	8" Pipeline, Crane to Odessa – November 1998 (0.5 mile remains to be constructed to Odessa Meter Station) Odessa Meter Station – In design Cleaning and refurbishment of the existing pipeline 18"/20"- March to November 1998 Equipment installation remaining at a few sites Pipeline Laterals – In design (from El Paso terminal to tie-in point with three interstate pipelines)

3. SYSTEM INTEGRITY PLAN

3.1. Introduction

3.1.1 Longhorn Commitment to Pipeline System Integrity Program:

Longhorn Pipeline expressly commits to proactively identify, analyze, and manage the inherent risks associated with the operation of the Longhorn Pipeline and its associated assets. Longhorn intends this commitment to be made to the public at large, the communities along the pipeline path, the environment, potentially impacted flora and fauna, regulatory agencies, Longhorn's employees, third party contractors and suppliers, and Longhorn's investors.

Longhorn is committed to constructing, operating, and maintaining its pipeline assets in a manner that ensures the long-term safety to the public and to its employees, and that minimizes the potential for negative environmental impacts.

Longhorn, through its Longhorn Pipeline System Integrity Plan (LPSIP), is committed to the philosophy and proactive practice of the prevention of accidents.

Longhorn further commits to work collaboratively with all of its stakeholders, which includes the public and regulatory agencies, to optimize the opportunity for success of its LPSIP.

3.1.2 Risk Management

Similar to all pipeline systems, the Longhorn Pipeline assets have specific physical attributes that are characterized by its materials of construction and installation and by maintenance methods. The Longhorn Pipeline is further characterized by the products that it transports, its operating parameters, and its routing through a variety of population densities, land uses, and environmentally defined areas. Taken collectively, Longhorn Pipeline's physical assets, products transported and operating systems are factors that characterize the relative risks to the surrounding environment and areas of population. Physical data, collected by and contributed from an integrated team of operating, technical, and subject matter experts, is the cornerstone for the "Risk Management" process.

As an outcome of the Environmental Assessment process, Longhorn has benefited from significant input, recognized industry expert opinion, and detailed system assessments and evaluations. Specifically, the input of individuals and organizations such as Radian International, Kiefner and Associates, Inc., W. Kent Muhlbauer, the Office of Pipeline Safety (OPS), the Environmental Protection Agency (EPA), and LBG-Guyton Associates, specifically Charles W. Kreitler, Ph.D., has contributed to an enhanced understanding, identification, and appreciation of the potential risks and areas of sensitivity along the Longhorn Pipeline route. The Environmental Assessment process has resulted in the implementation of a number of specific risk mitigation initiatives, which are being incorporated prior to or following startup of the pipeline. The Environmental Assessment process and the accompanying mitigation initiatives establish the system integrity baseline for the Longhorn Pipeline. Further, Longhorn will evaluate the incorporation of the remainder of the Environmental Assessment information into its ongoing System Integrity Plan.

Longhorn will utilize a formal, relative risk assessment model to assist it in meeting the commitments to system integrity that were expressed in the previous section. For purposes of the LPSIP, "risk" is defined as: the product of (1) the probability, or likelihood, of an event, and 2) the potential consequences of that event.

The LPSIP has been carefully designed to gather unique physical attributes of the Longhorn Pipeline System assets, to identify and assess the risks to the public and the environment, and to actively manage those risks through the implementation of risk mitigation plans. The LPSIP, as the core organizational driver for Longhorn management initiatives and operational priorities, is charged with making improvements based upon system integrity analysis and performance metrics. The LPSIP also has responsibilities for resource allocation (time, talent, and money) targeted at risk mitigation.

Since the Longhorn Pipeline System traverses Texas from East Houston to El Paso and passes through a variety of unique areas of land use, topography, and population density, it likewise presents a variety of risk concerns to these lands and to the people who either inhabit or are present in these areas. Longhorn's relative risk assessment model divides the pipeline into logical segments which are individually analyzed for risk, and which subsequently ranks these segments using a relative risk sorting. Specifically, as a result of this process, the entire Longhorn Pipeline System has been categorized in accordance with the following designations: Tier I (normal cross-country pipeline), Tier II (sensitive areas), and Tier III (hypersensitive areas). Further, the area across the Edwards Aquifer in South Austin is a Tier III designated area of additional heightened environmental sensitivity that has resulted in even more scrutiny and the commitment to incremental risk mitigation measures.

Relative risk assessment allows Longhorn to target and focus on those pipeline segments posing the highest risk to population and/or environment, so to facilitate the development of risk mitigation programs. This enables the implementation of controls and measures with which to reduce the likelihood of adverse events or to mitigate the potential consequences. The inherent value in Longhorn's risk management approach to its LPSIP is that it ensures that its resources (time, talent, and money) are effectively employed in those areas of highest risk.

3.1.3 System Integrity Program Mission

Identify and manage risks associated with operating the Longhorn Pipeline System in a manner that ensures long term safety to the public and employees, and which minimizes negative environmental impacts.

Of critical importance to the success of its mission, the LPSIP is intended to function in addition and complementary to the base regulatory requirements of the U.S. DOT's RSPA Pipeline Safety Regulation, Title 49, Subchapter D, Part 195 (Transportation of Hazardous Liquids by Pipeline).

3.1.4 Areas of Emphasis

System Integrity is focused on two fundamental areas of emphasis in relation to the risk management process:

1. Current pipeline assets - Manage risks of Longhorn Pipeline assets. This includes the allocation of financial resources for a risk mitigation plan such as internal inspection and depth of cover initiatives.

2. Construction and rehabilitation projects - Mitigation of existing and minimization of future installed pipeline risks to the public and to the environment.

3.1.5 LPSIP Goals

1. <u>Effective</u>

- To function as an integral part of, and value added contributor to, our ongoing pipeline operations, construction activities, and business development processes
- To minimize accidents, and their consequences, on the Longhorn pipeline
- To help guide the allocation of resources to minimize our operational risks
- To identify all risks along the pipeline
- To enhance long term safety
- To educate and inform all stakeholders on identified risks
- To meet the intent of OPS, other governing and regulatory agencies, and additional Longhorn commitments

2. <u>Efficient</u>

- To mitigate risk with the highest benefit to cost ratio

3. <u>Adaptable</u>

- To adapt to change and unique requests
- To monitor, evaluate, and implement new technologies

4. <u>Continuous Improvement</u>

- To provide a method to confirm or improve the effectiveness, efficiency, and adaptability of the program by continuously measuring, evaluating, and upgrading the program.

3.1.6 Longhorn Risk Management Program Guiding Principles

Risk Management is a comprehensive management decision support process, implemented as a program, and is integrated through defined roles and responsibilities into the day-to-day operations, maintenance, engineering, management, and regulatory decisions of the operator.

1. Risk Management is a continuous process.

2. Risk cannot be completely eliminated.

3. Risk can be controlled through the cost-effective application of finite resources.

4. Risk Management increases, integrates, and enhances the value of information concerning pipeline safety.

5. Risk Management programs are structured but flexible, allowing customized approaches to be developed for specific issues and situations, encouraging innovation, and supporting continuous improvement.

6. The implementation of a risk management program should result in superior public safety and environmental protection.

7. Risk Assessments are critically dependent on the information requested and gathered from field operations through an open dialogue format.

8. Inclusion of operational and technical personnel into the System Integrity Program ensures accuracy and validates the results of the relative risk ranking results.

3.2. Longhorn Pipeline Management Commitment

Longhorn management will be responsible for providing the resources necessary to implement the LPSIP and will ensure that the program is executed in accordance with the "Process Elements" discussed in Sections 3.2.1, 3.3, and 3.4.

Longhorn will ensure its operations, maintenance, and improvement activities will be governed by an overall system integrity and risk management process through the adoption of this LPSIP. Longhorn further adopts the current mitigation plan contained in the Longhorn Mitigation Plan for all subsequent years of operations, as modified periodically by the Operational Reliability Assessment ("ORA"), conducted in accordance with Section 3.3, the Annual Third Party Damage Prevention Program Assessment, conducted in accordance with Section 3.2.2.5, or other recommended modifications implemented in conjunction with OPS oversight and partnership discussed in this Section (collectively, the "Longhorn Continuing Integrity Commitment"). The Longhorn Continuing Integrity Commitment has been adopted by Longhorn for the express purpose of insuring that, over time, the integrity of the pipeline will be maintained and the environment will be protected at levels which are equivalent to those adopted by Longhorn at start-up of its pipeline, judged, at all times, by industry accepted and proven standards (as the same may change and improve over time).

As a proactive means to address the contributing factors of human error, Longhorn commits to expand its LPSIP to include formalized processes and programs which embrace and incorporate the elements of the Longhorn Integrity Management System (LIMS), Hazards and Operability Study (HAZOP), and Management of Change (MOC) processes. Through the integration of LIMS, HAZOP, and MOC into the LPSIP "Process Elements" (Section 3.4) and the Detailed Program Descriptions (Section 3.5), Longhorn commits to the installation, maintenance, and continuous improvement of its System Integrity Plan, which is further supported through performance based metrics and critical self-analysis.

Longhorn Pipeline commits to proactively share its self audit results and System Integrity Plan information with the Office of Pipeline Safety (OPS), and the information will be available to the public. Partnership with the OPS will ensure that Longhorn works cooperatively with the OPS in full keeping with the intent of the LPSIP, which will thereby improve Longhorn's opportunity to maintain and further improve upon the long term safety and overall integrity of its pipeline system. Partnership through the LPSIP is intended to further enhance the communication and information sharing between Longhorn and the regulatory agencies, which will lead directly to focusing resources on the most important threats and risks to Longhorn's immediate and long term pipeline safety. Longhorn fully endorses the following program goals:

- Enhance public safety and environmental protection by concentrating the deployment of Longhorn and OPS inspection resources to areas of greatest safety and environmental risk, and by addressing issues of mutual concern.
- Provide OPS with an enhanced understanding of Longhorn's entire system, including pipeline operation, maintenance, and emergency response programs. A more broad-based understanding of the Longhorn's integrity issues enables OPS to better consider and review with Longhorn the range of available integrity enhancements.

Longhorn Pipeline is fully committed to the active participation in and the proactive support of the State of Texas One-Call Damage Prevention Program (HB2295) for underground facilities. Longhorn further commits to stay abreast of regulatory and/or industry sponsored damage prevention programs. Longhorn has adopted the recommendations of the OPS sponsored "Dig Safely" (DAMQAT) and "Common Ground", One-Call Systems Best Practices Study Initiatives, and will require that its operator, contractors, and agents comply with same.

Longhorn management will employ, through its contract operator, a system integrity group that is technically competent and has demonstrated experience in pipeline operations and maintenance, technical support, risk identification, and overall management of mitigation measures and programs.

The System Integrity Group will be responsible for the following:

- Overall system integrity and risk management process
- Capital and maintenance funding oversight

- Incorporation of the management of change (MOC) process
- Development and distribution of system integrity status reporting centralization of pipeline attribute data
- Assessment and analysis of identified areas of risk
- Oversight and execution of the risk assessment model and development and maintenance of the relative risk assessment of the Longhorn Pipeline System
- Oversight of risk mitigation initiatives
- Capital and maintenance funding oversight and allocation of risk mitigation initiatives not related to routine operation and maintenance requirements
- Continuously evaluating new technology, new risk assessment processes, new mitigation processes and similar activities in a concerted effort to improve overall system integrity process

3.2.1 Longhorn Pipeline System Integrity "Process Elements"

The Longhorn Pipeline System Integrity Program consists of certain specific "Process Elements." The descriptions and program attributes of the Process Elements reflect action "over and above" those specified and required under various regulations and statutes, such as DOT's Title 49 C.F.R. Part 195.

Implementation of the "Process Elements" will ensure that Longhorn will effectively identify, analyze, and responsibly manage the most important threats to and risk of the Longhorn Pipeline System. The specific Process Elements are identified in Section 3.4 and are more fully described in Section 3.5.

As opposed to specific program descriptions and details on triggers for action within each program, the following information provides more of an overview of the general groupings and activities which comprise the LPSIP. Further, this information demonstrates the linkage between the various individual programs and the overall LPSIP.

3.2.2 Data Gathering and Identification and Analysis of Pipeline System Threats

1. The Longhorn Pipeline System Integrity Plan is specifically designed to identify, assess, and manage those elements and attributes that could lead to the inadvertent release of hydrocarbon products to the environment. The primary areas of focus include the following:

- An initial and ongoing assessment of the mechanical condition of the pipeline components
- An initial and ongoing assessment of controlling devices to ensure that operating pressures remain within safe parameters
- Internal analysis of product characteristics and protection efforts to eliminate issues of internal corrosion
- Mitigation plans to eliminate issues of external corrosion
- Third party damage prevention programs

RAD 38908

- Analysis of potential impacts to pipeline integrity resulting from acts of nature, such as earth movement, water caused erosion, and flooding

2. LPSIP has two fundamental components. The first component includes a focus on the mitigation of Third Party Damages, Corrosion, Incorrect Operations, and Mechanical Design/Installation. The second component is a detailed segmenting of the pipeline with respect to population density, drinking water supplies, endangered species and recreation areas. The preparatory work performed and the information gained during the Environmental Assessment process, along with the resulting Tier I, Tier II, and Tier III segmentation, have provided Longhorn with a sharp focus on high relative risk areas along its corridor. Collectively, the analysis of these components results in an assessment of those conditions and forces which could possibly impact the integrity of the pipeline and its contained products. It also focuses resources to those areas that are the most sensitive.

Results of the initial and periodically updated LPSIP will be presented quarterly to Longhorn senior management and annually to the Longhorn Board of Directors.

3. The LPSIP analyzes the relative "likelihood" and "consequences," and asset integrity, within the categories identified in item 2 above. The two components, likelihood and consequence, allow for the targeted analysis of those potential occurrences that could have the greatest impact on the environment or the public in the event of a product release. With a heightened awareness of targeted physical areas, a "Scenario Based Analysis" will be performed to identify, assess, and manage associated risks.

