Magellan Pipeline Company

Final Report No. 15-035

Final Report

2013 Operational Reliability Assessment of the Longhorn Pipeline System

Susan Rose, Harvey Haines, Carolyn Kolovich, Adam Steiner, Benjamin Wright, and Dennis Johnston

March 31, 2015

Kiefner Applus RTD

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on

2013 OPERATIONAL RELIABILITY ASSESSMENT OF THE LONGHORN PIPELINE SYSTEM

to

MAGELLAN PIPELINE COMPANY

March 31, 2015

by

Susan Rose, Harvey Haines, Carolyn Kolovich, Adam Steiner, Benjamin Wright, and Dennis Johnston

Kiefner / Applus RTD
5115 Parkcenter Avenue, Suite 200
Dublin, Ohio 43017

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TERMS, DEFINITIONS AND ACRONYMS

Many of the terms and definitions are taken directly from Section 2.0 of the ORA Process Manual titled Terms, Definitions, and Acronyms. Although all terms are highlighted in bold, *definitions that are lifted directly from the ORAPM or LMP are also italicized*.

1950 pipe material – Pipe material laid in 1950. Although the majority of the Existing Pipeline is made up of 1950 pipe material, some consists of newer replacement pipe such as the 19 mile 2002 pipe replacement in the Austin area.

1998 pipe material – Pipe material laid in 1998. Although the New Pipeline extensions consist almost entirely of 1998 pipe material some newer pipe material is contained in the existing 1950 pipeline in the form of pipe replacements.

Accident – As stated in the LMP, an undesired event that results in harm to people or damage to property.

Anomaly – A possible deviation from sound pipe material or weld. An indication may be generated by non-destructive testing, such as in-line inspection. [from NACE RP0102 In-Line Inspection of Pipelines]

AC – Alternating Current

API – American Petroleum Institute

ASME – American Society of Mechanical Engineers

COM – Coordinator of Operations and Maintenance, Magellan personnel responsible for coordinating activities in the field along the pipeline ROW.

CP – Cathodic Protection – A method of protection against galvanic corrosion of a buried or submerged pipeline through the application of protective electric currents.

d – Defect depth

D – Pipe diameter, usually the outside diameter of the pipeline (also see, OD).

Defect – An imperfection of a type or magnitude exceeding acceptable criteria. Definition based on API Publication 570 – Piping Inspection Code. (Also see, anomaly).

DOC – Depth of cover

DOT – Department of Transportation

EA – Environmental Assessment – An evaluation of the environmental, health and safety impacts of operating the proposed Longhorn Pipeline Project, including alternative proposals and mitigation measures. The US DOT/OPS and US EPA performed the EA as co-lead agencies.

Encroachments – Unannounced or unauthorized entries of the pipeline right-of-way by persons operating farming, trenching, drilling, or other excavating equipment. Also, debris and other obstructions along the right-of-way that must periodically be removed to facilitate prompt access to the pipeline for routine or emergency repair activities. The Longhorn Pipeline System Integrity Plan (LPSIP) includes provisions for surveillance to prevent and minimize the effects of right-of-way encroachments.

EPA – Environmental Protection Agency

EFW – Electric-flash weld is a type of EW using electric-induction to generate weld heat.

ERW – Electric-resistance weld is a type of EW using electric-resistance to generate weld heat.

EW – Electric welding is a process of forming a seam for electric-resistance (ERW) or electric-induction (EFW) welding wherein the edges to be welded are mechanically pressed together and the heat for welding is generated by the resistance to flow of the electric current. EW pipe has one longitudinal seam produced by the EW process.

Existing Pipeline – Originally defined in the EA, it consists of the portion of the pipeline originally constructed by Exxon in 1949-1950 that runs from Valve J-1 to Crane pump station. Currently the in-service portion of the Existing Pipeline runs from MP 9 to Crane because the 2 mile section from Valve J-1 to MP 9 is not in use.

GPS – Global Positioning System – a method for locating a point on the earth using the GPS.

HCA – High Consequence Area – as defined in 49 CFR 195.450, a location where a pipeline release might have a significant adverse effect on one or more of the following:
- Commercially navigable waterway
- High population area
- Other populated area
- Unusually sensitive area (USA)

HIC – Hydrogen-induced Cracking

Hydrostatic Test – An integrity verification test that pressurizes the pipeline with water, also called a hydrotest or hydrostatic pressure test.

ILI – In-Line Inspection – the use of an electronically instrumented device that travels inside the pipeline to measure characteristics of the pipe wall and detect anomalies such as metal loss due to corrosion, dents, gouges and/or cracks depending upon the type of tool used.

ILI Final Report – A report provided by the ILI vendor that provides the operator with a comprehensive interpretation of the data from an ILI.

Incident – An event defined in the Incident Investigation Program of the LMP: Includes accidents, near-miss cases, or repairs, and/or any combination thereof. Incidents are divided into three categories, Major Incidents, Significant Incidents, and Minor Incidents.

A "PHMSA (or DOT) reportable incident" is a failure in a pipeline system in which there is a release of product resulting in explosion or fire, volume exceeding 5 gallons (5 barrels from a pipeline maintenance activity), death of any person, personal injury necessitating hospitalization, or estimated property damage exceeding $50,000.

J-1 Valve – A main line pipeline valve in the Houston area, described in the LMP as the junction of the Existing Pipeline and a New Pipeline extension**.** Although this valve still exists, it is not contained in the currently active Longhorn pipeline, and the actual junction is at MP 9 (2 miles from the J-1 Valve).

L – Defect length

LFM – Low Field Magnetization

LMC – Longhorn Mitigation Commitment – Commitments made by Longhorn described in chapter 1 of the LMP.

***LMP* –** Longhorn Mitigation Plan – Commitments made by Longhorn to protect human health and the environment by conducting up front (prior to pipeline start-up) and ongoing activities regarding pipeline system enhancements and modifications, integrity management, operations and maintenance, and emergency response planning.

***LPSIP* –** Longhorn Pipeline System Integrity Plan – A program designed to gather unique physical attributes on the Longhorn Pipeline System, to identify and assess risks to the public and the environment, and to actively manage those risks through the implementation of identified Process Elements. Also Chapter 3 of the LMP.

MASP – Maximum Allowable Surge Pressure

MIC – Microbiologically Influenced Corrosion – Localized corrosion resulting from the presence and activities of microorganisms, including bacteria and fungi.

MFL – Magnetic flux leakage – The flow of magnetic flux from a magnetized material, such as the steel wall of a pipe, into a medium with lower magnetic permeability, such as gas or liquid. Often used in reference to an ILI tool that makes MFL measurements.

mil – One thousandth of an inch (0.001 in)

MOCR – Management of Change Recommendation

MOP – Maximum Operating Pressure

MP – Mile Post

NACE – NACE International formerly known as the National Association of Corrosion Engineers.

Near-Miss – An event defined in the Incident Investigation Program of the LMP as an undesired event which, under slightly different circumstances, could have resulted in harm to people or damage to property. In addition the LMP states: a specific scenario of a minor accident (minor actual loss) could also be a major near-miss (major potential loss). Thus a near-miss may or may not result in an incident.

New Pipeline – In 1998 extensions were added to the Existing Pipeline to make the current Longhorn pipeline. Extensions were added from Galena Park to MP 9 and Crane to El Paso Terminal. Laterals were added from Crane to Odessa, and from El Paso Terminal to Diamond Junction. In 2010 a 7-mile loop (3 ½ miles each way) was added, connecting Magellan's East Houston terminal to MP 6.

OD – Outside nominal diameter of line pipe.

One-Call – Texas 811 is a computerized notification center that establishes a communications link between those who dig underground (excavators) and those who operate underground facilities. The Texas Underground Facility Damage Prevention Act requires that excavators in Texas notify a one-call notification center 48 hours prior to digging, so the location of an underground facility can be marked. The Texas 811 System can be reached at toll free number 811 or website http://www.texas811.org/.

One-Call Violation – A violation of the requirements of the Texas Underground Facility Damage Prevention and Safety Act by an excavator. This ORA is concerned about violations within the Longhorn Pipeline ROW.

Operator – An entity or corporation responsible for day to day operation and maintenance of pipeline facilities.

OPS – Office of Pipeline Safety – co-lead agency who performed the EA, now a part of PHMSA.

ORA – Operational Reliability Assessment – Annual assessment activities to be performed on the Longhorn Pipeline System to determine its mechanical integrity and manage risk over time.

ORAPM – The ORA Process Manual

PHMSA – The Pipeline and Hazardous Materials Safety Administration, the federal agency within DOT with safety jurisdiction over interstate pipelines.

POE – Probability of Exceedance – The likelihood that an event will be greater than a pre-determined level; used in the ORA to evaluate corrosion defect failure pressures versus intended operating pressures. The POE for depth (POE_D) is the probability that an anomaly is deeper than 80-percent of wall thickness. The POE for pressure (POE_P) is the probability that the burst pressure of the remaining wall thickness will be less that the system operating pressure or surge pressure. The POE for each pipe joint is POE_{joint}.

Positive Material Identification Field Services – A process and procedure developed by T. D. Williamson to determine tensile strength, yield strength, and chemical composition on pipe in the field. The process includes mobile automated ball indention for mechanical properties and optical emission spectrometry for chemical composition.

PPTS – API's Pipeline Performance Tracking System – a voluntary incident reporting database for liquid pipeline operators.

Process Elements – Items to be implemented as part of the LPSIP, including programs for corrosion management, in-line inspection, risk assessment and mitigation, damage prevention, encroachment, incident investigation, management of change, depth of cover, fatigue analysis, incorrect operations mitigation, and LPSIP performance metrics.

Recommendation – Suggestion for activities or changes in procedures that are intended to enhance integrity management systems, but are not specifically mandated in the LMP.

Repair – The LMP describes a repair as 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.

Requirement – Activities that must be performed to comply with the LMP commitments.

Risk – A measure of loss measured in terms of both the incident likelihood of occurrence and the magnitude of the consequences.

Risk Assessment – A systematic, analytical process in which potential hazards from facility operation are identified and the likelihood and consequences of potential adverse events are determined. Risk assessments can have varying scopes, and be performed at varying levels of detail depending on the operator's objectives.

Root Cause Analysis – Evaluation of the underlying cause(s) and contributing factors of a pipeline incident or damage requiring repair.

ROW – Right-of-way

RPR – Rupture Pressure Ratio – for the Longhorn Pipeline System this is defined as the ratio of calculated Burst Pressure divided by the lesser of current MOP or MASP.

RSTRENG – A method of calculating the failure pressure (or Remaining STRENGth) of a pipeline caused by corrosion or metal-loss of the pipe steel. The method is capable of using an approximation of the defect profile rather than simpler two parameter methods that use simply the maximum defect depth (d) and overall length (L).

SCC – *Stress Corrosion Cracking* – a form of environmental attack of the pipe steel involving an interaction of local corrosive environment and tensile stresses in the metal resulting in formation and growth of cracks. (ASME 31.8S)

Tier I Areas – Areas of normal cross-country pipeline.

Tier II Areas – Areas designated in the EA as environmentally sensitive due to population or environmental factors.

Tier III Areas – Areas designated as in the EA as environmentally hypersensitive due to the presence of high population or other environmentally sensitive areas.

TFI – Transverse Field Inspection – an MFL Inspection tool with the field oriented in the circumferential direction. The tool differs from conventional MFL because these conventional tools have their field oriented in the axial direction or along the axis of the pipe.

TPD – Third-party damage

TPD Annual Assessment – "Longhorn System Annual Third Party Damage Prevention Program Assessment" Report. The annual report written by the operator to summarize the TPD prevention program. This report is also known in the ORAPM process manual Appendix D as Item 71 Annual Third Party Damage Assessment Report

TRRC – Texas Railroad Commission, the agency with safety jurisdiction over Texas intrastate pipelines.

UT – Ultrasonic testing – a non-destructive testing technique using ultrasonic waves.

wt – Wall thickness of line pipe

2013 Operational Reliability Assessment of the Longhorn Pipeline System

Susan Rose, Harvey Haines, Carolyn Kolovich, Adam Steiner, Benjamin Wright, Figen Ramirez, and Dennis Johnston

1. Introduction

Objective

This report presents the annual assessment of the operational reliability of the Longhorn Pipeline System for the 2013 operating year. Kiefner and Associates, Inc. (Kiefner) has carried out the operational reliability assessment (ORA) which is intended to provide Magellan with a technical assessment of the effectiveness of the Longhorn Pipeline System Integrity Plan (LPSIP), 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 assets, and provide recommendations to preserve the long term integrity or mitigate areas of potential concern before they result in a breach of the pipeline system.

Background

In 1999 and 2000, prior to its commissioning, Longhorn Partners Pipeline, LP, the previous owner, participated in an Environmental Assessment (EA) that was prepared by the US Environmental Protection Agency (EPA) and Department of Transportation (DOT). The EA Finding of No Significant Impact was conditioned upon Longhorn's commitment to implement certain integrity-related activities and plans prior to pipeline start-up and periodically throughout the operation of the system. Longhorn's commitment to minimize the likelihood and consequences of product releases was specified in the Longhorn Mitigation Plan (LMP). These commitments include the Longhorn Continuing Integrity Commitment wherein Longhorn has agreed to implement System Integrity and Mitigation Commitments and performance of annual ORAs. A list of the Longhorn Mitigation Commitments (LMC) covered by this ORA is provided in Appendix A. Magellan Pipeline Company, L.P. (Magellan) currently owns the Longhorn system assets; they purchased the pipeline in 2009, but have operated it since startup.

The LMP committed Longhorn to retain an independent third party technical company to perform the ORA, subject to the review and approval of the Pipeline and Hazardous Materials Safety Administration (PHMSA). Longhorn had selected and PHMSA approved Kiefner as the ORA contractor and Magellan is continuing with this agreement.

The LMP stipulates specific and general requirements of the ORA. Those requirements were extracted from the LMP and used to develop the Operational Reliability Assessment Process Manual (ORAPM). The ORA is carried out according to the ORAPM, revised as of April, 2011. Additional guidance for the ORA is provided by the "Mock ORA for Longhorn Pipeline" that was performed by Kiefner prior to commissioning of the pipeline. Among other things, the ORAPM requires the ORA contractor to provide periodic reports to Magellan and DOT/PHMSA.

The activities of the ORA contractor consist of assessing pipeline operating data and the results of integrity assessments, surveys, and inspections, and making appropriate recommendations with respect to seven potential threats to pipeline integrity. Managing these threats and preserving the integrity of the Longhorn system assets are among the goals of the LPSIP being carried out by Magellan. The seven threats are:

1. Pressure-Cycle-Induced Fatigue
2. Corrosion
3. Laminations and Hydrogen Blisters
4. Earth Movement and Water Forces
5. Third-Party Damage
6. Stress-Corrosion Cracking
7. Threats to Facilities Other than Line Pipe

The sixth of these threats, SCC, has not been identified as a threat of concern to the Longhorn pipeline, but was added as SCC has been an unexpected problem for some pipelines, even though these pipelines had not recognized SCC as a threat in the past.

ORA Interaction with the LPSIP

The LPSIP is the direct operator interface with the daily operations and maintenance of the Longhorn system assets. It contains twelve process elements that are used to formulate prevention and mitigation recommendations that are directly implemented on a periodic basis throughout pipeline operations. The LPSIP serves as the primary mechanism for the generation and collection of pipeline system operation and inspection data that are required for performance of ORA functions. Integrity intervention and inspection recommendations resulting from the ORA analyses are implemented by the LPSIP.

The twelve elements of the LPSIP are:

1. Corrosion Management Plan

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

Longhorn Pipeline System Description

During 2012 and 2013 the Longhorn system was split and a portion of the pipeline was reversed to begin shipping crude oil from Crane, Texas to East Houston, Texas. The flow reversal and displacement started on July 30, 2012 and was completed to Crane on August 17, 2012. The Longhorn systems went into service in April 2013 and are described below.

The first system transports refined products from Odessa to El Paso, TX. The refined product system is made up of 29 miles of 8-inch pipe from Odessa to Crane Station, a 237-mile segment of 18-inch pipe from Crane Station to the El Paso Terminal in West Texas, and four 9.4 mile lateral pipelines connecting El Paso Terminal to El Paso Junction (also known as the El Paso Laterals). Most of this pipe was built in 1998.

The second system transports crude oil over 424 miles of 18-inch pipeline from Crane Station to Satsuma Station with intermediate pumping stations at Texon, Barnhart, Cartman, Kimble, James River, Eckert, Cedar Valley, Bastrop, Warda, and Buckhorn. The crude system continues with 32 miles of 20-inch pipeline from Satsuma Station to the East Houston Terminal and 9 miles of 20-inch pipeline from East Houston Terminal to 9th street junction. This second system contains all of the Existing Pipeline built in 1949-1950, with some replacement and extensions in the Houston area.

The Longhorn System Map is presented in Figure 1.

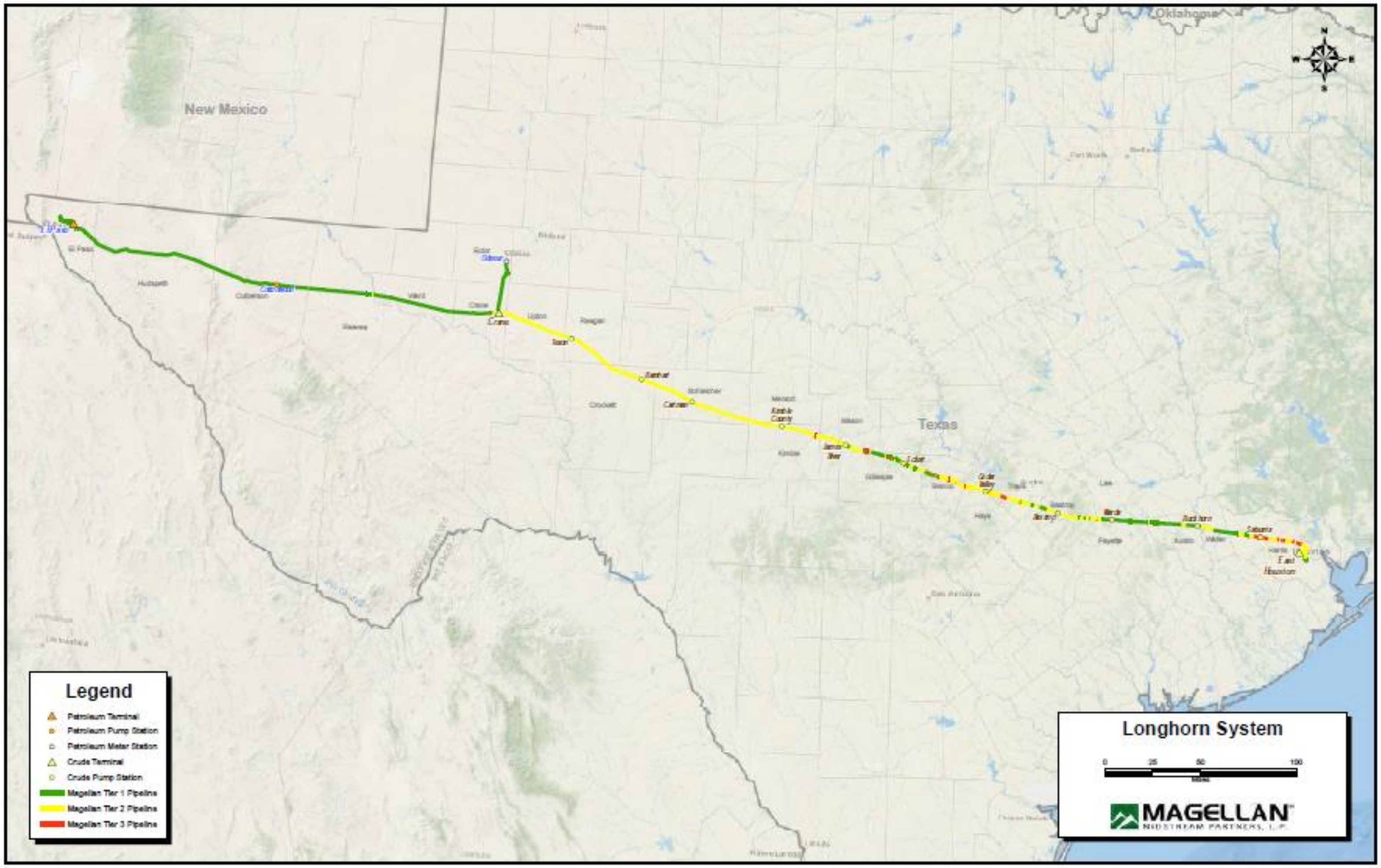

Figure 1. Longhorn System Map 2013

Time Scope

This report presents the annual assessment for 2013 of the operational reliability of the Longhorn system assets. The pipeline entered commercial refined product service on January 27, 2005. The first ORA Annual Report was prepared for the period from January 27, 2005 through January 26, 2006. Subsequent annual reports cover the calendar year, aligning the report period with annual reports prepared for the Longhorn pipeline, many of which are used to prepare this ORA annual report. In addition, this reporting period and ORA Report submission date complies with the requirements in LMC 38 of the LMP and Section 13 of the ORAPM.

