TABLE OF CONTENTS

LIST OF TABLES

APPENDICES
(See Volume 2)

6.0 OVERALL PIPELINE RISK ASSESSMENT

6.1 BACKGROUND AND PURPOSE

The Settlement Agreement (Settlement) calls for an overall risk assessment of the Longhorn Pipeline System (System) owned by Longhorn Partners Pipeline, L.P. (Longhorn) and operated by Williams Energy Services (WES). A risk assessment for the pipeline's condition, surroundings, and operation was performed as of summer 1999. This risk assessment is termed the "pre-mitigation" assessment and was conducted in two parts. The first part is a relative risk assessment using a scoring technique that compares the probability of failure for different segments of the overall pipeline and then uses these scores in the context of an impacts assessment described in Chapter 7. This allows the setting of priorities for mitigation of spills. The second part is a probabilistic risk assessment that allows the comparison of the risk at specific locations with other societal risks. This provides a comparative context for making risk-based decisions on the pipeline's operation. An additional relative risk assessment was performed on the pipeline's condition, surroundings, and planned operation after all Longhorn Mitigation Plan (LMP) actions are completed (see Chapter 9). This is termed the "post-mitigation" assessment and is described in Chapter 9. This chapter discusses only the pre-mitigation risk assessments.

The Settlement requires:

- *"An overall risk assessment of the Longhorn pipeline project consistent with recognized professional risk assessment standards;*
- *Discounting the magnitude of potential adverse consequences by probability of their occurrence and considering mitigation measures (both preventive and responsive) that Longhorn has implemented or has agreed to implement; and*
- *Consideration of:*
    1. *Characteristics of products to be transported in the pipeline, including physical and chemical properties, and toxicity;*
    2. *Potential hazards (e.g., fire, explosion, and toxicity);*
    3. *Most vulnerable points (e.g., stream crossings, pump stations, valves, construction areas);*
    4. *Magnitude of hazards based on volume of product in the uncontrolled pipeline segment, pressure in the segment, time typically required to shut down pipeline and range of ambient temperatures;*
    5. *Speed and extent of plume spread, considering further: (i) products the pipeline will carry; (ii) spill to the Colorado River or tributary at low*

flow, average flow, and flood conditions; (iii) spill onto the ground with wet or dry antecedent soil conditions; high and low water table conditions; and (iv) differing wind, temperature, and other climactic variations;

6. *Emergency response plans and procedures, including procedures for communicating releases or other hazardous conditions and for deploying personnel and equipment;*

7. *Availability of qualified emergency preparedness agencies and services provided by Longhorn, including trained personnel, containment equipment, personal protection equipment, and communications capabilities; and*

8. *Health, safety, and environmental consequences of the pipeline location in densely populated areas."*

6.2 PIPELINE HAZARDS

As required in the Settlement, transport hazards of crude oil and refined petroleum products were examined. These hazards were identified and used as input data for the risk assessments in this chapter and the impact analyses in Chapter 7, where crude oil and refined product impacts are compared.

The primary hazards of transporting petroleum products and crude oil arise from flammability and toxicity in the event of leaks and spills. Flammability contributes primarily to safety concerns and toxicity to environmental concerns; however, a fire can also, for example, endanger threatened species or damage archaeological and historic sites.

6.2.1 Product Properties, Leaks, and Spills

Crude oil and refined products are mixtures of many organic compounds. They are complex materials, but are not usually subjected to detailed chemical analyses during refining processes or when used in common commercial applications. These products are usually characterized by a set of key physical properties. The composition of the transported product affects flammability and toxicity as well as flow, dispersion, and persistence properties in the environment. In comparing the risks of the transporting refined products and crude oil, the relative properties of crude oil and refined products are a significant factor.

As a result of the diverse crude oil refining processes, such as distillation, reforming, and cracking, new organic compounds are created. Therefore, the distribution of compounds in crude oil is markedly different in the refined products. For example, olefins (alkenes) do not naturally occur in crude oil, but are produced through cracking into gasoline. The aromatic and branched alkane fractions also increase during the refining process. From a hazard standpoint, the following general statements can be made:

- Gasoline has a higher vapor pressure (i.e., is more volatile) than the medium and heavy crude oils historically carried by the Exxon Pipeline Company (EPC) pipeline.
- Gasoline typically contains approximately ten times more benzene than crude oil; gasoline may also contain an additive such as methyl tertiary-butyl ether (MTBE), which is not found in crude oil.

Some additional data on the composition of crude oil and gasoline are presented in Appendix 6A.

6.2.2 Spill Volumes

Potential spill quantities of refined products were estimated at several sensitive locations along the pipeline. The size of a leak is dependent upon the size of the opening in the pipe, the product density, the pipeline pressure, topography, and duration. The estimated release volumes shown in Table 6-1 consist of (a) the volume released during the time it takes to detect the leak and shut down the pipeline, plus (b) the maximum volume that can drain from the pipeline segments upstream and downstream of the leak site.

6.2.2.1 Hole Size

In assessing potential hole sizes, the failure mechanism and pipe material properties must be considered. A failure mechanism such as corrosion is characterized by a slow removal of metal and hence is generally prone to produce pinhole-type leaks rather than large openings. Outside forces, especially when cracking of the metal is precipitated, can cause much larger openings. The size of the opening is a function of many factors including stress levels and material properties such as ductility. Since there are so many permutations of factors possible, hole sizes can be highly variable. However, the opening size is at least partly dependent upon the initiating failure mechanism. The Environmental Assessment (EA) does not attempt to make correlations between failure mechanisms and leak sizes. Conservative (i.e., reasonable worst case) leak size assumptions, regardless of mechanism, are used by assuming complete pipeline rupture where the hole size is effectively the pipe diameter.

6.2.2.2 Reaction Times

With the existing Supervisory Control and Data Acquisition systems, Longhorn can identify large leaks and shut down the pipeline within five minutes. The pumps will stop automatically or can be shut down immediately from the control center when a leak is identified, and remote-controlled valves along the pipeline can be fully closed within one to three minutes. Leak detection capabilities are discussed in more detail in Appendix 6B. The state-of-the-art transient flow model system to be installed prior to startup will be capable of detecting leaks in the range of 100 to 130 barrels per hour (bph) within one minute. A certain amount of "reaction inefficiencies" is also embedded in the five-minute estimate since full pipeline ruptures can be detected and responded to in less than one minute. To ensure that a reasonable worst-case leak size is calculated, the leak rate was assumed to be equal to the maximum pumping rate through the pipeline during the five-minute shutdown time. For calculations, product release rate is assumed to be the full pumping rate of approximately 160 barrels per minute (at 225,000 barrels per day [bpd]).

6.2.2.3 Valves

The primary types of mainline valves in service on the Longhorn pipeline are swing-type check valves, remote controlled gate valves, and manually operated gate valves. Data from the literature indicate that the reliability of check valves and motor-operated gate valves is high (see Appendix 6C).

Manual block valves are generally placed in areas that are reasonably accessible. Longhorn has committed to responding to any spill in Tier 2 areas within 2 hours and to a spill in Tier 3 areas within 1 to 2 hours (see Chapters 7 and 9 for discussion of tiers and mitigations). Scenarios can be envisioned where a response time is more than 2 hours or much less than 2 hours. Given the commitments and upon examination of a variety of scenarios, it was determined that 2 hours was a reasonable average time estimate for a technician to reach and close a manual block valve.

The locations of most of the existing mainline valves along the Longhorn pipeline were selected with the objective of either protecting specific environmental areas (e.g., major streams, Edwards Aquifer) or isolating pump stations. They can also, depending on the location along the pipeline, provide some reduction in the maximum volume of product that can drain and be released from potential leak sites along the pipeline.

The maximum drainage volume released at any location between two mainline valves on the pipeline was estimated. In this estimate, it is assumed that both of the two valves at either end of the pipeline segment under consideration are closed within a time period consistent with their mode of operation (remote versus manual). Under this assumption, additional drainage from further upstream or downstream of the segment is prevented once the valves are closed.

6.2.2.4 Drain Volumes

The maximum potential loss resulting from drainage at any point along the pipeline was estimated using an algorithm developed for this purpose. The algorithm was created under the assumption that product drainage results only from gravitational effects, i.e., when there is no siphoning. The detailed description of the algorithm is provided in Appendix 6D. Pipeline elevation data were obtained from a Longhorn database. The database contains over 8,000 points with elevations at selected locations along the pipeline. Using the algorithm, total drainage potentials between mainline valves, expressed as linear feet of pipe, were determined at each 100-foot (ft) interval along the pipeline. The drained length is converted to drained volume by multiplying the length by the volume of a one-ft length of pipe.

The pipeline segments subject to draining are bounded by the upstream and downstream valves nearest to the spill location, provided these valves were either automatic, remote control, or check valves. If they were manually operated, it was assumed that they could be closed within two hours of the leak determination. During these two hours, liquids were assumed to be moving through the manually operated valve(s). Using common fluid flow equations, these volumes were estimated by calculating the velocity of the draining liquid in the respective pipeline segments. The algorithm used to produce estimates of maximum drain volumes is described in Appendix 6D.

Siphoning was not considered in the estimation of draindown volumes. Given the many rises and falls in elevation along most segments of the pipeline, the probability of significant amounts of siphoning is low. Additionally, developing an estimate of the amount of siphoning that would occur is difficult, and the results of such an estimate would be of questionable accuracy. There is already some conservatism in the estimation of draindown volumes, since it is assumed that all liquid that could potentially drain would be released at the leak location.

The majority of estimated maximum releases at the selected sites listed in Table 6-1 fall within the range of approximately 3,000 to 6,000 barrels (bbl). However, the two estimated release volumes at the Cenozoic Pecos Alluvium locations were substantially larger than the releases estimated at the other sites listed in Table 6-1. This is primarily due to the long distance between block valves in this region, ranging from 35 to 84 miles, allowing potentially greater drainage to occur.

6.2.2.5 Conservatism

Spill volumes calculated as described above are conservative. The maximum release volume estimated under the above assumptions would not always occur. All of the potential discharge might not be completely released before mitigating measures were implemented to stop or reduce the leak. For example, if the leak location can be identified, the downstream pump stations will be kept in service to evacuate product from the pipeline downstream of the leak. The downstream pump stations will be allowed to operate until they are automatically shut down due to low flow (Williams, 1999).

6.2.3 Pool Size

In the thermal effects modeling analysis described in Section 6.2.4, the entire volume of the spill was assumed to instantaneously form a maximum-sized liquid pool. Ignition of the pool or vapor cloud is assumed to occur when the pool or vapor cloud is at its maximum dimension. Flash fire and pool fire impact estimates are maximized via this assumption. In reality, the release would progress such that the pool and vapor cloud would grow over time with potential limitations in pool growth from evaporation, absorption into the spill surface, or early ignition. None of these limiting mechanisms were considered in the analysis. The same assumptions were applied throughout for both crude oil and gasoline to ensure that each fluid was analyzed on a common basis.

Pool growth was simulated using a calculation method specified by US Environmental Protection Agency (EPA), Federal Emergency Management Agency, and US Department of Transportation (DOT) (EPA, 1989). This correlation relates the release size to the pool area for a generic liquid spill as follows:

$$\text{Log}(A) = 0.492 \log(M) + 1.617$$

Where:

M = total liquid mass spilled, lbs
A = pool area, ft^2

The spill area calculated, using this technique, was compared to a maximum potential pool size based on the topographical features of each specific spill site. This "topographical maximum pool area" was established from US Geological Survey (USGS) data, and appears in Table 6-2 for each spill site. If the actual pool size from the above equation were to exceed the maximum allowed by site topography, the topographical maximum pool area was to be used in the modeling analysis. However, all of the maximum spill (worst-case) pool sizes calculated from the above equation were smaller than the topographical maximum pool area.

If a leak occurs on a pressurized hydrocarbon liquid pipeline, the leaked liquid would initially vaporize or spray as droplets into the air. This would occur whether the liquid was crude oil or a refined product, although many components of crude oil would not vaporize under ambient conditions. The extent to which the liquid would spray depends on the pressure at the point of release, the size of the hole, and the temperature and viscosity of the liquid. A higher internal pressure would transfer more energy to a release, causing a more intense spraying of droplets (atomization) and rapid vaporization. These effects could cause an increase in the local dispersion area and therefore an increase in ignition potential. This assumes that a larger vapor cloud would have a greater flammability zone, and hence, more probability of encountering an ignition source.

6.2.4 Fire and Explosion Hazards

6.2.4.1 Consequence Mechanisms

Several potential acute consequence mechanisms for a flammable liquid release include:

- **Pool fire.** A fire where the fuel is in the form of a liquid pool at the base of the fire;
- **Flash fire (vapor cloud fire).** The combustion of a flammable gas or vapor and air mixture in which the flame propagates through that mixture in a manner such that negligible or no damaging overpressure is generated; and
- **Vapor cloud explosion.** An explosion resulting from the ignition of a cloud of flammable vapor, gas, or mist in which flame speeds accelerate to sufficiently high velocities to produce significant overpressure.

The probability of an explosion from a gasoline pipeline, even in the event of a large leak or spill, is remote. Although a flash fire and subsequent pool fire can result from a large gasoline spill, the probability of a true explosion with overpressures that cause damage and injury by blast effects is remote.

One explosion has been reported among the hundreds of gasoline pipeline spills in the DOT database. Lack of detail prevents a determination of whether it was a true vapor cloud explosion, which is a phenomenon associated with highly volatile fluids, or rather a flash fire incorrectly reported as an explosion. Ignition of gasoline results in a fire but rarely an explosion.

Even ignition is a relatively rare event. Based on a review of experiences with both refined product (including gasoline) and crude oil spills from pipelines, as recorded in the DOT pipeline accident database, approximately 4 to 6 percent of gasoline pipeline accidents are accompanied by fire. Therefore, around 94 to 96 percent of the pipeline spills did not ignite, a necessary step towards any explosion. Decreasing probabilities of fire are logically associated with smaller spill sizes.

In the technical literature, data suggest that large natural gas leaks have approximately a 50 percent chance (0.50 probability) of ignition (EPA, 1989). Recent analysis of gasoline and crude oil spill data suggest a much smaller ignition probability for these materials (ADL, 1996). In that study, gasoline spills overall were found to have a three percent chance of ignition, based on historical data.

For flammable liquid spills, the most common events are flash fires and pool fires; therefore, the EA analysis focused on these. To establish “hazard zones” from the modeling, the following damage thresholds were applied:

- **Flash fire (vapor cloud fire).** The maximum distance of vapor cloud dispersion as defined by the lower flammability limit of the material. For hydrocarbons that will evolve from both gasoline and crude oil, a lower flammability limit value of 1.4 volume percent in air was used (NFPA, 1989).
- **Pool fire.** Two threshold values were used: 1 kilowatt per square meter (kw/m^2) and 4 kw/m^2 radiant heat flux from the burning pool. The 4 kw/m^2 threshold value represents a published lower threshold of pain to humans based on a 45-second exposure (Bryan, 1985). It is assumed that below 1 kw/m^2, no human injuries would be experienced.

A vapor cloud explosion was not modeled in this analysis because it is not considered a plausible event for either gasoline or crude oil spills in an open environment. This is primarily due to the lack of sufficient material in the vapor clouds resulting from slow-evaporating pools of either substance.

