Appendix 9B

Impact Probabilities/Residual Risk for Longhorn Pipeline

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1.0 Executive Summary

This report presents estimated impact frequencies and probabilities of nine different potential impacts along the Longhorn pipeline. The potential impacts are those associated with the proposed project, transporting refined products from Houston to El Paso at a maximum rate of 225,000 barrels per day (bpd). Impact frequencies are calculated for several scenarios involving various combinations of leak frequencies, spill sizes, and receptor vulnerabilities. Selected scenarios are also presented as leak probabilities. The calculations in this report offer some quantitative support to the findings of the EA, but, due to the uncertainties involved in such calculations, they are not the primary basis of the EA findings.

Post-mitigation impact frequencies (Case 4 as described below) are calculated to be 10 to 30 times lower than pre-mitigation and industry average frequencies. Estimated post-mitigation leak frequencies for the modeled potential impacts are tabulated below:

Table 1. Calculated Post-Mitigation Frequency of Selected Impacts

Average Mitigated Leak Rate per Mile-Year	Predicted Leak Count for 700 Miles and 50 Years	Potential Impact	Overall Risk		Segment-Specific Risk	
			Frequency over Life of Project	Annual Frequency	Frequency over Life of Project	Annual Frequency
0.00007	2.6	Drinking water contamination	0.005	0.00010	0.00000346	0.0000000692
		Drinking water contamination, no MTBE	0.003	0.000051	0.00000173	0.0000000346
		Fatality	0.005	0.00011	0.00000356	0.0000000712
		Injury	0.024	0.00047	0.00001600	0.00000032
		Recreational water contamination	0.087	0.00174	0.0000588	0.00000118
		Prime agricultural land contamination	0.035	0.00070	0.0000238	0.00000048
		Wetlands contamination	0.051	0.00101	0.0000462	0.00000092
		Lake Travis drinking water supply contamination	0.00019	0.0000038	0.00000013	0.0000000026
		Edwards Aquifer water contamination	0.00019	0.0000039	0.00000013	0.0000000026

The frequencies shown in Table 1 are converted to probabilities and shown in Table 2.

Table 2. Calculated Post-Mitigation Probabilities of Selected Impacts

			Overall Risk		Segment-specific Risk	
Average Leak Rate per Mile-Year	Predicted Leak Count for 700 Miles and 50 Years	Potential Impact	Probability of one or more events over the life of the project (%)	Annual probability of one or more events during the life of the project (%)	Probability of one or more events over the life of the project (%)	Annual probability of one or more events during the life of the project (%)
0.00007	2.6	Drinking water contamination	0.5	0.010	0.00035	0.00001
		Drinking water, no MTBE	0.3	0.005	0.00017	0.000004
		Fatality	0.5	0.011	0.00036	0.00001
		Injury	2.3	0.047	0.00160	0.00003
		Recreational water contamination	8.3	0.17	0.006	0.00012
		Prime agricultural contamination	3.5	0.070	0.002	0.00005
		Wetlands contamination	4.9	0.10	0.005	0.00009
		Lake Travis drinking water supply	0.02	0.0004	0.000013	0.00000026
		Edwards Aquifer water contamination	0.02	0.0004	0.000013	0.00000026

These estimates are supported by a combination of quantitative and qualitative information as described in this report. Nevertheless, there is a high level of uncertainty associated with these estimates, primarily due to the limited amount of data available.

2.0 Introduction

This report presents results of calculations that estimate frequencies of nine different potential impacts along the Longhorn pipeline. Impact frequencies are calculated for scenarios involving various combinations of leak frequencies, spill sizes, and receptor vulnerabilities. Selected probabilities were also calculated, using the frequencies and assuming a Poisson distribution of events. The calculations in this report offer some quantitative support to the findings of the EA, but, due to the uncertainties involved in such calculations, they are not the primary basis of the EA findings.

For the purposes of this report, "overall risk" is defined as the risks to receptors along the entire pipeline length over a period of 50 years. "Segment-specific risk" is defined as the risk to a point receptor that is presented by 2,500 ft of the pipeline, over a period of 50 years. In this usage, the pipeline segment-specific risk is essentially the overall risk normalized to a length of 2,500 ft. Except in special circumstances, a point receptor is exposed to risks from leaks occurring along a maximum pipeline length of 2,500 ft. The basis for this 'impact zone' is described in the EA. Longer receptors such as aquifers are exposed to multiples of the segment-specific risks, in proportion to their lengths. It is useful to examine a shorter length of pipeline in order to show risks that are more representative of individual receptor risks and are more comparable to other published risk criteria.

This report uses some special terminology that is defined as follows: "Reportable" refers to 49 CFR Part 195 criteria for formal reporting of accidents. A spill size of 50 barrels (bbl) is one of the triggers requiring the accident to be reported. Therefore, most OPS spill data contain spills of 50 bbl or greater, although there are some cases where a different criterion has mandated the reporting of an incident. A number of spills with volumes of less than 50 barrels are reported even though the reporting is not apparently required for any apparent reason. Because of the uncertainties associated with the reported spills of less than 50 barrels, “Reportable” is considered to include only spills of 50 barrels or more. "Index sum" refers to the EA relative risk model's measure of relative probability of failure. "Post-mitigation" means the condition of and risks to the pipeline after full and complete achievement of all aspects of the Longhorn Mitigation Plan (LMP). This includes the establishment of specified ongoing operation and maintenance activities. "Receptors" refer to the sites or organisms that are threatened by a spill of refined products. Receptors in this report include people, drinking water supplies, and wetlands. Each impact potentially damages one or more receptors.

3.0 Leak Frequencies

Pipeline leak frequencies are estimated from several data sources. Four (4) "frequency of leak" cases are examined in this report. Each case represents a different estimated incident rate and is used independently to perform an impacts assessment. Three cases use only historical data with no consideration given to possible benefits of mitigation. These are included for reference and represent impact frequencies that might be seen on an unmitigated Longhorn pipeline and on a typical US hazardous liquid pipeline. The fourth case considers the effects of mitigation. The four leak frequencies are generally described as follows:

<u>Case 1 (all U.S. hazardous liquid pipeline leak rate)</u>:
The average leak incident rate for reportable accidents on US hazardous liquids pipelines, from 1968-1999 (DOT, 1999 and in EA Chapter 5).

<u>Case 2 (former EPC pipeline, reportable leak rate)</u>:
The reportable incident (i.e., accidents in which spill volumes were 50 barrels or more) rate for 450 miles of this pipeline under Exxon Pipeline Company (EPC) operation in 29 years. (Incident rate) = (10 leaks) / (450 miles x 29 years).

<u>Case 3 (former EPC pipeline, overall leak rate)</u>:
The overall incident rate, regardless of spill size, for 450 miles of pipeline (not including pump stations) under EPC operations in 29 years. (Incident rate) = (26 leaks) / (450 miles x 29 years).

<u>Case 4 (uses an estimate of mitigation effects plus historical data)</u>:
Cases 1-3 use leak frequencies that do not consider index sums and hence do not consider effects of mitigation. In case 4, distinctions are made regarding the impacts of mitigation for the various tier categories or for a specific geographic area. The corresponding index sum is used to estimate a leak frequency. The leak frequency is therefore estimated by correlating the index

sum scale to an absolute leak frequency. This is described in Attachment A. The correlating equation used represents the curve that best fits the following points:

Index Sum	Probability of Leak (estimated by frequency in units of leaks per mile-year)
0	1.0 (100 percent chance of a leak)
189	0.00199 (historical EPC leak rate on this pipeline)
400	0 (virtually no chance of a leak)

Note that this exercise does not create a curve that passes exactly through each of these points. In fact, the curve that best fits all points actually passes through a point that represents a mitigation-effect level of 90 to 95 percent.

For Cases 3 and 4, leak probabilities are calculated in addition to leak frequencies. These are obtained by calculating the Poisson probability estimate of "one or more" leaks over the life of the project, as shown below.

The probability of no spills is calculated from:

$$P(X)SPILL = [(f * t)^{X} / X!] * \exp(-f * t)$$

where: P(X)SPILL = probability of exactly X spills

f = the average spill frequency for a segment of interest, spills /year

t = the time period for which the probability is sought, years

X = the number of spills for which the probability is sought, in the pipeline segment of interest.

The probability for one or more spills is evaluated as follows:

P(probability of one or more)SPILL = 1 – Probability of no spills

= 1 - P(X)SPILL; where X = 0.

The results of these calculations are shown in Table 2 (Executive Summary) and in Tables 5 through 8.

The leak frequency estimates have a high degree of uncertainty, primarily due to the limited amount of data available. No data that would better refine these estimates have been available. It is also important to note that frequencies and probabilities like these represent averages expected only over long periods of time. Short time periods can have different experience and still be appropriately represented by these frequencies. Therefore, the predictive power of these probabilities is limited.

As an additional evaluation step, the plausibility of the estimated post-mitigation leak frequency was examined qualitatively. The estimate is generally supported by this qualitative analysis, summarized as follows:

1. Low leak frequencies over long periods of time are being experienced by US pipeline operators on hazardous liquid pipeline of similar length to the Longhorn pipeline, but without the extraordinary level of mitigations as proposed in the LMP. This is indicated by informal interviews with pipeline operators and with searches and analyses of OPS accident data. Analyses of these latter data are discussed in Attachment E. Results of summary analyses of DOT and other data are provided. These data and analyses suggest that the estimated leak frequency is possible, especially with increased mitigation.

2. The correlation as described in Attachment A, although weak in terms of statistically valid data quantity and quality, nonetheless offers a semi-quantitative linkage that supports the estimate.

3. RS Appendix T shows leak rate estimates for approximately 60 US hydrocarbon liquid pipeline operators. These leak rates, presumably achieved under typical industry mitigation levels, show the range of different leak rates that are possible. This includes company-wide leak rates that are approaching the estimated post-mitigation leak frequency estimates for the Longhorn pipeline.

4. The scenario-based analyses detailed in Attachment B suggests that the estimated leak rate reductions can be achieved with rather modest assumptions regarding mitigation effectiveness, even for the more problematic challenge of reducing third-party damage.

5. An alternative approach to estimating failure probabilities from several common pipeline failure mechanisms has produced very similar results. This alternative approach, shown in the preliminary ORA (discussed in Appendix 9D), uses concepts from fracture mechanics, materials science, historical data, and statistics to calculate failure rates and probabilities. The fact that two separate approaches to failure probability estimation arrived at similar conclusions provides support for both calculations.

6. In the experience of the EA authors, the LMP reflects levels of mitigation unprecedented in the industry. This suggests that high levels of leak rate reductions are possible, even if not commonly observed.

In addition to overall leak frequencies, spill size frequency also plays a role in many of the impacts. A spill size distribution for spills larger than 50 bbl was derived from DOT hazardous liquid pipeline reportable spills from 1975 to early 2000. The fraction of spills smaller than 50 bbl was estimated from the 29 year EPC leak experience on the 450 mile segment from Valve J-1 to Crane. EPC leak experience contains too few larger-sized spills to create a meaningful profile.

Embedded in this approach is the assumption that the national spill size distribution (DOT data) is representative of the Longhorn's future spill size distribution. This implies that the following variables are also representative:

- Topography;
- Failure mechanisms that determine hole size;
- Leak detection capabilities; and
- Leak reaction capabilities.

Since the national pipeline system is not characterized in these terms, the similarities cannot be confirmed. However, since the LMP specifies several state-of-the-art spill size reduction measures not typically seen in other pipelines, it is reasonable to assume that the national data will not underestimate the spill size potential and very probably will overestimate the potential.

A second assumption is that the <50 bbl spill size fraction seen under EPC operations is representative of Longhorn's future spill size distribution. Since the <50 bbl size triggers few impacts and since >50 bbl spill fraction can be separated from the "all size" distribution, the absolute validity of this assumption is not critical to this analysis.

An additional underlying assumption in these estimates is that the relative probability of failure remains fairly constant over the life of the project. This is accomplished by Longhorn reacting appropriately to changing conditions along the line, as is specified in the LMP. It also requires that the integrity verifications as scheduled by ORA calculations, ensure that the probability of failure does not exceed the projected leak probabilities between integrity verifications. This is discussed in Appendix 9D.

4.0 Description of Potential Impacts

Nine distinct potential impacts are studied in this report. Impacts are site-specific and sensitive to many variables, and therefore must be somewhat generalized to present a risk picture of the entire line. For modeling purposes, the frequency of each impact is potentially affected by variables of:

- Index sum—representing the probability of pipeline failure;
- Spill size; and
- Tier designation—representing receptor vulnerability and sensitivity (e.g., Tier 3 is hypersensitive).

However, not all impacts are modeled as being sensitive to all of these, due to data availability limitations. Below is a general description of the impacts modeled. These descriptions offer the reader a general sense of the rationale behind the calculation, but note that the actual results are based on more than a hundred calculated scenarios. More detailed descriptions can be found in Attachment C.

4.1 Fatalities and Injuries

While it is common to express risks of injuries and fatalities as a function of “hours exposed,” this analysis uses only a calculation of fatalities and injuries per reportable leak. All distinctions of rural versus urban; permanent residents versus temporary exposures; distances to leaks; ignition probabilities; etc. are therefore aggregated in these ratios. This implies that the Longhorn system is similar to the national data in terms of these variables. The national pipeline system is not characterized to the extent that such similarities can be confirmed. However, no compelling reasons are found to suggest that Longhorn is not similar, with regards to the distinctions previously noted. Therefore, for the purposes of the overall impact estimations, the national data (DOT) is assumed to be representative of Longhorn’s future risks for this impact.

An example of fatalities and injuries, is Case 1 shown in Table 3. It can be described in general terms as follows:

1. Statistically, one fatality is expected to occur for every 217 reportable leaks and an injury is expected to occur for every 48 reportable leaks.

2. The industry average leak rate applied to this pipeline results in an estimate of 35 leaks over 50 years and, hence predicted fatalities and injuries of 0.16 and 0.72, respectively.

This impact is modeled with no sensitivity to actual population density differences or index sum differences along the line. A threshold spill size of 50 bbl is assumed, below which frequencies of fatality or injury are assumed to be zero.

Further discussion of the fatality and injury rates used can be found in Attachment C of this report.

4.2 Drinking Water Contamination

Drinking water contamination is defined as a potential level of contamination which :

- causes an exceedance of Texas drinking water standards, or causes an exceedance of proposed Texas ground water contamination limits; and
- can potentially impact a public drinking water supply for a period of time exceeding normal system storage capacity (estimated at about 24 hours).

The drinking water probability is a sum of the probability of impacting ground water resources used for public drinking water supplies, and the probability of impacting surface water resources used for drinking water.

There are 29 miles along the pipeline rated sensitive or hypersensitive for potential surface water drinking water quality. Based on surface water modeling performed at the most hypersensitive locations long the pipeline, a threshold spill size of 1,500 bbl was set for surface water drinking water impacts. A spill smaller than this would not (because of losses of water contaminants through natural processes such as volatilization), pose drinking water quality impact, even under adverse climate (rainfall, evaporation) conditions.

There are 66 miles rated sensitive or hypersensitive for potential ground water drinking water impacts. (Note: surface water and ground water sensitive areas are not necessarily mutually exclusive.) Based on the potential for various factors to retard transport of contaminants to an aquifer, two separate threshold levels are set:

- Over porous media aquifers, confined or unconfined, a threshold of 1,500 bbl reflects the potential for soil to absorb contaminants, and for conventional ground water remediation technologies such as pump-and-treat to control contaminants from reaching sensitive receptors.
- Over hypersensitive karst aquifers, a lower threshold of 500 bbl reflects the potential for adsorption on the thinner soil layers overlaying karst, and the rapid transport in karst aquifers which can limit remediation effectiveness. Rose (Rose, 1986) estimated this threshold at 1,000 bbl, and a figure one-half that estimate was used to add a factor of conservatism.

This impact is modeled as being sensitive to tier location, index sum, and spill volume. Since the tier designations consider vulnerability of drinking water sources, a 'probability of contamination' is assigned for each tier. Depending on the vulnerability of a given resource, threshold spill size is assumed before any impact is possible. Above that threshold, impacts are judged to be equally likely, regardless of spilled volume. This is conservative, since even the spill volumes closer to the threshold are modeled as being as harmful as the largest spill volumes.

An example of this impact is Case 1 shown in Table 3 and can be generally described as follows:

1. About 16 percent of reportable leaks are of a size to pose a threat to a drinking water supply.
2. Of those leaks, 50 percent would contaminate a surface water supply in Tier 3, 10 percent in Tier 2. Additionally, 75 percent would contaminate a ground water supply in Tier 3, 25 percent in Tier 2. Using the tier miles, these aggregate to a 100 percent chance for about 31 miles, or about 4 percent for the overall pipeline.
3. The industry average leak rate applied to this pipeline predicts 35 leaks and, hence, about 6 spills (16 percent of 35) would be of sufficient volume to contaminate a drinking water supply, and 0.2 spills would occur at a location that contaminates a drinking water supply. This is equivalent to saying one contamination episode occurs every five pipeline lifetimes or 250 years, since the 0.2 is based on a 50-year period.