2. Executive Summary

This 2013 annual ORA report of the Longhorn system assets addresses the following subjects:

- Threats and Potential Threats to the Pipeline:
    1. Pressure-Cycle-Induced Fatigue
    2. Corrosion
    3. Laminations and Hydrogen Blisters
    4. Hard Spots
    5. Earth Movement and Water Forces
    6. Third-Party Damage
    7. Stress-Corrosion Cracking
    8. Threats to Facilities Other than Line Pipe
- Technical Assessment of the effectiveness of the LPSIP

The analyses of operational pressure cycles to date show that the intensity of pressure cycles is relatively aggressive in relation to benchmarks established on the basis of typical liquid petroleum products and crude oil pipelines. If this continues to be the mode of operation, integrity reassessment from the standpoint of electric-resistance weld (ERW) seam anomalies will be necessary in the year 2018 as discussed in section 5.1 of this report. A transverse field inspection (TFI) tool run, completed in 2007 and early 2008, is used to define a flaw size that will determine the reassessment interval. Seventy-five seam weld features were identified and remediated during the 2007 and 2008 program. Therefore, the reassessment interval uses the seam weld feature detection threshold value from the TFI tool vendor.

Corrosion is a time dependent threat that is periodically monitored using in-line inspection (ILI), annual corrosion surveys, and close interval surveys (CIS). Ultrasonic (UT) wall measurement tools have been run from Galena Park to Crane and were completed in 2010; these were the most recent metal loss tool runs on the original Longhorn system. Results showed that no immediate digs were required and a substantially smaller number of repairs were required for probability of exceedance (POE) digs. The ultrasonic wall measurement tools provided data on metal loss due to corrosion and also provided information about the size and locations of laminations. A second magnetic flux leakage (MFL) tool run was completed on February 21, 2012 for the three laterals from El Paso to Diamond Junction.

The condition of any laminations and blisters using UT ILI data was analyzed on the Existing Pipeline from Galena Park to Crane in 6 segments. From 8,183 laminations identified in these 6 segments, 82 excavations were selected and 2 possible bulging laminations were discovered and repaired with Type B pressure containing sleeves in 2011.

From the standpoint of earth movement and water forces, the primary integrity concerns are ground movement from aseismic faults and soil erosion caused by scouring from floods at specific points along the pipeline. As of 2013, 9 years of data of aseismic fault movements have been taken. The results show fault movement on three of the faults continues to be so small that ground movement will not be a threat to the pipeline and the fourth fault at the Hockley site is only a minor threat. Semi-annual scour surveys of the crossings at the Colorado River and its tributary Pin Oak Creek are starting to show some evidence of soil erosion or scouring. These surveys need to be related to the remaining amount of cover for these two pipelines. This recommendation was made in March 2014. Because this was after the period of the current 2013 ORA, the surveys of remaining depth of cover will be reviewed in the 2014 ORA. The remaining river crossings are inspected visually once every 5 years and were last inspected in 2010.

The Longhorn third-party damage (TPD) prevention program far exceeds the minimum requirements of federal or Texas state pipeline safety regulations, and it represents a model program for the industry. The aerial surveillance and ground patrol frequencies exceeded the frequencies set forth in the LMP. However, two right-of-way (ROW) near-misses were reported; both were classified as One-Call Violations. There were no cases of third-party contact with the pipeline during 2013. The absence of reportable incidents involving mainline pipe suggests the Longhorn proactive damage prevention and maintenance plans (including the aerial surveillance frequency) have been effective and are functioning as intended.

No occurrence of stress-corrosion cracking (SCC) has ever been recorded on the pipeline, including the 449 miles of the Existing Pipeline. Magellan continues to carry out inspections as part of the normal dig program by performing an SCC examination program that uses magnetic particle testing at each dig site.

From the standpoint of facilities data acquired in 2013, one can conclude that pump station and terminal facilities had no adverse impact on public safety.

The technical assessment of the LPSIP indicates that Magellan is achieving the goal of the LPSIP, namely, to prevent incidents that would threaten human health or safety or cause environmental harm. In terms of activity measures, Magellan exceeded the goals of aerial surveillance and ground patrol in the total number of miles patrolled. In addition, public-awareness meetings were held, and right-of-way markers and signs were repaired or replaced where necessary. From the standpoint of deterioration measures, the number of anomalies found per mile requiring excavation decreased substantially between the MFL runs and the UT ILI runs. The number of anomalies requiring immediate repair was zero for the UT ILI runs, down from 0.02-0.04 anomalies per mile for the first MFL runs completed after the line was restarted. In terms of failure measures, there were two DOT-reportable incidents. Both reportable incidents involved releases. One of the releases was at a facility and the other at a valve site; both releases were recovered. There was no third party contact with the pipe or facilities.

3. RECOMMENDATIONS

3.1. Technical Assessment of LPSIP Effectiveness

The LPSIP contains twelve process elements. Seven of these elements are listed below along with an assessment of their effectiveness. These elements are most closely related to the threats addressed by the ORAPM and are summarized in detail with recommendations. The assessments for the remaining five elements can be found in the Annual LPSIP Self-Audit Report for Longhorn Pipeline System.

Longhorn Corrosion Management Plan

Internal corrosion is monitored using internal corrosion coupons. The coupon results have shown little change but monitoring should be continued. One internal corrosion coupon located at the Crane 16-inch Plains WTI delivery had a light corrosion rate of 0.11 mpy from April to September; four other internal corrosion coupons were also observed with a light corrosion rate (<0.06 mpy) at Cartman Station, Cedar Valley Station, Satsuma Station, and Crane 24-inch tank manifold (See Table B-4). The cathodic protection system is monitored to look for areas where external corrosion could be occurring. The corrosion management plan, in combination with the ILI program, has been effective at preventing and monitoring corrosion degradation.

In-Line-Inspection and Rehabilitation Program

One ILI inspection was conducted in November 2013 from Crane to Cottonwood and one deformation inspection was conducted on the 20-inch crude line from East Houston Terminal to Speed Junction. Caliper inspections also occurred in 2012 prior to displacement on the Existing Pipeline and repairs were made in 2013. Thirteen locations containing dents, four locations containing stopple fittings, two locations containing weld plus ends, one location containing a patch repair, two locations containing an A-sleeve, one location containing a weld misalignment, and eight locations for material grade testing were cut out of the pipeline during the reversal process in 2013. The ILI surveys have been effective and have shown a decrease in the number of required repairs and thus an improvement in the condition of the pipe with each successive ILI run.

Damage Prevention Program

The Longhorn third-party damage (TPD) prevention program far exceeds the minimum requirements of federal or Texas state pipeline safety regulations, and it represents a model program for the industry. The aerial surveillance and ground patrol frequencies exceeded the frequencies set forth in the LMP. No events resulted in contact with the pipeline during 2013; however, two ROW near-misses occurred and both were One-Call violations.

The absence of third-party incidents involving mainline pipe suggests the Longhorn proactive damage prevention and maintenance plans (including the aerial surveillance frequency) have been effective and are functioning as intended.

Encroachment Procedures

There were 112 encroachments recorded in 2013, none of which were unauthorized. The encroachment procedures, when followed by the encroaching party, have been effective at preventing TPD to the pipeline.

Incident Investigation Program

Magellan is performing incident investigations on all DOT reportable incidents as well as smaller non-reportable incidents. During 2013 there were twelve incident data reports filed; two were DOT Reportable. Both incidents involved releases, one occurred at a facility and one occurred during maintenance activities at a valve site. Both releases were recovered.

Depth of Cover Program

Ten maintenance reports were associated with addressing exposed pipe in August and September of 2013. Each of these areas were excavated, recoated, and backfilled. One new exposure was identified in 2013 by the Right-of-Way maintenance crew. The line was inspected, recoated, and a concrete revetment matting system was placed over the line. There was one area of shallow cover that was mitigated at mile post 343.5 where the landowner added cover over the line with a terrace system.

Magellan has a no-till agreement with one landowner in particular, which they monitor on a regular basis to ensure the landowner's farming practices do not jeopardize the integrity of the pipeline.

Fatigue Analysis and Monitoring Program

The 2013 fatigue analysis performed by Kiefner incorporated results from the 2007-2008 TFI tool runs and was effective at monitoring the potential of fatigue cracking failures from pressure-cycle-induced growth. The analysis for this program is covered under Section 5.1 of this report.

3.2. Recommended Intervention Measures and Timing

Phase 2 of the Longhorn Reversal Project consisted of increasing the flow rate on the pipeline from Crane, Texas to Houston, Texas from 134,000 bpd to 225,000 bpd. It also involved changing out the pumps at the three Phase 1 stations (Crane, Kimble County, and Cedar Valley), upgrading and reactivating the Satsuma Station, and adding an additional eight intermediate pump stations (Texon, Barnhart, Cartman, James River, Eckert, Bastrop, Warda, and Buckhorn). Table B-1 provides a list of the pump stations and milepost numbers. As a result of these additional stations, test stations will change in 2014.

Pressure-Cycle-Induced Fatigue

For the threat of pressure-cycle-induced fatigue, a reassessment in the year 2018 was calculated based on the pressure cycles for 2008 through mid-2013 and using the results from the 2007-2008 TFI tool runs. The pressure data through the end of the displacement process were used to determine the reassessment interval. The next assessments are as follows:

- East Houston to Satsuma (MP 0 to MP 34.1): 2032
- Satsuma to Warda (MP 34.1 to MP 112.9): 2020
- Warda to Cedar Valley (MP 112.9 to MP 181.6): 2018
- Cedar Valley to Eckert (MP 181.6 to MP 227.9): 2022

- Eckert to Ft McKavett (MP 227.9 to MP 321.9): 2021
- Ft McKavett to Crane (MP 321.9 to MP 457.5): 2018
- Crane to Cottonwood (MP 457.5 to MP 576.3): 2226

Corrosion

For the threat of corrosion, UT inspections for the Existing Pipeline were completed in 2010. Remediation was completed in 2010 and 2011. One ILI inspection occurred in November 2013 between Crane and Cottonwood. The next required ILI assessments are as follows:

- East Houston to Satsuma (MP 0 to MP 34.1): 22-Sept-2014
- Satsuma to Warda (MP 34.1 to MP 112.9): 24-Nov-2014
- Warda to Cedar Valley (MP 112.9 to MP 181.6): 24-Jan-2015
- Cedar Valley to Eckert (MP 181.6 to MP 227.9): 20-Feb-2015
- Eckert to Ft McKavett (MP 227.9 to MP 321.9): 25-Jun-2015
- Ft McKavett to Crane (MP 321.9 to MP 457.5): 8-Jul-2015
- Crane to Cottonwood (MP 457.5 to MP 576.3): 19-Nov-2018
- Cottonwood to El Paso (MP 576.3 to MP 694.4): 19-May-2017
- Crane to Odessa: 28-Jun-2016
- El Paso to Chevron 8-in (Line ID 6650): 23-Feb-2017
- Kinder Morgan 8-in Flush Line (Line ID 6652): 21-Feb-2017
- El Paso to Kinder Morgan 12-in (Line ID 6651): 22-Feb-2017

Laminations and Hydrogen Blisters

The change in the transported commodity from refined products to crude oil will lead to an increased threat of hydrogen blistering. Managing internal corrosion will provide mitigation of this threat by minimizing the production of hydrogen that is produced by anaerobic corrosion. Magellan has previously conducted inspection with ultrasonic UT smart pig in compliance with the LMP to find any blisters and injurious laminations that may exist in the system. All injurious laminations were repaired. As a future intervention method to prevent any existing non-injurious laminations from becoming injurious, future Electronic Geometry (EGP) runs will be used to inspect for the formation of blisters. These EGP tools are required to be run every three years in accordance with the LMP. This interval is 15 times more frequent than the interval required to form a blister.

A review of the 2013 maintenance reports showed no lamination anomalies were excavated. Magellan should continue to monitor for laminations with ILI tools to verify that no blisters are forming. The monitoring frequency recommended should coincide with the corrosion tool and deformation tool reassessment schedule in Section 7 as shown below:

- East Houston to Satsuma (MP 0 to MP 34.1): 22-Sept-2014
- Satsuma to Warda (MP 34.1 to MP 112.9): 24-Nov-2014
- Warda to Cedar Valley (MP 112.9 to MP 181.6): 24-Jan-2015
- Cedar Valley to Eckert (MP 181.6 to MP 227.9): 20-Feb-2015
- Eckert to Ft McKavett (MP 227.9 to MP 321.9): 25-Jun-2015
- Ft McKavett to Crane (MP 321.9 to MP 457.5): 8-Jul-2015

Earth Movement and Water Forces

The earth movement analysis continues to show that any movement on the seven faults that are monitored is an order of magnitude less than the assumptions used to justify the required monitoring program in the EA. Kiefner continues to recommend a five-year reassessment program for these seven faults rather than the current 6-month program. If the faults appear to become more active, then more frequent measurements can be implemented.

Scour inspections were completed in January and December 2013 on the Colorado River and Pin Oak Creek; scouring surveys indicated changes in the toe of the banks that may be related to measurement error. The Onion Creek baseline scour survey was performed for the very first time this year due to flooding in November 2013. Data from semi-annual scour inspections for the Colorado River and Pin Oak Creek were inconclusive because of water level fluctuations that were used for measurement. These measurements need to be related to the remaining depth of burial on the pipeline in the waterway so that Magellan can plan for any remediation that may be needed once an erosion threshold is reached (see Stream Crossings in Section 5.5). The scour inspection on these two crossings should continue as specified by studies referenced in LMC 19.

Third-Party Damage

For the threat of TPD, Magellan should continue both prevention and inspection activities. Prevention activities include ROW surveillance and public-awareness activities that continued to be successful in 2013. Inspection activities include ILI inspections required as part of the ORA, including the MFL-geometry, TFI-geometry, inspection in 2007-2008, the UT-geometry inspection in 2009-2010, and the geometry inspections in 2012. One ILI inspection for deformation was conducted in November 2013 from Crane to Cottonwood and one deformation inspection was conducted on the 20-inch crude line from East Houston Terminal to Speed Junction. LMC 12A requires inspections with a “smart” geometry tool be carried out within three years of a previous inspection. For specific inspection dates to fulfill the requirement for each of the six intervals spanning the Existing Pipeline from East Houston to Crane see Table 12 in Section 7 on Integration of Intervention Requirements.

Stress-Corrosion Cracking

As no evidence of SCC has been detected, it is not necessary to recommend an intervention measure. Magellan should continue to monitor for this threat through their current method, which consists of looking for evidence of SCC when maintenance excavations are performed.

Threats to Facilities Other than Line Pipe

From the standpoint of facility data acquired for 2013, one can conclude that active non-pipe facilities had no adverse impact on public safety. Longhorn monitors the integrity of these facilities through scheduled maintenance and inspection activities prescribed by the LPSIP and results are tracked in an electronic database.

The Longhorn facilities maintenance program represents a thorough and comprehensive means of facility inspection and preventive maintenance. Magellan continues its detailed documentation of incidents, facility integrity processes, and reporting of the facility preventive maintenance program.

3.3. Implementation of New Mechanical Integrity Technologies

Magellan has committed to conducting non-destructive or destructive strength tests for 50 percent of all annual pipe excavations associated with in-line inspection anomaly evaluations or remediation.

During 2013, T. D. Williamson developed processes and procedures for the field determination of pipeline mechanical properties and chemical composition. The mechanical properties include pipe yield strength and pipe tensile strength. A detailed procedure and process manual developed by T. D. Williamson was reviewed. The process is termed "Positive Material Identification Field Services". The process includes mobile automated ball indention for mechanical properties and optical emissions spectrometry for chemical composition. The procedure is thorough and provides a guide for technicians to field test pipe without having to remove samples for laboratory testing. Verification testing was performed at the Kiefner Material Testing Facility on eleven pipe samples that had been removed from the Longhorn Pipeline. Enhancements to the field process were made and tested during additional validation tests. The test results were presented to PHMSA by Magellan and T. D. Williamson.

3.4. ORA Process Improvements

No new processes were implemented in 2013.

4. New Data Used in This Analysis

The ORA Process Manual identifies 78 items in Appendix D consisting of data, data logs, and reports the ORA contractor must review and consider in conducting the ORA. These 78 items in the ORAPM are discussed in Appendix B of this report.

5. Results and Discussion of Data Analysis

This section presents an analysis of the data collected in Section 4 for the ongoing integrity threats monitored by the LMP: pressure-cycle-induced fatigue cracking, corrosion, pipe laminations and hydrogen blisters, hard spots, earth movement, third-party damage (TPD), stress-corrosion cracking (SCC), and threats to facilities other than line pipe.

5.1. Pressure-Cycle-Induced Fatigue Cracking

Pressure-cycle-induced fatigue-crack-growth of defects is recognized to be a potential threat to the integrity of the Longhorn Pipeline. Manufacturing defects in or immediately adjacent to the longitudinal ERW or EFW seams of the 1950 line-pipe material contained in the Existing Pipeline are considered to be the primary concern. The concern is that a defect that initially may be too small to fail at the operating pressure will grow through fatigue cracking and become large enough to cause a failure if exposed to sufficient numbers of large pressure fluctuations. Accordingly, Section 3 of the ORAPM requires the monitoring of pressure cycles during the operation of the pipeline, calculating the worst-case crack growth in response to such cycles, and reassessing the integrity of the pipeline at appropriate intervals to find and eliminate potentially growing cracks before they become large enough to cause a failure of the pipeline. Although the likelihood of such defects being present in the newer 1998, 2010, 2012 and 2013 pipe material is much less than that associated with the 1950 pipe material, pressure-cycle monitoring and crack-growth analyses were considered for the New Pipeline (MP 9 to East Houston, Crane to El Paso, and piping added for the 2012/2013 reversal project) as well as for the Existing Pipeline (MP 9 to Crane).

The potential effects of pressure-cycle-induced fatigue are calculated for the Existing Pipeline on the basis of the results of the TFI tool run from Galena Park to Crane completed in 2007 and early 2008.

