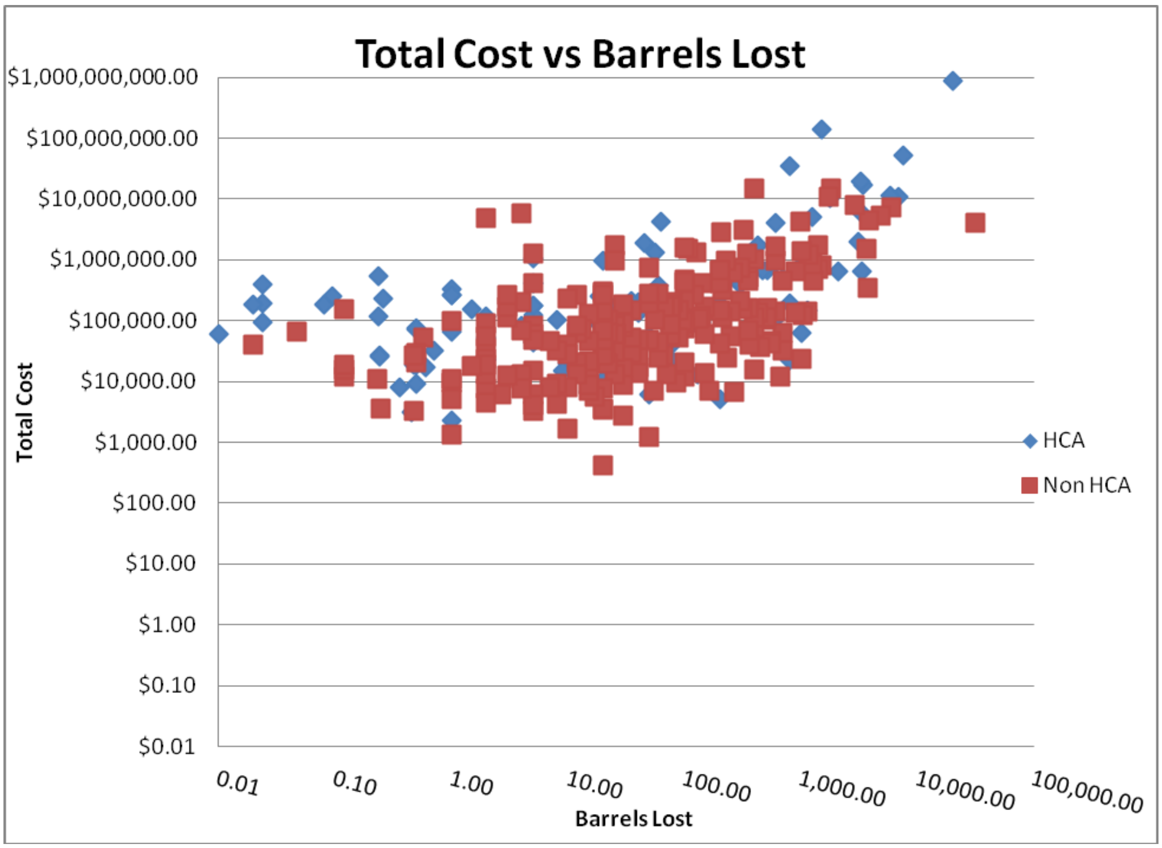


Figure 3. Mainline pipe, total damage costs – HCAs and non-HCAs.

The implication from the first conclusion is that the average total incident cost is the only reasonable cost consequence measure that could be used. The implication of the second conclusion is that although it appears that an upward trend line could be drawn above a value of 100 barrels lost, , using the three spill categories used in Appendix K is thought to capture that trend. The implication of the third conclusion is that though the average difference in cost between spills in HCAs and outside HCAs could not be shown to be statistically significant, a trend is present. In fact, the average damage cost in HCAs versus outside HCAs is higher, even after the $870 million cost of the Kalamazoo River spill is removed from the dataset.

4.2 Mainline Valves

Only 25 mainline valve incidents have occurred during the 11-year period beginning in 2002 and ending in 2012. None were large (above 1,000 barrels) and only 3 were medium sized spills. The mainline valves were separated from the mainline pipe just to show the differences, and in comparing Tables 2 and 3, those differences are evident. Figure 4 shows the wide scatter in the data and how poorly incident costs are correlated with spill size for mainline valves.

Table 3. Damage Cost Estimate for Mainline Valves.

Spill Size	Mainline Valves			Spill Probability
	HCA	Non HCA	Combined	
Large (>1000)	$ -	$ -	$ -	0.00%
Medium (50-999)	$11,234,322	$76,459	$7,515,034	12.00%
Small (<50)	$60,982	$29,415	$42,329	88.00%

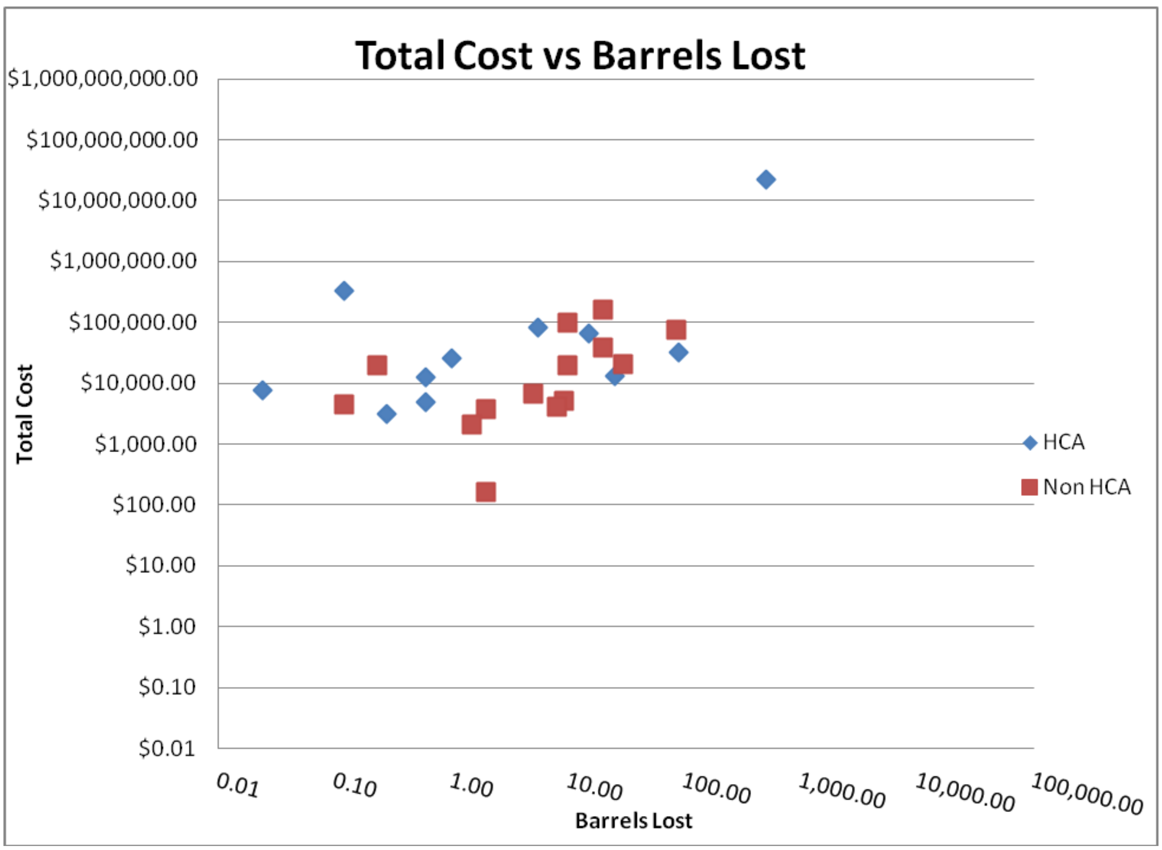


Figure 4. Total damage costs versus barrels lost for mainline valves -- HCAs and non-HCAs.

4.3 Reported Costs of Tank Failures

The largest crude oil spill reported during the 11-year period was from a tank failure, a 49,000 barrel spill from a storage tank. The damage cost from that 2006 spill, escalated to 2013 costs, was just under $1 million. There was a 25,000 barrel spill from a storage tank in 2005 that, in escalated dollars, cost over $23 million. The last one was in an HCA and the first one was not. Perhaps that is the reason for the factor of greater than 23 in total incident costs. There are about 92 total incidents associated with Storage Tank identified during the 11-year analysis period. Less than half, a total of 36, occurred in HCAs. There were seven large spills in HCAs and 12 large spills in a non-HCA. The average damage cost estimates are shown in Table 4.