A pipeline release that migrates to contained areas, either in the liquid or vapor phase, could result in a contained explosion. This condition was not modeled quantitatively because of the large number of possible spill, containment, and ignition configurations, and uncertainties in model predictions because of energy absorption by containment or directional effects. Qualitatively, the risk of such an event is considered higher for gasoline than for crude oil.

6.2.4.2 Thermal Effects Modeling

The purpose of consequence modeling, as it pertains to the risk assessment, is to characterize potential acute impacts resulting from loss of containment of liquid from the pipeline. Equivalent loss-of-containment scenarios were modeled for both crude oil and gasoline to provide a basis for comparing risks with the two different liquids. For purposes of this analysis, acute consequences are limited to the adverse effects of a liquid release and subsequent ignition of the vapors, resulting in vapor cloud fires (also known as a "flash fires") and pool fires. The potential for a vapor cloud explosion was also examined as part of the modeling process.

Flash fires and pool fires were modeled using the Complex Hazardous Air Release Model (CHARM®), a computer modeling program that calculates and predicts the dispersion and concentration of airborne plumes from chemical releases (see Appendix 6E). It can also calculate the heat radiation profiles surrounding a flammable chemical fire and the over-pressure profile for a vapor cloud explosion. CHARM® is used to provide estimates of distances affected by fires from gasoline spills in several example spill scenarios. CHARM® was also run in the vapor cloud explosion mode to see if the size of vapor clouds formed might lead to a vapor cloud explosion.

CHARM® is among several dense gas simulation models featured in an evaluation published by the EPA (US Environmental Protection Agency, *Evaluation of Dense Gas Dispersion Models*, Office of Air Quality Planning and Standards, May 1991, EPA-450/4-90-018). CHARM® is acceptable for use in modeling accidental chemical release effects under 40 CFR Part 68 of the EPA Risk Management Program regulation. Several documents on CHARM® were placed among the project documentation files in the public reading room of the Lead Agencies' Contractor ([1] CHARM User's Manual, URS Radian, November, 1997; [2] CHARM® Tutorial, URS Radian, November, 1997; and [3] CHARM Emergency Response System, Technical Reference Manuals, September 1995).

6.2.4.3 Methodology

CHARM® was used in two stages. The first took place early in the EA process as a means of selecting a "reasonable" corridor width to set the geographical boundaries for studying impacts on human health and safety. The second application was to estimate the approximate size of areas likely to be affected by heat radiation from a fire resulting from large spills along the pipeline.

In the first application, physical and chemical data on gasoline to be transported in the pipeline were approximated. The model requires physical, chemical, and transport property data for the substance being modeled to calculate release rates, liquid evaporation rates, air dispersion, and fire and explosion effects. Lacking Longhorn gasoline specifications initially, hexane was selected as a surrogate substance to use for the CHARM® modeling. Hexane is highly flammable and was considered to be a reasonable representation for gasoline, being one of the mid-range to light-range molecular weight components of gasoline.

Various source conditions for a release can be modeled. A sudden, massive spill of flammable liquid that results in a large pool fire was considered a worst case from a fire scenario. This case was used for both the initial hexane spill modeling and, later, gasoline spill modeling.

The second application of modeling was performed with gasoline as the spilled substance, once gasoline property data were available and entered into the CHARM® chemical properties database. For details of the methodology used in CHARM®, the references cited above can be consulted. Table 6-3 is an example of data input used in this modeling.

Meteorology can have a marked effect on the results of chemical release and dispersion modeling. For purposes of this analysis, local historical meteorological data for the Austin area were assembled to develop a prevailing set of weather conditions for the modeling analysis. Table 6-4 shows the meteorological parameters used in the analysis. These parameters form the basis for comparison of impacts resulting from gasoline and crude oil spills. While the absolute results of dispersion and fire impact modeling would be different when using other meteorological assumptions, the relative impacts between gasoline and crude oil spills are likely to be very similar for all conditions. Many permutations of weather conditions are possible, but for purposes of estimating the general magnitude of impact areas from fires, the conditions summarized below in Table 6-4 are considered to be appropriate.

The release modeling analysis was conducted using standard release quantities for each of several specific pipeline locations. Five release scenarios (release sizes) were modeled at each location. Four of the release sizes (5, 50, 500, and 1,500 bbl) were selected to establish a range of release conditions for the analysis.

The fifth release size is a "worst-case" quantity specific to each release site. The worst-case represents a complete loss of all liquid that can drain from the pipeline between the upstream and downstream pipeline block valves. The release locations and worst-case quantities associated with each location are shown in Table 6-1.

Modeling of the consequences of fire is based on the assumption of a pool fire with an area defined by drainage contours at the site location specified. The pool is the source of evaporation to form a vapor cloud in the analysis of flash fires and is the direct source for pool fire impacts analysis. The establishment of drainage contours is explained in Chapter 7. It is assumed that the liquid pool would migrate to the lowest point defined by these contours. This accounts for the spatial offsetting of impacts that results from downgrade spill migration. As described earlier, the pool is assumed to cover a circular area with a size (surface area) defined as the EPA pool spreading algorithm. This is a relatively conservative assumption, as it yields a large flame area and heat radiation flux, compared with smaller single or multiple pools. In a real situation, the assumed large single pool configuration is probably less likely than multiple rivulets or smaller pools that form due to terrain irregularities.

6.2.4.4 Modeling Results

Table 6-5 summarizes flash fire and pool fire consequence estimates from CHARM®. Results are presented for equivalent release scenarios for both gasoline and crude oil to provide a direct comparison of consequences. Summary Table 6-5 lists flash fire and pool fire consequence distances directly reported by CHARM® as measured from the pool centroid.

Table 6-6 lists the maximum consequence distance from the pipeline. In each modeled location, the fluid spill would migrate downgrade to form a pool whose centroid is some "offset distance" from the pipeline. As stated above, flash fire and pool fire consequence distances directly reported by CHARM® are measured from the pool centroid. To construct Table 6-6, the offset distance was added to the direct CHARM® output distance to obtain the consequence distance from the pipeline.

The actual consequence area for flash fires and pool fires would fall in a region near the pool itself. In the case of flash fires, the plume would assume somewhat of an elliptical shape directionally downwind. In the case of pool fires, the heat-effects region would assume an approximate circular area with a slight downwind directional effect due to wind-induced flame tilt. In all cases, maximum impact distances assume the wind is in a direction perpendicular to the pipeline, leading to conservative (high) consequence estimates. For example, an ellipticalshaped flash fire footprint with the wind blowing directly down the axis of the pipeline may not affect neighboring receptors at all, whereas effects with the wind blowing perpendicular to the pipeline would often be greater.

The results show higher acute consequence modeling predictions for gasoline than crude oil based on equivalent spill sizes and meteorological conditions. This is primarily attributed to the higher volatility of gasoline, resulting in greater hydrocarbon evaporation rates. In addition, differences in the properties of the two fluids (such as flame temperatures and heats of combustion) are a factor in determining predicted flash and pool fire effects.

Pool fire modeling of impacts near four sites in the Austin area was conducted. The scenario locations were selected as representative of the kinds of locations that would be of concern for fire impacts. The intent is to provide a sampling of locations and not to provide a detailed analysis of all possible sites along the pipeline. The locations selected have been identified as being of special concern or are considered to be representative of similar locations elsewhere along the pipeline route. Representative sites were chosen in the Austin area since the Settlement focused on the Austin area.

Tables 6-5 and 6-6 show modeling results for these sites, including two schools. These sites were not within the zone of impact at the 4 kw/m^2 heat flux level. If these results are applied to schools at closer distance to the pipeline, such as in the Houston area, some will be within the calculated zones of impacts. This conclusion is based on a modeled worst-case scenario with a radiant heat flux of 4 kw/m^2 —a person's discomfort level, but not hazardous for short durations—at approximately 750 feet (ft) as measured from the pool centroid. Topographical features could produce a greater impact distance depending on the degree of downgrade spill migration that could be experienced. The impacts assessment (Chapter 7) addresses the hazards and the special sensitivity of populated areas and areas near schools.

6.2.4.5 Impacts Corridor

For purposes of the EA, a corridor around the pipeline, in which detailed impacts analysis is performed, was established. The corridor width represents a potential “zone of impact” and is based on mathematical modeling of preliminary dispersion and fire effects. The original modeling (described previously) had predicted impact distances from approximately 1,000 ft to 1,500 ft, from which a 1,250-ft distance from the pipeline, 2,500-ft corridor, was derived. This resulted in a 2,500-ft wide corridor, 731miles in length, as the study area.

Later modeling showed that fire impacts from gasoline were within this range, although generally less (160 ft to 1,500 ft from the pool centroid). Scenarios can be envisioned where an impact zone could exceed this distance, such as a delayed ignition after a rapid dispersion, but a 2,500-ft corridor is a rational and conservative width for the majority of foreseeable events. This is also conservative compared to a commonly referenced 1,320-ft corridor (660 ft on either side of pipeline centerline) used in DOT gas pipeline regulations (49 CFR Part 192) to define class locations for graded regulatory requirements. Class locations are surrogates for population density in those regulations. The 2,500-ft width also compares conservatively with references reporting that two-thirds of all deaths and three-quarters of all injuries from pipeline accidents occur within 150 ft of the pipeline (API Research Study #040, July 1987).

The 2500-ft impacts corridor defines the area in which receptors such as population density and environmentally sensitive locations are characterized.

6.3 RISK ASSESSMENTS

6.3.1 Risk Concepts

Risk assessment is the core of risk management, the process of evaluating risks and allocating resources in a manner that controls risks and costs. Risk is defined in terms of an event probability and consequence as follows:

$$\text{Risk} = (\text{event probability}) \times (\text{severity of event consequence})$$

In the context of this study, risk can be expressed in absolute terms such as the probability of a leak or spill of a certain size. The “absolute scale” offers the benefit of comparability with other types of risks. Also common is the use of relative risk measures, whereby the risk of different parts of a system can be compared. The “relative scale” offers the advantage of ease-of-use when data are uncertain and when effects of individual system factors on risk are assessed. It is important to note that the two scales are not mutually exclusive. A relative risk ranking can be converted into an absolute scale by correlating absolute probabilities with relative risk values.

Some overall assumptions used in assessing the risks of pipeline transportation include the following:

- Increased probability of failure (POF) increases risk;

- Objects closer to the pipeline are at greater risk;
- Hazards associated with a product can be acute (immediate), chronic (longer-term), or both;
- A greater release quantity increases risk; and
- A greater spread area of released product increases risk.

In many cases, the high-risk portions of a system are relatively easy to identify, such as areas with a history of leaks, materials prone to failure, and areas with population density. A more detailed risk assessment becomes useful in areas where the risk picture is not so obvious. Interactions among many risk variables will often identify areas that would not otherwise be considered a high risk.

Risk assessment cannot predict when or if an accident might occur at any particular location. Rather, the assessment shows where in the System the risk might be higher or lower, based on the knowledge of potential failures and risk reducing (mitigation) activities. In a good model, all information is preserved and the risks can be examined in both an overview manner and a detailed manner. An effective pipeline risk management program then uses the risk assessment to allow a company to become more "proactive" and less "reactive" in the management of their pipeline. This includes the management of regulatory compliance.

6.3.2 Risk Assessment Methodologies

Potential causes and consequences of leaks or spills, that are necessary as the starting point for the risk assessment, are determined through a hazard analysis of the System.

6.3.2.1 General Methods

Hazards can be identified and analyzed by a variety of techniques, varying in approach and degree of formality. A relationship between procedures used to identify hazards and procedures used to analyze the causes and consequences of such hazards is incorporated into a formal risk assessment. For the Longhorn pipeline, a review of recent work was performed on formal hazard analyses for pump stations, potential causes of pipeline accidents based on the history of the pipeline and industry experience with similar pipelines, and previous risk assessments.

Common hazard evaluation tools such as event trees, fault trees, "what-if" analysis, and Hazard and Operability Studies (HAZOPS) are used to identify all factors that contribute to or reduce risk (CCPS, 1992). HAZOPS is a common risk assessment technique commonly seen in the chemical and hydrocarbon processing industry. It relies on a structured and comprehensive question-answer approach and expert participants to identify and remedy potential safety and operability issues. The HAZOPS method is an accepted technique for Process Hazard Analysis, as described in technical literature (CCPS, 1992) recognized by EPA and Occupational Safety & Health Administration in their respective Accidental Release Prevention Risk Management Program and Process Safety Management rules (40 CFR Part 68 and 29 CFR §119.1910). These hazard evaluation tools can then be combined into formal risk assessment methodologies including probabilistic risk assessments and scoring type techniques.

All methodologies have access to the same databases (at least when publicly available) and all must address what to do when data are insufficient to generate meaningful statistical input for a model. Data are not available for most of the relevant risk variables of pipelines. Including risk variables that have insufficient data require an element of “qualitative” evaluation. The only alternative is to ignore the variable, resulting in a model that does not consider variables that intuitively seem important to the risk picture. Therefore, all models that attempt to represent all risk aspects must incorporate qualitative evaluations.

6.3.2.2 EA Risk Assessment Approach

One common overall framework for risk assessment is an “indexing” or "scoring" methodology for relative risk assessment. In the EA Risk Model, a well-known indexing risk assessment model is used as a base for developing a risk profile for the System and is referred to as the EA Risk Model. In this model, risk is examined in two components: the POF and the consequences of failure.

The EA Risk Model is intended to be comprehensive—considering all critical aspects of risk. The use of more qualitative evaluations in the absence of statistical data is not thought to be a critical limitation, however, since a risk assessment can still provide at least a relative basis for judging the risks. General agreement among risk professionals can be used as a surrogate in the absence of “hard” data.

The underlying risk assessment principle of the EA Risk Model is that conditions constantly change along the length of the pipeline. A mechanism is required to measure the changes and assess their impact on failure probability and consequence. In the absence of statistical data, this can be effectively done on a relative basis.

In the POF portion of the EA Risk Model, scores are assigned to each risk factor or variable and importance factor "weightings" are assigned to logical groupings of these variables. The individual scores for each System segment are combined for an overall score of the pipeline. The POF portion of the EA Risk Model was chosen for its usefulness in the process and is based on the most widely adopted pipeline risk model currently available. It is well suited to the EA application in terms of comprehensiveness and its ability to indicate improvement opportunities (mitigations). The methodology is documented and recognized in industry as is evidenced by its use as a textbook, numerous articles in industry publications, and presentations at technical conferences since 1992. These factors were all considered in the choice to base aspects of the EA on this approach. The model basis is fully described in Pipeline Risk Management Manual, 2nd Edition (Muhlbauer, 1996).

The second part of the EA Risk Model is the consequence or impacts portion of the risk assessment. It is an assessment of relative impacts, is based on a tiering system, and is fully described in Chapter 7 of this report. Since a Superfund-type human health risk assessment was not within the scope of the EA nor considered appropriate in this application, chronic health effects from a pipeline spill, including receptor pathways, population classifications, and dose-response predictions, were not specifically estimated.