The failure pressure of each defect is controlled not only by its size, but by the diameter and wall thickness of the pipe, the strength of the pipe, and the toughness of the pipe. Toughness is the ability of the material containing a given-size crack to resist tearing at a particular value of applied tensile stress. Toughness in line-pipe materials has been found to correspond reasonably well to the value of "upper-shelf" energy as determined by means of standard Charpy V-notch impact tests. As noted in Reference 1, the Charpy V-notch energy levels for samples of the 1950 material ranged from 15 to 26 ft-lb. Prior to completing the TFI tool run, the ORAPM specified a process that used the previous hydrostatic test pressure levels to determine a starting defect size. In this case, toughness is a factor for establishing starting defect sizes and it is more conservative to use a higher value of toughness as it allows for a larger defect to remain after the hydrotest. Note that toughness is not a factor in establishing either starting defect size using the ILI detection threshold or the N10 notch. Toughness is needed to calculate the size of the defect that will cause failure at the operating pressure. In these cases, a lower toughness value generally leads to more conservative calculated fatigue lives. However, for the specific flaw sizes used in our analysis, the fatigue life does not change whether 15-ft lbs or 25 ft-lbs is assumed. This is due in part to the relatively short length of the starting defects. With a longer defect, it would be expected that using a value of 15 ft-lbs instead of 25 ft-lbs would decrease the fatigue life. We have used a value of 15 ft-lbs in our calculations.

To conduct a pressure-cycle analysis for the Longhorn Pipeline, we use the well-known and widely accepted "Paris Law" model in which the natural log of crack growth per cycle of pressure (or hoop stress) is assumed to be proportional to the natural log of the change in stress intensity represented by the pressure change. The slope and intercept of this relationship are constants that depend on the nature of the material and the environment in which the crack exists. In the absence of empirical data for the particular crack-growth environment of the Longhorn Pipeline, we use values for the constants that have been established through large numbers of laboratory tests and that are published in the Fitness-For-Service API Standard 579-1/ASME FFS-1. The change in stress-intensity factor corresponding to a change in pressure is calculated via a Raju/Newman algorithm. Details of these equations are available in the Mock ORA (Reference 2 or in Reference 3, a readily available technical publication).

Pressure-cycle data is provided to us by the operator of the Longhorn Pipeline. We use a systematic cycle-counting procedure called "rainflow counting" to pair maximum and minimum pressures. The rainflow-counted cycles are used in the Paris-Law model to grow a potential crack. For a given set of cycles, we can predict the number of such cycles and the length of time that it will take for the fastest growing defect to reach a size that will fail at the maximum operating pressure of the pipeline. We make Magellan aware of that time, and in accordance with the LMP, Magellan will carry out a reassessment of the integrity of the pipeline before 45-percent of the time to failure has expired.

The line pipe that is expected to be the most susceptible to longitudinal-seam fatigue-crack-growth is the 1947 to 1953 pipe material which includes the 20-inch OD, 0.312-inch WT Grade B pipe, the 18-inch OD, 0.281-inch and 0.312-inch WT X45 pipe, and the 18-inch OD, 0.250-inch WT X52 pipe. The results of the TFI tool run indicated the presence of 75 Seam Weld A and B features in the Galena Park to Crane segment, or those that are presumed to be crack-like in nature. Through the course of the 2007 and 2008 dig program, each of the crack-like indications called out by the tool have been repaired. Therefore, the procedure in Section 3.4 of the ORA Process Manual requires the use of detection threshold capabilities of the TFI tool to determine an appropriate reassessment interval. The TFI detection capabilities for seam weld features state that a depth of 50-percent of the wall thickness for features between one and two inches in length and a minimum depth of 25-percent of the wall thickness for features greater than two inches in length could be missed.

Based on these detection capabilities, the analysis assumes that a 50-percent through wall, 2-inch long crack-like feature could have been missed. The 50-percent through wall defect has a shorter life than a 25 percent through wall defect. In the Existing Pipe, we assume the defect could have been missed in a location that will provide the most conservative reassessment interval. We chose the pipe located closest to the discharge of a pump or right at a wall thickness or pipe grade transition to capture the strongest effects of the pressure cycles. It is not necessary to calculate a fatigue life at all the points where the susceptible pipe exists because pipe further downstream will have a longer fatigue life based on the hydraulic gradient and need not be evaluated.

A slightly different procedure is applied to the calculation of time to failure for the newly installed pipe. Instead of using the sizes of defects detected by the TFI tool, we use a starting defect size that is the largest defect that could have escaped detection in the manufacturer's ultrasonic seam inspection. That would be the size of the "calibration" defect used to test the ultrasonic seam inspection detection threshold. That size comes from API Specification 5L, and it is assumed by us to be the largest of the acceptable calibration defects in that standard, namely, the N10 notch. The N10 notch has an axial length of two inches, and a depth of 10 percent of the nominal wall thickness of the pipe. That defect is used as the starting defect size in our analysis. Otherwise the analysis procedure for determining the reassessment time for the 1998 pipe material is the same as that described above for the 1950 pipe material.

The case locations were chosen with reference to the operating direction and pump locations as of November 2013. The analysis was done in three sets to reflect the configurations of the pipeline during the 2007-2013 time period. The first analysis set used the 2007 to 2012 data to represent the operations since start-up and flow from east to west. The second analysis covered the time period between April 2013 to October 2013 in which the crude portion of the pipeline was operating from Crane to East Houston, and only a limited number of pumps were operating. The final analysis was completed using the November to December 2013 data, in which the line was operating in its fully reconfigured format and all pumps were in operation.

Our analysis shows that the shortest time to failure for a possible feature that could have been missed by the TFI tool is 10.7 years at the location that is now the Texon Station Discharge. The recommended reassessment interval is calculated by taking 45 percent of the shortest fatigue life, which corresponds to a factor of safety of 2.22 (1/0.45). Applying this factor of safety, we recommend a reassessment interval of 4.8 years based on the current operating pressures. An assessment would be required in 2018. The reversal of the pipeline from Crane to East Houston combined with the addition of pumping stations has increased the cycling intensity and frequency.

Table 1 summarizes the locations evaluated. The pressure data from 2007 to October 2013 were applied for a period of 12.4 years to include the actual time of operation multiplied by the factor of safety of 2.22 so that distortions to the remaining fatigue life and reassessment interval would be minimized. The November and December 2013 pressure data were applied to the depths and lengths obtained after applying the 2007 through October 2013 pressure data to determine the remaining life from that point in time. Therefore, the fatigue lives shown in Table 2 are to be taken from the November 2013 date. The factor of safety should be applied to these fatigue lives to determine the reassessment interval. As the Crane to El Paso products segment of the line operates separately from the Crane to East Houston segment, results for that segment may be considered separately. A fatigue life was calculated for the new 1998 pipe at Crane Station on the products line based on the maximum flaw size, described above as an API 5L N10 notch, a 10-percent, 2-inch-long flaw. Our analysis shows that the shortest time to failure for this segment is greater than 500. This would result in a reassessment interval of greater than 225 years.

Table 1. Pressure-Cycle-Induced Fatigue Cracking Analysis Locations

Case	Description	Seam Type	Manufact.	Station	Mile Post	Diameter, inches	Wall Thickness, inch	Pipe Grade
1	1947 Pipe near Satsuma Discharge	ERW-LF	UNKNOWN	1799+54	34.1	20	0.312	Grade B
2	1950 Pipe near Buckhorn Discharge	EFW	A.O. SMITH	3587+73	67.9	18	0.281	X45
3	1950 Pipe near Warda Discharge	EFW	A.O. SMITH	5960+75	112.9	18	0.281	X45
4	1950 Pipe near Bastrop Discharge	EFW	A.O. SMITH	7487+53	141.8	18	0.281	X45
5	1950 Pipe near Cedar Valley Discharge	EFW	A.O. SMITH	8402+75	159.1	18	0.312	X45
6	1950 Pipe near Eckert Discharge	EFW	A.O. SMITH	12032+98	227.9	18	0.281	X45
7	1950 Pipe near James River Discharge	EFW	A.O. SMITH	13736+94	260.2	18	0.281	X45
8	1950 Pipe near Kimble Discharge	EFW	A.O. SMITH	15585+45	295.2	18	0.281	X45
9	1950 Pipe near Cartman Discharge	EFW	A.O. SMITH	18212+02	344.9	18	0.281	X45
10	1950 Pipe near Barnhart Discharge	EFW	A.O. SMITH	19354+32	366.6	18	0.312	X45
11	1953 Pipe near Texon Discharge	EFW	A.O. SMITH	21998+56	416.6	18	0.250	X52
12	1953 Pipe near Crane Crude Discharge	EFW	A.O. SMITH	24060+69	455.7	18	0.250	X52

Case	Description	Seam Type	Manufact.	Station	Mile Post	Diameter, inches	Wall Thickness, inch	Pipe Grade
13	1998 Pipe near Crane Products Discharge	ERW-HF	U.S. STEEL	24160+18	457.6	18	0.281	X65
14	1947 Pipe at Cedar Valley Discharge	EFW	A.O. SMITH	8963+66	169.8	18	0.281	X45

Table 2 depicts the fatigue life for each of the above locations. The reassessment interval is based on the remediation of all cracks detectable by the TFI, a high probability of detection for TFI finding all features greater than 50-percent deep and two inches long, and no feature greater than 10 percent of the wall thickness existing in the new pipe and the factor of safety of 2.22.

Table 2. Fatigue Lives and Re-assessment Intervals for Analysis Locations

Case	Cycles per Year	Calculated Time to Failure since Nov 2013, years	Re-assessment Interval, years	Re-assessment Interval Safety Factor	Re-assessment Year
1	2,862	41.9	18.9	2.22	2032
2	3,030	22.4	10.1	2.22	2023
3	3,317	15.4	6.9	2.22	2020
4	3,200	10.8	4.9	2.22	2018
5	2,614	59.1	26.6	2.22	2040
6	3,048	18.3	8.3	2.22	2022
7	3,245	16.4	7.4	2.22	2021
8	2,677	24.9	11.2	2.22	2025
9	3,162	13.4	6.0	2.22	2019
10	2,470	43.0	19.4	2.22	2033
11	***2,928***	***10.7***	***4.8***	***2.22***	***2018***
12	2,443	16.3	7.3	2.22	2021
13	548	500+	225+	2.22	2229
14	2,530	27.4	12.3	2.22	2026

The fatigue lives for the Crane to East Houston segment of pipeline have changed due to altered line operation since November 2013. To illustrate the reduction in calculated time to failure of the case locations, a histogram was created showing the pressure cycle frequency and magnitude for the locations with the shortest remaining lives in this ORA and in the 2012 ORA. The November to December 2013 data and 2012 a random 2-month period in early 2012 were compared. The results are shown in Figure 3.

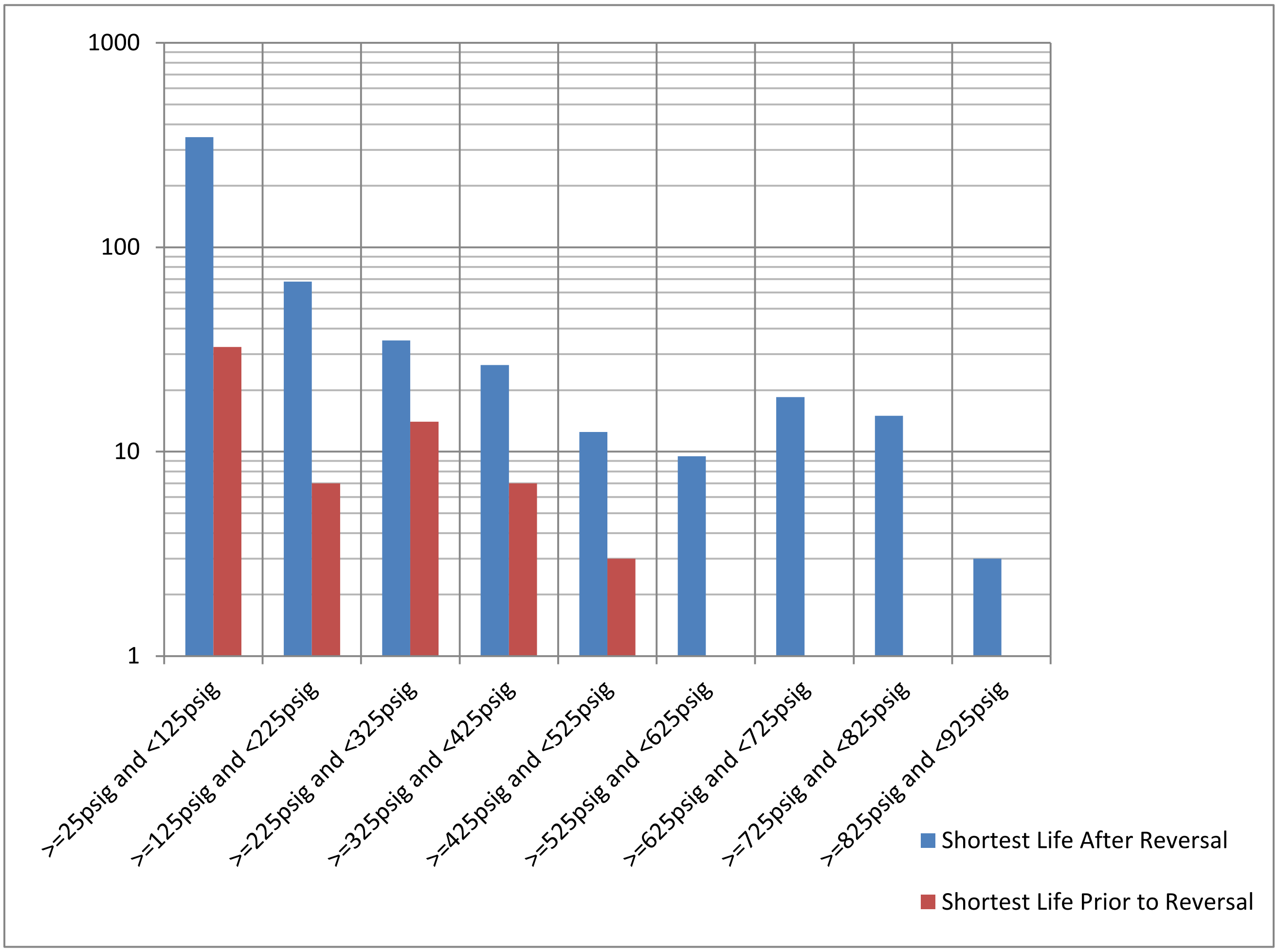

Figure 2. Histogram of Pressure Cycle Frequency and Magnitude Prior to and After Line Reversal

5.2. Corrosion

Monitoring the Possibility of Corrosion-Related Leaks using ILI

ILI results are commonly used by pipeline operators as a means for identifying and evaluating corrosion-caused metal loss and planning remediation. This typically involves running an ILI tool to identify and size corrosion features followed by remediation of features that exceed a depth or a pressure threshold as necessary. This generally accepted method is a valid approach for addressing line pipe corrosion. In 2013 MFL tools were run on one pipeline segment from Crane to Cottonwood.

ILI Inspections

Ultrasonic wall measurement tools provide information on internal and external metal loss, as well as geometrical anomalies such as dents, and also provided information on the existence of laminations and inclusions. A UT tool was run on the six segments from Galena Park through Crane beginning in 2009 with completion in 2010. Table 3 shows the metal loss anomalies that were remediated, by pipeline segment, in 2013 per maintenance reports.

Table 3. Summary of Metal Loss Anomalies Remediated in 2013

Pipeline Segment	Metal Loss Anomalies Excavated
Galena Park to Satsuma	0
Satsuma to Warda	0
Warda to Cedar Valley	0
Cedar Valley to Eckert	0
Eckert to Fort McKavett	0
Fort McKavett to Crane	13
Crane to Cottonwood	0
Cottonwood to El Paso	5
El Paso Kinder Morgan 12”	1

5.3. Pipe Laminations and Hydrogen Blistering

No laminations were excavated in 2013. The conversion of the pipeline to crude oil service in 2013 re-introduced trace amounts of hydrogen sulfide to the pipeline, similar to the crude oil that was transported from the early 1950’s until 1995. Monitoring of the lamination anomalies for the possibility of blister growth with ILI tools is recommended per the proposed Longhorn Pipeline Reversal EA Section 6.2.1.2. Deformation results from future ILI tool runs will be correlated to the locations of laminations identified by the ultrasonic wall measurement tool. Deformations that form at the location of laminations may be an indication of blister formation. The next ILI for laminations and blisters is scheduled to be performed in 2014.

5.4. Hard Spots

Magellan has committed to running a hard spot tool and remediating indications that pipe is susceptible to hard spots (over 325 Brinell hardness) based upon known pipe information (i.e.

manufacturing vintage, has had a past leak or failure due to a pipe hard spot in the pipeline) as soon as practicable but not later than one year after hard spot tool run.

A combination MFL and Low Field Magnetization (LFM) tool was run on twelve segments from Crane to East Houston to identify possible hard spot features in the pipe body (see Table 5 for inspection results). The Eckert to Cedar Valley segment reported two hard spots that were both rated 1 on a scale from 1 to 5; 5 being most likely and 1 being improbable. Both reported hard spots on the Eckert to Cedar Valley segment were investigated in 2014 and will be discussed in the next ORA report. Hard spots are formed during the manufacturing process due to local rapid cooling of the steel plate surface in the hot rolling mill that creates metallurgical changes. The conversion of the pipeline to crude oil service in 2013 re-introduced trace amounts of hydrogen sulfide into the pipeline which could be detrimental, as hard spots (particularly those with hardness exceeding 35 on the Rockwell C scale) can be susceptible to hydrogen induced cracking (HIC). Hard spots with an ILI tool predicted rating of 1 on a scale of 5 are unlikely to be hard enough to be susceptible to HIC.

Table 4. Summary of Hard Spots Detected

			Hard Spot Scale				
Pipeline Segment	**Date**	**Possible Hard Spots Identified**	**5 Most Likely**	**4**	**3**	**2 Questionable**	**1 Improbable**
Crane to Texon	10/15/2013	0	0	0	0	0	0
Texon to Barnhart	10/16/2013	0	0	0	0	0	0
Barnhart to Cartman	10/18/2013	0	0	0	0	0	0
Cartman to Kimble	10/22/2013	0	0	0	0	0	0
Kimble to James River	10/23/2013	0	0	0	0	0	0
James River to Eckert	10/24/2013	0	0	0	0	0	0
Eckert to Cedar Valley	11/11/2013	2	0	0	0	0	2
Cedar Valley to Bastrop	12/3/2013	0	0	0	0	0	0
Bastrop to Warda	10/30/2013	0	0	0	0	0	0
Warda to Buckhorn	11/1/2013	0	0	0	0	0	0
Buckhorn to Satsuma	12/4/2013	0	0	0	0	0	0
Satsuma to East Houston	8/28/2013	0	0	0	0	0	0

5.5. Earth Movement (Fault and Stream Crossings)

Fault Crossings

The Longhorn pipeline system crosses several aseismic faults between Harris County and El Paso, Texas. None of the faults west of Harris County are known to be active. Within Harris County, the pipeline crosses seven aseismic faults that are considered to be active. The location and geologic data concerning Akron, Melde, Breen, and Hockley are summarized in Table 5.

Table 5. Fault Location and Geologic Data for the Active Aseismic Faults in Harris County, Texas

	Location			Fault				Soil	
Fault	MP	Station	±feet	Orientation	Dip	Displacement	Width(ft)	Classification	Formation
Akron	3.84	202+90	60	N85E		down N		CL	
Melde	5.66	298+60	50	N64E		down N		CL	Beaumont
Breen	25.85	1364+85	50	N50E		down NW	13	CL	Lissie
Hockley	46.34	2446+60	70	N56W	67SW		80	CL	Lissie

Monitoring stations across four faults were installed in March 2004 in accordance with section 6.2 of the ORAPM. Baseline readings were taken in late May and early June 2004. Nineteen subsequent displacement readings have been taken at approximately 6-month intervals. A plot of the displacements over time is shown in Figure 3 below. Faults move in one direction only, so the up and down variability is an indication of the uncertainty of the measurement. With 10 years of data we attempted to measure the actual fault movement over time by calculating best fit trend lines. The trend lines show no measureable movement on the Melde and Breen faults, with only slight movement of 0.017 in/yr (0.43 mm/yr) over 9½ years for the Akron fault and -0.019 in/yr (-0.48 mm/yr) over 9½ years for the Hockley fault.