Table 4. Average Damage Costs for Tank Incidents in HCAs and outside HCAs.

	Tanks			
Spill Size	HCA	Non HCA	Combined	Spill Probability
Large (>1000)	$3,750,070	$1,802,524	$2,520,041	20.65%
Medium (50-999)	$384,960	$126,942	$191,447	30.43%
Small (<50)	$152,006	$60,883	$105,432	48.91%

Figure 5 shows the scatter diagram for tanks. The average incident costs show only a small upward trend with number of barrels lost.

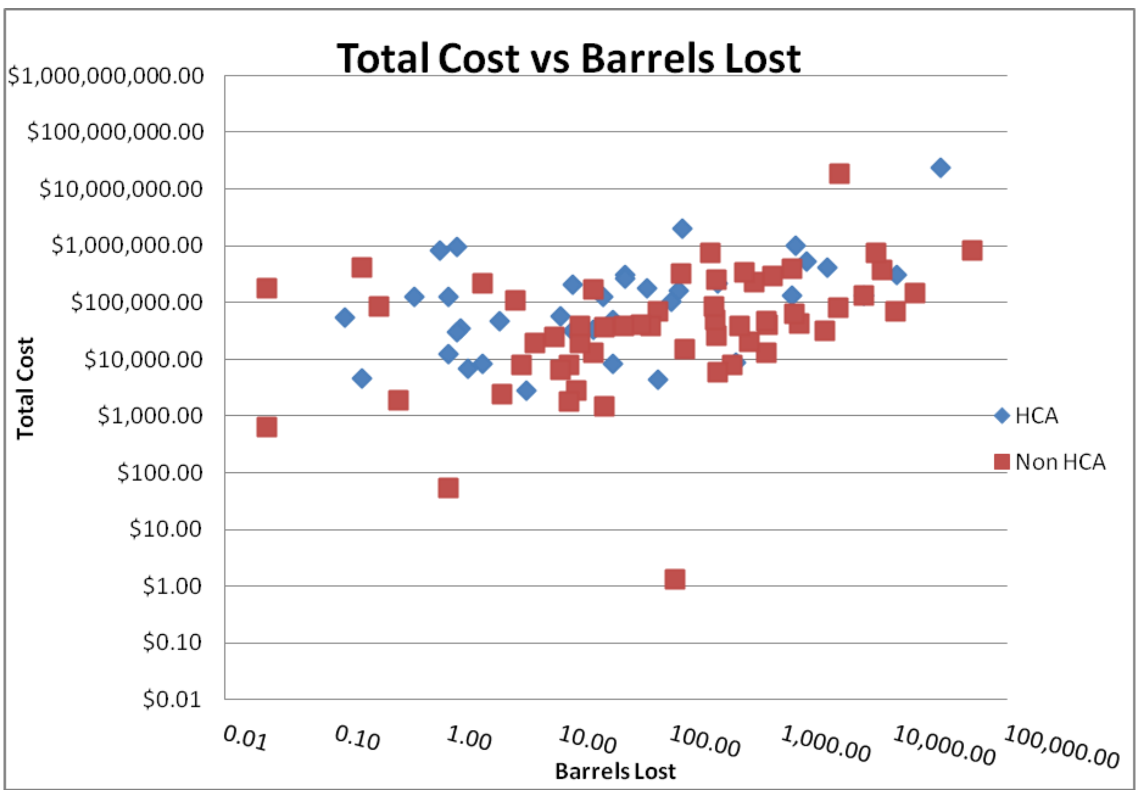


Figure 5. Total damage costs versus barrels lost for tanks – HCAs and non-HCAs.

4.4 Reported Cost of Other System Components

The final category of system elements is called other system components. A total of 355 spill incidents were classified as other system components. (This number is much less than the number identified in Appendix K, suggesting that some duplication might be in the Appendix K analysis.) These are not along the linear segments of the pipeline, rather they are at fixed facilities such as pumping and terminal facilities. Table 5 presents the average incident costs for other system components.

Table 5. Estimated Damage Costs for Other System Components – HCA and non-HCAs.

Spill Size	Other Discrete Elements			Spill Probability
	HCA	Non HCA	Combined	
Large (>1000)	$12,821,505	$25,412,550	$21,978,629	3.10%
Medium (50-999)	$217,239	$118,655	$140,420	21.69%
Small (<50)	$59,186	$50,977	$53,529	75.21%

In reviewing the data, a lot of incidents are classified as other system components; most are not large and since they are at fixed facilities, an attempt would be made to not site them in HCA areas. The exception of course is when the pipeline facility was initially constructed well away from any defined HCA and in the absence of any zoning regulations the HCAs are over time permitted to encroach on the facility. For the large spill estimate there were only four incidents in HCA areas and seven in non-HCA areas, showing that even though there are almost 700 other component incidents in the Database over the 11-year period, very few are large spills. Given the scatter in the data, the average damage cost estimate for the combined column involves only 11 data points. Since the medium spill contains 17 medium spill records in an HCA and 60 in non-HCAs, a single outlier will have a smaller effect on the average. There are about 83 small spill damage cost estimates that spilled crude oil in HCAs and 184 small spills that discharged crude oil into non-HCA areas over an 11-year period. The average costs calculated for HCA and non-HCA areas for small and medium spills will be used in the risk calculation.

The scatter diagram for other system components is shown in Figure 6. The density of the non-HCA symbols near the center of the diagram makes it difficult to see the HCA points at any place but at the fringes. As with all the plots there is a clear floor, which is why the spill size is such poor predictor of total damage costs.

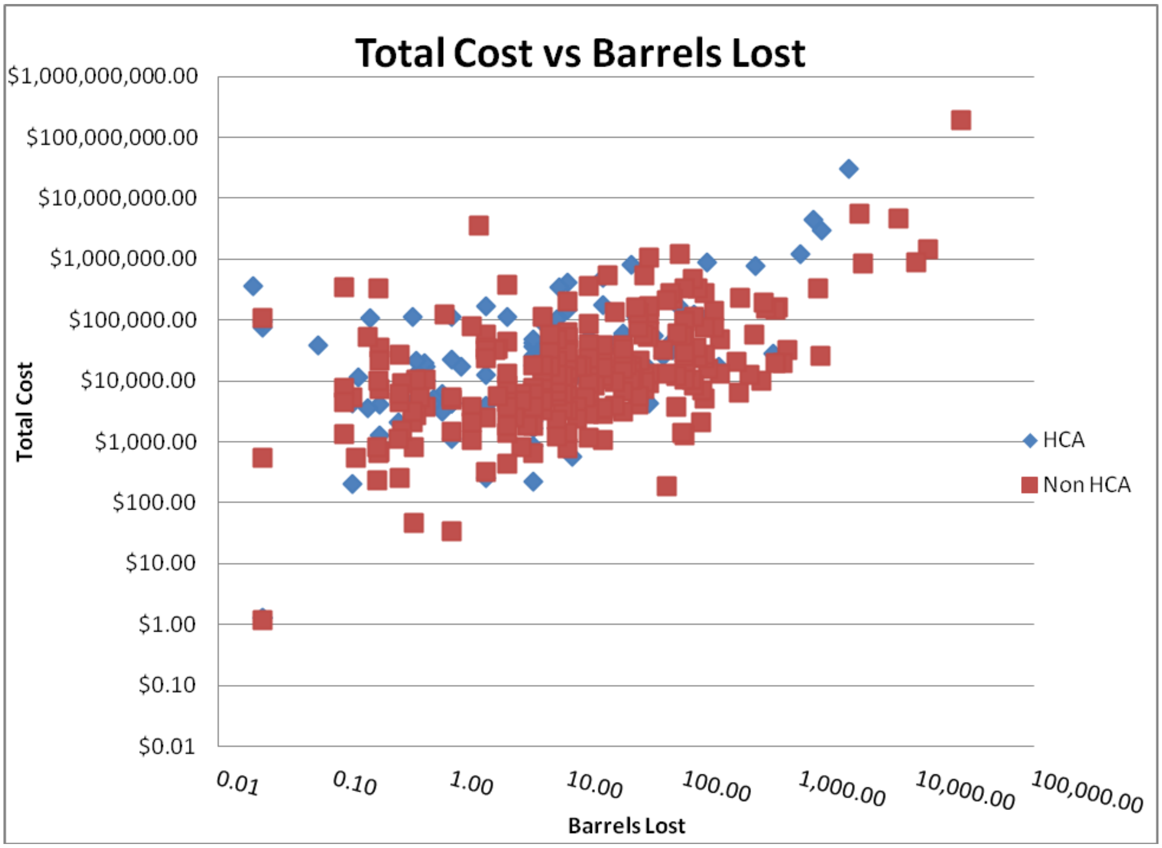


Figure 6. Total damage costs versus barrels lost for Other System Components – HCAs and Non-HCAs.