Index sum averages for each tier are used to estimate leak incident rates in Case 4. Further discussion of how this receptor is modeled can be found in Attachment C of this report.

4.3 Drinking Water Contamination—No MTBE

The previous impact assumes 15 percent MTBE is transported in the pipeline. If no MTBE is present, the potential for impacts is assumed to be one-half of the previous case. Rationale for this is presented in Attachment C of this report.

4.4 Edwards Aquifer Contamination

This is a special case of "ground water drinking water contamination," focused specifically on the three miles between Milepost (MP) 170.5 and MP 173.5 (all new pipe as proposed in LMP). Because of the documented pathways for rapid contamination of drinking water wells in Sunset Valley, this represents "worst case" probability for ground water contamination. This case has the following assumptions in addition to the general drinking water impacts.

- Since this area is over known hypersensitive karst, the spill size threshold is set at 500 bbl. Spills of this size and larger are assumed to be equally harmful.
- In the mitigated case, the enhanced leak detection system in this area is credited with reducing the frequency of larger sized spills. Specifically, the types of potential large spills reduced are those created by a slow leak, below the detection capabilities of normal leak detection, continuing for long periods of time.
- The index sum represents the additional leak prevention measures proposed in these three miles.

Further discussion of how this receptor is modeled can be found in Attachment C of this report.

4.5 Lake Travis Drinking Water Contamination

This is a special case of "surface water drinking water contamination" which focuses on spills in the Pedernales watershed that could impact drinking water supplies drawn from Lake Travis. The potential for contamination of Lake Travis was analyzed in detail because of the large number of people served by this reservoir (up to a million), and the duration contaminant levels in excess of drinking water criteria or advisory levels could be exceeded (on the order of 1 to 2 months for any lake water users, including the City of Austin). The analysis involves 1.54 miles of pipeline located in Tier 2 areas and 2.74 miles in Tier 3. This represents worst case probability for contamination of surface water used as a drinking water supply. The spill size threshold is set at 1,500 bbl. Spills of this size and larger are assumed to be equally harmful and spills below this threshold would not cause the impact.

Further discussion of how this receptor is modeled can be found in Attachment C of this report.

4.6 Recreational Water Contamination

Recreational water contamination is defined as levels of contamination which could cause violation of the Clean Water Act through creation of a visible petroleum sheen on any surface waters, or through impacts to fish populations (including levels of dissolved oxygen and toxic constituents in the water). No potential concentration levels were analyzed for recreational water contamination, and it is possible that contaminant levels in excess of those which may result from a pipeline release already exist in watersheds from urban runoff and usage of recreational watercraft. Threshold spill sizes applied for certain portions of the pipeline represent the size of spill which would need to occur prior to a spill reaching a surface water body.

This impact is modeled as being sensitive to tier location, specifics within the tier, and spill volumes.

An example of this impact is Case 1 shown in Table 3 and can be generally described as follows:

1. About 38 percent of reportable leaks are of a size to pose a threat to a recreational water supply.
2. Of those leaks, ~25 percent would contaminate the receptor. This is determined by characterizing the various lengths of such receptors present within each tier. Each length within each tier is assigned a probability, indicating that length's vulnerability. In aggregate, these compute to be the equivalent of about a 25 percent probability all along the pipeline.
3. The industry average leak rate applied to this pipeline predicts 35 leaks and, hence, about 13 (38 percent of 35) would be of sufficient volume, and ~2.8 would occur at the right location to contaminate one of these receptors.

Further discussion of how this receptor is modeled can be found in Attachment C of this report.

4.7 Prime Agricultural Land Contamination

A spill size of 500 bbl over prime agricultural land is viewed as impacting agricultural lands, based on the potential for spread of a rapid release to impact ¼ acre of agricultural lands. Further discussion of how this receptor is modeled can be found in Attachment C of this report.

4.8 Wetlands Contamination

A spill size of 500 bbl over wetlands is viewed as impacting the wetlands. This threshold is set as a level which would potentially overcome the natural processes of volatilization and adsorption, and cause serious degradation of high quality impacts. Discussion of how this receptor is modeled can be found in Attachment C of this report.

5.0 Summary of Results

Post-mitigation impact frequencies are calculated to be 10 to 30 times lower than pre-mitigation and industry average frequencies The frequency reduction is not constant since different permutations of leak frequencies, spill size frequencies, and lengths-impacted are combined.

The following tables show the results of all frequency estimates for all impacts. Case 4 in all tables shows the estimate for post-mitigation results. Other cases are included for comparison. Table 3 shows overall frequencies for all cases and Table 4 shows segment-specific frequencies for all cases. Tables 5 and 6 focus on Cases 3 and 4 and present probabilities (in slightly different formats than Tables 3 and 4) of impacts.

Table 3. Overall Risks

Case	if…	Average Leak Rate per Mile-Year	Estimated Leak Count for 700 Miles and 50 Years	Impact	Overall Risk: Frequency of Impact over Life of Project	Overall Risk: Annual Frequency (x1000) for Impact	Notes
1	Industry average reportable leak rate applies	0.001	35	Drinking water contamination	0.27	5.35	
				Fatality	0.16	3.21	4
				Injury	0.72	14.42	4
				Recreational water contamination	2.80	55.96	
				Prime agricultural land contamination	1.06	21.14	
				Wetlands contamination	1.65	32.92	
2	Pre-mitigation reportable leak rate continues	0.0007[1]	26.8	Drinking water contamination	0.20	4.10	10 reportable (>50 bbl) over 450 miles in 29 years
				Fatality	0.12	2.46	4
				Injury	0.553	11.05	4
				Recreational water contamination	2.14	42.88	
				Prime agricultural land contamination	0.81	16.20	
				Wetlands contamination	1.26	25.22	

Table 3. (Continued)

Case	if…	Average Leak Rate per Mile-Year	Estimated Leak Count for 700 Miles and 50 Years	Impact	Overall Risk		Notes
					Frequency of Impact over Life of Project	Annual Frequency (x1000) for Impact	
3	Pre-mitigation leak rate continues	0.00199[2]	69.7	Drinking water contamination	0.23	4.69	
				Fatality	0.14	2.82	
				Injury	0.63	12.65	
				Recreational water contamination	2.45	49.06	
				Prime agricultural land contamination	0.93	18.53	
				Wetlands contamination	1.44	28.86	
4	Post-mitigation leak rate estimate	0.00007[3]	2.6	Drink water contamination	0.005	0.10	
				Drinking water contamination, no MTBE	0.003	0.051	
				Fatality	0.005	0.11	4
				Injury	0.024	0.47	4
				Recreational water contamination	0.087	1.74	
				Prime agricultural land contamination	0.035	0.70	
				Wetlands contamination	0.051	1.01	
				Lake Travis water supply contamination	0.00019	0.004	Pedernales watershed
				Edwards Aquifer water contamination	0.00019	0.004	

Notes
1 10 reportable (>50 bbl) leaks over 450 miles in 29 years
2 26 leaks (some less than 50 bbl) over 450 miles in 29 years
3 Leak estimate is for any leak, including <50 bbl; approximate leak count for 50 bbl (reportable) = 1.1 in 50 years
4 Fatality and injury rates are based on DOT fatality and injury rates per reportable leak applied to 700 miles

Table 4. Segment-specific Risks

Case	if…	Average Leak Rate per Mile-Year	Estimated Leak Count for 700 Miles & 50 Years	Impact	Segment-specific Risk (2,500 ft of pipeline)		Notes
					Frequency (x 10^6) of Impact over Life of Project	Annual Frequency (x 10^6) for Impact	
1	Industry average reportable leak rate applies	0.001	35	Drinking water contamination	181	3.62	
				Fatality	109	2.17	4
				Injury	488	9.76	4
				Recreational water contamination	1893	37.85	
				Prime agricultural land contamination	715	14.30	
				Wetlands contamination	1502	30.03	3,372 ft, special length for this receptor
2	Pre-mitigation reportable leak rate continues	0.00077[1]	26.8	Drinking water contamination	139	2.77	
				Fatality	83	1.66	4
				Injury	374	7.48	4
				Recreational water contamination	1450	29.01	
				Prime agricultural land contamination	548	10.96	
				Wetlands contamination	1151	23.01	3372 ft special length for this receptor

Table 4. (Continued)

Case	if…	Average Leak Rate per Mile-Year	Estimated Leak Count for 700 Miles & 50 Years	Impact	Segment-specific Risk (2,500 ft of pipeline): Frequency (x 10^6) of Impact over Life of Project	Segment-specific Risk (2,500 ft of pipeline): Annual Frequency (x 10^6) for Impact	Notes
3	Pre-mitigation leak rate continues	0.00199[2]	69.7	Drinking water contamination	159	3.17	
				Fatality	95	1.90	
				Injury	428	8.55	
				Recreational water contamination	1659	33.18	
				Prime agricultural land contamination	627	12.54	
				Wetlands contamination	1316	26.33	3372 ft special length for this receptor
4	Post-mitigation leak rate estimate	0.00007[3]	2.6	Drinking water contamination	3.5	0.069	
				Drinking water contamination, no MTBE	1.7	0.035	
				Fatality	3.6	0.071	4
				Injury	16.0	0.320	4
				Recreational water contamination	58.8	1.175	
				Prime agricultural land contamination	23.8	0.475	
				Wetlands contamination	46.2	0.920	3372 ft special length for this receptor
				Lake Travis water supply contamination	0.13	0.003	Pedernales watershed
				Edwards Aquifer water contamination	0.132	0.003	

1 10 reportable (>50 bbl) leaks over 450 miles in 29 years
2 26 leaks (some less than 50 bbl) over 450 miles in 29 years
3 Leak estimate is for any leak, including <50 bbl; approximate leak count for 50 bbl (reportable) = 1.1 in 50 years
4 Fatality and injury rates are based on DOT fatality and injury rates per reportable leak applied to 700 miles

Table 5. Overall Impact Probabilities for Cases 3 and 4

Case	If…	Average Leak Rate per Mile-Year	Estimated Leak Count for 700 Miles and 50 Years	Overall Impact Probability* Impact	Overall Impact Probability* Probability of One or More Impacts over Life of Project	Annual Probability** of One or More Impacts over Life of Project	Probability Chances in a Thousand	Annual Chances in a Thousand	Notes
3	Pre-mitigation leak rate estimate	0.00199 [1]	69.7	Drinking water contamination	20.9%	0.47%	209	4.68	
				Fatality	13.1%	0.28%	131	2.81	2
				Injury	46.9%	1.26%	469	12.6	2
				Recreational water contamination	91.4%	4.79%	914	47.9	
				Prime agricultural land contamination	60.4%	1.8%	604	18.36	
				Wetlands contamination	76.4%	2.84%	764	28.4	
4	Post-mitigation leak rate estimate	0.00007[3]	2.6	Drinking water contamination	0.5%	0.010%	5.10	0.102	
				Drinking water contamination, no MTBE	0.3%	0.005%	2.55	0.051	
				Fatality	0.5%	0.011%	5.25	0.105	2
				Injury	2.3%	0.047%	23.38	0.473	2
				Recreational water contamination	8.3%	0.17%	83.20	1.736	
				Prime agricultural land contamination	3.5%	0.070%	34.50	0.702	
				Wetlands contamination	4.9%	0.10%	49.42	1.013	
				Lake Travis water supply contamination	0.02%	0.0004%	0.19	0.004	4
				Edwards Aquifer water contamination	0.02%	0.0004%	0.19	0.004	

* Overall impact probability is probability of one or more events in 50 years over 700 miles

** Overall impact probability, annual, is probability of one or more events in 1 year over 700 miles

Notes:

1 26 leaks (some less than 50 bbl) over 450 miles in 29 years

2 Fatality and injury rates are based on DOT fatality and injury rates per reportable leak, applied to 700 miles

3 Leak estimate is for any leak, including <50 bbl; approximate leak count for 50 bbl (reportable) = 1 in 50 years

4 Pedernales watershed

Table 6. Segment-specific Impact Probabilities for Cases 3 and 4

Case	If…	Average Leak Rate per Mile-Year	Estimated Leak Count for 700 Miles and 50 Years	Impact Probability for Specific Locations* Impact	Probability of One or More Impacts over Life of Project	Annual probability** of one or More Impacts over Life of Project	Probability Chances in a Million	Annual Chances in a Million	Notes
3	Pre-mitigation leak rate estimate	0.00199 [1]	69.7	Drinking water contamination	0.0159%	0.000317%	159	3.17	
				Fatality	0.0095%	0.000190%	95	1.90	2
				Injury	0.0428%	0.000855%	428	8.55	2
				Recreational water contamination	0.166%	0.00332%	1658	33.2	
				Prime agricultural land contamination	0.0627%	0.001254%	627	12.54	
				Wetlands contamination	0.132%	0.00263%	1315	26.3	
4	Post-mitigation leak rate estimate	0.00007[3]	2.6	Drinking water contamination	0.00035%	0.00001%	3.5	0.069	
				Drinking water contamination, no MTBE	0.00017%	0.0000035%	1.7	0.035	
				Fatality	0.00036%	0.00001%	3.6	0.071	2
				Injury	0.00160%	0.00003%	16.0	0.320	2
				Recreational water contamination	0.006%	0.00012%	58.8	1.175	
				Prime agricultural land contamination	0.002%	0.00005%	23.8	0.475	
				Wetlands contamination	0.005%	0.00009%	46.2	0.925	
				Lake Travis water supply contamination	0.000013%	0.00000026%	0.13	0.003	4
				Edwards Aquifer water contamination	0.000013%	0.00000026%	0.13	0.003	

* Impact probability for specific locations is probability of one or more events in 50 years per 2,500 ft

** Impact probability for specific locations, annual, is probability of one or more events in 1 year per 2,500 ft

Notes:

1 26 leaks (some less than 50 bbl) over 450 miles in 29 years

2 Fatality and injury rates are based on DOT fatality and injury rates per reportable leak, applied to 700 miles

3 Leak estimate is for any leak, including <50 bbl; approximate leak count for 50 bbl (reportable) = 2 in 50 years

4 Pedernales watershed

Attachment A

Correlation of Index Sum with Leak Frequency

1.0 Summary

This analysis indicates that the overall probability of failure is reduced substantially when mitigation measures in the Longhorn Mitigation Plan are applied. Although there are insufficient data points to precisely quantify the effect of mitigation on the predicted failure rate, it appears reasonable to assume a substantial decrease from pre-mitigation failure rates.

2.0 Background

Mitigation effects, as measured by changes in the EA relative risk model, are thought to reflect actual improvements in the probability of failure. This is because the numerical score is thought to relate to the absolute level of risk. A defined correlation between the relative and absolute pipeline failure rates or probabilities would define the mathematical relationship and thereby allow predictions of probability-of-failure based on measured relative risk scores.

An approach is discussed here for quantifying the leak probability reduction associated with proposed mitigation measures (see also Chapter 9 of EA, especially discussions related to Figure 9-1, *Approximate Linkage Between Index Sums Scores and Level of Pipeline Failures*). Ideally, meaningful statistical data on failure rates for multiple pipeline systems coupled with their corresponding index values before and after increased mitigation, would be used to correlate the differences in failure probability with pipeline system characteristics. However, comparable data from multiple pipeline systems are not available. Therefore, approximations are required based on failure rate and corresponding probability data from the former EPC pipeline and the index scores from the EA Relative Risk Model.

3.0 Mathematical Linking of EA Relative Risk Probability Scores (Index Scores) with Absolute Risk

Index sum scores are inversely related to the probability of failure. A higher score corresponds to a lower probability; a lower score is associated with a higher probability (Muhlbauer, 1996). There should be a mathematical relationship between index scores and absolute probability values. To establish this relationship, absolute risk is represented by the probability of failure where “failure” is defined as a leak of any size. For the pipeline as a whole, the average failure rate, based on 29 years of operation and 450 miles of data yields an average failure probability for any specified time interval. This value was calculated as 1.99E-03 (~2.0E-03) in any given year for a mile of pipe. This means that under the previous operation, there were roughly 2 chances in a thousand of any size leak occurring per mile of pipeline, each year. Pump stations are excluded from this analysis, but could be dealt with separately in a similar manner.

The relative probability of failure for a pipeline segment is represented by the Index Sum value calculated from the EA risk model. The range of values for the Index Sum is 0 to 400, with 0 representing the lowest safety level (highest risk)—certain failure. At the opposite end of the scale, 400 is a theoretical value representing the most failure-proof system imaginable (the highest safety, lowest risk)—no failure. Therefore, the Index Sum can be viewed as a "safety scale," whereby increasing points mean increasing safety—lower failure probability. Unfavorable conditions around the pipeline, inadequate operator activities, and increasing uncertainty (about existing conditions) all tend to reduce Index Sum scores—indicating lower safety and a correspondingly higher failure probability.

