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5.0 PIPELINE INTEGRITY ANALYSIS

5.1 BACKGROUND AND PURPOSE

This chapter discusses the analyses of the physical attributes affecting system integrity and proposed operating and maintenance (O&M) practices of the Longhorn Pipeline System (System). This evaluation of conditions and procedures, referred to as the Pipeline Integrity Analysis (PIA), examines the condition and the overall approach to operations and maintenance of the System and its ability to transport refined petroleum products safely with regard to people and the environment.

Presented herein is an overall summary of the pipeline's general condition and attributes, including a review of data from past inspections and tests. These data are used for determining the structural integrity of the pipeline as well as the System's ability to withstand specified operating conditions. This chapter also evaluates the pipeline's leak history, including a review of spill incidents, frequencies, volumes, causes, and a comparison with other pipeline event data under Exxon Pipeline Company (EPC) operation.

O&M procedures specify the details of all operating and maintenance activities. Proposed procedures of Williams Energy Services (WES), Longhorn Partners Pipeline, L.P. (Longhorn) operating contractor, are examined.

Additionally, this chapter reviews spill response procedures focusing on compliance and consideration of sensitive areas. A review of the Year 2000 (Y2K) Compliance Plan, as it relates to pipeline operation, is also examined. A summary of major findings concludes the chapter. The analysis of this chapter provides the foundation for the risk assessment of Chapter 6.

As a result of the Settlement Agreement (Settlement), topics comprising the PIA include those listed below. Where reference is made to Longhorn, except for asset ownership, all operational aspects actually apply to the proposed procedures of WES, the operating contractor.

Per the Settlement, the PIA includes:

1. *"Review of the compliance of the existing pipeline, new facilities, and testing of the pipeline with governmental safety standards for operation of oil pipelines, industry standards, and sound engineering practice.*

2. *Consideration of:*

- *Inspection, test records, and test methods (e.g., cathodic protection [CP] tests, Internal Line Inspection [ILI] [smart pig tests], depth-of-cover data, "fly-over" records, Office of Pipeline Safety [OPS] inspections and audits, hydrostatic tests);*
- *Maintenance records;*
- *Leak history of the existing pipeline, including pinhole leaks, line ruptures, third-party accidents;*
- *Aging effects on pipeline;*
- *Pipeline repairs (e.g., clamps, replaced sections);*
- *Sections of pipeline manufactured using low frequency electric resistance welding process;*
- *Block and check valve placement and spacing; and*
- *Stability of river and creek crossings, including weld integrity, pipeline strength, depth of cover, characteristics of cover material, potential for washout, and erosion threats to aerial supports.*

3. *Review of the compliance of Longhorn's proposed operational procedures and Longhorn's spill/leak response measures with:*
    - *Governmental safety standards (e.g., US Department of Transportation [DOT], US Environmental Protection Agency [EPA]);*
    - *Industry standards (e.g., American Petroleum Institute [API], National Association of Corrosion Engineers [NACE]); and*
    - *Sound engineering practices.*

4. *Identification of any areas where Longhorn's facilities, testing, operational standards and procedures, and response measures identified in Item 3 above are not consistent with industry standards or sound engineering practices. Any such identification specifies the industry standards or sound engineering practices sufficient to reasonably protect health, safety, and the environment that Longhorn has failed to meet, the appropriate and reasonable mitigation measures available to Longhorn to remedy any such failures and the anticipated benefit associated with each such mitigation.*

5. *Review of spill/leak response measures, including examination of the following:*
    - *Proposed leak detection system;*
    - *Procedures for pipeline sections considering resources at risk and reasonably available and proven technologies;*
    - *Shut-down decision process and timing;*

- *Level and type of pipeline surveillance for pipeline sections considering resources at risk;*
- *Staffing and equipment for spill response considering resources at risk;*
- *Clean-up standards and recovery plans considering resources at risk, including soil, surface water, ground water, threatened and endangered species; and*
- *Other components of the Oil Pollution Act of 1990 (OPA '90) Plan.*

6. *Identification of noncompliance with any current governmental safety standards.*

7. *Evaluation of whether Longhorn's computers for pipeline operations are Y2K*

The data gathering and analysis required to meet the foregoing requirements not only provide an indication of pipeline integrity, but also provide data needed in the risk assessment included in Chapter 6. The issues addressed are numerous and data are extensive. Of necessity, engineering judgment was required in some cases to select a representative sampling of data and information to satisfy the priority needs of this study. Current state-of-the-art practices have been reviewed and engineering judgments used to evaluate the integrity of the System. In the examination of attributes that determine system integrity, the implications of past practices of EPC on future system integrity are recognized.

At the time of the initiation of this study, some plans and actions for refurbishment, new construction, and operation of the System were still in progress. For example, some operational procedures were still in development and were unavailable for review in detail. Activities such as clearing some portions of the right-of-way (ROW), completing studies of potential earth movement, integrity verification and remediation of some exposed pipe remained to be completed. In such cases, the evaluation considered successful completion of those plans in addition to existing conditions. As discussed under various topics in the remainder of this report, additional specific actions and mitigation measures are planned for completion prior to or within a short period after startup. Chapter 9 details all proposed actions and timing of activities that are included in the Longhorn Mitigation Plan (LMP).

The remainder of this chapter examines operational procedures, including maintenance, and those features of the physical system that determine system integrity. In these discussions, the implications of past practices of EPC on future system integrity are recognized. Operational procedures are discussed in Section 5.2. The effects of proposed operations by WES, the operating contractor for Longhorn, are examined. After the discussion of procedures, findings of past inspections and tests and on the condition of the physical system are covered in Section 5.3. Pump station issues are discussed in Section 5.4. Spill and leak response plans and the adequacy of such plans to prevent or mitigate damage from loss of containment are discussed in detail in Section 5.5. Section 5.6 discusses Y2k issues, and Section 5.7 discusses leak history.

5.2 PIPELINE PHYSICAL EVALUATION

As discussed in Chapter 3, refurbishment and modifications have been made since Longhorn's acquisition of the System from EPC in October 1997. The present and future condition of the System, as it will be under Longhorn's operation, is influenced by past EPC practices, both in the original construction and as operated and maintained. This section examines the attributes and conditions of the System based on data and information available to this study. These attributes and conditions are relevant for assessing relative and absolute risks in Chapter 6 and impacts analyzed in Chapter 7. Attributes such as age, type of pipe, results of inspections and tests, in combination with O&M procedures (see next section) and mitigation measures (see Chapter 9), influence the integrity of the System.

5.2.1 General Attributes

The Longhorn pipeline consists of various segments installed at different times, as described in Chapter 3. Most of the pipeline (91 percent) between the Kemper Station near Crane and Valve J1 and between Satsuma Station and the Galena Park Station, in the Houston area, was built in 1949-1950. Short sections were replaced as needed over the years. The 18-inch pipeline connecting Crane to the El Paso Terminal was built in 1998, as was the 8-inch lateral from Crane to Odessa. A new 9.1-mile section of 20-inch pipeline between the Galena Park Station and Valve J1 was installed in 1999.

The age of major sections of the pipeline, between the Galena Park Station and the former Kemper Station near Crane is summarized in Table 5-1. A listing showing basic pipe characteristics is provided in Table 5-2. The age of the pipeline is a factor in the integrity evaluation because of the potential for age-related deterioration if the pipeline was not adequately maintained, and because of the potential effects of changes in manufacturing and construction specifications over time. The direct effects of age on physical condition and pipe properties from manufacture are discussed later.

Specifications in effect at the time of construction were used for all pipe. Specifications for the 1950 pipe were obtained from the bid package of Humble Oil in October 1949. Construction specifications in the new sections of the System are from WES documents from

1993 (Williams, 1993). These WES specifications apply to any construction since acquisition of the System and will be followed for any future construction.

An overview of construction specifications is provided in Table 5-3. In general, the 1993 specifications are more stringent and more detailed than the 1949 specifications. Some key differences are:

- The level of detail of the pipeline material specifications has increased.
- Minimum depth of cover and vertical clearance requirements have increased and new requirements have been added (for example, at road crossings).
- Major river crossings now require major bank reinforcement (rock plugs, riprap) and prior hydrostatic testing of the crossing section of the pipe.
- Coating type has changed from coal tar enamel to fusion-bonded epoxy for new construction.
- Welding requirements and techniques have changed.
- Hydrostatic testing pressure requirements have increased 55 percent, and test duration has doubled.
- No CP was required in 1949; it is specified in detail in 1993. It is unclear when the CP was installed on the pipeline.

Longhorn procedures call for new segments of the System to be designed, constructed, or qualified, inspected, and tested to the latest DOT regulations and industry standards, American Society of Mechanical Engineers (ASME) B31.4, API 1104, and Occupational Safety and Health Administration (OSHA). A limited amount of new construction is required to complete the proposed System. The El Paso laterals and the Odessa extension are scheduled to be constructed pending the EA decision.

Figures 5-1, 5-2, and 5-3 show the operating pressures, maximum operating pressures (MOPs), and minimum hydrostatic test pressures for No. 2 Fuel Oil at 72,000 barrels per day (bpd), 125,000 bpd, 206,000 bpd, and 225,000 bpd, respectively. Figures 5-4, 5-5, and 5-6 show the same information for gasoline. The elevation profile for the section length of the pipeline is shown in Figure 5-7. The purpose of these figures is to show the normal variation in operating pressures reflecting pressure drop and elevation changes along the pipeline route and how the planned local operating pressures compare with both the MOP and the hydrostatic test pressures. The latter were used to qualify the pipe for the specified MOP.

5.2.2 Effects of Age

Age alone is not a reliable indicator of pipeline integrity as some pipelines have been in good operating condition for more than 50 years (Muhlbauer, 1992). A perception that age causes an inevitable, irreversible process of decay is not an appropriate characterization of pipeline failure mechanisms. Mechanisms that can threaten pipe integrity exist but may or may not be active at any point on the pipeline. Integrity threats are well understood and can normally be counteracted with a degree of confidence. Possible threats to pipeline integrity are not necessarily strongly correlated with the passage of time, although the "area of opportunity" for something to go wrong obviously does increase with more time.

Experts believe that there is no effect of age on the microcrystalline structure of steel such that the strength and ductility properties of the pipe are affected. The primary metal-related phenomena are the potential for corrosion and for cracks from fatigue stresses. Therefore, the ways that the age of a pipeline can influence the potential for failures are through corrosion, fatigue, and possibly through older manufacturing and construction methods. These age effects are well understood and can be countered by appropriate mitigation measures.

A fatigue monitoring program was recommended by Kiefner (Johnston, 1999) and will be implemented by Longhorn. This, along with a corrosion predictive model, are key parts of the annual Operational Reliability Assessment (ORA, described in Chapter 9), a program designed specifically to addresses these integrity concerns.

5.2.2.1 Corrosion

Corrosion is time dependent and strongly influenced by the environmental conditions near the pipe. It is reasonable to assume, therefore, that with increasing passage of time, the opportunity for corrosion effects increases. Corrosion prevention measures are also time-sensitive. A coating system is susceptible to age-related deterioration from mechanical abrasion and chemical reaction from absorption of gases and liquids. Such deterioration may have occurred on the older portions of the System, as is indicated by the relatively high cathodic protection current density requirements to provide protection (see section 5.3.6). The cathodic protection system can also diminish in effectiveness as anode materials are consumed. The corrosion control program, discussed in Section 5.3.6 is designed to address these concerns. Proposed enhancements to the corrosion control program as well as integrity verifications to ensure active corrosion is not present are discussed in Chapter 9.

5.2.2.2 Fatigue

Fatigue, cycles of applied stress, can result in crack formation and propagation, which if unchecked, can lead to pipe failure. Pressure fluctuations during pipeline operation over long periods of time are the main source of fatigue. Fatigue effects can be predicted and therefore controlled to a large extent. Hydrostatic testing, fatigue monitoring, and ILI with crack detection tools are the three primary means by which fatigue problems are identified so that appropriate remedial actions can be taken. The annual ORA described in Chapter 9 details the intended response to fatigue potential.

5.2.2.3 Manufacturing and Construction Methods

The older portions of this System appear to have been manufactured and constructed with the best practices of the time. However, it is commonly accepted that older manufacturing and construction methods do not match today's standards.

A higher susceptibility to certain failure mechanisms has been identified in older electric resistance welding (ERW) pipe. This applies to pipe manufactured with a low-frequency ERW process, typically seen in pipe which was manufactured prior to 1970. On the Longhorn pipeline, over 50 percent of the pipe was manufactured by this low-frequency ERW process.

ERW creates a longitudinal weld seam. This type of weld seam is more vulnerable to failure mechanisms:

- Lack of fusion;
- Hook cracks;
- Nonmetallic inclusions;
- Misalignment;
- Excessive trim;
- Fatigue/corrosion fatigue;
- Selective corrosion (crevice corrosion);
- Hard spots; and
- Fatigue at lamination[1]/ERW interface.

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[1] Laminations are metal separations occurring in the wall of the pipe, produced during the pipe manufacturing process.

These mechanisms, failure databases, and supporting metallurgical investigations are more fully described in technical literature references (DOT, 1989; Fields, 1989). Since 1970, the use of high-frequency ERW techniques, coupled with improved inspection and testing techniques, has resulted in a more reliable pipe product.

Government agencies have issued advisories regarding this issue, but did not recommend de-rating the pipe or other special standards. The increased defect-susceptibility of this type of pipe is generally mitigated through integrity verification processes described in following sections. In their recent study (1999), Kiefner states that this pipe might be more prone to seam failure but that threat would be adequately addressed through recommendations in their report (Johnston, 1999). A preliminary ORA discussed in Chapter 9 illustrates how the low-frequency ERW issue is considered and addressed.

The pipe strength specified for the older pipeline was 45,000 pounds per square inch (psi) to 52,000 psi in the transverse direction and at least 42,000 psi in the longitudinal direction. This does not appear to be unusual for both strength and ductility for pipe manufactured at that time.

Laminations, or metal separations in the pipe wall, are not uncommon in older pipelines. They generally pose no integrity concerns unless they contribute to the formation of a blister. Hydrogen blistering at laminations was a reported cause of failure in two of the three hydrostatic test failures in 1995. This implies the presence of laminations and an aggravating presence of hydrogen, most likely from the previous sour crude oil service (Johnston, 1999). No further source of hydrogen is available from the products to be transported in the future. While hydrogen generation is possible from cathodic protection under certain circumstances, this is not thought to be a failure mechanism (Kiefner 2000). The potential for laminations that have survived previous pressure tests and might contribute to a future failure is discussed in Chapter 9.

Similar to the discussion on pipe manufacturing techniques, the methods for welding pipe joints have improved over the years. Girth welds today must pass a more stringent inspection than welds from the original construction of the pipeline. Welding standards such as API 1104 (incorporated by reference into 49 CFR Part 195) specify additional and different potential weld defects to be repaired than the standards from 1950. However, some welding specifications and options for welder tests were a part of the original Humble Oil Company construction specifications for the subject pipeline.

It is not certain that girth weld defects, as defined by today's welding inspection standards, increase the probability of weld failure in an inspected and tested pipeline. However, this issue illustrates an improving safety and risk-awareness evolution over time, presumably rooted in actual experience and supported by engineering calculations.

Arc burns, created during welding, are of concern due to the possibility of tiny cracks forming around the “hard spot” which might be created from the arc burn. EPC reports that their procedure was to remove arc burns, but documentation might not have reflected this.

A concern investigated was the potential existence of non-steel components in the older portions of the pipeline. Specifically, the possible use of cast-iron type materials, which are weaker than steel, was investigated. Valves and pumps were refurbished by a national contractor specializing in such activities for the pipeline industry. If the valves or pumps were not steel, this would be noted during the refurbishment. Components observed in the field carried the American National Standards Institute (ANSI) 600 series rating. That pressure rating corresponds to an operating pressure of 1,440 psi, consistent with the pipeline MOP range. At two locations ANSI 400 series components are installed for lower pressure service.

5.2.2.4 Countering Age Effects

Potential effects of age are countered through the maintenance program for identifying flaws in coatings, providing adequate CP, ILI, and hydrostatic testing. Inspection and testing is to be driven to a large extent by the ORA detailed in Chapter 9. If the potential age-related effects are properly controlled, the design life of the steel is considered indefinite.

5.2.3 Pipeline Inspection and Testing

Inspection and testing is fundamental to pipeline integrity. The purpose of inspection and testing is to validate the structural integrity of the pipeline and its ability to sustain the operating pressures. The goal is to test and inspect the pipeline system at frequent enough intervals to ensure pipeline integrity.

Pipeline integrity is ensured by two main efforts: (1) the detection and removal of any integrity threatening anomalies to ensure the current pipe integrity; and (2) the avoidance of future threats to the integrity. A defect is considered to be any undesirable pipe anomaly such as a crack, gouge, dent, or metal loss, which could lead to a leak or spill during operations. Possible defects include seam weaknesses associated with low-frequency ERW and electric flash welded pipe, dents or gouges from past excavation damage or other external forces, external corrosion wall loss, internal corrosion wall loss, laminations, pipe body cracks, and circumferential weld defects and hard spots.

The absence of any of the above defects of sufficient size to compromise the integrity of the pipeline is proven through hydrostatic testing and ILI, the two most comprehensive integrity validation techniques used in the industry today. CP counteracts soil conditions conducive to external corrosion, in the presence of coating inadequacies, and its potential effectiveness is determined through CP voltage surveys along the length of the pipeline. All of these measurement-based inspections and tests are occasionally supported by visual inspections of the System. Each of these components of inspection and testing of the pipeline is discussed further.

Inspections and testing methods consist of those mandated by regulations as well as those that are independently initiated by the operator. Some methods of inspection and testing are listed in Table 5-4.

5.2.3.1.1 Data Sources

Volumes of data logs, inspection results, analyses, and reports were provided by Longhorn, WES, and EPC and are available in the administrative record. These documents include results from the most recent ILI using state-of-the-art inspection tools, hydrostatic pressure testing, CP surveys, and other inspections. The "raw data" as well as the final reports from these inspections were reviewed by the contractor team and sometimes by additional independent reviewers.

In assessing the pipeline integrity, these inspections were not repeated for several reasons:

- Use of well-documented, recent inspections, even if conducted by the company being audited, is a well-established protocol in regulatory auditing.
- Although funded by Longhorn, specialized, independent, and often "certified" third-party pipeline test companies often prepared inspections. There is no reason to suspect that such professional companies would not produce fair and unbiased reports, and many legal and ethical reasons why they would produce only such reports.
- Additional tests and inspections are to be done prior to startup and shortly after startup to verify pipeline integrity, independent of previous inspections.
- As a means of "spot checking" the pipeline condition, on-site visual inspections were conducted.

5.2.3.2 Hydrostatic Testing

A hydrostatic test is a pressure test used to confirm the ability of the pipeline to sustain its specified operating pressure and establish a corresponding MOP. Hydrostatic testing is one component, along with others, of a sound integrity management program. The testing is beneficial in countering integrity concerns by removing critical defects. Hydrostatic testing to a level significantly higher than operating pressure (usually 1.25 times MOP) adds a margin of safety for future potential pipe weakening through corrosion, fatigue, or outside damage. This margin allows the pipeline to operate safely at the specified operating pressure.

Certain configurations of defects can survive a hydrostatic test. A very narrow and deep groove can theoretically survive a hydrostatic test and, due to very little remaining wall thickness, is more susceptible to failure from any subsequent wall loss. Such defect configurations are rare and their failure potential at a pressure lower than the test pressure would require on-going corrosion or crack growth.

