Magellan Pipeline Company

Final Report No. 19-047

2017 Operational Reliability Assessment of the Longhorn Pipeline System

Susan Rose, Adam Steiner, PE, Benjamin Wright,
Benjamin Zand, PhD, PE and Dennis Johnston

March 28, 2019

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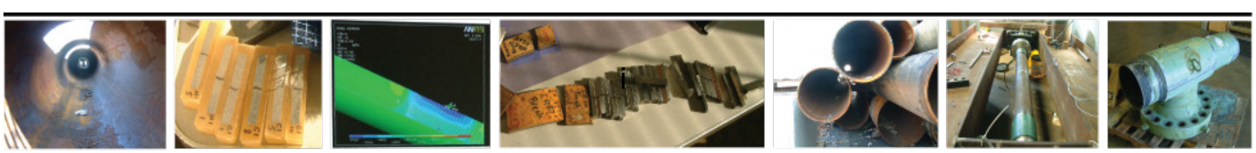

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on

2017 OPERATIONAL RELIABILITY ASSESSMENT OF THE LONGHORN PIPELINE SYSTEM

to

MAGELLAN PIPELINE COMPANY

March 28, 2019

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EXECUTIVE SUMMARY

This report presents the annual Operational Reliability Assessment (ORA) of the Longhorn Pipeline System for the 2017 operating year. Kiefner and Associates, Inc. (Kiefner) conducted the ORA which provides Magellan Pipeline Company, L.P. (Magellan) with a technical assessment of the effectiveness of the Longhorn Pipeline System Integrity Plan (LPSIP). The technical assessment incorporates the results of all elements of the LPSIP to evaluate the condition of the Longhorn assets. Recommendations are provided to preserve the long term integrity and mitigate areas of potential concern.

The analyses of operational pressure cycles to date show that an integrity reassessment from the standpoint of potential flaws in the electric-resistance weld (ERW) and flash welded (FW) seam will be necessary in the year 2022 for the Barnhart to Texon segment. Transverse field inspection (TFI) tool runs, completed in 2014 and 2015 were used to define a flaw size that determined the reassessment interval. The reassessment interval used the seam weld feature detection threshold value from the TFI tool vendor.

The 2017 maintenance reports were reviewed and correlated to in-line inspection (ILI) assessments from 2012, 2014, and 2015 to validate the ILI specified tool performance using the supplied background information and the API 1163 ILI validation methodology. Seventy-three of the maintenance reports included ILI anomaly investigations. The ILI anomaly investigations found correlating features on 72 out of the 73 digs. No features were found on Dig SIP-1 within the exposed location on the E. Houston to Speed Junction segment. ILI reported metal loss anomalies were found as metal loss in-ditch half of the time. Internal corrosion coupons continue to show low corrosion rates (<0.5% wall loss). Magellan continues to conduct field investigations to remediate and validate metal loss reported on future ILI assessments as necessary.

- Advanced NDE methodologies that have a high resolution are recommended for in-ditch evaluations to help characterize and size complex anomalies that are within the pipe body.

A Close Interval Survey (CIS) was performed by a third party in July and August of 2017 on Longhorn Tier III (environmentally hypersensitive) sections. No areas of concern were noted in the CIS report. As required by the LMP, Magellan will continue the annual CIS on all Tier III sections.

Laminations were reviewed concurrently with reported inside diameter (ID) reductions to determine if there were any potential hydrogen blisters on the line segments inspected in 2017. The 146 ID reductions identified from the 2017 electronic geometry pig (EGP) assessments

were compared to the existing laminations reported by the 2009/2010 UT assessments. Two ID reduction features correlated; one of the correlations has been previously repaired. Based on the 2017 maintenance reports, there are currently no areas that have indications or field findings of hydrogen blisters associated with these line segments. Magellan should continue to monitor for lamination anomalies with ILI tools.

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. The results of our analyses show that movement on six of the seven faults continues to be so small that ground movement will not be a threat to the pipeline. In 2014, the analysis of the allowable fault displacement at the Hockley Fault indicated that the cumulative fault movement since the installation of the pipeline is near the limit. Remediation options were provided in the 2014 ORA and included in Sections 3.4 and 8 of this ORA.

Waterway inspections were conducted in 2017 at five river crossings, including the Colorado River, Pin Oak Creek, Cypress Creek, Greens Bayou, and Brazos River. No exposures of the pipeline were found, with the exception of the Cypress Creek crossing. Magellan recorded this exposure in a 2003 maintenance report, conducted mitigation in 2005 by recoating it and has monitored it since then. The minimum cover depth at the Pin Oak Creek was found to be 1.5 feet. Close monitoring for this crossing is recommended. Remediation practice to stabilize the bank and river bottom contour will help prevent further loss of cover. Magellan continues to perform waterway inspections at the current frequency to monitor the conditions as required by the Magellan O&M manual.

The Longhorn third-party damage (TPD) prevention program exceeds the minimum requirements of federal and Texas state pipeline safety regulations, and it represents a model program for the industry. The aerial surveillance (low-level flight) and ground patrol frequencies met the goals set forth in the Longhorn Mitigation Plan (LMP) with a few exceptions due to bad weather in January, March, August (Hurricane Harvey), and September.

There were three physical hits to the pipeline during 2017. Two of the incidents involved subcontractors (second party), one was minor and the other resulted in a Department of Transportation (DOT)-reportable release (2,084 bbls). The root cause of the DOT-reportable incident was reported to be insufficient excavation practices. The third hit, which did not result in a release, involved a third-party contractor boring for gas service for a new subdivision.

- Magellan should increase their focus on damage prevention and maintenance plans to prevent damage to the pipeline during excavation and maintenance activities. (Note that Magellan implemented a new damage prevention training course in October 2017.)

There were four one-call violations during 2017; three were within a 10-mile segment. The ORA Process Manual states that an ILI tool capable of detecting TPD will be run in any 25-mile pipeline segment in the event that three or more one-call violations occur within a 12-month time period. Based on this requirement, an ILI inspection was required on the Buckhorn to Satsuma segment. The required inspection was completed in September of 2017. The fourth one-call violation was at MP 531.1. None of the one-call violations resulted in damage to the pipeline based on the results of the inspection.

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 conducting an SCC examination program that uses magnetic particle testing at each dig site.

The 2017 facilities data indicates the pump stations and terminal facilities have been properly maintained and operated and have had no adverse impact on public safety. Process Hazard Analyses (PHAs) are performed on all new facilities, when changes occur in existing facilities, and at five-year intervals to evaluate and control potential hazards associated with the operation and maintenance of the facilities. Three PHAs were completed in 2017, which included the Eckert and Warda Pump Stations, and the mainline valves.

A probabilistic risk model has been effectively used to manage pipeline integrity and evaluate risk in accordance with 49 CFR 195.452. The results show none of the pipeline segments exceeded Magellan's risk threshold; therefore no additional mitigative measures were required or recommended.

The technical assessment of the Longhorn Pipeline System Integrity Plan (LPSIP) indicated 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 and frequency of patrol. In addition, public-awareness meetings were held, and ROW markers and signs were repaired or replaced where necessary. There were three DOT-reportable incidents including a third-party contact with the pipeline that were considered in the failure measures.

Magellan performs incident investigations on all events including near misses. During 2017, there were 24 incidents along the Longhorn Pipeline System: three DOT-reportable releases, eight ROW near-misses, 13 minor, two significant, and one major. Magellan should continue to ensure all relevant data are recorded on the incident data reports, including a detailed description of the incident, root cause, as well as contributing factors to help improve the overall effectiveness of the incident investigation program.

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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 (ORAPM) titled Terms, Definitions, and Acronyms. Definitions in the ORAPM or Longhorn Mitigation Plan (LMP) are italicized.

Accident	As stated in the LMP, an undesired event that results in harm to people or damage to property.
AC	Alternating Current
AOC	Area of concern
AOEC	Area of elevated concern
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
AUT	Automated Ultrasonic Testing
bpd	barrels per day
bph	barrels per hour
CFR	Code of Federal Regulations
CGR	Corrosion growth rate
CIS	Close interval survey
CMFL	Circumferential magnetic flux leakage
CMP	Corrosion Management Plan
CMS	Content Management System
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).
Dent	An ID Reduction greater than or equal to 2% of pipe diameter
DOC	Depth-of-cover

DOT	Department of Transportation
EA	Environmental Assessment – The National Environmental Policy Act (NEPA) process begins when a federal agency develops a proposal to take a major federal action. These actions are defined in 40 CFR 1508.18. The environmental review under NEPA can involve three different levels of analysis: • Categorical Exclusion determination (CATEX) • Environmental Assessment/Finding of No Significant Impact (EA/FONSI) • Environmental Impact Statement (EIS)
EGP	Electronic geometry pig
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.
External Corrosion	Deterioration of the pipe due to an electrochemical reaction between the pipe material and the environment outside the pipe
Excavation damage	Any excavation activity that results in the need to repair or replace a pipeline due to a weakening, or the partial or complete destruction, of the pipeline, including, but not limited to, the pipe, appurtenances to the pipe, protective coatings, support, cathodic protection or the housing for the line device or facility.
FEA	Finite element analysis
FW	Flash welded

Geometric Anomaly (GMA)	An ID Reduction less than 2% of pipe diameter
GPS	Global Positioning System – A method for locating a point on the earth using the GPS
HAZOP	Hazard and Operability (Study)
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)
HNM	Hazard near-miss
Hydrostatic Test	An integrity verification test that pressurizes the pipeline with water, also called a hydrotest or hydrostatic pressure test.
H_2S	Hydrogen Sulfide
ID Reduction	A deformation of pipe diameter detected by the ILI tool
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.
IMP	Integrity Management Program
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.
Internal Corrosion	Deterioration of the pipe due to an electrochemical reaction between the pipe material and the environment outside the pipe
Ipy	Inches per year – Often referenced in conjunction with corrosion growth rates (1000 mpy)

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).

Kiefner Kiefner and Associates, Inc.

L Defect length

Leak Detection System Two technology-based leak detection systems are used for the Longhorn system: (1) A system-wide computer-based monitoring and alarm network using real-time flow information from various locations along the pipeline, and (2) a buried sensing cable installed over the Edwards Aquifer recharge zone and the Slaughter Creek watershed in the Edwards Aquifer contributing zone.

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.

LOPA Layer of Protection Analysis

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.

Magellan Magellan Pipeline Company, L.P.

Major Incident Per the Longhorn Mitigation Plan – Includes events which result in:

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

MASP Maximum Allowable Surge Pressure

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

Minor Incident	Per the Longhorn Mitigation Plan - Includes events which result in: • Fire/explosion/spill/release or other events with casualty/property/liability loss potential under $25,000 • Employee or contractor OSHA recordable injury/illness without lost workday cases • Citations under $25,000
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.
MG	Metal gain
mil	One thousandth of an inch (0.001 in)
ML	Metal loss
MOCR	Management of Change Recommendation
MOP	Maximum Operating Pressure
MP	Mile Post
MTR	Mill Test Report
Mpy	Mils per year – Often referenced in conjunction with corrosion growth rates.
NACE	NACE International – Formerly known as the National Association of Corrosion Engineers.
NDE	Nondestructive Evaluation
Near-Miss	Number of unplanned/undesired third-party related events that did not result in significant loss but which, under slightly different circumstances, could have resulted in a minor, serious or major incident. Near miss data is obtained from Hazard / Near Miss cards, incident investigations, aerial patrol reports, maintenance reports and ROW inspection reports. 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.
NEPA	National Environmental Policy Act
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.

Normal Distribution A probability distribution that is commonly referred to as the bell curve that is symmetrical around the mean value.

OD Outside nominal diameter of line pipe.

One-Call A notification system through which a person can notify pipeline operators of planned excavation to facilitate the locating and marking of any pipelines in the excavation area.

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.

One-Call Violations Number of excavations that occurred within the ROW boundaries where a one-call was not made and should have been made. Texas One-Call (Utilities Code: Title 5, Chapter 251, Section 251.002, Sub-Section 5) defines excavate as "to use explosives or a motor, engine, hydraulic or pneumatically powered tool, or other mechanized equipment of any kind and includes auguring, backfilling, boring, compressing, digging, ditching, drilling, dragging, dredging, grading, mechanical probing, plowing-in, pulling-in, ripping, scraping, trenching, and tunneling to remove or otherwise disturb soil to a depth of 16 or more inches." Additionally, one-call violations are identified when company personnel discover third-party activity on the ROW and inform the third party that a one-call is required. One-call violation data are obtained from Hazard / Near-Miss cards, One-Call tickets, incident investigations, aerial patrol reports, maintenance reports and ROW inspection reports.

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 Operational Reliability Assessment Process Manual

PHA Process Hazard Analysis

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

PLM Pipeline Monitor

PMI	Positive Material Identification
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% 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.
POF	Probability of Failure
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.
RBDA	Reliability-based design analysis
Requirement	Activities that must be performed to comply with the LMP commitments.
RES	TDW's High Resolution Residual Magnetism tool
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 – A strip of land where, through a legal agreement, some property rights have been granted to Magellan and its affiliates. The ROW agreement enables Magellan to operate, inspect, repair, maintain or replace the pipeline.
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).
SBRMA	Scenario-Based Risk Mitigation Analysis
Significant Incident	Per the Longhorn Mitigation Plan – Includes events which result in: • Fire/explosion/spill/release/ less than three hospitalized or other events with casualty/property/liability loss potential of $25,000 - $500,000 • Employee or contractor OSHA recordable injury/illness lost workday cases • Citations with potential fines greater than $25,000
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[1])
SIP	System Integrity Plan
SMFL	Spiral magnetic flux leakage – An MFL inspection tool acceptable strength of pipe purchased from a manufacturer. A measurable metallurgical strength parameter often used to calculate acceptable pipe operating and hydrostatic test pressures.
SMYS	Specified Minimum Yield Strength – A common measure of the minimum
Standard Deviation	A measure used to quantify the amount of variation or dispersion within a set of data.
Surge Pressure	Short-term pipeline pressure increase due to equipment operation changes such as valve closure or pump start-up. Surge pressures must be limited to no more than MOP in Tier II and Tier III areas, and no more than 110% of MOP elsewhere.
TDW	T.D. Williamson
Tier I Areas	Areas of normal cross-country pipeline

[1] ASME 31.8S (2016), Managing System Integrity of Gas Pipelines, ASME Code for Pressure Piping, B31

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 – Accidental or intentional damage by a third party (that is, not the pipeline operator or contractor) that causes an immediate failure or introduces a weakness (such as a dent or gouge) into the pipe.
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.
UT	Ultrasonic testing – A non-destructive testing technique using ultrasonic waves
WT	Wall thickness of line pipe
WTI	West Texas Intermediate (crude oil grade)
WTS	West Texas Sour (crude oil grade)

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Susan Rose, Adam Steiner, Benjamin Wright, Benjamin Zand, and Dennis Johnston

1. INTRODUCTION

1.1. Objective

This report presents the annual Operational Reliability Assessment (ORA) of the Longhorn Pipeline System for the 2017 operating year. Kiefner and Associates, Inc. (Kiefner) conducted the ORA which provides Magellan Pipeline Company, L.P. (Magellan) with a technical assessment of the effectiveness of the Longhorn Pipeline System Integrity Plan (LPSIP). The technical assessment incorporates the results of all elements of the LPSIP to evaluate the condition of the Longhorn assets. Recommendations are provided to preserve the long term integrity and mitigate areas of potential concern.

1.2. Background

The previous owner, Longhorn Partners Pipeline, LP, participated in an Environmental Assessment (EA) that was prepared by the U.S. Environmental Protection Agency (EPA) and the Department of Transportation (DOT) in 1999 and 2000, prior to the then newly configured pipeline refined product service. The EA "Finding of No Significant Impact" (FONSI) 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 included the Longhorn Continuing Integrity Commitment wherein Longhorn agreed to implement System Integrity and Mitigation Commitments and conduct annual ORAs. A list of the Longhorn Mitigation Commitments (LMCs) addressed in the ORA report is provided in Appendix A – Mitigation Commitments. Magellan has operated the Longhorn system since 2005 and has owned it since 2009.

The LMP committed Longhorn to retaining 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 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. The "Mock ORA for Longhorn Pipeline" that was performed by Kiefner prior to the commissioning of the pipeline provided additional information on the execution of the ORA. The ORAPM requires the ORA contractor to provide annual reports to Magellan and 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 pipeline integrity threats are:

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

The sixth threat, 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 pipeline operators had not recognized SCC as a threat in the past.

1.3. 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 12 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 12 elements of the LPSIP are:

1. Corrosion Management Plan
2. In-Line Inspection and Rehabilitation Program

3. Key Risk Area 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

Figure 1 provides a process schematic of the functions and relative interactions of the LPSIP and the ORA.

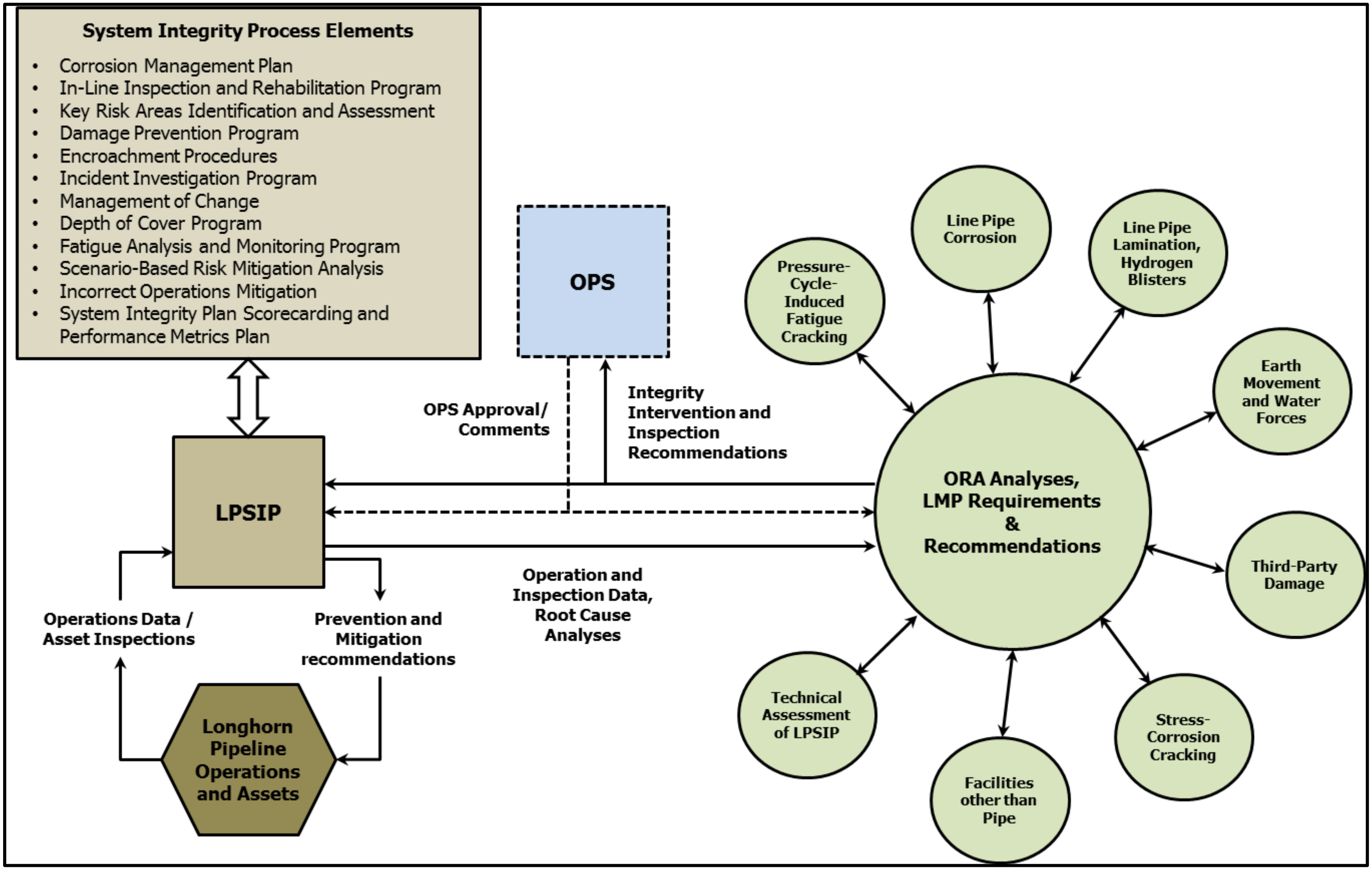

Figure 1. ORA Functions and Interaction with the LPSIP

1.4. 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, TX to East Houston, TX. The flow reversal and displacement started on July 30, 2012 and was completed on August 17, 2012. The Longhorn systems returned to service in April 2013 and are described below. The Longhorn System Map is presented in Figure 2 with a detailed map of the Houston area shown in Figure 3.

The western portion of the Longhorn 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 the El Paso Terminal to El Paso Junction (also known as the El Paso Laterals). Most of this pipe system was built in 1998.

The eastern portion of the Longhorn system transports crude oil over 424 miles through an 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 pipe from Satsuma Station to the East Houston Terminal and nine miles of 20-inch pipe from East Houston Terminal to 9th Street Junction. This system contains some of the Existing Pipeline (as named in the original EA) built in 1949-1950 with some replacements and extensions in the Houston area. The station locations for the crude oil and refined product systems are listed in Table 1 and Table 2.

Table 1. Crude Pipeline Station Locations

Station	Type	Milepost
Crane	Pump	457.5
Texon	Pump	416.6
Barnhart	Pump	373.4
Cartman	Pump	344.3
McKavett	Valve	324.0
Kimble County	Pump	295.2
James River	Pump	260.2
Eckert	Pump	227.9
Cedar Valley	Pump	181.6
Bastrop	Pump	141.8
Warda	Pump	112.9
Buckhorn	Pump	68.0
Satsuma	Pump	34.1
E. Houston	Terminal	2.35

Table 2. Refined Product Pipeline Station Locations

Station	Type	Milepost
Odessa[2]	Meter	NA
Crane	Pump	457.5
Cottonwood	Valve	576.3
El Paso	Terminal	694.4

During 2014 there was an increase in the flow rate from 225,000 to 292,000 barrels per day (bpd) from Crane to East Houston and an increase to 2,100 barrels per hour (bph) on the Western refinery connection at El Paso. The "connection" is an 8-inch flush line between El Paso and El Paso Junction. There were no operational changes to the Longhorn Pipeline System during 2017.

A timeline of the Longhorn Pipeline System is provided in Figure 4.

1.5. Analysis Information

The ORA Process Manual identifies the list of data needed to conduct the ORA. These data items are discussed in Appendix B of this report.

[2] The Longhorn Mitigation Plan (LMP) covers the Odessa pig trap. The tanks and metering are not covered by the LMP.