In order for the Index Sum to fairly represent the relative probability of failure in this correlation effort, the individual indexes, representing four separate failure modes, must show that all failure modes have similar probability of failure levels. The Index Sum is the total of the four separate indexes and hence the failure frequency represented by the Index Sum is the sum of the individual failure frequencies represented by each index. However, the Index Sum used in isolation might mask a deficiency in one or more failure modes. Since linking each failure mode with its own leak frequency is even more problematic than linking overall leak frequencies, this exercise relies on a prior verification that the Index Sum contains a 'balance' among the included failure modes and therefore fairly represents the overall failure frequency.

In developing a method for relating the relative probability of failure to the Index Sum score, only one "measured" data point is available to incorporate into the analysis. This point is the Index Sum score of 189 which is the pre-mitigation average Index Sum score for the J1 to Crane portion of the System, obtained by averaging all pipe segment scores after a risk assessment of the "as-is" pipeline (as of June 1999) was completed. This Index Sum corresponds to a leak frequency of 2.0E-03 leaks/year-mile based on the EPC 29 year operating history.

For further analyses, the pipeline could be divided into several segments and treating each of these segments as individual pipelines. However, when this was attempted by dividing the pre-mitigation pipeline into 5 approximately equal segments, the Index Sum scores for the segments only ranged from 189 to 204. This is a very narrow range. There is no guarantee that the functional form that fit the data would be valid outside this range. Furthermore, the Index Sum scores of interest, the results of the post-mitigation assessment, are far outside the interval, requiring a rather extreme extrapolation. Refining the analysis on the basis of five such points and performing the extrapolation as described is not considered to be meaningful. Other techniques for subdividing the pipeline to obtain additional data points proved to be similarly problematic, from a statistical point of view. However, since the boundary conditions for both scales can be defined in real terms, they can represent additional data points for these purposes.

As the Index Sum score approaches 0, the probability of failure can reasonably be expected to approach 1.0 (100 percent chance of failure). As the Index Sum approaches 400, the probability of failure can reasonably be expected to be very near zero. These two assumed points bound the range of interest and, therefore, avoid the error inherent in an extrapolation. Three data points, the minimum required to define a curve (and hence the relationship of interest), are now available. It can be reasonably assumed that the curve representing the mathematical relationship is monotonic, based on the calculation protocol of the Index Sum conditions or activities that reduce probability of failure always cause higher point scores. It is believed that there is widespread agreement as to the positive or negative direction (mathematically) caused by risk factors captured in the Index Sum. The magnitude of such impacts, however, might be debated.

A family of monotonic curves can be envisioned which pass very nearly through the data points. The development of two curves based on fundamentally different shapes and which somewhat encompass the family of all possible curves, can be defined. These two curves therefore provide bounds for the probability of interest. Thus, the two probability estimates presented by the curves represent informal bounds for the probability of failure corresponding to various Index Sum values.

The two mathematical relationships selected for their ability to 1) fit these three data points, 2) bound the family of curves possible, and 3) remain monotonic are:

- Equation A: $\ln P = a_1 + b_1 S$
- Equation B: $\ln (P/(1-P)) = a_2 + b_2 S$

Where: $P =$ Probability of failure
$S =$ Index Sum
a_i, b_i = constants

Either of these equations produces a relationship that reasonably fits the three data points, as shown in Figure 1.

Three data points are the minimum number of data points that can represent a curve. Therefore, strong conclusions should not be drawn from this analysis. Neither curve shape is necessarily inconsistent with intuitive beliefs about pipeline risk. The two relationships differ mostly in the initial portions—when risk is first reduced from the highest levels. For equation A, the initial curve steepness suggests that even minimal improvements in conditions or activities for an extremely poorly rated system yield large reductions in the probability of failure. An argument can also be made for the more gradual initial slope of equation B. Failure probability might be reduced only gradually until some threshold of risk-reduction is reached, perhaps because multiple failure modes are possible and significant gains aren't achieved until mitigation measures address a sufficient number. In either case, the portions of the curves of most interest to this analysis, the latter portions on the right side of the chart, are quite similar. Both curves suggest that as more improvements are made, it becomes more difficult to achieve improvements—a point of diminishing returns is reached.

Equation A predicts a relatively higher probability of failure at the higher Index Sums and is therefore more conservative in estimating the benefits of mitigations. The approximate relationship between the leak probability and the Index Sum based on Equation A is shown in Figure 2. It is convenient to show the form of Equation A in log-space, since the equation is linear in that space. If there were three or more measured points, a least-squares fit could be obtained. However, the probability corresponding to the Index Sum of 400 is assumed to be very small, essentially 0, and it is not possible to take the logarithm of 0. One could assign a small positive value to the probability to allow the logarithm to be taken. However, the results would be very sensitive to the arbitrary choice for the value that was chosen. Thus, three points are not available to allow the development of a least squares fit in log space.

Three points are available in linear space, however, and a nonlinear regression was performed. This solution uses the points of: [Index Sum of 0 with a probability of 1.0] and [Index Sum of 189 with a probability of 2.0E-3] and [Index Sum of 400 with a probability of 0] to fit the curve. This approach avoided the complexities of transforming the logarithmic regression into linear space. The model had the following form:

Leak Probability, = A * exp (-B*Index Sum/100)

where

A = 1.000; and
B = 3.2908

The average length-weighted post-mitigation Index Sum score is 289, and the leak frequency (probability) at this value is 7.4×10^{-5} leaks/mile-year. At these low values, leak frequencies are essentially the same as failure probabilities.

4.0 Uncertainties in Estimates

This linking of the relative and absolute risk measures and the resulting table of leak estimates is considered to be relatively conservative. Therefore, the relationship should tend to underestimate the benefits of mitigation. This is based on the following sources of conservatism:

1. The key Index Sum data point (189, for average probability of failure and score) reflects some operational improvements (made under WES), which have not been in place long enough to impact (favorably, it is assumed) the probability of failure. Therefore, the score of 189 probably represents a lower probability of failure than the 2.0E-03 that is being used.

2. The curve-fit relationship that generates the higher predicted probability-of-failure value is used to produce the estimates shown in the table. Therefore post-mitigation failure rates might be over estimated.

In spite of the conservatism, there remains a great deal of uncertainty in this relationship as well as in the underlying data. Historical leak data have uncertainties and the EA relative risk model is, in many instances, forced into more judgement-based evaluations. Given these uncertainties, a more definitive correlation between the absolute and relative probabilities cannot be established.

5.0 Conclusion

It seems logical that improvements in leak frequencies will result from the mitigation measures. The improvements have the potential be substantial and this correlation suggests that they would indeed be substantial, but the exact magnitude of improvement cannot be precisely determined at this time. Based on the described relationship and the uncertainty of the leak frequencies, it seems reasonable to expect improvements in a range perhaps on the order of a twenty-to-thirty fold decrease in leaks.

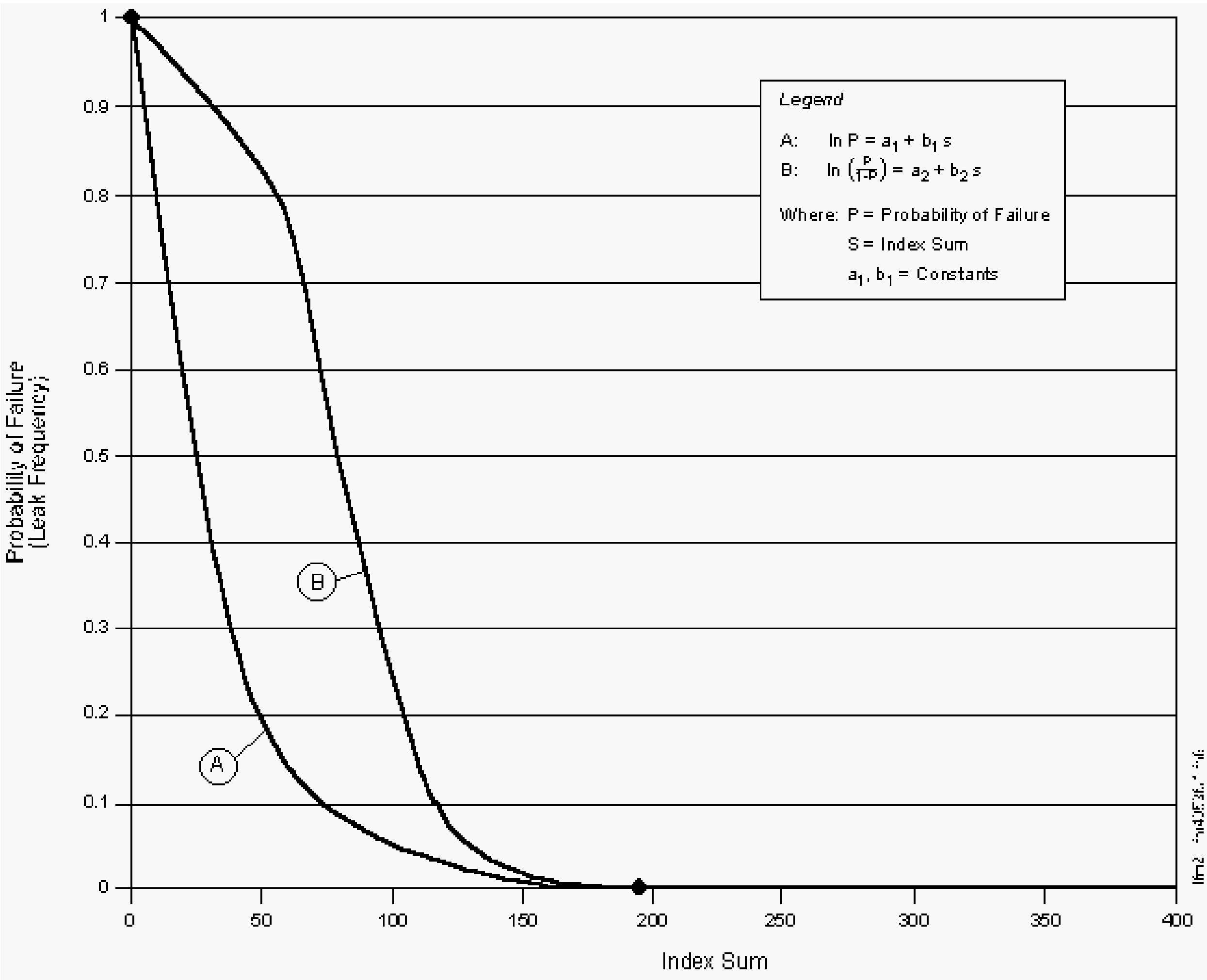

Figure 1. Leak Frequency as a Function of Index Sum

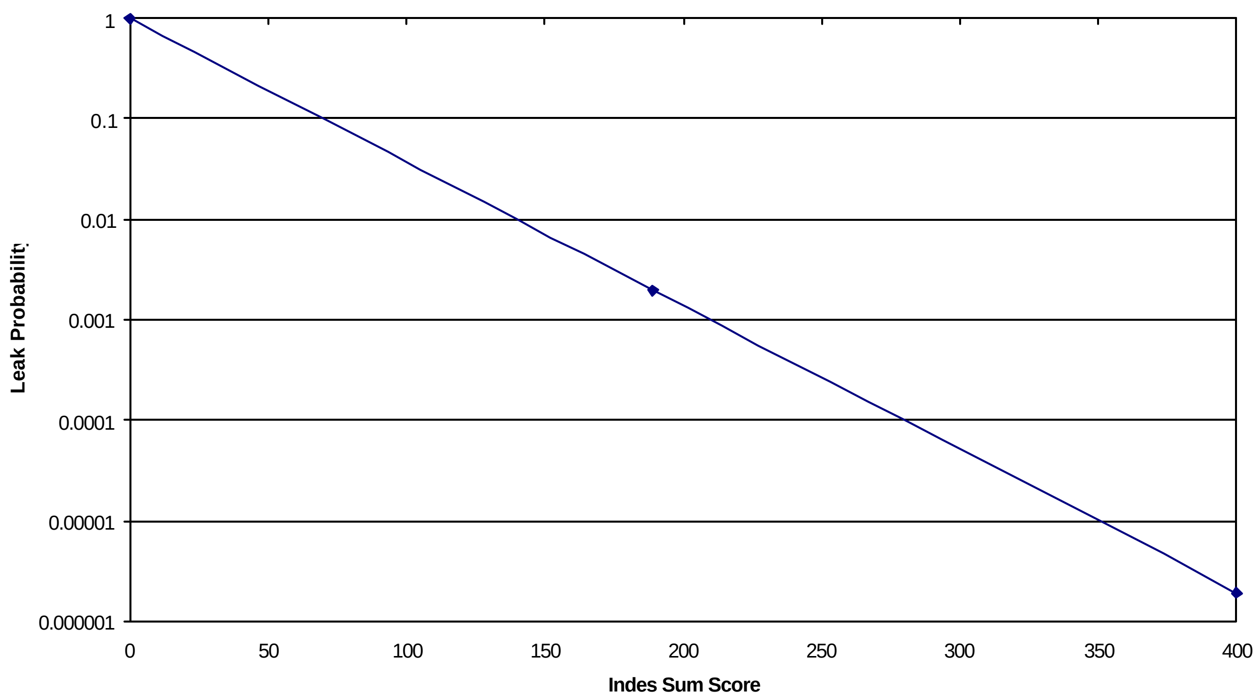

Figure 2. Leak Probability as a Function of Index Sum Score

Attachment B

Mitigation Effectiveness for Third-Party Damage—A Scenario-based Evaluation

Hypothesis to be examined:

At least 9 out of 10 third-party damage failures that would be otherwise expected, are avoided through the stringent implementation of the LMP.

Discussion

This failure estimation is suggested by modeling and analyses shown elsewhere in this report. There is a question of whether such an estimation can be supported by a logical event-tree analysis and examination of some of the past failures. Therefore, the objective is to determine if the LMP measures could have interrupted past failure sequences, at least 90 percent of the time, under some set of reasonable assumptions.

Third-party damage (or 'outside force') is a good candidate for this examination since this failure category is often viewed as the most random and hence, the least controllable through mitigations. Seven (7) out of twenty-six (26) historical leaks were categorized as being caused by “third-party damage.” It is useful to characterize these incidents based on some situation specifics. At least six (6) of the incidents involved heavy equipment such as backhoe, bulldozer, bulldozer with ripper/plow, and ditching machine (the seventh is not listed). Five (5) of the incidents suggest that a professional contractor was probably involved since activities are described as cable installations, water line installations, excavations for an oil/gas company, land clearing, etc. At least four (4) of these events occurred before a One-Call system was available in Texas (beginning in the early 1990s and mandated in late 1997). So, the opportunities for advance knowledge of the presence of the pipeline was limited to signs, ROW indications, and perhaps some records if the excavator was exceptionally diligent in a pre-job investigation. Contractor and public education efforts, ROW condition, and actual patrol frequency are unknown. Based on current survey information, depth of cover at these sites varies from 19 inches to over 48 inches.

Scenarios have been created to address the question: “How many failures, similar to these past incidents, might occur today?” These scenarios take into account the proposed LMP. Two tables are offered to show potential failure sequences and opportunities to interrupt those sequences. Since the previously discussed incidents occurred despite some prevention measures, the estimates are showing opportunities for damage avoidance above and beyond prevention practices thought to be prevalent at the time of the incidents. These tables are loosely using terminology to represent frequency of events and probability of events—this is not a rigorous statistical analysis.

In the first table, the estimated probabilities of various scenario elements are presented. (Any of these can be modified to see the change in resulting mitigation effectiveness.) The table begins with the assumption that a potentially damaging third-party activity is already present in the immediate vicinity of the pipeline.

Given that an activity is present, column 2 of the table characterizes the distribution of likely activities. The distribution is based on the predominance of heavy equipment involvement in previous incidents, and is conservative since that category is perhaps the most threatening to the pipeline.

Column 3 examines the possibility, under today's mandated and advertised One-Call system, that the system is used and the process works correctly to interrupt a potential failure sequence. It is assumed that 60 percent of heavy equipment operators would have knowledge of and experience with the one-call process and would therefore utilize it. It is further assumed that the one-call process 'works' 80 percent of the time it is used. (Both assumptions are thought to conservatively underestimate the actual effectiveness.) This yields a 48 percent chance (60 percent x 80 percent) that this variable interrupts the sequence for that type of activity. It is assumed that one in ten potentially damaging events would be similarly interrupted in the case of typical homeowner or farmer/rancher activity. This is lower than for the heavy equipment operators since the latter group is thought to be more targeted with training, advertising, and presentations from owners of buried utilities. The interruption rates reflect improvements over one-call effectiveness at the time period of the incidents, approximately 1969 to 1995, which includes periods when there was either no one-call system available or it was available but not mandated. The continuously increasing acceptance of the one-call protocols by the public and the response of the pipeline operator to notifications combine to create this estimated interruption rate.

