Appendix 9D

Results of Preliminary Operational Reliability Assessment

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Summary

Environmental Assessment Section 9.1.3.3 describes the Operational Reliability Assessment (ORA) to be performed by Longhorn as part of its Longhorn Mitigation Plan (LMP) and on-going system integrity programs. At the request of the Lead Agencies, a preliminary ORA has been prepared based on information available in early September 2000. This preliminary ORA demonstrates the techniques to be used continuously to ensure the Longhorn System integrity. In this demonstration, Longhorn has committed to controlling the calculated probability of failure for all common failure mechanisms. This is done by re-verifying the integrity at certain intervals. This preliminary ORA provides estimates based on data available at this time of the integrity re-verification intervals. These intervals are subject to change as new information is obtained. Not all failure mechanisms are addressed in the ORA, and assumptions employed in the calculations, while believed to be conservative, can nonetheless prove to be inaccurate. However, the ORA methodology demonstrated in the Longhorn documents appears to reflect the state-of-the-art in such programs, and the resulting recommendations should provide assurances that failure mechanisms are being controlled.

It is important to note that the ORA intervention actions are not the primary defense mechanisms against failure. These actions are, in most cases, the last defense against a failure if other preventive measures have been unsuccessful.

An important conclusion of this preliminary ORA is that the failure probabilities calculated in this ORA are consistent with the failure probabilities previously calculated for the post-mitigation pipeline (see EA Chapter 9 and Appendix 9B). The fact that two separate approaches to failure probability estimation produced similar results provides support for the validity of both calculations.

Discussion

Many of the technical aspects of this preliminary ORA were produced by a third-party contractor, Kiefner & Associates (Kiefner), whose expertise in pipeline metallurgy and failure mechanics is well regarded. Longhorn and Kiefner have provided documents and data sets explaining and demonstrating this ORA. These materials have been reviewed as part of the EA and are discussed in this appendix.

Integrity threats such as corrosion, cracking, third-party damages, and earth movements are all to be considered in the ORA, per the LMP. The ORA is to specify integrity re-verification schedules based on the most current information, including changing conditions along the pipeline route. As noted in the EA, this ORA goes beyond the classical ORA used in the pipeline industry in that it includes possible failure modes in addition to the corrosion and cracking threats typically addressed. It is recognized that recommendations from this preliminary ORA can and should be modified whenever new data become available. An example of pending new data is the MFL ILI scheduled within the first three months of operations (see LMP commitment 11).

It is important to re-iterate that this integrity re-verification is not the primary means of protecting the pipeline. Only in the case of cracking/ERW defects (and to a lesser degree, laminations and H_2 blistering) does the integrity re-verification play a primary role in preventing damages from normal operations. This is because that failure mode involves cracking mechanisms that are not reasonably preventable by other means. The other failure modes are prevented with a suite of preventative measures, and the integrity re-verification can correctly be seen as the last line of defense, should other measures be compromised.

A conservative assumption underlying the ORA is that defects are present in the pipeline and are growing at some rate, despite preventive measures. By inspecting or testing the pipeline at certain intervals, this growth can be interrupted before any defect reaches a failure size. Defects will theoretically be at their largest size immediately before the next integrity verification. This estimated size can be related to a failure probability by considering uncertainty in measurements and calculations. Therefore, the integrity re-verification interval is implicitly establishing a maximum probability of failure for each failure mode.

The preliminary ORA has produced integrity re-verification intervals for each of the potential failure modes considered for each portion of the pipeline. The pipeline is analyzed in different segments to allow for differences in age, pipe specifications, and past inspection history. The following table is created from Longhorn documents of the preliminary ORA and summarizes intervals and the corresponding estimated failure rates for those pipeline segments whose failure rates are estimated to be the highest. All other portions of the pipeline have estimated failure probabilities lower than those shown in this table.