The consequence portion of the assessment methodology described by Muhlbauer (1996) is expressed as the "leak impact factor" and considers spill size, sensitive receptors (such as nearby population density and environmentally sensitive areas); and product characteristics (such as flammability, toxicity, and spreadability). Risk assessments performed by both WES and EPC included the leak impact factor. In the EA Risk Model, the leak impact factor is omitted in favor of the tiering approach for assessing impacts (see Chapter 7). This is consistent with the basic risk assessment methodology on which the EA model is based. Muhlbauer states that it is often useful to separate the Index Sum component from the total risk score in order to focus on failure probabilities, which to a much larger extent, are under the control of the operator. Original documentation describing and supporting the relative risk methodology repeatedly emphasizes the need to examine risk components separately as well as in aggregate. The methodology is specifically designed to retain the intermediate calculations such as Index Sum for the express purpose of using them as independent measures of specific risk aspects (Muhlbauer, 1996). Therefore, separating the Index Sum as an indicator of POF, as is done for the EA Risk Model, is consistent with the intended use of the original model. The subsequent use of the Index Sum with the tier system for impacts assessment completes the EA Risk Model.

In addition to the relative risk assessment, probabilistic risk assessment has been performed for selected locations along the pipeline. This examines risk in terms of the probability that a specific event type could occur at a specific location. The relationship between the relative POF assessment and the probabilistic assessment is discussed in Appendix 9A.

6.3.3 Risk Factors

Models similar to the EA relative risk methodology have also been called "decision-support" models. Such models are designed to provide guidance or "decision support," as well as identification of areas with relatively higher risks. They do this by preserving the evaluation of conditions and activities that are causing the higher risks, thereby indicating specific factors that can be addressed in order to reduce risks. The model, in effect, highlights deficiencies and points to potential remedies.

A decision-support model for risk management involves tradeoffs between the number of factors considered and ease-of-use of the model. The variables that impact risk are widely recognized in the industry, but the number of variables to consider in a model and the depth of that consideration are chosen by the model developers.

A list of risk factors that add to or subtract from the amount of risk can be identified for the System. These factors are selected based on their ability to provide a useful evaluation of risk without adding unnecessary complexities. These factors and the rationale for their inclusion are detailed in the Pipeline Risk Management Manual, 2nd Edition (Muhlbauer, 1996) and discussed in later sections within this report.

The EA analysis does not solely rely on EPC or industry historical failure data, since such reliance could easily over- or underestimate the risks significantly. Extrapolations from population-wide data—failure rate information from all pipelines—to a specific pipeline are problematic. Since any conclusions drawn from such data must be considered weak, their usefulness in decision-making is accordingly weak. Industry-wide failure experience is captured informally in the risk assessment since knowledge gained from such failures contribute to the experience and judgement of variables.

The EA analyses focus on specific pipeline and environmental factors that contribute to the failure likelihood. These include consideration of all documented accidents on this pipeline while under EPC's ownership. The relative risk model penalizes pipeline segments with previous leaks or if they are near previous leaks. Therefore, previous accidents on this pipeline heavily influence the risk assessment and play a direct role in subsequent decisions regarding mitigation.

6.3.4 Assessed Facilities

6.3.4.1 Pump Stations and Tank Facilities

While pump station leak history is evaluated in this EA, a relative risk assessment similar to one completed for the pipeline was not done for pump stations. Since pump station risk factors on this System are not as variable as conditions along the pipeline, mitigation measures for pump stations are less site-specific in nature. More general mitigations can be applied to all pump stations, as are described in Chapter 9.

Pump stations also have different risk considerations than the pipeline. The leak rate for crude oil pump stations on the EPC portion of the Longhorn pipeline (147 leaks in 29 years) does not accurately reflect potential leak rates for the new pump stations for refined product service on this pipeline since the new pump stations are designed and operated with significant differences from a typical crude oil operation. As an example, many previous EPC leaks are attributed to tanks (approximately 75 percent of all post 1980 spill volume). Other than surge tanks, only two of the new pump stations have tanks, and those pump stations are substantially different in design and operation than those from the EPC crude oil service.

Differences in risk variables between pump stations and pipeline right-of-way (ROW) include leak response issues: pump stations in general tend to have more direct observation (opportunity to detect and respond to abnormal conditions), and they often have secondary containment to avoid offsite contamination. However, the presence of high-pressure, aboveground components could support scenarios where product is sprayed outside of the pump station boundaries. Pump stations are also fenced and locked, therefore creating a more controlled environment compared to most pipeline ROW. Continuous video surveillance, frequent visits by employees, and alarm systems also provide more security. However, a pump station or tank farm might present a more attractive target to vandals or saboteurs. Pump stations have more rotating equipment and appurtenances that historically have been more leak-prone than the simpler pipe and valve equipment seen on the ROW.

New pump stations are to have environmental evaluations, HAZOPS, and risk assessments performed as detailed in the LMP (see Chapter 9). In January 1999, WES completed a formal Process Hazard Analysis using the HAZOPS method to identify any hazards and operability problems that need correcting before startup. The conduct of these studies exceeds OPS regulatory requirements and is a voluntary effort on the part of Longhorn. The El Paso Terminal and the five pump stations that would be in service when operations begin were examined. The reports for the Crane, Kimble County, and Cedar Valley stations were reviewed. In general, the method appears to have been correctly applied. Results of these studies revealed some safety and operability issues that did not appear to be critical. However, the subject of surge pressure impact and protection was not addressed in the HAZOPS review for most pump stations.

6.3.4.2 Alternate Routes

The alternative route analysis focused primarily on environmental and population characteristics of the alternatives and associated possible impacts. It made use of broad-based information that was readily available. A risk assessment comparable in magnitude to the existing pipeline's risk assessment was not performed. Such an assessment would be based on many assumptions since there is no pipeline along these routes (design data would have to be assumed). Also, there is insufficient route-specific data upon which to make probability of failure estimates.

While a new pipeline can be designed to have a low POF, the design basis for a hypothetical pipeline along the new route is not known. If there is an assumption made that such a pipeline would be designed and built in accordance with current DOT minimum requirements and assuming no exceptional route conditions, it is reasonable to assume a failure frequency comparable to other new pipelines in similar environments.

6.4 RELATIVE RISK ASSESSMENT

The relative risk assessment is used to help identify or confirm high-risk areas. It is also used as a means to account for changes in absolute probabilities likely to be achieved with changes in design and operational practices.

The following sections describe the probability of failure aspects of the EA Risk Model and results of its application.

6.4.1 Overview

6.4.1.1 Segmenting

An efficient way of evaluating risk along a pipeline is to divide it into segments of similar risk characteristics.

The relative risk assessment process gathered data on conditions and activities, termed risk variables, all along the pipeline length. The number of variables considered in the process determined the number of segments. Segmenting criteria included variables such as pipe specifications (diameter, wall thickness, etc.), coating type, age, and population density. The variables overlap. Every time any variable changed, a new segment was created. Each segment, therefore, has a unique set of variables. This process resulted in the creation of approximately 8,000 segments for the initial risk assessment. Segment length is entirely dependent on how often the variables changed. The smallest segments are only a few feet in length where one or more variables are changing rapidly; the longest segments are several hundred feet long where variables are fairly constant. Pipeline segments and scores can be seen in Volume 3 of this EA.

6.4.1.2 EA Relative Risk Assessment

The EA Risk Model produces a measure of the relative POF by performing an assessment of important variables related to all known failure modes. This measure is used in the context of the environmentally and safety-sensitive tier categories, which are based on potential impacts of failure (see Chapter 7), to reflect total risk.

The POF is divided into four categories or indices, each corresponding to a possible failure mode: third-party damage, corrosion, design, and incorrect operations. Each index covers specific pipeline system variables that contribute to the POF (Muhlbauer, 1996). The most critical contributors to risk within each index are weighted based upon their respective contribution to the risk. The model captures the probability variables in index scores, which are summed into an overall "Index Sum" score. The variables are each assessed for the particular pipeline segment being evaluated. Table 6-7 lists the four indices and variables within them. More details of the algorithm are discussed later in this chapter.

The range of values for the POF measure, the Index Sum, is 0 to 400, where 0 represents the lowest safety level (highest risk)—imminent failure. At the opposite end of the scale, 400 is a theoretical value representing the most failure-proof system (i.e., the highest safety, lowest risk system possible). Therefore, the Index Sum can be viewed as a "safety scale," whereby increasing points mean increasing safety—lower failure probability. Unfavorable conditions around the pipeline, inadequate operator activities, and increasing uncertainty (about existing conditions) tend to reduce Index Sum scores—indicating a higher failure probability.

6.4.1.3 Data Gathering

Risk assessment data for the System were assembled from a variety of sources. The most desirable source of information is professional documentation that accurately describes conditions and/or activities related to risk. This information is used when available. It is not uncommon to find actual activities and/or conditions that deviate significantly from documentation. When such inconsistencies are encountered, reliance on the documentation is reduced.

In the absence of documentation, alternate sources of information were used, including field investigations and interviews with experienced company personnel. These types of data tend to be more subjective and are used cautiously. However, excluding such data would greatly limit the usefulness of the overall assessment.

Many pieces of input data were used to produce a risk score for each pipeline section. These data came from maintenance records, construction documents, design documents, employee interviews, expert testimonies, and inspections of facilities, including:

- Design documents and calculations provided by Longhorn, WES, and EPC;
- Reports and studies from outside agencies;
- Brief field inspections of ROW and aboveground facilities;
- Maintenance documentation (records, procedures, employee interviews, etc.); and
- Other documentation (construction drawings, maps, reports, calculations, etc.).

The risk assessment model can and should be updated with the most current information. This is a task to which Longhorn has committed for on-going System operations. A recent WES risk assessment for the System was also used in scoring variables in this risk assessment.

6.4.1.4 Field Investigations

An integrity analysis and physical examination of the subject pipeline was made as described in Chapter 5. Interviews were conducted with EPC employees regarding past operating and maintenance practices and with Longhorn and WES employees regarding future operations and maintenance procedures (Meeting, 1999).

The purpose of the fieldwork was primarily to support other data gathered and to provide an overall perspective on the facility. Field observations offer a frame of reference to "calibrate" against operator-subjective assertions of risk variables being described as, for example, "good," or "poor." For this reason, field investigations serve to establish a common ground for communication between the risk assessor and the operators of the System.

Secondary benefits from the inspection include information that is useful in judging other items by inference. For example, the attention to items such as housekeeping and marking equipment provides evidence for some of the more subjective evaluation items, such as commitment to safety and professionalism of the operation.

6.4.1.5 Data Compilation

The sources used and the data gathering process are described in Appendix 6F, Table 6F-1. An electronic database for the System, for use with the relative risk assessment tool, was assembled in Microsoft Excel® and Access®. Samples of some summary information obtained from the risk database are described in Table 6F-2. This summary table is useful in gaining an understanding of overall characteristics of the System.

6.4.2 EA Risk Model Probability of Failure Algorithm

The objective of the EA Risk Model's POF assessment is to capture all available data about the pipeline and condense it into useable summary numbers. The underlying algorithm is designed to capture existing information and produce relative POF values.

6.4.2.1 Uncertainty

A conservative overall assumption is made in the absence of data or information; increased uncertainty means increased risk. However, a degree of reasonableness must be exercised. "Known" deficiencies are certainly more evidence of risk than are "possible" deficiencies. For example, there are scenarios where a close interval survey must omit 50 ft of readings because of an asphalt road, and readings adjacent to the road are more than adequate. Such a situation should not drive the risk score to a point where an expensive investigation under the roadway is indicated over more productive expenditures. Alternatively, years of no integrity verification should reflect high risk since it is possible that a number of integrity-threatening mechanisms could have developed.

The following example scenarios have a presumed relative value for purposes of assessing risk:

Example Scenarios and Risk Assessment

Action	Results	Risk Relevance
Timely and comprehensive inspection performed	No flaws detected	Least risk
Timely and comprehensive inspection performed	Some flaws or indications of flaw potential detected. Root cause analysis and proper follow-up.	More risk
No timely and comprehensive inspection performed	High uncertainty	
Timely and comprehensive inspection performed	Some flaws or indications of flaw potential detected—uncertain reactions	Most risk

Again, some assumptions and "reasonableness" are employed in setting scores in the absence of data, but in general, worst-case conditions are conservatively used for default values.

6.4.2.2 Leak/Repair History

An additional assumption concerns the use of previous flaw indications. For modeling purposes, previous flaw indications such as leaks, repairs, and internal line inspection (ILI) indications are considered evidence of increased susceptibility to failure. A "zone-of-influence" is assumed and all pipe within that zone is similarly shown to have increased risk. The presence of a leak or other flaw therefore "penalizes" several hundred feet of pipe in the model, depending on the type of leak or flaw. This is driven by the assumption that failure mechanisms can extend some distance from the actual event. This is conservative, since most flaws are from a very localized initiator that has been permanently repaired. However, such previous indications also show that conditions were conducive to deterioration and/or failure, at least at one time. Even after a repair, the model conservatively assumes that the underlying failure mechanism still exists. This risk "penalty" can be removed if a formal root cause analysis is done and the conditions are permanently changed so that the flaw initiator is not a threat. For these purposes, a root cause analysis is a thorough investigation that conclusively identifies the chain of events leading to the failure and indicates the primary mechanism which should be addressed to prevent any future such failures. By this approach, the EA Risk Model will normally overestimate the risk initially. This provides incentive for the operator to fully investigate and affect permanent repairs or system changes. After the operator performs a formal, documented root cause analysis, then the model can incorporate the new information and cease the overestimation of risk.

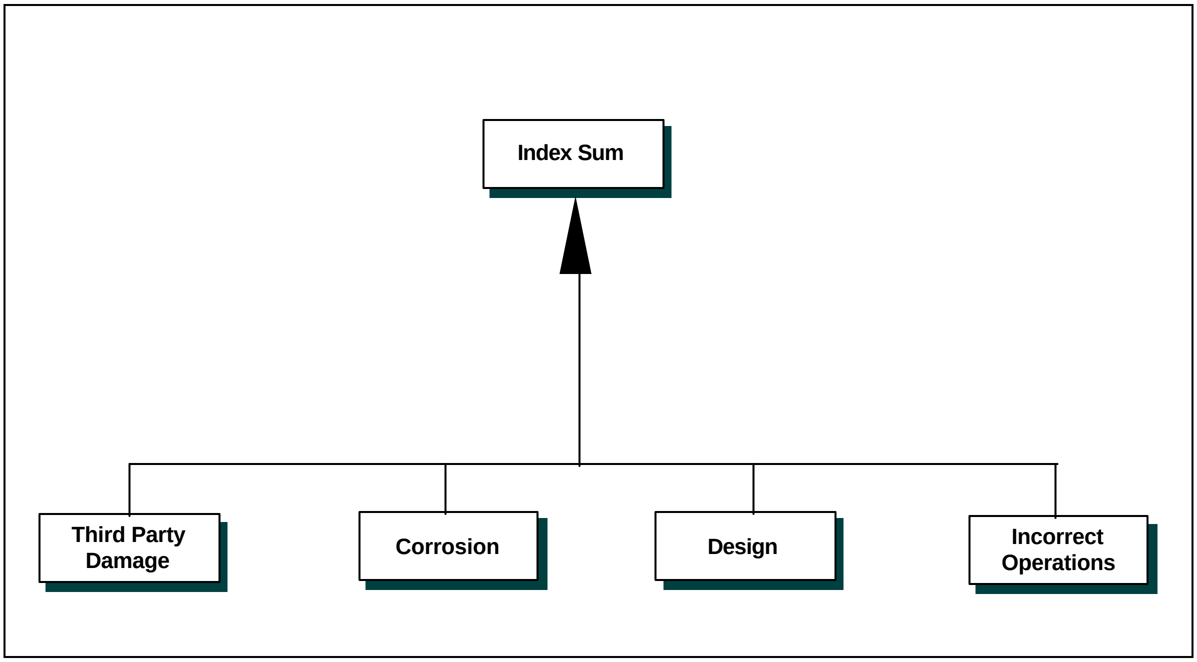
A leak (or other detected flaw) was evidence that a certain integrity-threatening mechanism was present at one time. However, if this underlying mechanism is identified and effectively mitigated, then the threat no longer exists. It would be imprudent to ignore the evidence that a historical leak provides or to assume that the underlying cause could never be removed. This does not cause an underestimation of risk.