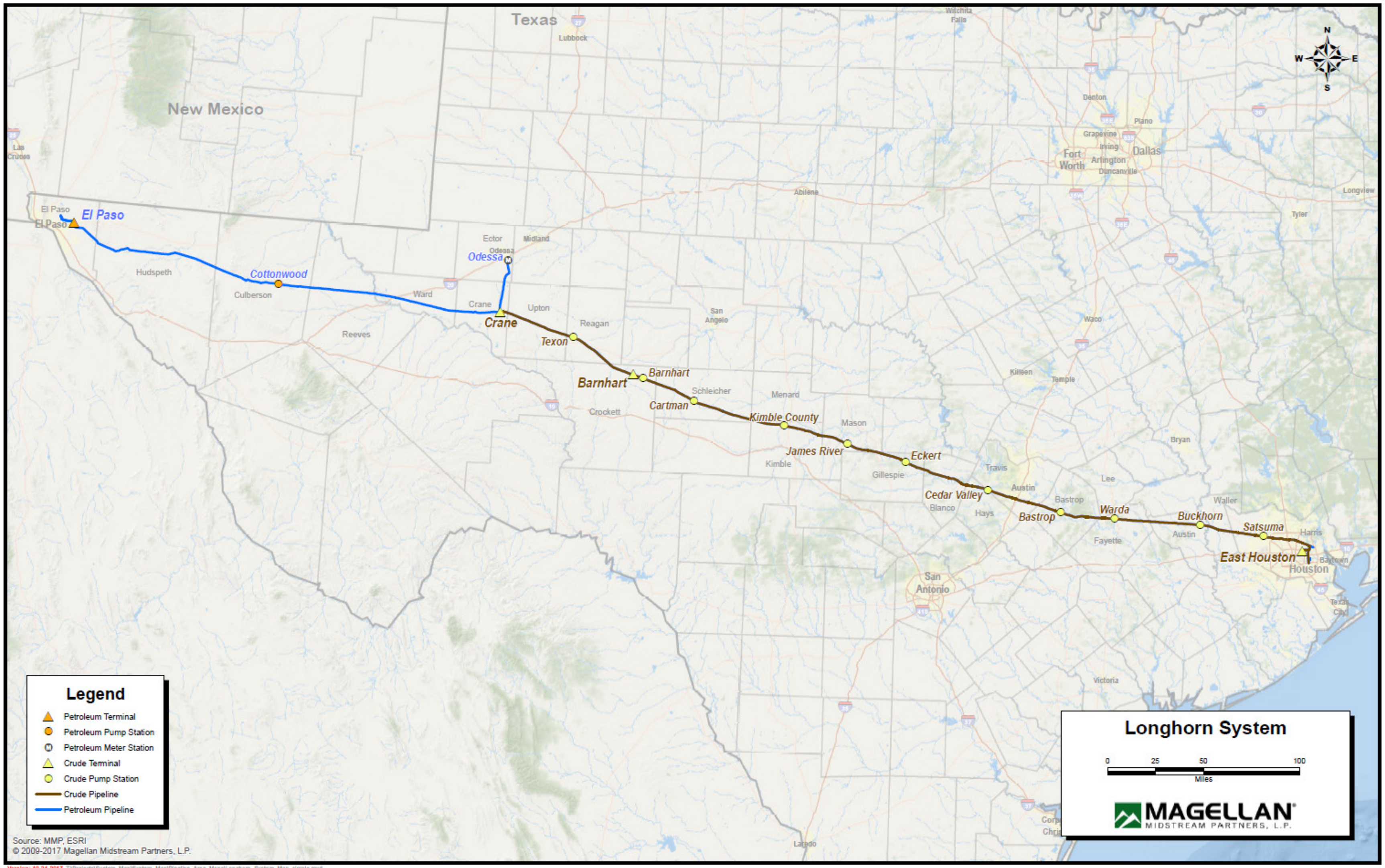

Figure 2. Longhorn System Map (2017)

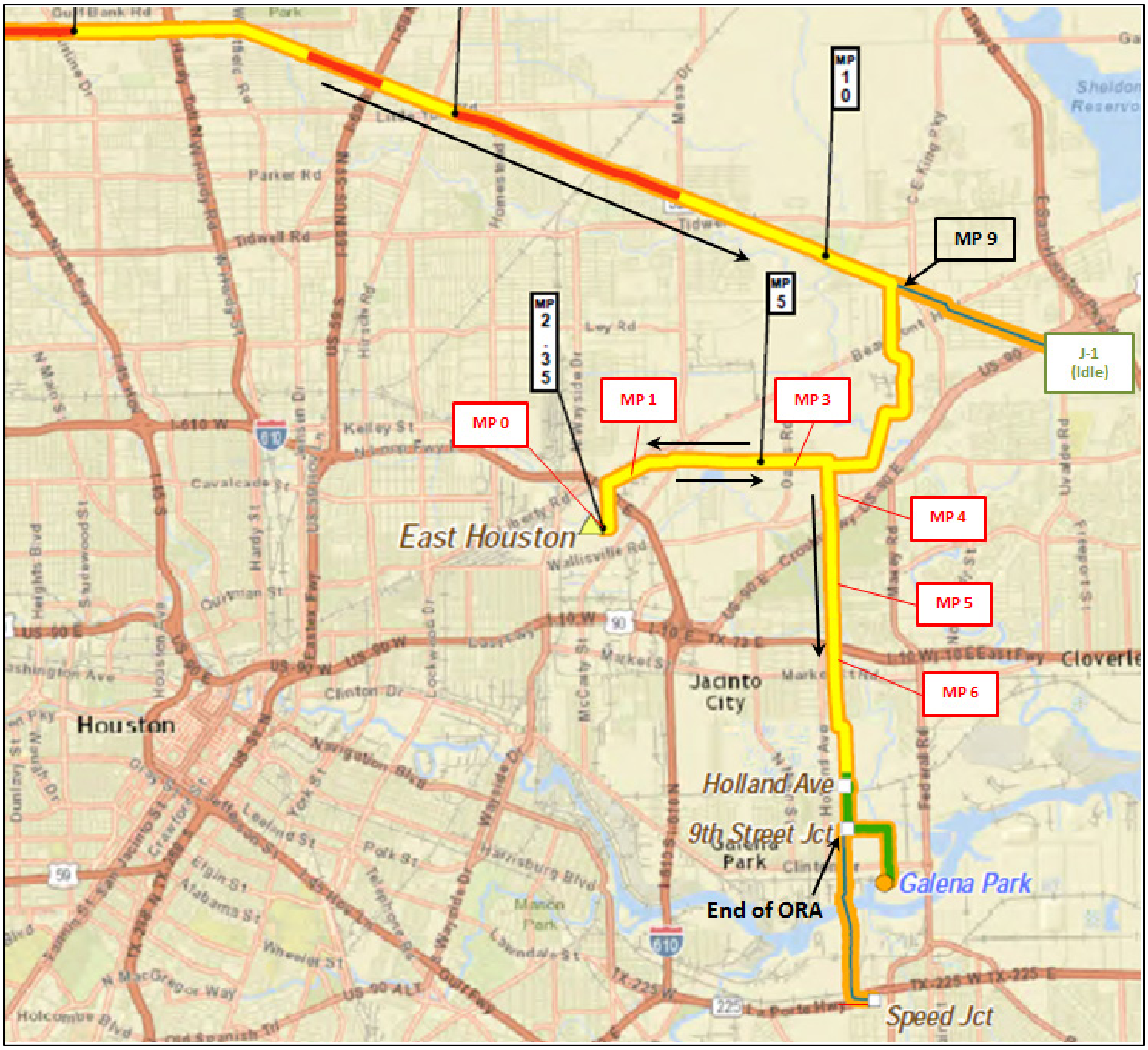

Figure 3. Map of Longhorn System within Houston Area (2017)

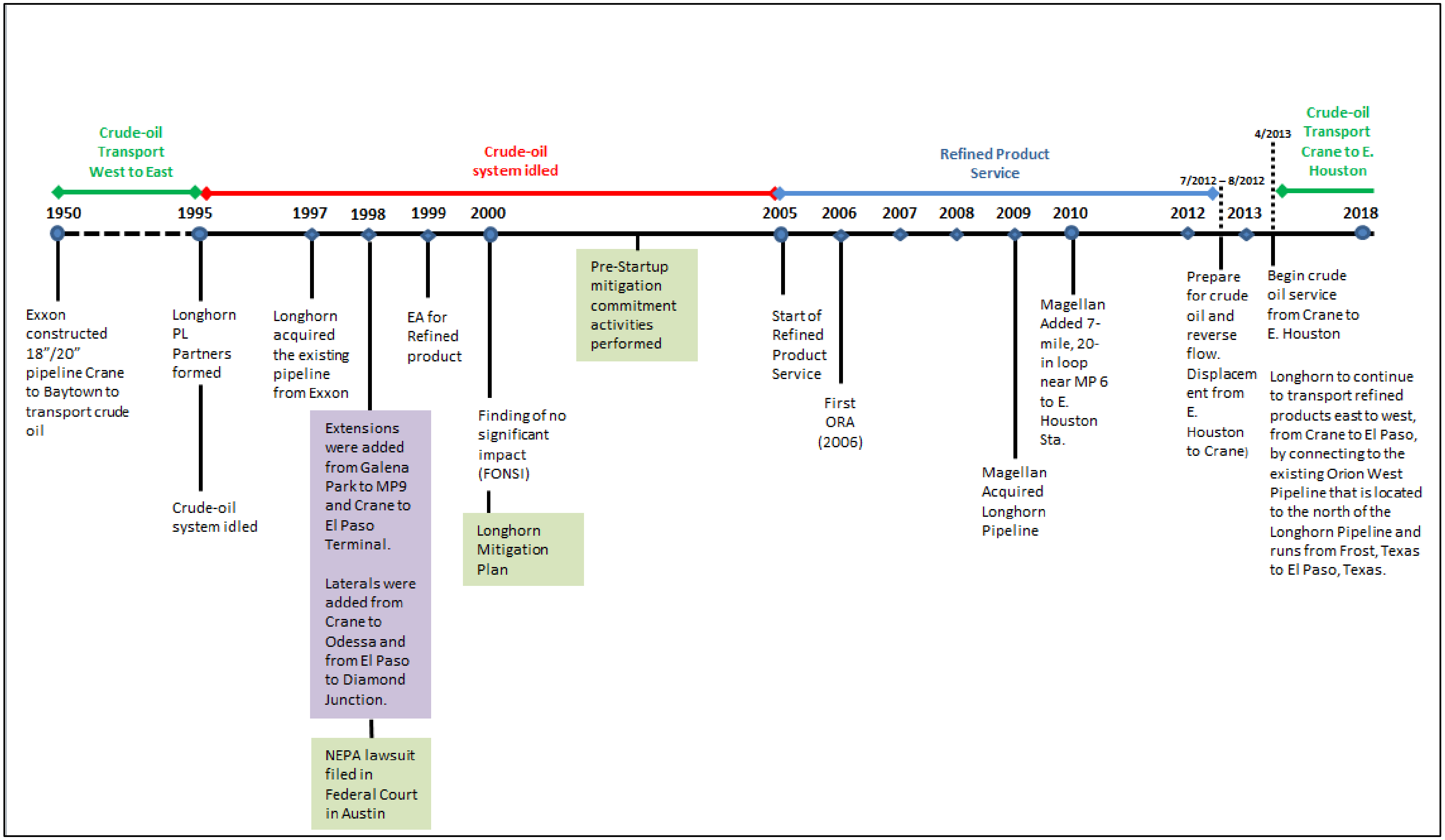

Figure 4. Timeline of the Longhorn Pipeline System

2. Technical Assessment of LPSIP Effectiveness

The LPSIP contains 12 process elements which 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.

2.1. Longhorn Corrosion Management Plan

The LMP entails an extensive Corrosion Management Plan (CMP) to control the extent of corrosion. The 2017 CMP considers the following items: review of internal corrosion coupons, probability of exceedance (POE) analysis, review of field dig reports (covered under Section 2.2, In-Line Inspection and Rehabilitation Program), and review of the cathodic protection system.

Internal corrosion is monitored using internal corrosion coupons. The coupon results have shown little change (<0.11 mpy) but monitoring should continue to identify future potential changes in the pipeline. Results from the internal corrosion coupons can be found in Appendix B, Table B-5.

POE calculations were performed on the 8-inch El Paso to Chevron Lateral, 8-inch Kinder Morgan Flush Line, and 12-inch El Paso to Kinder Morgan Lateral using the T.D. Williamson (TDW) Multi-dataset tool information. No metal loss features were found to meet POE dig requirements of 1×10^{-5}. Therefore, reliability-based design analysis (RBDA) calculations were not performed in 2017.

A CIS was performed by Energy Maintenance Services (EMS) from July 5 through August 3, 2017, on Longhorn Tier III sections (hypersensitive areas due to population or environmental factors). No areas of concern from the CIS report since all pipe-to-soil potentials were more negative than the allowed minimum for NACE standard SPO 169-2013. It is recommended to continue the annual CIS on all Tier III sections.

2.2. In-Line Inspection and Rehabilitation Program

Four in-line inspection (ILI) assessments and three electronic geometry pig (EGP) assessments were performed on the Longhorn system in 2017. The ILI assessments on the three El Paso Laterals were performed using TDW's Multi-dataset tool; refer to Table 3 for the specific segments. TDW's multi-dataset tool included SMFL, MFL, High resolution residual magnetism (RES), and Deformation technology. The ILI assessment on the Cottonwood to El Paso segment was performed using TDW's MFL and Deformation technology. The Cottonwood to El Paso final report was received in January 2018; analysis for this assessment will be included in the 2018 ORA report. The EGP assessments were performed using TDW's Deformation tool;

assessments were run from Warda to E. Houston. Inspection dates for each segment can be found in Table 3.

The 2017 ILI assessments were reviewed using the supplied background information and the API 1163[3] ILI validation methodology. Magellan provided 73 maintenance reports related to the 2012, 2014, and 2015 ILI investigations. A total of 145 individual ILI features (girth weld anomalies, inside diameter (ID) reductions, ID reductions with metal loss or seam weld, metal loss, and seam weld anomalies) were correlated to the features evaluated in 2017. An overview of the dig results can be found in Table 10 for metal loss features for girth and seam weld features, and Table 12 for ID reduction features. Using an API 1163 Level 2 validation, the TFI tool performed no worse than its depth sizing specification; further details on the API 1163 Level 2 validation can be found in Section 5.2 Corrosion – Tool Performance and In-ditch Investigations. This validation was performed and a statistical analysis on TFI reported external metal loss features from Texon to Barnhart, Eckert to Cedar Valley, and Bastrop to Buckhorn were evaluated. Magellan requires nondestructive testing of the pipe segment to determine pipe properties in at least 50% of the excavations or remediation required by ILI results if a segment of pipe does not have material documentation available. In 2017, Magellan met the requirement by performing material testing on 42 of the 64 segments that did not have material documentation available.

Table 3. ILI Assessments

Longhorn Crude System			**Longhorn Refined System**			
E. Houston to Satsuma	**Satsuma to Buckhorn**	**Buckhorn to Warda**	**Cottonwood to El Paso**	**8″ El Paso to Chevron**	**8″ Kinder Morgan Flush Line**	**12″ El Paso to Kinder Morgan**
2.35 to 34.1	**34.1 to 68.0**	**68.0 to 112.9**	**576.3 to 694.4**	**0.0 to 9.4**	**0.0 to 9.4**	**0.0 to 9.4**
Corrosion						
			MFL*	Multi-Data	Multi-Data	Multi-Data
			11/1/2017	7/13/2017	7/13/2017	7/14/2017
Pressure Cycle Induced Fatigue						
			MFL*	Multi-Data	Multi-Data	Multi-Data
			11/1/2017	7/13/2017	7/13/2017	7/14/2017
Third-Party Damage						
Deformation	Deformation	Deformation	Deformation*	Deformation	Deformation	Deformation
9/14/2017	9/13/2017	9/12/2017	11/1/2017	7/13/2017	7/13/2017	7/14/2017

*The final report for Cottonwood to El Paso was received in 2018. Analysis will be included in the 2018 ORA report.

[3] API Standard 1163, In-line Inspection Systems Qualification, Second Edition, April 2013

2.3. Identification and Assessment of Key Risk Areas

The objective of Magellan's risk management program is to ensure that resources are focused on those areas of the Longhorn Pipeline System with the highest identified or perceived risks.

Since the Longhorn Pipeline System traverses a variety of unique areas of land use, topography, and population density, it presents a variety of risk concerns to these lands and to the people who either inhabit or are present in these areas. To help prioritize risk management efforts, Magellan has categorized the Longhorn Pipeline System with the following designations:

- Tier I – normal cross-country pipeline
- Tier II – sensitive areas
- Tier III – hypersensitive areas

Further, the area across the Edwards Aquifer in South Austin is a Tier III designated area of additional heightened environmental sensitivity that has resulted in even more scrutiny and the commitment to incremental risk mitigation measures.

Magellan's probabilistic risk model utilizes integrated data and incorporates a dynamic segmentation process to maintain adequate resolution and avoid mischaracterization or loss of detail. The risk measurement methodology includes Probability of Failure (POF) threshold management to manage pipeline integrity and evaluate risk in accordance with 49 CFR 195.452. The POF measurement integrates all available information about the integrity of the pipeline. This integration aids in identification of preventive and mitigative measures to protect areas along the pipeline. Magellan is committed to maintaining a threshold of 1×10^{-4} (0.0001) failures (PHMSA reportable incidents) per mile-year at all locations along the non-facilities portions of the pipeline.

The pipeline risk model was updated with information from operations in 2017. The results show that none of the pipeline segments exceeded the risk threshold; therefore no additional mitigative measures were required or recommended.

2.4. Damage Prevention Program

Third-party damage (TPD) refers to the accidental or intentional damage by a third party – that is, not the pipeline operator or subcontractor – that causes an immediate failure or introduces a weakness (such as a dent or gouge) in the pipe.

The Longhorn 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 met the frequencies set forth in the LMP with a few exceptions due to bad weather in January, March, August (Hurricane Harvey), and September.

There were three physical hits to the pipeline during 2017; two involved subcontractors (second party) and one was a third-party contractor boring for gas service for a new subdivision which did not result in a release. One of the second-party incidents resulted in a failure and DOT-Reportable release (2,084 bbls).

Magellan should increase their focus on damage prevention and maintenance activities to prevent such events from recurring. (Note that Magellan implemented a new damage prevention training course in October 2017.)

2.5. Encroachment Procedures

Encroachments are entries to the pipeline right-of-way (ROW) by persons operating farming, trenching, drilling, or other excavating equipment. Also, debris and other obstructions along the ROW that must periodically be removed to facilitate prompt access to the pipeline for routine or emergency repair activities are considered encroachments.

The LPSIP includes provisions for surveillance to prevent and minimize the effects of unannounced or unauthorized ROW encroachments.

There were a total of 81 encroachments during 2017, nine of which were unauthorized and followed up with corrective actions to help prevent a recurrence. There was no damage to the pipeline. The encroachment procedures, when followed by the encroaching party, have been effective at preventing TPD to the pipeline.

2.6. Incident Investigation Program

Magellan is performing incident investigations on all Department of Transportation (DOT)-reportable[4] incidents as well as smaller non-reportable incidents and near-miss events.

During 2017, there were a total of 24 incidents along the Longhorn Pipeline System: 13 minor, two significant, one major, and eight ROW near-misses. There were three DOT-Reportable incidents.

Magellan should continue to ensure all relevant data are recorded on the incident data reports, including a detailed description of the incident, root cause, as well as contributing factors to help improve the overall effectiveness of the incident investigation program.

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[4] **DOT-Reportable Requirement.** 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.

2.7. Depth-of-Cover Program

A depth-of-cover (DOC) survey was completed in 2017 on the crude section of the Longhorn pipeline from Crane to East Houston. All areas of concern which included six possible areas in ranch road crossings with shallow pipe were analyzed by Asset Integrity. Two of the locations were mitigated in the fourth quarter of 2017 and four locations were mitigated in the first quarter of 2018. Forty-six exposed locations were noted in the report. All sites will be actively managed under the Outside Forces Damage Prevention Program in accordance with the LPSIP. No third-party damage was found.

As part of the ongoing monitoring, landowners are contacted annually to reaffirm that cultivation techniques and land use have not changed. Magellan monitors this on a regular basis to ensure that landowner farming practices do not jeopardize the integrity of the pipeline.

2.8. Fatigue Analysis and Monitoring Program

The 2017 fatigue analysis incorporated results from the 2014 Spiral MFL and 2015 TFI tool runs and was effective at monitoring the potential of fatigue cracking failures from pressure-cycle-induced growth. From the data obtained during the 2014 Spiral MFL and 2015 TFI tool runs, the shortest time to reassessment is calculated to be 2022. The analysis for this program is covered under Section 6.1 of this report.

2.9. Scenario-Based Risk Mitigation Analysis

The objective of Magellan's Scenario-Based Risk Mitigation Analysis (SBRMA) program is to identify preventive measures and/or modifications that can be recommended that would reduce the risks to the environment and the population in the event of a product release.

Magellan's risk model is updated periodically as new information becomes available. Process Hazard Analyses (PHAs) are performed on all new facilities, when changes occur in existing facilities, and on five-year intervals to evaluate and control potential hazards. Three PHAs were completed in 2017, which included the Eckert and Warda Pump Stations, and the mainline valves.

Magellan has set a target for probability of failure at 1×10^{-4}. Where the probability of failure does not meet this threshold, risk reduction measures are recommended. The analyses conducted during 2017 did not result in any scenarios above this threshold.

2.10. Incorrect Operations Mitigation

The objective of the Incorrect Operations Mitigation Program is to identify and subsequently reduce the likelihood of human errors that could impact the mechanical integrity of the Longhorn Pipeline System. "Incorrect Operations" is described as incorrect operation or maintenance procedures, or a failure of pipeline operator personnel to correctly follow procedures.

Ten of the incidents in 2017 involved human error/incorrect operations. Cases of incorrect operations have been formally documented and investigated and corrective actions have been implemented.

2.11. Management of Change Program

Magellan has established an effective program to manage changes to process chemical, technology, equipment, procedures, and facilities across the Longhorn Pipeline System.

The Longhorn Mitigation Plan requires that all changes on the Longhorn system be evaluated using an appropriate PHA.

The Magellan Management of Change Recommendation (MOCR) form is used to document whether a PHA is required and Magellan's procedures provide that the Asset Integrity Engineer should determine the appropriate PHA methodology for change requests. PHAs were conducted for the Eckert and Warda pump stations and the mainline valves; however, these were conducted based on the required five-year interval, not based on modifications.