Columns 4, 5, and 6 examine the possibility that, given that an activity has escaped the one-call process, the impending failure sequence will be interrupted byimproved ROW condition, signs, or public/contractor education. Assumptions of likelihood range from five in a 100 to 15 in a 100, respectively. This means that out of every group of threatening activities, at least a few will be interrupted by someone noticing the ROW and/or a sign or having been briefed on pipeline issues and reacting appropriately. In the interest of conservatism, relatively small interruption rates are assigned tothe LMP-specified improvements in these variables although they can realistically prevent an incident.

Column 7 examines the effect of depth of cover. Morgan (Morgan, 1996) cites Western European data (CONCAWE) which suggests that approximately 15 percent fewer third-party damage failures occur with each foot of cover over the normal (0.9 meters). Using this, a length-weighted average depth of cover was calculated for Tiers 2 and 3, respectively. Tier 3 and Tier 2 showed 7 percent and 4 percent improvement for each area, respectively, based on the lengths within the tier that are covered deeper than about 0.9 meters. Based on this, a value of 5 percent was assigned to the cover variable for the 'heavy equipment operations' type of activity. This means that five out of every 100 potentially damaging third-party activities would be prevented from causing damage by an extra amount of cover. For homeowner activities, depth of cover is judged to be a more effective deterrent, preventing three out of ten potential damages. One out of ten potentially threatening rancher/farmer activities are assumed to be rendered non-threatening by depth of cover.

Finally, the impact of patrolling is examined in column 8. A table of common third-party activities is presented against a continuum of opportunity to detect, expressed in days (see patrol figure/table). The "opportunity" includes an estimate of how long after the activity occurs, its presence can still be detected. Since third-party activities can cause damages that do not immediately lead to failure, this ability to inspect evidence of recent activity is important. The table is intended to provide an estimate of the types of activities that can reasonably be detected in a timely manner by a patrol. The frequency of the various types of activities will be very location- and time-specific, so frequencies shown are very rough estimates. It seems reasonable to assume that activity involving heavy equipment requires more staging, is of a longer duration, and leaves more evidence of the activity. All of these promote the opportunity for detection by patrol.

Statistical theory confirms that, with a few reasonable assumptions, the probability of detection is directly proportional to the frequency of patrols. For example, calculations indicate that the probability of detection in two patrols is twice the probability of detection in one patrol if detection of the same event cannot occur in both patrols. This condition is essentially satisfied for these purposes since patrol sightings subsequent to the initial sighting are no longer considered to be "detections." The key point here is that the probability that one or more events will occur is the sum of their individual probabilities if the events are mutually exclusive.

Discounting patrol errors, as the patrol interval approaches 0 hours (a continuous observation of the ROW), the detection probability approaches 100 percent. The patrol interval is changing from a historical maximum interval between patrols of 336 hours (once every two weeks on average, although it could be as high as three weeks or 504 hours). The LMP requires a patrol every 24, 60, or 168 hours, depending on the location. In theory, this improves the detection probability by multiples of 2 to 14. On the table of activities, patrol intervals of 24, 60, and 168 hours suggest detections of 93 percent, 75 percent, and 36 percent of activities, respectively. This means that, with a maximum interval between patrols of 24 hours, only 7 percent of activities would go undetected (given the assumed distribution of activities). Obviously, the real situation is much more complex than this simple analysis, but the rationale provides a background for making estimates of patrol benefits

In order to make conservative estimates (possibly underestimating the patrol benefits), theincreased detection probabilities under the LMP are assumed to be: 30 percent, 10 percent, and 20 percent for heavy equipment, homeowner, and ranch/farm operations, respectively. This means that about one-third of heavy equipment operations; one in every ten homeowner activities; and one in every five ranch/farm activities would be detected before damage occurred or, in the case of no immediate leak, would provide the operator time to detect and repair damages before a leak occurs. Homeowner and ranch/farm actions are judged to be more difficult to detect by patrol because such activities tend to appear with less warning and are often of shorter duration than the heavy equipment operations.

Table 2 converts Table 1 columns 3 through 8 into probabilities of the sequence NOT being interrupted—the "opposite" of Table 1.

Column 9 of Table 2 estimates the fraction of times that the line is under enough stress that, in conjunction with powerful enough equipment, a rupture would occur immediately. This stress level is a function of many variables, but it is conservatively estimated that 50 percent of the line is under a relatively high stress level. For the 50 percent of the line that could be damaged, but not to the extent that immediate leakage occurs, the LMP's corrosion control and integrity re-verification processes [including the Operational Reliability Assessment (ORA), which specifically factors in third-party damage potential in determining re-inspection intervals] are designed to detect and remediatesuch damages before leaks occur.

Column 10 of Table 2 estimates the frequency of a third-party activity involving equipment of enough power to cause an immediate leak. This may be somewhat correlated to depth of cover, but no such distinction is made here. Heavy equipment is assigned a value of 0.9—indicating high probability that the equipment has enough power to rupture the line. A minor reduction from a value of 1.0 that would otherwise be assigned, is recognized—it is assumed that such heavy equipment normally is operated by skilled personnel. So, while heavy equipment is certainly capable of rupturing a line, a skilled operator can usually 'feel' when something as unyielding as a steel pipe is encountered, and will investigate with hand excavation before extra power is applied. Homeowners and rancher/farmers are assumed to be using powerful equipment in 30 percent and 60 percent of their activities, respectively. No credit for operator skill is assumed in these cases.

Column 11 multiplies all column estimates and shows the combined frequency for the three types of activities.

Additional Factors

Although not quantified here, the impact of future focus on the issue of third-party damages can reasonably be considered. The pipeline industry shares this concern with buried utilities containing any of several types of data transmission lines. Interruption of such lines can represent enormous costs. Additional unexamined activities that would suggest efforts in the future to prevent such damages include on-going government industry initiatives addressing the issue. Longhorn participates in these efforts.

The LMP also requires that Longhorn adjust its integrity re-verification program on the basis of new third-party damage evidence. This is a part of both the LMP's ORA and SIP components.

Conclusions

It is important to note that this analysis is strictly a logic exercise, to test if the hypothesis could reasonably be supported through assumed effectiveness of individual mitigation measures.

This analysis suggests that under the proposed LMP, and assuming modest mitigation benefits from the LMP specifics, approximately 89 percent of third-party activities, not interrupted under previous mitigation efforts, can reasonably be expected to be interrupted before they cause a pipeline failure. The initial hypothesis therefore seems reasonable, given the results and the conservative assumptions employed in this analysis.

These calculations are based on realistic scenarios with assumptions that are thought to underestimate rather than overestimate prevention effectiveness. However, since they contain a large element of randomness, third-party damages are more difficult to predict and prevent. Scenarios can be envisioned where all reasonable preventive measures are ineffective and damage does occur. Such scenarios are usually driven by human error—an element that causes difficulty in making predictions.

Table 1

	p(activ)	p(interruption of event sequence by…) One Call	ROW	Signage	Public/Contractor Education	Cover	Patrol
Heavy equipment operations	80%	0.48	0.1	0.05	0.15	0.05	0.3
Homeowner equipment operations	10%	0.1	0.1	0.05	0.15	0.3	0.1
Ranch/agricultural equipment operations	10%	0.1	0.1	0.05	0.15	0.1	0.2
Notes	*4*	*1,12*			*9*	*2,3*	*6,7,8*

Table 2

		p(event) = 1 - p(interruption)						p(high stress)	p(equip powerful enough)	p(of leak happening after activity is proximal)
Heavy equipment operations	80%	0.52	0.9	0.95	0.85	0.95	0.7	0.5	0.9	9.05%
Homeowner equipment operations	10%	0.9	0.9	0.95	0.85	0.7	0.9	0.5	0.3	0.62%
Ranch/agricultural equipment operations	10%	0.9	0.9	0.95	0.85	0.9	0.8	0.5	0.6	1.41%
Total	100%									**11.08%**
								5	*10*	

Notes:
1 Assume that 60 percent of contractors follow one call procedure and that marking, etc. is 80 percent effective
2 Western Europe data suggests 15 percent failure reduction per foot of additional cover (over 'normal' depth)
3 Assume cover is more effective against non-heavy equipment damages
4 At least six of the seven EPC third-party involved heavy equipment used by contractors
5 Assume percent of line that is in a highly stressed condition; enough to promote leak upon moderate damage
6 Assume that these percentages are detected prior to incident or soon thereafter (damage assessment opportunity)
7 Previous third-party damage rate allowed 336 hours as maximum interval between detection opportunities; new is 24, 60, or 168 hours maximum
8 Assumes that homeowner and ranch activities tend to appear faster than most heavy equip projects
9 Includes door-to-door in Tier 3 and presentations to excavating contractors everywhere
10 Chances that equipment is powerful enough that, in conjunction with a higher stress condition in the pipe wall, immediate rupture is likely
11 P(damage detection before failure) = function of (patrol, CIS, ILI, fatigue, corrosion rate, stress level)
12 No one-call was available(?) for five out of seven EPC third-party leaks

Patrol as an opportunity to prevent failures caused by third-party damages.

Spectrum of third-party activities used to produce "probability of detection" graph (Figure 1 on the next page).

Activity	Activity Duration (plus evidence remaining)		Cumulative Frequency
	Days	Frequency of Occurrence	
Highway construction	14	0.03	0.03
Subdivision work	13	0.03	0.06
	12	0.03	0.09
	11	0.03	0.12
	10	0.05	0.17
	9	0.05	0.22
Buried utility crossings	8	0.07	0.29
	7	0.07	0.36
	6	0.07	0.43
Drainage work	5	0.1	0.53
Swimming pools	4	0.1	0.63
Land clearing	3	0.1	0.73
Agricultural	2	0.1	0.83
Seismograph crew	1	0.1	0.93
Fence post installation	0.5	0.05	0.98
Other	0.1	0.01	0.99

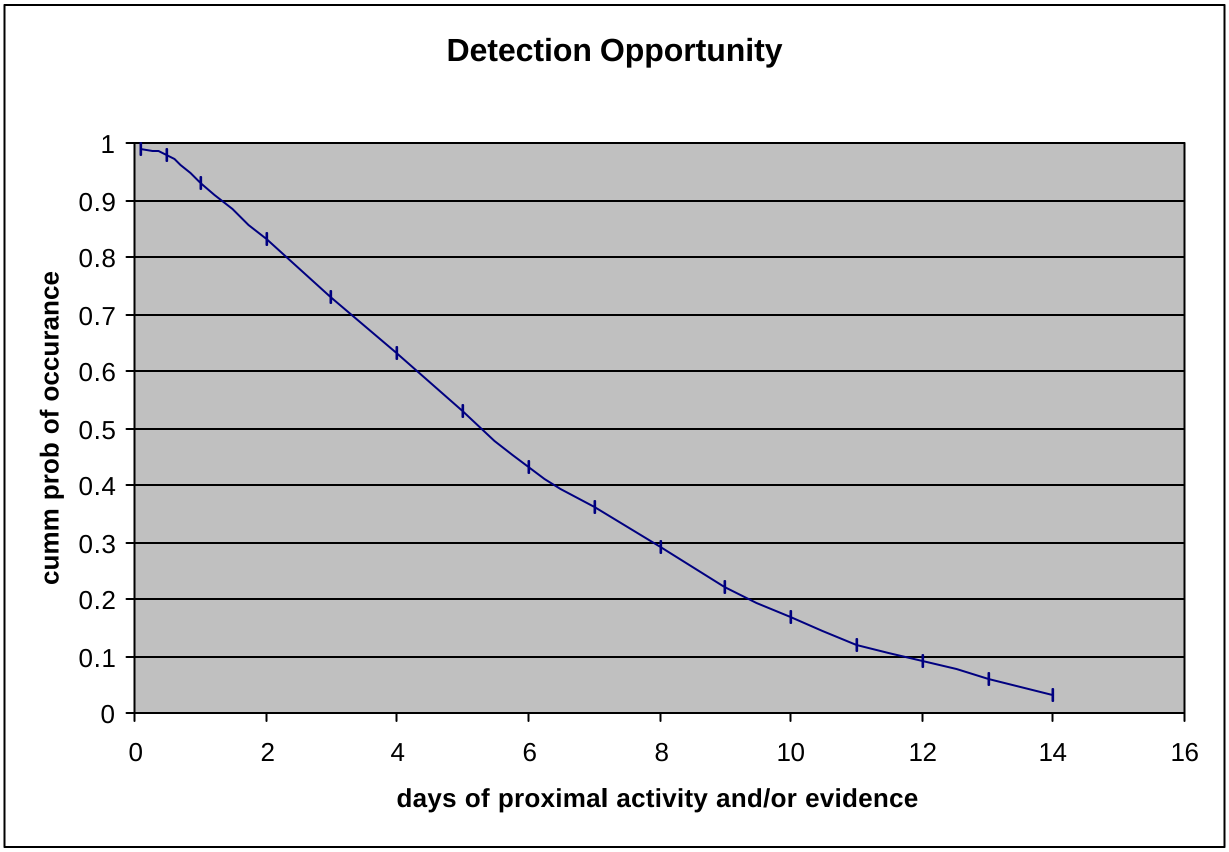
Detection Opportunity
cumm prob of occurance
days of proximal activity and/or evidence
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
0
2
4
6
8
10
12
14
16

Figure 1

Attachment C

Details of Assumptions and Calculations

Fatalities, and Injuries

The fatality and injury rates for the 4 cases described in Tables 3 and 4 of this appendix were calculated from data in the DOT Database (DOT, 1999). The fatality and injury rates for the period 1975-1999 were derived from the total number of fatalities and injuries associated with pipelines carrying refined products and crude oil during this period. These rates, expressed as fatalities/injuries per reportable spill, are calculated as the total number of fatalities or injuries divided by the total reportable spills (spill volumes ≥ 50 barrels, mostly) in the period 1975-1999. There were 11 fatalities and 57 injuries associated with 2,395 reportable spills during this 25-year period. The fatality rate is calculated as:

Fatality rate = 11 fatalities / 2395 reportable spills
= 0.00459 fatalities per reportable spill

The injury rate was calculated in a similar manner. The fatality and injury rates were 0.00459 and 0.0238 per spill, respectively.

This approach assumes that there is no more than one fatality/injury per reportable spill even though this is not the case. This assumption introduces conservatism into the fatality/injury rate estimates since the "fatalities/injuries per reportable spill" rates overstate the rate which is really sought: the frequency of "one-or-more fatalities/injuries per reportable spill". These two rates are referred to interchangeably in EA discussions, but are always based on the conservative calculations described here.

The overall risks of fatalities and injuries from pipeline spills were determined from the overall leak rate expressed as leaks per mile per year. For example, the estimated average number of Longhorn pipeline leaks predicted over the next 50 years, using industry average reportable leak rates as a basis, is 35. The equivalent number of fatalities that can be expected for this same length of pipeline over 50 years is 0.00459 (fatalities per spill) x 35 (spills per 50 years) = 0.16. The annual frequency is calculated as the project-life frequency divided by the project life of 50 years.

The fatality and injury rates for Case 2 were calculated in a similar manner, using the estimated leak count of 26.8 determined from the pre-mitigation reportable leak rate of 0.00077 leaks per mile per year (10 leaks in 450 miles over 29 years).

The average leak rate of 0.00199 leaks per mile used in Case 3 includes all leaks: those less than 50 barrels in volume in addition to reportable leaks. In estimating the fatality and injury rates, it was assumed that there were no injuries or fatalities associated with leaks of less than 50 barrels. Since the estimated leak counts included leaks of less than 50 barrels, the estimated leak rates were reduced by the ratio of reportable to total leaks. Approximately 56%

of the total leaks are below 50 barrels in size. Thus, the leak rates were multiplied by 0.44 to obtain the estimated fatality and injury rates. For example, the fatality rate for Case 3 was calculated in the following manner:

Fatalities = 0.00459 x 69.7 x 0.44 = 0.14 fatalities over the project life.

The fatality and injury rates for Case 4 were calculated in a similar manner. The average leak rate for Case 4 was determined as described elsewhere in this appendix.

The segment-specific fatality and injury frequencies shown in Table 4 were calculated in much the same manner as those given in Table 3. The frequencies for the 2500-ft segments were produced by reducing the frequencies for the entire pipeline by the ratio of 2500 ft to 700 miles. For example, the fatality frequency for Case 1 was calculated as follows:

Fatality frequency = (0.00459 x 35 x 2500) / (700 x 5280) = 109 x 10^{-6}

Drinking Water Contamination

Contamination of public drinking water resources may occur either from contamination of sensitive ground water or surface water supplies.

Tier 2 and Tier 3 areas for potential drinking water contamination were defined by the sensitive and hypersensitive designations in Chapter 7. The mileage of Tier 2 and Tier 3 areas for ground water and surface water were therefore derived directly from Tables 7-1 and 7-2. Note that sensitive and hypersensitive areas for ground water and surface water are not mutually exclusive, and therefore some overestimation of overall probability will result.