6.4.2.3 Model Structure

Many variables (approximately 75) were used in quantifying the relative POF for each pipeline segment. EA Risk Model variables were selected and weighted based on their role in the actual risk and on availability of information. Wherever possible, measurable data were used to assign risk points to these variables. For the Longhorn pipeline, these measurable data included or were derived from sources described in Section 6.4.2. Some of these data sources and the state of these attributes for the pipeline are also discussed in Chapter 5. When such data were unavailable, more qualitative assessments were made. Common industry practices, engineering judgement, and pipeline operations experience were used to support this effort in cases where measurable data were absent. A complete list of algorithm variables and input data can be found in Appendix 6G.

Probability-of-failure scores are grouped into the four failure probability indices: third-party damage, corrosion, design, and incorrect operations. Together these index scores comprise the relative POF for the segment of pipeline or pump station evaluated.

In Sections 6.4.4 through 6.4.7 the descriptions of the risk model probability variables are discussed under the index (failure mode category) in which they appear in the model (Muhlbauer, 1996). These descriptions and Appendix 6G refer to the initial risk assessment of the pipeline. Changes to these scoring protocols were required in assessing the post-mitigation risk levels (see Chapter 9).



Relative Probability of Failure Assessment

6.4.2.4 Sabotage

The risk of sabotage is not specifically addressed in the formal risk assessment. The likelihood of a pipeline system becoming a target of sabotage is a function of many variables, including the relationship of the pipeline owner with the community and with its own employees or former employees. Vulnerability to attack is another aspect. In general, the Longhorn pipeline is not thought to be more vulnerable than other pipeline systems. Standard or above-average security measures are to be in place, including fences, locks, increased patrols, and surveillance cameras. The motivation behind a potential sabotage episode would, to a great extent, determine whether or not this pipeline is targeted. Reaction to a specific threat would therefore be very situation-specific.

The risk of sabotage is difficult to fully assess since such risks are so situation-specific and subject to rapid change over time. The assessment would be subject to a great deal of uncertainty, and recommendations would be problematic. This type of assessment is not thought to add significant value to the EA.

6.4.2.5 Chain Reactions

The risk of a pipeline can be influenced by the presence of another pipeline nearby. If a leak from one pipeline can cause a leak in the other, the POF of the other pipeline is increased. This can be termed a “chain reaction” event. Additionally, the consequences of the original leak can become more severe if the product of a second pipeline becomes involved in the scenario. The means that the risk for each pipeline has been increased, at least to some degree. The DOT database on reportable accidents was examined in an attempt to identify such chain-reaction events. None were found, although a recent example of a propane pipeline accident east of El Paso, Texas, that affected a nearby pipeline, shows that such events are possible.

The potential for cumulative impacts has been examined qualitatively as described below and in more detail in Section 7.12 but is not a part of the formal risk assessment.

Information from Longhorn pipeline alignment sheets, valve exposure conditions (above grade or below grade), and Longhorn depth-of-cover study results were used to identify areas along the Longhorn pipeline where cumulative impacts could theoretically occur. In the vast majority of possible chain reaction situations on the subject pipeline, an adjacent pipeline was buried some distance from the subject pipeline. Several feet of earth provides an effective barrier to many blast and fire effects, thus limiting situations where effects could be transferred from one pipeline to the next. There could be an increase in third-party activity from maintenance on the neighboring pipeline(s) but this would be tempered by the fact that pipeline-knowledgeable personnel would be performing the activity. Such personnel would presumably be well versed in the presence and implications of the neighboring pipeline. There are also benefits to shared or adjacent ROW situations since sometimes patrol, corrosion control, and other activities are in effect duplicated—each pipeline potentially benefiting from its neighbor’s activities.

Calculations and analyses for such scenarios were not included here since the low likelihood of such accidents relative to other possible failure modes was not thought to materially impact the risk levels.

6.4.3 Third-Party Damage Index Scores

The Third-Party Damage Index is scored by items and associated weightings in the following table:

Scoring Variables for Third-Party Index

Parameter	Percent Contribution
Depth of cover	20
Activity level	20
Patrol	15
One-call	15
Public education	15
Aboveground exposures	10
ROW condition	5
Third-Party Index	**100**

6.4.3.1 Depth of Cover

A 1999 over-line depth-of-cover database was used to evaluate depth of cover. Actual probed depths were categorized into five groups for scoring purposes. Instrument readings (Metrotech) for depth of cover were also provided, 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. Credit was not given for casings as a means of protection against third-party damage, but additional protection from asphalt or concrete caps is considered ("extra" in table below).

Five cover categories were created for assignment of points:

Category	Points	Depth (inches)
1	0	0 (exposed)
2	4	0 - 18
3	8	19 - 36
4	12	>36
5	15 - 20	extra

Since it is very difficult to determine at what point cover begins to afford protection, the EA Risk Model does not make this distinction. It identifies "exposed" pipe and then "0-18" inches as the next category. Only 50 survey readings out of over 19,000 are less than 6 inches covered, but not exposed. Of these, most are approximately 5 inches of cover. It would be problematic to characterize risks in this range, and disregarding these instances is not thought to materially affect the assessment.

No cover survey information was initially available for the first 50,000+ ft in Harris County, so a score of 0 was conservatively assigned to that portion of the System, in the initial risk assessment. Actual data was later obtained and is reflected in the post-mitigation relative risk assessment (see Chapter 9).

6.4.3.2 Activity Level

The potential for third-party damage is strongly related to the level of potentially damaging activities nearby. For this pipeline, such damage might occur through activities such as installation and maintenance of other utilities and homeowner activities such as fence and pool construction, ditch clearing, dredging, and anchoring. The risk algorithm attempts to identify areas where these activities are more prevalent through the "activity level" variable. The following were used as indicators of increased activity:

- Number of One-call reports during August 1998 through March 1999;
- Activity level as assessed by WES in their risk assessment, presumably from interviews of knowledgeable personnel;
- The relative density of other buried utilities nearby; and
- Population density.

Table 6-8 shows the tabulated One-call data on the Longhorn pipeline from August 1, 1998 to April 1, 1999, from operational logs. The One-call data are broken down into total calls per county, cleared calls, dispatched calls, and percent calls dispatched. Total calls, cleared calls, dispatched calls, and percent calls dispatched are also tabulated for the entire pipeline. The table lists the total length of pipeline running through the county along with a density ratio number of one-calls per 10 ft of pipe. The counties with the largest density ratios were Harris, Travis, and Bastrop. The percent of calls dispatched averaged 65 percent system-wide with percent dispatched in Harris, Travis, and Bastrop counties of 64 percent, 66 percent, and 79 percent, respectively. The information showed that not all of the counties where the Longhorn pipeline is located received calls during the time period. The information also shows that there were one-calls listed in counties where the Longhorn pipeline is not present.

One-call volumes were categorized into 3 classes (high, medium, low) for scoring purposes in the risk model. Using this scoring protocol, approximately 590,000 ft scored 0 points (high density of one-calls); 870,000 ft scored 2.5 points, and 2,300,000 ft scored 4.5 points (low density of one-calls). Assessing on a county-wide level does not provide optimum resolution since within a county there are certainly pockets of higher and lower activity. However, additional resolution was not attainable for the initial assessment.

The density of other buried utilities was obtained from the geographic information system (GIS) database. Overall, the “activity” variable represents 20 percent of the third-party damage potential. Points are assigned based on the above conditions and ranged from 0.3 (high level of potentially damaging activities) to 19.5 (low level of activity).

6.4.3.3 Patrol Frequency and Effectiveness

From a reactive standpoint, a pipeline patrol is intended to detect evidence of a leak such as vapors, unusual dead vegetation, bubbles from submerged pipelines, and sheens on water. From a proactive standpoint, the patrol should also detect impending threats to the pipeline. Such 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. The patrol should also seek evidence of previous activity near the pipeline. Such evidence is usually present for several days after the activity and may prompt inspection of the pipeline.

This variable is weighted as 15 percent of the third-party damage potential. The effectiveness of the patrol effort depends on several factors such as frequency, type (ground or air patrol), and capabilities of the observer. Air patrol variables also include, speed, altitude, training of observer, and other variables impacting potential for detection. For the initial risk assessment, the assumptions were a weekly patrol frequency from a fixed-wing aircraft without an observer at typical altitudes and a typical level of response to discoveries. This yields a point score of 6 out of a potential 15 points. Actual patrol practices, which are different from the assumptions, would generate different point scores.

6.4.3.4 One-Call

This variable is thought to be consistent across the entire System. It is an evaluation of the effectiveness of the One-call provider, including the level of participation from the public, and the pipeline operator’s processes for receiving and responding to One-call reports. Based on the protocols in place and the perceived effectiveness of the One-call system, a score of 13 is assigned. This is the same score assigned by the WES risk self-assessment.

6.4.3.5 Public Education

Public education programs play a significant role in reducing third-party damage to pipelines. It is thought that most third-party damage is unintentional and due to ignorance. This is ignorance not only of a buried pipeline's exact location, but also of the aboveground indications of the pipeline's presence and of pipelines in general.

Some of the characteristics of an effective public education program, as evidenced, might include:

- Mailouts to adjacent residents and landowners;
- Meetings with public officials once per year;
- Meetings with local contractors/excavators;
- Regular education programs for community groups;
- Door-to-door contact with residents adjacent to the pipeline; and
- Advertisements in contractor/utility publications.

Regular contact with property owners and residents who live adjacent to the pipeline is an important step in public education. Other techniques that emphasize the good neighbor approach include regular mailouts, presentations at community groups, and advertisements. All of these activities can be individually scored (Muhlbauer, 1996).

Longhorn's proposed program of public education is described in the LMP in Chapter 9. It is scored as 11 out of 15 points for these risk assessment purposes. This score agrees with the WES self-assessment of the program.

6.4.3.6 Aboveground Exposures

In many cases, portions of the System which are not buried, such as certain valve sites, are exposed to different hazards than buried portions. These include traffic impacts, vandalism, weather events, and unintended uses. As discussed in Chapter 5, an assessment of exposed pipe is currently on-going by Longhorn. The WES risk model appears to make distinctions in this category. Fifty percent of the point value for this variable is based on the WES scores for "aboveground facilities." Areas with cover category of 1 (no cover) score 0 points and were the basis of the other 50 percent. The absence of aboveground exposure scores 5 points for the section. For the initial risk assessment, specific evaluations of the approximately 100 exposed locations were not available.

6.4.3.7 Right-of-Way Condition

Detailed assessments of ROW condition for the pipeline were not available for the initial assessment. For scoring purposes, results of a sampling of observations from field investigations were used. Approximately 10 miles were rated as “poor;” 236 miles were rated as “excellent” (mostly the new installations); and the balance was rated as “typical” or “good.” Scores of 0 to 5 points were assigned based on these ratings.

6.4.3.8 Third-Party Index Adjustment Factors

The final score for the Third-Party Index is obtained by summing scores for the previous variables and then adjusting the score downward if there is a history of third-party related leaks or detection of third-party induced defects. The rationale for this adjustment is that the presence of a leak or known defect, even if corrected, indicates that conditions are conducive to that type of failure (or at least, they were at the time of the incident). This penalty can be erased if a formal root cause analysis with permanent corrective actions has been done.

6.4.4 Corrosion Index Scores

In the table below, the Corrosion Index is described with the following items and associated weightings:

Scoring Variables for Corrosion Index

Parameter	Percent Contribution
Atmospheric corrosion	10
Internal corrosion	20
Buried pipe corrosion	10
Coating condition	15
Cathodic protection	15
Interference	15
Mechanical corrosion	5
ILI	10
Corrosion Index	100

6.4.4.1 Atmospheric Corrosion

In the risk assessment model, this variable does not command a high point value (due to the low rate of failures by this cause). It can serve as a "flag" to call attention to substandard situations.

The atmospheric corrosivity along the Longhorn pipeline is rated in three zones as shown in the following table:

Zones for Rating Atmospheric Corrosivity

Location	Atmospheric Corrosion Potential
Gulf Coast (0 - 50,000 ft)*	High
Hill Country (50,000 - 1,000,000 ft)*	Medium
West Texas (1,000,000 ft* to end of pipeline)	Low

* Stationing footage along pipeline

During the field inspections, it was noted that new construction had good paint coating or pump station equipment was soon to be painted. Other observed exposures had inadequate coatings. Since specific data for all exposed pipe were not available, conservative scores were assigned. The WES risk assessment identification of "aboveground facilities," the location of casings (from the GIS database), and the locations of exposed/very shallow pipe from the depth-of-cover survey establish the susceptibility of a pipeline segment to atmospheric corrosion.

If a pipe segment has no exposures to the atmosphere, including the annular space of a casing, it is awarded the maximum of 10 points. Where there are exposures, points are awarded based on the atmospheric type, including the presence of casings, and the atmospheric coating condition. Atmospheric coatings were assessed as "excellent," 5 points; "fair," 2 points; and "poor" as 0 points. Using this scoring protocol, approximately 174,000 ft of the pipeline scored 5 points; 8,000 ft scored 7.5 points, and 3,500,000 ft scored 10 points for atmospheric corrosion potential.

6.4.4.2 Internal Corrosion

The risk model conservatively penalizes portions of the pipeline where the potential for internal corrosion appears to be higher. Internal corrosion is weighted 20 percent of the total corrosion risk. The product to be transported, gasoline, is seen to be relatively benign from an internal corrosion view. Since the possibility of previous internal corrosion damage exists, and there is the possibility of unintended components (such as water) accumulating, secondary indicators were used. Indicators of increased risk of internal corrosion are:

- Portions of the pipeline previously used for sour crude oil transportation (construction date was used as an indicator);
- Low elevations where accumulation of corrosive agents is more likely; and
- ILI indications of possible internal corrosion.