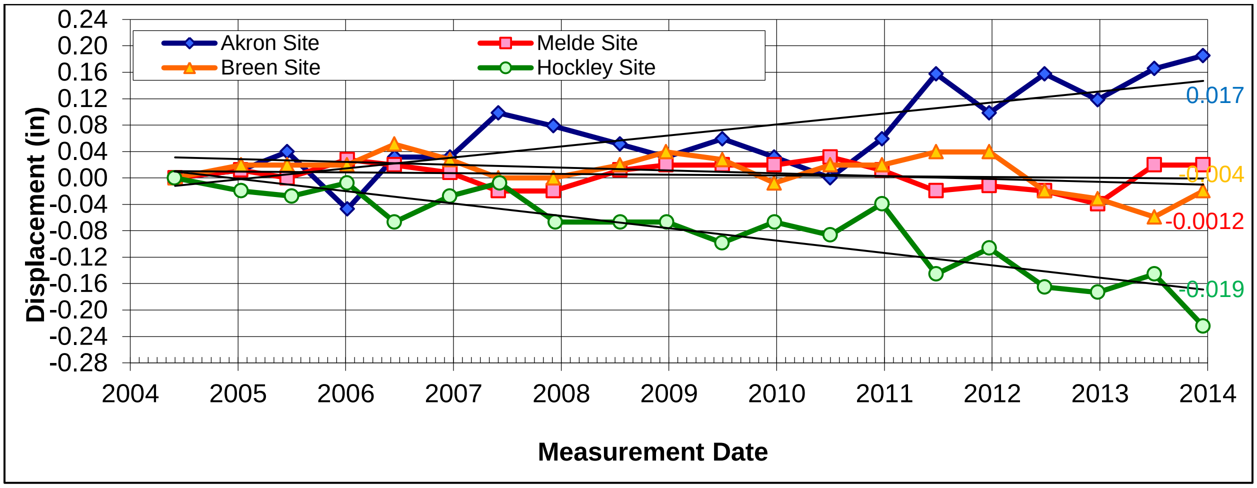

Figure 3. Fault Displacement over 9-Year Period

For this year's analysis with 10 years of data, we used the calculated movement from the best fit trend lines and compared these estimates of fault growth to the Kiefner stress analysis described in the 2005 ORA Annual Report. Table 7 shows the amount of movement at each fault that can occur before it exceeds the stress levels allowed by ASME B31.4. The differences in allowable fault displacements are caused in large part by differences in the angle of the fault movement. The calculated rate of displacement has accelerated and reduced the number of years to reach the allowed displacement from the amount reported in the first half of 2013 Report (Table 6). This decrease is not alarming but does warrant watching, especially for the Hockley fault.

Table 6. Summary of Estimated Allowable Fault Displacement Due to Stresses

	Displacement (in)	Ave. Rate of Movement (in/yr)	Time to Reach Displacement (yrs)
Akron	4.17	0.017	250
Melde	4.13	-0.001	> 1000
Breen	1.50	-0.004	349
Hockley	0.63	-0.019	34

Assumptions used in the analysis included: the stress in the Longhorn Pipeline is below the allowable stress levels of ASME B31.4 at this time; the initial stress in the pipeline is given by ASME B31.4 stress analysis; the soil properties are our best estimate for representative values of properties we could obtain; the fault movement can be represented by linear trend lines fit to the data. On the basis of these assumptions, Table 6 shows the amount of time it will take for stress levels to exceed those allowed by ASME B31.4.

Section 6.4 on Aseismic Faulting/Subsidence Hazards of Appendix 9E of the Environmental Assessment[4] estimated the rates of vertical movement on the order of 0.2 inch per year based on field observations. Actual measurements over the past 10 years show rates are more than an order of magnitude less than estimates from the EA. Thus one of the original reasons for monitoring these four faults was overly conservative in its estimation of fault movement rates. We continue to believe the time to failure is large enough that semi-annual monitoring is much more often than needed.

Hockley fault monitoring is recommended every 5 years even though the estimated time to failure for the fault is 34 years. Because the accuracy of the fault movement measurements appears to be 0.4 – 0.8 inch (1 - 2 mm), several measurements are needed over time to obtain a trend. The other three faults have reinspection times of 250+ years. Such long times to reach a displacement that could result in failure would normally not warrant any monitoring. However, according to the U.S. Geological Survey, September 2005[5] there are documented cases of fault movement reinitiating, so monitoring every five years for these 3 faults is also appropriate.

Three additional faults have been instrumented for the new lateral connecting the East Houston Terminal and existing Longhorn pipeline. Baseline readings have been taken for the McCarty, Negyev, and Oates faults in September 2012. There are five readings performed after the baseline readings in approximately one year. The trend line for Negyev and Oates show no movements. McCarty shows 0.183 in/yr (4.65 mm/yr) movement (Figure 4).

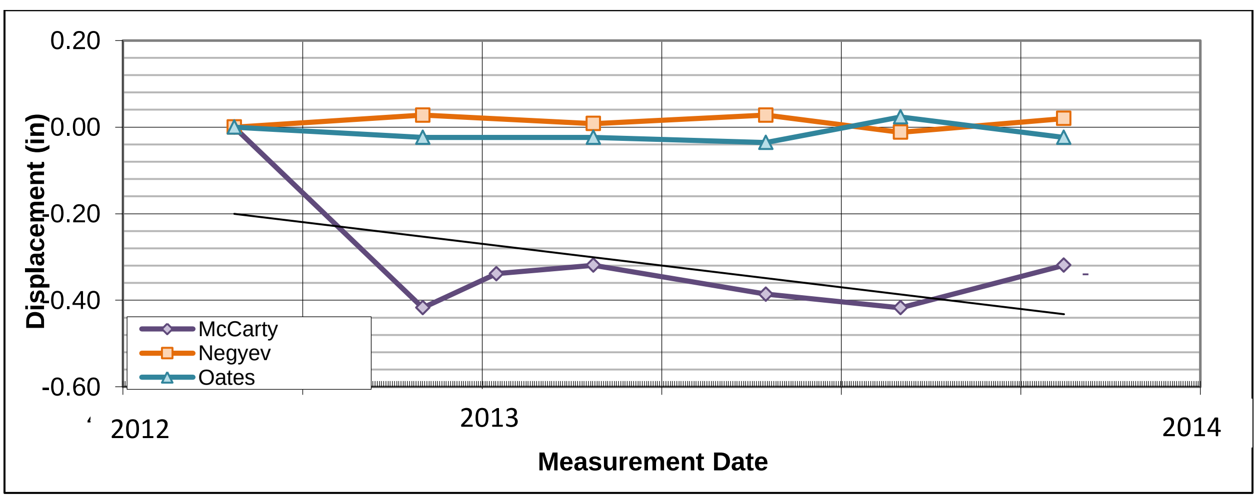

Figure 4. Fault Displacement over 1-Year Period for McCarty, Negyev and Oates

Trend lines established for McCarty, Negyev and Oates in Table 7 show the time to a significant displacement for pipeline to be under stress similar to the Melde and Akron faults. Calculations resulted a very long time to reach critical displacement for Negyev and Oates. McCarty may require more readings. Although this is suspect as it appears the baseline reading contains a significant error of almost ½-inch. If the point was eliminated the rate would be close to zero. Rather than delete this point because it is suspicious it was chosen to leave it in the analysis, because it will become less influential in the least squares curve fit as more data is collected over time and there is no immediate threat from the McCarty fault even with this suspect data.

No displacement limits were calculated for these faults; instead an average reading from the two closest faults was used for displacement limits.

Table 7. Summary of Estimated Allowable Fault Displacement Due to Stresses

	Displacement (in)	Ave. Rate of Movement (in/yr)	Time to Reach Displacement (yrs)
McCarty	4.1	-0.183	22
Negyev	4.1	0.001	>1000
Oates	4.1	0.000	>1000

Stream Crossings

There are many stream crossings on the Longhorn system, with all but two needing inspections once every 5 years according to studies generated by LMC 19(b) and covered in the ORA by section 6.3 of the ORAPM. The potential for failure was summarized in Appendix 9E of the original 2000 EA. The Colorado River (Figure 5) and its tributary Pin Oak Creek (Figure 6) were last surveyed in December 2013. The last reading performed in December 18, 2013 had missing readings; therefore it is omitted from calculations. The results show changes in the High Bank to the Toes on Pin Oak Creek of 6-7 feet and changes between the Toes of the bank of the Colorado River of 10-17 feet and changes on the west Bank between Toe and High Bank of 2 feet. Due to flooding, Onion Creek was also being monitored in 2013. The first inspection was performed in November 2013.

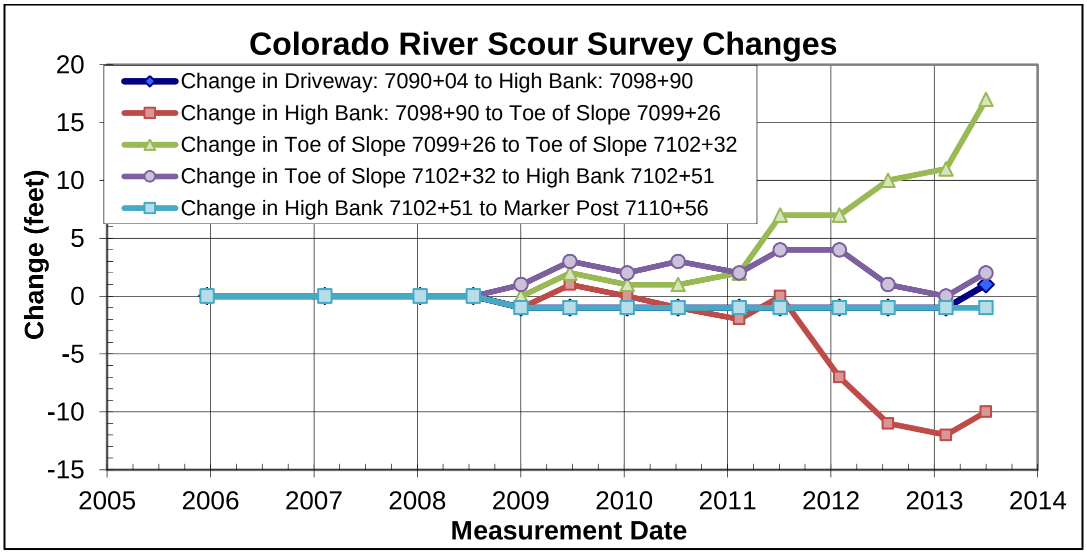

Figure 5. Changes in the Scour Survey of the Colorado River over 7 Years

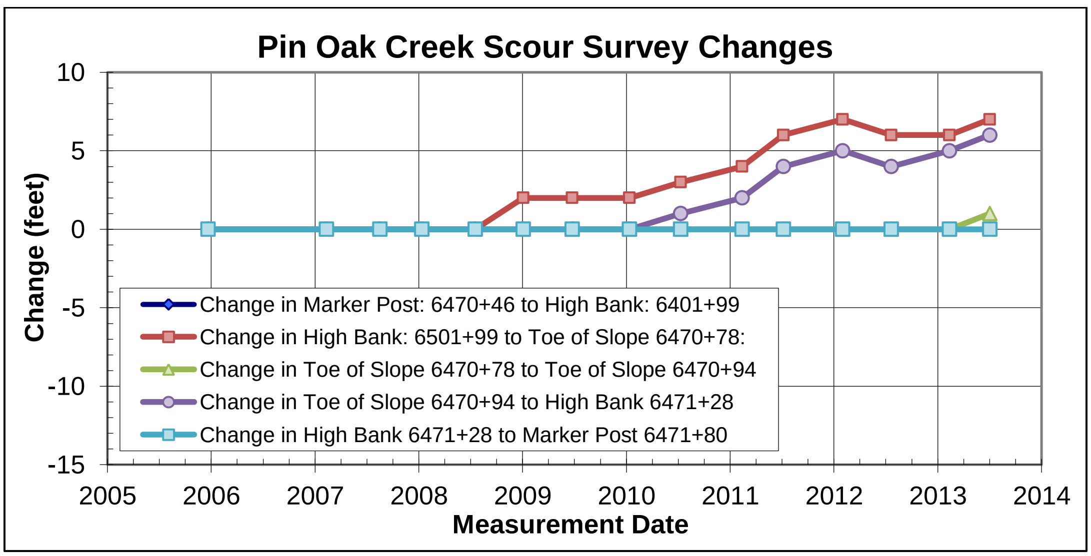

Figure 6. Changes in the Scour Survey of Pin Oak Creek over 7 Years

These changes in the distance from the High Bank to the Toes of Pin Oak Creek and the distance between the Toes and the distance from the West High Bank to the Toe of the Colorado River warrant a more accurate survey of the depth of burial of the pipeline in the river bed between the Toes of the two bodies of water to determine how much depth of cover loss is acceptable.

The Toe is apparently where the bank meets the water and can be affected by whether an upstream dam is open or closed. The measurements have also been affected by recent drought conditions. Such changes can also be an indication of erosion of cover over the pipeline. Because these measurements are showing large changes of 6 to 17 feet, a better measurement is recommended to determine if erosion is occurring and the pipeline is being exposed in the river bed.

5.6. Third-Party Damage

Section 7 of the ORAPM divides the assessment of TPD prevention into three parts: data review, One-Call violation analysis, and intervention recommendations.

Data Reviewed

The data reviewed included:

- Item 50, Right-of-Way (ROW) Surveillance Data
- Item 51, Third-Party Damage, Near-Misses
- Item 52, Unauthorized ROW Encroachments
- Item 53, TPD Reports on Detected One-Call Violations
- Item 56, Miles of Pipe Inspected by Aerial Survey by Month
- Item 57, Number of Pipeline Signs Installed, Repaired, Replaced by Month
- Item 58, Number of Public Outreach or Educational Meetings
- Item 59, Number of One-Calls by Month by Tier
- Item 60, Public Education and Third-Party Damage Prevention Ads Quarterly
- Item 61, Number of Website Visits to Safety Page by Month
- Item 67, Number of ROW Encroachments by Month
- Item 68, Number of Hits by Month
- Item 71, Annual Third-Party Damage Assessment Report (TPD Annual Assessment)
- Item 72, One-Call Activity Report
- Item 77, Results of ILI for TPD

From the data listed above including an analysis of the 2013 TPD Annual Assessment we conclude:

- There were 2 ROW near-misses reported; both were classified as One-Call Violations.
    - The first occurred in August, where a third-party contractor had called in a One-Call ticket, but did not list the entire scope of work and travelled outside the specified area.
    - The second was in November when a third-party contractor building a driveway within the ROW failed to call in a One-Call ticket.

- Regardless of an actual One-Call violation, excavators and/or landowners associated with a ROW Near-Miss are added to the Damage Prevention annual mailing distribution list. There were no other incident investigations involving Third-Party Damage to the pipeline.
- The 2013 TPD Annual Assessment shows an approximate 38 percent decline in unique aerial patrol observations, with a 53 percent drop in third-party activity or non-company aerial-patrol-observations.
- One-Call frequency increased approximately 15.5 percent and the number of tickets sent to Field Operations for clearing/locating increased by approximately 3.5 percent.

For further detail see Appendix B, Section 4.11 One-Call Violations and Third-Party Damage Prevention Right-of-Way Surveillance Data.

A new exposure was identified in 2013 by the Right-of-Way maintenance crew. The line was inspected, recoated, and a concrete revetment matting system was placed over the line. The location is no longer exposed. Six sites that have been actively managed under the Outside Forces Damage Prevention Program in accordance with the System Integrity Process (SIP) were repaired and are no longer exposed at this time. Additionally, three locations consisting of creek banks and a washout were repaired. The washout area will continue to be monitored through aerial patrol.

One-Call Violation Analysis

Out of 16,319 One-Calls in 2013, it appears that 20.6 percent required field locates and were potential ROW encroachments. The operator of the pipeline is effectively screening the One-Calls to separate, on the basis of the location, information associated with each "ticket", and the likely encroachments from the "no locates" (One-Call locations that are sufficiently remote from the ROW to assure that no effort is needed to mark the location of the pipeline).

Most One-Call tickets continue to occur in two counties. Harris County accounted for 10,215 (63 percent) of the One-Call tickets. Travis County accounted for 1,398 (8 percent) of the One-Call tickets. Thus, 71 percent of the One-Call notifications on the pipeline occurred in these large metropolitan areas. Clearly, based upon that data, these two areas present the greatest potential for third-party damage. El Paso came in third with 656 tickets (4 percent). Although there were no hits to the pipeline, Kiefner agrees with a Magellan recommendation from 2011 that temporary fencing should be used where appropriate for authorized encroachments into the ROW going forward and the Magellan SIP has been updated accordingly. Figure 76 below shows a flow chart analysis of the One-Calls. Out of 16,319 One-Calls, 2 resulted in third party near-misses; one involved a third-party contractor who had called in a One-Call ticket, but did not list the entire scope of work and had travelled outside the specified area approved by the ticket. The second involved a third-party contractor who was constructing a new driveway had failed to call in a One-Call ticket. Both of these violations were classified as near-misses and also One-Call Violations.

Magellan should continue to ensure all relevant data is recorded on the incident data reports, including how the ROW near-misses were detected, to help improve the overall effectiveness of the third-party damage program.

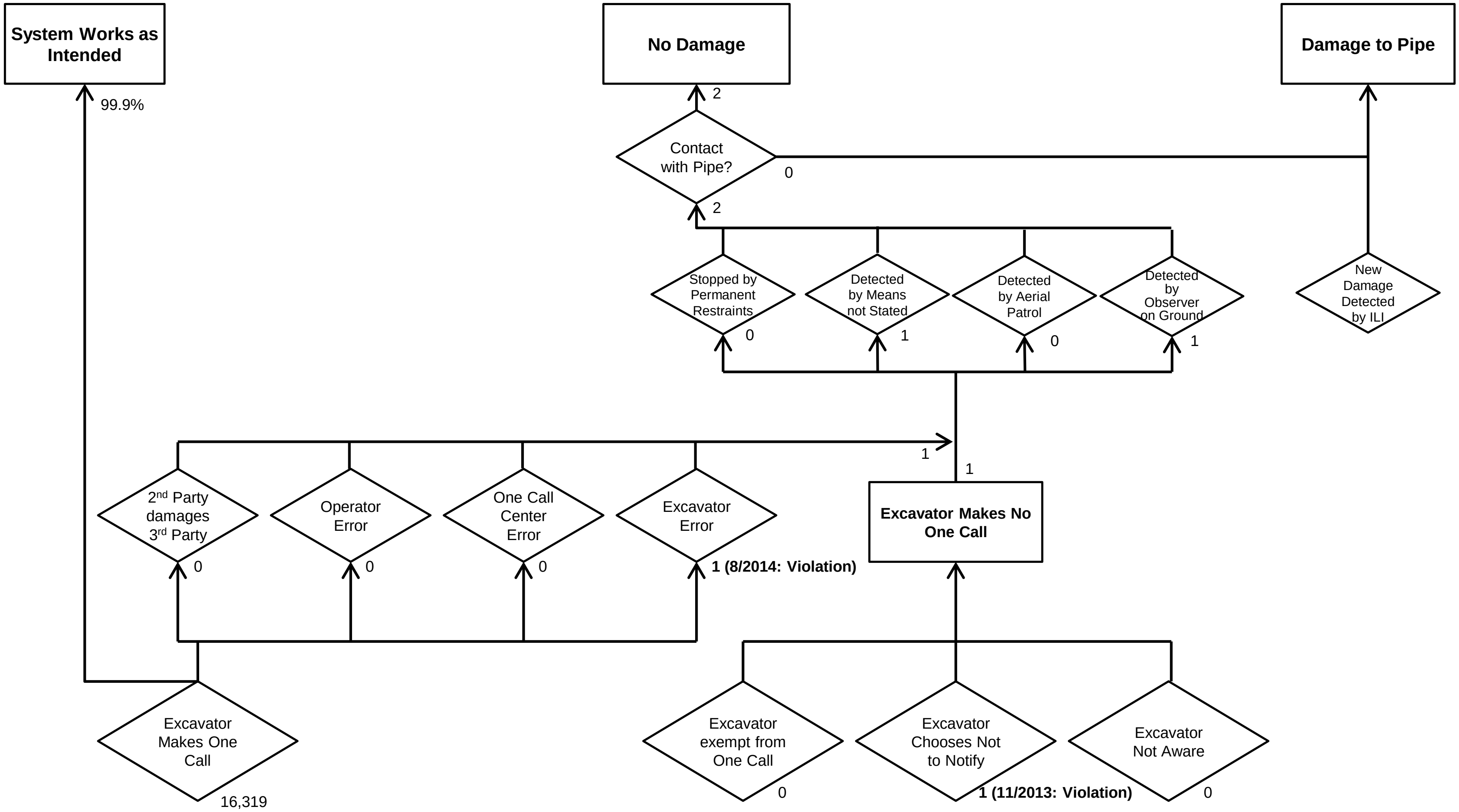

Figure 7. Flow Chart of 2013 One-Calls to the Longhorn System

The LMP commitment on pipeline surveillance as stated in LMP Section 3.5.4 is:

- Tier-II and Tier-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, and
- Edwards Aquifer Recharge Zone: Daily (1 day per week shall be a ground-level patrol).