4.5 Summary of Damage Costs by Pipeline Component

Figure 7 shows an inverse cumulative probability diagram, often called a risk spectrum for the total damage costs for mainline pipe incidents over the 11-year period between 2002 and 2012. The non-HCA curve is a typical risk spectrum curve. As the curve goes to the right, it drops very rapidly, indicating that the likelihood of a major incident drops off rapidly. The curve for the HCA shows a pattern that does not drop off but just continues at a constant slope for several more orders of magnitude. This is not a typically-shaped risk curve, in that the curve has not yet reached a point where frequency of a incurring a higher incident cost has not reached zero. The highest cost HCA incident was the Kalamazoo River incident in 2010 that in 2013 dollars resulted in total damage costs of just under $900 million.

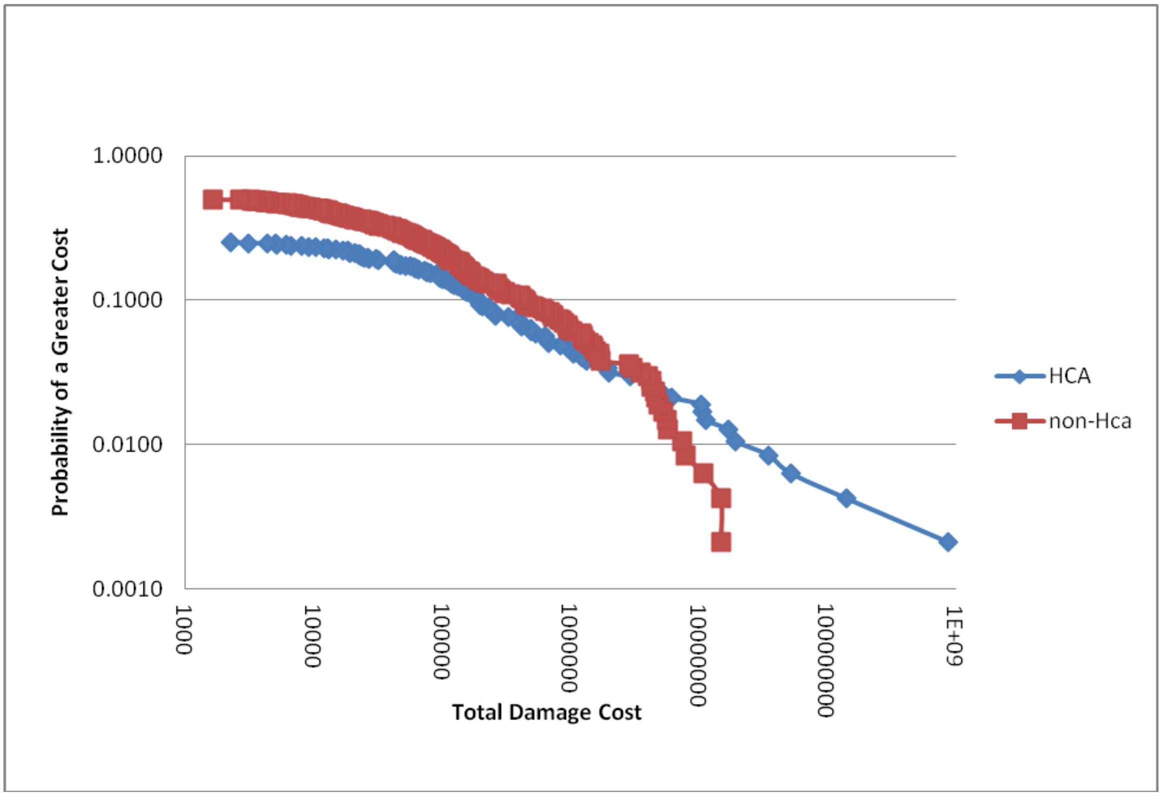


Figure 7. Risk spectrum diagram for mainline pipe – HCA and non-HCAs.

The risk data for mainline pipe shown in Figure 3 showed that the cost data are very scattered which is why the average damage costs for the three spill sizes shown in Table 3 used average values. When there is a lot of scatter, use of averages provides the best estimate of future costs. The PHMSA data show the incidents are episodic, meaning that a pipeline might experience very few incidents for several years and then experience a large one. There are many reasons why the costs for a given incident that results in the same total barrels lost can experience total damage costs that are orders of magnitude different. When the notice of a breach in the pipe is detected, one operator might take a very conservative approach and evacuate a large number of people and also call in a large cleanup crew to protect against the threat of a bigger spill. Another operator might trust the SCADA system and take a wait and see approach. One spill may be in an area that is very easy to access and clean up, another might be an area that is difficult to access and/or cleanup. These factors are not included in the accident description so it is very difficult to capture the important factors that might contribute to the variability in costs for different incidents. The log-log risk spectrum diagram takes a lot of data and removes much of the scatter. While it might not be a statistically significant difference, the trend shows it is more likely to have a higher damage cost for an incident in an HCA and a lower damage cost for an incident in a non-HCA area.

5. Development of Risk Profiles for Pipeline Components: Application to the Northern Segments of the Proposed Keystone XL Pipeline

As stated in the introduction, total costs incurred as a result of the incident will be used as a measure of the consequences of the incident. This consequence measure is considered the best measure available Data in Table 1 demonstrated that the total annual cost of all the incidents occurring a given year is highly variable, as are the average spill volumes for the year and total average number of spills. Given the variability from year to year in these terms, the product of two these parameters, incident likelihood and damage cost, will be more variable. The central limit theorem states that mean values are the best predictors of future performance.

Appendix K of the SEIS[2] estimated the failure frequency for four system elements: mainline pipe, mainline pipe valves, tanks at fixed facilities along the pipeline and other system components at fixed facilities along the pipeline. This analysis does not use the incident counts for the four system elements presented in Appendix K because they could not be duplicated. The requirement to have a positive incident cost and barrels lost might have contributed to the difference. To estimate the spill rates, the total pipeline mile-years or component-years used the data from Appendix K. The spill counts for the four component systems being analyzed, the numerator in the spill rate equation, used the spill count used to determine the average incident costs for the four component systems. As explained in Section 2, the risk is defined as the frequency times the consequences measured in average damage costs escalated to 2013 dollars. The tables in this section use the parallel tables in Section 3. The risk profile, as these tables in this section will be termed, are generated consistent with the equations in Section 2 by multiplying the incident frequency per mile or facility per year times the probability that an incident will be in one the three spill size categories, and lastly the total average damage costs for the three spill sizes. If the data set allows it, different average damage costs will be developed for incidents that occur in HCAs and incidents that occur outside HCAs. The HCA average damage costs will be used for facilities or route segments in the HCAs and the non-HCA average damage costs will be used for facilities or route segments outside an HCA. The route for the pipeline and the location of the pipeline facilities will determine which cost profile to use.

Sections 5.1 through 5.4 show risk profiles for the for system components: Mainline Pipe, Mainline Valves, Tanks, and Other System Components, respectively.

5.1 Risk Profile for Mainline Pipe

The risk profile is obtained directly from the average damage cost tables developed for each system component. The cost risk term is multiplied by frequency term which is calculated by taking the probability of a given sized spill and multiplying it by the mainline pipe spill rate per mile. The calculated spill or incident rate used is 0.00056 incidents per pipeline-mile year. Note this incident rate only included incidents with non-zero costs and non-zero spill quantities. Excluding the records with zero costs or spill quantities were considered essential to the risk assessment methodology used in this section. The risk profile for mainline pipe is shown in Table 6.

Table 6. Risk Profile for Mainline Pipe.

Risk $/ Mainline Pipe -Mile-Year			
Spill Size	**HCA**	**Non HCA**	**Combined**
Large (>1000)	$4,286	$200	$2,068
Medium (50-999)	$332	$114	$172
Small (<50)	$55	$53	$54

5.2 Risk Profile for Mainline Valves

Table 7 shows the risk profile for mainline valves. The data are sparse, only 25 data points. The incident frequency was estimated to be 0.00093 spills per mainline valve-year. Since there were no mainline valve spills, the risk for the large spill size was left blank.