4. The LPSIP incorporates the centralization and analysis of data collected through several distinct yet complementary programs. As pipeline attributes change, or as changes in environmental or population factors occur, the relative risk assessment model will be modified to ensure that the risk assessment process remains current and accurate. The relative risk assessment model also will be updated to reflect technological improvements and other sources of previously unavailable data.

Individual programs which contribute to the LPSIP risk assessment model include:

- Depth of cover surveys
- Population density surveys
- Land use and activity surveys
- One-Call activity levels surrounding the pipeline right-of-way easements
- Aerial patrol records, encroachment sightings, corrosion monitoring and maintenance program
- Internal corrosion coupon monitoring program
- Right-of-way condition monitoring and maintenance leak history reports
- Root cause analysis and incident investigations
- Cleaning pig reports and debris analysis
- Excavation reports and third party crossing line inspections
- Pipeline coating condition reports
- Metallurgical analysis of coupons

RAD 38909

- Smart pig results analysis
- Third party pipeline crossing inspections and cathodic protection interference data
- GIS mapping information and participation with the OPS National Pipeline Mapping System (NPMS) Program
- Metallurgical analysis of corrosion coupons and pipe cut outs
- Metal fatigue analysis and pressure cycling operational data

5. Annual Third Party Damage Prevention Program Assessment - Longhorn Pipeline will consider the probability and consequences of third party damage as a component of its System Integrity Plan. Through the active monitoring of one-call activity levels, by area designation, across the pipeline system, coupled with population densities, environmentally sensitive areas, and the proximity of the pipeline to areas of public access (such as roads, parks, and other non-dwelling places of public gathering), Longhorn will annually assess the potential for inadvertent third party caused damages.

Data input to the Third Party Damage Prevention Program Assessment will include the tracking of the number of detected unauthorized ROW encroachments, changes in activity levels, changes in one-call frequency, physical hits, near misses, and repairs that occur along the Longhorn pipeline. Other key contributors to the assessment will include results data from internal pipeline inspection tools that are capable of identifying, locating, and qualifying pipeline dents, scrapes, and potential general third party caused pipeline damages in comparison with baseline attribute data.

Taken collectively, the Annual Third Party Damage Prevention Program Assessment process can initiate mitigation measures including the application of internal dent detection inspection tools, additional emphasis on the Damage Prevention Program, pipeline inspection patrol frequencies, public education programs such as Dig Safely, the further application of right-of-way encroachment programs, and other listed LPSIP Process Elements. The Annual Third Party Damage Prevention Program Assessment will be provided to the contractor developing the ORA to be incorporated into the recommended integrity analyses and recommendations.

Undetected third party damage to pipeline assets presents several risk elements that will be considered by Longhorn. In addition to the immediate and sometimes severe issues created through the complete puncture of the pipeline wall, Longhorn will also consider the longer term issues created through third party excavation activities that may be conducted near or around its pipeline assets. Relatively minor scrapes, scratches, dents and gouges to the pipeline metal wall or coating materials can lead to accelerated fatigue effects such as corrosion, crack propagation, or stress points. Even "non-direct" contact to the pipeline, such as through the inadvertent impingement of rocks against the pipeline, displacement of the pipeline against hard ditch walls, or the severing of cathodic protection wires, groundbeds, anodes, or cables can all lead to an accelerated loss of pipe integrity. Consequently, Longhorn will consider both the likelihood and the consequences of these types of occurrences in its Third Party Damage Prevention Program and in its overall LPSIP and ORA analysis. Longhorn will look for both positive and inferred indicators of these third party damages as part of its program.

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One significant component of the Annual Third Party Damage Prevention Program is to consider the likelihood of "undetected" third party damages to the pipeline assets. Indicators of such damage potential includes:

- The number of times that ROW encroachments without prior notification are discovered through pipeline surveillance activities,
- A subjective sense of the respect and observance of one-call practices in areas along the pipeline by both the public at large and excavation contractors,
- The number of new third party pipeline damages that are discovered via internal or external pipeline inspections, the number of direct hits to the pipeline,
- The number of one-call reports (activity levels),
- One-call auditing process to provide feedback on the program effectiveness,
- Indications of "fresh" digging or excavation activity around the pipeline,
- The number of discovered pipeline coating damages,
- Unexpected changes in cathodic protection requirements and/or system performance,
- The number of foreign line crossings, along with a sense of the relative activity levels of these foreign lines in proximity to the Longhorn assets,
- Areas of seismic or heavy industrial activity in near proximity to the Longhorn assets,
- Aerial patrol and other surveillance reports, and
- Land use consideration, such as areas of cultivation, urban sprawl through commercial or housing developments, and roadbed or highway maintenance and construction activities.

The Third Party Damage attributes will be incorporated into the LPSIP, and by inclusion into the ORA, to further assist Longhorn and its third party consultants in the identification and recommendation of risk reduction mitigation measures. Further, inclusion of these attributes will allow for heightened awareness and sensitivity to those identified areas along the Longhorn corridor that appear to be more susceptible to third party damages. Heightened awareness and sensitivity will also provide guidance and input to possible increased public awareness education, increased surveillance activities, and emphasis on increasing pipeline markers. Results from Third Party Damage Assessment could also likely lead to recommendations for accelerated internal pipeline inspections or other investigative methods to assess overall pipeline integrity.

3.2.3 Integration of System-Wide Activities

The LPSIP will centralize and incorporate information and recommendations from the following individual programs, initiatives, or Groups:

- Pipeline Relative Risk Assessment Model
- Internal Corrosion Assessment
- External Corrosion Monitoring and Maintenance
- One-Call activity lists
- Field Operations gathered pipeline attribute data
- Operations Control Leak Detection Program

RAD 38911

- Operations Control Operating Data
- Real Estates Services Group for third party encroachment management
- Engineering Assessment
- Safety, Environmental, and Training Services (SETS)
- Design Services
- Product Quality Control and Testing/Analysis
- Management
- In-line inspection program (smart pigging)
- Depth of cover program

3.2.4 Incorporation of Engineering Analysis

The LPSIP incorporates the following engineering analysis programs and attributes as input:

- "Pipeline Risk Management Manual," Second Edition, by W. Kent Muhlbauer
- Office of Pipeline Safety Pipeline Risk Demonstration Program
- Office of Pipeline Safety Integrity Inspection Pilot Program
- Damage Prevention Quality Action Team Program (DAMQAT)
- "Common Ground," One-Call Systems Best Practices Study
- Third party Industry Technical Consultants
- Vendor Literature
- Industry Trade Association Recommended Practices and Standards

3.2.5 Integration of New Technologies

System Integrity Group personnel regularly participate in industry and government sponsored technical conferences, which allows for an awareness and evaluation of developing technology and practices. Additional information is gained through the active participation and support of organizations such as API, AOPL, GPA, NACE, ASME, and ASCE. Many of these provide active support and financial aid to organizations including the Gas Research Institute and Batelle, which are routinely involved with the development of new technologies such as high resolution smart pigging and mechanical fatigue testing of pipeline materials. Further, reference to vendor literature and presentations and technical publications are other avenues used to stay abreast of developing system integrity technologies and methodologies.

3.2.6 Root Cause Analysis and Lessons Learned

The Longhorn Pipeline System Integrity Program incorporates a formal Incident Investigation Program (see Section 3.5.6) that includes analyses for root causes in actual and near miss events. Also included in the root cause analysis process are pipeline or system component repairs that are made to correct deficiencies or possible breaches in system integrity or reduction in maximum allowable operating pressure capabilities. The findings from the Incident Investigation Program are published and shared with affected Operations and Technical personnel, and are also integrated into the ongoing LPSIP analysis process.

3.2.7 Industry-Wide Experience

Resources for input to the LPSIP include information from Williams, the designated operator of the Longhorn Pipeline System. Williams brings information and programs from its operation of approximately 22,530 miles of Part 195 regulated hazardous liquids pipelines (9,170 miles refined products and 13,360 miles NGL). Additional information and experience is available from API and AOPL developed data and pipeline industry associations.

Additionally, Longhorn has access to pipeline operations, maintenance, and risk management practices from ExxonMobil and BPAmoco, which provides a forum for the sharing of data and risk management program experiences from these respected operating companies.

3.2.8 Resource Allocation

The LPSIP will manage the allocation and distribution of maintenance capital and asset integrity expense funding.

Dedicated maintenance capital and expense funding pools are managed through a relative risk assessment methodology that ensures that funding is targeted to maximize the risk mitigation objectives.

3.2.9 Workforce Development

As part of an ongoing educational and developmental process, system integrity presentations, newsletters and advisory bulletins shall be distributed, and workforce training and system integrity presentations shall be conducted under the advisement of the System Integrity Group.

3.2.10 Communication to Longhorn and Operations Management

System integrity presentations, newsletters, advisory bulletins, and workforce training initiative status updates shall be provided to the Longhorn Board of Directors. Risk mitigation initiatives and project funding plans shall be provided to the Longhorn Board of Directors at regularly scheduled meetings.

3.2.11 Management of Change

Longhorn has in place guidelines for monitoring and reviewing environmental, safety, and regulatory compliance requirements and associated risks when operational, business, and project changes occur.

Longhorn's Management of Change process is described at Section 3.5.7. This Management of Change program controls all qualifying changes in operation and maintenance practices.

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3.2.12 Performance Monitoring and Feedback

The LPSIP will incorporate performance measures of program effectiveness through the scorecarding and analysis of incident rates, near miss occurrences, leak history, spill volumes, root cause analysis classification of incidents, service interruptions, quantity and associated costs of integrity initiatives, and categorization of integrity initiatives.

System Integrity Group performance measures and scorecard results shall be formally presented to Longhorn management on an annual basis. Quarterly performance updates shall also be distributed.

3.2.13 Self Audit

Longhorn will perform an annual self-audit of its LPSIP, with the intention of ensuring that stated plan goals, objectives, and commitments are being met. Longhorn also will perform a self-audit prior to implementing any throughput increase that requires the construction of new pump stations; the self-audit results will be shared with OPS, prior to implementation of the increase, and will be publicly available. Further, the Self Audit Process will provide the framework for overall LPSIP feedback and continual improvement.

3.2.14 Longhorn's Continuing Commitment

The Longhorn Continuing Integrity Commitment as described in Section 3.2 hereof has been adopted by Longhorn for the express purpose of insuring that, over time, the integrity of the pipeline will be maintained and the environment will be protected at levels which are equivalent to those adopted by Longhorn at start up of its pipeline, judged, at all times, by industry accepted and proven standards (as the same may change and improve over time). As part of the Longhorn Continuing Integrity Commitment, Longhorn has agreed to implement and be bound in the future by (a) the System Integrity commitments set out in Section 3.2 hereof, (b) the Mitigation Commitments described in Section 1.2 hereof, (c) the annual Operational Reliability Assessment described in Sections 3.3 and 4.0 hereof and (d) the required integrity verification procedures and remediation measures that will have to be implemented as a result such commitments and assessments. The results of these commitments will be incorporated into a formal relative risk assessment model similar to the one utilized in the Environmental Assessment process.

During the periods of time that Longhorn is implementing mitigation measures pursuant to the Longhorn Mitigation Plan, it will provide to OPS, and make available to the public, periodic reports setting out the status of mitigation commitment implementation and the results of mitigation-related studies and analyses. Additionally, Longhorn will perform an annual self audit of its System Integrity Plan for the purpose of ensuring that its stated plan goals, objectives and commitments are being met. The results of the annual self audit, including a relative risk assessment for the pipeline, will be shared with OPS and made available to the public. Further, Longhorn will submit periodic reports to OPS summarizing developments related to its Operational Reliability Assessment. These reports will be also made available to the public. Through the reports made available to the public, the public will be able to monitor Longhorn's continuing commitment to maintain the integrity of the pipeline at levels equivalent to those in place at start up.

Longhorn commits to maintain its relative risk assessment model with current up to date information and to make the results of that model available to the public as part of the reports described above. Longhorn considers this model to be an invaluable tool in the relative ranking of pipeline segments along its corridor. It needs to be noted though that the nature of the relative risk assessment model is that it results in an automatic decrease in scores over time. However, these decreases in scores have no direct relationship to a decrease in pipeline safety. Instead they provide a useful tool to analyze and prioritize maintenance, inspection and repair measures that will be implemented as part of Longhorn's Continuing Integrity Commitment, which measures will, in turn, raise the relative risk scores to levels consistent with the integrity baseline established for the pipeline at start up. Additionally, as pipeline attributes change, or as changes in environmental or population factors occur, the relative risk assessment model will have to be modified to ensure that the risk assessment process remains current and accurate. The relative risk assessment model also will have to be updated from time to time to reflect technological improvements and other sources of previously unavailable data. The modifications and updates to the relative risk assessment model that will have to be made over time will result in relative risk assessment scores in the future that will not be directly comparable to the relative risk assessment scores determined at the time of start up. Instead, Longhorn's continuing compliance with its Continuing Integrity Commitment will provide the best yardstick by which to measure the continuing safety of the Longhorn pipeline at levels equivalent to those in place at start up.

3.3 Longhorn Operational Reliability Assessment

Longhorn Pipeline will conduct an annual (not to exceed 15 months between assessments) ORA for its pipeline system (including physical pipeline, pump stations, terminals, and associated mechanical components). The ORA shall adjust integrity verification frequencies in response to changing uncertainties over time in response to environmental changes along the pipeline route and in response to data collected from integrity testing, additional attributes, changed attributes, root cause analysis results, or other programs identified in the LPSIP.