The data summarized under Item 56, Miles of Pipe Inspected by Aerial Survey by Month for 2013, show that Magellan exceeded these requirements in terms of the total mileage patrolled required in order to meet the minimum requirements.

Intervention Recommendations

Section 7.4.2 of the ORAPM specifies the requirement to run an ILI capable of detecting mechanical damage if three or more One-Call violations occur within a 25 mile interval within a 12 month period. There were two One-Call violations during 2013; therefore, there is no requirement to conduct an additional ILI inspection with a geometry tool at this time.

No additional direct examinations are recommended at this time.

5.7. Stress-Corrosion Cracking

In the 64 years the Existing Pipeline has been in operation, there have been no SCC failures and no SCC has been discovered at any location. However, in accordance with the LMC 19(a) and the 2003 OPS Advisory Bulletin ADM-05-03 "Stress Corrosion Cracking (SCC) Threat to Gas and Hazardous Liquid Pipelines," Longhorn performed investigative digs each year for three years in areas susceptible to SCC.

During the first three years 2005-2007, Longhorn was required to inspect for SCC by selecting specific sites most susceptible to SCC. Subsequent inspection for SCC has continued as a supplemental examination when the pipe is exposed and examined for other reasons such as ILI anomaly excavations.

5.8. Facilities Other than Line Pipe

From the standpoint of facility data acquired for 2013, one can conclude that active non-pipe facilities had no adverse impact on public safety. Facilities are monitored on an annual basis and the results tracked in an electronic database.

ORA Review of LPSIP Facility Integrity Program Results

The LPSIP Mechanical Integrity Program focuses on maintaining the integrity of all equipment within the Longhorn system (e.g., station pumps, tanks, valves, and controls systems). The program includes the following activities:

- Identification and categorization of equipment and instrumentation
- Inspection and testing methods and procedures
- Testing acceptance criteria and documentation of test results
- Maintenance procedures and training of maintenance personnel
- Documentation of specific manufacturer's recommendations.

A Baseline Preventive Maintenance Program has been established under the Mechanical Integrity Program through the use of a software database system called EMPAC (Enterprise Maintenance Planning and Control). The software system establishes a unique inspection and maintenance schedule for major equipment items in the Longhorn system that can be adjusted on the basis of risk level.

An Action Item Tracking and Resolution Initiative (database) provides a method to track mechanical integrity recommendations.

Facility safety review inspections addressing 54 items related to safety, security, and environmental compliance were completed for nine of the pipeline facilities during 2013. No major problems were identified based on a review of the inspection forms extracted from the database.

Additionally, a Facility Risk Management Program is now in place to manage the risks at above ground facilities.

Eight incident data reports were received during 2013 which involved facilities. Two were classified as DOT reportable incidents which involved releases which were recovered.

Integrity Review and Recommendations

The Longhorn facilities maintenance program represents a thorough and comprehensive means of facility inspection and preventive maintenance. Magellan continues its detailed documentation of incidents, facility integrity processes, and reporting of the facility preventive maintenance program.

6. LPSIP TECHNICAL ASSESSMENT

The LMP describes the philosophy of the LPSIP. By this philosophy, Magellan commits to "constructing, operating, and maintaining the Longhorn pipeline assets in a manner that insures the long-term safety to the public, and to its employees, and that minimizes the potential for negative environmental impacts." The ORAPM provides a method for evaluating the effectiveness of the LPSIP on an annual basis using performance measures from three categories:

- Activity measures – proactive activities aimed at preserving pipeline integrity
- Deterioration measures – evidence of deterioration of pipeline integrity
- Failure measures – occurrences of failures or near failures

The status of each of these measures for 2013 is evaluated below.

Activity Measures

The activity measures are metrics that monitor the surveillance and preventive activities that Magellan has implemented during the period since the preceding ORA. These measures provide indicators of how well Magellan is implementing the various elements of the LPSIP. These measures are:

- Number of miles of pipelines inspected by aerial survey and by ground survey (by pipeline segment) in a 12-month period. Compare to the previous 12-month periods. The goal would be 100-percent of the commitment. Magellan met this commitment in 2013.

- Number of warning or ROW identification signs installed, replaced, or repaired during 12-month period. The metric will be compared to previous Magellan performance. This metric will be used to measure consistent effort by Magellan to protect the ROW and to prevent TPD. There is no "passing grade", because proper placement and maintenance of signs may lead to fewer signs replaced or repaired in future years, and this decline will not indicate any failing on the part of Magellan. On the other hand, tracking the replacement or repair of signs by pipeline segment may indicate third party vandalism or carelessness in certain segments of the system which could be used as a leading indicator that additional public education might be needed in that region of the pipeline route.

- Number of outreach or training meetings (listed with locations and dates) to educate and train the public and third parties about pipeline safety. This metric will be used to gauge consistent effort by Magellan to educate the public regarding pipeline safety, with the goal of preventing TPD to the pipeline. There is no "passing grade", although a comparison of the results of this metric with sign placement, repair and replacement can be used to see if public education is being emphasized in the same geographic region where sign maintenance indicates problems. See Appendix B Item 58 for details.

- <u>Number of calls (sorted by Tier I, Tier II or Tier III) through the One-Call system to mark or flag the Longhorn Pipeline</u>. This will help measure the effectiveness of the One-Call system in preventing TPD. The measure will be compared to previous years of Magellan records. Since this is a metric that is not subject to control by Magellan, there is no "passing grade". However, this metric can be compared to encroachments allowing an overall measurement of how efficiently the One-Call process is being used.

Table 8 provides a summary of the LPSIP Activity Measures from 2005 through 2013.

Table 8. LPSIP Activity Measures

Measure		2005	2006	2007	2008	2009
Miles of pipelines inspected by aerial survey and by ground survey (86,310 mi required)		203,081	197,234	188,884	187,931	181,308
No. of warning or ROW identification signs installed, replaced, or repaired		979	732	237	545*	475*
No. of outreach or training meetings to educate and train the public and third parties about pipeline safety		28	18	25	21	17
No. of calls through the One-Call system to mark or flag Longhorn's pipeline	Tier I	5,402	6,509	6,622	6,791	6,185
	Tier II	6,881	7,874	7,852	7,059	5,840
	Tier III	1,498	1,617	1,653	1,459	1,217

* The 2009 Annual Third-Party Damage Prevention Program Assessment lists these numbers for 2008 and 2009 as 536 and 460 respectively.

Measure		2010	2011	2012	2013
Miles of pipelines inspected by aerial survey and by ground survey (86,310 mi required)		180,045	188,564	188,772	179,107
No. of warning or ROW identification signs installed, replaced, or repaired		291	76	66	539
No. of outreach or training meetings to educate and train the public and third parties about pipeline safety		22	20	22	17
No. of calls through the One-Call system to mark or flag Longhorn's pipeline	Tier I	5,277	5,757	7,707	8,637
	Tier II	4,265	4,415	5,354	6,370
	Tier III	833	918	1,072	1,312

Deterioration Measures

Deterioration measures are metrics that measure maintenance trends to indicate when the integrity of the system could be foreseen as potentially declining despite preventive actions. A summary of the deterioration measures from 2005 through 2013 are presented in Table 9.

Although the ILI runs are not being performed on the same segments from year to year nor is the same inspection tool being used, there is still a discernible trend downward in anomalies found per mile. The number of immediate corrosion anomalies predicted based on the reassessments had dropped to zero when compared to the initial corrosion assessments. This indicates that the excavation program is effective at reducing and actually eliminating the number of significant corrosion anomalies.

POE evaluations show a significant decrease of over an order of magnitude between 2005-2007 when the first in-line inspections for corrosion were performed to 2009-2010 when the second set of in-line inspections for corrosion were performed.

Hydrostatic leaks per mile have not been an indicator of performance because no hydrostatic reinspection tests have been performed for pipeline commissioning purposes.

Table 9. LPSIP Deterioration Measures

Measure		2005	2006	2007	2008	2009
Number of immediate ILI anomalies per mile pigged		0.029	0.0203	0.038	0.004	0
Number of immediate ILI anomalies, per mile pigged, sorted by tier classification.	Tier I	NA	0.0212	0.035	0.006	0
	Tier II	NA	0.0208	NA	NA	0
	Tier III	0.192	NA	0.003	NA	0
Total number of anomalies per hydrotest		NA	NA	NA	NA	NA
Number of POE Evaluations per mile pigged		1.48	0.54	0.69	0	0.017

Measure		2010	2011	2012	2013
Number of immediate ILI anomalies per mile pigged		0	0	0	0
Number of immediate ILI anomalies, per mile pigged, sorted by tier classification.	Tier I	0	0	0	0
	Tier II	0	0	0	0
	Tier III	0	0	0	0
Total number of anomalies per hydrotest		NA	NA	NA*	NA**
Number of POE Evaluations per mile pigged		0.14	0.035	0.025	0.033

* Hydrostatic tests were performed for pipeline commissioning purposes.
**No hydrotests were performed during 2013.

Failure Measures

Failure Measures are generated from leak history, incident reports, incident responses, and product loss accounting. These metrics can be used to gauge progress towards fewer spills and improved response, or alternatively to measure deterioration of overall system integrity. These measures are listed below in Table 10. Response times, volumes, and costs are for DOT reportable leaks.

Table 10. LPSIP Failure Measures

Measure		2005	2006	2007	2008	2009
Number of leaks (DOT reportable)		2	0	1	3	0
Average response time in hours for a product release.	Tier I	Immed.	NA	Immed.	Immed.	NA
	Tier II	NA	NA	NA	NA	NA
	Tier III	NA	NA	NA	NA	NA
Average product volume released per incident	Tier I	5.7 bbls	0	5.7 bbls	0.4 bbls	0
	Tier II	0	0	0	0	0
	Tier III	0	0	0	0	0
Total product vol. released in the 12-month period	Tier I	17 bbls	0	5.7 bbls	1.3 bbls	0
	Tier II	0	0	0	0	0
	Tier III	0	0	0	0	0
Cleanup cost totals per year		< $100k	$0	< $200k	< $150k	0
Cleanup cost per incident		< $35k	NA	< $200k	< $50k	0
Reports from aerial surveys or ground surveys of encroachments into the pipeline ROW without proper One-Call		1	0	1	3	3
Number of known physical hits (contacts with pipeline) by third-party activities		0	0	0	0	0
Number of near-misses to the pipeline by third parties		7	1	7	5	6
Number of service interruptions		115	165	155	74	16*

* Service interruptions counting changed between 2008 and 2009. In 2005-2008 service interruptions included all system stoppages including those related to business reasons, such as lack of throughput. In 2009-2010 service interruptions only includes stoppages related to safety.

Measure		2010	2011	2012	2013
Number of leaks (DOT reportable)		1	2	0	2
Average response time in hours for a product release.	Tier I	Immed.	Immed.	NA	Immed.
	Tier II	NA	NA	NA	Immed.
	Tier III	NA	NA	NA	Immed.
Average product volume released per incident	Tier I	0.4 bbls	1.2 bbls	NA	0.47 bbl
	Tier II	0	0	NA	0
	Tier III	0	0	NA	4 bbls
Total product vol. released in the 12-month period	Tier I	0.4 bbls	2.5 bbls	NA	0.47 bbl
	Tier II	0	0	NA	0
	Tier III	0	0	NA	4 bbls
Cleanup cost totals per year		< $50k	< $50k	NA	> $100k
Cleanup cost per incident		< $50k	< $25k	NA	< $25 < $50k > $100k
Reports from aerial surveys or ground surveys of encroachments into the pipeline ROW without proper One-Call		1	1	2	2
Number of known physical hits (contacts with pipeline) by third-party activities		0	2	0	0
Number of near-misses to the pipeline by third parties		2	4	3	2
Number of service interruptions		17	9	8	15

7. Integration of Intervention Requirements and Recommendations

Integration of Primary Line Pipe Inspection Requirements

Section 11 of the ORA Process Manual specifies integration of primary line pipe inspection requirements addressing corrosion, fatigue-cracking, lamination/H2S blistering, TPD, and earth movement. Magellan has four remediation commitments for using ILI for the pipeline, LMC 10, LMC 11, LMC 12, and LMC 12A. These commitments required Magellan to use an MFL tool for corrosion inspection in the first three months of operation, a TFI tool for seam inspection (which includes hook cracks and preferential seam corrosion) within the first three years of operation, a UT wall measurement tool within the first five years of operation for inspection of laminations and detection of blisters, and a geometry inspection tool (deformation tool) at least every three years for inspection of TPD to the pipe. Future inspection requirements are based on reassessment intervals set by the ORAPM with the additional requirement that smart geometry tools must be run at least every three years.

There is overlap in anomaly detection capabilities of the various commercially available ILI tools and considerable variability in vendor availability and cost. As each cycle of the ORA is performed, additional data will become available not only from ILI tools, but also from routine maintenance reports and ILI anomaly investigation reports. This data will be integrated by the ORA process on a continuing basis to minimize the level of risk to the pipeline system integrity from each of the identified failure modes. To maintain and further reduce risk where possible, the ORA will identify and recommend the most appropriate ILI technology to obtain the necessary additional information. The use of one ILI tool technology may satisfy multiple inspection requirements for a pipe segment.

The tools Magellan has committed to use have multiple capabilities. The tools specified in Longhorn Mitigation Plan Commitments 10, 11, 12, and 12A have specified uses; however these tools also have other capabilities to address threats outlined in the ORA. Longhorn had committed to run the MFL primarily for assessing corrosion metal-loss but the tool has secondary uses such as detecting mechanical damage and detecting indications of hydrogen blisters. Longhorn had committed to run the TFI for inspecting the long seam for anomalies and axial cracking in the pipe body. The TFI tool is also capable of detecting metal loss anomalies and mechanical damage. Longhorn had committed to run the UT tool for inspecting laminations and blisters. The UT tool can also characterize corrosion and has capabilities for detecting mechanical damage. Geometry tools are used for detecting and sizing deformation anomalies such as dents, buckles, blisters, and ovalities. The ORA directs integration of these technologies to maximize the effectiveness of activities that are required by the ORAPM or recommended by the ORA Contractor.

Table 11a and Table 12b are a compilation of the tools run to date, and required reassessments as specified by the ORAPM. Reassessment requirements for pressure-cycle-fatigue crack growth reassessment intervals were based on the analysis performed in section 5.1 of this report. All other reassessment requirements have not changed from the 2011 ORA. Earth movement, the fifth component for threat integration, is not included in Table 11a or 12b because it is currently addressed using surface surveys rather than ILI technology.

Table 11a. Existing ILI Runs and Planned Future Inspections

	Tool	Date of Tool Run	Threats Addressed: Corrosion	Pressure-Cycle Induced Fatigue	Laminations and Hydrogen Blisters	Third-Party Damage
East Houston to Satsuma MP 0 to MP 34.1	Deformation	10-Jun-04				X
	MFL [1]	28-Oct-04	X			X
	MFL [2]	14-Dec-05	X			X
	TFI	6-Jul-07	‡	X		X
	Deformation	5-Oct-07				X
	Deformation	11-Sep-09				X
	UT	22-Sep-09	X		X	X
	Deformation	7-June-12				X
	Deformation [3]	22-June-13				X
	Next Required Assessment		***22-Sep-14***	***2032***	***22-Sep-14***	***22-Sep-14*** [4]
Satsuma to Warda MP 34.1 to MP 112.9	MFL/Deformation	21-May-06	X			X
	Deformation	15-Dec-07				X
	TFI	20-Dec-07	‡	X		X
	Deformation	12-Oct-09				X
	UT	24-Nov-09	X		X	X
	Deformation	7-Jun-12				X
	Next Required Assessment		***24-Nov-14***	***2020***	***24-Nov-14***	***7-Jun-15***
Warda to Cedar Valley MP 112.9 to MP 181.6	MFL/Deformation	21-Jul-06	X			X
	TFI	19-Sep-07	‡	X		X
	Deformation	16-Oct-07				X
	Deformation	16-Dec-09				X
	UT	24-Jan-10	X		X	X
	Deformation	9-Jun-12				X
	Next Required Assessment		***24-Jan-15***	***2018***	***24-Jan-15***	***9-Jun-15***
Cedar Valley to Eckert MP 181.6 to MP 227.9	MFL/Deformation	15-Feb-07	X			X
	TFI	22-Mar-07	‡	X		
	Deformation	25-Jan-10				X
	UT	20-Feb-10	X		X	X
	Deformation	15-Jun-12				X
	Next Required Assessment		***20-Feb-15***	***2022***	***20-Feb-15***	***15-Jun-15***

1 The MFL tool run in Oct-04 was not a complete run.
2 The MFL tool run in Dec-05 was used to complete the Oct-04 MFL run.
3 The Deformation tool run in June-13 was from the East Houston Terminal to Speed Junction (10.80 miles) as noted in the Longhorn System 2013 Third Party Damage Prevention Program Assessment.
4 Per LMC 12A this portion should be inspected for third party damage every 3 years; however, since an MFL tool run is scheduled to be conducted for corrosion and laminations and hydrogen blisters in September 2014, it will also be inspected for third party damage at that time.
‡ The TFI was used to remediate Phase I and Phase II corrosion anomalies and in some cases was used to remediate POE anomalies, but was not used to set the next corrosion reassessment using the POE process.