Preliminary ORA Summary Table Based on Worst-Case Pipeline Segments

Failure Mode	Basis of Calculation	Calculated Re-Verification Interval	Committed Integrity Re-verification interval	Estimated Maximum Failure Rate (per mile per year) Between Integrity Verifications	Estimated Start-up Failure Rate
Crack/ERW Defects	1. Calculated surviving crack sizes 2. Pipe specification data and assumptions 3. Crack growth rates from similar pipelines 4. 2000 hydrostatic test results	0.46 year and 3.34 years[1]	As prompted by the ORA but not more than 3 years after system startup	$< 1 \times 10^{-8}$	$< 1x10^{-8}$ (2)
Corrosion	1. 1995 in-line inspection (ILI) data 2. Estimated corrosion rates 3. 2000 hydrostatic test results	2 years	Not more than 3 months after system startup (LMP Item 11); ORA driven thereafter	2.93×10^{-5}	4.27×10^{-11} (3)
Third-Party Damage	1. API 1999 Report (Publ. No. 1158) 2. Longhorn data	Fixed by LMP	Not more than 3 months after system startup (LMP Item 11); or ORA driven thereafter; 3 years maximum	3.12×10^{-5} (4)	3.12×10^{-5} (4)
Laminations/ H_2 Blisters	1. Longhorn data 2. Pipe manufacturing assumptions	Not calculated	As prompted by the ORA but not more than 5 years after system startup	2×10^{-6}	2×10^{-6}
Earth Movement[5]	1. Geologic data 2. Visual inspection	See Committed Initial Frequency	<u>Physical Inspections</u>: 1 year to 5 years[6]; <u>ILI</u>: As prompted by the ORA but not more than 3 years between ILIs capable of detecting external force damages	2.6×10^{-5}	$< 2.6x10^{-5}$ (7)

Notes:

1. Interval is 45 percent of earliest expected time to failure; two operating pressure cycle histories were used, one reflects a very intense pressure cycle scenario (resulting in 0.46 year re-inspection) and one thought to be more representative of Longhorn's intended operation (3.34 year re-inspection).
2. Estimated risk of pressure reversal failure upon re-pressurization.
3. Assumes aggressive corrosion rate and calculated on the basis of 88 percent of MOP limitation before the initial ILI (845 psig)
4. Represents incidents of rupture of previously damaged pipe, API Publication 1158 (1999), minimum annual number of incidents
5. Various earth movement studies conducted during this EA analyze different potential earth movement phenomena and recommend pre-operation mitigation and future inspection intervals. Includes seismic and aseismic events, scour, subsidence, landslide, and soil stress.
6. Managed by System Integrity Plan on time and event-based intervals
7. Represents rain/flood incidents, API Publication 1158 (1999)

Under this regime, at least a caliper type inspection tool will be run at a frequency not to exceed three years. The phrase "at least" is used here since the caliper tool is sensitive to geometric distortions of the pipe (dents, bends, ovalities, etc.) but provides little or no data on wall loss from corrosion or external damages or potential cracks. As a result, it does not provide as thorough an integrity verification as other ILI tools.

In general, each inspection interval is based on two factors: 1) the largest defect that could have survived or been undetected in the last test or inspection; and 2) an assumed defect growth rate. The specific basis of each interval is detailed in the Longhorn documents and discussed below:

Cracking

Initial crack size is estimated from calculations of the largest size crack that could have survived the 1995 and/or 2000 hydrostatic tests. This includes pipe material strength and toughness. Conservative values are assumed for older pipe with unknown toughness.

The re-inspection interval for possible cracks is based on the number and magnitude of pressure cycles. Crack growth can be correlated with pressure cycles so that an inspection or test can ensure that a crack has not grown to a size that will fail. The relationship between crack growth and pressure cycles is based on fracture mechanics principles and from fatigue fracture experience on a pipeline of similar vintage. Pressure cycle counts will be updated every month (for the first four months, quarterly thereafter) and crack growth calculations adjusted accordingly. Integrity re-verifications are to occur at 45 percent of the time at which the worst crack would grow to a critical size when exposed to the previous and intended pressure cycles.

The most realistic pressure cycle scenario leads to an integrity verification after about 3 years. A very aggressive pressure cycle scenario could lead to an integrity verification after only 0.69 years. The actual integrity re-verification will be based on measured and recorded pressure cycles from the beginning of operations.

A crack-related failure could occur before the integrity re-verification if a phenomenon called "pressure reversal" occurs. The probability of this occurring before the first integrity re-verification is estimated to be $1x10^{-8}$ per mile-year. The probability calculation is discussed in Kiefner's analysis. This is based on the pressure reversal experience of a ___ mile pipeline of similar vintage to Longhorn, but one that was pressure tested to 100 percent of SMYS, a much more severe test than was done on this System. In light of this and the fact that no pressure reversals have been observed on the System, the estimate is believed to be conservative. The pressure reversal potential is also being used as an estimate for the maximum on-going failure rate between integrity verifications. To some extent, the pressure reversal potential represents the possibility that a larger-than-expected defect remained after the last pressure test. This is not a precisely accurate value to use in projecting future failure rates since on-going pressure cycles can cause this unexpected defect to enlarge, perhaps even more rapidly than the expected defects. However, there does not appear to be an alternate calculation process that will produce more meaningful estimates of failure probabilities, since the fatigue crack growth calculations are deterministic in nature.