Although anticipated to be conducted on an annual basis, the ORA, or portions thereof as it relates specifically to any component of the overall Longhorn Pipeline System, may be conducted on a more frequent basis. Utilizing a methodology consistent with the overall integrity and risk assessment philosophy of the Longhorn Pipeline System Integrity Plan, triggering events such as major pipeline incidents, significant industry or agency advisories affecting pipeline integrity, or the advancement of new technologies that would result in dramatic reductions in pipeline risk or gained knowledge of mechanical attributes and component condition could lead to the initiation of an ORA at a more frequent interval. Other considerations for a more frequent ORA could include significant changes in pipeline operations, new or dramatic shifts to environmental issues, population shifts, or major reclassification of the activity level in areas around the pipeline assets, such as that caused by major construction or seismic induced stress considerations. Similarly, natural disasters such as flooding or ground movement faults that could jeopardize the integrity of the pipeline assets would also be considered in the evaluation for possibly increasing the frequency of the ORA.

The ORA expressly incorporates the Longhorn Continuing Integrity Commitment discussed in 3.2 above. By virtue of the incorporation of the Longhorn Continuing Integrity Commitment, the ORA shall clearly calculate changing risk over time and adjust integrity verifications in response to environmental changes over time along the pipeline route, considering all potential failure modes and contributing risk variables such as increasing activity levels, new buried utilities, any coating deterioration and other changes.

The ORA shall specifically include the results and data attributes of all internal inspection logs, close interval surveys, line condition reports, terminal and pump station inspection reports, product corrosivity reports, fatigue monitoring, and all other relevant system attributes, or other changes which would impact failure probability. Third party damage probability, based on the Annual Third Party Damage Prevention Program Assessment discussed in Section 3.2.2.5, will be considered when determining the recommended frequency of integrity verification inspections. The ORA results will include an assessment and discussion regarding the likelihood of both newly incurred and the growth/propagation of older existing external third party caused pipeline and coating damages. Further, the ORA shall make recommendations back through the process identified via the LPSIP in regards to third party damage mitigation and prevention initiatives.

The ORA is specifically intended to incorporate the results of all elements of the LPSIP as attributes and data to consider in the overall assessment of the mechanical condition of the Longhorn Pipeline assets. Further, any LPSIP or other initiated internal or external third party studies and evaluations, such as earth movement studies that may include specific areas such as landslide, erosion, scour and subsidence, will be made available to and incorporated into the ORA evaluation.

Surge analysis studies along with historical operating records of pressure peaks and cycles will be incorporated into and made a part of the ORA. For areas of potential and experienced surge pressures in excess of MOP in Tier I areas, the ORA shall consider the higher of surge pressures or MOP in determining the appropriate degree of scrutiny, evaluation, and resultant care in both the analysis process and the recommendations.

Longhorn will select and employ a reputable third party independent technical company, or companies, with demonstrated mechanical integrity/metallurgical pipeline and component analysis capabilities to perform its ORA assessment. Longhorn commits to select an ORA contractor(s) that will be subject to the review and the approval of OPS. With the approval of the OPS, Longhorn commits to implement the recommendations of the ORA based upon industry proven feasible methods of integrity verification required to timely implement proactive responses to prevent leaks and ruptures.

The ORA will provide Longhorn with an annual technical assessment of the actual effectiveness of the overall LPSIP. The ORA will also provide feedback on the adequacy, frequency, and additional element criteria of the evaluation plan, which includes use of internal inspection devices, hydrotests, and other mechanical integrity assessment and confirming processes and technologies. The ORA will also minimize risk degradation over time through ORA identified and recommended integrity verifications.

The ORA will proactively incorporate new and emerging technologies and processes that will assess and/or prove the integrity of the pipeline system. Employment of new and emerging technologies and processes, either in lieu of or incremental to existing known technologies, will be subject to the joint review and approval of OPS.

The ORA results will be factored back into the LPSIP, and will be integrated into the ongoing program.

As stated above, recommendations from the ORA, as identified by third party independent technical experts, with the approval of the OPS, will be implemented by Longhorn. Further, as ORA and LPSIP directed risk assessment and investigative activities and related mitigation initiatives are completed, updated data and pipeline attributes to Longhorn's formal relative risk assessment model (as identified in Section 3.1.2 of the LPSIP) will be incorporated into the model database. Longhorn commits to maintain its relative risk assessment model with current up to date information, and considers this model to be an invaluable tool in the relative ranking of pipeline segments along its corridor. The model allows for a multitude of investigative assessments that concentrate on specific attributes within the broader categories of Third Party Damages, Corrosion, Incorrect Operations, and Mechanical Design/Installation, and it is an excellent tool for "what if" and scenario based analysis. The model allows for perceived risks and threats to pipeline integrity to be proactively identified and evaluated. Coupling of the LPSIP commitments, the Longhorn Mitigation Plan (both initial and future identified initiatives), and the ORA recommendations and analysis, into the ongoing formal relative risk assessment model tool will enable Longhorn to honor its commitment to ensure the initial and long term integrity of its pipeline system. The net results of these efforts and commitments allow Longhorn to provide for the safety and protection of the public and the environment, and to provide a valuable service in the safe, effective, and economic transportation of motor fuels to Longhorn's direct and interconnecting market destinations.

3.4. A Synopsis of Longhorn's System Integrity Process Elements

Section 3.4 is comprised of summary descriptions of Longhorn's System Integrity Process Elements. Section 3.5 contains detailed descriptions of the Process Elements and the components of those Process Elements. These Process Elements, together with the Longhorn Mitigation Commitments, reflect Longhorn's commitment to human health and safety and the environment. They represent Longhorn's arsenal dedicated to the achievement of Longhorn's Pipeline System Integrity Plan Mission.

Briefly, Longhorn's System Integrity Process Elements include Longhorn's:

1. **Corrosion Management Plan.** Activities such as system surveys and evaluations, pipe design, coating selection and application, and cathodic protection are designed to maintain the Longhorn Pipeline System in a manner that ensures safety and environmental protection, with special attention paid to the discrete concerns associated with Tier I, Tier II and Tier III segments of the pipeline.

RAD 38917

2. **In-Line Inspection and Rehabilitation Program.** Employing the best examples of current technology in a range of in-line inspection tools, Longhorn will have command of a 360-degree end-to-end look at the Longhorn Pipeline System and the benefit of a risk based system of re-inspection.

3. **Key Risk Areas Identification and Assessment.** With a keen awareness of concerns such as population density, environmental impact, land use and product characteristics, coupled with Longhorn's goal of mitigating threats to system integrity, Longhorn will maintain its focus on risk mitigation, analysis and management, drawing input from a variety of data sources.

4. **Damage Prevention Program.** Through a program of pipeline marking, aggressive surveillance, and multi-focused education, Longhorn is committed to mitigate the risk of injury to the public and the environment.

5. **Encroachment Procedures.** Ever vigilant to the possibility of potential or actual encroachments on the pipeline right-of-way, Longhorn acts decisively and responsibly in the exercise of its rights as an easement owner to ensure the maintenance of a clear and unobstructed right-of-way, which is crucial to the safe operation of any pipeline system.

6. **Incident Investigation Program.** Longhorn embraces a structure for incident investigations designed not to find fault or to posture for litigation but to find root causes so that preventive action may be taken to prevent recurrences.

7. **Management of Change.** Benefiting from an effective system for managing change, Longhorn is prepared to give full consideration to the operational basis of change through design review, risk assessment, team communication, and state of the art training protocols.

8. **Depth of Cover Program.** Structured to be a proactive program to mitigate risks to the public and the environment, Longhorn's ongoing Depth of Cover Program identifies and mitigates shallow or exposed pipe locations under dynamic circumstances, with special attention paid to sensitive and hypersensitive areas.

9. **Fatigue Analysis and Monitoring Program.** Through another proactive program, Longhorn identifies and mitigates any development of pressure-cycle-induced fatigue related cracking, considering in detail the risk of crack development on the basis of careful evaluation of data generated in the course of pipeline operations.

10. **Scenario Based Risk Mitigation Analysis.** Focusing on pipeline operations, maintenance and integrity, surveillance programs, and public education, Longhorn determines appropriate preventative measures and system modifications to reduce the risk of releases of product, on a pipeline segment by pipeline segment basis.

11. **Incorrect Operations Mitigation.** Longhorn scrutinizes the areas of potential human error (design, construction, maintenance and operation) and develops damage prevention strategies to counter potential human action or inaction.

12. **System Integrity Plan Scorecarding and Performance Metrics Plan.** Longhorn's commitment to system integrity is underscored by its dedication to specific program performance monitoring and continual improvement through a structure featuring its ongoing System Integrity Plan Audit, direct accountability, and regular reporting to the Longhorn Board of Directors.

Through these System Integrity Process Elements, and the Longhorn Mitigation Commitments, discussed in detail at Sections 1.2 and 1.3, the Longhorn Pipeline System Integrity Plan manifests its pre-occupation with its own good faith concerns for the protection and preservation of human health and safety and the environment.

3.5. Detailed Program Description of the Process Elements

3.5.1 Longhorn Corrosion Management Plan

1. Introduction

The intent of this plan is to outline the purpose and the operational concepts for corrosion control activities on pipelines owned by Longhorn.

Corrosion control activities such as, but not limited to, system evaluations; pipe design, coating selection and application; criteria for cathodic protection; and cathodic protection design, installation, operations, and maintenance are designed to mitigate corrosion and thus maintain the Longhorn Pipeline System in a manner that ensures long-term safety to the public and employees and that minimizes negative environmental impacts.

2. LPP's Commitment to Corrosion Control

All corrosion related activities are developed through sound corrosion engineering concepts and are applied under the direction of competent personnel trained in the field of corrosion control. These activities are governed by company policies and procedures and Department of Transportation Part 195 regulations, and are consistent with NACE International RP 01-69, ASME, and API recommended practices where applicable. The Longhorn Corrosion Management Plan is founded on the concepts that all applicable regulations and industry standards are met as a minimum, and going forward the focus will be compliance plus.

3. Risk Based Corrosion Management

A priority rating system based on relative risk assessment will be developed to select Hypersensitive and Sensitive areas where enhancements to the base line Corrosion Control Program will be developed and implemented. Corrosion related data will be processed in the overall System Integrity Plan to determine/modify the frequency of pipe to soil potential surveys, close interval pipe to soil potential surveys, rectifier inspection, foreign line crossing surveys, internal inspection, coating rehabilitation initiatives and other corrosion mitigation measures or new developing technologies.

4. Types of Corrosion Control Surveys

Longhorn will utilize the following corrosion related surveys:

- Pipe to Soil Potential Surveys
- Close Interval Pipe to Soil Potential Surveys
- Rectifier Inspection Surveys
- Foreign Line Crossing Surveys
- Atmospheric Inspection Surveys
- Exposed Pipe Visual Inspection Surveys (Internal and External)
- Internal Coupon Surveys
- Coating Surveys
- New Survey Technologies

5. Pipe to Soil Potential Surveys

Pipe to Soil Potential Surveys will be conducted by qualified personnel and reviewed by NACE certified corrosion personnel.

These surveys will be conducted utilizing a high impedance voltmeter and a copper/copper sulfate reference electrode placed as close as practical and directly over the structure and in good contact with the soil.

These surveys will be conducted at pre-assigned test locations (ETS), cased crossings and above ground appurtenances.

All pipe to soil potential survey data will be recorded in the appropriate corrosion control database. Survey results and associated recommendations will be documented and made available to Longhorn management and the System Integrity Group.

6. Close Interval Pipe to Soil Potential Surveys

Close Interval Pipe to Soil Potential Surveys will be conducted by qualified personnel and under the direct supervision of NACE certified corrosion personnel.

These surveys will be conducted utilizing a high impedance voltmeter and a copper/copper sulfate reference electrode placed as close as practical and directly over the structure and in good contact with the soil.

Pipe to soil potential readings will be taken along the pipeline at approximately 3 foot intervals utilizing an eight-second on/two-second off frequency. Feedback from the surveys will be utilized to modify survey spacing requirements as necessary.

All close interval pipe to soil potential survey data will be recorded, and the information will be forwarded to the appropriate corrosion personnel for analysis.

Close interval pipe to soil potential surveys are typically triggered by annual pipe to soil potential surveys, internal inspection data, pipe inspection, or other related corrosion information or testing. In addition to these discrete corrosion data points, the LPSIP will initiate recommendations for close interval pipe to soil potential surveys based upon the overall relative risk assessment model. The relative risk assessment model can be influenced by population changes, environmental encroachments or other factors potentially affecting the overall integrity of the pipeline system.

Close interval pipe to soil potential survey information may trigger the need for internal inspection, test station installation, coating rehabilitation, pipe inspection (excavation), or other testing or mitigation activities.

7. Rectifier Inspection Surveys

Rectifier Inspection Surveys will be conducted by qualified personnel and reviewed by NACE certified corrosion personnel.

These surveys will include recording voltage, amperage, and kilowatt-hours (as appropriate). Voltage and amperage readings will be taken with a high impedance voltmeter.

All data will be recorded on the rectifier inspection form located inside the rectifier as well as forwarded to the appropriate Corrosion Technician for entry into the appropriate corrosion control database.

8. Foreign Line Crossing Surveys

Foreign Line Crossing pipe to soil potential surveys will be conducted by qualified personnel and reviewed by NACE certified corrosion personnel.

These surveys will be conducted utilizing a high impedance voltmeter and a copper/copper sulfate reference electrode placed as close as practical and directly over the pipe line crossing and in good contact with the soil.

Where bond test stations do not exist, additional voltage reading will be taken at 3 feet intervals either side of the crossing for approximately fifteen feet.

Where bond test stations exist, voltage and current drain data will be collected and the integrity of the bond confirmed.

Foreign line crossing pipe to soil potential data will be recorded in the appropriate corrosion control database.

Foreign line crossing pipe to soil potential surveys may be triggered by annual pipe to soil potential survey information, internal inspection data, pipe inspection data, foreign pipeline encroachment information, or other corrosion related information or testing.

RAD 38921

Foreign line crossing pipe to soil potential survey information may trigger the need for internal inspection, test station installation, coating rehabilitation, pipe inspection (excavation), or other testing or mitigation activities.