6.4.4.3 Buried Metal Corrosion

Information used to assess the potential for external corrosion for buried steel pipe includes:

- Corrosivity of the buried environment (soil electrolyte characteristics);
- Condition of the coating, evidenced by:
  - Coating age and type;
  - Visual inspections; and
  - Amount of cathodic protection (CP) currents required.
- Effectiveness of CP system, evidenced by:
  - Test lead readings (pipe-to-soil potentials) from 1972 to 1998;
  - Close Interval Survey (CIS) (pipe-to-soil potentials) results from 1994 and 1998; and
  - ILI "external corrosion" findings.
- Interferences potential, evidenced by:
  - Nearby utilities, foreign pipelines (bonded and unbonded); and
  - Presence of casings.
- Potential for mechanical corrosion, evidenced by:
  - Pipe stress levels; and
  - Conditions which could promote stress corrosion cracking or other specialized corrosion attacks.
- ILI type; and
- Time since the last integrity verification.

Weightings considered coating condition reports dating to 1972 with the first indication of "bad" coating occurring in 1978. Coating condition scoring is based upon approximately 280 visual inspection reports between 1989 and 1995. Ranges of coating condition based on these reports were established.

While more recent reports indicate current conditions, older indications of coating deterioration suggest an opportunity for corrosion to advance for longer periods.

As shown on the table below, coating types were grouped into three main categories and scored based on perceived performance for their respective ages.

Scores by Coating Type

Coating Type	Points
New epoxy/PE/Fusion bond epoxy	5.0
Old coal tar/plastic tape	3.0
Paint/Powercrete-J	3.0

The current condition of a coating system is dependent on many factors. The above table might not reflect conditions at any particular location on the pipeline, but rather serves as a screening tool to indicate areas where a coating is more likely to have experienced deterioration. The points shown are multiplied by an aging factor based on installation year.

A zone-of-influence was assumed for inspection results, such as ILI and test lead readings. The zone-of-influence recognizes that the inspection provides evidence of conditions close to the actual location of observation. The zone-of-influence concept was also used for areas of previous leaks.

The corrosion issues are treated in the risk model as follows:

1. Test lead readings are assumed to provide indications of corrosion protection adequacy for a zone of 1,000 ft on either side of the reading, or to the half-way point to the next reading, whichever is less.
2. Several years of test lead readings were used. A test lead reading less negative than -0.85 volts "on" penalizes the zone for inadequate corrosion protection and also for coating deterioration. Locations of multiple "bad" readings scored 0 points; single "bad" readings scored 2 points; "okay" or "unknown" readings scored 8 points. This is not the most conservative scoring possible since "unknown" readings are assumed to be "okay," but is thought to be reasonable, given a relatively low occurrence of "bad" readings. Using this scoring protocol,

approximately 5,000 ft of the pipeline scored 0 points; 38,000 ft scored 2 points, and 3,700,000 ft scored 8 points.

3. A CIS reading of less negative than -0.85 volts "on" penalizes the immediate reading location for inadequate CP and coating deterioration. This results in a score of 0. An "okay" reading or new construction (1998) warrants 10 points; and "unchecked" is 1 point. Using this scoring protocol, approximately 412,000 ft of the pipeline scored 0 points; 1,400,000 ft scored 1 point, and 1,900,000 ft scored 10 points.
4. Test lead readings for each year were assumed to be equally weighted.
5. The model score credit for the CIS inspection "decreases" to zero over 5 years. For scoring purposes, a 1998 survey of the entire pipeline was assumed, with the western stretches showing "unchecked" since they were not actually surveyed. New construction is awarded points as if a recent CIS survey had been done.
6. The model score credit for ILI inspection "decreases" to zero over 5 years.
7. Several years of coating inspections are used in scoring "buried coating" condition. New construction (1998) receives 12 points (15 maximum), and multiple instances of poor coating receives 0. Varying combinations of conditions observed over the years warrant intermediate scoring—between 0 and 12 points.

6.4.4.4 Corrosion Index Adjustment Factors

The final score for the Corrosion Index is obtained by summing the scores for previous variables and then adjusting the score downward if there is a history of corrosion-related leaks or detection of corrosion flaws. The rationale for this adjustment is that the presence of a leak or detected flaw, even if corrected, indicates that conditions are conducive to that type of failure (or at least at the time of the accident). This penalty can be erased if a formal root cause analysis with permanent corrective actions has been done.

6.4.5 Design Index Scores

This section summarizes the approach used in the model for parameters dealing with a variety of issues that are grouped together in a category called "design."

The following variables and associated weightings describe the design index:

Scoring Variables for the Design Index

Parameter	Percent Contribution
Pipe strength	20
System safety factor	10
Fatigue potential	15
Surge potential	15
Integrity tests	20
Earth movements	20
Design Index	**100**

6.4.5.1 Pipe Strength

Pipe strength is a risk variable that measures the relative strength of the pipeline. While the design process addressed this and determined a minimum margin of safety, purchasing and construction issues and changes from planned operations normally result in certain pipe segments having more "reserve strength" (or margin of safety) than others. Reserve pipe strength is quantified as a relative number for each pipe section as the ratio of pipe strength to the maximum operating pressure (MOP). Maximum credit is given for a ratio of two or more – situations where there is at least twice as much strength as is needed for design conditions.

MOP values are used in the calculations even though normal operating pressures would provide more realistic stress levels. Use of MOP is more conservative. For this pipeline, flow rate increases will not increase pressure levels along the pipeline. Some segments will even experience reduced pressures. The location and design of pump stations and the resulting hydraulic profile (including elevation effects) determines pressure at any point along the pipeline.

The pipe strength is calculated using the Barlow internal pressure formula (49 CFR Part 195, but without safety factors) multiplied by 0.95 (for a 5 percent consideration of external loadings) and then adjusted for pre-1970 electric resistance welded (ERW)/electric flash welded (EFW) pipe and for older (pre-1970) girth welds (in effect multiplying by 0.8 when such adjustments are warranted). Chapter 5 discusses low frequency ERW/EFW and girth weld issues related to these "penalties." The numerical adjustments are rooted in precedence for similar engineering calculations. The objective is to quantify, in a relative sense only, the belief that those "adjusted" pipeline segments may have less strength. When the pipe strength is unknown (approximately 2,300 ft has no pipe grade specified), a default minimum yield stress of 24,000 pounds per square inch is used.

The EA Risk Model considers possible pipe damages in this variable since they might suggest weakened pipe. Data input from the 1995 ILI was used and included possible mechanical damage, corrosion, cracking, dents, and other detectable anomalies. Many preliminary indications from ILI results are later judged to be insignificant or "false positives." After data evaluation and confirmation, approximately 150 indications, including corrosion anomalies, from the 1995 ILI were identified and input to the risk model as reductions to pipe strength. This is conservative, since in most cases, the indications are not threatening to pipe integrity.

6.4.5.2 System Safety Factor

The system safety factor compares the weakest component in the pipeline system to the intended maximum operating pressures. The weakest component of the pipeline may be the pipe, but it can also be the flange connections, valve bodies, pressure vessels, or other system component. Ignoring complications of safety factors of the various components, the weakest rated component is compared against the pipe strength (as previously calculated), and the weakest of those is ratioed against the MOP to determine this variable score. For scoring purposes in the pre-mitigation assessment, it was assumed that all non-pipe components carried an ANSI 600 rating. (This assumption was replaced with actual data in the post-mitigation assessment.) Maximum points are awarded when the weakest component is rated for twice the MOP.

6.4.5.3 Fatigue Potential

Fatigue potential for the initial assessment is measured by the following factors:

1. Distance from pump station discharge, where "within 1 mile" is the worst case and after 8 miles the risk is considered negligible;
2. Pipeline stress levels, based on projected normal operating pressures, where higher stress increases the likelihood of fatigue failures; and
3. Integrity tests, where a robust test detects and removes flaws which could lead to fatigue failures. (See "integrity tests" as a risk variable under this section.)

These three factors contribute equally to the points awarded (15 is the maximum).

6.4.5.4 Surge Potential

Surge potential is measured by the following factors:

1. The highest surge pressure (by a very approximate calculation methodology, with no attenuation of pressure wave assumed) is combined with the normal operating pressure profile and is expressed as a percentage of MOP. In other words, the surge spike was overlaid on the hydraulic profile to calculate a maximum surge pressure. Low elevation locations and sections near to the pump discharge locations will show higher risks under this scheme. The results were grouped in five classes based on the percentage of MOP. Calculated surge pressures ranged from 80 percent to 181 percent of MOP. Pressures greater than 130 percent of MOP were given the lowest score, while any pressure under 100 percent of MOP was given the highest score. These scores were used in the pipeline relative risk model, but the pressures do not represent realistic pressure potentials.

Surge Pressure Scores

Category	Points	Description
5	7.5	<100 (percent of MOP)
4	5.3	100 - 110 (percent of MOP)
3	3.8	110 - 120 (percent of MOP)
2	2.3	120 - 130 (percent of MOP)
1	0.0	>130 (percent of MOP)

2. Pipeline stress levels, where the higher stress increases the likelihood of fatigue failures.

A formal, more accurate surge analysis that was not completed in time for incorporation into the draft EA has now been completed and reviewed and is described in Chapter 9.

6.4.5.5 Integrity Tests

"Integrity Tests" is a variable which shows the improved risk situation after an integrity verification involving hydrostatic pressure testing and/or performance of ILI for cracks, laminations, longitudinal seam defects, etc. ILI specific to Design Index issues are assessed here. ILIs that are more appropriate to the detection of wall loss are evaluated in the Corrosion Index. For either hydrostatic test or ILI, the usefulness of the information is assumed to deteriorate each year for five years, at which point no value is available from the information. For the hydrostatic test, the pressure level is also considered. Higher test pressures give wider margins of safety which reduce risk, discounting any potential damages caused by the test itself. For the ILI, the crack-detection capabilities are also considered.

This variable commands a relatively high point value since the testing and inspection activities should remove uncertainty regarding the System's structural integrity.

6.4.5.6 Earth Movements

"Earth movements" is a variable for assessing the potential for seismic activity, landslides, and scour.

6.4.5.7 Seismic Activity

The initial risk assessment used USGS data to roughly characterize seismic potential. Shaking and ground failure hazards can be estimated from the peak ground acceleration (PGA) value. Information on the PGA for the System route was compiled from the USGS hazard maps, at a two percent probability of exceedance over 50 years. These maps do not include induced seismic activity, such as from deep well injection or similar events. The PGA is a measure of the acceleration experienced by a particle on the ground in the event of an earthquake. This value is calculated for potential earthquake locations and magnitudes along the pipeline route.

PGA is expressed as a percentage of gravitational acceleration. A serious earthquake can have a PGA over 11 percent of gravity. The correlation between PGA and damage to underground utilities, such as the pipeline, can be estimated. The PGA range over the length of the pipeline is 2 to 18 percent. A PGA of 1.5 percent of gravity is readily felt. Dishes and windows may break, and unstable objects may topple. A PGA of 15 percent causes considerable damage to ordinary buildings, including partial structural collapse especially for tall structures, such as columns and chimneys.

The PGA value range for the System route was divided into four categories:

PGA Value Range	Category
PGA < 6	low
6 ≤ PGA <11	medium
11 < PGA < 15	high
PGA > 15	very high

The Crane-to-El Paso portion of the route is most likely to experience seismic activity; earthquakes have occurred there within the last ten years.

Recent information indicates that the seismic risk might be overstated in this assessment, using the described scoring protocol. Specifically, the ranges of PGA seen along this pipeline route would not normally be damaging to a pipeline. In the final risk assessment (post mitigation, see Chapter 9), susceptibility to seismic events was evaluated from the more definitive study described in Appendix 9C.

6.4.5.8 Aseismic Faulting

For the initial risk assessment, a zone from the Galena Park Station to near Satsuma Station milepost (MP) (MP 0 to MP 35) was artificially labeled as “very high” on the seismic PGA scale described above, to account for the potential for aseismic faulting.

In the final risk assessment, susceptibility to aseismic faulting and proposed mitigation was evaluated from the more definitive study described in Appendix 9C. From that study: “More than two feet of additional subsidence will occur in some areas of the subsidence district. Again, 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 consequently does not pose a hazard.” Nevertheless, monitoring of active faults in the Houston area is part of the LMP, as described in Chapter 9.

6.4.5.9 Landslide

For the initial risk assessment, landslide data were obtained from the *US Department of the Interior, USGS Open-File Report 97-289, “Digital Compilation of Landslide Overview Map of the Conterminous United States,” 1997*. Three categories of landslide are defined: high, medium, and low, corresponding to the incidence and/or susceptibility. For the area evaluated in a USGS quadrangle, incidence/susceptibility is high if more than 15 percent of the area is involved in landsliding; medium applies to 1.5 to 15 percent, and low applies to less than 1.5 percent.

In the final risk assessment, landslide susceptibility was evaluated from the more definitive study described in Appendix 9C.

6.4.5.10 Scour Potential

This variable is a measure of the susceptibility of the pipeline segment to scour by stream flow. In the initial risk assessment, scour was assigned a default value of “0” indicating high scour potential everywhere. This was not a realistic assumption, but was a very conservative score pending the outcome of further analysis. In the final risk assessment, scour susceptibility was evaluated from the definitive study described in Appendix 9C.

6.4.5.11 Design Index Adjustment Factors

The final score for the Design Index is obtained by summing the previous variables and then adjusting the score downward if there is a history of leaks or detection of design flaws. The rationale for this adjustment is as follows: the presence of a leak or detected flaw, even if corrected, indicates that conditions are supportive of that type of failure (or at least they were at the time of the accident).

For example, the detection of a crack in a joint of pipe gives some evidence that surrounding pipe joints may also have cracks. However, if a root cause analysis identifies a crack initiator as unique to that joint, which could not have reasonably impacted nearby joints, then the “penalty” is removed after a repair is made, and the initiating mechanism is permanently eliminated.

6.4.6 Incorrect Operations Index Scores

Human error potential is assessed in the Incorrect Operations Index of the relative risk model. It is also an underlying element for all other risk measures, since human error can be a contributing factor in almost every failure. This is a component of risk that is difficult to measure because many complex behavioral and psychological factors are involved and because assessments are more judgement-based. The risk model examines peripheral aspects of human error that are widely believed to reduce the potential risk. These include training, use of proper procedures, communications protocols and systems, ease of overpressure, use of redundant safety systems, maintenance systems, etc. Assessments of these aspects are based on examinations of the intended operator’s systems, including visits to the operations control center and various field locations, review of operations and maintenance manuals, and interviews with operating personnel. The operator’s systems were found to generally meet or exceed the best practices of industry, warranting scores in the upper quartile of the point scales in many instances.

Since the human error aspect of risk is more judgement-based, it is more open to challenge. However, since most ingredients of this index are uniform across the entire system, the relative risk model is not making many risk distinctions from segment to segment using these scores. The aspects that are subject to change from segment to segment, such as stress level (part of the “ease of overpressure” variable), are based more on measurable data. Other aspects such as use of procedures, communications systems and protocols, and training are done at a company-wide level, resulting in few significant differences from segment to segment.

The following items and associated weightings describe the Incorrect Operations Index:

Scoring Variables for Incorrect Operations

Parameter	Percent Contribution
Construction/design	10
Training	20
Procedures	15
Maps and records	5
Overpressure potential	10
Safety systems	10
Maintenance	10
Communications	10
Mechanical error preventors	5
Risk assessment	5
Incorrect Operations Index	**100**

A review of human error factors was performed. Since some of the factors relate to operations activities which had not been finalized, generalized assessments of WES practices governed the scores in the initial risk assessment.