Table 12b. Existing ILI Runs and Planned Future Inspections

			Threats Addressed			
	Tool	**Date of Tool Run**	**Corrosion**	**Pressure-cycle Induced Fatigue**	**Laminations and Hydrogen Blisters**	**Third-Party Damage**
Eckert to Ft McKavett MP 227.9 to MP 321.9	MFL/Deformation	19-Dec-06	X			X
	TFI	9-Nov-07	‡	X		X
	Deformation	23-Jan-08				X
	Deformation	27-Mar-10				X
	UT	25-Jun-10	X		X	X
	Deformation	17-Jun-12				X
	Next Required Assessment		***25-Jun-15***	***2021***	***25-Jun-15***	***17-Jun-15***
Ft.McKavett to Crane MP 321.9 to MP 457.5	MFL/Deformation	12-Oct-06	X			X
	Deformation	21-Dec-07				X
	TFI	8-Jan-08	‡	X		X
	UT	8-Jul-10	X		X	X
	Deformation	5-Aug-10				X
	Deformation	1-Jul-12				X
	Next Required Assessment		***8-Jul-15***	***2226***	***8-Jul-15***	***1-Jul-15***
Crane to Cottonwood MP 457.5 to MP 576.3	Deformation	2-May-07				X
	MFL/Deformation	21-Nov-08	X			X
	MFL/Deformation	19-Nov-13	X			X
	Next Required Assessment		***19-Nov-18***	***2226***	***not susceptible***	***21-Nov-18***
Cottonwood to El Paso MP 576.3 to MP 694.4	Deformation	2-May-07				X
	MFL/Deformation	27-Mar-08	X			X
	MFL/Deformation	19-May-12	X			X
	Next Required Assessment		***19-May-17***	***not susceptible***	***not susceptible***	***19-May-17***
Crane to Odessa	MFL/Deformation	4-Nov-06	X			X
	MFL/Deformation	7-Mar-07	X			X
	MFL/Deformation	28-Jun-11	X			X
	Next Required Assessment		***28-Jun-16***	***not susceptible***	***not susceptible***	***28-Jun-16***
El Paso to Chevron 8" MP 0.0 to 9.4	MFL/Deformation	6-Mar-07	X			X
	MFL/Deformation	23-Feb-12	X			X

	Tool	Date of Tool Run	Threats Addressed: Corrosion	Pressure-cycle Induced Fatigue	Laminations and Hydrogen Blisters	Third-Party Damage
	Next Required Assessment		***23-Feb-17***	***not susceptible***	***not susceptible***	***23-Feb-17***
Kinder Morgan 8" Flush Line	MFL/Deformation	6-Mar-07	X			X
	MFL/Deformation	21-Feb-12	X			X
	Next Required Assessment		***21-Feb-17***	***not susceptible***	***not susceptible***	***21-Feb-17***
El Paso to Kinder Morgan 12" MP 0.0 to 9.4	MFL/Deformation	7-Mar-07	X			X
	MFL/Deformation	22-Feb-12	X			X
	Next Required Assessment		***22-Feb-17***	***not susceptible***	***not susceptible***	***22-Feb-17***

Integration of DOT HCA and TRRC Inspection Requirements

It is necessary for Magellan to be compliant with the DOT Integrity Management Rule, 49 CFR 195.452, for HCAs and the Texas Railroad Commission (TRRC) inspection requirements in 16 TAC §8.101 in addition to meeting the requirements in the LMP. The pipeline from Galena Park to El Paso is under DOT jurisdiction as well as the four laterals connecting El Paso to Diamond Junction. Only the section from Ft. McKavett to Crane (MP 312.9 to MP 457.5) does not contain any HCAs. The TRRC requirements apply only to the 8-inch lateral from Crane to Odessa.

The HCA rule states that an operator must establish five-year intervals, not to exceed 68 months, for continually assessing the pipeline's integrity. An operator must base the assessment intervals on the risk the line pipe poses to the HCA to determine the priority for assessing the pipe. At this time, corrosion has proven to be the higher priority risk of the five threats to the pipeline integrity. Because of the requirements of the LMP and the multiple capabilities of each of the required tools, the HCA line pipe between Galena Park and Crane has been inspected in intervals of less than five years. The HCA requirement will continue to be integrated into the ILI requirements as additional tool runs are completed to ensure the required five-year interval is not exceeded.

LMC 12A requires a "smart geometry" tool to be run every three years between Valve J-1 and Crane. For the three new pipeline extensions the HCA requirement (49 CFR 195.452) requires the smart geometry tool to run every five years. The risk for mechanical damage in these intervals is less because the pipeline is buried at least 30 inches deep where the Existing Pipeline upstream of Crane is often much shallower because this 30-inch depth of burial was not required at the time the pipeline was built.

The TRRC integrity rule requires that Magellan choose either a risk-based analysis or a prescriptive plan to manage the integrity of the 8-inch lateral from Crane to Odessa. An MFL-Deformation combination tool run was completed on March 7, 2007 and re-run June 28, 2011 with 3 digs being completed in 2012. The reinspection for mechanical damage in this interval was set to five years as required in the TRRC integrity rule using the same logic as expressed in the HCA requirement above.

Pipe Replacement Schedule

Other Pipe Replacements

A number of pipe replacements were completed in 2013 during the pipeline flow reversal on the original pipe segments. See Appendix C for a complete list. A number of potential integrity threats were removed from the pipeline during the reversal process. These include stopple fittings, weld plus end fittings, split tee fittings, a non-pressure containing sleeves, a patch, deformation anomalies, and corrosion anomalies.

8. Recommended Improvements to the ORA Process

Table 12. Summary of 2013 Recommendations

Topic	Recommendation	ORA Ref Page
Hydrogen Blistering	With the conversion of the pipeline back to crude oil service and the reintroduction of hydrogen sulfide, monitoring of the lamination anomalies for the possibility of blister growth with ILI tools is recommended per the EA of the proposed Longhorn Pipeline Reversal Section 6.2.1.2. These inspections should be coordinated with ILI runs for corrosion, deformation, and mechanical damage.	11
Aseismic faults	We continue to recommended that monitoring for faults be changed from 2 times per year to every 5 years because fault movements are more than an order of magnitude smaller than anticipated in the EA.	12
Stream Monitoring	Recorded changes in the distance from the High Bank to the Toes of Pin Oak Creek and the Colorado River warrant a survey of depth of burial of the pipeline in the stream beds between the toes of the banks of these two bodies of water.	12

References

1. Kiefner, J. F. and Mitchell, J. L., "Charpy V-Notch Impact Data for Six Samples of Seam-Weld Material from the Longhorn Pipeline", Kiefner and Associates, Inc., Final Report 06-6 to Longhorn Partners Pipeline Company, (January, 19, 2006).
2. Kiefner, J. F., Johnston, D. C., and Kolovich, C. E., "Mock ORA for Longhorn Pipeline", Kiefner and Associates, Inc., Final Report 00-49 to Longhorn Pipeline Partners, LP (October 16, 2000).
3. Kiefner, J. F., Kolovich, C. E., Zelenak, P. A., and Wahjudi, T. F., "Estimating Fatigue Life for Pipeline Integrity Management", Paper No. IPC04-0167, Proceedings of IPC 2004 International Pipeline Conference, Calgary, Alberta, Canada (October 4-8, 2004).
4. Verbeek, E.R., Ratzlaff, K.W., Clanton, U.S., Faults in Parts of North-Central and Western Houston Metropolitan Area, Texas, U.S. Geological Survey, September 2005.
5. Environmental Assessment, Appendix 9E, Longhorn Mitigation Plan Mandated Studies Summaries.

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APPENDIX A - MITIGATION COMMITMENTS

Longhorn Mitigation Commitments (LMCs)			
No.	**Description**	**Timing of Implementation**	**Risk(s) Addressed**
10	Longhorn shall, following the use of sizing and (where appropriate) geometry tools, perform an in-line inspection of the Existing Pipeline (Valve J-1 to Crane) with a transverse field magnetic flux inspection (TFI) tool and remediate any problems identified. See the Longhorn Pipeline System Integrity Plan at Sec. 3.5.2 and the associated Operational Reliability Assessment at Sec. 4.0.	At such intervals as are established by the Operational Reliability Assessment, provided that an inspection shall be performed no more than 3 years after system startup in Tier II and III areas	Material Defects, Corrosion, Outside Force Damage, and Previous Defects
11	Longhorn shall, following the use of sizing and (where appropriate) geometry tools, perform an in-line inspection of the Existing Pipeline (Valve J-1 to Crane) with a high resolution magnetic flux leakage (MFL) tool and remediate any problems identified. Until Mitigation Item 11 has been completed, an interim MOP (MOPi) shall be established for the Existing Pipeline at a pressure equal to 0.88 times the MOP. (NOTE: 1.25 times the MOPi is equal to the Proof Test Pressure discussed in Mitigation Item 2 above). See the Longhorn Pipeline System Integrity Plan at Sec. 3.5.2 and the associated Operational Reliability Assessment at Sec. 4.0.	Within 3 months of startup and thereafter at such intervals as are established by the Operational Reliability Assessment	Corrosion, Outside Force Damage and Previous Defects
12	Longhorn shall, following the use of sizing and (where appropriate) geometry tools, perform an in-line inspection of the Existing Pipeline (Valve J-1 to Crane) with an ultrasonic wall measurement tool and remediate any problems identified. See the Longhorn Pipeline System Integrity Plan at sec. 3.5.2 and the associated Operational Reliability Assessment at Sec. 4.0.	At such intervals as are established by the Operational Reliability Assessment, provided that an inspection shall be performed no more than 5 years after system startup	Corrosion, Material Defects, Outside Force Damage, and Previous Defects
12A	Longhorn shall perform an in-line inspection of the Existing Pipeline (Valve J-1 to Crane) with a "smart" geometry inspection tool and remediate any problems identified. See the Longhorn Pipeline System Integrity Plan at Sec. 3.5.2 and the associated Operational Reliability Assessment at Sec. 4.0.	At such intervals as are established by the Operational Reliability Assessment, provided that no more than 3 years shall pass without an in-line inspection being performed using an inspection tool capable of detecting third-party damage (e.g. TFI, MFL, or geometry)	Outside Force Damage

Longhorn Mitigation Commitments (LMCs)			
No.	**Description**	**Timing of Implementation**	**Risk(s) Addressed**
19	Longhorn has performed studies evaluating each of the following matters along the pipeline, and shall implement the recommendations of such studies (See Mitigation Appendix, Item 19):	Prior to startup	Outside Force Damage, Corrosion, and Material Defects
	(a) Stress corrosion cracking potential.		Outside Force Damage and Corrosion
	(b) Scour, erosion and flood potential.		Outside Force Damage
	(c) Seismic activity.		Outside Force Damage
	(d) Ground movement, subsidence and aseismic faulting.		Outside Force Damage
	(e) Landslide potential.		Outside Force Damage
	(f) Soil stress.		Outside Force Damage
	(g) Root cause analysis on all historical leaks and repairs.		Outside Force Damage, Corrosion, Material Defects, and Operator Error
20	Longhorn shall increase the frequency of patrols in hypersensitive and sensitive areas to every two and one half days, daily in the Edwards Aquifer area, and weekly in all other areas. See the Longhorn Pipeline System Integrity Plan, Section 3.5.4.	Continuously after startup	Outside Force Damage, Corrosion, Material Defects, Leak Detection and Control
25	Longhorn shall develop enhanced public education/damage prevention programs to, inter alia, (a) ensure awareness among contractors and potentially affected public, (b) promote cooperation in protecting the pipeline and (c) to provide information to potentially affected communities with regard to detection of and responses to well water contamination. See the Longhorn Pipeline System Integrity Plan, section 3.5.4. See Mitigation Appendix, Item 25. (This item has been superseded in large part by API RP 1162.)	Continuously after startup	Outside Force Damage, Leak Detection and Control
Appendix Item 3	Longhorn will replace approximately six miles of Existing Pipeline in the Pedernales River watershed that is characterized as having a time of travel for a spill from Lake Travis of eight hours or less.	Segment 5 crossing the Pedernales River will be completed prior to the date of pipeline startup. Segments 1 through 4 will be replaced as determined by the System Integrity Plan and Operational Reliability Assessment, but in any case no later than seven years from the startup date.	Outside force damage

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APPENDIX B - NEW DATA USED IN THIS ANALYSIS

This Appendix describes new data used in the analysis for this ORA Annual Report. It is divided into 16 sections specified in the ORA Report Outline from the ORAPM. In addition the ORA Process Manual identifies 78 items consisting of data, data logs, and reports the ORA contractor must review and consider to evaluate the effectiveness of the LPSIP and to assess whether or not Magellan is meeting the commitments of the LMP. A list of these 78 items is contained in Appendix B in the ORAPM. Each of the 78 data items is included under the appropriate ORA Report Data Sections described above.

4.1. Pipeline/Facilities Data

Mainline (Items 3, 7, 8, 9, 10, 11, and 12)

Kiefner received a listing of pipe replacements and related equipment that were installed during 2013. This listing is provided in Appendix C.

Pump Stations (Item 15)

Phase 2 of the Longhorn Reversal Project consisted of increasing the flow rate on the pipeline from Crane, Texas to Houston, Texas from 134,000 bpd to 225,000 bpd. Phase 2 involved changing out the pumps at the three Phase 1 stations (Crane, Kimble County, and Cedar Valley), upgrading and reactivating the Satsuma Station, and adding an additional eight intermediate pump stations (Texon, Barnhart, Cartman, James River, Eckert, Bastrop, Warda, and Buckhorn). The following is a list of the pump stations and milepost numbers.

Table B-1. Pump Stations

LINE	Beg ESN	End ESN	Beg MP	End MP	Station
6645	124+40	528+00	2.36	10.00	East Houston
6645	1799+20	1802+63	34.08	34.14	Satsuma
6645	3484+80	3907+20	66.00	74.00	Buckhorn
6645	5526+54	6283+20	104.67	119.00	Warda
6645	7471+20	7550+40	141.50	143.00	Bastrop
6645	9582+54	9606+43	181.49	181.94	Cedar Valley
6645	12034+54	12035+54	227.93	227.95	Eckert
6645	13733+28	13807+20	260.10	261.50	James River
6645	14652+00	16319+59	277.50	309.08	Kimble
6645	16684+80	17109+84	316.00	324.05	Ft McKavett
6645	17651+04	19343+41	334.30	366.35	Cartman
6645	19343+41	20712+21	366.35	392.28	Barnhart
6645	20712+21	22191+67	392.28	420.30	Texon
6645	24129+60	24367+20	457.00	461.50	Crane

Kiefner received process flow diagrams, a listing of the stations, and the Phase 2 Project Plan, Pump Station Materials and Construction.

Tier Classifications and HCAs (Items 1 and 2)

Kiefner received a listing of tier classifications and HCAs for the Longhorn System.

Charpy V-Notch Impact Energy Data (Item 14)

Charpy data from sixteen locations along the Longhorn Pipeline were tested in 2013 as part of the validation of the Positive Material Identification Field Services process developed by T. D. Williamson. The results are listed below:

Table B-2. Charpy V-Notch Impact Energy Data

Pipe Sample	Sample Milepost	Pipe Grade	Measured Upper Shelf Energy (ft-lbs)	Full Size Equivalent Upper Shelf Energy (ft-lbs)	Transition Temperature (deg F at 85% shear)
3	31.86	B	18	26.9	137.9
30	33.43	B	33	49	72.3
37	64.06	X-42	116	116.0	143
6	103.72	X-45	13	26.0	62
13	156.59	X-45	16	32.0	107.3
16	210.57	X-45	18	26.9	103.7
18	227.20	X-45	25.5	38.0	144
20	280.50	X-45	24	48.0	94.6
23	316.57	X-45	16.5	25.0	74
32	43.15	X-45	16	32.0	109.4
33	134.66	X-45	29	38.7	147
34	163.20	X-45	21	31.3	140.3
35	341.65	X-45	18	36.0	93.5
26	419.14	X-52	15	30.0	97
31	35.00	X-52	49	98.0	19.8
36	436.12	X-52	20.5	41.0	109.3

Mill Inspection Defect Detection Threshold (Item 13)

Magellan reviewed the documentation for each pipe segment covered by the Longhorn Mitigation Plan (LMP) to establish whether a mill test report (MTR) exists to confirm that the pipe meets the code or industry standard such as API 5L, 5LX, or 5LS. The results were summarized and submitted to PHMSA on January 14, 2013.

4.2. Operating Pressure Data

For Items 21, 22, and 23, Kiefner has received pressure and flow data for Galena Park, East Houston, Satsuma, Cedar Valley, Kimble County, Crane, and El Paso Pump Station since September 17, 2004. Starting on November 1, 2013 pressure and flow data has also been received for Texon, Barnhart, Cartman, James River, Eckert, Bastrop, Warda, and Buckhorn Pump Stations. The data is collected in 1-minute intervals and sent on a monthly basis.

4.3. ILI Inspection and Anomaly Investigation Reports

ILI Inspection Reports (Items 39, 40, 41, 44, 45 and 47)

Data was received from the following maintenance reports for cut-outs completed in 2013.

Table B-3a. Remediations per Maintenance Reports Completed in 2013

Line Segment	18" El Paso to Cottonwood	18" Cottonwood to Crane	18" Crane to Ft McKavett	18" Ft McKavett to Eckert	18" Eckert to Cedar Valley
ILI Date	5/19/2012	11/19/2013	8/5/2010	6/25/2010	2/20/2010
Maintenance Report	Yes	Yes	Yes	Yes	Yes
Tier 1	28	0	0	3	3
Tier 2	0	0	15	6	8
Tier 3	0	0	0	1	1
Total Digs	28	0	15	10	12
HCA	3	0	0	2	1
Non-HCA	25	0	15	8	11

Line Segment	18" Cedar Valley to Warda	18" Warda to Satsuma	20" Satsuma to Galena Park	8" El Paso to Chevron	12" El Paso to Kinder Morgan
ILI Date	1/24/2010	11/24/2009	9/22/2009		
Maintenance Report	Yes	Yes	Yes	Yes	Yes
Tier 1	2	6	1	3	2
Tier 2	7	2	7	0	0
Tier 3	0	1	1	0	0
Total Digs	9	9	9	3	2
HCA	4	1	8	0	0
Non-HCA	5	8	1	3	2

Table B-3b. Anomalies Called that were Excavated in the Above Remediations

ILI Anomaly Called	Number of Anomalies Addressed	18" El Paso to Cottonwood	18" Cottonwood to Crane	18" Crane to Ft McKavett	18" Ft McKavett to Eckert	18" Eckert to Cedar Valley	18" Cedar Valley to Warda	18" Warda to Satsuma	20" Satsuma to Galena Park	El Paso to Chevron 8"	El Paso to Kinder Morgan 12"	Kinder Morgan to 8" Flush Line
Ext Metal Loss	13	0	0	12	0	0	0	0	0	0	1	0
Int Metal Loss	7	7	0	0	0	0	0	0	0	0	0	0
Mill Anomaly w/Metal Loss	4	3	0	0	0	0	0	0	0	1	0	0
Lamination Intermittent	0	0	0	0	0	0	0	0	0	0	0	0
Lamination Intermittent Associated With Metal Loss	0	0	0	0	0	0	0	0	0	0	0	0
Lamination Sloping	0	0	0	0	0	0	0	0	0	0	0	0
Lamination Variable Depth	0	0	0	0	0	0	0	0	0	0	0	0
Lamination Bulging	0	0	0	0	0	0	0	0	0	0	0	0
Lamination Bulging Intermittent	0	0	0	0	0	0	0	0	0	0	0	0
Lamination	0	0	0	0	0	0	0	0	0	0	0	0
ID Reduction - Sharp - Dent on Weld	0	0	0	0	0	0	0	0	0	0	0	0
ID Reduction L<1.5D	0	0	0	0	0	0	0	0	0	0	0	0
ID Reduction L>1.5D	0	0	0	0	0	0	0	0	0	0	0	0
ID Reduction on Weld	3	0	0	0	2	0	0	1	0	0	0	0
ID Reduction	6	1	0	2	2	0	0	0	1	0	0	0
ID Reduction w/associated metal loss	13	9	0	1	2	1	0	0	0	0	0	0
ID Reduction affecting pipe curvature at seam weld	7	0	0	1	4	1	0	1	0	0	0	0
Girth Weld Anomaly	12	8	0	1	0	0	0	0	0	2	0	1
Expansion	1	0	0	1	0	0	0	0	0	0	0	0
Buckle	1	0	0	0	0	0	0	0	1	0	0	0
Geometric Anomaly Associated With Metal Loss	0	0	0	0	0	0	0	0	0	0	0	0

ILI Anomaly Called	Number of Anomalies Addressed	18" El Paso to Cottonwood	18" Cottonwood to Crane	18" Crane to Ft McKavett	18" Ft McKavett to Eckert	18" Eckert to Cedar Valley	18" Cedar Valley to Warda	18" Warda to Satsuma	20" Satsuma to Galena Park	El Paso to Chevron 8"	El Paso to Kinder Morgan 12"	Kinder Morgan to 8" Flush Line
Area Of Bulge	0	0	0	0	0	0	0	0	0	0	0	0
Surface Irregularity	0	0	0	0	0	0	0	0	0	0	0	0
Weld Irregularity	0	0	0	0	0	0	0	0	0	0	0	0
Ext Metal Loss Associated With Brc Dent	0	0	0	0	0	0	0	0	0	0	0	0
Ext Metal Loss Associated With Lamination	0	0	0	0	0	0	0	0	0	0	0	0
Ext Metal Loss Crosses Girth Weld	0	0	0	0	0	0	0	0	0	0	0	0
Ext Metal Loss Crosses Long Seam	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	67	28	0	18	10	2	0	2	2	3	1	1

Results of ILI for TPD between J-1 and Crane (Item 77)

See above. Please note that J-1 is no longer in service.