The safety margin provided by the hydrostatic test may decrease over time because the test only verifies the pipe integrity at the time of the test. The probability of defect growth and addition since the test date must be considered. Since a new defect could be introduced at any time or defect growth could accelerate in a very localized region, the test usefulness is tied to other operational aspects of the pipeline. Introduction of new defects could come from a variety of sources, such as third-party activities or corrosion. For this reason, hydrostatic test data have a finite lifetime as a measure of pipeline integrity without other supporting evidence such as proof of continuing cathodic protection, ILI, and fatigue analysis. More safety is obtained from the additional integrity verification and re-verification program as well as mitigation measures designed to prevent on-going corrosion and crack growth.

Hydrostatic testing is a DOT regulatory requirement for new construction and replacement pipe. There is not a re-test requirement. Hydrostatic test results are most useful at the time they are taken, but conditions of the pipe can change. Therefore, technical literature suggests a means for estimating re-test intervals if an operator were to conduct periodic testing as a risk control measure (Johnston, 1996).

A hydrostatic re-test conducted on the EPC system in 1995, with the associated defect repairs and removals, provides some evidence of past pipe integrity. A summary of hydrostatic tests performed on the EPC pipeline system is presented in Table 5-5. The table shows the segments involved by stationing, the test pressures used, and the results in terms of where failures occurred. These failed sections of pipe have been repaired or replaced. In addition to tests on the EPC system, hydrostatic tests are being performed on new pipeline sections installed from the Galena Park Station to Valve J1, Crane Station to the El Paso Terminal, and Crane Station to Odessa, when construction is completed.

External corrosion could have occurred during the period from 1995 to the present in areas where coating was damaged or CP voltage was inadequate. Corrosion control measures were applied during the period since the last test in 1995. This is discussed further in Section 5.2.3.3 on CP history. Fatigue-induced defect growth from pressure fluctuations should not have occurred since the pipeline was not in operation since the hydrostatic test. Any non-service-related fatigue loadings (such as traffic over roadway crossings) are normally of minor magnitude and are not typically thought to contribute significantly to fatigue stresses for crossings that are cased or have adequate depth of burial.

Any defects, such as cracks and corrosion, of a size and configuration that would cause the pipe to fail under the pressures applied, would have been detected during the hydrostatic test. Defects of a size and configuration smaller than those that survived the hydrostatic test, would not be expected to fail under normal operating pressures, since the test pressure was 25 percent higher than the MOP for each pipeline segment tested.

5.2.3.3 In-Line Inspection

ILI, also called “smart pigging” or “intelligent pigging,” is the use of an electronically instrumented device, travelling inside the pipeline that measures characteristics of a pipe wall. The industry began to use these tools in the 1980s. The pipe conditions found which require further inspection are referred to as anomalies. General and detailed discussions of these tools are available in the technical literature (Muhlbauer, 1996; Conference Proceedings, 1998). The use of ILI is not currently a regulatory requirement, but in recognition of the value of these devices and their growing use in the pipeline industry, DOT regulations require that all new pipe installations be designed to accommodate ILI devices. The pipeline diameter, fittings, valves, and other parts of the pipeline must therefore be able to accommodate the passage of these devices. Proposed regulations would require the use of ILI for integrity verification and re-verification.

The state-of-the-art ILI has advanced to the point that many pipeline companies are basing extensive integrity management programs around such inspection. A wealth of information is expected from such inspections when a high quality, in-line device is used and supported by knowledgeable data analysis. It is widely believed that pipe anomalies that are a size not detected through failure under a normal hydrostatic test can be detected through ILI. However, anomaly detection is not 100 percent accurate even with the most advanced techniques. Uncertainty regarding true system strength will remain even after inspection, and similar to the hydrostatic test, ILI test results are strictly valid for a finite time period.

General types of anomalies that can be detected to varying degrees by ILI include:

- Geometric anomalies (dents, wrinkles, out-of-round pipe);
- Metal loss (gouging and general, pitting, and channeling corrosion); and
- Laminations, cracks, or crack-like features.

Some examples of available ILI devices are: caliper tools, magnetic flux leakage low and high resolution tools, ultrasonic wall thickness tools, ultrasonic crack detection tools, and elastic wave crack detection tools. Each of these tools has specific applications. Most tools can detect previous third-party damage or impacts from other outside forces. Caliper tools are used to locate pipe deformations such as dents or out-of-round areas. Magnetic flux leakage tools identify areas of metal loss with the size of the detectable area dependent on the degree of resolution of the tool. Ultrasonic wall thickness tools detect general wall thinning and laminations. So called “crack tools” are specifically designed to detect cracks, especially those whose orientation is difficult to detect by other means. Currently, no single tool is superior in detecting all types of anomalies. Not all ILI technologies are available for smaller pipeline sizes. The Longhorn pipeline consists of 18- and 20-inch diameters and is large enough to accommodate most tools—the 8-inch diameter pipeline to Odessa is of a size that not all types of ILI tools can be utilized.

Depending on vendor specifications and ILI tool type, detection thresholds can vary. The degree of resolution (the ability to characterize an anomaly) also depends on anomaly size, shape, and orientation in the pipe. The probability of detecting an anomaly using ILI increases with increasing anomaly size. Smaller anomalies as well as certain anomaly shapes and orientations have lower detection thresholds than others. Vendors report detection thresholds for general corrosion, with detection capabilities up to anomaly diameters greater than the pipe wall thickness and depths greater than 5 to10 percent of the wall thickness. Detection thresholds for pitting corrosion are in the range of 10 to 40 percent of the wall thickness, and anomaly characterization accuracy is ±10 percent of wall thickness for corrosion depth (Conference Proceedings, 1998).

The pipe wall thickness is designed to safely accommodate the expected operating stresses, including normal operating pressure, surge pressure, external forces (e.g., traffic loadings), the weight of the pipe itself, and other factors. Any abrupt changes in wall thickness or shape can amplify the stress level in the pipe wall, potentially resulting in failure. Therefore, the ILI detection of anomalies, which reduce the wall thickness or which have the potential to amplify the stress level in the wall, is an important preventative measure.

After receiving an ILI indication of an anomaly, an excavation is required to more accurately inspect the pipe and make repairs. Excavating to inspect the pipe is also used to validate the ILI results. The process of selecting appropriate excavation sites from the ILI results can be challenging. The most severe anomalies are obviously inspected, but depending on the resolution of the ILI tool and the skills of the data analyst, significant uncertainty surrounds a range of anomalies, which may or may not be serious. Some inaccuracies also exist in current ILI technology such as with pig distance measuring and errors in pig data interpretation. These inaccuracies make locating anomalies problematic.

Probability calculations can be performed to predict anomaly size survivability based on ILI tool detection capabilities, measurement accuracy, and follow-up validation inspections. These, combined with loading conditions and material science concepts, would theoretically allow a probabilistic analysis of future failure rates. Such calculations are dependent upon many assumptions and are not fully developed under the current scope of this analysis.

Several industry-accepted methods exist for determining corrosion-flaw severity and for evaluating the remaining strength in corroded pipe. ASME B31G, ASME B31G Modified, and RSTRENG are examples. Several proprietary calculation methodologies are also used by pipeline companies. The contractor (CorrPro) hired by Longhorn to evaluate the 1995 ILI data reportedly used a variation of the calculation methodology to estimate the MOP for the pipe based on anomaly characteristics and incorporating the ASME B31G method. These calculation routines require measurements of the depth, geometry, and configuration of corroded areas. Depending upon the depths and proximity to one another, some areas will have sufficient remaining strength despite the corrosion damage. The calculation determines whether the area must be repaired.

EPC performed an ultrasonic ILI in 1991, and the data were deemed to be inconclusive, according to testimony received (Deaver, 1998). Smart pigging on this pipeline was next carried out in 1995, prior to Longhorn's acquisition of the System in 1997.

In 1995, the pipeline from Crane to Kemper and from Kemper to Satsuma was inspected by Vetco using a geometry pig and low-resolution magnetic flux internal inspection device. In the Kemper-to-Satsuma segment, approximately 4,000 anomalies (labeled with an "L") were indicated as having an approximate depth of 0 percent to 30 percent wall penetration. About 300 anomalies (labeled M+, M, and M-, with + indicating the greater damage) with 31 to 50 percent penetration and 79 (labeled S) with penetrations of 51 percent or more were also indicated. A contractor, CorrPro, conducted an excavation program for EPC to inspect and repair anomalies as needed in 1996. Initial excavations and inspections indicated that most M- anomalies were caused by minor corrosion damage that did not significantly affect the structural integrity of the pipeline, and these anomalies were not investigated further. By inference, corrosion associated with L-rated anomalies was of even lesser significance. After the inspection of several of the anomalies labeled M (for moderate), the contractor found that they were not serious and did not require repairs. As a result, the inspection of M anomalies was discontinued. However, anomalies labeled M+ or S were excavated, examined, and, if necessary, repaired.

There were 70 dents reported in the 1995 Vetco survey. In their 1998 review of the pipeline ILI data, Kiefner identified 5 of these as potentially significant dents for possible further excavation and inspection. Kiefner also recommends that an additional 18 dents be investigated if any of the 5 are found to contain “detrimental anomalies” (Johnston, 1998). In all, approximately 187 anomaly locations were recommended for direct inspection (dig-outs). The results of the excavation and inspections (dig-outs) are summarized in Tables 5-6. Table 5-6 shows the segments inspected, the types of anomalies found, and the pipe length with anomalies. Table 5-7 shows the anomaly count.

The inspection had a resolution that would detect anomalies in excess of 25 percent of the pipe wall thickness in depth. Cracks, laminations, pits of certain depths, and some anomaly configurations might not have been reliably detected by this inspection.

It is reasonable to assume that the opportunity for operational-related anomaly growth was limited or non-existent because the pipeline was not in operation since the 1995 inspection. Since a new anomaly could occur following the inspection or localized anomaly growth rates could change, operational aspects of the System, such as third-party damage prevention and corrosion control, are important between ILI. Longhorn has committed to additional ILI (see Chapter 9 for further details).

5.2.3.4 Cathodic Protection History

One issue for this pipeline is the reliability of the CP system when EPC operated the pipeline, especially between the EPC shutdown and Longhorn's acquisition of the pipeline. The contractual agreement between Longhorn and EPC stipulated that EPC would maintain the System. A copy of that contract was obtained and verified. Several sources of data yield information regarding corrosion control effectiveness for the subject pipeline. For instance, test lead readings from 1992 to 1998 were examined, as were close interval surveys (CIS) from 1994 and 1998. Rectifier inspections and CP surveys taken during the interim period were also examined. There is indication from the ILI results that shows corrosion anomalies and from CP records that there might have been some gaps in CP. Areas that did not meet the voltage criteria level were identified and some questions regarding current and resistance (IR) compensation suggest that CP levels at other areas may have been deficient.

In the event of low CP potentials, less negative than -0.85 volt, a "-100 millivolt (-0.10 volt) shift" criterion can be applied to determine if the pipe is adequately protected. The low readings in some cases might indicate problems in coating condition or other deficiencies in the corrosion prevention systems. Note that since CP is used in conjunction with coating, the coating would also have to be defective, and soil moisture and electrolyte conditions would have to be such that the rate of corrosion during the interrupted period would lead to a problem. Low readings do not necessarily mean that corrosion has occurred.

Station test lead results for the EPC/Longhorn pipeline are summarized in Table 5-8. CIS data were available from 1994 and 1998. Results of the 1998 survey are summarized in Table 5-9. Pipe-to-soil voltages measured in such surveys are often taken with the rectifier on and also with it briefly interrupted, in order to obtain more data to interpret possible corrosive conditions. The CIS survey in 1998 used an "on" reading from the Galena Park Station to Crane, with the exception of two sections where "instant off" was used. One, about 21 miles long, begins west of Cedar Valley Station and extends across the Pedernales River. The other is about 12.5 miles long and is located just east of Big Lake Station. While this is consistent with the CP criteria used by WES, the lack of an "instant off" reading over most of the pipeline limits the ability to find special situations or to fully diagnose problem areas.

5.2.3.5 Visual Inspections

Visual inspections are required by regulations whenever a buried pipe is exposed and, as a matter of course, for other parts of the System that are normally observable. Routine inspections of the System as a whole are covered in the section on ground patrols and aerial surveillance. This section is restricted to a discussion of coating inspection and inspection of pipe that is exposed.

A file of inspection and repair reports from 1972 to 1996 was compiled and reviewed for identifications of coating condition. The inspection data from EPC for the last ten years are found in Table 5-10. The data comprises approximately 425 reports:

- 1970s: 28 reports;
- 1980s: 263 reports; and
- 1990s: 134 reports.

The coating was noted in the reports as follows:

- Good: 274 observations;
- Fair: 91 observations; and
- Poor or bad: 32 observations.

Visual inspection of the internal surface of the pipe is typically conducted when the pipeline is cut, excavated, and/or removed during pipeline replacement or repair activities.

5.2.3.6 Site Inspections

In addition to inspections performed by Longhorn, OPS and third-party contractor staff visually inspected the entire pipeline ROW and observed some Longhorn tests of CP potentials and block valve operation. Particular attention was paid to stream crossings, exposed pipe, and areas close to sensitive receptors.

Some general observations from these site visits are as follows: Spot checks of CP potentials and valve operations indicated no deficiencies. Signage appeared adequate in most locations although some out-of-date and hard-to-read information were occasionally observed. ROW clearing was inadequate for effective patrol in some locations. Some encroachments on the ROW were observed. Coating condition of exposed portions of the pipeline was seen to be poor in some areas.

5.2.3.7 Ground Patrols and Aerial Surveillance

Regular patrols are used to prevent and detect damage to the System and are considered to be another form of inspection of the pipeline. The visual inspection of the ROW is intended to detect evidence of a leak such as vapors, unusual dead vegetation, bubbles from submerged pipelines and sheens on water. Threats include excavating equipment operating nearby, new construction of buildings or roads, or any other activity that could cause a pipeline to be struck, exposed, or otherwise damaged. Evidence of past activity is usually present for several days after the activity and may warrant inspection of the pipeline. The effectiveness of the aerial surveillance depends on several factors such as frequency, surface vs. air patrol, speed, altitude, training of spotter, and other variables impacting response to discoveries.

ROW overgrowth and canopy cover was observed over many stretches. This would reduce the ability to effectively patrol from the air and, in some cases, from the ground. In some cases, the size of the vegetation indicated that the overgrowth had been present for many years.

5.2.4 Depth of Cover and Exposed Pipe

Depth of cover is one of several actions or conditions available to provide reduction of third-party damage threats to the pipeline and therefore increased safety for the public.

Pipelines are not required by law to be buried. However, when companies elect to bury them, depths are specified. DOT regulations (49 CFR §195.248) require that new pipe in industrial, commercial, and residential areas should be buried to a depth of 36 inches for normal excavation and 30 inches for rocky excavation. Other special situations require depths ranging from 18 to 48 inches for newly constructed pipelines. Maintenance of depth of cover is not required by DOT regulations.

Cover over the pipeline offers some protection from external hazards such as being struck by excavating equipment; the deeper the pipe, the less likely it will be hit by an excavator. In some areas, such as overpass stream crossings, the pipe is deliberately aboveground. Unintended exposures occur from time to time, primarily from ground erosion and stream scouring.

5.2.4.1 Depth of Cover

Depth-of-cover surveys have been conducted by remote sensing and probing. The most recent survey was completed in April 1999 by Longhorn. Many depth-of-cover readings were taken at a spacing of 2 to 5 feet (ft). The average spacing for all 19,000+ readings is about 190 ft. Instrument readings (Metrotech) for depth of cover were part of the survey, but these data were not used since it appeared that the probed readings were more conservative. They showed shallower depths than did the instrument readings.

Figure 5-8 shows a profile for the length of the pipeline and indicates that the depth of cover varies considerably along the entire route. This variability is a function of several factors including differences in subsurface conditions, original construction specifications, and changes overtime. As discussed earlier, the 1949 construction specifications called for a minimum 24 inches of cover in soft terrain and 12 inches in rocky terrain. The current construction specifications call for a minimum depth of cover of 30 inches or deeper in normal conditions as shown in Table 5-3. As an example of the profile with a greater degree of resolution in a local area, Figure 5-9 shows the depth-of-cover profile across a shorter section of the route covering the Edwards Aquifer zone, a section which also includes the high population zones in the Austin area, from the Colorado River to Cedar Valley Station. The full survey data are given in the cited reference, which is retained in the administrative record.

In the refurbishment of this system, various areas were selected for remediation of depth of cover. At this time, WES is continuing to evaluate various areas along the pipeline for possible future changes in depth of cover.

5.2.4.2 Exposed Pipe

Specific areas of exposed pipe were identified during overall depth of cover survey. Exposed pipe, while reducing the chance of accidental damage from excavation strikes, might be a concern because of the increased vulnerability to outside force damage other than excavation (e.g., vandalism) and because of the potential for coating deterioration and atmospheric corrosion.

It is not clear whether an exposed pipe has more risk of third-party damage than buried pipe. It is often assumed that shallow burial, less than six inches, for example, is worse than a full exposure since the cover is inadequate to provide much protection, but does conceal the presence of the pipeline.

Exposed pipe was surveyed during the winter of 1998 and 1999 by Longhorn, which includes both intentional (such as some stream crossings) and unintentional exposures. A total of 137 instances of exposed pipe were documented, ranging in length from one foot to 1,200 ft. The total lengths of exposed pipe occurring in pipeline segments from pump station to pump station are shown in Figure 5-10. This survey is more detailed and recent than the one described in the Kiefner audit (Johnston, 1999). Figure 5-11 shows the instances of exposed pipe in more detail for the Edwards Aquifer zone.

5.2.5 Crossings

Like most pipelines, the Longhorn pipeline crosses creeks and rivers as well as man-made linear features such as roads, railroads, or other pipelines. These crossings are potentially vulnerable points along the pipeline. Rivers and creeks are subject to erosion that can dislodge the pipeline. Vehicle traffic on roads and railroads can cause recurring stresses and vibrations in the subsurface. For these reasons, pipelines are fortified at crossings and protective measures are specified depending on the circumstances. These can include thicker wall pipe and increasing depth of burial and casings at road and railroad crossings.

5.2.5.1 Stream and River Crossings

There are two primary issues associated with stream crossings: conditions that would contribute to a pipeline failure and the sensitivity of the crossing to a petroleum product spill.

The Longhorn pipeline crosses several large rivers and numerous creeks. The crossings were built under two different sets of specifications, depending on when the crossing was built or upgraded. Crossings can be elevated over a stream or be subsurface and below the stream bed. There are elevated crossings in the System. However, new pipeline crossings have been installed by directional drilling (except for one which was conventionally bored) to place the pipeline under the stream. Heavier-walled pipe was used in those crossings. Since 1997, portions of the former EPC pipeline have been refurbished, including certain stream crossings. The 600-ft James River crossing was lowered. The pipeline was further lowered in two locations in Kimble County. Also, the crossings of Whiskey, Beaver, and Bear creeks were lowered to 3.5 ft, 2 ft rock, and 4 ft of cover, respectively.

In a 1999 audit report, replacement of the Rabb's Creek crossing, not far from the old Warda Station, was recommended (Johnston, 1999). This small creek crossing is scheduled for replacement because the crossing supports have deteriorated and the vertical column supports have corroded. It has also been observed that, at the Marble Creek crossing near Austin, a tributary of Onion Creek, one of the pipe bridge supports has been displaced from the vertical and leans in a downstream direction.