2.12. System Integrity Plan Scorecarding and Performance Metrics Plan

Magellan has implemented an effective method for evaluating the effectiveness of the LPSIP on an annual basis using performance measures (or scorecarding) 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 technical assessment of the LPSIP indicated 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 ROW markers and signs were repaired or replaced where necessary. From the standpoint of metal loss deterioration measures, there were no metal loss features that met POE dig requirements from the 2016 ILI runs. In terms of failure measures, there were three DOT-reportable incidents, one third-party contact with the pipeline (minor incident, no release), and eight near-miss events. Specific details are presented in Section 6 of this report.

3. Intervention Measures and Timing

3.1. Pressure-Cycle-Induced Fatigue

For the threat of pressure-cycle-induced fatigue, a reassessment in the year 2022 was calculated as the segment with the shortest time to failure based on the pressure cycles since the most recent TFI tool run for each segment. The next assessments are as follows:

- 9th Street Junction to East Houston (MP 10.83 to MP 2.35): 11-Jul-2174
- East Houston to Satsuma (MP 2.35 to MP 34.1):01-Apr-2035
- Satsuma to Buckhorn (MP 34.1 to MP 68.0): 01-Mar-2034
- Buckhorn to Warda (MP 68.0 to MP 112.9): 23-Nov-2027
- Warda to Bastrop (MP 112.9 to MP 181.6): 05-Apr-2024
- Bastrop to Cedar Valley (MP 141.8 to MP 181.6): 09-Feb-2040
- Cedar Valley to Eckert (MP 181.6 to MP 227.9): 09-Aug-2034
- Eckert to James River (MP 227.9 to MP 260.2): 27-Jun-2025
- James River to Kimble County (MP 260.2 to MP 295.2): 28-Aug-2030
- Kimble County to Cartman (MP 295.2 to MP 344.3): 20-Oct-2023
- Cartman to Barnhart (MP 344.3 to MP 373.4): 22-Apr-2045
- Barnhart to Texon (MP 373.4 to MP 416.6): 11-Dec-2022
- Texon to Crane (MP 416.6 to MP 457.5): 14-Oct-2027
- Crane to El Paso (MP 457.5 to MP 694.4): 22-Mar-2109

3.2. Corrosion

The threat of corrosion can be monitored using ILI assessments. An ILI reassessment schedule can be found in Section 7, Table 19 for the Longhorn Crude system and in Table 20 for the Longhorn refined system. The next crude system assessment for corrosion is in 2019 from Satsuma through 9th Street Junction. The next refined system assessment for corrosion is due in 2018 for the Crane to Cottonwood segment.

3.3. Laminations and Hydrogen Blisters

Laminations can occur as a result of oxides or other impurities trapped in the material. As the material cools in the manufacturing process, a small pocket may form internally in the steel plate or billet. A lamination can eventually lead to failure when it is oriented such that it eventually grows to the inner or outer wall of the pipe or pipeline component through pressure cycles. Laminations that are parallel to the surface of the pipe wall generally do not pose an integrity concern unless the formation of a blister occurs. Crude oil may contain hydrogen sulfide which can lead to the formation of hydrogen through anaerobic internal corrosion. Laminations in the pipe wall can trap hydrogen from the corrosion reaction and generate blisters. Elevated CP can also lead to hydrogen migration and hydrogen blistering. Managing internal corrosion and monitoring CP levels will help mitigate these threats.

ID reductions identified from the 2017 electronic geometry pig (EGP) assessments were correlated with the reported laminations from the 2009/2010 UT assessments. Two reported ID reductions from the 2017 assessments were found to correlate with laminations from the 2009/2010 UT assessments. One correlation was on the Warda to Buckhorn segment and is noted as having been previously repaired with a sleeve; the other correlation was on the Satsuma to East Houston segment. Eight joints were found to have both a reported ID reduction from the 2017 EGP assessment and reported lamination or multiple laminations from the 2009/2010 UT assessments. Two of these joints have been previously repaired; one on the Warda to Buckhorn segment and one on the Satsuma to E. Houston Segment. The remaining six joints breakdown as follows: two on Warda to Buckhorn, one on Buckhorn to Satsuma, and three on Satsuma to E. Houston.

Per the Longhorn EA Section 9.3.2.3, the monitoring frequency recommended should coincide with the EGP tool assessment schedule. Section 9.3.2.3 requires an EGP assessment every three years in accordance with the LMP. A reassessment schedule for EGP assessments can be found in Section 7, Table 19 for the Longhorn Crude System and Table 20 for the Longhorn Refined System. The next crude system EGP assessment is in 2018 for Crane to Warda. The next refined system EGP assessment is in 2018 for the 18-inch Crane to Cottonwood segment.

3.4. Earth Movement, Water Forces, and Blasting

3.4.1 Earth Movement

Semi-annual fault measurements have been conducted at the seven fault monitoring sites from the inception of the ORA in mid-2004[5] through December 2017.

The fault movement analysis used conservative assumptions to set the acceptance limits of the fault movement. The earth movement analysis shows that the cumulative fault movements since the installation of the pipeline are currently acceptable at six sites. At the Hockley Fault

[5] The monitoring started in mid-2012 for three faults crossed by the 2012 constructed pipeline connecting the existing Longhorn line to East Houston.

the accumulative movement is approaching the acceptance limit. Two potential paths for remediation include:

- Excavate and expose the pipeline segment including three joints at each side of the fault within five years. From the distribution of longitudinal stress provided in the 2014 ORA, the recommended excavation length is enough to release the majority of accumulated longitudinal stress. The pipe will then be restored to a state free of stress caused by fault movement. The pipe can resist an additional 1.25 inches of fault movement before the next excavation. It is also recommended that the quality of the girth welds in the exposed segment be examined at this time.
- If no dig is scheduled in the near future, a literature review could be conducted to determine the fault movement history at the location since the installation of the pipeline.

The monitoring of at the fault sites should continue.

3.4.2 Water Forces

Magellan conducts annual waterway inspections to survey the depth of cover of the pipeline at five water crossings (Colorado River, Pin Oak Creek, Cypress Creek, Greens Bayou, and Brazos River). The surveys found shallow cover at the Pin Oak Creek Crossing and an exposed segment at the Cypress Creek crossing. Magellan first recorded this exposure in 2003 and recoated the 23-foot segment in 2005. Further remediation may be considered if necessary. Examples of the practice include installing the pipeline deeper through horizontal directional drilling (HDD) or placing a concrete mat at the river bottom to prevent scouring.

3.5. Third-Party Damage

For the threat of TPD, Magellan should continue with the current prevention and inspection activities. Prevention activities include ROW surveillance, One-Call System, and public-awareness activities that continued to be successful in 2017. Inspection activities include ILI assessments required per the ORA using "Smart Geometry" tools (EGP) and high resolution MFL or UT tools. LMC 12A requires ILI assessments for TPD detection between Valve J-1 and Crane Station be carried out within three years of a previous inspection. (Note that the 2-mile section from Valve J-1 to MP 9 is no longer in use). EGP inspection tools were run in 2017 on three pipeline segments from Warda to E. Houston. For specific inspection dates to fulfill the requirement for each of the 12 intervals spanning the Existing Pipeline from East Houston to Crane see Section 7, Table 19 on Integration of Intervention Requirements.

3.6. Stress-Corrosion Cracking

SCC is a form of environmental attack of the pipe steel involving an interaction of a local corrosive environment and tensile stresses in the metal resulting in formation and growth of cracks. SCC has not been identified as a threat to the Longhorn Pipeline, but was added since SCC has been an unexpected problem for some pipelines. Since no evidence of SCC has been detected, it is not necessary to recommend an intervention measure. Magellan will continue to monitor for this threat through their current method, which consists of looking for evidence of SCC when maintenance excavations are performed as described in Section 5.6.

3.7. Threats to Facilities Other than Line Pipe

The Longhorn facilities maintenance program represents a thorough and comprehensive means of facility inspection and preventive maintenance.

The LMP requires that all changes on the Longhorn system be evaluated using an appropriate PHA methodology (Hazard and Operability (HAZOP), What-if Analysis). PHAs are also conducted on a five-year interval to evaluate and control the hazards associated with the Longhorn facilities. Three PHAs were completed in 2017, which included the Eckert and Warda Pump Stations, and the mainline valves.

During 2017, 11 of the 24 incidents occurred at Longhorn facilities, two of which were DOT-reportable. Nine were minor incidents and two were significant.

From the standpoint of facility data acquired for 2017, one can conclude that the facilities had no adverse impact on public safety. Kiefner recommends that Magellan continue its detailed documentation of incidents, facility integrity processes, and reporting of the facility preventive maintenance program.

4. IMPLEMENTATION OF NEW MECHANICAL INTEGRITY TECHNOLOGIES

4.1. Positive Material Identification

During 2013, T. D. Williamson (TDW) 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 TDW 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 Kiefner on 11 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 TDW.

When material documentation is not available, Magellan has committed to conducting non-destructive or destructive strength tests for 50% of all annual pipe excavations associated with ILI anomaly evaluations or remediation.[6] In 2017, Magellan met the requirement by performing material testing on 42 of the 64 segments that did not have material documentation available.

4.2. Multiple Dataset Platform

The TDW Multiple Dataset Platform that was utilized in 2017 incorporates the following technologies: the SpirALL magnetic flux leakage, magnetic flux leakage, low field magnetic flux leakage, deformation and XYZ navigation. The use of this type of ILI tool allowed for multiple assessment types to be performed on a single inspection allowing for improved data alignment and detection of multiple, including interacting, threat types in one pass. The modules can detect the following threats: axial and circumferential metal loss, deformations with various types of metal loss, and metal loss crossing a long seam. This technology is still being evaluated by Magellan and is being tested and validated. As this technology develops it will be used as available on selected segments of the pipeline system.

5. RESULTS AND DISCUSSION OF DATA ANALYSIS

This section presents an analysis of the data collected in Appendix B for the ongoing integrity threats monitored by the LMP: pressure-cycle-induced fatigue cracking, corrosion, pipe laminations and hydrogen blisters, earth movement, TPD, SCC, and threats to facilities other than line pipe.

In 2017, ILI assessments were performed using TDW's Multi-dataset tool (SMFL, MFL, RES, and Deformation) on three of the refined product El Paso laterals: 8-inch El Paso to Chevron, 8-inch Kinder Morgan Flush Line, and 12-inch El Paso to Kinder Morgan. One MFL assessment was performed on the refined product Cottonwood to El Paso segment. EGP assessments were run on three segments in July 2017 between the Warda (MP 112.9) and E. Houston (MP 2.35) pump stations. Refer to Table 3 for a list of ILI assessments performed in 2017 by pipeline segment.

[6] Per Section 9.3.3.3.1 of the Environmental Assessment for the Longhorn Pipeline Reversal, 2012

5.1. Pressure-Cycle-Induced Fatigue Cracking

Pressure-cycle-induced fatigue-crack-growth of flaws is recognized to be a potential threat to the integrity of the Longhorn Pipeline. Manufacturing flaws in or immediately adjacent to the longitudinal electric resistance welded (ERW) or electric flash welded (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 flaw 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 flaws 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, East Houston to Speed Junction, Crane to El Paso, and piping added for the 2012 and 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 and Spiral MFL tool runs from East Houston Station to Crane completed in 2014 and 2015.

The failure pressure of each potential flaw 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 have 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 flaw size. In this case, toughness is a factor for establishing starting flaw sizes and it is more conservative to use a higher value of toughness as it allows for a larger flaw to remain after the hydrostatic test.

Note that toughness is not a factor in establishing either starting defect size using the ILI detection threshold or the N10 notch (the basis for an initial flaw size from API 5L[7]).

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[7] API Specification 5L, Forty-fifth Edition, Includes Errata, 2015

Toughness is needed to calculate the size of the flaw 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 flaws. With a longer flaw, it would be expected that using a value of 15 ft-lbs instead of 25 ft-lbs would decrease the fatigue life. Based on this information, a value of 15 ft-lbs was used in the calculations.

To conduct a pressure-cycle analysis for the Longhorn Pipeline, the well-known and widely accepted "Paris Law" model was used, 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, 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[8] were used. 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]).

Pressure-cycle data are provided to Kiefner by Magellan. A systematic cycle-counting procedure called "rainflow counting" to pair maximum and minimum pressures was used. The rainflow-counted cycles are used in the Paris-Law model to grow a potential crack. For a given set of cycles, the number of such cycles and the length of time that it will take for the fastest growing flaw to reach a size that will fail at the maximum operating pressure of the pipeline can be predicted. Kiefner will notify Magellan of the calculated date of failure, apply a safety factor, and in accordance with the LMP, Magellan will complete reassessment of the integrity of the pipeline as required.

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 outside diameter (OD), 0.312-inch wall thickness (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. All sized seam weld features found during the 2014 and 2015 TFI tool runs were remediated prior to 2017.Pursuant to the procedure in Section 3.4 of the ORA Process Manual, the detection threshold capabilities of the TFI tool were used to calculate an appropriate reassessment for anomalies that have not been detected by the TFI tool. The TFI tool can detect seam weld features with a depth of 50% of

[8] API RP 579-1/ASME FFS-1, Fitness-For-Service, Third Edition, 6/1/2016

the wall thickness for features between one and two inches in length and a minimum depth of 25% of the wall thickness for features greater than two inches in length.

Based on these detection capabilities, the analysis assumes that a 50% through wall, 2-inch long crack-like feature could have been missed. The 50% through wall flaw has a shorter life than a 25% through wall flaw. In the Existing Pipe, it was assumed the flaw could have been missed in a location that will provide the most conservative reassessment interval. The pipe located closest to the discharge of a pump or right at a wall thickness or pipe grade transition was chosen 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 flaws detected by the TFI tool, a starting flaw size that is the largest flaw that could have escaped detection in the manufacturer's ultrasonic seam inspection was used. That would be the size of the "calibration" flaw used to test the ultrasonic seam inspection detection threshold. That size comes from API Specification 5L and it is assumed by Kiefner to be the largest of the acceptable calibration flaws in that standard, namely, the N10 notch. The N10 notch has an axial length of two inches, and a depth of 10% of the nominal wall thickness of the pipe. This is used as the starting flaw size in the 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 2017. The analysis was completed using the pressure data available from the most recent TFI or Spiral MFL inspection to December 2017.

The analysis showed that the shortest time to failure for a possible feature that could have been missed by the 2015 TFI tool run is 16.3 years (from August 11, 2015) at the location that is now the Texon Station Discharge. The recommended reassessment interval is calculated by taking 45% of the shortest fatigue life, which corresponds to a factor of safety of 2.22 (1/0.45). Applying this factor of safety, a reassessment interval of 7.3 years (from August 11, 2015) is recommended based on the current operating pressures. An assessment would be required in 2022 for the Texon to Barnhart segment. Therefore, the detection threshold anomalies determine the appropriate reassessment intervals. Assessments for the other segments would be required between 2023 and 2174, as stated in Section 3.1. The pressure cycling frequency decreased in 2017 for the East Houston to Satsuma, Buckhorn to Warda segments and all the pipe from Cedar Valley to Crane compared to 2016. The Satsuma to Buckhorn, Warda to Bastrop, and Bastrop to Cedar Valley segments had increased pressure cycling frequency in

2017 compared to 2016. Figure 5 displays the pressure cycles at the Texon Station discharge during 2017. Figure 6 displays the pressure cycles at the Texon Station discharge during 2016.

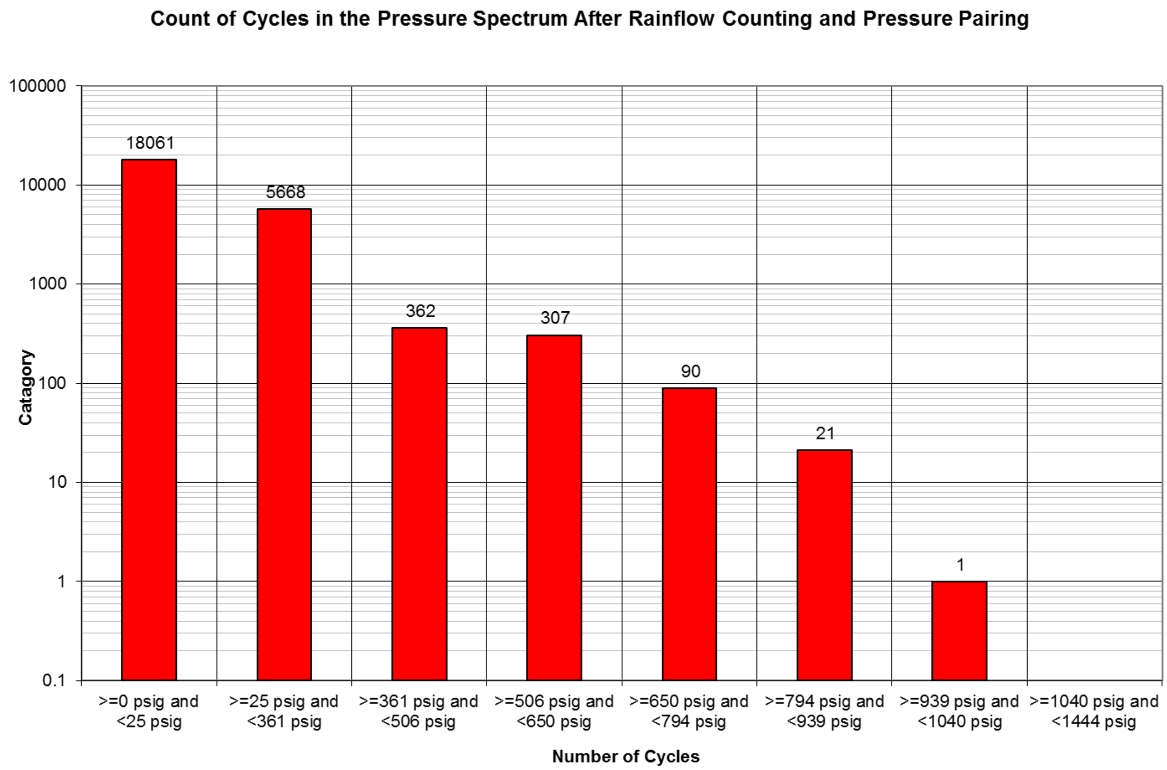


Figure 5. Pressure Cycles at Texon Station in 2017

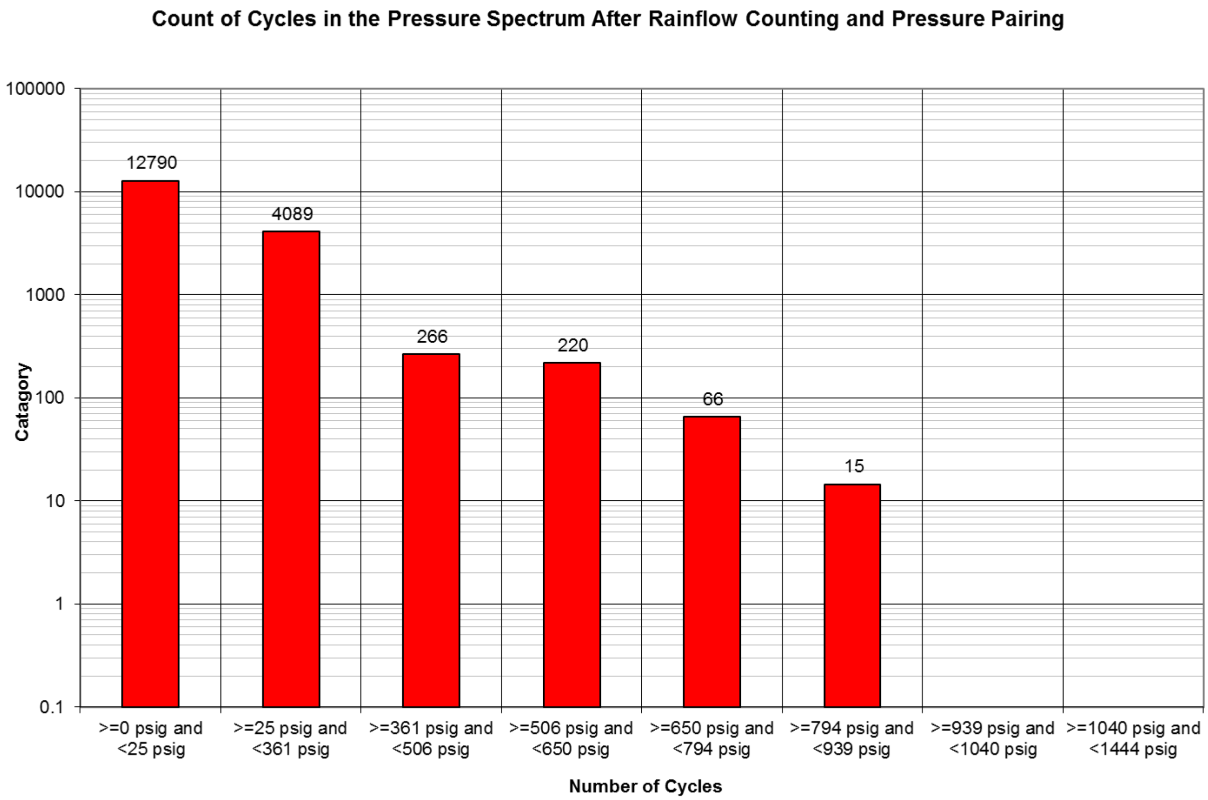


Figure 6. Pressure Cycles at Texon Station in 2016

Table 4 summarizes the locations evaluated. For the pipe between Crane Station and El Paso Station, 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. The November 1, 2013 through December 31, 2017 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. For the pipe between the East Houston Station and Crane Station, the pressure data recorded after each segment's TFI ILI data were used in the analysis. For the pipe between East Houston Station and Speed Junction, the pressure data recorded after the line reversal was used in the analysis. The factor of safety should be applied to these fatigue lives to determine the reassessment interval. As the Crane to El Paso products and East Houston to Speed Junction crude segments of the line operate separately from the Crane to East Houston segment, results for these segments may be considered separately.

A fatigue life was calculated for the new 1998 pipe at Crane Station on the products line and on 1998 pipe in the East Houston to Speed Junction segment based on the maximum flaw size, described above as an API 5L N10 notch, a 10%, 2-inch-long flaw. The analysis showed that the shortest time to failure for the Crane to El Paso segment is 211.9 years. This would result in a reassessment interval of a minimum of 95.5 years. This reassessment interval decreased by 58% due to increased severity of pressure cycling in this segment. The shortest time to failure for the East Houston to Speed Junction segment is 357.0 years. This would result in a reassessment interval of a minimum of 160.8 years. This reassessment interval decreased 15% compared to the 2016 ORA due to increased severity of pressure cycling in this segment. Comparisons of reassessment intervals from all segments between 2015 and 2017 are shown in Table 6.

Table 5 depicts the fatigue life for each of the locations analyzed. 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% deep and 2-inches long, and no feature greater than 10% of the wall thickness existing in the new pipe, and the factor of safety of 2.22.