Table 7. Risk Profile for Mainline Valves.

Risk $/ Mainline Valve-year			
Spill Size	**HCA**	**Non HCA**	**Combined**
Large (>1000)	$ -	$ -	$ -
Medium (50-999)	$1,206	$8	$807
Small (<50)	$48	$23	$33

5.3 Risk Profile for Pipeline System Tank

Table 8 shows the risk per year for a single storage tank. Whereas in the mainline valves the cost risk for the smaller spills is higher than the medium spill, here the risk per tank-year goes up with each higher spill category. This basically says that the effect of the cost difference among the spill categories is greater than the difference in the spill frequency terms.

Table 8. Risk Profile for Storage Tanks.

Risk $ / Tank – Year			
Spill Size	**HCA**	**Non HCA**	**Combined**
Large (>1000)	$3,619	$1,739	$2,432
Medium (50-999)	$547	$181	$272
Small (<50)	$347	$139	$241

5.4 Risk Profile for Other System Components

The other system component group of reported instances has the most reported incidents over the 11-year analysis period, 355. There are three in the large spill category for HCAs and 8 large spill events for other system components in the non-HCA area. Using the 355 spills, the spill rate per component, using the number of components from Appendix K of the SEIS[2] becomes 0.029 incidents/other system component-year. The results are shown in Table 9.

Table 9. Risk Profile for Other System Components.

	Risk $ / System Component-year		
Spill Size	**HCA**	**Non HCA**	**Combined**
Large (>1000)	$11,647	$23,084	$19,965
Medium (50-999)	$1,381	$754	$893
Small (<50)	$1,305	$1,124	$1,180

5.5 Application of the Risk Profiles for the Proposed Northern Segment of the Keystone XL Pipeline

Table 10 shows the estimated total cost per year and the contributors to that cost for the proposed northern segment of the Keystone XL Pipeline. Given the large scatter in the data, it is important to state that while it might be expected that if the pipeline performed like current pipelines, on average, TransCanada might experience an annual Damage Cost of over $1 million.

Given the characteristics of the Damage Costs, perhaps the best way to think about this number is as an insurance premium: How much must TransCanada reserve each year to ensure that they have the money to pay any Damage Costs from pipeline spills. Given the characteristics of the HCA risk curve, that might not be enough because a single event, costing in the hundreds of millions of dollars could occur during the lifetime of the pipeline and at $1 million a year, enough money would never be accumulated to pay for the damages.

A perhaps more useful application of the risk data is to look at the fraction of the cost risk that is associated with each of the four system elements that have been analyzed. These data are shown in Tables 10 and 11. These results show that even if the mainline pipe and valves performed without failure, there is a still a sizable risk associated with the other system components – the thousands of items that are part of a pumping station. Thus, eliminating all the mainline pipe risk will not reduce the operating pipeline risk to zero, but perhaps reduce it significantly.

Section 6 will look at ways of estimating the effectiveness of several of the design features incorporated into the design and operating conditions. If one thing is clear, given the poor correlation between spill volume and damage costs, prevention of spills will be the surest way of minimizing damage costs in the long run.

Table 10. Cost Risk for the Northern Section of the Proposed Keystone XL Pipeline.

Facility	Spill Size	Risk ($/yr)
Mainline Pipe in HCA	Large (>1000)	$300,003
	Medium (50-999)	$23,224
	Small (<50)	$3,816
Mainline Pipe in non-HAS	Large (>1000)	$161,372
	Medium (50-999)	$92,007
	Small (<50)	$42,941
Mainline Valves in HCA	Large (>1000)	0
	Medium (50-999)	$2,421
	Small (<50)	$99
Mainline Valves in non-HCA	Large (>1000)	0
	Medium (50-999)	$25,829
	Small (<50)	$1,067
Tanks	Large (>1000)	$4,864
	Medium (50-999)	$545
	Small (<50)	$482
Other Components	Large (>1000)	$399,303
	Medium (50-999)	$17,858
	Small (<50)	$23,606
	Total Risk	**$1,099,435**

Table 11 shows the total pipeline cost risk and the contribution from each of the four system elements. The two systems that dominate are the mainline pipe and the other system components. Taken together, they represent almost 97 percent of the cost risk associated with the proposed northern section of the Keystone XL Pipeline.

It is also easy to see the effect of more mainline valves. If an additional valve is placed in on the Keystone Pipeline, using the composite risk numbers in Table 7 would add about 850 dollars to the risk total, less than a 0.1 percent increase in the risk.

Table 11. Risk Contributions from the four System Elements.

Annual Risk of Pipeline Operation ($/year)		
Pipeline System	**Risk per Year**	**Percentage of Total**
Mainline Pipe	$623,363	57%
Mainline Valves	$29,416	2.68%
Tanks	$5,890	0.54%
System Components	$440,766	40%
All	**$1,099,435**	

Figure 8 shows a risk spectrum displaying the risk spectrums for all four system components considered. In comparing the four curves, it is clear that the other system components and mainline pipe dominate the risk both in terms of cost and probability of occurrence. Thus in Section 6, characteristics of the Keystone XL Pipeline that will reduce the likelihood or damage cost in these two areas will have the greatest effect on risk. Another conclusion from both Table 11 and Figure 8 is that reducing the likelihood or damage costs for one of these components will at most reduce the risk in half.

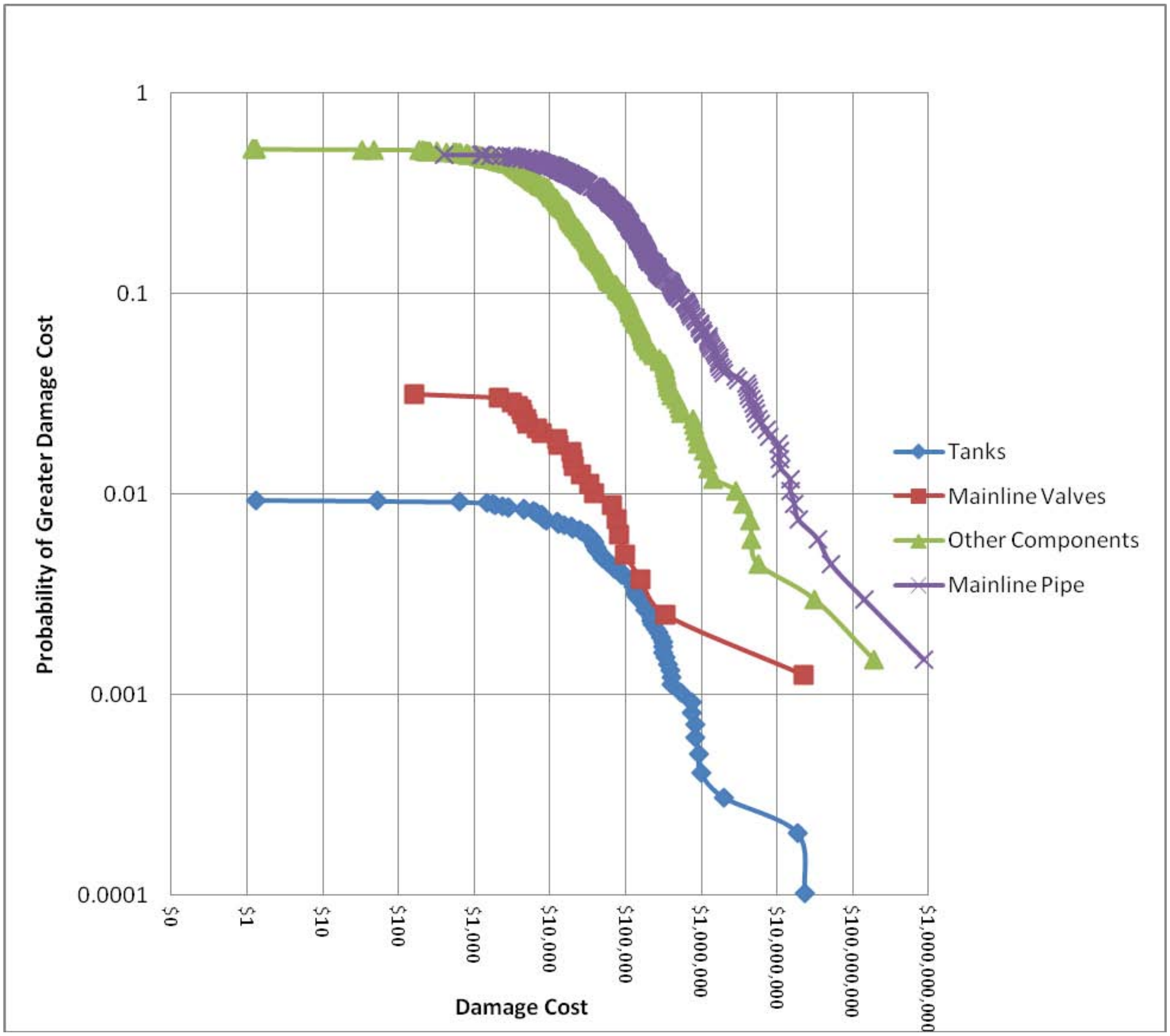


Figure 8. Risk spectrum curves for the Northern Section of the Keystone XL Pipeline – by system component.