Field observations of some of the elevated crossings for the System suggest that some of this pipe could need a closer coating examination and possible coating replacement or repainting. There were sections in the Houston and Austin areas where the protective coating had been peeled away or had deteriorated.

Erosion of embankments and bottom scour are threats to crossings. In the history of the EPC system, there were several instances where pipe was exposed or damaged from unstable embankment areas and required remediation or repair. These cases include:

- The James River crossing in Mason County experienced a washout during flood conditions that dislodged the pipe. This did not occur while the pipeline was in operation and, in fact, appears to have occurred precisely because the pipeline was empty due to shutdown. It floated and was displaced by the flowing water. Had flooding occurred when the pipe was in service, this incident might not have happened.
- In 1991 and again in 1995, action was taken at the Brazos River crossing. Riprap was placed under, around, and above the 18-inch pipeline to repair erosion in the river bed. Then in 1995 the crossing was replaced.
- In 1993, the pipe was exposed in the Colorado River. Eighty ft of exposed 18-inch pipe was covered with sandbags to provide additional cover and an erosion or scour barrier.

It was also noted that smaller stream and drainage ditch crossings in the Houston area, where there is potential vulnerability to vandalism, show evidence of use as foot bridges, graffiti painting, and tampering with the protective coatings. At one crossing, measures had been taken to counter such activities by placing a barrier fence at each end to restrict use of the pipe as a bridge. Short sections at either end, where the pipe emerged from burial, were still accessible. Longhorn is examining major crossings as part of its pipeline refurbishment program. Longhorn continues to evaluate and correct problem crossings.

5.2.5.2 Road and Railroad Crossings

Some small rural road crossings were installed by trenching in accordance with the 1949 and the 1993 company specifications. Boring and/or cased crossings were used on larger roads. The subject pipeline has approximately 177 casings, mostly on the older portion, which are discussed further in the Chapter 6 section on relative risk assessment. Casings were originally installed as a means to reduce the effects of vehicle loadings on the buried pipe, to provide a path for leaks to be routed and detected without damaging the road or railroad structure, and to facilitate less intrusive pipe replacements. Railroad crossings require more depth of cover than road crossings.

Casings are generally thought to create increased corrosion potential, although DOT has not found them to be a significant contributor to past accidents. They have the potential to: 1) act as a shield so that protective CP currents cannot reach the carrier pipe, 2) create an environment for unobservable atmospheric corrosion, 3) create an opportunity for a "short circuit" in which the carrier pipe becomes anodic to the casing pipe and accelerated corrosion occurs on the carrier pipe. In much of today's construction practices, casings are avoided.

5.2.6 Maintenance Repairs and Rehabilitation

Proper maintenance is essential to preserving the integrity of the pipeline system.

The major activities consist primarily of repairs or replacement of the following:

- CP system rectifiers and electrical circuitry;
- Test leads attached to the pipe;
- Casings and casing/pipe electrical isolation for road and railroad crossings;
- Pipe protective coatings, including paint on aboveground pipe and components;
- Pipe segments;
- Block and check valves;
- Pressure and temperature sensors;
- Pipe bridge supports for elevated stream crossings; and
- Pump station equipment, including pumps, valves, pipe and fittings, instrumentation, controls, and tanks.

EPC maintained the System through October 1997, after which maintenance was taken over by Longhorn. A summary of the repairs performed from 1988 through 1998 is provided in Table 5-11.

5.2.7 Control Systems

The operation of each pump station is controlled by a combination of local control systems and remote operators monitoring via a centralized Supervisory Control and Data Acquisition (SCADA) system located at the WES Tulsa Operations Control Center. Each data source transmitting information to the SCADA system communicates approximately every 3 seconds. The signals are electronically transmitted to the Tulsa Operations Control Center by satellite communications. Telephone modems are in place as a backup to the satellite system. The modem system can be used if there is an isolated failure in satellite communications from individual stations or if there is a failure of the entire satellite system. When all locations are being accessed with the backup modem system, the scan intervals increase significantly and can take up to three and a half minutes when scanning all parameters at all stations.

However, local control systems provide much of the protection against abnormal operation at each of the pump stations. Table 5-12 lists emergency shutdown alarms and devices located at pump stations. These local control systems are designed to provide an orderly shutdown of the pump station if an alarm condition occurs or if certain operating parameters are violated. At the same time that the shutdown sequence has been initiated, a shutdown alarm is transmitted to the Tulsa Operations Control Center.

As examples of local control, a low suction pressure (typically less than 50 pounds per square inch gauge [psig] at several stations) will cause the pump to automatically shut down. A pump discharge pressure above a specific pressure setting will also produce an automatic pump shutdown. Other sensors and controllers act in a similar manner. The primary objective of these local controls is to prevent abnormal conditions from damaging the pipeline and pump station equipment and potentially causing or contributing to a leak. The capability to detect smaller leaks and to respond with appropriate action resides primarily with the controllers in the Tulsa Operations Control Center via the SCADA system.

5.2.8 Flow Rates and Hydraulic Profile

To increase flow rates on an existing pipeline, the pressure drop per mile of pipeline must generally increase. In some cases, an additive can be used to reduce the viscosity of the product and achieve higher flow rates at the same pressures. The Longhorn pipeline plans to increase flow rates by increasing pumping pressures at existing pump stations, by adding additional pumps between existing pumping locations, or by adding flow enhancing additives (also known as “drag reducing agents,” DRA).

The pressures generated by pumping and the pressures created by topography (elevation) effects combine to form a hydraulic profile. The hydraulic profiles for six proposed flow rate regimes (three for gasoline and three for fuel oil) are shown in Figures 5-1 through 5-6 where the resulting pressure at all points along the pipeline can be seen. To protect pipeline integrity, pressures are to always be below MOP under normal operations. Under abnormal conditions, such as brief surges, some portions of the system are allowed to reach 110 percent of MOP, in accordance with DOT regulations.

Data for the last ten years of EPC operation were examined for flow rates and pressures. The data revealed that average annual throughput rates declined from the beginning toward the end of that period, ranging from a high of around 180,000 barrels per year (bpy) to a low of about 50,000 bpy during the ten-year period. Exact pressure data for the EPC system for the full range of flow rates and, more particularly, at the times the leaks occurred during that period were not available. However, from available data and engineering estimates, pressure profiles for several crude oil flow rates were derived.

Total pressure at any point in the pipeline depends on flow rate, elevation, and relationship to the location of the pump stations. Pumping refined products does not result in a higher pressure than pumping crude oil at all locations. The changed hydraulic profile (due to changed product, pump station configurations, and direction of flow) exposes some portions of the pipeline to more pressure and some to less pressure than in previous service.

One notable observation is that across the central Texas area, including parts of the Austin metropolitan area and Edwards Aquifer recharge zone, the proposed refined products pipeline appears to result in lower pressures at both the mid-range flow rate and high flow rate than the mid-range rate for the system previously in crude oil service.

Surge pressures can be generated when the kinetic energy of flowing product is rapidly changed to potential energy as the flow rate is suddenly stopped. The resulting pressure "spike" is a function of the flow rate, the rate of flow stoppage, and product and pipe wall characteristics. These pressure spikes are additive to the pressures indicated by the hydraulic profile. Several studies have been performed to calculate possible surge pressures under a variety of scenarios. Results of these studies are discussed in Section 5.3.8.

5.2.9 Earth Movements

As with any buried structure, this pipeline is susceptible to impacts from various types of ground movements. These have structural integrity implications and hence, risk implications and are discussed here as well as in Chapter 6. Several related studies have been done as part of this EA and are discussed in Appendix 9D.

Most of the possible earth movement issues deal with rare threats to this pipeline, compared with other potential failure modes. They include:

- Scour, washout, or erosion;
- Soil stresses;
- Seismic events;
- Landslides; and
- Subsidence or settlement.

They are briefly discussed below.

5.2.9.1 Scour

Scour or washout can expose pipe and/or remove needed support from the pipeline. Topography, water flows, soil conditions, and pipe position play important roles in scour susceptibility. A scour study and span study for the Longhorn pipeline have been conducted and evaluated as part of the EA. These studies gauge the susceptibility of water crossings to scour and other forces and recommend remedial actions where appropriate.

5.2.9.2 Soil Stresses, Settlement, and Subsidence

Temperature changes can add longitudinal stress to a pipeline. In this pipeline, temperature changes resulting from changes in the ambient temperature are minimal due to the depth of cover (soil is a good insulator), the relatively constant temperature of the flowing product, and the atmospheric temperature ranges seen in this part of the country. Increased temperature changes and, hence, more stresses could occur with wide variations in product temperatures. Such variations are not anticipated, and if they occur, design protocols have considered these stresses and the effects are normally minor.

Soil movements associated with changing moisture conditions and temperatures can also cause longitudinal stresses to the pipeline, and in extreme cases, can cause a lack of support around the pipe.

Unlike most water and wastewater utility pipelines, hydrocarbon transmission lines like this one are a welded steel pipeline designed to operate under high internal pressures. Most water and wastewater utility pipelines are not designed for high internal pressures, are often constructed from more brittle materials, and often have joint connectors less structurally strong. All of these factors tend to increase their susceptibility to failure modes not commonly seen in pipelines such as the Longhorn pipeline.

Temperature changes and soil movements can cause coating damages as the pipe moves against the adjacent soil. Coating damages increase the potential for corrosion of the external pipe wall. Coating damages are normally offset by CP currents until such damages are located by CISs, and in extreme cases, by indications of light corrosion in an ILI.

There is no evidence of failures due to the effects of change in temperature or soil conditions on this pipeline while in crude service or on any other pipelines in similar operations, either crude or gasoline. Related failure initiators such as erosion, subsidence, and other earth movements have caused failures in similar pipelines.

5.2.9.3 Seismic Events

Underground pipelines are vulnerable to seismic activity. The primary damage to pipe during an earthquake occurs during shaking and ground failures, which cause direct damage or indirect damage from soil displacement. Factors that affect this vulnerability are pipe material, pipe diameter, joint type, and corrosion. Pipe ruptures are a major cause of concern in emergency response after an earthquake.

5.2.9.4 Landslide

Landslides can occur from heavy rain, especially on slopes or hillsides with heavy cutting of vegetation or loadings from construction or other activities that disturb the land. Slides can also be caused by seismic activity. Landslide displacement of pipe can cause structural damage and leaks by increased external force loading if the pipeline is buried under displaced soil. Areas susceptible to landslides may also be susceptible to other ground failures in the event of an earthquake, such as liquefaction or ground waves.

5.2.9.5 Aseismic Faulting and Subsidence

A specific type of ground movement potential in the Houston area, identified as "aseismic faulting," is potentially damaging to pipe coating if not to the pipe's structural integrity itself. It has been reported that some pipeline operators in the Houston area monitor ground conditions around such faults. This might indicate a history of damaging events.

This pipeline crosses several faults between Harris County and El Paso, Texas, but none of those west of Harris County are known to be active aseismic faults. Approximately 300 active faults are known in the Houston Metropolitan Area. All are aseismic because their movement events are too small and continuous to cause measurable earth tremors. Harris County aseismic, active faults are not discrete fractures in the earth. Rather, they are zones of intensely sheared ground measuring a few tens of feet wide in a horizontal direction perpendicular to the trend of the fault. The prediction is that approximately two ft of additional subsidence will occur along the pipeline. More than two ft of additional subsidence will occur in some areas of the subsidence district. However, deformation along the pipeline corridor will be distributed over a distance greater than 30 miles. Consequently, it will have little or no measurable effect on the pipeline, and therefore does not pose a hazard (IT Corporation, 2000).

While susceptibilities are noted here, there is no evidence to suspect damages from previous earth movements. Similarly, no previous pipeline failures on this system have been attributed to earth movements.

5.3 OPERATING AND MAINTENANCE PRACTICES

This section discusses the evaluation of Longhorn's proposed operational procedures and standards to determine if they comply with governmental safety and regulatory requirements and if they are consistent with industry standards and sound engineering practices as required by the Settlement. Activities associated with both the pipeline and pump stations are noted. The WES System of Operating Manuals is discussed. This includes a review of procedures addressing topics or issues of concern as identified by the plaintiffs' and other public comments.

5.3.1 Procedures

Activities associated with the operation and maintenance of the pipeline include the following:

- Inspection and maintenance of valves, motors, pumps, flow meters, instrumentation, electrical components, supervisory control system, and communications equipment;
- Inspection and maintenance of corrosion control systems;
- Inspection and maintenance of block valves to ensure proper operation;
- Periodic verification of pipeline integrity;
- Calibration of all instrumentation to comply with company standards, manufacturers' recommendations, and applicable state and federal regulations;
- Inspection and maintenance of pipeline ROW including signs and markers;
- Surveillance of ROW for encroachments and physical condition; observation of all construction activities, by others, on or near the Longhorn ROW;
- Inspection of river and stream crossings and crossings of Longhorn pipeline by other pipelines, highways, and utilities;
- Performance of damage prevention and public education programs; and
- Regulatory record keeping.

5.3.1.1 Pump Stations and the El Paso Terminal

Activities associated with the operation and maintenance of the stations and terminals, include the following:

- Maintenance of valves, motors, pumps, flow meters, instrumentation, electrical components, supervisory control system, and communications equipment;
- Truck driver safety training and certification;
- Daily tank farm safety inspection and maintenance;
- Daily truck loading rack safety inspection and maintenance;
- Maintenance of vapor combustion unit;
- Refined product receipts, sampling, and testing;
- Regulatory record keeping; and
- Observation of all construction activities, by contractors, within the El Paso Terminal.

The review of operating procedures was accomplished by two methods. First, compliance checklists were developed for the applicable regulations and industry standards. The checklists shown in Appendix 5A and Appendix 5B note the section(s) from Longhorn's manuals that addresses each of the requirements. This type of review is consistent with regulatory audits of procedures. The second review method involved a more detailed examination of Longhorn's manuals and procedures with respect to key issues identified through plaintiff and public comments. WES's current practices and proposed practices for the Longhorn pipeline that exceed requirements are discussed.

5.3.1.2 Basis for Operational Procedures

DOT requires that liquid pipeline companies prepare and follow a manual of written procedures for conducting normal operations and maintenance activities and for managing abnormal operations and emergency situations. To meet this requirement, Longhorn has adopted the WES System of Operating Manuals for liquid pipelines.

Operation and maintenance of the System will follow the guidelines set forth in the manuals. The following volumes comprise the System of Operating Manuals:

- Chemical Hazard Communication/Chemical Hygiene Plan;
- Emergency Response Plan (ERP);
- Maintenance and Calibration;
- Measurement;
- Oil Spill Response Plan;
- On-the-Job Training Program – Maintenance Crew;

- On-the-Job Training Program – Pipeline Operators;
- Operating Manual;
- Operations Control/Dispatcher Procedures;
- Preventive Maintenance;
- Safety; and
- Welding and Radiographic Procedures.

The WES manuals address written procedures for conducting normal operations and maintenance activities and for handling abnormal operations and emergencies. The manuals address DOT, OSHA, EPA, and/or company requirements. The System of Operating Manuals consists of 12 individual volumes of information, which are listed and summarized in the following paragraphs.

Williams Energy Services Chemical Hazard Communication/Chemical Hygiene Plan. The Chemical Hazard Communication Program provides information for all employees who have potential on-the-job exposure to hazardous chemicals. The program complies with the requirements of OSHA, 29 CFR §1910.120. The program includes an overview of the OSHA standard, hazardous properties of chemicals in the form of material safety data sheets and container labeling, safe handling procedures, and measures of personal protection.

Williams Energy Services Maintenance and Calibration. This manual deals with technical aspects of equipment, controls, and circuitry. It provides control limits for pumping operations. The manual contains maintenance inspection lists, which address periodic testing of safety and control devices.

Williams Energy Services Measurement. This manual addresses the measurement of product volume and characteristics through the pipeline system, including storage tanks, piping, pumping, and transfer. The manual includes physical properties, normal operations, design criteria, maintenance, and appendices.

Williams Energy Services Oil Spill Response Plan. The FRP provides protocols and procedures to be followed in the event of a spill from the Longhorn pipeline. The purpose of the plan is to minimize potential spills and mitigate effects of spills. Preventative measures include securing the source of the release, containing it as close to the source as possible, protecting threatened, environmentally sensitive and economically important areas, and removing the spilled material and associated debris as quickly as possible. The manual is written to comply with 49 CFR Part 194. Along with procedures, the manual includes descriptions of the chain of command and organizational lines of authority; job assignments, duties, and responsibilities; and available resources for quick and efficient response.

Williams Energy Services Maintenance Crew On-the-Job Training (OJT). The Maintenance Crew OJT Program provides training for maintenance crew employees. The program includes both knowledge-based training (i.e., computer-based module training and safety training) and skill-based training procedures. The Maintenance Crew program includes specific written procedures on safety skills, mainline skills (which cover skills on locating, inspecting, and testing the mainline pipe), and general skills that cover the testing, response, and cleanup of leaks and spills and use of equipment to access mainlines. The manual also includes checklists for recording the training of employees.

Williams Energy Services Operators On-the-Job Training Program. The Pipeline Operators OJT Program provides training for station and terminal operators. The program includes both knowledge-based and skill-based training procedures. The program includes written procedures on safety skills, general skills on the operation of tank farms, computer operations, pumping unit operations, station/terminal manifold operations, tank operations, metering, and rack operations. The manual also includes checklists for recording the training of employees.

Williams Energy Services Operating Manual. This manual contains information on normal, abnormal, and emergency operating procedures. Major topics in the manual are as follows:

- Hazardous materials handling;
- Tankage;
- Product handling;
- Manifolds;
- Mainlines;
- Pumping stations;
- Recovery systems;

- Terminals;
- Buildings and grounds;
- Materials and supplies;
- Waste handling guidelines;
- Training;
- Liquid petroleum gases;
- Crude oil;
- Special instructions on internal corrosion control;
- Capital and project expense budgeting;
- Company vehicle and tractor standards;
- 49 CFR Part 195; and
- Safety reporting.

Williams Energy Services Operations Control/Dispatcher Procedures. This manual includes written procedures for the operation and control of the pipeline. The procedures include normal, abnormal, emergency, maintenance, and pressure settings of tanks, mainline valves, pumps, and surge relief systems. The manual also includes startup and shutdown procedures for pump stations. Forms to track the operations and controls are included in the manual.

Williams Energy Services Preventative Maintenance. This manual covers the inspections of pipeline operating equipment performed on a regular cycle by trained employees. Inspections may require routine maintenance or emergency repair to rectify situations found. The manual covers inspections required at various frequencies including weekly, monthly, quarterly, semiannually, tri-annually, annually, and biannually. The manual includes inspection and maintenance instructions, frequencies, checklists, and forms.

Williams Energy Services Safety. This manual includes safety modules, which comply with governing federal, state, and local occupational safety and health laws, rules, and regulations. The procedures also address issues of industry standard practice. Topics covered include design, construction, and operation of the pipeline facilities. The procedures are in place to prevent employee injury, operational loss, and property damage.

Williams Energy Services Welding and Radiographic Procedures. This manual includes specifications and procedures to be used for construction, fabrication, and maintenance of all company operated pipeline systems. The manual also includes procedures for tank welding applications, magnetic particle testing, visible dye penetrant testing, arc burn removal, and safety considerations, along with corresponding forms and records.