The assignment of sensitive and hypersensitive areas is based on hydrological and hydrogeological evaluation of the characteristics of surface water streams and aquifers which could be impacted by the pipeline. The designation of sensitive was intended to indicate those areas where it is deemed possible for damages to occur to a drinking water supply resulting from a release. The designation of an area as hypersensitive suggests that there is a higher probability of an impact within these areas. A release to either a sensitive or hypersensitive area does not guarantee an impact. There are various location- and time-specific determining factors, such as distance to surface water or karst feature, flow rate in a receiving stream, saturation of soils, temperature, and wind speed, and nature of the event causing the release.

Based on an overview of these factors, the probability of contaminating drinking water supplies as a result of a major release along the pipeline were set conservatively at the rates shown in this report. Fifty percent potential contamination for surface water/drinking water contamination was set after reviewing modeling results of the most sensitive crossing with respect to significant drinking water contamination along the pipeline—the crossing of the Pedernales River upstream from Lake Travis. Modeling exercises conducted to date show that during mean flow conditions on the Pedernales, a worst case spill at this location would have no significant impacts on drinking water quality. Therefore, under at least 50 percent of the flow conditions in the river, there would be no impact. The 50 percent number is also conservative with respect to the worst case crossings at Flat Creek and the Pedernales. The 50 percent estimate is also thought to be very conservative in light of other areas which are currently designated hypersensitive, but for which more recent modeling suggests that a sensitive/Tier 2 designation would be more appropriate.

Surface water drinking supplies in Tier 2 areas are less vulnerable than those in Tier 3 areas. For surface water contamination in a Tier 2 area to impact public drinking water supply, very improbable stream flow, soil, and water use (such as drought stage water needs) would need to occur simultaneously. These conditions exist at a lower frequency than is represented by 10 percent probability number assigned for Tier 2 areas.

For ground water, a higher probability (relative to the surface water case) is assigned to Tier 2 sensitive and Tier 3 areas, in order to account for a number of factors. These include the uncertainty about localized ground water flows at every point along the pipeline, the potential presence of private drinking water wells which may be impacted, the distance to karst recharge features, the extent of time for which contaminants could remain in ground water at significant concentrations, and the variations in ground water flux due to aquifer level and rainfall conditions. However, a major spill in a hypersensitive area does not guarantee impacts to drinking water quality within the associated aquifer. Factors such as uptake by the soil, runoff, and volatilization from the surface can reduce much of the volume of the product which reaches the aquifer.

Additional modeling assumes a case where MTBE is removed from the gasoline, and that benzene is the primary constituent of concern. This modeling indicates that the potential for significant impacts to drinking water use when MTBE is removed is far less than one-half the potential for spills containing MTBE. In order to be conservative, the impact was set at one-half of the potential with MTBE.

Edwards Aquifer Contamination

The three miles of pipeline crossing hypersensitive recharge formations in the Edwards Aquifer/Balcones Fault Zone were concluded to represent worst case ground water impacts.

As explained generally in LMC 33, and specifically in the Phase II BA, Longhorn will investigate and seal off any recharge features within the pipeline ROW while laying new pipe. This should reduce pathways for product spilled to impact the aquifer by percolating through surface soils to a subsurface recharge feature or flowing overland to a recharge feature.

It is assumed that soils will readily absorb between 500 and 1,500 bbl of a spill: the lower level (500 bbl) is set as the minimum spill of consequence. The probability of any spill greater than 500 bbl impacting ground water is set at 75 percent, to reflect the large number of recharge features in the zone. It is assumed that any contamination of the aquifer will in turn impact drinking water supplies in Sunset Valley.

Lake Travis Drinking Water Contamination (Pedernales Watershed)

A number of river and stream crossings in the Pedernales watershed were rated as hypersensitive for potential drinking water quality impacts to Lake Travis.

Additional creeks as well as some dry channels identified as potential overland flow paths of concern, were identified as sensitive. The total mileage of these sensitive (Tier 2) and hypersensitive (Tier 3) stretches along the pipeline were factored in as locations which could impact Lake Travis water quality, using the factors described for "Drinking Water

Recreational Water Contamination

The potential for recreational waterways contamination is based on the idea that any product spill which reaches a waterway has the potential for negatively impacting recreational uses. This may be a result of short-term impacts to surface water quality which limit contact recreation, and fish kills or contamination which may limit recreational fishing.

Two thresholds of spill size were used in determination whether a surface water body would potentially be affected by a spill. For portions of the pipeline where it is more likely that a spill would impact a surface water body, a threshold of 500 bbls was used. For those portions of the pipeline that were either very remote from the potentially threatened surface water body, or which were in an area of very flat topography, a threshold of 1500 bbls was used as a minimum spill size.

It should be noted that most of the streams that are crossed by the pipeline are small, and in many cases are seasonal. A product release may therefore result in a large portion of the total stream flow consisting of product contaminants, for some distance downstream from the point of release. Therefore, a probability of 100 percent for contamination was set for any 100-meter segment along the pipeline containing a river or stream crossing as well as for each of the adjoining 100-meter segments in order to account for the close overland pathways which could impact a stream.

In addition, some probability exists that a release at additional points in the watershed may impact the surface water quality. Since overland flow modeling was performed to identify the flow pathways from points along the pipeline, the characteristics of these flow pathways were used to establish for each pathway a probability of impacting the surface water stream during a major release.

These characteristics included distance from the pipeline along the pathway to the surface water body, slope of the pathway, terrain type (urban, agricultural, forested, rangeland) – as an indicator of ground cover which could promote or retard overland flow, and soil permeability. These characteristics are used to generate a composite number for each flow pathway. Those pathways which were not within a 300-meter band across each stream crossing, but which had a score equal to or higher than the 300-meter band, were assigned a probability of impact of 90 percent. Areas of lower scores were rated incrementally with probabilities of 70 percent and 40 percent. The final two sets of pathways were scored at 10 percent and 0 percent probability. Pathways that are assigned a 0 percent probability largely represent points along the pipeline over flat, high permeability rangelands in the western portion of the pipeline.

Prime Agricultural Land Contamination

A spill volume of 500 bbl is set as the threshold for impacts to agricultural lands, A spill this size resulting from a rupture could be expected to contaminate about 1/4 of an acre of soil.

Impacts to agriculture were evaluated by reviewing soils data from US Department of Agriculture databases. Prime agricultural was identified as those farmlands having the following soil types: BaA, BaB, BeB, Bo, BuB, HeB, HoB, KrA, Nd, No, RoB, Sa, Sg, Sm, and Tr.

The distance of these types of soils crossed by the pipeline was measured, with the supposition that any prime farmland along the pipeline could be impacted from a pipeline accident up to a distance of 1,250 ft from the point of release. Therefore, the band of impact along the pipeline for evaluating any point was 2,500 ft. In most cases, overland spread would cause impacts of two to three acres from any individual spill event.

Although localized channels, ditches, or roadways may provide a conduit for product to avoid major contamination of farmland, in general, it is assumed that any release over farmland will have an impact to that farmland. Therefore, a probability of 100 percent for impacts to agriculture is associated with any release over prime farmland.

For most of the pipeline, it was assumed that prime farmland was over Tier 1 areas. However, in Bastrop County, where a major portion of the pipeline is rated as sensitive for potential contamination of ground water resources, the distance of agricultural lands covered by Tier 1 and Tier 2 portions of the pipeline were tabulated separately.

The average farmlands crossing distance was 872 ft, and the median 94 ft.

Wetlands Contamination

A spill volume of 500 bbl is set as the threshold for impacts to wetlands.

Two separate types of wetlands crossings are noted along the pipeline right-of-way—palustrine and riverine. A total of 967 wetland areas were identified within the pipeline corridor, with a total of 159.7 miles of pipeline crossing or adjacent to wetlands. These figures were tabulated by comparing the pipeline right-of-way with national wetlands inventory maps. Of the wetlands types, there were 857 palustrine wetlands which could be potentially impacted, consisting mainly of small ponds within the 2,500-foot (ft) corridor. The average linear distance of the palustrine wetlands is 711 ft. The average linear distance of the 110 riverine wetlands is 2,127 ft, with a median distance of 1,339 ft.

Therefore, the potential for impact to any wetland resource is represented by the distance across the wetland plus 1,250 ft to either side along the pipeline. A length of analysis for impacts to individual wetlands is set at 3,372 ft in order to encompass the average wetland crossing, plus the 1,250 ft to either side which could impact the wetland during a spill. The probability of impact from a spill into or proximal to the wetland is set at 100 percent.

Attachment D

Mileages of Impact Zones

Impact | **Mileage Scheme**

frequency* (Number per thousand) for impact over life of project

Drinking water contamination

Drinking water, no MTBE

		prob-weighted length calc			
type	tier	prob	miles	prob x miles	
surface	2	0.1	22	2.2	
surface	3	0.5	7	3.5	
ground water	2	0.25	53	13.25	
ground water	3	0.75	8	6	
both	1	0	610	0	
			700	24.95	**3.56%**

Fatality

Injury

Tier	Miles
1	587.2
2	91.11
3	21.69
Total	700.0

Fatalities and injuries are based on leak rate only

Recreational water contamination

Tier	100%	90%	70%	40%	10%	5%	1%		
1	36.5	8.3	29.0	67.4	191.1	181.6	32.8	546.8	
2	11.0	5.3	8.4	15.3	39.1	12.7	0.0	91.9	
3	8.0	0.6	1.5	3.3	9.0	2.2	0.0	24.5	
Total	55.5	14.3	38.9	85.9	239.2	196.5	32.8	663.2	totals

Prime agricultural contamination

Tier	miles	Percent
1	0.43	5%
2	7.72	92%
3	0.2	2%
Total	8.35	100%

Wetlands contamination

Tier	miles	Percent
1	58.22	69%
2	20.11	24%
3	6.29	7%
Total	84.62	100%

Lake Travis water supply

Tier	miles	Percent
2	1.54	36%
3	2.74	64%
	4.28	100%

Edwards Aquifer water contamination

Tier	miles
3	3

Attachment E

Comparison of Estimated Longhorn Pipeline Post-Mitigation leak Rates with Leak Rates from Operating Hazardous Liquid Pipelines

1.0 Introduction

Longhorn has committed to the implementation of an array of mitigation measures to reduce the likelihood of leaks from the pipeline. The EA relative risk model has been used to estimate the relative decrease in likelihood as a result of applying the proposed mitigation measures to the Longhorn pipeline. As described in Attachment A of Appendix 9B, a method has been developed for relating the Index Sum (relative likelihood of failure) scores from the EA risk model to the estimated post-mitigation leak frequencies and probabilities.

The reasonableness of the estimated post-mitigation leak frequency is examined by comparing the estimated overall post-mitigation leak frequency of 0.00007 leaks/year/mile with historical leak frequency data from other pipeline systems. This has been done using the DOT OPS Hazardous Liquid Pipeline Accident Database (DOT Database) (DOT, 2000), and a subset of the data in this DOT Database. The comparisons are not exact, since the leak frequencies developed from the DOT Database are based on reportable leaks, while the frequency of 0.00007 leaks/mile/year refers to total leaks, regardless of their volume. The leaks reported in the DOT Database are primarily those whose volume is equal to or greater than 50 barrels, although there are a relatively small number of leaks of less than 50 barrels also reported in the Database. This is a drawback in the comparison since the Longhorn estimate is based on all spill sizes.

In addition to the above comparisons, accident data from the DOT Database were combined with information published in the Oil and Gas Journal (True, 1998) to develop leak frequencies for comparison to the post-mitigation leak frequency estimated for the Longhorn Pipeline.

These topics are presented and discussed in the following sections.

2.0 The DOT OPS Hazardous Liquid Database

The DOT Database (DOT, 2000) is the primary source of the data used in comparing the estimated Longhorn post-mitigation leak frequency with leak frequencies of other hazardous liquid pipelines. A leak data subset (DOT subset) of the DOT Database was developed and provided by DOT (Little, 2000) for comparison with the estimated Longhorn post-mitigation leak frequency. This subset is provided in Table 9B-E-1. Since leak frequencies are expressed as leaks/mile/year, the calculation of these frequencies from the DOT subset requires that the lengths of pipeline be known. These lengths are not included in the DOT Database, but they were obtained from DOT user fee information. Only the total lengths of pipeline operated by individual companies are available from 1986 to 2000, so the DOT subset data analysis is limited to the last 14-15 years. Where more than one contiguous pipeline segment is included in the total length on the user fee forms, the lengths of the individual pipeline segments could not be determined.

To develop the DOT subset, the DOT Database was first screened to filter out all leak sources other than “line pipe.” Leaks from pump stations, tank farms, and other non-pipeline components were not included in this analysis since the estimated Longhorn leak frequencies do not include these elements. The DOT subset contains information on pipelines carrying all types of hazardous liquids, because it was not possible to associate pipeline segment lengths with individual products transported in the pipelines. Data from companies that did not have a reportable accident (i.e., one in which the spill volume was 50 barrels or more) during the period 1986 through 2000 were also compiled from user fee information and merged into the DOT subset to provide a more complete profile of hazardous liquid pipeline accident performance.

The leak frequency data from the above sources have been used in the analyses and comparisons are discussed below. Summaries of the comparisons and conclusions from them are presented in Section 4.0.

3.0 Summary of Leak Frequency Comparisons

The leak frequencies associated with following three data sets are presented and discussed in this section of the attachment:

- The DOT subset (Little, 2000);
- Data from 16 pipeline operators operating systems of lengths similar to Longhorn (Little, 2000); and
- Leak frequencies of hazardous liquid pipelines in petroleum service (True, 1998).

3.1 Leak Frequencies Associated with Hazardous Liquid Pipelines

Table 9B-E-1 contains the DOT subset of line pipe leak data.

Leak frequencies (leaks/mile-year) have been calculated for each operator. The DOT subset was subdivided into several groups according to length of pipeline. This was done to estimate whether there were any obvious gross effects of the length of pipeline operated on the leak frequencies. The average leak frequency, weighted for years and length was calculated for each of the groups according to the following equation:

$$Weighted\ Average\ Leak\ Frequency = \frac{Total\ Number\ of\ Leaks}{\sum_i (\ Miles\ of\ Pipeline\ i)(\ Years\ for\ Pipeline\ i)}$$

The leak frequencies for each of the size groups are summarized in Table 9B-E-2. Some individual leak frequencies were not included in calculating the composite values. Excluded sources included pipelines with 3 years or less of operational time, since these could be unrepresentative of typical long-term operations. Also excluded from the summary tables are those pipeline operators with less than 100 miles of pipeline, because these may not be representative of larger pipeline operators. Small pipeline operators may not, for example, have operating resources equivalent to those of larger operators.

The weighted average leak frequencies were relatively consistent among the five size groups, ranging from 0.0005 to 0.00078 leaks per mile per year. The average of the individual frequencies fell into similarly comparable size ranges. Between 12 and 70 percent of the pipelines in the five size groups had leak frequencies of less than 0.00007 leaks/mile/year. For the DOT subset, approximately 40 percent of the operators with more than 100 miles of pipeline experienced leak frequencies of 0.00007 or less. Approximately one-third of the companies operating 100 miles or more of pipelines did not report any leaks over the 14-15 year period. Sixteen percent of companies operating over 600 miles of pipeline had no reportable leaks over an average operating period of 11 years. These results suggest that the estimated Longhorn post-mitigation leak frequency of 0.00007 leaks/mile-year is reasonable. Pipelines that have presumably not implemented the level of mitigation that Longhorn has committed to put into practice have achieved such levels or lower.

3.2 Leak Frequencies of Hazardous Liquid Pipelines of Comparable Total Length to that of the Longhorn Pipeline

With extensive mitigation measures in place, Longhorn will have a post-mitigation Index Sum score of 289. A correlation, which is described in Attachment A of Appendix9B, was used to transform the post-mitigation Index Sum of 289 to an estimated leak rate of 0.00007 leaks/mile/year. The regression model is based on very limited data. As a result, there is some uncertainty about the prediction because of the small amount of information available for the regression. It is beneficial, then, to address the reasonableness of the estimated leak rate on the basis of the performance of other pipelines.

The leak-rate histories for 16 pipeline operators for which data were available, and who operated a total length of 600 to 800 miles of pipeline were analyzed. These data are shown in Table 9B-E-3. These total lengths are similar to the 723-mile Longhorn pipeline.

Using pipelines with comparable lengths and durations of data records facilitates the statistical comparisons in various ways. First, if leak frequency varied with pipeline length, selecting pipelines with lengths comparable to that of Longhorn pipeline would minimize this effect. Second, for reasons discussed below, a set of pipelines selected to represent the best performance in the database must consider variability to be valid. Identifying pipelines that are comparable after accounting for variability is facilitated if pipelines that have comparable numbers of mile-year combinations are chosen.