9. Atmospheric Inspection Surveys

Atmospheric Inspection Surveys will be conducted by qualified personnel, and the data will be reviewed by NACE certified corrosion personnel.

Atmospheric inspection data will be documented on the appropriate Atmospheric Inspection Form.

Atmospheric Inspection Survey information may trigger the need for pipe/coating rehabilitation, additional pipe inspection, system redesign, or other mitigation measure.

10. Exposed Pipe Visual Inspection Surveys

Exposed Pipe Visual Inspection Surveys will be conducted by qualified personnel, and the data will be reviewed by NACE certified corrosion personnel.

Exposed Pipe Visual Inspection data will be documented on the appropriate Pipe Inspection Form.

Exposed Pipe Visual Inspection Surveys may be triggered by annual pipe to soil potential survey information, internal inspection data, close interval pipe to soil potential data, foreign line crossing pipe to soil potential surveys, foreign pipeline encroachment information, or other corrosion related information or testing.

Exposed Pipe Visual Inspection Survey information may trigger the need for internal inspection, test station installation, coating rehabilitation, foreign line crossing surveys, further investigation to determine the extent of damage (if active corrosion is identified), or other testing or mitigation activities.

11. Internal Coupon Surveys

Longhorn Pipeline will address internal corrosion from both a product quality and integrity standpoint. Only pre-approved laboratories will be utilized for product testing.

Product samples will be tested every two months with a target of maintaining an "A" rating with respect to the NACE rust test (NACE TM 0172-93, "Determining Corrosive Properties of Cargoes in Petroleum Product Pipelines"). The corrosion inhibitor dosage will be adjusted in order to maintain this rating.

Baker Octel DCI-6A 80/20 corrosion inhibitor (or equivalent) will be injected at the pipeline origin at the GATX terminal. This inhibitor will establish a protective film on the pipe wall, and will protect the pipe against any water and/or corrodent in the product. The rate of injection will initially be 0.75 pounds per one thousand barrels.

Additionally, corrosion coupons are pulled, inspected, and analyzed for corrosion 3 times per year (not to exceed 4½ months between surveys). Target coupon corrosion rate is less than 1 mpy, with no pitting. Sample and coupon locations will be at El Paso terminal and Odessa station.

Pipeline pigging is done in order to clean the line of debris and water. This is beneficial to product quality and allows the corrosion inhibitor to establish a protective film on the pipe wall. Pigging is accomplished with cup/disc combination pigs, as well as brush pigs and TDW Pit Boss pigs. Williams – operated product lines are pigged twice per year.

Internal Coupon Surveys may be triggered by internal inspection data, product quality information, visual line inspections during project or maintenance work, or other data received regarding line conditions.

Internal Coupon Survey information may trigger the need for internal inspection, further investigation (if active corrosion is identified), inhibitor injection, product specification changes, or other mitigation measures.

Internal corrosion coupon data will be maintained in the appropriate internal corrosion coupon database.

12. Coating Surveys

Coating Surveys will be conducted by qualified personnel and under the direct supervision of NACE certified corrosion or coatings personnel.

These surveys will be conducted utilizing proven methods, such as close interval pipe to soil potential surveys and/or other technology such as direct current voltage gradient (DCVG) survey. State of the art equipment will be used, and surveys will be conducted in accordance with generally accepted industry practice. Surveys for disbonded coating utilize various technologies including the Pearson Survey.

All coating survey data will be recorded, and the information will be forwarded to the appropriate technician for analysis.

Coating surveys may be triggered by annual pipe to soil potential surveys, internal inspection data, pipe inspection, or other related corrosion information or testing. Findings of coating surveys will be incorporated into the LPSIP and the associated ORA.

13. New Corrosion Related Technologies

It is a primary responsibility of the Corrosion Control Department to identify, review, test, and implement applicable new corrosion related technologies.

Vendors, periodicals, conferences, and the like will be used as necessary to stay apprised of new corrosion related products and/or ideas.

Problems and/or inefficiencies may trigger the implementation or research into a new technology or process.

14. Corrosion Control Surveys - Frequency

- Pipe to Soil Potential Surveys

  Tier I – Pipe to soil potential surveys will be conducted annually (not to exceed 15 months between inspections) at pre-assigned test locations (ETS), including cased crossings and above ground appurtenances.

  Tier II & III – Pipe to soil potential surveys will be conducted semi-annually (not to exceed 7 ½ months between inspections) at preassigned test locations (ETS), cased crossings, and above ground appurtenances. The annual close interval survey will substitute for one of the semi-annual surveys in Tier III areas.

- Close Interval Pipe to Soil Potential Surveys

  Tier I & II – Close interval pipe to soil potential surveys will be managed through the relative risk assessment process within the System Integrity Model and conducted as necessary.

  Tier III – Close interval pipe to soil potential surveys will be conducted annually (not to exceed 15 months between inspections). (See triggers above for more information.)

- Rectifier Inspection Surveys

  Tier I, II & III – Rectifier Inspection Surveys will be conducted monthly (not to exceed 45 days between inspections) at each cathodic protection rectifier.

- Foreign Line Crossing Surveys

  Tier I, II, & III – Foreign Line Crossing surveys will be managed through the relative risk assessment process within the System Integrity Model and conducted as necessary. (See triggers above for more information.)

  In addition, interference bonds whose failure would jeopardize structure protection shall be inspected at intervals not to exceed six months.

- Atmospheric Inspection Surveys

Tier I, II, & III – Atmospheric Inspection surveys will be conducted annually at pre-assigned above ground piping and facilities.

- Exposed Pipe Visual Inspection Surveys

Tier I, II, & III – Exposed Pipe Visual Inspection surveys will be conducted whenever a buried pipeline is exposed for any reason. A visual inspection of the internal portion of the pipeline will be conducted whenever any pipe is removed from the pipeline.

- Coating Surveys

Tier I, II & III – Coating surveys will be performed as dictated by pipe to soil potential surveys, close interval pipe to soil potential surveys, the relative risk assessment model, and the Operational Reliability Assessment.

15. Corrosion Control Surveys - Criteria and Remediation Schedule

A root cause analysis will be performed to identify both contributing causes and root causes of anomalies identified by any corrosion control survey. Such analyses, the findings of which will be incorporated into the LPSIP process, will assure that factors contributing to potential system deficiencies are counteracted on a permanent basis.

- Pipe to Soil Potential Surveys (including Close Interval and Foreign Line Crossing)

Tier I – Where practical a pipe to soil potential of at least -0.850 volts, at the pipe-to-electrolyte interface, with the protective current applied will be maintained. Potential drops other than those across the structure to electrolyte boundary will be considered by utilizing one or more of the following methods: measuring or calculating the voltage drops, reviewing the historical performance of the cathodic protection system, placing the reference electrode in close proximity to the structure, or interrupting the cathodic protection current source(s).

Where maintaining a -0.850 volt potential is not practical, a minimum of 100 MV shift of cathodic potential between the structure and a stable reference electrode shall be utilized. The information of polarization from native state or decay of polarization from the instant off potential can be used to satisfy this criterion.

Tier II & III – Where practical, a polarized pipe to soil potential of -0.850 volts will be maintained. During close interval surveys, potential drops other than those across the structure to electrolyte boundary will be considered by interrupting the cathodic protection current source(s) and recording the "ON" and "OFF" pipe to soil potentials. Once established, the "ON" potential and "OFF" potential will be utilized to correct future pipe to soil potential readings until such time as the system configuration or coating condition changes, or a new close interval survey is performed.

RAD 38925

Where maintaining a -0.850 volt potential is not practical, a minimum of 100 MV shift of cathodic potential between the structure and a stable reference electrode shall be utilized. The formation of polarization from native state or decay of polarization from the instant off potential can be used to satisfy this criterion.

While no evidence exists that would indicate that excessive cathodic protection has caused damage to the external coating on the Longhorn Pipeline, the entire pipeline will be monitored for overprotection as well as underprotection. Cathodic protection system adjustments will be made, as necessary, to remediate any area of concern.

Overprotection will be monitored and minimized through the analysis of data from annual pipe to soil potential surveys, close interval pipe to soil potential surveys, and pipeline visual inspections. A practical value of -1.2 volts (polarized) in reference to copper/copper sulfate cell will be used as the value beyond which monitoring for overprotection shall be implemented.

<u>Tier I, II, & III</u> – Corrective action for noted deficiencies shall be determined and completed as soon as practical, depending on the severity of the situation with respect to location of the pipeline and the potential for damage. All deficiencies will be resolved within one (1) year of discovery, except deficiencies of such a nature they present a more urgent threat to pipeline integrity, in which case corrections will be done immediately.

<u>Casings</u>: During each cathodic protection survey, readings shall be taken at each cased crossing to detect any location where the carrier pipe may be shorted to the casing pipe. If the casing potential is within 100 millivolts of the pipeline potential, the casing shall be investigated to determine whether a metallic short to the carrier pipe is present. If a short is verified, a plan of action shall be developed within three months from the time of discovery. The practicality of clearing the short will be considered before any other measures are used. Action shall be taken to clear the short (a) in Tier I areas within six months of development of the action plan; and (b) in Tier II and Tier III areas within three months of development of the action plan.

In the interim, from the time a short is verified and action taken to clear the short, the location will be inspected for corrosion or the casing/pipe interstice may be filled with a high dielectric corrosion inhibiting material. During any interval that a casing has been determined to be shorted, the casing/pipe interstice will be monitored. Tier I areas will be monitored twice per year at intervals not to exceed 7 ½ months. Tier II and III areas will be monitored monthly at intervals not to exceed six weeks.

- Rectifier Inspection Surveys

  Tier I, II, & III – Corrective action for noted deficiencies in rectifier operation shall be determined and completed as soon as practical, depending on the severity of the situation with respect to location of the pipeline and the potential for damage. All deficiencies will be resolved within one (1) month of discovery except deficiencies of such nature they present a more urgent threat to pipeline integrity, in which case corrections will be done immediately.

  Rectifier outages are typically triggered by a natural event, such as a thunderstorm. A pattern or trend of rectifier outages will trigger a detailed analysis by NACE certified corrosion control personnel. This inspection will include the use of a multimeter and/or various other electrical testing equipment as well as visual inspection of the rectifier components. System enhancements identified during this analysis to mitigate against any such pattern or trend will be implemented as soon as practical, not to exceed six months.

- Atmospheric Inspection Surveys

  Tier I, II, & III – Corrosion found during atmospheric inspection surveys will be evaluated using the RSTRENG Effective Area method.

  Coatings will be evaluated during atmospheric inspection surveys utilizing ASTM D610/SSPC-Vis2 standard.

  Corrective action for noted deficiencies found during atmospheric inspection surveys shall be determined and completed as soon as practical, depending on the severity of the situation with respect to location of the pipeline and the potential for damage. Deficiencies relating to pipeline integrity will immediately be forwarded to "System Integrity", "Engineering" and "Field Operations" for resolution. Deficiencies in external coating (paint) will be resolved within one (1) year of discovery except deficiencies of such nature they present a more urgent threat to pipeline integrity, in which case corrections will be done immediately.

- Exposed Pipe Visual Inspection Surveys

  Tier I, II & III – Corrosion found during exposed pipe visual inspection surveys will be evaluated using the RSTRENG Effective Area method.

  Coatings will be evaluated during exposed pipe visual inspection surveys.

  Corrective action for noted deficiencies found during exposed pipe visual inspection surveys shall be determined and completed immediately. Deficiencies relating to pipeline integrity will immediately be forwarded to "System Integrity", "Engineering" and "Field Operations" for resolution.

• Internal Coupon Surveys

Tier I, II, & III – Internal corrosion coupon results will be evaluated 3 times per year (not to exceed 4½ months between surveys) utilizing the following guidelines:

	General Corrosion Rate (mpy)
Low	<1
Moderate	1.0 – 4.9
High	5.0 – 10
Severe	>10

Coupon corrosion rates over 1 mpy of general corrosion, or if pitting is observed, will trigger a detailed analysis directed by NACE certified corrosion control personnel. This analysis will include a review of incoming product quality sampling data, inhibitor injection rates, bacteria testing and, if necessary, inhibitor performance testing.

Corrective action for noted deficiencies found during internal corrosion coupon analysis shall be determined and completed as soon as practical, depending on the severity of the situation with respect to location of the pipeline and the potential for damage. Deficiencies will be resolved within six (6) months of discovery; except deficiencies of such nature they present a more urgent threat to pipeline integrity, in which case corrections will be done immediately.

Longhorn will use internal corrosion inhibitors to control potential internal corrosion, including microbial-induced internal corrosion. Coupons will be inspected for evidence of microbial-induced corrosion, and, if identified, responsive action will be taken to counter such potential.

16. Corrosion Control Documentation

- Data Storage

All pipe to soil potential survey, rectifier inspection, and foreign line crossing pipe to soil potential data will be recorded in the appropriate corrosion control database.

All close interval pipe to soil potential survey data will be recorded in a hard copy report as well as the appropriate electronic format (i.e., Bass, Excel, Lotus 123, etc.)

Atmospheric inspection data and exposed pipe visual inspection data will be documented on the appropriate forms and distributed appropriately.

Internal corrosion coupon data will be maintained in the appropriate internal corrosion coupon database.

- Reporting

All survey results will be submitted to the appropriate Longhorn representatives annually or as required on a project by project basis.

As a minimum these reports will include the survey data, a summary of findings, and recommendations to resolve any anomalies or implement changes.

- Roll up

Corrosion related data will feed into and be processed in the overall LPSIP by populating the appropriate portions of the relative risk assessment model.

3.5.2 In Line Inspection and Rehabilitation Program

1. Introduction

Longhorn has committed to an aggressive In-Line Inspection Program of its pipeline system. ILI provides a non-destructive 360-degree end to end look at a pipeline system. Longhorn will use this program to determine the physical integrity of its pipeline to ensure maintenance of the safest possible pipeline system.