Corrosion

The corrosion re-inspection interval is based on (1) ILI detection of anomalies and (2) assumed corrosion rates. Since there is a margin of error associated with sizing a detected anomaly, a probability that the anomaly is actually of a critical size is calculated. A probability of exceedance (POE) calculation represents the chance that a defect has reached a critical size--in effect, a size that represents imminent failure. Subsequent excavations with direct measurements of detected anomalies verify the probability calculations and provide data to include in the next calculations. Longhorn has committed to excavate, examine, and repair, if needed, anomalies with a calculated probability of failure of 10^{-7}. Immediately after the ILI and associated excavations, the anomalies are assumed to grow at a rate equal to the assumed corrosion rate.

Longhorn has committed to run subsequent ILI and/or perform additional excavations to ensure that anomalies never grow larger than a size equivalent to a calculated probability of failure of 1×10^{-5}. The failure size for purposes of probability calculations is determined by two criteria; 1) the depth of the anomaly = 90 percent and 2) a calculated remaining pressure containing capacity of the defect configuration. Two criteria are required since the accepted calculations for 2) are not considered as reliable when anomaly depths exceed 80 percent of the wall thickness. Note that the depth used for probability of failure calculations is different from the depth threshold that triggers an immediate repair, which is depth = 70 percent of the wall thickness. Depth alone is not a good indicator of failure potential since stress level and defect configuration are also important variables.

Several corrosion rate estimates are used for calculation purposes. For the period prior to the MFL inspection (within 3 months of start up), a corrosion rate of 7 mil per year applied to the worst anomaly and assuming the worst density of anomalies (anomalies per mile) from the 1995 ILI inspection, yields a failure probability of 4.27×10^{-11} per mile-year. After the MFL inspection, failure probability will be held to no greater than 1×10^{-5} for an anomaly. The conservative step of applying the anomaly count from the worst mile of the pipeline to every other mile of the pipeline is used to calculate the probability of failure on a per mile per year basis. This means that the worst pipeline segment failure probability is estimated to reach no higher than 2.93×10^{-5} failures per mile-year between integrityre-verifications.

For new pipe, no previous ILI results are available. Conservative assumptions related to the pipe manufacture process and pipeline construction process were used to calculate corrosion failure rates for newly installed sections of the pipeline. Longhorn has committed to verifying the newer pipeline integrity based on new ORA information and per pending regulations (see 65 Fed.Reg. 21695; April 24, 2000), but no longer than 10 years from start up. From that point on, the ORA calculations will govern future integrity re-verifications.

Laminations—Blistering

A lamination is a metal separation within the pipe wall. A lamination can be a contributing cause of failure when hydrogen blistering is involved. Hydrogen blistering occurs when atomic hydrogen penetrates the pipe steel to a lamination and forms hydrogen molecules which cannot then diffuse through the steel. A continuing buildup of hydrogen pressure can separate the layers of steel at the lamination, causing a visible bulging at the ID and OD surfaces. The transport of sour crude oil through parts of this system could have introduced the atomic hydrogen that contributed to hydrogen blistering. There are three known failures due to hydrogen blistering, all during hydrostatic pressure tests and not while under normal operating pressures.

While there is no longer a source of hydrogen from this line in refined products service (excessive cathodic protection levels can theoretically produce atomic hydrogen, but this is deemed to be negligible per Kiefner), there is nonetheless an integrity threat, albeit a very minor threat. Per Kiefner's analysis:

> "... if blisters had formed during the prior crude oil service but were not severe enough to fail in the 1995 or 2000 hydrostatic tests, they could pose a threat to the integrity of the pipeline. While hydrogen-induced cracking is no longer possible, the presence of a blister represents a possible defect that would be adversely affected by pressure-cycle-induced fatigue. Since there is no proven method of predicting the failure pressure level of a blister and no proven method to calculate its crack-driving potential from the standpoint of fatigue, one cannot reliably predict the probability that a given blister will cause a failure. Also, the locations of any potential blisters that may still exist are not known. The 1995 and 2000 hydrostatic tests provide some assurance that no blister is currently on the verge of failure. No blister has ever been associated with a service failure."

Kiefner's analysis of the probability of such failures takes into account the probability of errors during the pipe manufacturing process and estimates of contributing causes under the proposed operations. While such calculations are highly uncertain due to the numbers of assumptions that must be made, the resulting probability estimate of 2×10^{-6} per mile per year does not seem to be unreasonable.