Table 4. Pressure-Cycle-Induced Fatigue Cracking Analysis Locations

Case	Description	Seam Type	Manufacturer	Station	Mile Post	Diameter, inches	Wall Thickness, inch	Pipe Grade
1	1998 in East Houston to Speed Junction	ERW-HF	U.S. STEEL	187+87	3.6	20	0.312	X52
2	1947 Pipe near Satsuma Discharge	ERW-LF	UNKNOWN	1799+54	34.1	20	0.312	Grade B
3	1950 Pipe near Buckhorn Discharge	EFW	A.O. SMITH	3587+73	67.9	18	0.281	45,000 SMYS
4	1950 Pipe near Warda Discharge	EFW	A.O. SMITH	5960+75	112.9	18	0.281	45,000 SMYS
5	1950 Pipe near Bastrop Discharge	EFW	A.O. SMITH	7487+53	141.8	18	0.281	45,000 SMYS
6	1947 Pipe at Cedar Valley Discharge	EFW	A.O. SMITH	8963+66	169.8	18	0.281	45,000 SMYS
7	1950 Pipe near Eckert Discharge	EFW	A.O. SMITH	12032+98	227.9	18	0.281	45,000 SMYS
8	1950 Pipe near James River Discharge	EFW	A.O. SMITH	13736+94	260.2	18	0.281	45,000 SMYS
9	1950 Pipe near Kimble Discharge	EFW	A.O. SMITH	15585+45	295.2	18	0.281	45,000 SMYS
10	1950 Pipe near Cartman Discharge	EFW	A.O. SMITH	18212+02	344.9	18	0.281	45,000 SMYS
11	1950 Pipe near Barnhart Discharge	EFW	A.O. SMITH	19354+32	366.6	18	0.312	45,000 SMYS
12	1953 Pipe near Texon Discharge	EFW	A.O. SMITH	21998+56	416.6	18	0.25	X52
13	1953 Pipe near Crane Crude Discharge	EFW	A.O. SMITH	24060+69	455.7	18	0.25	X52
14	1998 Pipe near Crane Products Discharge	ERW-HF	U.S. STEEL	24160+18	457.6	18	0.281	X65

Table 5. Fatigue Lives and Reassessment Intervals for Analysis Locations

Case	Cycles per Year	Date of Previous Assessment	Calculated Time to Failure from reversal date or 2014, 2015 TFI run date, years	Reassessment Interval, years	Reassessment Year
1	977	N/A	357.0	160.8	2174
2	3,458	10/1/2014	45.5	20.5	2035
3	2,067	12/18/2015	40.4	18.2	2034
4	2,047	12/16/2015	26.5	11.9	2027
5	2,322	12/11/2015	18.5	8.3	2024
6	1,901	9/19/2007	53.7	24.2	2040
7	1,879	3/22/2007	41.5	18.7	2034
8	3,292	8/19/2015	21.9	9.9	2025
9	2,851	9/1/2015	33.3	15.0	2030
10	3,025	8/28/2015	18.1	8.2	2023
11	2,482	8/24/2015	65.9	29.7	2045
12	2,698	8/11/2015	16.3	7.3	2022
13	2,507	7/17/2015	27.2	12.3	2027
14	533	N/A	211.9	95.5	2109

Table 6. Comparison of Reassessment Dates from Past ORAs

Segment	2015 Report	2016 Report	2017 Report
9th Street Junction to East Houston (MP 10.83 to MP 2.35)	5/15/2214	8/23/2202	7/11/2174
East Houston to Satsuma (MP 2.35 to MP 34.1)	9/14/2027	11/14/2032	4/1/2035
Satsuma to Buckhorn (MP 34.1 to MP 68.0)	6/15/2028	1/31/2039	3/1/2034
Buckhorn to Warda (MP 68.0 to MP 112.9)	12/27/2020	10/23/2027	11/23/2027
Warda to Bastrop (MP 112.9 to MP 181.6)	6/16/2020	4/7/2025	4/5/2024
Bastrop to Cedar Valley (MP 141.8 to MP 181.6)	3/6/2039	8/13/2046	2/9/2040
Cedar Valley to Eckert (MP 181.6 to MP 227.9)	8/1/2023	9/30/2033	8/9/2034
Eckert to James River (MP 227.9 to MP 260.2)	7/9/2027	11/5/2023	6/27/2025
James River to Kimble County (MP 260.2 to MP 295.2)	9/25/2034	9/11/2027	8/28/2030
Kimble County to Cartman (MP 295.2 to MP 344.3)	11/23/2024	3/29/2022	10/20/2023
Cartman to Barnhart (MP 344.3 to MP 373.4)	12/16/2053	1/17/2040	4/22/2045
Barnhart to Texon (MP 373.4 to MP 416.6)	9/9/2024	7/23/2021	12/11/2022
Texon to Crane (MP 416.6 to MP 457.5)	4/24/2023	4/13/2022	10/14/2027
Crane to El Paso (MP 457.5 to MP 694.4)	11/29/2238	11/29/2238	3/22/2109

5.2. Corrosion

5.2.1. Metal Loss Features

ILI assessments 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. This method is a valid approach for addressing line pipe corrosion.

In 2017, ILI assessments were completed between Cottonwood to El Paso and on three El Paso laterals; 8-inch El Paso to Chevron, 8-inch Kinder Morgan Flush Line, and 12-inch El Paso to Kinder Morgan. Table 3 lists, by pipeline segment, the 2017 ILI assessments; mile posts are noted under each pipeline segment.

A run-to-run comparison was performed on all three El Paso laterals for metal loss (ML) features reported by the previous (2012, 2014) and current (2017) MFL assessments. The 2017 ILI assessments reported a total of 102 metal loss features combined on the three El Paso laterals: 62 ML features on the 8-inch El Paso to Chevron segment, 19 ML features on the 8-inch El Paso to Kinder Morgan segment, and 21 ML features on the 12-inch El Paso to Kinder Morgan segment. The run-to-run comparison of all three El Paso laterals resulted in 11 total data matches (three external ML and eight internal ML) combined. There are not enough data points (11 matches), to support corrosion growth rate (CGRs) calculations for the three line segments. Note: the ML feature counts between the 2012 and 2017 MFL assessments were on the same order of magnitude; reported metal loss depths were <25% Wt. Data correlation and calculations were done using Kiefner's CorroSure software.

5.2.2. ID Reductions

Magellan runs "Smart Geometry" tools (EGPs) to assess the threat of TPD and to monitor for possible hydrogen blistering. The ORA classifies ID reductions as a deformation of pipe diameter detected by the ILI tool. If an ID reduction is greater than or equal to 2% of the pipe diameter the ID reduction is referred to as a dent. If an ID reduction is less than 2% of the pipe diameter the ID reduction is referred to as a geometric anomaly.

The 2017 EGP assessments reported 150 ID reductions, 16 are noted as being previously repaired. Of the remaining 134 ID reductions, two are classified as dents and 132 are classified as geometric anomalies. The two dents are located on the bottom 1/3 of the pipe with depths of 2.0 and 2.7% OD. They are located on the E. Houston to Satsuma and the Satsuma to Buckhorn segments.

Two geometric anomalies were reported as interacting with either a seam or a girth weld. The geometric anomaly on the Warda to Buckhorn segment is reported as affecting the girth weld; the feature is located on a pipe joint installed in 1950 with an ERW seam weld. The geometric anomaly on the 12-inch El Paso to Kinder Morgan lateral is reported as crossing the long seam; the feature is located on a pipe joint installed in 2002 with an ERW seam weld. The 12-inch El Paso to Kinder Morgan pipeline listing noted the geometric anomaly feature crossing the long seam as re-rounded; the re-rounding was reported by TDW's multi-dataset tool. No dents were reported as interacting with metal loss anomalies.

The Longhorn Pipeline System travels through a number of HCAs from Warda to East Houston and in the El Paso area. As shown in Table 7, 76 of the reported ID reductions are located within HCAs; however, these ID reductions do not meet regulatory repair criteria (equal to or greater than 2% OD and interacts with a long seam or girth weld, or on the bottom of the pipe and with a depth greater than 6% OD).

Table 7. ID Reductions Located within HCAs [9]

Segment	Within HCA		
	Quantity	**Peak Depth (% OD)**	**Comment**
Satsuma to E. Houston	42	2.7	• 3 dents and 4 geometric anomalies are noted as repaired • One dent with a depth of 2.7% OD located on bottom 1/3 of pipe (has not been repaired) • 24 geometric anomalies located on top 2/3 of pipe • 10 geometric anomalies located on bottom 1/3 of pipe
Buckhorn to Satsuma	13	2.2	• 2 dents noted as repaired • Six geometric anomalies located on top 2/3 of pipe • Five geometric anomalies located on bottom 1/3 of pipe
Warda to Buckhorn	17	1.8	• Six geometric anomalies located on top 2/3 of pipe • 11 geometric anomalies located on bottom 1/3 of pipe; one noted as repaired
8-in El Paso to Chevron	2	1.3	• Two geometric anomalies located on top 2/3 of pipe
8-in Kinder Morgan Flush Line	1	1.0	• One geometric anomaly located on the bottom 1/3 of pipe
12-in El Paso to Kinder Morgan	1	0.5	• One geometric anomaly located on top 2/3 of pipe
Total	**76**		

5.2.3. Tool Performance and In-ditch Investigations

The ILI assessments were evaluated using the ILI verification standard API 1163 2nd Edition, April 2013. Sections 7 and 8 of this standard describe methods that can be applied to verify that the ILI tool was performing as expected and reported inspection results are within the performance specification for the pipeline being inspected. The standard defines results with and without field verification measurements. API 1163 Section 7 provides information on what the ILI vendor is to provide regarding pre-, mid-, and post-inspection checks for tool runs. API 1163 Section 8 describes a process for validating ILI measurements using three levels of validation.

The validation levels differ based on the risk of the pipeline segment and the amount of validation data. Validation Levels 1, 2, and 3 could be described as a good, better, or best analysis approach. A Level 1 validation just looks at how the tool ran during the assessment;

[9] ID reductions are classified as either dents or geometric anomalies. A dent is an ID reduction greater than or equal to 2% OD and a geometric anomaly is an ID reduction less than 2% OD.

no statistical analysis is performed. A Level 2 validation builds on Level 1 by adding validation measurements: greater than or equal to five, but not statistically significant. Level 2 validations can be used to reject an ILI tool assessment. A Level 3 validation builds on the Level 1 and adds a statistically significant number of validation measurements which allows an as-run tool performance to be confidently stated.

The three levels of validation all consist of the following steps:

- A process verification or quality control Level 1 (§8.2.2 and Annex C.1)
- Comparison with historic data for the pipeline being inspected (§8.2.3)
- Comparison analysis of pipeline component records (§8.2.4)

<u>Validation Level 1 (Annex C)</u>

- A comparison with large-scale historic data for pipeline segments similar to the pipeline being inspected (§8.2.3)

Validation Level 1 only applies to pipelines with anomaly populations that present a lower risk of consequence or probability of failure. Typically there is only a limited number or no validation measurements taken on the pipeline being inspected. A Level 1 validation assumes the ILI specified tool performance is neither proven nor disputed for the ILI run. This assumption means the validity of the ILI run cannot be rejected solely based on a Level 1 validation. A Level 2 or Level 3 validation is required before an ILI run can be rejected.

<u>Validation Level 2 (Annex C)</u>

- A comparison with field excavation results warranted by the reporting of significant indications (§8.2.6)

Validation Level 2 applies to pipelines with a lower risk of consequence or probability of failure that have indications of significance reported by ILI. Typically there are enough validation measurements taken on the pipeline being inspected to confidently state whether the ILI tool is performing worse than the ILI specification and possibly reject the ILI run. However, a Level 2 validation does not let one confidently state that the ILI tool is performing within ILI specification. The number of validation measurements will be greater than or equal to five, but not statistically significant with which to perform a Level 3 validation. If the ILI tool specification can be rejected, then there is the option to progress to a Level 3 validation which may require additional validation measurements.

Validation Level 3 (Annex C)

- A comparison with field excavation results warranted by the reporting of significant indications (§8.2.3)

Validation Level 3 applies to pipelines with a higher risk of consequence or probability of failure that have indications of significance reported by ILI. Typically there are a statistically significant number of validation measurements taken on the pipeline being inspected to confidently state an as-run tool performance.

Depending on the analysis of the data using the API 1163 decision chart process, the tool performance can be rejected, accepted, or non-conclusive. If tool performance is determined to be non-conclusive it does not mean the inspection failed. Instead an additional course of action may be required.

For each assessment listed in Table 3, process verification and quality control was reviewed. The general results for all of the 2017 ILI assessments were that the functionality of the ILI inspection tools was determined to be within normal standard operating conditions and the locating of reference points by the ILI tool was determined to be consistent over the entirety of the ILI assessment. One item to note from the ILI assessment reports:

- TDW reports the EGP tool stopped during the ILI assessment on the Warda to Buckhorn segment. TDW's final report states the tool stopped and backed up; this backup caused additional footage to be recorded on Joint 25860 at 99349.0 ft absolute distance.

In 2017, Magellan performed 135 in-ditch assessments; 73 of the assessments were ILI anomaly investigations which correspond to current ILI assessments (2012 and 2014 MFL and 2015/2016 TFI). The 2012 Longhorn Pipeline Reversal EA (Reference [6]) Magellan requires Positive Material Identification (PMI) tests to be completed at 50% of the ILI anomaly investigation locations that do not have material documentation. In 2017; 64 of the 73 ILI anomaly investigations met the PMI requirement, Magellan performed PMI testing at 42 of the 64 anomaly investigation locations (65%) which satisfies PMI requirements. Table 8 contains the breakdown of ILI anomaly investigation digs and material identification tests that were performed in 2017 by pipeline segment. Table 9 gives an overview of PMI testing since the requirement to perform PMI testing was added. An overview of the ILI anomaly investigation dig results can be found in Table 10 for metal loss features, Table 11 for girth and seam weld features, and Table 12 for ID reduction features.

Table 8. Summary of ILI Investigations in 2017

Pipeline Segment	Number of ILI Investigation Digs	Number of Material Identification Tests
8-in El Paso to Chevron	0	0
8-in Crane to Odessa	0	0
12-in El Paso to Kinder Morgan	0	0
18-in Cottonwood to El Paso	0	0
18-in Crane to Cottonwood	0	0
18-in Crane to Texon	0	0
18-in Texon to Barnhart	3	3
18-in Barnhart to Cartman	0	0
18-in Cartman to Kimble County	0	0
18-in Kimble County to James River	0	0
18-in James River to Eckert	0	0
18-in Eckert to Cedar Valley	7	7
18-in Cedar Valley to Bastrop	7	6
18-in Bastrop to Warda	9	4
18-in Warda to Buckhorn	18	14
18-in Buckhorn to Satsuma	15	8
20-in Satsuma to E. Houston	5	0
20-in E. Houston to 9th Street Junction	0	0
Total	**64**	**42**

Table 9. Positive Material Identification Testing Activity

Pipeline Segment	2014	2015	2016	2017
18-in Crane to Texon	0	1	7	0
18-in Texon to Barnhart	0	0	8	3
18-in Barnhart to Cartman	0	0	11	0
18-in Cartman to Kimble County	0	0	12	0
18-in Kimble County to James River	0	0	5	0
18-in James River to Eckert	0	1	3	0
18-in Eckert to Cedar Valley	1	0	6	7
18-in Cedar Valley to Bastrop	0	0	20	6
18-in Bastrop to Warda	0	1	3	4
18-in Warda to Buckhorn	0	2	0	14
18-in Buckhorn to Satsuma	0	0	0	8
20-in Satsuma to E. Houston	0	4	0	0
20-in E. Houston to 9th Street Junction	0	0	0	0
Total PMI Tests Performed	**1**	**9**	**75**	**42**
Segments without available Material Documentation	**2**	**18**	**141**	**64**
Percentage Addressed (Requirement of 50%)	**50%**	**50%**	**53%**	**65%**

Table 10. Overview of 2017 ILI Field Investigation Metal Loss Data Correlations

Pipeline Segment	EXT ML to EXT ML	EXT ML to Lamination	EXT ML to Sloping Lamination	EXT ML to Planar Laminations	EXT ML to Lamination with ID Metal Loss	EXT ML to Mill or Grind Repair	EXT ML to Dent Associated with ML	EXT ML to Gouge	EXT ML to Wall Thickness Variation	INT ML to INT ML	INT ML to OD Inclusion	INT ML to Planar Lamination	INT ML to Sloping Lamination	INT Mill Anomaly to Planar Lamination	INT ML to Wall Thickness Variation	EXT ML to INT ML	INT ML to EXT ML	Total Data Correlations
18-in El Paso to Cottonwood	0	0	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0	**6**
18-in Crane to Texon	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
18-in Texon to Barnhart	0	0	0	0	0	4	0	1	0	0	0	0	0	0	0	0	0	**5**
18-in Barnhart to Cartman	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
18-in Cartman to Kimble County	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
18-in Kimble County to James River	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
18-in James River to Eckert	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
18-in Eckert to Cedar Valley	9	1	6	0	0	0	0	0	0	0	0	0	0	0	0	1	0	**17**
18-in Cedar Valley to Bastrop	0	2	5	0	1	0	0	0	0	0	0	0	0	0	0	0	0	**8**
18-in Bastrop to Warda	5	8	0	0	0	0	0	0	0	0	0	0	0	0	0	4	0	**17**
18-in Warda to Buckhorn	11	0	3	0	0	0	0	0	0	4	0	2	7	1	0	2	1	**31**
18-in Buckhorn to Satsuma	1	3	2	1	0	0	0	2	0	0	1	0	0	0	1	0	0	**11**
18-in Satsuma to E. Houston	0	0	1	0	0	0	0	1	0	2	0	0	0	0	0	2	0	**6**
18-in E. Houston to Speed Jct	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Total	**26**	**14**	**17**	**1**	**1**	**4**	**0**	**4**	**0**	**12**	**1**	**2**	**7**	**1**	**1**	**9**	**1**	**101**

*Note: data correlations are between reported features from most recent ILI assessment; 2014 MFL and 2015/2016 TFI; and the 2017 in-ditch reported findings.

Table 11. Overview of 2017 ILI Field Investigation for Girth and Seam Weld Anomaly Data Correlations

Pipeline Segment	SW Anomaly to SW Anomaly	SW Anomaly to Lack of Fusion	SW Anomaly to Geometry on SW	SW ML to INT ML on SW	SW Anomaly to Thinned Wall Pipe at SW with OD crack-like indication	SW Anomaly to Thinned Wall Pipe at SW	SW Anomaly to Thinned Wall Pipe Area	GW Anomaly to Underfill on GW	GW Anomaly to Weld Geometry	Total Data Correlations
18-in El Paso to Cottonwood	0	0	0	0	0	0	0	0	0	**0**
18-in Crane to Texon	0	0	0	0	0	0	0	0	0	**0**
18-in Texon to Barnhart	0	0	0	0	0	0	0	0	0	**0**
18-in Barnhart to Cartman	0	0	0	0	0	0	0	0	0	**0**
18-in Cartman to Kimble County	0	0	0	0	0	0	0	0	0	**0**
18-in Kimble County to James River	0	0	0	0	0	0	0	0	0	**0**
18-in James River to Eckert	0	0	0	0	0	0	0	0	0	**0**
18-in Eckert to Cedar Valley	0	1	0	0	0	0	0	0	0	**1**
18-in Cedar Valley to Bastrop	0	3	0	0	0	0	0	0	0	**3**
18-in Bastrop to Warda	0	2	0	0	0	0	0	0	0	**2**
18-in Warda to Buckhorn	0	0	0	0	0	0	0	0	0	**0**
18-in Buckhorn to Satsuma	0	0	1	0	2	3	4	2	0	**12**
18-in Satsuma to E. Houston	0	0	0	1	0	0	0	0	2	**3**
18-in E. Houston to Speed Jct	0	0	0	0	0	0	0	0	0	**0**
Total	**0**	**6**	**1**	**1**	**2**	**3**	**4**	**2**	**2**	**21**

*Note: data correlations are between reported features from most recent ILI assessment; 2014 MFL and 2015/2016 TFI; and the 2017 in-ditch reported findings.

Table 12. Overview of 2017 ILI Field Investigation ID Reduction Data Correlations

Pipeline Segment	Dent w/ML to Dent w/ML	Dent to Dent w/ML	Dent w/ML to Dent	Dent to Dent	Dent to Dent w/Gouge	Dent Interacting with SW to Dent w/ML	Dent Interacting with SW to Dent w/Gash	Dent to Dent Affecting SW	Total Data Correlations
8-in Crane to Odessa	0	0	0	0	0	1	1	0	**2**
18-in El Paso to Cottonwood	0	0	2	1	0	0	0	0	**3**
18-in Crane to Texon	0	0	0	0	0	0	0	0	**0**
18-in Texon to Barnhart	0	0	0	0	0	0	0	0	**0**
18-in Barnhart to Cartman	0	0	0	0	0	0	0	0	**0**
18-in Cartman to Kimble County	0	0	0	0	0	0	0	0	**0**
18-in Kimble County to James River	0	0	0	0	0	0	0	0	**0**
18-in James River to Eckert	0	0	0	0	0	0	0	0	**0**
18-in Eckert to Cedar Valley	0	0	0	0	0	0	0	0	**0**
18-in Cedar Valley to Bastrop	0	0	0	0	0	0	0	0	**0**
18-in Bastrop to Warda	0	0	0	0	0	0	0	0	**0**
18-in Warda to Buckhorn	0	2	0	1	0	0	0	0	**3**
18-in Buckhorn to Satsuma	0	0	0	0	0	0	0	0	**0**
18-in Satsuma to E. Houston	0	0	0	0	0	0	0	0	**0**
18-in E. Houston to Speed Jct	0	0	0	0	0	0	0	0	**0**
Total	**0**	**2**	**2**	**2**	**0**	**1**	**1**	**0**	**8**

*Note: data correlations are between reported features from most recent ILI assessment; 2014 MFL and 2015/2016 TFI; and the 2017 in-ditch reported findings.

The TFI tool performance analysis considered results from all assessments from Crane to East Houston. Segments were also looked at individually (i.e. Warda to Buckhorn) and compared to the overall result to see if any segment differed significantly from the whole. If a segment had less than five metal loss data pairs it was not considered for individual tool performance as there was not a statistically significant number of metal loss validation measurements.

The 2014 Multi-dataset and 2015 TFI assessments were correlated with 2017 dig results found in the ILI in-ditch investigation maintenance reports. The ILI investigation digs resulted in 145 individually correlated features. The individually correlated features were interacted to the field results for a total of 121 interacted correlated features. A breakdown of the dig results can be found in the preceding tables, Table 10, Table 11, and Table 12. The correlated data show that features reported by TFI as external metal loss (ML) were identified as corrosion approximately 50% of the time in the field. The remaining were laminations, gouges, or mill defects. Forty-three different laminations were identified during 32 ILI investigation digs. None of these laminations correlated with reported ILI ID reductions.