2. Longhorn's Commitment to Internal Inspection

Longhorn is committed to internally inspecting the 18"/20" pipeline from Valve J-1 to Crane Station, within three (3) months of system startup, with a high resolution magnetic flux leakage (MFL) inspection tool, which is currently accepted as the best available technology for identifying corrosion and other metal-loss pipe anomalies. The MFL tool will also establish a baseline for implementation of the Operational Reliability Assessment. The frequency of future in-line inspections of the pipeline system, and the type of inspection tool to be employed, will be determined by Longhorn's Operational Reliability Assessment.

3. Risk Based ILI Re-Inspection Intervals

Hypersensitive and Sensitive areas of the pipeline will be primary selection criteria for the ILI re-inspection program. A priority rating system based on relative risk assessment will be developed to select future pipeline segments to determine re-inspection schedules. The frequency of re-inspections will be determined by previous inspection data along with fitness for purpose surveys which include corrosion growth models, leak history, monitored one-call activity, fatigue cycles, cathodic protection data, and current population and environmental status. A major factor that is included in the overall re-inspection frequency determination is the inclusion of the attributes of the Operational Reliability Assessment.

4. Types of In-line Inspection Tools

Longhorn will include the following as potential ILI tools that could be required by the ORA:

- High Resolution Magnetic Flux Leakage (MFL)
- Transverse Field Magnetic Flux Leakage (TFI)
- Ultrasonic
- Geometry/Sizing Tools

New ILI tools and inspection technologies will be incorporated into the program using a benefit analysis assessment.

A. High Resolution MFL Tools

This ILI tool will obtain an accurate indication of the corrosion condition of the pipeline by magnetically saturating the pipe in the axial direction as the tool passes down the line. The presence of corrosion, or any feature that changes the uniformity of the flux path, such as a third party strike or dent or other outside force damage, will cause some flux to leak out the pipe wall. The magnetic sensors detect this leakage and the data is collected along the pipeline for a full inspection run.

B. TFI Tools

The TFI tool will accurately detect hook cracks, lack of fusion, narrow axial external corrosion, dents with coincident cracks and gouges, and long narrow metal loss by magnetically saturating the pipe in the orthogonal direction as the tool passes down the line. Applying the magnetic field in a circumferential or transverse direction around the pipe, the tool can more easily discern defects orthogonal to that field. The presence of corrosion, or any feature that changes the uniformity of the flux path, such as a third party strike or dent or other outside force damage will cause some flux to leak out the pipe wall. The magnetic sensors detect this leakage and the data is collected along the pipeline for a full inspection run. The TFI tool examines both the pipe seam area and the pipe body.

C. Ultrasonic Tools

This ILI tool will locate laminations (potential hydrogen blister sites) and other three-dimensional metal loss features. By measuring the ultrasonic waves (time of flight) perpendicular to the pipe wall and collecting the data in a fluid medium, the tool can accurately determine the remaining pipe wall thickness and will indicate the location of dents, such as those caused by a third party strike or other outside force damage.

D. Geometry/Sizing Tools

Prior to running High Resolution MFL, TFI or Ultrasonic tools, Longhorn will run a sizing tool ("Dummy Tool") to ensure that the pipeline is fit to accommodate the passage of the inspection tool. If the "Dummy Tool" indicates passage problems, a geometry tool will be launched to locate and size the obstructions. MFL and TFI technology will detect dents in the pipeline. Although sizing of dents isn't within the MFL and TFI tool capabilities, any detection of dents will trigger a geometry tool run.

5. Running the Tool

In preparation for the specific ILI project, the project manager will write a detailed project scope and plan for the particular line section being inspected. This scope and plan will define in detail the actual line preparation, ILI tool sequencing, timelines and job duties for each and every line section involved in the ILI inspection. The ILI vendor, inspection personnel, and operations personnel will be familiarized with the details of the scope prior the execution phase of the project. The following provides a general overview of the ILI inspection process:

- ILI vendor will perform site survey and detailed review of line section (alignment sheets, length of segments, tool capabilities etc.).
- Select the appropriate ILI tool made of the correct composition, for the product being used as a medium to transport the tool.
- As necessary scraper traps are modified to accommodate the length of the ILI tool. This can be done by installing flanges and using extension barrels and/or permanently installing the traps. This may also include installing temporary traps at intervals not to exceed certain distances as protection against excessive cup wear and tool re-runs, and which provides for enhancement of data gathering capabilities.
- In-line inspection marker locations or some other reference point such as mainline valves or side bends must be surveyed for reference location.
- Verify the pipeline is fit and will allow the ILI tool safe passage (corrosion coupons, interface detectors, probes, and the like are removed to eliminate internal interference with the ILI tool).
- Line must be cleaned by means of cleaning pigs.
- Sizing (dummy) tool and/or geometry tool inspection must be performed prior to other ILI inspection tools being run.
- In-line inspection marker boxes must be placed over pipeline at predetermined reference locations.
- Load ILI tool in launch trap, assuring proper valve alignment.
- Launch tool, tracking it through in-line inspection marker and valve site locations.
- Receive and remove ILI tool.
- ILI vendor will download data from tool and verify successful tool run.
- Return traps to normal configuration.

6. The Analysis Process

- Preliminary Indications
- Phase I Investigation
- Vendor Final Report
- Phase II Investigation
- Features Discovered During Routine Maintenance
- Methods of Inspection and Repair
- Documentation

ILI technology is a rapidly developing field, and industry expectations include the development of ILI tools of greater accuracy than exists presently and with the capacity to identify a broader range of defects than is currently the case. As a result, present-day tools may not provide data that will allow precise identification of every inspection indication discussed in this section. However, Longhorn has included such indications in order to demonstrate the investigation criteria that should apply when those tool capabilities become generally available.

Preliminary Indications and Phase I Investigation

Longhorn requires that a Preliminary Report be provided by the ILI vendor. The following table presents categories of preliminary indications, corresponding response actions, and the time period within which the response action shall be initiated:

PRELIMINARY INDICATION	RESPONSE	INITIATION OF RESPONSE
Metal loss greater than 70% of nominal wall thickness, regardless of dimensions	Site inspection or excavation or other effective mitigation actions	Within 5 days of receipt of Preliminary Report
Top of the line dents (above 4 and 8 o'clock position) with any indicated metal loss	Excavation and repair, reduction in operating pressure by 20% (with concurrent resetting of pressure relief device setpoints), or other effective mitigation actions	Within 5 days of receipt of Preliminary Report
A significant anomaly that in the judgment of the data evaluator requires immediate action	Effective mitigation action that reduces the integrity threat posed by the anomaly	Within 5 days of receipt of Preliminary Report
Top of the line dents (above 4 and 8 o'clock position) without indicated metal loss and with depths greater than 6% of the pipe outside diameter	Excavation and repair, reduction in operating pressure by 20% (with concurrent resetting of pressure relief device setpoints), or other effective mitigation actions	Within 60 days of receipt of Preliminary Report
Cracks to the extent preliminary indications are an established TFI tool reporting procedure	Site inspection or excavation or other effective mitigation actions	Within 5 days of receipt of Preliminary Report

Vendor Final Report

The ILI vendor will provide a detailed and extensive final inspection report that will at a minimum contain these main features:

- Length, depth, and ERF (Estimated Repair Factor) of all detected metal loss defects as predicted by the analysis process; location, discrimination between internal and external defects and discrimination between metal loss and manufacturing faults.
- Cracks located in longitudinal ERW weld seam (TFI tool specific)
- The location of dents, gouges, and scratches and the presence of any associated metal loss
- The location and extent of girth weld anomalies such as cracks
- The location of eccentric or shorted casings and any associated metal loss

- The location of any foreign metal objects in close proximity to the pipe
- A listing of all nominal wall thickness changes
- A listing of all repair patches and sleeves
- A listing of all "hard" references and above ground marker devices, which have been used as location reference points

Phase II Investigation

The following table presents categories of indications which shall be investigated within 6 months of receipt of the in-line vendor final report; mitigation action, if necessary, will occur after evaluation by excavation:

INDICATION
Dents with any of the following: Metal loss, corrosion, exceeds 6% of the outside diameter, or located in longitudinal seam or girth weld
Remaining strength of the pipe results in a safe operating pressure that is less than the current MOP at the location of the anomaly using a suitable safe operating pressure calculating criterion (e.g., B31.G, modified B31.G, RSTRENG or LAPA)
Casing shorts with associated metal loss
Girth weld anomalies
Corrosion within 3" of either side and/or across girth welds
Preferential corrosion of or along seam welds
Gouges or grooves greater than 50% of nominal wall
Cracks located in the pipe body, girth weld and longitudinal seam that are determined to be injurious to the integrity of the pipeline

Remaining indications shall be documented, and relevant information shall be integrated into the Relative Risk Assessment Model, as described under the heading "Documentation" in this Section 3.5.2.

The corrosion assessment methods identified above evaluate the likelihood that, based on the predicted depth and axial length of a corroded area or other flaw, the predicted failure pressure of the feature is less than the maximum allowed operating pressure. Features with failure pressures below maximum allowed operating pressure, as identified by the assessment criteria, will be chosen and prioritized for investigation. Crack-like defects will be evaluated by the vendor's data processing methods.

Upon excavation, the severity of an identified corrosion feature is assessed using the RSTRENG corrosion assessment criteria. Crack-like defects will be analyzed using external ultrasonic technology. Mechanical damage and or gouging will be assessed using ASME B31.4 recommended practices for pipeline repair.

Features Discovered During Routine Maintenance

Features discovered during routine maintenance activities will be addressed as they are discovered. The following features will be investigated upon discovery, and if necessary repaired:

- Corrosion exceeding 70% wall loss
- Corrosion areas shall be assessed based upon one or more of the assessment criterion (B31G, RSTRENG 0.85, or RSTRENG). Repairs or pressure reductions are required in the event that the MOP is greater than the calculated safe maximum allowable operating pressure based upon all of these assessment methods
- Corrosion exceeding 12.5% of the nominal wall thickness and within 1/2" either side of the longitudinal seam for ERW pipe and girth weld; B31G assessment criteria does not apply to corrosion in the girth or longitudinal weld or related heat affected zones per ASME B31.4. 451.6.2 Disposition of Defects
- Corrosion areas that are within a dent
- Corrosion areas that are within 3 inches of either side and/or across girth weld
- Dents in excess of 6% of the outside diameter
- Dents located in longitudinal seam
- Dents with associated metal loss
- Any indication with associated metal loss (gouges, scratches, third party damage, and the like)
- Severe mill related defects (lamination, hard spots, etc.)
- Girth weld anomalies
- Cracks located in girth weld
- Cracks located in pipe body
- Cracks located in longitudinal seam

Repairs will be made utilizing company standards and procedures which incorporate industry recommended practices. Prior to commencement of an actual repair project, a detailed project scope and plan for the particular line section being repaired will be developed.

7. Methods of Inspection and Repair

Investigation evaluations will be performed by qualified personnel. Each investigation, whether it results in a repair or not, is documented, and relevant information is incorporated into a database. Defects and features found by the ILI tools that require repair will be repaired utilizing the following methodology:

- Type A full-encirclement split sleeve in accordance with the Longhorn Welding & Radiographic Procedural Manual and/or Maintenance Manuals
- Type B full-encirclement split sleeve in accordance with the Longhorn Welding & Radiographic Procedural Manual and/or Maintenance Manuals
- Pipe Cut-Out and/or Pipe Replacement in accordance with the Longhorn Welding & Radiographic Procedural Manual and/or Maintenance Manuals
- Composite and or other new developing repair methods will be evaluated for appropriate utilization

Repairs will be made utilizing company standards and procedures which incorporate industry recommended practices. Prior to initiating the rehabilitation project, the project manager will write a detailed project scope and plan for the particular line section being rehabilitated. This scope and plan will define all of the components identified below, in detail, for each and every line section. The following process will take place upon the completed review of the final report:

1) Survey crew will stake dig locations in preparation for rehabilitation
2) Rehabilitation construction crew will ensure lines have been spotted correctly
3) Line pressure will be monitored prior to excavation
4) Crew will excavate line in accordance with OSHA regulations, including 29 CFR parts 1926.650 through 1926.652.
5) Ditch will be checked with hazardous gas monitor prior to entry
6) Coating shall be removed, and actual corrosion dimensions will be evaluated using RSTRENG assessment
7) Line pressure shall be monitored prior to welding
8) Repair Methodology: Type A or Type B full-encirclement split sleeve, Cut-Out and/or Replacement, or other new developing repair methods
9) Repair shall be allowed to cool and then be properly coated
10) Repair information is incorporated into permanent pipeline records

Documentation

The vendor supplied ILI report will be maintained on file for the life of the pipeline. All field inspection results and reports will be placed in a project book for permanent storage, and in addition the Pipeline Integrity and Corrosion Groups will maintain the vendor report for the life of the pipeline.

For each repair made to pipe, a record will be made and it will be kept for the life of the system. This record shall include the following: the date, location, and description of each repair; the nominal size, wall thickness, grade, mill test reports, and manufacturer of any pipe used for repairs. A copy of the record will be forwarded to the Manager of Data Resources. Technical Services shall register repairs on the alignment sheets or other appropriate maps and will provide copies to the appropriate Area offices. The following is a list of reports that will be maintained for the life of the pipeline:

1. ILI Report
2. Dig Sheet Report
3. Maintenance Report
4. Daily Reports (Project Work-Progress)
5. Welder Qualification Report
6. Daily Safety Meeting Reports
7. Contractor Drug Testing Report
8. Right-of-Way Reports
9. Mill Certification (MTR's) Report

Relevant data from the reports generated during investigations is maintained in a database. The data is used in support of, and incorporated into, the relative risk assessment process and the Operational Reliability Assessment.