Third-Party Damages

Longhorn calculates the probability of failure from third-party damages by using industry data as published in American Petroleum Institute (API) issued Publication 1158, dated January 7, 1999, entitled "Analysis of DOT Reportable Incidents for Hazardous Liquid Pipelines, 1986 Longhorn's estimated frequencies range from 3.12×10^{-5} to 7.78×10^{-5} incidents per mile per year. This range is based on the lowest value reported as "Incidents Caused by Rupture of Previously Damaged Pipe (RPDP)" in the API report, 3.12×10^{-5} incidents per mile per year, and the observed frequency of 7.78×10^{-5} incidents per mile per year on the 1970 through 2000 experience on the Longhorn pipeline.

Longhorn does not commit to a calculated failure probability threshold for the ORA because of the high level of uncertainty surrounding the ongoing evaluations of pertinent conditions. However, Longhorn cites LMP measures to reduce third-party damages and concludes that these programs "...should render the likelihood of a third-party-induced failure

Earth Movements

Based on studies (see EA Appendix 9E), potentially damaging earth movements are seen to be extremely rare threats to this system's integrity. If such events should occur, pipe bending, buckling, or ovality would be the more expected types of damage. Indications of damaging earth movements are more often detected by inspection of surface conditions or by visual inspection of an excavated portion of the pipeline. The studies recommend inspections where warranted. The commitment to run at least a caliper tool at a frequency not to exceed three years, provides an additional measure to detect pipe damage from earth movements since the caliper tool is sensitive to geometric distortions of the pipe.

The probability of a failure due to earth movements is calculated for all types of earth movements in aggregate. The calculated probability of failure is $<2.6x10^{-5}$ per mile year based on API 1158. This estimate is believed to be conservative since this System has undergone specific studies for such failure potential and is under increased monitoring for such potential, compared to industry common practice.

Other

Failure modes that are not considered in this ORA include stress corrosion cracking and selective seam corrosion. These are very rare phenomenon and involve simultaneous and coincident failure mechanisms. Stress Corrosion Cracking (SCC) is addressed in an independent study (see Appendix 9E). A conclusion is that SCC in this type of line would be extremely unlikely and, while SCC could theoretically initiate a crack in this pipeline, the crack growth would more likely be dominated by mechanical fatigue, rather than continuing SCC induced crack growth. Mechanical fatigue is addressed in the ORA.

Selective seam corrosion is a possible, but rare, on low frequency ERW pipe. However, the possibility cannot be dismissed entirely. It is an aggressive form of localized corrosion that had no known predictive models associated with it. As such, it cannot be reasonably modeled in an ORA. Not all low frequency ERW pipe is vulnerable since apparently, special metallurgy is required for increased susceptibility. Evidence suggests that the older portions of this System are not highly susceptible to this mechanism. Kiefner suggests that evidence of this susceptibility would have already appeared in the 50 year service life if the System had characteristics making it more vulnerable.

Limitations to ORA

The ORA addresses several common failure mechanisms some of which increase in likelihood with the passage of time and tend to be predictable over time. The ORA estimates of failure rates are not applicable to certain other failure mechanisms. These other mechanisms are much more rare and should not appreciably impact overall failure rate estimates. Nevertheless, the failure potential does exist.

In addition, there is the possibility that calculations and underlying assumptions will underestimate the failure potential. Most ORA assumptions are reasonable and conservative but might nonetheless prove to be inaccurate.

Therefore, the ways in which the ORA failure rate estimates might prove to understate the actual failure rate are as follows:

1. Actual corrosion rate is greater than estimated: even though 7 mils per year is considered an aggressive corrosion rate, even higher rates are possible under special circumstances. Such circumstances include selective seam corrosion (a low frequency ERW pipe susceptibility), micro-biologically induced corrosion, interferences, and SCC. Extremely aggressive corrosion rates that accompany these more rare forms of corrosion are very situation specific and do not lend themselves to predictive calculations. Hence, the ORA is not sensitive to these potentials.

2. Anomalies were missed or their dimensions were understated (beyond the vendor-stated accuracy limitations) during last ILI (1995).

3. Pressure reversal phenomena cause an understatement of the size of a surviving defect. Hence the time to failure from pressure cycles is shorter than predicted.

4. Material properties are not as assumed, leading to larger initial defects and/or more rapid crack growth under future pressure cycles.

5. There are more laminations with hydrogen accumulation than are estimated.

6. Geotechnical analyses underestimate potential for damaging events.

7. The effectiveness of third-party damage mitigation is overestimated.

Based on the conservative assumptions underlying the ORA calculations, the possibilities of these underestimations is deemed to be very low.