Each of the manuals listed above was reviewed with respect to meeting regulatory requirements as well as industry recommendations and sound engineering practices for operational and maintenance procedures. All references to the manuals will be assumed to have "Williams Energy Services" in the title.

5.3.2 Applicable Regulations

Most of the Longhorn pipeline is regulated by OPS because it is an interstate pipeline. The Odessa Lateral is intrastate and is therefore regulated by the Railroad Commission of Texas (RRC), Oil and Gas Division. Applicable federal regulations are listed and described below:

- **Pipeline Safety Regulations.** 49 CFR Parts 40, 190, 194, 195 and 199 are applicable to hazardous liquid pipelines. Part 40 prescribes procedures for drug and alcohol testing. Part 190 prescribes procedures used by the OPS for regulating pipeline safety. The enforcement authority of OPS and civil and criminal penalties for violating the Pipeline Safety Act are detailed in this regulation. Part 194 contains requirements for oil spill response plans to reduce the environmental impact of onshore pipeline oil spills. Longhorn procedures and practices relative to this regulation are discussed under Section 5.5 of this chapter. Part 195 prescribes safety standards and reporting requirements for pipeline facilities used in the transportation of hazardous liquids. Part 199 addresses the requirements for drug and alcohol testing and references the procedures of Part 40.
- **National Oil and Hazardous Substance Pollution Contingency Plan.** EPA regulations found at 40 CFR Part 300 provide an organizational framework and procedures for preparing to respond to discharges of oil and accidental releases of hazardous substances into locations which present danger to public health or welfare. The document specifies responsibilities among federal, state, and local regulatory agencies during an emergency response. It establishes requirements for federal, regional, and area emergency response plans and addresses procedures for the response of other persons as well. This document also provides response plans per Comprehensive Environmental Response, Compensation, and Liability Act requirements. The evaluation of Longhorn's procedures relative to this regulation is discussed in Section 5.5 of this chapter.

- **Hazardous Waste Operations and Emergency Response (HAZWOPER).** OSHA regulations found at 29 CFR §1910.120 cover HAZWOPER activities. Hazardous waste activities include clean-up operations required by a governmental body involving hazardous substances at uncontrolled hazardous waste sites, corrective actions involving clean-up operations at Resource Conservation and Recovery Act sites, voluntary clean-up operations at sites recognized by governmental bodies as uncontrolled waste sites, and operations involving hazardous wastes at treatment, storage, and disposal facilities. Emergency response operations for releases of hazardous materials comply with requirements of paragraph (q) of this regulation. The evaluation of Longhorn's procedures relative to this regulation is discussed in Section 5.5 of this chapter.

Longhorn pipeline operation and maintenance procedures were reviewed against regulatory requirements in 49 CFR Part 195. A checklist of items reviewed is provided in Appendix 5A. Regulatory topics related to Emergency Response are discussed in more detail in Section 5.5. Items listed in Table 5-13 are areas where regulatory requirements are met in documents outside of the System of Operating Manuals.

The adequacy of industry standards and regulatory requirements is not evaluated here. The standards and requirements provide a baseline for understanding industry experience and reflect lessons learned. However, in many cases, the EA analyzes risks and mitigations independently from recommendations and requirements of these standards.

5.3.2.1 EPC Regulatory Compliance History

EPC's past compliance or noncompliance is not directly relevant to Longhorn, which is a different corporate entity with management and staff operating under different management systems and procedures. For purposes of this EA, however, past maintenance activities were considered to the extent that they provide limited, indirect evidence of current pipeline integrity.

Although RRC does not have jurisdiction over interstate pipeline operations, under a temporary interstate agreement with DOT, the agency performed a safety evaluation of the EPC pipeline system in 1996 prior to acquisition by Longhorn. The evaluation included a review of the pipeline system's operating procedures and manuals, and the review consisted of a checklist form indicating "Satisfactory," "Unsatisfactory," or "Not Applicable" for the items required by 49 CFR Part 195 Subpart F, *Operation and Maintenance*. The evaluation by RRC, ranked the EPC operating procedures and manuals "Satisfactory" for all items reviewed.

Two concerns were reported in a letter dated April 30, 1996, from RRC to DOT. The concerns were failure to maintain a test lead at a road crossing (US Highway 290, near Austin) and failure to reconnect a rectifier after the Kemper pump station was dismantled. A Letter of Concern was issued by DOT to EPC. Subsequent field inspections showed that this concern had been resolved.

5.3.3 Industry Standards

The intent of industry codes and standards is to improve the pipeline system by understanding the causes for failures and establishing guidelines, procedures, and methods for reducing pipeline failures. Many national codes and industry standards for pipelines and the transport of petroleum products are applicable to Longhorn's pipeline operations. For example, Table 5-14 lists the standards incorporated by reference into 49 CFR Part 195. These referenced documents, or portions of documents, are incorporated into the regulations as if they were printed in full. Therefore, pipeline operators must also abide by the requirements or recommendations of these codes and standards.

A sampling of the most prominent and dominant industry standards bearing on pipeline integrity was used as an indicator of Longhorn's overall adherence to industry best practices. For the purpose of this evaluation, two standards were selected to review against Longhorn's operational procedures: ASME B31.4 and API Recommended Practice 1129. ASME B31.4, *Liquid Transportation Systems for Hydrocarbons, Liquid Petroleum Gas, Anhydrous Ammonia, and Alcohols,* sets forth the engineering requirements deemed necessary for safe design and construction of pressurized piping. The primary purpose of this code is to establish requirements for safe design, construction, inspection, testing, operation, and maintenance of liquid pipeline systems for protection of the general public and operating personnel as well as for reasonable protection of the piping system and the environment. API Recommended Practice 1129, *Assurance of Hazardous Liquid Pipeline System Integrity,* is a basic guide and resource to provide increased assurance of a pipeline system's integrity. The purposes are to compile a wide base of current industry experience, knowledge, information, and management practices into a cohesive document comprising a range of best practices and to assist pipeline operators in increasing the integrity of their pipeline systems.

Longhorn's operational procedures were checked against the requirements of ASME B31.4 and API Recommended Practice 1129, respectively. Checklists are provided in Appendix 5B. Topics that are covered in Longhorn's Emergency Response manual are discussed in Section 5.5.

A few topics that did not appear to be explicitly addressed in the System of Operating Manuals are listed in Table 5-15.

"Sound engineering practices" is a generic phrase applied to various good practices used in the industry, which may or may not be formally codified. This EA also uses phrases such as "good industry practices" to indicate activities that are common among pipeline operators. The phrase is loosely defined and is included in the EA only to provide the reader a basis for comparison, when activities that exceed practices of most other pipeline operators are referenced. Assessing what is "common" is first based on the existence of published standards such as API, ASME, and NACE which recommend certain practices for design, operations, and/or maintenance, sometimes in excess of DOT regulations. Additional evidence of common practices comes from DOT experience in auditing operators as well as from EA contractor's experience; informal interviews with other pipeline company personnel, industry consultants, and vendors providing services to the industry.

In this EA, "common industry practice" shall mean practice consistent with reasonable and prudent operations in the industry, including, as applicable, compliance with API Provisions, NACE Provisions, ASME Provisions, and company standards.

A formal distinction between "good" and "bad" practices is not made, but the intent is to identify practices that are considered to be more thorough and more prudent and to label these as "good practices." Failure to adopt accepted or otherwise prudent practices could be considered "bad practice."

Table 5-16 lists selected major topics related to operating procedures. The table indicates where these topics are covered in the various regulations and standards as well as where Longhorn's procedures address these topics.

Longhorn has performed and has committed to make additional improvements to the System. These commitments have been considered in this EA. These measures were conducted in 1998 and 1999 and continue in 2000. These and other commitments are fully discussed in Chapter 9 on mitigation measures.

5.3.4 Control Documents

5.3.4.1 Longhorn Control Documents

Longhorn has created a set of control documents that describe all aspects of the intended operation of the System. The Longhorn Pipeline System Integrity Program (LPSIP) is described by Longhorn as the “core organizational driver for Longhorn management initiatives and operational priorities.” Longhorn states that “...the LPSIP is intended to function in addition and complementary to the base regulatory requirements of the US DOT's RSPA Pipeline Safety Regulation, Title 49, Subchapter D, Part 195 (Transportation of Hazardous Liquids by Pipeline).” LPSIP incorporates an earlier program called the Longhorn Integrity Management System (LIMS). The stated purpose of LIMS is consistent with recent trends in the hydrocarbon industrial sector. It provides an overall environmental, health and safety management system as an operating framework into which all procedures, practices, and activities fit so that they achieve explicitly defined performance objectives in these areas. The philosophical context of such a system is similar to the International Standards Organization (ISO) 9000 quality standard and ISO 14000 environmental management standard. It is also consistent with Environmental Health and Safety management systems developed within the petroleum industry during the last decade by firms such as Exxon, Chevron, and Mobil.

LPSIP describes 12 process elements. These are listed below and discussed in Chapter 9.

1. Corrosion Management Plan;
2. In-Line Inspection and Rehabilitation Program;
3. Key Risk Areas Identification and Assessment;
4. Damage Prevention Program;
5. Encroachment Procedures;
6. Incident Investigation Program;
7. Management of Change;
8. Depth of Cover Program;
9. Fatigue Analysis and Monitoring Program;
10. Scenario Based Risk Mitigation Analysis;
11. Incorrect Operations Mitigation; and
12. System Integrity Plan Scorecarding and Performance Metrics Plan.

The entire set of WES operations and maintenance procedures, policies, and manuals that relate to the Longhorn System, fall under the LIMS program, which in turn falls under the LPSIP. Also under LPSIP is the Operational Reliability Assessment (ORA) that establishes integrity verification intervals.

Longhorn has adopted the mitigation plan contained in the Longhorn Mitigation Plan (LMP) for all subsequent years of operations. The LMP describes the LPSIP as well as the list of 39 specific mitigation measures. The LMP is discussed in Chapter 9.

5.3.4.1.1 Surveys and Studies

Surveys and studies that were recently performed include:

- Depth-of-Cover Survey;
- Exposed Pipe Survey;
- CP/CIS
- Seismic activity
- Scour, erosion, flood potential at selected stream and river crossings
- Span evaluations
- Landslide potential
- Root cause analyses

These surveys have provided data for Longhorn's Risk Assessment and Integrity Management programs. They also have provided Longhorn with data to design and implement corrective actions and to identify and resolve potential issues. Findings from the surveys have provided Longhorn with information to design and implement a risk management program, which specifically addresses these findings and monitors integrity and condition on an on-going basis.

5.3.4.1.2 WES Operating Manuals

As operator of the pipeline, WES is required to implement a set of processes that conform to the LIMS expectations. In addition, the processes will also conform to the WES Operations and Technical Services Group strategies which include the OSHA Process Safety Management program.

Within the overall operational procedure framework just discussed, specific procedures related directly to major pipeline system integrity factors were reviewed. These categories of procedures deal with:

- Damage prevention;
- Corrosion control;

- Leak detection;
- Surge control and overpressure protection;
- Fatigue monitoring;
- Crossings;
- Staffing; and
- Training.

WES operating manuals are described in Section 5.3.1.

5.3.4.1.3 Formal Risk Assessment and Management

Risk assessments performed for the System as part of this EA are discussed in Chapter 6. Risk assessment and risk management are also parts of the LPSIP. The following discussion addresses risk assessment and management as a Longhorn operating program, detailed in the LMP (see Chapter 9). Longhorn states that it is committed to constructing, operating, and maintaining its pipeline assets in a manner that:

- Ensures long-term safety to the public and Longhorn employees; and
- Maximizes environmental protection.

Longhorn also states that each pipeline system has unique characteristics and presents unique challenges in meeting these objectives. Longhorn uses a risk management approach to manage these objectives. This risk management approach is defined by DOT sponsored Liquid Risk Assessment Quality Team as:

> "The overall logical process by which a company understands the risk associated with the operation of its facilities (risk assessment) and determines whether to take action and how to take action to reduce or accept these risks (risk management)."

Longhorn states that, through the risk management process, it will implement controls to reduce the likelihood of adverse events and to mitigate the potential consequences.

This program has all of the elements recommended by the DOT sponsored Liquid Risk Assessment Quality Team's Risk Management Program Standard. It is consistent with best industry practices for risk assessment and risk management of pipelines.

5.3.4.1.4 Risk Model

Longhorn has adopted a Relative Risk Assessment Model for its risk assessment process consistent with the EA Risk Model and a model used by WES. This model, based on the work of W. Kent Muhlbauer (Muhlbauer, 1996) evaluates:

- Potential for third-party damage;
- Probability of pipeline corrosion;
- Characteristics of pipeline design; and
- Possibilities of operations upsets.

Each factor is assigned a numerical index as outlined below.

- Third-party Damage Index – The Third-party Damage Index evaluates items such as depth of cover, activity level, One-call systems, and public education.
- Corrosion Index – The Corrosion Index uses atmospheric, internal, and buried metal corrosion attributes in its scoring.
- Pipeline Design Characteristics Index – Some of the characteristics under evaluation in the Pipeline Design Characteristics Index include pipe materials, hydrostatic testing, and design safety factors.
- Operations Upsets Index – An evaluation of operations and maintenance characteristics will consider issues such as operational complexity and maintenance history.

The indices are aggregated and multiplied by a consequence factor. This factor is developed with consideration for the types of product in the pipeline and the location of the pipeline relative to population and environmentally sensitive areas.

5.3.4.1.5 Risk Rankings

The pipeline system is divided into logical segments (see Chapter 6), based upon the total risk characteristics of that segment as developed above. Approximately 55 data inputs for each segment of the pipeline will have been placed into the model. The segments are then ranked based on their score from the risk assessment. This allows for prioritization of pipeline segments based on their relative risks.

According to the LMP, the relative risk ranking results will be used to appropriately allocate resources to reduce Longhorn’s overall operational risk. The LMP cites benefits of an effective risk management program including: a sharper focus on continuously identifying and reducing real risk issues, reduction in accidents, prioritization of inspection programs, prioritization of maintenance plans, and assistance in project design. Risk management will provide a means to continuously evaluate the System.

5.3.4.1.6 On-going Programs

Longhorn will further evaluate the findings of the Depth-of-Cover and Exposed Pipe Surveys on the basis of relative risk evaluation. The relative risk of exposed pipe and shallow cover will be based upon the likelihood of the hazard occurrence and the severity of potential consequences. Longhorn will similarly evaluate third-party damage potential, corrosion probability, pipeline design characteristics and theoretical operational upsets. These programs will be continually evaluated in connection with the LPSIP. Risk assessments conducted as part of the LPSIP may compel a periodic reordering of risk management priorities.

5.3.4.1.7 Integrity Audit

An integrity audit was conducted by Kiefner & Associates, Inc. (Johnston, 1999). Dr. John Kiefner, principal of the firm, is recognized in the pipeline industry as a leading authority on pipe integrity and metallurgy. The audit report states that the Longhorn pipeline is suitable for its intended service with an acceptably low potential for releases, provided the audit report's recommendations are implemented. Longhorn has committed to implementing the recommendations (Longhorn, 1999) or their equivalent, as are described in the LMP.

5.3.5 Damage Prevention

The purpose of damage prevention is to protect the pipeline from third-party interference. The Longhorn Damage Prevention Program includes public relations and patrol protocols. The protocols are described in Chapter 6 of the Operating Manual and Skill Numbers 2.17 and 2.18 of the Maintenance Crew OJT Manual Program. The public relations protocols address complaints, rewards for reporting leaks, lease-line responsibilities checklists, access to location of pipelines, encroachment, permits and agreements, owner/tenant relations during repairs, property with tile drainage systems, excavation One-call system, open ditch, backfilling, final operations, and abandonment. The lease-line responsibilities checklists include sections on maintenance repair and use, regulatory and engineering record keeping, pipeline modifications, real estate and claims, taxes, insurance, and other issues.

Other aspects of the Longhorn pipeline operations relating to damage prevention include public education efforts, One-call, pipeline depth of cover, and pipeline markers. These topics are addressed in the following paragraphs.

Public education/communication. Public education procedures are also described on page 19.9 of the Operating Manual. This section describes a communications program with residents, community officials, and excavators along the pipeline ROW. The program is consistent with the requirements of 49 CFR §195.440. Components of the program include use of pipeline markers, participation in industry-sponsored public education efforts, distribution of safety brochures to residents and excavating contractors, One-call membership, and contacts and distribution made during routine operation and maintenance activities.

Longhorn plans to produce and distribute public education brochures on an annual basis (Longhorn, 1999). Distribution of the brochures would be developed using zip code/address cross-reference databases and current maps. These brochures address various safety and public awareness topics such as how to identify and locate a pipeline, how to identify and respond to a pipeline release, when to contact a one-call system, and warnings concerning excavation, digging, and plowing near pipelines.

Specifically, these brochures would include the following information and topics:

- A brief explanation of the specific pipeline system (e.g., products transported, product end uses, etc.);
- A full color depiction of a pipeline marker sign;
- An explanation of pipeline marker signs, including the type of marker used, the information provided on the marker, and where markers are normally located;
- A reminder to notify the appropriate one-call system prior to any digging, excavating, or plowing near the pipeline;
- The Texas One-call system phone number;
- Longhorn's emergency toll-free phone number (1-888-465-9512);
- An explanation of how to recognize a pipeline release through the senses of sight, sound, and smell;
- A list of appropriate actions that should be taken in the event of a pipeline release;
- A full-color system map; and
- A request to pass the information along to family members and business associates.

To provide a distribution to the appropriate audience, Longhorn initially proposed to adopt the following target audience guidelines:

- Residential and Business Addresses. One-quarter-Mile Wide Corridor Distribution: Brochures would be distributed to all residential and business addresses located within one-eighth mile each side of the pipeline systems.
- Excavators and Contractors. County-wide Distribution: Brochures would be distributed to all excavators and contractors with mailing addresses within each county where the pipeline system is located.
- Public Safety Officials, Local Emergency Planning Committees, Emergency Responders, Local Government Agencies and Public Officials. County-wide Distribution: Brochures would be distributed to all public safety officials, local emergency planning committees, emergency responders, local government agencies and public officials with mailing addresses within each county where the pipeline system is located.
- Two-language versions (English /Spanish) of the brochures will be distributed to people living near the Longhorn pipeline.

The Maintenance Crew OJT Program addresses informing and educating third parties on WES procedures. This training addresses typical reasons for informing and educating the public, communication methods available, and a list of forms and records required for documenting communications.

Community Outreach Program. Longhorn sponsors community outreach efforts that focus on the safety aspects of the pipeline. Longhorn employs a Safety Consultant for the state of Texas who travels throughout the state, concentrating on the communities along the route of the System. The consultant meets regularly (at least annually) with local emergency preparedness groups to discuss the location of the pipeline, products in the pipeline, and how to deal with any emergency situation involving the pipeline. Longhorn will regularly conduct mock drills with these emergency response groups to better plan for emergency situations.

This program, conducted in conjunction with the WES program, is a company-wide community relations program that supports employees in partnerships with the cities and towns where they live and work. In each community, a team made up of local employees works with community leaders and organizations to understand local needs and to sponsor community projects, either with volunteer time, financial support, or both. Each community has an opportunity to work with the local team to help choose the projects that are the most important in its area.

Depth of cover. Several sections in the WES Operating Manual address depth of cover. Section 2.15 of the Maintenance Crew OJT Program describes procedures for survey of shallow pipelines and defines a shallow pipeline as less than 18 inches of cover. Maintenance Crew OJT Program describes procedures for lowering pipelines.