The development of an Operational Reliability Assessment (ORA) involves a review of the current in-line inspection results in conjunction with subsequent excavations, cathodic protection data, corrosion growth models, previous internal inspection information, pressure cycle monitoring, coating type and condition, and metallurgical components of the steel pipe. The ORA is conducted annually using available information and the accuracy of the ORA is not dependent on new internal inspection every year. Thus, it is not necessary to conduct internal inspections every year for the purpose of conducting the ORA. The ORA provides additional data to the relative risk assessment model to facilitate a line specific maintenance plan. The ORA will assist in the determination of the timing of additional excavations and/or re-inspections (see ORA at Section 4.1).

3.5.3 Key Risk Areas Identification and Assessment

1. <u>Objective</u>

The objective of this program is to ensure that resources (time, talent, and money) are focused on those areas of the Longhorn Pipeline System with the highest identified or perceived risks. The results of this heightened focus typically include risk mitigation and/or risk management initiatives that directly lead to the reduction in likelihood or consequence of an unintended product release.

2. Areas of Focus

The Key Risk Areas Identification and Assessment Program is designed to focus on the following areas:

- Hypersensitive and Sensitive Areas
- Land Use
- Mechanical Integrity
- Physical Asset Attributes
- Product Characteristics
- Incorrect Operations
- Control Measures and Safeguards

3. Data Sources

The Key Risk Areas Identification and Assessment Program receives data input from a number of sources. Included among these are population density surveys, land use surveys, geological surveys to indicate areas of potential concern, topography, endangered flora and fauna surveys, physical attributes of the pipeline assets, transported product characteristics, operational parameters, and system controls.

4. Risk Identification

Collected data regarding the external and internal attributes of the Longhorn Pipeline System are loaded into the Relative Risk Assessment Model. The data sets are split into "segments", which allow for the grouping of similar internal and external pipeline attributes. The heaviest weighting for segmentation purposes is based upon changes in the surrounding population, the environment, or mechanical attributes of the pipeline. This approach allows for a targeted focus on those segments that would have the greatest impact to the public or to the environment in the event of an unintended product release from the pipeline.

The Relative Risk Assessment Model is designed to automatically prioritize and sort pipeline segments in accordance with their scored relative risk in relation to all of the other segments. Risk is defined as the product of likelihood and consequence, with the consequence factor increasing as population density or environmental sensitivity increases.

To date, the entire Longhorn Pipeline has been categorized into Tier I, Tier II, or Tier III areas. Tier I is identified as general pipeline routing with normal issues and concerns. Tier II is labeled as "sensitive" areas through which the pipeline is routed. Finally, Tier III is used to identify the "hypersensitive" regions along the Longhorn Pipeline. By way of specific example, remote regions of West Texas typically fall into Tier I with densely populated areas of Houston falling into Tier III, as do the environmentally sensitive areas over the Edwards Aquifer.

5. <u>Risk Analysis</u>

Following the identification of risk areas along the pipeline, the individual segments by prioritized Tier groupings are analyzed to determine if there are protective measures or mitigation methods that could reduce the likelihood of the occurrence of a negative event. This typically brings an analysis of operating parameters, third party damage prevention measures, public awareness programs, and available control measures and system safeguards, all of which lead to a pipeline system of higher integrity and overall risk reduction.

Enhanced risk mitigation measures, implemented as a result of the Relative Risk Assessment Model, in the areas of corrosion, third party damage and incorrect operations are discussed in the respective appendices relative to Tier groupings. Physical attributes describing the current system design and system condition were loaded into the Relative Risk Assessment Model and assessed against the progressively increasing requirements of Tier I, Tier II and Tier III areas. The specific mitigation measures outlined in the Longhorn Mitigation Commitments resulted in part from that assessment.

The results of the Key Risk Area Identification and Assessment Program are subsequently provided to the Scenario Based Risk Mitigation Analysis Program.

6. <u>Update Process</u>

As new information is made available, as population or environmental shifts impact the line segmentation, or following the incorporation of various risk mitigation initiatives, the Relative Risk Assessment Model is rerun to ensure that the risk identification and assessment model remains current and accurate.

The annual updating of population density and areas of environmental sensitivity results from a combination of aerial and land based surveillance patrol data collection.

3.5.4 Damage Prevention Program

1. Objective

The Damage Prevention Program is a comprehensive approach designed to educate the public and to prevent accidents resulting from excavation activities. Through cooperative efforts with excavators and the public, this program will achieve widespread awareness on the importance of damage prevention. The program will exceed current DOT Part 195 in the areas of permanent pipeline markers, ground and aerial surveillance, excavator education, public education, and line spotting activities to achieve uncompromising public safety.

2. Pipeline Markers

Permanent pipeline markers are used to notify the public of the general location of our pipeline. Permanent pipeline markers are maintained in Tier I (general), Tier II (Sensitive), and Tier III (Hypersensitive) areas as follows:

- Pipeline markers meet or exceed all requirements of 49 C.F.R. §195.410.
- Marker spacing for Tier I areas will be such that they are placed within line-of-sight of each other. Exceptions may be necessary for land use (i.e., cultivation), and landowner and tenant issues. Discussions explaining the importance of line markers, as identified in our Public Education program, will be held with landowners or tenants.
- Marker spacing for Tier II and III areas will be such that if any one marker is removed, the location of the pipeline can still be identified from either direction from any point in between.
- All line markers will be written in English and Spanish.
- Marker placement and density will be evaluated routinely through aerial and ground surveillance.
- Missing or damaged markers will be replaced within 7 days of discovery.
- Markers will be located at all aboveground facilities to identify the operator of the system.
- Markers will be located on each side of each public road crossing, water crossing, and railroad crossings.

3. Pipeline Surveillance

Most pipeline rights-of-way corridors are accessible through aerial surveillance, which is the primary method of right-of-way inspection and damage prevention. Periodic conditions such as weather, however, may render certain segments of the right-of-way inaccessible via fixed wing aircraft or helicopter and thus ground surveillance will supplement air surveillance. In addition, ground surveillance will be utilized when vegetation temporarily obstructs aerial surveillance.

Surveillance intervals will be as follows:

- Tier II and III areas: Every 2.5 days, not to exceed 72 hours

- Tier I areas: Once a week, not to exceed 12 days, but at least 52 times per year
- Edwards Aquifer Recharge Zone: Daily (one day per week shall be a ground-level patrol)

Aerial and ground surveillance frequency will be increased across Tier II (sensitive) and Tier III (hypersensitive) areas when the threat of flooding and/or severe erosion is identified near the pipeline right-of-way.

Emergency situations identified during aerial or ground surveillance will be immediately reported to the Longhorn Pipeline Control Center. All surveillance personnel and line spotters will be trained and certified in OSHA HAZWOPER to the first responder level.

Every consideration will be given to endangered species while conducting ground surveillance in and around the pipeline right-of-way. Maps depicting the location and habitat of endangered species will be utilized for this purpose.

4. Excavator Education

Excavator education is an important element of damage prevention in order to reduce the likelihood of unintended third party damage caused from excavation activity. The program focuses on promoting cooperation and awareness throughout the following groups:

- General contractors (i.e., irrigation, dirt, fencing, plumbing, landscaping)
- Land owners
- Real estate developers
- Utility companies
- Mining and quarry operations

The identified excavators will be provided with the following:

- Information on the "Dig Safely" program initiated by DAMQAT (Damage Prevention Quality Action Team - a joint industry and government effort to educate the public on the prevention of damages to all underground and submerged facilities).
- Information on the Texas One-Call system.
- Information about the location of the pipeline and products in the line.
- What to do in the event that unintentional damage of the pipeline occurs.
- Instructions on how to recognize and report a leak.

Direct mail flyers, written in English and Spanish, will include items such as dashboard calendars and stickers so that emergency contact information and "Dig Safely" information will be readily available. Reply cards will be included to measure the damage prevention program effectiveness.

Advertisements will be placed in various trade journals and/or community publications along the Longhorn right of way to reinforce the "Dig Safely" program and to instruct the excavators to use the One-Call system.

5. **Public Education**

Public education is an important element for insuring widespread awareness and cooperation to protect the public, property, and the environment. This program will utilize mailings and flyers, meetings to educate the local public, emergency responder meetings, periodic radio public service announcements, and newspaper ads.

Annual mailing to groups such as schools, residences, hospitals, churches, retirement homes and other businesses will include the following information:

- One-Call information
- Product identification information
- How to identify and report a suspected leak
- Personal safety guidelines in the event of a leak
- "Dig Safely" program information

Annual (not to exceed 15 months) mailings will target a one-quarter (1/4) mile radius of the pipeline in metropolitan areas and a one (1) mile radius in rural areas. Mailings will include items such as phone stickers, refrigerator magnets, and rulers to ensure that emergency contact information and "Dig Safely" information will be readily available. Door-to-door visits with the public in areas adjacent to the pipeline will be performed in Tier II and III areas every two years (not to exceed 30 months).

Damage prevention flyers, such as the "Dig Safely" program, will be distributed to the public at county fairs, trade shows, agricultural shows, feed and seed stores, home and garden shows, and equipment rental companies.

Non-emergency response government agencies that are exempt from one-call mandates, such as city and county planning, zoning and building permit offices, and agricultural agencies will be contacted annually (not to exceed 15 months) with mailings and a personal visit to distribute maps of the pipeline route and inform developers of the presence of the pipeline.

Reply cards and records of personal visits, along with third party damage incident scorecards, will be used to measure the effectiveness of the program.

Emergency response agencies within each county that the pipeline passes through will be contacted annually (not to exceed 15 months) in person and provided with maps of the system. Specific emergency response requirements and plans will be developed and reviewed on an annual basis with applicable LEPC and emergency responders. Annual emergency response drills will be conducted.

RAD 38940

6. Line Marking and Inspection

Accurate line marking is an important element of damage prevention in order to reduce the likelihood of unintended third party damage caused from excavation activity. Line marking will include the following:

- When excavation is to occur within 50 feet of the pipeline, the line will be marked and a report of the activity will be submitted to the Area Maintenance Coordinator.
- When the pipeline is exposed due to excavation, a company representative will remain at the excavation site to inspect the work until there is no further threat of damage to the pipeline.
- Any time the line is exposed the relevant pipeline attributes will be recorded to evaluate the condition of the pipeline system. Information such as coating inspections, cathodic protection levels, and depth of cover levels will be measured and recorded and input into the Relative Risk Assessment Model.
- Prior to any road, highway or bridge construction, a technical review will be conducted to evaluate the associated stress to the pipeline, and to take any recommended protective measures to prevent consequential pipeline damage.
- Prior to any blasting near the pipeline, a technical review will be conducted to evaluate the impact of the blasting on the integrity of the pipeline and determine if a post-blast monitoring and inspection program is required. As appropriate, mitigation of potential damages caused by, or actual prevention of, proposed blasting activities will occur based upon technical review and recommendations.

3.5.5 Encroachment Procedures

1. General

Longhorn's primary mission is to ensure:

- Encroachments do not hinder the ability to safely operate and maintain the assets
- Pipeline adjustments are designed in accordance with sound engineering judgement to ensure compliance with governing regulations.
- The respective rights and privileges in the easements are maintained.
- Proper reimbursement for work performed.

An encroachment is any infringement on the pipeline and associated rights-of-way. An encroachment is any activity or structure that interferes with or impedes the pipeline(s) or easement rights.

2. Introduction

The maintenance of a clear, unobstructed right-of-way is critical to the safe operation of any pipeline system. Encroachments not only obstruct the system from observation, but also introduce additional activities over the pipeline assets. As such, it is the responsibility as the owner of certain easement rights to protect them. It is necessary to watch for and take appropriate protective action against any potential or occurring encroachments. In all cases, the need for early reporting and documentation of encroachment issues is vital to the integrity of the rights and eventually the pipeline systems.

Protecting the right-of-way from encroachments is of major importance to daily operations. Every employee must be concerned about encroachment problems. We should not allow encroachments that would interfere with the legal rights and obligations.

These guidelines provide general procedures for handling encroachments. Consideration for appropriate protective action against such potential encroachments should be high priority.

3. <u>Interoffice Procedure</u>

Pipeline representatives that observe or hear of an impending or in-progress encroachment should notify the responsible Real Estate Services Representative and Coordinator of Operations and Maintenance (COM). The COM will gather information pertaining to the encroachment.

Since different easement forms have been utilized and subsequently modified and amended, familiarity with the extent of the rights in one easement does not assure familiarity with any other easement. Prior to contacting the encroaching party, the information gathered above should be relayed to the respective Real Estate Services Representative in order to review the specific easement rights across the subject property. The Real Estate Services Representative will make the COM aware of these rights.

The Real Estate Services Representative may make the initial contact to advise the encroaching party of the steps necessary and the basic details of what will be allowed within the right-of-way. The assigned Engineer and/or the COM will discuss with the encroaching party their proposal for resolution of the encroachment.

Once the details have been worked out, determination of the appropriate written agreement to be entered between Longhorn and the encroaching party must be determined.

Example forms may include:

- Pipeline Location and Encroachment Permit
- Short Form Encroachment Permit
- Reimbursement Agreement
- Encroachment Agreement

For encroachments having an impact to the facilities, the Real Estate Services Representative will prepare Encroachment and Reimbursement Agreements based on information and required restrictions given by the Engineer and/or the COM. Said encroachments should be submitted to the Real Estate Services Representative who will, in turn, put together the necessary agreement to be jointly executed by the landowner or encroaching facility owner (Owner) and Longhorn.

3.5.6 Incident Investigation Program

1. Introduction

This program includes guidelines for conducting incident investigations. The guidelines specify what constitutes an incident, when the investigation is to begin, who is to participate in the investigation, the preparation of the Incident Investigation Report and the criteria for conducting an incident report review and critique.

2. Purpose

The purpose of this program is not to find fault, but to identify and understand why the incident took place in order to prevent recurrences.

3. Scope

This program applies to all pipeline assets, and terminals owned by Longhorn.

4. Definitions:

Accident - An undesired event that results in harm to people or damage to property

Near-Miss - An undesired event which, under slightly different circumstances, could have resulted in harm to people or damage to property.