The 2017 field investigations resulted in 33 external ML to external ML data pairs from Crane to East Houston. Thirty of the 33 external ML to external ML data pairs correlate to the 2015 TFI assessments; the other three data pairs correlate to the 2014 MFL assessments. A review of the TFI external ML to external ML data pairs found 29 out of the 30 correlations were within the ±15% tool performance specification. A review of the MFL external ML to external ML data pairs found two out of the three correlations were within the ±10% tool performance specification.

The 2017 TFI field investigation results were combined with the 2016 TFI field investigation results to determine how the TFI tool performed. The 2016 and 2017 combined field investigations results in 247 external ML data pairs; 238 of the ML data pairs were within the ±15% tool performance specification. Figure 7 shows the in-ditch and ILI data pairs expressed as a unity plot for the TFI data; 2016 data is only shown for pipeline segments that correspond to the 2017 pipeline segments addressed (i.e. Texon to Barnhart). The unity plots shown in Figure 7 indicate that the TFI tool is over calling depth on an average of 4.8% for correctly identified external metal loss features found in 2016 and 2017. Figure 8 shows the in-ditch and ILI data pairs expressed as a unity plot for the MFL data; there is not enough data to determine a trend for the MFL tool.

A statistical analysis was performed to determine the average and standard deviation, and if outliers or extreme values were present. Extreme values have a low probability of occurrence on the order of 10^{-6} or less and should be noted with the reason for the occurrence. These values should be removed from the statistical analysis so that the results are not skewed. Outliers should be individually reviewed to determine the reason for the occurrence and if the data should remain incorporated within the statistical analysis. There were six correlated external ML features that were removed: four due to being reported in the field as internal metal loss interacting with a lamination and two reported in the field evaluations with a general comment of "external metal loss less than 12.5% WT." The statistical analysis results are also shown in Table 13. Note that if the statistical analysis results in a negative value it represents that the ILI tool has under called the features when compared to the in-ditch data.

Figure 9 demonstrates the difference between the ILI predicted and in-ditch depth based on a normal distribution for all correlated external metal loss features. Ideally, a cumulative fraction curve of 0.5 will be 0% WT as shown in ±15% WT for 80% of the data. The cumulative fraction curve for the best fit data shows that the 2016/2017 combined ILI assessment has an overcall of approximately 4.8% WT. The curve indicates that the tool is performing better than specification if bias is accounted for. If the bias is accounted for, the tool is performing better than specification at ±8.0% WT

One recommendation to consider for future in-ditch anomaly investigations came from the review of the 2017 maintenance and NDE reports. This recommendation is to use advanced NDE methodologies that have a high resolution for in-ditch evaluations to help characterize and size anomalies that are within the pipe body.

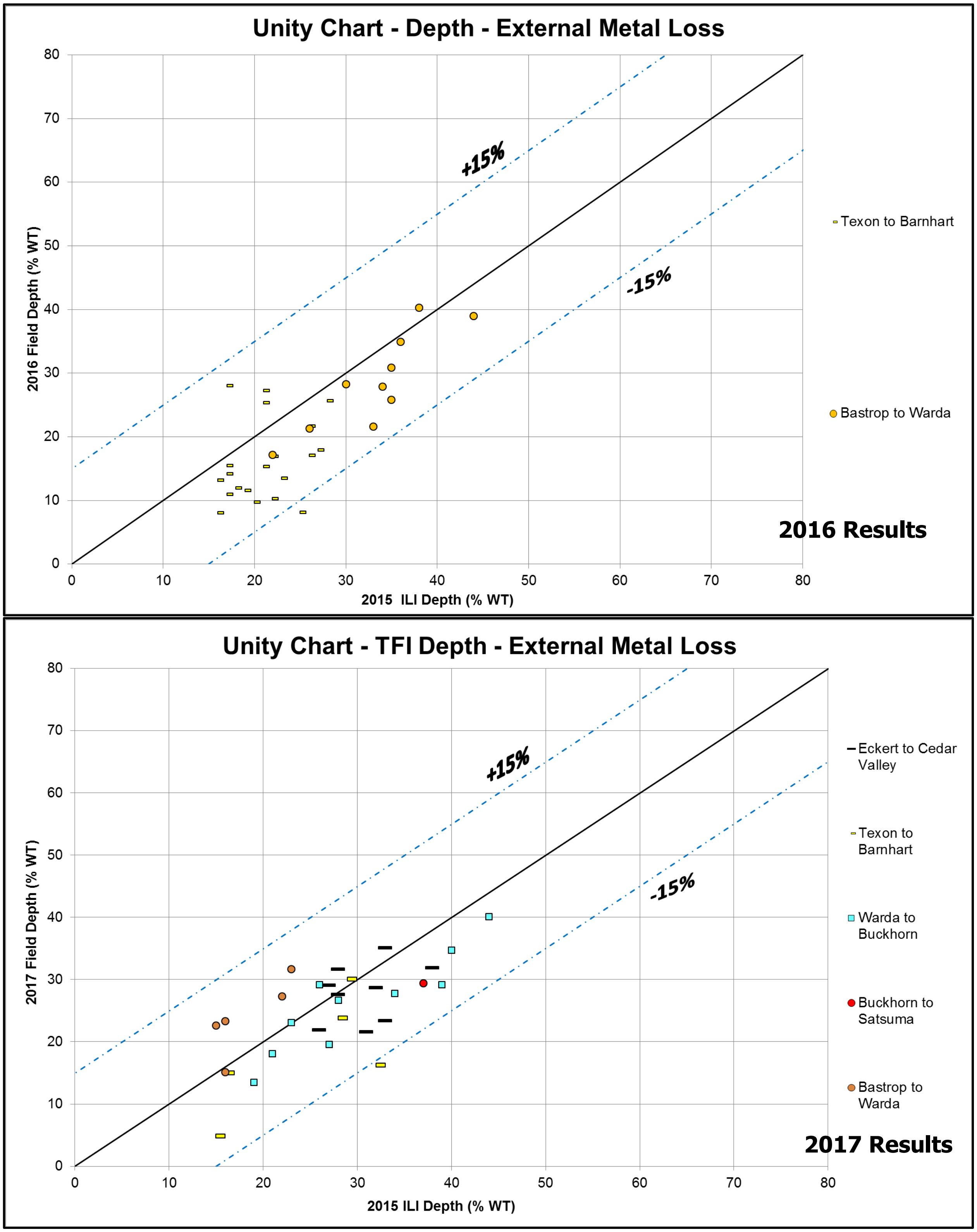


Figure 7. Unity Chart for Depth Verification for TFI External Metal Loss (Upper Bound ±15% WT)

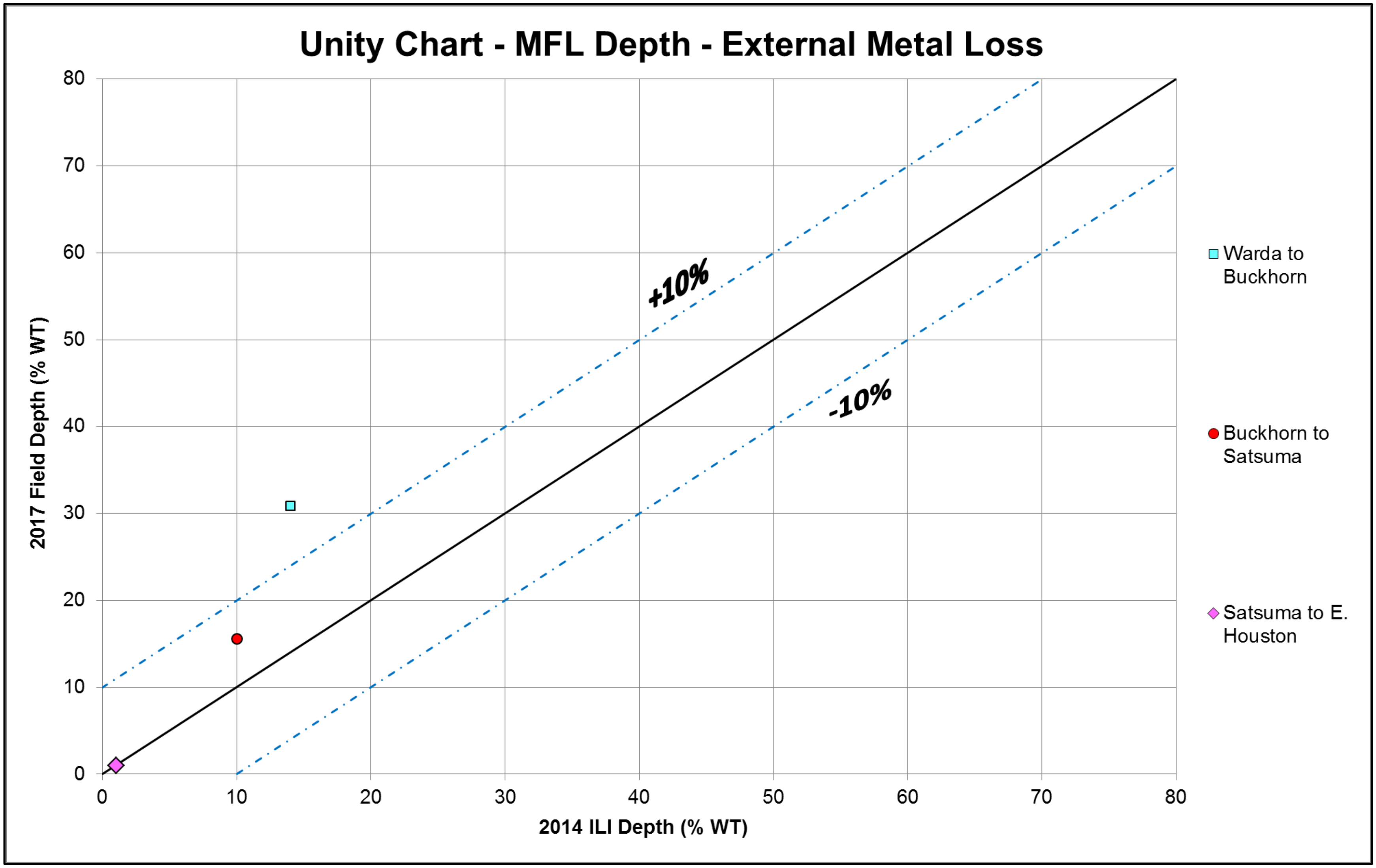
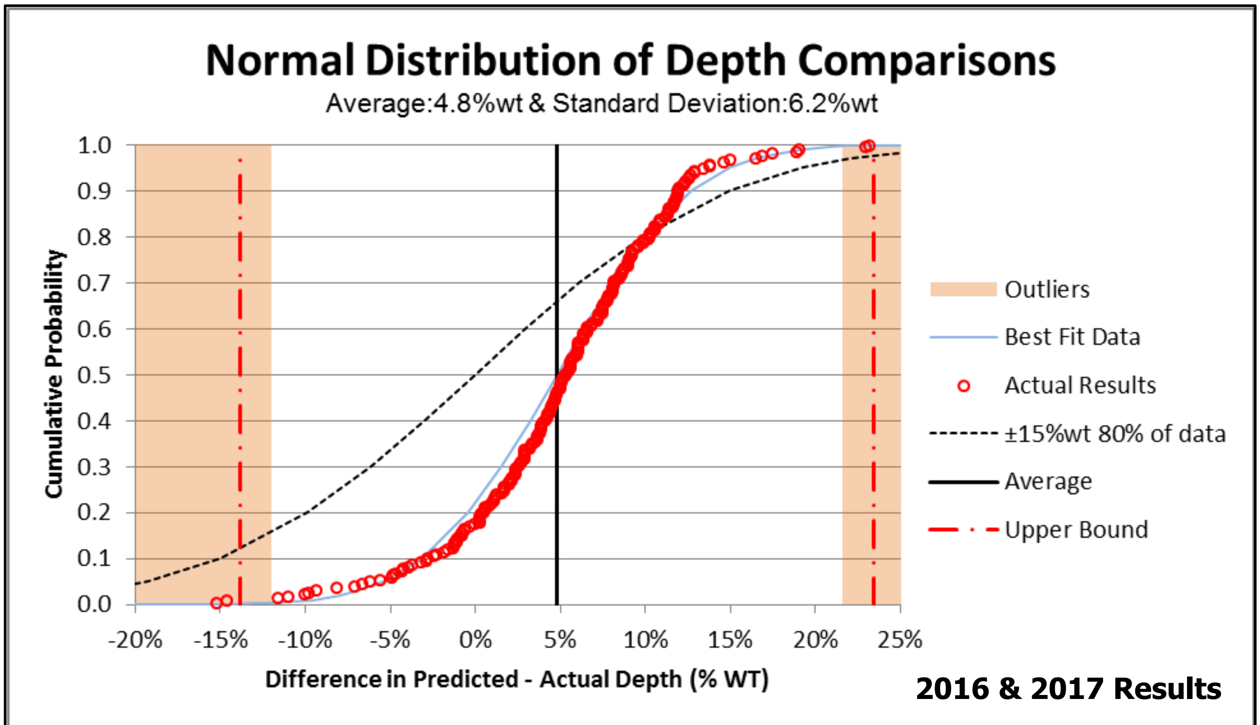


Figure 8. Unity Chart for Depth Verification for MFL External Metal Loss (Upper Bound ±10% WT)

Table 13. Summary of Sizing and Population Density for TFI External Metal Loss Features

		Overall TFI External ML Results (2016 & 2017)	2017 Overall TFI External ML Results	Texon to Barnhart*	Eckert to Cedar Valley	Bastrop to Warda*	Warda to Buckhorn
Number of features used in analysis		247	30	26	9	15	10
Total number of features		253	30	26**	9	15~	10
Average size difference		4.8% WT	2.5% WT	5.0% WT	2.9% WT	1.2% WT	3.9% WT
Standard deviation		6.2% WT	5.9% WT	6.3% WT	5.0% WT	6.2% WT	3.8% WT
Outliers		≤ -12.0% WT	≤ -13.5% WT	≤ -11.8% WT	≤ -10.7% WT	≤ -15.6% WT	≤ -6.5% WT
		≥ 21.6% WT	≥ 18.5% WT	≥ 21.8% WT	≥ 16.5% WT	≥ 18.0% WT	≥ 14.3% WT
Extreme Values		≤ -24.6% WT	≤ -25.5% WT	≤ -24.4% WT	≤ -20.9% WT	≤ -28.2% WT	≤ -14.3% WT
		≥ 34.2% WT	≥ 30.5% WT	≥ 34.4% WT	≥ 26.7% WT	≥ 30.6% WT	≥ 22.1% WT

*Calculations include ILI anomaly investigation dig results from 2016 and 2017.
**Twenty-one dig results from 2016 and five dig results from 2017
~Ten dig results from 2016 and five dig results from 2017



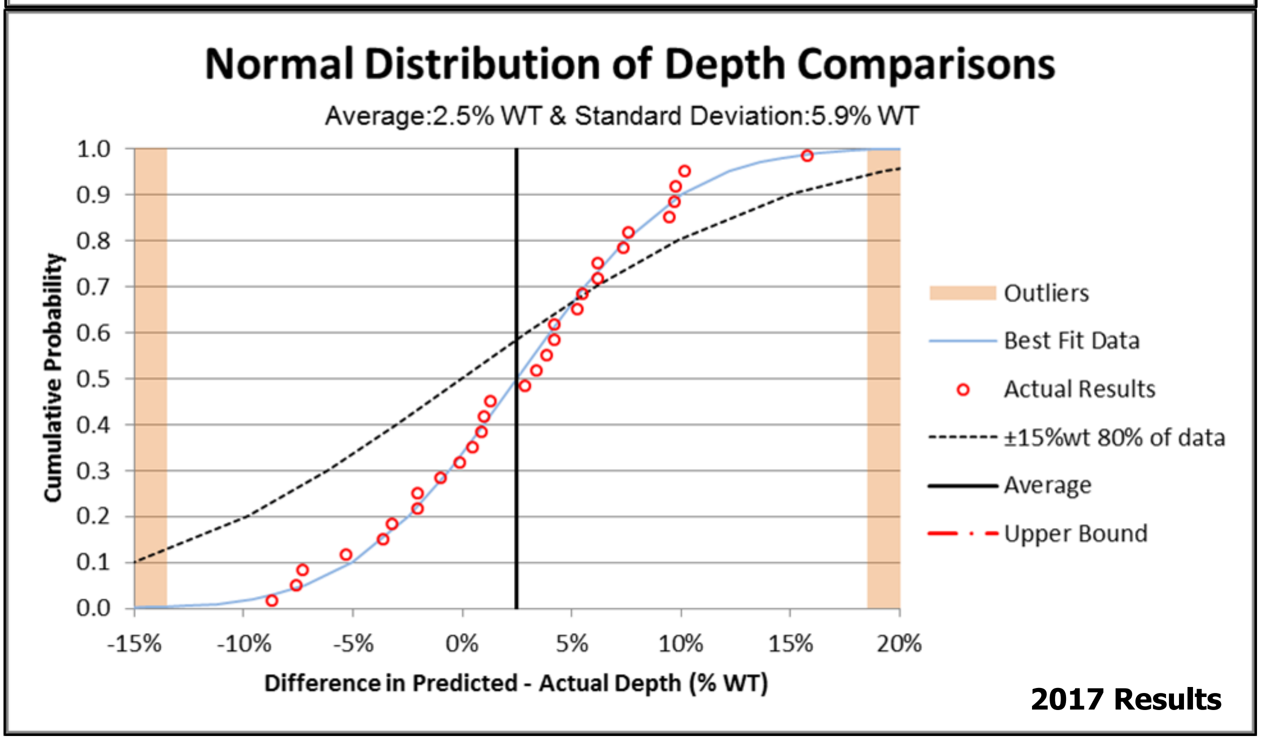


Figure 9. Normal Distribution Chart for the Difference between In-ditch and ILI Predicted Depths for 2016 and 2017 ILI Anomaly Investigation Data Pairs

5.3. Pipe Laminations and Hydrogen Blistering

Crude oil can contain hydrogen sulfide which can lead to the formation of hydrogen through anaerobic internal corrosion. Laminations in the pipe wall can trap hydrogen from the corrosion reaction and generate blisters. Elevated CP can also lead to hydrogen migration and blistering. Managing internal corrosion and monitoring CP levels will help mitigate these threats.

A review of the 2017 maintenance reports showed that no digs were scheduled for ILI investigation digs due to laminations. Laminations were identified in 32 of the 73 in-ditch ILI investigation digs. No laminations found during in-ditch assessments were reported to be associated with a deformation or with blistering. ID reductions identified from the 2017 EGP assessments were aligned with the reported laminations from the 2009/2010 UT assessments; two reported ID reductions were found to correlate with laminations; refer to Section 3.3 Laminations and Hydrogen Blisters for a correlation breakdown between ID reductions and laminations. Monitoring reported laminations for ID reductions may indicate the initiation of a hydrogen blister.

Continued monitoring of the lamination anomalies for the possibility of blister growth with ILI tools was recommended per the Longhorn Pipeline Reversal EA, Section 6.2.1.2.

5.4. Earth Movement (Fault and Stream Crossings)

5.4.1. Fault Crossings

The Longhorn Pipeline System crosses several aseismic faults between Harris County (Houston area) and El Paso, TX. 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 original Longhorn Pipeline crosses four faults, including Akron, Melde, Breen, and Hockley, the location and geologic data of which are summarized in Table 14.

Table 14. Fault Location and Geologic Data for Akron, Melde, Breen and Hockley Aseismic Faults in Harris County, TX

	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

*CL refers to low plasticity clay
Note: Blank fields indicate that data was unavailable.

Monitoring stations across the 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. Twenty-seven subsequent displacement readings have been taken at approximately 6-month intervals. A plot of the vertical displacements over time is shown in Figure 10. In 2017, there was a considerable amount of backward movement in the Akron Fault in comparison to the previous 12 years of monitoring. At the end of 2017, the accumulated displacement since the start of the monitoring of the fault has diminished. The monitoring contractor suggested that a period of movement is typically followed by a period of rebound for these types of faults. Using the 13.5 years of data, an attempt was made to measure the actual fault movement over time by calculating best fit trend lines. The trend lines show no measurable movement on the Melde and Breen Faults, with only slight movement of 0.013 inch/year over 13.5 years for the Akron Fault and 0.017 inch/year over 13.5 years for the Hockley Fault.

Three additional faults have been instrumented for the lines that were constructed to connect the existing Longhorn line to East Houston in 2012. The three faults include the McCarty Fault near Station 35+80, Negyev Fault near Station 140+00, and Oates Fault near Station 147+00. Baseline readings were taken for the McCarty, Negyev, and Oates faults in September 2012. After the baseline readings there have been 13 readings taken as shown in Figure 11. The trend lines for the Negyev and Oates faults show no movement. At the McCarty Fault, there is a jump of about one-half inch between the baseline reading and the first reading point though no movement was observed subsequent to the initial jump. The jump at the first reading point is likely due to measurement error of the baseline reading.