Maintenance of the specified depths is not required by regulation, but the LMP specifies a depth-of-cover maintenance program. The exact amount of risk reduction achieved by various burial depths is situation-specific and is a function of the type of activities that might occur. For example, auguring or boring activities present a different threat than do normal agricultural activities.

Right-of-way maintenance. The pipeline ROW is kept clear to facilitate surveillance and is marked with signs to discourage improper use and promote means to notify the pipeline owner. Procedures are listed for clearing and maintaining the ROW and for investigating third-party damage to the pipeline, including documentation with photographs and site drawings and third-party statements.

A pipeline operator generally has certain rights on the easement which include access to the pipeline or aboveground components, the removal or trimming of vegetation, and the control of drainage and erosion. Access to the ROW is normally described as well as provisions for possible additional work space and related landowner damages. Normal use of the ROW includes vegetation control to facilitate aerial observation and access and over-line surveys by personnel on foot or in light trucks. The pipeline is designed for such ROW activities. Episodes of erosion, settlement, upheaval, or other impacts to the cover or support of the pipe might warrant excavation and/or grading or other activity to restore the pipeline and ROW to as-designed condition.

Markers. The Maintenance Crew OJT Program Skill Number 2.08 addresses pipeline marking requirements. The section describes permanent pipeline markers; identifies special tools, equipment, and materials for marking; lists procedures for permanent markings; and discusses the installation of aerial markers used in air patrols. The Pipeline Marking Standard is referenced in the table of contents for the Operating Manual.

Pipeline warning markers are placed along the pipeline route to notify the public that a refined petroleum product pipeline is buried in the vicinity and to warn them not to dig before notifying Longhorn. The markers provide a toll-free telephone number to contact WES's Operations Control Center. The center is staffed 24 hours per day, 365 days per year.

Right-of-way surveillance. ROW surveillance issues addressed in the manuals include methods of patrol, patrol intervals, patrol routines, general patrol procedures, patrol observation items, reports and forms, and emergency reports. The pipeline ROW is scheduled for weekly aerial and/or ground surveillance. The surveillance is used to evaluate the condition of the ROW and identify potential encroachments or pipeline exposures. If an emergency situation is identified, the aerial patrol would notify the area operations team so that appropriate action, based on the circumstances, can be taken. If the aerial patrol identifies any unauthorized construction activity on or near the pipeline ROW, those engaged in the activity would be immediately notified that they are working near a refined products pipeline, to stop work, and contact Longhorn Operations Control Center.

Both helicopters and fixed-wing aircraft will perform surveillance. Helicopters will be used from the Galena Park Station to the Cedar Valley Station. The helicopter will fly approximately 60 miles per hour, flying at an altitude of 400 to 500 ft in urban areas and 200 to 300 ft in rural areas. From Cedar Valley to El Paso, surveillance will be conducted by fixed-wing aircraft flying at speeds of about 100 to 110 miles per hour. These aircraft will fly at altitudes of about 500 ft in urban areas and about 300 ft in rural areas.

Ground patrols will be done on a random schedule unless they are utilized to fulfill patrol schedule requirements of the LMP. They will also be conducted to investigate any areas of concern identified in aerial surveillance and when weather conditions or obstructions such a trees and encroachments prevent effective aerial surveillance.

One-Call. Longhorn will respond to one-calls through the Texas One-call system. The system provides a toll-free number for contractors and individuals to call prior to digging on or near the pipeline ROW. WES One-Call Services, Inc. (WilCall) provides one-call ticket management and screening services for the Longhorn pipeline. Services include pipeline locating, excavation assistance, dispatching, record keeping, and auditing services. Longhorn operations personnel will locate and mark (e.g., flags, painting of the ground) the exact location of the pipeline and will be present when excavation occurs near or across the pipeline to ensure that construction activities do not endanger the pipeline.

5.3.6 Corrosion Control

Corrosion control procedures primarily involve maintaining the integrity of the pipeline coating and the CP system for the pipeline. The types of corrosion that must be prevented are external corrosion and internal corrosion. Conditions in the soil and atmosphere affect external corrosion. Internal corrosion is related to the products carried by the pipeline.

Atmospheric corrosion. The slow rate of metal loss and the ability to inspect most steel exposures to the atmosphere create a low failure rate due to atmospheric corrosion. Experience, however, indicates that certain “hot spots” can facilitate accelerated corrosion. These hot spots include casings (where an alternate wet and dry environment, coupled with inability to inspect, is especially problematic), splash zones, insulation, and supports. Preventative measures most often employed are the application and maintenance of a protective paint coating.

Aboveground facilities, pipe in casings, and exposed or very shallow pipe are susceptible to atmospheric corrosion. On sampling field inspections, conducted by DOT and the Contractor, it was noted that new construction generally had good paint coating or was soon to be painted (new station equipment). Some exposures were observed to have what appear to be inadequate coatings.

Buried metal corrosion. The potential for external corrosion for buried steel pipe depends on:

- Corrosivity of the soil;
- Condition of the coating, evidenced by:
  - Coating age and type;
  - CP current density requirements; and
  - Visual inspections;
- Effectiveness of CP system, evidenced by:
  - Annual CP survey pipe-to-soil potentials;
  - CIS pipe-to-soil potentials; and
  - ILI findings;
- Interference potential, depending on:
  - Nearby utilities; and
  - Presence of casings;
- Potential for mechanical corrosion, depending on:
  - Pipe stress levels; and
  - certain soil characteristics; and
- ILI type and date.

Pipe coating. Coating of buried metal surfaces is addressed in the Maintenance and Calibration Manual, MC-7.19, which references the recommended industry practice for coating piping as NACE RP0169-96—Control of External Corrosion on Underground or Submerged Metallic Piping Systems. The metal surfaces include valves, steel plate liners, tanks, mechanical couplings, metal connectors, valve boxes, and piping. Longhorn has a policy which requires all newly buried steel lines, including mainline, terminal, and station piping, to be coated. Coating selection requirements, handling requirements of coated pipe, and repair requirements of coated pipe are listed on pages 6.53 to 6.58 of the Operating Manual.

The fusion-bonded epoxy coating, applied to newer portions of the line, has effective corrosive prevention properties assuming it is properly applied. The original coal tar coating, applied on the older portions of the line, was a widely used design and has proven to have a long life span in many cases. Coatings are susceptible to age-related deterioration from mechanical abrasion and chemical reaction from absorption of gases and liquids. Evidence of the current coating condition is found through visual inspection reports, pipe-to-soil potential surveys, and detection of previous corrosion damages.

Coatings prevent water and/or soil from making direct contact with the pipe steel, thus eliminating the electrolytic path necessary for corrosion to occur. According to construction specifications, precautions were taken in handling, bending, and backfilling the pipe to maintain the integrity of the coating. Coating for the newly constructed sections of pipe consist of fusion-bonded epoxy (14 to 16 mils). Lilly 2040 Topcoat was used where additional coating protection was necessary, such as crossings. Coatings on the refurbished 18-inch and 20-inch diameter pipeline consist of hot coal tar, asbestos felt, and glass fiber.

Cathodic protection. If the pipeline coating is perfect, there is no need for additional corrosion control, and CP would be unnecessary. However, coatings are never initially perfect and can be damaged from contact with rocks or equipment during installation or during operation. Coatings can also deteriorate over time. Where the coating is damaged, disbonded, or otherwise compromised, the pipeline can experience external corrosion. Indirect evidence (depleted anode beds) and experience suggest that some sections of inadequate coating are to be expected in the subject pipeline. CP provides an additional method of protection from corrosion. CP is the application of direct-current electricity from an external source to oppose the discharge of corrosion current from anodic areas. When a CP system is properly installed, all portions of the protected structure (pipeline) collect current from the surrounding electrolyte (soil), and the entire exposed surface becomes cathodic. The original number and location of these systems is based on calculated demand for CP current. Additional systems are added as necessary to maintain adequate CP on the pipeline and associated facilities. CP on interstate hazardous liquid pipelines has been mandated by DOT since 1973.

A CP system is in place for the refurbished 18-inch and 20-inch diameter pipeline. Temporary CP was applied to the newly constructed segments through bonds to other current sources. Permanent CP systems are currently being installed.

A description of Longhorn's CP system is included in the Maintenance and Calibration Manual on pages 7.15 to 7.18, and 49 CFR Part 195 requirements are listed on page 19.5 of the Operating Manual. DOT regulatory requirements for CP systems include testing of protected underground facilities once each calendar year, bimonthly testing of rectifiers, and testing of unprotected pipe once every five years. These requirements are addressed on pages 6.53 to 6.58 of the Operating Manual. Maintenance of CP equipment is addressed in the computer training module Computer-Based Training (CBT) Module #20. Locating rectifiers is addressed in the Maintenance Crew OJT Program Manual Skill Number 2.25.

Protective currents are provided from electrically connected anodes or from an alternating current/direct current rectifier in conjunction with anodes. Anode beds have a design life, become depleted over time, and must be replaced. Depleted anode beds are detected by changes in CP and rectifier readings. Part of the refurbishment of the System requires replacement of inadequate anode beds. Sixteen sites for CP enhancements were identified (see LMP in Chapter 9). Enhancements included thirteen new anode beds that were installed between the existing 50 beds from the Galena Park Station to the Crane Station. New anode bed designs for Longhorn in the Houston area use a CP current density of 0.12 milliamp per sq ft. The CP current density may suggest a poor coating, since higher current densities are required where coating is not providing good isolation from the surrounding electrolyte. Design for a new coating system typically specifies a current density from about 0.001 to 0.01 milliamp per sq ft. An example of recommendations for CP improvements is shown in Table 5-17. This was created by WES corrosion control personnel after some initial evaluations. Some of these recommendations have been modified recently, and the modifications are included in the LMP, which is provided in Appendix 9C.

Associated with the use of CP currents is the concern related to excessive CP voltages. A voltage level that is too high electrolyzes water, resulting in hydrogen (H_2) liberation on any exposed pipeline metal. This could possibly lead to coating disbondment or to blistering of the pipe wall. These concerns were not specifically addressed in the pre-mitigation O&M manuals.

These can be serious and are one key impetus for performing CIS. These concerns were not specifically addressed in the pre-mitigation O&M manuals.

Stress corrosion cracking is a phenomenon described as a failure mechanism due to the simultaneous presence of high tensile stress and a susceptible material in a conducive environment. The potential for this failure mechanism to occur on the pipeline is thought to be low due to its specific coating system, environment, and intended mode of operation. These factors are detailed in the report in Appendix 9E. These concerns were not specifically addressed in the pre-mitigation O&M manuals.

As noted earlier, low frequency ERW pipe has an increased susceptibility to a special form of corrosion—"selective seam corrosion" or "crevice corrosion." While CP is thought to be effective in preventing formation of initiators, its effectiveness in stopping on-going corrosion in an existing crevice depends on the current density and the electrolyte in the crevice. These concerns were not specifically addressed in the pre-mitigation O&M manuals.

Cathodic protection surveys. The effectiveness of the CP system depends on the sufficiency of the voltage and current provided along the pipeline. Periodic measurements of the CP voltage potential are required to verify the adequacy of the CP. Voltage readings between the pipe and a reference electrode are measured. Test leads or stations, installed at fixed locations along the pipeline, are used for annual or semi-annual measurements of pipe-to-soil voltages. These test stations consist of electrical wire connected to the pipe and brought to the top of the ground over the pipe. Rectifiers, installed to provide the CP current, are inspected monthly.

CIS's take voltage readings at intervals shorter than test lead intervals and are conducted periodically in selected areas. The CIS interval used by WES is usually from 3 to 15 ft along the pipeline. Since corrosion problems can be localized, CIS increases the opportunity for detecting potential problems compared with station tests. This is especially important in the ability to detect interferences.

Current regulations require that the pipeline operator "...conduct tests ... to determine whether the protection is adequate" at least once each calendar year. DOT anticipates that companies will follow "common industry practice," which includes recommended practices of NACE.

In addition to pipe-to-soil surveys, ILI also provides evidence of corrosion control effectiveness, but mostly by detecting areas of corrosion—indicating the failure of the control methods. An exception to the "only after corrosion is present" detection capability is the ability of certain ILI techniques to infer potential interferences. The presence of nearby buried metal can be detected in the magnetic flux leakage tool. Such indications normally warrant increased scrutiny from a corrosion-control perspective, if not immediate excavation for further inspection.

Cathodic protection voltage measurement criteria. A generally accepted criterion for CP pipe-to-soil voltage readings, as measured by a copper-copper sulfate reference electrode, is at least -0.85 volts at the pipe-to-electrolyte boundary. A lower reading indicates decreased protection. For liquid pipelines, this value is used, based on its specification in DOT regulations for Natural Gas Pipelines (49 CFR Part 192), and is cited by NACE and elsewhere in the technical literature on corrosion control (NACE, 1996). The actual practice of ensuring adequate levels of CP is often more complex than this simple criterion. Readings must be carefully interpreted in light of the measurement system used.

There is controversy in the industry concerning appropriate methods to ensure adequate CP currents on all portions of the pipe. The reading of interest is the pipe-to-soil potential directly at the pipe-soil interface. Since this reading cannot practically be taken directly, a reading at the surface is taken and adjusted to reflect the reading at the pipe-soil interface. The adjustment from readings taken to reading of interest is often termed "IR compensation," with the implication that "IR" or "IR drop" is the part of the voltage reading that should not be considered in assessing the adequacy of CP. The surface readings can be taken with the impressed electric current supply to the System turned either "on" or "instant off." WES and EPC past practices both indicate that they use only a -0.85 volt "on" reading as the primary criterion. The IR drop subtracts the voltage drop through the soil from the reading to yield the "true value" of the pipe-to-reference electrode potential. If the IR drop is high, an "on" reading of -0.85 volts might actually be less negative than this, to a level considered inadequate to protect the pipe. Under certain conditions then, the pipe might not have adequate CP even when an "on" reading that is more negative than -0.85 volt is seen. The "instant off" reading might therefore better reflect the actual level of protective currents. However, there is no industry or regulatory agreement on the issue of how best to compensate for IR in the readings. The -0.85 volt is usually considered a conservative criterion since a safety margin is already included for most soil conditions.

In addition to deficient CP voltage, a potential concern noted earlier is excess voltage. WES uses -1.2 volts as a limit on pipe-to-soil voltage as an informal guideline. Episodes of higher voltage must be individually evaluated.

Owners of pipelines, whose CP systems have been found to be interfering, normally cooperate by installing bonds between the systems. Some of these are termed 'critical bonds' indicating that serious CP system malfunction is possible upon damage to the bond. Such bonds are required to be inspected at regular intervals, as part of compliance with regulations to ensure adequate CP.

5.3.6.1 Internal Corrosion

Internal corrosion (IC) is the result of corrosive constituents in the products carried. The former EPC system carried crude oil. Compared with refined petroleum products, crude oil is generally more corrosive to the interior of a pipeline. The crude oil was more likely to cause IC than the future refined products.

Protection against IC is based on material of construction selection for the pipe and control of product specifications. Longhorn will control the threat of IC by:

- Specifying low-corrosivity products to be transported by the System.
- Corrosion inhibitor injection at Galena Park Station (injection rate of 0.75 pounds/1000 bbl). Dosage will be adjusted to maintain an “A” rating on the
- Corrosion coupon tests, performed three times a year at El Paso Terminal and Odessa Station. The target corrosion rate will be less than 1 mil per year.
- Use of cleaning pigs twice per year to clean the pipeline of debris and water and allow the corrosion inhibitor to establish a protective film on the pipe wall.
- Internal surface inspection for evidence of corrosion, whenever pipe is removed from the System for any reason.
- Further investigation to determine the extent of the corrosion, followed by remedial actions, if necessary.

As with external corrosion, the inspection and test program is the final countermeasure.

Several sections of the Operating Manual address the control of IC. Chapter OP-15 of the Operating Manual discusses approved inhibitors, pump settings and dosage rates, precautionary measures for injection pumps, and sampling requirements for residual quantities of inhibitors at end terminals and metering stations. Internal examination of mainline corrosion coupons is addressed in OP-6.58. The Operator OJT Program manual includes Skill Number 5.29 for the removal of corrosion coupons and Skill Number 5.31 for the sampling of products. The Operating Manual, page 19.6, lists the generation of an ILI report, monthly inhibitor injection report, and a work order and damage report in response to the DOT regulations for internal corrosion control.

5.3.7 Leak Detection

The SCADA system provides continuous monitoring of pump stations and block valve status. Leak detection is provided by field instrumentation and the SCADA system to enhance pressure and temperature compensated volume balance analysis between Galena Park Station, El Paso Terminal, and Odessa Meter Station. In addition, the Tulsa Operations Control Center performs a manually calculated measurement line balance every two hours. All leak detection capabilities are discussed here and in detail in Appendix 6D.

Larger leaks would be signaled by an alarm in the Tulsa Operations Control Center indicating that the pressure and/or flow rate has deviated outside of preset parameter limits. These limits are six percent and eight percent for pressure and flow rates at origination stations, respectively (16 and 6 percent, respectively, at intermediate stations) (Williams, 1999). Thus, a decrease in flow greater than eight percent from the target rate would cause an alarm at the Center within six seconds of the time the sensor detected the low flow rate. When a pressure or flow parameter alarm occurs, the controller reviews the pipeline operations and checks the pipeline. If no cause is apparent, the controller will shut down the pipeline. Mainline isolation valves will be closed, and the pipeline will be kept under pressure to determine its integrity and to identify the location of any leak. The estimated time to detect, verify, and respond to the alarm is reported to be five minutes (Pearson, 1999).

The second method of detecting leaks is a manual mass balance calculation performed on the pumping and receiving meters. These balances are performed at the Tulsa Operations Control Center every two hours when the pipeline is operating at steady state. Discrepancies as low as ± 0.3 to 0.6 percent of flow rate can be detected. When such a difference is noted, the accuracies of the meters in question are checked by remotely proving each one. If the meters prove to be accurate, a leak is suspected, and the pipeline is shut down. The estimated time to prove the meters, verify the findings, and shut down the pipeline is estimated to be 30 minutes to two hours. The total leak detection time of this method is estimated to be four hours.

Leak rates of less than 0.3 percent of flow rate cannot be detected by current WES instrumental or mass balance means. Leaks of this level can only be detected by visual means or at the leak location or by new proposed systems (see Appendix 6D and Chapter 9).

Table 5-18 summarizes the detection time, response time, and the maximum amount of product that could be released during the time it takes to detect the possible leak and shut down the pipeline. Release volumes are provided for both the 72,000 bpd and 225,000 bpd cases. The rates and volumes shown are based on the assumption that the leak rate is equivalent to the flow rate in the pipeline. Thus, the rates and volumes represent the maximums that would occur.

The Tulsa Operations Control Center is integrating enhancements to leak detection capabilities that would allow more rapid detection of smaller leaks. One enhancement is the implementation of a "rate of change" feature that already exists within the VECTOR software currently used with the SCADA system. Such a feature would help detect unusual changes that might indicate a leak.

As a second enhancement, UTSI International Corporation conducted a theoretical leak detection performance evaluation of the Longhorn pipeline (Williams, 1999). They concluded that, with the installation of some additional instrumentation and a transient flow software model, potential leak detection performance could be significantly improved. A state-of-the-art transient flow model system is to be installed prior to startup and will be capable of detecting leaks in the range of 100 to 130 barrels per hour (bph) within a one minute observation.

In the Edward's Aquifer recharge zone and the Slaughter Creek watershed in the contributing zone(MP 170.42 to MP 178), additional leak detection systems are planned. These include an instrumented hydrocarbon sensing cable system described as mitigation measures in Chapter 9.