The lack of a sharp downturn in the risk curve at the high damage cost end of the spectrum for three of the four curves, tanks being the exception, shows that the high cost consequence events dominate the risk. There are two implications from this fact: first, that the average damage cost is not a complete indicator of the risk and second, that prevention of these high consequence events, making them less likely, is a good risk management strategy.

In addition, since damage costs are poorly correlated with spill quantity, it may not be possible to lower costs by reducing the quantity lost. The scatter in the damage cost was large and in an attempt to look at the components of the damage cost, seven different ones presented similar scatter in the damage cost data. Thus spill prevention in the most easily affected environments should be the focus of any meaningful risk reduction strategy.

The PHMSA Incident Databases provide entries for the seven cost components in the 2002 – 2009 database and six cost components in the 2001 – 2012 database. When using cost as a consequence measure the normal approach is to estimate the consequences for each component and then add these cost elements up to get the total cost. Unfortunately the scatter in the data for the cost components is as great as the scatter in the data for total cost. In addition, using the component costs presents the challenge of handling numerous zero entries. The inability to detect a trend in the information contained in the cost component data makes it difficult to determine the relative impact of those components to overall risk. Hence, without being able to estimate the consequence of each component to reduce risk the risk reduction strategy must be focused on prevention which is the focus of the next section titled, Development and Application of Risk Reduction Factors.

6. Development and Application of Risk Reduction Factors

This pipeline risk assessment uses average damage costs for the three sizes of spills, which aggregates data for pipelines in the U.S., regardless of when they were designed and constructed. In contrast, modern pipelines being constructed are required to meet ever higher standards. Under the direction of PHMSA, the design basis for the Keystone XL Pipeline carries not only the expectations for modern pipelines but a step beyond the normal requirements, as outlined in the 57 Special Conditions imposed by the PHMSA[3].

To assess at the effect of higher standard of performance requires an experience base like that of the PHMSA Database to quantify their impact on reduced incident frequency and reduced average incident cost. Unfortunately, the Keystone XL system is the first pipeline subject to these conditions, so that a database does not exist to quantify such safeguards. The condition that requires tougher line-pipe steel should result in a lower frequency of incidents per mile-year of pipeline operation. Likewise, higher toughness should significantly reduce the axial length of a failure, leading to a smaller leak due to a rupture, should it occur. Better system controls, and leak detection methods possible through the use of a well designed SCADA system, should make it possible to identify the spills quicker, although that capability is based on a percentage of the flow rate. However, it is also important to note that these special conditions could potentially offset the benefits such as better system controls and leak detection methods, as tougher steel might make it more difficult for the SCADA-based detection scheme to detect the loss.

Such actions relative to the Keystone XL Project are considered next in regard to mitigation (which limits release consequences), prevention (which involves avoiding a release), and what are termed protective measures (which constitutes actions that minimize release impacts). It is noteworthy 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. Modern pipeline systems are being built to ever higher standards each decade. The average age of the pipeline system is over 40 years old, so the design, construction, operations, and maintenance circumstances for the incidents reported in the PHMSA Database are dominated by pipelines built to lower standards as compared to those being built today. This could mask the improved performance of the modern pipeline, unless the data can be easily managed to account for age of the pipeline. Important developments that have occurred in that timeframe include the continued development of line-pipe steel, in welding, and in coatings to protect against corrosion and construction damage. In addition, complex system controls such as SCADA have been developed and refined, as has leak detection, to name a few. Another factor to consider when utilizing data from the PHMSA Database is that over that time the Federal Regulatory structure has continued to develop, since its introduction circa 1970, which has changed the mandated reporting that underlies the PHMSA Database. As causes of incidents are better understood, the reporting requirements have changed. While the requirements today present the detail needed to uncouple and quantify the risk reduction factors, changes in the scope of those requirements in some ways confound isolating and trending them to quantify what is needed. Accordingly, it is necessary to infer relevant factors by like-similar analysis through reference to data developed and reported for modern pipeline systems designed and constructed under Regulatory requirements and Codes comparable to that in the U.S.

6.1 Role of System Age

In a recent article published in Australia[(4)], an incident per mile rate was calculated based on their reporting system and it shows that the incident rate per mile is a factor of ten lower than in this country. While portions of the Australian pipeline system are dated, the vast majority of their system has been built to modern pipeline standards. At face value that reference suggests that if by some miracle, all of the old pipe could be replaced by a modern pipeline, a factor of ten reduction in incident rate would occur. However, that reduction might not affect a corresponding reduction in risk level because the data indicate that mainline pipe risk accounts for about half the risk.

6.2 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 of Title 49 of the CFR (and appendices) establish the minimum requirements for any hazardous liquid pipeline. Recognizing that the preventive actions implicit in the applicable Regulations must be satisfied, this subsection focuses on additional actions over and above the minimum that are either known, or otherwise merit consideration for the Keystone XL Project. Key findings include:

1. Analysis by Exponent[(5)] indicates that leaks larger that about 20 barrels could be detectable above-ground, visually or by other sensors within a reasonable timeline:
    a. Analysis discussed in the leak detection section of the Battelle Report (pages 60-67) indicates that spills in the order of 1,400 barrels can be detected within 2 hours under Keystone’s current detection commitment, suggesting this volume could be reduced to several hundred barrels detected within 45 minutes – this is encouraging, but it still opens to concern for smaller leaks;
    b. Given that Exponent’s work indicates that small leaks can be recognized within a reasonable timeframe aboveground (detectable visually or by other sensor), consideration should be given to the use of detection technologies in complement to computational pipeline modeling/monitoring CPM and the other schemes currently adopted, and to a patrol frequency that is matched to such technologies;
2. Depending on the nature of the terrain and aspects of the water table and other factors, consideration should be given to the selective use of concrete coated line pipe, or an

equivalent/better scheme, such as Rock Jacket® that in contrast to a concrete coating can be field-bent and facilitates cathodic protection CP;

3. While Keystone has used leading practices in assessing valve location and spacing, there is potential value in refining the existing plan:
    a. Four types of emergency flow restricting devices (EFRDs) exist including remote controlled valves (RCVs), check valves (CVs), automatic control valves (ACVs), and manual operated valves (MOVs) , with evidence that all but ACVs are involved in this Project (note that the MOVs are placed in conjunction with and just downstream to the CVs);
    b. Because ACVs respond automatically to pipeline flow conditions this poses the chance for anomalous response. Because an ACV conceptually represents a simple leak detection system (LDS) and an EFRD in one package, as technology matures and these become more reliable, they can be programmed for closure to minimize surge;
    c. Valve response times for liquid lines are limited by the potential of fluid hammer and related over-pressure surge (literature citation). points out, 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;
4. As noted above in 1 above, detection of small leaks can be problematic in view of the prior work(6) that considered this topic:
    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 schemes should be considered to prevent leaks, such as discussed in the next subsection and noted above in the context of prevention.

It is difficult to quantify a risk reduction due to the above actions. Suffice it here to note that if spills are prevented there is less need to manage spills or protect against them. In this regard such protective actions may never be required.

6.3 Role of Environmental Protection and Spill Mitigation

Analysis results and the process used to place valves provided by Keystone can be used to evaluate the role environmental protection and spill mitigation. The system simulation-data provided quantified the effectiveness of the protection affected by the valve placement at critical locations along the RoW, and its 20-mile spacing in between. Effectiveness can be quantified 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 9 trends these distributions, presenting 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 dark grey hashed line is the trend for the initial placement plan, while that shown toward the right (light grey) is the spill trend for the revised plan, representing what Keystone terms an optimized plan that involved additional valves and modified locations.