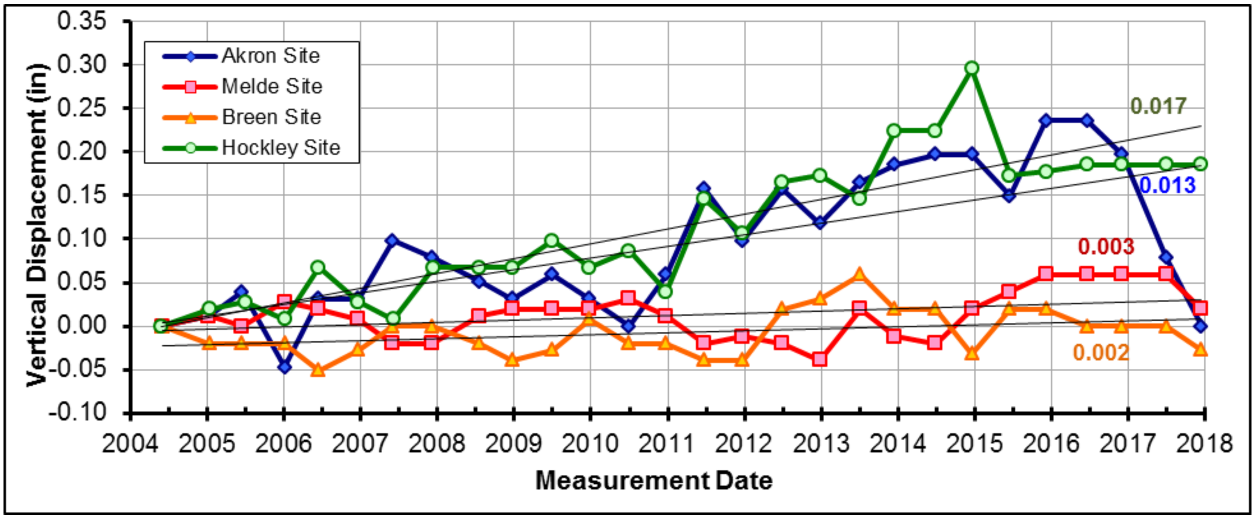


Figure 10. Fault Displacement over 13.5-Year Period at Akron, Melde, Breen and Hockley Faults

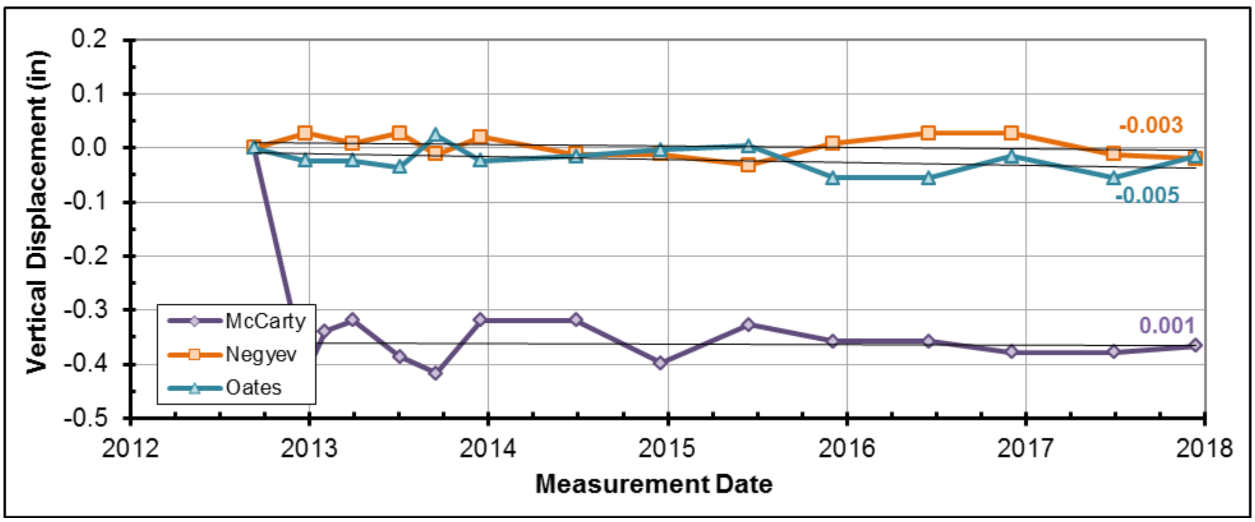


Figure 11. Fault Displacement over 5-Year Period for McCarty, Negyev and Oates

Kiefner conducted the original stress analysis to determine the maximum allowable displacements at the Akron, Melde, Breen and Hockley faults in the 2005 ORA Annual Report. Assumptions used in the 2005 analysis included: the allowable stress levels based on the version of ASME B31.4[10] available at that time; the stress resulting from regular operation (instead of fault movement) in the pipeline was determined by ASME B31.4 stress analysis; the

[10] ASME B31.4-2002, Pipeline Transportation Systems for Liquids and Slurries, ASME Code for Pressure Piping, B31. The standard allows longitudinal stress up to 54% of SMYS.

soil properties from a best estimate for representative values of obtainable properties; and the fault movement rates represented by linear trend lines fit to the data. In the 2014 ORA Annual Report, the maximum allowable displacements at the McCarty, Negyev, and Oates faults were also determined. Due to the high rate of movement and the relatively low allowable displacement at the Hockley Fault, the stress analysis was also repeated at this fault for the 2014 ORA Annual Report. In the 2014 analysis, the stress in the pipelines at various fault displacements were predicted through finite element analysis (FEA) with the same soil properties as used in the previous 2005 analysis. The allowable fault displacement was then determined when the stress reached the allowable stress levels in the latest ASME B31.4 at the time[11]. An important difference is that ASME B31.4 increased the allowable longitudinal stress level from 54% SMYS to 90% SMYS in 2012. The new allowable longitudinal stress level of 90% SMYS was used to determine the critical displacement at the three faults passed by the new East Houston Line constructed in 2012. However, a lower allowable longitudinal stress of 80% SMYS was used to determine the critical displacement at the Hockley Fault to compensate the potential lower quality of girth welds in the vintage 1950s Longhorn Pipeline passing the fault. Refer to the 2014 ORA Report for details of the analysis.

Table 15 shows the allowable displacement at each fault, the average rate of the movement over the monitoring period, and the time to reach the allowable displacement with this rate. The allowable displacements at the Akron, Melde, and Breen faults were determined by the original 2005 analysis and those at Hockley, McCarty, Negyev and Oates faults by the 2014 analysis as described above. The average rate of movement was determined by linear regression of the recorded fault movement as shown in Figure 10 and Figure 11. The calculated rate of displacement and reduced number of years to reach the allowed displacement are similar to the values in the 2015 ORA Annual Report. The slight variation of values between the reports may be due to the measurement tolerance. It should be noted that the "time to reach displacement (yrs)" in the last column is the total time from when the pipe is free of stress resulting from fault movement to the final failure. The time to reach the allowable displacement at the Hockley Fault has been close to the life of the pipeline segment at the region which was installed in the 1950s. The pipeline life exceeded the predicted time to failure due to the following:

- The safety margin between the selected 80% SMYS allowable stress level and the actual stress level for failure,
- The fault movement history before the monitoring period is unknown, and
- Built-in conservatisms in the FEA as discussed in the 2014 ORA Annual Report.

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[11] ASME B31.4-2012. The standard allows longitudinal stress up to 90% of SMYS.

Nevertheless, recommendations for Magellan to consider for remediating the pipeline segment at the Hockley Fault location or conducting more detailed analysis were provided in 2014 ORA Annual Report and discussed in Section 3.4 of this report. The other six faults have more than 100 years to reach the allowable displacement. Such long time periods to reach a displacement resulting in failure would normally not warrant any monitoring; however, according to the U.S. Geological Survey of September 2005 (Reference [4]) there are documented cases of fault movement reinitiating.

Table 15. Summary of Estimated Allowable Fault Displacement at Faults

	Allowable Displacement (in)	Average Rate of Movement (in/yr)	Time to Reach Allowable Displacement (yrs)
Akron	4.17	0.019	222
Melde	4.13	0.002	1,937
Breen	1.50	0.003	471
Hockley	1.25	0.019	67
McCarty	0.95	0.002	625
Negyev	2.65	0.001	4,138
Oates	2.65	0.006	476

* Ignoring the jump of ½ inch between the baseline point and the first reading point

Finally, Section 6.4 on Aseismic Faulting/Subsidence Hazards in Appendix 9E of the EA (Reference [5]) estimated the rates of vertical movement on the order of 0.20 inch per year based on field observations at the top four faults listed in Table 15. Actual measurements over the past 13 years show rates that are more than an order of magnitude less than the 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. Kiefner continues to believe that the semi-annual monitoring frequency is appropriate.

5.4.2. Waterway Inspection

Beginning in 2015, Magellan has conducted annual waterway inspections by directly measuring the depth-of-cover (DOC) above the pipe under the river crossings. In 2017, the waterway inspection was conducted by ONYX Service Incorporated (ONYX) at the five risk crossings, including, the Colorado River, Pin Oak Creek, Cypress Creek, Greens Bayou, and Brazos River. The pipeline has been buried deep below the crossing at the Brazos River and Colorado River via HDD. The depths from the top of the buried pipe to the river bottom are at least 30 feet. There is minimum risk for the pipeline being exposed at these two crossings.

The Longhorn Pipeline crosses the Greens Bayou near MP 9.9 in Harris County, TX. The water inspection was conducted at this crossing on September 3, 2017. During the inspection, the width of the waterway was 44 feet and the maximum depth of the water was 3 feet, 8 inches. The DOC was at least 4 feet at the bank of the river. The minimum DOC of nearly 4 feet was detected from the river centerline extending until to the east shoreline. The banks are covered in sand that was deposited during flooding. The entire river bottom is covered with a concrete bag mat to prevent scour.

The Longhorn Pipeline crosses the Cypress Creek near MP 47.1, also in Harris County, TX. The water inspection was conducted at this crossing on September 3, 2017. During the inspection, the width of the waterway was 95 feet and the maximum depth of the water was 11 feet, 8 inches. The DOC was at least five feet at the bank of the river. There is about a 16-foot long pipeline segment exposed at the center of the river. Magellan recorded this exposure in a 2003 maintenance report and conducted mitigation in 2005 by recoating a 23-foot long segment.

The Longhorn Pipeline crosses the Pin Oak Creek near MP 122.5 in Fayette County, TX. The water inspection was conducted at this crossing on September 7, 2017. During the inspection, the width of the waterway was 32 feet and the maximum depth was 4 feet. The DOC was at least 5 feet at the bank of the creek. The minimum DOC of about 1.5 feet was detected at the creek bottom near the creek centerline. The creek bottom consisted of soft mud. By comparing the inspection results between 2016 and 2017, no significant change of the river bottom was found. However, the elevation of the pipeline top determined by the 2017 inspection was about 1 foot higher than that determined by the 2016 inspection. Since the pipeline had never been exposed from 2016 to 2017, the physical elevation of the pipeline top should not change. ONYX believed the pipeline elevation from the 2017 inspection represents the real pipeline position and the difference in elevation is due to the inaccuracy in previous inspections. Due to the limited DOC left at the center of the river bottom, Magellan should continue to perform waterway inspections at the current frequency to monitor the conditions and perform further remediation at the Pin Oak Creek if necessary, such as installing the pipeline deeper through HDD or placing a concrete mat at the river bottom to prevent scouring.

5.4.2.1 Flood Monitoring

The water surface was inspected daily and compared with the specified flood stage at three rivers, including the Colorado River, the Pin Oak Creek, and the Pedernales River. The monitoring site for the Colorado River is at Bastrop. The water surface exceeded the flood stage of 23 feet by 2.11 feet on August 28, 2017[12]. The monitoring site for the Pin Oak Creek

[12] Flooding occurred as a result of Hurricane Harvey which reached land on August 25, 2017. Numerous waterway crossings were surveyed following Hurricane Harvey.

is at Smithville. The water surface exceeded the flood stage of 20 feet over a three-day period from August 27 to August 29, 2017. The highest water level of 31.78 feet occurred on August 28, which exceeds the flood stage of 20 feet by 11.78 feet. The monitoring site for the Pedernales River is near Johnson City. The water surface did not exceed the flood stage of 14 feet during 2017.

Magellan has committed to visually inspecting the water crossings whenever a flood condition occurs.

5.5. Third-Party Damage

The susceptibility of a pipeline to third-party excavation damage is dependent on characteristics such as the extent and type of excavation or agricultural activity along the pipeline ROW, the effectiveness of the One-Call System in the area, the amount of patrolling of the pipeline by the operator, the placement and quality of ROW markers, and the depth-of-cover over the pipeline. In all cases, different threats will exist at different locations along the pipeline.

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

5.5.1. Data Reviewed

The data reviewed included:

- Item 1, Tier Classification
- Item 2, HCA Pipeline Sections
- Item 3, Date of Pipeline Installation
- Item 4, Hydrostatic Test Pressure Achieved on Last Test
- Item 5, Current MOP
- Item 6, Current MASP
- Item 7, Outside Pipe Diameter
- Item 8, Pipe Wall Thickness
- Item 9, Pipe SMYS
- Item 17, Type of ILI Tool Data
- Item 18, Location and Type of Repair
- Item 19, Depth-of-Cover Surveys
- Item 24, Corrosion Control Survey Data
- Item 43, Maintenance Reports on Line Pipe Anomalies
- Item 46, Facility Inspection and Compliance Audits
- Item 49, Action Item Tracking and Resolution
- Item 50, 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 2017 TPD Annual Assessment, Kiefner concluded:

- There were 3 physical hits to the pipeline.
- There were 8 ROW near-misses and 4 one-call violations.
- The 2017 TPD Annual Assessment shows an increase of approximately 16% in the number of aerial patrol observations.
- There was an approximate 7% increase in unique[13] aerial patrol observations, with a 39% increase in third-party activity or non-company aerial-patrol-observations.
- There has been a slight shift in non-company activity: increased sightings pertaining to housing developments.
- The majority of aerial observations involved third party observations (other pipeline operators, city utilities, landowners) versus first and second party (Magellan and/or contractors under their control).
- One-call frequency decreased approximately 1.2% and the number of tickets sent to Field Operations for clearing/locating increased by approximately 8.6% from 2016 to 2017.

For further details see Appendix B, Section B.11 One-Call Violations and Third-Party Damage Prevention Right-of-Way Surveillance Data.

[13] Unique observations refer to first and second party.

5.5.2. One-Call Violation Analysis

There were four one-call violations during 2017; three were within a 10-mile segment. The ORA Process Manual states that an ILI tool capable of detecting TPD will be run in any 25-mile pipeline segment in the event that three or more one-call violations occur within a 12-month time period. Based on this requirement, an ILI inspection was required on the Buckhorn to Satsuma segment. The required inspection was completed in September of 2017. The fourth one-call violation was at MP 531.1. None of the one-call violations resulted in damage to the pipeline.

Of 17,353 one-calls in 2017, it appeared that 20% of the required field locates were potential ROW encroachments.

Magellan 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 (Houston) accounted for 8,212 (47%) of the one-call tickets. Travis County (Austin) accounted for 4,006 (23%) of the one-call tickets. Thus, 70% of the one-call notifications on the pipeline occurred in these large metropolitan areas. Clearly, based upon those data, these two areas present the greatest potential for third-party damage. El Paso has the next highest number with 1,666 tickets (10%).

Magellan should continue to ensure all relevant data are recorded on the incident data reports to help improve the overall effectiveness of the third-party damage program.

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

- Galena Park to the Pecos River (Tier-II and Tier-III areas)[14]:
    - Every 2.5 days, not to exceed 72 hours
- Pecos River to El Paso Terminal (Tier-I areas):
    - Once a week, not to exceed 12 days, but at least 52 times per year
- Edwards Aquifer Recharge Zone (MP170.5-MP173.3):
    - Daily (one day per week shall be a ground-level patrol)

Magellan met this frequency requirement.

[14] Note that the patrol now includes E Houston to 9th Street Junction.

The data summarized under Item 56, Miles of Pipe Inspected by Aerial Survey by Month for 2017 showed that Magellan exceeded these requirements in terms of the total mileage patrolled.

The ORA Process Manual requires that an ILI tool capable of detecting TPD will be run in any 25-mile pipeline segment in the event that three or more one-call violations occur within a 12-month time period. Based on this requirement, no additional ILI inspections regarding TPD are required.

No additional direct examinations are recommended at this time.

5.6. Stress-Corrosion Cracking

In the 67 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 has performed investigative digs each year for three years in areas that could be most 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 by Magellan as a supplemental examination when the pipe is exposed and examined for other reasons such as ILI anomaly excavations. In 2017 Magellan performed 73 ILI investigation digs and during each dig, the exposed pipe surface was checked for SCC using magnetic particle testing.

Magnetic particle inspection is conducted on the full pipe circumference between coating cuts. Coating is typically removed a couple of feet to either side of the ILI target anomaly. If there are multiple ILI target anomalies within a single joint, then coating is typically removed for the entire distance between the target anomalies (unless the two target anomalies are at extreme opposite ends of the joint.)

No SCC has been found.

5.7. Facilities Other than Line Pipe

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 recommendations.

A Preventive Maintenance Program has been established under the Mechanical Integrity Program through the use of a software database system called Enviance/CMS. 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 of tracking mechanical integrity recommendations.

Facility safety review inspections addressing items related to safety, security, and environmental compliance were completed for 11 pipeline facilities during 2017: Satsuma to Texon. No problems were identified based on a review of the inspection forms extracted from the database.

Additionally, a Facility Risk Management Program is in place to manage the risks at above ground facilities. The Management of Change process requires that all changes be evaluated using an appropriate hazard analysis technique (HAZOP, What-If) and that the change be assessed to ensure that the appropriate risk mitigation levels on the system are maintained.

Process Hazard Analyses (PHAs) are performed on all new facilities, when changes occur in existing facilities, and at five-year intervals to evaluate and control potential hazards associated with the operation and maintenance of the facilities. Three PHAs were completed in 2017, which included the Eckert and Warda Pump Stations, and the mainline valves.

From the standpoint of facility data acquired for 2017, one can conclude that the facilities had no adverse impact on public safety.

6. Overall LPSIP Performance Measures

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 of 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 (or scorecarding) 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 2017 is evaluated below.

6.1. 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. This metric is compared to the previous 12-month period. The goal is 100% of the commitment. Magellan met this commitment in 2017.

- Number of warning or ROW identification signs installed, replaced, or repaired during 12-month period. The metric is compared to previous Magellan performance. This metric is 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 being 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 is 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.

- Number of calls (sorted by Tier I, Tier II or Tier III) through the one-call system to mark or flag the Longhorn Pipeline. This is completed to measure the effectiveness of the one-call system in preventing TPD. The measure is 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 16 provides a summary of the LPSIP Activity Measures from 2005 through 2017.

Table 16. LPSIP Activity Measures

Measure		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
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	180,045	188,564	188,772	179,107	176,884	175,920	173,996	162,030
No. of warning or ROW identification signs installed, replaced, or repaired		979	732	237	536	460	291	76	66	539	266	130	315	194
No. of outreach or training meetings to educate and train the public and third parties about pipeline safety		28	18	25	21	17	22	20	22	17	30	36	15	16
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	5,277	5,277	5,757	5,757	8,637	10,268	4,302	4,745	5,620
	Tier II	6,881	7,874	7,852	7,059	4,265	4,265	4,415	4,415	6,370	7,641	9,183	9,706	8,940
	Tier III	1,498	1,617	1,653	1,459	833	833	918	918	1,312	1,554	3,167	3,111	2,793

6.2. Deterioration Measures

Deterioration measures are metrics that evaluate 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 2006 through 2017 are presented in Table 17.

In 2017 there were no immediate conditions as defined by the LPSIP and 49 CFR 195.452. The 2017 results follow a similar trend to recent years (2009-2016) where no immediate conditions had been reported. The monitoring and excavation program should continue to address significant reported anomalies.

No ILI reported metal loss features met POE evaluation dig requirements in 2017. POE calculations should continue to be performed.

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

Table 17. LPSIP Deterioration Measures

Measure		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Number of immediate ILI anomalies per mile pigged		0.029	0.0203	0.038	0.004	0	0	0	0	0	0	0.004	0	0
Number of immediate ILI anomalies, per mile pigged, sorted by tier classification	Tier I	NA	0.0212	0.035	0.006	0	0	0	0	0	0	0	0	0
	Tier II	NA	0.0208	NA	NA	0	0	0	0	0	0	0.004	0	0
	Tier III	0.192	NA	0.003	NA	0	0	0	0	0	0	0	0	0
Total number of anomalies per hydrotest		NA	NA	NA	NA	NA	NA	NA	NA*	NA**	NA**	NA**	N/A	N/A
Number of POE Evaluations per mile pigged		1.48	0.54	0.69	0	0.017	0.14	0.035	0.025	0.033	0.017	0.013~	0	0

* Hydrostatic tests were performed for pipeline commissioning purposes.
**No hydrotests were performed during 2014 through 2016.
~POE calculations only performed on the MFL assessments; the number of POE evaluations per mile pigged did not include the TFI mileage.

6.3. 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 18. Response times, volumes, and costs are for DOT-reportable leaks.

Table 18. LPSIP Failure Measures

Measure		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Number of leaks (DOT-reportable)		2	0	1	3	0	1	2	0	2	2	0	0	3
Average response time in hours for a product release.	Tier I	Immed.	NA	Immed.	Immed.	NA	Immed.	Immed.	NA	Immed.	Immed.	NA	NA	Immed.
	Tier II	NA	NA	NA	NA	NA	NA	NA	NA	Immed.	Immed.	NA	NA	NA
	Tier III	NA	NA	NA	NA	NA	NA	NA	NA	Immed.	Immed.	NA	NA	Immed.
Average product volume released per incident (bbl)	Tier I	5.7	0	5.7	0.4	0	0.4	1.2	NA	0.47	2.74	0	NA	1048
	Tier II	0	0	0	0	0	0	0	NA	0	0	0	NA	NA
	Tier III	0	0	0	0	0	0	0	NA	4	0	0	NA	28
Total product vol. released in the 12-month period (bbl)	Tier I	17	0	5.7	1.3	0	0.4	2.5	NA	0.47	5.48	0	NA	2096
	Tier II	0	0	0	0	0	0	0	NA	0	0	0	NA	NA
	Tier III	0	0	0	0	0	0	0	NA	4 bbls	0	0	NA	28
Cleanup cost totals per year		< $100k	$0	< $200k	< $150k	0	< $50	< $50	NA	> $100k	< $25	0	NA	>$528k
Cleanup cost per incident		< $35k	NA	< $200k	< $50k	0	< $50	< $25	NA	< $25k < $50k > $100k	< $25	0	NA	$28k $500k No info
Reports from aerial surveys or ground surveys of encroachments into the pipeline ROW without proper one-call		1	0	1	3	3	1	1	2	2	0	3	2	4
Number of known physical hits (contacts with pipeline) by third-party activities		0	0	0	0	0	0	2	0	0	0	0	0	1
Number of near-misses to the pipeline by third parties		7	1	7	5	6	2	4	3	2	0	4	0	8
Number of service interruptions		115	165	155	74	16*	17	9	8	15	15	11	8	13

7. INTEGRATION OF INTERVENTION REQUIREMENTS AND RECOMMENDATIONS

7.1. 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 and hydrogen blisters, 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 interval procedures set by the ORAPM with the additional requirement that "smart geometry" tools (EGP) 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. 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. These 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 caused 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 longitudinal 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 committed to running the UT tool to inspect for laminations and blisters. The UT tool can also characterize corrosion and has capabilities for detecting mechanical damage. The commitment was to perform a UT five years after startup and at intervals established by the ORA. 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 19 is a compilation of the tools run to date on the crude system 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 6.1 of this report. Reassessment requirements for corrosion and third-party damage are based on the most recent inspection date; corrosion inspections are required to be run every five years while third-party damage inspections are required every three years. Earth movement, the fifth component for threat integration, is not included in Table 19 because it is currently addressed using surface surveys rather than ILI technology.

Table 20 presents the completed ILI runs and planned inspections for the refined system.