Human error risk is conservatively examined in all phases of the System life cycle: design, construction, operations, and maintenance. Since the System is a new operation with new or refurbished equipment, new procedures, and newly assigned personnel, the human error potential could be higher. A certain amount of System and location unfamiliarity is to be expected. Offsetting this, to some extent, is the fact that the operator is quite experienced with similar systems and the personnel assigned to this System are experienced with this type of pipeline operation. The following aspects of this index were assessed at 80 percent of the best possible score for the entire pipeline:

- Training;
- Procedures;
- Communications (both voice and data systems);
- Maps and records; and
- Risk assessment.

This score reflects a favorable review of these aspects of operation. Improvements are possible and error potential will decrease with increasing experience of operating personnel. Experience is implied in the training and procedures scores.

6.4.6.1 Training

WES documentation includes training manuals, procedures, needs analysis by job function, and re-training. The effectiveness of the training is best assessed through interviews and testing of employees. However, based on the completeness of the training documentation reviewed and WES' reputation as a leader in training materials development, a higher score was established.

6.4.6.2 Overpressure Potential

Overpressure potential is a measure of how easy it is to overpressure a portion of the pipeline through human error. This potential was assessed based on pipe stress level and susceptibility of the pipeline segment to surges. From a risk standpoint, the worst situation is where a pipeline could be immediately overpressured from a relatively simple human error. The best case is where there are no pressure sources powerful enough to overpressure the pipeline under any condition. From the projected hydraulic profile at 72,000 bpd, approximately 69,000 ft of the pipeline were assessed a relatively higher overpressure potential; approximately 1,900,000 ft were assessed a relatively lower potential; and the rest of the system, approximately 169,000 ft, was placed into one of three intermediate categories.

6.4.6.3 Safety Systems

"Safety systems" is a variable that examines devices and systems designed to protect pipe integrity. A full study of the workings and reliability of such systems would allow more complete assessments to be done. From an initial inspection, a score of 50 percent of the maximum benefits was assigned. This score is consistent with most pipeline operations in the US. Additional points are available for systems which incorporate multiple levels of redundancy and elimination of all single points-of-failure. This is typically not done for pipeline systems since they are often not of a complexity to warrant such additional measures.

6.4.6.4 Construction/Design

Older portions of the System were identified as having more probability of design or construction phase errors. This assumes that improvements in techniques, inspections, and general error prevention have been made over the years. A counterargument could speak to the evidence that the older portions have withstood the "test of time"; however, certain defects might not surface for several years. The older portions of the pipeline, approximately 450 miles, were scored 4 points, and the newer portions were scored 8 points for this variable. The maximum of

10 points could have been awarded if, based on a more thorough review of construction documents and/or interviews with construction personnel, exceptional job site practices were confirmed. Such a review was not done.

6.4.6.5 Mechanical Error Preventors

No credit is given for mechanical error preventors, although certain computer permissives described in Longhorn documents might warrant some risk reduction "'credit" in this variable. Systems which hinder an employee from making an error include locks on critical equipment, key-lock-sequencing systems, the use of color, and others (Muhlbauer, 1996).

6.4.6.6 Incorrect Operations Index Adjustment Factors

The final score for the Incorrect Operations Index is obtained by summing the previous variables and then adjusting the score downward if there is a history of human-error-related leaks. The presence of a leak, even after a repair, indicates that conditions are supportive of that type of failure (or at least they were at the time of the incident). This penalty can be erased if a formal root cause analysis with permanent corrective actions has been done.

6.4.7 Index Sum

The combination of the above indices creates the Index Sum, which is the overall measure of relative POF. As stated earlier, the theoretical range of scores for the Index Sum is 0 to 400 points, with 400 points representing the safest pipeline system conceivable.

6.4.8 Consequence Variables

As discussed earlier, the EA Risk Model deviates from the consequence portion of the relative risk assessment methodology described by Muhlbauer (1996). This was done in order to more appropriately characterize the wide range of possible impacts from a spill on this pipeline. In the self-assessments used by WES and EPC, the consequence portion of the risk equation is measured by the leak impact factor (LIF) as described by Muhlbauer (1996). The probability of a pipeline leak (the Index Sum) is adjusted by the LIF to arrive at the risk value. The LIF includes consideration of:

- Product hazard (PH);
- Receptors (R);
- Spill volume (S); and

- Spread range or dispersion (D).

The EA Risk Model captures consequences in a tiering system fully described in Chapter 7. The tier system considers the same variables as does the LIF, but also greatly expands the types of receptors and the specific potential impacts on those receptors.

6.4.9 Results

6.4.9.1 Mainline

In many cases, the risk model output will parallel commonly held beliefs about the risks along the pipeline. In other cases, due to the ability to simultaneously consider many more risk variables, the model will provide new information.

The 695 miles of mainline pipe (Galena Park Station to the El Paso Terminal) were divided into approximately 8,000 segments with each segment having similar risk characteristics. A score is assigned to each segment. As previously described, risk is examined in two components: the probability of a leak and the consequences of a leak. Each score is a measure of relative POF, the Index Sum, and is most appropriately viewed in terms of the corresponding impacts or consequence assessment. In this System, higher numbers represent safer conditions (less risk).

As described earlier, the Index Sum is divided into four sub-categories. These correspond to possible failure modes, which are Third-Party Damage Index, Corrosion Index, Design Index, and Incorrect Operations Index. As previously discussed, many factors or variables are combined in each.

These segment scores are compared to each other for purposes of identifying relative “hot spots” of higher risks. If a number of scores from other pipelines are available, the comparisons can be more robust, perhaps providing more insight into absolute risk levels, but this does not diminish the usefulness of within-system comparisons. Determining areas of greater need within the subject pipeline is the basis of proper resource allocation.

It is also important to note that although the risk model has index scales that end at 100 points, this is not comparable to a grading scale familiar to students. A score of 100 reflects a theoretical condition where all imaginable actions, regardless of reasonableness, have been taken to reduce risk and/or virtually no threats exist for that failure mode. In this way, the model allows for all possible actions and conditions to be scored. However, scores significantly lower than 100 are entirely appropriate and may reflect high levels of safety.

Examining the Index Sum scores for the entire mainline, the following averages are seen:

Overall Index Score Averages

Index Sum	195.3
Third-Party Damage	52.0
Corrosion	37.2
Design	39.8
Incorrect Operations	66.3

This table should be used as a reference in examining the following tables. The index scores are most meaningful in the context of other comparable index scores. The following paragraphs describe findings in relation to other portions of the System or other benchmark scores. They do *not* imply that the risks seen are either too high or acceptable.

Since this portion of the risk assessment is focused solely on POF, the Index Sum and the indices comprising it will be the focus on discussion of results.

The scores of the following tables are also shown graphically in Appendix 6H and in the map figures in Chapter 9.

Segments where the POF are seen to be relatively high (lower Index Sum scores) comprise approximately 8 miles of non-contiguous pipeline (142 segments of varying lengths). These segments are roughly in the following ranges, but do not comprise the entire range:

Milepost Ranges

9-36
51-53
61-67
150-172
212
280
340-400
406-415
424-453

Criteria Index sum<= 170

These are areas where the POF is seen to be higher due to higher failure probabilities in one or more of the four indices. On average, these 142 segments compare with the overall segmented pipeline as follows:

Comparison of 142 Pipeline Sections with the Overall Sectioned Pipeline

	Index Sum	Third-Party Damage	Corrosion	Design	Incorrect Operations
Overall average (entire pipeline)	195.3	52.0	37.2	39.8	66.3
Average of the "highest probability" segments (highest 8 miles)*	165.9	42.9	23.6	34.6	65.4
Highest probability segments average as percent of overall average	15	18	36	13	1

* Adjustment to these numbers for leak and repair histories affect the calculated averages. Therefore, the sum of the averages is not necessarily equal to the overall average.

As seen in the above table, the higher overall POF sections are driven to a great extent by a higher corrosion risk. Comparisons specific to each index can be found in the following discussions.

Examining each index or failure mode independently is useful to ensure that deficiencies in certain areas are not being masked by the overall numbers. The following observations are also illustrated graphically in Appendix 6H.

6.4.9.2 Third-Party Damage

Segments seen to have the highest risk of third-party damage comprise approximately 46 miles of noncontiguous pipeline (811 segments of varying lengths). These segments are roughly in the following ranges and do not comprise the entire range:

Milepost Ranges

0-4
7-23
171-175
281-295
339-450

Criteria <= 40

These are areas where the probability is higher due to the influences of or evidenced by:

- Higher activity levels;
- Less depth of cover;
- Presence of exposed facilities;
- Poor ROW condition; and
- Presence of previous third-party damage.

The other risk variables from this index were either constant or did not impact the risk to the extent that the listed variables did.

6.4.9.3 Corrosion

Segments seen to have the highest risk of corrosion-related failure comprise approximately 7.3 miles of noncontiguous pipeline (42 segments of varying lengths). These segments are widely scattered in the following ranges, covering most of the sensitive areas crossed by the pipeline, and do not comprise the entire range.

Milepost Ranges

9-18
21-35
53
142
205
341-344
360-400
455-456

Criteria <= 20

Areas where the probability is higher due to the influences of or evidenced by factors such as:

- Coating condition;
- Verifications of CP effectiveness;
- Possible sources of interference with CP;
- Internal corrosion potential;

- Presence of casings (for both atmospheric corrosion and interference potential);
- Exposures to atmospheric corrosion (in addition to buried components); and
- Previous corrosion leaks or repairs or ILI indications.

6.4.9.4 Design

Pipeline segments that have the highest risk of design-related failure comprise approximately 11 miles of noncontiguous pipeline (253 segments of varying lengths). This index produced many short segments because pipe specifications often changed in short lengths. The higher probability segments are roughly in the following ranges and do not comprise the entire range:

Milepost Ranges

34 - 70
81 - 100
112 - 165
295 - 302

Criteria <= 30

These are areas where the probability is higher due to the influences of, or evidenced by many possible factors. Each situation shows a higher risk due to some combination of the following:

- Pipe operating pressure compared to pipe maximum strength;
- Maximum pipe strength as a function of manufacture technique, grade, construction technique, etc.;
- Fatigue potential;
- Earth movements potential (including landslide, scour, seismic events);
- Integrity testing (hydrostatic tests and ILI);
- Surge potential; and
- Previous design-related leaks, repairs, and ILI indications.

No hydrostatic test reports for the Galena Park to Valve J1 segment (new construction) were found. This indicates higher risk for that segment, until information is incorporated.

6.4.9.5 Incorrect Operations Index

The Incorrect Operations Index shows more consistent failure probability along the entire pipeline length. Many aspects of this failure mode are consistent, such as training, the use of procedures, risk assessments, condition of maps and records, and the presence of error-prevention devices. Aspects which do change for the Longhorn pipeline and create the differences seen, are as follows:

- Potential for overpressure (shown as higher where the surge potential and pipe stresses are higher); and
- Construction and design (shown as higher for the older portions of pipeline).

6.4.9.6 Crane-to-Odessa Lateral

An assessment of the Crane-to-Odessa lateral pipeline was conducted independently from the mainline as part of this study. The above results do not include this portion of the pipeline. This pipeline is approximately 28 miles long and was mostly constructed in 1998. In its current configuration, planned product transport rates are approximately 1,400 bph.

A relative risk assessment was performed using the same model as was used to assess the mainline. As with the mainline, this assessment focuses on the POF part of the risk equation. This is a relatively short pipeline, recently constructed, and with no operating history. Consequently, it shows few risk differences along its length compared with the mainline. Differences that are identified include:

- Pipe specifications;
- Depth of cover;
- Drain potential;
- Landslide potential (low or medium according to USGS database);
- Crossings of other buried utilities; and
- Pressure profile.

Based on these changes, the pipeline is divided into 352 segments for purposes of risk assessment. Scores were generated using conservative assumptions in most cases.

Examining the 352 Index Sum scores, the following averages are seen:

Overall Averages

Index Sum	250
Third-Party Damage	74
Corrosion	73
Design	35
Incorrect Operations	67

These scores compare favorably with the mainline and are consistent with the belief that new pipe in a very benign environment should have relatively high scores. The Design Index scores are perhaps artificially low due to conservative assumptions regarding surge potential, pressure profile, and earth movements. A more detailed earth movements analysis should add significantly to this index and hence the Index Sum. Therefore, the risk is probably over-stated in these numbers.

6.4.9.7 Urban versus Rural

Urban areas might experience increased failure rates, although this is not evidenced by historical EPC leak rates (see Appendix 6J). A hypothetical increase in failure rates is based on the belief that some failure mechanisms are potentially enhanced in urban settings. This is considered in the relative risk assessment (for example, population density as an indicator of increased third-party activity and the presence of other buried utilities as potential interferences with corrosion control). Therefore, urban area "penalties" assigned in the risk model must be overcome in the achievement of tier point levels. Urban areas also present the potential for increased impacts. As such, the urban areas are required to have a higher level of mitigation than rural areas (unless the rural area has some additional impact consideration such as ground water sensitivity), as discussed in Chapter 9.

6.4.10 Risk Benchmarking

A comparison of these POF scores with other benchmarks has been done. Benchmarks selected are:

- DOT minimum requirements; and
- EPC's previous operations in crude oil service.

6.4.10.1 Comparisons with Current Regulations-Implied Risk Levels

A direct comparison with the risk level implied by current DOT pipeline regulations is difficult. Since many aspects of the regulations are written in "performance language," specific actions or acceptable conditions which would define risk levels are not mandated. For example, 49 CFR Part 195 does not specifically mandate quality and condition of buried pipe coatings, but coating in good condition is inferred by the current CP requirements. It is believed that an "audit compliance" level is different from a "regulations compliance" level. Typical regulatory audit forms have more details and specifics than do the regulations themselves. In general, it appears that more risk reduction activities are mandated as a result of the audit process than directly from the literal text of the regulations.

A related complication is how the regulations treat uncertainty. The model used in this analysis recognizes increasing risks with passage of time. For example, the model shows higher risk when integrity tests and/or inspections have not been done recently. This can be offset by new inspections and tests. There does not seem to be an analogous aspect to the regulations. If one accepts the correlation between uncertainty and risk, then there can be a difference between the risk level that is achieved by the enforcement of regulations and that which actually exists.

It is important to note that the risk model explicitly addresses factors only implicit or not part of regulations. The comparison with the assumed DOT risk levels is *not* a measure of compliance with current regulations. For example, current regulations do not require an additional safety factor for pre-1970 ERW pipe or for girth welds which would not pass current acceptability criteria. The model recognizes an increased failure probability associated with these and assigns risk levels accordingly. Consequences are assumed to be constant for purposes of this comparison. Therefore, differences in risk are driven solely by differences in POF.

The following table shows a comparison by index average. Comparisons must be "normalized" for the conditions of the pipeline scored. For purposes of the table, scores are based on hypothetical pipelines either in the harshest environment (much third-party activity, corrosive soil, old coating, earth movements, etc.) or in environments comparable to the subject pipeline. Note that individual portions of the subject pipeline might show a quite different comparison; these are averages only. Higher numbers indicate a safer (less risk) situation.