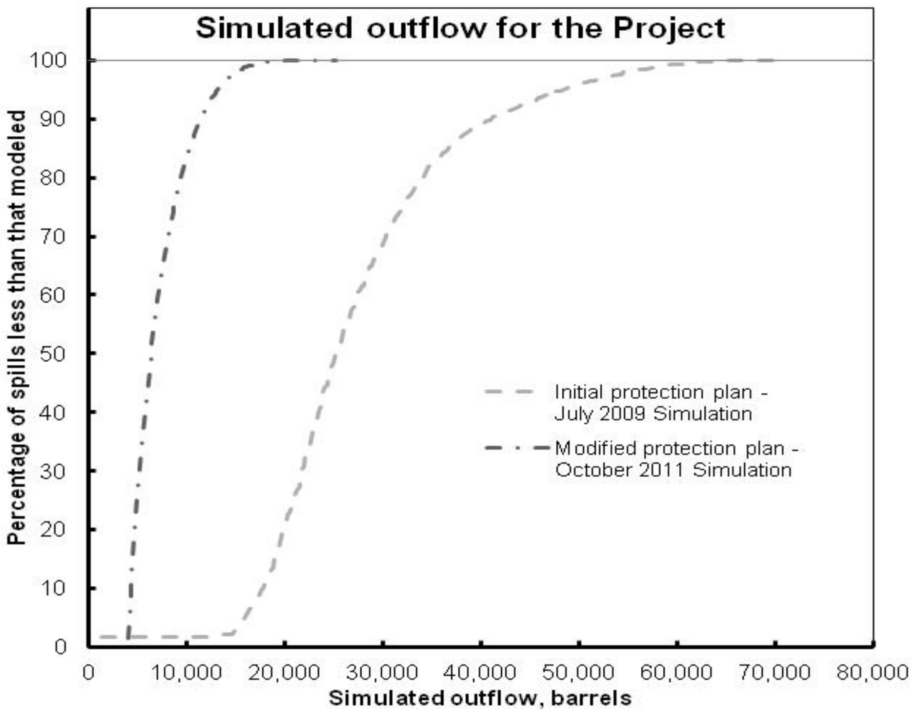


Figure 9. Protection afforded by values for the final versus initial valve placement.

It is apparent from Figure 9 that the simulated releases for the updated plan affects 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 from Figure 9 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 9 indicates 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 9 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 that 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 9, which is equally so for most any other spill – and means that valves and their placement are central to spill control. Accordingly, this review has focused on the number of valves and optimizing their placement in balance 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 the algorithm used by Keystone targets the minimum total spill volume, and considers issues such as up-slope 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 it affords effective control and protection for the environment. It is noteworthy however to point out that the adage “a little is good, so a lot is better” is not applicable in regard to valves. As has been noted elsewhere, 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 reason 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 SOTA or better. On this basis, and in light of the effectiveness of the outcome achieved in Figure 9, Battelle considers the existing plan for valve placement 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 considers the current plan viable in regard to the SOTA, or better.

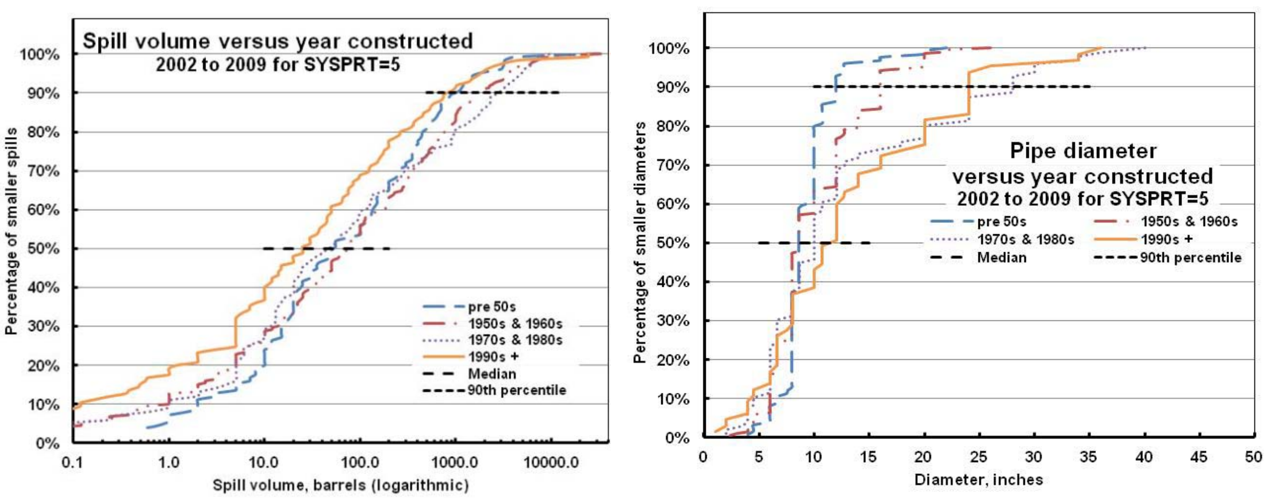
Aspects of the mitigation plan also were reviewed, although such analyses are in practical terms less quantitative. Suffice it to note that through responses to Battelle’s inquiries it is apparent that the response plans are targeted to the ecosystems and resources traversed, with a view to address unique/site-specific aspects. 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. Follow-up on these plans in the event the project moves forward under PHMSA’s oversight is crucial.

It is also difficult to quantify a risk reduction in light of the above actions. Suffice it here to note that if spills are prevented there is less concern to manage their outflow or protect against them.

6.4 Modern Pipelines and Spill Volume

The benefit of transporting crude in modern pipelines is the 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 10.

Prior discussion has adopted cost as the metric for consequence, where it is evident that spill volume and cost are not well correlated. For that reason, this discussion evaluates consequence directly in terms of spill volume. Figure 10 presents spill volume as a function of period of construction and illustrates the role of pipe diameter. Part a) of Figure 10 shows the cumulative distribution of spill volume on the y-axis as a function of the spill volume on a logarithmic x-axis. The contours shown in this figure represent time intervals for the pipeline's construction intervals grouped for data available to 2008. Part b) of Figure 10 shows the cumulative distribution of pipeline diameter on the y-axis as a function of diameter on the x-axis, with contours shown for the same construction intervals considered in Part a).



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

Figure 10. Spill volume and pipe diameter as a function of period of construction

Figure 10 indicates that in spite of the greatly increased throughput transported by modern construction, the spill volume has actually decreased. This is evident directly in the trends in Figure 10a, which show about a five-fold decrease in spill volume in spite of the increase in pipeline mileage over the period shown. The trends shown in Figure 10b provide the basis to translate the increase in pipeline mileage to the increase in pipeline capacity. Using the median result, this figure indicates about a two-fold increase in diameter. Thus, when the effect of diameter is considered, the five-fold reduction in spill volume has been achieved while the system capacity roughly doubled. As such, it is clear that aside from incurring fewer releases, modern construction is associated with a 10-fold net reduction in relative spill volume. The smaller less frequent spills achieved by new construction suggests that recent construction can bring clear environmental benefits with regard to spill prevention and the size of the release all else being equal.

6.5 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 “if you cannot quickly detect smaller leaks, then you have to prevent them.” In addition, given that even the best laid plans cannot preclude a leak, care must be taken to establish viable outflow management, and ensure that the mitigation plans address expectations. It follows from the above discussion that spill prevention will have a greater effect on risk than spill size, detection or mitigation, as prevention mitigates concern for spills. Note that the risks are not all pipeline risks and it is uncertain if the modern pipeline can better resist a significant risk element, natural phenomena risks. Note that in the recent report to Congress, PHMSA evaluated one natural phenomena risk, flooding. In looking at the causes of the pipeline failures from flooding, about 25 percent of the incidents occurred where flooding was not expected so no safeguards against flooding were in place. Thus the safeguards incorporated into the design of the pipeline might only be 75 percent effective. Safeguards that reduce corrosion and mechanical/weld failure affect only 25 percent of the risk. Thus at best, the relative improvements noted above might result in a lower risk of perhaps 75 percent.

6.6 Diameter, Incident Rate, and Risk

Earlier discussion of the Australian analysis that showed a much reduced incidence rate as compared to the U.S. has been detailed in the discussion of Appendix K[(2)]. That same quantitative analysis done for the U.S. for construction over the interval from 1995 to the present thus is expected to show a decrease in the incident rate. Currently some reduction in rate can be detected, but it is not a factor of ten. All the reasons why the factor of ten reduction is not being realized are not known at the present time. One reason might be that the Australian data reflect much smaller pipelines than in the U.S., and also involve a much smaller spread on pipeline diameter. In regard to the diameter trends in Figure 10b, one anticipates little influence of diameter on their incident rate.