Results of Ultrasonic ILI for Laminations and Blisters between J-1 and Crane (Item 78)

Based on the 2013 and previous ILI excavation reports, no confirmed blisters have been found on the original Longhorn segments. No lamination anomalies were excavated during 2013.

4.4. Hydrostatic Testing Reports

All new pipe installed during 2013 was pre-tested in 2012.

Hydrostatic Leaks and Ruptures (Item 75)

No hydrostatic tests of the Existing Pipe were performed during 2013.

4.5. Corrosion Management Surveys and Reports

Corrosion Control Survey Data (Item 24)

Corrosion Control Survey data was received from Magellan covering 2013.

TFI MFL ILI Investigations (L and d Results) (Item 35)

See section 4.3 above.

External Corrosion Growth Rate Data (Item 36)

No new data was obtained.

Internal Corrosion Coupon Results (Item 37)

Internal corrosion coupon reports were reviewed at 15 locations for the 2013 annual report. Four lines were sampled with coupons placed in the 8-inch Odessa lateral at Crane, the 8-inch Plains lateral at El Paso, the 18-inch main line at El Paso, and the 20-inch Galena Park to East Houston line at East Houston.

Table B-4. Internal Corrosion Coupon Results

Pipe OD (in)	Location	Line Designation	Coupon Number	Inserted	Removed	Exposure (days)	Corrosion Rate (MPY)	Comments
		Crude Line						
16	Crane	Advantage- delivery to Crane	T0210	9/20/2013	12/23/2013	94	0	First coupon in new line segment
12	Crane	Centurion-delivery to Crane	S9454	4/29/2013	9/20/2013	144	0	First coupon in new line segment
12	Crane	Centurion-delivery to Crane	T0209	9/20/2013	12/19/2013	90	No data	Coupon broke off in the pipe
16	Crane	Plains WTI-delivery to Crane	S9455	4/29/2013	9/20/2013	144	0.11	First coupon in new line segment. Before we treat with inhibitor.
16	Crane	Plains WTS-delivery to Crane	S9456	4/29/2013	9/20/2013	144	0	First coupon in new line segment. Before we treat with inhibitor.
16	Crane	Plains WT-delivery to Crane	T0207	9/20/2013	12/23/2013	94	0	
16	Crane	Plains WTI-delivery to Crane	T0208	9/20/2013	12/23/2013	94	0	
24	Crane	Tank Manifold at Crane	E3552	3/15/2013	4/29/2013	45	0.01	First coupon in new line segment
24	Crane	Tank Manifold at Crane	E3557	4/29/2013	9/20/2013	144	0.06	
24	Crane	Tank Manifold- at Crane	E4851	9/20/2013	12/23/2013	94	0	
18	Cartman	Cartman Station ML (6645)	E3545	5/3/2013	7/20/2013	78	0	First coupon in new line segment
18	Cartman	Cartman Station ML (6645)	E4850	9/26/2013	12/16/2013	81	0	
18	Cedar Valley	Cedar Valley Station ML (6645)	E3502	4/11/2013	4/30/2013	19	0	First coupon in new line segment
18	Cedar Valley	Cedar Valley Station ML (6645)	E3548	4/30/2013	9/4/2013	127	0	
18	Cedar Valley	Cedar Valley Station ML (6645)	F4844	9/4/2013	12/23/2013	111	No data	Coupon lost in mail.
18	Satsuma	Satsuma Station ML (6645)	E3506	4/12/2013	5/9/2013	27	0	First coupon in new line segment
18	Satsuma	Satsuma Station ML (6645)	E3551	5/9/2013	9/19/2013	133	0.06	
18	Satsuma	Satsuma Station ML (6645)	E4846	9/19/2013	1/3/2014	106	0	
20	East Houston	East Houston ML (6645)	S6505	3/20/2013	8/30/2013	163	0.04	First coupon in new line segment
20	East Houston	East Houston ML (6645)	T0193	8/29/2013	12/31/2013	126	0	
20	Speed Jct.	Speed Jct Manifold from E. Houston(6643)	E3527	4/16/2013	8/30/2013	136	0	

Pipe OD (in)	Location	Line Designation	Coupon Number	Inserted	Removed	Exposure (days)	Corrosion Rate (MPY)	Comments
20	Speed Jct.	Speed Jct Manifold from E. Houston(6643)	F4848	8/30/2013	12/31/2013	123	0	
		Refined Line						
8	Crane	Odessa to Crane 8" (6648)	T0211	9/20/2013	12/23/2013	94	0	First coupon in new line segment
18	El Paso	18" Mainline (6645)	AX0079	12/31/2012	5/1/2013	121	0	
18	El Paso	18" Mainline (6645)	AX0084	5/1/2013	8/29/2013	120	0	
18	El Paso	18" Mainline (6645)	AX0087	8/29/2013	12/31/2013	124	0	
8	El Paso	Plains 8" (6650) - Outbound	AX0080	12/31/2012	5/1/2013	121	0	
8	El Paso	Plains 8" (6650) - Outbound	AX0086	5/1/2013	8/29/2013	120	0	
8	El Paso	Plains 8" (6650) - Outbound	AX0093	8/29/2013	12/31/2013	124	0	

Line Pipe Anomalies/Repairs (Item 43)

See section 4.3 above. A number of potential integrity threats were removed from the pipeline during the reversal process. These include stopple fittings, weld plus end fittings, split tee fittings, a non-pressure containing sleeves, a patch, deformation anomalies, and corrosion anomalies. The following table lists the maintenance performed based on the 96 maintenance reports.

Table B-5. Maintenance Report Items

Maintenance Report Items	Number
A-sleeve cut out	2
AC mitigation	7
B-sleeve recoat	1
Corrosion cut out	3
Dent cut out	13
Address exposed pipe	10
Patch cut out	1
PMIFS	3
Split tee cut out	2
Stopple cut out	2
Install test station	1
Trap upgrade	3
Valve installation	4
Weld plus end cut out	2
Weld misalignment cut out	1
Material grade testing cut out	8

All ILI Metal Loss and Deformation Related to Line Pipe Anomalies (Item 44)

See section 4.3 above.

All ILI Pipe Wall Deformation, Out-of-Roundness, 3D Location Related to the Threat of Third-Party Damage (Item 45)

See section 4.3 above.

Number of Anomalies Measured by ILI, by Tier and by DOT Repair Conditions Based on the Annual Assessment of the LPSIP (Item 74)

See section 4.3 above.

4.6. Fault Movement Surveys and Natural Disaster Reports

Pipeline Maintenance Reports at Fault Crossings (Item 30)

Semi-annual fault displacement monitoring reports were received covering the fault crossings in 2013.

Periodic Fault Benchmark Elevation Data (Item 31)

Semi-Annual Fault Displacement Monitoring was performed July 3, 2013 and December 16, 2013 which covers semi-annual fault measurements at the 7 fault monitoring sites since inception in mid-2004 through December 2013.

Pipeline Maintenance Reports for Stream Crossings (no item number)

Scour reports were received for the three stream crossings, the Colorado River, its tributary Pin Oak Creek which were last monitored December 2013, and Onion Creek which was monitored first time Nov 2013.

Flood Monitoring (no item number)

Flood monitoring spreadsheets were received for Colorado River, Pin Oak Creek, and the Pedernales River. The Colorado River exceeded its flood stage on November 1, 2013; the Pin Oak Creek on November 1 and 2, 2013 and the Onion Creek on November 13, 2013.

4.7. Maintenance and Inspection Reports

Depth-of-Cover Surveys (Items 19 and 27)

One new exposure was identified in 2013 by the Right-of-Way maintenance crew. The line was inspected, recoated, and a concrete revetment matting system was placed over the line. The location is no longer exposed. Six sites that have been actively managed under the Outside Forces Damage Prevention Program in accordance with SIP were repaired and are no longer exposed at this time. Additionally, three locations consisting of creek banks and a washout were repaired.

Ten maintenance reports were associated with addressing exposed pipe. These occurred at pipeline milepost 85.9, 98, 98.3, 118.7, 141.5, 213.2, 213.35, 248.05, 412.46, and 619.67. Each of these areas were excavated, recoated and backfilled.

Seam Anomaly/Repair Reports Related to Fatigue Cracking of EFW and ERW Welds, and Seam Anomalies (Items 33 and 34)

None found.

Mechanical Integrity Inspection Reports (Item 46)

None found.

Mechanical Integrity Evaluations (Item 47)

None found.

Facility Inspection and Compliance Audits (Item 48)

Comprehensive safety inspections of each facility are made by Magellan personnel using a detailed check list called a Facility Safety Review Form. The multi-page form contains 10 sections, each with a list of items to check with spaces for indicating yes or no regarding whether or not a given point or item met the standard set by company policies or procedures. Spaces are also provided for action items to bring the item into compliance. The topics covered include:

1. Posting of Notices, Signs, and Posters
2. Exits
3. Ladders
4. Hand Held Tools; Fixed Machinery; and Equipment
5. Electrical/Lighting
6. Vehicles and Equipment
7. Flammable Liquids Storage
8. Compressed Gas Cylinders
9. Pump Rooms
10. Miscellaneous

Kiefner received Facility Safety Reviews for nine of the pipeline facilities completed during 2013.

Maintenance Progress Reports (Item 73)

A computerized mechanical integrity/preventive maintenance system was implemented in 2007 and all DOT station inspections were scheduled utilizing this system. Maintenance was tracked according to the schedule at hourly, weekly, monthly, quarterly, semi-annual, tri-annual, and annual intervals.

4.8. Project Work Progress and Quality-Control Reports

Access to Action Item Tracking and Resolution Initiative Database (Item 49)

Table B-6. Number and Status of Action Items per Month for 2013

Action Items	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Total
New	4	77	7	0	2	2	0	38	0	0	0	0	130
Completed	1	41	39	2	0	0	2	11	27	4	3	1	131
Open at End of Month	4	40	8	6	8	10	8	35	8	4	1	0	

4.9. Significant Operational Changes

Number of Service Interruptions per Month (Item 70)

Table B-7. Service Interruptions per Month for 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Total*
No./Month	0	0	0	1	1	0	4	3	1	2	0	3	15

* From the Daily Ops Report ending Dec 31, 2013.

4.10. Incorrect Operations and Near-Miss Reports

Four of the incidents that occurred in 2013 involved incorrect operations, three were classified as minor and one was a near-miss.

There were two ROW near-misses reported in 2013 as part of the TPD Annual Assessment, both classified as One-Call Violations.

4.11. One-Call Violations and Third-Party Damage Prevention Data Right-of-Way (ROW) Surveillance Data (Item 50)

A complete log of aerial and ground surveillance data is maintained by Magellan and received by Kiefner. Each entry on the log represents a report of an observation by the pilot that represents or could represent the encroachment of a party on the ROW with the potential to cause damage to the pipeline. The observations range in significance from observations that turn out to have no impact on the ROW to those that could result in damage to the pipeline without intervention on the part of the pipeline operator. Each observation on the log is identified by location (milepost and GPS coordinates), by date of first observation, and whether the activity is an emergency or non-emergency observation. A brief description of the observation is recorded, and the action to be taken is recorded as well.

The number of One-Call violations is also summarized as part of the TPD Annual Assessment. In 2013, there were two One-Call violations.

Third-Party Damage (TPD), Near-Misses (Item 51)

There were 2 ROW near-misses in 2013 which were documented in the 2013 TPD Annual Assessment and Incident Reports. Tier location was determined by comparing the location to pipeline strip maps.

Table B-8. Number of Third-party Damage Near-Misses for 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Tier 1	0	0	0	0	0	0	0	0	0	0	1	0	2
Tier 2	0	0	0	0	0	0	0	1	0	0	0	0	0
Tier 3	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**0**	**0**	**1**	**0**	**2**

Unauthorized ROW Encroachments (Item 52)

During 2013 there were 112 encroachments, all authorized.

TPD Reports on Detected One-Call Violations (Item 53)

One-Call violations are defined on a state-by-state basis. For the Longhorn ORA they are defined by the Texas Underground Facility Damage Prevention and Safety Act as referenced in the 2013 TPD Annual Assessment. In 2013, there were two One-Call violations. The first occurred in August, where a third-party contractor had called in a One-Call ticket, but did not list the entire scope of work and had travelled outside the specified area. The second was in November when a third-party contractor building a driveway failed to call in a One-Call ticket. Both of these violations were classified as near-misses.

TPD Reports on Changes in Population Activity Levels, Land Use and Heavy Construction Activities (Item 54)

The 2013 TPD Annual Assessment shows a 5.4 percent drop in non-company activity level from unique aerial patrol observations. This is primarily due to a decrease in housing development, and miscellaneous TP activity.

Miles of Pipe Inspected by Aerial Survey by Month (Item 56)

Total possible mileage includes the 694-mile main line plus the 29-mile lateral from Crane to Odessa, and the four 9.4 laterals from El Paso Terminal to Diamond Junction. The 3.5-mile double lateral from East Houston to MP 6 was added to the patrol mileage in 2011. Tier II and Tier III areas (Segment 301) must be inspected every 2½ days not to exceed 72 hours. The Tier I area from the Pecos River to El Paso (Segment 303) only needs to be inspected once per week (not to exceed 12 days). Daily patrols are also required over the Edwards Aquifer Recharge Zone with one patrol per week to be a ground-level patrol. In an attempt to meet this requirement through aerial patrols, the pipeline ROW was flown daily from the Pecos River to Galena Park (weather permitting). Regular ground patrols were made in the Edwards Aquifer recharge zone (Milepost 170.5 to Milepost 173.5). The cumulative miles of patrols for these three areas by month were as follows:

Table B-9. Cumulative Miles of Patrols

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total*
Aerial Patrol													
301: MP528 to Galena Park	12,136	12,267	15,005	14,197	14,553	15,791	14,968	14,912	12,000	14,677	13,187	11,950	165,643
303: Crane Station to MP694	1,320	1,056	1,056	1,056	1,320	1,056	1,320	1,056	1,056	1,320	1,056	1,056	13,464
Ground Patrol													
Edwards Aquifer	28	16.8	19.6	19.6	2.8	11.2	16.8	16.8	28	2.8	0	2.8	165.2

Magellan was able to meet the Longhorn commitment to inspect Tier II and III areas (Segment 301) from the Galena Park to Pecos River at least every 72 hours with the following exceptions:

- MP45 to MP528 (9/19-9/21)
- MP455 to MP528 (11/16-11/18)
- MP138 to MP528 (11/20-11/23)
- MP354 to MP528 (12/4-12/6)
- Edwards Aquifer (11/17, 11/20, 11/22, 11/23, 11/25, 12/5, 12/8)

These exceptions were due to episodes of bad weather which prohibited aerial patrols, so ground patrols were organized to complete (or in an attempt to complete) the required right-of-way patrols.

Magellan was able to meet the Longhorn commitment to inspect Tier I areas from Crane to MP694.

Number of Pipeline Signs Installed, Repaired, Replaced by Month (Item 57)

Table B-10. Markers Repaired or Replaced

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
No. Repaired or Replaced	13	366	71	4	6	10	8	2	6	20	28	5	539

Number of Public Outreach or Educational Meetings Regarding Pipeline Marker Signs and Safety (Item 58)

Magellan participates in a variety of outreach efforts for the public and the stakeholders along the pipeline which are summarized in TPD Annual Assessment.

Table B-11. Educational and Outreach Meetings

EVENT	2005	2006	2007	2008	2009	2010	2011	2012	2013
Emergency Responder / Excavator Meetings	14	12	11	11	11	11	11	11	11
School Program:									
School Program - Houston	2	2	3	4		6	5	6	1
School Program - Austin	3	2	7	3	4	3	4	5	5
Neighborhood Meetings	2	2							
Misc. Meetings:									
Creekside Nursery	1								
Cy Fair ISD	1								
Region 6 LEPC Conference (Houston)	1								
Public Events	4		4	3	2	2			
TOTAL	28	18	25	21	17	22	20	22	17

NOTE: Public meetings were tallied for the years 2005-2013 as follows:
Emergency Responder / Excavator Meetings: Count only the number of meetings (not the total number of counties).

School Program: Houston Program - count the schools that request the Safe at Home Program; Austin Program - count only schools where Longhorn/Magellan gave presentations.

Neighborhood Meetings: Phased out in 2007, and was replaced by enhancements to school program and public events.

Misc. Meetings: Count all other meetings that are not public events (i.e. daycares, church meetings, public speaking engagements, etc.).

Public Events: Count events such as rodeos, county fairs, fundraisers, home shows, Safety Day Camps, etc.

Number of One-Calls by Month by Tier (Item 59)

The number of reported One-Calls by month by tier for 2013 is in Table B-9 below.

Table B-12. Number of One-Calls by Tier

Tier	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
I	365	399	370	373	384	362	406	417	436	399	328	308	4,546
II	662	663	700	713	761	687	760	820	872	869	669	692	8,869
III	201	225	232	222	243	213	239	269	289	308	232	231	2,903
Total	1,228	1,287	1,302	1,308	1,388	1,261	1,405	1,506	1,598	1,576	1,229	1,231	16,319

Public Awareness Summary Annual Report (Item 60)

The Longhorn Public Awareness Plan incorporates a variety of activities to reach the various stakeholder audiences and provide them with damage prevention information, including annual mailings, emergency response / excavator meetings, door-to-door visits, meetings with emergency response agencies, school presentations, public service announcements and safety information provided on the Magellan website.

Number of Website Visits to Safety Page by Month (Item 61)

The number of visits to the safety section of the website per month is shown in the following table.

Table B-13. Number of Website Visits

Page Name	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec	Total
Safety/Environment	196	143	129	167	154	155	198	168	134	200	143	167	1,954
– Call Before You Dig	94	36	42	76	54	38	69	51	72	58	31	27	648
– Pipeline Safety	116	80	107	124	125	77	126	113	91	126	87	102	1,274
– System Integrity Plan	109	78	68	92	81	75	79	71	80	101	69	70	973
– Longhorn Info.	848	864	1158	849	969	722	666	728	579	1023	595	494	9,495
– Pipeline Emergencies	36	20	22	39	23	34	39	26	26	32	20	19	336
– Call Before You Dig Video	4	1	1	6	5	1	3	1	3	0	0	1	26
Home Page – 811 Logo	0	0	0	3	0	0	0	0	11	1	1	0	16
Total	1,403	1,222	1,527	1,356	1,411	1,102	1,180	1,158	996	1,541	946	880	14,722

Number of ROW Encroachments by Month (Item 67)

Table B-14. Table of ROW Encroachment by Month

Encroachments	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Authorized	15	5	22	2	12	9	18	6	10	0	8	5	112
Unauthorized	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	15	5	22	2	12	9	18	6	10	0	8	5	112

Number of Physical Hits to Pipeline by Third Parties, by Month (Item 68)

No physical hits were reported during 2012 and 2013. Two physical hits to the pipeline requiring coating repair were reported in 2011, while no physical hits were recorded in the previous 5 years from 2006-2010.