For 14 of the 16 pipeline operators, records exist for 12 to 15 years over the period 1986-2000. This analysis focuses on these 14 pipelines. Data exist for two years and for four years for the two other pipelines. Less emphasis is placed on these because the short operating periods may bias the data low.

There may be differences between Longhorn and the pipelines in the data set that affect performance. For example, the Williams Company that will operate the Longhorn pipeline, operates many more miles of pipeline. It is probable that some or most of the pipelines in the data set are operated by companies that are larger or smaller than Williams Company size might affect some practices that impact the leak rate. In addition to company size, the product carried might affect leak frequency. Different products may differ with respect to corrosivity or other properties that affect leak frequency.

The mitigation measures proposed by Longhorn are more extensive than those for most pipelines and are expected to result in a post-mitigation leak frequency for Longhorn that will be less than that of the best-performing pipelines. An analysis was performed to identify the upper tier of the 16 pipelines and to compare their leak frequencies with the estimated Longhorn post-mitigation leak frequency as a measure of the achievability of the latter.

Analysis of the Data Set as a Whole

Table 9B-E-4 presents the data set for the 16 subject operators. Five, or about a third, of the pipelines have leak rates less than the 0.00007 leaks/mile/year estimated for Longhorn. After excluding the data for the two pipelines with two and four years of operation, four of 14 remaining pipelines had no reportable leaks over the 14-year reporting period (considered to be exemplary operators).

Thirty-one percent of the 16 pipelines and 29 percent of the 14 pipelines with 12 or more years of data have leak rates less than or equal to the estimated value for Longhorn. A point is considered an outlier if it falls in the extremities (for example, below the 5^{th} percentile or above the 95^{th} percentile). The Longhorn estimate is clearly not an outlier relative to the historical leak rates and could reasonably have come from the same statistical distribution that characterizes those leak rates.

The median leak frequency for the 16 pipelines is 0.000235 leaks/mile/year. The median for the 14 pipelines with 12 years or more of recorded data is the same. The median leak rate for the complete data set is about 0.4 times larger than the estimate of 0.00007 leaks/mile-year for the Longhorn System This is not a large discrepancy, and, moreover, as is discussed below, there is reason to compare Longhorn's estimated leak rate to that of the best-performing subset of the 16 pipelines.

Identification and Analysis of Best Performing Pipelines

Given the extensive mitigation measures proposed for Longhorn, it is reasonable to expect that its leak rate will be less than that of the pipelines represented in the foregoing data set. Figure 9B-E-1 is a plot of the leak frequencies and 95 percent confidence intervals for the leak frequencies for the 16 pipelines. The pipelines are numbered in the order of increasing leak rate; the order is the abscissa in the plot. The confidence intervals were calculated using methodology for the Poisson distribution presented by Hahn and Meeker (Hahn, 1991).

The confidence intervals quantify the uncertainty of the estimated leak rate for each pipeline, in view of the finite data set and the role of random variability in the occurrence of rare events. The confidence interval for a given pipeline has a 95 percent probability of containing the true leak rate for that pipeline. The statistically true leak rate is the value that would be obtained if the pipeline could be observed for an infinite time period, thereby allowing all sources of random variability to average out.

The leak rates increase in a gradual manner for the first 13 pipelines. This property is qualitatively consistent with what one would expect if these 13 pipelines had the same basic performance, and the differences in leak rates for the observed time period were only random.

Pipeline 14 has a leak rate of 0.00225 leaks/mile/year, which is almost three times the leak rate for pipeline 13. The step increase is apparent in Figure 1. This, together with the discussion above, suggests that the best 13 pipelines are consistent with each other and collectively represent the best performance among the set of 16. Further justification for this conclusion is discussed below.

Figure 9B-E-1 also reveals that pipelines 5 and 16 have noticeably wide confidence intervals. Pipelines 5 and 16 have only four years and two years worth of data available, respectively. As a result, more emphasis is placed on the other 14 pipelines.

Figure 9B-E-2 presents a similar plot for the first 13 pipelines. Although the leak rate varies among these pipelines, the 95 percent confidence intervals all overlap each other. Further, as is indicated earlier, there is no step increase, as there is between pipelines 13 and 14. From Figure 9B-E-1, the confidence intervals for pipelines 14, 15, and 16 are disjoint from almost all of the confidence intervals for the best 13 pipelines.

These results suggest that the best 13 historical leak rates are similar or equivalent to each other after accounting for random variability. There is reason to say that the results for pipelines 14, 15, and 16 are not consistent with this set of 13. Thus, there is a basis for treating the 13 pipelines with the lowest-recorded leak records as representative of the best performance in this particular data set. Suppose pipeline 5, for which there are only four years worth of data, is also excluded. This exclusion is conservative, since pipeline 5 had an observed leak rate of 0 leaks/mile/year.

There are reasons for excluding pipelines with small numbers of pipeline-year combinations. The random variability of the observed leak rate for such pipelines is greater than the variability for the 12 selected pipelines. As is shown in Figure 9B-E-2, the confidence intervals for such pipelines are wide. Thus, it is more likely that the confidence intervals for a large set of pipelines that are fundamentally different will overlap, just because of the high degree of uncertainty. Selecting the 12 pipelines with comparable lengths and years of recorded data addresses these issues.

Of the 12 remaining pipelines, four, or one-third, have leak frequencies less than or equal to the Longhorn estimate of 0.00007 leaks/mile/year. The median leak frequency for the 12 pipelines is 0.00016 leaks/mile/year, which is larger than the Longhorn estimated leak rate. However, there is a large uncertainty associated with the median of only 12 values. Here, the 95 percent confidence interval for the median extends from 0 leaks/mile/year to 0.00038 leaks/mile/year. Methodology presented by Hahn and Meeker (Hahn, 1991) was used to compute this confidence interval. This is a non-parametric confidence interval; that is, the leak rates were not assumed to have a normal, lognormal, or other specific distribution in computing the confidence interval.

The comparisons described above show that Longhorn's estimated leak rate falls very near the center of the distribution of leak rates among the 12 pipelines in the upper tier. This comparison establishes that Longhorn's estimated leak rate is consistent with the distribution of historical leak rates for the pipelines in the upper tier.

One could also use the average of the 12 leak rates as a basis of comparison. For an asymmetric distribution, however, the average can be dominated by a small number of large values. For example, the average leak rate for the 12 pipelines is 0.00022 leaks/mile/year, but excluding the one largest leak rate reduces the average by more than 20 percent, to 0.00017 leaks/mile/year. The excluded pipeline had seven of the 19 leaks observed for all 12 pipelines. Given the instability of the mean as a measure of central tendency when the distribution is asymmetric, the comparisons presented earlier should suffice for the intended purposes here.

3.3 Performance of Pipelines Transporting Petroleum Products

In the Annual Pipeline Issue of *Oil & Gas Journal* (True, 1998), those pipeline operators transporting petroleum products are listed along with the total length of pipeline operated by each company. The number of reportable leaks occurring on each pipeline (line pipe only) over the past 10 years was determined using the DOT OPS Hazardous Liquid Pipeline Database (DOT, 2000). The shaded Company ID Numbers indicate those companies whose name may have changed through acquisition or merger, so the associated leak rates are somewhat uncertain.

The leak frequencies were calculated for each company, and the results are shown, in order of ascending leak frequency, in Table 9B-E-5. The unweighted average (the average of all the individual leak rates) is 0.00062 leaks per mile per year. The weighted average (total leaks divided by total mile-years) is .00045 leaks/mile/year, and the mean leak frequency is 0.00036 leaks/mile/year. The four operators with the lowest leak frequencies had leak frequencies of 0.000074 to 0.000085, which are in the same range as the leak frequency of 0.00007 leaks/mile-year estimated for the Longhorn Pipeline after mitigation.

It is unlikely that any of the 56 operators have implemented mitigation measures as extensive as those proposed by Longhorn. The fact that four of the major pipelines transporting petroleum products have maintained leak frequencies near the estimated Longhorn post-mitigation frequency indicates that this level of leak incidence can be achieved, particularly with a very extensive mitigation program.

4.0 Summary and Conclusions

With the proposed mitigation measures, the Longhorn Pipeline will have an estimated leak frequency of 0.00007 leaks/mile/year. The data on which the curve fit is based are quite limited, and the steps taken to address the resulting uncertainty are discussed previously in this document. Despite these steps, there is still an uncertainty in the leak rate estimated by the regression model. The reasonableness of this estimated leak rate was evaluated by comparing it with historical leak rates for other pipelines.

Historical leak rates have generally been developed using DOT's Hazardous Liquid Accident Data database (DOT, 2000). The leaks reported in this database are, for the most part, 50 barrels or more in size. The estimated post-mitigation leak of 0.00007 leaks/year/mile refers to leaks of any size. The equivalent estimated leak rate for reportable leaks only would be somewhat smaller (possibly by a factor of about 2-3) than the estimated rate of 0.00007. However, the conclusions drawn from the comparisons with historical data should not change significantly.

The estimated post-mitigation leak rate was compared with the DOT subset of reportable leaks (Little, 2000) from line pipe for the years 1986-2000. The data set included leak data from 180 pipeline operators with the miles of pipeline being operated ranging from 100 to nearly 8,000 miles per operator. Forty percent of these operators experienced leak frequencies below the Longhorn level, and about 30 percent of the operators had no reportable leaks during the period of 1986-2000. Sixteen percent of companies operating over 600 miles of pipelines had no reportable leaks over an average operating period of 11 years.

The data set of 16 companies operating 600-800 miles of pipeline was analyzed several ways. Five, or about a third of the 16 pipelines, had leak rates less than or equal to the estimated leak rate for Longhorn. Since the mitigation measures proposed for the Longhorn Pipeline are believed to be more extensive than those used for most pipelines, it is reasonable to compare Longhorn's estimated leak rate to the lowest leak rates in the data set of these 16 operators.

To this end, a further analysis identified 13 of the 16 pipelines that have similar performance within random variability and that represent the best performance in the data set. The results establish that the estimated leak rate for Longhorn is consistent with the leak rates for the 12 pipelines in the upper tier in the data set. In view of the stringent mitigation measures planned for Longhorn, it is expected that Longhorn will have a lower leak rate than those pipelines, indicating that the estimated rate for Longhorn is reasonable.

The number of reportable leaks from 56 pipeline operating companies transporting petroleum products were reported (DOT, 2000; True, 1998) along with the total length of pipeline operated by each company. The number of reportable leaks in the past 10 years was obtained from the DOT database. The leak frequencies were calculated for each company. The four companies with the lowest leak rates had leak frequencies of 0.000074 to 0.000085 leaks/mile/year. These rates are in the same range as the estimated leak frequency of 0.00007 leaks/mile/year for the Longhorn Pipeline. It is unlikely that these pipelines have implemented mitigation plans as extensive as those proposed by Longhorn.

From the examinations of historical pipeline leak frequency data described above, it appears that the post-mitigation level of reductions in leak frequencies estimated for the Longhorn Pipeline can be attained, particularly with an extensive mitigation program.

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Table 9B-B-1. Summary of Reportable Leaks from Hazardous Liquid Pipeline Line Pipe During 1986 – 2000
(A) Pipeline Miles = 3,000 and above

Pipeline Operator	Years of Operation - 1986 Most Recent	Earliest	Total	Number of Incidents	Miles of Pipeline	Leaks/Year/ Mile	Year Miles
Permian Corp.	2000	1986	14	0	4,600	0.00000	64,400
Texas Eastern Transmission Corp.	1988	1986	2	0	4,125		
Crown Central Pipeline Co.	2000	1993	7	0	3,020	0.00000	21,140
Marathon Ashland Pipe Line LLC	2000	1998	2	3	4,866		
Continental Pipeline Co.	1988	1985	3	4	3,641		
Texas Eastern Product Pipeline Co., LP	2000	1986	14	25	4,321	0.00041	60,494
Wood River Pipeline Co.	2000	1986	14	26	3,967	0.00047	55,538
Colonial Pipeline Co.	2000	1985	15	41	5,349	0.00051	80,235
Marathon Pipe Line Co.	1999	1986	13	35	5,051	0.00053	65,663
Plantation Pipe Line Co.	2000	1985	15	26	3,153	0.00055	47,295
Texaco Pipeline Inc	2000	1988	12	26	3,872	0.00056	46,464
Mid - America Pipeline Co. (Mapco)	2000	1985	15	73	7,632	0.00064	114,480
Shell Pipeline Corp.	2000	1986	14	70	7,740	0.00065	108,360
Mobil Pipeline Co.	2000	1985	15	49	4,626	0.00071	69,390
Williams Pipeline Co.	2000	1985	15	84	7,225	0.00078	108,375
Chevron Pipeline Co.	2000	1985	15	64	4,460	0.00096	66,900
Conoco Inc (Aka Conoco Pipe Line)	2000	1986	14	52	3,689	0.00101	51,646
Phillips Pipe Line Co.	2000	1986	14	67	4,275	0.00112	59,850
Amoco Pipeline Co.	2000	1985	15	111	6,270	0.00118	94,050
Exxon Pipeline Co.	2000	1985	15	72	3,931	0.00122	58,965
				821			1,173,245

(B) Pipeline Miles = 1,000 to 3,000

Pipeline Operator	Years of Operation - 1986 Most Recent	Earliest	Total	Number of Incidents	Miles of Pipeline	Leaks/Year/ Mile	Year Miles
Oxy NGL Pipeline Co.	1992	1986	6	0	1,228	0.00000	7,368
Trident NGL Inc.	1997	1992	5	0	1,098	0.00000	5,490
Dome Pipeline Corp.	2000	1986	14	1	1,358	0.00005	19,012
Chevron U.S.A. Inc. - Pipelines	2000	1986	14	1	1,015	0.00007	14,210
Dixie Pipeline	2000	1986	14	2	1,300	0.00011	18,200
Coastal Corp.	1997	1993	4	1	1,668	0.00015	6,672
All American Pipeline Co.	2000	1988	12	3	1,286	0.00019	15,432
Texas - New Mexico Pipeline Co.	2000	1986	14	4	1,366	0.00021	19,124
Cenex Pipeline	2000	1986	14	3	1,007	0.00021	14,098
Amoco Oil Co.	2000	1986	14	8	2,099	0.00027	29,386
Mapco Ammonia Pipeline Inc.	2000	1990	10	3	1,097	0.00027	10,970
Sinclair Pipeline Co.	2000	1986	14	4	1,036	0.00028	14,504
Kinder Morgan Energy Partners, L.P.	2000	1986	14	7	1,721	0.00029	24,094
Koch Pipeline Company, L.P. Ammonia	2000	1985	15	12	1,995	0.00040	29,925
Koch Refining Co.	2000	1986	14	8	1,298	0.00044	18,172
Kaneb Pipeline Co.	2000	1985	15	18	2,563	0.00047	38,445
Mid - Valley Pipeline Co.	2000	1986	14	8	1,089	0.00052	15,246
Westtex 66 Pipeline Company	2000	1994	6	5	1,561	0.00053	9,366
Buckeye Pipeline Company LP	2000	1985	15	23	2,746	0.00056	41,190
Koch Gathering Systems Inc.	2000	1986	14	9	1,010	0.00064	14,140
Southern Pacific Pipeline Co.	1997	1986	11	17	2,331	0.00066	25,641
Texas Pipeline Co.	1987	1986	1	2	2,289		
Explorer Pipeline Co.	2000	1986	14	18	1,413	0.00091	19,782
Lakehead Pipe Line Company Inc.	2000	1985	15	40	2,739	0.00097	41,085
Santa Fe Pacific Pipeline Partners LP	2000	1989	11	33	2,729	0.00110	30,019
Citgo Products Pipeline Company	2000	1996	4	5	1,072	0.00117	4,288
Arco Pipe Line Company	1999	1995	4	7	1,191	0.00147	4,764
Sun Pipeline Co.	2000	1985	15	43	1,889	0.00152	28,335
Coastal States Crude Gathering Co.	2000	1986	14	44	1,616	0.00194	22,624
Arco Pipe Line Co.	2000	1985	15	76	1,839	0.00276	27,585
Four Corners Pipeline Co.	1995	1985	10	37	1,323	0.00280	13,230
Chevron Pipe Line Northwest Region	2000	1999	1	11	1,614	0.00682	
				440			582,397