In contrast to Australia, the U.S. hazardous liquid pipeline system includes diameters from a few inches up 48 inches, which Figure 10b indicates has a significant effect on relative incident rate if rate is assessed in terms of system capacity rather than system length. As above, using the median result in Figure 10b leads to about a two-fold increase in diameter, or a four-fold increase in capacity. Thus, when the effect of diameter is considered, the incident rate discussed earlier is decreased for the modern large-diameter construction by about four-fold. Coupled with the smaller less frequent spills achieved by new construction, as discussed above, recent construction brings clear environmental benefits.

6.7 Preventive Actions

Preventive actions focus on keeping the product within the pressure boundary of the line-pipe and the system components. Parts 194 and 195 of Title 49 of the CFR(7) (and their appendices) establish the minimum requirements for any hazardous liquid pipeline, whose eventual implementation is under the oversight of the PHMSA. In this context, several of the key preventive elements in TCPL's design basis for Keystone XL include:

1. Design requirements and actions(8) over and above the Code minimum. These include: 1) the entire pipeline is being designed as an HCA, 2) greater than the required depth of cover will be provided for usual trenched construction (four feet in general, locally deeper for select sites), and 3) horizontal directional drills (HDDs) will be used for select crossings:
    a. evaluation indicates that reasonable judgment underlies the site-selection process used by Keystone; and
    b. because the wall thickness is already that for a HCA/USA, wall thickness relative to that for a HCA/USA cannot be added to locally reduce risk or avoid consequences – more importantly, data show that added wall thickness does not affect risk relative to threats such as corrosion(9);
2. Consideration of the selective use of (micro-) bores to better manage threats near sites such as critical/high-value resources, or sites where history indicates a locally higher threat, such as the potential for scour or washout being unusually high;
3. Consideration of alternative practices in regard to seals and seats, from material selection through maintenance;
4. Consideration of more frequent scheduled maintenance for valves and other equipment, at least initially;
5. Consideration of the use of pre-service offsite leak checks and equipment shakedown where plausible;
6. Consideration of more frequent patrols in population-defined HCAs, because the nominal two-week interval is less effective than desirable where encroachment is likely;
7. Improving 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; and
8. Avoiding onerous aspects tied to the focused use of smart ball technology, including considering running such technology as part of an early pig train, which is part of usual operations to establish the background, and then consider its periodic use as part of pig trains that are required for IMP.

6.8 Role of Leak Prevention, In-Line Inspection, and Increased Wall Thickness

Inspection and maintenance are key aspects of any risk management program, so it is instructive to evaluate these aspects for the lineal portion of the pipeline system where the threat of environmental exposure is also most difficult to detect and mitigate. This evaluation is made 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 third party damage (TPD) as these are the primary threats in light of the data that underlie Figure 10b in Reference 6, and the observations regarding corrosion rate and damage susceptibility in regard to Figures 11 and 12 in Reference 6.

Methods to predict the response of anomalies to the forces on pipelines exist, have been validated by full-scale testing, and form the basis for this assessment[(10)]. Such models have been developed to quantify this response for anomalies that fail by either plastic collapse, or by fracture, and 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 usual to consider that orientation.

With this background, the results for predictions for axially oriented features are presented in Figure 11. 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 the figure 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 11 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% of SMYS corresponds to a horizontal line at a y-axis value of 0.72; while service at 50% of SMYS corresponds to a horizontal line at a y-axis value of 0.50; and so on. The upper-most 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.

Three bounds are included in Figure 11, 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%, 60%, and 80% with corresponding cutoff pressures. These respectively correspond to “scheduled” or 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 11, these bounds are separated by an increment in wall thickness equal to 20% of the wall, or for the mainline pipe nominally 0.093 inch.

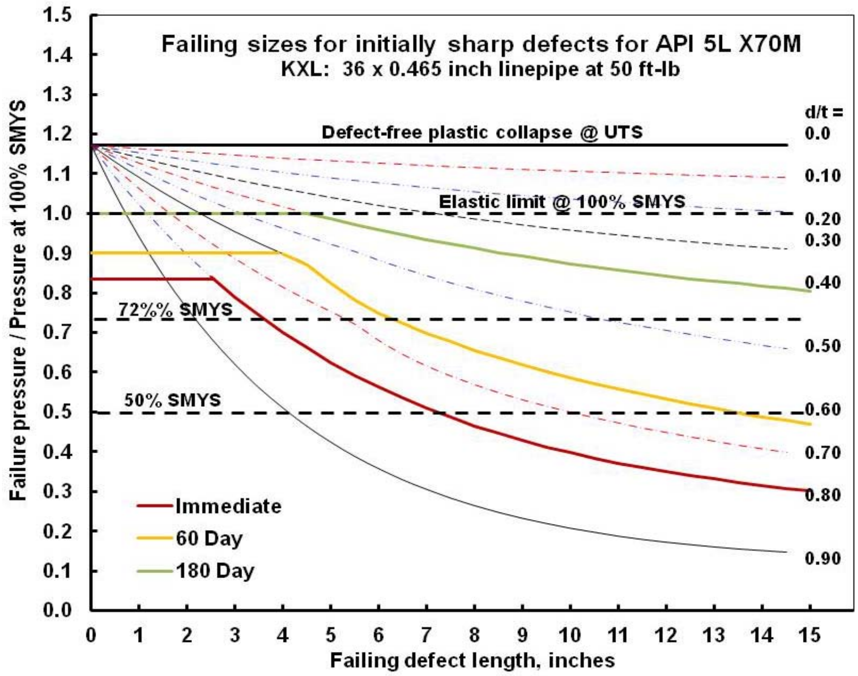


Figure 11. Failure boundaries for sharp defects in the Project line pipe

It is apparent from Figure 11 that for operation at 72% 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% wall depth is associated with shorter cracking, the order of 6 inches overall. The depths associated with both of these response thresholds can be reliably found using ILI that targets corrosion.

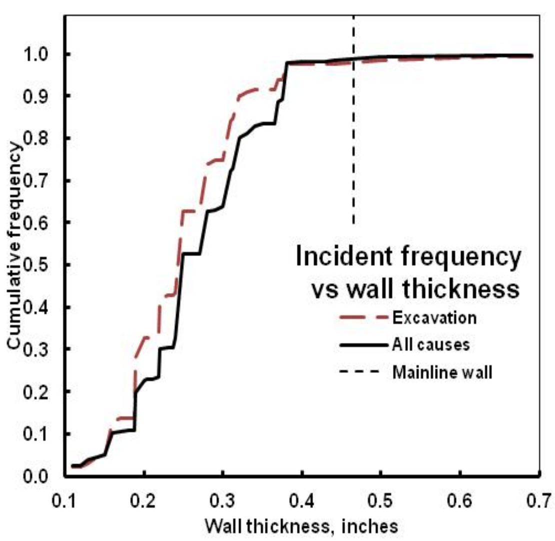
Considering that the usual 10% allowance for uncertainty in ILI outcomes is offset by the conservatism embedded by representing blunt corrosion by a sharp crack, and using the NACE RP 0502 suggested corrosion growth rate of 0.015 inch-per-year, it is found that the transition between these response intervals corresponds to a little more than 6 years. The PHMSA mandates ILI for the hazardous liquid pipeline industry at a maximum interval of 5 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% of the wall. If a benchmark ILI run is made pre-service – as suggested above in the Preventive Actions – then the nominally defect-free pre-service pipeline system will experience a total of three ILI cycles prior to even reaching the first schedule threshold, which according to the worst-case rate would occur after a total of 12 years of operation.

The role of wall thickness is evident in regard to Figure 11, as the absolute value of the wall thickness serves as the denominator of the relative defect depth that applies to each of the contours shown therein. As such doubling the wall thickness translates into higher failure pressure as well as more reliable ILI.