5.3.8 Surge Control and Overpressure Protection

Surge pressures are created when a moving fluid is suddenly brought to a halt. The kinetic (moving) energy is converted to potential energy, resulting in an increase in pressure and the creation of a pressure wave. In a fluid-filled pipeline, a positive pressure wave is propagated upstream of the point where the fluid flow is interrupted. Flow interruptions in a pipeline are usually due to valve closures or pump shutdowns.

A negative pressure wave travels downstream from the point of interruption. The pressure can decrease below the vapor pressure of the liquid, and some of the liquid can vaporize, forming vapor cavities. Each cavity may be large enough to separate the liquid into two segments. When the pressure in the system equalizes, the vapor cavity will collapse. The velocities of the liquid can be very high during these collapses, producing a significant pressure wave.

Willbros Engineers, Inc. performed an initial surge analysis on the pipeline from Galena Park Station to the El Paso Terminal. This study was completed in August 1998. However, the maximum allowable operating pressure and maximum allowable surge pressure (MASP) were calculated from pipe grade and wall thickness data. Another surge analysis was performed using the maximum allowable operating pressure that was determined from the results of hydrostatic testing. The initial analysis was completed in August 1999 and additional calculations have been performed since. This initial analysis is discussed in more detail in Appendix 5H. Sixty-one cases, including proof cases, were examined in the analysis. Most cases involved valve closures, but six pump shutdown cases and two emergency system shutdown cases were also examined. For the purposes of this study, the transported product was conservatively assumed to be No. 2 fuel oil since this product produces the largest surges. The SPS Program Version 2.0, developed by Stoner & Associates, Inc., was used for the surge analysis. Four cases were considered in the analysis:

- Galena Park Station to El Paso Terminal at a flow rate of 4,850 bph (Case 1);
- Galena Park Station to Crane Station at a flow rate of 5,000 bph (Case 2);
- Galena Park Station to El Paso Terminal at a flow rate of 8,675 bph (Case 3 – ultimate flow rate); and
- Galena Park Station to Crane Station at a flow rate of 3,225 bph (Case 4 – startup).

For Cases 1, 2, and 4, the effects of transient valve closures and pump shutdowns were determined for most of the remote control valves and pump stations along the pipeline. These locations are summarized in Table 5H-1 in Appendix 5H. Case 3 represents the hypothetical maximum flow rate at which the pipeline would operate. However, several additional pump stations would be needed to achieve the maximum flow. The exact locations of these pump stations have not been defined, and the pump performances at the projected stations are also undetermined at this time. Because of these uncertainties, no Case 3 studies were performed.

The results of the surge analysis are summarized in Table 5H-2 in Appendix 5H. Initially, the surge pressures were determined and compared to the MASPs, defined in the mitigation plan (Chapter 9), along the pipeline. The MOPs and MASPs were determined from Longhorn hydrostatic test data and from the LMP. As shown in Table 5H-2, the surge pressure exceeded the MASP limits at some locations for most of the modeled scenarios.

According to the surge analysis report, the MOP levels for the existing system were approximately 30 to 160 psig lower than those allowed by ASME B31.4 and 49 CFR Part 195. By hydrostatically testing portions of the pipeline to higher pressures, the MOP levels can be raised above the maximum surge pressures. This is a mitigation measure discussed in Chapter 9.

Longhorn also commissioned a study to determine the benefits of additional pipeline valves in reducing spill volumes. As a result, seven additional check valves were proposed for the pipeline. A "check" case surge analysis was performed under the assumption that the seven valves were in place along the pipeline. The check case assumed a closure of a valve at the Llano River crossing**.** The results are summarized in Table 5H-3a in Appendix 5H. In the initial analysis, the MASP was exceeded along one segment of the pipeline. In a second analysis of the same system, but with a proposed operational bypass pressure relief system around the mainline valves at the major river crossings, the MASP's were not exceeded at any locations.

The results of this study as well as measures proposed to limit possible surge pressures are discussed in the mitigations discussed in Chapter 9.

5.3.9 Fatigue Monitoring

Fatigue monitoring uses data on pressure fluctuations of the pipeline system to estimate the potential for crack growth in the pipeline. There is no regulatory requirement for fatigue monitoring. Some pipeline operators have implemented formal fatigue monitoring programs that consist of collecting pipeline pressure data from the SCADA system and analyzing trends. This analysis includes using mathematical methods for predicting potential crack growth and determining the remaining fatigue life of the system. Longhorn does not currently have a formal fatigue monitoring program in place for this pipeline but has committed to such a program (see Appendix 9C) which is consistent with recommendations from Kiefner & Associates (Johnston, 1999).

5.3.10 Control Room Procedures

For the purposes of monitoring and control from the Tulsa control center, the WES pipeline system is divided into three zones: south, central, and north. The Longhorn pipeline will be assigned to the south zone. Each zone is under the control of an individual who continually monitors the pipeline operations. Each of these controllers works a 12-hour shift. A supervisor is also present in the control center on weekdays and is on call at other times. Each controller is familiar with the operations in all three zones.

Controllers can start and stop flow of product into the pipeline from supply points, start and stop pumps, operate valves, and monitor pipeline pressures, flow rates, product densities, and temperatures. The control room is therefore an important component of the leak detection system since potential leak indications are diagnosed and responded to from there.

Detailed procedures for all control room operations are contained in the O&M manuals, which are reviewed as part of a normal DOT inspection.

5.3.11 Exposed Pipe Control

There are two types of exposed pipe. The first is pipe exposed to the atmosphere by design. The second type of exposed pipe is previously buried pipe that has been exposed because of soil erosion and wash outs. Several sections of the operating manuals address the inspection of exposed piping. The inspections at crossings include visual inspection of the outer surface of the pipe for overall condition, coating, contacts to supports and the supports themselves, and record keeping. For buried piping exposed to atmosphere, the inspection identifies the condition of coating and evidence of corrosion, surface pipe pitting or leakage, and corrective and remedial actions. Lowering of exposed pipelines includes special lowering procedures.

Exposed pipe is continuously evaluated to determine where such pipe requires re-burial or other corrective actions.

5.3.12 Water Crossings

Waterway crossings are regulated by 49 CFR §195.412(b) which requires that crossings under navigable waterways be inspected once every five years to determine the condition of crossings. Several sections of the Operating Manual address water crossing inspections, including OP-19.5 which states the DOT requirements, OP-6.48 to 6.51, and Maintenance Crew OJT 2.06. Inspections include re-establishing base lines on plan drawings, locating pipe, re-establishing reference points and benchmarks, inspecting exposed pipe, and reporting surveys and inspections.

5.3.13 Staffing

Longhorn plans to locate field staff to cover the entire route of the System and the El Paso Terminal. The pipeline system and terminal would be supported through area operating teams consisting of: field technicians, corrosion technicians, maintenance coordinators, PSM specialists, field tech supervisors, field office administrators, and area managers. These teams would be supported by a centralized technical services team that includes engineering, environmental, health and safety, DOT regulatory compliance, training, corrosion and risk mitigation, operations control, design, and real estate services.

5.3.14 Training

Longhorn has established and conducts a continual training program to instruct operating and maintenance personnel as well as support personnel in engineering, safety, and environmental protection. Annual training is reviewed to assure its effectiveness. Training reviews are documented on various forms including the Employee Performance Review Form, Training Enrollment, Training Class Attendance, OJT qualification checklist, and automatically in the CBT documentation program. Longhorn's Operations Training Program consists of the following major components:

- New employee orientation;
- OJT;
- CBT;
- In-house hands-on and vendor training schools/seminars;
- Technical training;
- Safety meeting training program;
- Supervisor training; and
- System of operating manuals.

The new employee is introduced to overall company policies and procedures through the New Employee Orientation. Emphasis is placed on personnel and facility safety. Following the New Employee Orientation, new employees are trained with OJT Procedures and CBT Program modules. OJT manuals provide information regarding specific job tasks at the facility. Manuals have been developed for both station operators and maintenance crew operators. One week of field training is required for new hires who have not previously had field experience. Qualification checklists track job relevant skills and assess the training and development of the operator. Guidelines and requirements are mandated for the first 180 days of employment for new employees.

In OJT, workers are evaluated for their current knowledge of the subject material. Skills are discussed and illustrated with an open forum format for questions. Key points are also covered. Workers would be checked for understanding and performance of the skill set. Checklists are maintained for each worker. The checklists cover required modules with sign offs for dates of demonstrated competency. The checklists also allow for critical checks of core knowledge in the event that the worker needs additional training on key concepts. Hazard assessments and selection of personal protective equipment selection skills are reviewed annually.

The CBT Program includes 44 modules. These modules are designed to teach the fundamental concepts and principles of pipeline operations. Certain modules are designated for the training of newly hired field and operating employees. There are additional requirements for temporary and summer employees. A total of 19 modules are designated for the training of newly hired operators. These modules are required to be completed within the first 120 days of employment. Computer-based modules track the training of employees in the computer modules with quizzes at the end of the lessons. Supervisors may request that an employee re-take a module if the supervisor determines that the employee's knowledge in the area is weak.

Other operator and employee training includes field refresher training with nine computer modules on field safety training. Portions of the refresher training are required on an annual, biannual, and triannual basis. The in-house/vendor training is a program for providing expert information on specialized training of specific operations or equipment through outside vendor consultants or in-house experts. The Safety Training Program provides training for all operating employees for safe performance of all designated job responsibilities. The Supervisor Training Program develops and maintains effective field supervisors capable of managing the day-to-day operation of the facilities.

5.3.15 Tank Maintenance Inspection

All tanks and related equipment have been constructed in accordance with industry standard API 650—Welded Steel Tanks for Oil Storage; API 651 – Cathodic Protection of Aboveground Petroleum Storage Tanks; API 2000 – Venting Atmospheric and Low Pressure Storage Tanks; API 2003 – Protection Against Ignitions Arising Out of Static, Lightning, and

Stray Currents; API 2350 – Overfill Protection for Storage Tanks in Petroleum Facilities; and National Fire Protection Association (NFPA) 30 – Flammable and Combustible Liquids Code.

The main purpose of the Tank Maintenance Inspection Program is to inspect all tanks in accordance with API 653 inspection requirements and make recommendations on necessary repairs to ensure the integrity of the tanks. Under DOT tank rules, an annual inspection is required. The following paragraphs describe some of the components of the Tank Maintenance Program.

All of the pump stations are equipped with 1,000-gallon sump tanks. Product from equipment drains, scraper (pig) launcher and receiver pads, and thermal relief valves is collected in these tanks. A sump pump is installed at each station to periodically pump the collected product back to the mainline.

In addition to swap and storage tanks, Crane Station also includes a 1,500-bbl pressure relief tank. A low-pressure relief system relieves into this tank to protect the ANSI 150-psi piping on the tank manifold from the mainline pressure. The relief tank is sized to contain a volume equivalent to 10 minutes of flow at the maximum mainline flow rate. A relief tank is also provided at Satsuma Station. There are 19 tanks located at the El Paso Terminal.

All product storage tanks have been constructed in accordance with industry API standards as a minimum requirement. All tanks are designed with a single steel bottom, with leak detection between the tank bottom and an underlying liner. Small pipes are installed to allow periodic inspections for early indications of tank-bottom failure.

All storage tanks are located within diked areas. At the El Paso Terminal, the areas around each tank inside the dikes are surfaces with compacted, liquid-tight crushed shale. Each dike is sized to contain 110 percent of the largest volume of liquid that can be released from the largest tank within the diked area. This requirement exceeds NFPA 30 requirements. Drainage inside the dikes is designed to divert liquid away from the tanks.

5.3.15.1 External or In-Service Inspections

All tanks are given a visual external inspection by an inspector certified in API 653. This inspection is conducted at least every five years or at the quarter corrosion rate life of the shell, whichever is less. The inspection includes a survey of the tank for settlement activity, measurement of the shell thickness for corrosion, inspection of vents, inspection for tank shell damage, seal gap measurements, floating roof inspection, fixed roof inspection, etc. The inspection is performed by a certified inspector according to API 653 and documented on an In-Service Inspection Form. The forms are retained in the records of the Tank Maintenance Department.

5.3.15.2 Internal or Out-of-Service Inspection

All tanks are given a formal internal inspection to ensure the integrity of the tank bottom. This inspection is initially conducted after ten years of operation. Subsequent inspections are established in accordance with API 653, but do not exceed 20-year intervals. The inspection is performed by inspectors certified pursuant to API 653 and documented on an Out-of-Service Inspection Form. A copy of the documentation is retained in the Tank Maintenance Department's records.

5.4 PUMP STATIONS AND MAINLINE BLOCK VALVES

Pump stations and valves are important parts of the pipeline system and significant to its integrity. They are potential sources of leaks themselves and affect pressure conditions in the piping. The factors affecting the integrity of the existing and proposed pump stations and mainline valves on the pipeline from Houston to the El Paso are discussed and described in this section. Pump stations and valves are discussed separately from the pipe portions of the pipeline. They consist of equipment items and configurations that can be examined individually to evaluate their integrity and potential risk.

Many connections, not falling under current design standards, were removed as part of the pipeline conversion. No branch connections not meeting DOT code requirements were identified. No cast iron or "semi-steel" or other non-steel components are known to be present.

5.4.1 Pump Stations and El Paso Terminal

The purpose of pump stations along the pipeline is to provide the driving force to maintain liquid product flow at a desired flow rate through the pipeline from the Galena Park Station to the El Paso Terminal. The stations are located along the pipeline at distances that are primarily determined by the pipeline elevation profile, the product characteristics, and the desired product flow rate. The liquid product enters each station at a relatively low pressure, and the pressure is increased through the station pumps.

5.4.1.1 Pump Station Description

There are five newly constructed or refurbished pump stations located along the pipeline route from Houston to El Paso. A new terminal has also been built at El Paso. As an example of a pump station process, a simplified flow diagram of the Cedar Valley Station is provided in Figure 5-12. This particular process design is also used for the Kimble County Station and will be used for the majority of the additional stations that are needed to reach a product flow rate of 225,000 bpd (see also sections 3.1.2.6, 6.3.4, 7.13.1, and 9.1.2.4 of the EA).

In this pump station, the product enters from the upstream side of the station and passes through a strainer to remove any entrained particulate matter. The product then passes successively through the two pumps in series where the pressure is increased to the level needed to maintain the desired flow rate to the next downstream pump station. At some stations, pumps may be operated in parallel configuration. The pressure at the outlet of the second pump is regulated by a pressure control valve to prevent excessively high pressure in the pipeline. The outlet pressure is regulated at or below the MOP. Check valves in each pump bypass line and in the mainline bypass line prevent recirculation or reverse flow of the product back through the pipeline in the event of a pump shutdown or valve closure. These check valves also permit the product to bypass either or both of the pumps.

Other major equipment present at some or all of the pump stations include relief and storage tanks, booster pumps, scraper (pig) launchers and receivers, meter provers, pressure relief tanks, and sump tanks. Tanks are only located at the Satsuma Station, Crane Station, and the El Paso Terminal. Scraper launchers and/or receivers are installed at the Galena Park Station, Satsuma, Crane, and the El Paso Terminal. These launchers and receivers are used for pigging.

All of the pumps are centrifugal models equipped with single mechanical seals. The pumps at the Galena Park Station and Kimble County Station are single stage, but the pumps at the other stations are multi-stage pumps, with the number of stages varying from two (Cedar Valley) to six (Crane). With the exception of one new mainline pump installed at the Crane Station, all the mainline pumps in the new stations are refurbished pumps originally removed from other stations taken out of service or dismantled. Refurbishment can include inspection, trimming the impellers to match performance, trimming the seals as needed to be compatible with all of the pumped products, and repairing any deficiencies.

The pumps are all driven by weather-protected Type II electric motors. The electrical systems and circuits are designed to meet or exceed National Electric Code and Underwriters Laboratory specifications to protect against ignition in hazardous atmospheres.

The suction and discharge pressures of all pumps are projected for the pipeline when transporting fuel oil as the refined product, since the pressures are highest when transporting heavier products such as fuel oil, compared to lighter products like gasoline. In several instances, the pump discharge pressures closely approach or are equal to the MOP. At locations where the pump discharge pressures can exceed the MOP, the discharge pipeline pressures are reduced and controlled by throttling through pressure control valves.

The number of block/control valves and flanges over two inches in diameter and in liquid product service were estimated from the piping and instrumentation diagrams for each pump station or from permit applications for the El Paso Terminal. These estimates are shown in Table 5-19 for all three design flow rates. Check valves are not included in the estimates. Although not explicitly described in the Longhorn Project Description, it is assumed that the additional pump stations needed for the highest-capacity case would all be similar to the Cedar Valley design.

These component counts are used to develop estimates of fugitive hydrocarbon losses from the valves, pumps, and, in the aggregate, from pump stations and the El Paso Terminal.

Most of the valves of interest to System integrity are large block or control valves in the size range of 10 to 20 inches. There are also a number of small valves, usually one inch or less in size, associated with instrumentation, and particularly, with thermal safety valves (TSVs). TSVs are installed on any segment of pipe in liquid service that could be blocked in under any circumstance. A blocked-in segment of line could be heated by the sun, ambient air, or other sources. The liquid within the pipe segment could expand and, without the TSVs, could cause the pipe or associated valves to rupture. Pressure due to liquid expansion causes a TSV to open and drain liquid to the sump tank, thus preventing damage and a possible release of product.

5.4.2 Mainline Block Valves

There are both block and check valves located on the Longhorn pipeline. Block valves are located at pump stations and other strategic points along the pipeline. Block valves are placed to minimize draindown during maintenance and to minimize potential spill volumes. Check valves prevent back flow and draindown in the event of an upstream failure or a flow reversal. The characteristics and locations of these valves are described and discussed in this section. Also presented are estimated maximum leak/spill volumes for selected sensitive locations.

The location and types of mainline valves on the existing Longhorn pipeline are listed in Table 5-20. The valves on the section of the pipeline between the Galena Park and Satsuma stations are 20 inches in diameter. The mainline valves located west of Satsuma Station are 18 inches in diameter.

The block valves are reported to be gate valves, and the check valves are reported to be swing type. All valves are constructed of steel and have an ANSI rating of 600 after system modifications are complete. The valves are manufactured by companies such as Daniels, Cooper, WKM, US Steel, and Kerotest. As part of the pipeline refurbishment, all mainline valves were removed from the line, refurbished, and placed back in the pipeline. There are 17 block valves that are remotely controlled from the control center. Closure time for the remotely controlled block valves ranges from 90 seconds to 3.2 minutes depending on supplier and model (Willbros, 1998).

The mainline valves are installed in locations that can isolate the pumping stations, protect certain environmentally sensitive areas, or isolate sections in long segments of the pipeline unbroken by pumping stations. There are remote-controlled valves on the eastern (upstream) side of several environmentally sensitive area crossings. These valves are often paired with a check valve and a manually operated valve on the downstream side of the crossings. In the event of a pipeline leak in the sensitive areas, valves can prevent additional drainage from upstream and downstream sections of the pipeline into the sensitive areas, when such valves are closed in a timely manner.

5.5 SPILL AND EMERGENCY RESPONSE PLANS

This subsection deals with the response of Longhorn, contractors, and public agencies to a pipeline spill: compliance with regulations, adequacy of planning/preparations to protect sensitive areas, response time, and coordination between various response entities. Each of these issues is discussed below.