Incident - Includes accidents, near-miss cases, or repairs, and/or any combination thereof

Major Incident - Includes events which result in:

- A fatality
- Three or more people hospitalized
- Major news media coverage
- Property loss, casualty, or liability potentially greater than $500,000
- Major uncontrolled fire/explosion/spill/release that presents imminent and serious or substantial danger to employees, public health, or the environment

Significant Incident - Includes events which result in:

- Fire/explosion/spill/release/less than three hospitalized or other events with casualty/property/liability loss potential of $25,000 - $500,000
- Employee or contractor OSHA recordable injury/illness lost workday cases
- Citations with potential fines greater than $25,000

Minor Incident - Includes events which result in:

- Fire/explosion/spill/release or other events with casualty/property/liability loss potential under $25,000
- Employee or contractor OSHA recordable injury/illness without lost workdays cases
- Citations under $25,000

Repair – A temporary or permanent alteration made to the pipeline or its affiliated components that are intended to restore the allowable operating pressure capability or to correct a deficiency or possible breach in mechanical integrity of the asset.

5. Classifying Incidents

Incidents are normally classified as major, significant or minor. However, it is possible that an incident could be a combination. A specific scenario of a minor accident (minor actual loss) could also be a major near-miss (major potential loss).

Furthermore, root cause analysis (see Overview, below, and Section 3.2.6) classifies the causes of repairs as an analytical step. Such classification enables the analyst to eliminate potential causes, which in turn adds precision to the identification of root causes and contributing causes as well as trends that may require mitigation. An example of a classification of potential causes follows:

- Corrosion
  - Atmospheric
  - Internal
  - External (buried pipe)

- Incorrect Operation
  - Design
  - Material Defect
  - Joining
  - Operations Control
  - Field Operations

- Third Party Damage
  - Depth of Cover
  - Public Education
  - Patrol
  - Right-of-Way Condition
  - One-Call

- Design
  - Hydrostatic Test Failure
    - Internal Corrosion

- External Corrosion
- Material Defect

6. Overview

The ultimate aim of an incident investigation is to reduce the likelihood of accidents, near-misses, and the need for future repairs. However, there are several other aspects of the investigation process that provide value to the company and employees, such as:

Preventing recurrences

Complying with policies and regulatory requirements

Maintaining employee awareness of the importance of safe work habits

Prevention is the primary reason for conducting an incident investigation. Unless the unsafe acts or conditions that caused the incident are identified and eliminated, or at least controlled, the possibility remains that similar mishaps will occur. Additionally, government regulations may require a formal investigation of some kinds of accidents, especially those resulting in fatalities, serious injury, environmental harm or substantial property damage. LPP commits to investigate "close calls" or "near-misses". A near miss will be considered an accident that didn't happen. Its causes have to be identified and eliminated; otherwise, the next near miss could result in a serious accident. Similarly, repairs made to the pipeline or its system components will be investigated to determine the root cause that led to the needed repair. Understanding what caused the conditions that led to the repair, and the proactive application of the information gained from the investigation process, should directly lead to a reduction in future related incidents, near-misses, or similar natured repairs.

Initial incident investigation and reporting is usually the responsibility of field operations where the incident occurred; however, they are not the only ones involved. Team members should be selected based on their training, knowledge and ability to contribute to an effective investigation. The investigation team must consist of a minimum of two people, of which at least one person is knowledgeable in the process involved, including contract employees if the incident involved work of the contractor, and another person/s with appropriate knowledge and experience to investigate and analyze the incident thoroughly. The incident investigation team must begin the investigation as promptly as possible, but not later than 48 hours following the incident.

An investigation report must be prepared and distributed. After the report is reviewed, the final report, resolutions and corrective actions will be distributed to all affected personnel relevant to the incident findings (including contract employees when applicable) and a copy sent to the Incident Investigation Program administrator.

Each incident investigation has the potential to be different and must be managed accordingly.

7. **Incidents Requiring Investigation**

The incident investigation program is required to utilize a three-tiered approach for investigating all incidents meeting the definition of minor, significant, and major incidents. The three-tiered approach promotes expending a variable effort in conducting investigations based on an assessment of the incident's actual and potential loss. Small leaks such as valve packing leaks or pump seal leak off are considered nuisance leaks and should be addressed during regular maintenance and repair activities. However, nuisance leaks would be investigated if they fell in to the near-miss classification. Serious incidents warrant a more comprehensive team investigation. If appropriate, the investigation is to be conducted under the direction and control of LPP legal counsel.

3.5.7 Management of Change

1. **Longhorn Commitment and Program Objective**:

At the commencement of operations, Longhorn will implement a management of change process. The objective of the program is to establish a policy and procedure for managing changes that affect process chemicals, technology, equipment, procedures and facilities across the Longhorn Pipeline System.

2. **Policy**

To ensure that any changes in the program chemistry, technology, equipment, procedures and facilities, excluding "replacement in kind," are addressed prior to implementation or start up of the proposed change.

3. **General Discussion**

- The Management of Change process requires that all temporary and permanent changes and modifications require approval by the individuals responsible for the maintenance, operation and engineering aspects related to the change.
- The Management of Change process requires that all changes be evaluated using an appropriate hazard analysis (HAZOP, what if, etc.) and that the change be risk assessed to ensure that the appropriate risk mitigation levels are maintained on the system.
- The amount of time a temporary change will be in effect must be agreed upon and approved by those assigned review and approval responsibilities.
- A list of all temporary and permanent changes including expiration dates shall be maintained at the appropriate local field office.
- All documents and files affected by the change (O&M procedures, P&ID's, instrumentation and electrical drawings, emergency procedures, equipment specifications, training materials, etc.) must be identified and revised as necessary on a timely basis.

4. **Responsibilities**

Longhorn senior operations management, through Williams senior operations management, will ensure that an effective program for managing change is in place. An "effective program for managing change" is herein described as having the following attributes:

- Full consideration of the operational basis of the change
- Revision to the affected process information (O&M procedures, P&ID's, equipment lists, etc.)
- Design reviews, risk assessment, communication of change training
- Pre-start up reviews

Longhorn will require Williams to be responsible for:

- Ensuring that identified safety and health hazards created by changes are eliminated or controlled through engineering, administrative and/or personal protective measures.
- Ensuring that the impact of the change has been assessed by the Systems Integrity Group to verify that the change has been evaluated to determine that total system risk has been considered in terms of the change and that appropriate risk mitigation measures have been implemented concurrent with the change as appropriate.
- Establishing approval levels for authorizing change requests.
- Ensuring that change requests and supporting documentation packages are adequate for the change and have been properly reviewed, approved and tracked to completion.

3.5.8 Depth of Cover Program

1. **Objective**

The objective of the Depth of Cover (DOC) Program is designed to proactively identify areas of shallow or exposed pipe along the Longhorn Pipeline System. Secondly, through a formalized DOC Mitigation Process, this Program intends to manage the associated risks through a variety of methods, all designed to reduce the likelihood of unintended outside force damage and consequential damages to a defined level.

2. **On-Going Program**

The DOC Program is designed to be an on-going initiative. Land use, population density, environmental issues, and changes to the absolute coverage of the Longhorn Pipeline are expected to change over time. Consequently, DOC data will become outdated as new subdivisions are built, as changing patterns of land erosion occur, and as topsoil is generally moved over time as a result of wind, water, and mechanical forces.

3. Relative Risk Assessment Approach

Similar to many other System Integrity Group initiatives, the DOC Program is designed to prioritize those areas of highest relative risk. The investigative and resulting mitigation processes will consequently focus on the defined areas of hypersensitive (Tier III), sensitive (Tier II), and other (Tier I), in descending order. Further, as the defined classifications are modified over time due to changing population and environmental concerns, so the DOC prioritizations will be modified.

4. Program Elements

The DOC Program is structured in four governing categories: Identify, Notify, Protect, and DOC Risk Mitigation/Management. Further description of these categories is provided below:

- Identify:

Timely identify through aerial patrols, operational activities, public input and other means target areas requiring DOC surveys based upon land use, environmental concerns, population density, and construction and excavation activity levels.

Prioritize the targeted areas in accordance with Tier III, Tier II, and Tier I classifications.

Conduct DOC surveys to identify areas of shallow and exposed pipeline facilities.

For areas of shallow or exposed pipe, quantify the associated depths and lengths.

NOTE: Shallow pipe is herein defined as either (a) being within the physical interference level of the normal land use within the prescribed pipeline segment routing or (b) being at a depth that may not continue to provide adequate protection in light of changing population densities and/or environmental concerns. An example of the first type of shallow pipe would be a pipeline in a cultivation area with twenty four inches of cover that is periodically plowed to a thirty inch depth. An example of the second type of shallow pipe is pipeline in an area being developed for a new subdivision where the building of roads, the installation of utilities and the construction of new homes will require "pipeline adjustments." Pipeline adjustments are reasonable and prudent measures undertaken to ensure that the existing and reasonably anticipated land use and environmental sensitivity of the area under evaluation can safely coexist with the pipeline facilities that are in place. Pipeline adjustments will include, but not be limited to, pipeline lowering, pipeline replacement, installation pipeline protective devises, increased patrols and/or increased signage.

- Notify:

Report findings to System Integrity Group and Field Operations.

Notify landowners and/or tenants of potential areas of concern.

Communicate with developers and local authorities to ensure an appropriate awareness of the location and risks of the pipeline and to coordinate appropriate pipeline adjustments in anticipation of and in connection with construction and development activities.

- Protect:

Formally notify impacted developers, contractors, local land use authorities, landowners and/or tenants via certified letters with detailed mapping and description of areas of concern.

Enhance pipeline warning markers as deemed appropriate.

Develop pipeline adjustments that are reasonable responses to changing conditions.

- DOC Risk Mitigation/Management:

Evaluate appropriate pipeline adjustments.

Select preferred risk mitigation or risk management method.

Allocate funding as appropriate.

5. <u>DOC Program Prioritization Guidelines</u>

The DOC Program, along with its resulting mitigation initiatives, will be prioritized in accordance with the following guidelines. Process flow diagrams, labeled as "Longhorn Prioritization for Exposed Pipe" (Figure 1), and "Longhorn Prioritization for Shallow Pipe" (Figure 2) are attached hereto.

- Priority 1 Items – Immediately develop and execute a corrective action plan
- Priority 2 and 3 Items – Risk assess/prioritize, and develop and execute a corrective action plan
- Priority 4 Items – Continue monitoring

Examples of priority items are described on Figure 1 and Figure 2.

Any pipe replaced will be installed as described in Section 1.2 of this Mitigation Plan.

6. **Data Management and Initiative Implementation**

Data initially obtained and periodically updated via the DOC program will be centralized and maintained in a formal database. The System Integrity Group will utilize the DOC database as an input to its overall risk management process, which includes the relative risk assessment process and the ORA. (See, also Section 3.5.8.3 above).

The System Integrity Group will further manage the recommendation and funding process associated with the implementation of DOC mitigation initiatives.

7. **DOC Relative Risk Assessment**

The relative ranking of identified DOC line segments are assessed in accordance with the following:

Relative DOC Risk = Land Use Index + Population Index + Environmental Index
+ Cultivated Index + Creek/Water Index

3.5.9 Fatigue Analysis and Monitoring Program

1. **Objective**

The objective of the Fatigue Analysis and Monitoring Program is to perform an initial and ongoing assessment/analysis of the potential and likelihood of the Longhorn Pipeline System to develop pressure-cycle-induced fatigue related cracks. The Program is also intended to proactively prevent any fatigue related incidents and consequential damage to the public or the environment through the avoidance of operating in a manner that would exacerbate the formation of cracks, and through the early identification and mitigation of newly developing cracks or the growth of existing cracks.

2. **Analysis Process**

Longhorn will commission pipeline industry recognized third party pipeline metal fatigue experts, such as Kiefner and Associates, Inc., to perform annual pressure-cycle-induced growth of crack metallurgical analysis on the Longhorn Pipeline System. The analysis process will incorporate the attributes of the Operational Reliability Assessment.

3. **Operator Supplied Information**

On an annual basis, Longhorn will supply the contracted analysis firm the following information:

A schematic of the line sections to be analyzed, showing annual operating pressures, nominal pipe diameters, wall thickness, and yield strength data.

Identification of sensitive (Tier II) and hypersensitive (Tier III) Longhorn pipeline segments to ensure a heightened awareness and closer scrutiny of the pipeline assets located in these areas.

4. **Contractor Provided Information**

The selected pipeline metal fatigue contractor will be requested to provide Longhorn a report that will include the following information:

- All inputs and assumptions made or used in the pressure-cycle-induced growth of crack analysis/assessment program.
- A schematic of the line sections that were analyzed, showing operating pressures, nominal pipe diameters, wall thickness, and yield strengths.
- Graphs showing failure pressure as a function of crack size and crack growth over time.
- A summary of the results of the analysis.
- A recommendation of any mitigation methods or corrective action to be taken, including recommended changes in operating pressures, to ensure the safe operation of the pipeline.

5. **Longhorn Incorporation of Recommendations**

Longhorn commits to modify the operating parameters of its pipeline segments in accordance with the third party expert findings and recommendations of the pressure-cycle-induced growth of crack analysis. Further, non-operating pressure recommendations will be submitted to the System Integrity Group for incorporation into its overall Risk Management Program.

3.5.10 Scenario Based Risk Mitigation Analysis

1. **Objective**

Following the relative risk assessment of the various Longhorn Pipeline segments (see Key Risk Areas Identification and Assessment Program), the Scenario Based Risk Mitigation Analysis Program is designed to identify preventive measures and/or modifications that can be recommended that would reduce the risks to the environment and the population in the event of a product release.

2. **Areas of Focus**

Scenario based risk mitigation assessments will typically focus on items including pipeline operations, maintenance, physical pipeline components, pipeline patrol, corrosion inspection, depth of cover, and public education. The intent is to analyze those aspects of pipeline operations and maintenance that could lead to the release of product into the environment. Consequently, the primary focus in a scenario based assessment will be on mechanical integrity, operating controls, and the prevention of third party damage.