Table 19. Completed ILI Runs and Planned Future ILI's for Longhorn Crude System (pg 1 of 2)

	E. Houston to Satsuma	Satsuma to Warda		Warda to Cedar Valley		Cedar Valley to Eckert
		Satsuma to Buckhorn	Buckhorn to Warda	Warda to Bastrop	Bastrop to Cedar Valley	
Mileage	**2.35 to 34.1**	**34.1 to 68.0**	**68.0 to 112.9**	**112.9 to 141.8**	**141.8 to 181.6**	**181.6 to 227.9**
Assessments						
Corrosion						
Tool	MFL[1]					
Date of Tool Run	28-Oct-04					
Tool	MFL[2]					
Date of Tool Run	14-Dec-05					
Tool		MFL		MFL		MFL
Date of Tool Run		21-May-06		21-Jul-06		2/15/2007
Tool	TFI	TFI		TFI		TFI
Date of Tool Run	6-Jul-07	20-Dec-07		19-Sep-07		22-Mar-07
Tool	Multi-Data	MFL	MFL			
Date of Tool Run	1-Oct-14	18-Dec-14	16-Dec-14			
Tool				MFL	MFL	MFL
Date of Tool Run				11-Jan-15	10-Jan-15	27-Mar-15
Tool		TFI	TFI	TFI	TFI	TFI
Date of Tool Run		18-Dec-15	16-Dec15	11-Dec-15	8-Dec-15	4-Dec-15
Pressure Cycle Induced Fatigue						
Tool	TFI ‡	TFI ‡		TFI ‡		TFI ‡
Date of Tool Run	6-Jul-07	20-Dec-07		19-Sep-07		22-Mar-07
Tool		TFI	TFI	TFI	TFI	TFI
Date of Tool Run		18-Dec-15	16-Dec-15	11-Dec-15	8-Dec-15	4-Dec-15
Third Party Damage						
Tool	Def.					
Date of Tool Run	10-Jun-04					
Tool		Deformation		Deformation		
Date of Tool Run		21-May-06		21-Jul-06		
Tool	Def.	Deformation		Deformation		Def.
Date of Tool Run	5-Oct-07	15-Dec-07		16-Oct-07		15-Feb-07
Tool						
Date of Tool Run						
Tool	Def.	Deformation		Deformation		
Date of Tool Run	11-Sep-09	12-Oct-09		16-Dec-09		
Tool						Def.
Date of Tool Run						25-Jan-10
Tool	Def.	Deformation		Deformation		Def.
Date of Tool Run	7-Jun-12	7-Jun-12		9-Jun-12		15-Jun-12
Tool	Def.					
Date of Tool Run	22-Jun-13					
Tool	Def.	Def.	Def.			
Date of Tool Run	1-Oct-14	18-Dec-14	16-Dec-14			
Tool				Def.	Def.	Def.
Date of Tool Run				11-Jan-15	10-Jan-15	27-Mar-15
Tool	Def.	Def.	Def.			
Date of Tool Run	14-Sep-17	13-Sep-17	12-Sep-17			
Next Required Assessment						
Corrosion	1-Oct-19	18-Dec-20	16-Dec-20	11-Dec-20	8-Dec-20	4-Dec-20
Pressure-Cycle Induced Fatigue	2035	2034	2027	2024	2040	2034
Third-Party Damage	14-Sep-20*	13-Sep-20*	12-Sep-20*	11-Jan-18*	10-Jan-18*	27-Mar-18*

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.
‡ 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.
* Per Longhorn EA section 9.3.2.3, EGP assessments are required every 3 years in accordance with the LMP. Deformations identified from these assessments will be correlated to the existing laminations found from the UT assessments.

Table 20 (continued). Completed ILI Runs and Planned Future ILI's for Longhorn Crude System (pg 2 of 2)

		Eckert to Ft McKavett			Ft McKavett to Crane		
		Eckert to James River	James River to Kimble County	Kimble County to Cartman	Cartman to Barnhart	Barnhart to Texon	Texon to Crane
	Mileage	**227.9 to 260.2**	**260.2 to 295.2**	**295.2 to 344.3**	**344.3 to 373.4**	**373.4 to 416.6**	**416.6 to 457.5**
Assessments	**Corrosion**						
	Tool	MFL			MFL		
	Date of Tool Run	19-Dec-06			12-Oct-06		
	Tool	TFI					
	Date of Tool Run	9-Nov-07					
	Tool				TFI		
	Date of Tool Run				8-Jan-08		
	Tool	TFI	TFI	TFI	TFI	TFI	TFI
	Date of Tool Run	19-Aug-15	1-Sep-15	29-Aug-15	24-Aug-15	11-Aug-15	17-Jul-15
	Pressure Cycle Induced Fatigue						
	Tool	TFI ‡					
	Date of Tool Run	9-Nov-07					
	Tool				TFI		
	Date of Tool Run				8-Jan-08		
	Tool	TFI	TFI	TFI	TFI	TFI	TFI
	Date of Tool Run	19-Aug-15	1-Sep-15	29-Aug-15	24-Aug-15	11-Aug-15	17-Jul-15
	Third-Party Damage						
	Tool	Deformation			Deformation		
	Date of Tool Run	19-Dec-06			12-Oct-06		
	Tool				Deformation		
	Date of Tool Run				21-Dec-07		
	Tool	Deformation					
	Date of Tool Run	23-Jan-08					
	Tool	Deformation			Deformation		
	Date of Tool Run	27-Mar-10			5-Aug-10		
	Tool	Deformation			Deformation		
	Date of Tool Run	17-Jun-12			1-Jul-12		
	Tool	Def.	Def.	Def.	Def.	Def.	Def.
	Date of Tool Run	6-Aug-15	4-Aug-15	31-Jul-15	25-Jul-15	19-Jul-15	18-Jun-15
	Next Required Assessment						
	Corrosion	19-Aug-20	1-Sep-20	29-Aug-20	24-Aug-20	11-Aug-20	17-Jul-20
	Pressure-Cycle Induced Fatigue	2025	2030	2023	2045	2022	2027
	Third-Party Damage	6-Aug-18*	4-Aug-18*	31-Jul-18*	25-Jul-18*	19-Jul-18*	18-Jun-18*

‡ 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

* Per Longhorn EA section 9.3.2.3, EGP assessments are required every 3 years in accordance with the LMP. Deformations identified from these assessments will be correlated to the existing laminations found from the UT assessments.

Table 20. Completed ILI Runs and Planned Future Inspections for Longhorn Refined System

		Crane to Cottonwood	Cottonwood to El Paso	Crane to Odessa	8" El Paso to Chevron	8" Kinder Morgan Flush Line	8" El Paso to Kinder Morgan	12" El Paso to Kinder Morgan
	Mileage	**457.5 to 576.3**	**576.3 to 694.4**	**0 to 29.26**	**0 to 9.4**	**0 to 9.4**	**0 to 9.4**	**0 to 9.4**
Assessments	**Corrosion**							
	Tool			MFL				
	Date of Tool Run			4-Nov-06				
	Tool			MFL	MFL	MFL	MFL	MFL
	Date of Tool Run			7-Mar-07	6-Mar-07	6-Mar-07	8-Mar-07	7-Mar-07
	Tool	MFL	MFL				Out of service between 2007 and 2012	
	Date of Tool Run	21-Nov-08	27-Mar-08					
	Tool			MFL				
	Date of Tool Run			28-Jun-11				
	Tool		MFL		MFL	MFL		MFL
	Date of Tool Run		19-May-12		23-Feb-12	21-Feb-12		22-Feb-12
	Tool	MFL					MFL	
	Date of Tool Run	19-Nov-13					28-Jan-14	
	Tool			Multi-Data				
	Date of Tool Run			5-Oct-2016				
	Tool		MFL		Multi-Data	Multi-Data		Multi-Data
	Date of Tool Run		1-Nov-17		13-Jul-17	13-Jul-17		14-Jul-17
	Third-Party Damage							
	Tool			Deformation				
	Date of Tool Run			4-Nov-06				
	Tool	Deformation	Deformation	Deformation	Deformation	Deformation	Deformation	Deformation
	Date of Tool Run	2-May-07	2-May-07	7-Mar-07	6-Mar-07	6-Mar-07	8-Mar-07	7-Mar-07
	Tool	Deformation	Deformation				Out of service between 2007 and 2012	
	Date of Tool Run	21-Nov-08	27-Mar-08					
	Tool			Deformation				
	Date of Tool Run			28-Jun-11				
	Tool		Deformation		Deformation	Deformation		Deformation
	Date of Tool Run		19-Jun-12		23-Feb-12	21-Feb-12		22-Feb-12
	Tool	Deformation						
	Date of Tool Run	19-Nov-13						
	Tool			Deformation				
	Date of Tool Run			5-Oct-2016				
	Tool		Deformation		Deformation	Deformation		Deformation
	Date of Tool Run		1-Nov-17		13-Jul-17	13-Jul-17		14-Jul-17
	Next Required Assessment							
	Corrosion	19-Nov-18	1-Nov-22	5-Oct-2021	13-Jul-22	13-Jul-22	28-Jan-19	14-Jul-22
	Pressure-Cycle Induced Fatigue	*Not Susceptible*	*Not Susceptible*	*Not Susceptible*	*Not Susceptible*	*Not Susceptible*	*Not susceptible*	*Not Susceptible*
	Third-Party Damage	21-Nov-18	1-Nov-22	Oct-5-2021	13-Jul-22	13-Jul-22	28-Jan-19	14-Jul-22

7.2. Integration of DOT HCA Inspection Requirements

It is necessary for Magellan to be compliant with the DOT Integrity Management Rule, 49 CFR 195.452, for HCAs in addition to meeting the requirements in the LMP. The pipeline from 9th Street Junction to El Paso is under DOT jurisdiction as well as the four laterals connecting El Paso to Diamond Junction and the lateral from Odessa to Crane.

The HCA rule states that an operator must establish 5-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 9th Street Junction 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 5-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. The Existing Pipeline east of Crane is often more shallow because when built there was not a 30-inch depth of burial requirement.

7.3. Pipe Replacement Schedule

7.3.1. Other Pipe Replacements

A number of pipe replacements were completed in 2013 during the pipeline flow reversal on the original pipe segments. 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, non-pressure containing sleeves, a patch, deformation anomalies, and corrosion anomalies.

During 2017, a section of pipe was replaced via horizontal directional drilling (HDD) under the Colorado River at MP 134.5.

8. SUMMARY OF RECOMMENDATIONS

Table 21 provides a summary of recommendations from the 2017 ORA.

Table 21. Summary of 2017 Recommendations

Topic	Recommendation	ORA Section
In-line Inspection	Advanced NDE methodologies that have a high resolution are recommended for in-ditch evaluations to help characterize and size complex anomalies that are within the pipe body.	Executive Summary, 5.2.3
Damage Prevention	Magellan should increase their focus on damage prevention and maintenance plans to prevent damage to the pipeline during excavation and maintenance activities. (Note: Magellan implemented a new damage prevention training course in October 2017.)	Executive Summary, 2.4
Earth Movement – Faults	The current 6-month monitoring practice is recommended for the Hockley Fault and an option for remediation: Excavate and expose the pipeline segment including three joints at each side of the fault within five years. From the distribution of longitudinal stress provided in the 2014 ORA, the recommended excavation length is enough to release the majority of accumulated longitudinal stress. The pipe will then be restored to a state free of stress caused by fault movement. The pipe can resist an additional 1.25 inches of fault movement before the next excavation. It is also recommended that the quality of the girth welds in the exposed segment be examined at this time. If no dig is scheduled in the near future, a literature review could be conducted to determine the fault movement history at the location since the installation of the pipeline.	Executive Summary, 3.4

9. 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.
6. Final Environmental Assessment of the Longhorn Pipeline Reversal, PHMSA-2012-0175, December 2012.

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 ORA, 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 LPSIP at Sec. 3.5.2 and the associated ORA at Sec. 4.0.	Within 3 months of startup and thereafter at such intervals as are established by the ORA	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 LPSIP at sec. 3.5.2 and the associated ORA at Sec. 4.0.	At such intervals as are established by the ORA, 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 LPSIP at Sec. 3.5.2 and the associated ORA at Sec. 4.0.	At such intervals as are established by the ORA, 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 LPSIP, 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 LPSIP, 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 ORA, but in any case no later than seven years from the startup date.	Outside force damage

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 ORAPM 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.

B.1. Pipeline/Facilities Data

The Longhorn Pipeline system includes the physical pipeline, pump stations, terminals, storage tanks, and associated mechanical components.

B.1.1. Mainline (Items 3, 7, 8, 9, 10, 11, and 12)

Kiefner received strip maps, alignment sheets, line fill data, and process flow schematics for the mainline system. During 2017, a section of pipe was replaced via horizontal directional drilling (HDD) at the Colorado River crossing at MP 134.5.

B.1.2. Pump Stations (Item 15)

Phase 2 of the Longhorn Reversal Project consisted of increasing the flow rate on the pipeline from Crane, TX to Houston, TX from 134,000 bpd to 225,000 bpd. It 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 eight additional intermediate pump stations (Texon, Barnhart, Cartman, James River, Eckert, Bastrop, Warda, and Buckhorn). This was completed in 2013. During 2014 there was an increase in flowrate from 225,000 bpd to 292,000 bpd from East Houston to Crane and an increase to 2,100 bph on the Western refinery connection at El Paso.

Kiefner received process flow schematics for the refined product transport from Odessa through Crane and to the El Paso Terminal and the crude system from Crane to the East Houston Terminal and South to 9th Street Junction. Table B-1 provides a current list of the Longhorn pump stations, milepost numbers, tier levels, and elevations from Crane to East Houston.

There were no significant changes involving the pumping stations or terminals during 2017.

Table B-1. Crude Oil System Pump Stations and Terminal

Milepost	Facility Name	Tier	Elevation, feet	
			Suction	Discharge
457.54	Crane	II	2524	2524
416.64	Texon	II	2673	2673
373.60	Barnhart	II	2603	2603
344.28	Cartman	II	2446	2446
295.19	Kimble County	II	2221	2221
260.17	James River	I	1709	1709
227.94	Eckert	I	1726	1726
181.60	Cedar Valley	II	1035	1035
141.78	Bastrop	I	386	386
112.90	Warda	I	359	359
67.95	Buckhorn	I	171	171
34.09	Satsuma	III	129	129
2.35	East Houston	II	42	42

B.1.3. Tier Classifications and HCAs (Items 1 and 2)

Kiefner received a listing of tier classifications and HCAs for the Longhorn System. There were no changes during 2017.

B.1.4. Mill Inspection Defect Detection Threshold (Item 13)

Magellan reviewed the documentation for each pipe segment covered by the 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[7], 5LX[15], or 5LS[16]. The results were summarized and submitted to PHMSA on January 14, 2013.

B.1.5. Charpy V-Notch Impact Energy Data (Item 14)

Charpy V-Notch (CVN) impact tests are used to determine material toughness. CVN data from 16 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 (TDW). The results are listed in Table B-2.

[15] API Standard 5LX, Specification for High-Test Line Pipe
[16] API Standard 5LS, Specification for Spiral-Welded Line Pipe

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	45,000 SMYS	13	26.0	62
13	156.59	45,000 SMYS	16	32.0	107.3
16	210.57	45,000 SMYS	18	26.9	103.7
18	227.20	45,000 SMYS	25.5	38.0	144
20	280.50	45,000 SMYS	24	48.0	94.6
23	316.57	45,000 SMYS	16.5	25.0	74
32	43.15	45,000 SMYS	16	32.0	109.4
33	134.66	45,000 SMYS	29	38.7	147
34	163.20	45,000 SMYS	21	31.3	140.3
35	341.65	45,000 SMYS	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

No Charpy V-Notch tests were conducted during 2017.

B.2. Operating Pressure Data

For Items 21, 22, and 23, Kiefner has received pressure and flow data for Galena Park[17], East Houston, Satsuma, Cedar Valley, Kimble County, Crane, and El Paso Pump Station since September 17, 2004. From November 1, 2013 to December 31, 2017 pressure and flow data have also been received for Texon, Barnhart, Cartman, James River, Eckert, Bastrop, Warda, and Buckhorn Pump Stations. From September 1, 2016 to December 31, 2017 pressure and flow data have been received for Speed Junction Station. The data are collected in 1-minute intervals and sent on a monthly basis.

[17] Galena Park is no longer part of the Longhorn Pipeline System.

B.3. ILI Inspection and Anomaly Investigation Reports

B.3.1.1. ILI Inspection Reports (Items 39, 40, 41, 44, 45 and 47)

A total of 135 maintenance reports were received for evaluations completed in 2017. Anomaly investigations were completed in 73 of the 135 maintenance reports. Anomaly investigations also included nondestructive evaluation (NDE) reports with detailed investigation results. PMI reports were available for 42 of the 73 anomaly investigation reports. Table B-3 shows the breakdown of where the maintenance reports occurred (HCA, segment, and tier) and Table B-4 shows a breakdown of what reported ILI anomalies were excavated per segment. In Table B-4 the total number of anomalies addressed includes the targeted ILI anomalies for each dig and any anomaly found in the area of repair for that associated dig.

Table B-3. Remediations per Maintenance Reports Completed in 2017

	18" El Paso to Cottonwood	18" Cottonwood to Crane	18" Crane to Texon	18" Texon to Barnhart	18" Barnhart to Cartman	18" Cartman to Kimble County	18" Kimble County to James River	18" James River to Eckert	18" Eckert to Cedar Valley	18" Cedar Valley to Bastrop	18" Bastrop to Warda	18" Warda to Buckhorn	18" Buckhorn to Satsuma	20" Satsuma to E. Houston	20" E. Houston to Speed Jct	8" El Paso to Chevron	8" Kinder Morgan Flsuh Line	8" El Paso to Kinder Morgan	12" El Paso to Kinder Morgan	8" Crane to Odessa
ILI Date*	11/1/17											9/12/17*	9/13/17*	9/14/17*		7/13/17	7/13/17		7/14/17	
Maintenance Report	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	No	No	No	No
Tier I	6	0	0	0	0	0	0	0	5	2	5	18	8	0	0	0	0	0	0	2
Tier II	0	0	0	3	0	0	0	0	1	5	4	0	5	3	1	0	0	0	0	0
Tier III	0	0	0	0	0	0	0	0	1	0	0	0	2	2	0	0	0	0	0	0
Total Digs	6	0	0	3	0	0	0	0	7	7	9	18	15	5	1	0	0	0	0	2
HCA	0	0	0	0	0	0	0	0	4	4	2	4	3	5	1	0	0	0	0	0
Non-HCA	6	0	0	3	0	0	0	0	3	3	7	14	12	0	0	0	0	0	0	2

*Per Longhorn EA Section 9.3.2.3, EGP assessments are required every 3 years in accordance with the LMP.

Table B-4. Reported Anomalies Excavated per the 2017 Maintenance Reports

ILI Anomaly Called	Number of Anomalies Addressed	18″ El Paso to Cottonwood	18″ Cottonwood to Crane	18″ Crane to Texon	18″ Texon to Barnhart	18″ Barnhart to Cartman	18″ Cartman to Kimble County	18″ Kimble County to James River	18″ James River to Eckert	18″ Eckert to Cedar Valley	18″ Cedar Valley to Bastrop	18″ Bastrop to Warda	18″ Warda to Buckhorn	18″ Buckhorn to Satsuma	20″ Satsuma to E. Houston	20″ E. Houston to Speed Jct	8″ El Paso to Chevron	12″ El Paso to Kinder Morgan	8″ Crane to Odessa
External Metal Loss	132	0	0	0	5	0	0	0	0	28	14	18	37	20	9	1	0	0	0
Internal Metal Loss	41	6	0	0	0	0	0	0	0	0	0	0	30	2	3	0	0	0	0
Mill Anomaly w/Metal Loss	1	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0
Lack of Fusion External	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lack of Fusion Mid-wall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lack of Fusion Internal	0	0	0	0	0	0	0	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	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	0	0	0	0	0	0	0
ID Reduction L<1.5D	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0
ID Reduction on Weld	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ID Reduction	3	0	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0
ID Reduction w/associated metal loss	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ID Reduction affecting pipe curvature at seam weld	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
Geometric Anomaly	2	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0
Girth Weld Anomaly	4	0	0	0	0	0	0	0	0	0	0	0	0	2	2	0	0	0	0
Hard Spot Investigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Buckle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geometric Anomaly Associated w/Metal Loss	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Area Of Bulge	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Seam Weld Feature B	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Seam Weld Anomaly	14	0	0	0	0	0	0	0	0	1	3	2	0	8	0	0	0	0	0
Surface Irregularity	0	0	0	0	0	0	0	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	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	0	0	0	0	0	0	0
Int Metal Loss Crosses Long Seam	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0
TOTAL	**202**	**9**	**0**	**0**	**5**	**0**	**0**	**0**	**0**	**30**	**17**	**20**	**71**	**32**	**15**	**1**	**0**	**0**	**2**

B.3.1.2. Results of ILI for TPD between 9th Street Junction and Crane (Item 77)

There was no sign of third-party damage identified by the ILI runs.

B.4. Hydrostatic Testing Reports

B.4.1.1. Hydrostatic Leaks and Ruptures (Item 75)

A hydrostatic test was performed on 4/28/2017 on the replacement pipe under the Colorado River.

B.5. Corrosion Management Surveys and Reports

B.5.1.1. Corrosion Control Survey Data (Item 24)

ILI assessments were performed on the following segments in 2017 to monitor corrosion: Cottonwood to El Paso, 8-inch El Paso to Chevron, 8-inch Kinder Morgan Flush Line, and 12-inch El Paso to Kinder Morgan. The next crude system ILI assessment for corrosion is in 2019 from Satsuma through 9th Street Junction. The next refined system ILI assessment for corrosion is in 2018 for Crane to Cottonwood.

B.5.1.2. TFI MFL ILI Investigations (L and d Results) (Item 35)

See Section 6.2.

B.5.1.3. External Corrosion Growth Rate Data (Item 36)

The correlation of MFL assessments (2012 to 2017) for the three El Paso lateral segments; 8-inch El Paso to Chevron, 8-inch Kinder Morgan Flush Line, and 12-inch El Paso to Kinder Morgan; resulted in 11 data pairs (three external and eight internal). External CGRs were not calculated due to too few data pairs available to support confidence in a normal distribution.

B.5.1.4. Internal Corrosion Coupon Results (Item 37)

Internal corrosion coupon reports were reviewed at 13 locations along the Longhorn system. The internal corrosion coupons are evaluated three times per year with a not-to-exceed of 4.5 months between surveys. The 13 locations sampled with coupons were: the 8-inch Odessa lateral at Crane; the 8-inch Plains lateral at El Paso; the 12-inch Centurion Delivery at Crane; the 16-inch Advantage Delivery at Crane; the 16-inch Plains WTI Delivery at Crane; the 16-inch Plains WTS Delivery at Crane; one at each of the following 18-inch stations: Cartman, Cedar Valley, and Satsuma; the 18-inch mainline at El Paso; one each on the 20-inch line at East Houston ML and Speed Junction Manifold; and at the 24-inch Tank Manifold at Crane. Little to no corrosion was observed on the internal corrosion coupons and one coupon was reported as being lost in the mail. Table B-5 shows the results from the internal corrosion coupons.