(C) Pipeline Miles = 400 to 1000

Pipeline Operator	Years of Operation - 1986 Most Recent	Earliest	Total	Number of Incidents	Miles of Pipeline	Leaks/Year/Mile	Year Miles
Chaparral Pipeline (NGL) Co.	2000	1989	11	0	978	0.00000	10,758
Santa Fe Pipeline Co.	1988	1986	2	0	922		
Oxy Petrochemicals Pipeline Co.	2000	1986	14	0	877	0.00000	12,278
Yellowstone Pipe Line Company	2000	1986	14	0	765	0.00000	10,710
Amoco Cushing - Chicago Crude Oil Pipeline	2000	1986	14	0	701	0.00000	9,814
Texaco Trading & Transportation Inc	2000	1986	14	0	699	0.00000	9,786
Sterling Hydrocarbon Co.	2000	1986	14	0	631	0.00000	8,834
Huntsman Corporation	2000	1996	4	0	623	0.00000	2,492
Express Pipeline Partnership	2000	1999	1	0	513		
Texoma Pipeline Co. (C/O Nat Gas P/L Co of America)	2000	1993	7	0	504	0.00000	3,528
Farm Bureau Oil Co	2000	1993	7	0	500	0.00000	3,500
Getty Pipeline Inc	1988	1986	2	0	452		
Arco Permian Sheep Mountain Pipeline System	2000	1993	7	0	440	0.00000	3,080
D.S.E. Pipeline Company	2000	1998	2	0	420		
Okie Pipeline Co.	2000	1986	14	0	408	0.00000	5,712
Ohio River Pipeline Co.	2000	1986	14	0	400	0.00000	5,600
Minnesota Pipeline Co.	2000	1985	15	1	671	0.00010	10,065
Union Pacific Resources Co.	2000	1988	12	1	786	0.00011	9,432
Dow Pipeline Co.	2000	1986	14	1	540	0.00013	7,560
Texas Eastman Co.	2000	1986	14	1	470	0.00015	6,580
Diamond Shamrock Refining & Marketing Co.	2000	1986	14	2	710	0.00020	9,940
West Texas Gulf Pipeline Co.	2000	1985	15	2	579	0.00023	8,685
Alyeska Pipeline Service Co.	2000	1986	14	3	800	0.00027	11,200
Atlantic Pipeline Corp.	2000	1987	13	3	815	0.00028	10,595
Unocal Pipeline Co. - Western Region	1998	1986	12	3	863	0.00029	10,356
Enterprise Products Co.	2000	1986	14	3	721	0.00030	10,094
Associated Natural Gas Co.	1995	1989	6	1	539	0.00031	3,234
Chase Transportation Co..	2000	1986	14	4	756	0.00038	10,584
Portal Pipeline Co.	2000	1986	14	3	558	0.00038	7,812
Seadrift Pipeline Corp.	2000	1986	14	5	827	0.00043	11,578
Sigmor Pipeline Co.	2000	1986	14	3	437	0.00049	6,118
Calnev Pipeline Co.	2000	1986	14	4	558	0.00051	7,812
SOHIO Pipeline Co.	2000	1986	14	5	638	0.00056	8,932
The Shamrock Pipe Line Corp.	2000	1985	15	8	949	0.00056	14,235
West Shore Pipeline Co.	2000	1986	14	7	652	0.00077	9,128
Warren Petroleum Co.	2000	1995	5	2	464	0.00086	2,320
Belle Fourche Pipeline Co.	2000	1986	14	5	413	0.00086	5,782
Wyco Pipe Line Co.	1995	1986	9	6	552	0.00121	4,968
Ashland Pipeline Co.	2000	1986	14	10	403	0.00177	5,642
Total Pipeline Corp.	2000	1985	15	14	482	0.00194	7,230
Wesco Pipeline Co.	1987	1986	1	1	514		
American Petrofina Pipeline Co.	2000	1986	14	15	517	0.00207	7,238
Genesis Crude Oil LP	2000	1999	1	2	955		
Pride Refining Inc	2000	1988	12	19	703	0.00225	8,436
Jayhawk Pipeline L.L.C.	2000	1986	14	25	755	0.00237	10,570
Shell Oil Co.	1988	1986	2	6	613		
				156			312,218

(D) Pipeline Miles = 200 to 400

Pipeline Operator	Years of Operation - 1986 Most Recent	Earliest	Total	Number of Incidents	Miles of Pipeline	Leaks/Year/ Mile	Year Miles
Promix System Pipelines	2000	1986	14	0	395	0.00000	5,530
Union Texas Products Corp.	2000	1986	14	0	391	0.00000	5,474
High Island Pipeline System (Amoco)	2000	1986	14	0	389	0.00000	5,446
Butte Pipeline Co.	1993	1993	0	0	372		-
Diamond Shamrock Pipeline Co.	2000	1996	4	0	358	0.00000	1,432
Laurel Pipeline Co.	2000	1986	14	0	357	0.00000	4,998
Owensboro - Ashland Co.	2000	1986	14	0	351	0.00000	4,914
Enron Louisiana Energy Co.	2000	1996	4	0	346	0.00000	1,384
Dow Pipeline Co.	2000	1986	14	0	330	0.00000	4,620
Hess Pipeline Co.	1996	1986	10	0	329	0.00000	3,290
Seagull Energy Corp.	2000	1996	4	0	316	0.00000	1,264
Pioneer Pipe Line Co.	2000	1986	14	0	307	0.00000	4,298
Chevron Pipe Line Chemical Systems	2000	1999	1	0	295		
Frontier Pipeline Co.	2000	1986	14	0	290	0.00000	4,060
Mustang Pipeline Co.	2000	1986	14	0	284	0.00000	3,976
Meridian Oil Production Inc	2000	1991	9	0	281	0.00000	2,529
Bravo Pipeline System	2000	1993	7	0	269	0.00000	1,883
Casa Pipeline System - Operated by Arco Pipeline Co.	2000	1986	14	0	250	0.00000	3,500
EPC Partners Ltd.	1992	1986	6	0	249	0.00000	1,494
El Paso Natural Gas Co.	2000	1986	14	0	247	0.00000	3,458
Chicap Pipeline Co.	2000	1993	7	0	235	0.00000	1,645
Chicap Pipeline Co.	2000	1986	14	0	231	0.00000	3,234
Champlin Petroleum Co.	1987	1986	1	0	229		
Chisholm Pipeline Co.	2000	1986	14	0	224	0.00000	3,136
El Paso Hydrocarbons Co.	1988	1986	2	0	220		
Exxon Co. USA - Houston Production Organization	2000	2000	0	0	217		-
Mustang Pipe Line Partners	2000	1999	1	0	211		
Tecumseh Pipe Line Co.	2000	1986	14	0	206	0.00000	2,884
Attco Pipeline Co.	2000	1989	11	0	205	0.00000	2,255
Navajo Pipeline Co.	2000	1986	14	1	398	0.00018	5,572
Black Lake Pipeline Co.	2000	1986	14	1	315	0.00023	4,410
Cayuse Pipeline Co.	2000	1986	14	1	277	0.00026	3,878
Olympic Pipe Line Co.	2000	1985	15	2	399	0.00033	5,985
Badger Pipeline Co.	2000	1986	14	2	330	0.00043	4,620
Fina Oil & Chemical Co. (Now Trust & River P/L Co.)	2000	1986	14	3	380	0.00056	5,320
CSX NGL Corp	1995	1987	8	1	218	0.00057	1,744
National Coop Refinery Association	2000	1986	14	2	228	0.00063	3,192
Texaco Inc.	1995	1986	9	3	356	0.00094	3,204
West Emerald Pipe Line Corp.	2000	1986	14	4	297	0.00096	4,158
Mobil Oil Corp.	2000	1986	14	4	230	0.00124	3,220
Navajo Refining Co.	2000	1986	14	5	245	0.00146	3,430
Citgo Pipeline Co.	2000	1986	14	7	313	0.00160	4,382
Scurlock Oil Co.	2000	1986	14	8	322	0.00177	4,508
Central Florida Pipeline Corp.	2000	1985	15	6	201	0.00199	3,015

(D) Pipeline Miles = 200 to 400 (Continued)

Pipeline Operator	Years of Operation - 1986 Most Recent	Earliest	Total	Number of Incidents	Miles of Pipeline	Leaks/Year/ Mile	Year Miles
Mid - Continent Pipeline Co.	2000	1985	15	10	320	0.00208	4,800
Mobil Pipeline Co. - Mobil West Coast Pipeline	2000	1986	14	10	272	0.00263	3,808
Eott Energy Pipeline Limited Partnership	2000	1997	3	3	361		
Pride Texas Plains, L.P.	2000	1986	14	14	242	0.00413	3,388
				84			149,338

(E) Pipeline Miles = 100 to 200

Pipeline Operator	Years of Operation - 1986 Most Recent	Earliest	Total	Number of Incidents	Miles of Pipeline	Leaks/Year/ Mile	Year Miles
Warren Petroleum Corp. - Pipelines	2000	1989	11	0	179	0.00000	1,969
Fin-Tex Pipe Line Company	2000	2000	0	0	179		-
Wyoming Pipeline Co.	2000	1993	7	0	170	0.00000	1,190
Seagull Products Pipeline Co.	2000	1996	4	0	170	0.00000	680
Coastal Refining And Marketing Inc	2000	1993	7	0	160	0.00000	1,120
Clear Creek Inc.	1993	1993	0	0	154		-
Bow Pipeline Co.	2000	1987	13	0	144	0.00000	1,872
Western Gas Resources, Inc	2000	1999	1	0	137		
Osage Pipeline Co.	2000	1986	14	0	136	0.00000	1,904
Este CO_2 Pipeline System/ C/O Mobil Pipe Line Co.	2000	1999	1	0	135		
Enterprise Petrochemical Co.	1992	1986	6	0	133	0.00000	798
Texaco Exploration & Production Inc.	2000	1996	4	0	133	0.00000	532
Koch Hydrocarbon Co.	1992	1991	1	0	133		
Southern California Edison Co.	2000	1986	14	0	131	0.00000	1,834
Buckeye Pipe Line Co of Michigan LP	2000	1989	11	0	130	0.00000	1,430
Collins Pipeline Co.	2000	1986	14	0	126	0.00000	1,764
Dynegy Crude Gathering Services, Inc.	2000	1995	5	0	126	0.00000	630
Jet Lines Inc.	2000	1986	14	0	120	0.00000	1,680
Mobil Pacific Pipeline Co.	2000	1994	6	0	112	0.00000	672
Western Oil Transportation	2000	1986	14	0	111	0.00000	1,554
Hunt Refining Co.	2000	1986	14	0	108	0.00000	1,512
Warren NGL Pipeline Co. Inc.	2000	1992	8	0	106	0.00000	848
Enron Products Pipeline Inc.	1992	1991	1	0	104		
Kentucky Hydrocarbon (Division of Equitable Resource)	2000	1986	14	0	103	0.00000	1,442
Golden West Refining Co.	2000	1986	14	0	101	0.00000	1,414
Support Terminals Operating Partnership, L. P.	2000	1986	14	1	192	0.00037	2,688
Lion Oil Co.	2000	1992	8	1	184	0.00068	1,472
Portland Pipeline Corp	2000	1986	14	2	166	0.00086	2,324
Exxon Co. USA	2000	1986	14	2	159	0.00090	2,226
Mobil Oil Exploration & Production Se Inc	2000	1986	14	2	130	0.00110	1,820
Arbuckle Pipeline Co.	1990	1986	4	1	133	0.00188	532
San Diego Pipeline Co.	1988	1986	2	1	123		
Ciniza Pipeline Inc.	2000	1986	14	9	135	0.00476	1,890
Bridgeline Gas Distribution LLC	2000	1996	4	3	151	0.00497	604

(E) Pipeline Miles = less than 100

Pipeline Operator	Years of Operation - 1986 Most Recent	Earliest	Total	Number of Incidents	Miles of Pipeline	Leaks/Year/ Mile	Year Miles
Farmland Industries Inc.	2000	1986	14	0	97	0.00000	1,358
Mobil Producing Texas & New Mexico Inc.	2000	1986	14	0	93	0.00000	1,302
Monsanto Co.	2000	1990	10	0	92	0.00000	920
Texaco Natural Gas Plants & Liquids Division	2000	1996	4	0	89	0.00000	356
Chevron USA Production Co.	2000	2000	0	0	88		-
Main Pass Oil Gathering System	2000	1999	1	0	83		
Mitchell Gas Services LP	2000	2000	0	0	82		-
Mesa Pipeline System	2000	1989	11	0	80	0.00000	880
Beartooth Pipeline	2000	1999	1	0	76		
Dynegy Energy Resources, L.P.	2000	1998	2	0	75		
CNG Transmission Corp.	2000	1986	14	0	71	0.00000	994
Conoco Pipe Line Co. - Razorback	2000	1990	10	0	67	0.00000	670
Celanese Pipeline Company	2000	2000	0	0	66		-
Murphy Exploration & Prod Co NE Odeco Oil & Gas Co.	2000	1989	11	0	65	0.00000	715
Tenneco Oil Co Empire Pipeline	2000	1986	14	0	63	0.00000	882
Moem Pipeline LLC	2000	1999	1	0	63		
C & T Pipeline Inc.	2000	1986	14	0	62	0.00000	868
Texaco Refining & Marketing Inc	2000	1986	14	0	59	0.00000	826
Kaw Pipeline Co.	2000	1986	14	0	58	0.00000	812
Oryx Gas Energy Company	2000	1987	13	0	58	0.00000	754
UCAR Pipeline Inc.	2000	1986	14	0	57	0.00000	798
Mobil Eugene Island Pipeline Co.	2000	1998	2	0	57		
Sonat Oil Transmission Inc	2000	1986	14	0	56	0.00000	784
Edgington Oil Co. Inc.	2000	1986	14	0	55	0.00000	770
Enogex Products	2000	1999	1	0	52		
Union Oil Company of California	2000	1998	2	0	49		
Universal Energy Services, L.C.	1993	1993	0	0	49		-
Tesoro Hawaii Corporation	2000	1986	14	0	44	0.00000	616
National Pipeline Co.	2000	1986	14	0	44	0.00000	616
Slaughter CO_2 Pipeline C/O Mobil Pipe Line Co.	2000	1999	1	0	44		
Southwest Pipeline Co.	2000	1986	14	0	42	0.00000	588
Anschutz - Ranch East Pipeline Co.	2000	1993	7	0	42	0.00000	294
Wyoming Refining Co.	2000	1996	4	0	42	0.00000	168
Exxon Co., USA - Retail Business Center	2000	1986	14	0	40	0.00000	560
Anderson Prichard Pipeline Corp.	2000	1986	14	0	39	0.00000	546
Heartland Pipeline Co.	2000	2000	0	0	39		-
Ergon Trucking, Inc.	2000	1986	14	0	38	0.00000	532
Kuparuk Transportation Co.	2000	1986	14	0	37	0.00000	518
Florida Power & Light Co.	1992	1986	6	0	36	0.00000	216
Trico Pipeline Co.	1994	1993	1	0	36		
Javelina Co.	2000	1997	3	0	35		
Everglades Pipeline Co.	2000	1986	14	0	34	0.00000	476
Texaco - Cities Service Pipeline Co.	1988	1986	2	0	34		

(E) Pipeline Miles = less than 100 (Continued)

Pipeline Operator	Years of Operation - 1986 Most Recent	Earliest	Total	Number of Incidents	Miles of Pipeline	Leaks/Year/ Mile	Year Miles
Dynegy Oil Pipeline Company	2000	2000	0	0	32		-
Ultramar Refining Co.	2000	1989	11	0	31	0.00000	341
G & T Pipeline Co.	2000	1986	14	0	30	0.00000	420
Conoco Pipe Line Co. - Jolliet	2000	1990	10	0	29	0.00000	290
Mcmurrey Pipeline Co.	1988	1986	2	0	29		
Oliktok Pipeline Company	2000	2000	0	0	28		-
Texpata Pipeline Co.	2000	1986	14	0	26	0.00000	364
Sun Refining & Marketing Co.	2000	1993	7	0	26	0.00000	182
Minden Pipeline Co.	1988	1986	2	0	24		
Kenai Pipeline Co.	1988	1988	0	0	24		-
Clarco Pipeline Co.	1988	1986	2	0	23		
Ben's Run Pipeline Corp.	1988	1986	2	0	21		
Northern Rockies Pipeline Co.	2000	1986	14	0	18	0.00000	252
Macmillan Ring Free Oil Co.	1988	1986	2	0	18	0.00000	
Mesquite Pipeline Co.	2000	1996	4	0	17	0.00000	68
Enron Liquid Fuels Co. (Ex. UPC Inc)	1988	1986	2	0	15		
Holly Corp.	1988	1986	2	0	13		
Koch Oil Co.	1988	1986	2	0	12		
Conoco Pipe Line Co. - Milne Point	2000	1986	14	0	11	0.00000	154
Mesa Transmission Co.	1988	1986	2	0	11		
Fletcher Oil & Refining Co.	1988	1986	2	0	11		
Rexene, Inc.	2000	1995	5	0	10	0.00000	50
Valero Refining Co.	1988	1986	2	0	10		
Canyon Pipe Line	2000	1993	7	0	9	0.00000	63
Mitco Pipeline Co.	1988	1986	2	0	9		
Santa Fe Energy Co.	1988	1986	2	0	9		
Wilmington Liquid Bulk Terminals	1988	1986	2	0	9		
Cities Service Oil & Gas Corp.	1988	1986	2	0	8		
Hill Petroleum Co.	2000	1993	7	0	7	0.00000	49
Liquid Pipeline Inc.	1988	1986	2	0	7		
White Shoal Pipeline Corp.	1988	1986	2	0	7		
Pennzoil Producing Co.	1988	1986	2	0	6		
Eureka Pipeline	1988	1986	2	0	6		
Whittier Pipeline Corp.	1988	1986	2	0	5		
Texaco CO_2 Pipeline	2000	1998	2	0	5		
Sun Oil Line Co of Michigan	1988	1986	2	0	4		
Landsea Terminals Inc.	1988	1986	2	0	3		
Damson Oil Corp.	1988	1986	2	0	3		
T & M Terminal Co.	1988	1986	2	0	2		
San Diego Gas & Electric Co.	1988	1986	2	0	1		
Harbor Pipeline Co.	2000	1986	14	1	80	0.00089	1,120
Sunniland Pipeline Co. Inc.	1997	1986	11	1	90	0.00101	990
Liquid Energy Corp.	2000	1986	14	1	50	0.00143	700
Pacific Gas & Electric Co.	2000	1986	14	1	50	0.00143	700
Cook Inlet Pipeline Co.	2000	1986	14	1	44	0.00162	616
Kiantone Pipeline Corp..	2000	1986	14	2	73	0.00196	1,022
Tesoro Pipeline Co.	2000	1986	14	2	71	0.00201	994