Annual TPD Assessment Report (Item 71)

The Longhorn System 2013 Annual Third-Party Damage Prevention Program Assessment (TPD Annual Assessment) was received in August 2014. Much of the data received in this report is used to summarize other parts of Section 4.11 and section 5.5 on third-party damage prevention.

One-Call Activity Reports (Item 72)

A summary of One-Call activity by month is supplied in Table B-12 below as extracted from the TPD Annual Assessment. Results show that 16,319 One-Call notifications were made.

Table B-15. One-Call Activity by Month

Month	One-Call Clear	Field Locate	Total Tickets
Jan	491	165	1,228
Feb	481	186	1,287
Mar	635	190	1,302
Apr	568	269	1,308
May	556	275	1,388
Jun	478	282	1,261
Jul	557	323	1,405
Aug	586	355	1,506
Sep	607	341	1,598
Oct	658	380	1,576
Nov	516	310	1,229
Dec	475	293	1,231
Totals	6,608	3,369	16,319

4.12. Incident, Root Cause, and Metallurgical Failure Analysis Reports

During 2013 there were twelve internal incident data reports filed, two of which were DOT Reportable which involved releases which were recovered.

Eight of the incidents occurred at facilities: 6 were classified as minor, 1 was serious/significant (lifting injury), and 1 near-miss (valve left in closed position). Four incidents involved pipeline operations: one minor incident due to incorrect operations, one serious/significant (ankle sprain) and two ROW near misses, both One-Call violations.

Incident investigations were conducted on six of the twelve incidents.

4.13. Other LPSIP/Risk Analyses, Evaluations, and Program Data

Kiefner received Process Hazards Analyses (PHAs) and Layer of Protection (LOPA) studies which were conducted on the pump stations during Phase 1 of the reversal in 2012 and Phase 2 in 2013.

4.14. Major Pipeline Incidents, Industry, or Agency Advisories Affecting Pipeline Integrity

PHMSA Advisories

DEPARTMENT OF TRANSPORTATION ADB-2013-01 January 30, 2013
Pipeline and Hazardous Materials Safety Administration
Pipeline Safety: Accident and Incident Notification Time Limit: Issuance of Advisory Bulletin
AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA); DOT.
ACTION: Notice; Issuance of Advisory Bulletin.
SUMMARY: Owners and operators of gas and hazardous liquid pipeline systems and liquefied natural gas (LNG) facilities are already required to provide telephonic reports of pipeline incidents and accidents to the National Response Center (NRC) promptly, accurately, and fully communicate the estimated extent of the damages. PHMSA is issuing this advisory bulletin to notify the owners and operators that, as required by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, the agency will issue a proposed rule to revise telephonic reporting regulations to establish specific time limits for telephonic or electronic notice of accidents and incidents involving pipeline facilities to the NRC.

DEPARTMENT OF TRANSPORTATION ADB-2013-02 July 12, 2013
Pipeline and Hazardous Materials Safety Administration
Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Flooding
AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA); DOT.
ACTION: Notice; Issuance of Advisory Bulletin.

SUMMARY: PHMSA is issuing this advisory bulletin to all owners and operators of gas and hazardous liquid pipelines to communicate the potential for damage to pipeline facilities caused by severe flooding. This advisory includes actions that operators should consider taking to ensure the integrity of pipelines in case of flooding.

DEPARTMENT OF TRANSPORTATION ADB-2013-04 August 28, 2013
Pipeline and Hazardous Materials Safety Administration
Pipeline Safety: Notice to Operators of Hazardous Liquid and Natural Gas Pipelines of a Recall on Leak Repair Clamps Due to Defective Seal
AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA); DOT.
ACTION: Notice; Issuance of Advisory Bulletin.
SUMMARY: PHMSA is issuing an Advisory Bulletin to alert all pipeline operators of a T.D. Williamson, Inc. (TDW) Leak Repair Clamp (LRC) recall issued by TDW on June 17, 2013. The recall covers all TDW LRCs of any pressure class and any size. The LRCs may develop a dangerous leak due to a defective seal. Hazardous liquid and natural gas pipeline operators should verify if they have any TDW LRCs subject to the recall by reviewing their records and equipment for installation of these LRCs. Operators with TDW LRCs should discontinue use immediately and contact TDW for further recall instructions. Operators can obtain recall information through TDW's Web site at http://lrc.tdwilliamson.com/ or by calling TDW at 888-770-7085.

4.15. DOT Regulations

No new regulations affecting the Longhorn ORA occurred in 2013.

4.16. Literature Reviewed

See references.

APPENDIX C - LIST OF PIPE REPLACEMENTS FOR 2013

LINE	BEGIN STATION MP	END STATION MP	PIPE SIZE	PIPE GRADE	PIPE WALL	FREQ WELD CDE	MANUFACTURER NME	PIPE COATING DSC	PIECE TYPE NME
6645	5.898496212	5.899882576	20	35000	0.375	ERW-HF	MANNESMANN	FUSION BOND EPOXY	FITTING
6645	5.899882576	5.900397727	20	60000	0.375	ERW-HF	HYUNDAI	FUSION BOND EPOXY	PIPE
6645	5.900397727	5.902162879	20	35000	0.375	ERW-HF	MANNESMANN	FUSION BOND EPOXY	FITTING
6645	5.902162879	5.902784091	20	60000	0.375	ERW-HF	HYUNDAI	FUSION BOND EPOXY	PIPE
6645	5.902784091	5.904204545	20	35000	0.375	ERW-HF	MANNESMANN	FUSION BOND EPOXY	FITTING
6645	11.98377462	11.98424811	20	35000	0.375	SMLS	UNKNOWN	DENSO 2888	FITTING
6645	11.98424811	11.98472159	20	52000	0.375	ERW-HF	U.S. STEEL	DENSO 2888	PIPE
6645	11.98472159	11.98484848	20	35000	0.375	SMLS	UNKNOWN	DENSO 2888	FITTING
6645	11.98484848	11.98560606	20	35000	0.375	SMLS	M & J 303	DENSO 2888	VALVE
6645	11.98560606	11.98573295	20	35000	0.375	SMLS	UNKNOWN	DENSO 2888	FITTING
6645	11.98573295	11.98620644	20	52000	0.375	ERW-HF	U.S. STEEL	DENSO 2888	PIPE
6645	11.98620644	11.98667992	20	35000	0.375	SMLS	UNKNOWN	DENSO 2888	FITTING
6645	21.19782197	21.19829545	20	35000	0.375	SMLS	UNKNOWN	PAINT	FITTING
6645	21.19981061	21.20028409	20	35000	0.375	SMLS	UNKNOWN	PAINT	FITTING
6645	35.02102273	35.0219697	18	65000	0.281	ERW-HF	AMERICAN STEEL	FUSION BOND EPOXY	PIPE
6645	51.80018939	51.80416667	18	65000	0.281	ERW-HF	AMERICAN STEEL	FUSION BOND EPOXY	PIPE
6645	64.06212121	64.06268939	18	65000	0.375	ERW-HF	AMERICAN STEEL	FUSION BOND EPOXY	PIPE
6645	93.75549242	93.75757576	18	65000	0.281	ERW-HF	AMERICAN STEEL	FUSION BOND EPOXY	PIPE
6645	128.8395833	128.8418561	18	65000	0.281	ERW-HF	AMERICAN STEEL	FUSION BOND EPOXY	PIPE
6645	128.8492424	128.8513258	18	65000	0.281	ERW-HF	AMERICAN STEEL	FUSION BOND EPOXY	PIPE
6645	134.6570076	134.6579545	18	65000	0.375	ERW-HF	AMERICAN STEEL	FUSION BOND EPOXY	PIPE
6645	149.0649621	149.067803	18	65000	0.281	ERW-HF	AMERICAN STEEL	FUSION BOND EPOXY	PIPE
6645	154.5172348	154.51875	18	65000	0.281	ERW-HF	AMERICAN STEEL	FUSION BOND EPOXY	PIPE

LINE	BEGIN STATION MP	END STATION MP	PIPE SIZE	PIPE GRADE	PIPE WALL	FREQ WELD CDE	MANUFACTURER NME	PIPE COATING DSC	PIECE TYPE NME
6645	158.6	158.6022727	18	65000	0.281	ERW-HF	AMERICAN STEEL	FUSION BOND EPOXY	PIPE
6645	163.1848485	163.1863636	18	65000	0.281	ERW-HF	AMERICAN STEEL	FUSION BOND EPOXY	PIPE
6645	166.2539773	166.2551136	18	65000	0.281	ERW-HF	AMERICAN STEEL	FUSION BOND EPOXY	PIPE
6645	166.6656402	166.6696174	18	52000	0.5	ERW-HF	HYSCO	PLASTIC TAPE/PAINT	PIPE
6645	166.6696174	166.6699962	18	35000	0.375	SMLS	UNKNOWN	PAINT	FITTING
6645	166.6699962	166.6701231	18	35000	0.375	SMLS	UNKNOWN	PAINT	FITTING
6645	166.6701231	166.670786	18	35000	0.375	SMLS	M & J 303	PAINT	VALVE
6645	166.670786	166.6709129	18	35000	0.375	SMLS	UNKNOWN	PAINT	FITTING
6645	166.6709129	166.6712917	18	35000	0.375	SMLS	UNKNOWN	PAINT	FITTING
6645	166.6712917	166.6752689	18	52000	0.5	ERW-HF	HYSCO	PLASTIC TAPE/PAINT	PIPE
6645	169.2971591	169.2981061	18	65000	0.375	ERW-HF	AMERICAN STEEL	FUSION BOND EPOXY	PIPE
6645	202.7825758	202.7837121	18	65000	0.281	ERW-HF	AMERICAN STEEL	FUSION BOND EPOXY	PIPE
6645	214.6410985	214.6431818	18	65000	0.281	ERW-HF	AMERICAN STEEL	FUSION BOND EPOXY	PIPE
6645	230.28125	230.2823864	18	65000	0.281	ERW-HF	AMERICAN STEEL	FUSION BOND EPOXY	PIPE
6645	232.0511364	232.0556818	18	65000	0.281	ERW-HF	AMERICAN STEEL	FUSION BOND EPOXY	PIPE
6645	253.2356061	253.2367424	18	65000	0.281	ERW-HF	AMERICAN STEEL	FUSION BOND EPOXY	PIPE
6645	276.4616629	276.4620417	18	35000	0.375	SMLS	UNKNOWN	DENSO 2888	FITTING
6645	276.4629583	276.4633371	18	35000	0.375	SMLS	UNKNOWN	DENSO 2888	FITTING
6645	289.0246212	289.0255682	18	65000	0.281	ERW-HF	AMERICAN STEEL	FUSION BOND EPOXY	PIPE
6645	302.5498106	302.5507576	18	65000	0.281	ERW-HF	AMERICAN STEEL	FUSION BOND EPOXY	PIPE
6645	321.9513258	321.9528409	18	52000	0.375	ERW-HF	U.S. STEEL	DENSO 2888	PIPE
6645	337.0420455	337.0441288	18	65000	0.281	ERW-HF	AMERICAN STEEL	FUSION BOND EPOXY	PIPE
6645	337.0964015	337.0984848	18	65000	0.281	ERW-HF	AMERICAN STEEL	FUSION BOND EPOXY	PIPE
6645	345.9306818	345.9316288	18	65000	0.281	ERW-HF	AMERICAN STEEL	FUSION BOND EPOXY	PIPE

LINE	BEGIN STATION MP	END STATION MP	PIPE SIZE	PIPE GRADE	PIPE WALL	FREQ WELD CDE	MANUFACTURER NME	PIPE COATING DSC	PIECE TYPE NME
6645	345.9388258	345.9399621	18	65000	0.281	ERW-HF	AMERICAN STEEL	FUSION BOND EPOXY	PIPE
6645	348.6965909	348.6984848	18	65000	0.281	ERW-HF	AMERICAN STEEL	FUSION BOND EPOXY	PIPE
6645	350.5876894	350.5899621	18	65000	0.281	ERW-HF	AMERICAN STEEL	FUSION BOND EPOXY	PIPE
6645	350.5905303	350.592803	18	65000	0.281	ERW-HF	AMERICAN STEEL	FUSION BOND EPOXY	PIPE
6645	354.6933712	354.6952652	18	65000	0.281	ERW-HF	AMERICAN STEEL	FUSION BOND EPOXY	PIPE
6645	366.5590909	366.5607955	18	65000	0.281	ERW-HF	AMERICAN STEEL	FUSION BOND EPOXY	PIPE
6645	42.96193182	42.96458333	18	42000	0.375	ERW-HF	HUSTEEL	FUSION BOND EPOXY	PIPE
6645	42.96458333	42.96723485	18	42000	0.375	ERW-HF	HUSTEEL	FUSION BOND EPOXY	PIPE
6645	42.96723485	42.96856061	18	42000	0.375	ERW-HF	HUSTEEL	FUSION BOND EPOXY	PIPE
6645	42.96856061	42.97121212	18	42000	0.375	ERW-HF	HUSTEEL	FUSION BOND EPOXY	PIPE
6645	42.97121212	43.05094697	18	42000	0.375	ERW-HF	HUSTEEL	FUSION BOND EPOXY	PIPE
6645	43.05094697	43.05359848	18	42000	0.375	ERW-HF	HUSTEEL	FUSION BOND EPOXY	PIPE
6645	43.05359848	43.05492424	18	42000	0.375	ERW-HF	HUSTEEL	FUSION BOND EPOXY	PIPE
6645	43.05492424	43.05757576	18	42000	0.375	ERW-HF	HUSTEEL	FUSION BOND EPOXY	PIPE
6645	43.05757576	43.06022727	18	42000	0.375	ERW-HF	HUSTEEL	FUSION BOND EPOXY	PIPE
6645	171.519697	171.5410985	18	52000	0.375	ERW-HF	U.S. STEEL	DENSO 2888	PIPE
6645	171.5688598	171.5692386	18	35000	0.375	SMLS	UNKNOWN	PAINT	FITTING
6645	171.5692386	171.5693655	18	35000	0.375	SMLS	UNKNOWN	PAINT	FITTING
6645	171.5693655	171.5700284	18	35000	0.375	SMLS	M & J 303	PAINT	VALVE
6645	171.5700284	171.5701553	18	35000	0.375	SMLS	UNKNOWN	PAINT	FITTING
6645	171.5701553	171.5705341	18	35000	0.375	SMLS	UNKNOWN	PAINT	FITTING
6645	172.2872311	172.2876098	18	35000	0.375	SMLS	UNKNOWN	DENSO 2888	FITTING
6645	172.2876098	172.2877367	18	35000	0.375	SMLS	UNKNOWN	DENSO 2888	FITTING
6645	172.2877367	172.2883996	18	35000	0.375	SMLS	M & J 303	DENSO 2888	VALVE
6645	172.2883996	172.2885265	18	35000	0.375	SMLS	UNKNOWN	DENSO 2888	FITTING

LINE	BEGIN STATION MP	END STATION MP	PIPE SIZE	PIPE GRADE	PIPE WALL	FREQ WELD CDE	MANUFACTURER NME	PIPE COATING DSC	PIECE TYPE NME
6645	172.2885265	172.2889053	18	35000	0.375	SMLS	UNKNOWN	DENSO 2888	FITTING
6645	172.2889053	172.2904205	18	52000	0.375	ERW-HF	U.S. STEEL	DENSO 2888	PIPE
6645	174.9442386	174.9446174	18	35000	0.375	SMLS	UNKNOWN	DENSO 2888	FITTING
6645	174.9446174	174.9447443	18	35000	0.375	SMLS	UNKNOWN	DENSO 2888	FITTING
6645	174.9447443	174.9454072	18	35000	0.375	SMLS	M & J 303	DENSO 2888	VALVE
6645	174.9454072	174.9455341	18	35000	0.375	SMLS	UNKNOWN	DENSO 2888	FITTING
6645	174.9455341	174.9459129	18	35000	0.375	SMLS	UNKNOWN	DENSO 2888	FITTING
6645	175.4946023	175.4983902	18	52000	0.375	ERW-HF	U.S. STEEL	DENSO 2888	PIPE
6645	175.4991477	175.4995265	18	35000	0.375	SMLS	UNKNOWN	PAINT	FITTING
6645	175.4995265	175.4996686	18	35000	0.375	SMLS	UNKNOWN	PAINT	FITTING
6645	175.4996686	175.5003314	18	35000	0.375	SMLS	M & J 303	PAINT	VALVE
6645	175.5003314	175.5004735	18	35000	0.375	SMLS	UNKNOWN	PAINT	FITTING
6645	175.5004735	175.5008523	18	35000	0.375	SMLS	UNKNOWN	PAINT	FITTING
6645	177.1272727	177.1301136	18	52000	0.375	ERW-HF	U.S. STEEL	DENSO 2888	PIPE
6645	177.1895038	177.1898826	18	35000	0.375	SMLS	UNKNOWN	DENSO 2888	FITTING
6645	177.1898826	177.1900095	18	35000	0.375	SMLS	UNKNOWN	DENSO 2888	FITTING
6645	177.1906723	177.1907992	18	35000	0.375	SMLS	UNKNOWN	DENSO 2888	FITTING
6645	177.1907992	177.191178	18	35000	0.375	SMLS	UNKNOWN	DENSO 2888	FITTING
6645	178.5223485	178.5231061	18	35000	0.375	SMLS	WHEATLEY	WAX	VALVE
6645	182.0261364	182.0268939	18	35000	0.375	SMLS	WHEATLEY	WAX	VALVE
6645	185.8779508	185.8783295	18	35000	0.375	SMLS	UNKNOWN	DENSO 2888	FITTING
6645	185.8783295	185.8784564	18	35000	0.375	SMLS	UNKNOWN	DENSO 2888	FITTING
6645	185.8784564	185.8791193	18	35000	0.375	SMLS	M & J 303	DENSO 2888	VALVE
6645	185.8791193	185.8792462	18	35000	0.375	SMLS	UNKNOWN	DENSO 2888	FITTING
6645	185.8792462	185.879625	18	35000	0.375	SMLS	UNKNOWN	DENSO 2888	FITTING
6645	186.4810606	186.4835227	18	52000	0.375	ERW-HF	U.S. STEEL	DENSO 2888	PIPE
6645	186.8599583	186.8603371	18	35000	0.375	SMLS	UNKNOWN	DENSO 2888	FITTING
6645	186.8603371	186.860464	18	35000	0.375	SMLS	UNKNOWN	DENSO 2888	FITTING
6645	186.860464	186.8611269	18	35000	0.375	SMLS	M & J 303	DENSO 2888	VALVE
6645	186.8611269	186.8612538	18	35000	0.375	SMLS	UNKNOWN	DENSO 2888	FITTING
6645	186.8612538	186.8616326	18	35000	0.375	SMLS	UNKNOWN	DENSO 2888	FITTING
6645	186.9852273	186.9869318	18	65000	0.281	ERW-HF	AMERICAN STEEL	FUSION BOND EPOXY	PIPE
6645	187.4333333	187.4340909	18	35000	0.375	SMLS	WHEATLEY	WAX	VALVE

LINE	BEGIN STATION MP	END STATION MP	PIPE SIZE	PIPE GRADE	PIPE WALL	FREQ WELD CDE	MANUFACTURER NME	PIPE COATING DSC	PIECE TYPE NME
6643	3.54280303	3.543996212	20	60000	0.375	ERW-HF	HYUNDAI	FUSION BOND EPOXY	PIPE
6643	3.543996212	3.546458333	20	60000	0.375	ERW-HF	HYUNDAI	FUSION BOND EPOXY	PIPE
6643	3.546458333	3.547617424	20	60000	0.375	ERW-HF	HYUNDAI	FUSION BOND EPOXY	PIPE