Table B-5. Internal Corrosion Coupon Results

Pipe OD (in)	Location	Line Designation	Coupon Number	Inserted	Removed	Exposure (days)	Rate (MPY)	Comments
Crude Line								
20	Speed Jct	Speed Jct Manifold from East Houston (6643)	G3841	12/30/2016	4/14/2017	105	0.00	
20	Speed Jct	Speed Jct Manifold from East Houston (6643)	H4179	4/14/2017	8/18/2017	126	0.03	
20	Speed Jct	Speed Jct Manifold from East Houston (6643)	H0406	8/18/2017	12/12/2017	116	0.01	
20	E. Houston	East Houston ML (6645)	U4326	12/28/2016	4/28/2017	121	0.00	
20	E. Houston	East Houston ML (6645)	U4321	4/28/2017	8/18/2017	112	0.01	
20	E. Houston	East Houston ML (6645)	U8823	8/18/2017	12/14/2017	118	0.03	
18	Satsuma	Satsuma Station ML (6645)	G2928	1/11/2017	4/21/2017	100	0.00	
18	Satsuma	Satsuma Station ML (6645)	H4180	4/21/2017	8/31/207	132	0.02	
18	Satsuma	Satsuma Station ML (6645)	H0410	8/31/2017	12/29/2017	120	0.02	
18	Cedar Valley	Cedar Valley Station ML (6645)	G4092	1/3/2017	4/13/2017	100	0.00	
18	Cedar Valley	Cedar Valley Station ML (6645)	H4175	4/13/2017	8/22/2017	131	0.01	
18	Cedar Valley	Cedar Valley Station ML (6645)	H0409	8/22/2017	12/14/2017	114	0.00	
18	Cartman	Cartman Station ML (6645)	G3939	12/12/2016	4/21/2017	130	0.00	
18	Cartman	Cartman Station ML (6645)	H4178	4/21/2017	8/28/2017	129	0.02	
18	Cartman	Cartman Station ML (6645)	H0408	8/28/2017	12/12/2017	106	0.02	
24	Crane	Tank Manifold at Crane	G4122	12/27/2016	4/26/2017	120	0.00	
24	Crane	Tank Manifold at Crane	H4181	4/26/2017	8/18/2017	114	0.02	
24	Crane	Tank Manifold at Crane	H0397	8/18/2017	12/4/2017	108	0.01	
16	Crane	Plains WTI – Delivery to Crane	S7882	12/27/2016	4/25/2017	119	0.00	
16	Crane	Plains WTI – Delivery to Crane	U4319	4/25/2017	8/18/2017	115	0.03	
16	Crane	Plains WTI – Delivery to Crane	U8821	8/18/2017	12/4/2017	108	0.11	
16	Crane	Plains WTS – Delivery to Crane	U4323	12/27/2016	4/25/2017	119	0.00	
16	Crane	Plains WTS – Delivery to Crane	U4329	4/25/2017	8/18/2017	115	0.01	
16	Crane	Plains WTS – Delivery to Crane	U8824	8/18/2017	12/4/2017	108	0.02	
12	Crane	Centurion – Delivery to Crane	U4322	12/27/2016	4/25/2017	119	0.00	
12	Crane	Centurion – Delivery to Crane	U4328	4/25/2017	8/18/2017	115	0.03	
12	Crane	Centurion – Delivery to Crane	U8830	8/18/2017	12/4/2017	108	0.03	
16	Crane	Advantage – Delivery to Crane	U4389	12/27/2016	4/25/2017	119	0.00	
16	Crane	Advantage – Delivery to Crane	U4317	4/25/2017	8/18/2017	115	0.00	
16	Crane	Advantage – Delivery to Crane	U8817	8/18/2017	12/4/2017	108	0.01	
Refined Line								
8	Crane	8” Odessa to Crane (6648)	U4390	102/27/2016	4/26/2017	120	0.00	
8	Crane	8” Odessa to Crane (6648)	U4318	4/26/2017	8/18/2017	114	0.00	
8	Crane	8” Odessa to Crane (6648)	U8818	8/18/2017	12/4/2017	108	0.01	
18	El Paso	18” Mainline (6645)	N0158	1/3/2017	4/19/2017	106	0.00	
18	El Paso	18” Mainline (6645)	N0048	4/19/2017	8/16/2017	119	0.00	
18	El Paso	18” Mainline (6645)	N0043	8/16/2017	12/15/2017	121	0.00	
8	El Paso	8” Plains Outbound (6650)		1/3/2017	4/19/2017	106	0.00	
8	El Paso	8” Plains Outbound (6650)		4/19/2017	8/16/2017	-	-	Lost in mail
8	El Paso	8” Plains Outbound (6650)		8/16/2017	12/15/2017	121	0.00	

B.5.1.5. Line Pipe Anomalies/Repairs (Item 43)

A number of potential integrity threats were addressed in 2017. These included investigations (anomaly and 3rd party), new buried and overhead line crossings, ROW repair, road crossings, line removal, and pipeline recoats. Table B-6 lists the 135 maintenance reports received and includes the 42 PMI reports.

Table B-6. Maintenance Report Items

Maintenance Report Items	Number
3rd Party Investigation	1
3rd Party Encroachment	4
Unauthorized 3rd Party Encroachment	2
Anomaly Investigation	73
Concrete Cap	2
Corrosion Cut Out	0
Dent Cut Out	0
Foreign Line Crossing	31
Remove Foreign Line Crossing	1
Fix Pipeline Marker	0
Lease Road Crossing ROW	2
New Fence and Gate Across ROW	2
New Fiber Optic Cable Crossing ROW	2
New Irrigation Ditch Crossing ROW	1
New Overhead Powerline Crossing ROW	7
POE Investigation	0
Positive Material Identification	42
Road Repair	1
Recoat and Backfill	1
Repair Lease Road	2
Pipeline Maintenance	1
Pipeline Recoat	1
Valve Replacement	1

B.5.1.6. All ILI Metal Loss and Deformation Related to Line Pipe Anomalies (Item 44)

See Section B.3 above.

B.5.1.7. All ILI Pipe Wall Deformation, Out-of-Roundness, 3D Location Related to the Threat of Third-Party Damage (Item 45)

See Section B.3 above.

B.5.1.8. 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 B.3 above.

B.6. Fault Movement Surveys and Natural Disaster Reports

B.6.1.1. Pipeline Maintenance Reports at Fault Crossings (Item 30)

Semi-annual fault displacement monitoring reports were received covering the fault crossings in 2017. The reported measurements at the Oates Fault on 12/13/2017 were incorrect in the Second Half 2017 Semi-Annual Fault Displacement Monitoring Report dated January 2018. The corrected values were provided later by Geosyntec Consultants in an email to Magellan and Kiefner on 11/13/2018.

B.6.1.2. Periodic Fault Benchmark Elevation Data (Item 31)

Semi-annual fault displacement monitoring was performed on June 27, 2017 and December 13, 2017 which covers semi-annual fault measurements at the seven fault monitoring sites from inception in mid-2004[18] through December 2017.

B.6.1.3. Waterway Inspections

Beginning in 2016, scour inspections were replaced by annual waterway inspections. The waterway inspection reports were provided for five river crossings, including the Colorado River, Pin Oak Creek, Cypress Creek, Greens Bayou, and Brazos River. All of the inspections were conducted in September 2017.

B.6.1.4. Flood Monitoring

Flood monitoring spreadsheets were received for the Colorado River, Pin Oak Creek, and Pedernales River. The Colorado River exceeded its flood stage on August 28, 2017. The Pin Oak Creek exceeded its flood stage during August 27-29, 2017.

B.7. Maintenance and Inspection Reports

B.7.1.1. Depth-of-Cover Surveys (Items 19 and 27)

No new pipe exposures were identified in 2016. Four sites that have been actively managed under the Outside Forces Damage Prevention Program in accor\dance with the SIP were repaired after additional erosion was found. There was no third-party damage found at any of the remediated locations.

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[18] The monitoring started in mid-2012 for three faults passed by the 2012 constructed pipeline connecting the existing Longhorn line to East Houston.

B.7.1.2. Seam Anomaly/Repair Reports Related to Fatigue Cracking of EFW and ERW Welds, and Seam Anomalies (Items 33 and 34)

None found.

B.7.1.3. Mechanical Integrity Inspection Reports (Item 46)

Kiefner received and reviewed Magellan's Mainline Valve Inspection Procedure (7.13-ADM-1035) which establishes the process for DOT mainline valve inspections in accordance with 49 CFR Part 195.420. Kiefner also received the bi-annual inspection reports for 2016.

B.7.1.4. Mechanical Integrity Evaluations (Item 47)

A Preventive Maintenance Program has been established under the Mechanical Integrity Program through the use of a software database system called Enviance/CMS. 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.

Kiefner received the CMS Year End Task Report for 2017.

B.7.1.5. Facility Inspection and Compliance Audits (Item 48)

Comprehensive safety inspections of each facility are conducted 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. Manned facilities are inspected once a year; unmanned facilities are inspected every two years. Pump stations located in sensitive and hypersensitive areas are inspected every two and one-half days. 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 the following Facility Safety Reviews for 2017 listed in Table B-7.

Table B-7. Facility Safety Reviews

Facility	Manned	Tier	Inspection Date
Crane	Yes	II	10/19/2017
Texon	No	II	6/16/2017
Barnhart	No	II	6/16/2017
Cartman	No	II	9/15/2017
Kimble County	No	II	9/12/2017
James River	No	I	10/20/2017
Eckert	No	I	8/1/2017
Cedar Valley	No	II	8/2/2017
Bastrop	No	I	8/25/2017
Warda	No	I	7/18/2017
Buckhorn	No	I	7/19/2017
Satsuma	No	III	7/21/2017
El Paso	Yes	I	9/13/2017

The pump stations are remotely operated and controlled and generally are not manned. Technicians are onsite on a regular basis to perform routine maintenance and operation activities. Technicians are also on-call to respond to emergencies or other operational events at any time. Additionally, remote cameras are in place for monitoring purposes. Atmospheric Inspection surveys are conducted annually at pre-assigned above ground piping and facilities.

B.7.1.6. 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.

B.8. Project Work Progress and Quality-Control Reports

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

Table B-8. Number and Status of Action Items per Month for 2017

Action Items	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Total
New	535	496	700	754	497	565	598	503	792	811	508	688	**7447**
Completed	530	494	636	734	496	563	588	479	772	807	507	670	**7276**
Open at End of Month	5	2	64	20	1	2	10	24	20	4	1	18	**171**

B.9. Significant Operational Changes

Number of Service Interruptions per Month (Item 70)

Table B-9. Service Interruptions per Month for 2017

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Total
No./Month	1	0	1	0	0	3	1	0	1	1	2	3	**13**

B.10. Incorrect Operations and Near-Miss Reports

During 2017 there were 24 incidents within the Longhorn Pipeline System. "Incorrect Operations" is described as a failure of pipeline operator personnel to correctly follow procedures. Ten of the incidents in 2017 involved human error/incorrect operations. Cases of incorrect operations have been formally documented and investigated and corrective actions have been implemented. There were eight near miss incidents during 2017. All were ROW near misses that either involved unauthorized encroachments or one-call violations.

B.11. One-Call Violations and Third-Party Damage Prevention Data Right-of-Way Surveillance Data (Item 50)

The annual Third-Party Damage (TPD) Prevention Program Assessment contains Longhorn specific information. Data included in this assessment include the number of detected unauthorized right-of-way encroachments, changes in activity levels and one-call frequency, physical hits, near-misses, depth-of-cover, and repairs that occurred along the pipeline. Potential TPD such as dents, scrapes, and gouges detected by in-line inspection tools and maintenance activities are also part of this assessment.

Kiefner received a complete log of aerial and ground surveillance data for 2017. 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.

B.11.1.1. Third-Party Damage, Near-Misses (Item 51)

In 2017 there was one incident involving a contractor who accidently hit the pipeline during excavation to install a gas line for a new subdivision at Milepost 692 near El Paso. There was no release. There were eight ROW near-misses.

B.11.1.2. Unauthorized ROW Encroachments (Item 52)

There were 81 ROW encroachments recorded in 2017, nine of which were unauthorized.

B.11.1.3. 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 2017 TPD Annual Assessment. There were four one-call violations in 2017.

B.11.1.4. TPD Reports on Changes in Population Activity Levels, Land Use and Heavy Construction Activities (Item 54)

The 2017 TPD Annual Assessment shows a 39% increase in non-company activities from unique aerial patrol observations. There have been increased sightings pertaining to housing developments: 2% in 2016 versus 5.2% in 2017 as well as a shift in Industrial Activity versus Third-Party Activity.

B.11.1.5. 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 mile laterals from El Paso Terminal to Diamond Junction. The 3.5-mile double lateral from East Houston to MP6 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) needs to be inspected once per week (not to exceed 12 days, but at least 52 times per year). Daily patrols are also required over the Edwards Aquifer Recharge Zone (MP170.5-MP173.3) with one patrol per week to be a ground-level patrol.

To meet this requirement through aerial patrols, the pipeline ROW was flown over daily from the Pecos River to 9th Street Junction (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 for 2017 are listed in Table B-10.

Table B-10. Cumulative Miles of Patrols

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Aerial Patrol (every 2.5 days, not to exceed 72 hours)													
301: MP528 to E. Houston	10,722	12,754	12,433	13,723	15,292	15,673	14,818	13,426	13,477	15,524	13,963	10,099	**161,904**
Aerial Patrol (once/week, not to exceed 12 days)													
303: MP528 to MP694	1,320	1,056	1,056	1,056	1,056	1,320	1,056	1,320	792	1,584	1,031	689	**13,336**
Ground Patrol (once/week)													
Edwards Aquifer: MP170.5-MP173.3	25	14	6	3	6	8	14	3	22	3	14	20	**137**

Magellan was able to meet the Longhorn commitment to inspect Tier II and III areas (Segment 301) from the East Houston Terminal to the Pecos River at least every 72 hours with a few exceptions due to bad weather in January, March, August (Hurricane Harvey), and September.

Magellan was able to meet the Longhorn commitment to inspect Tier I areas from the Pecos River (MP528) to the El Paso Terminal (MP694), including the El Paso Laterals.

B.11.1.6. Number of Pipeline Signs Installed, Repaired, Replaced by Month (Item 57)

Table B-11. Markers Repaired or Replaced[19]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
No. Repaired or Replaced	6	10	3	2	1	9	17	16	6	64	56	4	194

B.11.1.7. 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 include the following activities:

- Annual Mailings
- Emergency Response / Excavator Meetings
- Door-to-Door Program
- Face-to-Face Liaison Meetings
- Public Official Program
- School Program
- Public Events
- Ads / Public Service Announcements
- Website Information

Table B-12 shows the number of educational and outreach meetings held in 2017.

[19] Mitigation Plan Scorecard 2017

Table B-12. Educational and Outreach Meetings[20]

EVENT	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Emergency Responder / Excavator Meetings	14	12	11	11	11	11	11	11	11	25	30	30	16
School Program:													
School Program - Houston	2	2	3	4		6	5	6	1	3	4	4	5
School Program - Austin	3	2	7	3	4	3	4	5	5	2	2	2	3
Texas Statewide School Pipeline Safety Outreach													16
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	30	36	36	24

NOTE: Public meetings were tallied for the years 2005-2017 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.
* Refer to the TPD Annual Assessment for details.

[20] 2017 Longhorn.com Stats.pdf

B.11.1.8. Number of One-Calls by Month by Tier (Item 59)

The number of reported one-calls by month and by tier for 2017 is listed in Table B-13 below.

Table B-13. Number of One-Calls by Tier[21]

Tier	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
I	439	420	518	463	494	500	432	467	456	511	435	484	**5,620**
II	928	812	802	669	682	564	718	836	847	783	686	612	**8,940**
III	252	249	263	206	215	184	217	261	276	259	217	194	**2,793**
Total	**1,619**	**1,481**	**1,583**	**1,338**	**1,391**	**1,248**	**1,368**	**1,564**	**1,579**	**1,554**	**1,338**	**1,290**	**17,353**

B.11.1.9. 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.

B.11.1.10. Number of Website Visits to Safety Page by Month (Item 61)

The number of visits to the safety section of the website per month during 2017 is shown in the following table.

Table B-14. Number of Website Visits

Page Name	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec	Total
Safety/Environment	181	74	88	101	122	150	119	110	149	157	126	98	1475
Pipeline Safety	288	135	163	186	156	179	171	136	152	175	164	367	2272
Call Before You Dig	69	45	59	74	72	31	65	50	39	63	59	68	694
Call Before You Dig Video	No longer host the video. Magellan links to Common Ground Alliance hosted video.												
System Integrity Plan	156	117	122	117	108	85	128	103	117	122	130	103	1408
Longhorn Info.	427	492	371	355	333	286	456	413	440	394	430	277	4674
Pipeline Emergencies	0	0	0	0	61	51	97	75	81	90	61	104	620
Home Page – 811	No longer a trackable link.												

B.11.1.11. Number of ROW Encroachments by Month (Item 67)

The number of ROW encroachments during 2017 is shown in the following table. The Annual TPD Report identified 73 encroachments, 9 of which were unauthorized.

[21] Third-Party Damage Report for 2017

Table B-15. Table of ROW Encroachment by Month

Encroachments	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Authorized	5	11	6	5	3	14	6	6	5	4	6	2	73
Unauthorized	1	0	2	2	1	2	0	1	0	0	0	0	9
Total	**6**	**11**	**8**	**7**	**4**	**16**	**6**	**7**	**5**	**4**	**6**	**2**	**82**

B.11.1.12. Number of Physical Hits to Pipeline by Third Parties, by Month (Item 68)

There was one third-party incident involving a hit to the pipeline by a backhoe in 2017. It involved a contractor boring for gas service to a new subdivision. It did not result in a release.

No physical hits were reported from 2012 through 2016. Two physical hits to the pipeline requiring coating repair were reported in 2011, while no physical hits were recorded in the previous five years from 2006-2010.

B.11.1.13. Annual TPD Assessment Report (Item 71)

The Longhorn System 2017 Annual Third-Party Damage Prevention Program Assessment (TPD Annual Assessment) was received in August 2017. Much of the data received in this report are used to summarize other parts of Sections 3.5 and 6.6 on third-party damage prevention.

B.11.1.14. One-Call Activity Reports (Item 72)

A summary of one-call activity by month is supplied in Table B-16 below as extracted from the 2017 TPD Annual Assessment. Results show that 17,353 one-call notifications were made.

Table B-16. One-Call Activity by Month

Month	One-Call Clear	Field Locate	Total Tickets
Jan	764	314	1619
Feb	744	215	1481
Mar	858	243	1583
Apr	746	223	1338
May	762	263	1391
Jun	593	243	1248
Jul	611	307	1368
Aug	672	352	1564
Sep	779	322	1579
Oct	638	357	1554
Nov	513	285	1338
Dec	512	297	1290
Totals	**8,192**	**3,421**	**17,353**

B.12. Incident, Root Cause, and Metallurgical Failure Analysis Reports

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 four categories, Near-Miss, Minor, Significant, and Major Incidents.

Kiefner received incident data and investigation reports for 24 incidents along the Longhorn Pipeline System for 2017. In summary, there were:

- 13 minor, 2 significant, 1 Major, 8 ROW near-misses
- 3 physical hits (1 involved a DOT-reportable release)
- 10 caused by human error / incorrect operations
- 1 equipment failure (o-ring leak)
- 1 internal corrosion (8-inch bypass relief line)
- 4 one-call violations
- 5 unauthorized encroachments

There were three DOT-Reportable incidents[22]:

- 1/23/2017: James River Station, Sump Overfill (Significant)
  - Magellan technician failed to close pig trap drain valves allowing crude oil to flow to sump and overfill (12 bbls).
  - Root Cause was a failure to follow procedures.
- 7/13/2017: Bastrop Station Pipeline Strike during Maintenance Activity (Major)
  - Magellan contractor excavating equipment hit mainline pipe tap during maintenance (2,084 bbls crude oil released).
  - Root Cause was reported to be insufficient excavation practices.[23]
- 12/13/2017: Satsuma, Release at Receiver Trap Bypass Relief Line (Significant)
  - Internal corrosion on 8-inch bypass relief line (28 bbls crude oil released).
  - Magellan developing procedure to periodically flush relief lines in crude service.

[22] **DOT-Reportable Requirement.** 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.
[23] There was an incident investigation by an outside source that was not available for review due to legal reasons.

There were no metallurgical failure analyses conducted during 2017.

B.13. Other LPSIP/Risk Analyses, Evaluations, and Program Data

The objective of Magellan's Scenario-Based Risk Mitigation Analysis (SBRMA) program is to identify preventive measures and/or modifications that can be recommended that would reduce the risks to the environment and the population in the event of a product release.

Magellan's probabilistic risk model utilizes integrated data and incorporates a dynamic segmentation process to maintain adequate resolution and avoid mischaracterization or loss of detail. The risk measurement methodology includes Probability of Failure (PoF) threshold management to manage pipeline integrity and evaluate risk in accordance with 49 CFR 195.452. The PoF measurement integrates all available information about the integrity of the pipeline. This integration aids in identification of preventive and mitigative measures to protect areas along the pipeline. Magellan is committed to maintaining at or below 1×10^{-4} (0.0001) failures (PHMSA reportable incidents) per mile-year at all locations along the non-facilities portions of the pipeline.

The pipeline risk model was updated with information from operations in 2017 and executed. Results show no areas along the pipeline with PoF greater than 1×10^{-4} failures and as such supports the effectiveness of Magellan's existing Integrity Management Program (IMP). No additional mitigative measures are required or recommended at this time.

Magellan's pipeline risk model is updated periodically as new information becomes available.

The LMP requires that all changes on the Longhorn system "be evaluated using an appropriate hazard analysis (HAZOP, What-if, LOPA etc.)." The Magellan Management of Change Recommendation (MOCR) form includes a yes / no checkbox to indicate whether a PHA is required, and Magellan's procedures provide that the asset integrity engineer should determine the appropriate PHA methodology for change requests.

PHAs are also conducted on a five-year interval to evaluate and control the hazards involved with the facilities. Three PHAs were completed in 2017, which included the Eckert and Warda Pump Stations, and the mainline valves.

B.14. Major Pipeline Incidents, Industry, or Agency Advisories Affecting Pipeline Integrity

B.14.1.1. PHMSA Advisories

There were none that were applicable to the Longhorn Pipeline during 2017.

B.14.1.2. DOT Regulations

No new regulations affecting the Longhorn ORA occurred in 2017.

B.16. Literature Reviewed

See references.