3. **Process**

As noted above, the Scenario Based Risk Mitigation Analysis Program starts with the relative risk ranking of the Longhorn pipeline segments via the Relative Risk Assessment Model, and will be conducted annually. Next, representatives from areas including Field Operations, Pipeline Control, System Integrity, Risk Management, and Technical Services, and other subject matter experts, gather to discuss specific attributes of these risk ranked segments. Using a variety of "what if?" probing questions, the analyzed segments are thoroughly evaluated to determine the probable likelihood of an unplanned event or product release that would result in consequential damage to the environment or the population.

Following the scenario based analysis, ideas are shared on potential mitigation methods that would result in either lowering the likelihood or the consequence, or both, of an event.

The results of the Scenario Based Risk Mitigation Analysis Program are then presented back to the appropriate workgroups for consideration. As an example, items that will require the unbudgeted release of capital or expense funds are provided to the System Integrity Group for further evaluation and consideration. Items that require adjustments in operating procedures or methodologies are typically sent to the Field or Pipeline Operations Groups. In all cases, the System Integrity Group acts as the custodian for the results of this process. The System Integrity Group also scorecards these mitigation methods and provides periodic updates to Longhorn management.

3.5.11 Incorrect Operations Mitigation

1. **Objective**

The objective of the Incorrect Operations Mitigation Program is to identify and subsequently reduce the likelihood of human errors that could impact the mechanical integrity of Longhorn Pipeline.

2. **Underlying Premise**

Incorrect Operations Mitigation primarily focuses on damage prevention items and actions that are impacted by either action or inaction on the part of the operations, technical, maintenance, design, and construction personnel.

3. **Areas of Focus**

The Incorrect Operations Mitigation will focus on the following areas of potential human error that could lead to a breach of mechanical integrity:

- Design
- Construction
- Maintenance

- Operation

4. Design Index

Longhorn will incorporate Design Index attributes into new construction, system modifications, or substantive changes in Longhorn facilities. In accordance with the "Pipeline Risk Management Manual," W. Kent Muhlbauer, Design Index attributes are used to mitigate potential errors by focusing on proactive error prevention actions including following:

- Hazard Identification - Incorporation of "Haz-Op," process safety management (PSM) or similar analysis on a five-year cycle, or more frequently when triggered by the Management of Change program.
- MOP Potential - Optimally strive to categorize the potential for overpressure as "extremely unlikely" or "impossible" through redundancy and critical path separation protective devices and/or processes.
- Safety Systems - Focus on the incorporation of "fail-safe" equipment and processes that reduce the likelihood of operator errors.
- Material Selection - Utilization of confirming documentation, with technical calculations, along with metallurgical review, to ensure installed equipment and components are suitable and compatible with operating and design conditions.
- Checks - Review and certification of critical design calculations and decisions, typically through a licensed engineer.

5. Construction Index

Longhorn will incorporate Construction Index attributes into new construction and system modifications. In accordance with the "Pipeline Risk Management Manual," W. Kent Muhlbauer, Construction Index attributes are used to mitigate potential errors by focusing on proactive error-prevention actions including following:

Inspection - Utilization of qualified inspectors.

Materials - Confirmation that installed equipment and materials are verified for authenticity and conformance to specifications.

Joining - Utilization of workmanship inspection methods, such as 100% x-ray weld inspection.

Backfill - Employ high quality of suitable backfill materials and inspection processes to ensure that no coating or pipe damage occurs, and that unintended stress forces are not inflicted upon the pipeline or accompanying components.

Handling - Ensure proper material handling practices to minimize stresses outside of component design levels and to otherwise protect the materials from damage during transporting, moving, installing, or storage.

Coating - Ensure initial and installed integrity of protective coating materials in accordance with design standards.

6. Maintenance Index

Longhorn will incorporate Maintenance Index attributes into the ongoing maintenance of its pipeline assets. In accordance with the "Pipeline Risk Management Manual," W. Kent Muhlbauer, Maintenance Index attributes are used to mitigate potential errors by focusing on proactive error-prevention actions including the following:

- Documentation - Implementation of a formal records program to ensure that defined maintenance activities are satisfactorily conducted at established intervals.
- Schedule - Development of a formal schedule of maintenance activities, with process for incorporating adjustments as a result of operating history.
- Procedures – Establishment of written procedures to guide personnel in the repair, maintenance, and replacement of equipment. Procedures will ensure that original design factors are preserved throughout the life of the equipment, or until proper validation and authorization of new factors are confirmed.

Many of the individual LPSIP programs are designed to provide a formal maintenance program which covers targeted initiatives intended to confirm, protect, or maintain the mechanical condition of the pipeline assets. Included in this category are investigative programs such as depth of cover profiling, internal "smart pig" inspections, corrosion monitoring, right of way maintenance, and external hydrocarbon monitoring programs.

7. Operations Index

In accordance with Muhlbauer's "Pipeline Risk Management Manual," this category of Operations Index likely represents the most critical index in terms of incorrect operations. Once the pipeline assets have been appropriately designed and installed, and are subsequently maintained in accordance with formalized schedules and programs, ongoing operations and the associated processes and procedures are the most susceptible to human error. Unlike design issues that occur in a controlled environment with typically multiple levels of checks and validations, operating decisions and actions are made over the life of the assets under a variety of circumstances. Operating decisions cover the span of normal, abnormal, startup, shutdown, and emergency conditions that by nature lend themselves to higher frequencies of errors or deviations from standard procedures.

In addition to a focus on error prevention, the Operations Index also includes a focus on the ability to detect and subsequently mitigate deviations from normal operations that could lead or contribute to a breach in mechanical integrity. The concepts of operational observability and controllability go hand in hand, and both are emphasized in Operations Index.

Longhorn will incorporate Operations Index attributes into the ongoing operations of its pipeline assets. In accordance with the "Pipeline Risk Management Manual," W. Kent Muhlbauer, Operations Index attributes are used to mitigate potential errors by focusing on proactive error-prevention actions including the following:

- Procedures - Incorporates written procedures for all aspects of pipeline operations, including startup, normal, abnormal, emergency, and shutdown situations. Particular emphasis will be given to the establishment of operating procedures for valve maintenance, safety device inspection and calibration, pipeline shutdown and startup, pump operations, product movement changes, right-of-way maintenance, flow meter calibrations, instrument maintenance, and management of change.
- SCADA/Communications - Provides an overall operational view of the entire pipeline system from a single location. The SCADA system enables system diagnosis, leak detection, and product movement analysis. The SCADA system is designed to provide continuous monitoring of the pipeline system, which allows for the incorporation of automatic alarms that detect and warn the Operations Controller of abnormal or rapidly changing conditions, and further, to provide early indication of a potentially negative event or developing situation.

  Longhorn will employ a SCADA/Communications system, which will be designed primarily to provide system overview, start/stop operations, and system isolation. The local control systems and mechanical devices located along the pipeline system will be designed to prevent overpressurization and loss of mechanical integrity. This approach places the SCADA/Communications system in a role of operations monitoring and first responder isolation versus a primary role of integrity protection.

  Longhorn will ensure that a backup communication system is employed in the event of loss of SCADA communications, although by design, such loss will not jeopardize the mechanical integrity of the pipeline system.

- Drug Testing - Longhorn will enforce the following drug testing practices for its DOT covered employees and contractors: random testing, testing for cause, pre-employment testing, post-accident testing, and return-to-work testing.
- Safety Programs - Longhorn will incorporate an encompassing Safety Managing System for its pipeline operations, with a focus on employee participation and proactive attention to safe work practices.
- Surveys - These issues are further described in other programs and initiatives, and they include surveys such as close interval, coating condition, water crossing, deformation detection by pigging, population density, depth of cover, and leak detection. These surveys fall into the proactive mode of the detection of contributing causes to the loss of mechanical integrity and incident mitigation.
- Mechanical Error Prevention - The application of mechanical devices to reduce or prevent the likelihood of operational error. These devices include the use of devices such as chains and locks, error prevention computer permissives and logic, warning signs, high profile painting of critical components, and key lock sequence programs. Longhorn shall incorporate mechanical error prevention devices where applicable to minimize the likelihood of operator error.

- Training - Viewed as the first line of defense against human error and accident reduction. Longhorn commits to approach training from a failure prevention perspective. This approach concentrates on the avoidance of any human error that could threaten life, property, or the environment through an unintended product release.

  Longhorn commits to the development and incorporation of a training program that contains the following components: product characteristic awareness, pipeline material stresses and associated component mechanical design limitations, pipeline corrosion awareness, pipeline control devices and operating knowledge, and maintenance awareness.

  Longhorn further commits to the incorporation of emergency mock drills and tabletop reviews. In addition to post accident consequence mitigation, these programs will also provide operating and system integrity personnel with a proactive opportunity to identify potential contributing causes to product releases which could be prevented through the implementation of risk reduction initiatives, procedures, or processes.

- Job Skills - Longhorn commits to establishing a job skills progression program for its field operations personnel that targets a technical progression ladder. The job skills program emphasizes the following: <u>What</u> skills are included, the correct method of <u>how</u> to perform the skills, <u>why</u> these skills are performed and <u>why</u> the taught practices are the right way, and <u>when</u> the skills should be performed. The job skills program is designed to provide the targeted field operations personnel with the knowledge, skills, and diagnostic abilities with which to both improve efficiencies and to ensure the overall safeguarding and protection of the Longhorn Pipeline System.
- Scheduled Retraining - Longhorn commits to periodic retraining, complete with associated documentation, to ensure that trained employees retain the knowledge and proficiency with which to safely perform their required job duties.
- Operator Qualification - Longhorn will proactively comply with the proposed OPS regulation for operator qualification, verification, and certification of employees and contractors for DOT Part 195 covered activities.

3.5.12 System Integrity Plan Scorecarding and Performance Metrics Plan

1. <u>Introduction</u>

The intent of this section is to outline the Longhorn Pipeline System Integrity Plan Scorecarding and Performance Metrics Plan.

Scorecarding and performance metrics provide feedback to evaluate the effectiveness of the LPSIP. Through performance modeling, these measures will be used to evaluate and modify the LPSIP, using a continual improvement approach that incorporates lessons learned and trend analysis forecasting data. Empirical analysis of performance metrics will allow Longhorn to identify which activities and initiatives should be continued, enhanced, modified, or discontinued.

2. Performance Measurement

Table 1 below lists the general performance measures that will be used to evaluate the System Integrity Program.

Table 1 - General Program Performance Measurement Criteria

Category	Measure	Comments
Incident Data	Releases in each Tier	Tier I, Tier II, and Tier III
	Releases in sensitive and hypersensitive areas	Tier II and Tier III
	Releases by cause	Third party damage, corrosion, design, incorrect operations
	Releases by volume	Tier I, Tier II, and Tier III
	Near Misses	Tier I, Tier II, and Tier III
Risk Awareness	Identification of new and/or previously unrecognized risks	Scenario based analysis and individual program Recommendations.
	Number and type of projects completed that are not required by prescriptive code	Indication of proactive application of Longhorn Pipeline's System Integrity Program
Public Customer Service	Number of validated complaints on safety or environmental issues	Outward measure through public response and regulatory agencies of LPSIP effectiveness
	Number of landowner contacts related to pipeline safety and land use	Measure of Damage Prevention, dig Safely, and Third Party effectiveness Programs.
Operator Resources and Innovation	Number of new technologies, alternative methodologies and innovative approaches to control risk	Through partnering with the OPS, Longhorn demonstrates the proactive application of new ideas and technologies into the LPSIP and the Operation Reliability Assessment (ORA) Plans.

The following are measures of specific components of the System Integrity Program.

Table 2- Specific Programs Performance Measures

Program	Measure
Corrosion Management Plan	Smart Pig Results
Depth of Cover Program	Number, type, and location of third party damage incidents
Damage Prevention Program	Number of third party damage incidents due to One-call Process not being practiced

Additional performance measures will be developed as needed to adequately measure the effectiveness of the program.

3. System Integrity Plan Audit

As a continuous improvement process, system integrity requires program evaluation to determine effectiveness, gauge performance, and make modifications to improve the program. Performance measures provide the means to measure progress toward established goals. Progress toward these goals will be reviewed annually through an internal audit commissioned by Longhorn.

Longhorn will review the LPSIP to re-examine the processes used to identify and assess risks, evaluate risk control options, review justification for resource allocation, and monitor performance. Performance measures will be compared against historical data and the expected outcomes. In addition, the annual review will test the quality and effectiveness of the administration, communication, and documentation of the program. The annual review report will specifically address the following five areas:

- A synopsis of the most important integrity issues being addressed on the Longhorn Pipeline System and the status of activities and programs used to manage these risks.
- Important insights, results, and lessons learned from the previous year.
- Insights from new integrity management processes or technologies, or innovative applications of existing technologies.
- Performance measurement results.
- New integrity management programs or activities that will be conducted, or significant improvements to existing programs and activities.

The LPSIP Audit Report will be provided to the Longhorn Board of Directors on an annual basis.

4. OUTLINE OF OPERATIONAL RELIABILITY ASSESSMENT FOR THE LONGHORN PIPELINE

The following discussion focuses on specific attributes of the ORA, which is intended to provide Longhorn with a technical evaluation of the integrity of its pipeline assets, and to provide specific recommendations that are intended to either preserve the long term integrity or to mitigate areas of potential concern before they can result in a breach or loss of product containment capabilities.

The overall ORA philosophy, and the included components and attributes of the data assessment process, are more fully defined in Section 3.3, "Longhorn Operational Reliability Assessment." Examples of these items include earth movement studies, third party damages, and overall LPSIP programs and data attributes.

4.1. Overview

The integrity of the Longhorn Pipeline will be monitored and any required remedial responses will be made in a timely manner to prevent leaks and ruptures. Typically, the plan and schedule by which this is accomplished is called an operational reliability assessment. An operational reliability