5.5.1 Compliance with Regulations

Planning and responding to spills from pipeline operations is regulated under several different federal and state programs, including:

- 49 CFR Part 194;
- 49 CFR Part 195;
- Oil Pollution Act of 1990;
- OSHA HAZWOPER; and
- Texas Natural Resource Conservation Commission (TNRCC) Spill Prevention and Control (Chapter 327).

In addition, there are various industry guidelines that suggest the format and content of an appropriate emergency-planning program. The ANSI B31.4 and API Recommended Practice 1129 are examples of such guidelines that were used for comparison to the Longhorn emergency response planning.

Two emergency response-planning documents that apply to the Longhorn pipeline were reviewed:

- Longhorn Pipeline Oil Spill FRP;
  - Volume I Core Plan;
  - Volume II and III Zone and Facility Plans; and
- WES System of Operating Manuals, Volume ERP.

The FRP is specific to the Longhorn pipeline and was developed primarily to comply with the requirements of OPA '90 and 49 CFR Part 194. The plan was originally submitted to DOT on November 2, 1998 for review and approval. The FRP has been updated on March 24, 2000 and has expanded to three volumes.

The FRP is a general document that applies to all facilities operated by Williams Energy Systems. The ERP covers general principles of emergency response, organization, communications, and training issues. The ERP complies with the requirements of OSHA HAZWOPER. The FRP provides information on spill response planning, training, resources and procedures. The plan includes:

- Notification procedures for initiating a response and for regulatory reporting;
- Release detection procedures and release mitigation procedures;
- Description of initial response actions, including immediate response steps, securing the source of the spill, safety and health considerations, storage/disposal of waste materials, endangered species and wildlife rehabilitation, and documentation of the response;

- Description of response teams and their responsibilities (all operations and maintenance personnel have the authority to act as the Incident Commander/ Qualified Individual);
- Communication equipment;
- Personnel and resources available for responding to a spill, including Longhorn and oil spill response contractors (Employees are generally located within a one-hour response time along the pipeline. Longhorn has response agreements with emergency response contractors that have equipment and personnel located in Houston, San Antonio, Austin, Eastland, Midland/Odessa, and El Paso. The contractors are expected to meet or exceed the requirements of 49 CFR Part 194); and
- Containment and diversion booming strategies to protect human life and sensitive resources.

The pipeline is mapped on 1:100,000 US Geological Survey (USGS) topographic maps that indicate any lakes, rivers, and streams within five miles of the pipeline. The topographic maps also indicate the potential down gradient flow direction from the pipeline locations. Environmentally sensitive areas are mapped within a radius of one mile of the pipeline per 49 CFR §194.103. Beyond 49 CFR Part 194 requirements, detailed mapping on USGS 7.5-minute topographic maps is included for at least 15-miles downstream on river crossings and in the Houston and Austin areas. Mapping also includes aerial photos of the Houston and Austin areas.

The spill training program for field employees includes spill response training, incident command training, and OSHA's HAZWOPER training. Tabletop exercises are included as part of the spill training. Longhorn encourages local response agencies to participate in periodic tabletop and spill response exercises.

An Austin Sub-area Plan was prepared to provide more detailed response information beyond the scope of OPA Plan requirements. This plan includes map locations for known caves and detailed response strategies for the creek crossings in the Austin area.

Longhorn will meet yearly with Local Emergency Planning Committees to work towards appropriate emergency response awareness.

Volume I presents emergency planning information that is general in nature and common to all portions of the pipeline. Volumes II and III address specific response zones and sensitive areas within those response zones. The plan specifies two response zones:

- Sugar Land Zone—Covers the pipeline from Harris to Llano counties; and

- Hobbs Zone—Covers the pipeline from Mason to El Paso counties.

Within each of these two response zones, a number of sensitive areas have been identified for a higher degree of specific planning:

- Initial Response Actions (IRAs); and
- Technical Response Plans (TRPs).

The regulations and guidelines listed above were analyzed to extract individual requirements to facilitate a detailed compliance evaluation. The ERP, part of the system of operating manuals, addresses DOT, OSHA, and EPA requirements for emergency operations. The ERP is incorporated as part of the Pipeline Oil Spill FRP. Detailed requirements of emergency response regulations, a cross reference to the portions of the Longhorn FRP and/or ERP that apply to that requirement, and a compliance status comment are summarized in Appendices 5D, 5E, and 5F. Appendix 5G presents a summary of the Longhorn FRP.

The Longhorn FRP and ERP appear to satisfy the requirements for emergency planning and preparedness in the applicable regulations. Table 5-21 summarizes the apparent regulatory compliance status and includes the few compliance issues that were noted in the detailed review.

5.5.2 Sensitive Areas Response

This subsection addresses how the Longhorn FRP has identified and planned response for sensitive areas along the pipeline. As discussed in the previous subsection, Volumes II and III of the FRP include~~s~~ IRAs and TRPs in Section 4 to address specific response issues. The IRAs are multi-page tabular checklists of emergency planning information that include:

- Initial responder actions;
- Area Manager/Qualified Individual actions;
- Estimated response times for Longhorn and contractor personnel;
- Local emergency management agencies;
- Listing of environmentally sensitive areas near the pipeline section;
- Contractor resources that would be used in the response;
- Fire and public safety cautions; and
- Information about threatened and endangered species.

One IRA is typically done for each county that the pipeline crosses.

The TRPs are on a folded 11x17-inch page presented in a color page layout format. The TRPs include:

- Color map showing the route to access the site;
- Tabular driving directions to access the site;
- Text box containing the response strategy;
- Tables estimating the personnel and equipment required to implement the response;
- Photos and/or drawings illustrating the implementation of the strategy (such as where booms or dams would be installed, where the vacuum truck would park and similar considerations); and
- Series of photos assembled into a panoramic view of the site with annotations added for directions of flow of any water bodies.

There are typically several TRPs per county. The TRPs are primarily associated with water crossings and sites down gradient from water crossings where spilled oil can be contained and collected.

Section 4 of the FRP also includes a detailed set of pipeline routing maps that show highways, population centers, schools, hospitals, parks/recreation areas, aquifers, water intakes, and waterways. These maps have been further annotated to show areas of known karst formations (caves) and potential work sites near the pipeline. A complete listing of sensitive areas is provided along with a reference to the map or maps on which they are shown, as well as contact information for the sensitive areas.

5.5.3 Recent Emergency Response Experience

A recent accident on this pipeline offers an opportunity to examine the emergency response procedures employed in an actual incident. An explosion occurred on the Longhorn pipeline near the Wood Bayou subdivision in Harris County at 11:30 AM on October 7, 1998. The pipeline was not in service at the time so the accident was not associated with an operating pipeline. It was being tested using a smart pig that was propelled through the pipeline by diesel fuel. This is a non-standard testing procedure. It is estimated that 1,000 bbl of diesel fuel were released from the pipeline, much of which is thought to have been consumed by fire. One person was injured with first-degree burns.

The Houston Fire Department was first to respond to the site and assumed control of the incident. Exposed power lines hampered early response. Longhorn personnel and their response contractor, Boots and Coots (B&C), were on the scene within two hours. Oil was reported in Hunting Bayou about three hours after the incident, and B&C began deploying containment booms and absorbent pads within 35 minutes of that report. These were critical to preventing more widespread contamination. A limited assessment near the release site was started within five hours of the release. Notifications were made to federal and state agencies, and many of these agencies dispatched inspectors to the site. Plans for containment, recovery, and cleanup were developed and reviewed with agency personnel. These containment and cleanup operations were implemented early on October 8, 1998. An under-flow dam was built in the gully near the spill site. Hard containment booms and absorbent booms were installed in the upper and lower creek areas, in addition to those already in place in Hunting Bayou. Soil, water, and air samples were collected. After all containment was in place and the site was secured, removal of contaminated soil began on October 10, 1998. All site cleanup activities were completed by October 15, 1998.

As a result of the cleanup activities, approximately 173 bbl of an oil/water mixture were recovered from Hunting Bayou, of which about 141 bbl were believed to be diesel fuel (Capitol, 1999). One hundred and thirty-six soil and water samples were collected to establish the degree of contamination and also to confirm that the cleanup had been successful. The results show that the excavation actions and other cleanup activities undertaken by the emergency response coordinator were successful in remediating the contaminated soils and water.

"Soils remaining in-place upon completion of the remediation activity were found to have petroleum concentrations below the (TNRCC established site-specific) cleanup level of 100 mg/kg" (Capitol, 1999).

Approximately 780 cubic yards of soil were removed and sent off-site for disposal. The majority of the contaminated soil (580 cubic yards) was disposed of as Class II non-hazardous waste and the remainder as Class I non-hazardous waste. A 20 cubic yard roll-off box and two 55-gallon drums of contaminated debris were also disposed of as Class I non-hazardous waste by the response coordinator.

A Natural Resource Damage Assessment (NRDA) of preliminary injury was performed by the emergency response coordinator due to the recovery and treatment of a single oiled bird, and the migration of diesel into Hunting Bayou. The NRDA consisted of visual inspection of the pipeline break area and surrounding areas, and inspection and collection of surface water samples from Hunting Bayou. The NRDA report commented that:

"…there were no oiled (or dead) animals, reptiles, amphibians or other forms of life observed…"

and

"...there were no instances of observed stressed vegetation as a result of the spill noted during the preliminary assessment."

The NRDA concluded that:

"Based on visual observations made during the field assessment, and the analytical data derived from the water samples of Hunting Bayou, the creek and gully, there was no evidence exhibited, either visually or analytically, that would indicate an injury to natural resources as result of the Longhorn diesel spill of October 7, 1998." (Capitol, 1999)

It should be noted that the above statements are quotations from reports describing the incident. The Texas Parks and Wildlife Department Houston Field Office inspected the site and confirmed the findings on October 8, 1998. Possible impacts of a spill to surface water quality are discussed in Section 7.6.2 of this document.

It should also be noted that this incident occurred on a section of new pipe that was installed to connect the Galena Park Terminal to the existing Baytown-Satsuma line. This new pipeline was being inspected at the time of the October 1998 explosion. Pipe in the immediate vicinity of the explosion was removed and replaced (approximately 373 ft).

5.6 YEAR 2000 COMPLIANCE

5.6.1 Background and Purpose

This section includes a review of WES efforts to prepare for computer problems that could have been caused by the date rollover from December 1999 to January 2000.

The scope of this task was limited to computer systems that have a direct impact on pipeline operation. This included control systems and "smart" devices on the pipeline itself, the SCADA network between the pipeline and WES' operations center, and the SCADA system computers.

The basic questions that this task addressed were:

- Does WES have a plan and project in place for Y2K readiness?
- Are WES efforts consistent with other industry efforts?
- Is the Y2K project adhering to plan and on schedule?
- Is the plan complete with regard to the Longhorn pipeline?

No issues were identified nor are expected at this point. The project plan required WES to address all elements of the pipeline control and SCADA system, including "smart" instruments, programmable logic controllers, remote terminal units, telecommunications interfaces, and the computers, network, and software in the pipeline control center.

5.7 LEAK HISTORY

This section reviews the leak history of the sections of EPC pipeline. It also compares EPC data to national and other company data.

5.7.1 Background and Purpose

This section analyzes the spill history of the EPC pipeline system assets that now comprise the System. The purpose is to determine the frequency, causes, and consequences of previous leaks and spills, as an indicator of possible future performance.

Several sources of EPC spill data were reviewed for this evaluation. A comprehensive list of EPC accidents was assembled from the various sources and then analyzed. The analysis compares the former EPC pipeline data with those of other comparable companies and with national averages. The data are used as a measure of realistic performance expectations in developing event probabilities for the probabilistic risk assessment in Chapter 6.

5.7.2 Data Sources

The EPC and Longhorn files were reviewed for sources of information on the spill history for the EPC system assets, now owned by Longhorn. The following sources were available:

- Copies of incident report forms were provided by Longhorn for 113 EPC spills. The information was provided in a variety of formats, including: EPC internal company incident forms, DOT reportable incident forms, and RRC H-8 forms. Forty-three of these address spills that were 50 bbl or greater.

- Fluor Daniels Williams Brothers Company (FDWBC) Due Diligence Report, Environmental Site Assessment Phase I cites 170 accidents (144 at pump stations and 26 on the pipeline) from a search of EPC records by Fluor Daniel Williams Brothers Company (FDWBC, 1995). The report includes 57 spills above the DOT reporting threshold of 50 bbl and 115 accidents below the threshold value.
- Kiefner "Audit of Existing Portions of Longhorn Pipeline" (Johnston, 1999) document lists 23 DOT reportable spills of various sizes attributed to Longhorn-owned assets.
- Memorandum by R.L. Deaver, "Longhorn Project – Analysis of DOT Accident Reports on Exxon Pipeline Company" (Deaver, 1998) lists 26 spills obtained from DOT records by a Freedom of Information Act request. Deaver's analysis compared the DOT reportable records to the 53 spills in the FDWBC report. Deaver did not address a few spills in the Satsuma-to-Moore Road segment of the EPC pipeline, which were in the FDWBC report.

The first source listed above contained copies of the original documents, some of which included the stamp indicating transmission to DOT as an accident report. The last two sources only summarized the accident reports cited in source numbers 1 and 2. The original forms, with more detailed information on each accident, were not included in the latter sources.

Data were obtained on other liquid pipeline company spills for comparative purposes. Sources for this information included:

- The DOT/OPS web site, ops.dot.gov, which presents summary spill statistics for hazardous liquid pipeline operators;
- A data analysis of average national hazardous liquid pipeline and specific company corporate performance from spill data in the national DOT database (Allegro, 1999); and
- The RRC Oil and Gas Division, Crude Oil, Gas Well Liquids or Associated Loss Report, Form H-8 data (report on spills of 5 bbls or more) on all EPC pipeline and all Company A[2] pipeline assets in the counties through which the Longhorn pipeline runs. The Company A crude oil pipeline runs along a similar route and was constructed around the same period as the EPC system. It could provide another comparative point for the EPC pipeline leak history. This data source was of limited use since the RRC database contains a summary spreadsheet, but not all of the copies of the original H-8 forms. These data were not used in the analysis since the spills attributable to the pipeline and pump stations could not be readily separated from those of other EPC and Company A assets.

[2] In the interest of focusing on Longhorn, other companies are referred to generically as Company A, Company B, etc.

5.7.3 Spills Database

A database was assembled from the sources listed in the previous section that contained the most comprehensive list possible for EPC spills. A database was assembled starting with the copies of the incident report forms, supplemented by other data on spills which had no accompanying report form, but were listed and referenced in the sources discussed in Section 5.7.2. The resulting database contains 173 spills, 58 of which are over the DOT reportable threshold of 50 bbl. DOT regulations define reportable events as spills or leaks of 50 bbl or greater, events where an injury or death occurred, where financial damage exceeded a DOT-specified threshold, or where a fire or explosion occurred (49 CFR §195.50). In comparison, the RRC requires all oil producers in the state to report crude oil spills of 5 bbl or larger.

Table 5-22 shows the sources of data and the size of spills within each data set. The cumulative database was audited for consistency to ensure that no incident reports were ignored. Dates and volumes were reviewed from the various data sets to ensure that spills were neither double counted nor overlooked. The FDWBC was the most comprehensive, containing 170 of the 173 known spills.

The cumulative database contained 58 spills of 50 or greater bbl. Fifty-six of these fifty-eight spills were in FDWBC data tables. Forty-three of these 58 spills also had EPC report forms provided by Longhorn. One additional incident report was provided by Deaver (Deaver, 1998).

5.7.4 Spill Frequency and Volumes

The spill data were analyzed in two sets, one for the subset of larger accidents of 50 bbl or greater and one for all spills. These data were used as the basis for probability determinations in the probabilistic risk assessment of Chapter 6.

5.7.4.1 Analysis of All Accidents

The database of 173 accidents included some small spills (less than 50 bbl) as well as those of 50 bbl and greater. The spill frequency for "all EPC accidents" was 1.33×10^{-2} spills/mile/year (173 spills/450 miles/29 years). The EPC spill rate excluding pump station spills was 1.99×10^{-3} spills/mile/year (26 spills/450 miles/29 years).

Small spills only contributed a negligible amount to the overall spill volume. The total volume released for the subset of spills that were less than 50 bbl was only 1,426 bbl, while the total volume released for all spills was 87,498 bbl (86,072 + 1,426). The average volume released per spill for the 115 accidents not included in the “Spills of 50 bbl or greater” database was 12.4 bbl/spill (1,426 bbl/115 spills).

Table 5-23 shows the distribution of spill volume and number of spills split between pipe and pump stations for all sizes of spills. The table also shows spill frequencies for various size ranges. The majority (85 percent) of spills on the EPC system occurred at pump stations.

5.7.4.2 Analysis of Spills of 50 bbl or Greater

Table 5-24 lists the events with spill volumes of 50 bbl or greater for the EPC system. Figure 5-13 shows the spill count data in a timeline, while Figure 5-14 shows the volume data in a timeline. This spill data is not strictly a summary of “DOT reportable” spills, because DOT reportable spills can contain volumes less than 50 bbl if there is an injury, death, or financial damage exceeding the DOT threshold quantity. There are no known EPC spills with associated deaths or injuries. Property damage for EPC spills of less than 50 bbls were estimated to be below the DOT threshold quantity. Thus, the EPC spill database is an estimate of the reportable spills on the EPC system and only reflects spills of 50 bbls or more.

The EPC system had 58 spills that were 50 bbl or greater in volume over a 29-year period. This results in an average of 2 spills of this size per year. Even though DOT reportable criteria were not in existence for the whole life of the EPC system, it is estimated that the EPC 'reportable-equivalent' spill rate is 4.4×10^{-3} spills/mile/year (58 spills/450 miles/29 years). The total volume of crude oil spilled (at 50 bbl or more) was 86,072 bbl, an average of 2,968 bbl per year. Of the 58 spills of 50 bbl or greater, 48 (83 percent) occurred at pump stations. The pump station spills accounted for 51,003 bbl, or 59 percent (51,003/86,072) of the total spilled volume. Only 10 of the 58 spills of 50 bbl or greater were on the mainline (about 17 percent). These spills accounted for 41 percent (35,069/86,072) of the total spilled volume. Thus, on average, the EPC system had 1.7 (48 spills/29 years) reportable spills per year at pump stations and 0.35 (10 spills/29 years) reportable spills per year on the mainline.

When both pump stations and mainline are included, the leak history shows that among the 58 reported spills of 50 bbl or greater, the average size was 1,484 bbl. EPC experienced four spills greater than 5,000 bbl (25,224 bbl - 1979 - pipe; 10,500 bbl - 1977 - pump; 8,550 bbl - 1969 - pump; 5,550 bbl - 1968 - pump). These large spills accounted for 58 percent of the total volume lost in a 29-year period. The average spill size for spills greater than 5,000 bbl was 12,456 bbl.

The main pipeline had a >50 bbl spill frequency rate of 7.66×10^{-4} spills/year/mile (10 spills/29 years/450 miles). Figure 5-15 shows the mainline spills count data in a timeline, while Figure 5-16 shows the mainline volume data in a timeline. The average volume lost from mainline spills was 2.7 bbl/year/mile (35,069 bbl/29 years/450 miles) for the 29-year history. The average volume lost per spill on the mainline was 3,507 bbl/spill (35,069 bbl/10 spills). The average volumes for mainline spills are greatly influenced by the one large spill in 1979.