(E) Pipeline Miles = less than 100 (Continued)

Pipeline Operator	Years of Operation - 1986 Most Recent	Earliest	Total	Number of Incidents	Miles of Pipeline	Leaks/Year/ Mile	Year Miles
Florida Power Corp.	2000	1987	13	1	33	0.00233	429
Meridian Oil Hydrocarbons Inc.	1994	1988	6	1	69	0.00242	414
Emerald Pipe Line Corp.	2000	1986	14	3	86	0.00249	1,204
Kerr-McGee Refining Corp.	1999	1985	14	2	52	0.00275	728
Chevron USA Inc - Hawaii	2000	1989	11	2	50	0.00364	550
GATX Terminals Corp.	1999	1986	13	3	62	0.00372	806
Los Angeles Dept of Water & Power	2000	1986	14	1	16	0.00446	224
Fina Pipe Line Co.	2000	1986	14	2	30	0.00476	420
Shell Offshore Inc. - Coastal Division	1999	1994	5	1	40	0.00500	200
Tosco Corp.	1997	1986	11	4	48	0.00758	528
Powerline Oil Co.	2000	1986	14	4	33	0.00866	462
Oiltanking of Texas Pipeline Co.	2000	1986	14	3	24	0.00893	336
Valero Marketing Co.	1996	1986	10	2	18	0.01111	180
Con - Dor Pipeline Co.	1988	1986	2	2	68		
Forest Oil Corp.	1995	1986	9	1	7	0.01587	63
Mobil Pipeline Co. - Empire	1998	1989	9	10	63	0.01764	567
Paramount Petroleum Corp.	2000	1986	14	1	3	0.02381	42
Witco Chemical Corp.	1994	1986	8	3	14	0.02679	112
Beacon Oil Co.	1987	1986	1	1	36		

Table 9B-E-2. Summary of Leak Frequencies for Hazardous Liquid Pipelines

	Leak Frequencies, Leaks/Mile/Year			Pipelines with Leak Frequencies Less than 0.00007 leaks/mile/year [2]	
Miles of Pipeline Operated	**Weighted Mean**	**Average**	**Median**	**Number**	**Percent of Operated Pipelines**
600 - 800[1]	0.00051	0.00076	0.00023	5	31
3,000 or greater	0.0007	0.00066	0.00064	2	12
1,000 - 3,000	0.00078	0.0009	0.00047	4	13
400 - 1,000	0.0005	0.00051	0.00028	12	31
200 – 400	0.00056	0.00054	0	24	59
100 – 200	0.00055	0.00057	0	19	70

[1] Exemplary operators (see Table 9B-E-3)
[2] Pipelines with less than 4 years of operation or operators with less than 100 miles of pipelines were not considered to be representative, and were not included in the analyses.

Table 9B-E-3. Companies that Operate Total Lengths of Pipeline (600-800 miles)* Similar to Longhorn

Operator Name	Most Recent Year of Operation	Earliest Year of Operation[1]	Years of Operation[2]	Number of Accidents[3]	Total Miles of Pipeline	Leak Frequency, Leaks/Yr/Mile
Yellowstone Pipe Line Company	2000	1986	14	0	765	0.00000
Amoco Cushing - Chicago Crude Oil Pipeline	2000	1986	14	0	701	0.00000
Texaco Trading & Transportation Inc.	2000	1986	14	0	699	0.00000
Sterling Hydrocarbon Co.	2000	1986	14	0	631	0.00000
Huntsman Corporation	2000	1996	4	0	623	0.00000
Minnesota Pipeline Co.	2000	1985	15	1	671	0.00010
Union Pacific Resources Co.	2000	1988	12	1	786	0.00011
Diamond Shamrock Refining & Marketing Co.	2000	1986	14	2	710	0.00020
Alyeska Pipeline Service Co.	2000	1986	14	3	800	0.00027
Enterprise Products Co.	2000	1986	14	3	721	0.00030
Chase Transportation Co.	2000	1986	14	4	756	0.00038
Sohio Pipeline Co.	2000	1986	14	5	638	0.00056
West Shore Pipeline Co.	2000	1986	14	7	652	0.00077
Pride Refining Inc.	2000	1988	12	19	703	0.00225
Jayhawk Pipeline L.L.C.	2000	1986	14	25	755	0.00237
Shell Oil Co.	1988	1986	2	6	613	0.00489
				76		0.00076

[1] Earliest year in the period 1986-1998
[2] Years operated during the period 1986-1998
[3] Accidents refers to occurrences of leaks or spills that release products in volumes equal to or greater than 50 bbls
* Exemplary operators

Table 9B-E-4. Historical Leak-Rate Data and Confidence Intervals for 16 Exemplary Pipeline Operators

Order by Leak Rate	Miles	Years	Number of Incidents	Leaks/Mile/ Year	95% Confidence Interval (Leaks/Mile/Year)	
1	765	14	0	0.00000	0.00000	0.00034
2	701	14	0	0.00000	0.00000	0.00038
3	699	14	0	0.00000	0.00000	0.00038
4	631	14	0	0.00000	0.00000	0.00042
5	623	4	0	0.00000	0.00000	0.00148*
6	671	15	1	0.00010	0.00000	0.00055
7	786	12	1	0.00011	0.00000	0.00059
8	710	14	2	0.00020	0.00002	0.00073
9	800	14	3	0.00027	0.00005	0.00078
10	721	14	3	0.00030	0.00006	0.00087
11	756	14	4	0.00038	0.00010	0.00097
12	638	14	5	0.00056	0.00018	0.00131
13	652	14	7	0.00077	0.00031	0.00158
14	703	12	19	0.00225	0.00136	0.00352
15	755	14	25	0.00237	0.00153	0.00349
16	613	2	6	0.00489	0.00180	0.01065*

*The confidence intervals for these two pipelines are noticeably wide because of the small number of years of operation represented in the database.

Table 9B-E-5. Number of Spills of Petroleum Products from Pipelines in Recent Ten Years (> 1990)[1]

Company ID Number	Accident Count, Recent 10 Years	Mileage (total)	Accidents per mile	Accidents per mile per year
1	**13**	17601	7.4E-04	7.4E-05
2	**1**	1303	7.7E-04	7.7E-05
3	**1**	1233	8.1E-04	8.1E-05
4	**1**	1176	8.5E-04	8.5E-05
5	**1**	750	1.3E-03	1.3E-04
6	**5**	3221	1.6E-03	1.6E-04
7	**2**	1284	1.6E-03	1.6E-04
8	**1**	619	1.6E-03	1.6E-04
9	**9**	5393	1.7E-03	1.7E-04
10	**1**	579	1.7E-03	1.7E-04
11	**8**	4339	1.8E-03	1.8E-04
12	**2**	1080	1.9E-03	1.9E-04
13	**3**	1608	1.9E-03	1.9E-04
14	**2**	962	2.1E-03	2.1E-04
15	**2**	962	2.1E-03	2.1E-04
16	**2**	951	2.1E-03	2.1E-04
17	**1**	460	2.2E-03	2.2E-04
18	**1**	425	2.4E-03	2.4E-04
19	**2**	755	2.6E-03	2.6E-04
20	**1**	366	2.7E-03	2.7E-04
21	**2**	696	2.9E-03	2.9E-04
22	**18**	6257	2.9E-03	2.9E-04
23	**5**	1688	3.0E-03	3.0E-04
24	**15**	4996	3.0E-03	3.0E-04
25	**1**	331	3.0E-03	3.0E-04
26	**2**	624	3.2E-03	3.2E-04
27	**6**	1732	3.5E-03	3.5E-04
28	**11**	3141	3.5E-03	3.5E-04
29	**2**	557	3.6E-03	3.6E-04
30	**29**	6130	4.7E-03	4.7E-04
31	**34**	7107	4.8E-03	4.8E-04
32	**26**	5353	4.9E-03	4.9E-04
33	**14**	2867	4.9E-03	4.9E-04
34	**53**	10408	5.1E-03	5.1E-04
35	**1**	177	5.6E-03	5.6E-04
36	**24**	4167	5.8E-03	5.8E-04
37	**33**	5322	6.2E-03	6.2E-04
38	**18**	2643	6.8E-03	6.8E-04
39	**4**	541	7.4E-03	7.4E-04
40	**7**	882	7.9E-03	7.9E-04
41	**4**	476	8.4E-03	8.4E-04

Table 9B-E-5. Number of Spills of Petroleum Products from Pipelines in Recent Ten Years (> 1990)[1] (continued)

Company ID Number	Accident Count, Recent 10 Years	Mileage (total)	Accidents per mile	Accidents per mile per year
42	**13**	1413	9.2E-03	9.2E-04
43	**4**	419	9.5E-03	9.5E-04
44	**4**	417	9.6E-03	9.6E-04
45	**32**	2802	1.1E-02	1.1E-03
46	**33**	2857	1.2E-02	1.2E-03
47	**4**	321	1.2E-02	1.2E-03
48	**35**	2769	1.3E-02	1.3E-03
49	**1**	78	1.3E-02	1.3E-03
50	**11**	720	1.5E-02	1.5E-03
51	**2**	122	1.6E-02	1.6E-03
52	**6**	339	1.8E-02	1.8E-03
53	**2**	113	1.8E-02	1.8E-03
54	**11**	615	1.8E-02	1.8E-03
55	**1**	55	1.8E-02	1.8E-03
56	**48**	2635	1.8E-02	1.8E-03
	575			
			MAX	**1.8E-03**
			MIN	**7.4E-05**
			Weighted Average	**4.5E-04**
			Average	**6.2E-04**
			Median	**3.5E-04**

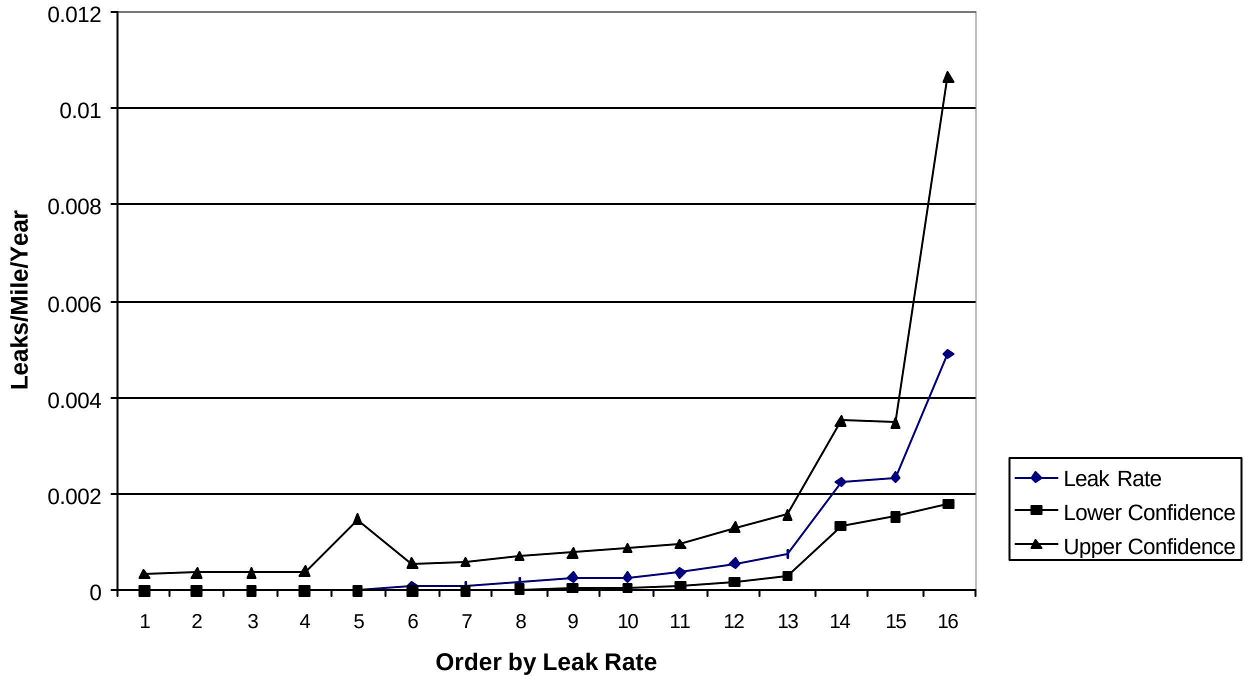

Figure E-1. Leak Rates and 95% Confidence Intervals for 16 Pipelines

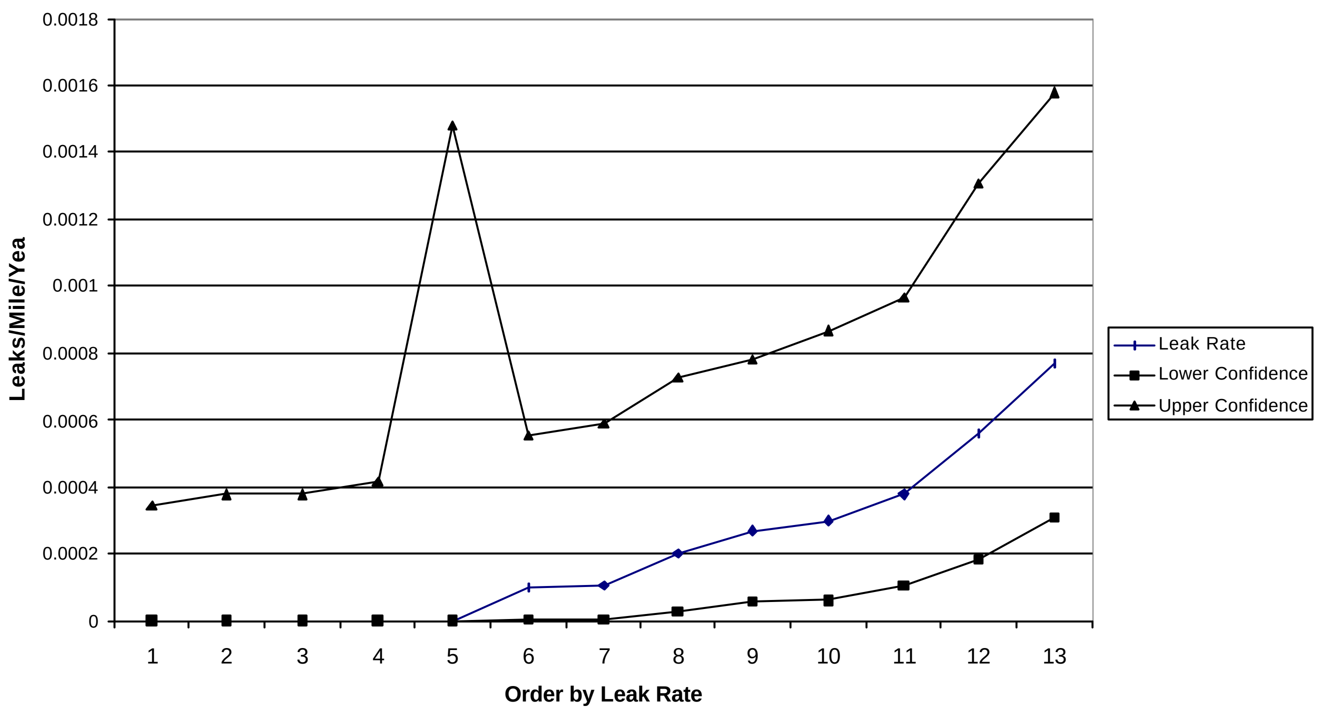

Figure E-2. Leak Rates and 95% Confidence Intervals for 13 Pipelines