Comparison by Index Average

	Index Sum	Third-Party Damage	Corrosion	Design	Incorrect Operations
Longhorn Pre-mitigation Scores: Overall average	195.3	52.0	37.2	39.8	66.3
Regulatory Minimum Scores: Minimum compliance for a typical audit in environment comparable to Longhorn's	161	48	28	39	46

The conclusion of this comparison is that the System shows a lower POF than a pipeline that meets the implied minimum regulatory risk level. This does not imply full compliance with regulations, only the apparent lower POF compared to an implied minimum regulatory risk level.

6.4.11 Previous Relative Risk Assessments

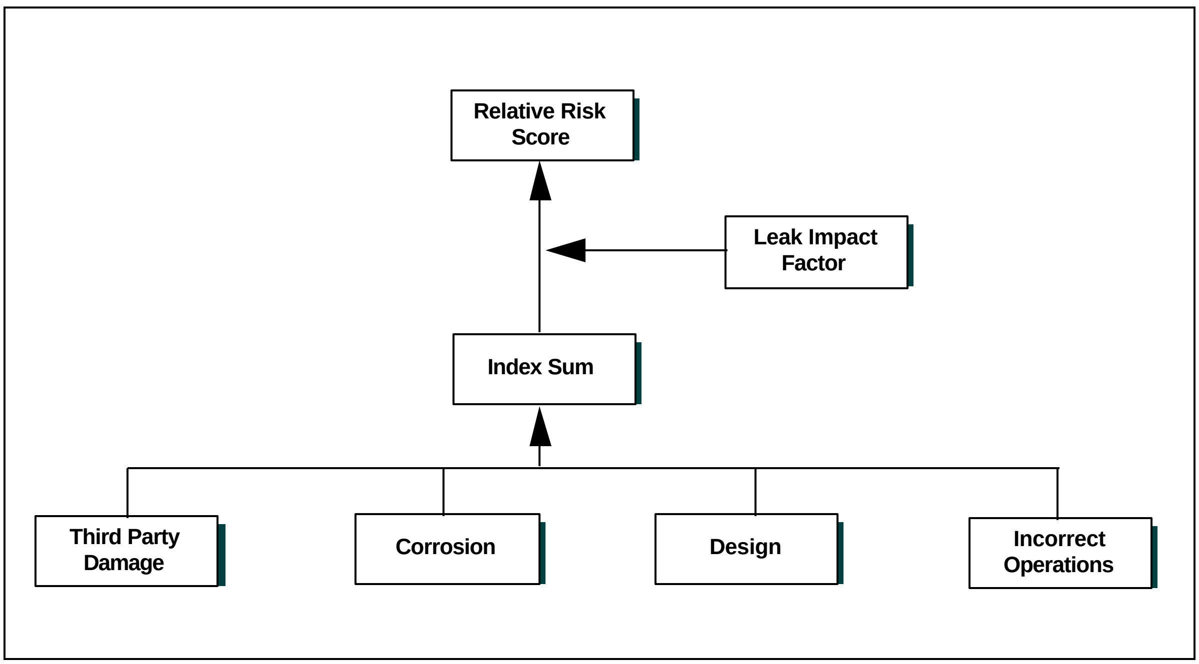
Two previously completed risk assessments were reviewed. These previous assessments were performed by EPC on parts of the Longhorn pipeline and by WES for the System. These previous studies were reviewed to compare the relative scores assigned to the qualitative variables. Note, however, that the current risk model was prepared independently of these other models.

It is recognized that previous risk assessments were not directly comparable to the EA risk assessment for several reasons. These include differences in assessors, system configuration, and data availability. However, the previous work is useful for other reasons. These include illustrating that the EA relative risk methodology is used in the industry and that the methodology achieves similar results, even with differences in data specifics and assessors. The previous work also indicates an intent by operators to identify higher risk areas, and presumably, to direct resources accordingly.

The EPC relative risk model partitions approximately 400 miles of pipeline into seven segments and evaluates approximately 50 risk variables for each segment. A 1993 and 1997 updated assessment, were available for review, each using crude oil as the product in the pipeline. The 1999 WES relative risk model divided 695 miles of pipeline into 138 segments and evaluated approximately 54 risk variables for each segment. It assumed refined products were the transported material.

Both models are based on the same reference documentation and can be directly compared to a large extent. Their common structure is illustrated below and fully detailed by Muhlbauer (1996).

Both seem to be thorough and fair assessments based on information reviewed. The EPC model uses larger segment lengths and is based on a different product, pressures, flow direction, and operations and maintenance practices. Nevertheless, the two studies have assigned similar values to various risk factors. More details of the two risk assessments are briefly discussed below.



Structure of EPC and WES Relative Risk Assessment Models

6.4.11.1 EPC Relative Risk Assessment

A 1993 relative risk assessment is thought to coincide with EPC's beginning use of this risk model. A 1997 update, which assumed crude oil service for calculation purposes was then reviewed. It is unclear if the 1997 assessment goes to Galena Park since some titles refer to "Moore Road." A small database was built to study the assessments. The models each assessed 49 risk variables. In both, some actual input conditions were available as well as the risk scores, which were based on the actual conditions and presumably also on interviews and expert judgements. A review of the data entry forms used in the assessment indicates a relatively thorough and fair assessment.

Between the 1993 and 1997 assessments, little change in risk was noted except in Segment 6 (Satsuma Station to Baytown), where POF was indicated to have been reduced by approximately 14 percent. This reduction is noted by improvements in the Design Index and the Incorrect Operations Index. There was no change in consequences for any segment between the 1993 and 1997 assessments.

The segment lengths in these assessments are rather long. It is unclear whether scores in the segment reflect average or worst-case conditions. EPC considers their risk assessment data to be proprietary, so a comparison within the EPC universe of pipelines could not be done. Therefore, it is not known how EPC viewed the risk of this pipeline relative to other pipelines.

Since this is a relative assessment, it is also useful to compare scores between segments of the same pipeline. There are sometimes large differences in consequences between the segments. Differences in consequences are a result of population densities, ranging from one to three on a 4-point scale. Small consequence differences are also seen in spill score, due to differences in spill volumes and soil permeabilities. There were no expected differences in product hazard.

On the probability side of the risk equation, minor differences between segments are noted in Third-Party Damage Index and Corrosion Index; no differences are noted in Incorrect Operations Index, and larger differences are noted in the Design Index. The larger differences in the Design Index are attributed to differences in factors which compare component pressure ratings with actual pressures and in the hydrostatic test factor.

6.4.11.2 WES Relative Risk Assessment

This relative assessment modeling study, summarized in a final report dated April 22, 1999, and studied from detailed reports dated May 10, 1999, is a more detailed assessment of the entire length of the System. One hundred thirty-eight segments were created for scoring purposes. The average segment length is 5 miles; the shortest segment is 366 ft, and the longest segment is 166 miles. This is not unusual for this type of model since certain segments of pipeline will have changing conditions, while others will remain constant for long lengths.

Table 6-9 summarizes the higher risk sections identified in the WES study.

A review of the details behind the assessment shows a relatively thorough and fair assessment. It appears that sufficient detail and discrimination were used to obtain meaningful distinctions in risk levels along the pipeline. There is a greater difference in probability seen in this model as compared with the EPC model. The range of consequences is the same as the EPC assessments.

WES did not document all sources of information supporting their model's risk scores. Apparently much of this support comes from interviews of knowledgeable personnel. It is not clear how much "more-measurable" information was incorporated. Therefore, a major difference between the WES study and the current EA study is that the latter made use of more location-specific and direct measurement information, such as actual test lead readings, CIS results, depth-of-cover surveys, and ILI results, as well as more detailed examinations of spill pathways and consequence receptors. Inputs to the EA Model are listed in Appendices 6F and 6G.

Longhorn intends to use this risk assessment or equivalent as part of future integrity management for the pipeline. Recommendations from the report, dated April 22, 1999, are not location-specific. Resource allocation strategies, risk-based decision support for specific projects, and remediation efforts are usually the reason for such studies. To meet such an objective, specific follow-up actions for identified risks will be required. In general, the three risk assessments can be compared as shown in Table 6-10.

In addition to the differences seen in the referenced table, some previous findings or assessment approaches that differ from the current model include those shown in Table 6-11.

These differences are speculative because information regarding the WES and EPC model specifics was not available. Differences are due in large part to the resolution (segment length) or the amount of input data available. A thorough analysis of previous risk assessments was not performed.

6.5 PROBABILISTIC RISK ASSESSMENT

6.5.1 Overall Approach

The relative assessment of Section 6.4 compares the relative POF of different parts of the pipeline and examines the variations in relative probability in response to changes in hardware, operational practices, and external conditions along the pipeline route. The probabilistic risk assessment, conducted for sample locations along the pipeline, provides a measure of absolute risk that can be compared to other common individual and societal risks and places the risk of the Longhorn pipeline in a conceptual frame of reference for decision making.

As discussed previously, the risk of an event is the combination of the probability and severity of the event and its consequences. If risk is defined in terms of event consequences, such as the chance of a certain size spill, or chance of a fatality, then the risk to a “receptor” can be expressed numerically in terms of probability. "Receptors" refer to the sites or organisms that are threatened by a spill of refined products. Receptors in this study include humans, drinking water supplies, and features such as wetlands. Each impact potentially damages one or more receptors.

The probabilistic risk assessment is a series of calculations that estimate frequencies of six different potential impacts along the Longhorn pipeline length. Impact frequencies are calculated for numerous scenarios involving various combinations of leak frequencies, spill sizes, and receptor vulnerabilities.

For the purposes of this assessment, “overall risk” is analogous to “societal risk” commonly seen in other risk assessments and is defined as the risks to receptors along the entire pipeline length over a period of 50 years. “Segment-specific risk” is analogous to “individual risk” commonly used in risk assessments and is defined as the risk to a point receptor that is presented by 2,500 ft of the pipeline over a period of 50 years. In this usage, the segment-specific risk is essentially the overall risk normalized to a length of 2,500 ft. Except in special circumstances, a point receptor is exposed to risks from leaks occurring along a maximum length of 2,500 ft. The basis for this “impact zone” is described in Chapter 5. Other receptors such as aquifers are exposed to multiples of the segment-specific risks, in proportion to their lengths. Since risks are not uniform along the pipeline, this length-normalization can be viewed more as an average of the overall risks. It is useful to examine a shorter length of pipeline in order to show risks that are more representative of individual receptor risks and to be more comparable to other published risk criteria.

Ideally a probabilistic assessment is based on statistically valid historical data. Historical leak and spill frequency data, discussed in Chapter 5 for various spill sizes, were used to estimate probability. However, estimating pipeline leak rates and leak characteristics from such data is very problematic. Since data is limited in both quantity and quality, some judgments were required in determining the appropriateness of certain subsets of data used to predict leak rates from future operations.

Regardless of the specific assumptions and methodology employed in analyzing historical leak rates, results of such analyses cannot be correctly used in isolation. They can easily over- or understate the actual probability of future failures, due to the small amount of available data and the constantly changing environment. The probabilities calculated here are intended to complement the assessment of risk factors discussed in the previous section to determine risks. The relative POF assessment is linked to estimates of future leak rates as is shown in Appendix 9A of this final EA. As with other estimates, this approach has considerable uncertainty but is felt to be the most realistic appraisal of post-mitigation leak rates.

6.5.2 Input Data

6.5.2.1 Leak Frequency

Historical leak frequencies are used to predict future leak frequencies. In this analysis, there are no considerations for the changing relative POF along the length of the pipeline. Leak frequencies are assumed to be uniformly distributed in time and space.

"Reportable" spill or leak refers to DOT criteria for formal reporting of accidents at 49 CFR §195.50. A spill size of 50 bbl is one of the triggers requiring the incident to be reported. Therefore, most DOT spill databases predominantly contain spills of 50 bbl or greater, although there are cases where a different criterion has mandated the reporting of an incident.

Three "frequency of leak" cases are examined. Each case represents a different estimated incident rate and is used independently to perform an impacts assessment. These cases use only historical data with no consideration given to possible benefits of mitigation. These therefore represent impact frequencies that would be seen on an unmitigated Longhorn pipeline and, on average, US hazardous liquid pipelines. The leak frequencies used are generally described as follows:

<u>Case 1 (all US hazardous liquid pipeline leak rate)</u>

The average leak incident rate for reportable incidents on US hazardous liquids pipelines, from 1968-1999.

<u>Case 2 (former EPC pipeline, reportable leak rate)</u>

The reportable incident rate for 450 miles of this pipeline (not stations) under EPC operations in 29 years. (Incident rate) = (10 leaks) / (450 miles x 29 years).

Case 3 (former EPC pipeline, overall leak rate)

The overall accident rate, regardless of spill size or reportable nature, on the 450 miles of pipeline (not stations) under EPC operations in 29 years. (Incident rate) = (26 leaks) / (450 miles x 29 years).

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

In addition to overall leak frequencies, spill size frequency also plays a role in many of the impacts. A spill size distribution for spills larger than 50 bbl was derived from DOT hazardous liquid pipeline reportable spills from 1975 to early 2000. The fraction of spills smaller than 50 bbl was estimated from the 29-year EPC leak experience on the 450-mile segment from Valve J1 to Crane. EPC leak experience contains too few larger-sized spills to create a meaningful profile.

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

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

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

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

6.5.2.2 Receptors

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

- Probability of pipeline failure;
- Spill size; and
- Receptor vulnerability and sensitivity.

However, not all impacts are modeled as being sensitive to all of these, due to data availability limitations. Below is a general description of the impacts modeled. These descriptions offer the reader a general sense of the rationale behind the calculation, but the actual results are based on more than a hundred calculated scenarios. The six receptors examined are:

- Fatality;
- Injury;
- Drinking water contamination;
- Recreational water contamination;
- Prime agricultural contamination; and
- Wetlands contamination.

More detailed descriptions can be found in Appendix 9A.

6.5.2.3 Fatalities and Injuries

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

An example of fatalities and injuries is Case 1 shown in Table 6-12. It can be described in general terms as follows:

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

2. The industry average leak rate applied to this pipeline predicts 35 leaks over 50 years and, hence expected fatalities and injuries of 0.16 and 0.72, respectively.

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

Further discussion of the fatality and injury rates used can be found in Appendix 9B of this EA.

6.5.2.4 Drinking Water Contamination

The assignment of sensitive and hypersensitive areas is based on engineering and hydrogeological evaluation of the characteristics of surface water streams and aquifers that could be impacted by the pipeline. This impact is modeled as being sensitive to tier location (see Chapter 7), Index Sum, and spill volume. Since the tier designations consider vulnerability of drinking water sources, a “probability of contamination” is assigned for each tier. A threshold spill size of 1,500 bbl is assumed before any impact is possible. The rationale for the threshold is presented in Appendix 9B. Above that threshold, impacts are judged to be equally likely, regardless of spilled volume. This is conservative, since even the spill volumes closer to the threshold are modeled as being as harmful as the largest spill volumes.

An example of this impact is Case 1 shown in Table 6-12 and can be generally described as follows:

1. Approximately 16 percent of reportable leaks are of a size to pose a threat to a drinking water supply.

2. Using the receptors sensitivities described in Chapter 7, these aggregate to a 100 percent chance for about 31 miles or 4 percent for the overall pipeline.