The pump stations have a rate of 0.21 spills/year/ station (48 spills/29 years/8 EPC stations). Figure 5-17 shows the pump station spill count data in a timeline, while Figure 5-18 shows the pump station volume data in a timeline. The average spill volume for pump stations was 220 bbl/year/station (51,003 bbl/29 years/8 stations) for the 29 years of record keeping history. The average volume per station-year is greatly influenced by three events: 5,550 bbl 1968 spill, 8,550 bbl 1969 spill, and 10,500 bbl 1977 spill.

5.7.5 Leak and Spill Causes

This section analyzes the causes of the spills of 50 bbl or greater. As noted above, the primary locations of EPC spills were pump stations. A distinction is made between the pipeline and pump stations because of important differences in factors that cause releases and in the consequences of releases. While pipe failures are more likely to be associated with pipe corrosion or outside forces, leaks or spills at pump stations can be the result of a variety of other unique causes. These causes include rotating equipment mechanical failures (e.g., pump seal failures), tank corrosion, or operating errors (e.g., not taking action to stop a relief tank overflow caused by equipment malfunction). Figure 5-19 shows the causes for the 48 pump station spills greater than 50 bbl in size. The leading cause was corrosion, followed by equipment failure, and repair and installation activities. For mainline pipe, Figure 5-20 shows the causes for the 10 spills greater than 50 bbl in size. The leading cause was outside force (third-party damage), which accounted for 70 percent of these events. Corrosion, incorrect operation, and unknown causes accounted for the remaining 30 percent.

Summary profiles of all the reported leaks at pump stations on the EPC pipeline are also presented in Tables 5-25 and 5-26. The leak records cover a period of approximately 29 years from November 17, 1966 through May 13, 1995.

The size of the reportable leaks and spills ranged from 50 bbl to 25,224 bbl. The causes of the three largest leaks are shown in the table footnotes. As might be expected, the smaller leaks and spills of 50 bbl and greater (41 leaks between 50 and 999 bbl) make up the bulk, nearly

70 percent, of the number of reported leaks. However, these small leaks account for less than eleven percent of the total volume of material spilled. The 17 large leaks between 1,000 bbl and 25,224 bbl account for most of the total volume released (76,460 bbl or 89 percent) over the reporting period. The three largest releases are responsible for nearly half of the total volume released over the 29-year reporting period.

Of the reportable leaks, nearly 16 percent did not list a specific cause for the release. Most of the releases with known causes were due to corrosion, equipment failures, repair/installation, or third-party damage. Of the equipment failures at stations, six were due to pump seal failures. The largest release due to a pump seal failure was 150 bbl. There were also nine failures associated with station valves, four of which were due to valve flange gasket failures, with the remaining five caused by failures of the valves themselves. Eleven releases occurred during equipment replacement or repair, but after 1971, no releases due to this type of incident were reported.

The Kemper Station along the EPC pipeline had 18 tanks. Eleven of the leaks with identified causes attributed to pump stations were due to tank losses at the Kemper Station. There will be three locations on the Longhorn pipeline that will have product tanks: the Satsuma Station (1 relief tank), the Crane Station (4 tanks), and the El Paso Terminal (19 tanks).

The causes and frequency of leaks and spills at pump stations are used to develop pump station leak probabilities that were used in the risk assessment of Chapter 6.

5.7.6 Trends

The trend in incident frequency over time was examined for the “spills of 50 bbl or greater” database. The number of spills has been variable over the years of EPC pipeline operation, as shown in Figure 5-13. While the average is 2 spills per year greater than 50 bbl over the 29-year period, there were 8 years with no spills greater than 50 bbl and 3 years with 5 or more spills greater than 50 bbl.

The annual spill rate shows a downward trend over the 29-year period of operation, as shown by Figure 5-21. This figure shows five-year averages of pipeline spill counts. With the exception of 1966 through 1970, there has been a continuous decline in the spill frequency. Such a trend indicates a learning curve, where performance improves as causes are identified and corrected, and the operator learns to improve performance.

The EPC spill history was also examined to determine if the frequency of accidents varied geographically, a possible indication of a "geographic factor." All EPC accidents of 50 bbl or greater have occurred within nine of the 17 counties crossed by the pipeline. Thus, eight of the counties have never experienced a spill of 50 bbl or greater of crude oil. In fact, most EPC reportable spills have occurred within Crane, Reagan, and Harris counties, as shown in Table 5-27 and on Figure 5-22. Crane and Reagan counties account for 60 percent of these spills.

Many of the EPC spills occurred at pump stations. Longhorn has revised pump station locations from the previous EPC operation. When the pump station data are excluded, Kimble (2 spills), Travis (3 spills), and Harris (2 spills) counties have the most spills, as shown on Figure 5-23. When the resulting pipe-only spill count is normalized by pipe length per county, Travis County stands out as having a higher spill rate than the other counties, as shown on Figure 5-24. The high mainline spill rate in Travis County is due exclusively to third-party damage.

A frequency-of-leak comparison between urban and rural areas has been calculated for the EPC pipeline as is shown in Appendix E of the RS. These calculations suggest that there is no significant statistical difference between expected leak rates in urban and rural areas. Urban area leak rates were statistically indistinguishable from rural areas, at a 90 percent confidence level, for this pipeline while it was under EPC operational control. However, differences between urban and rural leak rates would not be unexpected based on probable increased third-party activity levels and certain corrosion control complications found in urban settings.

5.7.7 Comparisons with Other Pipeline Spill Data

Some limited industry-wide pipeline failure rate information is available. Failure investigators cite difficulties in obtaining failure data for specific types of pipelines. For example, separating pipelines of specific diameters, age, type of product, etc., from overall incident statistics is problematic. This is due to incomplete database information. It would be especially difficult to find accurate failure rate information for other pipelines substantially similar to this one, including the change-in-product aspect. DOT has made changes in its reporting protocols, and consequently, better information should be available in the future.

Spill rates for the EPC system were compared with national average data and with WES and "Company A" data to answer the following questions (Table 5-28):

- Were previous operations better or worse than national averages?
- How does the WES performance compare with EPC performance as a factor in suggesting how future operations might compare with past operations?

- Was there any difference between Exxon corporate performance (including all Exxon liquid pipeline assets) and that of other corporate operators?

A comparison of EPC to national data and to the Kiefner data is shown in Table 5-29. It should be noted that EPC and national data being compared are based on reportable spills, (the EPC data are estimated to be all spills 50 bbls or more on the EPC system) while the Kiefner data are based on selected spills of any size throughout the pipeline operation period. Since the basis for the Kiefner, EPC, and National data are different, a comparison might be expected to show some differences. Table 5-29 shows that 5 percent of all spills nationwide (from 1993 to 1998) were attributed to seam failures. Kiefner data suggests that nearly 35 percent (8 seam leaks/23 total leaks) of the EPC leaks were a result of seam failures. The EPC data suggests the occurrence of seam failures on the System was much lower (1.7 percent or 1 seam failure leak/58 total leaks). Thus, the EPC seam failure data more closely resemble the national data. The large seam failure rate from the Kiefner analysis is the result of a number of very small spill volume accidents; only two of the eight accidents analyzed by Kiefner was greater than 50 bbl. The direct cause of one of the accidents over 50 bbl (25,224 bbl - Kimble County) was incorrect operation. The incorrect operation propagated the seam failure; thus the EPC database assigned the leak cause to incorrect operation rather than seam failure.

5.7.7.1 National Data

Crude oil and refined products data from 1975 through 1999 available on the DOT web site was the basis for the national data analysis. From 1975 to 1999, 3,479 crude oil and refined products spills have occurred within the US. Of the 3,479 spills, 2,080 are crude oil spills and 1,399 are refined products spills.

The *Oil & Gas Journal* reported that for 1998, the total miles of pipe carrying crude oil and refined products was 157,234; of this mileage, 74,603 miles of pipe carried crude oil and 82,631 carried refined products. These 1998 pipe mileages were assumed to be constant for the entire data period (1975 - 1999). Based on the mileage assumption, analysis of the spill data yielded an average spill rate of 8.9×10^{-4} spills/mile/year for all crude and refined products[3] spills, 1.1×10^{-3} spills/mile/year for crude oil (only) and 6.8×10^{-4} spills/mile/year for refined products (only). The EPC spill rate (crude only) for the same period was 2.7×10^{-3} (30 spills/450 miles/25 years? spills/year/mile. Thus, the EPC system had a crude spill rate higher than the national average (1.1×10^{-3} national versus 2.7×10^{-3} EPC). Both the DOT and the EPC data

[3] Refined products are diesel, gasoline, fuel oil, oil gasoline mix, jet fuel, kerosene, #2 oil, turbine oil.

included spills from the pipe and the pump stations. Table 5-30 compares national crude and refined products pipeline statistics to EPC statistics.

The 3,479 crude oil and refined products spills from the DOT data have resulted in 126 injuries and 17 fatalities. Thus, the injury rate and fatality rate for crude and refined products spills are 3.6×10^{-2} (injury/spill) and 4.9×10^{-3} (fatality/spill), respectively. The 1,399 refined products spills have caused 68 percent of all injuries (or 85 of the 126 injuries) and 71 percent of all fatalities (or 12 of the 17 fatalities). No deaths or injuries have been reported on the EPC pipeline.

In addition to DOT crude and refined products data, hazardous liquids spill data (including crude and refined products) from the DOT database were analyzed for this report (Allegro, 1999). Using this DOT data analysis, trends in national data were developed for comparison to EPC operation. Figure 5-25 shows that the volumes of interstate hazardous liquid spills have generally decreased, while the number of spills has remained relatively constant since the 1980s. Thus, the national data suggests that the severity of accidents is decreasing. The EPC data showed this same general trend.

National pipeline data, as shown in Figure 5-26, indicates that, while most of the volume comes from mainline pipe spills, a significant portion comes from pump station spills. This is similar to EPC's experience.

DOT data provide spill counts for total hazardous liquid pipeline mileage. For an analysis of crude pipeline performance, the mileage of crude pipelines must be gathered from another source. The total mileage of crude oil pipeline in the US was obtained from Pennwell Maps, Inc., Houston, Texas, which reported 114,932 miles of interstate crude oil pipelines in the US. If this is used in conjunction with the volume of crude spilled as determined from DOT data (61,299 bbl per year average spilled for 1993 through 1998), the national average unrecovered spill frequency for crude pipelines is 0.53 bbl per/mile/year. The EPC initial spill volume of 5.0 bbl/mile/year is higher than the national average, influenced by a few large spills for the EPC system. However, the 94 percent recovery exceeds the average recovery rate for all hazardous liquid spills as was seen in comparing the overall national average spill volume of 0.754 bbl/mile/year with the EPC volume of 0.30 bbl/year/mile over a comparable period.

5.7.7.2 Other US Pipeline Company Data

This section compares national spill frequency of EPC with WES and other liquid pipeline operators. See also Appendix 9C for more comparative analyses. Exxon (the previous operator of the EPC system) and WES (operating contractor of the Longhorn pipeline) are compared to the national averages for hazardous liquids pipelines as well as to Company A's performance. Company A operates a neighboring pipeline that parallels the EPC/Longhorn pipeline at some places within a common route. (The company is unnamed since they are not a party to this EA process.) It is important to note that the Exxon assets discussed in this paragraph are all interstate hazardous liquids pipelines operated by Exxon, not just the former crude oil line now owned by Longhorn.

The results of this comparison are shown in Table 5-28. Based on the overall corporate record, Exxon's spill rate and volume of spills is less than the national average. WES also has a spill frequency less than the national average. WES had a spill volume greater than the national average, which was apparently caused by a single large station or terminal spill in 1997.

5.7.7.3 Future Trends

Chapter 6 uses the spill frequency data and volume per spill data from this section to estimate probabilities of leaks and spills. However, it should be noted that future spill performance may differ from historical values for the following reasons:

- Improvements that have already occurred recently in the life of the EPC pipeline (industry standards implemented by Exxon over the life of the pipeline such as SCADA systems, or recent improvements such as ILI, and lowering crossings);
- Difference in future product;
- Differences in future operation (changes in pressures, flows, and improvements in operation due to WES and Longhorn practices, and improvements due to future inline inspection and repair);
- Aging of the pipeline (continuing corrosion and fatigue issues); and
- Changes in pump station configurations (improvements in station layout may mean improvements in spill performance) and changes in pump station locations (addition of stations in the future mean more risk from station spill causes).
- Proposed mitigation (see Chapter 9).

Some of these listed reasons may increase and some may decrease the likelihood of spills.

Reduced operating pressures and reduced activities at pump stations might reduce spill frequency. This could be a factor in the observed decline in leak rates under EPC operations in more recent years, but there are many other possible reasons for changes in leak rate. Condition changes such as increasing population might increase spill frequency in the same period. The relative risk model (see Chapter 6) considers changing conditions such as these to assess failure probabilities.

Previous spill data on this System is used with other data to estimate a distribution of potential spill sizes. The distribution of spill sizes depends on the causes of the leaks or spills, where they occur, and the pressure in the pipeline at that point. Higher flow rates in the proposed operation do not necessarily translate into higher spill volumes because of variables such as: (1) different operating pressure profiles along the pipeline; (2) different valve locations and types; (3) potential differences in leak cause distributions and hence, hole size; and 4) differences in leak detection and shut-down practices. Given the wide range of possibilities of locations and sizes of failures, any distribution estimate will have a degree of uncertainty.

5.8 SUMMARY OF FINDINGS

This summary presents highlights of major findings derived from the preceding sections of this chapter. The relationship between these findings, as presented here, and the physical integrity of the pipeline system is qualitative. These findings are based on a combination of technical facts and engineering judgement. The details that support them, in this chapter, are translated into quantitative estimates of system integrity in the relative and probabilistic risk assessments of Chapter 6.

Overall, the EPC pipeline has experienced a greater than average rate of accidents (leaks and spills) as compared to national average crude oil data. It also shows a decline in spill rate in the years preceding the operational shutdown in 1995. The attributes of the System and its route are directly related to potential threats to System integrity. Mitigation measures, as discussed in Chapter 9, are further opportunities to reduce risks for future operation of the System.

5.8.1 General Attributes

1. The pipeline system has a significant amount of pipe dating from about 1950. This pipe has low-frequency ERW seam welds, generally considered less reliable than fabrication welds produced after 1970.

2. The operating pressure profile for this line is within limits consistent with the specified yield stress associated with the pipe strengths. It is also consistent with the specifications for valves, fittings, and pumps.

3. The EPC pipeline compliance history reveals two instances of areas of concern in the DOT records.

4. Leak detection capabilities from the control center are consistent with industry practices. Longhorn reports planned upgrades to these capabilities.

5. There are locations of inadequate ROW clearing that reduced air patrol effectiveness.

6. Preliminary data reviewed indicates some possible areas of landslide, seismic and active faulting susceptibility along the pipeline route.

7. The pipeline was built according to construction specifications that appear to be consistent with best practices for the time.

5.8.2 Operating Procedures

1. Longhorn is generally adopting the WES System Operating Manuals for their pipeline. Revisions to these manuals to address Longhorn-specific activities are planned.

2. Longhorn has introduced a number of new procedures in the 1998 through 1999 period. These include the LPSIP and other activities (Longhorn, 1999).

3. Current operations and maintenance activities appear to be, for the most part, consistent with industry-accepted sound practices.

4. Operating procedures include some practices beyond minimum regulatory requirements that are not documented in manuals. This is consistent with practice throughout the pipeline industry.

5. Review of the WES System Operating Manuals against 49 CFR Part 195, ASME B31.4, and API Recommended Practice 1129 indicates that the procedures generally meet the requirements, although there were a number of items in these standards not specifically covered by the procedures.

5.8.3 Inspection and Testing

1. Based on reviews of materials of construction, inspection results, maintenance reports, and past leak history, the most likely potential problem areas in the older portions of the subject pipeline are thought to be:

    - Seam weaknesses and susceptibilities associated with low-frequency ERW pipe;
    - Corrosion metal loss; and
    - Possible undetected external force damages such as dents and gouges.

2. Hydrostatic testing and ILI in 1995, followed by digs and visual inspections, revealed areas on the pipeline that required or will require repair or replacement.

5.8.4 Depth of Cover and Exposed Pipe

1. Depth of cover for the buried pipe is highly variable, reflecting, in part, original installation practices and changes over time.

2. Some sections of pipe are intentionally exposed.

3. Longhorn has identified and is evaluating shallow and exposed pipe areas.

4. There are locations of possible minor vandalism.

5.8.5 Effects of Age

1. The only identified age-related deterioration mechanisms are fatigue and corrosion.

2. Previous integrity verifications provided a measure of confidence that deterioration mechanisms had not compromised pipeline integrity as of the test dates.

3. No significant causes of fatigue have been present since 1995, so crack-flaw growth from mechanical causes should not have occurred since the 1995 tests.

5.8.6 Corrosion Control

1. Corrosion control effectiveness for the EPC pipeline may have had gaps, as evidenced by CP records and ILI inspection results.

2. CIS inspections and annual surveys (1990, 1994, 1998, 1999) provide some indications of CP effectiveness.

3. Past EPC corrosion control practices are questionable based on requirements of relatively high levels of CP voltage and current, indicating relatively low coating effectiveness in some areas.

4. CP surveys revealed areas of low potentials and some possibly shorted casings.

5. Protection from atmospheric corrosion appears inadequate at some locations.

6. Current practices appear to have improved compared with previous practices.

5.8.7 Leak History

1. The EPC system, prior to shutdown in 1995, had 58 DOT reportable spills. Of these, 10 occurred on the pipeline and 48 occurred in the pump stations or terminal. The spill rate is greater than the national average for crude oil (1.1×10^{-3} national versus 2.7×10^{-3} EPC).

2. The primary cause of pipeline spills of 50 bbl or greater in size has been outside force (70 percent of spills of 50 bbl or greater). Corrosion, incorrect operation, and unknown causes accounted for the remaining 30 percent.

3. Seam splits, such as those associated with ERW pipe, have led to one spill of 50 bbl or greater on the EPC pipeline and may have been a contributing factor in an additional 6 smaller spills.

4. Spill frequency declined over 29 years of operation, as shown with five-year averages of accidents (Figure 5-21).

5.8.8 Pump Stations and Valves

1. Pump stations are typical in layout and design to others in the industry.

2. Pumps and valves have been refurbished for use in the upgraded or new pump stations.

5.8.9 Spill Response

1. The Longhorn pipeline is in compliance with federal and Texas emergency response regulations.

2. The Longhorn Facility Response Plan exceeds the regulatory requirements in a number of areas, including the level of detail in the Work Site Response Plans.

3. The emergency response planning is consistent with that for the pipeline industry in general and exceeds that level in some areas.

4. The designation of two response zones (Hobbs and Sugar Land) and the locations of two response subcontractors, based in Houston and other more distant areas, allows response time in the middle sections of the pipeline that is consistent with the industry.

5. Local fire departments outside of these areas are mostly volunteer departments and might lack the equipment and training to fight a HAZMAT fire.

6. There are sensitive environmental areas and special land use areas that do not have detailed response plans in the FRP.

7. Estimated maximum or worst-case spill volumes were calculated at several selected locations. Most of these volumes fell within a range of about 3,000 to 6,000 bbl. However, a maximum release volume of 36,000 bbl was estimated at one location over the Cenozoic Pecos Aquifer.

5.8.10 Year 2000

1. No major Y2K risk issues were identified.

2. The pipeline operator has a Y2K plan and project in place.

3. The plan is complete and consistent with efforts in other industries and with industry efforts as surveyed by the API.

4. The Y2K project was completed on schedule.

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