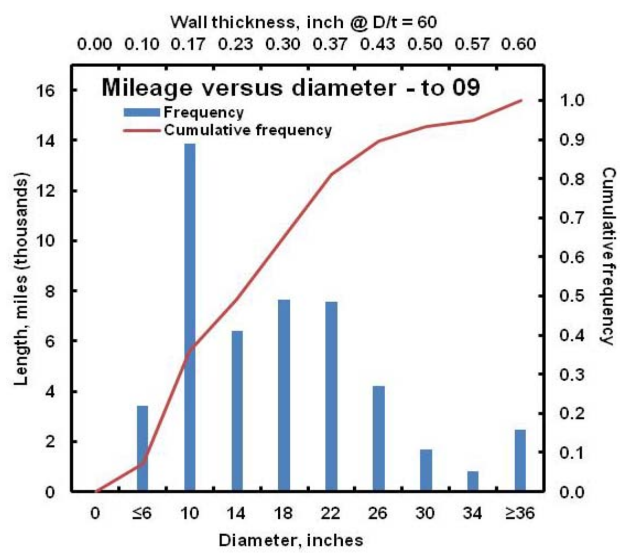
Because work in Reference 6 and related discussion there indicate the NACE corrosion rate is close to the upper-bound for the historic database, it follows that the interval prior to first IMP concern for a scheduled anomaly response is typically much longer than just discussed. If a more representative rate based on a mean or upper-percentile is adopted, the above-noted interval of 6 years to traverse 20% 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 is typically considered prior to the start of 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 12a 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 absent a decimal point as large as 375, which is inferred to be in units of thousands of an inch. Obvious outliers such as that were rationalized en route to the trending in Figure 12



a) Database trends on thickness



b) inferred wall-thickness distribution

Figure 12. Excavation / third-party damage and wall thickness implications

The trend for incidents decreasing as wall thickness increases evident in Figure 12a 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 is 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 12a, the diameter-mileage distribution must be transformed into a thickness-mileage distribution, in reference to the trend between diameter, D, and thicknesses, 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 MOP to SMYS as compared to code limits, and consistency between the D/t ratio and historic industry practice. Records found inconsistent with those metrics have either been rationalized where an obvious data reporting error was evident, or culled. This process led to a value of D/t the order of 43 for the historic data, whereas 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 12b.

Figure 12b 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 12a 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.

It is apparent from Figure 12a 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 to using burial depth deeper than code required, the use of HDDs, and the segment-specific use of an abrasion resistant overlay (ARO) coating, and the several other protections cited in the risk assessment.

6.9 Enhancements Incorporated into the Construction and Operation of the Keystone XL Pipeline

What follows was borrowed in large part from Exponent's reporting(5).The Risk Assessment discussed specific portions of the Project referred to as contributory pipeline segments (CPSs) where, if a spill were to occur, crude oil has the potential to reach HCAs (i.e., "could affect" segments). The authors then developed a process to rank, in risk levels from 1 to 4, the degree of the potential risk for specific pipeline segments by assessing the spill volume and physical transport pathway factors.

The Integrity Management Rule requires that the pipeline be evaluated to identify pipeline segments in which the released crude oil from a failure occurring anywhere between the two endpoints of the value segments could migrate to and affect a HCA. To identify the segments of the pipeline that could potentially affect HCAs, a three-step process was used:

- In the first step, HCAs were screened to determine which areas were within a reasonable proximity to the Project's proposed centerline of the pipeline and also had a viable physical pathway to transport a spill to the HCA.
- The second step of the process was to review those specific segments of the pipeline where, if a spill were to occur, crude oil could potentially reach areas of a HCA or HCA buffer area that contribute to the purpose of the HCA. CPSs were eliminated if the intersection of HCA buffer with the pipeline did not interfere with the purpose of the HCA (e.g., the drinking water HCA buffer area intersects with pipeline below the drinking water intake).
- The third step involved ranking the relative risk of each pipeline segment capable of affecting a HCA.

Most of the pipeline was removed from consideration in Step 1 and Step 2 of the process. The risk ranking step utilized five factors to categorize the identified CPSs into one of four levels, with level 1 being of the highest concern and level 4 being of lower concern for potential impacts to impact HCAs. The proximity and number of HCAs and maximum spill volume within the CPS were key factors in the ranking of a CPS. The evaluation conservatively assumed 900,000 bpd throughput to calculate maximum spill volume.

The ranking process identified 196.5 miles of the pipeline where the CPSs were ranked from 1 to 4. For risk category 1 (the highest concern), 63.7 miles of the pipeline consisting of nine CPSs, were identified. The higher risk ranking was associated with major river crossings.

The CPS locations are a particular focus for Exponent's review because they are identified in relation to HCAs and because Exponent was tasked with identifying environmental characteristics that may indicate where other sensitive areas are located along the proposed route that are not specifically defined as HCAs. To the extent that such areas are identified in our review, the pipeline segments near these locations may be considered CPSs for the purpose of considering the advisability of additional oil spill controls (e.g., valves) or countermeasure plans.

A quick review of the PHMSA conditions indicates the vast majority of them are requirements to ensure the continued integrity of the pipeline once it is constructed. Given that it is a billion dollar investment, it is prudent to meet these requirements just to protect the investment long term. A few that might affect risk include Numbers 25 through 31, which specify SCADA requirements – those could affect spill volumes or frequencies. Others like the increased strength and toughness requirements in Conditions 1, 2 and 7 could affect failure frequency, 19 depth could affect failure frequency, 35 to 37 could affect the frequency of corrosion failures, 40, 41 and 53 the first two markers and flyovers, and the last security, could also affect the frequency term. It follows that there are five categories that could be discussed. However, much of this is represented in other modern systems such as that of the Australian operators, for which a risk reduction factor the order of 10 is determined.

Beyond the above, consideration could be given to enhancements to reduce likelihood or size/cost of a release. While this is technically plausible, the work scope carries well beyond the few weeks afforded this effort, and as such is left open.

6.10 Risk Reduction Estimate

The listing of the PHMSA special conditions, which have been incorporated the pipeline design specifications are found in Appendix B of the SEIS. For each condition, the last column there presents a possible risk reduction impact of implementing the condition. However, as noted earlier it is difficult to quantify these in an isolated framework. Rather, it seems best to reflect on the Australian experience and adopt an experience-based reduction factor that might be as high as a factor of 10 in mainline pipe risk. In Section 6.6, some reasons why this factor of 10 might not be realized in this country were discussed

7. Summary

The risk assessment shows that cost of incidents is highly variable. It appears that while some of the variation is due to poor reporting, much of the variability can be rationalized by differing circumstances and so should be accepted as fact until proven otherwise. While this makes cost a difficult metric to quantify consequences, the average cost of an incident should be a viable measure, as it conveys risk in spite of the scatter.

The key findings include:

- Incident costs correlated poorly with spill volume. While the general trend is upward as the volumes get larger, there is so much variability among incidents that involve the same amount of release the data does not support developing average incident costs for more than three categories of release, small – less than 50 barrels, medium – 50 to 1000 barrels and large – greater than 1000 barrels.
- The risk spectrum curves show that the high end of the incident cost spectrum, the probability of a much higher incident cost cannot be ruled out.
- In comparing the average risks associated with the four system components analyzed, Mainline Pipe, Mainline Valves, Tanks and Other System Components, 97 percent of the risk was in the Mainline Pipe and Other System Component risks – almost evenly split. These two risk components represent the risks associated with the mainline pipe and fixed facilities such as pumping stations.
- Given the dominance of these two system components, a risk management program that addresses these system components will be most effective in reducing risk.
- Given the inability to predict the cost of an incident based on past damage costs, suggests that the best risk management strategy is to keep the crude oil inside the boundary of the pipeline system. Costs can be controlled by preventing the number of leaks at to a lesser extent, the total volume spilled.
- Many of the special conditions being applied to the Keystone Pipeline focus on prevention which is the correct focus.
- The requirement for effective PHMSA oversight is crucial. This should be a regulatory, industry corporative effort and not a punitive effort.
- Given the tremendous uncertainty in incident costs, both the pipeline operator, TransCanada and the regulators have a great deal of incentive to make the special regulatory conditions imposed on the pipeline effective. The proof will be the effectiveness of their risk management programs they have committed to perform.
- The 57 Special Conditions imposed by the PHMSA make for a safer pipeline with less operational risk. For example, the use of tough steel, which acts to limit the size of a

breach in the wall, and facilitate detection of anomalies within the mandated periodic re-inspection of the pipeline.

- Although the experience in Australia demonstrates modern pipeline might have factor of 10 lower spill risk, the full factor of 10 reduction might not be realized in the U.S. While total damage or incident cost can be a good consequence measure, the inability to model the component costs (e.g. damage to property, emergency response, environmental damage) and generate the total cost from them means that risk reduction strategies that would lower the component costs cannot be valued. Clearly there is value in minimizing environmental damage. While we cannot directly quantify these component costs in this risk modeling, the value of spill prevention and the 57 Special Conditions is evident.

8. References

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