3. The industry average leak rate applied to this pipeline predicts 35 leaks and, hence, approximately 6 spills (16 percent of 35) would be of sufficient volume to contaminate a drinking water supply, and 0.2 would occur at a location that contaminates a drinking water supply. This is equivalent to saying one contamination

episode occurs every five pipeline lifetimes or 250 years, since the 0.2 is based on a 50-year period.

Further discussion of how this receptor is modeled can be found in Appendix 9B of this report.

6.5.2.5 Recreational Water Contamination

The recreational waterways contamination potential is based on the idea that any product spill which reaches a waterway has the potential for negatively impacting recreational uses. This may be a result of short-term impacts to surface water quality which limit contact recreation and fish kills or contamination which may limit recreational fishing. This impact is modeled as being sensitive to tier location (see Chapter 7), specifics within the tier, and spill volumes.

An example of this impact is Case 1 shown in Table 6-12 and can be generally described as follows:

1. Approximately 38 percent of reportable leaks are of a size to pose a threat to a recreational water supply.

2. Of those leaks, approximately 25 percent would contaminate the receptor. This is determined by characterizing the various lengths of such receptors present within each tier. Each length within each tier is assigned a probability, indicating that length's vulnerability. In aggregate, these compute to be the equivalent of about a 25 percent probability all along the pipeline.

3. The industry average leak rate applied to this pipeline predicts 35 leaks and, hence, approximately 13 (38 percent of 35) would be of sufficient volume, and approximately 2.8 would occur at the right location to contaminate one of these receptors.

Threshold spill sizes of 500 bbl and 1,500 bbl, depending on the tier location, are assumed before impacts are considered to be significant. Above those thresholds, impacts are judged to be equally likely, regardless of spill volume. This is conservative, since even the spill volumes closer to the threshold are modeled to be as harmful as the largest spill volumes.

Further discussion of how this receptor is modeled can be found in Appendix 9B of this report.

6.5.2.6 Prime Agricultural Land Contamination

Impacts to agriculture were evaluated by reviewing soils data from US Department of Agriculture databases. Prime agricultural land was identified as those farmlands having certain soil types well suited to crops or orchards.

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

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

Further discussion of how this receptor is modeled can be found in Appendix 9B of this report.

6.5.2.7 Wetlands Contamination

Two separate types of wetlands crossings are noted along the pipeline ROW—palustrine and riverine. It is conservatively assumed that any contamination that reaches a wetland could impact the entire wetland. Therefore, the potential for impact to any wetland resource is represented by the distance across the wetland plus 1,250 ft on either side along the pipeline. A length of analysis for impacts to individual wetlands is set at 3,372 ft in order to encompass the average wetland crossing length, plus the 1,250 ft on either side of the pipeline that could impact the wetland during a spill. The probability of impact from a spill into or proximal to the wetland is conservatively set at 100 percent.

Discussion of how this receptor is modeled can be found in Appendix 9B of this report.

6.5.3 Event Frequencies

Tables 6-12 and 6-13 show the results of all frequency estimates for all impacts. Table 6-12 shows overall frequencies for all cases and Table 6-13 shows segment-specific frequencies for all cases. The overall frequencies shown in Table 6-12 are highest for impacts to recreational water (2.4 to 2.8) and wetlands (1.4 to 1.7). The impact frequencies are lowest for fatalities

(0.14 to 0.16), injuries (0.63 to 0.72) and contamination of prime agricultural land (0.14 to 0.16) and drinking water (0.17 to 0.20). The relative frequency values remain similar for both annual impacts and those for the whole life of the project. The segment-specific risks, as might be expected, are much lower than the overall risks, regardless of impact category. The distribution of risks is very similar to those for the entire pipeline.

The corresponding impact probabilities for some of these cases are discussed below and shown in Table 6-14 and Table 6-15.

6.5.4 Probabilities

The relationship between leak frequency and probability is expressed in terms of a Poisson probability distribution function. For pipeline and pump station equipment failures, the following equation relating the probability of a spill ("spill" will refer to any release, regardless of size) to the spill frequency applies:

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

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

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

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

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

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

P(probability of one or more)SPILL = 1 - P(X)SPILL; where X = 0.

A discussion of the rationale for the use of this functional form is found in the technical literature (Lees, 1996).

6.5.4.1 Basic Pipeline and Pump Station Probabilities

Spills can occur along the pipeline, at pump stations, or at terminals. Because dominant causes are different between the pipeline and pump stations and the effects due to possible locations differ, the pipeline and pump station cases are handled separately.

Inserting the average spill frequency for the pipeline in the above equation yields the probability for a pipeline spill *somewhere* along the route. Table 6-16 summarizes the probabilities for several spill size ranges along the pipeline (excluding stations). This is illustrated in Table 6-16 where the probability of one or more leaks occurring over the length of the pipeline is shown for a one-year and 50-year period. Probability must always be associated with a specific time frame; probability is the chance that an event will occur within a certain time period. Using the same equation with pump station event frequency data yields, pump station probabilities were similarly calculated and are shown in Table 6-17.

Probabilities associated with the previously discussed impact frequencies are shown in Table 6-14 and Table 6-15.

6.5.4.2 Confidence Limits

Confidence limits or intervals are commonly used in association with statistical calculations. Available data are a sample used to estimate characteristics of the overall population—all possible data including future measurements. The sample data can be used to calculate a point estimate, such as a mean value or the average leak rate in leaks per mile per year. A point estimate approximates the value for the entire population of data, termed the "true" value. However, this approximation is affected by the uncertainty in the sample data set. A confidence interval bounds the uncertainty associated with the point estimate. For example, a 95 percent confidence interval for the leak rate has a 95 percent probability of including the true leak rate.

When the number of data points available is small, the confidence limits are wide, indicating that there is not enough information available to be confident that all future data will be close to the small data set already obtained. Data on pipeline failure rates are limited. Hence, the use of upper limits of statistical confidence intervals, especially at a high, 95 percent confidence level, would not present meaningful representations of true failure potential. It will present unrealistically large predictions, strictly as a result of the small number of data points available.

Such predictions do not represent best estimates of failures. It may be theoretically correct to say, for example, that "one can be 95 percent confident that there is no more than a one in ten chance of a spill in this area" as a result of a statistical confidence calculation on limited spill data. However, the *best* estimate of spill probability might be only one chance in a thousand. In the EA, the future leak probabilities are estimated using the mean historical leak frequencies. In most engineering calculations, the mean values of those factors that have been derived from historical data are most often chosen as being the most likely to be predictive of future performance.

An alternative to the normal calculation of confidence intervals or bounds about the mean leak frequency is available for instances where the data set is very small. The confidence intervals can be calculated using methods proposed in Hahn and Meeker[1] and assuming a Poisson distribution of the leak frequency data. The calculation of these confidence intervals for the EPC pipeline over the past 29 years and over the most recent 10 years of operation are summarized on the following page.

[1] Hahn, G.J., and W.O. Meeker. Statistical Intervals, A Guide for Practitioners, John Wiley & Sons, Inc., New York, New York, 1992.

Confidence Intervals about the Leak Frequency, f

Case A: Last 10 years of Operation
Pipeline Length = 449.67 miles
Number of Leaks = 8

n = pipeline mile-year combinations
= 4496.7

for 8 occurrences, values of G from Table A.25 in Hahn & Meeker are:

G for 95% lower confidence bound = 3.454
G for 95% upper confidence bound = 15.76

Upper confidence bound = G (upper) / n
Lower confidence bound = G (lower) / n

Applying this method to Case A gives

Leak frequency	=	0.00178 leaks/mile/year
Lower 95% confidence limit	=	0.00077 leaks/mile/year
Upper 95% confidence limit	=	0.00350 leaks/mile/year

Case B: Last 29 years of Operation
Pipeline Length = 449.67 miles
Number of Leaks = 26

n = pipeline mile-year combinations
= 13040.43

for 26 occurrences, values of G from Table A.25 in Hahn & Meeker are:

G for 95% lower confidence bound = 16.98
G for 95% upper confidence bound = 38.10

Upper confidence bound = G (upper) / n
Lower confidence bound = G (lower) / n

Applying this method to Case B gives

Leak frequency	=	0.00199 leaks/mile/year
Lower 95% confidence limit	=	0.00130 leaks/mile/year
Upper 95% confidence limit	=	0.00292 leaks/mile/year

6.6 COMPARISONS WITH OTHER RISKS

This section discusses the risks that result from the operation of the Longhorn pipeline, before any risk mitigation is applied, in the context of comparable risks faced by society, government, and individuals.

6.6.1 Other Modes of Transportation

The history of pipeline operations in general shows that pipelines are a safer means of transportation for liquid products than other means of transportation. Pipelines have fewer high consequence incidents than truck or rail transport. Table 6I-1 in Appendix 6I compares accident data from other transportation modes with pipeline incident data. Truck transportation has a fire and explosion incident rate approximately 35 times higher and rail transportation 8.5 times higher than pipeline transportation accident rates. Death rates are correspondingly 85 and 2.5 times higher, respectively, and injury rates are 2 and 0.5 times higher. Table 6I-2 compares volumes of product spilled for different modes of transportation. On the average, the volume of product spilled for every million barrel-miles of product transported is approximately 2 times higher for truck transportation than for pipelines.

6.6.2 Other Pipeline Operators

Risks are posed by operation of other pipelines and by pipeline operators other than Longhorn. In Chapter 5, national spill statistics for WES (the proposed operator of the Longhorn pipeline), EPC (the former operator of a large segment of the pipeline), and another company that also operates a crude oil pipeline close to the Longhorn route, were compared to the national average for all hazardous liquid pipeline operators. All three operators showed spill rates below the industry average.

6.6.3 Other Common Risks Faced by Individuals

There are many threats that face individuals in common activities. Table 6-18 presents some of these common risks. For example, the table shows that during a 50-year exposure to these risks, a person has a 1 in 2 chance of being injured in an automobile accident. The risk of death as a driver is about 1 in 82 over the same period. These values compare with a 1 in 3,700 chance of death from recreational boating and 1 in 45,500 for death in a tornado. These risks can be compared with individual location risks for the pipeline, based on results discussed in Section 6.5.4.

6.7 SUMMARY OF FINDINGS

The overall findings of this risk assessment show that risk of a spill is highly variable along the length of the pipeline. It shows that these variations occur because of different system and geographic characteristics along the route. These characteristics were discussed in Chapter 4 and Chapter 5.

The probability of explosion arising from a leak on a gasoline pipeline is statistically very remote. If a pipeline spill and subsequent ignition occurs, a flash fire and/or pool fire is possible. However, 96 percent of pipeline gasoline spills do not ignite. The areas potentially impacted by heat effects along the pipeline show ranges in distances from the pipeline from a few hundred feet up to approximately 2,000 ft from the pipeline, depending on the size of a spill and site-specific drainage conditions. Gasoline fires affect distances about 20 percent farther than crude oil fires.

A corridor of 2,500 ft, 1,250 ft either side of the pipeline centerline, was generally used as the impacts zone to identify sensitive receptors.

6.7.1 Relative Risk Assessment

This assessment provides a relative measure of the conditions and activities that impact POF along the pipeline route. This assessment should therefore correlate to a level of absolute POF that exists in various segments of the pipeline. It provides a rational basis for prioritizing mitigation measures to reduce risks.

The relative assessment used as much “raw” data as could be assimilated. This was done to remove as much subjectivity as possible and thus provide the most realistic analysis possible. A high level of detail was achieved as evidenced in the creation of several thousand pipeline segments for analysis.

As expected, there were many variations in risk along the route of this pipeline. Differences are due to varying conditions external to the pipeline system, such as:

- Topography;
- Soil conditions;
- Potential for damaging earth movements; and
- Potential for third-party damage.

Differences are also due to varying pipeline system characteristics such as:

- Pipe type;
- Coating condition;
- Normal operating pressure; and
- Types and dates of integrity validations.

There are many ways to examine these data, statistically and graphically. Many correlations between risk variables can be made and are illustrative in analyzing specific aspects of the total risk.

Older portions of the pipeline have the higher POF scores. This is driven to a large extent by the corrosion potential and third-party damage potential in these areas. Some of these areas are in Houston and Austin. Few differences are seen in the human operator error (Incorrect Operations Index) potential along the pipeline. The few differences are mostly because of the differences in potential stress levels of the pipe (ease of overpressure) and system age considerations.

The relative POF scores are intended to be used with the impact zones, tiers described in Chapter 7, in order to complete the risk assessment.

Comparison with other relative risk assessments for this pipeline by EPC and WES shows similar relative results overall, although differences in resolution and factors considered make specific comparisons imprecise.

6.7.2 Probabilistic Risk Assessment

Using historical failure rate data as a basis for estimating probability of future accidents has its limitations. However, using these data, estimates of impact frequencies and probabilities have been made.

If the site-specific probabilities are compared with other common risks, the risks of accidents on this pipeline for specific receptors are lower than the other common risks.

6.8 REFERENCES

Allegro Energy Group, Analysis of DOT Reported Data, 1992-1997, Internal Information Package, Prepared for URS Radian, 1999.

Bryan, J.L., “Defining Damageability: The Examination, Review and Analysis of the Variables and the Limits of Damageability for Buildings, Contents, and Personnel from Exposure in Fire Accidents,” March 1985.

Center for Chemical Process Safety (CCPS), “Guidelines for Hazard Evaluation *American Institute of Chemical Engineers*, New York, N.Y., 1992.

EPA, “Handbook of Chemical Hazards Analysis Techniques,” US Environmental Protection Agency, US Department of Transportation, and the Federal Emergency Management Agency, 1989.

Lees, F.P., “Loss Prevention in the Process Industries,” Butterworth’s, 1996.

Longhorn Partners Pipeline, Longhorn Project Description, March 1, 1999.

Longhorn Partners Pipeline OPA ’90 Plan, Department of Transportation, URS Radian No. 206, 1999 (date obtained).

LUFT (1988) “Leaking Underground Fuel Tank Manual: Guidelines for Site Assessment, Cleanup, and Underground Storage Tank Closure,” State of California Leaking Underground Fuel Tank Force, May 1988.

Meeting, US Environmental Protection Agency, US Department of Transportation, and URS Radian representatives with Longhorn Partners Pipeline, Williams Energy Services, and Exxon Pipeline Company representatives in Houston, March 4, 1999.

Morgan, E.I.B., D. Little, and M. Beard “An Approach to the Risk Assessment of Gasoline Pipelines,” The Pipeline Reliability Conference, Houston, Texas, November 19-22, 1996.

Muhlbauer, W.K., “Pipeline Risk Management Manual, Gulf Publishing Co., 1992.

Muhlbauer, W.K., “Pipeline Risk Management Manual,” Second Edition, Gulf Publishing Co., 1996.

National Fire Protection Association (NFPA) 704, “Identification of Fire Hazards of

The Pipeline Reliability Conference, Houston, Texas, November 19-22, 1996.

US Department of Transportation, Office of Pipeline Safety, Common Ground, Study of One-Call Systems and Damage Prevention Best Practices, June 1999.

Williams Energy Services Operations Control Procedures, URS Radian No. 879, 1999 (dated obtained).